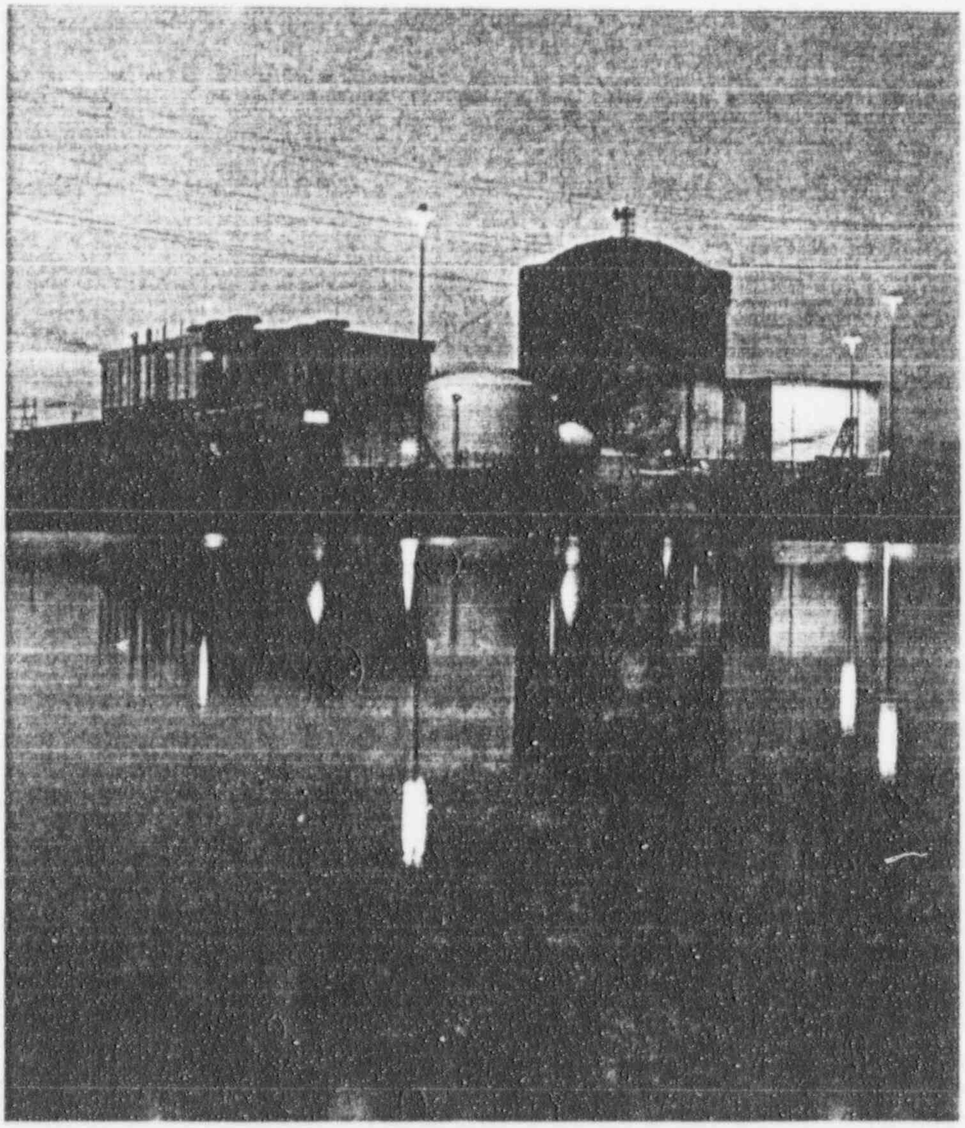
SCE&G

V. C. Summer Nuclear Station



Individual
Plant Examination
for
Severe Accident
Vulnerabilities

RESPONSE TO NRC QUESTIONS
1996

Prepared by:

South Carolina Electric & Gas Company

RESPONSE TO THE NRC REQUEST

FOR ADDITIONAL INFORMATION

ON THE VCSNS IPE

MARCH 1996

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A. FRONT-END ANALYSIS QUESTIONS

1) Please discuss the availability of the turbine-driven emergency feedwater (EFW) pump after battery depletion in a station blackout (SBO). The discussion should include the environmental conditions that may affect the controlling equipment and the operator, where long lasting manual control is assumed to be exercised (e.g., in the EFW room). Explain how emergency feedwater flow is controlled under these conditions. Please discuss the impact of your assumptions regarding EFW pump control on core damage frequency (CDF).

Response

The turbine-driven emergency feedwater (TDEFW) pump is designed to continue to operate, without compressed air or DC power. The governor on the turbine is reverse acting such that a loss of air input will cause the TDEFW pump to fail to the maximum speed setting. The transducer which converts the 4-20 mA instrument signal into the 3-15 PSIG pneumatic signal is direct acting such that a loss of power will fail the air signal to minimum, also resulting in maximum speed. This feature is tested during a periodic surveillance test by failing the air input signal at the transducer, and verifying that the TDEFW pump settles at the high speed setting without tripping. Significant margin exists between the high speed setting(4150 $\pm$ 50 RPM) and the overspeed trip setpoint(5060 RPM). This margin provides additional assurance that the TDEFW pump will continue to operate after a loss of DC power or compressed air.

The VCSNS SBO Coping Study evaluated the ability of the TDEFW pump and the required equipment in the TDEFW pump room to cope with a loss of HVAC. This equipment is expected to operate at higher peak temperatures than are predicted for SBO operation. Since the SBO room heat-up analysis provided a final *steady-state* room temperature, operation beyond the four hour SBO coping window should not result in failure. The operator is <u>not</u> required to enter the TDEFW pump room to take local control of the pump. TDEFW flow control is accomplished by locally throttling the flow control valves, located in an open area above the TDEFW pump room.

The EFW to Steam Generator flow control valves (FCVs) for the TDEFW pump are air operated, normally open, fail open valves with handwheels for local control if air, or DC power is lost. The valves are provided with individual air accumulators sized to ensure isolation capability, but not long-term modulation capability in the event air is lost. As will be discussed in response to question 2.d, a non-safety diesel powered air compressor is started per EOP-6.0, "LOSS OF ALL AC ESF POWER", if available. Without compressed air or after DC power is lost, local control of the TDEFW FCVs will be required.

All three TDEFW FCVs are located in an easily accessed, open area of the Intermediate Building. This area has multiple emergency lighting units with 8 hour rated batteries. Emergency tool kits are located throughout the plant that contain flashlights which could be used as backup sources of light if the blackout extended beyond 8 hours. The emergency lights and toolkits are Appendix "R" related. Since the TDEFW FCVs are not located in the TDEFW pump room, the temperature in the open IB area should not impede valve operation.

During the initial phase of an SBO, local operation of the TDEFW FCVs would be established if compressed air was not available. The valves would be positioned while communicating with the control room using hand held radios. The control room would use SG level and/or EFW flow indication to determine the need for EFW flow adjustment. If the SBO extended beyond the rated four hour capacity of the vital batteries, SG level indication would eventually be lost. It is important to note that the batteries are expected to last well beyond the four hour rating. The battery duration calculation includes degradation for battery aging, minimum connected cells, temperature variations, and maximum load. The calculations <u>do not</u> take credit for procedurally directed load shedding of parasitic non-essential loads which would extend battery life. However, the batteries will eventually be exhausted at some point beyond four hours. When DC power and SG level indication are lost, the reactor decay heat level will be slowly falling such that a constant TDEFW FCV position will result in a gradual overfill. Since only 1 of 3 SGs is required to provide adequate heat removal, this should not lead to a complete loss of heat sink.

The VCSNS IPE SBO event tree includes a top event to address the need for TDEFW flow to continue to operate beyond four hours. This top event, Emergency Feedwater Continues(EFC), includes the probability of the TDEFW pump continuing to run, <u>and</u> an operator action to manually control EFW flow locally at the FCVs. This operator action is a Job Performance Measure(JPM) performed approximately once every two years during Appendix "R" training. In the SBO event tree, if TDEFW flow is lost at four hours, core damage is assumed to occur within the next two hours if power is not restored. If power is restored between the fourth and sixth hours, additional high head injection capacity is required to prevent core damage. The "EFC" value was increased by a factor of 100 to determine the impact on CDF. The result yielded less than a 2% increase in CDF.

2) At this plant, the SBO contribution to the total CDF is about 21%. It is not clear from the submittal if plant changes due to the SBO rule were credited in the analysis. Please provide the following information:

a. Report whether plant changes (e.g., procedures for load shedding, AC power) made in response to the SBO rule were credited in the IPE and which specific plant changes were credited.

b. If available, give the total impact of these plant changes to the total plant CDF and to the station blackout CDF (i.e., reduction in total plant CDF and SBO CDF).

c. If available, give the impact of each individual plant change to the total plant CDF and the SBO CDF (i.e., reduction in total plant CDF and SBO CDF).

d. Report any other changes to the plant that are separate from those strictly in response to the SBO rule, that nonetheless may reduce the SBO CDF. In addition, report whether these changes are implemented or planned, report whether credit was taken for these changes in the IPE, and, if available, discuss the impact of these changes to the SBO CDF.

Response

a.) The original vital batteries did not have sufficient capacity to cope for four hours without stripping non-essential loads. VCSNS was categorized as a four hour coping plant in accordance with Regulatory Guide 1.115, "Station Blackout". A plant modification (MRF-21595) was performed to extend battery capacity beyond the four hour requirement without the need for operator action to strip loads. The SBO event tree does assume a four hour battery capacity. No other plant modifications were required to cope with an SBO.

b.) Since the changes required to cope with an SBO were minor, and completed well before the IPE "freeze" date, no sensitivities have been performed.

c.) As in the answer to question 2.b above, no sensitivities were done on any specific SBO equipment enhancements. The changes that have probably had the greatest impact on our ability to cope with an SBO, other than the battery capacity increase, are in the areas of training, and procedures. The Emergency Operating Procedures used to mitigate an SBO event are reviewed in licensed operator requal(LOR) frequently. The training involves both simulator drills, and in-plant JPMs on required local actions. Recovery of either onsite emergency DG is not credited in the SBO event tree. In reality, a high percentage of DG failures could be repaired prior to core damage. Actions such as local starting of a failed DG, which is one of the SBO related JPMs, is not credited in the IPE. Loss of offsite power is also a frequent scenario during site wide Emergency Plan Drills. These drills include trouble-shooting and repairing failed DGs, and restoration of offsite power.

d.) A diesel driven "Sullair" air compressor is available for manual start if no other permanent air compressors are available. This compressor is only credited in the Loss of Instrument Air(IA) initiator, where it must be manually started and valved in to the permanent IA header. Although no credit was taken for the compressor preventing a reactor trip, since too much time may be required to put it in service, it was credited for subsequent control of air operated valves post-trip. The human error analysis highlighted the importance of the timing aspect of putting the diesel Sullair in service. The operator must start the air compressor in the yard on the 436' elevation, and then go to the 412' elevation of the turbine building to open an isolation valve(which may require a ladder). Based on PRA group input, the normal position of the isolation valve in the turbine building was changed to "open" to allow quicker operator response on a loss of IA event. If the diesel driven air compressor was credited in the SBO event tree, some improvement would be expected since air operated valves used to control EFW flow and atmospheric steam dump could be controlled directly from the control room until the station batteries were depleted. The diesel air compressor is available for use, but is not credited in the IPE or current PRA for events other than the "Loss of IA" initiator.

In response to requirements in the Maintenance Rule(10CFR50.65), risk significant systems and components will be monitored to detect trends in reliability and availability. Cumulative component/system availability, and reliability targets have been set with PRA input as triggers to require additional review, and possible corrective action. The areas that are being monitored include many SBO sensitive components/systems such as:

- Vital Batteries
- Vital AC Buses
- Switchyard components related to 1E Offsite sources
- ESF Load Sequencer
- Vital Inverters
- Turbine Driven EFW Pump
- Emergency Diesel Generators(EDGs)

As an example, the recommendation for reliability of the EDGs is more restrictive than the commitment in the SBO coping analysis.

Another "by-product" of the Maintenance Rule is the Safety Function Matrix. This matrix provides guidance to the operations and scheduling groups with respect to on-line maintenance configurations. The goal of the matrix is to optimize when corrective maintenance is allowed based on current plant conditions. This matrix requires management approval for configurations that could be precursors for serious events. The items that are restricted, and related to SBO sequences, include combinations of:

- Turbine Driven EFW Pump and Main Steam Supply
- Condensate Storage Tank
- Emergency Diesel Generators(EDGs)
- Service Water
- Vital AC Power
- Severe Weather
- Switch Yard work
- Sullair Diesel Instrument Air Compressor

Both Maintenance Rule items, risk significant system performance monitoring and the safety function matrix, are being finalized to allow completion by July of 1996. No specific PRA analysis has been done to quantify the cumulative benefits, nor were they credited in the IPE.

3) It appears that losses of AC buses were not included as initiating events. Please explain the basis for screening these initiators, and provide an estimate on the impact on the CDF and important accident sequences if they were included.

Response - An initiating event is any occurrence that disrupts normal plant operation enough to require a reactor trip, either automatically or manually. NUREG/CR-3862 (Reference 1) provides a grouping of plant transient events. PWR Category 36 is the loss of power to necessary plant systems. This transient occurs when power is lost to a component or group of components such that plant shutdown is necessary. It does not include loss of power to those components whose failure causes another defined transient to occur.

During the electric power system analysis, loss of the various AC and DC buses and panels were examined to determine the effect on the plant. If a loss of a set of buses/panels led directly to a plant trip it was included as an initiator. If the bus/panel loss impacts other systems which would then cause a plant trip, that is, it would indirectly cause a plant trip, then the loss of these buses/panels were included as an initiator through the affected system. This approach identified the loss of the 120 VAC panels and loss of one 125 VDC bus as initiators. The following discusses the reasons other AC buses were not included as initiators.

Loss of ESF AC Buses

The V.C. Summer Nuclear Station has two emergency AC power trains, XSW1DA and XSW1DB, which power the critical safety equipment. Normally operating equipment powered by Bus XSW1DA includes the A train charging pump, component cooling water pump, chilled water pump, and service water pump. Bus XSW1DB services the B train pumps in those systems. The C train pumps can be powered from either bus. Normally, only one train of equipment is operating with the other train in standby, except for service water which has two trains normally operating.

If power is lost to the emergency bus with the operating equipment, the train connected to the other bus is available. No reactor trip is required unless the other ESF bus is lost (which would be bounded by the station blackout accident) or the other train of safety equipment does not function. The swing pumps of the systems can be aligned to either power bus and thus provides another means to provide the necessary equipment. Because this event does not cause a reactor trip and it is bounded by the station blackout accident, it is not quantified as a special initiator.

For a loss of offsite power, the failure of both ESF buses is considered in the determination of a station blackout condition given, however, the failure probability of both emergency buses is an insignificant contributor compared to the failure of the diesel generators.

With offsite power available, a special initiating event for the loss of both emergency buses was not included in the model. In this case, the loss of both emergency buses is similar to the station blackout scenario, with the exception that the non-ESF buses could be available. Therefore, the station blackout condition is more limiting. In addition, the initiating event frequency would not be significant compared to the station blackout frequency. This is demonstrated by comparing the diesel generator unavailability contribution to the loss of both emergency AC buses. The frequency for station blackout events equals the LOSP frequency x emergency AC bus unavailability, which equals 7.3E-02/yr x 9.1E-03 = 6.6E-04. (7.3E-02/yr is from IPE Submittal Table 3.1.1-1, 9.1E-03 is from IPE Submittal Table 3.3.5-1). With offsite power available (diesel generators not modeled), the probability of losing both emergency buses is 2.32E-07 (VCSNS IPE Submittal Table 3.3.5-1). With a loss of offsite power (diesel generators modeled), the probability of losing both emergency buses is 9.10E-03. The contribution of the failure of both buses is negligible. Although the failure of both ESF buses was not modeled as an initiating event, it is modeled as a potential failure in the AC power support state model for all other initiating events.

In summary, the loss of one ESF bus is not included as an initiator since it does not lead to a reactor trip. For a loss of offsite power event, the loss of both ESF buses is included in the analysis. As noted above, the impact on core damage frequency of explicitly including the failure of both ESF buses (with offsite power available) as an initiating event is negligible.

Loss of Non ESF AC Buses

The loss of a non-ESF electrical bus was not included as a separate initiating event. The loss of a non-ESF bus does not have an effect on the systems required for safe shutdown. It does affect the availability of some equipment modeled in the VCSNS IPE, for example, instrument air and main feedwater. Both of these events are included in the IPE as initiators. Loss of non-ESF buses is included in the determination of the frequency for these initiators via fault tree analysis for the loss of instrument air initiator and via plant trip experience for the main feedwater and other such initiators. Therefore, the losses of non-ESF buses were not modeled as separate initiating events, consistent with the Category definition 36 in Reference 1 below, but are included through their effect on other systems that can cause a plant trip.

References:

1. NUREG/CR-3862, "Development of Transient Initiating Event Frequencies for Use in Probabilistic Risk Assessments", Idaho National Engineering Laboratory, May 1985.

4) A review of the common cause failure (CCF) analysis in the IPE (pages 3-156, 3-157) indicates that some components, in spite of their importance, were not analyzed or apparently included in "the generic component, All."

a. Provide an explanation of the notion "generic component, All" in deriving multiple Greek letter (MGL) parameters for components as diverse as check valves, chillers, or fans.

b. Provide the reasons why the same MGL parameters are used for the various failure modes (e.g., failure to run and failure to start) of various components.

c. Provide the basis for the omission of the following components from the CCF analysis or for their inclusion into "the generic component:" circuit breakers (AC, DC, reactor trip breakers excluded); relays (engineered safety features actuation system (ESFAS)); and electrical switchgear.

d. Please discuss the impact of the above assumptions on the CDF, dominant accident sequences, and your conclusions regarding plant vulnerabilities.

e. Provide a discussion of how the common cause losses of AC and DC buses were treated as initiating events.

Response

a. and b. The Multiple Greek Letter (MGL) parameter factors for common cause failures did not differentiate between failure modes and did use the generic "All" values for some components for a number of reasons.

Two resources were used as the basis in the formulation of MGL common cause factors used in the VCSNS IPE: NUREG/CR-4780 "Procedures for Treating Common Cause Failures in Safety and Reliability Studies" (Reference 1) and EPRI NP-3967 "Classification and Analysis of Reactor Operating Experience Involving Dependent Events" (Reference 2). The MGL factors were calculated using the failure event data from EPRI NP-3967 for all components except chillers, fans, and check valves. Data having a screening category of "C" designating common cause events applicable to parametric modeling, and a number of linear single event failures mapped up from a two component to a four component system, were used for the calculations. The values of beta used for chillers, fans, and check valves comes from NUREG/CR-4780. No values were available for gamma or delta for these components, so a value equal to the value for the average of all component failures was used.

When the MGL factors used in the VCSNS IPE were determined, the EPRI common cause event data base was in an interim state (draft 1990 document). The data base was documented in a report EPRI NP-3967 issued in June 1985 and was later updated and issued in April 1992. The results of this study produced tables of "Generic Beta Factors" to be used in common cause calculations with no delineation with respect to specific failure modes.

NUREG/CR-4780, in Table 3-7 "Event Classification & Analysis Summary" on page 3-58, did not split out the "generic beta factors" by failure mode. As stated on page 3-57:

> "The Table 3-7 values of the beta factor include both failures to start on demand and failure to run for all components except breakers and valves. Hence, they represent an average of these modes weighted by their relative frequency of occurrence."

At the time of the VCSNS IPE analysis, only limited common cause data existed that had been compiled into a usable form. Due to the limited data, breakdown of common cause further into failure modes, or introducing new component groups, was deemed to be speculative and detrimental to realistic modeling of common cause. Also note that screening the EPRI data base for applicability of specific common cause events to VCSNS was not performed. Therefore, the MGL factors used for VCSNS would, overall, be more conservative because some of the events in the data base may not have been applicable to VCSNS. Thus, for the VCSNS IPE study, a single set of MGL parameters was applied to a component group. Given the scarcity of data on which to base failure mode specific MGL parameters, the approach was taken to group all failure modes. The MGL calculation approach taken for the VCSNS IPE represented a reasonable approach given the data available at the time.

The common cause quantification captures all the major component groups and parameters used in the calculations and adequately represents the weight of common cause failures. Thus, the models are suitable to identify both the outlier accident sequences and the dominant contributors to plant risk.

c. Common cause failures of electrical components such as circuit breakers, relays, inverters, logic circuits, batteries, and switchgear were explicitly modeled in the system fault trees. The components chosen for common cause failures were determined by quantifying the system fault trees without common cause failures and examining the cutsets to identify which cutsets may be susceptible to common cause failures. A calculation was then performed to determine the common cause contribution from each cutset. In addition, the fault trees and results were reviewed for non-minimal cutsets and the appropriate common cause contribution was calculated for these. The total common cause contribution was then added to the unavailability from the fault tree quantification. Although the EPRI database did not provide any generic experience for these types of components, it was recognized that common cause failures of these components could influence the system unavailability. As discussed in the response to parts a and b, because specific data for these components was not available at the time, the generic MGL factors were used in the common cause calculations. Using the generic values, common cause failures of these types of components were dominant contributors to the two train unavailabilities for the electrical power system (AC and DC), the reactor protection system, and the engineered safety features actuation system. A review of the system fault tree cutsets showed that this would still be the case if the common cause contribution was reduced by more than an order of magnitude.

d. The contribution of common cause failures to the total CDF was determined by performing a sensitivity quantification in which the common cause failure basic events were set to 0.0. The core damage frequency decreased by approximately 30%. This demonstrates that common cause failures, as a group, are important contributors to the VCSNS CDF. The sensitivity CDF quantification results are very similar to results documented in the VCSNS IPE submittal. The loss of offsite power initiating event sequences are major contributors to the CDF. These sequences, like those in the IPE submittal, involve a loss of offsite power with a subsequent failure of all onsite power (station blackout) or other combinations of system failures that degrade RCP seal cooling and eventually result in a RCP seal LOCA. The top 11 sequences in the sensitivity quantification are the same as those in the IPE submittal, with the order switched around some due to the effects of setting the common cause failures to 0.0. In addition, most of the sequences which contributed 1% or more to the IPE submittal CDF (IPE submittal Table 1.4-2) are the same as those which contribute 1% or more to the sensitivity CDF. Those sequences which are different in the sensitivity quantification did not significantly move up in the sequence list. Based on the results of the sensitivity analysis, it is concluded that even with the large change of setting the common cause failures to 0.0, the CDF results are similar enough to those in the IPE submittal such that the vulnerabilities and conclusions reached in the IPE submittal would not significantly change. Therefore, changes in the MGL factors used, if specific factors were available for all components and failure modes, would be much less than those examined in the sensitivity quantification and would not alter the conclusions documented in the IPE submittal.

e. A general discussion of the initiating event screening process, and the resulting electric power failures which were considered as initiating events, is provided in the response to front end question 3. The two electric power initiating events included in the VCSNS IPE were the loss of a 125 VDC bus and the loss of two 120 VAC vital instrument panels.

For the loss of a 125 VDC bus, there were no cutsets identified for common cause failure calculations (refer to the response in "c" above for the method of identifying and including common cause failures in the fault tree analysis). The failure of both 125 VDC buses is not a minimal failure required for the initiating event, so common cause failures which would fail both 125 VDC buses were not explicitly examined. Common failures, however, would only be a fraction of the initiating event frequency for the loss of one 125 VDC bus. In addition, the loss of a 125 VDC bus contributes less than 0.1% of the CDF, therefore, postulated common failures causing the loss of both 125 VDC buses are insignificant.

For the loss of two 120 VAC panels initiating event, the fault tree analysis determined that there were no significant common cause contributors.

References:

1. NUREG/CR-4780, "Procedures for Treating Common Cause Failures in Safety and Reliability Studies," Pickard, Lowe, and Garrick, January 1988.

2. EPRI NP-3967 "Classification and Analysis of Reactor Operating Experience Involving Dependent Events," prepared for Electric Power Research Institute by Pickard, Lowe, and Garrick, June 1985.

5) Please discuss why the main feedwater (MFW) system, or parts thereof (e.g., condensate and feedwater booster pumps) cannot be credited in a small loss of coolant accident (LOCA). Are there procedures to shut off the MFW after a small LOCA and how is this modeled in the IPE? What are the associated human error probabilities (HEPs)? Why can't the MFW (or associated condensate and feedwater booster pumps) be used in the same manner as the EFW in small LOCAs?

Response

Following the initiation of a small LOCA, an automatic trip and safety injection will occur on low pressurizer pressure. The operator will enter Emergency Operating Procedure EOP-1.0, "Reactor Trip/Safety Injection Actuation" following the reactor trip. The operator will verify reactor trip, turbine/generator trip, power to both ESF buses, check if safety injection is actuated, ensure main feedwater (MFW) isolation, and ensure emergency feedwater (EFW) pumps are running, in addition to verifying several other functions are operating. The step to ensure feedwater isolation requires ensuring that the MFW flow control valves, MFW flow control bypass valves, MFW isolation valves, SG blowdown isolation valves, and SG sample isolation valves are closed, and that all MFW pumps are tripped. MFW isolation occurs automatically on an SI signal. The logic that initiates MFW isolation valve closure "seals in" such that the valves cannot be re-opened until after the reactor trip breakers are re-closed(P4 is reset). Specific operator actions to terminate main feedwater flow are not specifically modeled in the small LOCA plant response tree.

If EFW is not available, then the operator will be instructed to restore secondary heat using EOP-15.0 "Response to Loss of Secondary Heat Sink". EOP-15.0 instructs the operator to try to re-establish EFW flow to at least one steam generator. If this fails, the operator is instructed to establish feed flow from the condensate system through a condensate pump and feedwater booster pump. This requires the operator to stop all reactor coolant pumps, verify at least one condensate pump is running, ensure one feedwater booster pump is running, send an I&C crew to perform local actions to defeat feedwater isolation so that the feedwater bypass regulating valves and isolation valves can be opened, depressurize the reactor coolant system(RCS) to 1925 psig, and depressurize at least one steam generator to less than 350 psig. The local actions required by the I&C crew include installing several jumpers in two different termination cabinets, and removing a fuse in a third cabinet.

An analysis performed using the TREAT-PC Computer Code indicated that approximately 10 minutes is available to complete the action to establish feedwater flow from the condensate system prior to reaching the criteria to establish feed and bleed cooling. It was judged by plant personnel in the human reliability analysis talk-throughs that it would not be possible to complete the required actions in the time allowed. Therefore, using the condensate and feedwater booster pumps as a means of decay heat removal for small LOCAs is not addressed.

After the IPE was submitted, a modification which installed switches to allow easy bypass of the MFW isolation signal was completed. Please refer to the response to front-end question 12 for more details on this change.

6) Describe the process used to identify and account for Interfacing System LOCAs (ISLOCA). Discuss the most likely flow paths and the impact of the degradation or loss of mitigating systems due to ISLOCA.

Response

The initiating event category encompassing Interfacing Systems Loss of Coolant Accident (ISLOCA) considers the entry of fluid at normal RCS pressures into directly connected supporting systems not rated for such high pressures. Such an interfacing systems LOCA could disable the Emergency Core Coolant System (ECCS) and bypass containment. An ISLOCA can be a result of valve or piping ruptures, or valve misalignment.

ISLOCAs can be divided into two categories according to the location of the primary system coolant loss relative to containment. If the primary system coolant remains within containment during an ISLOCA, the accident is termed an ISLOCA inside containment. The limiting factor in an ISLOCA inside containment is the loss of the function performed by the breached interfacing system. Conversely, if the primary system coolant escapes the containment during an ISLOCA, the accident is termed an ISLOCA outside containment. The limiting factors in an ISLOCA outside containment are the loss of the function performed by the breached interfacing system, the failure of containment isolation, and the loss of emergency core coolant recirculation for long term core cooling. In general, the potential consequences of an ISLOCA outside containment are more severe than those of an ISLOCA inside containment, and for this reason the VCSNS IPE assumed ISLOCAs outside containment bounded those inside containment. It is noted that the frequency and potential consequences of an ISLOCA inside containment are implicitly examined during the consideration of small and medium LOCA initiating events.

The identification of potential ISLOCA (outside containment) pathways begins with the identification of all systems which interface with the RCS and may be subjected to normal RCS operating pressure. VCSNS piping and instrumentation drawings were reviewed to identify all significant ISLOCA flow paths. Significant flow paths are those with a diameter greater than 3/8 inch and through which low pressure piping outside containment could be exposed to RCS pressure. The identified flow paths are then evaluated one-by-one to determine possible mechanisms (i.e., valve disc ruptures, check valve failures, human error, etc.) which could result in RCS pressure being applied to the interfacing system. In addition, relevant piping strengths and relief valve sizing are evaluated to determine the consequences of a pressurization. For VCSNS, the following significant interfacing system flow paths were identified:

- RCP seal water return and excess letdown lines

- Containment penetrations between the RCS and centrifugal charging pump discharge header
- RHR discharge lines
- RHR suction lines

The frequency of an interfacing systems LOCA at VCSNS was calculated for each of these pathways. The ISLOCA frequency is calculated as the product of the pressure boundary failure frequency and the probability that the ISLOCA flowpath is not isolated soon after the pressure boundary failure. The VCSNS ISLOCA initiating event frequency is the sum of these four separate ISLOCA events. The initiating event frequency was dominated by the RHR suction lines, and, in addition, this pathway is generally considered to be the most severe ISLOCA due to its effect on the long term heat removal capability of the plant. Therefore, the RHR suction line ISLOCA was used for Plant Response Tree (PRT) and success criteria development.

The RHR suction ISLOCA event occurs as the result of catastrophic rupture of two motor operated valves in series (XVG-8701A and XVG-8702A, or XVG-8701B and XVG-8702B). These valves provide the pressure interface between the RCS and RHR pump suction piping. For the purposes of PRT development, it is assumed that this initiating event results in the failure of the RHR pump in the affected train. RHR pump failure can be postulated to occur due to piping failure or as a result of pump seal failure.

The sequence progression is considered via the VCSNS ISLOCA plant response tree. For either of the scenarios, RHR pump failure in the affected line due to piping failure or seal leakage, the other train RHR pump is assumed to be unaffected by the initiating event. The check valve downstream of the unaffected train's heat exchanger (XVC-8716A or XVC-8716B) and the check valve downstream of the affected train's RWST suction isolation valve (XVC-8958A or XVC-8958B) prevent any significant flow of high pressure RCS coolant to the unaffected train. Although the VCSNS ISLOCA considers each of these scenarios, the quantification of the ISLOCA assumes that the fraction of ISLOCA events that result in pipe breaks is a negligibly small portion such that the PRT will always branch to the RHR pump seal leak scenario. [Reference: IDCOR Technical Report 23.5, Evaluations of Containment Bypass and Failure to Isolate Sequences for the IDCOR Reference Plants]

Following the ISLOCA event initiation, the RHR system piping is protected by 5 relief valves, two 3-inch valves relieve to the Pressurizer Relief Tank (PRT) and three 3/4-inch valves relieve to the Boron Recycle System. The loss of primary coolant through the pressure boundary breach (relief valves and RHR pump seal) will result in RCS depressurization and subsequent reactor trip plus safety injection on low pressurizer pressure. The mass and energy release to the PRT from the RHR system relief valves will result in PRT disc rupture, and a large increase in reactor building pressure such that the reactor building spray actuation on high-3 pressure occurs. The reactor building sprays will deplete the RWST contents, and sufficient water to satisfy NPSH pump requirement for ECCS recirculation will be injected to the containment. High pressure injection will provide decay heat removal in the short term, however long term decay heat removal is compromised. The closed loop mode of operation for long term decay heat removal is disabled because the coolant level is expected to remain below the hot leg elevation (any coolant at or above the hot leg elevation is assumed to be lost through the ruptured RHR pump seal). The intact RHR train is therefore assumed to be unable to take suction from an RCS hot leg. The long term containment recirculation mode of operation is disabled by the lack of a direct pathway from the RCS to the reactor building sump after RCS pressure decreases below the setpoint of the RHR safety relief valves. To maintain core cooling for up to 24 hours, the VCSNS Emergency Operating Procedures are modeled.

The VCSNS ISLOCA PRT considers the progression through the VCSNS EOPs, including the eventual transfer to EOP-2.4, LOSS OF EMERGENCY COOLANT RECIRCULATION, Rev. 4. The necessary action from this procedure which is modeled in the ISLOCA PRT is the minimization of ECCS flow. The operators must reduce safety injection flow (recirculation flow) to the minimum required for decay heat removal in order to maintain adequate inventory for 24 hours of decay heat removal. This EOP directs the operators to regulate high pressure flow by aligning the system through the normal charging line and throttling flow via FCV-122, and using Attachment 1 and 2 of EOP-2.4, "REQUIRED INJECTION FLOW TO REMOVE DECAY HEAT VS TIME AFTER REACTOR SHUTDOWN." Finally, EOP-2.2, "TRANSFER TO COLD LEG RECIRCULATION" will result in attempts to establish ECCS recirculation once the RWST level is depleted below 18% (by the combination of injection and spray). With flow throttled, establishing recirculation via the remaining RHR pump will result in adequate decay heat removal for 24 hours; however, accident management will be necessary to establish a long term safe, stable state.

7) This question concerns your treatment of flooding. The submittal indicates that all but one flood zone were eliminated from further consideration through a qualitative analysis. The submittal describes the qualitative screening process, but it is not clear if certain assumptions were used for eliminating some zones, e.g., the three areas where "either no water sources were found or the sources were out of range of safe shutdown equipment and reactor trip components," or some rooms where no reactor trip is said to occur (e.g., the 480V switchgear room, the heating ventilation and air conditioning (HVAC) chilled water pump area, the local relay panel room, etc.). For the one area included in the analysis, the intermediate building elevation 412' general floor area, room 12-02, it is not clear if assumptions were made with respect to flow rates and flood isolation timing, effect of spray/flooding on other parts of the component cooling water (CCW) or service water (SW) system and spray/flooding effects on other safety components in the area.

The internal flooding CDF is 1.5E-6. The flooding is caused by ruptures in the SW or CCW systems in the intermediate building elevation 412' general floor area, room 12-02. Ruptures in the CCW system are calculated to occur with a frequency of 9.9E-4/yr, giving a CDF of 1.2E-6/yr, resulting in a conditional CDF (CCDP) of 1.2E-3.

For the flooding initiator loss of train A of SW (caused by SW ruptures), the initiating event frequency is 1.1E-4/yr, the CDF is 2.9E-7/yr and the CCDP is 2.6E-3; for loss of train B of SW, the IE frequency is 1.0E-4/yr, the CDF is 1.9E-8/yr and the CCDP is 1.9E-4. It should be noted that, according to the submittal, these events result in a loss of a single train of CCW or SW, with no other failures. However, if it is possible to disable the whole SW system, with no additional failures, the flooding CDF from that scenario would potentially rise, as the CCDP from the internal events analysis for total loss of SW is 0.48 (initiating event frequency of 3.6E-5/yr and CDF of 1.74E-5/yr), i.e., 2-3 orders of magnitude higher than in the flooding analysis.

Additionally, the CCDP and the CDF from all flooding scenarios might rise if additional safety equipment in the room can be affected. A statement is made that no other equipment (except for the leaking component) would be affected in the flooding scenario, because the flood water would flow into the tendon jacking area and the tendon access gallery. It should be noted that there are several safety components in the room (battery charger, CCW pumps, all motor-driven and steam-driven EFW pumps, SW booster pumps, CCW cross-connection valves). None of these components is spray protected. It is not clear if there are assumptions in the IPE regarding isolation of flooding in a certain time period to prevent these components from being flooded (i.e., assumptions regarding the flow rate vs. the capacity of the tendon jacking area and the tendon access gallery). There may also be additional assumptions made in the IPE regarding the spray effect.

a. Please describe the process addressing the zones with safety-related equipment considered, the types of flood initiators in these zones, and the frequency of the initiators. Provide enough details of your flooding analysis to understand the scenarios more fully, e.g., equipment in the room, equipment affected by the scenario, probability of total loss of SW or CCW in the one zone admitted into the flooding analysis, response of the plant, existence of any flood barriers, quantification of various components of your flood scenario, assumptions made. Discuss your consideration of drains (including backflooding to other areas and probability of failure, i.e., due to blockage), separation, doors allowing flood propagation to other areas, credit given for actions by operators to stop the flood or to mitigate the consequences and the specific criteria used to eliminate each zone.

b. Please describe your treatment of the spray effect resulting from the spurious actuation of the fire suppression equipment in your flood scenarios.

c. Discuss how maintenance errors were treated in the flooding analysis. Include errors committed while in cold shutdown, which were left undiagnosed until the flood event occurred while the unit is at power.

Response

a. The following presents and discusses the IPE flooding analysis approach:

1.0 Introduction

1.1 Methodology

The general methodology used for the internal flooding analysis consisted of the following steps:

1. A list of all components necessary for the safe shutdown of the plant was compiled from the lists provided in the Fire Protection Evaluation Report,[3] Potential Internal Plant Flooding Report,[4] and Essential Equipment List.[5] The list included the component tag number, component description, and the location of the component within the plant. Walkdown checklists showing plant rooms/areas and the safe shutdown components within those areas were prepared using this list. The Appendix R shutdown equipment was included in the overall safe shutdown list. The equipment's actual impact on safe shutdown is reviewed as required in Section 3.0.

2. Each room/area was reviewed. Those areas containing equipment whose failure would initiate a reactor trip were retained, and those areas with no potential for initiating a reactor trip were eliminated from further analysis. Only a flood/spray event in a room with both trip potential and safe shutdown equipment could lead to core damage.

3. The plant walkdown was performed. Each room/area retained from the previous step was investigated for flood/spray sources, possible effects of such sources on equipment in the room, drainage paths, etc. The information collected was entered on the walkdown checklists.

4. The completed walkdown checklists were used to perform an initial screening of the rooms/areas identified as having safe shutdown components in step 1 above. This screening eliminated the rooms with no trip potential, and no flood/spray sources. The resulting "short list" of rooms represented the only possibilities for core damage resulting from a flooding event.

5. A qualitative analysis of each room on the short list was performed. This analysis is documented in Section 3. The walkdown checklists were reviewed for each of these rooms. Various rooms were eliminated from consideration as possible contributors to core damage from flooding events based on various criteria, including:

   a) No critical components (components necessary for safe shutdown or whose failure would initiate a reactor trip) in the room are effected by either water spray or flooding.

   b) Flooding and/or spraying will cause failure of safe shutdown equipment, but will not affect components whose failure will cause a reactor trip.

   c) Flooding and/or spraying will fail components that will initiate a reactor trip, but will not cause failure of safe shutdown components.

   d) The room has sufficient drainage for any potential flooding event, and criteria a, b, or c above apply with respect to spraying.

   e) Spraying will not affect any critical components, and criteria a, b, or c above apply with respect to flooding.

   Other criteria used for this evaluation are described in Section 3, along with the aspects of each room and the specific reasons for eliminating the room from further analysis, or for retaining the room for quantitative analysis in the next step.

6. Those rooms retained from the previous step are the only ones with core damage potential. The event frequencies for flooding events in these rooms were then quantified and used to calculate associated core damage frequencies. The flooding event frequency calculations are documented in Section 4.

1.2 Judgments and Assumptions

Various engineering judgments and assumptions provided a basis for the internal flooding analysis. They are listed in this section.

1.2.1 Reactor Building The Reactor Building is considered to be out of the scope of any flooding analysis. The equipment within the building is designed to withstand the effects of the most limiting LOCA, and is qualified for service in harsh environments, including spray and steam. As such, flooding and spray effects have been factored into the design of this equipment.

1.2.2 Reactor Trip Without Safe Shutdown Equipment Failure The reactor is assumed to trip several times per year due to various initiators. The Safe Shutdown Systems/Equipment as a whole are sufficient to limit core damage frequencies to below acceptable limits for initiators of this frequency. Flooding initiators include low probability events such as valve, tank, and piping ruptures. The frequency of such events is on the order of 0.002 per year. This is several orders of magnitude lower than the frequencies of the aforementioned events, and is therefore a negligible contributor to core damage frequency. Therefore, the flooding analysis addresses only those flooding events that both 1) initiate a reactor trip, and 2) result in failure of equipment necessary to the safe shutdown of the reactor. In this case only would contribution to core damage frequencies be non-negligible.

1.2.3 Sufficient Drainage Most of the general operating floors of the various buildings and elevations have large floor openings and/or gridworks to permit equipment transfer between levels. These openings are sufficient to drain any credible flood source to the lower building levels. The openings are normally surrounded by a 6 to 8" lip, which could raise water levels to perhaps 12" during extreme flooding conditions. Most equipment in these areas that could be affected by flooding is raised at least 12" above the floor level. Therefore, flooding is only considered a credible event for the lowest elevations in these buildings. Components for which this is not true are addressed in Section 3.

1.2.4 Harsh Environment Qualification Many areas of the plant are subject to harsh environmental conditions following various Design Basis events. As described in VCSNS FSAR[7] Section 3.11, a harsh environment includes high temperatures and pressures, and more significantly, 100% humidity. The equipment in these areas that is needed for safe plant shutdown is therefore qualified to fulfill its safety function even under these harsh conditions.

For the purposes of this analysis it is assumed that any equipment qualified for operation in a harsh environment, including 100% humidity, can fulfill its safe shutdown function in the presence of a water spray. Other components will be assumed to have failed. Whether these components will initiate a reactor trip and/or inhibit safe shutdown will be determined on a case-by-case basis in the Qualitative Evaluation described in Section 3.

1.2.5 Walls and Doors Walls are assumed to remain intact throughout a flooding event. Doors are also assumed to remain intact and in their normal position, e.g. normally closed doors remain closed unless opened by plant personnel.

1.2.6 Pipe Spray Area As a general guideline, water spray from a pipe is assumed to affect components within a 10 foot radius and in a line of sight from the pipe. Engineering judgement is used when appropriate to extend this range of effect due to other factors such as: a very high elevation spray source that could splash off of other equipment or the floor; cable trays or other items that could redirect the water flow and/or cause waterfall effects at extended distances from the break.

1.2.7 Normally Clear Pipes Pipes that are free of liquid during normal operation such as drain lines and uncharged fire protection lines are not considered as credible flood/spray sources.

1.2.8 Water Effects Flooding of components is assumed to result in failure in all cases. Spraying of unprotected equipment is assumed to result in failure of the equipment unless it is properly environmentally qualified, as discussed in section 1.2.4 above. Spraying or flooding of electrical panels is assumed to result in shorting to ground, with attendant loss of power to supported equipment; no spurious actuation of supported equipment is assumed to occur.

1.2.9 Motor Operated Valves

Motor Operated Valves (MOVs) require the application of current to the motor to change the valve position. Without power, the valve will remain in its current position. Flooding and/or spraying of an MOV will therefore cause the valve to fail as is. The effect this has is addressed for each valve in question in Sections 3 and 4.

1.2.10 Operating Mode The nuclear station is assumed to be at power when the flooding event occurs. Analysis of refueling and cold shutdown modes of operation is beyond the scope of this study per NUREG-1335.[1]

1.2.11 Reactor Trip Time Limit Only automatic or manual reactor trips initiated within 2 hours of the flooding event were considered for this analysis. Shutdowns initiated after this time period are addressed as Technical Specifications required instead of a direct result of the flood.

1.2.12 Mission The mission time used for this analysis was 24 hours, per NUREG-1335.[1] The plant must be capable of achieving hot shutdown mode after a flooding event, per the Appendix to NUREG-CR-1174.[2] Safe shutdown equipment is therefore defined as that equipment necessary to achieving hot shutdown mode.

1.2.13 High Energy Line Breaks The effects of breaks in high energy lines such as reactor coolant, feedwater, and steam piping are analyzed as part of the High Energy Line Break Analysis. They are therefore outside of the scope of this flooding analysis.

1.2.14 Typical Doors The discussions in Section 3 refer frequently to "typical" doors. For the purposes of this analysis, a typical door is a hollow steel door with a minimal floor gap. It may be equipped with a keycard device for access control. If so, this is stated in the discussion.

1.2.15 Typical Drains The discussions in Section 3 refer frequently to "typical" drains. A typical drain consists of a 4" drain pipe with a slotted cover and a wide-screen mesh filter to prevent plugging. During the walkdown such drains were found to be clean and free from contaminants or materials that could cause plugging.

1.2.16 Concurrent Initiating Events Concurrent events such as a flood-initiated event combined with a loss-of-offsite power event are not assumed in this analysis because of the low probability of occurrence.

2.0 Plant Walkdown and Initial Screening

2.1 Data Collection and Plant Walkdown

A list of all components necessary for the safe shutdown of the plant and their locations within the plant was compiled from the Fire Protection Evaluation Report,[3] Potential Internal Plant Flooding Report,[4] and Essential Equipment List.[5] Based on this information, a checklist was prepared for each location within the plant that included equipment necessary to the safe shutdown of the plant. Each checklist showed the plant location and equipment therein.

Prior to investigating the plant areas, the checklists were reviewed by the walkdown team, which included an SRO licensed individual. This review determined which of the plant areas represented included components whose failure could result in a reactor trip. Those plant areas with no "trip potential" were not investigated. The remaining areas, containing both safe shutdown equipment and equipment whose failure could initiate a reactor trip, were investigated.

2.2 Initial Screening

With the information gathered during the walkdown, an initial screening of the plant areas could be performed. Table FE Q7-1 (FE denotes "Front End" question) provides a list of all areas containing equipment necessary for safe plant shutdown. It shows the various plant rooms/areas, and indicates the presence of safe shutdown equipment and trip equipment, and the presence of flooding and/or spray sources. A "Y" in the Table indicates the presence, and an "N" indicates the absence of the item. A "-" indicates that the area was not investigated because it did not include equipment with trip potential. Only those areas with 1) safe shutdown equipment, 2) trip potential, and 3) flooding or spray sources represent core damage risk for the plant from flooding events. Table FE Q7-2 includes only those areas that represent core damage risk based on this initial screening technique.

3.0 Qualitative Screening

The initial screening discussed above resulted in Table FE Q7-2, a list of Plant rooms/areas with potential for flood susceptibility. These areas include equipment essential to the safe shutdown of the plant, as well as equipment whose failure would initiate a reactor trip. If a flooding event within an area could cause failure of both types of equipment, reactor core damage could result. For many plant areas, this type of flooding event is not credible. In some cases, no spray sources exist that would cause failure of both types of equipment, while drainage from the area is adequate to mitigate the effects of any flooding event that could occur. In other cases, equipment is qualified for operation in a harsh environment, and will survive the effects of a spray. In most cases, these areas can be identified without detailed flood height calculations, event trees, or other quantitative means. The following sections discuss the areas listed in Table FE Q7-2, and qualitatively screen these areas, eliminating areas posing no core damage risk to the plant due to flooding.

3.1 Auxiliary Building

<u>AB 00-01</u>

Various critical components are located on the shield slab at elevation 400' of the Auxiliary Building. This includes:

Charging Pump suction cross connection motor operated valves,
Charging Pump discharge isolation motor operated valves,
two Charging Pump Suction Header RWST Isolation Motor-Operated Valves,

and the Refueling Water Supply Tank level gauge.

The components are all mounted at about 3' above the floor level. The entry way to the area has no door, is about 3' wide, and has an 18" curb. Various pipes in the area could spray any of the components, although flood water would flow over the curb and down to the AB elevation 388' general floor area, eliminating any possible flooding of components in this area. There are no flood propagation paths into this area.

Rupture of an RWST isolation valve could flood the area, overtop the 18" curb, and spread to the 388' elevation general floor area. These areas can accommodate considerable quantities of flood water before affecting critical equipment. This would allow ample time to isolate the flood using Manual Valve XVG-6700-SF, located near the RWST. No reactor trip would occur.

The MOVs would fail as is if sprayed, and would not trip the plant. Failure of the RWST level gauge would not trip the plant. Therefore, this area poses no core damage threat to the plant, and can be eliminated from further analysis.

<u>AB 12-28</u>

Three critical components are located in this room:

XFN-0132-VL	Train A Motor Control Center Switchgear Air Handling Unit Fan
XMC-1DA2Y-ES	Train A ESF Motor Control Center
XPN-5455-VL	Local Fuse Panel

The room has one 5' wide typical door, with a small floor gap of less than 1/2". One 4" pipe located in this room could flood the area, but would not spray the components. Steel planks about 10' long cover a floor opening in the area, leaving gaps between. The gaps are about 1/4" wide and 10' long, and there are 16 of them. This provides about 480 square inches of drainage to the lower level, adequate to drain the flow of the 4" pipe, and to drain flow under the door propagating from outside the room. This area poses no threat to core damage from flooding/spray, and was eliminated from further analysis.

<u>AB 26-02W</u>

Five critical valves are located on the partial shield slab of elevation 426' of the Auxiliary Building. They are all mounted at about 3' above the floor level. The entry way to the area has no door, is about 3' wide, and has a 6" lip. There is 1 typical floor drain in the area. Various 10" water pipes in the area could spray any of the valves, although flood water would flow over the lip and down to the AB elevation 412' general floor area, eliminating any possible flooding of these valves. There are no flooding propagation paths into this area.

Volume Control Tank outlet isolation valves LCV-115C-CS and LCV-115E-CS are normally open motor operated valves. Water spray will cause them to fail as is, and will not initiate a reactor trip. Charging Pump miniflow valve XVG-8106-CS is also motor operated, and would fail as is; a safe position.

Letdown header bypass valve XVT-8409-CS is normally closed. Its failure would not initiate a reactor trip, and it is not needed for safe shutdown. RHR cleanup header flow control valve HCV-142-CS is used during operation of the Residual Heat Removal System. It directs a small letdown flow from the RHR System to the Chemical and Volume Control System for chemistry control. It is not used during normai operation, and its failure will not initiate a reactor trip. It is a normally closed air operated valve that fails closed. Its operation is not essential to safe shutdown capability.

Valve failures in this area will not initiate a reactor trip or impair safe shutdown capability. The area poses no core damage threat to the plant, and can be eliminated from further analysis.

AB 36-18

Six critical components are located in the general mezzanine floor area of the Auxiliary Building at elevation 436'. They are each mounted approximately 4 1/2' above the floor level. This area has several openings to the lower elevations, providing sufficient drainage for any potential flooding. The components could, however, be sprayed by a 4" fire protection system pipe.

Steam Generator A Outlet Pressure Transmitter IPT-475-MS, and instruments IPT-474-MS and IPT-476-MS are qualified to operate in a harsh environment, and are immune to spray effects per assumption 1.2.4. Failure of pressure transmitters IPT-2000-MS and IPT-2000A-MS would not initiate a reactor trip, nor would failure of instrument ILS-2008-MS. The area poses no threat to core damage due to flooding/spray, and was eliminated from further analysis.

AB 63-01

Room 63-01 of the Auxiliary Building contains various critical components. Failure of ESF Motor Control Center XMC-1DB2Y-ES (a safe shutdown component) could initiate a reactor trip. There are no flooding or spray sources within this room. Propagation from the failure of the Volume Control Tank in the room next door (63-02) might affect equipment in this room.

The two rooms are joined by a door atop a 6" curb. The tank room communicates with the general floor area of this elevation over a similarly elevated curb, but through an open passageway. Flood water would flow through the open passageway preferentially. The equipment in room 63-01 is elevated 6", allowing for some small leakage under the door. The tank room has a floor drain, and the room itself would contain most, if not all of the water from the tank due to the curbs at the entryways, while the drain carried the water away.

