Evaluation of Potential Severe Accidents During Low Power and Shutdown Operations at Surry, Unit 1

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Analysis of Core Damage Frequency from
Internal Events During Mid-Loop Operations

Main Report (Chapters 1-6)

Prepared by
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Brookhaven National Laboratory

Prepared for
U.S. Nuclear Regulatory Commission

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ABSTRACT

Traditionally, probabilistic risk assessments (PRA) of severe accidents in nuclear power plants have considered initiating events potentially occurring only during full power operation. Some previous screening analyses that were performed for other modes of operation suggested that risks during those modes were small relative to full power operation. However, more recent studies and operational experience have implied that accidents during low power and shutdown could be significant contributors to risk.

During 1989, the Nuclear Regulatory Commission (NRC) initiated an extensive program to carefully examine the potential risks during low power and shutdown operations. The program includes two parallel projects being performed by Brookhaven National Laboratory (BNL) and Sandia National Laboratories (SNL). Two plants, Surry (pressurized water reactor) and Grand Gulf (boiling water reactor), were selected as the plants to be studied.

The objectives of the program are to assess the risks of severe accidents initiated during plant operational states other than full power operation and to compare the estimated core damage frequencies, important accident sequences and other qualitative and quantitative results with those accidents initiated during full power operation as assessed in NUREG-1150. The scope of the program includes that of a level-3 PRA.

The objective of this volume of the report is to document the approach utilized in the level-1 internal events PRA for the Surry plant, and discuss the results obtained. A phased approach was used in the level-1 program. In phase 1, which was completed in Fall 1991, a coarse screening analysis examining accidents initiated by internal events (including internal fire and flood) was performed for all plant operational states (POSS). The objective of the phase 1 study was to identify potential vulnerable plant configurations, to characterize (on a high, medium, or low basis) the potential core damage accident scenarios, and to provide a foundation for a detailed phase 2 analysis.

In phase 2, mid-loop operation was selected as the plant configuration to be analyzed based on the results of the phase 1 study. The objective of the phase 2 study is to perform a detailed analysis of the potential accident scenarios that may occur during mid-loop operation, and compare the results with those of NUREG-1150. The scope of the level-1 study includes plant damage state analysis, and uncertainty analysis. Volume 1 summarizes the results of the study. Internal events analysis is documented in Volume 2. It also contains an appendix that documents the part of the phase 1 study that has to do with POSSs other than mid-loop operation. Internal fire and internal flood analyses are documented in Volumes 3 and 4. A separate study on seismic analysis, documented in Volume 5, was performed for the NRC by Future Resources Associates, Inc. Volume 6 documents the accident progression, source terms, and consequences analysis.

In the phase 2 study, system models applicable for shutdown conditions were developed and supporting thermal hydraulic analysis were performed to determine both the timing of the accidents and success criteria for systems. Initiating events that may occur during mid-loop operations were identified and accident sequence event trees were developed and quantified. In the preliminary quantification of the mid-loop accident sequences, it was found that the decay heat at which the accident initiating event occurs is an important parameter that determines both the success criteria for the mitigating functions and the time available for operator actions. In order to better account for the decay heat, a "time window" approach was

developed. In this approach, time windows after shutdown were defined based on the success criteria established for the various methods that can be used to mitigate the accident. Within each time window, the decay heat and accident sequence timing are more accurately defined and new event trees developed and quantified accordingly. Statistical analysis of the past outage data was performed to determine the time at which a mid-loop condition is reached, and the duration of the mid-loop operation. Past outage data were used to determine the probability that an accident initiating event occurs in each of the time windows. This probability is used in the quantification of the accident sequences.

The mean core damage frequency of the Surry plant due to internal events that may take place during mid-loop operations is $5\text{E-}06$ per year, and the 5th and 95th percentiles are $5\text{E-}07$ and $2\text{E-}05$ per year, respectively. This can be compared with the mean core damage frequency from internal events of $4\text{E-}05$ per year estimated in the NUREG-1150 study for full power operations.

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S. EXECUTIVE SUMMARY

S.1 Background

This volume presents the results of a level one probabilistic risk assessment (PRA) of the Surry Nuclear Power Plant for accidents initiated during mid-loop operations. It also contains accident initiating event analysis, and system analysis for other low power and shutdown conditions. The work was performed by Brookhaven National Laboratory (BNL) for the Nuclear Regulatory Commission (NRC) Office of Nuclear Regulatory Research (RES) in support of the NRC response to the Chernobyl accident; and the program was later modified by the NRC staff's follow-up actions to the March 20, 1990 Vogtle incident.

A phased approach was taken in this project. In phase 1, a broadly-scoped screening analysis, which included internal fires and flooding, was completed in November, 1991. This analysis produced a preliminary level one PRA for accidents initiated during low power and shutdown (LP&S) and also gave insights on potential accident scenarios and potentially vulnerable configurations during low power and shutdown conditions. Phase 2 focused on a detailed analysis of mid-loop operation which was selected because many incidents have occurred during mid-loop operations throughout the world. Further, recent studies, including phase 1 of this program, found that the core-damage frequency during mid-loop operation is comparable to that of power operation. This report documents the results of the analysis of phase 2 internal events. It contains also an appendix, Appendix I, that documents an updated version of the key chapters/sections of the Phase 1 draft report. The work on internal fire, internal flood, seismic analysis, and level 2/3 analysis are reported in separate volumes.

Surry Unit 1 was chosen for this study in part because the Surry plant was previously analyzed in the Reactor Safety Study and NUREG-1150, and in part because Virginia Power offered to cooperate. The core-damage frequency during low power and shutdown calculated in this study will be compared with that calculated in NUREG-1150 for accidents during full power. The Surry plant has two Pressurized Water Reactors (PWRs), each rated at 788 megawatts (electrical) capacity, and is located near Surry in Virginia. Grand Gulf, a boiling water reactor, was selected as the plant for a parallel analysis performed by Sandia National Laboratories (SNL).

Throughout the study, the LP&S team had many trips to the Surry plant to gather plant information, walk down the plant, and participate in meetings with the Virginia Power staff. The draft reports were also provided to Virginia Power for their comments. The comments received were resolved and incorporated into the final report.

A total of 5 meetings of the Senior Consulting Group (SCG) were held, during which the BNL and SNL staff presented the details of the analyses as well as the approaches used in various tasks. The SCG members provided their suggestions and comments. The comments from the SCG were addressed by the PRA teams at the two labs and the proposed resolutions were presented at the following SCG meeting.

In addition to the comments from the SCG and Virginia Power, an internal BNL Quality Assurance team reviewed the draft reports and provided comments. The comments received were resolved and incorporated into the final report.

S.2 Objectives

The objectives of phase 2 of this program are:

- 1) Estimate the frequencies of severe accidents that might be initiated during mid-loop operation,

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- 2) Compare the estimated core-damage frequencies, important accident sequences, and other qualitative and quantitative results of this study with those of accidents initiated during full power operation (as assessed in NUREG-1150), and
- 3) Demonstrate methodologies for accident sequence analysis for plants in modes of operation other than full power.

S.3 Methodology

Due to the changing plant configuration during low power and shutdown operation, it was necessary to define different outage types, and different plant operational states (POSs) within each outage type. Within each POS, the plant configuration continues to change with time, and the decay heat continues to decrease. These factors significantly affect scenario frequencies. Therefore, a "time window" approach was developed in which different time windows were defined representing different levels of decay heat and success criteria. Within each time window, the approach used in performing the PRA for a particular POS in a particular outage type is similar to that used in the NUREG-1150 study. The approach includes typical PRA tasks, such as identification of initiating events, development of fault trees and event trees, and their quantification. The following is a summary of the approach used in the key tasks of this study. We believe that the approach developed in this study can be readily adopted for studies of POSs other than mid-loop and for other PWRs.

Outage Types, Plant Operational States and Time Windows

Outages were grouped into four different types: refueling, drained maintenance, non-drained maintenance with use of the residual heat removal (RHR) system, and non-drained maintenance without the RHR system. Due to the continuously changing plant configuration in any outage, plant operational states (POSs) were defined and characterized within each outage type. Each POS represents a unique set of operating conditions (e.g. temperature, pressure, and configuration). For example, in a refueling outage, up to 15 POSs were used, representing the evolution of the plant throughout a refueling from low power down to cold shutdown and refueling, and back-up to low power. An extensive effort was made to collect Surry-specific data to characterize each POS, that included reviewing operating and abnormal procedures for shutdown operations, the shift supervisor's log books, and the monthly operating reports, and performing supporting thermal hydraulic calculations. Three mid-loop POSs, in which the reactor coolant system (RCS) level is lowered to the mid-plane of the hot leg, were selected for detailed analysis. Two of them occur in a refueling outage, POSs R6 and R10, and one in a drained maintenance outage, POS D6. They are characterized by different levels of decay heat, and different plant configurations, such as the number of RCS loops that are isolated, and whether or not the RCS has a large vent. R6 represents a mid-loop operation that takes place early in a refueling outage allowing the RCS loops to drain quickly to permit eddy current testing of the steam generator tubes. R10 takes place after the refueling operation is completed to allow additional maintenance of equipment in the RCS loops. D6 represents mid-loop operation in which maintenance activities require the plant to go to mid-loop, and is characterized by the highest level of decay heat among the three mid-loop POSs.

To more accurately define the decay heat level when an accident is initiated, a time-window approach was developed. Four time windows after shutdown were defined, each with its unique set of success criteria reflecting the decay-heat level. For POSs R6 and D6, all four windows were needed. For POS R10, only time windows 3 and 4 were applicable. One hundred and sixty event trees were developed for 16 initiating events.

During the latest Surry Unit 1 refueling outage that started on February 28, 1992, the utility changed previous practice and avoided going to mid-loop operation. It is our understanding that the plant staff intends to continue this new practice. However, it is believed that certain maintenance requirements may prevent totally

avoiding going to mid-loop in the future. With NRC concurrence, BNL developed the PRA model based on outages (that included mid-loop operation) before the February 1992 refueling. Since the results are presented on a per-unit-time basis, the present results can be used to draw conclusions on the management of mid-loop outages.

Initiating Event Analysis

To identify initiating events, review of existing studies, licensee event reports, (LERs), published NRC documents, and current Surry operating procedures was performed. This approach should ensure that any incident that has occurred or any scenario that has been studied will be considered in the present study. However, no systematic approach was undertaken, such as a failure mode and effect analysis (FMEA) or a hazard and operability study (HAZOP), to further assure that all possible initiating events in all possible operating states were identified.

Event Tree Analysis

In phase 1 of this study, accident scenarios were developed for all low power and shutdown POSs. For those POSs that are similar to power operations, (e.g., low power operations), the relevant NUREG-1150 event trees developed for Surry were reviewed and modified (if necessary) to reflect the current plant design and operation. For other POSs, event trees were developed in group discussions, involving typically four or more BNL staff members with expertise in PWR operations, PRA, human reliability analysis (HRA), and thermal hydraulics. Frequent communications were held with the staff at Virginia Power to ensure that the PRA reflects the current plant design and operations.

In phase 2, the event trees developed for the mid-loop POSs were reviewed and modified to incorporate additional information obtained in the system analysis, and to reflect our current understanding of the expected operator responses to the accidents. A two-day meeting with Virginia Power operations personnel was held to discuss potential accident scenarios, and the expected responses of the plant and operator.

System Analysis

The fault tree models, developed as part of NUREG-1150 study, were reviewed and modified, when necessary, to develop two fault tree models for the plant applicable to shutdown and to low power operation for each system. The system configuration during shutdown was identified by reviewing the operating procedures used during shutdown, shift supervisor's log books, and the system training manual. Typically, the following changes were made to NUREG-1150 fault trees to derive the fault trees applicable to shutdown conditions.

- 1) Valve failure modes were changed. The position of valves during shutdown may be different from that during power operation. Therefore, the applicable failure modes of the valves will be different from those of power operations.
- 2) Human error events associated with backup of automatic actuated systems or components which failed were modified to manual actuation with no automatic backup.
- 3) Maintenance unavailabilities relevant to the specific POS were estimated. For mid-loop POSs, the reduced inventory check list was used to determine whether certain maintenance events are permitted; those events prohibited, e.g., diesel generator maintenance, were deleted from the model.
- 4) System success criteria were changed, if necessary.

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Definition of Core-Damage - In the NUREG-1150 study, core-damage is defined for PWRs to be the RCS level reaching the top of active fuel. Due to the high decay heat level, the difference between this time and the time of cladding failure is small. In the low power and shutdown condition, the decay heat level may be significantly lower, and this difference becomes more significant. In this study, core-damage is defined to be the collapsed RCS level reaching 2.5 feet above the bottom of the core. This is based on the result of a MELCOR calculation of RCS level in the core region when cladding temperature reaches 1340 degree F, above which phenomena such as clad oxidation and ballooning will have an impact on core behavior. Time to core-damage is used in the level-1 study as the time available for operator actions such as initiating safety injection. The more realistic estimate of the time available has the tendency of lowering the associated human error probabilities.

Supporting Thermal Hydraulic Analysis

The main purpose of the thermal hydraulic analysis was to support the development of event trees and quantification of accident sequences. Thermal hydraulic considerations are the basis of the time-window approach. Basically, the time windows were defined on the times when the success criteria of important mitigating functions change. In the phase 1 study, assumptions were made based on simple "back of the envelope" calculations. It was found that more detailed calculations were needed to confirm the simple calculations, and support the assumptions made.

In the phase 2 study, a more detailed calculation was done to determine the timing of a feed and bleed operation during mid-loop operation. The calculation also gave information on the amount of water from the refueling water storage tank (RWST) needed to sustain the feed and bleed operation, as well as the timing of core uncover for different initial conditions.

The MELCOR code also was used to assess whether or not gravity feed from the RWST could be used to provide long term cooling (i.e. 24 hours, decay heat removal). It was found that although gravity feed is sufficient only when the decay heat is low, it can provide a few hours for restoring other means of removing decay heat even when the decay heat is high.

For reflux cooling, the studies at the Idaho National Engineering Laboratory (INEL), Westinghouse, and Virginia Power were used to determine the success criteria. The analysis of feed and spill, gravity feed and reflux cooling were used to determine the boundary of the time windows. For example, the time boundary between windows 2 and 3 was chosen to be the time when recirculation is not necessary for the first 24 hours after the accident started. The boundary was estimated to be 10 days, based on the inventory available in the refueling water storage tank (RWST) and the flow needed in the feed-and-spill operation.

Quantification

A Bayesian approach was used to estimate the initiating event frequencies. The basic event data for hardware failures were derived from the NUREG-1150 data base for Surry. The IRRAS computer code was used to quantify the fault tree and event tree. An uncertainty analysis of the total core-damage frequency was performed by propagating the uncertainty of the parameters used in the model.

Human Reliability Analysis

Two types of human error events were identified and modeled in this study: pre- and post-accident errors. The pre-accident errors identified in the NUREG/CR-4550 study for Surry were adopted, together with others identified in the system analysis task and added to the system fault trees.

To evaluate human actions and recovery actions that follow an initiator we first qualitatively defined the event scenario, required actions, important factors affecting operator performance, and the consequences of the action being unsuccessful. Two types of post accident human errors were modeled, failure to diagnose and failure to carry out the needed action given successful diagnosis. They were used in the fault trees for the top events of the event trees. It was assumed that, given failure to diagnose, the operator would fail to perform the needed actions; therefore, core-damage would result. The same basic event representing failure to diagnose was used in all fault trees of a given event tree. On the other hand, failure to carry out the action given successful diagnosis would only fail the specific top event of the event tree.

The qualitative evaluation of the actions and the important parameters that affect operator's performance were used to derive the human error probabilities (HEPs) by adapting the success likelihood index methodology. This methodology assumes that the likelihood of operator error in a particular situation depends on the combined effects of a small set of performance-shaping factors (PSFs) that influence the operator's ability to accomplish the action.

To quantify the HEPs, the PSFs were rated with weights that reflect the relative influence of each PSF on the likelihood of the success of the action, and a score that reflects whether the PSF helps or hinders the operator in carrying out the actions. With the rating for PSF, the numerical model was calibrated using well-defined actions obtained from analysis for other PRAs. Calibration ensures that the error probabilities are realistic and consistent with the data, observed human behavior, and the results from comparable expert evaluations of similar activities.

Data Base Analysis

An extensive effort was devoted to collecting data to characterize the plant during shutdown.

- 1) A data base of initiating events was compiled for the initiating event analysis.
- 2) The shift supervisor's log books, outage schedules, minimum equipment list, and monthly operating report were reviewed to collect the data needed to estimate the frequency of shutdown, duration of plant operational states, and maintenance unavailabilities.
- 3) The shift supervisor's log books were reviewed to determine the time that the plant is in different configurations. For example, the reactor coolant loops were found to be isolated for a long period in a refueling.

S.4 Results and Insights

Table S-1 summarizes the results of the event tree quantification, showing the core-damage frequency as a function of the initiating events and POSs. The core damage frequency is the frequency that core-damage occurs while the reactor is at mid-loop, and includes the fraction of a year that the reactor is at mid-loop. POS 6 of a drained maintenance outage (D6), and POS 6 of a refueling outage are the most dominant POSs.