Flooding calculations provided in VCSNS Flooding Calculation PR-41[9] show that even with conservative assumptions, the maximum flood in the Volume Control Tank room would not exceed the 6" curb height separating that room from room 63-01. The calculations also show that the maximum flood in the general floor area of elevation 463' would not exceed 4". This would not effect any equipment in room 63-01, as it is all elevated 6" above the floor level. This area poses no threat to core damage due to flooding/spray, and was eliminated from further analysis.

AB 88-13NE

Seven critical components are located in the general floor area of the sub-basement of the Auxiliary Building at elevation 388'.

XET-2002C-CS	Charging/SI Pump C 7.2kV Power Transfer Switch
XPN-0040-ES	Charging Pump C Power Transfer and Motor Control Panel
XPN-5529-VL	Local Control Station for XFN-0047-VL
XPN-5450-VL	Local Control Panel
XPN-5451-VL	Local Control Panel
XPN-5452-VL	Local Control Panel
XPN-5519-VU	Local Transformer for XVX-6524C-VU

Only two components (XET-2002C-CS and XPN-0040-ES) are subject to spraying from a 2" water line overhead. The remainder of the components are not subject to spray. The area contains many typical floor drains that would drain the flow of the 2" source, negating any flooding effects. The maximum flood height for this area as reported in VCSNS Flooding Calculation PR-41[9] is about 4", which is well below the level of the components in the area. The failure of the two components due to spray effects may cause a reactor trip, but will not affect safe plant shutdown, therefore this area poses no core damage risk for the plant. This area can be eliminated from further analysis.

AB 88-23, 24, and 25

The three Charging/Safety Injection Pump rooms are identical rooms in the Auxiliary Building at elevation 388'. They each contain a pump and miniflow valve that are critical to both operation and safe shutdown. The pumps are elevated about 12" above the floor level, and the valves approximately 18".

Each room has one door, 5' wide, mounted over a curb elevated about 6" above the floor, and opening out into the general floor area. Each door has a louvered opening about a foot above the bottom of the door. Opening this door would effectively eliminate any flooding problem within the room, as water would flow over the 6" door threshold before it would reach the level of the pump or valve. However, the door is normally closed.

Operators would be alerted to failure of the operating pump by low flow and pump trip alarms in the control room. The second and third charging pumps would be available to be manually started to replace the lost charging flow. The operators would have more than 30 minutes to perform this action, before the normal letdown flow of about 85 gpm would deplete the pressurizer coolant inventory to the point where letdown would be automatically isolated. No reactor trip would occur unless all three charging pumps were inoperative.

The only flooding sources are the overhead suction and discharge coolant pipes for the charging pumps. Either of these pipes could spray the individual charging pump and mini-flow valve. The operators would have 30 minutes to start the second or third charging pump. The charging pump discharge check valve would block back flow on the discharge side. The expected leak rate after the failure of one of these pipes would slowly fill the affected charging pump room until the elevation of the door louvers was reached. The flood rate from the low pressure suction source of the charging pump is not expected to overwhelm the numerous floor drains on the AB 388' elevation.

The maximum flood height for the general floor area of this elevation was calculated as about 4" in VCSNS Flooding Calculation PR-41.[9] This would not be sufficient to overtop the entrance curbs to the Charging Pump rooms. Therefore, no potential exists for flood water to propagate to all three rooms.

Since no spray or flooding sources that are within the scope of this analysis are located within the rooms, and no potential for propagation between rooms exists, this area was eliminated from further analysis.

3.2 Control Building

<u>CB 25-01</u>

Control Building room 25-01 contains Feedwater Local Relay Panel XPN-5244-FW. A 1" fire sprinkler line could spray the component and cause failure. However, this panel was modified through MRF's 20158 and 20967 such that it does not initiate a reactor trip. This panel contains relays for control of two Air Handling system dampers. This area therefore poses no threat to core damage due to flooding/spray, and was eliminated from further analysis.

CB 36-11

The Control Building Relay Room contains many critical components. The only water source is a normally charged Fire Protection System 3" pipe and fire hose station.(Note - The fire hose is normally isolated at the hose reel by a closed manual valve.) It is in a position to spray SSPS 120V AC Vital Instrument Panel APN-5906-EV and Balance of Plant Instrument Panel XPN-6003-BP as well as panels DPN-1HX1-ED, APN-1FX1-EM, APN-1FX-EM, XPN-6006-BP, XPN-6033-BP, and XPN-6034-BP. All of the equipment panels and cabinets rest on the floor, although many of the components inside are elevated well above floor level. All other critical components are out of the spray range.

The room contains 4 typical floor drains, 4 typical 3' wide doors, and one 5' wide door. All doors have a floor gap of about 1/4". The floor drains and door gaps are more than sufficient to drain the outflow of the fire pipe. All doors are normally closed, therefore flooding propagation under the doors from other areas would be drained by the floor drains and the doors to other rooms.

Panel APN-5906-EV supplies the Reactor Coolant Pump Vibration and Locked Rotor Panel XCP-6090-RC. Although no direct reactor trip is expected, there is a high likelihood that an indirect reactor trip would result from the loss of multiple balance of plant instrument loops. However, the SCE&G VCSNS Electrical Feeder List[8] shows no safeguards loads for APN-5906-EV, so its failure is not detrimental to safe shutdown or accident mitigation. Panel XPN-6003-BP provides non-safety balance of plant indications, control, and computer points on the main control board. Its failure could cause a transient or reactor trip but will not affect safe shutdown capability. Failure of panels: DPN-1HX1-ED, Non-class 1E 125V DC Panel; APN-1FX1-EM and APN-1FX-EM, 120V Instrument Main Distribution Panels; XPN-6006-BP, BOP Instrument Panel; and XPN-6033-BP and XPN-6034-BP, BOP Auxiliary Relay Rack Panels, will not affect safe shutdown capability.

Since flooding is not a problem for this room, and spray failure of APN-5906-EV and XPN-6003-BP may trip the reactor but not inhibit safe shutdown, this room poses no threat to core damage due to flooding/spray. It was eliminated from further analysis.

CB 48-02

The Control Building upper cable spreading area contains several local relay panels and many main control board termination panels. They are all elevated approximately 6' above floor level, and are inside steel cabinets. One normally open fire damper measuring 15" on a side is located in one wall 4' above floor level. There are 6 typical floor drains, and two typical 3' wide doors to the room. The gaps under the doors are very small. Two 6" Pre-action Fire Protection System pipes run the length of the room, at ceiling level. Since they are not normally charged, they do not represent a spray problem. There is also a fire hose and 4" pipe near one of the doors. This pipe and hose are considerably further away than 10' from the nearest cabinet and will therefore not represent a spray hazard. In case of potential water buildup from the hose/pipe spray source, the many floor drains and the fire damper would drain flood water from the room effectively.

These panels are well-sealed, and that those with vents are designed to prevent water intrusion due to spray. This room poses no threat to core damage due to flooding/spray. It was eliminated from further analysis.

3.3 Intermediate Building

IB 12-02

The Intermediate Building elevation 412' general floor area contains many critical components. Failure of Battery Main Distribution Panel DPN-1HX-ED or failure of 3 out of 3 Component Cooling Water (CCW) Pumps could cause or lead to a reactor trip. The lowest vulnerable components within the Battery Panel are elevated at least 12" above the floor level. The CCW pumps are elevated about 12" above the floor level. The room contains numerous 24" and smaller pipes from the Component Cooling Water and Service Water Systems, although none of them as a single spray source could fail all three CCW pumps. There is also a large ceiling opening to the upper levels of the building on the side of the room next to the containment building.

A large area next to the containment building opens down to the Tendon Jacking Area and the Tendon Access Gallery over an approximately 8" curb. The opening to the Tendon areas represents a huge sink for flood water. Per VCSNS Flooding Calculation PR-40,[6] the combined volume of these areas was calculated as over 22,480 cubic feet, or 168,000 gallons, and the floor area of this room was reported as 13,209 square feet. Flood water would have to reach a depth of 8" before overflowing to the Tendon areas. This translates to approximately 8,800 cubic feet, or about 66,000 gallons.

The Battery Main Distribution Panel (DPN-1HX-ED) and Battery Charger 1X (XBC-1X-ED) are located under a group of insulated 1.5" chilled water pipes, and 3 valves. This collection represents a significant spray source that could cause failure of the panel and charger, though a single pipe or valve failure would not represent a flooding threat due to the sumps in the room. Failure of battery charger XBC-1X-ED would have no impact on the plant, as 125 VDC battery XBA-1X would assume the load. Failure of DPN-1HX-ED will de-energize DPN-1HX1-ED, DPN-1HX2-ED, and DPN-1HX3-ED. SCE&G VCSNS Electrical Feeder List[8] indicates that these are non-ESF buses that do not supply safe shutdown equipment. Failure of DPN-1HX-ED may initiate a reactor trip, but will not degrade safe shutdown or accident mitigation capability. Failure of any of these chilled water pipes or valves will, therefore, not pose a threat to core damage for the plant.

The room contains 3 sumps with two pumps each. Each sump will hold about 540 gallons (72.5 cubic feet) of water, and each pump has a capacity of 75 gpm. The sumps discharge to the Turbine Building sump, which discharges to the lake. The sumps have level switches/alarms that trip main feedwater flow when the water reaches the top of the sump. A reactor trip will follow within minutes of a loss of main feedwater flow.

According to VCSNS Flooding Calculation PR-40,[6] a break in a large CCW pipe will leak at a rate of over 850 gpm. A SW pipe break will leak at a similar rate. Therefore, a break in any of the large Service Water or Component Cooling Water pipes will overwhelm the sump pumps, whose combined pumping capacity is 450 gpm. This will result in a loss of main feedwater flow and subsequent reactor trip within several minutes of the event.

An 850 gpm leak in the CCW system would likely exceed the system make-up capacity. Such a leak in the SW system is a small enough percentage of the total flow that it is expected to have a minor impact on the total flow in a single SW Train. However, in either case, such a large leak would have to be isolated to protect other equipment in the area from flooding. This would result in loss of one train of the affected system.

The combination of reactor trip and loss of one train of a safety system may make a significant contribution to core damage frequency. The flooding event frequency for this area is, therefore, quantified in Section 4.

IB 12-10

The eastern end of the Intermediate Building elevation 412' general floor area contains the motor driven Emergency Feedwater Pumps, as well as room 12-10, which contains the turbine driven Emergency Feedwater Pump. Flooding/spray failure of the EFW Pumps will not initiate a reactor trip, as they are not normally in service. Because of component spacing, and because the turbine driven pump is in a room by itself, no single spray source can fail all three EFW Pumps. This area is a portion of IB 12-02: flooding of the area is discussed in the previous section. Because flooding/spray in this area will not result in a reactor trip, this area was eliminated from further analysis.

IB 12-13

The three Chilled Water pumps are located in separate rooms (12-13A, B, and C) at elevation 412' of the Intermediate Building. They are elevated about 12" above floor level, and the rooms are separated by typical doors. If all three pumps failed, a plant shutdown would be required, although no immediate trip would result. Because they are in separate rooms, no single spray source could affect all three pumps.

The general floor area of this elevation is capable of keeping any potential flooding to a maximum height of 8" per VCSNS Flooding Calculation PR-40.[6] Flood propagation from the general floor area into room 12-13 would produce a flood height of 8", which is the maximum possible for this room, as reported in VCSNS Flooding Calculation PR-41.[9]

This area poses no threat to core damage due to flooding/spray, and was eliminated from further analysis.

IB 36-02

The Intermediate Building general floor area at elevation 436' contains many critical components. Various floor penetrations to the lower levels over 6" curbs limit the maximum flood height to about 6", as calculated and reported in VCSNS Flooding Calculation PR-40.[6] All components are elevated above this height.

Several components in this area could initiate a reactor trip if failed, and are located under potential spray sources. They include:

XVM-2801A-MS	Main Steam Isolation Valve A, Air Operated
XVM-2801B-MS	Main Steam Isolation Valve B, Air Operated
XVM-2801C-MS	Main Steam Isolation Valve C, Air Operated
IPV-2010-MS	Main Steam Header B Power Operated Relief Valve
IFT-486-FW	Steam Generator B Feedwater Flow D/P Transmitter
IFT-487-FW	Steam Generator B Feedwater Flow D/P Transmitter
IFT-496-FW	Steam Generator C Feedwater Flow D/P Transmitter
IPT-494-MS	Steam Generator C Main Steam Header Pressure Transmitter
IFV-478-FW	Main FW to SG A Flow Control Valve
IFV-488-FW	Main FW to SG B Flow Control Valve
IFV-498-FW	Main FW to SG C Flow Control Valve

The MSIVs and Steam Generator C Main Steam Header Pressure Transmitter are qualified to operate in a harsh environment category and are not affected by spray. The Main Steam PORV fails into a safe state (fails closed) in a harsh environment. Air Operated Valves IFV-478-FW, IFV-488-FW, and IFV-498-FW are qualified to operate under harsh environmental conditions.

Several of the above components could fail under spray conditions, and may initiate a reactor trip. However, the spray sources are feedwater pipes, which are High Energy Line Break (HELB) sources, and are outside the scope of this flooding analysis as discussed in Section 1.2.13. This area was therefore eliminated from further analysis.

<u>IB 63-02</u>

Intermediate Building room 63-02 contains three isolation fuse panels (XPN-5258, 5259, and 5260-EM) and reactor switchgear (XSW-1). All equipment rests on the floor. There is one 3' wide typical door, one 5' wide card access door, and no floor drains. A 6" water pipe above the panels represents a spray hazard for all of them.

Failure of reactor switchgear XSW-1 will initiate a reactor trip. Panel XPN-5258-EM provides power to Control Rod Drive Mechanism power panel XCA-0001A-CR. Without power to the CRDM panel, the control rods cannot be withdrawn. Panels XPN-5259-EM and XPN-5260-EM provide power to control rod position indication panel APN-1FC1-EM. Failure of these panels will fail all position indication in the control room for the control rods.

A water spray that fails these components will trip the reactor, but will not impair safe shutdown capability. Control rod position indication and capability to withdraw the rods will be lost, but these are not necessary to safely shut the reactor down.

This area poses no threat to core damage due to flooding/spray effects, and was eliminated from further analysis.

<u>IB PAA-36-01 West Penetration Area</u>

The Intermediate Building West Penetration Area at elevation 436' contains various critical components. They are:

IFT-0476-FW	SG A FW Flow DP Transmitter
IFT-0477-FW	SG A FW Flow DP Transmitter
IFT-4466-SW	SW Booster Pump A Disch Flow Transmitter
IPV-2000-MS	AOV, Main Steam Header A PORV
IPY-2000-MS	Signal Modifier

IVV-7096-CC	CCW Surge Tank Vent Valve
XVC-1009A-EF	AOV, SG A EF Header Discharge Isolation Valve
XVG-1611A-FW	AOV, Main Feed to SG A Header Isolation Valve
XVG-1689A-FW	MOV, FW Loop A Forward Flush Isolation Valve
XVG-9568-CC	MOV, Excess Letdown HX Inlet CC Header Isol Vlv
XVG-9606-CC	MOV, RB CC Return Header
XVK-1633A-FW	MOV, SG A Chemical Feed Header Stop Check Valve
XVT-1678A-FW	AOV, Main FW to SG A Warm-up Header Flow
XVT-2660-IA	AOV, RB Instrument Air Supply Isolation Valve
XVT-2877A-MS	AOV, Main Steam Header A Moist Collect Drain
XVX-9357-SS	SOV, Pressurizer Sample Header Isolation Valve

These components are elevated more than 4' above the floor level. The room contains several typical floor drains and an approximately 4" wide gap between the floor edge and the containment wall. The gap has a 6" curb. Due to these features, a maximum flood height of 18" for the room was calculated in VCSNS Flooding Calculation PR-40.[6] This is well below the level that would affect the critical components.

The components are located under an approximately 18" diameter Industrial Cooling Water pipe, which could act as a potential spray source. The effects this would have are enumerated below:

- XVG-1611A-FW, XVG-1689A-FW, XVT-1678A-FW, XVT-2877A-MS, and XVX-9357-SS are qualified to operate in a harsh environment and are not affected by spray.

- IPV-2000-MS and IPY-2000-MS fail to a safe position if subjected to a harsh environment.

- Failure of IVV-7096-CC will neither initiate a reactor trip nor impair safe shutdown.

- MOVs XVG-9568-CC, XVG-9606-CC, and XVK-1633A-FW will fail as is.

- Failure of XVT-2660-IA would close the instrument air service to the reactor building and would lead to a reactor trip. However, disabling this component would not inhibit safe shutdown because critical AOVs in the reactor building have air accumulators that can be used.

- Failures of any of the remaining components will not initiate a reactor trip.

Reactor Building Instrument Air Supply Isolation Valve XVT-2660-IA, and Main Steam Header PORV IPV-2000-MS, could both be sprayed at the same time. This would initiate a

Reactor Trip and fail the PORV closed, potentially impairing safe shutdown capability. This could contribute to core damage frequency for the plant. However, Table 4-6 of VCSNS Miscellaneous Systems Notebook[10] shows that this event will not have a significant impact on core damage frequency for the plant. This is discussed below.

Cases STMDMP2A and STMDMP3 of Table 4-6 of VCSNS Miscellaneous Systems Notebook[10] have identical rates for failure of the Main Steam System. The difference between these two cases is the lack of one Steam Generator PORV. For any initiating event, including spray/flooding events, the lack of one PORV is therefore immaterial to the success of Main Steam System pressure relief. Therefore, the spray event described above is in effect only an initiating event, with no accompanying impairment of safe shutdown capability. The pipe rupture frequency reported in EGG-SSRE-9639[12] (1.2E-10/hour-foot) translates on an annual basis into an initiating event frequency of approximately 1.1E-06 events/year. This is insignificant compared to the various other initiators reported in VCSNS Initiating Events Notebook[11] for the V.C. VCSNS Nuclear Station. This area was therefore eliminated from further analysis.

IB PAI-36-01 East Penetration Area

The Intermediate Building East Penetration Area at elevation 436' contains several critical components. Failure of Steam Generator B and C Pressure Transmitters could initiate a plant trip. Failure of Main Feedwater to Steam Generator B Header Isolation Valve XVG-1611B-FW would also initiate a reactor trip. These components are elevated more than 4' above the floor level. The room contains several typical floor drains, and a gap between the floor edge and the containment wall. The gap is about 4" wide, with a 6" lip. Due to these features, a maximum flood height of 18" for the room is calculated and reported in VCSNS Flooding Calculation PR-40.[6] This is well below the level that would affect these components.

Both the pressure transmitters and the isolation valve are located under potential spray sources. However, they are qualified to operate in a harsh environment and are immune to spray effects. The area poses no threat to core damage due to flooding/spray effects, and was eliminated from further analysis.

3.4 Service Water Pumphouse

SW 25-01, 25-02, and 25-03 Valve Pit Rooms

The SW pump operating floor (SW 36-02) is a large open area with the three SW pumps standing in a row, separated from direct line of sight of each other by large concrete partition walls. The partition walls extend only a fraction of the length of the room. Water is drawn from the Service Water Pond perhaps 30' directly beneath the pumps. Large grates beneath each pump allow a direct view of the pond level, and permit water to flow back down to the pond. Each pump has a valve pit manhole within 10' in front of it.

The valve pits, located below the SW pump operating floor, are small, self-contained rooms accessed through the man-holes in the operating floor. All three pits contain essentially the same equipment, for their respective Service Water Pumps. They all contain valves and pipes that represent both flooding and spray sources for the equipment in the room. The valve pits were not accessed during the flooding walkdown, due to safety concerns.

The grates in the operating floor are large enough that in combination they should drain away any potential flood volume at that level. However, nothing would stop the flood from spreading out over the floor area and filling the valve pits at the same time.

The valve pits are physically located in a row, with the A and B pits on the end and the C pit in the middle. The piping in the A and B pits is connected to the C pit piping through wall penetrations around the pipes. These penetrations would allow direct communication of water between the pits during a flooding event. This configuration permits a flood in any of the valve pits to propagate to the other two pits.

Each valve pit contains the following:

SW Pump Discharge MOV
Local Control Panel for the SW Pump Discharge MOV
Temperature element

The MOVs and Panels are elevated about 5' above the floor level of the pit and are above the level of the piping and the wall penetrations to the other valve pits and the pump pits.
Any flood or spray event in the SW pumphouse operating floor or valve pits will eventually propagate to all of the pits. The pits will fill up to the pipe level and would conceivably continue to fill to the operating floor level. The discharge MOV and the control panel above the floor of each valve pit in this scenario would be submerged and would become disabled. However, it is assumed that the discharge valves would fail as-is and would therefore not affect the service water supply or operation. The control panels would be shorted to ground, and would fail the discharge valves in the as-is position (see Section 1.2.8) and still not affect the service water supply. A break in this moderate energy piping may leak as much as 900 gpm (substituting 36" pipes and 50 psig operating pressure in the equations used for the CCW System in VCSNS Flooding Calculation PR-40[6]). This is only about 5% of the normal operating flow of 16,800 gpm for the SW Pumps, and may not be noticed until the MOVs and Local Control Panels fail.

Since the MOVs will fail as is, no reactor trip will result, although one train of Service Water may be lost. The loss of one train of Service Water due to passive piping and valve failures would occur much less frequently than a loss due to random failures of active components. This event is therefore bounded by a loss of one train of Service Water as analyzed in the IPE. This area was therefore eliminated from further analysis.

SW 36-01 and 36-02 Operating Floor and Service Water Screens

The SW pump motors are raised about 3' above the floor level. Two 4" Service Water pipes in the room are located too far from other equipment to be a spray problem, and would drain to the Valve Pit Rooms and through the floor grates to the Service Water Pond. Nothing on the operating floor or in the Service Water Screen area is at risk from either spray or flooding, therefore this area was eliminated from further analysis.

3.5 Turbine Building

The only Safe Shutdown components located in the Turbine Building are at elevation 436'. This is more than 25' above the lowest elevation of the Building, and above the maximum potential flood level, even for Condensate System pipe breaks. This makes the Turbine Building safe from any potential flooding events.

TB 36-01

Turbine Building room 36-01 contains the A Train RCP trip breaker, as well as the 480V AC Bus XSW-1B1. The room has one 4' wide typical door, with a 1/2" floor gap, opening out to the general floor area at elevation 436'. The general floor area has floor penetrations and grates sufficient to drain any potential flooding from this elevation. A single 8" pipe in the room was found to be a non-active roof drain header. Therefore, no spray or flood will occur in this room. This room was eliminated from further analysis.

4.0 Quantitative Evaluation of Flooding Initiators

Based on the qualitative assessment documented in Section 3.0, only one room was retained for quantification; Intermediate Building Room 12-02. All other rooms were eliminated from consideration because they either did not have a spray or flooding source or did not result in both a reactor trip and in a degraded safe shutdown state.

IB Room 12-02

The Intermediate Building elevation 412' general floor area contains the Component Cooling Water (CCW) Pumps and Heat Exchangers. The CCW pumps are elevated about 12" above the floor level. The room contains numerous 24" and smaller pipes from the Component Cooling Water and Service Water Systems, although none of them as a single spray source could fail all three CCW pumps.

The room contains 3 sumps with two pumps each. Each sump will hold about 540 gallons of water, and each pump has a capacity of 75 gpm, for a combined pumping capacity of about 450 gpm. The sumps have level switches/alarms that trip main feedwater flow when the water reaches the top of the sump. A reactor trip will follow due to a Turbine Trip on trip of 3 out of 3 Main Feedwater Pumps.

A break in a large CCW or SW pipe will leak at a rate of over 850 gpm. This will overwhelm the sump pumps, whose combined pumping capacity is 450 gpm, and result in a loss of main feedwater flow and subsequent reactor trip. The leaking CCW or SW pipe would be isolated, resulting in the loss of one Train of the affected system.

A large area next to the containment building opens down to the Tendon Jacking Area and the Tendon Access Gallery over an approximately 8" curb. The combined volume of the Tendon areas is over 168,000 gallons. To flood the floor area of room 12-02 to a level of 8" would require about 66,000 gallons of water. To flood the combined floor and Tendon area volumes (234,000 gallons) at a rate of approximately 850 gpm would take over 4 hours. This provides the operators with more than enough time to isolate the affected Train before any equipment is flooded.

The postulated leak from one train of SW is expected to have a minor impact on the total flow in a single SW Train. In addition, there is sufficient time available (4 hours) to isolate the leaking train from the intact Train. Therefore, a leak in one of the SW Trains is not expected to disable the complete SW system. Note - The two normally operating SW trains are completely separated except for the common SW pond.

The combination of reactor trip and loss of one train of a safety system may make a significant contribution to core damage frequency. The flooding event frequency for this area is therefore calculated below.

Component Cooling Water System

Only the operating train of Component Cooling Water(CCW) is pressurized and vulnerable to a pipe or valve break. Vulnerable components are listed below.

- 1 CCW Pump is pressurized during normal operation. (1 pump)

- Each CCW pump has inlet and outlet isolation valves and an outlet check valve. (6 valves)

- The common inlet and outlet headers have two cross-connect valves each. (4 valves)

- The non-operating headers have one cross-connect valve each still pressurized, isolating the non-operating train. (2 valves)

- The operating Heat Exchanger has locked open inlet and outlet isolation valves. The Component Cooling Water is on the shell side of the Heat Exchanger. (1 Heat Exchanger, 2 valves)

- One non-essential loads isolation valve is located in this room. (1 valve)

- The check valve isolating the Service Water make-up line from the operating train is located in this room. (1 valve)

- VCSNS Technical Work Record[13] calculates the length of CCW piping in the room as 875 feet.

All of the above components are part of the large Component Cooling Water piping system in the room, and could rupture, producing the type of flooding event described above.

Service Water System

Both Trains of Service Water are almost always operating. The effects of a Service Water rupture on other plant systems may differ depending on the affected Train. Therefore, flooding frequencies will be calculated separately for the two Trains. The vulnerable components are listed below.

- Each Component Cooling Water Heat Exchanger has two inlet and two outlet isolation valves. (4 valves per Train)

- Two Emergency Feedwater valves tap off of the main Service Water inlet pipe. (1 valve per Train)

- The two Service Water Booster Pumps are located in room 12-02. The inlet pipes for the pumps are 16" in diameter, and could produce a flooding event of the magnitude described above. The inlet isolation valves for the Pumps are in these lines. A reducer is located downstream of the inlet isolation valves, upstream of the Pumps. Everything below the reducer is considered to be too small in size to produce a flood of sufficient magnitude to be of concern. (1 valve per Train)

- VCSNS Technical Work Record[13] calculates the length of Service Water piping as about 86 feet for Train A, and 79 feet for Train B.

All of the above components are part of the large Service Water piping system in the room, and could rupture, producing the type of flooding event described above.

Loss of One Train of CCW Initiating Event Frequency

The frequency for the loss of the operating train of Component Cooling Water event is calculated below using the failure rates from EGG-SSRE-9639.[12] Initiating events are derived for a mission time of one year, or 8760 hours. The components vulnerable to rupture are enumerated above, and summarized below.

(1 CCW Pump) X (1.2E-09 failures/pump-hour) =	1.20E-09 failures/hour
(1 Heat Exchanger) X (4.0E-10 failures/HX-hour) =	4.00E-10 failures/hour
(16 valves) X (4.0E-10 failures/valve-hour) =	6.40E-09 failures/hour
(875 feet of Pipe) X (1.2E-10 failures/foot-hour) =	1.05E-07 failures/hour
	1.13E-07 failures/hour

(1.13E-07 failures/hour) X (8760 hours) = 9.9E-04 failures/year

The event consists of a large break in the CCW system, followed by Main Feedwater Pump Trip, and subsequent Reactor Trip.

Loss of One Train of SW Initiating Event Frequency

The frequency for the loss of one train of Service Water event is calculated below using the failure rates from EGG-SSRE-9639.[12] Initiating events are derived for a mission time of one year, or 8760 hours. The components vulnerable to rupture are enumerated above, and summarized below.

Loss of Service Water Train A

(6 valves) X (4.0E-10 failures/valve-hour) =	2.40E-09 failures/hour
(86 feet of Pipe) X (1.2E-10 failures/foot-hour) =	1.03E-08 failures/hour
	1.27E-08 failures/hour

(1.27E-08 failures/hour) X (8760 hours) = 1.1E-04 failures/year

Loss of Service Water Train B

(6 valves) X (4.0E-10 failures/valve-hour) =	2.40E-09 failures/hour
(79 feet of Pipe) X (1.2E-10 failures/foot-hour) =	9.48E-09 failures/hour
	1.19E-08 failures/hour

(1.19E-08 failures/hour) X (8760 hours) = 1.0E-04 failures/year

The event consists of a large break in the SW system, followed by Main Feedwater Pump Trip, and subsequent Reactor Trip.

5.0 References

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2. NUREG/CR-1174, "Evaluation of Systems Interactions in Nuclear Power Plants," Dale Thatcher, US NRC, May 1989.

3. V.C. Summer Nuclear Station Fire Protection Evaluation Report, Amendment 3, Revision Notice RN-831, February 14, 1990.

4. "Potential Internal Plant Flooding," Serial 239-02-7834, G. G. Williams, February 24, 1986.

5. Drawing S-200-971, Rev 0, "Essential Equipment List."

6. V.C. Summer Nuclear Station Flooding Calculation PR-40, Rev. 0, Gilbert Commonwealth, August 2, 1989.

7. V.C. Summer Nuclear Station Final Safety Analysis Report, Section 3.11, "Environmental Qualification of Mechanical and Electrical Equipment."

8. SCE&G Virgil C. Summer Nuclear Station Electrical Feeder List, GMP-112.000, Revision 0, October 16, 1984

9. V.C. Summer Nuclear Station Flooding Calculation PR-41, Rev. 2, Gilbert Associates, Inc., March 16, 1990.

10. V.C. Summer Nuclear Station "Miscellaneous Systems Notebook," Revision 0, May 1992.

11. CN-PORI-91-289, V.C. Summer Nuclear Station "Initiating Events Notebook," Revision 0, January 1992.

12. EGG-SSRE-9639, "Component External Leakage and Rupture Frequency Estimates," S.A. Eide, et al, November 1991.

13. V.C. Summer Nuclear Station Technical Work Record, "Piping Lengths (CCW/SW)", D. Gatlin, June 1992.

Table FE Q7-1: V.C. Summer Plant Flooding Area Screening

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
AB	00-01	AB-1.4	Sub-basement Floor Area and Shield Slab	Y	Y	Y	Y
AB	00-02	AB-1.9	Charging Pump Cooling Units Room	Y	N	-	-
AB	12-01		AB Motor Control Center Cooling Unit Room	Y	N	-	-
AB	12-05	AB-1.16	RHR HX Room B and Partial Shield Slab	Y	N	-	-
AB	12-06	AB-1.15	RHR HX Room A and Partial Shield Slab	Y	N	-	-
AB	12-11	AB-1.10	Basement Floor Area	Y	N	-	-
AB	12-13		Seal Water Heat Exchanger Room	Y	N	-	-
AB	12-27			Y	N	-	-
AB	12-28	AB-1.10	Basement floor area, and partial shield slab	Y	Y	Y	N
AB	12-30	AB-1.15	RHR HX Room A and Partial Shield Slab	Y	N	-	-
AB	12-31			Y	N	-	-
AB	26-02W	AB-1.10	Basement floor area, and partial shield slab	Y	Y	Y	Y
AB	36-03	AB-1.18	Mezzanine Floor Area	Y	N	-	-
AB	36-07		Boric Acid Blender Room	Y	N	-	-
AB	36-14			Y	N	-	-
AB	36-16			Y	N	-	-
AB	36-18	AB-1.18	Mezzanine Floor Area	Y	Y	Y	Y
AB	526-21		Seal Water Filter Room	Y	N	-	-
AB	52-01		Boric Acid Pump Room A	Y	N	-	-
AB	52-02		Boric Acid Pump Room B	Y	N	-	-
AB	63-01	AB-1.29	480V Switchgear Room	Y	Y	Y	N
AB	63-03			Y	N	-	-
AB	63-06		Boric Acid Tank Room	Y	N	-	-
AB	63-09		H2 Recombiner Control Panel Room	Y	N	-	-

Table FE Q7-1: V.C. Summer Plant Flooding Area Screening

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
AB	63-15			Y	N	-	-
AB	63-16	AB-1.21	Operating Floor Area and Filter Area	Y	N	-	-
AB	63-17		BTRS Chiller Room	Y	N	-	-
AB	63-19		Acoustic Leak Monitor System Preamp Panel Room	Y	N	-	-
AB	74-09	AB-1.1	Sub-basement	Y	N	-	-
AB	74-16	AB-1.3	Sub-basement RHR/Spray Pump Room B	Y	N	-	-
AB	74-17	AB-1.2	Sub-basement RHR/Spray Pump Room A	Y	N	-	-
AB	88-05			Y	N	-	-
AB	85-08			Y	N	-	-
AB	88-13NE	AB-1.4	Sub-basement Floor Area and Shield Slab	Y	Y	Y	Y
AB	88-23	AB-1.5	Sub-basement Charging Pump Room B	Y	Y	Y	Y
AB	88-24	AB-1.6	Sub-basement Charging Pump Room C	Y	Y	Y	Y
AB	88-25	AB-1.7	Sub-basement Charging Pump Room A	Y	Y	Y	Y
AB	97-02	AB-1.18	Recirculation Valve Room	Y	N	-	-
AB	97-02N	AB-1.8	Recirculation Valve Room, Mezzanine Floor Area	Y	N	-	-
AB	97-02S	AB-1.8	Recirculation Valve Room, Mezzanine Floor Area	Y	N	-	-
CB	12-04		Chase Area	Y	N	-	-
CB	12-05		Stairwell	Y	N	-	-
CB	25-01		Local Relay Panel Room	Y	Y	Y	Y
CB	25-04			Y	N	-	-
CB	36-04			Y	N	-	-
CB	36-06		Security Equipment Room	Y	N	-	-
CB	36-09		TSC Equipment Room	Y	N	-	-
CB	36-10		Plant Computer Room	Y	N	-	-

Table FE Q7-1: V.C. Summer Plant Flooding Area Screening

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
CB	36-11	CB-6	Relay Room	Y	Y	Y	Y
CB	48-01			Y	N	-	-
CB	48-02	CB-15	Upper Cable Spreading Area	Y	Y	Y	Y
CB	63-04		Chase Area	Y	N	-	-
CB	63-05	CB-17.1	Control Room	Y	Y	N	N
CB	63-07			Y	N	-	-
CB	63-10		Rest Room	Y	N	-	-
CB	82-01	CB-23	HVAC Equipment Room B	Y	N	-	-
CB	82-02	CB-22	HVAC Equipment Room A	Y	N	-	-
CB	82-03		Control Room Emergency Fan Room	Y	N	-	-
CB	82-04		Control Room Emergency System Filter Plenum Room	Y	N	-	-
CB	82-H-11			Y	N	-	-
DB	27-02	DG-2.2	Diesel Generator B Aux Equipment Room	Y	N	-	-
DB	27-03	DG-2.2	Diesel Generator B Aux Equipment Room	Y	N	-	-
DB	27-04	DG-1.2	Diesel Generator A Aux Equipment Room	Y	N	-	-
DB	36-01	DG-1.2	Diesel Generator A Aux Equipment Room	Y	N	-	-
DB	36-02	DG-2.2	Diesel Generator B Aux Equipment Room	Y	N	-	-
DB	36-03	DG-2.2	Diesel Generator Room B	Y	N	-	-
DB	36-04	DG-1.2	Diesel Generator Room A	Y	N	-	-
DB	63-03		Diesel Generator Filter Silencer Room	Y	N	-	-
DB	63-04		Diesel Generator Filter Silencer Room	Y	N	-	-
FB	12-01	FH-1.1	Boron Injection Tank Room	Y	N	-	-
FB	12-05			Y	N	-	-
FB	28-01		Fuel Transfer Tube Room	Y	N	-	-

Table FE Q7-1: V.C. Summer Plant Flooding Area Screening

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
FB	36-01			Y	N	-	-
FB	63-01			Y	N	-	-
FB	63-01S	FH-1.4	Fuel Pool Operating Floor, Pool, Canal, Cask Pit	Y	N	-	-
IB	12-02	IB-25.1	General Floor Area	Y	Y	Y	Y
IB	12-03	IB-1	Battery Bank 1X of DC Power Supply Area	Y	Y	N	N
IB	12-04	IB-2	Battery Bank A, DC Power Supply Area	Y	N	N	N
IB	12-05	IB-3	Battery Charger A, Power Distr Panels, DC Power Supply Area	Y	Y	N	N
IB	12-06	IB-4	Battery Charger B, Power Distr Panels, DC Power Supply Area	Y	Y	N	N
IB	12-07	IB-5	Battery Charger A/B, DC Power Supply Area	Y	N	-	-
IB	12-08	IB-6	Battery Bank B, DC Power Supply Area	Y	N	N	N
IB	12-10	IB-25.2	Turbine Driven Emergency Feedwater Pump Room	Y	N	-	-
IB	12-10	IB-25.1	General Floor Area	Y	Y	Y	Y
IB	12-11		Stairwell	Y	N	-	-
IB	12-12	IB-23.1	HVAC Water Chiller Equipment Room A	Y	N	Y	Y
IB	12-13	IB-7	HVAC Chilled Water Pump Area	Y	Y	Y	Y
IB	12-14	IB-8	HVAC Water Chiller Equipment Room C	Y	N	-	-
IB	12-15	IB-9	HVAC Water Chiller Equipment Room B	Y	N	-	-
IB	236-01		HVAC Equipment Room	Y	N	-	-
IB	23-01	IB-22.1	Battery Room Ventilation Equipment Room B	Y	N	-	-
IB	23-02	IB-10	Battery Room Ventilation Equipment Room A	Y	N	-	-
IB	236-01		EFW Pump Cooling Unit Room	Y	N	-	-
IB	26-01	IB-11	SW Booster Pump Area Cooling Equip Room B	Y	N	-	-
IB	26-02	IB-23.2	SW Booster Pump Area Cooling Unit	Y	N	-	-
IB	36-01	IB-22.2	ESF Switchgear Room B	Y	Y	N	N

Table FE Q7-1: V.C. Summer Plant Flooding Area Screening

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
IB	36-02	IB-25.6	General Floor Area	Y	Y	Y	Y
IB	36-03	IB-15	Control Room Evacuation Panel Room B	Y	Y	N	N
IB	36-03A	IB-14	Control Room Evacuation Panel Room A	Y	Y	N	N
IB	36-03B		Reactor Protection Panel Room	Y	Y	N	N
IB	36-04	IB-23.3	Component Cooling Speed Switch Room A	Y	N	N	N
IB	36-05	IB-13	Speed and Transfer Switch Room C	Y	N	N	N
IB	36-06	IB-12	Speed Switch Room B	Y	N	N	N
IB	36-07			Y	N	-	-
IB	51-01	IB-16	ESF Switchgear Room Cooling Unit A	Y	N	-	-
IB	51-02	IB-17	ESF Switchgear Room Cooling Unit B	Y	N	-	-
IB	51-03	IB-19	Speed Switch Room Cooling Unit Room B	Y	N	-	-
IB	51-04	IB-18	Speed Switch Room Cooling Unit Room A	Y	N	-	-
IB	63-01	IB-20	ESF Switchgear Room A	Y	Y	N	N
IB	63-02		Reactor Switchgear Room	Y	Y	Y	Y
IB	63-03		Landing Area Between 1DA and Stairwell (Hall)	N	Y	-	-
IB	PAA-12-01	IB-25.4	West Penetration Access Area	Y	N	-	-
IB	PAA-36-01	IB-25.8	West Penetration Area	Y	Y	Y	Y
IB	PAA-63-03	IB-25.9	West Penetration Area	Y	N	-	-
IB	PAI-12-01	IB-25.3	East Penetration Access Area	Y	N	-	-
IB	PAI-36-01	IB-25.5	East Penetration Area	Y	Y	Y	Y
SW	25-01	SWPH-5.1	Valve Pit Rooms	Y	Y	Y	Y
SW	25-02	SWPH-5.1	Valve Pit Rooms	Y	Y	Y	Y
SW	25-03	SWPH-5.1	Valve Pit Rooms	Y	Y	Y	Y
SW	25-04	SWPH-2	Electrical Equipment Room C	Y	N	Y	Y

Table FE Q7-1: V.C. Summer Plant Flooding Area Screening

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
SW	25-05	SWPH-1	Electrical Equipment Room A	Y	N	Y	Y
SW	36-01		Service Water Screens	Y	Y	Y	N
SW	36-02	SWPH-5.2	Operating Floor	Y	Y	Y	N
SW	41-01	SWPH-3	Electrical Equipment Room B	Y	N	-	-
SW	41-01	SWPH-4.1	Ventilation Duct Room	Y	N	-	-
SW	41-02	SWPH-4.2	Ventilation Equipment Room	Y	N	-	-
TB		TB-1	Steam Generator Blowdown Valve Area	Y	N	-	-
TB	36-01	TB-1	Power Bus and RCP Trip Breaker Room	Y	Y	Y	N
TB	63-02	TB-1	Electrical Equipment Area	Y	Y	N	N
YD			Storage Tank Area	Y	N	-	-
YD	Yard	YD-2	Condensate Storage Tank	Y	N	-	-

Table FE Q7-2: V.C. Summer Plant Potential Flooding Areas

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
AB	00-01	AB-1.4	Sub-basement Floor Area and Shield Slab	Y	Y	Y	Y
AB	12-28	AB-1.10	Basement floor area, and partial shield slab	Y	Y	Y	N
AB	26-02W	AB-1.10	Basement floor area, and partial shield slab	Y	Y	Y	Y
AB	36-18	AB-1.18	Mezzanine Floor Area	Y	Y	Y	Y
AB	63-01	AB-1.29	480V Switchgear Room	Y	Y	Y	N
AB	88-13NE	AB-1.4	Sub-basement Floor Area and Shield Slab	Y	Y	Y	Y
AB	88-23	AB-1.5	Sub-basement Charging Pump Room B	Y	Y	Y	Y
AB	88-24	AB-1.6	Sub-basement Charging Pump Room C	Y	Y	Y	Y
AB	88-25	AB-1.7	Sub-basement Charging Pump Room A	Y	Y	Y	Y
CB	25-01		Local Relay Panel Room	Y	Y	Y	Y
CB	36-11	CB-6	Relay Room	Y	Y	Y	Y
CB	48-02	CB-15	Upper Cable Spreading Area	Y	Y	Y	Y
IB	12-02	IB-25.1	General Floor Area	Y	Y	Y	Y
IB	12-10	IB-25.1	General Floor Area	Y	Y	Y	Y
IB	12-13	IB-7	HVAC Chilled Water Pump Area	Y	Y	Y	Y
IB	36-02	IB-25.6	General Floor Area	Y	Y	Y	Y
IB	63-02		Reactor Switchgear Room	Y	Y	Y	Y
IB	PAA-36-01	IB-25.8	West Penetration Area	Y	Y	Y	Y
IB	PAI-36-01	IB-25.5	East Penetration Area	Y	Y	Y	Y
SW	25-01	SWPH-5.1	Valve Pit Rooms	Y	Y	Y	Y
SW	25-02	SWPH-5.1	Valve Pit Rooms	Y	Y	Y	Y
SW	25-03	SWPH-5.1	Valve Pit Rooms	Y	Y	Y	Y
SW	36-01		Service Water Screens	Y	Y	Y	N
SW	36-02	SWPH-5.2	Operating Floor	Y	Y	Y	N

Table FE Q7-2: V.C. Summer Plant Potential Flooding Areas

Bldg	Room No.	Fire Area	Room Description	Safe Shutdwn	Trip Potential	Flood Source	Spray Source
TB	36-01	TB-1	Power Bus and RCP Trip Breaker Room	Y	Y	Y	N

b. Pipes that are free of liquid during normal operation such as uncharged fire protection lines are not considered as credible flood/spray sources and were not evaluated. Charged fire suppression lines were considered in the analysis where there was a potential to affect safe shutdown equipment and to trip the reactor. To see the specific areas which addressed fire suppression lines refer to section 3 of the response to question 7a. Section 1.2.6 of the response to question 7a discusses judgements and assumptions for pipe spray area.

c. Two types of maintenance (or test) human actions were implicitly considered in the flooding analysis; those that could leave a mitigating system improperly aligned such that its ability to respond to an event is degraded and those that could cause a flood or spray event.

For those actions that could degrade mitigating systems, the process to identify and quantify the probability of maintenance or test related errors due to human actions was discussed in detail in response to Human Reliability Analysis Questions 2 and 4. As noted in these responses, this was done during the system analysis process for the systems modeled in the IPE. These type of errors are included in the quantification of the model to determine the frequency of core damage from flooding events, as they are for any other event.

The second type of errors were addressed during the qualitative analysis of each room on the short list as part of the flooding analysis (see response to Question 7a). Part of this qualitative analysis postulated potential breaks in the areas or rooms of interest and assessed the impact of these breaks on local equipment. This assessment considered potential flooding or spray of equipment, available drainage, etc. (as discussed in Section 3.0 of the response to Question 7a). In this part of the analysis, a break would have a similar flooding impact as a mispositioned valve, on a drainage line for example, on the system of interest. In addition, mispositioned valves, that could be considered flooding sources, would be detected through system checks, such as pump or system flow tests, following the maintenance activity or would be detected when the system is charged or pressurized also following the maintenance activity.

8) It is not apparent that loss of HVAC has been considered, either as an initiator or as part of subsequent failures. Given the function of this system and given the fact that this system has been found to be important to risk at some plants, please provide a more detailed discussion of your investigation into the impact of loss of HVAC in rooms containing safety-related equipment, including rooms with pumps, electrical equipment, and the control room.

a. Provide a discussion of loss of HVAC both as an initiating event and as a failure subsequent to the initiator. Your discussion should include the following: systems in the areas considered; basis for elimination; credited operator actions; alarms; procedures; and staged equipment.

b. Please consider the fact that upon loss of room cooling equipment may be isolated prior to reaching the damaging temperature. Also consider that, if the damaging temperature is reached, timely recovery of such equipment should probably not be credited.

Provide the impact of your consideration on the results (CDF, important sequences) and the Fussell-Vesely importance of the HVAC failures (including maintenance) to the total CDF.

Response

Loss of HVAC was considered in the V.C. Summer IPE. The following paragraphs provide a discussion of HVAC and chilled water (which serves as the heat sink for much of the HVAC equipment), and a summary of the HVAC impacts identified for and modeled in the IPE. In addition, dependencies of frontline and other support systems on Chilled Water and HVAC are noted in the discussion on Dependency Matrices in Appendix C of the IPE.

The following HVAC systems, which are described in Section 3.2.1 of the IPE, provide ventilation and cooling to areas within the plant related to Engineered Safety Features and equipment necessary for safe shutdown:

- Auxiliary Building Pump Room Cooling Systems
- Intermediate Building Pump Room Cooling Systems
- Service Water Pumphouse Ventilation System
- Battery Room Systems
- ESF Switchgear Rooms and Speed Switch Rooms Cooling Systems
- Diesel Generator Building Ventilation System
- Relay Room Cooling System
- Control Room Air Handling System

The effects of failures in these HVAC systems, both in terms of random failures following an initiating event as modeled in the IPE and as initiating events, is presented in the following paragraphs.

Auxiliary Building Pump Room Cooling Systems

An evaluation was performed as part of the IPE to determine the ability of the charging/safety injection pumps, RHR pumps, and containment spray pumps, which are the only pumps relevant to the IPE that are located in these rooms, to operate given a failure of room cooling. This evaluation showed that these pumps would be expected to operate for at least 24 hours given a failure of room cooling at the time of reactor trip. Safe shutdown of the reactor is therefore not dependent on the Auxiliary Building Pump Room Cooling Systems which supply cooling to the rooms in which these pumps are located.

Failure of room cooling to these rooms would not result in a reactor trip, since containment spray, RHR, and safety injection are standby functions, and the normal charging pump (as well as the other listed pumps) would continue to operate even if room cooling failed. Given a failure of room cooling, a high room temperature alarm would annunciate on the HVAC board in the main control room. Further, operators would be expected to detect a failure of room cooling in these rooms during routine rounds, even without instrumentation regarding the status of the room cooling system or room temperature. In either case, the operators would respond, per Annunciator Response Procedure ARP-16-XCP-6210, and take action to reduce room temperature. Reactor trip due to loss of room cooling to the charging pump room requires a sufficiently large number of independent failures that the initiating event frequency is judged to be small relative to other modeled events with similar consequences.

Given the above, it was not necessary to incorporate failures in the Auxiliary Building Pump Room Cooling Systems into the IPE models.

Intermediate Building Pump Room Cooling Systems

Component cooling water pumps are located in the intermediate building general open area. These pumps have TEWAC-type harsh-environment motors. SCE&G evaluations concluded that the CCW pumps require no external HVAC.

The service water booster pumps are also located in this area of the intermediate building. Evaluations have been performed by SCE&G to demonstrate that HVAC is not needed for operation of the service water booster pumps.

The motor-driven emergency feedwater pumps are in an open area of the intermediate building. Evaluations have been performed by SCE&G to demonstrate that room cooling is not needed for operation of the EFW pumps. The turbine-driven EFW pump is in an enclosed room in the intermediate building, but this pump is designed to operate without HVAC.

Based on the above, safe shutdown of the reactor is therefore not dependent on the Intermediate Building Pump Room Cooling Systems. Since none of the pumps relevant to the IPE analysis are dependent on HVAC for operation, failure of room cooling to the associated pump areas cannot result in a reactor trip. Given the above, it was not necessary to incorporate failures in the Intermediate Building Pump Room Cooling Systems into the IPE models.

Service Water Pumphouse Ventilation System

The rooms in which the service water pumps are located are served by this system. The system is composed of two 100% trains, and cools using outside air. Each train has a non-safety cooling coil that can be used to cool during abnormally hot periods. These coils are supplied via SW pump discharge. With outside temperature below 60°F, ventilation is not needed for the service water pumps. As outside temperature increases above 60°F, 1 of the 2 trains of ventilators may be required to operate to maintain temperature in the service water pump area below tech spec limits (102°F for the switchgear in this area). However, the temperature rise is slow. There is a service water pump area high temperature alarm on the HVAC board in the main control room. Annunciator Response Procedure ARP-16-XCP-6210 instructs the operators to take action to reduce and monitor temperature. Since service water pump failure due to ventilation failure would require failures of both trains of ventilators, failure of the operators to respond, could only occur during a portion of the year, and would require a relatively long time, any associated contribution to service water system unavailability would be small relative to the contribution from service water equipment faults already included in the IPE models.

Similarly, failure of service water pumphouse ventilation would not result in a reactor trip, because indication would be available to the operators, and there would be sufficient time to restore ventilation, provide alternate ventilation, or perform a controlled shutdown of the reactor.

Given the above, it was unnecessary to incorporate failures of the Service Water Pumphouse Ventilation System into the IPE models.

Battery Room HVAC Systems

Evaluations performed by SCE&G show that the 125VDC batteries will continue to operate for at least 4 hours without room cooling. Since these batteries are not required for more than 4 hours following an initiating event, battery room cooling is not required to ensure safe shutdown.

Failure of room cooling to the battery rooms would not be a significant contributor to the loss of 125VDC bus initiating event for several reasons. Room temperature for the rooms in which both the batteries and battery chargers are located are alarmed on the HVAC board in the main control room. There is sufficient time for the operators to detect high room temperature and correct the situation before battery and battery charger failures (both necessary for loss of bus power) occur. Two trains of room cooling are provided to each vital battery, and battery charger room. Each cooling train includes both a supply and exhaust fan, but either fan in a given train would provide sufficient room cooling to prevent battery or charger failure. Thus, although there could be some initiating event frequency contribution to loss of a 125VDC bus due to loss of room cooling, it was not necessary to model this because the failure probability would be small relative to failures that have been included in the initiating event frequency calculations.

Given the above, it was not necessary to incorporate failures of the Battery Room HVAC Systems into the IPE models.

ESF Switchgear Rooms Cooling System

The ESF switchgear are dependent on room cooling for operation. Switchgear room heat up calculations were performed for the IPE to determine whether failure of the room coolers would result in failure of the equipment inside the room within the IPE mission time of 24 hours. These rooms include fan-coil coolers, cooled by chilled water, with a nonsafety-related, expansion type, cooler backup that automatically starts if room temperature reaches 85°F. The fans in the switchgear rooms are common to both the chilled water and compression coolers in the respective rooms. In MCC room AB-63-01, the backup cooling unit is totally independent as it has it's own fan.

For the IPE, a calculated room temperature given fan failure, using conservative assumptions (e.g., no credit for heat capacity of interior walls or equipment), of less than 132°F at 24 hours was used as the basis for determining equipment success. The equipment, if initially operable, would be expected to continue operating at elevated room temperature during the period of interest to the IPE, although future operability might be compromised.

The following electrical equipment rooms were examined:

- Switchgear Room IB-36-01
- Switchgear Room IB-63-01
- MCC/Switchgear Room AB-63-01
- MCC Room AB-12-28

Evaluations performed by SCE&G show that, for room AB-12-28, the room temperature remains below the maximum allowable environmental qualification temperature even with no chilled water (VU unavailable) under expected conditions. Therefore, room heatup is not a concern for this room.

Evaluations performed for the IPE for the remaining switchgear rooms showed that, if room cooling were lost (fan failure) and no action taken by the operators, the room temperature (assuming room cooling lost at time zero) would exceed 132°F at about 4 hours (AB-63-01), or about 8 hours (IB 36-01 or IB-63-01). However, if the operators open the door to room IB-63-01/ IB-36-01 by 90 minutes following loss of room cooling, room temperature remains below about 126°F.

If the operators open the door to room AB-63-01 by 30 minutes following loss of room cooling, room temperature remains below 132°F for 21.4 hours; with operator action by 90 minutes, room temperature remains below 132°F for 18 hours.

For the switchgear rooms, there are both high room temperature alarms and fan trouble alarms. Only a fan failure would be expected to result in a relatively rapid rise in room temperature, since there is a backup to the chilled water room cooler. If a high room temperature alarm (at 99°F) or a fan trip alarm occurs, the operators would attempt to restore cooling to the room, and would monitor room temperature, in accordance with annunciator response procedure ARP-16-XCP-6210 and Tech Spec Interpretation TSR-1020, Rev.0. (TSR-1020 requires increased frequency of temperature monitoring as a function of the proximity to the Tech Spec limit. If within 5°F of the Tech Spec limit, hourly temperature surveys are required.)

As a result of these evaluations, the system fault trees for AC power (both with onsite power available and for loss of offsite power) include logic such that a given train of AC power fails if the room cooling unit for the associated switchgear room fails and the operator does not respond to an alarm indicating loss of room cooling and open the switchgear room door within 30 minutes. For equipment in MCC room AB-63-01, this action was not modeled, since loss of room cooling would require failure of both the room cooler and the backup room cooler (i.e., fan failure is not a common failure of both sources of room cooling for this room).

Therefore, room AB-63-01 cooling faults would be low probability events relative to other faults in the models, and were not included in the fault trees.

Failure of room cooling to a switchgear room would not cause an initiating event, since loss of a single AC bus is not an initiating event. Further, as noted in the above discussion, there would be alarms and procedural guidance to the operators, and sufficient time for actions that could be taken to prevent even a single AC bus loss due to room cooling failure.

Speed Switch Rooms Cooling System

Based on SCE&G evaluations, equipment failure is not expected due to room heatup after a loss of HVAC. The CCW pump motor speed switches are manually-operated devices that are expected to function even at elevated temperatures.

Diesel Generator Building Ventilation System

The design of the diesel generator building ventilation system provides two 50% capacity fans per diesel generator room. However, analyses have shown that both fans are needed only when outside temperature exceeds 95°F. This system uses outside air to cool, and is not dependent on the Chilled Water System. Diesel generator test data indicates that a sufficient amount of time would be available to establish backup ventilation to allow for continued diesel generator operation if one of the fans failed. Based on this information, the IPE AC power fault tree model for loss of offsite power includes logic for each diesel generator such that the diesel generator fails if both of its associated ventilation fans fail. Ventilation faults were not significant contributors to the fault tree quantification for the loss of offsite power AC power tree.

No associated operator recovery action was modeled for ventilation failure, although such actions would be expected since the operators would be monitoring diesel generator conditions if a diesel generator was running. High diesel generator room temperature alarms annunciate on the HVAC panel in the main control room, and response guidance is provided in Annunciator Response Procedure ARP-16-XCP-6210.

Thus, even for the portion of time that outdoor temperatures exceeded 95°F when diesel generator operation was required, it would be appropriate to credit operator response to establish alternate means of ventilation.

Failures of the ventilation fans in the diesel generator building are not relevant as initiating event contributors, since the diesel generators are not required during normal operation.

Relay Room Cooling System

The relay room is a relatively open area that is cooled by both trains of HVAC, supplied by chilled water, either train of which is capable of supplying adequate cooling. As a result, multiple HVAC failures would be required in order to affect equipment in this room. Such multiple failures would not significantly affect the quantification results. The IPE fault trees related to equipment in this room (e.g., for vital 120 VAC) therefore do not include HVAC failures.

Failure of room cooling to the relay room would also not be a significant contributor to an initiating event (i.e., loss of two vital 120VAC panels). This is because both trains of HVAC would have to fail, there is a high relay room temperature alarm on the HVAC panel in the main control room, and procedural guidance for the operators to respond to high relay room temperature (at 80°F per Annunciator Response Procedure ARP-16-XCP-6210, and relay room Tech Spec temperature limit of 83°F). Although the heat loads were less, an evaluation of relay room temperature response was performed to support the SBO evaluation which concluded that reasonable time was available for the operator to take action before equipment operability was threatened. Therefore, there would be sufficient time for the operators to detect high room temperature, either via room temperature alarm or on routine rounds, and correct the situation before high room temperature caused equipment failure.

Main Control Room

The main control room is provided with two trains of 100% capacity HVAC that provide room cooling (among other functions). There is a control room high temperature alarm (at 77°F) and a control room air temperature Tech Spec of 85°F .

In addition to the above features, the control room is continuously manned, so that, even following an initiating event on which the operators might be focusing their attention, there would be only an insignificantly small probability that the operators would fail to notice a complete HVAC failure and fail to either: take action to reduce control room temperature prior to overheating to the point at which control room equipment would fail; or decide to abandon the control room and take positions at the remote shutdown panels to continue response to the event. For the former possibility, since the control room is cooled by two redundant 100% capacity HVAC units, only one of which is normally operating, one of the simplest operator actions would be to provide cooling from the redundant unit. Other possible actions would include opening the door to the control room or installing temporary fans. The use of temporary fans is specifically addressed in the "TOTAL LOSS OF CHILLED WATER" abnormal operating procedure(AOP-501.2). For the latter possibility, the initial response to the transient would be well underway, and the plant most likely stabilized, before relocation to the remote panels would be necessary. Adequate procedural guidance and control capability exist to successfully accommodate this possibility. Less likely outcomes would not be significant contributors to core damage frequency, and would not be expected to provide useful insights not already obtained.

Failure of room cooling to the main control room would also not be a significant initiating event contributor. Upon failure of the running HVAC unit, the plant would be in a 7-day LCO condition, and the operators would be aware of the possible need to shut down: the Tech Specs require that, if the second train of HVAC fails, the plant must be in hot standby within 6 hours if at least one of the HVAC trains is not restored within 1 hour. Thus, the plant would operate for no more than 1 hour with both trains of control room HVAC failed, at which time a controlled shutdown would be undertaken. Therefore, there would be sufficient time for establishment of a stable plant condition before any serious control room equipment heating occurred. Since the operators are present in the control room, the initiating event frequency for failure of the Control Room Air Handling System with failure of the operators to detect and respond to this failure is judged to be much lower than the general transient initiating event frequency. Thus, although this HVAC failure was not explicitly modeled in the IPE, any effect on core damage frequency would be small.

Given the above, it was not necessary to incorporate failures of main control room HVAC into the IPE models.

Chilled Water System

The Chilled Water System (designator VU in the IPE) is the cooling source for various plant areas and equipment in the V.C. Summer Nuclear Station. The operation of this system is described in the VCSNS IPE in Section 3.2.1, which lists the specific cooling loads served by Chilled Water. The Chilled Water System provides cooling for portions of the various HVAC systems. Chilled water also provides pump motor cooling to the component cooling water pumps and gear/oil cooling to the charging/SI pumps.

Chilled water system unavailability is modeled both in terms of plant response to initiating events, and as a special initiating event (loss of chilled water). The chilled water system is included as top event VU in the support state models. Its train-wise availability (or unavailability) constitutes part of the definition of the various support states, which in turn determine the availability of component cooling water and of frontline systems dependent on chilled water. It is therefore explicitly considered in the core damage frequency quantification.

The IPE includes as a special initiating event; The Total Loss of Chilled Water. Although loss of chilled water results in loss of room cooling to a number of areas, the loss of room cooling due to loss of chilled water, as originally modeled in the IPE, had less of an immediate effect than did the direct loss of cooling to the charging and component cooling water pumps due to the loss of chilled water flow. Thus, the IPE models this event as resulting in an RCP seal LOCA. Although the room cooling impacts (switchgear rooms and control room) were not included in the evaluation of this event, the above discussions note that there would be sufficient time and proceduralized options available to the operators to deal with loss of room cooling in addition to the initiating event.

After the IPE was submitted, the plant configuration was changed such that the dependency of component cooling water and charging pumps on chilled water was removed. Thus, the current impact of a loss of chilled water would be loss of HVAC to the various areas, but without a seal LOCA. As noted above, there would be sufficient time and proceduralized options available to the operators to initiate a controlled shutdown and deal with loss of room cooling.

In conclusion, the V.C. Summer IPE considered the impacts of loss of HVAC, both in terms of consequential failures and as an initiating event. The IPE analyses have appropriately addressed these impacts.

The IPE includes as a special initiating event; The Total Loss of Chilled Water. Although loss of chilled water results in loss of room cooling to a number of areas, the loss of room cooling due to loss of chilled water, as originally modeled in the IPE, had less of an immediate effect than did the direct loss of cooling to the charging and component cooling water pumps due to the loss of chilled water flow. Thus, the IPE models this event as resulting in an RCP seal LOCA. Although the room cooling impacts (switchgear rooms and control room) were not included in the evaluation of this event, the above discussions note that there would be sufficient time and proceduralized options available to the operators to deal with loss of room cooling in addition to the initiating event.

After the IPE was submitted, the plant configuration was changed such that the dependency of component cooling water and charging pumps on chilled water was removed. Thus, the current impact of a loss of chilled water would be loss of HVAC to the various areas, but without a seal LOCA. As noted above, there would be sufficient time and proceduralized options available to the operators to initiate a controlled shutdown and deal with loss of room cooling.

In conclusion, the V.C. Summer IPE considered the impacts of loss of HVAC, both in terms of consequential failures and as an initiating event. The IPE analyses have appropriately addressed these impacts.

9) The transient initiating event frequency reported in the submittal seems high, especially for certain categories (e.g., spurious safety injection signal 0.57/yr, positive reactivity insertion 0.56/yr, total or partial loss of feedwater flow 2.77/yr, etc.). It should also be noted that the on-line maintenance unavailability of the chilled water system, which contributes to the initiating event frequency of 1.8E-02/yr, is relatively high. In view of the fact that transients contribute 40% to the reported CDF of 2.0E-04/yr, are there any systematic programs in place to reduce the transient frequency, and if so, how effective are they? Please discuss the plant-specific data used for calculation of these initiating event frequencies and share any insights as to why the frequency numbers are so high.

Response

Plant Specific Data Used to Calculate Initiating Event Frequencies

Anticipated transient initiating event frequencies were calculated using plant specific data where available. Where sufficient plant specific data was not available, generic industry data was used. The plant specific initiating event data was collected from January 1, 1984 to June 30, 1990, although the plant specific frequencies were calculated using data from January 1, 1985 to June 30, 1990 to exclude data from the first commercial year of operation. The first year is excluded consistent with the generic database, to ensure the frequencies represent mature plant operation. Over this 5 1/2 year period, a total of 31 reactor trip events have occurred. A breakdown of these events by year, including the initial year of operation, follows:

Year	Number of Events
1984	11
1985	12
1986	6
1987	4
1988	4
1989	5
1990	0 (up to June 30, 1990)
Total	42

This results in an average frequency of 5.6 events/yr over this time period.

The process used to calculate initiating event frequencies for each event category involved partitioning the plant specific data into the NUREG/CR-3862 categories for each event category and then summing the NUREG category frequencies for each event category. Plant specific data was used to calculate the frequency for each NUREG category where available. Generic data was used to calculate the frequency for each NUREG category where plant specific data was not available.

Table FE Q9-1 provides a summary of this process for the events specifically noted in the question for which the plant specific data was used in place of generic data. This shows the events by NUREG category that adversely impact the initiating event frequencies. It is important to note the following:

i. Plant specific Initiating Event(IE) frequencies used were higher than the generic frequencies.

ii. The VCSNS historical data was used directly to determine IE frequencies; it was not incorporated through a Baysian update process. Using this data directly results in larger IE frequencies than through a Baysian update technique.

The IPE submittal report contains a sensitivity analysis that examined the impact of including the VCSNS operating history from June 30, 1990 to December 1992 in the analysis (see Section 3.4.5 of the Submittal report). During this time period the plant experienced only two trips. The plant specific and generic databases were updated to include this additional time period. The generic data used corresponds to the same time interval. Table FE Q9-2 provides a summary of the results. A comparison of Table FE Q9-1 and Q9-2 shows reduced initiating event frequencies for the events of interest.

Reactor trip experience since 1992 shows further improvement in plant performance. A breakdown of the events by year, including 1990 and 1991, follows:

Year	Number of Events
1990	0
1991	0
1992	2
1993	1
1994	0
1995	0

It is evident from this information that plant performance, with respect to transient event frequency, has significantly improved since the early years of operation.

A review of the event descriptions for the transient events included in the database from January 1985 to June 1990 indicates that approximately three quarters of the events occurred near or above the 90% power level, with the majority of these at the 100% power level. The remaining events occurred with the power level near or below 30%. This review also shows that approximately 40% of the events were caused by equipment failures or malfunctions, and approximately 60% were related to test or maintenance activities, with only a few related to operator errors.

The following specifically addresses the initiator categories mentioned in the this question:

Spurious Safety Injection (0.57/yr)

There are three plant specific events included in this combined category which increases the frequency from the purely generic data value, 1.7E-01/yr, to the plant specific value of 0.57/yr. Two of these events were classified as Inadvertent Safety Injections (NUREG/CR-3862 Category 9). Both inadvertent safety injections were caused by sudden drops in steam line pressure that activated the rate compensated Low Steam Line Pressure Safety Injection function. The first event occurred during turbine roll-up and was caused by an apparent malfunction in the turbine control circuit. The second event occurred when a main steam isolation valve(MSIV) inadvertently closed during partial stroke testing. The other two steam line pressures dropped rapidly, activating the rate compensated Low Steam Line Pressure Safety Injection function. The MSIV test circuitry was later modified to decrease the probability of an accidental closure. The third event was classified as a Pressurizer Spray Valve Failure (NUREG/CR-3862 Category 36). This event was caused by a failure in the valve positioner that resulted in one of the two pressurizer spray valves failing open. There have been no additional events that would be categorized under Spurious Safety Injection in the past seven years.

Positive Reactivity Insertion (0.56/yr)

This category includes three plant specific reactivity related events that occurred in 1985. The plant specific data increases the generic value for this category from 7.56E-02/yr to 5.6E-01/yr. Two of the events were attributed to electrical rod control system problems. These events were not true reactivity insertion events, but are grouped in this manner as general reactivity control events. The third event occurred due to an improper "estimated critical rod position calculation." The core reactivity inventory was under-estimated which led to an early criticality and a positive rate trip during a reactor start-up. Several corrective actions were taken including the required use of 1/M plots for every reactor start-up. A 1/M plot requires a very slow methodical approach to criticality that will prevent a similar reactivity management problem during a reactor start-up. There has been one additional event in 1993 that would be categorized under Positive Reactivity Insertion. This event occurred due to an un-demanded opening of the main transformer high side oil cooled breaker(OCB). The opening of this OCB at 100% power caused a sudden increase in reactor coolant pump(RCP) speed. The increase in RCP speed caused an increase in RCS flow, and a positive reactivity addition. Corrective actions included replacing or repairing several protection relays that may have contributed to this event. No similar events have occurred.

Total Or Partial Loss Of Feedwater Flow (2.77/yr)

These categories include eleven plant specific events generally classified as loss of feedwater events. These events are the single largest contributor to the high, plant specific, transient initiator frequency. The plant specific data increases the generic value for this category from 1.41/yr to 2.77/yr. Due to the Westinghouse Model D steam generators, which include a preheater, automatic feedwater isolation was included for low flow(<13%), and low temperature(<225°F). This feature protected the preheater from water hammer at these low power conditions This FW isolation feature, which was completely eliminated in 1994 with the replacement of the Model D SGs with Westinghouse Delta-75s, caused many of the early transients as can be seen below. The events can be broken down as follows:

CAUSE OF EVENT	NUMBER OF EVENTS	CORRECTIVE ACTIONS
Equipment Failures	5	Changes in maintenance practices, modifications including fixed speed condensate pumps, new vital instrument power inverters, replacement of FW isolation valve operators, and other operational practices.
Human Error	2	New programs on the conduct of special plant testing, and re-validation of information use to determine plant effects of removing power from panels during tag-outs.

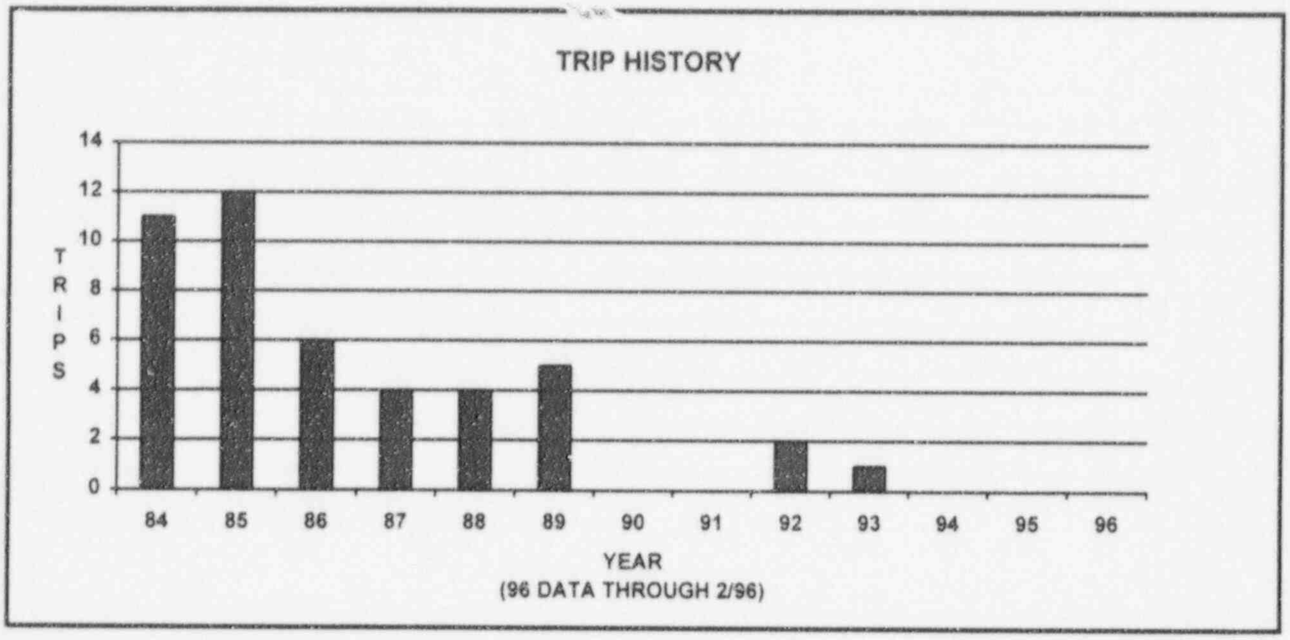
CAUSE OF EVENT	NUMBER OF EVENTS	CORRECTIVE ACTIONS
FW Isolation valve closure	4 (There are four events in this category; however, in several of the events above, a reactor trip may have been avoided if the events had occurred after the enhancement to the FW control system were made.)	Numerous enhancements were made to the secondary plant to improve feedwater flow control. They include the removal of variable speed condensate pumps, the addition of deaerator tank level control valves, and improvements in the modeling fidelity and training use of the plant simulator. In 1994, the replacement of the Model D preheater type SGs allowed removal of the low flow/low temperature isolation feature.

There has been one additional FW related reactor trip since the submittal of the IPE. This trip occurred in 1992 due to a FW isolation on low flow/low temperature. The FW system instability was caused by a design change to the steam dump system that did not perform as expected. The steam dump system modification was corrected prior to plant re-start.

Systematic Programs in Place to Reduce Transient Frequencies

As noted in the response to the "high initiator frequency" categories in the table above, various changes have been made over the life of the plant to reduce the transient frequency. Changes include modifications, procedural enhancements, simulator fidelity improvements, and cultural changes. Procedures are in place that require a thorough investigation of events that result in a reactor trip/safety injection. Root cause determination and corrective actions are a key part of event investigations. VCSNS also has a "Near Miss" program to identify problems before an event occurs. A large effort has been expended at VCSNS to obtain the good operating record that has been the standard over the past six years. The modifications to the secondary plant(including the eventual deletion of the low flow/low temperature FW isolation function) have been a large contributor to reducing unnecessary reactor trips, but there are also numerous small enhancements that have contributed to the current level of performance.

The effectiveness of this program is demonstrated in the following graph:



<u>Chilled Water System</u>

Unavailability or failure of the chilled water system is dominated by failure of the chillers. From January 1, 1984 through December 31, 1989 the chilled water system experienced 20 chiller failures which have caused the chillers to fail to start, or fail to run. This experience resulted in a significant chiller unavailability due to maintenance, relatively high failure to run and failure to start probabilities, and a high contribution to core damage frequency from failure of the chilled water system. As the reviewer notes, maintenance unavailability contributes to the high initiating event frequency. The chilled water system consist of two 100% chiller/pump trains with a third "installed spare" chiller/pump set that can be aligned to either train. The high unavailability comes primarily from the out of service time of the non-aligned components. The in service train components have very low out of service times. The unavailability of the non-aligned chiller/pump set is only important if both aligned train units fail.

Table FE Q9-3 provides a summary of chiller failure history. A review of this information indicates:

- the majority of the time the chillers start, but fail to run

- the spare chiller, chiller C, fails more often than chillers A and B
- the chillers fail for a variety of reasons, but chillers failing to run due to low oil pressure or air inside the chiller have been identified in a number of the failures

Due to the importance of the chilled water(VU) system, and the heightened awareness of it's impact on plant risk provided by the IPE, a modification was made after the IPE was submitted to eliminate the use of the VU system to cool the charging pumps and CCW pump motors. Through this plant modification, the charging pumps are now cooled by the component cooling water system, and the component cooling water pump motors receive cooling water from the discharge of the component cooling water pump(ie, self-cooled). As noted in the response to front end question number 8, chilled water is not vital in maintaining equipment operability for the IPE mission time of 24 hours. However, several activities have been completed, or are underway, to address chiller reliability.

- Modifications to the chillers have been completed to address a key contributor to air entrainment.

- A chiller rotation policy is now in place that minimizes the chiller stand-by time, which increases the reliability to start and run.

- The Chilled Water(VU) system engineer is involved in on-going efforts to increase the reliability of the VU system and/or replace the existing units.

- A dedicated oil clean-up system has been installed on the "C" chiller.

- The TOTAL LOSS OF CHILLED WATER Abnormal Operating Procedure still exists to provide guidance on back-up room cooling in the event VU is lost.

Table FE Q9-1

Summary of Transient Initiating Event Analysis - Basis for IPE

Transient Event Category and NUREG Category	NUREG Cat.	Events		Frequency (/year)		
		Generic Data	VCSNS Data	Generic Data	VCSNS Data	IPE Frequency
Positive Reactivity Insertion						
- Uncontrolled rod withdrawal	2					
- CVCS malfunction-boron dilution	11					
- Press/temp/power imbalance	12	16	3	6.35E-02	5.45E-01	5.45E-01
- Startup of inactive RCP	13					
- Control rod ejection						
Total						5.6E-01
Total Loss of Main Feedwater Flow						
- Total loss of FW flow (all loops)	16					
- Increase in FW flow (one loop)	19					
- Increase in FW flow (all loops)	20					
- FW flow instab-mech problem (SG-H)	22H					
- FW flow instab-mech problem (SG-L)	22L	110	7	4.37E-01	1.27E+00	1.27E+00
- Loss of cond pumps (all loops)	24	3	2	1.19E-02	3.64E-01	3.64E-01
Total						2.0E+00

Table FE Q9-1

Summary of Transient Initiating Event Analysis - Basis for IPE

Transient Event Category and NUREG Category	NUREG Cat.	Events		Frequency (/year)		
		Generic Data	VCSNS Data	Generic Data	VCSNS Data	IPE Frequency
Partial Loss of Main Feedwater Flow						
- Loss of reduction in FW flow	15					
- Full/partial closure of MSIV(s)	17	27	1	1.07E-01	1.82E-01	1.82E-01
- FW flow instab-man control (SG-H)	21H					
- FW flow instab-man control (SG-L)	21L	33	1	1.31E-01	1.82E-01	1.82E-01
- Loss of cond pump (1 loop)	23					
Total						7.7E-01
Safety Injection Signal						
- Low pressurizer pressure	6					
- Inadvertent safety injection	9	33	2	1.31E-01	3.64E-01	3.64E-01
- Containment pressure problems	10					
- Pressurizer spray failure	36	2	1	7.94E-03	1.82E-01	1.82E-01
Total						5.7E-01

Table FE Q9-2 Summary of Transient Initiating Event Analysis Update to Include Plant Experience Through 1992				
Transient Event Category and NUREG Category	NUREG Cat.	Frequency (/year)		
		Generic Data	VCSNS Data	IPE Frequency
Positive Reactivity Insertion				
- Uncontrolled rod withdrawal	2			
- CVCS malfunction-boron dilution	11			
- Press/temp/power imbalance	12	1.66E-02	4.29E-01	4.29E-01
- Startup of inactive RCP	13			
- Control rod ejection				
Total				4.4E-01
Total Loss of Main Feedwater Flow				
- Total loss of FW flow (all loops)	16			
- Increase in FW flow (one loop)	19			
- Increase in FW flow (all loops)	20			
- FW flow instab-mech problem (SG-H)	22H			
- FW flow instab-mech problem (SG-L)	22L	2.98E-01	1.00E+00	1.00E+00
- Loss of cond pumps (all loops)	24	8.28E-03	2.86E-01	2.86E-01
Total				1.5E+00
Partial Loss of Main Feedwater Flow				
- Loss of reduction in FW flow	15			
- Full/partial closure of MSIV(s)	17	9.94E-02	1.43E-01	1.43E-01
- FW flow instab-man control (SG-H)	21H			
- FW flow instab-man control (SG-L)	21L	1.24E-02	1.43E-01	1.43E-01
- Loss of cond pump (1 loop)	23			
Total				5.5E-01
Safety Injection Signal				
- Low pressurizer pressure	6			
- Inadvertent safety injection	9	7.87E-02	2.86E-01	2.86E-01
- Containment pressure problems	10			
- Pressurizer spray failure	36	8.28E-03	1.43E-01	1.43E-01
Total				4.6E-01

Table FE Q9-3 Chiller Component Failure Data			
Component ID	**Event Date**	**Failure Mode**	**Event Description**
XHX-1A	7/30/85	FTS	Defective breaker
XHX-1A	12/07/85	FTR	Trips on low oil pressure
XHX-1A	11/23/85	FTS	Cycling excessively, will not chill
XHX-1A	5/24/88	FTS	Surging abnormally, not purging
XHX-1A	10/06/87	FTS	Non-cond. in system
XHX-1A	01/27/86	FTR	Trips on low refrig. temp.
XHX-1A	3/11/86	FTR	Trips
XHX-1B	8/22/88	FTS	Chiller will not start due to low oil level
XHX-1B	02/26/85	FTR	Chiller tripped, will not manually reset
XHX-1C	10/06/87	FTS	Replace feeder breaker
XHX-1C	11/14/85	FTR	Chiller trips (low oil pressure)
XHX-1C	7/20/86	FTR	Chiller trips (low oil pressure)
XHX-1C	10/07/97	FTR	Chiller trips (low oil pressure)
XHX-1C	5/29/84	FTR	Air in chiller - replace valve
XHX-1C	6/26/84	FTR	Air in chiller - replace solenoid valve subassembly
XHX-1C	6/19/84	FTR	Air in chiller - replace valve
XHX-1C	8/03/84	FTR	Air inside - vented air (cycled on/off)
XHX-1C	8/31/84	FTR	Replace solenoid valve
XHX-1C	10/08/85	FTR	Chiller tripped, would not restart
XHX-1C	3/26/85	FTR	Chiller will not carry load

10) The calculated CDF from internal events is relatively high (2.0E-04/yr). The submittal treats the issue of vulnerabilities by subdividing the CDF into several groups, subdividing the groups into subgroups, applying Nuclear Management & Resources Council (NUMARC) criteria to these subgroups and occasionally qualitatively taking credit for unscheduled future improvements to bring the subgroup CDF below NUMARC guidelines (10^{-5} to 10^{-6} range). For instance, Group IIA (induced LOCA with loss of primary coolant makeup or adequate heat removal in the injection phase) contributes 64% to the CDF (or 1.3E-04/yr). It is further subdivided into several subgroups, one of which, SBO, contributes 21% to the total CDF. Here, credit is taken for a future (date unspecified) installation of the new reactor coolant pump (RCP) seal O-rings and a future (date unspecified) consideration of fire service system connection to RCP seal thermal barrier cooling.

Another way to look at vulnerabilities would be to scan the table of top event (Fussell-Vesely) importances, which shows the contribution of various failures to the CDF. The chilled water system is the top contributor, at 39% importance, followed by diesel generators at 39%, followed by SW at 27%. Chilled water is important because it provides cooling for CCW and charging pumps, as well as HVAC for important safeguards systems throughout the plant. SW is a support system for both component cooling and chilled water systems. The plant has another dependency that most plants do not, i.e., RCP seal thermal barrier cooling depends on offsite power. Some of these dependencies may have been addressed by recent post-submittal improvements (see related question).

Also, it could be noted that the IPE submittal's results point out a high or relatively high conditional core damage probability (CCDP) for certain initiators, e.g., a CCDP of 0.48 for loss of SW, 3.7E-02 for loss of two 120V AC panels, 1.1E-03 for loss of offsite power.

In view of the above, please justify your treatment of the vulnerability issue. Please consider the situation where the CDF groups are not divided into subgroups or where a definition of vulnerabilities similar to the one mentioned above were used, and state whether or not vulnerabilities (and which ones) would exist for your plant. Please also state what would be the actions taken to address such vulnerabilities and what would be the impact of these actions on your results.

Response

As noted, the vulnerability issue was explicitly addressed using the NUMARC(NEI) Guidelines. These categories were screened against the NUMARC screening criteria to determine if additional actions need to be taken to address vulnerabilities. Also as noted above, there are other methods that can be used to identify vulnerabilities, such as, using system level importance calculations, review of top sequences, or by initiating event contribution to core damage frequency. Although these methods were not explicitly addressed and discussed in the IPE Submittal, they were used implicitly in the vulnerability screening process. In addition, as the IPE program was in progress, vulnerabilities were identified during the development of the plant response trees, system analyses (fault tree development), and human reliability analysis.

Development of an IPE requires a detailed review and understanding of many documents. For example, the development of the plant response trees requires a detailed review of emergency operating procedures and abnormal operating procedures, development of success criteria, and identification of system/operator interactions. The system analyses require detailed review of the system surveillance test procedures, mechanical maintenance procedures, system operating procedures, system alignment requirements, system design information, FSAR, P&IDs, and identification of system/operator interactions. The human reliability analysis also requires detailed review of much of the same documentation to ensure the HRA analysts fully understand the actions being modeled and interactions between the operator and equipment. In addition, throughout the process the analysts involved in the IPE effort are discussing the modeling, assumptions, plant response, plant operating history, system and component operating history, etc. with knowledgeable plant personnel. At the completion of the IPE process, the plant and its vulnerabilities are fully understood and providing a concise summarization of the vulnerabilities is a formality. The NUMARC process was used in this submittal to summarize the screening for plant vulnerabilities to be consistent with the industry, but the identification of vulnerabilities was not limited to using the NUMARC process. As noted, vulnerability identification was done as an ongoing process. The discussion of the vulnerabilities are organized along the NUMARC Guidelines, but implicitly includes all the knowledge gained from the complete IPE process. The vulnerabilities identified would remain the same regardless of the formal process used to present and discuss them in the Submittal Report.

For instance, consider using the summary of core damage frequency by initiating event (see Submittal Table 3.4-1). This indicates that loss of offsite power events contribute 39% to the core damage frequency. Then from reviewing the top 100 accident sequences, it is seen that failure of the diesel generators to function is a key event. Reviewing the top accident sequences shows that failure of chilled water is also an important event. This appears as a system failure in sequences involving loss of offsite power and it also is important as a special initiator (total loss of chilled water). A close examination of the information provided by the accident sequences, core damage frequency by initiator, and top event importances leads to the same conclusions provided from the NUMARC process. The primary conclusion is that failure of support systems dominate the VCSNS risk profile, and that the chilled water system and the station blackout event are important contributors.

It should also be noted that several IPE full and partial preliminary quantifications were completed during the IPE process leading to the final results presented in this report.

These included sensitivities that examined the impact of "fixes" for events, system failures, etc. that have significant impacts or contributions to core damage frequency.

The importance of the chilled water system to plant safety was identified during the IPE process. This importance was acknowledged and was addressed by implementing a "Total Loss of Chilled Water" Abnormal Operating Procedure (AOP). Implementation of this procedure in the IPE is reflected only in loss of offsite power events since sequences originating from this initiator were dominating one of the preliminary quantifications. As noted in the vulnerability screening discussion, this AOP is also used to mitigate loss of service water events and loss of chilled water events. When this AOP is fully implemented in the PRA model, the importance of these initiators on core damage frequency will by significantly reduced. The sensitivity analysis in Section 3.4.5 of the IPE Submittal presents and discusses the impact on plant risk of implementing the Total Loss of Chilled Water AOP for all transient events that are initiated by or lead to loss of both trains of chilled water. The results indicate that the contributions from loss of chilled water (directly or indirectly) are greatly reduced. Tables FE Q10-1 and FE Q10-2 provide comparisons of the top event importances and top 10 initiating event contributions to core damage frequency for IPE base case and this sensitivity case.

As noted in the Question, the IIA category was further broken down into contributions from station blackout, loss of offsite power, loss of chilled water, and transients and flood events with loss of support systems. This was done in an effort to identify potential improvements. The IIA category is very broad and includes sequences that originate from different sources and require different plant improvements to address identified issues. For example, RCP seal LOCAs due to failure of seal cooling with offsite power available can be addressed with different improvements than RCP seal LOCAs originating from station blackout events.

One identified plant improvement that goes beyond implementation of the "Total Loss of Chilled Water" AOP will address contributors in Category IIA for all the subcategories except SBO. This plant modification involves changing the cooling dependency of the component cooling water pumps and charging pumps from the chilled water system to the CCW system. This was identified as a plant improvement that will address the contributors to these subcategories and was implemented during the fall '94 refueling outage. The impact of implementing this change on plant safety was evaluated using the plant IPE/PRA model. The results, in terms of core damage frequency by initiator and top event importances, are also shown on Tables FE Q10-1 & 2. This information indicates that the primary plant contributor to core damage frequency is now from station blackout events. If a detail NUMARC categorization was done on this latest set of PRA results, this same conclusion would be reached.

The use of PSA at VCSNS is not driven by the "pursuit" of lower CDF numbers. As stated before, an integral part of the IPE development process involves quantifying the model with limited recovery actions and conservative assumptions, and then seeking out large contributors. In some cases, more realistic success criteria or crediting a proceduralized recovery action lowers the likelihood of a particular sequence, or set of sequences. But in other cases, such as the loss of Chilled Water(VU), a need is identified for a plant change. The development of the Loss of VU AOP involved producing a new procedure, pre-staging dedicated hoses, fittings, and tools, and training the operations staff. VCSNS had previous experience operating a charging pump using a temporary demineralized water connection, which added to the confidence level of this procedure. After the IPE was submitted, a decision was made to further eliminate our dependency on VU by using the more reliable CCW system to cool the charging pump skids, and the CCW pump motors. In addition, dedicated connections were installed on the new charging pump cooling lines for "Emergency Cooling" in the event CCW is lost. These connections are in an easily accessed, open area on an elevation directly above the charging pumps. A new Total Loss of CCW procedure was written to address the loss of CCW and take advantage of the pre-staged hoses, and proximity to back-up chilled water, demineralized water, and fire service water sources. This modification had been considered years before, but not until the IPE process was complete had the magnitude of the change on plant safety been understood. This is one of the key benefits of the IPE/PSA process, and demonstrates the adherence to the intent of Generic Letter 88-20 in understanding the most likely severe accident sequences. Other plant changes, are discussed in the response to front end question number 12.

The importance of SBO has not yet been completely addressed. Installation of the new reactor coolant pump seal O-rings and a fire service system connection to RCP seal thermal barrier cooling have not yet been implemented. Credit has not been taken for either of these improvements in the IPE or latest PRA update. To improve diesel generator performance when using back-up fire service water cooling, steps were added to the EOPs to monitor the DG temperatures and reduce loads if the engine temperature increased. The IPE did not take credit for this either.

Within the industry, the NRC is currently examining the RCP seal LOCA issue. The latest information from the NRC indicates that the SBO issue will be addressed by the plant IPEs, although no guidance has yet been issued.

It is concluded from this discussion that examining for vulnerabilities using different measures will still lead to the same conclusions. As noted by the reviewer, there are different methods that can be used to "uncover" vulnerabilities. The plant improvements implemented to date reduce the contributions to CDF from system or event failures to acceptable levels based on the NUMARC screening criteria and good engineering judgement, which includes input from a variety of sources as previously discussed. The process at VCSNS, which in affect is still in progress via the "living PSA", goes beyond trying to juggle CDF numbers. The modification which removed the VU system from the charging and CCW pumps demonstrates the continuing use of risk insights to improve safety at VCSNS.

The lone remaining issue is SBO. As stated, this is an ongoing issue. The current Westinghouse guidance is to replace the standard O-rings with the new high temperature O-rings that tend not to extrude under SBO(or loss of seal cooling) conditions. See front end question 12 for details on planned implementation.

VCSNS uses the time dependent Westinghouse methodology to determine the likelihood of core uncovery due to seal leakage. This seal LOCA model, which is discussed in section 3.1.7 of the IPE submittal, includes very conservative early failure mechanisms including seal binding and "popping". The resulting event tree node(CNU) is used to evaluate the probability of core uncovery at various time steps in the SBO event tree, and after recovery of systems required to support seal cooling. The CNU node produces a large penalty for even short term interruption of seal cooling. The value of CNU at one hour, or the probability that the core has uncovered within the first hour, is 0.02829. This conservatively high value may over-state the impact of RCP seal LOCAs to some degree.

Table FE Q10-1 Summary of Top Event Importance Rankings					
IPE Base Case		IPE Sensitivity Case		PRA Update Case	
Top Event Name	Importance Ranking	Top Event Name	Importance Ranking	Top Event Name	Importance Ranking
VU	39.5	AC	51.5	AC	54.7
AC	39.4	VU	38.4	SBO	45.7
SW	27.2	SBO	35.0	1HR	42.4
SBO	26.5	1HR	32.5	4HR	29.4
1HR	24.6	LPR	28.8	CNU	23.9
SLO	23.4	HPI	23.1	CC	20.5
LPR	21.9	4HR	22.6	XHR	17.4
SWR1	20.1	CNU	16.6	LPR	16.2
SWR2	20.1	ESF	15.9	SW	14.1
ESFS	19.4	VUSB	15.4	OAAC	13.0
HPI	17.2	SLO	15.4	HPI	11.5
4HR	17.1	XHR	13.3	YHR	11.3
CNU	12.9	SW	11.0	REC	6.5
ESF	12.3	ESFS	10.1	EFT	6.3
SWS	12.0	YHR	8.7	LCCW	6.2
VUSB	11.7	OASC	7.6	ESF	6.1
XHR	10.7	REC	6.7	EFW	5.6
YHR	6.6	VUFW	6.5	OAF	5.6
VUR1	6.0	RBC	6.3	RBC	5.2

Table FE Q10-1 (Cont'd)
Summary of Top Event Importance Rankings

IPE Base Case - Results presented in the IPE Submittal Report

IPE Sensitivity Case - Same as the IPE Base Case, but with implementation of Loss of Chilled Water Abnormal Operating Procedure throughout the model (see IPE Submittal Report Section 3.4.5).

PRA Update Case - Same as IPE Base Case with the elimination of component cooling water pump and charging pump dependency on chilled wat· ·

Definitions

VU - Chilled water system failure
AC - AC power (diesel generators) failure
SW - Service water system failure
SBO - Station blackout (diesel generator and service water system failures following loss of offsite power)
1HR - Offsite power recovery within 1 hour fails
SLO - Consequential seal LOCA (loss of RCP seal cooling following transient events due to SW, VU, or CC support system failures or seal failures)
LPR - Low pressure recirculation failure
SWR1 - Restore SW in 2 hours: failure of plant personnel to restore one train of service water within 2 hours following transient events with loss of service water and loss of service water events
SWR2 - Restore SW in 3 hours: failure of plant personnel to restore one train of service water within 3 hours following transient events with loss of service water and loss of service water events (Note: SWR2 fails with the probability of 1.0 given SWR1 fails.)
ESFS - Engineered Safety Features Actuation System Switch: applied as an event tree switch for transient events if ESF recovery is not addressed (not applicable) to direct path through the event tree. If ESF recovery is addressed, it represents failure of OA or failure of OA plus VU and CC. The relatively high importance to CDF is due to the switch function which does not indicate system failure.

Table FE Q10-1 (Cont'd)
Summary of Top Event Importance Rankings

Definitions(Cont'd)

HPI -	High pressure injection failure
4HR -	Offsite power recovery within 4 hours fails
CNU -	Core not uncovered (core uncovery and core damage occur because of loss of RC inventory through RCP seals)
ESF -	Engineered safety features system failure
SWS -	Service water switch: applied as a switch (0 or 1 value) to direct support states of transient events not supporting RCP seal cooling and recovering SW to the loss of SW event tree. If RCP seal cooling is available and SW recovery is addressed it then represents random failure of RCP seals. The relatively high importance to CDF is due to the switch function which does not indicate system failure.
VUSB -	Standby chilled water train cooling (availability of the installed spare chilled water pump and chiller)
XHR -	Offsite power restored in X hours (offsite power not recovered before core damage occurs)
YHR -	Offsite power restored in Y hours (offsite power not recovered before containment fails)
VUR1 -	Restore chilled water in 12 Hours (failure of plant personnel to restore one train of chilled water within 12 hours)
OASC -	Operator action to align alternate cooling to the charging pumps
REC -	Recovery switch (switch used to direct recoverable support states for transient events to appropriate event trees)
RBC -	Reactor building cooling units
VUFW -	Chilled water flow/no flow split (percentage of time VU failures are due to chillers)
CC -	Component cooling water failure
OAAC -	Operator action to establish alternate cooling to the charging pumps
EFT -	Emergency feedwater from turbine-driven pump
LCCW -	Loss of component cooling water support state switch
EFW -	Emergency feedwater system failure
OAF -	Operator action to align condensate feedwater

Table FE Q10-2
Summary of Core Damage Frequency by Initiating Event

Initiating Event	IPE Base Case		IPE Sensitivity Case		PRA Update Case	
	CDF	Percent	CDF	Percent	CDF	Percent
Loss of Offsite Power	8.01E-05	39.3	8.01E-05	52.0	6.51E-05	53.4
Small Loss of Coolant Accident	2.72E-05	13.4	2.72E-05	17.6	1.68E-05	13.8
Total Loss of Service Water	1.74E-05	8.6	9.59E-07	0.6	2.56E-06	2.1
Loss of Main Feedwater	1.49E-05	7.3	7.82E-06	5.1	3.24E-06	2.7
Total Loss of Chilled Water	1.14E-05	5.6	2.16E-06	1.4	--	--
Reactor Trip	1.08E-05	5.3	5.48E-06	3.6	2.06E-06	1.7
Medium Loss of Coolant Accident	7.62E-06	3.7	7.62E-06	5.0	7.47E-06	6.1
Partial Loss of Main Feedwater Flow	5.73E-06	2.8	3.01E-06	2.0	1.25E-06	1.0
Turbine Trip	5.39E-06	2.7	2.82E-06	1.8	1.14E-06	0.9
Inadvertent Safety Injection Signal	4.24E-06	2.1	2.23E-06	1.5	9.22E-07	0.8
Total Core Damage Frequency	2.04E-04		1.54E-04		1.22E-04	

IPE Base Case - Results presented in the IPE Submittal Report

IPE Sensitivity Case - Same as the IPE Base Case, but with implementation of Loss of Chilled Water Abnormal Operating Procedure throughout the model (see IPE Submittal Report Section 3.4.5)

PRA Update Case - Same as IPE Base Case with the elimination of component cooling water pump and charging pump dependency on chilled water.

11) NUREG-1335, Section 2.1.6 part 4 requests "a thorough discussion of the evaluation of the decay heat removal function." Section 3.4.3, Decay Heat Removal (DHR) Evaluation, deals with this issue. However, certain details are missing. Please provide the contribution of DHR and its constituent systems (including feed and bleed) to CDF and the relative impact of loss of support systems on the frontline systems that perform the DHR function.

Response

Decay heat removal, as modeled in the VCSNS IPE, is accomplished by two different means; emergency feedwater and bleed and feed cooling. Decay heat removal using emergency feedwater also requires the condenser steam dump system, the steam generator atmospheric steam dump valves, the steam generator PORVs, or the steam generator safety valves for steam removal from the steam generator. Bleed and feed cooling is provided by high-pressure injection/recirculation or low-pressure injection/recirculation. Except for large and medium LOCAs which have a sufficient break flow, both high- and low-pressure recirculation require the pressurizer PORVs for the bleed path for bleed and feed cooling. The normal residual heat removal system is also modeled for cases in which the RC system has been successfully cooled down and depressurized. The RH system heat exchanger is required for removing the decay heat for bleed and feed operation and for normal RH system operation. The reactor building cooling units are modeled as a backup source for removing decay heat for bleed and feed operations.

The table below provides information about the relative contribution to core damage of the systems modeled for decay heat removal. The column titled "Importance" relates the summation of accident sequence frequencies in which the system/component top events appear (either due to random failure or guaranteed failure because of support system failures) to the total core damage frequency, expressed as a percentage. The list below is limited to those systems/components which have an importance greater than 1%.

System/Component	Importance (%)
Low-Pressure Recirculation	21.92
High-Pressure Injection	17.22
Reactor Building Cooling Units	4.81
Low-Pressure Injection	4.09
Emergency Feedwater	3.74
Pressurizer PORVs	2.84
High-Pressure Recirculation	2.04
SG Pressure Relief	1.12

The availability of the systems used for decay heat removal is dependent on the availability of their support systems. The support systems required for the decay heat removal components are discussed in Appendix C of the VCSNS IPE. The relative impact of the loss of support systems on the frontline systems that perform the decay heat removal functions can be shown by comparison. The table which follows presents the system unavailability with all support available, the system unavailability when the loss of support has degraded the system (e.g., only one train is supported), and the approximate factor for the unavailability increase. The examples are taken from VCSNS IPE Table 3.3.5-1.

System	Case Description	Unavailability	Factor Increase
Emergency Feedwater	1/2 MD pumps or 1 TD pump to 1/3 SGs, all support, tran, OA, & AMSAC	4.96E-05	-
	1/2 MD pumps or 1 TD pump to 1/3 SGs, train A (or B) fails, OA, & AMSAC	2.55E-04	5
	1/2 MD pumps or 1 TD pump to 1/3 SGs, TDP only, OA, & AMSAC	2.16E-02	400
High-Pressure Injection	1/2 CHG/SI pumps to 2/3 cold legs, all support avail, SLOCA	5.08E-04	-
	1/2 CHG/SI pumps to 2/3 cold legs, Train A fails, SLOCA	5.21E-03	10
	1/2 CHG/SI pumps to 2/3 cold legs, Train B fails, SLOCA	1.28E-02	25
High-Pressure Recirculation	1/2 RH pumps, 1/2 CHG/SI pumps to 2/3 cold legs, all support avail	2.02E-03	-
	1/2 RH pumps, 1/2 CHG/SI pumps to 2/3 cold legs, Train A fails	3.17E-02	15
	1/2 RH pumps, 1/2 CHG/SI pumps to 2/3 cold legs, Train B fails	3.09E-02	15
Low-Pressure Injection	1/2 RH pumps to 2/2 intact cold legs, (HPI success), all support avail	6.82E-03	-
	1/2 RH pumps to 2/2 intact cold legs,	2.37E-02	4

	(HPI success), loss of 1 train support		
Low-Pressure Recirculation	Cold leg recirc, 1/2 RH pumps to 2/2 cold legs, all support avail	6.19E-04	-
	1/2 RH pumps to 2/2 cold legs, Train /B fails	1.17E-02	20
Pressurizer PORVs	2/3 Pzr PORVs & block valves fail to open, all support	3.47E-04	-
	2/3 Pzr PORVs & block valves fail to open, only Train A DC, all AC avail	5.98E-03	15
	2/3 Pzr PORVs & lock valves fail to open, Train A DC, Only Train A AC avail	9.02E-02	250
Reactor Building Cooling Units	RBCUs providing cooling, 1/2 RBCU, all support avail	4.46E-03	-
	RBCUs providing cooling, 1/1 RBCU, Train A/B fail	4.69E-02	10
Steam Generator Relief Valves	A similar comparison case is not available from VCSNS IPE Table 3.3.5-1		

With the exception of the emergency feedwater system, the system unavailabilities generally increase 10 to 25 times from the all support available cases to the one train support available cases. The emergency feedwater system unavailability results show a modest increase of approximately 5 times when one motor-driven pump train is unavailable, and a large unavailability increase (~400 times) when only the turbine-driven pump is available.