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Their characteristics are high decay-heat level and a relatively short time available for operator action. In contrast, POS 10 of a refueling outage has a very low decay heat, and its core-damage frequency is approximately one order of magnitude lower.

Table S-2 compares the results of this study with those of NUREG-1150 and the individual plant examination (IPE) performed by Virginia Power. The results are displayed in two ways. The core-damage frequency, shown in the first row, is the frequency that core-damage occurs when the plant is at mid-loop, and the conditional core-damage frequency, shown in the third row, is the core-damage frequency divided by the fraction of time the plant is at mid-loop. The former accounts for the fact that the plant is at mid-loop only a small fraction of the time, while the latter is the conditional frequency at which core-damage occurs given the plant is at mid-loop. The contribution to total core-damage frequency due to mid-loop operations is approximately one eighth of that of power operation as estimated in NUREG-1150, since the plant is in mid-loop operation approximately 7% of a year. The numbers in the parentheses of the third row of the table are the conditional probability of core-damage due to over-draining events, given that the plant enters mid-loop operation in the POS.

The core-damage frequencies shown in the first row of Table S-2 are additive. That is, the sum of the core-damage frequencies of the 3 POSs is the total core-damage frequency of mid-loop operation. This total, 5 E-06 per year, can be added to the core-damage frequency of power operation, e.g., 4 E-05 per year for NUREG-1150. Therefore, the sum of 4.5 E-05 per year is the frequency per year that core-damage occurs while the plant is at full power or mid-loop operation.

The conditional core-damage frequency shown in the third row of Table S-2 is a measure of how susceptible a plant configuration is with respect to core-damage. For example, the fact that the conditional core-damage frequency of mid-loop operation, 8 E-05 per year, is higher than that of full power operation, 4 E-05 per year, shows that mid-loop operation is more susceptible to core-damage than full power operation, although the plant is at mid-loop only a small fraction of the time.

Table S-3 lists the key uncertainty characteristics of the core-damage frequencies for mid-loop operation and power operation, and shows that the core-damage frequency for mid-loop operation has a broader distribution than that of power operation. Note also that the mean total CDF in Table S-3 is slightly different for the total CDF in Tables S-1 and S-2. This is because the numbers in Tables S-1 and S-2 are point estimates whereas the information in Table S-3 reflects an uncertainty analysis.

The following insights were gained from this study. They are based on the Surry specific design and operation. Their applicability and significance with respect to other PWRs have to be assessed separately.

Operator Response- The dominant cause of core-damage was the operator's failure to mitigate the accident. (Note that there is very large uncertainty in the human error probabilities used in this study.) In general, it would be beneficial to have good training, procedures, and instrumentation to ensure that the utility's staff can respond to shutdown accidents.

Procedures for Shutdown Accidents- Very few procedures are available for accidents during shutdown; the procedure for loss of decay heat removal, AP 27.00, is the only one that was written specifically for the shutdown scenarios analyzed in this study. The procedure is conservative with regard to the equipment needed to establish reflux cooling and feed-and-bleed. In this study, the use of fewer than the number of steam generators specified in the procedure for reflux cooling was treated as a recovery action, and a more realistic success criteria was used for feed-and-bleed when the decay heat is high. In most cases, the information in the procedures for power operation is helpful, for shutdown accidents. For example, the procedure for station blackout, ECA-0.0, gives instructions for dumping steam to the condenser. Credit for this procedure was taken

into account in this study. However, some procedures written for power operation would mislead the operator if followed during shutdown. For example, the procedure for loss of offsite power, AP 10.00, states that "When the EDG is the only source of power to an emergency bus, the Component Cooling Pump should NOT be in service". During shutdown, CCW flow to the RHR heat exchanger is necessary for decay heat removal. Therefore, following this procedure under these circumstances would not be the most appropriate operator response.

Instrumentation- It was recognized that the level instrumentation used during mid-loop operation, i.e., standpipe level instrumentation and ultra-sonic level instrumentation, has limited applicability during a shutdown accident. The standpipe system indicates the correct level only when there is no build-up of pressure in the system. The ultra-sonic level instrumentation only provides level indication when the level is within the reactor coolant loops, and therefore, may not be useful during a feed and bleed operation.

Supporting Thermal Hydraulic Analysis- The thermal hydraulic behavior of the reactor coolant system is rather complex, mainly because the pressurizer is usually the relief path for coolant or steam, and the vessel head does not have a large vent. When performing thermal hydraulic analysis in support of the PRA effort, consideration must be given to longer term system behavior, at least 24 hours into the accident. In this study, such calculations were done for feed-and-bleed operation using a charging pump, and with gravity feed from the RWST. It is believed that additional calculations would be helpful to better understanding the effectiveness of reflux cooling, and feed and bleed using a low pressure injection pump. In this study, the conservative results of the Virginia Power Technical Report # 865 (Revision 1, dated July 3, 1992) were used to determine the number of steam generators needed as a function of time after shutdown, because such criteria are explicitly written in the procedure for loss of RHR. In the event trees and fault trees, it was assumed that if there were too few, then no credit was given to reflux cooling. In this case, reflux cooling still would help. In fact, a review of the studies performed by Westinghouse and Idaho National Engineering Laboratory found that one steam generator is sufficient for any level of decay heat. To take some credit for reflux cooling in this case, a recovery action with failure probability 0.1 was applied to those core-damage cutsets that involve failure of reflux cooling due to insufficient steam generators. It was assumed that hot-leg injection using a low head injection pump is adequate to prevent core-damage. Due to the low shut-off head of the pumps, approximately 150 psig, the concern is that if boiling takes place in the system, the low head pump may be unable to inject.

Maintenance Unavailability- A review of shift supervisor's log books and minimum equipment lists for three refueling outages showed that the maintenance unavailabilities of equipment that can be used to mitigate an accident were very high. For example, two out of three charging pumps were found to be tagged out practically throughout the whole mid-loop period. The two low-head injection pumps also were unavailable a large fraction of the time. Generic letter 88-17, requires the plant to have one high-head pump and one low-head pump available. In our quantifications, we assumed that charging pump A, charging pump cooling water pump A, and low head injection pump B are available. Based on the check list used for reduced inventory conditions, it was also assumed that the maintenance of diesel generators, 4 kv emergency buses, and stub buses is not allowed.

We found that maintenance unavailability is the dominant cause of equipment unavailability. In combination with human errors, maintenance of the charging pump cooling water pump, the charging pump, and the low head injection pump appear in the dominant cutsets for some of the core-damage sequences.

Isolation of Reactor Coolant Loops- It was found that isolation of the RCS loops is an important contributor to core-damage frequency. Review of the plant shutdown experience indicated that the reactor coolant loops are isolated for extended periods in a refueling outage, making the steam generators unavailable for decay-heat removal upon loss of RHR. In a cold shutdown condition, the steam generators are usually maintained in the

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wet lay-up condition with the secondary side filled with water. During mid-loop operation, the availability of the SGs makes reflux cooling a possible method of mitigating a loss of RHR; this might be the only mitigation function available in a station blackout.

Single Failures of the RHR System- The RHR system at Surry has no active safety function (i.e., it does not perform the safety injection function in scenarios initiated at full power). Consequently, many single component failures can cause loss of RHR. In the RHR system, a single suction line from the loop A hot leg and a single flow control valve HCV-1758 are used. During its operation, a single CCW header provides cooling to both RHR pump seal coolers and the operating RHR heat exchanger, and two CCW return lines from the RHR system are used. Hence, a failure of the trip valve 109A or B in one of the two CCW return lines can cause loss of the system. These trip valves also fail closed on loss of instrument air, or vital bus. It was found that closure of the TV-109 valves is a significant contributor to loss of RHR. It was assumed that the opening of the RHR flow control valve HCV-1758 as a result of loss of vital bus III will cause RHR pump run out; this also was a significant contributor to loss of RHR.

Valve Arrangement of Auxiliary Feedwater System and Main Steam System During Shutdown- The auxiliary feedwater system has six MOVs (151A,B, C, D, E, and F) in the flow path to the steam generators, that are normally closed during shutdown. They are difficult to locate during a station blackout. Similarly, the main steam non-return valves are normally closed during shutdown, and have to be opened to use steam dump to the condenser. They depend on offsite power and would be very difficult to open without it.

Potential for Plugging the Containment Sump When Recirculation Is Needed- Because of activities inside the containment, transient material and equipment are brought into it during shutdown. For example, large plastic Herculite sheets are often used to separate work areas from the rest of the containment. If an accident requiring recirculation from the containment sump occurs, as is the case in time windows 1 and 2, the material would increase the potential for plugging the containment sump.

S.5 Conclusion

This study shows that the core-damage frequency during mid-loop operation at the Surry plant is comparable to that of power operation. The probability distribution of the core damage frequency during mid-loop operation is wider than that of power operation. This is due to the large uncertainty in the human error probabilities used in this study. It was identified that only a few procedures are available for mitigating accidents that may occur during shutdown. Procedures written specifically for shutdown accidents would be useful. Realistic thermal hydraulic analysis should be used as the basis of the procedures.

It was assumed that reduced inventory check list was followed, and found that the maintenance unavailability of equipment not on the list were dominant contributors to system unavailability. However, the check list is believed to be sufficient for ensuring the availability of essential equipment.

S.6 Key Assumptions and Sources of Uncertainty

The following is a discussion of the various modeling issues and how they were treated in this study.

Changing plant practices and information- BNL observed that the plant is aware of the potential safety concerns of reduced inventory operations and is constantly improving its practice regarding such operation. This is reflected in the improvement in the operating procedures and abnormal procedures used during shutdown, as well as changes in the plant practice. The most significant change in plant practice started in

the refueling outage of unit one in 1992, during which mid-loop operation was totally avoided; this appears to be the new policy. Another way of reducing the risk is to carry out reduced inventory operation while the fuel in the core is removed during refueling operation.

To limit the changes in the model developed for this study to account for the changes in plant practice and information, it was decided to use the procedures and other plant information available as of April 30, 1993. Regarding the plant's policy of avoiding mid-loop operation, it was decided that this study would use the data collected from past outages before the unit 1 refueling outage of 1992. Consequently, the estimated core-damage frequency could be an overestimation of that of the current plant. However, it is emphasized that the core-damage frequency calculated in the current study was reduced significantly by changes made after the start of the study and before April 1, 1993.

Changing Plant Configuration- Due to the activities taking place during shutdown, the plant configuration changes with time, which, in turn, affects the likelihood of accident initiating events and the plant's ability to mitigate the accidents. In this study, the constantly changing plant configuration is approximated by a few discrete configurations, by introducing different outage types, POSs, and time windows. It also is reflected by the different basic events and different event trees for different outage types, POSs, and time windows. The following is a description of the basic events and how they are varied.

Initiating event frequency- The initiating events are assumed to occur with constant rates independent of the outage type or POS. The conditional probability that an IE occurs in a POS is calculated as the product of the rate and the duration of the POS. The initiating event frequency is the frequency of the POS multiplied by the conditional probability. The frequency that it occurs in a given time window of a given POS of a given outage type is the initiating event frequency times the conditional probability of the time window of the given POS.

Loop isolation probability- Isolating the loops makes it impossible to establish reflux cooling. Its probability was estimated by judgment using the information from the log books for outages, and an outage plan for a refueling outage. It was estimated as a function of the outage types, and time windows.

Removal of pressurizer safety valves- The fraction of time that the safety valves are removed in a given time window of a given POS in a given outage type was estimated by judgment, using information from the log books for outages, and an outage plan for a refueling outage. With the safety valves removed, it is possible to use gravity feed from the RWST, but not reflux cooling because of inventory loss through the opening.

Maintenance unavailabilities- Maintenance unavailability was estimated as a function of the POSs of a refueling outage by reviewing the log books for 3 refueling outages. The data was collected for the period when the plant was at mid-loop. Due to lack of sufficient information, it is assumed to be independent of the time windows. It was also assumed that the data for a refueling outage is applicable to a drained maintenance outage.

Success Criteria- The success criteria for shutdown conditions were determined by reviewing various studies, and performing supporting thermal hydraulic analysis based on the Surry-specific design. The changing level of decay heat was accounted for by defining four time windows after shutdown, each with its own set of success criteria. In general, whenever the success criteria for one system or mitigating function changes, a new time window needs to be defined, and potentially, more than four time windows would be needed. The use of four, therefore, is a trade-off between the accuracy of the model and the level of effort needed to arrive at a solution; it is believed that four time windows gives an adequate representation.

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During development of the time window approach, it was recognized that the procedure for loss of RHR, AP-27.00, is conservative with respect to the success criteria for reflux cooling and feed-and-spill, and does not include all possible methods of establishing recirculation. These are the areas in which the plant model used in this study deviated from the abnormal procedure. The following describes how these issues were treated.

Reflux cooling- In AP 27.00, the number of steam generators (SGs) needed for reflux cooling is given as a function of the decay heat, e.g, 3 SGs are needed for the first 75 hours after shutdown. This value is based on the thermal hydraulic consideration of Virginia Power NE technical report 865. From a review of existing studies performed by INEL and Westinghouse on reflux cooling, and BNL calculations, we determined that one steam generator should be sufficient. Therefore our current understanding is that one SG would be sufficient, while the abnormal procedure states that three would be needed. The issue is, how much credit should be given to reflux cooling when less than three SGs are available. In this study, the success criterion based on the procedure was used in the logic model, and whenever reflux cooling was failed due to insufficient SGs, a recovery action was entered with a failure probability of 0.1.

Feed-and-spill- In AP27.00 and its supporting study (Virginia Power NE technical report 865), the number of pumps and PORVs needed for this operation was determined based on the flow from the RWST needed to maintain sub-cooling, the capacity and shut-off head of the pumps, and the relieving capability of the PORVs. For example, during the first 129 hours after shutdown, 2 charging pumps and 2 PORVs would be needed. This success criterion was derived from the requirement to maintain sub-cooling, and is more stringent than the criterion needed for feed-and-bleed during an accident that occurs during full power operation. An alternative to feed-and-spill, (i.e. feed-and-steam), which is also discussed in technical report 865, is much less demanding in terms of the needed flow. However, feed and steam is not the recommended method because of the difficulty in maintaining the RCS level, and the potential for over pressurization. In this study, a success criterion of 1 charging pump and 1 PORV was used, based on the understanding that this is sufficient to prevent core-damage.

Recirculation- AP 27.00 instructs the operators to establish high pressure recirculation by using the low-pressure injection pump to take suction from the containment sump, and discharge to the suction of the high pressure injection system; this requires that a low head injection pump and a charging pump are available. In the fault tree model for recirculation, two alternative methods also are modeled, low-pressure feed-and-steam (by taking suction from the containment sump), and low-pressure feed and spill (by taking suction from the sump and using spray recirculation). In these modes, low-head injection is needed. The feed-and-steam mode requires that the safety valves be removed to provide an adequate vent path, and does not require cooling of the sump water. The feed-and-spill operation requires operation of the spray recirculation systems to cool the water in the sump, so that sub-cooling in the reactor vessel can be established.

Operator Response- The operator's actions modeled in this study were identified in developing the event trees. The identification process involved reviewing abnormal and emergency procedures, and discussing the accident scenarios with plant personnel. In most cases, the operator's responses to various accidents are identified in the procedures. For example, abnormal procedures for loss of RHR, loss of instrument air, and loss of offsite power give guidance on what to do in case of respective losses during shutdown. The latter two procedures are not written specifically for shutdown conditions. In case of a station blackout, the procedure written for power operation in mind, (1-ECA-0.0), does not address shutdown conditions. Therefore, only the relevant steps in the procedure are applicable. Similarly, for other initiating events, such as loss of component cooling, spurious safety injection, and loss of a vital bus, there is no specific procedure for shutdown condition, and the ability of the operators to use the relevant steps in the procedures for power operations becomes very important. As discussed under success criteria, some of the operator's actions modeled in this study are not explicitly spelled-out in the existing plant procedures, and some recovery actions modeled are extension of the existing procedures.

S. Executive Summary (continued)

The operator actions needed to mitigate an accident are included in the high level fault trees. A high level fault tree models one method of mitigating the accident, e.g., feed-and-spill operation which typically contains two human error events, and one transfer to the fault tree for hardware failures. One human error event represents the failure of the operator to diagnose, so that the correct actions cannot be decided upon; the other represents failure to carry out the action after correct diagnosis. Assuming that the failure to diagnose would lead to core damage, many of the dominant core-damage cutsets are caused by such events. Human error probabilities were quantified using the method of failure likelihood index that involves assessing weights and scores on various performance-shaping factors, and calibration using the HEPs from existing studies.