Neither the system importances nor the system unavailabilities, listed above, reveal whether the majority of decay heat removal system failures are in combination with support system failures (i.e., limiting the trains available). To assess this, the CDF sequences listed VCSNS IPE submittal Table 3.4-3 were reviewed. The top 22 CDF sequences each contributed 1% or more to the total CDF, and only two of these include a decay removal system failure when support was available for all trains. In addition, of the top 100 CDF sequences, only 12 include a decay removal system failure when support was available for all trains. The 12 sequences contributed less than 10% of the total CDF. For the rest of the sequences which have failures of the decay heat removal systems, support system failures have limited the number of trains available. The CDF contributions due to all-train available failures of the decay heat removal systems are small because the multi-train designs are reliable.

The results are consistent with the decay heat removal system design features of (1) a two-train high pressure injection/recirculation system with 3 100% capacity pumps; (2) a two-train low pressure injection/recirculation system with 2 100% capacity pumps; (3) a three-train emergency feedwater system with 2 100% capacity motor driven pumps and one turbine driven pump; (4) two trains of reactor building cooling units (one train required for success); (5) 3 pressurizer PORVs (2 of 3 were modeled for success, but further analysis could show only 1 of 3 would be required); and (6) multiple steam release paths through the atmospheric steam dump valves, the steam dump valves to the condenser, the steam generator PORVs and the steam generator safety valves.

This information supports the conclusions in VCSNS IPE Section 3.4.3 that the decay heat removal systems provide an effective and reliable means for decay heat removal.

12) It is not always clear from the IPE submittal whether the plant improvements described are being proposed for further consideration or were actually implemented. For example, in Section 3.4.2, Vulnerability Screening, mention is made of the new RCP seal O-rings and a fire water connection for RCP thermal barrier cooling, yet these actions do not appear on the list of improvements (proposed and/or implemented) in Section 6.1, Plant Improvements. In addition, please provide the details of certain recent improvements which may address the chilled water dependency of the charging and CCW systems (apparently, chilled water is no longer used for CCW motor cooling, i.e., CCW now cools itself, and charging pumps are no longer cooled by chilled water but by CCW).

Please provide the following, if not already provided, regarding each improvement:

a. The specific improvements that have been implemented, are being planned or are under evaluation.
b. The status of each improvement, i.e., whether the improvement has actually been implemented already, is planned (with scheduled implementation date), or is under evaluation.
c. The improvements that were credited in the reported CDF.
d. If available, the reduction to the CDF or the conditional containment failure probability that would be realized from each plant improvement if the improvement were to be credited in the reported CDF (or containment failure probability), or the increase in the CDF or conditional containment failure probability if the credited improvement were to be removed from the reported CDF (or containment failure probability).
e. The basis for each improvement, i.e., whether it addressed a vulnerability, was otherwise identified from the IPE review, was developed as part of other NRC rulemaking (such as the SBO Rule), etc.

Response

Section 6.1 of the IPE Submittal lists the improvements to the plant that were a result of the IPE Program. These improvements address potential vulnerabilities or deficiencies, either directly or indirectly, that improved operator response to accidents or improved system or component performance. In addition to these improvements, the Submittal also discusses the use of the new O-rings in the reactor coolant pumps and also the use of the fire service system for emergency RCP thermal barrier cooling.

Table FE Q12-1 provides a summary of the plant improvements discussed in the submittal and also the improvement to eliminate the dependency of the component cooling water pumps and charging pumps on the chilled water system for cooling. For each improvement, the following information is provided:

- description of the improvement
- date the improvement was implemented in the plant or status of evaluation
- whether or not the improvement was credited in the IPE
- the impact of the improvement on the core damage frequency
- the basis for the improvement

This provides the information requested in parts a-e of the question.

As noted on this table, the majority of the improvements have not been credited in the IPE. One improvement was evaluated in a sensitivity study and provided in the IPE Submittal Report (Item 1), and one was evaluated in a study after the IPE results were submitted to the NRC (Item 11). It is difficult to quantify the benefits of several of the improvements due to the qualitative nature of the changes. The benefits of several of the improvements are qualitatively assessed to be relatively small (Items 2, 7).

Item 11 provides some information on the elimination of chilled water dependency of the component cooling water (CCW) pumps and charging pumps. This plant modification involved changing the charging pump cooling to the CCW system and using CCW flow to also cool the CCW pump motors. This change was evaluated using the VCSNS IPE through detailed modeling changes. The results of the evaluation are provided in Table FE Q12-2 for core damage frequency distribution by initiating events, and in Table FE Q12-3 for top event importances (for those with a ranking greater than 5). From this summary, it is seen that the impact of implementing this change has a significant impact on the plant risk profile. The core damage frequency is reduced to 1.22E-04/yr from the IPE Submittal value of 2.04E-04/yr. The current "best estimate" PRA model, that incorporates plant specific data through mid-1993, shows a further reduction in CDF primarily due to lower initiating event frequencies.

Table FE Q12-1 Summary and Status of VCSNS Improvements					
Plant Improvement	Improvement Description	Date Implemented In Plant	Credited In IPE	Impact on CDF (1)	Basis For Improvement
1. Alternate Charging Pump Cooling	Developed Abnormal Operating Procedure "Total Loss of Chilled Water". Use AOP following loss of both trains of chilled water. Alternate cooling for charging pumps is established, using the preferred Demineralized Water System or the Fire Service System, so RCP seal injection can be maintained.	7/93	IPE credit only for LOSP event Sensitivity credit for all events	2.04E-04 (2) 1.54E-04	IPE Vulnerability
2. Chilled Water System Reliability	A "chiller rotation" policy to reduce the time a chiller will be down has been implemented. Data has indicated a correlation between chiller downtime and failure to start probability.	1/93	No	NA	IPE Vulnerability

Table FE Q12-1 Summary and Status of VCSNS Improvements					
Plant Improvement	Improvement Description	Date Implemented In Plant	Credited In IPE	Impact on CDF (1)	Basis For Improvement
3. Diesel Generator Temperature Monitoring	The Fire Service System is a backup to the Service Water System for DG cooling, but the Fire Service System is not sized to maintain the DG at rated load. Steps were added to an Emergency Operating Procedure to monitor DG temperature and reduce load if temperatures increase.	9/92	No credit in IPE for alternate cooling of DG	NA, but will reduce SBO frequency due to failure of service water	IPE System Analysis
4. Energizing Pressurizer PORV Block Valves	Revised EOP "Response to Loss of Secondary Heat Sink" to direct operators to re-energize any PZR PORV block valves that were closed and racked out. The steps were moved up in the procedure to allow operators more time to prepare for feed and bleed before complete loss of heat sink.	8/92	Yes	NA, included in IPE Submittal report results(3)	IPE System Analysis

Table FE Q12-1 **Summary and Status of VCSNS Improvements**					
Plant Improvement	Improvement Description	Date Implemented In Plant	Credited In IPE	Impact on CDF (1)	Basis For Improvement
5. Use of Main Feedwater Pumps for a Loss of Heat Sink Event	Use the turbine-driven Feedwater System pumps to supply feedwater to the SGs if the Emergency Feedwater System fails. Currently, EOPs call for using feedwater booster pumps which require SG depressurization to less than 350 psig (the HRA showed the operator could not complete the required steps in the available time).	Not Implemented	No	NA, but will reduce the CDF due to transients that do not lead to consequenti al LOCAs	IPE System Analysis
6. Bypasses and Inoperable Status Indication (BISI)	The computerized BISI System, which provides a graphic control room indication of critical system operability, was reviewed and updated based on insights gained during the IPE system analyses.	6/91	No	NA, but will improve operator awareness of system problems	IPE Related Improvement

Table FE Q12-1 Summary and Status of VCSNS Improvements					
Plant Improvement	Improvement Description	Date Implemented In Plant	Credited In IPE	Impact on CDF (1)	Basis For Improvement
7. Reactor Building Instrument Air Supply	Operators are required to re-establish instrument air to the pressurizer PORVs to ensure sufficient air supply is available for multiple openings of the PORVs during feed and bleed. Locally opening of the valve dominating failure to re-establish instrument air was included as an improvement.	12/93	No	NA, but will improve feed and bleed availability	IPE System Analysis
8. Training and Emergency Planning Input	The IPE results have been used to identify drill scenarios that can be used in training and emergency planning.	2/93	No	NA, but there would be some benefit to HEPs lowering CDF	IPE Related Improvement

Table FE Q12-1 Summary and Status of VCSNS Improvements					
Plant Improvement	Improvement Description	Date Implemented In Plant	Credited In IPE	Impact on CDF (1)	Basis For Improvement
9. New RCP Seal O-rings	Use of new RCP seal O-ring to provide better performance under loss of thermal barrier cooling and seal injection conditions	Will be phased in during normal pump maintenance starting with the 1997 Fall outage (Refuel 10)	No	NA, but will improve ability of the plant to with-stand SBO	IPE Vulnerability
10. Fire Water Connection for RCP Thermal Barrier Cooling	Alternate and diverse cooling source for RCP thermal barrier to address loss of RCP seal cooling events.	Not Planned	No	NA, but could reduce CDF due to SBO events	IPE Risk Informed Improvement
11. Elimination of CCW and Charging/SI Pump Chilled Water Dependency	Change the cooling dependency of the CCW pumps and charging pumps from the chilled water system to the CCW system	11/94	No	1.22E-04	IPE Risk Informed Improvement

Table FE Q12-1 Summary and Status of VCSNS Improvements					
Plant Improvement	Improvement Description	Date Implemented In Plant	Credited In IPE	Impact on CDF (1)	Basis For Improvement
12. Installation of key switches to allow use of condensate feed during a loss of EFW.	Key switches have been provided, with the keys kept in the control room, to bypass FW isolation signals during a loss of heat sink accident. (4)	11/94	No	NA, but will reduce CDF due to loss of heat sink events	IPE Risk Informed Improvement

Notes:

1 - This column provides the core damage frequency with the improvement implemented.

2 - The results presented in the IPE Submittal report credit the "Loss of Chilled Water" AOP during loss of offsite power event only.

3 - The IPE does include the action to re-energize and open a closed pressurizer PORV block valve if closed, in order to initiate feed and bleed cooling. However, based on PSA input, the operator action to re-energize any closed & de-energized block valve has been moved to the front of the Loss of Heat Sink EOP. This will increase the allowed operator action time beyond the original 30 minute assumption, and increase the likelihood of success. A new HEP has not been calculated for this procedure change.

4 - The switches eliminate the need to install jumpers and remove a fuse, in order to re-open the FW isolation valves after an SI has occurred. See the response to front end question number 5 for more details on the procedure to establish condensate feed after a loss of all EFW. The original HRA analysis of the time available to establish condensate feed and the required actions to enable condensate feed(ie, jumpers & fuses) led to the conclusion that the required actions could not be completed in time. Therefore, the HEP for OAF(Establish Condensate Feed) was set to a value of 1.0(ie, assumed to fail). The use of the new switches will be included in a future PRA model update. No impact on CDF is available at this time.

Table FE Q12-2 Summary of Core Damage Frequency by Initiating Event (Elimination of CCW and Charging Pump Dependency on Chilled Water)		
Initiating Event	**CDF**	**Percent**
Loss of Offsite Power	6.51E-05	53.4
Small Loss of Coolant Accident	1.68E-05	13.8
Total Loss of Component Cooling	1.33E-05	10.9
Medium Loss of Coolant Accident	7.47E-06	6.1
Loss of Main Feedwater Flow	3.24E-06	2.7
Large Loss of Coolant Accident	2.75E-06	2.3
Total Loss of Service Water	2.56E-06	2.1
Reactor Trip	2.06E-06	1.7
Partial Loss of Main Feedwater Flow	1.25E-06	1.0
Turbine Trip	1.14E-06	0.9
Total Loss of Instrument Air	1.13E-06	0.9
Flooding Initiator, Loss of Train A CCW	1.10E-06	0.9
Safety Injection Signal (Inadvertent)	9.22E-07	0.8
Positive Reactivity Insertion	9.06E-07	0.7
Steam Generator Tube Rupture	6.59E-07	0.5
Primary System Transient	6.31E-07	0.5
Loss of Condenser	2.10E-07	0.2
Loss of Reactor Coolant Flow	2.04E-07	0.2
Loss of One 125 VDC Bus	1.39E-07	0.1
Flooding Initiator, Loss of Train A SW	1.27E-07	0.1
Interfacing Systems LOCA	1.04E-07	0.09
Reactor Vessel Rupture	1.00E-07	0.09

Table FE Q12-2 Summary of Core Damage Frequency by Initiating Event (Elimination of CCW and Charging Pump Dependency on Chilled Water)		
Initiating Event	**CDF**	**Percent**
Secondary Side Break Inside Containment	7.21E-08	0.06
Inadvertent Opening of Steam Valve	4.39E-08	0.04
Secondary Side Break Outside Containment	3.56E-08	0.03
Flooding Initiator, Loss of Train B SW	1.31E-08	0.01
Loss of 120 VAC Panels 5901-5904	6.12E-10	0.00
Total	1.22E-04	--

Table FE Q12-3 **Summary of Top Event Importance Rankings** **(Elimination of CCW and Charging Pump Dependency on Chilled Water)**	
Top Event Name	Importance Ranking
AC Power (AC)	54.7
Station Blackout (SBO)	45.7
Power Recovery in 1 Hour (1HR)	42.4
Power Recovery in 4 Hours (4HR)	29.4
Core Not Uncovered (CNU)	23.9
Component Cooling Water (CC)	20.5
Power Restored in X Hours (XHR)	17.4
Low Pressure Recirculation (LPR)	16.2
Service Water (SW)	14.1
Operator Action, Establish Alternate Cooling to Charging Pumps (OAAC)	13.0
High Pressure Injection (HPI)	11.5
Power Restored in Y Hours (YHR)	11.3
Recovery Switch (REC)	6.5
EFW from TDP during SBO (EFT)	6.3
LOSP, Loss of CCW Support State Switch (LCCW)	6.2
Engineered Safety Features- signals (ESF)	6.1
Emergency Feedwater (EFW)	5.6
Operator Action, Align Condensate Feed (OAF)	5.6
Reactor Building Cooling (RBC)	5.2
Low Pressure Injection (LPI)	5.1

13) In your discussion of core cooling success criteria, it is stated that the operators are not required to initiate the inadequate core cooling procedure until the steam temperature in the vessel is greater than 700°F (in conjunction with a low reactor vessel level indication system (RVLIS) indication). However, at this temperature, the pressure is 3100 psi, and at 705°F, the critical pressure for saturated steam, the pressure is over 3200 psi. It is not clear whether the steam is saturated or superheated. Please clarify. If the steam is saturated, please verify that the limiting reactor coolant system (RCS) pressure (e.g., used in your anticipated transient without scram (ATWS) analysis) is above 3200 psi, and discuss what bearing, if any, this pressure has on the procedure addressing inadequate core cooling. Also please verify that the correct core cooling success criteria used in your Modular Accident Analysis Program (MAAP) analysis is 1200°F for maximum fuel cladding temperature, not for core exit thermocouple temperature as stated in the submittal.

Response

The discussion of the basis for the core cooling success criteria, presented in page 3-6 of the V.C. Summer IPE is based on the definitions of degraded and inadequate core cooling used in the V.C. Summer Emergency Operating Procedures (i.e., the Monitoring Critical Safety Functions - EOP-12.0). The 700°F and 1200°F values in the Critical Safety Function Status Trees refer to the fluid conditions measured by the core exit thermocouples which are situated at the top of the fuel assembly. These success criteria were chosen to assure consistency with the operator actions modeled in the VCSNS IPE plant response trees.

In all cases where this success criteria is used in the VCSNS IPE, the fluid measured by the core exit thermocouples is expected to be superheated steam. The core cooling criteria was not used in the ATWS plant response tree for cases in which the RCS pressure is greater than the pressurizer safety valve setpoint (see ATWS plant response tree on page A-81 of the VCSNS IPE and note that top event HPI only appears in accident sequence paths where other previous successes have resulted in RCS pressures less than the pressurizer safety valve setpoint). Thus, we are always considering plant conditions where the steam exiting the core is superheated. In these cases, the core is partially uncovered, as when the core exit thermocouples indicate 700°F or greater, the water in the reactor vessel is steaming from the top of the mixture level. This steam would gain additional heat as it passes the uncovered portion of the fuel rods and becomes superheated. Thus, the measurement of fluid temperatures at the core exit would indicate a superheated state with respect to the reactor coolant system pressure.

Where the 700°F and 1200°F temperature success criterion were used to interpret the results of severe accident thermal hydraulic analyses (e.g., MAAP code results), the code parameter for the hottest core node temperature was used rather than the steam temperature exiting the core. The description of the core cooling success criteria on page 3-6 of the VCSNS IPE could be clarified to reflect that the actual success criteria was a 1200°F hottest fuel node from the results of the MAAP analyses. However, the success criteria is technically correct since the hottest core node will always reach the specified temperature before the core exit thermocouples reach that same temperature. Since MAAP 3.0 core model does not include separate nodes for the cladding and the fuel pellets, the hottest core node temperature represents a lumped core node containing both cladding and fuel material. Evaluations documented in the WOG Emergency Response Guidelines, Rev. 1B provide evidence that the difference between the peak fuel rod cladding temperature and the fluid conditions at the core exit thermocouple location can be more than 200°F. Brookhaven National Laboratories have performed an extensive investigation of the applicability of the MAAP 3.0 code for developing success criteria and concluded that the MAAP 3.0 code can be used to determine success criteria as long as, among other criteria, the core temperature does not exceed 1200K, which is approximately 1700°F ["The MAAP 3.0B Core Evaluation Final Report", Brookhaven National Laboratories, FIN-L-1499, October 1992]. Thus, the use of a 1200°F hottest core node from the MAAP code as the criteria for core cooling success is within the applicable range as determined by Brookhaven National Laboratories and is below the temperature at which the plant operating staff would be expected to use the Inadequate Core Cooling Functional Restoration Procedure, EOP-14.0.

14) The success criteria used in the VCSNS IPE submittal are more optimistic than the ones traditionally used for certain accidents in previous probabilistic risk assessments (PRAs). The success criteria in the submittal can be compared to those in the NUREG/CR-4550 analysis, specifically the ones for Surry, as the two plants have certain outward similarities (both are 3-loop Westinghouse PWRs of similar power ratings, with VCSNS having a higher rating, and the containments are of equal size though Surry's is subatmospheric). In addition the LOCA size ranges for LOCA categories are the same as in the NUREG/CR-4550 analysis for Surry (with the minor variation that your small LOCAs also encompass the very small LOCAs defined for Surry, i.e., RCP seal failures, etc.). The specific instances where your success criteria differ are noted below:

- for large LOCAs, the short term success is defined as either one residual heat removal (RHR) pump (with no accumulators needed) or one high head injection (HPI) pump in conjunction with 2/2 accumulators. No early containment pressure suppression is required. The success criterion used in the NUREG/CR-4550 requires 2/2 accumulators in addition to the RHR pump, and the HPI pump is not credited. Also, early containment pressure suppression is required for containment integrity.

- for medium LOCAs, the submittal's success criteria indicate that the RCS pressure will stay above the RHR pump shutoff head, unless action is taken to depressurize via the secondary side. In the NUREG/CR-4550 analysis, medium LOCA will lead to a quick RCS depressurization, such that one RH pump and two accumulators are needed, in addition to the one HPI pump. Early containment pressure suppression is needed, as well.

a. Are these novel success paths reflected in the emergency procedures, and if not how were the HEPs estimated for the actions needed in these success paths?

b. What is the impact on timing of operator actions if containment sprays come on in certain LOCAs? Are the operators instructed to shut off the sprays to conserve the refueling water storage tank (RWST) water? If yes, how are such actions accounted for in the model? If not, does the timing of your scenarios account for the fact that the RWST will run out of RWST sooner than anticipated because both trains of sprays might come on automatically?

c. If available, please estimate the impact of these novel success paths on your results (CDF, important sequences).

Response

Discussion of Large LOCA Success Criteria

In the question, it is stated: "-for large LOCAs, short term success is defined as either one RHR pump (with no accumulators needed) or one HPI pump in conjunction with 2/2 accumulators. The success criterion used in NUREG/CR-4550 requires 2/2 accumulators in addition to the RHR pump, and the HPI pump is not to be credited."

In fact, as noted in the VCSNS Large LOCA PRT notebook and the VCSNS Success Criteria notebook, low pressure injection is required for short term success. There are no paths on the large LOCA PRT which end in success (i.e., no core damage) without success of low pressure injection. Consideration of high pressure injection and accumulators will only delay core damage, as seen in the end states for the large LOCA PRT. To define this success criteria, a VCSNS-specific analysis for a large LOCA event, using the MAAP computer code, was completed which showed that 1 RHR pump will prevent core exit temperatures from exceeding 1200°F. The MAAP results are discussed in the VCSNS Success Criteria notebook, and are presented in Appendix A of this notebook. It is noted that in NUREG/CR-4550, there is not a detailed discussion as to the source of the success criteria (i.e., low pressure injection AND 2/2 accumulators). This success criteria is believed to be excerpted from Surry design basis analysis; the results of such analysis are recognized to be conservative due to the inherent conservative assumptions of such analysis.

Additionally, the question states: "...No early containment pressure suppression is required. ...early containment pressure suppression is required [in NUREG/CR-4550] for containment integrity."

To define the containment cooling success criteria, VCSNS-specific analyses for a large LOCA event, using the MAAP computer code, were completed which showed that without any EARLY containment heat removal, containment integrity was maintained during the early part (i.e., injection phase) of the event. For the long term (i.e., recirculation phase), the VCSNS-specific analyses showed that 1 Reactor Building Cooling Unit or at least 1 RHR heat exchanger being cooled while on low pressure recirculation will maintain containment pressure and temperature conditions such that containment integrity is not challenged. The MAAP results are discussed in the VCSNS Success Criteria notebook, and are presented in Appendix A of this notebook. It is noted that in NUREG/CR-4550, there is not a detailed discussion as to the source of the success criteria; the PRT only models 'CS' or containment systems. In fact, it appears that NUREG/CR-4550 only considers containment spray as the containment systems, the heat removal capability of the reactor building cooling units (RBCU) is not acknowledged. Thus, the success criteria of NUREG/CR-4550 does not reveal a true representation of the systems available at VCSNS for containment cooling.

Discussion of Medium LOCA Success Criteria

Regarding Medium LOCA, the question states: "-for medium LOCAs, the submittal's success criteria indicate that the RCS pressure will stay above the RHR pump shutoff head, unless action is taken to depressurize the secondary side. In the NUREG/CR-4550 analysis, medium LOCA will lead to a quick RCS depressurization, such that one RH pump AND two accumulators are needed, in addition to the one HPI pump."

It is believed that part of the discrepancy in comparing VCSNS IPE success criteria results and Surry success criteria results from NUREG/CR-4550 for the medium LOCA is the break size considered. For VCSNS, a medium LOCA is defined in the medium LOCA PRT notebook as '... all postulated reactor coolant system ruptures inside the reactor building with blowdown rates such that RCS pressure remains above the shutoff pressure of the RHR pumps.' Furthermore, it is noted that the range of break sizes considered as medium LOCA in the VCSNS IPE is two to six inches, while the accident progression (and success criteria) model a medium LOCA of approximately two to three inches in diameter. For NUREG/CR-4550, the break size range is defined as 2-6 inches, with no criteria for this range. It is believed that the medium LOCA considered in the NUREG/CR-4550 event tree discussion is the maximum of the range identified.

Additionally, for VCSNS, the plant response for the medium LOCA is based upon MAAP analysis results as discussed in the VCSNS Success Criteria notebook, and presented in Appendix A of this notebook. For NUREG/CR-4550, as there is no detailed discussion of the basis for the success criteria, it is believed that the plant response is based upon a 6-inch small LOCA design basis analysis for Surry or a similar plant. With the degraded SI flow assumed for design basis small LOCA analysis, it is not surprising that the RCS depressurized below the shutoff head for the RHR pumps. A review of the current Surry small LOCA design basis analyses (and VCSNS small LOCA design basis analyses) show that for 2-, 3- and 4-inch cases, the RCS does NOT depressurize below the shutoff head of the RHR pumps, even with the degraded SI flow. It is believed that the representation of a medium LOCA as a scenario in which additional equipment and operator interventions are necessary to utilize the low pressure pumps is a more realistic modeling of such an event.
As stated above for a large LOCA, which bounds the medium LOCA, no early containment pressure suppression is required, whereas early containment pressure suppression is required in NUREG/CR-4550 for containment integrity.

To define this containment cooling success criteria, VCSNS-specific analyses using the MAAP computer code were completed which showed that 1 Reactor Building Cooling Unit or at least 1 RHR heat exchanger being cooled while on low pressure recirculation will maintain containment pressure and temperature conditions. The MAAP results are discussed in the VCSNS Success Criteria notebook, and presented in Appendix A of this notebook. It is noted that in NUREG/CR-4550, there is not a detailed discussion as to the source of the success criteria; the PRT only models 'CS' or containment systems. In fact, NUREG/CR-4550 only considers containment spray as the containment systems, the heat removal capability of the reactor building cooling units (RBCU) is not acknowledged. Thus, the success criteria of NUREG/CR-4550 does not reveal a true representation of the systems available at VCSNS for containment cooling.

a. Success criteria vs. Emergency Procedures

The VCSNS emergency procedures are based on the Westinghouse Emergency Response Guidelines (ERGs) which are symptom based. Thus, the diagnosis of the initiating event is unnecessary to use the VCSNS emergency procedures. Via the use of VCSNS Emergency Procedures EOP-1.0 (Reactor Trip/Safety Injection Actuation), EOP-2.0 (Loss of Reactor or Secondary Coolant), EOP-2.2 (Transfer to Cold Leg Recirculation), EOP-2.3 (Transfer to Hot Leg Recirculation) and EOP-14.0 (Response to Inadequate Core Cooling), the equipment and operator actions modeled in the large and medium LOCA event trees are considered. For instance, EOP-1.0 ensures RHR pumps are running (Step 8) and ensure at least 2 RBCU are running (Step 9). Also, EOP-2.0 checks if RB spray is necessary (Step 8) and via the reference page checks the necessity of transfer to cold leg recirculation.

The operator actions which are modeled in the large LOCA PRT and the relevant VCSNS emergency procedures include:

- Establish RHR Heat Exchanger Cooling (EOP-2.2)
- Realign RHR for Cold Leg Recirculation (EOP-2.2)
- Realign RB spray for RB spray Recirculation (EOP-2.2)
- Realign RHR system for Hot Leg Recirculation (EOP-2.3)

The operator actions which are modeled in the medium LOCA PRT and the relevant VCSNS emergency procedures include:

- Depressurize secondary side (EOP-2.1)
- Depressurize primary side (EOP-14.0)
- Establish RHR Heat Exchanger Cooling (EOP-2.2)
- Realign RHR for Cold Leg Recirculation (EOP-2.2)

- Realign RB spray for RB spray Recirculation (EOP-2.2)
- Realign RHR system for Hot Leg Recirculation (EOP-2.3)

Thus, all paths and related operator actions are believed to be reflected in the current VCSNS emergency procedures.

b. Impact of timing of operator actions on RB spray operation

For the large LOCA event tree, reactor building spray (RB spray) operation is conservatively modeled in the VCSNS IPE. The development of operator action times to establish ECCS recirculation for large LOCA PRTs assume that the both trains of RB spray are injecting to containment, at a total flow rate of 5000 gpm, in addition to the ECCS pumps. This assumption is made regardless of the number of operating reactor building cooling units. This is a conservative representation since for the situations in which less than 2 trains of RB spray operate, the available operator action time would be greater, and thus the HEP for the related operator actions such as transfer to recirculation would be greater. As noted in the VCSNS success criteria notebook, the time for transfer to recirculation is 15 minutes.

For the medium LOCA event tree, RB spray operation is again conservatively modeled in the VCSNS IPE. For all cases, RB spray operation is assumed. The timing difference in transfer to recirculation HEP calculations is dependent upon the RCS cooldown actions in conjunction with RB spray operation. For the case with RCS cooldown successful, and RB spray successful, it is assumed that the spray will deplete the RWST prior to time that the shutoff pressure of the RHR pumps is reached such that the timing for transfer to recirculation need only consider RWST drain from the 2 HPI pumps and 2 spray pumps. This time is determined to be 60 minutes via the VCSNS success criteria notebook. For the case with RCS cooldown successful, but RB spray failed, it is assumed that low pressure injection is possible before the RWST is depleted; thus the RWST depletion would be via 2 HPI and 2 LPI pumps. However, for the purpose of the HEP calculation for transfer to ECCS recirculation, the data calculated for large LOCA is used---in other words, it is conservatively assumed that 2 HPI, 2 LPI AND 2 RB spray are draining the RWST in order to minimize the time to transfer to recirculation. As noted in the VCSNS success criteria notebook, this time is determined to be 15 minutes. Finally, for the case in which RCS cooldown is not successful, the shortest time to deplete the RWST would be the case in which RB spray is successful and thus 2 HPI and 2 RB spray are draining the RWST; as discussed above, this would result in a time to switchover of 60 minutes. However, the ATWS and secondary breaks switchover times have been determined to be 20 minutes, and since the operator actions are the same for ATWS, secondary break and this specific medium LOCA case, it is conservatively assumed for this medium LOCA case that 20 minutes are available for the transfer to ECCS recirculation.

In terms of the LOCA PRTs, although it is recognized that VCSNS emergency procedure EOP-2.4 (Loss of Emergency Coolant Recirculation) instructs the operators to minimize RB spray, no such actions are credited in the VCSNS IPE. Such an action would be an integral action in conserving RWST inventory, such as in RWST refill, but no credit is taken for RWST refill in the VCSNS IPE.

c. Impact of Success Paths on CDF

Based on the above discussion, it is apparent that the success paths for the VCSNS medium and large LOCA initiating events should not be considered novel (i.e., unique), but rather 'better estimate' or 'realistic'. With respect to large LOCA, based on success criteria in NUREG/CR-4550, the inclusion of accumulator injection would be the revision necessary to determine the impact of revised success criteria. Since the accumulators are passive tanks, the failure probability is fairly small. The failure which would dominate consideration of the accumulators would more than likely be the combination(s) of valves necessary for accumulator injection. An estimate of such a sensitivity can be completed by a simple consideration of a new large LOCA core damage sequence: large LOCA initiating event and failure of 2/2 accumulators (Surry success criteria). From the VCSNS quantification notebook, the failure probability of 2/2 accumulators is 5.3E-3, while the large LOCA initiating event frequency is 3E-04 leading to a CDF for this new sequence of 1.6E-6. In the current VCSNS quantification, this would be sequence #28 and would account for approximately 0.78% of core damage. Currently, the top large LOCA sequence is failure of low pressure injection at 1.1E-6, sequence #37 contributing 0.54%. Considering the addition of this new large LOCA sequence would increase the VCSNS overall CDF to 2.051E-04 from 2.035E-4, an increase of less than 1%. The large LOCA contribution to core damage would increase to 4.739E-06 from 3.139E-06; the large LOCA contribution to overall CDF would increase to 2.3% from 1.5%.

For medium LOCA, if the success criteria noted in the RAI were adopted, the core damage frequency would increase. As noted above, the success criteria of HPI, LPI AND accumulators is considered unrealistic for a medium LOCA event. However, consideration of the following new core damage sequences for medium LOCA will enable an estimate of the change to overall CDF: 1) medium LOCA and failure of HPI, 2) medium LOCA and failure of LPI and 2) medium LOCA and failure of accumulators.

Using data from the VCSNS quantification notebook, including the medium LOCA initiating event frequency of 8.0E-4, the data for these three new sequences is presented below:

Sequence	CDF	New Sequence #	Similar Seq	% Contribution* (New Sequence)
HPI Fail (5.62E-3)	4.5E-6	#12	#25 (1.89E-6)	2.1%
LPI Fail (HPI Success) (4.14E-3)	3.31E-6	#16	#14 (2.82E-6)	1.6%
ACC Fail (5.3E-3)	4.24E-6	#13	n/a	2.0%

Total	1.21E-5			

* Based on new overall CDF = 2.109E-4

Now consider that the overall Medium LOCA core damage frequency as predicted by the VCSNS Level 1 IPE is 7.620E-6. Subtracting the similar sequences as noted above and assuming that the remaining medium LOCA sequences are valid results in a remaining medium LOCA contribution of 7.620E-06 - (2.82E-06 + 1.89E-06) = 2.91E-06. Adding this to the 3 new cases as noted above yields a new medium LOCA contribution of 1.21E-05 + 2.91E-06 = 1.50E-05.

The overall CDF would increase to 2.109E-04 from 2.035E-04, an increase of less than 4%. The medium LOCA contribution to overall CDF would increase to 1.50E-05 (7.1%) from 7.62E-06 (3.7%).

15) Please provide the following information missing from the submittal:

a. What are the success criteria for the running time of the diesel generators in a loss of offsite power accident and what is the basis?

b. What is the assumed failure pressure of the RCS in an ATWS and what is the basis?

Response

a. The mission time (run time) for the diesel generators for a loss of offsite power event is 8 hours. This is based on the VCSNS Station Blackout Evaluation that determined the required coping duration category to be 4 hours. This value was conservatively increased by a factor of 2. It was judged, based on the power recovery curve for VCSNS and based on specific calculations available from other PRAs to determine a mission time based on probability of recovering offsite power, that using a longer time mission time for the diesel generators would lead to unrealistically conservative results.

b. The assumed failure pressure of the RCS in an ATWS event is 3200 psig. This is the value corresponding to the ASME Boiler and Pressure Vessel Code Level C service stress criterion for Westinghouse PWRs, which is used as a conservative failure threshold in WCAP-11993, "ASSESSMENT OF COMPLIANCE WITH ATWS RULE BASIS FOR WESTINGHOUSE PWRS." The following is an excerpt from the WCAP:

> "An underlying premise of the SECY-83-293 ("Amendments to 10 CFR 50 Related to Anticipated Transients Without Scram (ATWS) Events", USNRC, July 19, 1983) study is that core damage will occur any time the reactor coolant system pressure exceeds 3200 psig, which has been selected as a conservative bound of the ASME Boiler and Pressure Vessel Code Level C service limit criterion for Westinghouse PWRs. This assumption is conservative since there are sets of conditions for which this stress limit could be withstood without causing severe loss of reactor coolant system integrity and resultant core damage."

B. HUMAN RELIABILITY ANALYSIS (HRA) QUESTIONS

1) It is not clear from the submittal whether the risk impact of the human potential to cause an accident was considered. Identification of the pre-initiator human events that can disable a system, such as failure to properly restore after maintenance or miscalibration of instrumentation, are essential to the HRA. Section 3.3.3, "Human Failure Data," of the submittal and associated Table 3.3.3-2 "Operator Actions Important to System Operation" (including system alignment and system actuation actions), Table 3.3.3-3 "Operator Actions Important to Restoration of Failed Equipment," and Table 3.3.3-5 "Operator Actions Related to System Alignment" do not show the relative risk associated with the pre-initiator human actions. Please provide a list of the types of pre-initiator human events, in order of decreasing importance, that were considered in the analysis.

Response

Table HRA Q1-1 provides the list of pre-initiator human events that were quantified and directly included in the VCSNS IPE model. Additional pre-initiator human events were considered, but were screened from further analysis according to the procedure discussed in Response to HRA Question #2. For each pre-initiator human event, Table HRA Q1-1 provides a description of the action, as well as identification of the system of interest, human error probability, and the risk achievement worth (RAW) and risk reduction worth (RRW) ranking values. The list is provided in decreasing order based on the RAW value. The process to identify these pre-initiator human actions is discussed in response to HRA Question #2 and the quantification process is discussed in response to HRA Question #4. As is evident from the response to the HRA Questions #1-5, pre-initiator human events were thoroughly addressed in the VCSNS IPE.

Table HRA Q1-1 Pre-Initiator Human Events Quantified and Included in the VCSNS IPE					
System	Operator Action Description	Identifier	HEP	RAW	RRW
Low Pressure Injection	Alignment of cross-connect upstream of injection lines following a return to power from refueling or shutdown (valves XVG-8972A & B)	HXVXVG8972ABHE	3.0E-04	7.306	1.002
Emergency Feedwater	Train re-alignment following test on turbine-driven pump	D-VLVMISPOS-HE	7.4E-04	3.305	1.002
Chilled Water	Align chilled water pump C when chilled water pump C is aligned to train B	ZCXV-------1HE	3.0E-03	2.391	1.004
Emergency Feedwater	Train re-alignment following test on motor-driven feedwater pump A	DAMVXVG1021AHE	3.5E-04	2.052	1.000
Emergency Feedwater	Train re-alignment following test on motor-driven feedwater pump B	DAMVXVG1021BHE	3.5E-04	2.052	1.000
High Pressure Injection	Valve re-alignment following test on charging pump B	FBVG84858109HE	6.9E-04	1.964	1.001
High Pressure Injection	Chilled water valve alignment for charging pump B gear and oil cooler	FBXV35366479HE	2.2E-03	1.964	1.002
Reactor Building Spray	Flange removal following valve XVC03009A-SP	KA--BLOCKAGEHE	3.5E-04	1.139	1.000

Table HRA Q1-1 Pre-Initiator Human Events Quantified and Included in the VCSNS IPE					
System	Operator Action Description	Identifier	HEP	RAW	RRW
Reactor Building Spray	Flange removal following valve XVC03009B-SP leak test	KB--BLOCKAGEHE	3.5E-04	1.139	1.000
Reactor Building Spray	Train re-alignment following test on train A	KAXVXVG3010AHE	1.3E-05	1.139	1.000
Reactor Building Spray	Train re-alignment following test on train B	KAXVXVG3010BHE	1.3E-05	1.139	1.000
Reactor Building Spray	Flange removal following valve MVG-3004A leak test	LA--BLOCKAGEHE	3.5E-04	1.137	1.000
Reactor Building Spray	Flange removal following valve MVG-3004B leak test	LB--BLOCKAGEHE	3.5E-04	1.137	1.000
Component Cooling Water	Align chilled water flow path for CC pump C motor cooler and train isolation requirement when CC pump C is aligned to Train B	CCXVXVT----3HE	2.2E-03	1.102	1.000
High Pressure Injection	Chilled water valve alignment for charging pump C gear and oil cooler aligned to trn B	FBXVVU------HE	3.7E-03	1.065	1.000
High Pressure Injection	Valve re-alignment following test on charging pump C	FCVG84858109HE	6.9E-04	1.065	1.000

Table HRA Q1-1 Pre-Initiator Human Events Quantified and Included in the VCSNS IPE					
System	Operator Action Description	Identifier	HEP	RAW	RRW
High Pressure Injection	Valve re-alignment following stroke test on valves XVG-8131A & B	FMVXVG8131ABHE	1.5E-03	1.050	1.000
Component Cooling Water	Align chilled water flow path through CC pump C motor cooler when CC pump C is aligned to train A	CCXVXVT----1HE	2.2E-03	1.031	1.000
Low Pressure Injection	Valve re-alignment following test on RH pump A	HAMVXVG8887AHE	3.5E-04	1.009	1.000
Low Pressure Injection	Valve re-alignment following test on RH pump B	HBMVXVG8887BHE	3.5E-04	1.009	1.000

2) If the submittal does include pre-initiators human actions, it is important to describe the process used to identify and select the important pre-initiators involving miscalibration of instrumentation and the failure to properly restore to service after test or maintenance. The process used to identify and select the instrumentation calibration related human action events may include the review of procedures, and discussions with appropriate plant personnel on interpretation and implementation of the plant's calibration procedures. For assessing the failure to restore important equipment to service after test or maintenance, the process may include the review of maintenance and test procedures, and discussions with appropriate plant personnel on the interpretation and implementation of the plant's test and maintenance procedures. In Section 3.3.3, "Human Failure Data," of the submittal, there is no description of the process used to identify and select the pre-initiators human actions in Tables 3.3.3-2 "Operator Actions Important to System Operation" (including system alignment and system actuation actions), and 3.3.3-5 "Operator Actions Related to System Alignment." Please provide a description of the process that was used to identify pre-initiator human actions involving miscalibration of instrumentation and failure to restore equipment to service after test or maintenance. In addition, please provide examples illustrating the processes using several relatively important pre-initiator human actions.

Response

Table 3.3.3-2 (Operator Actions Important in Systems) list two types of operator actions; those important to system alignment and those important to system operation during an event. Of these two types, only the former is related to pre-initiators and are of interest in this response.

As noted in the question, two types of pre-initiator human actions need to be addressed in the IPEs. These are the pre-initiators involving failure to properly restore a system following a test or maintenance activity (or a shutdown activity) and miscalibration of instrumentation. The following paragraphs discuss how these were addressed in the VCSNS IPE.

Pre-initiator Human Actions - Failure to Properly Restore a System

The identification of pre-initiator human actions is done during the development of the fault tree models that are used to determine the system unavailability and system cutsets. A detailed review of system surveillance test procedures, mechanical maintenance procedures, system operating procedures, and re-alignment requirements following outages, is done to identify the test or maintenance activities that may require alignments that result in the system being unavailable when required for operation (accident mitigation). References 1-3, for the component cooling water system, identify several documents available for review by the system analyst that are used to identify pre-initiators.

The system surveillance test, component mechanical maintenance, and system operating procedures are also reviewed in detail to identify human actions following such activities that are required to be followed to ensure the system is re-aligned properly. This step identifies pre-initiator human actions that may prohibit or degrade operation of the system. Of particular interest are actions that may lead to flow blockage or diversion, or the inability of equipment to perform its required function (start and run for example). During the system analysis process the operation of the system of interest, including review of system test and maintenance activities, and the identification of pre-initiators, is reviewed with knowledgeable plant personnel to verify proper and accurate modeling and assumptions.

The failure of test and maintenance personnel to return valves, pumps, and other safety system components to their normal position after test or maintenance activities is considered a credible fault in development of the fault tree models under the following circumstances:

- proper valve positioning cannot be detected using specified component actuations required following the test or maintenance activity (such as pump flow tests)

- the mispositioning of valves or other components cannot be immediately detected by status lights and/or alarms at the main control board, and the valve is not automatically re-aligned by an ESFAS signal

So, identification of pre-initiator human actions related to system restoration is done by system analysts during development of the system fault tree models using surveillance test procedures, mechanical maintenance procedures, and system operating procedures with review and feedback from plant personnel.

Miscalibration of Instrumentation

Miscalibration of instrumentation was also considered in the development of the VCSNS IPE. This type of pre-initiator human action is primarily important to the proper operation of instrumentation systems, particularly the reactor protection system used to generate reactor trip signals and engineered safety features actuation signals. Of concern is the miscalibration of reactor protection system analog channels, the setting of the channel trip setpoints, which could lead to early actuations as well as prohibiting actuations when required.

Such pre-initiator human actions were considered in the analysis of the reactor protection system, but they were not considered important and were not included in the IPE model for the following reasons:

- Signals to trip the plant or actuate engineered safety features are available from a number of diverse sources, including operator actuation, for each potential event (transients, LOCAs, SGTR, etc.). For example, a reactor trip signal for a loss of feedwater event could be generated by either low-low steam generator level, steam/feed flow mismatch w/low steam generator level, high pressurizer level, high pressurizer pressure, or operator action. A safety injection actuation signal for a LOCA would be generated by low pressurizer pressure, high containment pressure, or operator action. In addition to the diverse number of sources for generation of a signal, the signal generation from each source, steam generator level for example, requires 1 of 2, 2 of 3, or 2 of 4 logic, that is, failure of an actuation signal requires failure of multiple channels. This indicates that not only would multiple channels within the same function need to be miscalibrated, but also miscalibration across several unrelated functions would be necessary.

- Miscalibration errors would be as likely to produce a premature actuation as well as prohibit an actuation.

- Analysis of the reactor protection system in the Westinghouse Owners Group Technical Specification Optimization Program (References 4-6) examined the unavailability of reactor trip and engineered safety features actuation signals. This analysis included a miscalibration human error in the analog channel unavailability model which conservatively assumed that all miscalibrations will prohibit signal generation when required. The value used for this human error was 1.0E-03. The analog channel unavailability models also included unavailability due to components, such as comparators, sensors, and amplifiers, and unavailability due to test and maintenance. Typical channel unavailabilities in this analysis ranged from 7.8E-03 to 1.2E-02, which indicates that miscalibration contributed approximately 10% to channel unavailability; not a significant contribution. As previously noted, multiple failures of channels across several diverse channel sets are required to fail actuation functions.

From this information it was concluded that miscalibration of channels are not significant contributors to actuation signal unavailability and this failure mode could be eliminated from the analysis without any adverse impact on VCSNS PRA model.

Example Illustrating Process

The following example shows the process used to identify system alignment pre-initiator human actions. It is based on the requirement to align the chilled water flow path through component cooling water (CCW) pump C motor cooler when CCW pump C motor cooler is aligned to train A. Steps 1-3 are completed with respect to the operation of the component cooling water system. The remaining steps are written for this particular example.

Step 1: Collect and review relevant system design and operating information, such as, system surveillance test, component mechanical maintenance, and system operating procedures, Technical Specification requirements, design basis documentation, and P&IDs.

Step 2: Identify system dependencies.

Step 3: Develop simplified P&ID diagram(s) (see Figure HRA Q2-1).

Step 4: Determine function and alignment requirements of standby component cooling water pump C. Identify component alignments that may prohibit proper system operation.

Step 5: Review relevant procedures related to the system of interest (CCW) that specify initial system alignment requirements and re-aligning requirements following system test and maintenance activities. For this case see SOP-118 (Reference 3). Attachment VIA of this SOP specifies the lineup for CCW pump C to train A. This lineup procedure is attached at the end of the response to this question.

Step 6: Based on the information from Steps 4 and 5, identify steps required to be completed to ensure the system is aligned properly.

Step 7: Eliminate those steps that if not properly completed would be detectable by required flow tests or immediate control room indication, or if the component would align properly on a safeguards signal.

Step 8: Identify the final set of steps required to be complete that have not been eliminated by Step 7 (marked with a * on the attached procedure). Review the results of the process and conclusions with relevant plant personnel.

Step 9: Define the human action required and provide to the HRA analyst for evaluation.

This process was implicitly applied by all system analysts for all the systems modeled in the IPE. Since the same process is used on all systems, it has been illustrated only once in this response.

References

1. V.C. Summer Nuclear Station, Nuclear Operations, Surveillance Test Procedures
   a. STP-122.002, "Component Cooling Pump Test".
   b. STP-122.003, "Component Cooling Valve Operability Test".

2. V.C. Summer Nuclear Station, Mechanical Maintenance Procedures
   a. MMP-320.013, " Component Cooling Water Pump Disassembly and Assembly".

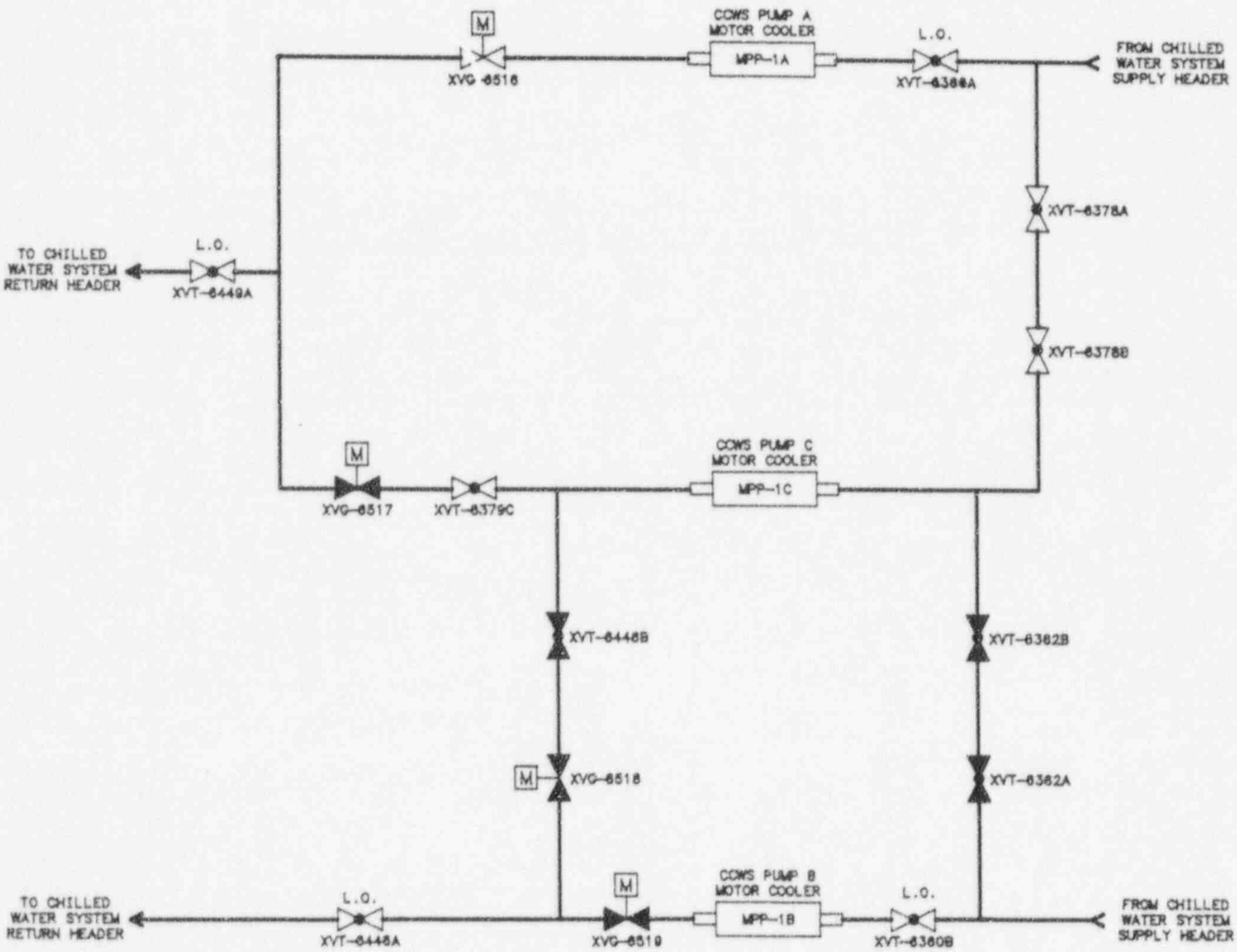
3. V.C. Summer Nuclear Station, Nuclear Operations, "System Operating Procedure SOP-118", Component Cooling Water.

4. "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System", WCAP-10271-P-A, May 1986.

5. "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System, Supplement 1", WCAP-10271, Supplement 1-P-A, May 1986.

6. "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System", WCAP-10271-P-A, Supplement 2, Revision 2.

Figure HRA Q2-1
Simplified Diagram of Chilled Water System Cooling Path to CCWS Pumps



Person(s) Completing checklist (print) _______________ _______________ _______________ _______________	Initial _______ _______	COMPONENT COOLING PUMP C TO TRAIN A LINEUP
Reviewed by SS/CRS _______________	Date/Time ____/____	Date/Time Started ____/____ Date/Time Completed____/____ Train in Service__________

COMPONENT COOLING PUMP C TO TRAIN A LINEUP

COMPONENT	DESCRIPTION	REQUIRED POSITION	INITIAL LINEUP BY	VERIFIED BY	BISI UPDATED BY
XVB09519-CC	LOOP B CC PUMP C SUCTION XCONN VALVE	CLOSED			
XVB09520-CC	LOOP B CC PUMP C SUCTION XCONN VALVE	CLOSED			
XVB09523B-CC	LOOP B CC XCONN INLET HEADER VALVE	CLOSED			
XVB09523C-CC	LOOP B CC XCONN INLET HEADER ISOL VALVE	CLOSED			
XVB09521-CC	LOOP A CC PUMP C SUCTION XCONN VALVE	OPEN			
XVB09522-CC	LOOP A CC PUMP C SUCTION XCONN VALVE	OPEN			
XVB09523A-CC	LOOP A CC XCONN INLET HEADER VALVE	OPEN			
XVB09523D-CC	LOOP A CC XCONN INLET HEADER ISOL VALVE	OPEN			
MVG-6517	CHILLED WATER SUPPLY VALVE TO CC PUMP MOTOR	ENERGIZED			N/A
XVT06362A-VU	CC PUMP C MTR CLR VU ALT INLET ISOL VLV	CLOSED			N/A

COMPONENT COOLING PUMP C TO TRAIN A LINEUP (Cont'd)

COMPONENT	DESCRIPTION	REQUIRED POSITION	INITIAL LINEUP BY	VERIFIED BY	BISI UPDATED BY
XVT06362B-VU	CC PUMP C MTR CLR VU ALT INLET VALVE	CLOSED			N/A
XVT06446B-VU	CC PUMP C MTR CLR VU ALT OUTLET VALVE	CLOSED			N/A
* XVT06378A-VU	CC PUMP C MTR CLR VU INLET ISOL VALVE	OPEN			N/A
* XVT06378B-VU	CC PUMP C MOTOR COOLER VU INLET VALVE	OPEN			N/A
* XVT06379C-VU	CC PUMP C MOTOR COOLER VU OUTLET VALVE	OPEN			N/A
XSW1DA 07	CC PUMP C XPP0001C-CC	RACKED UP AND DC POWER ON			N/A
XSW1DB 11	CC PUMP C XPP0001C-CC	OPEN AND RACKED DOWN			N/A
XET2001C	TRANSFER SWITCH, COMP COOLING PUMP C	A TRAIN SWITCH CLOSED			N/A

3) It is not clear from the submittal what screening values were used and the bases for the values. In Section 3.3.3, "Human Failure Data," there is no description of any screening values or process used to identify and select the pre-initiators human actions. Please provide all of the screening value(s) used and the basis for the value(s); i.e., provide the rational of how the selected screening value(s) did not eliminate (or truncate) important pre-initiator human events. In addition, please provide a list of actions initially considered and those screened.

Response

The process to identify pre-initiator human actions was discussed in response to question HRA Q2. To summarize, the identification of pre-initiator human actions is done during the development of the fault tree models that are used to determine the system unavailability and system cutsets. A detailed review of system surveillance test and maintenance requirements is done to identify the test or maintenance activities that may require alignments that result in the system being unavailable. The system surveillance test and component mechanical maintenance procedures are also reviewed in detail to identify human actions following such activities that are required to be followed to ensure the system is re-aligned properly. This step identifies pre-initiator human actions that may degrade the operation of the system. Of particular interest are actions that may lead to flow blockage or diversion, or the inability of equipment to perform its required function.

A two step process is used in the analysis of the pre-initiator human actions. The first step is a screening process which identifies those actions that cannot be eliminated and require further analysis. This step does not use screening values, but criteria to identify those human actions that require further analysis. The second step is the detailed analysis to determine the human error probabilities for the actions not screened out.

The initial screening process is done in parallel with the system analysis used to develop system fault trees. As noted above, the surveillance test and maintenance procedures are reviewed to identify pre-initiator human actions that could lead to system mis-alignments. These pre-initiators are then screened to determine if additional analysis is required according to the following criteria:

- mis-alignments, mechanical or electrical, that can be detected by post-test or post-maintenance system, train, or component functional tests

- mis-alignment of valves in diversion flow paths if the cross-sectional area is less that 10% of the main flow line since such a flow path will not significantly impact the flow rate in the main line

- valve mis-alignments that are immediately detectable by position indication lights and alarms in the control room

- valves that receive actuation signals to return to their correct positions under accident conditions

An identified pre-initiator that meets any of the above criteria is screened from further analysis and is not required to be included in the IPE model. All other pre-initiators are retained for further detailed HRA analysis and are included in the IPE models.

Using such an approach eliminates the need to identify and use screening values, and addresses issues such as possible elimination of important pre-initiator human events due to truncation limits. It may also lead to retaining some pre-initiator human actions that have no impact on system reliability, but this would result in a conservative assessment.

4) The submittal does not clearly identify the actual recovery factors applied in quantifying the pre-initiator human events. Factors that are used to modify the generic basic human error probability (BHEP) can include, for example, post-maintenance or post-calibration tests, daily written checks, independent written verification checks, administrative controls, etc. In Section 3.3.3, "Human Failure Data," of the submittal, there were no pre-initiator recovery factors mentioned. If they are used, please provide a list of recovery factors considered, their associated values, and provide specific examples illustrating their use. Also, if used, please provide a concise discussion of the justification and process that was used to determine the appropriateness of the recovery factors utilized.

Response

To better understand the response to this question, information related to system alignment controls and the model used to calculate human error probabilities for pre-initiator human events is initially discussed.

System Alignment Controls

System alignments are controlled in accordance with various procedures including Station Operating Procedures (SOPs), General Operating Procedures (GOPs), Surveillance Test Procedures (STPs), and the Locked Valve and Removal and Restoration programs. These are used to establish 1) initial system alignments, 2) system alignments following maintenance activities, and 3) system alignments following surveillance testing.

The alignment requirements specified in the SOPs and STPs give the component, component description, and required position for the component. There are columns to indicate that the alignment was completed and verified. Discussions with plant personnel and review of Station Administrative Procedure 153 (SAP-153, Reference 1) indicate that the verification is independent of the initial alignment. That is, it is completed by a qualified second person and at a different time when possible. SAP-153 provides the requirements for independent verification.

Plant and system status is controlled by SAP-205, Status Control and Removal and Restoration (Reference 2). The purpose of this SAP is to "define the method for controlling system status, locked valves and removal and restoration of systems either required by Technical Specifications or other administrative programs". The System Status Control Program "provides assurance that Safety Systems important to accident mitigation and shutdown of the plant shall remain operable". This program is accomplished through a combination of the following:

- Technical Specifications
- Main control board status lights and indications
- Bypass inoperable status indication CRT (BISI)
- Plant safety system display (PSSD)
- SOPs and GOPs
- Surveillance test program (SAP-134, Reference 3)
- Operating logs and records (SAP-204, Reference 4)
- Danger tag log (SAP-201, Reference 5)
- Equipment removal and restoration log (SAP-205, Reference 2)
- Locked valve program (SAP-204, Reference 4)
- Shift relief (SAP-200, Reference 6)

SAP-205 also indicates that "any change in status from the Station or General Operating Procedure's designated alignment shall be documented in the system status file or surveillance test file by a copy of the document that controlled the change". These documents include:

- Completed danger tagouts
- Completed locked valve tracking sheets
- Completed R&R checklists
- Completed operations' STPs

Of primary interest are the R&R (Removal and Restoration) log and the surveillance test program. R&R logs are used to follow the status of systems which are inoperable primarily due to maintenance activities. The surveillance test procedure requires surveillance tests to be logged into the station logs which are then used to track these tests. The control room supervisor, shift supervisor, shift engineer, and reactor operator are all responsible for assuring system alignments. Plant/system status is passed from shift to shift via these logs.

Danger tagouts are not necessarily used on all system maintenance activities and are not necessarily used on all activities that could effect plant safety. They are primarily used to protect personnel safety and are used at the discretion of the shift supervisor and personnel performing the maintenance activity.

HRA Assumptions and Model

This model used to calculate human error probabilities for pre-initiator human events is provided on Figure HRA Q4-1 in event tree form. It assumes restoration procedures are available for all required system alignments (this was confirmed for each human event evaluated), but there is no guarantee that the procedures will be used. This may be overly conservative, as strict procedure use and adherence is mandatory. Failure to re-align the system is based on the particular situation being considered. Some re-alignments require several valves to be in specific positions, while others may only require one of two valves to be in specific positions. The failure of personnel to complete alignments is based on omission of steps in the restoration procedure. Credit is given for independent verification of re-alignments based on SAP-153 (Reference 1). Operator detection is credited only for components that have position indication in the control room.

The following is the basis for the model:

1. Processes exist to track all test and maintenance activities which could cause system mis-alignments and lead to system inoperability. Procedures are in place to ensure that there is independent verification of all system alignments following test and maintenance activities, and to confirm initial system alignments. These processes are discussed in the previous paragraphs.

2. Optimum level of stress - this indicates that the personnel performing the maintenance procedures are not subject to a high stress environment or a very low stress environment. That is, sufficient time is available to perform the required procedures, sufficient safety precautions are available, etc.

3. Skilled personnel perform the procedures - this assumes that the personnel performing the required tasks have at least 6 months experience in the area.

4. The length of the list, short or long, for assessing omission of items from a checklist will be dependent on the procedure.

5. During an independent system alignment check, the checker will use written procedures and will be independent of the person who initially did the alignment (see SAP-153, Reference 1).

The HRA event tree top event descriptions are:

RSL: This node models the probability that personnel use the restoration or alignment lists. Restoration lists are available for all the re-alignment actions that have been identified. The probability of using the restoration list is based on Assumption 1. This indicates that procedures and processes are in place which require the use of restoration lists.

PRE: This node models the probability that personnel fail to restore the system to the correct alignment and is identified as PRE_1. The probability value used is based on the omission of a step in the restoration or alignment list. For the situation when these lists are used, the probability value used is dependent on the length of the list, short or long. If the list is not used, then the value used is independent of the list length and the node is identified as PRE_2.

PCHK: This node models the probability that the checker fails to detect and correct the alignment errors. It is assumed that the checker or verifier is independent of the person who initially completes the system alignment (see Assumption 5).

OCHK: This node models the probability that the operators in the control room fail to detect and correct the alignment error.

The end states are labeled success and failure. Success indicates that the system was properly aligned and failure indicates that the system was mis-aligned.

Human Error Probabilities

The following values are used to assess the probability that personnel fail to align systems properly. Based on Assumption 1, the HEPs provided in Table 20-6 of Reference 7 should not be adjusted for the level of component status tracking available in the plant. Assumptions 2 and 3 indicate that the HEPs provided in Table 20-7 and 20-22 of Reference 7 should not be adjusted for either the level of stress on the personnel performing the tasks or for the skill level of the personnel performing the tasks.

1. Failure to use a valve change or restoration list:
   HEP (mean) = 1.2E-02 (Reference 7, Table 20-6)

2. Omission per item of instruction when use of written procedures is specified given a short list (less than or equal to 10 items) and procedures with checkoff provisions are correctly used:
   HEP (mean) = 1.2E-03 (Reference 7, Table 20-7)

3. Omission per item of instruction when use of written procedures is specified given a long list (greater than 10 items) and procedures with checkoff provisions are correctly used:
   HEP (median) = 3.7E-03 (Reference 7, Table 20-7)

4. Omission per item of instruction when written procedures are available and should be used, but are not used:
   HEP (mean) = 8.1E-02 (Reference 7, Table 20-7)

5. Failure that a checker will detect errors made by others on checking routine tasks with the checker using procedures:
   HEP (mean) = 1.6E-01 (Reference 7, Table 20-22)

6. Failure for operators to respond to inappropriate alignments displayed on the control board for daily control board surveillances:
   No credit was taken for this action, HEP = 1.0

Example Calculation

Emergency Core Cooling System/High Pressure Injection (chilled water valve alignment of charging/SI pump B gear and oil cooler): SOP-501 (Reference 8) specifies aligning valves XVT-6435B, XVT-6436B, and XVT-6379B to the open position. The valve lineup list is a long list and is given in Attachment I of SOP-501. None of these valves has control room indication. The top event failure probabilities are:

RSL - Failure to use the alignment list.
HEP = 1.2E-02

PRE_1 - Failure to establish correct alignment (when a restoration list is used).
Personnel will be required to skip either of three steps in a long list.
HEP = 3 x 3.7E-03 = 1.1E-02

PRE_2 - Failure to establish correct alignment (when a restoration list is not used).
Personnel will be required to skip either of three steps.
HEP = 3 x 8.1E-02 = 2.4E-01

PCHK - Failure of checker to detect errors.
HEP = 1.6E-01

OCHK - Failure of operators to detect errors.
There is no control room indication for these valves so no credit is taken for operator detection.
HEP = 1.0

HEP = ((1-RSL) x PRE_1 x PCHK x OCHK) + (RSL x PRE_2 x PCHK x OCHK)
(from the event tree quantification)
HEP = 2.2E-03

Recovery Factors

Based on this discussion, the "recovery factors" that were considered in the analysis of pre-initiator human events are specifically included in the model to determine the human error probabilities. These "recoveries" are based on 1) checker fails to detect or identify errors, as previously discussed, and 2) operators fail to identify errors from the control room.

The HEPs used for these "recoveries" in all calculations are:

1. HEP (checker fails to detect error) = 0.16
2. HEP (operator fails to identify error from the control room) = 1.0
   Note: Although included in the model, no credit was taken for operator identification of the error from the control room for any of the pre-initiator human errors.

The justification for using these "recovery factors" are embedded in the various procedures controlling system alignments. As discussed in the System Alignment Controls Section, these include the Station Operating Procedures (SOPs), General Operating Procedures (GOPs), Surveillance Test Procedures (STPs), Station Administrative Procedures (SAPs), and the Locked Valve and Removal and Restoration programs. These are used to establish 1) initial system alignments, 2) system alignments following maintenance activities, and 3) system alignments following surveillance testing.

Additional recoveries of mis-aligned systems were considered in event tree recovery top events which model system recovery following failure of the service water, component cooling water, and chilled water systems. These recoveries are discussed in detail in response to HRA Q14 and are only credited following an initiator involving the complete loss of one of these functions.

References

1. "Station Administrative Procedure, SAP-153, Independent Verification", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, April 1989, Revision 0.

2. "Station Administrative Procedure, SAP-205, Status Control and Removal and Restoration", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, March 1990, Revision 7.

3. "Station Administrative Procedure, SAP-134, Status Control and Removal and Restoration", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, March 1990, Revision 7.

4. "Station Administrative Procedure, SAP-204, Operating Logs and Records", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, Revision 6.

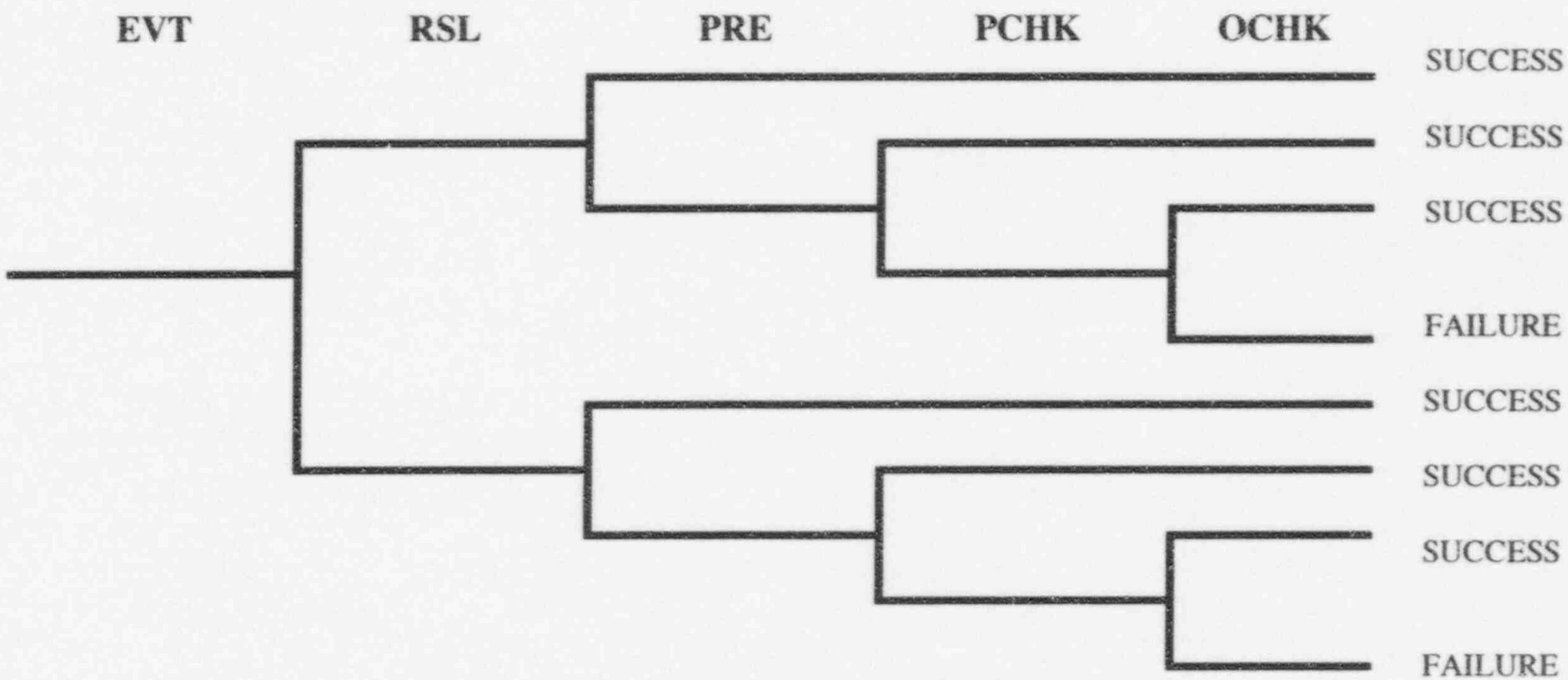
5. "Station Administrative Procedure, SAP-201, Danger Tagging", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, Revision 4.

6. "Station Administrative Procedure, SAP-200, Conduct of Operations", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, Revision 6.

7. NUREG-1278, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications", Swain, A.D. and Guttmann, H.E., August 1983.

8. "System Operating Procedure, SOP-501, HVAC Chilled Water System", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, April 1988, Revision 10.

Figure HRA Q4-1
OPERATOR ACTION MODEL FOR SYSTEM ALIGNMENT ERRORS



RSL -	RESTORATION LIST USED
PRE -	PERSONNEL RESTORATION/ALIGNMENT ERROR
PCHK -	PERSONNEL DETECTS RESTORATION/ALIGNMENT ERROR
OCHK -	OPERATOR DETECTS RESTORATION/ALIGNMENT ERROR

5) It is not clear from the submittal how dependencies associated with pre-initiator human errors were addressed and treated. There are several ways dependencies can be treated. In the first example, the probability of subsequent human events is influenced by the probability of the first event. For example, in the restoration of several valves, a bolt is required to be "tightened." It is judged that if the operator fails to "tighten" the bolt on the first valve, he will subsequently fail on the remaining valves. In this example, subsequent HEPs in the model (i.e., representing the second valve) will be adjusted to reflect this dependence. In the second example, poor lighting can result in increasing the likelihood of unrelated human events; that is, the poor lighting condition can affect different operators' abilities to properly calibrate or to properly restore a component to service, although these events are governed by different procedures and performed by different personnel. This type of dependency is typically incorporated in the HRA model by "grouping" the components so they fail simultaneously. In the third example, pressure sensors "x" and "y" may be calibrated using different procedures. However, if the procedures are poorly written such that miscalibration is likely on both sensor "x" and "y", then each individual HEP in the model representing calibration of the pressure sensors can be adjusted individually to reflect the quality of the procedures. The submittal in Section 3.3.3 contains a two-paragraph discussion on "Dependent Events" without any reference to pre-initiator human actions. Table 3.3.3-2 "Operator Actions Important to System Operation" (including system alignment and system actuation actions), and 3.3.3-5 "Operator Actions Related to System Alignment" do not indicate anything about the implementation of pre-initiator human action dependencies. Please provide a concise discussion of how dependencies were addressed and treated in the pre-initiator HRA such that important accident sequences were not eliminated. If dependencies were not addressed, please justify.

Response

In developing the model used to determine human error probabilities for pre-initiator human actions (see response to Question HRA Q4), the following dependencies were considered:

- functional relationships among tasks and activities
- time relationships between tasks and activities
- environmental considerations (lighting, ventilation, etc.)
- dependencies between sequential actions or procedural steps
- dependencies between maintenance/test personnel and checkers
- availability of adequate procedures

These dependencies were eliminated from consideration as follows:

- A plant walkdown was conducted as part of the IPE process. During this walkdown environmental conditions for the safety systems of interest were noted. For the systems of interest in the pre-initiator analysis, it was concluded that no adverse conditions exist for these systems that could impact test and maintenance activities.

- The test and maintenance activities of interest are not expected to be completed either in succession or by the same plant personnel over a short timeframe. Therefore, it was judged that time relationships and commonality of personnel were not valid dependencies.

- Discussions with plant personnel and review of Station Administrative Procedure 153 (SAP-153, Reference 1) indicate that the verification is independent of the initial alignment. That is, verification is completed by a qualified second person and at a different time when possible. SAP-153 provides the requirements for independent verification. (See the response to Question HRA Q4 for additional information.)

- Separate documents are available for each surveillance test procedure and each system operating procedure. During the process to assess the pre-initiator HEPs, the applicable system procedures were reviewed. From this review, it was judged that there are no dependencies that could be attributed to procedures.

- In the majority of cases, each step identified as important to successful completion of each activity or task needs to be completed. That is, if one task fails, then the activity or task fails. In these cases dependencies between tasks are not important. In the few cases where only one of several tasks are required to be completed, for successful completion of the activity, the tasks were assumed to be independent. The impact of this assumption is discussed in the following paragraphs.

The assumption of independence between actions noted in the last item is important to only four pre-initiator human actions. For most of the pre-initiator actions, each step needs to be completed. For only four of the actions can success still be achieved when a step is missed (such as the requirement to close two valves for isolation between trains, but one closed valve will perform the isolation function). The HEPs for these four actions were recalculated assuming a moderate dependency between subsequent steps. The results are:

1. Component cooling water: align chilled water flow path CC pump C motor cooler and train isolation requirement when CC is aligned to train B
   HEP (assuming no dependency) = 2.2E-03
   HEP (assuming moderate dependency) = 2.4E-03

2. Reactor building spray: train alignment following test on train A pump
   HEP (assuming no dependency) = 1.3E-05
   HEP (assuming moderate dependency) = 4.8E-05

3. Reactor building spray: train alignment following test on train B pump
   HEP (assuming no dependency) = 1.3E-05
   HEP (assuming moderate dependency) = 4.8E-05

4. ECCS/high pressure injection: chilled water valve alignment for charging pump C gear and oil cooler aligned to train B
   HEP (assuming no dependency) = 3.7E-03
   HE[illegible]uming moderate dependency) = 3.9E-03

From this it's seen that the only HEPs significantly impacted by the dependency assumption are those associated with train alignment for the reactor building spray system. These will increase by less than a factor of 4. A review of the cutsets associated with reactor building spray injection unavailability, both single train and dual train unavailability, indicates that including dependencies with have a negligible impact (<0.1%) on function unavailability.

Reference

1. "Station Administrative Procedure, SAP-153, Independent Verification", South Carolina Electric & Gas, Virgil C. Summer Nuclear Station, Nuclear Operations, April 1989, Revision 0.

6) The submittal is not clear about the risk significance of human actions to contribute to, and mitigate the consequences of an accident. Table 3.3.3-4, "Human Reliability Quantification Results" of the submittal does not contain this important information. Table 3.4.1-3, "Human Error Probability (HEP) Sensitivity Analysis Dominant Sequences" provides the post-initiators increased by an order of magnitude to maintain the relative importance of these actions. Table 1.5.1-3, "Key Contributors to Dominant Accident Sequences" of the submittal is not detailed enough to provide this information. Please provide a list of the most important risk significant post-initiator human actions and their associated HEPs in the most important sequences in which they appear.

Response

Table HRA Q6-1 provides a list of the most important post-initiator human actions and their associated HEPs in the most important sequences in which they appear. The risk reduction worth (RRW) and risk achievement worth (RAW) values of each human action are also provided. These are listed in decreasing importance according to the RAW value. The selection criteria for the operator actions provided is based on:

- RAW > 2
- RRW > 1.005

If either criterion was met, then it was included on the list. This is consistent with the EPRI "PSA Applications Guide" (Reference 1).

On this list, the operator actions described in Items 12-17 are recovery actions that plant personnel take to restore failed equipment. These are discussed in detail in response to HRA Question 14.

Reference

1. "PSA Applications Guide", EPRI TR-105396, August 1995.

Table HRA Q6-1 Summary of Most Important Post-Initiator Human Actions					
Item Number	Operator Action ID	Action Description	RAW	RRW	HEP
1	OAR (OAR2)	Establish low pressure cold leg recirculation (RH pumps stopped)	46.08	1.004	9.18E-05
2	OCC (OCC1)	Start second CC pump on failure of first pump	19.86	1.022	1.12E-03
3	OAL (OAL2)	Establish low pressure hot leg recirculation	6.081	1.001	1.85E-04
4	OAR (OAR4)	Establish high pressure cold leg recirculation (RH pumps stopped)	5.394	1.004	8.49E-04
5	OAQ (OAQ_1)	Initiate SI and establish EF	4.960	1.011	2.83E-03
6	ZBPMRF-----1HE	Start chilled water loop B or C during transient	3.479	1.003	1.19E-03
7	CBPM---XPP1BHE	Start component cooling water pump B or C during a transient	3.334	1.001	6.07E-04
8	OAR (OAR1)	Establish low pressure cold leg recirculation (RH pumps running)	3.182	1.001	2.40E-04
9	OAB (OAB2)	Initiate bleed and feed (actuate SI)	2.382	1.007	4.84E-03
10	OASC (OASC4)	Align alternate cooling to charging pumps	1.983	1.058	5.30E-02
11	ESFS (ESFS3)	Start train B ESF equipment from control board during transient	1.936	1.061	5.70E-03

Table HRA Q6-1 Summary of Most Important Post-Initiator Human Actions					
Item Number	Operator Action ID	Action Description	RAW	RRW	HEP
12	VUR1 (VU_R1)	Recover at least one train of chilled water when both trains failed, but supported, within 12 hours (loss of chilled water initiator)	1.267	1.062	1.80E-01
13	VUSB (VUSB2)	Align and start chiller C and pump C to train B	1.151	1.053	2.08E-01
14	SWR1 (SW_R1)	Recover at least one train of SW when both trains failed, but supported, within 2 hours (loss of SW initiator)	1.094	1.087	4.6E-01
15	SWR1 and SWS (SW_R4)	Recover train A of SW when train A fails and only train A support is available within 2 hours (transient initiator)	1.010	1.044	8.1E-01
16	SWR1 and SWS (SW_R3)	Recover at least one train of SW when both trains failed, but supported, within 2 hours (transient initiator)	1.007	1.064	8.9E-01
17	SWR1 and SWS (SW_R5)	Recover train B of SW when train B fails and only train B support is available within 2 hours (transient initiator)	1.004	1.015	7.8E-01
18	OAF (OAF_1)	Establish condensate feedwater	1.000	1.037	1.0

7) The submittal does not clearly describe the type of human errors considered for each post-initiator human event identified. For example, a human event identified may be the failure to feed and bleed, while the types of human errors considered may involve failure to open the correct valve (error of omission), or opening an incorrect valve (error of commission). No mention of types of human errors was found in the submittal's Section 3.3.3, "Human Failure Data." Please identify what types of human errors were considered for the human event identified.

Response

The HRA includes both errors of omission and commission for each post-initiating human event. Omission errors are evaluated in the HRA, based on the concept of the operator skipping the steps which are essential to the success of the task. THERP has defined BHEPs for omission when procedures with checkoff are used, and a higher set of BHEPs when procedures without checkoff are used. These omission errors are selected from Table 20-7 of the THERP handbook, NUREG/CR-1278.

Commission errors are evaluated in the HRA, based on the concept of the operator doing something different from what is intended. Errors such as selecting the wrong control for the equipment, selecting wrong component display, or misreading a plant parameter fall into this classification. These commission errors are selected from Tables 20-10 and 20-12 of the THERP handbook.

In modeling each operator action or subtask, appropriate errors of omission and errors of commission are considered; the model reflects summation of both types of error.

8) The submittal does not clearly describe the method used to identify and select response type actions and recovery type actions for analysis. The method utilized should confirm the plant emergency procedures, design, operations, and maintenance and surveillance procedures were examined and understood to identify potential severe accident sequences. The submittal's Section 3.3.3, "Human Failure Data" and associated Table 3.3.3-4, "Human Reliability Quantification Results" are not clear on the identity of the response type actions and recovery type actions used. Also, the method used was not addressed. Please provide a description of the process that was used for identifying and selecting the response and recovery type actions evaluated.

Response

The response-type operator actions were identified and selected through an iterative process. The event tree analyst determined success and failure paths of critical safety functions, and the need for operator actions taking into account (1) Engineered Safety Features (ESF) equipment which actuates automatically following reactor trip or SI signals, (2) the consequences of failure of ESF equipment, and (3) any key decision points or operator actions called for in the emergency operating procedures (EOPs) which significantly alter the progression of the accident.

The human reliability analyst then used the EOPs, abnormal operating procedures and system operating procedures (as necessary) to determine critical subtasks for each task identified; this exercise was done in collaboration with the event tree/system analyst. The draft subtasks were then transmitted to V.C. Summer for review among the plant's engineering, operations and simulator training personnel. From these reviews and comments exercises, agreement was formed on the response-type operator actions to be selected. Therefore, cognizant plant personnel were involved in the HRA from the start of the process.

In general, if it was determined that the operators are required to perform subtasks that were not proceduralized, such subtasks could be included in the model with the agreement by Plant Operations that they would be proceduralized. Therefore, part of the HRA process was to identify credit for procedural enhancements that were proposed by the IPE analysts and V.C. Summer personnel, and, after review, deemed acceptable by plant personnel and committed to be implemented at the plant. During the V.C. Summer IPE effort, only one major procedural change was required; this change was made in the loss of chilled water abnormal operating procedure to take credit for operator recovery.

The recovery analysis for the V.C. Summer IPE was conducted, after the majority of the plant response tree and fault tree modeling had been completed, through an iterative process generally consisting of the following steps:

1. reviewing quantification results to determine where contribution to core damage frequency of dominant contributors could be reduced through credit for appropriate and reasonable actions or equipment not already in the IPE models;

2. modeling these actions or equipment;

3. requantifying the results;

4. and repeating the process to address new dominant contributors.

In general, operator actions called for in the V.C. Summer emergency or abnormal procedures were considered to be expected rather than recovery actions, as long as there was a clear path through the procedures for each event being considered. Actions that could be taken from the control room (e.g., manually starting a pump that failed to start automatically, operating valves that failed to actuate automatically, and so forth), and for which the operators would receive indication as to the need for the action, were treated as anticipated responses rather than recovery actions. Such actions are generally included in the fault tree quantification for the appropriate top event. Actions for which all or most of the diagnosis and response required outside-control-room activity were generally considered as recoveries.

For the recovery analysis process, the specific steps included:

1. identifying possible recoveries in the fault tree models, plant response tree (PRT) models, support system models, or combinations of these;

2. identifying necessary additional modeling;

3. discussions among IPE analysts and V.C. Summer cognizant personnel to clarify and verify the actions to be taken or equipment needed;

4. modifications to the various models and quantification input values (including additional human reliability and success criteria analysis, where needed) to accommodate the recoveries; and

5. requantification of results.

The modeling of recovery actions generally takes one of several forms:

- credit for existing systems or procedures that were not included in the initial models;
- credit for procedural enhancements that were proposed by the IPE analysts or V.C. Summer personnel, and, after review, deemed acceptable by V.C. Summer personnel and committed to be implemented at the plant;
- credit for equipment modifications that were proposed by the IPE analysts or V.C. Summer personnel, and, after review, deemed acceptable by V.C. Summer personnel and committed to be implemented at the plant; or
- combinations of the above.

For most of the items selected, a summary description was prepared. These summary descriptions briefly describe the situation for which a recovery is needed, provide information on the operator actions and timing available and any plant equipment required. The recovery actions modeled in the HRA are identified and discussed in the responses to HRA Questions 12 and 14.

9) The submittal does not clearly indicate whether a screening process was utilized to help differentiate the more important post-initiator human events. No mention of screening post-initiator human errors was found in the submittal's Section 3.3.3, "Human Failure Data." If a screening process was used, please provide all of the screening value(s) used and the basis for the value(s); i.e., provide the rationale for how the selected screening value did not eliminate (or truncate) important human events. Also, provide a list of errors initially considered and those screened. If a screening process was not used, please identify the more important post-initiator human events.

Response

No formal screening of operator actions was performed on the V.C. Summer HRA. The decision to conduct a detailed evaluation of each operator action was made early in the IPE process with the aim of obtaining an operator response model of the plant that is as realistic as possible.

It was recognized that considerably more effort would be required to conduct a detailed evaluation on each operator action identified in the PRA, but it was also recognized that there were major benefits to be derived if operator actions were not screened out. One benefit in providing detailed evaluated human error probabilities (HEPs) for all modeled operator actions is to identify the main subtask(s) contributing to failure of each task; but the major benefit is to derive a meaningful assessment of how the operator actions compare with each other. This approach helped the HRA reviewers (V.C. Summer personnel from Operations, Training and Engineering included) to provide valuable inputs at various stages in the IPEs to finalize the HRA model.

Therefore, unlike many IPEs in which screening values are used and only a minimal subset of operator actions are selected for detailed evaluation, the HRA process used to conduct the V.C. Summer IPE was quite extensive and did not screen out any operator actions.

The risk important operator actions have been identified per EPRI TR-105396 (PSA Application Guide, August 1995). The criteria for selection is: risk reduction worth (RRW) greater than 1.005, and/or risk achievement worth (RAW) greater than 2. Based on these criteria, the important post-initiator human events are provided on Table HRA Q9-1.

Table HRA Q9-1 Risk Important Operator Actions			
Operator Action ID	Description	RRW	RAW
OAB (OAB2)	Initiate Bleed & Feed (Actuate SI)	1.007E+00	2.382E+00
OAF (OAF_1)	Establish Condensate Feedwater	1.037E+00	1.000E+00
OAL (OAL2)	Establish Low-pressure Hot Leg Recirculation	1.001E+00	6.081E+00
OAQ OAQ_1)	Initiate SI and Establish EF	1.011E+00	4.960E+00
OAR (OAR1)	Establish Low-pressure Cold Leg recirculation (RH pumps running)	1.001E+00	3.182E+00
OAR (OAR2)	Establish Low-pressure Cold Leg recirculation (RH pumps stopped)	1.004E+00	4.608E+01
OAR (OAR4)	Establish High-pressure Cold Leg recirculation (RH pumps stopped)	1.004E+00	5.394E+00
OASC (OASC4)	Align Alternate Cooling to Charging Pumps	1.058E+00	1.983E+00
VUSB (VUSB2)	Align and Start Chiller C and Pump C to Train B	1.053E+00	1.151E+00
OCC (OCC1)	Start Second CC Pump on Failure of First Pump	1.022E+00	1.986E+01
SWR1 (SW_R1)	Recover at least One Train of SW when both Trains Failed but Supported within 2 hours (loss of SW initiator)	1.087E+00	1.094E+00
SWR1 and SWS (SW_R3)	Recover at least One Train of SW when both Trains Failed but Supported within 2 hours (transient initiator)	1.064E+00	1.007E+00
SWR1 and SWS (SW_R4)	Recover Train A of SW when Train A Failed and only Train A Support is available within 2 hours (transient initiator)	1.044E+00	1.010E+00
SWR1 and SWS	Recover Train B of SW when Train B	1.015E+00	1.004E+00

Table HRA Q9-1 Risk Important Operator Actions			
Operator Action ID	Description	RRW	RAW
(SW_R5)	Failed and only Train B Support is available within 2 hours (transient initiator)		
VUR1 (VU_R1)	Recover at least One Train of VU when both Trains Failed but Supported within 12 hours (loss of VU initiator)	1.062E+00	1.267E+00
ZBPMRF-----1HE	Start Chilled Water Loop B during Transient	1.003E+00	3.479E+00
CBPM--XPP1BHE	Start CC Pump B or C during Transient	1.001E+00	3.334E+00
ESFS (ESFS3)	Start Train B ESF Equipment from Control Board during Transient	1.061E+00	1.936E+00

10) In applying performance shaping factors (PSFs), the consideration of time is important. The submittal is not clear on how available time and "required" time were calculated for the various post-initiator human events. "Required" time is the time needed for an operator to diagnose and perform the actions. Table 3.3.3-4, "Human Reliability Quantification Results," of the submittal is a summary of all the HEPs used to support the VCSNS accident sequence quantification. This includes the results of the technique for human error rate prediction (THERP) analysis and conditional analysis. The "Time Window" specified in the table is the time from initial indication that action is required until the operator action must be completed for success of the action. For several of the important post-initiator human events examined, provide the available and "required" times estimated for the operator action and the bases (e.g., calculated from simulator exercises, estimated from walkdowns) for the time chosen. Also provide illustrations of how different times were calculated for the same task but in different sequences.

Response

The time windows for operator actions modeled in the V.C. Summer HRA are supported by MAAP code analyses, TREAT code analyses, and, in some cases, hand calculations. These time windows were reviewed by V.C. Summer training and operations personnel to determine if the needed (or actual) action times to perform the respective actions (and any recovery actions if required) would exceed the specified time windows. The reviewers applied experiences gathered from simulator training exercises to assess the adequacy of available times; there was no attempt to derive an exact actual time for each task; this is consistent with the requirements of the THERP Handbook.

If it was determined that the actual time for a task would be greater than the time window, the task was assigned an HEP of 1.0. This was evidenced during talk-throughs on operator action OAF (establish condensate feed, given a transient); the participants determined that the actions could not be completed within the specified 10 minute time window, and OAF was therefore assigned an HEP of 1.0. This was consistent with simulator experience at the time, which indicated that feed and bleed was usually required before a SG could be successfully depressurized below the shut-off head of a feedwater booster pump. The operator action to align alternate cooling to the charging pump(OASC) was validated via an operator walkdown at less than 40 minutes versus the time window of 60 minutes. Additionally, a talk-through was conducted on several key operator actions with licensed operators to second check assumptions regarding timing, and critical steps.

With regards to the treatment of time for the same action in different accident sequences, if different time windows are estimated for specific cases, then the actual times are assessed relative to these time windows; this is shown in the modeling of OAR1 and OAR2. OAR1 (perform cold leg recirculation, given a medium or large LOCA) has a time window of 15 minutes, and OAR2 (perform cold leg recirculation, given a small LOCA or SGTR) has a time window of 60 minutes; adequacy of actual time was assessed for each case.

In some cases, the same time window is estimated for performing the same task for different initiating events. For such cases, each event is examined to ensure the task could be performed within the time window, and the limiting event is evaluated as the representative case; this approach is believed to be conservative. This is shown in the modeling of OAD (depressurize the secondary side) for SGTR, small LOCA, or medium LOCA; since medium LOCA was determined to have the smallest time window (30 minutes from event initiation), it was used to deduce a single HEP for all of these events.

The available times for important post-initiator human events are shown in Table HRA Q10-1. As stated previously, the adequacy of the actual times for the respective tasks was established by reviews and talk-throughs with V.C. Summer personnel who evaluated the adequacy of time based on their simulator and operations experience. Determination of exact actual times was not conducted; this process is consistent with the method shown in accepted human reliability analyses by other organizations using the THERP methodology.

Table HRA Q10-1 Available Times for Post-Initiator Human Events		
Operator Action ID	Description	Time Window
OAB (OAB2)	Initiate Bleed & Feed (Actuate SI)	30 minutes
OAF (OAF_1)	Establish Condensate Feedwater	10 minutes
OAL (OAL2)	Establish Low-pressure Hot Leg Recirculation	30 minutes
OAQ (OAQ_1)	Initiate SI and Establish EF	15 minutes
OAR (OAR1)	Establish Low-pressure Cold Leg recirculation (RH pumps running)	15 minutes
OAR (OAR2)	Establish Low-pressure Cold Leg recirculation (RH pumps stopped)	60 minutes
OAR (OAR4)	Establish High-pressure Cold Leg recirculation (RH pumps stopped)	20 minutes
OASC (OASC4)	Align Alternate Cooling to Charging Pumps	10 minutes to stop running charging pump; 60 minutes to align alternate cooling
VUSB (VUSB2)	Align and Start Chiller C and Pump C to Train B	60 minutes
OCC (OCC1)	Start Second CC Pump on Failure of First Pump	30 minutes
SWR1 (SW_R1)	Recover at least One Train of SW when both Trains Failed but Supported (loss of SW initiator)	2 hours
SWR1 and SWS (SW_R3)	Recover at least One Train of SW when both Trains Failed but Supported (transient initiator)	2 hours
SWR1 and SWS (SW_R4)	Recover Train A of SW when Train A Failed and only Train A Support is available (loss of SW and transient initiator)	2 hours

Table HRA Q10-1 Available Times for Post-Initiator Human Events		
Operator Action ID	Description	Time Window
SWR1 and SWS (SW_R5)	Recover Train B of SW when Train B Failed and only Train B Support is available (loss of SW and transient initiator)	2 hours
VUR1 (VU_R1)	Recover at least One Train of VU when both Trains Failed but Supported (loss of VU initiator)	12 hours
ZBPMRF----1HE	Start Chilled Water Loop B during Transient	15 minutes
CBPM---XPP1BHE	Start CC Pump B or C during Transient	15 minutes
ESFS (ESFS3)	Start Train B ESF Equipment from Control Board during Transient	30 minutes

11) It is not clear from the submittal what plant-specific PSFs were used to modify the BHEP and what the bases were for reducing HEPs through their application. The plant-specific information could include the size of crew, availability of procedures, time available, time required, etc. The process could include an examination of procedures, training, human engineering, staffing, communication, and administrative controls.

The submittal in Section 3.3.3 briefly states that "...PSFs were also used concurrently to modify the nominal HEP (that is, the probability of a given human error when the effects of plant-specific PSFs have not yet been considered)." and is not mentioned again. Please provide a list of the types of plant-specific PSFs considered and their values, and discuss by way of example how these PSFs were used to modify the BHEPs of important post-initiator human events.

Response

The typical crew in the control room consists of the control room supervisor (CRS), a primary systems operator often referred to as the reactor operator (RO), a balance of plant operator (BOP). The shift supervisor (SS) is not required to be in the control room complex at all times but is expected to be within a "few minutes" from the control room; a shift technical advisor (STA) is required to be in the vicinity of the control room such that the STA could be in the control room within ten minutes. The RO and BOP are trained in the operations and controls of the entire control room; each is assigned one position for a shift, but can be rotated to the other position on a different shift. During an accident, dependency levels from the THERP handbook are assigned among crew members to take credit for crew recovery that may be possible.

In responding to transient events, the first ten steps of EOP-1.0 are memorized. The RO and BOP perform these steps, and report when they are completed. The CRS then reads each of the immediate action steps, and the responsible operator acknowledges that the action was completed. Immediate actions are usually completed and checked within 3 minutes. If the event keeps the operators in EOP-1.0 (such as following SI actuation), then it typically takes about 10 minutes to reach the diagnosis steps of EOP-1.0.

Based on the above considerations, operator talk-throughs, simulator visit, discussions with the V.C. Summer personnel, and examination of the nature of the actions being modeled (e.g.; knowledge-based actions were excluded), the following major assumptions were made in the HRA:

1. Operators are highly skilled in performing the necessary tasks; each having more than 6 months experience. In some cases, normal (moderate level) stress is applied to the events. It is believed that the operator will experience high stress during a steam generator tube rupture, LOCA, or loss of all AC power accident. During quantification, the different

stress levels are used as performance shaping factors which are multiplied by the nominal human error probabilities (HEPs) of the subtasks.

2. Control room indication is provided for equipment status, with visual and audible alarm indications of equipment failures or parameter deviations.

3. Visual and audible alarms serve as prompts for initial operator response. Loss of component cooling water and loss of service water events are diagnosed within the respective Abnormal Operating Procedures. For any other abnormal plant condition resulting in a reactor trip or the need for reactor trip, the operators' activities begin with the proceduralized steps in EOP-1.0 within which diagnosis of the event is conducted. In other words, the operators are not led from the alarm indications directly to diagnosis of the event, without going through the procedure.

4. The nominal HEPs are not reduced by PSFs for events with time window less than or equal to 5 minutes; it is assumed that such events are fairly complex. However, appropriate stress levels are applied to these events.

5. Crew recovery is assigned similar to the THERP recommended dependency application for events having time window greater than 5 minutes. Credit for STA is considered in actions performed 10 minutes after the initiating event.

6. If the operators have more time than the average amount of time needed to complete an action, then it is assumed that the operator's performance in diagnosis and action execution is not believed to be time dependent, since the operator has to follow the applicable procedure(s), and the operator does not have a physical time clock running during an abnormal operating condition. However, potential recovery within that event may be time dependent.

   The underlying implication in this assumption is based on the THERP Handbook which states (on page 12-10) that, with the advent and acceptance of symptom-based procedures, it is possible that the need to diagnose an unusual event may diminish in importance for PRA. The Handbook also states that the cognitive models recommended there-in are based on then current written procedures that are not symptom-based in most cases.

7. In general, a PSF of 0.1 is applied to the HEPs for commission errors. In other words, it is believed that the HEPs for commission errors are less than the nominal values, given the assumed highly skilled operators who are performing the tasks with the use of symptom-based procedures, and proper labeling of the equipment and controls. This PSF applies especially since the controls used are main ones; either often used by the operators and/or are on the main control panels.

8. In analyzing pre-initiator events, it is assumed that operators may not use the applicable procedures during system alignments for testing and maintenance activities. In that regard,

the analysis of such activities evaluates the failure probability based on the assumption that the operator may use the procedure or the operator may not use the procedure. In other words, the failure probability of the activity is the summation of the failure probabilities of the actions when the operator uses the procedure and when he does not use the procedure.

Tasks and subtasks dependency application is covered in the response to HRA Question 13. Levels of dependency are evaluated in accordance with THERP, Tables 20-17 and 20-18.

The bases for the above assumptions are summarized as follows:

In applying the THERP methodology, described in NUREG/CR-1278, it was realized that modifications to THERP base human error probabilities (BHEPs) can be made logically to account for changes in nuclear power plants operating philosophy and procedures, which came about (in 1985) after THERP BHEPs were developed (during 1980 to 1983). Such changes, surrounding the development of generic Westinghouse Owners Group Emergency Response Guidelines, are outlined as follows:

a) development of PWR plant specific symptom-based procedures
b) training on the use of these symptom-based procedures
c) usage of these symptom-based procedures in actual plant emergencies.

Operator actions are classified as skill-based, rule-based, and knowledge-based actions. Skill-based actions are those viewed as being second nature; rule-based actions are carried out under written procedural guidelines; knowledge-based actions involve a high degree of deciphering by the operating crew in order to diagnose the event and/or provide corrective action.

Given the type of procedures which existed when the THERP methodology was developed, it is believed that most of the THERP BHEPs (especially those for event cognitive diagnosis) can be classified as knowledge-based. In the IPE work, operator actions are classified as rule-based because the operators are using the symptom-based procedures. In any case, THERP examples in NUREG-1278 support this application numerically; THERP indicates that a cognitive diagnosis failure followed by alarms would result in a failure path with a probability of failure that is less than 1.0E-05 (for example, failure path F4 in Figure 21-5 of NUREG-1278).

To account for the advantages or enhancements in using the symptom-based procedures, given the type of the event and timing considerations, some THERP BHEPs were adjusted. The method of adjustment and rationale are outlined in the following sections.

Control Room Recovery

THERP assumes high dependency between senior reactor operator (SRO) and reactor operator (RO), low to moderate dependency between shift supervisor (SS) and other crew members, and (if the shift technical advisor (STA) is present) low to moderate dependency for STA diagnosis and high dependency for STA during task manipulation.

In the V.C. Summer HRA, dependency assumed among operating crew members is applied as follows: moderate dependency is assigned between CRS and RO; the THERP BHEP is multiplied by the stress PSF to estimate the RO's failure, and the estimated moderate dependency for the SRO is rounded to 0.1. Although a shift supervisor is a member of the operating crew, we have not taken credit directly for recovery by the SS. To be somewhat conservative, we combined the SS recovery with that of the SRO and applied one moderate dependency value of 0.1 for both. In order to reflect some degree of variation for recovery among different classes of events, we select the BHEP of 8.1E-02 (from THERP Table 20-22) and modify it by the stress factor associated with the event; this modified HEP is used for STA dependency recovery. This BHEP, although recommended by THERP for application to normal operating conditions, is judged to be appropriate for emergency operating conditions since it is modified by the stress factor assessed for the event, which, in many cases, is conservatively high stress level (a multiplier of "5"); therefore, the STA recovery is estimated to be 1.62E-01 (i.e.; 8.1E-02 x 2) for the cases of moderate stress application, and 4.05E-01 (i.e.; 8.1E-02 x 5) for high stress application. The crew dependency levels applied to the V.C. Summer HRA yield results that are generally higher than would be obtained by the recommended THERP dependency levels described above. The HEP of 8.1E-02 and other HEPs from THERP Table 20-22 have been used for recovery during abnormal operating conditions in accepted HRAs performed by other organizations.

Local Recovery

For local actions, including pre-initiating event assessment, a local recovery failure probability of 1.6E-01 is applied. This BHEP was selected from the THERP BHEP for "checking routine tasks". Although the THERP definition for checking is not exactly the same as the definition meant for this kind of recovery, the error rate of 1.6E-01 seems most suitable to represent this recovery. For post-initiator events, this local recovery is based on the existence of radio communication between control room and auxiliary operators, and also, in some cases, on the existence of control room indication of the status of equipment being locally manipulated. This BHEP is modified by the stress level for the event; therefore, this credit is 3.2E-01 for events assigned moderate stress level, and 8.0E-01 for events assigned high stress level. For pre-initiator events, this recovery is based on the existence of an independent checker.

The recovery factor applied for STA discussed previously, is **not** applied to the recovery of local actions.

Commission Errors

Commission errors are evaluated in the HRA, based on the concept of the operator doing something different from what is intended. Errors such as selecting the wrong control for the equipment, selecting wrong component display, or misreading a plant parameter fall into this classification.

From talk-throughs and control room simulator visits, it was determined that controls for the actions modeled in the V.C. Summer HRA are properly labeled, mimic lines are clearly drawn, and violation of stereotypes does not exist. Most importantly, symptom-based procedures have explicit equipment identifications, and the actual equipment or instrument numbers are communicated back and forth between the operator who is reading the procedure and the operator who is carrying out the action on the control board. Therefore, it is believed that commission errors are less than the THERP BHEPs.

There is no guideline to modify THERP BHEPs to account for such factors. Therefore, based solely on engineering judgement, a factor of 0.1 is applied to the BHEP for commission errors to account for the benefits in using the new type of procedures, along with the operating philosophy which includes constant communication feedback. The "0.1" adjustment factor is consistent with modifications made in typical Human Reliability Analyses using the THERP methodology.