S. Executive Summary (continued)

Table S.1 Summary of Results-Core-Damage Frequency by Initiating Event and Plant Operational States

	Initiating Event	IE Frequency	Core-Damage Frequency (per year)			
1.	Loss of RHR		R6	R10	D6	Total
	RHR2A-Over Draining	1.6E-02/Demand	1.8E-7	5.3E-8	2.6E-7	4.9E-7
	RHR2B-Failure to Maintain Level	1.2E-05/hr	2.1E-08	2.0E-8	2.9E-8	7.0E-8
	RHR3-Non-Recoverable Loss of RHR	4.1E-06/hr	1.5E-7	8.4E-9	3.0E-7	4.6E-7
	RHR4-Non-Recoverable Loss of Operating Train of RHR	5.3E-06/hr	7.6E-9	1.2E-9	2.3E-8	3.2E-8
	RHR5-Recoverable Loss of RHR	2.1E-05/hr	4.0E-8	4.1E-09	9.3E-8	1.4E-7
2.	LOOP-Loss of Offsite Power	7.0E-06/hr				
	L1-Both 1H and 1J Energized	6.2E-06/hr	3.3E-7	7.0E-8	7.6E-7	1.2E-6
	L2-1H and 2H energized, not 1J	7.4E-07/hr	1.0E-7	1.3E-8	1.7E-7	2.9E-7
	L3-1H energized, not 1J, unit 2 blackout	3.8E-08/hr	4.2E-8	1.3E-8	9.9E-8	1.5E-7
	B1-Unit 1 Black Out	2.0E-08/hr	4.8E-8	1.1E-8	1.7E-7	2.3E-7
	B2-2 Unit Blackout	3.2E-09/hr	3.8E-8	4.2E-8	1.1E-7	1.9E-7
3.	4KV-Loss of 4kv Bus	2.1E-05/hr	1.4E-7	1.9E-8	2.4E-7	4.0E-7
4.	VITAL-Loss of Vital Bus	5.6E-06/hr	2.8E-8	5.1E-9	7.3E-8	1.1E-7
5.	AIR-Loss of Outside Instrument Air	2.1E-6/hr	7.9E-10	-	3.2E-9	4.0E-9
6.	CCW-Loss of CCW	3.8E-06/hr	6.3E-8	1.1E-10	2.1E-7	2.7E-7
7.	SWGR-Loss of Emergency Switchgear Room Cooling	1.8E-08/hr	3.6E-8	1.2E-8	7.4E-8	1.2E-7
8.	ESFAS-Inadvertent Safety Feature Actuation	1.1E-04/hr	2.7E-7	2.7E-8	6.8E-7	9.8E-7
9.	Dilute-Boron Dilution (CDF)	2.0E-07/hr				6.8E-08
TOTAL			1.5E-6	3.0E-7	3.3E-6	5.1E-6*

* Not including boron dilution

Table S.2 Comparison of Total Core-Damage Frequency with NUREG-1150 and IPE

Study	Results				
PWR Low Power and Shutdown Study (Mid-Loop POSs, Internal Events Only)		R6	R10	D6	TOTAL
	CDF* per year	1.5E-06 (1.8E-07)**	3.1E-07 (5.5E-08)**	3.3E-06 (2.7E-07)**	5.1E-06 (5.0E-07)**
	Fraction of a year the plant is in mid-loop	1.6E-02	1.5E-02	3.5E-02	6.6E-02
	Conditional CDF*** per year (CDP)	8.1E-05 (3.0E-07)	1.7E-05 (1.8E-07)	8.6E-05 (2.2E-07)	7.6E-05 (2.4E-07)
NUREG-1150 (Internal Events Only)	4.0E-05				
IPE(Internal Events Only)	7.4E-05				

* CDF reflects the fraction of time the plant is at mid-loop

** Contribution of over-draining events

*** Frequency of core-damage given that the plant is at mid-loop (core damage frequency due to non-over-draining events divided by the fraction of time the plant is at mid-loop)

CDP probability of core-damage due to over-draining to the POS

Table S.3 Result of the Uncertainty Analysis for Total Core-Damage Frequency (per year)

	Mid-Loop Operation (per year)	Full Power Operation* (per year)
Mean	4.9E-06	4.0E-05
5th Percentile	4.8E-07	6.8E-06
50th Percentile	2.1E-06	2.3E-05
95th Percentile	1.5E-05	1.3E-04
Error Factor	5.7	4.4

* NUREG-1150

FOREWORD

(NUREG/CR-6143 and 6144)

Low Power and Shutdown Probabilistic Risk Assessment Program

Traditionally, probabilistic risk assessments (PRA) of severe accidents in nuclear power plants have considered initiating events potentially occurring only during full power operation. Some previous screening analysis that were performed for other modes of operation suggested that risks during those modes were small relative to full power operation. However, more recent studies and operational experience have implied that accidents during low power and shutdown could be significant contributors to risk.

During 1989, the Nuclear Regulatory Commission (NRC) initiated an extensive program to carefully examine the potential risks during low power and shutdown operations. The program includes two parallel projects performed by Brookhaven National Laboratory (BNL) and Sandia National Laboratories (SNL), with the seismic analysis performed by Future Resources Associates. Two plants, Surry (pressurized water reactor) and Grand Gulf (boiling water reactor), were selected as the plants to be studied.

The objectives of the program are to assess the risks of severe accidents due to internal events, internal fires, internal floods, and seismic events initiated during plant operational states other than full power operation and to compare the estimated core damage frequencies, important accident sequences and other qualitative and quantitative results with those accidents initiated during full power operation as assessed in NUREG-1150. The scope of the program includes that of a level-3 PRA.

The results of the program are documented in two reports, NUREG/CR-6143 and 6144. The reports are organized as follows:

For Grand Gulf:

NUREG/CR-6143 - Evaluation of Potential Severe Accidents during Low Power and Shutdown Operations at Grand Gulf, Unit 1

- Volume 1: Summary of Results
- Volume 2: Analysis of Core Damage Frequency from Internal Events for Operational State 5 During a Refueling Outage
  - Part 1: Main Report
    - Part 1A: Sections 1 - 9
    - Part 1B: Section 10
    - Part 1C: Sections 11 - 14
  - Part 2: Internal Events Appendices A to H
  - Part 3: Internal Events Appendices I and J
  - Part 4: Internal Events Appendices K to M
- Volume 3: Analysis of Core Damage Frequency from Internal Fire Events for Plant Operational State 5 During a Refueling Outage
- Volume 4: Analysis of Core Damage Frequency from Internal Flooding Events for Plant Operational State 5 During a Refueling Outage
- Volume 5: Analysis of Core Damage Frequency from Seismic Events for Plant Operational State 5 During a Refueling Outage

Foreword (continued)

- Volume 6:**   **Evaluation of Severe Accident Risks for Plant Operational State 5
During a Refueling Outage**
Part 1: Main Report
Part 2: Supporting MELCOR Calculations

For Surry:

**NUREG/CR-6144-   Evaluation of Potential Severe Accidents during Low Power and Shutdown
Operations at Surry Unit-1**

- Volume 1:**   **Summary of Results**
- Volume 2:**   **Analysis of Core Damage Frequency from Internal Events during
Mid-loop Operations**
Part 1: Main Report
Part 1A: Chapters 1 - 6
Part 1B: Chapters 7 - 12
Part 2: Internal Events Appendices A to D
Part 3: Internal Events Appendix E
Part 3A: Sections E.1 - E.8
Part 3B: Sections E.9 - E.16
Part 4: Internal Events Appendices F to H
Part 5: Internal Events Appendix I
- Volume 3:**   **Analysis of Core Damage Frequency from Internal Fires during
Mid-loop Operations**
Part 1: Main Report
Part 2: Appendices
- Volume 4:**   **Analysis of Core Damage Frequency from Internal Floods during
Mid-loop Operations**
- Volume 5:**   **Analysis of Core Damage Frequency from Seismic Events during
Mid-loop Operations**
- Volume 6:**   **Evaluation of Severe Accident Risks during Mid-loop Operations**
Part 1: Main Report
Part 2: Appendices

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ACRONYMS

Acronym	Meaning
ACC	Accumulator
AEOD	Office for Analysis and Evaluation Operational Data, US NRC
AFW	Auxiliary Feedwater
AHU	Air Handling Unit
ANS	American Nuclear society
AOT	Allowed Outage Time
AOV	Air Operated Valve
AP	Abnormal Procedure
ASEP	Accident Sequence Evaluation Program
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BAT	Boric Acid Tank
BHEP	Basic Human Error Probability
BAST	Boric Acid Storage Tank
BIT	Boron Injection Tank
BNL	Brookhaven National Laboratory
BRT	Boron Recovery Tank
CAS	Compressed Air System
CCW	Component Cooling Water
CD	Core Damage
CDF	Core Damage Frequency
CEDM	Control Element Drive Mechanism
CESSAR	Combustion Engineering Standard Safety Analysis Report
CFR	Code of Federal Regulation
CIS	Containment Isolation Signal
CLCS	Consequence Limiting Control System
CPC	Charging Pump Cooling

Acronyms

CPS	Containment Pressure Suppression
CRA	Control Rod Assembly
CS	Containment Spray
CSD	Cold Shutdown
CSR	Cable Spreading Room
CSS	Containment Spray System
CST	Condensate Storage Tank
CVCS	Chemical and Volume Control System
CW	Circulating Water
DHR	Decay Heat Removal
ECA	Emergency Contingency Action
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EF	Error Factor
ELO	End of Licensed Life
EP	Emergency Procedure
EPS	Emergency Power System
ESF	Emergency Safety Feature
ESFAS	Emergency Safety Feature Actuation System
ESGR	Emergency Switchgear Room
ESR	Emergency Switchgear Room
FAI	Fail as Is
FCV	Flow Control Valve
FMEA	Failure Mode and Effect Analysis
FO	Fail Open
FW	Feed Water
GOP	General Operating Procedure
HAZOP	Hazard and Operability Study
HEP	Human Error Probability
HHSI	High Head Safety Injection
HPI	High Pressure Injection
HPR	High Pressure Recirculation

Acronyms

HRA	Human Reliability Analysis
HSD	Hot Shutdown
HVAC	Heating Ventilation and Air Conditioning
HX	Heat Exchanger
HZP	Hot Zero Power
IAEA	International Atomic Energy Agency
LAW	In Accordance With
IE	Initiating Event
INEL	Idaho National Engineering Laboratory
IPE	Individual Plant Evaluation
IRRAS	Integrated Reliability and Risk Analysis System
ISD	Intermediate Shutdown
ISLOCA	Interfacing Systems LOCA
ISR	Inside Spray Recirculation
KV	Kilo-volt
LCO	Limiting condition of Operation
LER	Licensee Event Report
LHS	Latin Hypercube Sampling
LHSI	Low Head Safety Injection
LOCA	Loss of Coolant Accident
LOSP	Loss of Offsite Power
LPR	Low Pressure Recirculation
LP&S	Low Power and Shutdown
LTOP	Low Temperature Overpressurization
MCC	Motor Control Center
MCR	Main Control Room
MELCOR	A Computer Code for Nuclear Reactor Severe Accident Source Term and Risk Assessment Analysis
MFW	Main Feedwater
MOP	Maintenance Operating Procedure
MOV	Motor Operated Valve

Acryonyms

MSTV	Main Steam Trip Valve
MW	Mega-watt
MWt	Mega-watt Thermal
NC	Normally Closed
NO	Normally Open
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation, US NRC
NRV	Non-Return Valve
NSAC	Nuclear Safety Analysis Center
NSS	Normal Station Service
NSS	Nuclear Steam System
OD	Operator Depressurization
OOS	Out of Service
OP	Operating Procedure
OSR	Outside Spray Recirculation
PCS	Power Conversion System
PCV	Pressure Control Valve
PG	Primary Grade
PORV	Pilot Operated Relief Valve
POS	Plant Operational State
PPM	Parts Per Million
PPRS	Primary Pressure Relief System
PRA	Probabilistic Risk Assessment
PRT	Pressurizer Relief Tank
PRZR	Pressurizer
PSA	Probabilistic Safety Analysis
PSF	Performance Shaping Factor
PSIA	Pound Per Square Inch Absolute
PSID	Pound Per Square Inch Defferential
PSIG	Pound Per Square Inch Gauge

Acronyms

PTL	Pull-to-lock
PTS	Pressurized Thermal Shock
R&D	Refueling and Drained Maintenance
RC	Reactor Coolant
RCCA	Reactor Control Cluster Assembly
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REA	Rod Ejection Accident
RES	Office of Nuclear Regulatory Research, US NRC
RF	Recovery Factor
RF	Range Factor
RHR	Residual Heat Removal
RMP	Remote Monitoring Panels
RMT	Recirculation Mode Transfer
RMTS	Recirculation Mode Transfer System
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RSS	Reserve Station Service
RTND	Reference Temperature for Transition to Nil-Ductility
RTS	Return to Service
RVLIS	Reactor Vessel Level Indication System
RWST	Refueling Water Storage Tank
RX	Reactor
RY	Reactor year
SBO	Station Blackout
SCSS	Sequence Coding Search System
SFP	Spent Fuel Pool
SG	Steam Generator
SGRCT	Steam Generator Reactivity
SGRTS	Steam Generator Recirculation and Transfer

Acryonyms

SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIAS	Safety Injection Actuation System
SIS	Safety Injection System
SLB	Steam Line Break
SNL	Sandia National Laboratories
SRV	Safety Relief Valve
SV	Safety Valve
SWS	Service Water System
TAF	Top of Active Fuel
TOP	Temporary Operating Procedure
TWC	Through the Wall Crack
UFSAR	Updated Final Safety Analysis Report
VCT	Volume Control Tank
VEPCO	Virginia Electric Power Company
WR	Wide Range

1 INTRODUCTION AND APPROACH

1.1 Background

This volume presents the results of a level one probabilistic risk assessment (PRA) of the Surry Nuclear Power Plant for accidents initiated during mid-loop operations. It also contains accident initiating event analysis, and system analysis for other low power and shutdown conditions. The work was performed by Brookhaven National Laboratory (BNL) for the Nuclear Regulatory Commission (NRC) Office of Nuclear Regulatory Research (RES) in support of the NRC response to the Chernobyl accident; and the program was later modified by the NRC staff's follow-up actions to the March 20, 1990 Vogtle incident.

A phased approach was taken in this project. In phase 1, a broadly scoped screening analysis, which included internal fire and flood, was completed^[1] in November, 1991. This analysis produced a preliminary level one PRA for accidents initiated during low power and shutdown (LP&S) and also gave insights on potential accident scenarios and potentially vulnerable configurations during low power and shutdown conditions. Phase 2 focused on a detailed analysis of mid-loop operation which was selected because many incidents have occurred during mid-loop operations throughout the world. Further, recent studies, including phase 1 of this program, found that the core damage frequency during mid-loop operation is comparable to that of power operation. This report documents the results of the analysis of phase 2 internal events. It contains also an appendix, Appendix I, that documents an updated version of the key chapters/sections of the Phase 1 draft report. The work on internal fire, internal flood, and seismic analysis are reported in separate volumes.

Surry Unit 1 was chosen for this study in part because the Surry plant was previously analyzed in the Reactor Safety Study^[2] and NUREG-1150,^[3] and in part because Virginia Power offered to cooperate. The core-damage frequency during low power and shutdown calculated in this study will be compared with that calculated in NUREG-1150 for accidents during full power. The Surry plant has two Pressurized Water Reactors (PWRs), each rated at 788 megawatts (electrical) capacity, and is located near Surry in Virginia. Grand Gulf, a boiling water reactor, was selected as the plant for a parallel analysis performed by Sandia National Laboratories (SNL).

Throughout the study, the LP&S team had many trips to the Surry plant to gather plant information, walk down the plant, and participate in meetings with the Virginia Power staff. The draft reports were also provided to Virginia Power for their comments. The comments received were resolved and incorporated into the final report.

A total of 5 meetings of the Senior Consulting Group (SCG) were held, during which the BNL and SNL staff presented the details of the analyses as well as the approaches used in various tasks. The SCG members provided their suggestions and comments. The comments from the SCG were addressed by the PRA teams at the two labs and the proposed resolutions were presented at the following SCG meeting.

In addition to the comments from the SCG and Virginia Power, an internal BNL Quality Assurance team reviewed the draft reports and provided comments. The comments received were resolved and incorporated into the final report.

1.2 Objectives

The objectives of phase 2 of this program are:

1 Introduction and Approach

- 1) Estimate the frequencies of severe accidents that might be initiated during mid-loop operation,
- 2) Compare the estimated core damage frequencies, important accident sequences, and other qualitative and quantitative results of this study with those of accidents initiated during full power operation (as assessed in NUREG-1150), and
- 3) Demonstrate methodologies for accident sequence analysis for plants in modes of operation other than full power.

1.3 Methodology

Due to the changing plant configuration during low power and shutdown operation, it was necessary to define different outage types, and different plant operational states (POSs) within each outage type. Within each POS, the plant configuration continues to change with time, and the decay heat continues to decrease. These factors significantly affect scenario frequencies. Therefore, a "time window" approach was developed in which different time windows were defined representing different levels of decay heat and success criteria. Within each time window, the approach used in performing the PRA for a particular POS in a particular outage type is similar to that used in the NUREG-1150 study. The approach includes typical PRA tasks, such as identification of initiating events, development of fault trees and event trees, and their quantification. The following is a summary of the approach used in the key tasks of this study. We believe that the approach developed in this study can be readily adopted for studies of POSs other than mid-loop and for other PWRs.

Outage Types, Plant Operational States and Time Windows

Outages were grouped into four different types: refueling, drained maintenance, non-drained maintenance with use of the residual heat removal (RHR) system, and non-drained maintenance without the RHR system. Due to the continuously changing plant configuration in any outage, plant operational states (POSs) were defined and characterized within each outage type. Each POS represents a unique set of operating conditions (e.g. temperature, pressure, and configuration). For example, in a refueling outage, up to 15 POSs were used, representing the evolution of the plant throughout a refueling from low power down to cold shutdown and refueling, and back-up to low power. An extensive effort was made to collect Surry-specific data to characterize each POS, that included reviewing operating and abnormal procedures for shutdown operations, the shift supervisor's log books, and the monthly operating reports, and performing supporting thermal hydraulic calculations. Three mid-loop POSs, in which the reactor coolant system (RCS) level is lowered to the mid-plane of the hot leg, were selected for detailed analysis. Two of them occur in a refueling outage, POSs R6 and R10, and one in a drained maintenance outage, POS D6. They are characterized by different levels of decay heat, and different plant configurations, such as the number of RCS loops that are isolated, and whether or not the RCS has a large vent. R6 represents a mid-loop operation that takes place early in a refueling outage allowing the RCS loops to drain quickly to permit eddy current testing of the steam generator tubes. R10 takes place after the refueling operation is completed to allow additional maintenance of equipment in the RCS loops. D6 represents mid-loop operation in which maintenance activities require the plant to go to mid-loop, and is characterized by the highest level of decay heat among the three mid-loop POSs.

To more accurately define the decay heat level when an accident is initiated, a time-window approach was developed. Four time windows after shutdown were defined, each with its unique set of success criteria reflecting the decay-heat level. For POSs R6 and D6, all four windows were needed. For POS R10, only time windows 3 and 4 were applicable. A statistical analysis was made on the time to and duration of mid-loop to determine the probability that a given accident occurs in a particular time window, conditional on the

accident occurring. In this approach, an event tree was developed for each accident initiating event, POS and time window. One hundred and sixty event trees were developed for 16 initiating events.

During the latest Surry Unit 1 refueling outage that started on February 28, 1992, the utility changed previous practice and avoided going to mid-loop operation. We understand that the plant staff intend to continue this new practice. However, mid-loop operation cannot be totally avoided in the future. With NRC concurrence, BNL developed the PRA model based on outages (that included mid-loop operation) before the February 1992 refueling. Since the results are presented on a per-unit-time basis, the present results can be used to draw conclusions on the management of mid-loop outages.

Initiating Event Analysis

To identify initiating events, we reviewed existing studies, licensee event reports, (LERs), published NRC documents, and current Surry operating procedures. This approach should ensure that any incident that has occurred or any scenario that has been studied will be considered in the present study. However, we did not undertake a systematic approach, such as a failure mode and effect analysis (FMEA) or a hazard and operability study (HAZOP), to further assure that all possible initiating events in all possible operating states were identified.

Event Tree Analysis

In phase 1 of this study, accident scenarios were developed for all Low Power and Shutdown POSs. For those POSs that are similar to power operations, (e.g., low power operations), the relevant NUREG-1150 event trees developed for Surry^[4] were reviewed and modified (if necessary) to reflect the current plant design and operation. For other POSs, event trees were developed in group discussions, involving typically four or more BNL staff members with expertise in PWR operations, PRA, human reliability analysis (HRA), and thermal hydraulics. Communications with the staff at Virginia Power clarified questions on the plant's design and operations.

In phase 2, the event trees developed for the mid-loop POSs were reviewed and modified to incorporate additional information obtained in the system analysis, and to reflect our current understanding of the expected operator responses to the accidents. A two-day meeting with Virginia Power operations personnel was held to discuss potential accident scenarios, and the expected responses of the plant and operator.

System Analysis

The fault tree models, developed as part of NUREG-1150 study, were reviewed and modified, when necessary, to develop two fault tree models for the plant applicable to shutdown and to low power operation for each system. The system configuration during shutdown was identified by reviewing the operating procedures used during shutdown, shift supervisor's log books, and the system training manual. Typically, the following changes were made to NUREG-1150 fault trees to derive the fault trees applicable to shutdown conditions.

- 1) Valve failure modes were changed. The position of valves during shutdown may be different from that during power operation. Therefore, the applicable failure modes of the valves will be different from those of power operations.

1 Introduction and Approach

- 2) Human error events associated with backup of automatic actuated systems or components which failed were modified to manual actuation with no automatic backup.
- 3) Maintenance unavailabilities relevant to the specific POS were estimated. For mid-loop POSs, the reduced inventory check list was used to determine whether certain maintenance events are permitted; those events prohibited, e. g. diesel generator maintenance, were deleted from the model.
- 4) System success criteria were changed, if necessary.

Definition of Core-Damage - In the NUREG-1150 study,^[2] core-damage is defined to be the RCS level reaching the top of active fuel. Due to the high decay heat level, the difference between this time and the time of cladding failure is small. In the low power and shutdown condition, the decay heat level may be significantly lower, and this difference becomes more significant. In this study, core-damage is defined to be the collapsed RCS level reaching 2.5 feet above the bottom of the core. This is based on the result of a MELCOR^[5] calculation of RCS level in the core region when cladding temperature reaches 1340 degree F, above which phenomena such as clad oxidation and ballooning will have an impact on core behavior. Time to core-damage is used in the level-1 study as the time available for operator actions such as initiating safety injection. The more realistic estimate of the time available has the tendency of lowering the associated human error probabilities.

Supporting Thermal Hydraulic Analysis

The main purpose of the thermal hydraulic analysis was to support the development of event trees and quantification of accident sequences. Thermal hydraulic considerations are the basis of the time-window approach. Basically, the time windows were defined on the times when the success criteria of important mitigating functions change. In the phase 1 study, assumptions were made based on simple "back of the envelope" calculations. It was found that more detailed calculations were needed to confirm the simple calculations, and support the assumptions made.

In the phase 2 study, a more detailed calculation was done to determine the timing of a feed and bleed operation during mid-loop operation. The calculation also gave information on the amount of water from the refueling water storage tank (RWST) needed to sustain the feed and bleed operation, as well as the timing of core uncover for different initial conditions.

The MELCOR^[5] code also was used to assess whether or not gravity feed from the RWST could be used to provide long term cooling (i.e. 24 hours, decay heat removal). It was found that although gravity feed is sufficient only when the decay heat is low, it can buy a few hours for restoring other means of removing decay heat even when the decay heat is high.

For reflux cooling, the studies at the Idaho National Engineering Laboratory (INEL),^[6-7] Westinghouse,^[8] and Virginia Power^[9] were used to determine the success criteria. The analysis of feed and spill, gravity feed and reflux cooling were used to determine the boundary of the time windows. For example, the time boundary between windows 2 and 3 was chosen to be the time when recirculation is not necessary for the first 24 hours after the accident started. The boundary was estimated to be 10 days, based on the inventory available in the refueling water storage tank (RWST) and the flow needed in the feed-and-spill operation.

Quantification

A Bayesian approach was used to estimate the initiating event frequencies. The basic event data for hardware failures were derived from the NUREG-1150 data base for Surry. The IRRAS^[10] computer code was used to quantify the fault tree and event tree, with a truncation limit of 10^{-10} . An uncertainty analysis of the total core damage frequency was performed by propagating the uncertainty of the parameters used in the model.

Human Reliability Analysis

Two types of human error events were identified and modeled in this study: pre- and post-accident errors. The pre-accident errors identified in the NUREG/CR-4550^[4] study for Surry were adopted, together with others identified in the system analysis task and added to the system fault trees.

To evaluate human actions and recovery actions that follow an initiator we first qualitatively defined the event scenario, required actions, important factors affecting operator performance, and the consequences of the action being unsuccessful. Two types of post accident human errors were modeled, failure to diagnose and failure to carry out the needed action given successful diagnosis. They were used in the fault trees for the top events of the event trees. It was assumed that, given failure to diagnose, the operator would fail to perform the needed actions; therefore, core damage would result. The same basic event representing failure to diagnose was used in all fault trees of a given event tree. On the other hand, failure to carry out the action given successful diagnosis would only fail the specific top event of the event tree.

The qualitative evaluation of the actions and the important parameters that affect operator's performance were used to derive the human error probabilities (HEPs) by adapting the success likelihood index methodology. This methodology assumes that the likelihood of operator error in a particular situation depends on the combined effects of a small set of performance-shaping factors (PSFs) that influence the operator's ability to accomplish the action.

To quantify the HEPs, the PSFs were rated with weights that reflect the relative influence of each PSF on the likelihood of the success of the action, and a score that reflects whether the PSF helps or hinders the operator in carrying out the actions. With the rating for PSF, the numerical model was calibrated using well-defined actions obtained from analysis for other PRAs. Calibration ensures that the error probabilities are realistic and consistent with the data, observed human behavior, and the results from comparable expert evaluations of similar activities.

Data Base Analysis

An extensive effort was devoted to collecting data to characterize the plant during shutdown.

- 1) A data base of initiating events was compiled for the initiating event analysis.
- 2) The shift supervisor's log books, outage schedules, minimum equipment list, and monthly operating report were reviewed to collect the data needed to estimate the frequency of shutdown, duration of plant operational states, and maintenance unavailabilities.

1 Introduction and Approach

- 3) The shift supervisor's log books were reviewed to determine the time that the plant is in different configurations. For example, the reactor coolant loops were found to be isolated for a long period in a refueling.

1.4 Organization of the Report

Chapter 1 is an introduction and approach of this study. Chapter 2 defines the scope of the level-1 study. Chapter 3 discusses the definition and characterization of the outage types and plant operational states (POSs). A description of the major activities during a refueling outage is provided. Chapter 4 documents the initiating event analysis, including identification, categorization, and quantification of the accident initiating events that may take place during all low power and shutdown conditions. Chapter 5 documents the thermal hydraulic analyses performed in support of the accident scenario development for mid-loop operations. Chapter 6 documents the fault tree analysis of the systems. Chapter 7 documents the event trees for the mid-loop POSs. Chapter 8 documents the human reliability analysis in support of the quantification of the accident scenarios. Chapter 9 documents the effort in data analysis. Chapter 10 documents the quantitative results of the study, including tabulation of frequencies of core damage sequences and the recovery actions modeled. Chapter 11 documents the plant damage state analysis that provides the needed input to the level 2 and 3 analysis. Chapter 12 documents the uncertainty and importance analysis of the total core damage frequency.

1.5 References

1. Chu, T.L., et.al., "PWR Low Power and Shutdown Accident Frequencies Program Phase 1A-Coarse Screening Analysis," Brookhaven National Laboratory, November 13, 1991.
2. Reactor Safety Study-- An Assessment of Accident Risks in U. S. Commercial Nuclear Power plants," U. S. NRC, WASH-1400 (NUREG 75/014), October 1975.
3. "Severe Accident Risks: An Assessment for Five U. S. Nuclear Power Plants, " NUREG-1150, June 1989.
4. Robert C. Bertucio, et al., "Analysis of Core Damage Frequency: Surry, Unit 1 Internal Events", Sandia National Laboratories, July 1987, NUREG/CR-4550, Rev. 1, Volume 3, Part 1.
5. Summers, R.M., et.al., "MELCOR 1.8.0: A Computer Code for Nuclear Reactor Severe Accident Source Term and Risk Assessment Analysis," NUREG/CR-5531, Sandia National Laboratories, January, 1991.
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7. Wald, L.W., et.al., "Consequence of the Loss of Residual Heat Removal Systems in Pressurized Water Reactors," NUREG/CR-5820, Idaho National Engineering Laboratory, May 1992.
8. Audreycheck, T.S., et. al., "Loss of RHRs Cooling while the RCS is partially filled," WCAP - 11916, Westinghouse Electric Corporation, July 1988.

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9. "Background and Guidance For Ensuring Adequate Decay Heat Removal When RCS Loop Stop Valves are Closed, Surry and North Anna Power Stations," NE Technical Report No.865, Revision 1, Virginia Power Company, June 1992.
10. Russell, K., et. al., "Integrated Reliability and Risk Analysis System," Version NEW5, Developed by Idaho National Engineering Laboratory.

2 PROGRAM SCOPE

The level-1 part of the PWR Low Power and Shutdown Program(LP&S) was conducted in two phases. In phase 1, completed in November, 1991, a coarse screening level-1 probabilistic risk assessment (PRA)^[1], including internal fire and flood, was completed for all low power and shutdown plant operational states (POSS). In phase 2, a detailed PRA of mid-loop operations was completed, consisting of three POSS, two in a refueling outage and one in a drained maintenance outage. The scope of the phase 2 analysis includes internal events, internal fires, and internal floods. An assessment of seismic events was performed by Future Resources Associates. This volume, Volume 2, documents the analyses on internal events. The analyses on internal fires, internal floods, seismic events, and the Level-2 and 3 analyses are documented in separate volumes.

This volume documents the results of the phase 2 internal event analysis, as well as the part of the work completed in phase 1 on initiating event analysis, system analysis, and data base development that are applicable to all low power and shutdown POSS. The chapters on event tree analysis, accident sequence quantification and uncertainty analysis cover only the three mid-loop POSS. An appendix, Appendix I, contains an updated version of those chapters or sections, that are applicable to POSS other than mid-loop, of the phase 1 report^[1].

The scope of the LP&S program includes only those accidents that can potentially affect the fuel located in the reactor vessel, and does not consider any accidents that may occur to the fuel in transit or in the spent fuel pool.

The mission time for successful termination of a transient or accident was chosen to be 24 hours, the same as that used in PRAs for full power operation. The assumption is that if the plant can be maintained in a stable condition during the first 24 hours after the accident initiating event occurs, many mitigating measures may become available to prevent any further degradation of the condition. For example, in a loss of RHR scenario in which reflux cooling is effective in removing decay heat, if the secondary side of the steam generators has a sufficient amount of inventory to last more than 24 hours, it is considered a successful sequence. This time was also used as the mission time for the systems and components.

2.1 References

1. Chu, T.L., et.al., "PWR Low Power and Shutdown Accident Frequencies Program Phase 1A-Coarse Screening Analysis," Brookhaven National Laboratory, November 13, 1991.

3 DEFINITION AND CHARACTERIZATION OF OUTAGE TYPES AND PLANT OPERATIONAL STATES

3.1 Introduction

The scope of the initiating event and system analysis includes all operational modes (less than 15% power) as defined in the Updated Surry Final Safety Analysis Report (UFSAR). Table 3-1 summarizes the definitions of the seven operational modes in the Surry Technical Specifications in terms of reactor criticality, reactor power, reactor temperature, and pressure. Table 3-2 summarizes the definitions of the operational modes of the Westinghouse Standard Technical Specifications. The Surry Tech. Specs. differ from the Westinghouse standard Tech. Specs. in the definition of operational modes. Neither of them are detailed enough for a shutdown study. For example, in cold shutdown, mid-loop operation is an unique condition that requires special modelling to account for the low Reactor Coolant System (RCS) inventory. However, the results of the shutdown study can probably be used to determine the respective contributions of these operational states.

In this study, four different types of outages are considered and discussed in Section 3.2. Table 3-3 lists the estimated frequency of each outage type. Within each type of outages, Plant Operational States (POSs) are defined and characterized. Table 3-4 lists the parameters used in the definition and characterization. Sections 3.3 discusses the definition of POSs in a refueling outage. Section 3.4 defines the POSs for other outages in terms of the POSs of a refueling. Section 3.5 outlines the characterization of the POSs of a refueling outage. An important part of the characterization is the activities undertaken during the outage; Section 3.5 gives detailed descriptions of the operating procedures used in the outage. Section 3.6 is the characterization of the mid-loop POSs that are the subject of this study.

3.2 Outage Types

Existing risk assessments^[1-4] for a PWR at shutdown all used a phased approach. References 1 to 3 considered three types of outages: refueling, drained maintenance, and non-drained maintenance. Each type was further divided into phases that are defined in terms of the plant condition, such as vessel level, temperature, pressure, and whether or not the containment equipment hatch is open. These phases can be considered as plant operational states (POSs) that are characterized in terms of time after shutdown, and the durations of the phases estimated from plant experience. The use of phases may be related to the operational procedures used in different stages of an outage. Using plant experience to define the shutdown phases allows more realistic modelling of the plant and requires detailed information that may only be available in the log books.

In this study, four types of outages were defined: refueling, drained maintenance, non-drained maintenance with use of the RHR system, and non-drained maintenance without use of the RHR system. Table 3-3 lists the estimated frequency of these outages based on Surry's data.

3.3 Definition of Plant Operational States for a Refueling Outage

Table 3-5 summarizes the definition and characterization of the 15 POSs for a refueling outage. Basically, the POSs are intended to demonstrate the evolution that the plant goes through during refueling outage.