In general, the "0.1" multiplicative factor for commission errors is used for any event, except the early actions in an ATWS event which have a time window of approximately 2 minutes. The ATWS cases, referred to, are categorized as skill-based actions. In other words, the "0.1" factor is applied only to rule-based activities where the operators are following the symptom-based procedures.

Omission Errors

Omission errors are evaluated in the HRA, based on the concept of the operator skipping the steps which are essential to the success of the task. THERP has defined BHEPs for omission when procedures with checkoff are used, and a higher set of BHEPs when procedures without checkoff are used.

The V.C. Summer emergency operating procedures (EOPs) have check-off boxes and bible strings. Talk-throughs with V.C. Summer personnel revealed that operators use the check-off boxes and bible strings as they go through the EOPs. Therefore, for omission errors, the HRA applied the BHEPs defined in THERP for "omission when procedures with checkoff provisions are used".

Omission errors can be made if the operator who is reading the procedures skips a step, or if the control board operator skips the step. On that basis, no adjustment is made to the BHEP for error of omission except for applying the stress factors.

Diagnosis Errors

THERP defines Diagnosis as having three components namely, Detection + Diagnosis + Decision. The THERP definition is believed to be applicable to knowledge-based responses, whereby the operators went through more thought-process (deciphering) in order to diagnose an event. The new generic procedures are based on the philosophy of symptomatic responses to an emergency operating situation, and therefore, reduce the diagnosis of an event to responding to cues such as alarms, annunciators, indicators (detection); thus avoiding the cognitive aspects (diagnosis + decision). Therefore, it is advisable NOT to use Table 20-3 of the THERP Handbook or similar models for actions governed by symptom-based procedures in which the operators are trained; such activities are termed rule-based actions.

Diagnosis is modeled as responding to appropriate alarm cues and performing prescribed procedure checks. It should be noted that this approach is conservative because, if the THERP cognitive diagnosis model is applied, the cognitive HEP will be multiplied by the alarm cues (as shown in the THERP Handbook examples, Figures 21-2 and 21-5) and result in lower diagnosis HEPs than are shown in the V.C. Summer HRA.

Therefore, in modeling the crew diagnosis with use of the symptomatic procedures, the alarm response BHEPs are applied and modified by: 0.5 for the vast majority of initiating events which are assigned high stress level; and 0.2 for events assigned moderate stress level.

As stated previously, this reduction is applied only to events having a time window greater than 5 minutes and if it is judged that slack time of at least 5 minutes exists; "slack time" being the "time window" minus the "estimated actual time".

Timing

The general treatment of time is discussed in the response to HRA Question 10. The concept of slack time recovery is summarized in the next paragraph.

For events having relatively long time windows (with estimated actual times that are judged to be short) such that slack time longer than 60 minutes is believed to exist, a recovery factor of 0.21 is applied. This factor is derived by applying moderate dependency to the THERP BHEP of 8.1E-02; (i.e., $[(1 + 6 \times 8.1E\text{-}02) / 7]$) which equates to 0.21).

Comparison with Unmodified THERP

As mentioned earlier, the THERP methodology was applied in the V.C. Summer HRA model while attempting to reflect the operating crew responses with use of the symptom-based EOPs during emergency conditions. It was not the intent of the HRA to demonstrate whether or not the crew might be less likely to fail with the use of symptom-based procedures. However, the model has shown that, in general, the HEPs in the V.C. Summer HRA are the same or higher than the HEPs that would be expected if the THERP methodology was applied without these symptom-based-related assumptions.

In that regard, five operator post-initiator actions, representative of the V.C. Summer HRA, have been requantified using THERP as prescribed in the Handbook. These operator actions are:

1. OAI - Diagnose SGTR and Isolate Ruptured SG
2. ESF - Recognize the Need and manually Actuate Safety Injection
3. OAP - Recognize the Need and Depressurize RC for Core Cooling
4. CI - Recognize the Need and Actuate Phase A Containment Isolation
5. HLR - Recognize the Need and Realign Cold Leg Recirculation.

The requantification of these operator actions using the THERP Handbook process is provided below. The results are compared with the HEPs from the V.C. Summer HRA, and indicate that the HEPs used in the IPE are the same or higher than the recalculated HEPs.

It is concluded that the HEPs calculated for the V.C. Summer HRA are realistic and consistent with those that could be obtained by using the THERP Handbook process without modification.

OAI: Diagnose SGTR and Isolate Ruptured SG

INPUTS:

1) Time Window for these activities is 30 minutes.

2) Assume diagnosis must be completed within 20 minutes from event initiation; and action execution can be completed in less than 10 minutes. THERP Table 20-3 is applied for the crew cognitive error.

3) Assume 3 high radiation alarms are provided to which the crew is required to respond.

4) STA presence is credited after 10 minutes from the event initiation.

5) During diagnosis, no credit is taken for the STA function; this is believed to be conservative.

6) During action execution, STA function is assigned a high dependency on the function of other crew members.

7) BOP operator is assigned a high dependency on the RO.

8) SRO is assigned a high dependency on the RO.

9) A shift supervisor (SS) is assumed to be on duty. Conservatively and contrary to THERP, no credit is taken for the SS during diagnosis. However, in accordance with THERP, moderate dependency is assigned for the SS during action execution.

10) A high stress level (dynamic tasks) is assigned for this task according to THERP 20-16, item 5.

(D_{HEP}) Diagnosis Error Calculation:

D1: Failure to diagnose SGTR within 20 minutes = 2.7E-02 [THERP 20-3 (3)]
$D2_{(RO)}$: Failure to respond to 1 of 3 alarms = 2.7E-03 [THERP 20-23 (3)]
$D2_{(BOPO)}$: High crew dependency assigned to BOPO = 0.5 [THERP 20-4]
$D2_{(SRO)}$: High crew dependency assigned to SRO = 0.5 [THERP 20-4]

$D2 = D2_{(RO)} \times D2_{(BOPO)} \times D2_{(SRO)} = 2.7E\text{-}03 \times 0.5 \times 0.5 = 6.75E\text{-}04$.

$(D_{HEP}) = D1 \times D2 = 1.82E\text{-}05$.

(A_{HEP}) Action Execution Calculation:

A1 <u>Identify Ruptured SG</u>

a) Misreads SG narrow range level (commission error) = 7.5E-03 [THERP 20-10 (3)]
b) Omit step to verify SG NR level (omission error) = 3.8E-03 [THERP 20-7 (2)]

<u>**AND**</u>

c) Misreads SG steamline radiation monitor (commission error) = 7.5E-03 [THERP 20-10 (3)]
d) Omit step to identify high radiation in any SG (omission error) = 3.8E-03 [THERP 20-7 (2)]
e) Stress multiplier = 5

$A1_{(RO)}$ = [(a + b)(c + d) x c = 6.38E-04;
$A1_{(BOPO)}$ = 0.5 [THERP 20-18]
$A1_{(SRO)}$ = 0.5 [THERP 20-18]
$A1_{(SS)}$ = 0.15 [THERP 20-18]
$A1_{(STA)}$ = 0.5 [THERP 20-18]
$A1_{HEP}$ = $A1_{(RO)}$ x $A1_{(BOPO)}$ x $A1_{(SRO)}$ x $A1_{(SS)}$ x $A1_{(STA)}$ = 1.20E-05.

A2 <u>Isolate Ruptured SG</u>

a) Set SG PWR relief CNTRL to wrong position (commission error) = 2.7E-03 [THERP 20-12 (9)]
b) Omit step to set SG PWR relief CNTRL (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A2_{(RO)}$ = (a + b) x c = 3.25E-02;
$A2_{(BOPO)}$ = (1 + 3.25E-02)/2 = 0.52 [THERP 20-17]
$A2_{(SRO)}$ = (1 + 3.25E-02)/2 = 0.52 [THERP 20-17]
$A2_{(SS)}$ = [1 + (6 x 3.25E-02)]/7 = 0.17 [THERP 20-17]
$A2_{(STA)}$ = (1 + 3.25E-02)/2 = 0.52 [THERP 20-17]
$A2_{HEP}$ = $A2_{(RO)}$ x $A2_{(BOPO)}$ x $A2_{(SRO)}$ x $A2_{(SS)}$ x $A2_{(STA)}$ = 7.75E-04.

A3:

a) Set STMLN PWR relief switch to wrong position (commission error) = 2.7E-04 [THERP 20-12 (8)]
b) Omit steps to set STMLN PWR relief switch (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A3_{(RO)}$ = (a + b) x c = 2.04E-02;
$A3_{(BOPO)}$ = 0.5 [THERP 20-18]
$A3_{(SRO)}$ = 0.5 [THERP 20-18]
$A3_{(SS)}$ = 0.16 [THERP 20-18]
$A3_{(STA)}$ = 0.5 [THERP 20-18]
$A3_{HEP}$ = $A3_{(RO)}$ x $A3_{(BOPO)}$ x $A3_{(SRO)}$ x $A3_{(SS)}$ x $A3_{(STA)}$ = 4.08E-04.

A4 a) Set SG PWR relief CNTRL to wrong position (commission error) = 2.7E-04 [THERP 20-12 (8)]
b) Omit step to set SG PWR relief CNTRL (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A4_{(RO)}$ = (a + b) x c = 2.04E-02;
$A4_{(BOPO)}$ = 0.5 [THERP 20-18]
$A4_{(SRO)}$ = 0.5 [THERP 20-18]
$A4_{(SS)}$ = 0.16 [THERP 20-18]
$A4_{(STA)}$ = 0.5 [THERP 20-18]
$A4_{HEP}$ = $A4_{(RO)}$ x $A4_{(BOPO)}$ x $A4_{(SRO)}$ x $A4_{(SS)}$ x $A4_{(STA)}$ = 4.08E-04.

A5 a) Select wrong control for valve to TD EFP (commission error) = 1.3E-03 [THERP 20-12 (3)]
b) Omit step to close valve to TD EFP (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A5_{(RO)}$ = (a + b) x c = 2.55E-02;
$A5_{(BOPO)}$ = (1 + 2.55E-02)/2 = 0.5 [THERP 20-17]
$A5_{(SRO)}$ = (1 + 2.55E-02)/2 = 0.5 [THERP 20-17]
$A5_{(SS)}$ = [1 + (6 x 2.55E-02)]/7 = 0.16 [THERP 20-17]
$A5_{(STA)}$ = (1 + 2.55E-02)/2 = 0.5 [THERP 20-17]
$A5_{HEP}$ = $A5_{(RO)}$ x $A5_{(BOPO)}$ x $A5_{(SRO)}$ x $A5_{(SS)}$ x $A5_{(STA)}$ = 5.10E-04.

A6 a) Select wrong beaker to deenergize MS loop (commission error) = 6.2E-03 [THERP 20-12 (11)]
b) Omit step to deenergize MS loop (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A6_{(RO)}$ = (a + b) x c = 5.0E-02;
$A6_{(BOPO)}$ = (1 + 5.0E-02)/2 = 0.53 [THERP 20-17]
$A6_{(SRO)}$ = (1 + 5.0E-02)/2 = 0.53 [THERP 20-17]
$A6_{(SS)}$ = [1 + (6 x 5.0E-02)]/7 = 0.19 [THERP 20-17]
$A6_{(STA)}$ = (1 + 5.0E-02)/2 = 0.53 [THERP 20-17]
$A6_{HEP}$ = $A6_{(RO)}$ x $A6_{(BOPO)}$ x $A6_{(SRO)}$ x $A6_{(SS)}$ x $A6_{(STA)}$ = 1.42E-03.

A7 a) Select wrong control for MSIV (commission error) = 1.3E-03 [THERP 20-12 (4)]
b) Omit step to close MSIV (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A7_{(RO)}$ = (a + b) x c = 2.55E-02;
$A7_{(BOPO)}$ = (1 + 2.55E-02)/2 = 0.5 [THERP 20-17]
$A7_{(SRO)}$ = (1 + 2.55E-02)/2 = 0.5 [THERP 20-17]
$A7_{(SS)}$ = [1 + (6 x 2.55E-02)]/7 = 0.16 [THERP 20-17]

$A7_{(STA)}$ = $(1 + 2.55E\text{-}02)/2 = 0.5$ [THERP 20-17]
$A7_{HEP}$ = $A7_{(RO)} \times A7_{(BOPO)} \times A7_{(SRO)} \times A7_{(SS)} \times A7_{(STA)} = 5.10E\text{-}04$.

A8
a) Misread SG NR indication (commission error) = 7.5E-03 [THERP 20-10 (3)]
b) Omit step to close MSIV (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A8_{(RO)}$ = $(a + b) \times c = 5.65E\text{-}02$;
$A8_{(BOPO)}$ = $(1 + 5.65E\text{-}02)/2 = 0.53$ [THERP 20-17]
$A8_{(SRO)}$ = $(1 + 5.65E\text{-}02)/2 = 0.53$ [THERP 20-17]
$A8_{(SS)}$ = $[1 + (6 \times 5.65E\text{-}02)]/7 = 0.19$ [THERP 20-17]
$A8_{(STA)}$ = $(1 + 5.65E\text{-}02)/2 = 0.53$ [THERP 20-17]
$A8_{HEP}$ = $A8_{(RO)} \times A8_{(BOPO)} \times A8_{(SRO)} \times A8_{(SS)} \times A8_{(STA)} = 1.60E\text{-}03$.

A9
a) Select wrong control for to stop feed flow (commission error) = 1.3E-03 [THERP 20-12 (4)]
b) Omit step to close MSIV (omission error) = 3.8E-03 [THERP 20-7 (2)]
c) Stress multiplier = 5

$A9_{(RO)}$ = $(a + b) \times c = 2.55E\text{-}02$;
$A9_{(BOPO)}$ = $(1 + 2.55E\text{-}02)/2 = 0.5$ [THERP 20-17]
$A9_{(SRO)}$ = $(1 + 2.55E\text{-}02)/2 = 0.5$ [THERP 20-17]
$A9_{(SS)}$ = $[1 + (6 \times 2.55E\text{-}02)]/7 = 0.16$ [THERP 20-17]
$A9_{(STA)}$ = $(1 + 2.55E\text{-}02)/2 = 0.5$ [THERP 20-17]
$A9_{HEP}$ = $A9_{(RO)} \times A9_{(BOPO)} \times A9_{(SRO)} \times A9_{(SS)} \times A9_{(STA)} = 5.10E\text{-}04$.

Therefore, total action execution HEP (A_{HEP}) is: $A1_{HEP} + A2_{HEP} + \dots + A9_{HEP} = 6.15E\text{-}03$;
The total HEP for OAI is: $(D_{HEP}) + (A_{HEP}) = 1.82E\text{-}05 + 6.15E\text{-}03 = 6.17E\text{-}03$.

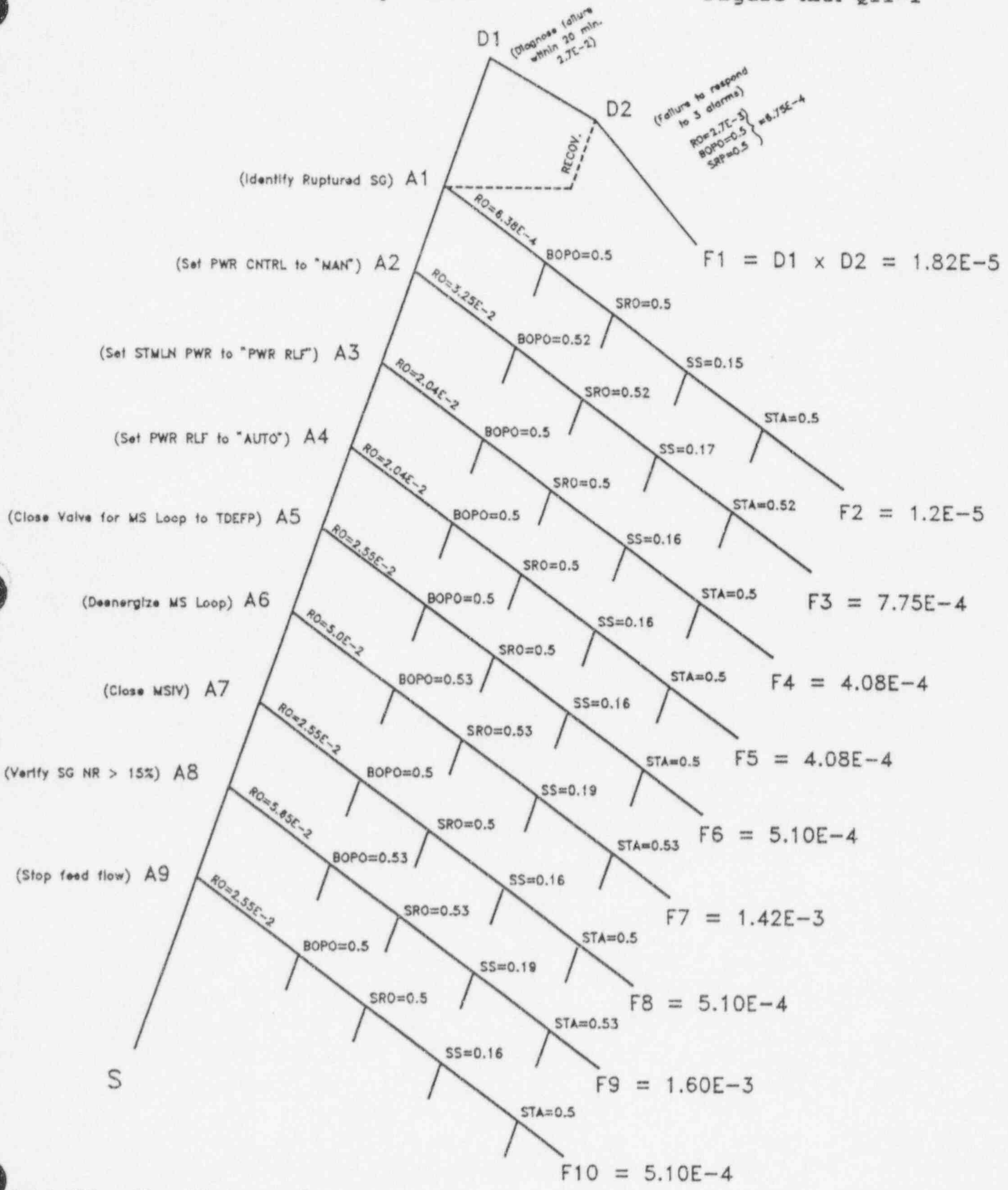
(See Figure HRA Q11-1 for THERP Tree for this event).

COMPARISON:

Action	Current V.C. Summer HEPs	New THERP HEPs
OAI (D_{HEP})	2.90E-05	1.82E-05
OAI (A_{HEP})	6.60E-03	6.15E-03
OAI (total)	6.63E-03	6.17E-03

Diagnose SGTR and Isolate Ruptured SG

Figure HRA Q11-1



Total HEP = F1 + F2 + ... + F10 = 6.17E-3

ESF: Recognize the Need and Manually Actuate Safety Injection

INPUTS:

1) Time Window for these activities is 20 minutes.

2) Assume diagnosis must be completed within 15 minutes from event initiation; and action execution can be completed in less than 1 minute. THERP Table 20-3 is applied for the crew cognitive error.

3) Assume 3 alarms are provided to which the crew is required to respond.

4) STA presence is credited after 10 minutes from the event initiation.

5) During diagnosis, STA function is assigned a moderate dependency on the function of other crew members.

6) During action execution, STA function is assigned a high dependency on the function of other crew members.

7) BOP operator is assigned a high dependency on the RO.

8) SRO is assigned a high dependency on the RO.

9) A shift supervisor (SS) is assumed to be on duty. Conservatively and contrary to THERP, no credit is taken for the SS during diagnosis. However, in accordance with THERP, moderate dependency is assigned for the SS during action execution.

10) A moderately high stress level (dynamic task) is assigned for this task according to THERP 20-16, item 3.

(D_{HEP}) Diagnosis Error Calculation:

D1: Failure to recognize the need for SI actuation within 15 minutes = 2.7E-02 [THERP 20-3 (3)]
$D2_{(RO)}$: Failure to respond to 1 of 3 alarms = 2.7E-03 [THERP 20-23 (3)]
$D2_{(BOPO)}$: High crew dependency assigned to BOPO = 0.5 [THERP 20-4]
$D2_{(SRO)}$: High crew dependency assigned to SRO = 0.5 [THERP 20-4]
$D2_{(STA)}$: Moderate crew dependency assigned to STA = 0.15 [THERP 20-4]
$D2 = D2_{(RO)} \times D2_{(BOPO)} \times D2_{(SRO)} \times D2_{(STA)} = 2.7E\text{-}03 \times 0.5 \times 0.5 \times 0.15 = 1.01E\text{-}04$.

$(D_{HEP}) = D1 \times D2 = 2.73E\text{-}06$.

(A_{HEP}) Action Execution Calculation:

A1 a) Select wrong control for SI actuation switch (commission error) = 1.3E-03 [THERP 20-12 (3)]
b) Omit step to actuate SI (omission error) = 1.3E-03 [THERP 20-7 (1)]
c) Stress multiplier = 1

$A1_{(RO)}$ = (a + b) x c = 2.6E-03;
$A1_{(BOPO)}$ = 0.5 [THERP 20-18]
$A1_{(SRO)}$ = 0.5 [THERP 20-18]
$A1_{(SS)}$ = 0.15 [THERP 20-18]
$A1_{(STA)}$ = 0.5 [THERP 20-18]
$A1_{HEP}$ = $A1_{(RO)} \times A1_{(BOPO)} \times A1_{(SRO)} \times A1_{(SS)} \times A1_{(STA)}$ = 4.88E-05.

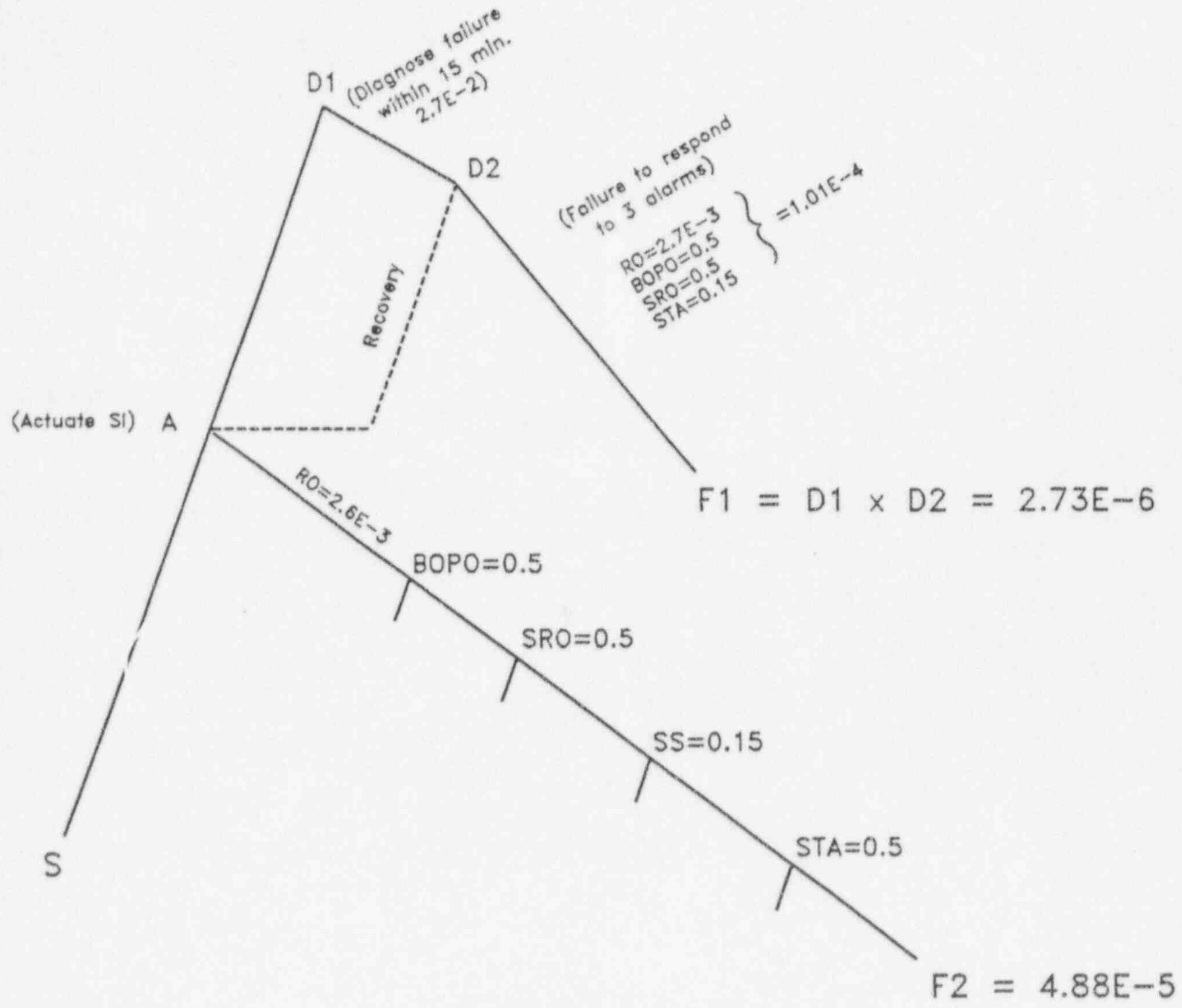
The total HEP for ESF is: (D_{HEP}) + (A_{HEP}) = 2.73E-06 + 4.88E-05 = 5.15E-05.

(See Figure HRA Q11-2 for THERP Tree for this event).

COMPARISON:

Action	Current V.C. Summer HEPs	New THERP HEPs
ESF	5.07E-05	5.15E-05

Recognize the Need & Actuate SI Figure HRA Q11-2



Total HEP = F1 + F2 = 5.15E-5

OAP: Recognize the Need and Depressurize RC for Core Cooling

INPUTS:

1) Time Window for these activities is 15 minutes.

2) Assume diagnosis must be completed within 10 minutes from cue response; action execution can be completed in less than 1 minute. THERP Table 20-3 is applied for the crew cognitive error.

3) Assume core exit TCs > 1200°F is provided as a primary cue to which the crew is required to respond.

4) STA presence is credited after 10 minutes from the event initiation.

5) During diagnosis, STA function is assigned a moderate dependency on the function of other crew members.

6) During action execution, STA function is assigned a high dependency on the function of other crew members.

7) BOP operator is assigned a high dependency on the RO.

8) SRO is assigned a high dependency on the RO.

9) A shift supervisor (SS) is assumed to be on duty. Conservatively and contrary to THERP, no credit is taken for the SS during diagnosis. However, in accordance with THERP, moderate dependency is assigned for the SS during action execution.

10) A high stress level (dynamic task) is assigned for this task according to THERP 20-16, item 5.

(D_{HEP}) Diagnosis Error Calculation:

D1: Failure to diagnose event within 10 minutes = 2.7E-01 [THERP 20-3 (2)]
$D2_{(RO)}$: Failure to recognize core exit TC > 1200°F = 1.2E-03 [THERP 20-10 (2)]
$D2_{(BOPO)}$: High crew dependency assigned to BOPO = 0.5 [THERP 20-4]
$D2_{(SRO)}$: High crew dependency assigned to SRO = 0.5 [THERP 20-4]
$D2_{(STA)}$: Moderate crew dependency assigned to STA = 0.15 [THERP 20-4]
$D2 = D2_{(RO)} \times D2_{(BOPO)} \times D2_{(SRO)} \times D2_{(STA)}$ = 8.0E-03 x 0.5 x 0.5 x 0.15 = 4.5E-05.

(D_{HEP}) = D1 x D2 = 1.22E-05.

(A_{HEP}) Action Execution Calculation:

A1	a)	Select wrong controls to PORV or block valve; total dependency assumed (commission error) = 1.3E-03[THERP 20-12 (3)]
	b)	Omit step to open valves (omission error) = 3.8E-03 [THERP 20-7 (2)]
	c)	Stress multiplier = 5
$A1_{(RO)}$	=	(a + b) x c = 5.1E-03;
$A1_{(BOPO)}$	=	0.5 [THERP 20-18]
$A1_{(SRO)}$	=	0.5 [THERP 20-18]
$A1_{(SS)}$	=	0.15 [THERP 20-18]
$A1_{(STA)}$	=	0.5 [THERP 20-18]
$A1_{HEP}$	=	$A1_{(RO)} \times A1_{(BOPO)} \times A1_{(SRO)} \times A1_{(SS)} \times A1_{(STA)}$ = 9.56E-05.

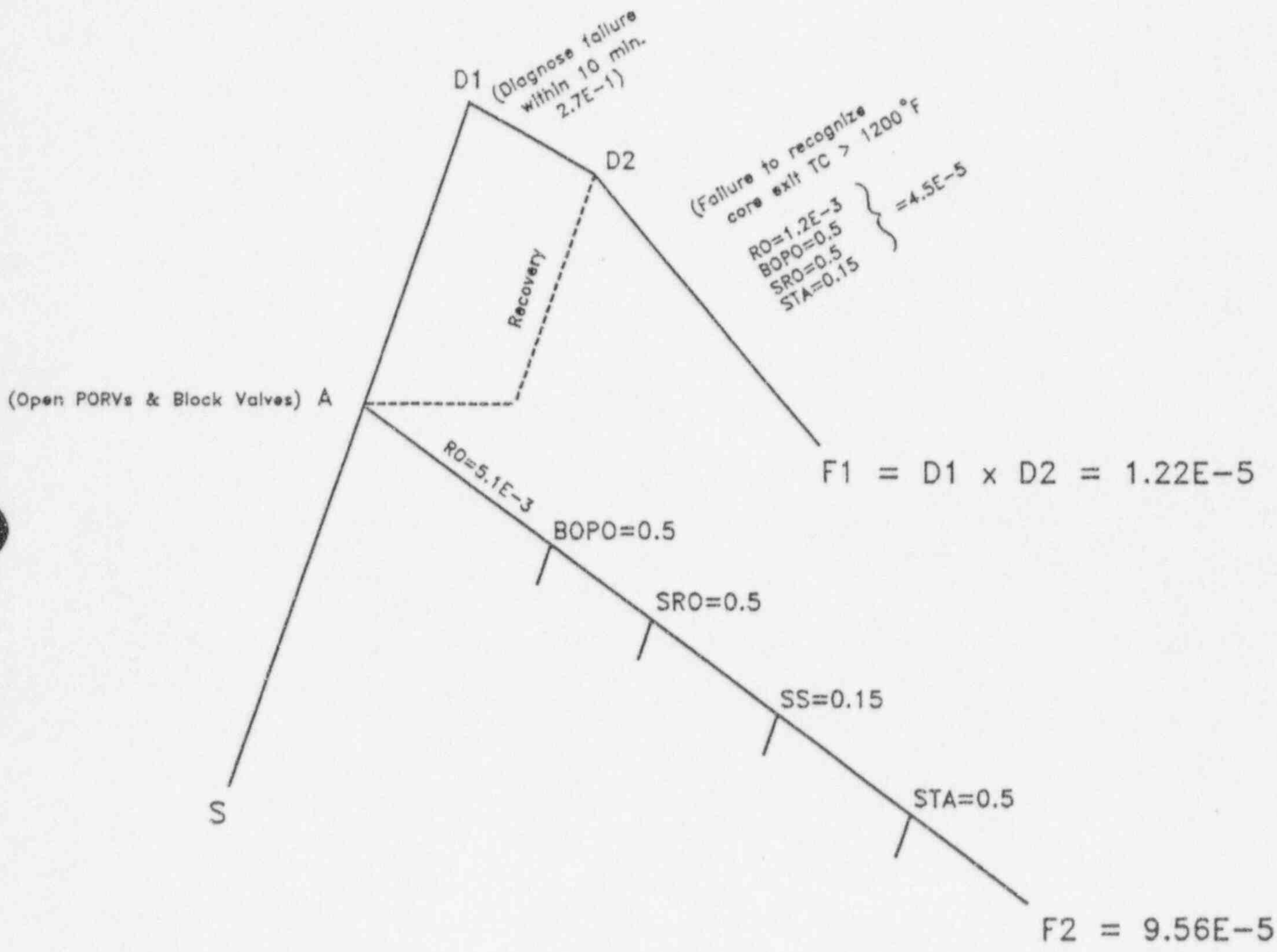
The total HEP for OAP is: $(D_{HEP}) + (A_{HEP})$ = 1.22E-05 + 9.56E-05 = 1.08E-04.

(See Figure HRA Q11-3 for THERP Tree for this event).

COMPARISON:

Action	Current V.C. Summer HEPs	New THERP HEPs
OAP	1.51E-03	1.08E-04

Recognize the Need & Depressurize RC for Core Cooling Figure HRA Q11-3



Total HEP = F1 + F2 = 1.08E-4

CI: Recognize the Need and Actuate Phase A Containment Isolation

INPUTS:

1) Time Window for these activities is 15 minutes.

2) Assume diagnosis must be completed within 10 minutes from cue response; action execution can be completed in less than 2 minutes. THERP Table 20-3 is applied for the crew cognitive error.

3) Assume ESF monitor light indications are provided as primary cues to which the crew is required to respond.

4) STA presence is credited after 10 minutes from the event initiation.

5) During diagnosis, STA function is assigned a moderate dependency on the function of other crew members.

6) During action execution, STA function is assigned a high dependency on the function of other crew members.

7) BOP operator is assigned a high dependency on the RO.

8) SRO is assigned a high dependency on the RO.

9) A shift supervisor (SS) is assumed to be on duty. Conservatively and contrary to THERP, no credit is taken for the SS during diagnosis. However, in accordance with THERP, moderate dependency is assigned for the SS during action execution.

10) An optimum stress level (dynamic task) is assigned for this task according to THERP 20-16, item 3. However, a multiplier of 2 is used.

(D_{HEP}) Diagnosis Error Calculation:

D1: Failure to diagnose event within 10 minutes = 2.7E-01 [THERP 20-3 (2)]
$D2_{(RO)}$: Failure to recognize ESF monitor lights BRIGHT = 3.8E-03 [THERP 20-7 (2)]
$D2_{(BOPO)}$: High crew dependency assigned to BOPO = 0.5 [THERP 20-4]
$D2_{(SRO)}$: High crew dependency assigned to SRO = 0.5 [THERP 20-4]
$D2_{(STA)}$: Moderate crew dependency assigned to STA = 0.15 [THERP 20-4]
$D2 = D2_{(RO)} \times D2_{(BOPO)} \times D2_{(SRO)} \times D2_{(STA)}$ = 8.0E-03 x 0.5 x 0.5 x 0.15 = 1.43E-04.
(D_{HEP}) = D1 x D2 = 3.85E-05.

(A_{HEP}) Action Execution Calculation:

A1 a) Select wrong actuation switch or valve control; total dependency assumed valve closure (commission error) = 2.7E-04 [THERP 20-12 (8)]

b) Omit step to actuate containment isolation (omission error) = 3.8E-03 [THERP 20-7 (2)]

c) Stress multiplier = 2

$A1_{(RO)}$ = (a + b) x c = 8.14E-03;

$A1_{(BOPO)}$ = 0.5 [THERP 20-18]

$A1_{(SRO)}$ = 0.5 [THERP 20-18]

$A1_{(SS)}$ = 0.15 [THERP 20-18]

$A1_{(STA)}$ = 0.5 [THERP 20-18]

$A1_{HEP}$ = $A1_{(RO)}$ x $A1_{(BOPO)}$ x $A1_{(SRO)}$ x $A1_{(SS)}$ x $A1_{(STA)}$ = 1.53E-04.

A2 a) Select wrong control to close damper (commission error) = 1.3E-03 [THERP 20-12 (3)]

b) Omit step to close damper (omission error) = 3.8E-03 [THERP 20-7 (2)]

c) Stress multiplier = 2

$A2_{(RO)}$ = (a + b) x c = 1.02E-02;

$A2_{(BOPO)}$ = 0.5 [THERP 20-18]

$A2_{(SRO)}$ = 0.5 [THERP 20-18]

$A2_{(SS)}$ = 0.15 [THERP 20-18]

$A2_{(STA)}$ = 0.5 [THERP 20-18]

$A2_{HEP}$ = $A2_{(RO)}$ x $A2_{(BOPO)}$ x $A2_{(SRO)}$ x $A2_{(SS)}$ x $A2_{(STA)}$ = 1.92E-04.

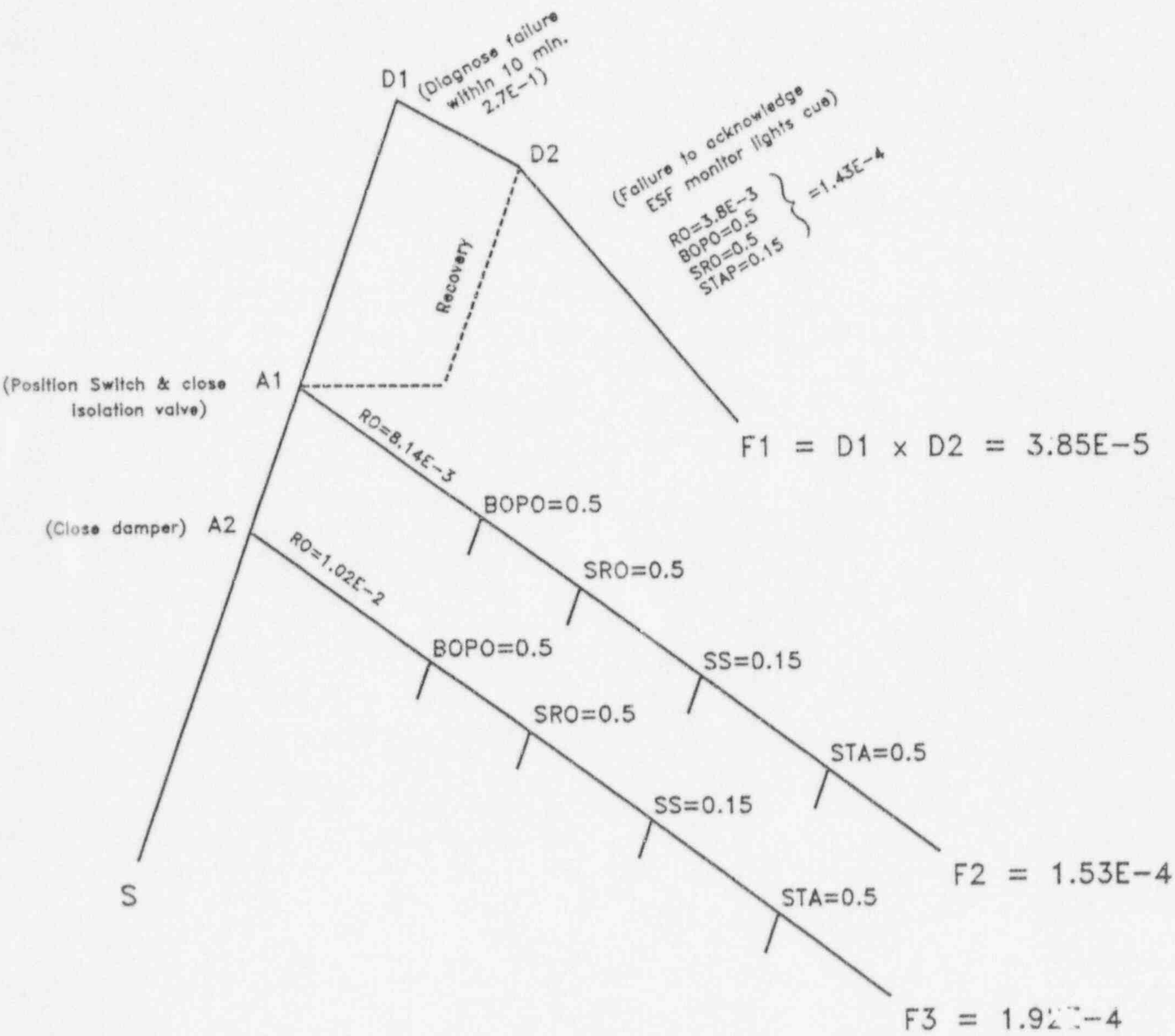
Therefore, total action execution HEP (A_{HEP}) is: $A1_{HEP}$ + $A2_{HEP}$ = 3.45E-04;
The total HEP for OAP is: (D_{HEP}) + (A_{HEP}) = 3.85E-05 + 3.45E-04 = 3.84E-04.

(See Figure HRA Q11-4 for THERP Tree for this event).

COMPARISON:

Action	Current V.C. Summer HEPs	New THERP HEPs
CI	6.33E-04	3.84E-04

Recognize the Need & Actuate Phase A CNMT Isolation   Figure HRA Q11-4



Total HEP = F1 + F2 + F3 = 3.84E-4

HLR: Recognize the Need and Realign Cold Leg Recirculation

INPUTS:

1) Time Window for these activities is 35 minutes.

2) Assume diagnosis must be completed within 30 minutes from cue response is required; action execution can be completed in less than 3 minutes. THERP Table 20-3 is applied for the crew cognitive error.

3) Assume status tree red path is provided as the primary cue to which the crew is required to respond.

4) STA presence is credited after 10 minutes from the event initiation.

5) During diagnosis, STA function is assigned a moderate dependency on the function of other crew members.

6) During action execution, STA function is assigned a high dependency on the function of other crew members.

7) BOP operator is assigned a high dependency on the RO.

8) SRO is assigned a high dependency on the RO.

9) A shift supervisor (SS) is assumed to be on duty. Conservatively and contrary to THERP, no credit is taken for the SS during diagnosis. However, in accordance with THERP, moderate dependency is assigned for the SS during action execution.

10) A high stress level (dynamic task) is assigned for this task according to THERP 20-16, item 5.

(D_{HEP}) Diagnosis Error Calculation:

D1: Failure to diagnose event within 30 minutes = 2.7E-03 [THERP 20-3 (4)]

$D2_{(RO)}$: Failure to acknowledge status tree RED PATH directions = 1.2E-02 (engineering judgement)

$D2_{(BOPO)}$: High crew dependency assigned to BOPO = 0.5 [THERP 20-4]

$D2_{(SRO)}$: High crew dependency assigned to SRO = 0.5 [THERP 20-4]

$D2_{(STA)}$: Moderate crew dependency assigned to STA = 0.15 [THERP 20-4]

$D2 = D2_{(RO)} \times D2_{(BOPO)} \times D2_{(SRO)} \times D2_{(STA)}$ = 8.0E-03 x 0.5 x 0.5 x 0.15 = 4.5E-04.

(D_{HEP}) = D1 x D2 = 1.22E-06.

(A_{HEP}) Action Execution Calculation:

A1 a) Misread SI flow indication (commission error) = 3.7E-03 [THERP 20-10 (1)]
b) Omit step to verify SI flow (omission error) = 1.3E-03 [THERP 20-7 (1)]
c) Stress multiplier = 5

$A1_{(RO)}$ = (a + b) x c = 3.0E-02;
$A1_{(BOPO)}$ = 0.52 [THERP 20-17]
$A1_{(SRO)}$ = 0.52 [THERP 20-17]
$A1_{(SS)}$ = 0.17 [THERP 20-17]
$A1_{(STA)}$ = 0.52 [THERP 20-17]
$A1_{HEP}$ = $A1_{(RO)}$ x $A1_{(BOPO)}$ x $A1_{(SRO)}$ x $A1_{(SS)}$ x $A1_{(STA)}$ = 7.17E-04.

A2 a) Select wrong control for PWR lockout switch (commission error) = 1.3E-03 [THERP 20-12 (4)]
b) Omit step to turn switch ON (omission error) = 1.3E-03 [THERP 20-7 (1)]
c) Stress multiplier = 5

$A2_{(RO)}$ = (a + b) x c = 1.3E-02;
$A2_{(BOPO)}$ = 0.5 [THERP 20-18]
$A2_{(SRO)}$ = 0.5 [THERP 20-18]
$A2_{(SS)}$ = 0.15 [THERP 20-18]
$A2_{(STA)}$ = 0.5 [THERP 20-18]
$A2_{HEP}$ = $A2_{(RO)}$ x $A2_{(BOPO)}$ x $A2_{(SRO)}$ x $A2_{(SS)}$ x $A2_{(STA)}$ = 2.44E-04.

A3 a) Select wrong control for 3 of valves (commission error) = 1.3E-03 x 3 = 3.9E-03 [THERP 20-2 (3)]
b) Omit 3 of 3 steps to position valves (omission error) = 1.3E-03 x 3 = 3.9E-03 [THERP 20-7 (1)]
c) Stress multiplier = 5

$A3_{(RO)}$ = (a + b) x c = 3.9E-02;
$A3_{(BOPO)}$ = 0.52 [THERP 20-17]
$A3_{(SRO)}$ = 0.52 [THERP 20-17]
$A3_{(SS)}$ = 0.18 [THERP 20-17]
$A3_{(STA)}$ = 0.52 [THERP 20-17]
$A3_{HEP}$ = $A3_{(RO)}$ x $A3_{(BOPO)}$ x $A3_{(SRO)}$ x $A3_{(SS)}$ x $A3_{(STA)}$ = 9.87E-04.

A4 a) Select wrong control for CHG/SI pump (commission error) = 1.3E-03 [THERP 20-2 (3)]; total dependency assumed for restarting pump later
b) Omit step to stop pump (omission error) = 1.3E-03 [THERP 20-7 (1)]
c) Stress multiplier = 5

$A4_{(RO)}$ = (a + b) x c = 1.3E-02;
$A4_{(BOPO)}$ = 0.5 [THERP 20-18]
$A4_{(SRO)}$ = 0.5 [THERP 20-18]
$A4_{(SS)}$ = 0.15 [THERP 20-18]
$A4_{(STA)}$ = 0.5 [THERP 20-18]
$A4_{HEP}$ = $A3_{(RO)}$ x $A3_{(BOPO)}$ x $A3_{(SRO)}$ x $A3_{(SS)}$ x $A3_{(STA)}$ = 2.44E-04.

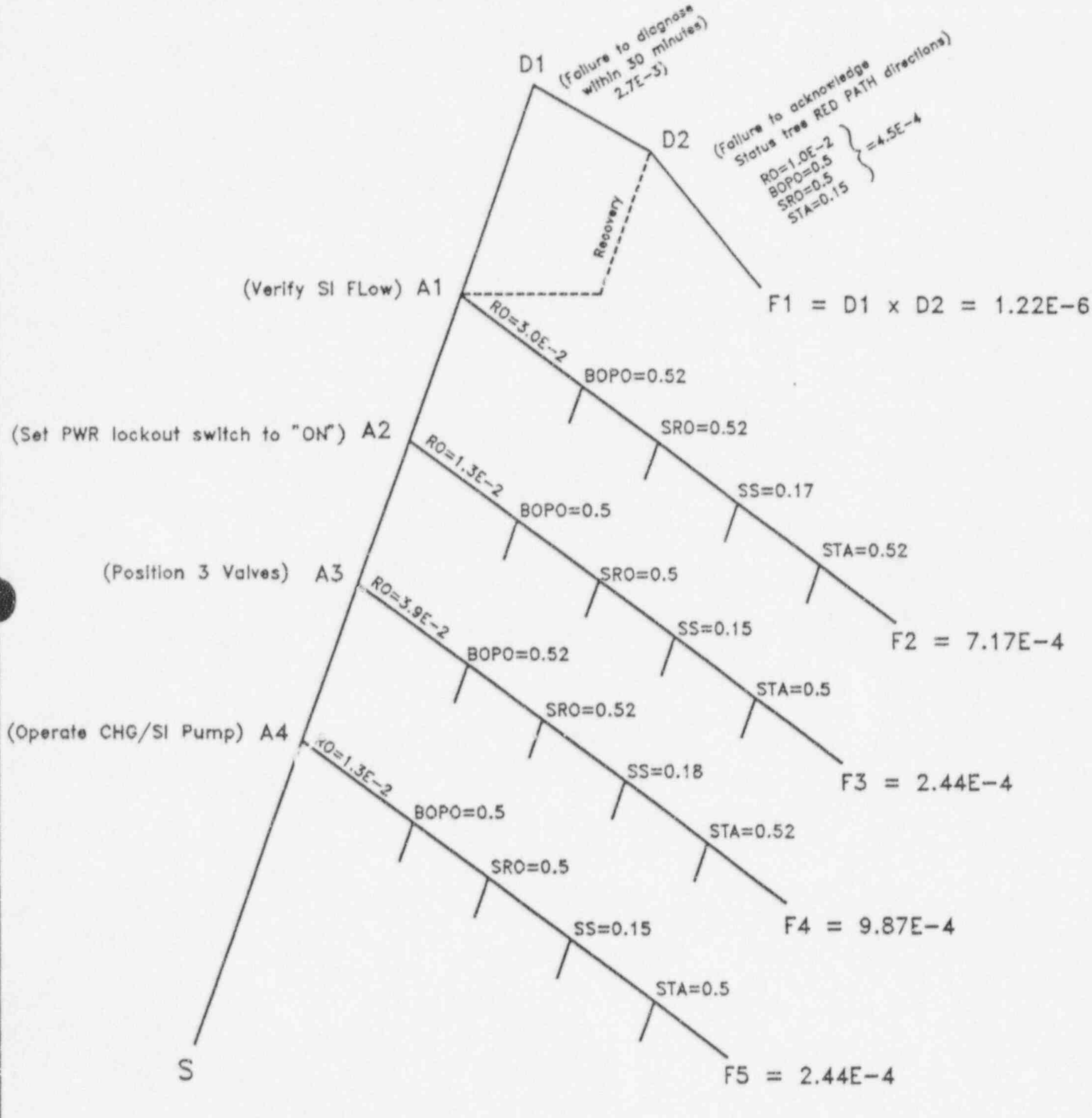
Therefore, total action execution HEP (A_{HEP}) is: $A1_{HEP} + A2_{HEP} + A3_{HEP} + A4_{HEP}$ = 2.19E-03;
The total HEP for OAP is: (D_{HEP}) + (A_{HEP}) = 1.22E-06 + 2.19E-03 = 2.19E-03.

(See Figure HRA Q11-5 for THERP Tree for this event).

COMPARISON:

Action	Current V.C. Summer HEPs	New THERP HEPs
HLR	2.10E-03	2.19E-03

Recognize the Need & Realign Cold Leg Recirculation Figure HRA Q11-5



Total HEP = F1 + F2 + ... + F5 = 2.19E-3

12) The submittal is not clear whether response type actions and recovery type actions were considered. Response type actions include human actions performed in response to the first level directive of the emergency operating procedures (EOPs). For example, suppose the EOP directive instructs the operator to determine reactor water level status, and another directive instructs the operator to maintain reactor water level with system X. These actions - reading instrumentation to determine level and actuating system X to maintain level - are response type actions. Recovery type actions include those performed to recover a specific failure or fault and may not be "proceduralized." For example, suppose the EOP directive instructs the operator to maintain level using system x, but the system fails to function and the operator then attempts to recover it. This action - diagnosing the failure and then deciding on a course of action to "recover" the failed system - is a recovery type action. Section 3.3.3 has not made a distinction between the response type actions and recovery type actions used as defined above. Please provide separate lists of the response and recovery actions considered in the analysis. If response or recovery actions were not considered, please justify. Also justify why recovery actions, if used, are not proceduralized.