3 Outage Types & POSs

Decay heat is an important parameter in determining the time available for operator actions. The time after shutdown is used to characterize the POSs and is measured from the time the reactor trip takes place. The times given in Table 3-5 were based on the October 1986 refueling outage of Surry Unit 2. Such data were taken from the control room log books for each outage over 5 calendar years from 1985 to 1989. The average durations, shown in Table 3-6, that the plant spent in the POSs are used as the durations of the POSs. The thermal hydraulic calculations to support the characterization of the POSs are discussed in Chapter 5. The effort in collecting the maintenance data of the components is described in Chapter 9.

Also identified in Table 3-5 are the operating procedures used in the POSs. The PRA team made a step-by-step review of these procedures to understand the activities performed during the POSs. Section 3.5 gives a summarized description of the procedures.

3.4 Plant Operational States for Other Types of Outages

The POSs for outage types other than refueling are defined in a similar manner to a refueling outage. Table 3-6 summarizes the POSs for the four types of outages and their average durations. Tables 3-7 to 3-10 list the duration of each individual outage over the 5 calendar years from 1985 to 1989.

3.5 Low Power and Shutdown Outage Activities

Preparation for POS 1

Before entering POS 1 of a normal shutdown, the main turbine/generator load and reactor (RX) power are gradually decreased from the normal operating level in accordance with operating procedures. During power reduction, the following significant events are completed:

- Perform functional tests of the Steam Generator (SG) Feedwater (FW) bypass flow and pump recirculation valve
- Bypass the Protection Interlock (P-8 loss of one RCS loop RX trip) when RX power <35%
- Shutdown one of the two main SG FW pumps
- Transfer the main turbine steam bypass (dump) valves to manual pressure control
- Remove the Moisture Separators and Reheaters (MSRs) from service when RX power is stabilized between 25% to 30%
- Transfer all unit electrical loads from Normal Station Service (NSS) transformer power off the unit main generator to Reserve Station Service (RSS) transformer power off the electrical power grid outside the unit.
- Isolate the First Point heaters extraction steam and open the First Point heaters extraction steam valve, as well as the turbine inlet and cross-under drain isolation valves when turbine power <20%

3.5.1 POS 1-Low Power Operation and Reactor Shutdown

3.5.1.1 Summary of POS 1 Activities

Starting from normal power operations, both turbine and RX power levels are decreased to low power levels IAW normal load-reduction procedures without causing a RX trip or loss of the Power Conversion System (PCS). Power is stabilized at 10-15% to facilitate the transfer of the operational mode from automatic to manual in controlling SG water levels and RX inventory, so that loss of the main turbine or a RCP will not trip the RX. The RX power is manually decreased to below the fission-heating level and then shutdown by tripping the control rod assembly banks that are still withdrawn. The shutdown banks of RX control rod assemblies may be withdrawn after the trip while RCS average temperature (T_{avg}) is held at 547°F by controlling the main steam flow which is being bypassed to the main condenser; the RX is maintained in Hot Shutdown (HSD) conditions by adjusting the required HSD boron concentration in the RCS.

3.5.1.2 Significant POS 1 Activities

As the turbine/generator load is manually reduced using the EHC system and stabilized at less than 15% of the rated, the (control) Rod Control Mode is switched from auto (with the Reactor Control System) to manual (by the operator). Thus the generator can be taken off line without causing a reactor trip. The control of the water level in the steam generator also is transferred to manual by opening the feedwater regulating bypass valves, HCV-155A/B/C, allowing the feedwater regulating valves FCV-1478/1488/1498 to automatically close to 0% position. These FCVs then are placed in manual control and the feedwater stop valves MOV-154A/B/C are shut off.

3 Outage Types & POSs

When Trip Status indications show that turbine power and reactor power are less than 10% of the rated, it is verified that Permissive signal P-10 is off, and P-7 is on. P-10 is off so that automatic reactor trip will be functional on source range high flux, intermediate range high flux, and low-setpoint power range high flux. On the other hand, Permissive signal P-7 is on, so that automatic reactor trip is prevented from turbine trip, Pzr low pressure, Pzr high level, low flow in more than one RCS loop, RCP (buses) undervoltage, and RCP (buses) underfrequency.

Using the turbine valve-position limiter of the EHC system, the unloading of the turbine/generator is continued until the generator output becomes 0. The generator is removed from the grid by opening generator output breakers OCB-G102 and OCB-G1T240. The exciter field breaker and voltage regulator are switched off. With the reactor power being maintained stable at 2%, and RCS temperature T_{avg} at 547°F by manually adjusting control rod positions while steam flow from the steam generator is directed through the steam dump valves to the condenser, Reactor Shutdown and Trip Data is recorded for future reference.

Verifying that the turbine is tripped, reactor power is further reduced below the point of adding heat, indicated as below 1×10^{-6} amp on the Intermediate Range Channels. It is verified that the Source Range detectors are automatically re-energized, and that visual and audible equipment for source range neutron flux is ready for use. As the neutron population continues to decrease, the audio multiplier is adjusted to ensure a continuous audible indication. To prevent an uncontrolled cooldown after reactor shutdown, it is verified that RCS temperature T_{avg} is not decreasing beforehand.

The reactor is manually tripped off so that all 48 control rods are fully inserted. Checking that reactor neutron flux is less than 10^{-10} amp equivalent, the shutdown banks are fully withdrawn, unless the shift supervisor has decided otherwise. Before going into the next POS, the RCS temperature T_{avg} is maintained at hot shutdown condition (specifically, 547°F), using the steam dump valves to dissipate steam generated by heat added to the RCS from decay heat, as well as the three RCPs.

3.5.1.3 Associated POS 1 Operating Procedures

Commence GOP-2.2, Rev 1 dated 2/27/92 at Step 5.4.2 and complete GOP-2.2.

Commence and complete GOP-2.3, Rev 1 dated 2/27/92.

Withdraw shutdown control rod assembly banks In Accordance With (IAW) OP-58.2.1.

3.5.2 POS 2-Cooldown with SGs to 345°F

3.5.2.1 Summary of POS 2 Activities

Beginning from the HSD conditions of 547°F, 2235 psig, and appropriate boron concentration, the RX is cooled down until the RCS temperature reaches 350°F by controlling main steam bypass to the main condenser after the boron concentration is increased to establish and maintain RX shutdown margin at Cold Shutdown (CSD) concentration. Two RCPs (B and either A or C) are shutdown and Przr spray put in manual Przr control during the cooldown in accordance with the cooldown rate limits and the pressure-temperature curve. As Reactor Coolant (RC) temperature and pressure is decreased to 345°F, and ~345 psig, respectively, Low Temperature Over-Pressure (LTOP) protection is established.

3.5.2.2 Significant POS 2 Activities

With the RCS temperature T_{avg} being stabilized at 547°F in HSD conditions on the steam dump valves, the shutdown control rod banks being fully withdrawn, the maximum letdown purification flow being maintained, and the CSD Boron Concentration (C_B) having been determined, the RCS boron concentration is increased sufficiently to provide the shutdown margin required for the CSD xenon-free condition. RCS boration is accomplished by using the CVCS (including the makeup subsystem) to feed concentrated boric acid through the boric acid blender to the charging pumps and into the RCS, while bleeding the reactor coolant via the letdown line to the Boron Recycle System (BRS). The Przr PORVs PCV-1455C and PCV-1456 are tested and the main feedwater regulating valves FCV-1478/1488/1498, their associated stop valves MOV-154A/B/C, as well as the bypass valves HCV-155A/B/C are checked for operational capability. All of the six RCS loop isolation valves MOV-1590/1591/1592/1593/1594/1595 are removed from their backseat positions and opened electrically. A HSD walkdown in the containment is made to identify all primary and secondary leaks, to record the Przr PORV air-bottle pressures, and to prepare the RHR system for service. The RHR system is prepared via checking the RHR pumps and stroke-testing the RHR flow control valve FCV-1605, the RHR combined Hx discharge valve HCV-1758, and the RHR to letdown HCV-1142 which is placed in closed position when the RHR return line is opened. HCV-1142 is kept 20% open during normal plant operation.

After chemical analysis has verified that the RCS C_B is $\geq$ the required CSD C_B and the blend flow of the CVCS makeup subsystem is set at the RCS C_B , RCP-B and either RCP-A or C are stopped and the associated Przr spray valve PCV-1455A (or PCV-1455B) is closed (or checked to be closed). The RCS cooldown is started by adjusting the pressure control setpoints to increase the opening positions of the steam dump valves. As the RCS temperature nears 543°F, the low T_{avg} interlock for the steam dump valves is bypassed to allow the steam dump valves to remain open. During the cooldown, the limits of maximum cooldown rates must be observed, i.e., 100°F/hr for RCS temperatures $> 440^\circ\text{F}$, and 50°F/hr for RCS temperatures from 440°F and 200°F. With the RCS temperature decreasing, the RCS pressure is reduced in accordance with the RCS pressure-temperature curve by opening the Przr spray valve PCV-1455B (or PCV-1455A). As the RCS pressure decreases, the position of the isolation of the letdown valve PCV-1145 is changed to maintain the proper letdown flow and pressure, thereby preventing water from flashing to steam downstream of the letdown orifices. Also, seal injection flow is adjusted to compensate for the RCS pressure changes.

As the RCS pressure decreases below 2,000 psig, the signal of Safety Injection on Low Przr pressure and Steam Header/Line ΔP is blocked. When the RCS pressure falls below 1,000 psig, the accumulator discharge isolation valves MOV-1865A/B/C are disabled by mechanically closing the valves and electrically locking open the associated breakers to prevent an inadvertent safety injection. During the cooldown, more and more makeup flow is needed to maintain the Przr level; the actual blend flow C_B must be $\geq$ RCS C_B .

When the RCS pressure approaches ~ 360 psig, while the RCS temperature is higher than 350°F, reactor-vessel overpressure protection is established by placing the standby charging pump(s) in Pull-to-Lock (PTL), ensuring that the Przr PORV isolation valves MOV-1535/1536 are open, and so enabling the RX vessel overpressure mitigation system for the PORVs PCV-1455C/1456. Then, the RCS is cooled down to 345°F.

3.5.2.3 Associated POS 2 Operating Procedures

Commence and complete GOP-2.4, Rev. 1 dated 2/27/92.

Boration with blender to CSD boron concentration IAW OP-8.3.3.

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3.5.3 POS 3-Cooldown with RHR to 200°F

3.5.3.1 Summary POS 3 Activities

Starting with several hours hold (up to 8 hours) at 345°F for SG hideout return chemistry activities, cooldown of the shutdown RX and the RCS is continued from 345°F to cold shutdown conditions of $\leq 200^\circ\text{F}$ by controlled main turbine steam bypass (while maintaining SG steam pressure). The Residual Heat Removal system (RHR) is placed in service during the hold. Before cooldown, the engineered safeguards pumps (except one charging pump) will be prevented from operating (by their control switches placed in PTL) while the Low Pressure Safety Injection (SI) and AFW discharge valves are closed. Throughout this POS, RC pressure is maintained at ~ 345 psig with a bubble in the Przr, while LTOP protection is continued. Also, the maximum ΔT of 300°F across the Przr surge line must not be exceeded.

3.5.3.2 Significant POS 3 Activities

With the RX shutdown by (at least) the control rod assembly control banks, and with CSD boron concentration at a RC temperature and pressure of 345°F, and ~ 345 psig with LTOP protection, the engineered safeguards equipment is deactivated by putting the associated control switches in the PTL positions for the following pumps, low pressure SI, recirculation spray, containment spray and motor driven Auxiliary Feedwater (AFW) and close LPSI to RCS cold leg isolation valve (SI-MOV-1890C) and AFW to SG injection valves (FW 151A thru-151F).

While maintaining RC pressure at 300 psig, maximum Przr surge line ΔT of 300°F, and minimum RCP SEAL ΔP of 200 psid, the RHR system is setup and placed in service IAW OP-14.1 and the PRT drained in preparation for draining the RCS.

Continue RCS cooldown at a rate $< 50^\circ\text{F/hr}$ via the SGs and main turbine steam bypass while the RHR System is being setup. This setup includes system fill via alignment to CVCS letdown (using HCV-1142, the 2" RHR letdown valve and PCV-1145, the normal letdown pressure control valve), starting the RHR pump system heatup to 345°F via RCS interface (by opening the 14" RHR series supply valves MOV-1700 and 1701 from RCS loop C hot leg and discharging via HCV-1142 and controlling RHR heatup rate $\leq 150^\circ\text{F/hr}$), and ensuring RHR boron concentration (C_B) $\geq$ RCS C_B before placing in service (by opening the 12" RHR parallel discharge valves MOV-1720A and B to RCS loop A & B cold legs). The RHR is placed in service during the hold at 345°F.

When RHR is in service both SG steaming and RHR cooling are used together to continue the cooldown until SG pressure decreases to 5 to 15 psig (RC temp 228 to 250°F). Then, the main turbine steam bypass valves are closed, the SG secondary sides are isolated, and N_2 aligned to maintain positive pressure in the SGs before the RC temp is $< 212^\circ\text{F}$.

3.5.3.3 Associated POS 3 Operating Procedure

Commence and complete GOP-2.5, Rev 1 dated 2/27/92.

Place RHR System in service IAW OP-14.1.

3.5.4. POS 4-Cooldown to Ambient Temperatures (using RHR)

3.5.4.1 Summary of POS 4 Activities

Commencing from RCS temperature at $\sim 195^{\circ}\text{F}$, the RCS is cooled down to 140°F by controlling RHR HX flow, and the RX is maintained in shutdown conditions by varying the RCS boron concentration level above the required CSD boron concentration. Throughout this POS, RC pressure is maintained at ~ 345 psig with a bubble in the Przr while LTOP is continued. Also, the maximum ΔT of 300°F across the Przr surge line must not be exceeded.

3.5.4.2 Significant POS 4 Activities

With the RX controlled in shutdown by control rod assemblies and CSD boron concentration at a RC temperature between $190 \sim 195^{\circ}\text{F}$ with the RCS on LTOP protection, the Containment Purge System is placed in service IAW OP-21.1.1. The RCS cooldown is continued to 175°F at a rate $\leq 40^{\circ}\text{F/hr}$ by continued RHR operation (i.e., by manually controlling RHR HX flow using HCV-1758 while total RHR flow is automatically controlled at 3500 gpm by FCV-1605 (RHR HX bypass flow valve) while the Component Cooling Water (CCW) return from the operating RHR HX is controlled at $100\text{-}120^{\circ}\text{F}$.

If the Przr is to be drained to less than 5% level, the Shutdown Cooling Level Instruments are calibrated while the RCS temperature is held at 175°F . Also, if the shutdown is a refueling outage, the RCS temperature is maintained at 175°F until the Hydrogen Peroxide residual is established.

The cooldown continues at $\leq 20^{\circ}\text{F/hr}$ from 175°F to more than 110°F by RHR operation. Meanwhile, breaking the main condenser vacuum IAW OP-36.1, verifying $\text{RCS } C_B \geq \text{CSD } C_B$, and removing the Gland Steam System from service IAW OP-39.1 are completed. Furthermore, each Accumulator is verified isolated once per 12 hours. Also, the B-phase speed-sensing relay plug for each RCP is removed.

If CSD (RCS temperatures $< 200^{\circ}\text{F}$) is scheduled for ≥ 5 days, the SGs will be placed in wet layup. The SGs are drained to 0% Wide Range (WR) level, then filled to 98-100% WR level and the Recirculation Transfer (RT) system is placed in service. If the Volume Control Tank (VCT) of the CVCS is scheduled for a tagout during the outage, the VCT atmosphere is purged to $> 99\%$ nitrogen.

3.5.4.3 Associated POS 4 Operating Procedures

Commence and complete GOP-2.6, Rev. 1, dated 2/27/92.

Place RHR System in service IAW OP-14.1 SG Wet Layout IAW OP-31.2, -31.3 and 63.1.

3.5.5 POS 5-Draining the RCS to Mid-loop

3.5.5.1 Summary of POS 5 Activities

Starting at 140°F with a bubble in the Przr, the one operating RCP (1A or 1C) and Przr heaters secured, the RCS is depressurized by spraying down the Przr and filling it. The Przr is filled and then pressurized by 5-30

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psig N_2 , and the RCS is drained cautiously to the "referenced" mid-loop ($\sim 9"$ above the actual mid-loop level) while RHR continues to remove decay heat.

3.5.5.2 Significant POS 5 Activities

With the RX maintained in shutdown by control rod assemblies and CSD boron concentration at a RC temperature and pressure of $\leq 140^\circ\text{F}$ and ~ 345 psig on LTOP protection, the RCS temperature is controlled by varying the RHR HX flow and temperature. The RCS pressure is maintained by controlling the bubble in the Przr by using Przr heaters and manual spray via the only operating RCP (either A or C). To maintain the ΔT across the Przr Surge line below the 300°F limit, the RC pressure must be controlled at 300 psig, which is the minimum RC pressure for operating a RCP. This pressure will also provide the required minimum RCP No. 1 seal ΔP of 200 psid.

3.5.5.2.1 Draining the RCS to 5% Pressurizer Level (29.0 ft)

Before beginning the RCS drain down, the crud burst is cleaned up by placing in service one mixed-bed demineralizer of the CVCS. H_2 concentrations in the RCS and the Przr vapor space are verified to be less than 4 cc/kg and 4%, respectively. N_2 is cut in to the VCT with H_2 manually isolated. The RCS is stabilized at $\sim 175^\circ\text{F}$ for adding hydrogen peroxide. When the hydrogen peroxide residual is established, the RCS is further cooled down to between 135°F and 140°F at a rate less than 20°F/hr , while the RCS pressure is controlled between 300 psig and 325 psig. This cleanup may last 2 to 5 days.

In preparation for the RCS drain to 5% Przr level, it is verified that capacity of the liquid waste storage is adequate. To ensure the Przr surge line $\Delta T \leq 300^\circ\text{F}$ during draining, the RCS pressure is controlled between 300 psig and 325 psig and the temperature between 135°F and 140°F . Also, the temperature of the component cooling header is controlled between 85°F and 120°F to compensate for leakage through the RHR HXs combined discharge valve HCV-1758 while it is closed, and the RHR HXs flow through FCV-1605 is set to maintain 3500 gpm. After the switches for the Przr backup heaters, groups A, B, D, and E are placed in lockout and the switch for Przr heaters, Group C, is pulled to lock, the RCS pressure is controlled between 300 psig and 325 psig by increasing the Przr level.

Because the RCS is on RHR, the Reactor Vessel Level Indication System (RVLIS) is not accurate and should not be used to indicate the RX vessel level.

When the Przr level is 25% to 50%, and the ΔT between the regenerative HX outlet temperature is verified to be less than 320°F , the last operating RCP is secured and the RCP seal water return valves HCV-1303 A, B, and C are closed. In addition, equipment is protected by the rack-out and tagout of all RCPs breakers and all Przr heater groups breakers.

The RCS then is depressurized by opening the Przr auxiliary spray valve HCV-1311 and closing the charging line regenerative HX outlet isolation valve HCB-1310A. (The Przr spray valves PCV-1445A and B were closed because there is no normal spray water from the RCS cold legs.) To cooldown the Przr, it is filled by increasing the charging line flow control valve FCV-1122, and by decreasing the letdown line pressure control valve PCV-1145. During this filling, RCS depressurization is slow. The depressurization can be accelerated

by increasing the Przr auxiliary spray. When the RCS pressure is less than 25 psig and before the Przr level reaches 85%, the Przr PORVs are opened to prevent the RCS from going solid. When the Przr relief tank level indicates an increase, showing that the Przr is full, the charging line flow is balanced with the letdown line flow, and Przr cooling is continued. When the Przr temperature is less than 212°F, HCV-1310A is opened and HCV-1311 is closed.

Draining the Przr from full to 5% level by an atmospheric drain takes up to 3 hours. Therefore, if the RCS is not vented, and the level in the Przr Relief Tank (PRT) is controlled between 5% and 10%, the PRT N₂ pressure is increased to between 5 psig and 30 psig to maintain a N₂ blanket on the RCS, thereby reducing the time for draining. Prior to the draining, the Przr spray valves are open, the charging line flow control valve FCV-1122 is closed, and RHR letdown flow isolation valve HCV-1142 is checked open. After RHR HXs flow setpoint is verified (or, adjusted) to be at ~2900 gpm and the annunciator "RHR Hx Lo Flow" is verified as not being lit, the letdown line pressure control valve PCV-1145 is opened to start RCS draining. Draining is verified by observing that the Przr level is falling and the VCT level control valve is diverting to the Boron Recovery Tank (BRT). When the Przr level falls between 5% and 7%, PCV-1145 is closed.

When the Przr is stable at the 5% level, the Reactor Vessel Level Indication System (RVLIS) is isolated, the reactor head vent is placed in service by installing a new Tygon tube between the head vent control valve and the pressurizer safety valve discharge pipe vent. The RCS standpipe for temporary indication of the level in the reactor vessel is also placed in service, the cold shutdown RCS level narrow range loop is calibrated, and the associated switch and vital bus distribution panel are verified to be in service. Figure 3-1 shows the installation of the head vent and the standpipe.

3.5.5.2.2 Draining the RCS from 5% Pressurizer Level (29.0 ft) to Mid-Nozzle (12.5 ft)

Because there is no RCS level indication from 0% in the Przr to 24.0 ft in the standpipe, an inventory balance is taken using the BRT Δ level method, while draining from 5% Przr level, so that the operator knows the volume of RX coolant being removed. The BRT levels are recorded before starting the drain down and after the RCS level is stabilized at the target

level. The difference in the levels is then converted into the volume removed from the RCS inventory. We note that at a flow of 40 gpm, less than 30 minutes is required to drain from 5% Przr level (29.0 ft) to less than 24.0 ft where the standpipe level gets on scale.

The drain from 29.0 ft is initiated by opening the letdown line pressure control valve PCV-1145, and verifying that the charging flow control valve FCV-1122 is closed and that the VCT level control valve LCV-1115A is diverting to the BRT, whose increase in level is closely monitored. Also, when the standpipe level is on scale, the difference between the local and remote standpipe indications is checked to be less than 0.3 ft.

If the target level in the reactor vessel is higher than 15.3 ft, PCV-1145 is closed when the standpipe indicates the target level is reached. If the target level is less than 15.3 ft, PCV-1145 is closed before the standpipe indicates 15.6 ft. Draining from 29.0 ft to 15.3 ft may take up to four hours. After verifying that containment closure is established (if the reactor has been shut down for less than 150 hours), the reduced inventory checklist is used to verify the requirements for entering reduced inventory (<15.3 ft). The requirements include that the following are available: at least one charging pump along with at least one high head SI or charging flowpath, at least one low head SI pump along with at least one low head SI flowpath, and at least

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one incore thermocouple on each ICC-train. Also, to prevent an RCS adverse configuration, at least one RC loop is isolated with the hot leg, cold leg, and bypass isolation valves open.

Then, PCV-1145 is slowly opened to resume draining to below 15.3 ft. During the approach to the mid-nozzle, which may take up to 2 hours (12.5 ft), the standpipe is closely monitored to track changes in RCS level. The RHR pump amps also are monitored because amp fluctuations indicate an impending loss of RHR flow due to vapor binding. If this should happen, the corresponding contingency procedure (e.g., AP-27: Loss of Decay Heat Removal Capability) must be carried out.

When the standpipe shows that the RCS level is between 12.8 ft and 12.5 ft, PCV-1145 is closed. Draining is complete after verifying that the VCT level is stable, LCV-1115A is not diverting, and the standpipe level is stable between 12.8 ft and 12.5 ft, and consistent with the cold shutdown RCS level narrow range indication.

3.5.5.3 Associated POS 5 Operating Procedures

Commence and complete OP-RC-004, Rev 1 dated 4/7/92, and OP-RC-005, Rev. 1 dated 4/7/92.
Perform PRT N₂ Makeup and Purge IAW OP-5.1.3.
Perform chemical Addition to RCS IAW OP-8.4.

3.5.6 POS 6-Mid-loop Operation

3.5.6.1 Summary of POS 6 Activities (including Significant ones)

Beginning with the RCS drained to mid-loop, vented to the process vent system, and controlled by RHR HX flow at <140°F, the RC loops are isolated and drained completely via the loop drains in preparation for loop maintenance or SG tube inspection. The SG primary side manways are removed for, and replaced after, SG tube inspection (or other mid-loop activity completed). The RCS level does not have to be at mid-loop once the loop stop valves are closed.

The RX is maintained shutdown to CSD boron concentration. In particular, if work is to be done on an RC loop cold leg with the RX vessel head in place, at least one loop's isolation valves and its respective loop bypass valve is required to remain open, thus avoiding an ADVERSE RCS CONFIGURATION.

3.5.6.2 Associated POS 6 (Maintenance) Operating Procedure

Commence and complete MOP 5.3, 5.4 or 5.5, dated 02/01/88.

3.5.7 POS 7-Fill for Refueling

3.5.7.1 Summary of POS 7 Activities (including significant ones)

Starting with the POS 6 Mid-loop conditions, the water level in the RX vessel is raised to just below the RX vessel head flange. Then, having installed the refueling cavity seal, the RX head is de-tensioned, unbolted,

and lifted by the containment polar crane and then the water level is raised to flood the open RX vessel up into the refueling cavity. The head is stored dry in the containment's lower level, and the flooding of the refueling cavity continued to 26'0"-27'6" above the RX vessel's head flange. Then, the upper internals structure of the vessel can be removed by the polar crane and stored underwater, after the control rod assemblies are unlatched from their drive shafts leaving them in the RX core as the upper internal structure is removed with the drive shafts enclosed. The integrity of the containment during refueling is established and maintained before the RX head and upper internals structure are moved.

3.5.7.2 Associated POS 7 Operating Procedure

Commence and complete OP 4.1 thru Step 5.48 dated 4/20/89.

Raising RX Vessel Level using LPSI IAW OP 5.8.1 or using CVCS IAW OP-5.8.2.

(Filling RX Refueling Cavity IAW OP-7.1.2).

3.5.8 POS 8-Refueling

3.5.8.1 Summary of POS 8 Activities (including Significant ones)

Commencing with the RX vessel head removed, the RX refueling cavity seal installed, the open RCS and the Refueling Cavity flooded to 26'0" - 27'6" above the vessel head flange, and the RHR HX flow controlling RCS temperature <140°F, the refueling sequence of removing all the spent fuel assemblies from the RX core, and adding the new and spent fuel assemblies to the core is undertaken one assembly at a time, using the manipulator crane, upenders, and the rest of the fuel transfer system. The integrity of the containment which is established for and maintained during fuel movement is relaxed during other times of the refueling.

3.5.8.2 Associated POS 8 Operating Procedures

Continue and complete OP-4.1 dated 4/20/89 Steps 5.49 thru 5.60.

3.5.9 POS 9-Draining RCS to Mid-loop After Refueling

3.5.9.1 Summary of POS 9 Activities (including Significant ones)

Starting with the RX vessel head removed, the RX Refueling Cavity seal installed, the open RCS and the Refueling Cavity flooded to 26'0" - 27'6" above the head flange, and the RHR HX flow controlling RCS temperature <140°F, the RX upper internals structure is returned to the RX vessel with the control rods assemblies being relatched to their drive shafts. The refueling cavity then is drained to 17-18' above the RX vessel flange with the RX head being lowered into the cavity just above the water level. Then, the head and the water level are lowered together, as the alignment of the control rod assembly RCCA drive shafts is observed as they enter the head thermal sleeves. When the water level drops just below the vessel flange, draining is suspended while the RX vessel head is set and head bolts tensioned. The RCS temperature is maintained >80°F with the head bolts tensioned. Refueling Containment Integrity is maintained during the

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replacement of the upper internals structure in the RX vessel, Refueling Cavity dewatering, and RX head replacement, and relaxed during other times, such as after the RX vessel head is set on the vessel. The RCS is again cautiously drained to "referenced" mid-loop (~9" above the actual mid-loop level) as was done in POS 5.

3.5.9.2 Associated POS 9 Operating Procedures

Continue and complete OP-4.1 dated 04/20/89 Steps 5.61 thru 5.91.

Commence OP-RC-004, Rev. 1 dated 4/07/92 at Section 5.3 and complete.

Commence and complete OP-RC-005, Rev. 1 dated 4/07/92 in conjunction with OP-4.1.

Unlatch and Latch control rod assembly drive shafts IAW OP-4.4

Dewater Refuel Cavity using RHR IAW OP-14.3 and/or using RL System IAW OP-15.2.

3.5.10 POS 10-Mid-loop Operations After Refueling

3.5.10.1 Summary of POS 10 Activities (including Significant ones)

Commencing with the RCS drained a second time to "referenced" mid-loop, vented to the process vent system, and controlled by RHR HX flow to $<140^{\circ}\text{F}$, the RC loops are still isolated and drained as required in POS 5 for uncompleted loop maintenance and/or SG tube inspection. The RX is maintained shutdown to CSD boron concentration. In particular, if work is to be done on an RC loop cold leg with the RX vessel head in place, at least one loop's isolation valves and its respective loop bypass valve are required to remain open thus avoiding an ADVERSE RCS CONFIGURATION.

3.5.10.2 Associated POS 10 (Maintenance) Operating Procedures

Possibly commence and complete MOP-5.3-5.5 dated 02/09/88

Isolating and draining RC loops 1A-1C.

3.5.11 POS 11-Refill RCS Completely (After Mid-loop Operation)

3.5.11.1 Summary of POS 11 Activities

Starting with the RCS drained a second time to "referenced" mid-loop, vented to the process vent system, and controlled by RHR HX flow to $<140^{\circ}\text{F}$ with one or more RC loops possibly isolated and drained from POSs 6 and/or 10 after loop maintenance or SG tube inspection, the water level in the vessel is raised using CVCS. With the head vent and standpipe isolated when the water level reaches the Przr, and with the Przr PORVs and their block valves verified open, the isolated loop(s) are unisolated when the Przr is almost full. With the Przr full, the loops are vented by closing the PORVs with LTOP, pressurizing the RCS to ~345 psig jogging a RCP, depressurizing the RCS, and venting the RX vessel and repeating. The RCS is again brought solid after each depressurization cycle to ensure it is completely filled.

3.5.11.2 Significant POS 11 Activities

The water level in the RX vessel is raised using the CVCS to deliver a charging flow with ≥ 2000 ppm C_b (to account for refueling shutdown conditions). Preparation is made for eventual solid plant operation by verifying Low Temperature Over-Pressure (LTOP) protection before continuing to fill the RCS using CVCS

normal charging and RCP seal water injection ≤ 150 gpm; the Przr PORVs and their isolation valves are verified open and the PRT continues to be vented to the process vent system.

During the refill, the head vent and standpipe are isolated when the water level reaches the Przr while all isolated loops are unisolated as Przr level reaches 90%. When the Przr is full, as indicated by the increasing level in the Przr Relief Tank (PRT), the fill rate is reduced and RC pressure maintained < 100 psig by automatic letdown pressure control until RCS pressure is stabilized. Then, the RCS is vented by increasing RCS pressure to 300-345 psig, jogging a RCP, and then decreasing pressure < 125 psig and venting the RX vessel head. This cycle is repeated for a longer time with another RCP. Repeated pressurization - RCP jog-depressurization - head vent cycles will finally result in the RCS filled solid at a RC pressure < 125 psig, ready to commence a solid RCS heatup.

3.5.11.3 Associated POS 11 Operating Procedures

Commence GOP-1.1, Rev. 2 dated 4/22/92 at Section 5.2 and complete up to Section 5.7.

Raise RX vessel level using CVCS IAW OP-5.8.2

Fill the RCS IAW OP-5.1.1

Vent the RCS IAW OP-5.1.2 except Steps 5.20 and 5.21

Fill RC Loop 1A, 1B, or 1C IAW MOP-5.6, -5.7 or 5.8

Start any RCP IAW OP-5.2.1

Secure any RCP IAW OP-5.2.2

3.5.12 POS 12-RCS Heatup Solid and Draw Bubble

3.5.12.1 Summary of POS 12 Activities

Commencing with the RCS filled solid, pressurized to < 125 psig, and controlled to $< 140^\circ\text{F}$ by RHR HX flow, the preparations for a RCS heatup are started. The RX is maintained shutdown to CSD boron concentration with the control rod assembly shutdown banks withdrawn and LTOP.

In preparation to start a RCP (either A or C) to heatup the RCS, the solid RCS is repressurized and maintained ~ 345 psig via PCV-1145. Then, the RCP is started with the Przr heaters energized to heatup the Przr. After the bubble is drawn, the Przr level is reduced to normal operating ($\sim 22\%$), and the Przr level control is switched from manual to automatic, while Przr pressure continues to be manually controlled at ~ 345 psig by spray and heaters.

3.5.12.2 Significant POS 12 Activities

As part of the verification that the RCS is solid at the conclusion of POS 11, the RCS is repressurized and manually maintained by charging at ~ 345 psig, and either RCP A or C started with the RC and letdown pressures nearly equal and with RC pressure responding quickly to charging in the solid RCS. By using the Przr heaters in conjunction with opening the Przr spray valve associated with the operating RCP, along with controlling RHR HX flow, a heatup to 175°F at a rate $\leq 40^\circ\text{F/hr}$ will be accomplished. At 175°F , the RCS temperature is stabilized for a Chemistry hold until RCS is within limits and the Volume Control Tank (VCT) is purged with H_2 . Then, preparation for drawing a bubble in the Przr is initiated by energizing all Przr heaters, closing the Przr spray valves, placing the letdown pressure control in automatic at ~ 300 psig. The

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RCS heatup to 190-195°F continues to be controlled at $\leq 40^\circ\text{F/hr}$, while the Przr heatup is controlled by the heaters at $\leq 100^\circ\text{F/hr}$. While drawing a bubble with a RCP operating, the RC pressure must be manually controlled while solid, so as not to go below 300 psig (the minimum for RCP operation) yet not go so high as to challenge LTOP PORV settings. Also, the maximum limit of $280^\circ\text{F } \Delta T$ between the Przr and its Spray line must be observed. When the bubble forms (as indicated by the letdown pressure control valve, PCV-1145, opening in automatic while RC pressure is maintained to increase letdown flow with no increase in charging flow), the Przr level is decreased to the normal operating setpoint and charging flow placed in automatic manually by the operating RCP's Przr Spray valve at ~ 345 psig. This will satisfy the 200 psig minimum ΔP requirement for the RCP No. 1 Seal, as well as the 300 psig minimum RCS pressure for operating a RCP.