Response

Both response type and recovery type actions were considered in the V.C. Summer HRA. The definition of these actions and the method of selecting them are provided in the response to HRA Question 8.

The justification for selecting and the process of evaluating the recovery type actions are provided in the response to HRA Question 14. As stated in the response to HRA Question 14, these recovery actions are designed to repair or restore components to operable conditions, and do not involve the ability of the plant operator to respond to events via procedures.

The lists of response and recovery actions are provided in Table HRA Q12-1.

Table HRA Q12-1 Response and Recovery Type Human Actions			
RESPONSE-TYPE ACTIONS			
Top Event	Description	Time Window	Human Error Probability
RT	Initiate Manual Reactor Trip	1 minute	2.80E-03
ESF	Initiate Manual Safety Injection via SI switch	20 minutes	5.07E-05
OAB	Initiate Bleed and Feed (SI in progress)	30 minutes	1.70E-03
OAB	Initiate Bleed and Feed (Actuate SI)	30 minutes	4.84E-03
OAB	Initiate Bleed and Feed (ATWS)	30 minutes	1.77E-02
OAF	Establish Condensate Feedwater	10 minutes	1.0
OAR	Establish Low-Pressure Cold Leg Recirculation (RH pumps running)	15 minutes	2.40E-04
OAR	Establish Cold Leg Recirculation (RH pumps running) (Conditional on OAH)	15 minutes	1.56E-01
OAR	Establish Low-Pressure Cold Leg Recirculation (RH pumps stopped)	60 minutes	9.18E-05
OAR	Establish High-Pressure Cold Leg Recirculation (RH pumps running)	20 minutes	5.94E-04
OAR	Establish High-Pressure Cold Leg Recirculation (RH pumps stopped)	20 minutes	8.49E-04
OAR	Establish High-Pressure Cold Leg Recirculation (RH pumps stopped) (ISLOCA)	20 minutes	6.26E-03
OAL	Establish Low-Pressure Hot Leg Recirculation	30 minutes	1.85E-04
OAL	Establish High-Pressure Hot Leg Recirculation	30 minutes	3.71E-04

Table HRA Q12-1 Response and Recovery Type Human Actions			
RESPONSE-TYPE ACTIONS			
Top Event	Description	Time Window	Human Error Probability
OAH	Establish CC to RH Heat Exchangers	30 minutes	1.17E-03
OAI	Isolate Ruptured Steam Generator Diagnose Identify Isolate	30 minutes	 2.90E-05 1.92E-05 6.58E-03
OAD	Depressurize the Secondary Side (Normal cooldown)	30 minutes	6.39E-03
OAD	Depressurize the Secondary Side (Accelerated Cooldown)	15 minutes	1.92E-02
OAD	Depressurize the Secondary Side (SGTR only)	15 minutes	3.35E-03
OAP	Depressurize RC for Inadequate Core Cooling	15 minutes	1.51E-03
OAP	Depressurize RC (Conditional on OAD)	15 minutes	1.44E-01
OAP	Depressurize RC to Stop Leakage to Ruptured SG	15 minutes	2.39E-04
OAT	Terminate Safety Injection (SGTR)	30 minutes	1.93E-04
OAT	Terminate Safety Injection (SSB)	15 minutes	2.04E-03
OAC	Cooldown RC to RH Conditions	1 hour	5.70E-05
OAC	Cooldown RC to RH Conditions (Conditional on OAT)	1 hour	1.42E-01
OAN	Establish Normal RH Cooling	30 minutes	1.58E-03
OAN	Establish Normal RH Cooling (Conditional on OAH)	30 minutes	1.44E-01
EFC	Maintain EF Supply to SGs	8 hours	3.02E-04

OAD	Depressurize Secondary Side by Manual Local Control	45 minutes	9.70E-04
OAQ	Initiate SI and Establish EF	15 minutes	2.83E-03
MRI	Manually Drive Control Rods into Core	1 minute	1.30E-02
MRI	Manually Drive Control Rods into Core (Conditional)	1 minute	1.55E-01
OAE	Establish Emergency Boration	10 minutes	4.59E-06
OAS	Establish Reactor Building Spray Recirculation	1 hour	9.18E-05
OAS	Establish Reactor Building Spray Recirculation (Conditional on OAR)	1 hour	1.43E-01
OIL	Isolate Letdown	20 minutes	1.01E-04
OSR	Minimize SI Flowrate (RB Spray Running)	44 minutes	1.46E-02
OSR	Minimize SI Flowrate (RB Spray not Running)	99 minutes	6.45E-04
OASC	Align Alternate Cooling to Charging Pumps	10 minutes; 60 minutes	5.30E-02
OAA	Start Diesel Air Compressor and Align to IA System	30 minutes	4.03E-03
OEF	Actuate EF, Power Level < 40%	30 minutes	1.19E-04
OCC1	Start Second CC Pump on Failure of First Pump	30 minutes	1.12E-03
VUSB	Align and Start Chiller C and Pump C to Train B	1 hour	2.08E-01
VUSB	Align and Start Chiller C and Pump C to Train A	1 hour	1.26E-03
SW	Start SW Pump C During Transient	15 minutes	2.95E-06
CC	Start CC Pump B During Transient	15 minutes	6.07E-04

CC	Start CC Pump C During LOSP	10 minutes	3.36E-03
VU	Start Chilled Water Loop B During Transient	15 minutes	1.19E-03
CI	Actuate Phase A Containment Isolation	15 minutes	6.33E-04
N/A	Restore Instrument Air on LOSP (reset supplemental air compressor)	30 minutes	2.51E-03
N/A	Isolate RCP Seal Water Return Line	5 minutes	1.55E-02
EFW	Manually Start EF Pump Given Failure of Automatic Signals	30 minutes	8.00E-04
AC	Open AC Power Switchgear Room Door	30 minutes	5.21E-03
HLR	Realign Back to Cold Leg Recirculation Following Failure of Hot Leg Recirculation	35 minutes	2.10E-03
PZR	Establish Instrument Air to Reactor Building	15 minutes	4.16E-03
PZR	Open Block Valve during Initiation of Bleed and Feed	30 minutes	1.77E-02
ESFS	Start Trains A & B ESF Equipment from Control Board During Transient	30 minutes	9.03E-03
ESFS	Start Train A ESF Equipment from Control Board During Transient	30 minutes	4.10E-03
ESFS	Start Train B ESF Equipment from Control Board During Transient	30 minutes	5.70E-03

Table HRA Q12-1 Response and Recovery Type Human Actions			
RECOVERY-TYPE ACTIONS			
Top Event	Description	Time Window	Human Error Probability
CCR and CCS	Recover at least One Train of CC when Both Trains Failed but Supported (loss of CC and transient initiator)	2 hours	1.10E-01
CCR and CCS	Recover Train A of CC when Train A fails and only Train A Support Is Available (loss of CC and transient initiator)	2 hours	4.20E-01
CCR and CCS	Recover Train B of CC when Train B Fails and only Train B Support Is Available (loss of CC and transient initiator)	2 hours	2.80E-01
CCR	Recover at least One Train of CC when both Trains Failed but Supported (loss-of-offsite-power initiator)	2 hours	1.50E-01
CCR	Recover Train A of CC when Train A Fails and only Train A Support Is Available (loss-of-offsite-power initiator)	2 hours	1.30E-01
CCR	Recover Train B of CC when Train B Fails and only Train B Support Is Available (loss-of-offsite-power initiator)	2 hours	1.30E-01
VUR1	Recover at least One Train of Chilled Water when both Trains Failed but Supported (loss of chilled water initiator)	12 hours	1.80E-01

Table HRA Q12-1 Response and Recovery Type Human Actions			
RECOVERY-TYPE ACTIONS			
Top Event	Description	Time Window	Human Error Probability
VUR1 and VUS	Recover Train A of Chilled Water when Train A Fails and only Train A Support Is Available (loss of chilled water and transient initiator)	12 hours	5.20E-01
VUR1 and VUS	Recover Train B of Chilled Water when Train B Fails and only Train B Support Is Available (loss of chilled water and transient initiator)	12 hours	4.50E-01
VUR1 and VUS	Recover at least One Train of Chilled Water when both Trains Failed but Supported (transient initiator)	12 hours	2.40E-01
SWR1	Recover at least One Train of SW when both Trains Failed but Supported (loss of SW initiator)	2 hours	4.60E-01
SWR1 and SWS	Recover Train A of SW when Train A Fails and only Train A Support Is Available (loss of SW and transient initiator)	2 hours	8.10E-01
SWR1 and SWS	Recover Train B of SW when Train B Fails and only Train B Support Is Available (loss of SW and transient initiator)	2 hours	7.80E-01
SWR1 and SWS	Recover at least One Train of SW when both Trains Failed but Supported (transient initiator)	2 hours	8.90E-01

13) It is not clear from the submittal how dependencies were addressed and treated in the post-initiator HRA. The performance of the operator is both dependent on the accident under progression and the past performance of the operator during the accident of concern. Improper treatment of these dependencies can result in the elimination of potentially dominant accident sequences and, therefore, the identification of significant events. The submittal in Section 3.3.3 contains a two paragraph discussion on "Dependent Events" without any reference to post-initiator human actions. Tables 3.3.3.1, "Operator Actions Evaluated in Plant Response Trees and their Initiating Event Contexts," 3.3.3.3, "Operator Actions Important in Restoration of Failed Equipment" and 3.3.3.4, "Human Reliability Quantification Results" do not indicate anything about the implementation of post-initiator human action dependencies. Please provide a concise discussion and examples illustrating how dependencies were addressed and treated in the post-initiator HRA such that important accident sequences were not eliminated. If the submittal did not address dependencies in the quantification, please justify. The discussion should address the two points below:

a. Human events are modeled in the fault trees as basic events such as failure to manually actuate. The probability of the operator to perform this function is dependent on the accident in progression - what symptoms are occurring, what other activities are being performed (successfully and unsuccessfully), etc. When the sequences are quantified, this basic event can appear, not only in different sequences, but in different combinations with different systems failures. In addition, the basic event can potentially be multiplied by other human events when the sequences are quantified which should be evaluated for dependencies.

b. Human events are modeled in the event trees as top events. The probability of the operator to perform this function is still dependent on the accident progression. The quantification of the human events need to consider the different sequences and the other human events.

Response

a. Several actions included in the VCSNS IPE model were included in the fault trees. For the most part these actions are assumed to be independent from other actions taken by the operators following an event initiation. These actions can be divided into three categories: 1) those used to start standby trains of normally operating systems, 2) those taken to restore or maintain functions, and 3) those taken per Emergency Response Procedures (EOPs). The actions of interest are divided into these categories as follows:

Category 1: Actions used to start standby trains of normally operating systems

- Start service water pump C during transient
- Start chilled water loop B or C during transient
- Start component cooling water pump C during loss of offsite power

- Start component cooling water pump B or C during transient

Category 2: Actions taken to restore or maintain functions

- Open switchgear room doors for AC power equipment
- Restore instrument air on LOSP (reset supplemental air compressor)
- Re-establish instrument air to reactor building

Category 3: Actions taken per EOPs

- Manually start emergency feedwater given failure of automatic signals
- Actuate phase A containment isolation
- Re-establish cold leg recirculation given hot leg recirculation fails

Category 1: Actions used to start standby trains of normally operating systems

Emergency Operating Procedure 1.0, which is followed whenever a reactor trip is necessary, leads the operators through a series of actions that confirm reactor trip and turbine/generator trip have occurred, both ESF buses are powered, and to determine if safety injection is necessary. If safety injection is not required then the operators transfer to EOP-1.1 (Reactor Trip Recovery). If safety injection is required, then the operators remain in EOP 1.0.

During normal plant operation, both trains of service water are operating, one train of chilled water is operating, and one train of component cooling water is operating. It was assumed in the IPE that trains A of chilled water and component cooling water are the operating trains. It was also assumed that the installed spare for these systems will typically be aligned to train A unless train B is in maintenance, then it is aligned to train B.

During normal operation or following an event, loss of service water will be indicated in the control room. In response to this indication, the operators will start SW pump C per SOP-117. The action to start pump C is taken from control room indication separate from the reactor trip indication and follows a separate procedure. Credit for an operator starting pump C during an event is only taken when pump C is aligned to train A and pump A fails. Given that there is unique and independent indication and guidance to start pump C, it was concluded that there will be no dependence between this action and those actions being followed in the EOPs to respond to the trip event.

A similar plant and operator response is expected for loss of the operating train of chilled water or component cooling water during normal operation or during an event. The action to start the standby pump or train is indicated in the control room and the operators refer to the proper SOP to start standby pump. SOP-501 (HVAC Chilled Water System) is used for the chilled water system and SOP-119 (Component Cooling Water) is used for the component cooling water system. Again, given that there is unique and independent indication and guidance to start the standby trains, it was concluded that there will be no dependence between this action and those actions being followed in the EOPs to respond to the event.

These actions were only credited to transient events. If an event was in progress that required the operators to remain in EOP-1.0, then this was not credited.

Category 2: Actions taken to restore functions

The response to Front End Question 8 discusses HVAC (room cooling) requirements as modeled in the IPE. To maintain the appropriate temperature conditions in several of the switchgear rooms an operator action to provide an alternate means of heat removal (open room doors) is credited. This action is initiated by either high temperature alarms or fan trouble alarms. On a high temperature alarm the operator would attempt to restore room cooling and would monitor room temperature. The Alarm Response Procedure (ARP-16-XCP-6210) would be followed. This indication and response procedure are unique and independent of the EOPs for a possible event in progress. Therefore, there was no operator action dependencies included in the HEP evaluation.

Instrument air needs to be re-established during a transient event with reactor building isolation and also during a loss of offsite power event. During these events, per EOP-15.0 (Loss of Secondary Heat Sink) the operator is directed to establish instrument air to the reactor building. The air supply is required for multiple actuations of the PORVs during bleed and feed operation. This action is credited in the transient and LOSP event trees. It is dependent on only one potentially failed operator action that previously occurred; operator failure to actuate emergency feedwater (EFW). The operator action to actuate EFW is included in the EFW fault trees. It is one of several methods to actuate EFW. The other methods are by an automatic signal from either the engineered safety features actuation system, AMSAC, or the trip of 3/3 main FW pumps. Therefore, failure of the OA to actuate EFW does not necessarily fail EFW. In addition, failure of EFW is dominated by failure of EFW components, not actuation signals. Therefore, modeling of the operator action to re-establish instrument air assumes that the previous operator action to actuate EFW was successful (EFW failed for other reasons), that is, it is not necessary to consider possible dependencies on a previously failed operator action. Also, the typical control room response during implementation of the EOPs has the BOP operator responsible for the section of the control board that contains the EFW controls, and the RO responsible for the section that contains the Instrument Air(IA) system controls. In other words, it is unlikely that the same operator will be involved with both the EFW and IA systems. There may be a slight non-conservatism in the analysis, but it is judged to be of no consequence to the results for the previously stated reasons.

Category 3: Actions taken per EOPs

Manual actuation of emergency feedwater is incorporated into the emergency feedwater fault trees. As stated above, EFW can be actuated from a variety of sources. Dependencies between this operator action and any previous or following operator actions were considered implicitly in the development and quantification of the IPE models. A review of the fault tree quantification results for the EFW system indicates that EFW system failure or unavailability is dominated by failure of mechanical or electrical components, not by the actuation signals, due to the number of and diversity between sources of signals. Given the model approach of including the actuation signals for EFW within the EFW fault tree(s) and the small contribution of actuation signals to EFW system unavailability, it would be overly conservative to assume dependence between EFW failure and subsequent operator actions or between failed operator actions previous to EFW actuation, such as operator action for reactor trip, and EFW. Therefore, the approach assumed independence between the EFW actuation operator action and previous or subsequent operator actions. This is a slight non-conservatism in the analysis, but it is judged to be of no consequence to the results for the previous stated reasons.

Actuation of containment isolation can be accomplished by either the engineered safety features actuation system or by operator action. The reactor building isolation analysis credited automatic isolation only; the operator action to initiate isolation was not included in the model. Therefore, dependencies between operator actions are not addressed.

The requirement to re-establish cold leg recirculation following failure of hot leg recirculation is incorporated into the hot leg recirculation fault tree. This action is modeled only in the large and medium LOCA event trees, and is only addressed following a successful operator action (OAL) to initially switch to hot leg recirculation. Following successful OAL, the top event HLR is addressed. In addition to modeling components required to switch to hot leg recirculation, HLR also includes modeling to return to cold leg recirculation if hot leg recirculation fails. Included is the operator action required to re-establish cold leg recirculation. The HLR top event, including the operator action, is only addressed following the success of OAL. <u>If OAL has failed, then the switch to hot leg recirculation and possible return to cold leg recirculation are not addressed</u>. Therefore, the dependencies between the operator action to re-establish cold leg recirculation and previous operator action do not need to be addressed.

b. The question on how dependency was addressed among human events modeled in the event trees as top events is best answered by describing the process for treating dependencies among top events, as well as dependencies among inputs (subtasks) of a given top event; this process is described in the paragraphs that follow. The discussion under Category 3 (HRA Response 13a) provides the basic considerations for determining dependency among top events.

The dependency evaluation covers positive dependency between events whereby failure on the first task increases the probability of failure on the second task. The dependency evaluation does not cover negative dependency which implies that failure on the first task reduces the probability of failure on the second task; application of negative dependency produces results that may not be realistic.

Dependencies are evaluated by the equations provided by THERP (NUREG/CR-1278, Tables 20-17 and 20-18).

The dependency modeling is addressed as conditional probabilities based on the following set of criteria:

i. Dependencies in manipulating 2 or more of the same type of component, by the same operator in the same procedure step are modeled as follows:

   1. Failure to operate 2 of 2 controls (e.g., failure to start 2 of 2 pumps) is modeled with the second action having a low dependency of the first action. The model will reflect BHEP x 0.05. However, we have applied moderate dependency which results in BHEP x 0.15.

      If the operator manipulates both controls together, then complete dependency is assumed; that is, if one control is missed, the other is missed also.

   2. Failure to operate 3 of 3 controls is modeled with the second action having a low dependency of the first action, and the third action having a moderate dependency on the previous actions. The model will reflect BHEP x 0.05 x 0.15.

   3. Failure to operate N of N controls (N > or = 4) is modeled with the second action having a low dependency of the first action, the third action having a moderate dependency on the previous actions, and fourth and subsequent actions (each) having a high dependency on previous actions. The model will reflect BHEP x 0.05 x 0.15 x 0.5 x ... x 0.5. In general, we have assigned one high dependency value (0.5) for all fourth and subsequent actions. Therefore, the joint conditional probability, for N > than 4, is evaluated by BHEP x 0.05 x 0.15 x 0.5.

   4. Failure to operate M of N controls (2 < M < N) is modeled by applying the appropriate dependency level (shown in 1, 2 or 3 above) based on the value of M. The binomial coefficient of "M out of N" shows up in this evaluation. For example, failure to operate 2 of 4 controls will reflect BHEP x 0.15 x 6.

ii. In selecting the critical subtasks for an operator action, each step of the applicable procedure(s) is examined to determine its significance relative to system success. Subtasks that are recovery actions of, or redundant to, other previous subtasks are judged to be dependent on failure of the previous subtasks; total dependency relation between such actions is conservatively assumed in most cases. This is particularly true in the selection of omission errors; depending on the structure of the procedure, if a step in one column of the procedure is missed, then recovery steps provided in the alternate path will most likely be missed.

In most cases, verification actions were not modeled because of total dependency on a previous step, or the effects of not performing such an action could be realized in a subsequent step that is judged to be critical.

iii. Dependencies between different (top) events are assigned when operator actions are in the path of a previously failed operator action. The THERP handbook provides no direction on determining dependency levels among events; therefore, moderate dependency was assigned to each identified case.

For example, in the SGTR, SLOCA, MLOCA, LLOCA, ATWS, transient or secondary break sequences, operator action OAR (Establish Cold Leg Recirculation) is followed closely by OAS (Establish Reactor Building Spray Recirculation). Therefore, failure of operator action OAS is dependent on failure of OAR.

The unconditional HEP for OAS is 9.18E-05. Therefore, based on THERP Table 20-17, the conditional probability of OAS is: $[(1 + 6 \times 9.18E\text{-}05) / 7] = 1.43E\text{-}01$.

14) The submittal in Section 3.3.3 noted that "operator actions important to equipment restoration were assessed via expert judgment." Please describe the expert judgement process and who the experts were to render such judgment by stating their number and individual qualifications.

Response

General Approach

Accident mitigation of initiating events that address system recovery requirements include the loss of service water, loss of chilled water, and loss of component cooling water events. The event trees for these initiators include top events for the recovery of service water at 2 and 3 hours, recovery of chilled water at 12 hours, and recovery of component cooling water at 2 hours. Recovery in this context refers to the ability of plant personnel to repair or restore components to the operable conditions within a given amount of time, it does not involve the ability of the plant operators to respond to events via procedures.

Of particular interest is the probability that one train of the failed system can be repaired and restored to operation within the specified time. The same system recoveries are important to recovery from support state system failures in the transient and loss of offsite power support state models, in addition to recovery from engineering safety feature actuation signal (ESFAS) failures. ESFAS failures are different in nature since they can be overcome by manual actuation of components from the control room. Such operator actions are evaluated in the human reliability analysis.

Since there was insufficient plant data to assess the probability of system recovery, the following approach was used. The probability of recovering the systems of interest was based on the probability of recovering the individual component failures that lead to the system failures. These component recovery probabilities are then combined by a weighted average. The weighting is based on the importance of the component failure to the system failure, that is, the cutset probability for that component. The components of importance are identified from a review of the fault tree modeling for the systems of interest and the cutsets resulting from the system unavailability quantification. Typically, cutsets representing at least 85% of the system unavailability were used in this analysis. Note that for common cause failures, it is assumed that if one of the components fails to be recovered, recovery of the second of the common cause group also fails. That is, the "failure to recover" value is applied only once, not to both components of a common cause group.

Component Recovery Probabilities

To determine the probability of repairing system components in the required time frames, component recovery data sheets were developed for each system and plant experts were asked to judge the probability of repairing components of the system of interest within the specified times. The judgements of four plant experts were solicited.

The survey requested information on the probability of recovery of failed components for the component cooling water system within 2 hours, chilled water system within 12 hours, and service water system within 2 and 3 hours. The components of interest were identified from the dominant cutsets from the system analyses. The probability of recovery estimates were divided into five levels; very high (99%), high (90%), medium (50%), low (10%), and none (0%). A sample survey form with individual responses summarized for the service water system is shown on Table HRA Q14-1. Individual responses are indicated with an "x" on these tables and the values used for recovery are also listed on this table. The majority value was applied in the analysis where possible. If the probabilities identified were equally divided between two adjacent recovery probabilities the lower of the two were used and if the identified probabilities were equally divided between two non adjacent recovery probabilities, the center probability was used.

Train Recovery Probability

The method to determine the probability of recovering a single train, of service water in this example, is shown on Table HRA Q14-2. As previously stated, this involves a weighting process where the weighting is based on the value of the cutset of the potentially recoverable component. The columns are defined as:

Column 1:	component failure and failure mode (based on the system failure cutsets)
Column 2:	probability of failure to recover the component failure described in column 1 (1 - the probability of component recovery from Table HRA Q14-1)
Column 3:	probability of failure to recover one train (product of each component failure to recover value for the cutset)
Column 4:	weighting factor (cutset contribution to system failure)
Column 5:	weighted factor (column 3 x column 4)

Column 4 and column 5 are totaled and then the total of column 5 is divided by the total of column 4 to obtain a failure to recover probability. The cutset total for the sequences included on Table HRA Q14-2 is 3.32E-05. This accounts for 92% of the total system unavailability. The probability of failing to recover service water within two hours is 0.46.

Recovery Probabilities

The recovery probabilities used in the VCSNS IPE are provided in Table 3.3.3-4 of the IPE Submittal Report. They are also provided in Table HRA Q14-3 of this response. It is evident from these values that very limited credit was taken for these recoveries. In addition, no credit was taken for recovery of service water at 3 hours.

Plant Experts

The plant personnel included in the expert judgement were two shift engineers, one shift engineer with PRA experience, and one shift supervisor. Shift engineer input is especially appropriate for equipment recovery estimates. They are responsible for interfacing with the maintenance personnel, and coordinating maintenance activities, during both normal and abnormal plant operation. Their experience is summarized on Table HRA Q14-4.

Table HRA Q14-1
Recovery of Service Water System Components Within 2 Hours

Component and Failure Mode to be Recovered (assumed to be "Emergency" maintenance)	Probability of Recovery Within 2 Hours None (0%)	Low (10%)	Medium (50%)	High (90%)	Very High (99%)	Values Applied
SW pump fails to start (includes pump, motor, and associated breaker)			xxx	x		50%
SW pump fails to run (includes pump, motor, and associated breaker		xxxx				10%
MOV 3116B fails to open on demand (includes valve, motor operator, & asso. breaker)			x	xx	x	90%
7200 VAC feeder breaker spuriously opens		xx	x	x		10%
7200 VAC bus fails	xxx	x				0%
Restoration of 1 pump unavailable due to maintenance (tracking R&R)		x	xx	x		50%
Restoration of 1 of 2 pumps unavailable due to maintenance (action R&R)			x	xxx		90%

Note: Each "x" indicates one response.

Table HRA Q14-2
Recovery within 2 Hours: Loss of Service Water Special Initiator

Component/Failure Mode	Probability of Failure to Recover	Probability of Failure to Recover One Train	Weighting	Weighted Factor
1-CCF: Pumps A&B fail to run	0.90			
Pump C fails to start & run	0.50	0.45	2.78E-05	1.25E-05
2-CCF: Pumps A&B fail to run	0.90			
MOV 3166C fails to open	0.10	0.09	1.23E-06	1.11E-07
3-RF: 7200 VAC breaker transfers open	0.90			
Pumps B fails to run	0.90	0.81	3.14E-06	2.54E-06
4-RF: Pump A fails to run	0.90			
Pumps B&C in maint. (action R&R)	0.10	0.09	1.01E-06	9.09E-08
Total			3.32E-05	1.52E-05

Probability of Failure of Recovery = 1.52E-05/3.32E-05 = 0.46

Table HRA Q14-3 Summary of Recovery Failure Probabilities		
Description	**Time Window**	**Recovery Failure Probability**
Recover at least one train of CC when both trains failed but supported (loss of CC and transient initiator)	2 hours	1.1E-01
Recover train A of CC when train A fails and only train A support is available (loss of CC and transient initiator)	2 hours	4.2E-01
Recover train B of CC when train B fails and only train B support is available (loss of CC and transient initiator)	2 hours	2.8E-01
Recover at least one train of CC when both trains failed but supported (loss of offsite power initiator)	2 hours	1.5E-01
Recover train A of CC when train A fails and only train A support is available (loss of offsite power initiator)	2 hours	1.3E-01
Recover train B of CC when train B fails and only train B support is available (loss of offsite power initiator)	2 hours	1.3E-01
Recover at least one train of chilled water when both trains fail but supported (loss of chilled water initiator)	12 hours	1.8E-01
Recover train A of chilled water when train A fails and only train A support is available (loss of chilled water and transient initiator)	12 hours	5.2E-01
Recover train B of chilled water when train B fails and only train B support is available (loss of chilled water and transient initiator)	12 hours	4.5E-01
Recover at least one train of chilled water when both trains fail but supported (transient water initiator)	12 hours	2.4E-01
Recover at least one train of SW when both trains fail but supported (loss of SW initiator)	2 hours	4.6E-01
Recover train A of SW when train A fails and only train A support is available (loss of SW and transient initiator)	2 hours	8.1E-01
Recover train B of SW when train B fails and only train B support is available (loss of SW and transient initiator)	2 hours	7.8E-01

Table HRA Q14-3 Summary of Recovery Failure Probabilities		
Description	**Time Window**	**Recovery Failure Probability**
Recover at least one train of SW when both trains fail but supported (transient initiator)	2 hours	8.9E-01

Table HRA Q14-4
Plant Experts and Experience

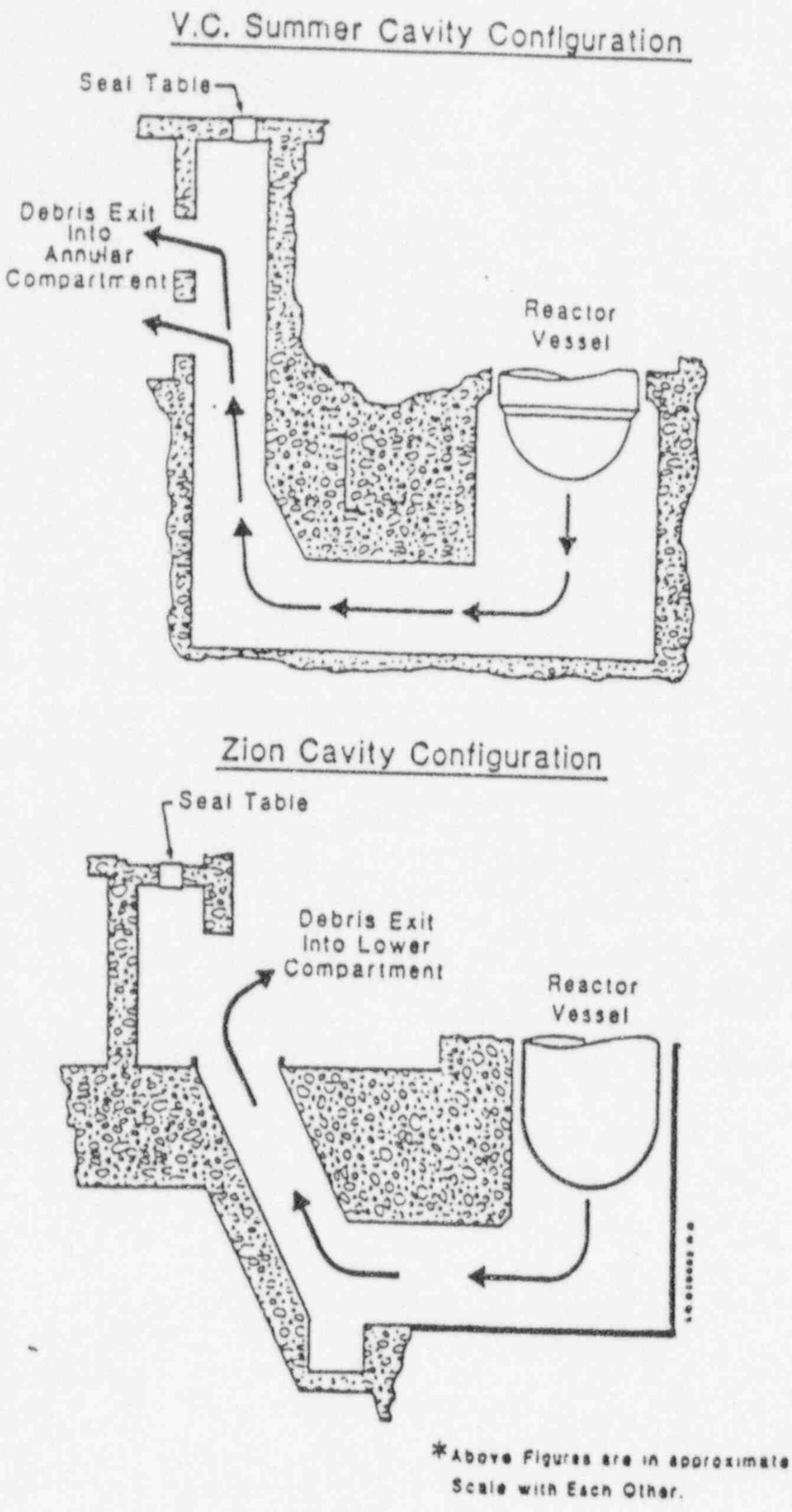
Name	Years of Commercial Nuclear Experience	Plant Qualification	Position Held During IPE Input	Professional Information	Other Plant Positions or Related Experience
Curtis Fields	16	SRO/STA (10 yrs)	Shift Engineer (Assistant to plant manager)	BSME PE Mechanical Engineering	- Tech Support Engr. - Licensing Engr - Manager Materials & Procurement
Chris Allen	18	SRO (11 yrs) Shift Supv. (5 yrs)	Shift Supervisor		- US Navy - EWS - Aux. Operator - Reactor Operator - Control Room Supv.
Dan Gatlin	15	SRO/STA (10 yrs)	Shift Engineer on loan to Engr. for IPE project	BSEE PE Electrical Engineering	- I&C Engr. - Startup Engr. - ISEG - Design Engineer
George Lippard	13	Certified RO/SRO Training Instructor (10 yrs) SRO (3 yrs)	Shift Engineer	BSME	- Nuclear Trng Instructor - Acting Mgr. - Licensing & Operating Experience

C. BACK-END ANALYSIS QUESTIONS

1) It is stated in the IPE submittal that "Comparison of VCSNS and Zion cavity/instrument tunnel designs clearly indicates that the VCSNS geometry would trap and de-entrain more debris than in the Zion configuration." Please provide a more detailed discussion by comparing the cavity configurations of the two plants and point out the similarities and differences that support the above claims.

Response

The attached figure compares the Zion and V. C. Summer cavity and instrument tunnel configurations. Core debris leaving the V. C. Summer reactor vessel will have to make two 90° turns before entering the cavity cooling ducts and exiting into the annular compartment. Debris leaving the Zion cavity travels up a 64° incline before making a 90° turn at the seal table and into the lower compartment. The VCSNS configuration has two small openings compared to the instrument tunnel cross-sectional area that exit into the annular compartment. The cavity design will influence the de-entrainment of particulated debris from a high velocity gas stream. Each change in direction will tend to separate the heavier particles from the gas stream with the smaller particles responding to the change in gas flow. The V. C. Summer configuration would tend to de-entrain more debris due to the 90° changes in gas flow when compared to the 64° and 90° change in Zion. As a result, the DCH tests performed for Zion could be viewed as a bounding assessment for V. C. Summer.



Comparison of V. C. Summer and Zion cavity configuration.

2) According to the IPE, the majority of the core debris will be de-entrained by containment structures and remain in the cavity during high pressure melt ejection (HPME). Please provide a more detailed discussion of the debris flow path and debris distribution during HPME. Please include in the discussion the effect of the two cavity cooling fan openings, which, according to the IPE submittal, connect the lower compartment and the reactor cavity (through the instrument tunnel, Figure 4.2.1-5) and allow water on the lower compartment floor to flow to the reactor cavity. Please discuss the effect of these openings on the dispersion and distribution of core debris after vessel melt-through and, consequently, any adverse effect on containment integrity or equipment availability.

Response

The first step in assessing the Debris Distribution is the determination of the entrained mass which occurs concurrent with the gas discharge from the failed vessel under high pressure conditions. The entrained mass is proportional to the square root of the RCS pressure and size of the breach. Under conservative assumptions derived from an assessment of a Station Blackout, a mass of 41759 kg was calculated. This mass which is carried in the gas flow stream is swept across the cavity floor, turning 90° and then directed through the instrument tunnel where it impacts the seal table and its enclosure. Located below the seal table along the instrument tunnel wall are the two reactor cavity cooling fan openings. The gas flow stream would then make a second 90° turn and enter the two openings from which it could be expelled into the containment annular region, after it passes through the fan units themselves.

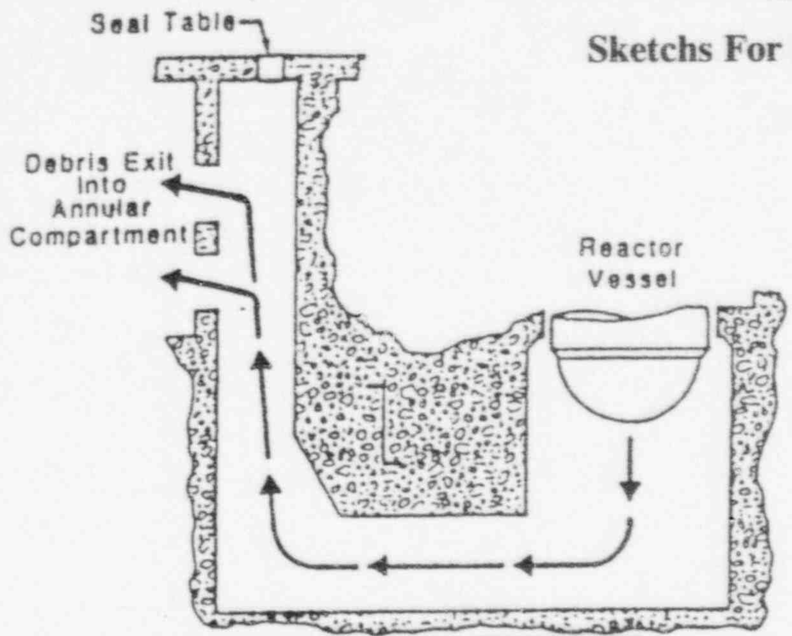
At each of the two 90° turns and passage through the fan units, a fraction of the originally entrained mass is de-entrained due to impact with structures. The V. C. Summer analyses took credit for de-entrainment at only one of the two 90° turns and assumed the remaining mass was released to the containment atmosphere as particulated debris capable of reaching thermal equilibrium with the containment atmosphere thus resulting in a pressure rise.

The de-entrainment factor calculated for a single 90° turn was 86.5%, and was based on the work of J. V. Walker as documented in NUREG/CR-5039, SAND 87-2411, "Reactor Safety Research Semi-Annual Report." Thus 41759 kg of debris was originally entrained, and 86.5% was de-entrained at the first 90° turn resulting in 5,637 kg traveling through the instrument tunnel, through a second 90° turn without any de-entrainment and through the fan cooling units, again without de-entrainment and finally into the containment gas space.

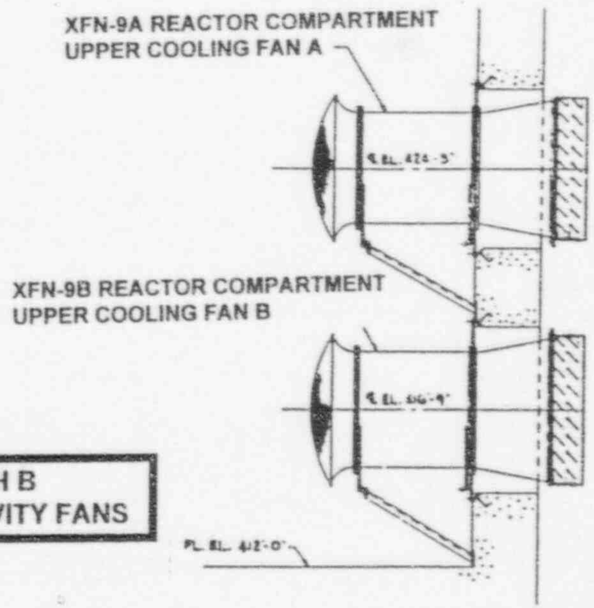
The attached figure depicts the various paths of the debris flight path. Sketch A identifies the cavity, instrument tunnel and cavity cooling fan openings. The debris would travel approximately three feet before reaching the fan unit damper shown in Sketch B. Once through the fan unit and into the annular compartment, the flight path would be approximately 22 ft to the containment wall over the recirculation sump pit (Sketch C). No equipment is in the direct flight path of the debris.

The purpose of the DCH or HPME analysis for V.C. Summer was to derive a bounding estimate for debris released into the containment gas space and formulate the resultant pressure rise, thus credit for only one 90° turn was taken in calculating de-entrainment. The debris velocity and mass would be reduced further with the second 90° turn followed by break-up of the jet as it encounters the fan damper and structure. The result would be whatever debris is released past the fan would be dispersed to the containment gas space with some residing on the floor and within the recirculation sump.

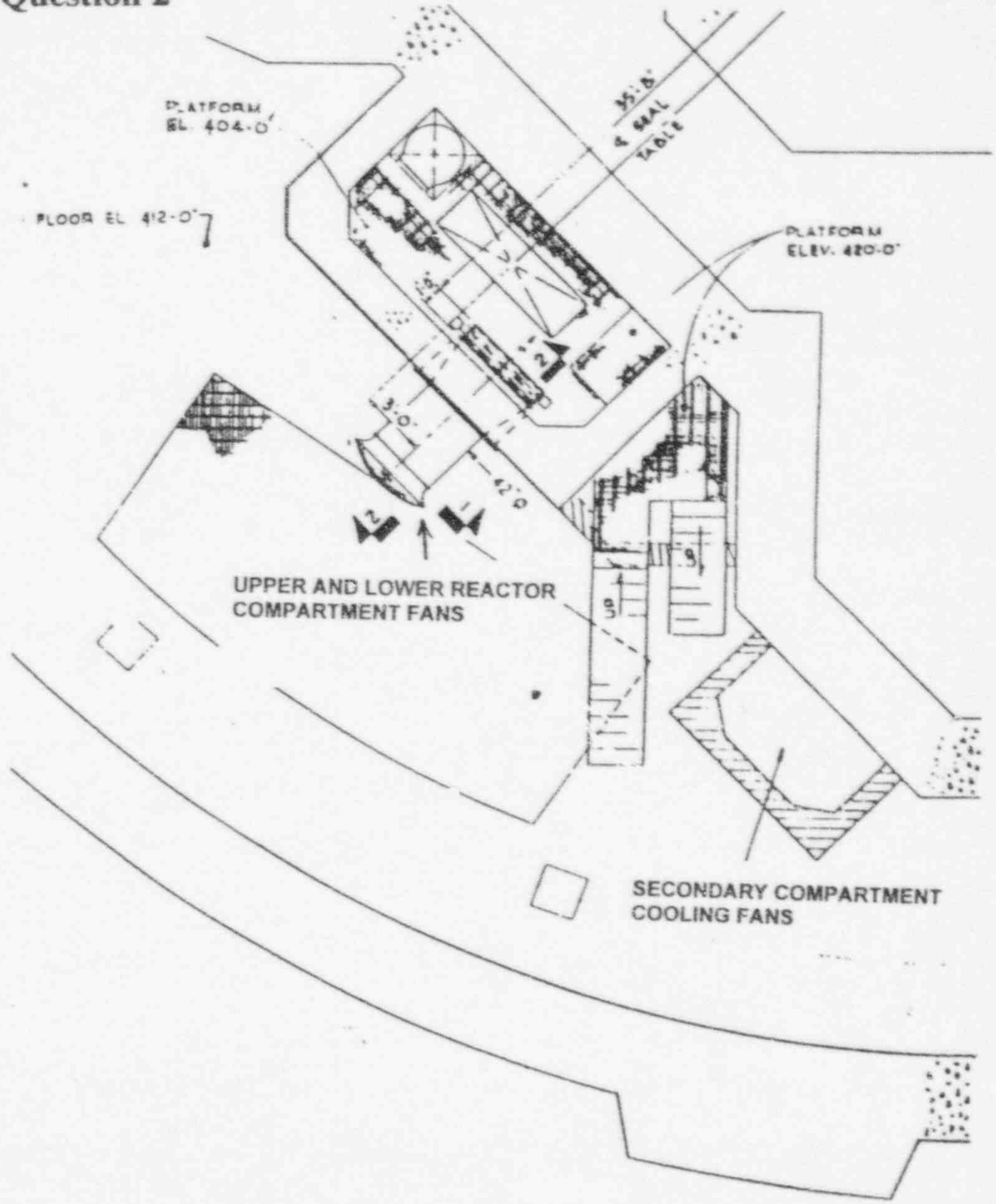
Sketchs For Back End Question 2



SKETCH A
VCSNS CAVITY CONFIGURATION



SKETCH B
REACTOR CAVITY FANS



SKETCH C
CAVITY FAN LAYOUT

3) In the IPE, molten core-concrete interaction (MCCI) was evaluated using a simple bounding analysis model to determine whether the aggressive attack on concrete by molten core debris could lead to late containment failure. The conclusion in the IPE is that molten core-concrete can be excluded from consideration as a significant late containment failure mechanism. Keeping in mind the assumed maximum coolable debris depth of 25 cm mentioned in Generic Letter 88-20, please discuss the depth of core debris in the VCSNS cavity and the effect of non-uniform spread of debris on debris coolability.

Response

The bounding analysis model used to investigate molten core-concrete interaction (MCCI) in the VCSNS IPE [FAI/91-42] indicates that even if 100% of the decay heat is present in the reactor cavity and is contributing to concrete attack, that melt-through of the cavity basemat will not occur within the first 48 hours following accident initiation (the bounding analysis predicted basemat failure in 150 hours).

Because of the long time available to implement recovery actions before cavity melt-through could occur, and because long-term recovery actions are not credited in the IPE, sequences containing MCCI and intact containments at the 48 hour mission time have been classified as "Success with accident management." Thus, in the source term analysis, such sequences were not considered to contribute to late containment failures and their source terms resulted from normal containment leakage, only.

To address coolability following implementation of recovery actions, the expected debris depth in the cavity can be estimated as follows. An upper bound on the debris mass expected in the cavity is 250,000 lbm, with a density ranging from 438 lbm/ft^3 (7000 kg/m^3) to 563 lbm/ft^3 (9000 kg/m^3). If this debris spreads evenly; over the 716 ft^2 cavity floor then debris depths, depending on the density, will range from 19 to 24 cm. Both of these averaged debris depths are less than the 25 cm coolable depth mentioned in Generic Letter 88-20.

The debris may not spread evenly, of course, and debris depths in <u>limited areas</u> may be larger than the averages computed above. However, if water addition to the cavity covers the entire 716 ft^2 floor area, water ingression into the debris bed will be substantial. Thinner areas of the debris bed will be cooled quicker than the thicker portions of the debris bed. Thus, the uncooled portions of the bed will be encapsulated in, and be able to transfer energy with, the already cooled portions of the debris bed. Also, cooling of a debris bed over such a large area as the cavity floor will tend to enhance water ingression since the large bed is expected to be mechanically unstable. This will enhance cooling of all portions of the debris bed. These observations suggest that addition of significant quantities of water to the cavity within a reasonable amount of time following accident initiation will almost certainly cool the debris prior to the 150+ hours required for basemat melt-through.

Even if recovery actions are not implemented within the 150 hour period prior to cavity basemat melt-through, the likely containment failure mode will be overpressurization. The MAAP analyzed sequence SBE17IH used in the VCSNS source term analysis [FAI/92-02] supports this assessment, thus providing additional indication why MCCI is excluded as a significant late containment failure mechanism in the VCSNS IPE. This sequence, a station blackout with designator SBE17IH, models a loss of offsite power with consequential RCP seal LOCA and no power recovery during the 48 hour mission time. This sequence was analyzed with MAAP, indicated significant cavity concrete ablation, and no containment failure within 48 hours due to either overpressurization or basemat melt-through. Key figures-of-merit for this analyzed sequence are presented in Table 3-9 of the VCSNS Source Term Notebook, and are summarized here for convenience.

Sequence type:	Station Blackout
Sequence number in top 100:	19
Sequence frequency:	1.9E-5
Sequence designator:	SBE17IH
Time of RV failure (hr):	9.2
Maximum containment pressure (psia):	116
Cavity concrete ablation depth at end of 48 mission time (ft):	4.0
Volatile fission products retained in primary system (%):	86.

The maximum containment pressure and concrete ablation depth shown above can be compared to the lower bound containment failure pressure of 135 psia and the combined thickness of the cavity floor and basemat of 13.7 ft. Also, several key points should be noted from these MAAP calculations. First, the containment pressure reached elevated levels prior to basemat melt-through, and in the case of SBE17IH, assuming no recovery actions beyond 48 hours, results indicate that over pressure failure could be expected prior to basemat melt-through. Thus, even if MCCI could not be mitigated after 48 hours, containment failure due to over pressurization would still be the likely late containment failure mode. Second, a large portion of volatile fission products, and hence a significant quantity or decay heat generation, is still contained within the primary system rather than the reactor cavity, even at the end of the 48 hour mission time. This indicates the conservative nature of the bounding calculations provided in the analysis model used to investigate molten core-concrete interaction (MCCI) in the VCSNS IPE [FAI/91-42], and suggests that the actual time required to melt-through the cavity floor would be in excess of 150 hours. Third, based on the Level II binning, sequences with MCCI and isolated containments account for 10% of the total core damage frequency. So, in these sequences, even if the likely equipment recoveries and the likely late over pressure failure mechanism are neglected, then these sequences could lead to late containment failure due to MCCI well beyond 48 hours. This unlikely outcome would then result in a conditional probability of MCCI-induced containment failure given core melt of 10%. The currently reported conditional probability of late containment failure is 20%. Thus, although the MCCI contribution to late containment failure would not be insignificant, it would not be the dominant contributor.

Overall, the best assessment is that since MCCI-induced containment failures would require in excess of 150 hours to take place, late recoveries would occur which would mitigate MCCI and prevent cavity basemat melt-through. Also, if late recoveries are neglected then late over pressure failure would occur prior to the MCCI-induced containment failures.

REFERENCES

FAI/92-02, "V. C. Summer Nuclear Station Source Term Notebook for Individual Plant Examination," Revision 1, Fauske & Associates, Inc., Westinghouse Electric Corporation, Nuclear and Advanced Technology Division (June 1993).

FAI/91-42, "A Position Paper on Molten Core-Concrete Interaction in Support of VCSNS Individual Plant Examination Program," (April, 1993).

4) The second paragraph on page 4-26 of the submittal states that in the absence of external cooling of the RPV, relocation of the molten core debris into the lower head is assumed to lead directly to failure of the reactor vessel; no attempt is made to take credit for potential in-vessel recovery." However, in the VCSNS water can flow to the reactor cavity from the containment floor and the lower part of the vessel can be submerged. Please discuss the likelihood of a submerged vessel for VCSNS and the effect of omitting this external cooling when defining the source term. Since this mechanism may delay, if not terminate, vessel penetration, fission product production and release paths are affected (e.g., in-vessel release from a dry debris bed versus ex-vessel release from a debris bed covered by water). The release of fission products to the environment may actually increase if the containment fails and external cooling was accounted for in the source term calculation. Please also discuss the effect of external vessel cooling (which results in maintaining the RCS at high temperature for a longer time) on the probability of creep rupture of RCS boundaries and steam generator tubes, and consequently, the effect on containment performance and source terms for VCSNS.

Response

Four broad issues related to external cooling of the reactor vessel are discussed in question 4: 1) likelihood of submerging the reactor vessel lower head; 2) effect on source term and the volatile fission product release from the debris; 3) effect on RCS and steam generator tube integrity (i. e., likelihood of creep ruptures); and 4) effect on containment performance. Each of these issues will be addressed. Overall, the best assessment is that consideration of external cooling of the reactor vessel will not adversely impact the source term calculations. On the other hand, inclusion of ex-vessel cooling in the source term analysis would lead to termination of the accident progression in-vessel and exclude from consideration the severe accident phenomena associated with high pressure melt ejection, MCCI, and debris coolability in the reactor cavity.

Likelihood of submerging the reactor vessel lower head

The VCSNS containment facilitates flooding of the reactor cavity. Water can easily drain from the upper compartment to the annular and lower compartment floors. Water on the lower compartment floor would have to reach a depth of 2 ft 4 in. before it could spill into the reactor cavity through the cavity cooling fan opening. This is likely to occur at VCSNS during a severe accident in which the entire usable RWST volume is injected into the containment.

In the VCSNS IPE, the total frequency of sequences leading to core melt which have successful RWST injection is about 1.7E-04 per year, which is 85% of the total core damage frequency. This includes all non-bypass sequences with functional failure identifiers (i.e., the 4th and 5th digit of the plant damage state designator, per Table 3-3 in the VCSNS Source Term Notebook) of 1 through 15 since such sequences have either successful ECCS or containment sprays. These sequences fall into source term bins 1, 2, 3, 4, 5, and 10 with a total CDF of 1.7E-4, as shown in Table 3-11 of the VCSNS

Source Term Notebook. It is this subset of core damage sequences which are at issue here, and which could possibly be influenced by the inclusion of ex-vessel cooling in the source term analysis.

Effect on source term and volatile fission product release from the debris

Extended retention of debris in-vessel will not lead to a larger volatile release from the debris bed, based on MAAP analysis. MAAP models indicate a release of > 99% of all volatiles from the fuel material during the core melt progression phase of the accident. Thus, the debris bed, whether it is retained in-vessel or submerged in a water pool ex-vessel, will have very little volatile fission product content.

Effect on RCS and steam generator tube integrity (likelihood of creep ruptures)

Since the creep rupture phenomena is only an issue of significance for high pressure scenarios, the following discussion will be limited to such sequences.

Previous analyses have indicated that if the primary system is at high pressure and the steam generators have boiled dry, then the RCS hot legs and steam generator tubes are subject to creep rupture failures. However, due to the material properties and geometrical differences between hot legs and steam generator tubes, the hot legs have been shown to fail due to creep prior to the steam generator tubes. Considering, for the moment, a creep failure of a hot leg, the primary system will depressurize and any additional creep failures will be prevented. Also, the timing of hot leg heatup during high pressure core melt sequences indicates that creep ruptures would most likely occur during the core melt progression phase of an accident prior to significant relocation of debris to the lower head. Furthermore, no study has been made of VCSNS to investigate whether ex-vessel cooling will lead to creep ruptures in the RCS pressure boundary, at all. Thus, the assumption of ex-vessel cooling leading to creep ruptures is uncertain, at best. Based on this assessment, ex-vessel cooling would have little additional impact on the likelihood of creep-induced failures of either the hot leg or steam generator tubes.

In any case, the impact on source term of a hot leg creep rupture is bounded by analyses of large LOCA core melt sequences which exhibit a reduced volatile fission product retention in the primary system. A comparison of two core melt sequences - a medium LOCA and a loss of service water transient - analyzed with MAAP and reported in the VCSNS Source Term Notebook gives some insight into the possible impact of hot leg creep rupture on source term. First, the transient, TRE13IH, models a total loss of service water plus a RCP seal LOCA with successful operation of containment sprays and emergency feedwater water. This sequence progresses to early core melt followed by vessel failure at high pressure. The containment remained intact until 47.8 hours into the sequence at which time 94% of the volatiles were still retained in-vessel while 2.E-05% were released to the environment due to normal containment leakage. The medium LOCA, MLM06IL, on the other hand modeled successful ECCS injection, containment sprays and emergency feedwater, and resulted in a late, low pressure vessel failure. At the 48 hour sequence end time, 58% of the volatiles were retained in-vessel while 1.E-4% were released to the environment due to normal containment leakage. In similar fashion, a hot leg creep rupture occurring during a high pressure sequence could result in a decrease of in-vessel fission product retention from the 90% range to the 50% range, while releases to the environment would remain low. This comparison demonstrates that even though the primary system fission product retention could be affected by a hot leg creep rupture, releases to the environment would still be controlled by the containment performance.

Finally, suppose that, despite the findings of previous analyses, creep ruptures could occur preferentially in the steam generator tubes. Now, only sequences progressing to high pressure core melt with successful RWST injection to submerge the vessel lower head and failure of emergency feedwater to cover the steam generator tubes are of interest. These types of sequences would be candidates for ex-vessel cooling and induced steam generator tube ruptures. Based on the VCSNS quantification, the frequency of sequences falling into this category is less than 1.E-6 per year. By comparison, core melt sequences initiated by tube ruptures which are already accounted for in the VCSNS source term quantification have a total core damage frequency of 1.E-6. Thus, even if ex-vessel cooling could lead to induced steam generator tube creep ruptures, the effect on the reported source term would be negligible.

In summary, the best estimate is that if ex-vessel cooling leads to creep ruptures in the RCS pressure boundary, the rupture will occur in the hot leg and no adverse impact on accident source term is expected. It is also important to note that an uncertainty remains as to whether ex-vessel cooling would lead to any induced creep rupture whatsoever.

Effect on containment performance

One of the most important effects of ex-vessel cooling does not have to do with RCS boundary creep rupture or fission product release from the debris, but rather with the containment performance. Clearly, if significant amounts of decay heat are transferred through the vessel wall and into the cavity water pool, then a substantial, sustainable steam source will be present. Just as with cavity debris beds submerged in water pools, the steam addition would lead to containment pressurization, and, in the absence of containment heat removal, could lead to overpressure failure of the containment. In any case, if water is present in the cavity, whether debris is retained in the vessel or relocated to the cavity, the containment pressure response due to steam generation would be about the same. Thus, ex-vessel cooling does not pose new or additional challenges to the containment integrity not currently accounted for in the VCSNS IPE.

5) Containment isolation status is one of the VCSNS Plant Response Tree top events. It is also indicated by the sixth digit in the 7-digit plant damage state (PDS) designator. With respect to the analysis of containment isolation failure probability, NUREG-1335 (Section 2.2.2.5, page 2-11) states that "the analyses should address the five areas identified in the Generic Letter, i.e., (1) the pathways that could significantly contribute to containment isolation failure, (2) the signals required to automatically isolate the penetrations, (3) the potential for generating the signals for all initiating events, (4) the examination of the testing and maintenance procedures, and (5) the quantification of each containment isolation failure mode (including common-mode failure)." Please discuss your findings related to all of the above five areas.

Response

The analysis performed to determine the containment isolation unavailability for the VCSNS IPE is discussed below with respect to the 5 areas in the question.

(1) The reactor building penetrations at VCSNS were reviewed for inclusion into the containment isolation failure analysis. The penetrations were categorized into three major types: electrical penetrations, mechanical penetrations, and fluid penetrations. The fluid penetrations were further classified as administratively controlled penetrations and non-administratively controlled penetrations. Each type of penetration was then evaluated.

Electrical Penetrations

Electrical penetrations were not explicitly modeled as part of the containment isolation failure for following four reasons:

- Electrical penetrations do not have "open/closed" positions; they are permanently sealed.
- Electrical penetrations do not have the capability to carry radioactive fluids except under gross failure conditions.
- Electrical penetrations are periodically leak tested.
- The failure of electrical penetrations as a result of the accident conditions are considered in the evaluation of containment failure during an accident.

Mechanical Penetrations

The evaluation of potential failures of the mechanical and sealant materials for mechanical and fluid system penetrations was limited to only the personnel access penetrations. These are the only mechanical penetrations which may be "sealed" and "unsealed" during plant operations. All other mechanical and fluid system penetration mechanical and sealant materials do not have to be explicitly modeled in this evaluation of containment isolation for the following two reasons:

- The mechanical and fluid system penetration mechanical and sealant materials are tested as part of the containment leakage surveillance to ensure compliance with the plant technical specifications. This provides a degree of assurance that the performance of the penetration is acceptable at the initiation of the accident.

- The failure of sealant materials for mechanical and fluid system penetrations as a result of accident conditions are considered in the evaluation of containment failure during the accident.

Personnel Access and Administratively-Controlled Fluid System Penetrations

For the purposes of this analysis, administratively-controlled fluid system penetrations are defined as those systems which are not required to support normal operation of the plant. For these and the personnel access penetrations, the containment isolation failure probability can be entirely attributed to human error which results in a technical specification violation during plant operation. Reference 1 presents a review of commercial power reactor unisolated containment events and gives an unisolated containment frequency of 1.2E-04 per year for all administratively-controlled penetrations taken collectively. The value of 1.2E-04 per year is believed to realistically reflect the conditions applicable to large dry PWR containments for administratively-controlled penetrations. For these reasons, 1.2E-04 per year is the value used in this analysis as the isolation failure probability of the personnel access and administratively controlled fluid system penetrations. Beyond this probability of isolation failure, administratively controlled fluid system penetrations are not explicitly modeled.

Non-Administratively-Controlled Fluid System Penetrations

Non-administratively-controlled fluid system penetrations are those fluid system penetrations needed to support normal operation and post-accident shutdown of the plant. Two criteria were used for determining whether non-administratively controlled fluid system penetrations should be explicitly modeled in the containment isolation model. First, containment penetrations less than 2 inches in diameter are considered too small to release a significant amount of fission products to the environment. This criterion is the direct adoption of a recommendation made in Reference 2. Second, containment penetrations which are a part of a closed system either inside or outside containment pose no significant threat to containment isolation. This criterion is based on the small probability of two independent, low probability events occurring simultaneously, one event being the failure of a penetration's isolation valves to close and the other event being a pipe break in the closed system associated with that penetration.

Containment penetrations serving secondary system fluid pipes are excluded from explicit containment isolation consideration since the steam generator secondary side is a closed system inside containment for all accident sequences except steam generator tube rupture (SGTR) events and steam/feedwater line breaks inside containment. In all steam generator tube rupture event sequences resulting in core damage, the containment is assumed to be bypassed through the ruptured U-tube and a steam line or feed line containment penetration. However, since all other containment penetrations must be isolated during a SGTR to minimize the release of fission products following core damage, containment isolation is still modeled in the SGTR plant response tree. In steam/feedwater line breaks inside containment, isolation of the broken steam generator's containment penetrations is modeled directly in the plant response tree. Containment isolation is assumed to fail if the broken steam generator's secondary side is not isolated.

Five screening criteria were used to identify fluid system penetrations which do not require explicit modeling to determine their impact on containment isolation. These criteria are:

Criterion Number	Description
1	Containment penetrations less than two Inches in diameter are not considered significant sources of leakage, unless the penetration serves a containment sump line. (Also see criterion 5)
2	Administratively-controlled mechanical and fluid system containment penetrations are considered separately in this analysis.
3	Penetrations of systems closed to both the RCS and containment atmosphere are not considered significant sources of leakage.
4	Penetrations of systems closed to the environment outside of containment are not considered significant sources of leakage.
5	Penetrations whose only containment leakage pathways are from containment sump suction lines to the RWST are not considered significant sources of fission product leakage to the environment. Various scenarios were evaluated and all resulted in water remaining in the RWST or the containment sump for fission product scrubbing.

Applying these criteria, the penetrations which remain for analysis are listed in Table BE Q5-1.

TABLE BE Q5-1

Pene-tration Number	Penetration Description	Valve Number & Location (IC or OC)	Line Size (in.)	Valve Type	Isola-tion Signal (Train)
103	Alternate Reactor Building Purge Supply Line	6056, IC 6057, OC	6 6	AOV AOV	K(A) K(B)
222	High Head Safety Injection to Reactor Loops	8995A, IC 8995B, IC 8995C, IC 8885, OC	2 2 2 3	Check Check Check MOV	- - - J(B)
226	Residual Heat Removal Pump Suction from Reactor Coolant Loop C	8701B IC	12	MOV	J(B)
227	Low Head Safety Injection to Reactor Coolant Loops	8974B, IC 8888B, OC	10 10	Check MOV	- J(B)
302	Alternate Reactor Building Purge Exhaust Line	6066, IC 6067 OC	6 6	AOV AOV	K(A) K(B)
303	Supply to Reactor Building Spray Nozzles - Train B	3009B, IC 3003B, OC	10 10	Check MOV	- T(B)
316	Residual Heat Removal Pump Suction from Reactor Coolant Loop A	8701A, IC	12	MOV	J(A)
319	Reactor Building Instrument Air Compressor Suction Line	2662B, IC 2662A, OC	6 6	AOV AOV	T(B) T(A)
322	Low Head Safety Injection to Reactor Coolant Loops	8974A, IC 8888A, OC	10 10	Check MOV	- J(A)

Pene-tration Number	Penetration Description	Valve Number & Location (IC or OC)	Line Size (in.)	Valve Type	Isola-tion Signal (Train)
325	Low Head Safety Injection to Reactor Coolant Loop Hot Legs	8988A, IC 8988B, IC 8889. OC	6 6 10	Check Check MOV	- - J(A)
401	Supply to Reactor Building Spray Nozzles Train A	3009A, IC 3003A, OC	10 10	Check MOV	- T(A)
409	Charging Line to Regenerative Heat Exchanger	8381, IC 8107, OC 8108, OC	3 3 3	Check MOV MOV	- S(A) S(B)
412	High Head Safety Injection to Reactor Coolant Loops	8990A, IC 8990B, IC 8990C, IC 8886, OC	2 2 2 3	Check Check Check MOV	- - - J(B)
415	High Head Safety Injection to Reactor Coolant	8992A, IC 8992B, IC 8992C, IC 8884, OC	2 2 2 3	Check Check Check MOV	- - - J(A)
422	Pressure Relief Tank Makeup	8046, IC 8028, OC	3 3	Check AOV	- T(B)
423	Reactor Coolant Drain Tank	7135, IC 1003, IC 7136 OC	3 3 3	Diaph. AOV AOV	LC T(A) T(B)
424	Reactor Building Sump Drain	6242A, IC 6242B, OC	3 3	AOV AOV	T(A) T(B)

Pene-tration Number	Penetration Description	Valve Number & Location (IC or OC)	Line Size (in.)	Valve Type	Isola-tion Signal (Train)
426	Boron Injection to Reactor Coolant Loops	8997A, IC	2	Check	-
		8997B, IC	2	Check	-
		8997C, IC	2	Check	-
		8801A, OC	3	MOV	S(A)
		8801B, OC	3	MOV	S(B)

Table Notes :

Valve Identifiers

AOV - Air Operated Valve
Check - Check Valve
Diaph. - Manually Operated Diaphram Valve
IC - Inside Containment
MOV - Motor Operated Valve
OC - Outside Containment

Isolation Signals

J - Remote Manual
K - Reactor Building Purge Isolation
LC - Locked Closed
S - Safety Injection
T - Containment Isolation (Phase A)

(2) The signals required to automatically isolate the penetrations analyzed are indicated in Table BE Q5-1. Containment isolation (Phase A) is generated automatically with a safety injection (SI) actuation signal, a containment spray actuation signal, or manually. Reactor building purge isolation is actuated on a SI signal or a containment radioactivity-high signal actuation. A SI signal will close, directly or indirectly, all of the automatically closing valves listed in Table BE Q5-1. Refer to part (5) of the response for a discussion of the penetrations which have manually controlled valves.

(3) Containment isolation is modeled on the core damage paths of the VCSNS IPE event trees. As discussed in part (2), conditions which lead to the generation of a SI signal will cause the automatic valves in Table BE Q5-1 to isolate. For LOCA events, SI will be initiated by low pressurizer, or high-1 containment pressure. For secondary side breaks, SI will be initiated on low steam line pressure, differential steam line pressure, or high-1 containment pressure. For transient events (intact RCS and secondary side) core damage paths in the event trees require loss of decay heat removal. If core cooling via the emergency feedwater system is not successful, the operators are instructed by the emergency operating procedures to initiate bleed and feed. This requires actuating SI. If the operator fails to initiate bleed and feed, then core damage and vessel failure are postulated which will actuate the SI signal and containment isolation.

A SI signal is expected to occur on low pressurizer pressure for an interfacing systems LOCA or a steam generator tube rupture, however, all core damage sequences for these two initiating events go to containment bypass endstates.

(4) For the penetrations included in the analysis, the testing and applicable maintenance procedures were reviewed. For those penetrations which contained valves with hourly failure rates, the test intervals were used to determine the mean time for possible failures. Isolation valve unavailability due to test was not included because the isolation signals and valves are available during the test to isolate if a signal is generated. In addition, many of the valves cannot be tested on-line. Unavailability due to maintenance was also not included in the analysis. Per the plant Technical Specifications, if any maintenance activity renders a containment isolation valve inoperable, the valve (or another valve for the same penetration) must be closed and deactivated within 4 hours. Maintenance on the containment isolation valves is not typically performed because if it threatens the leak tightness of a valve, then a 10CFR50 Appendix J Type C test must be performed and many of these valves cannot be tested on-line.

(5) The systems and penetrations were reviewed to determine the appropriate failure logic for containment isolation failure. Fault trees were developed to quantify the failure probability using basic events such as AOV fails to operate, relays mechanically bound, relay contacts fail to open/close, check valves fail to close, and others. Common cause failures were combined with the fault tree analysis failure probabilities to determine the total failure probability for the containment penetrations. The cutsets for a given containment isolation fault tree were reviewed for similar components which would belong to the same common cause group. After identifying the common cause groups, the Multiple Greek Letter Method was used to estimate the probability of common cause failure due to the common components.

For the penetrations with remote manually operated valves a conservative approach was generally taken. The analysis for the penetrations which include a motor operated valve and a check valve typically modeled only the failure of the check valve for failure of the penetration. This simplified the isolation failure logic because these penetrations are for systems which are used at various times during events for accident mitigation.

To complete the quantification, the failure probabilities for the penetrations were summed to determine the total failure probability for containment isolation. This included penetrations that are administratively controlled, penetrations not needed for accident mitigation, and penetrations for the reactor building spray system.

References:

1. D. D. Carlson, et. al., "Reactor Safety Study Methodology Applications Program: Sequoyah #1 PWR Power Plant", Sandia National Laboratories, NUREG/CR-1659, 1981.

2. IDCOR Technical Report T86.3a2, "IPE Source term Methodology for PWR's," Fauske and Associates, Inc., March 1987.

6) Temperature-induced steam generator creep rupture, which is considered in other IPEs, is not addressed in the VCSNS IPE. In some IPEs, the probability of induced steam generator tube rupture (SGTR) increases as the RCP is restarted following the direction of procedures. Please discuss the probability of induced SGTR. Please include in the discussion the probability of RCP operation and the effect of RCP operation on the probability of induced SGTR.

Response

The first element of the question states that we have excluded temperature-induced steam generator tube creep rupture (ISGTR) failures for high pressure sequences. Before we address this sensitivity analysis, it is appropriate to provide the following perspective. Analyses by the NRC and the industry on Zion-like reactors under high pressure conditions result in hot leg creep or surge line rupture. This was documented through sample problems in the MAAP4 User's Manual and transmittal documents for Zion-like reactor systems as well as for the SCDAP/RELAP5 calculations performed by INEL in support of resolution of the DCH issue for Zion-like reactors. This latter information is reported as Appendix C in NUREG/CR-6075, Supplement 1.

With the agreement between industry and NRC contractor calculations, it is further appropriate to add that the VCSNS plant design has three hot legs and a thermal power rating of 2775 MW while the Zion plant design has 4 hot legs and a thermal rating of 3250 MW. Also, the hot legs of both plants are of similar diameter, and the tube surface area of a single steam generator is similar, as well. These design details would lead to similar natural convection heat fluxes from the core to the steam generators for both plants under degraded core conditions. Therefore, one would expect essentially the same type of behavior for these circulation flows. Thus, a conclusion of hot leg creep rupture under degraded core conditions at VCSNS can be made based on the analysis of the Zion-like reactor.

Consequences related to hot leg creep rupture have been investigated with a MAAP 3.0B sensitivity analysis of core damage sequence SBE12IH. As shown in Table 4-4 of the VCSNS Source Term Notebook, Revision 1, MAAP sequence HLCR considers a 1.0 ft^2 induced hot leg creep rupture for sequence SBE12IH. Results of the MAAP calculation indicate a reduced retention of volatile fission products in the primary system, but no adverse impact on containment performance due to the hot leg creep rupture.

The question also asks to discuss the probability of induced steam generator tube creep rupture. During high pressure sequences with dry steam generator, circulatory flows from the upper plenum, through the hot leg, and into the steam generators clearly begin to heat the steam generator tubes. However, even if the steam generator tubes reach 1000°F (800 K), their structural strength will not degrade from the tube strength present at normal, full power conditions. Thus, these tubes typically do not approach failure conditions before the hot leg fails due to creep. This is consistent with the results reported in NUREG/CR-6075, Supplement 1, which addresses the issue with respect to Zion-like reactors. For these reasons, ISGTR events were not considered during high pressure sequences in the VCSNS IPE. Also, the issue of ISGTR events is addressed in the Westinghouse Owners Group (WOG) Severe Accident Management Guideline (SAMG), and therefore this issue will be given further consideration by VCSNS during implementation of its accident management program.

Finally, the question asks to include effects of RCP operation on the probability of ISGTR. Operator actions to restart RCPs and clear loop seals in order to provide additional core cooling have only a small impact on the timing of core damage, and so were excluded from the VCSNS IPE. Clearing the loop seals during high pressure sequences following steam generator secondary side dryout may, however, lead to an increased risk of ISGTR.

To consider ISGTR, the following conditions, which are consistent with analyses presented in WCAP-11910, NUREG-1150, and the EPRI Technical Basis Report, must exist:

1. degraded core conditions;

2. RC pressure at, or near, the pressurizer safety relief set point (i.e., no large or medium LOCAs, no large RCP seal LOCAs, no operator actions to lock open pressurizer PORVs, such as in bleed and feed actions, no prior RCS boundary creep rupture).

3. steam generator secondary side dryout (i.e., no emergency feedwater; and

4. RCP operation, such as during RCP restart on high core exit temperature.

Note that VCSNS has implemented Westinghouse ERG Maintenance Item #DW-93-019 which procedurally prevents operators from restarting the RCPs if the steam generator water level is too low. Thus, if the current procedures are followed, then under no circumstances can the four criteria listed above for ISGTR be satisfied.

For the moment, suppose the procedural modifications had not been implemented according to DW-93-019. Then, sequences meeting the four criteria listed above would be a subset of the VCSNS core damage sequences as presented in Table 3-5 of the VCSNS Source Term Notebook. For purposes of selecting sequences from Table 3-5 for consideration of ISGTR, the four criteria can be translated into high pressure core damage sequences ("H" in 7th character of end state designator), without emergency feedwater, but with power available prior to core damage. The first core damage sequence in the top 100 meeting the four criteria is sequence number 64, TRE12IH, with a core damage frequency of 5.23E-7. This sequence is initiated by a loss of main feedwater followed by a failure to establish emergency feedwater. A list of all sequences in the top 100 which have conditions consistent with the possibility of ISGTR follows:

Sequence Number	Frequency	Percent of total CDF	Damage State
64	5.23E-7	0.26	TRE12IH
75	3.68E-7	0.18	TRE12IH
82	3.22E-7	0.16	TRE12IH
89	2.76E-7	0.14	TRE12IH
TOTAL:	1.49E-06	0.74	

As shown, four sequences, all with the TRE12IH damage state, with a total core damage frequency of 1.5E-6, have conditions consistent with the possibility of ISGTR. Even in these sequences, however, there is some uncertainty as to whether the prerequisite conditions for ISGTR will exist. For instance, the operator action to restart RCPs has not been quantified.

If these sequences are treated as ISGTR sequences, then they would fall into release category "T - Containment bypassed, >10% volatiles released." The conditional probability of release category T given core damage would then increase from .004 to .012.

7) In NUREG-1335 it is stated that "documentation should be provided to support the availability and survivability of systems and components with potentially significant impact on the containment event tree (CET) or the radionuclide release." This issue is not discussed in the back-end part of the VCSNS submittal. Please discuss the survivability of the equipment under severe accident conditions. Please include in the discussion the environmental conditions (e.g., temperature, pressure, radiation, aerosol plugging, and debris effects) derived and used in the evaluation.

Response

Severe accidents challenge equipment and components beyond design basis conditions. For the issue of equipment survivability, only equipment and components located in the containment and necessary to maintain containment integrity is relevant. Components which are a part of the containment boundary (i.e., penetrations, equipment hatches, personnel air locks....) were analyzed for severe accident conditions (FAI/91-111) and determined capable of maintaining containment integrity under severe accidents. Equipment needed for isolation purposes has also been analyzed (WCALC. Note CN-PORI-91-285-R1) for their ability to isolate at the onset of an accident and found acceptable. This limits discussion to the Reactor Building Cooling Units (RBCUs). The effect of high temperature, pressure, humidity and aerosol plugging are discussed below for RBCU's operability. Only one of the four RBCUs is required for containment heat removal and a severe accident phenomenon must challenge all four RBCUs to necessarily compromise containment heat removal. Also, containment heat removal ensures equipment survivability. Containment gas temperature and pressure do not threaten RBCU's operability if one is operating.

Temperature and Pressure

The location of the RBCUs precludes impingement by debris or steam/hydrogen jets. The four RBCUs are located at the 514 ft elevation, two located on the south end and two directly opposite at the north end. None of the four will come into contact with molten debris. The debris would need to make several 90° turns between the reactor cavity exiting the cooling fan housing at approximately the 420 ft elevation and the 514 ft elevation to contact an RBCU. There are several floor levels/obstructions between the seal table and the RBCUs that create debris impaction area. RBCUs are separated from any part of the reactor coolant system where a steam or hydrogen jet might emanate (ref. Dwg. E-303-332 (rev. 1)).

NUREG-1335 postulates that containment upper compartment temperature and pressure could compromise RBCU functions. This concern can be addressed by comparing severe accident conditions to the DBA LOCA conditions for which equipment inside containment has been qualified. Design Basis Accident conditions are 321.5°F peak temperature and 57 psig, and a design temperature of 283°F (ref. FSAR Table 6.2-1). The RBCUs are qualified for ambients of 350°F for 3 to 4 hours and pressures of 79.7 psia (ref. Joy Manufacturing report X-604). A review of source term runs shows that long term pressure and temperature remain below design basis levels if containment heat removal (one RBCU) is available. Sequences included medium and small LOCAs. The maximum temperature in the upper containment for these sequences within 24 hours was 260°F. Brief transients can exceed DBA LOCA temperatures without effecting the RBCUs. A lumped capacitance thermal time constant for a thin (say 3 mm) steel plate is at least ten minutes, assuming natural convection heat transfer to the plate. Upper compartment gas temperature transients due to vessel failure, hydrogen burns, etc., that last only a few minutes do not pose a threat to RBCU integrity if containment heat removal is available in the long term.

The station blackout sequence represents a case where the RBCUs could be subjected to an adverse environment and then be called upon with the restoration of AC power to alleviate the adverse containment conditions. Two station blackout sequences were analyzed, one with recovery at 20 hours and the other without recovery. At 20 hours when recovery occurred, the upper compartment pressure was at 73 psia and the temperature was at 350°F. These figures reflect qualified conditions for the RBCUs. The fan cooler motor would typically be the life limiting component of the RBCU, and within the motor the stator insulation the material of concern. The fan cooler motor for the VCSNS RBCUs are form-wound with a Class H insulation. The Class H insulation temperature rating is 115°C. This rating is based on a 50°C ambient, and 65°C temperature rise (Joy report X-604). The motor was qualified to operate at 350°F for 3 to 4 hours. Therefore, the motor qualification testing demonstrated a higher total temperature exposure based on a 350°F ambient. The analysis indicates that the RBCU motor should survive the ambient conditions and be available for recovery. It should be recognized that the motor is not operating while exposed to these elevated conditions and therefore not subjected to the temperature rise. This provides added assurance of the motor's ability to survive a SBO. Once recovered and operational the ambient conditions will be reduced. With no recovery, temperatures will reach close to 400°F and pressures of 100 psia can be expected at 48 hours. The likelihood of an unrecovered SBO of 48 hours is probabilistically insignificant, thus the 20 hour recovery is a bounding assessment. With a fan cooler operational, temperatures are expected to remain within design and tested limits and recovery late in a SBO sequence demonstrate reasonable judgement of successful recovery.

Humidity

RBCUs are qualified for LOCA conditions of 100% humidity.

Aerosol Plugging

RBCU operation during severe accident conditions will collect fission product aerosols on RBCU tubes and fin plates. Aerosol agglomeration can plug fins, decrease heat transfer to component cooling water, and, in general, degrade RBCU performance. This occurs in sequences with extensive molten-core concrete interaction, but poses no threat for "wet" sequences. Wet sequences have RWST injection and containment heat removal. RWST injection by LPI, HPI, or containment sprays, and

RBCU operation maintains a water pool in the cavity and prevents MCCI. Again, RBCU functions ensure RBCU survival, with the stipulation that RWST injection is necessary to prevent MCCI and aerosol generation.

This phenomenon is relevant then only in "dry" sequences where RBCUs act as containment heat removal, but there is no RWST injection. A review of the VCSNS quantification shows that only two sequences in the top 100 meet this requirement and constitute less than 1% of the total CDF. If RBCUs do not operate, RBCU surfaces do not collect aerosols on fin and tube surfaces. Airborne aerosols do not pose a threat to recovery of an RBCU after a prolonged period of MCCI.

8) The Generic Letter CPI recommendation for PWR dry containments is the evaluation of containment and equipment vulnerabilities to localized hydrogen combustion and the need for improvements (including accident management procedures).

Please discuss whether plant walkdowns have been performed to determine the probable locations of hydrogen releases into the containment. Discuss the process used to assure that: (1) local deflagrations would not translate to detonations given an unfavorable nearby geometry, and (2) the containment boundary, including penetrations, would not be challenged by hydrogen burns.

Please identify potential reactor hydrogen release points and vent paths. Estimates of compartment free volumes and vent path flow areas should also be provided. Please specifically address how this information is used in your assessment of hydrogen pocketing and detonation. Your discussion (including important assumptions) should cover likelihood of local detonation and potentials for missile generation as a result of local detonation.

Response

The issues brought up by this question are all thoroughly addressed in the VCSNS phenomenological evaluation summary on hydrogen deflagration and detonation [FAI/91-60].

Walkdowns performed by FAI and VCSNS indicated that the open design and significant venting areas for the subcompartments within the containment help ensure a well-mixed atmosphere, a feature which inhibits combustible gas pocketing.

The lower and upper compartments communicate through large openings around the steam generators and above the reactor coolant pumps (RCPs). Also, there is a 12 inch gap between the operating deck floor at the 463 ft elevation and the containment wall, and an equipment hatch, with grating, open to the containment floor in the lower compartment at the 412 ft elevation.

Like the operating deck, the floor at the 436 ft elevation (i.e., the intermediate deck) has a 12 inch gap around the periphery which allows communication to the containment floor (412 ft elevation). Additionally, the intermediate deck in the annular compartment is connected to the containment floor through two open stairways.

The lower and annular compartments communicate through the secondary compartment cooling fans at the 412 ft elevation. From the lower compartment at the 412 ft elevation, access to the steam generator and pressurizer enclosures is also possible. These enclosures are not densely packed with equipment, thus during the walkdown, the steam generators could be clearly viewed overhead. There are many flow paths between the steam generator and pressurizer compartments, including a doorway and nine cooling fan ducts that circulate air through the compartments. Finally, the walkdown revealed that the steam generator and pressurizer enclosures were open at the top to the upper compartment.

This last feature, top and bottom venting of enclosures, has been shown to promote mixing in the containment be creating a chimney effect [Plys, et al., 1996]. Also, it is likely that pipe breaks for LOCAs and seal leaks during SBOs will further enhance this chimney effect by creating either buoyant plumes originating near the base of the steam generators or by creating uneven heating among the steam generator enclosures. Both of these effects will enhance natural circulation mixing within containment by forcing lower compartment gas into the upper compartment, causing cross-flows in the lower compartment between unevenly heated steam generator enclosures, and by drawing gas from the annular compartment into the lower compartment to feed the chimneys.

In addition to the open and well vented containment design employed at VCSNS, several active systems also promote hydrogen mixing. First, the four reactor building coolant units (RBCUs) take air from the upper compartment, cool it, and distribute it throughout other regions of containment. For instance, a ring duct which accepts air from the RBCUs and discharges it to the containment dome and the 429 ft elevation runs around the containment circumference above the operating deck. Vertical ducts connected to the ring duct pass through openings in the floor at the 463 ft elevation to deliver air to the 429 ft elevation. Second, containment spray injection and recirculation would also promote natural circulation and mixing. Two pairs of containment spray headers are located at the top of the upper compartment above the polar crane. These headers are arranged to ensure an even distribution of spray flow throughout the upper compartment.

The walkdown noted only one potential location for hydrogen pocketing, and that was in the vicinity around the "C" accumulator at the 436 ft elevation. This region of containment creates a closed-ended volume about 12 feet high. The walkdowns also noted that no ignition sources were found at the 436 ft elevation and that at worst, hydrogen combustion at this elevation could destroy the vertical duct risers. No potential for challenging the structural integrity of containment was noted.

The phenomenological evaluation summary, FAI/91-60 evaluated hydrogen deflagrations as a potential early containment failure mode. It provided a bounding assessment of the pressure rise caused by hydrogen deflagration at reactor vessel failure based on the following assumptions:

1. station blackout conditions at the time of vessel failure;
2. 100% oxidation of all zirconium and metallic constituents of the lower core plate;
3. complete combustion regardless of the containment gas composition; and
4. adiabatic, isochoric, complete combustion.

Containment temperature and pressure after combustion were calculated as 1047°F and 114 psia, respectively. Compared to the fragility curve, a 114 psia peak pressure is less than the lower bound failure pressure of 120 psia. Additionally, the likelihood that all the assumptions listed above hold true is extremely small. For instance, zirconium oxidation is never complete, and the containment atmosphere is inerted at the time of vessel failure for station blackout sequences. On this basis, hydrogen deflagration is not considered as an early containment failure mechanism.

The summary paper also evaluates the potential for transition from deflagration to detonation (DDT) as a function of mixture reactivity and geometric configuration. This evaluation assumed the containment was well-mixed for the reasons stated above. The lower and annular compartments are modeled as channels with transverse venting, because flame propagation from the bottom of either compartment will experience side venting due to the opening in the walls separating the two compartments. Furthermore, upward flame propagation in the annular compartment will be "vented" in a transverse direction due to the size of the annular compartment. Both the lower section of the lower compartment and the annular compartment were judged to be unfavorable to flame acceleration, and that DDT in these regions was unlikely.

The steam generator enclosures form vertical, straight channels, and, although both ends are open, there is no transverse venting. Thus, DDT in these enclosures was judged to be possible. However, an assessment of actual steam generator enclosure dimensions revealed that they were less than the minimum channel size required to accelerate a flame to DDT. This is discussed in more detail below.

The summary paper compared the containment dimensions to the minimum channel size required at reactor scale to accelerate a flame to DDT. Details are left to the summary paper, but the evaluation procedure and results are presented here. The procedure is as follows:

1. assume the extreme conditions of an SBO with 100% oxidation of zirconium and the lower core plate, and a 10% steam molar fraction, which is significantly less than the value predicted by MAAP.

2. determine the equivalence ratio and detonation cell width;

3. define a scale factor to extrapolate from the FLAME facility to the reactor scale;

4. find the minimum channel size required at reactor scale for DDT; and

5. compare to the VCSNS compartment dimensions.

This procedure was applied to the annular, lower, and steam generator compartments. The minimum channel size required at reactor scale to accelerate a flame to DDT for compartments with transverse venting (i.e., the lower and annular compartments) was calculated as 120 ft x 160 ft. This is much larger than the physical dimensions of the lower or annular compartments, thus there is no potential for DDT in these regions.

The minimum channel size required at reactor scale to accelerate a flame to DDT for compartments without transverse venting (i.e., the steam generator enclosures) was calculated as 15 ft x 20 ft. The free space in the lower portion of the steam generator enclosures is on the order of that required for flame acceleration to DDT. However, in the upper portion of the enclosure, the channel width is reduced to about 3 to 4 ft, which is much smaller than the required channel size. Therefore, it is unlikely that DDT can be supported and sustained through the steam generator enclosure.

Overall, the detailed assessment for hydrogen deflagration and detonation concluded that these phenomena were unlikely to lead to containment failure at VCSNS.

REFERENCE

M. G. Plys and G. T. Elicson, Fauske & Associates, Inc., C. Cirauqui and Maite Otero, Central Nuclear Vandellos II, "Hydrogen Mixing and Deflagration/Detonation Potential in a Large Dry PWR Containment," submitted for publication, ANS 1996 Annual Meeting and Embeded Topicals, Reno, Nevada, June 16-20, 1996.

9) In the VCSNS IPE ten source term bins (STBs) are selected for source term calculations. Among these ten STBs, three involve containment bypass or isolation failure. Of the remaining seven STBs, only one involves containment failure (STG 5, with a frequency of 4.1E-5, contributing 20% of total CDF, Tables 4.4.3-2 and 4.4.4-3). However, according to the results of the source term calculation, the release fraction of volatile fission products for STB 5 is the lowest among all STBs (Tables 4.4.4-1 and 4.4.4-3). The release fraction for STB 5 is significantly less than that of some STBs in which the containment remains intact. It seems that the operation of containment spray is one of the primary reasons for the small release. Please discuss the dependence of the spray system on other support systems (e.g., cooling requirement) and the availability of the spray system (while emergency core cooling system (ECCS) is not available) for the sequences binned in STB 5. Please discuss the models used for the sprays for fission product scrubbing, the uncertainty of these models and their effects on the uncertainty of fission product releases. Please also discuss the long-term releases (beyond the calculation time of 48 hours) and the effect of revaporization of fission products on long-term releases. Since containment failure area is also an important factor, please estimate the change in source terms by the use a containment failure area greater than that used in the IPE to address the uncertainty in containment failure area (e.g., a failure area of the order of 1 ft^2. The IPE uses 0.03 ft^2 for the base case and 0.1 ft^2 for the sensitivity case.).

Response

The question presented consists of several parts, each part will be addressed separately.

<u>Discuss the dependence of the spray system on other support systems and the availability of the spray system for the sequences binned in STB 5.</u>

Successful operation of the reactor building spray system is dependent upon the following support systems (CN-PORI-91-282-R1):

Electric Power:	AC power provides motive power for the pump and DC power supplies the pump control circuit.
Engineered Safety Features Actuation System:	This system provides the initiation signal to operate.
Chilled Water (VU):	HVAC supplies cooling to the spray pump rooms and chilled water provides the cooling medium for the HVAC pump room coolers.

The chilled water system discharges heat to the service water system. Upon loss of either service water or chilled water the reactor building spray pumps would loose room cooling. However, it has been documented (Calc. No. CN-CDBT-90-235-RO) that upon loss of HVAC, or chilled water, that the room will not heat up within 24 hrs, to the temperature where the pumps would be expected to fail. The mission time for Level II is 48 hours. It is anticipated that the room temperature at 24 hours will be the steady state value and a minimal temperature rise will be expected over the next 24 hour period. Therefore, loss of room cooling does not result in the loss of spray pump function.

All sequences in source term bin 5 (STB 5) (ref. Table 4.4.3-2) have spray injection and recirculation.

<u>Discuss the models used for the sprays for fission product scrubbing, the uncertainty of these models and their effects on the uncertainty of fission product releases.</u>

The rate of change of suspended aerosol mass for any of the modeled fission products is given as

$$\frac{dm}{dt} = -\lambda m + \dot{m}_p$$

m - instantaneous suspended mass

$\dot{m}_p$ - mass rate production

λ - removal factor

The aerosol removal factor (λ) is determined predicated on the type of removal mechanism under consideration. For containment sprays, the removal factor is calculated by MAAP as

$$\lambda = \frac{FEFFDR \bullet VOL}{V}$$

VOL represents the volumetric spray flow rate, V the containment volume and FEFFDR a defined model parameter, representing the collection efficiency of a single spray droplet.

The collection efficiency values were derived from the Containment System Experiments (CSE) (Hillard, 1971) as shown in the attached figure. The dashed line identified as total represents the combined collection efficiency of diffusiophoresis, brownian interception and impaction methods. This was originally used as an estimate of spray collection efficiency. The numbered circles and square data points on the graph are actual CSE test results. This data shows a collection efficiency far greater than predicted. The range of efficiencies based on the test data is approximately 0.01 to 0.05, and represents the band of uncertainty in selecting a collection efficiency. The V.C. Summer analysis used a value on the lower or conservative end of the band, of 0.2. This minimized the collection efficiency of the spray system.

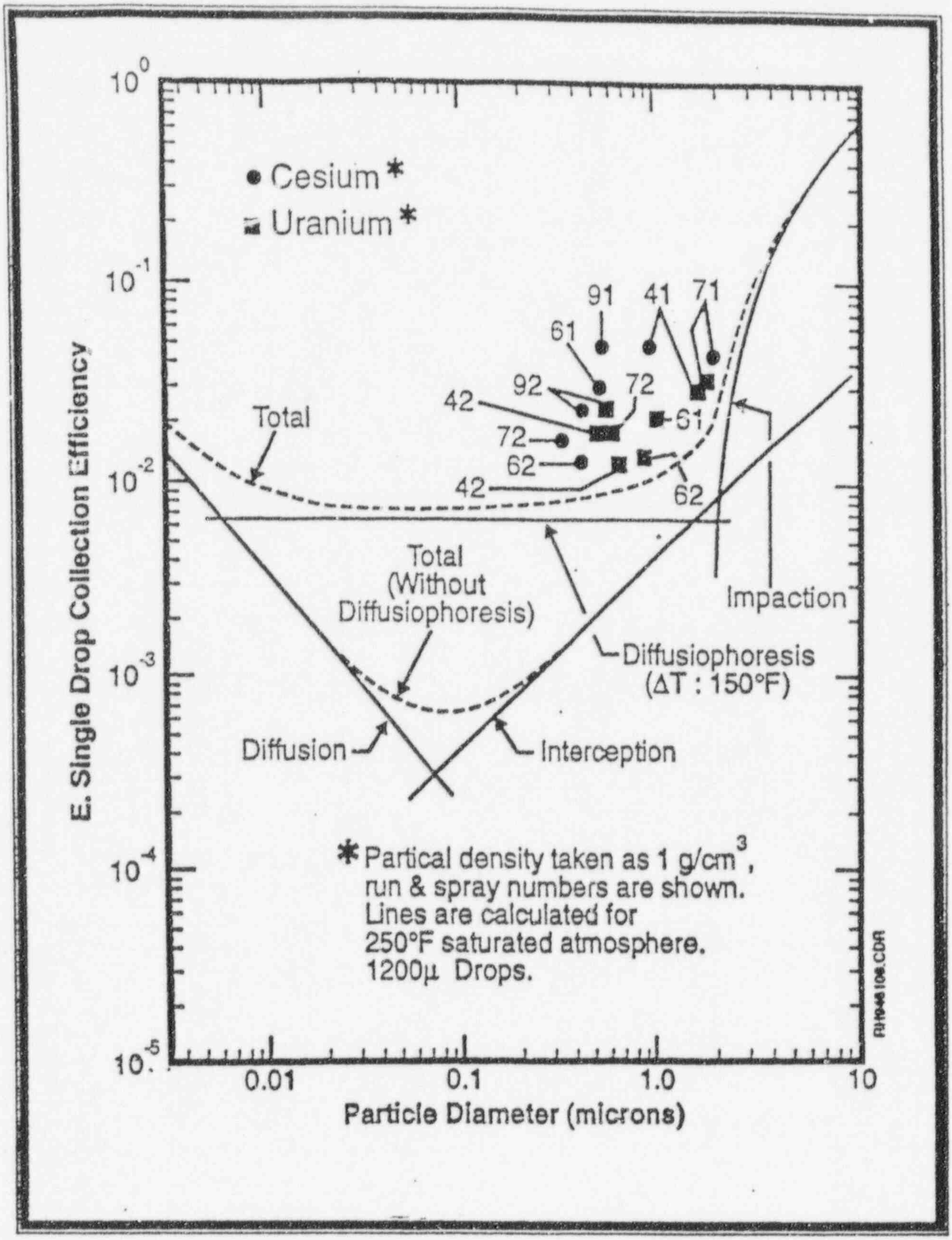


Figure for Question #9

The fission product removal factor (λ) is dependent upon the collection efficiency which is at a conservative value and the volumetric flow rate of the spray system, which is fixed by plant design conditions. The sensitivity case NS compared spray recirculation versus no recirculation and concluded that aerosol (volatile) releases increased by an order of magnitude without containment spray recirculation. Sprays are important to fission product scrubbing and their scrubbing effect is dependent upon the spray rate fixed by plant conditions, and the collection efficiency dependent upon test data.

Discuss the long-term releases, beyond 48 hours, and the effect of revaporization of fission products on long-term releases.

Long term releases, beyond the Level II mission time, for this sequence are not expected to increase the release of volatile fission products. Continued spray operation will help to maintain surface temperatures and minimize revaporization as well as continued scrubbing of the containment gas space. Furthermore, with the containment depressurized, a significant driving force would not be present to force the flow of fission products from containment. In addition, recovery actions are fully expected within the 48 hr mission time which will also serve to minimize any further releases.

Estimate the change in source terms by the use of a containment failure area greater than that used in the IPE to address the uncertainty in containment failure area, (e.g. a failure area of 1 ft^2).

No significant change in the source term release is expected with a 1 ft^2 break area. Once the containment depressurizes the driving force which causes releases from containment is diminished, and releases from containment are minimized. A 1 ft^2 break leads to a rapid drop in pressure and will sweep out a portion of the airborne aerosols during the depressurization. However, once depressurized the releases are minimal. Containment spray operation is more important to maintaining release levels as was shown with the sensitivity case on failure to align sprays for recirculation. Thus, volatile fission products are expected to remain comparable to the 0.1 ft^2 break with sprays calculated as a sensitivity case in the analysis.

10) A containment failure area of 0.03 ft^2 is assumed in the VCSNS IPE. This seems to be based on the leak-before-break behavior assumed to occur at slow pressurization. In the VCSNS IPE, containment integrity is assumed to be maintained before containment pressure reaches a containment failure pressure of 142 psig. Since it is more likely to have a larger containment failure area at higher containment pressure, please discuss the dependence of containment failure area on containment pressure load for VCSNS. Please address uncertainties in the discussion.

Response

The question points out that the IPE assumed a containment failure pressure of 142 psig. This failure pressure represents the mean failure pressure from the VCSNS fragility curve as developed in FAI/91-158. The mean failure pressure indicates that the containment has a 50% probability of failing at or below 142 psig. Two other points of significance from the fragility curve are the "lower bound" failure pressure of 120 psig (i.e., 5% probability of failure at or below 120 psig), and the "upper bound" failure pressure of 154 psig (i.e., 95% probability of failure at or below 154 psig). These bounds represent a realistic range of uncertainty for containment over pressure failure.

The IPE also used a leak-before-break model of containment failure. This model assumes that as the containment pressurizes, leaks will develop which will be sufficient to prevent any additional pressurization. In this instance, the leak rate will be limited by choked flow of the containment gas through the leak sites and can be estimated by matching the containment leak rate to the steaming rate from decay heat generation, on a molar basis. This model will produce an inverse linear dependence between the leak size and the containment pressure.

Estimates of the leak size at the upper and lower bound failure pressures can be calculated as follows. First, if the containment gas is assumed to behave as an ideal, compressible gas which expands isothermally through the break, then the gas flow rate can be calculated as,

$$w_{leak} = A_{leak} P \sqrt{\frac{M_{gas}}{RT}}$$

where,

w_{leak} = containment leak rage, kg/sec

A_{leak} = effective leak area from containment, m^2

P = containment absolute pressure, Pa

M_{gas} = gas molecular weight

R = ideal gas constant

T = containment gas temperature, K

Next, the maximum containment pressurization rate can be obtained by assuming the entire decay heat load is used to generate steam and by neglecting heat losses to containment heat sinks. Near the expected time of containment overpressure failure, decay heat is about 0.5% (14 MW) and the latent heat of vaporization is h_{fg} = 2 MJ/kg. These quantities yields a steaming rate, w_{st} of,

$$w_{st} = \frac{q_D}{h_{fg}} = \frac{14}{2} = 7\ kg/\mathrm{sec}$$

Then, for a given pressure, a leak size can be found which yields a leak rate equivalent to the steam generation rate, on a molar basis, as:

$$\frac{w_{st}}{M_{st}} = \frac{A_{leak}\,P}{M_{gas}} \sqrt{\frac{M_{gas}}{RT}}$$

Solving for the effective leak are, yields:

$$A_{leak} = \frac{w_{st}}{P}\,\frac{M_{gas}}{M_{st}} \sqrt{\frac{RT}{M_{gas}}}$$

If the containment is assumed to be at the lower bound failure pressure (120 psig; 0.929 MPa) and 350°F (450 K), and the containment gas can be characterized by the molecular weight of steam, then the lower bound leak area is, .037 ft^2 (.0034 m^2). At the upper bound failure pressure (154 psig; 1.16 MPa), the leak area is reduced to 0.030 ft^2 (.0028 m^2).

The previous calculations are most sensitive to pressurization due to gas production (condensible or non-condensible) and the gas temperature, rather than the containment failure pressure, since at any failure pressure, the leak rate will be equal to the gas production rate. The gas production rate, in turn, is dependent on the fraction of decay heat used for steam generation and heat losses to containment heat sinks. Actual MAAP calculations reported in the IPE address these sensitivities by mechanistically modeling the containment gas composition, decay heat production and transport, water pool steaming, and containment heat sinks.

The remaining uncertainty lies in the determination of the containment pressure at which the containment leak rate equals the gas mole production rate (i.e., the leak-before-break failure pressure). The .03 ft^2 value selected in the IPE was based on MAAP calculations of the required leak rate to stop containment pressurization, and is representative of leakage at the mean containment failure pressure for the postulated accident scenarios.

11) There are number of items in the level 2 part of the submittal which need clarification:

a. The last paragraph of Section 4.4.4 (page 4-55) states that "lastly, Table 4.4.4-4 summarizes the source-term results by release category and shows the conditional probability of each release category given core damage. These results show that should a core damage event occur at VCSNS, there is more than a 97-percent probability that the radionuclide release would represent less than or equal to 0.01 percent of the volatile fission products." The values quoted here do not seem to be consistent with the numbers presented in Table 4.4.4-4. Please clarify.

b. Sequence 98 is initiated by a total loss of SW with containment isolation failure. Results of the MAAP calculation for this case are presented in both Table 4.4.4-1 (for the base case) and 4.5.2-1 (for the base case in the sensitivity analyses). Although results presented in these two tables are in general similar, they are not the same. Results presented in Table 4.5.2-1 show the occurrence of hydrogen burns and a much higher containment temperature, while Table 4.4.4-1 does not show hydrogen burns and a lower containment temperature. Please explain the discrepancy.

c. It seems that the "Analyzed Functional Sequence" for Source-Term Bin 5 should be TRE13IH instead of TRE12IH. Please clarify.

Response - a. The comment has identified an inconsistency on page 4-55, the statement should have stated "...less than or equal to 0.1 percent of the volatile fission product."

b. The data presented for sequence 98 in Table 4.5.2-1 was intended to replicate the results in Table 4.4.4-1 for comparative purposes with the sensitivity cases. The comment has identified a discrepancy in the two tables for sequence 98.

The base case analysis for sequence 98(TRE12NH) in Table 4.4.4-1 is in error. A hydrogen burn did occur as recorded for this sequence in Table 4.5.2-1. A comparable burn also occurred for the sensitivity sequence N8, which is tabulated as not having a burn.

The calculations indicated a burn for these sequences, and it was properly analyzed. However, the transcription of results was in error. As a result of this comment, all of the dominant sequence results for time of core uncovery, time of vessel failure, time of containment failure, maximum containment pressure, fraction of clad reacted and percent release of fission products were reviewed. Only minor transcription errors were identified that did not impact any results or conclusions.

c. TRE13IH was the analyzed sequence for source term bin 5. Table 4.4.3-2 has been corrected.