3.5.12.3 Associated POS 12 Operating Procedures

Continue GOP-1.1, Rev. 2 dated 4/22/92 at Section 5.8 and complete.
Verify RCS solid IAW OP-5.12 Steps 5.20 and 5.21.
Start Any RCP IAW OP-5.2.1.

3.5.13 POS 13-RCS Heatup to 350°F

3.5.13.1 Summary of POS 13 Activities

Starting with the Przr level automatically controlled, its pressure manually controlled by Przr Spray (and Przr heaters) at ~ 345 psig, and its temperature manually controlled by RHR HX flow at 195°F , the RX is maintained shutdown to CSD boron concentration.

When the prerequisites for $>200^\circ\text{F}$ are met, the other two RCPs are started to aid in the RCS heatup. Above 212°F , the steam commencement can be used to prepare the SG and main turbine steam bypass to control RCS temperature along with the RHR. The heatup is stopped when the RC temperature reaches 350°F with RHR being removed from service after the engineered safe-guards alignment is reestablished.

3.5.13.2 Significant POS 13 Activities

Before the heatup is continued $>200^\circ\text{F}$, there are many prerequisites including completing the containment integrity and containment checklists, commencing drawing containment vacuum, and providing cooling for and withdrawing the control rod assembly shutdown banks. In addition, the appropriate part of the pre-startup checkoff list is performed. The other two RCPs are started to help the heatup which is maintained at $\leq 40^\circ\text{F/hr}$ by controlling RHR HX flow, if necessary. Before the RC temperature reaches 212°F , the SGs are prepared for steaming. When steaming commences, the SGs and main steam system will be prepared (along with the rest of the PCS to control RC temperature by main turbine steam bypass). At 350°F , the engineered safeguards alignment is reestablished. The RHR system is secured and isolated before RC temperature and exceeds 350°F , with RC pressure being maintained at 345 psig.

3.5.13.3 Associated POS 13 Operating Procedures

Continue and complete GOP-1.1, Rev. 2 dated 4/22/92 by performing Section 5.1.

Commence and complete GOP-1.2, Rev. 1 dated 3/26/92.
Commence GOP-1.3, Rev. 3 dated 6/9/92 and complete thru Step 5.3.4.
Remove RHR from service IAW OP-14.2.

3.5.14 POS 14-Startup with SGs

3.5.14.1 Summary of POS 14 Activities

Begin with the Przr level automatically controlled at normal level by CVCS, its pressure manually controlled by Przr spray (and heaters) at ~345 psig, and its temperature manually controlled at 350°F by RHR HX flow and main turbine steam bypass control (with SG levels being manually controlled), the RX is maintained shutdown to CSD boron concentration.

LTOP protection is disabled, and then, the RCS and secondary systems continue the unit heatup within heatup rate limits and pressurization in accordance with the pressure-temperature curve. The boron concentration should be adjusted when the normal Hot Shutdown (HSD) RC temperature and pressure (547°F and 2235 psig) are reached, pressure is put into automatic control, whereas the operator manually controls RC temperature with the main turbine steam bypass. The boron concentration also should be brought to HSD conditions.

3.5.14.2 Significant POS 14 Activities

Before the heatup is continued, tests are made of the motor driven auxiliary feedwater pump flow and LTOP protection is disabled. Then, heatup continues at $\leq 40^\circ\text{F/hr}$ and the pressurization is performed IAW the pressure-temperature curve. Meanwhile, the secondary plant is continuing to heatup at $\leq 150^\circ\text{F/hr}$. Finally, the RC temperature and pressure reach normal-HSD and low power operating values of 547°F and 2235 psig, where RC temperature is controlled by automatic SG pressure control with the steam bypass and RC pressure is automatically controlled by Przr spray valves and proportional heaters (when the pressure exceeds 1700 psig). The boron concentration is reduced to HSD conditions.

3.5.14.3 Associate POS 14 Operating Procedures

Commence GOP-1.3, Rev. 3 dated 6/9/92 at Step 5.3.5 and complete.

3.5.15 POS 15-Reactor Startup and Low Power Operation

3.5.15.1 Summary of POS 15 Activities

Starting with the RC pressure at the normal operating value 2235 psig, and temperature at the HSD value of 547°F (while $\geq 530^\circ\text{F}$) with all three RCPs are operating, RC temperature is maintained by the Power Conversion System (PCS) (automatic pressure control of the main turbine steam bypass valves) and manual control of the SG water level, while RC pressure is maintained by the Przr (via automatic Przr spray and/or heater control), and RC level is maintained by the CVCS (via automatic Przr level control by the charging flow). The RX is maintained at HSD boron concentration (with control rod assembly shutdown banks withdrawn).

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The RCS is diluted to critical boron concentration and then the RX brought critical on the expected control rod assembly control bank and power increased ($<10\%$) to warmup, rollup, and then the turbine generator is put on the grid. In the meantime, the SG water level and RX T_{avg} (therefore RX power) are controlled manually. When power is increased and stabilized at $\sim 15\%$, the control of T_{avg} and SG water level is transferred to automatic. Under these conditions, Surry Unit 1 is no longer in a Low Power and Shutdown Outage Plant POS but essentially at a normal operating conditions (except for the unit electrical power supply source and additional PCS equipment such as Heater Drain Pumps, Moisture Separator Reheaters, and additional Feed and Condensate pumps).

3.5.15.2 Significant POS 15 Activities

Before the RX is startup (brought critical), the RCS must be cautiously diluted by CVCS to the critical boron concentration after verifying that the control rod assembly shutdown bank is in a fully withdrawn status. In addition, before dilution and then criticality by the expected control rod assembly control bank at or sufficiently near its estimated critical position (ECP), several of prerequisites must be completed, including Reactor Shutdown and Trip Report, Minimum Equipment List, valve and breaker position alignment and/or verification. After diluting RCS by CVCS and achieving RX criticality by the appropriate control bank, RX power is raised to $\sim 2\%$ with control bank withdrawal while maintaining the RC temperature at "no load" T_{avg} of 547°F , with the main turbine steam bypass valves passing the 2% steam flow to the main condenser (and the SG water levels still manually controlled). At this point, the flow of the turbine-driven auxiliary-feedwater pump is tested (while the main SG FW pump continues to feed to SG).

During this POS, power is increased manually by control bank withdrawal (with the control rod assemblies always maintained in the programmed band while maintaining RC temperature, T_{avg} at a specified-referenced valve, T_{ref} (based on power) by manual control bank control). Thus, RX power is raised by the RX operator to $<10\%$ while the main turbine is warmed up and rolled up to 1800 rpm. When the tests of the turbine trip are completed, and the exciter field breaker is closed, RX power is increased $>10\%$. With the main turbine at 1800 rpm, RX power should be $\sim 15\%$ with turbine steam bypass in manual. Then, the main generator is synchronized to the grid and its breakers closed. The turbine power is increased by loading the generator. RX power must be increased to maintain T_{avg} before the turbine steam bypass valves close.

Power is stabilized at $\sim 15\%$ to transfer from manual to automatic control of the SG water level (by FW regulating valves transferred from the bypass valves first) and RX power (by selected control bank control of T_{avg}). Also control of the main turbine steam bypass control is transferred to T_{avg} control.

When these transfers to automatic control are made at $\sim 15\%$, the unit is no longer considered in POS 15 but essentially at normal power conditions; there are a few exceptions, such as electrical power not yet having been transferred from the RSS to the NSS transformers, and additional PCS equipment as needed such as Heater Drain Pumps, Moisture Separate-Reheaters, and additional Condensate pumps as well as the second main FW pump.

3.5.15.3 Associated POS 15 Operating Procedures

Commence and complete GOP-1.4, Rev. 2 dated 4/23/92.

Commence GOP-1.5, Rev. 4 dated 4/25/92 and complete up to step 5.3.26.

Dilution with blender to HSD boron concentration IAW OP-8.3.2.

3.6 Characterization of Mid-Loop POSs

Three mid-loop POSs were considered in this study, POSs 6 and 10 of a refueling outage, and POS 6 of a drained maintenance outage. Early in a refueling outage, the plant goes into mid-loop operation, POS R6, to perform eddy current test of the steam generator tubes. In approximately half of the refueling outages at Surry, the plant went into the second mid-loop, POS R10, after the refueling operation was completed. In a drained maintenance outage, the plant goes into mid-loop operations, POS D6, for the needed maintenance. In this section, the configuration of the plant during mid-loop operations is described, and the differences between the mid-loop POSs discussed. These descriptions are based on the past refueling outages. The refueling outage of unit 1 that started in March 1992 deviated significantly from the past practice. In this outage, Unit one avoided entering mid-loop operation. This study on mid-loop operations is based on the experience before the March 1992 refueling outage.

Mid-loop level is defined to be somewhere between 12.8 and 12.5 feet, the latter being the level of mid-nozzle. Figure 3-1 shows the connection of the standpipe system to the vessel head vent. The pressurizer PORVs are open connecting the pressurizer to the pressurizer relief tank, which is vented to the process vent system through a 3/4 inch line. The vessel head vent is connected to the discharge side of the PORVs through piping that consists of a section of tygon tube which can withstand approximately 40 psia of pressure.

The latest procedure for draining the RCS, 1-OP-RC-005, requires the use of a reduced inventory checklist, (Table 3-11). The reduced inventory is defined as 15.3 feet and below. In addition to the requirements specified in the Surry's response to generic letter 88-17, the A and C reserve station service supplies, and EDGs 1 and 3 are required to be operable, and the batteries cannot be cross-tied. Containment closure is required within first 150 hours of shutdown.

One important difference between the mid-loop POSs is the level of decay heat which is determined by the time after shutdown when the POS is reached, and the duration of the POS. Table 3-12 lists the key characteristics of the time to and duration of mid-loop of the three POSs. The distributions of the times were estimated using Surry data. Appendix D documents the statistical analysis of time to and duration of mid-loop. To account for the variability of the decay heat when the accident initiating event occurs, the time-window approach was developed. Four time windows are defined, each with a different set of success criteria. Sections 5.4 and 7.2 discuss the time window approach. Table 3-13 lists the definition of the time windows, and the conditional probability that the accident initiating event occurs in the time window. The probability was estimated from the distributions for time to mid-loop and duration of mid-loop; the analyses are described in Section 9.3 and appendix D.

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Isolation of the reactor coolant loops has a very important effect on the ability to use steam generators to remove decay heat. During mid-loop operation, one such method of mitigating a loss of RHR is reflux cooling. Chapter 9 documents the data collected on isolation of the loops. In reviewing the outage experience, we found that in one out of three refueling outages, the loops were isolated before reaching mid-loop, i.e. POS 6. In the other two outages, the loops were isolated during mid-loop operations. Once the loops were isolated in POS 6, they remain isolated until POS 12 was entered. Therefore, in POS 10, all 3 loops are assumed to be isolated. The outage logbooks also showed that no more than one loop is isolated in a drained maintenance outage, typically because a corrective maintenance of equipment associated with one loop is needed. Therefore, we assumed that one loop is isolated in a drained maintenance. Table 3-14 lists the probability that the RCS loops are isolated, so that the success criteria for reflux cooling cannot be satisfied, as a function of the time windows and POSs.

In an outage that is expected to stay in cold shutdown more than 5 days, the secondary side of the steam generators is usually filled with water in the "wet layup" condition, i.e. 98 to 100% on the wide range instrumentation. Therefore, the steam generators serve as a heat sink for the reactor coolant system if the

reactor coolant loops are not isolated. Sludge lancing operation is a condition that may require the steam generators be drained. The fraction of time that the steam generators are drained was estimated to be 0.83% (see Chapter 9).

In reviewing the log books, we recognized that, in the past refueling outages, the safety valves on the pressurizer were removed for an extended period of time; they were removed while the RCS was in mid-loop, and re-installed after the refueling job was complete and the vessel head set. Removal of the safety valves provided a large vent of the RCS and could relieve the system pressure, when needed. It allows gravity feed from RWST. On the other hand, reflux cooling becomes impossible, due loss of inventory through the opening. The effects of safety valve removal are modeled in the fault trees and event trees.

Based on the log books of the 3 refueling outages, and the outage plan of the 1992 unit 1 refueling outage, the safety valves are removed approximately 2 weeks into the refueling outage, and re-installed after refueling operation is completed. Table 3-15 lists the probability that the safety valves are removed in each of the time windows; the estimates were based on the above information. For a drained maintenance, it is assumed that the pressurized safety valves are not removed.

3.7 References:

1. T.L. Chu, et al., "Improved Reliability of Residual Heat Removal Capability in PWRs as Related to Resolution of Generic Issue 99," Brookhaven National Laboratory, NUREG/CR-5015, BNL-NUREG-52121, May 1988.
2. K. L. Kiper, et al., "Seabrook Station Probabilistic Safety Study, Shutdown(modes 4,5, and 6)," New Hampshire Yankee, May 1988.

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3. D. C. Bley, et al., "Zion Nuclear Plant Residual Heat Removal PRA," EPRI/NSAC Report NSAC-84, prepared by Pickard Lowe, and Garrick, Inc., July 1983.
4. J. M. Mattei and G. Bars, "Probabilistic Analysis of 900 MWe PWR Shutdown Technical Specifications," Proceedings of Probabilistic Safety Assessment and Risk Management, PSA '87," August 30 - September 4, 1987.

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NOTE: The valve designators are for location only.
They DO NOT indicate valve position.

Figure 3-1 Connection of the Standpipe System to the Vessel Head Vent
NUREG/CR-6144 3-20

Table 3-1**Operational Modes Defined in Technical Specifications of the Surry Plant**

1. Refueling Shutdown - When the reactor is subcritical by at least 10% $\Delta k/k$ and T_{avg} is $\leq 140^{\circ}\text{F}$ and fuel is scheduled to be moved to or from the reactor core.
2. Cold Shutdown Condition - When the reactor is subcritical by at least 1% $\Delta k/k$ and T_{avg} is $\leq 200^{\circ}\text{F}$.
3. Intermediate Shutdown Condition - When the reactor is subcritical by amount greater than or equal to 1.77% $\Delta k/k$ and $200^{\circ}\text{F} < T_{avg} < 547^{\circ}\text{F}$.
4. Hot Shutdown Condition - When the reactor is subcritical by an amount greater than or equal to 1.77% $\Delta k/k$ and T_{avg} is $\geq 547^{\circ}\text{F}$.
5. Reactor Critical - When the neutron chain reactor is self-sustaining and $k_{eff} = 1.0$.
6. Power Operation - When the reactor is critical and the neutron-flux power-range instrumentation indicates greater than 2% of rated power.
7. Refueling Operation - Any operation involving movement of core components when the vessel head is unbolted or removed.

3 Outage Types & POSS

Table 3-2 Operational Modes

Westinghouse Standard Technical Specifications Rev. 3

Mode	Reactivity Condition, K_{eff}	% Rated Thermal Power*	Average Coolant Temperature
1. Power Operation	≥ 0.99	$> 5\%$	$\geq 350^{\circ}\text{F}$
2. Startup	≥ 0.99	$\leq 5\%$	$\geq 350^{\circ}\text{F}$
3. Hot Standby	< 0.99	0	$\geq 350^{\circ}\text{F}$
4. Hot Shutdown	< 0.99	0	$350^{\circ}\text{F} \geq T_{avg} > 200^{\circ}\text{F}$
5. Cold Shutdown	< 0.99	0	$\leq 200^{\circ}\text{F}$
6. Refueling**	≤ 0.95	0	$\leq 140^{\circ}\text{F}$

* Excluding decay heat.

** Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

Table 3-3

Outage Types and Their Estimated Frequencies
(based on data in 1985-1989)

	# of Events	Frequency
1. Non-Drained Maintenance (N1) (with RHR System)	8	0.8/yr
2. Non-Drained Maintenance (N2) (without RHR System)	24	2.4/yr
3. Drained Maintenance (D)	12	1.2/yr
4. Refueling (R)	6	0.6/yr

3 Outage Types & POSSs

Table 3-4

**Parameters Used in the Definition and
Characterization of POSSs**

Frequency
Plant Configuration
System Availability
Shutdown Activities
Time to Core Uncovery
Maintenance Unavailability
RCS Integrity
Containment Integrity
Reactivity
Reactor Coolant Temperature
Reactor Coolant Pressure
Reactor Vessel Level
Time after Shutdown
Duration of POSSs

Table 3-5
Plant Operational States for Surry Unit 1 - Low Power and Shutdown Outage Activities

		Times ⁽¹⁾ 10/86 Outage	Activities	Level	K	T F	P psig	Surry T.S.	Standard T.S. Mode	Operating Procedures ⁽³⁾
1	Low Power Operation & RX Shutdown	18 Minutes	• Transfer to manual RX control • Transfer to manual SG level control	In Przr.	=1.0 (<15% Power)	547	2235		1,2	GOP-2.2 GOP-2.3 OP-58.2.1
		0			≤0.9823 TS ⁽³⁾	547	2235	HSD		
2	Cooldown With SG	27 hours 18 minutes	• Borate RCS • Stop 2 RCPs • Block auto SI & accumulators • Establish LTOP <350°F		<1.0				3	GOP-2.4 OP-8.3.3
		27:18		In Przr.	<0.96Ad m ⁽⁴⁾	345	345	ISD		
3	Cooldown With RHR	6 hours 48 minutes	• Disable Engineered Safeguards • Initiate RHR						4	GOP- 2.5 OP-14.1
		34:06		In Przr.	<0.96Ad m ⁽⁴⁾	200	345	CSD		

Table 3-5 (continued)

		Times ⁽¹⁾ 10/86 Outage	Activities	Level	K	T F	P psig	Surry T.S.	Standard T.S. Mode	Operating Procedures ⁽³⁾
4	Cooldown With RHR	46 hours 45 minutes	• No longer need Ctmt Integrity or Ctmt vacuum ⁽⁵⁾ • Secure SGs						5	GOP- 2.6 OP-14.6 OP-31.2,- 31.3,-63.1
		80:51		In Przr.	<0.96Ad m ⁽⁴⁾	140	345	CSD		
5	Drain RCS To Mid- loop	19 hours 7 minutes	• Deenergize Przr heaters • Stop last RCP • Cooldown Przr by fillup						5,6	OP-RC-004 OP-RC-005 OP-5.1.3 OP-8.4
		95:58		Mid- loop	<0.96Ad m ⁽⁴⁾	<1 40	0	CSD		
6	Mid-loop Operation	41 hours 38 minutes	• Possible loop isolation						5,6	MOP-5.3 -5.4 -5.5
		141:36		Mid- loop	<0.96Ad m ⁽⁴⁾	<1 40	0	CSD		

Table 3-5 (continued)

		Times ⁽¹⁾ 10/86 Outage	Activities	Level	K	T F	P psig	Surry T.S.	Standard T.S. Mode	Operating Procedures ⁽³⁾
7	Fill for Refueling	234 hours 27 minutes	- Remove vessel head & upper internals structure - Establish Refueling Cmt Integrity						6	OP-4.1 5.8.1 5.8.2 OP-7.1.2
		376:03		Refue l Cavity Full	<0.95TS ⁽²⁾	<1 40	0	CSD		
8	Refueling	437 hours 28 minutes	Move fuel assemblies per refueling sequence						6	OP-4.1
		813:31		Refue l Cavity Full	<0.95TS ⁽³⁾	<1 40	0	CSD		

Table 3-5 (continued)

		Times ⁽¹⁾ 10/86 Outage	Activities	Level	K	T F	P psig	Surry T.S.	Standard T.S. Mode	Operating Procedures ⁽³⁾
		933:22		Mid-loop	0.96Adm ⁽⁴⁾	<1 40	0	CSD		
1 0	Mid-loop Operation After Refueling	52 hours 15 minutes	• Possible further loop isolation						5,6	MOP-5.3 -5.4 -5.5
		985:36		Mid-loop	<0.96Adm ⁽⁴⁾	<1 40	0	CSD		
1 1	Refill RCS completely	49 hours 23 minutes	• Pressurize RCS & jog RCP for RCS vent & Fill • Unisolate any and all loops						5,6	GOP-1.1 OP-5.8.2 5.1.1 5.2.1 MOP-5.6,-5.7, or -5.8
		1034:59		RCS Full	<0.96Adm ⁽⁴⁾	<1 40	<12 5	CSD		

Table 3-5 (continued)

		Times ⁽¹⁾ 10/86 Outage	Activities	Level	K	T F	P psig	Surry T.S.	Standard T.S. Mode	Operating Procedures ⁽³⁾
1 2	RCS Heatup Solid and Draw Bubble	271 hours 46 minutes	• Pressurize RCS, start RCP & energize Przr. htrs • Establish Ctmt. Integrity and Ctmt. vacuum						5	GOP-1.1 OP-5.2.1 OP-5.12
		1306:45		In Przr.	<0.98Ad m ⁽⁴⁾	200	345	CSD		
1 3	RCS Heatup	13 hours 48 minutes	• Start other RCPs • Enable Engineered Safeguards • Secure RHR						4	GOP-1.1 GOP-1.2 GOP-1.3 OP-14.2
		1320:33		In Przr.	<0.9823 TS ⁽³⁾	350	≈34 5	ISD		

Table 3-5 (continued)

		Times ⁽¹⁾ 10/86 Outage	Activities	Level	K	T F	P psig	Surry T.S.	Standard T.S. Mode	Operating Procedures ⁽³⁾
		1373:16		In Przr.	≤ 0.9823 TS ⁽²⁾	547	2235	HSD		
1 5	RX Startup & Low Power Operation	22 hours 34 minutes	• Flow test TDAFW • Transfer to auto SG level • Transfer to auto RX control		≈ 1.0 ($< 15\%$ power)	547	2235		1,2	GOP-1.4 GOP-1.5 OP-8.3.2
1396:07										
Full Power Operation										

- (1) The time is based on the October 1986 refueling outage of Unit 2. Both duration of POS and cumulative time after shutdown are shown.
- (2) The operating procedures listed are based on the most updated information as of yet. Some of these procedures' numberings are different from those prevailing in October 1986.
- (3) Shutdown Margin Requirements - Per Technical Specifications (1.0 Definitions)
 CSD(Cold Shutdown) Condition - RX subcritical by at least $1\% \Delta K/K$ ($\therefore K \leq \approx 0.99$) and T_{avg} is $\leq 200^\circ\text{F}$.
 ISD(Intermediate Shutdown) Condition - RX subcritical by $\geq 1.77\% \Delta K/K$ ($\therefore K \leq \approx 0.9823$) and T_{avg} is $> 200^\circ\text{F}$ but $< 547^\circ\text{F}$.
 HSD(Hot Shutdown) Condition - RX subcritical by $\geq 1.77\% \Delta K/K$ ($\therefore K \leq \approx 0.9823$) and T_{avg} is $> 547^\circ\text{F}$.
- (4) Shutdown Margin Administrative Limits - Per 1-OP-1C, Shutdown Margin Calculation

A further requirement states that except for during the approach to criticality, the minimum boron concentration allowed in a shutdown core must be the greater of the following:

Critical Boron for the 0% power insertion limit OR

The boron required to maintain the administratively (Adm*) required shutdown margin > 5500 pcm ($K=0.945$) from BOL (beginning of life) to 9000 MWD/MTU and > 4000 pcm ($K \approx 0.960$) after 9000 MWD/MTU.

- (5) As in the recently implemented OP-RC-005, before entering Reduced Inventory within 150 hours of shutdown, containment integrity must be established.

3 Outage Types & POSs

Table 3-6

Estimated Durations of Plant Operational States

(based on data in 1985-1989)

Plant Operational State	Refueling (R)	Drained Maintenance (D)	Non-Drained Maintenance (w.RHRS) (N1)	Non-Drained Maintenance (w/o RHRS) (N2)
1	0.56	0.7	0.1	0.56
2	22.3	15.1	12.3	15.
3	10.7	13.6	16.8	
4	154.4	196.3	127.9	
5	45.5	20.2		
6	183	202		
7	374.0			
8	810.8			
9	206.			
10	107			
11	118.	44.1		
12	1840.	175		
13	34.4	10.3		
14	69.	40.4	21.	
15	56.1	12.7	18.6	9.93

Table 3-7 Duration of Plant Operational States - Non-Drained Maintenance w.RHR (N1)

DATE	UNIT	POS 1	POS 2	POS 3	POS 4	POS 5	POS 6	POS 7	POS 8	POS 9	POS 10	POS 11	POS 12	POS 13	POS 14	POS 15
		hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min
02/16/86	Surry 2	0 2	13 41	14 3	143 82	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	18 1	15 54
07/23/86	Surry 2	0 17	6 28	7 49	44 100	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	20 7	2 46
09/19/86	Surry 1	0 0	12 5	9 19	66 63	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	17 33	70 9
06/08/87	Surry 1	0 11	13 3	55 7	253 70	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	16 2	4 55
09/20/87	Surry 1	0 0	16 47	13 43	166 42	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	36 18	6 17
10/03/87	Surry 1	0 5	11 28	4 32	73 56	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	16 4	5 14
11/26/87	Surry 1	0 6	8 25	12 34	111 79	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	19 15	16 16
03/27/88	Surry 2	0 0	16 57	17 40	158 95	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	24 57	27 57
	TOTAL	0 41	95 234	131 227	1014 587										166 137	145 268
MEAN DURATION OF POS		0.08	12.3	16.8	127.9										21.0	18.

Table 3-8 Duration of Plant Operational States - Non-Drained Maintenance w/o RHR (N2)

DATE	UNIT	POS 1	POS 2	POS 3	POS 4	POS 5	POS 6	POS 7	POS 8	POS 9	POS 10	POS 11	POS 12	POS 13	POS 14	POS 15
		hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min
01/13/85	Surry 1	0 12	19 30	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 10
01/13/85	Surry 1	0 0	2 28	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	2 2
01/26/85	Surry 1	0 0	17 11	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	5 6
01/27/85	Surry 1	0 0	11 53	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	4 47
01/28/85	Surry 1	0 0	5 8	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	2 22
06/ /85	Surry 2	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	2 2
07/ /85	Surry 2	12 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
09/11/85	Surry 1	0 0	12 39	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	9 59
09/27/85	Surry 1	0 49	32 14	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	7 56
11/06/85	Surry 2	0 0	3 31	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	2 23
01/07/86	Surry 1	0 0	8 10	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	9 6
01/19/86	Surry 1	0 0	9 55	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	13 35
02/07/86	Surry 1	0 0	5 8	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	5 19
05/11/86	Surry 2	0 0	19 25	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	9 15
12/01/86	Surry 2	0 0	0 59	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	36 48
04/04/87	Surry 2	0 0	7 30	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	30 49
08/07/87	Surry 1	0 0	20 18	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	9 57
02/16/88	Surry 1	0 0	16 27	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	7 34
03/11/88	Surry 1	0 35	48 33	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	6 4
08/15/88	Surry 1	0 0	35 22	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	20 44
07/09/89	Surry 1	0 0	17 9	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	5 10
09/19/89	Surry 2	0 0	6 71	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	13 4
09/22/89	Surry 2	0 0	19 49	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
09/28/89	Surry 2	0 0	40 40	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	21 54
TOTAL		12 96	350 670													226 597
MEAN DURATION OF POS		0.56	15.0													9.8

Table 3-9 Duration of Plant Operational States - Drained Maintenance (D)

DATE	UNIT	Pos 1		POS 2		POS 3		POS 4		POS 5		POS 6		POS 7		POS 8		POS 9		POS 10		POS 11		POS 12		POS 13		POS 14		POS 15	
		hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min	hrs	min
04/29/85	Surry 1	0	0	8	7	14	45	40	40	31	10	153	25	0	0	0	0	0	0	0	0	47	39	26	11	10	0	27	3	15	56
08/06/85	Surry 1	0	0	16	29	10	15	60	47	17	53	42	30	0	0	0	0	0	0	0	0	99	25	69	18	11	12	27	9	30	19
10/29/85	Surry 2	0	23	12	19	12	31	3	43	32	34	79	23	0	0	0	0	0	0	0	0	61	50	165	131	7	52	72	130	3	34
01/24/86	Surry 1	0	0	11	10	12	30	38	20	12	50	180	101	0	0	0	0	0	0	0	0	20	24	28	53	6	4	32	45	5	31
06/17/86	Surry 2	0	0	9	12	16	41	16	49	10	38	190	55	0	0	0	0	0	0	0	0	34	17	39	19	12	31	35	59	5	1
12/11/86	Surry 1	7	20	9	0	11	33	228	92	17	50	1071	60	0	0	0	0	0	0	0	0	43	0	358	90	11	5	36	37	5	28
12/09/86	Surry 2	0	0	9	53	6	50	1264	57	0	0	59	56	0	0	0	0	0	0	0	0	21	46	845	62	14	16	53	31	24	4
05/16/87	Surry 1	0	0	21	36	14	17	17	23	21	37	144	13	0	0	0	0	0	0	0	0	33	0	30	-21	25	45	19	7	7	58
06/23/87	Surry 1	0	18	13	7	7	25	22	2	10	52	10	56	0	0	0	0	0	0	0	0	10	27	17	-8	4	34	24	59	0	50
12/09/87	Surry 2	0	17	8	37	18	33	120	32	35	50	28	19	0	0	0	0	0	0	0	0	24	34	74	-44	6	52	20	59	42	30
05/16/88	Surry 2	0	0	33	31	17	79	215	65	22	41	206	28	0	0	0	0	0	0	0	0	100	63	244	245	5	15	23	49	5	40
10/12/89	Surry 2	0	13	28	73	19	49	325	13	28	73	265	44	0	0	0	0	0	0	0	0	31	78	178	43	8	50	108	70	5	55
	TOTAL	7	91	177	314	156	448	2348	483	235	488	2427	510	0	0	0	0	0	0	0	0	523	403	2073	599	119	316	476	558	146	406
MEAN DURATION OF POS		0.70		15.1		13.6		196.3		20.2		202.		0		0		0		0		44.1		173.		10.3		40.4		12.	

Table 3-10 Duration of Plant Operational States - Refueling (R)

DATE	Unit	POS 1	POS 2	POS 3	POS 4	POS 5	POS 6	POS 7	POS 8	POS 9	POS 10	POS 11	POS 12	POS 13	POS 14	POS 15
		hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min	hrs min
03/20/85	Surry 2	0 42	13 47	15 10	29 18	45 13	11 44	39 103	736 45	667 0	70 141	8 210	24 48	12 18	5 72	54 58
05/10/86	Surry 1	0 55	20 19	10 18	48 18	2 2	61 44	103 0	593 57	0 0	0 0	0 395	3 230	13 20	50 96	15 76
10/04/86	Surry 2	0 18	27 18	6 48	46 45	19 7	41 38	234 27	437 28	119 50	52 15	49 23	274 -10	11 44	52 43	22 51
04/09/88	Surry 1	0 50	33 111	14 95	376 65	24 13	79 21	479 17	537 50	442 30	0 0	37 0	453 31	12 17	63 99	84 46
09/14/88	Surry 1	0 34	16 44	6 8	270 18	21 50	100 0	43 2	1801 75	0 0	0 0	0 0	4626 93	87 30	56 27	46 18
09/10/88	Surry 2	0 4	21 21	10 25	155 28	16 8	680 78	1253 51	756 68	9 52	452 4	18 51	5406 175	69 3	71 32	47 56
10/ /89	Surry	0.85	14.2	14.1	78.45	107.	8.57	405.	342.1	179.	54.2	6.95	463.	8.83	60.4	52.
TOTAL		0 203	130 260	61 204	924 178	271 125	1095 192	2242 136	4860 323	1237 202	645 27	709 101	11500 287	204 149	410 270	333 218
MEAN DURATION OF POS		0.56	0 22.3	0 10.7	0 154.4	0 45.5	0 183.	0 374.	0 810.8	0 206.	0 107.	0 118.	0 1840	0 34.4	69.0	0 56.

Oct. 90 Unit 1 outage was not used in calculating the mean durations

Table 3-11
Reduced Inventory (15.3 ft) Checklist

- 1 Verify that at least one CHARGING PUMP is operable.
- 2 Verify that at least one HIGH HEAD SI or CHG flow path is operable.
- 3 Verify that at least one LOW HEAD SI PUMP is operable.
- 4 Verify that at least one LOW HEAD SI flow path is operable.
- 5 Verify that at least one incore thermocouple is operable on ICC-TRAIN A.
- 6 Verify that at least one incore thermocouple is operable on ICC-TRAIN B.
- 7 Record the Incore Thermocouple Temperatures and RCS STANDPIPE LEVEL every six hours in 1-PT-36, Instrument Surveillance.
- 8 To prevent an RCS Adverse Configuration, verify by red light indication that at least one loop is unisolated (HOT LEG and COLD LEG open with the associated BYP ISOL VV open).

___ LOOP A	___ LOOP B	___ LOOP C
___ MOV-1590 T _H	___ MOV-1592 T _H	___ MOV-1594 T _H
___ MOV-1588 BYP	___ MOV-1586 BYP	___ MOV-1587 BYP
___ MOV-1591 T _C	___ MOV-1593 T _C	___ MOV-1595 T _C

- 9 Verify that 1-OP-1G Refueling Containment Integrity and RCS Mid-Loop Containment Closure Checklist has been performed IAW the NOTE on page 6 of 75.
- 10 Verify that no evolutions are planned that may cause perturbations in the RCS.
- 11 Review the Action Statement Log to determine the status of OC-28, Assessment of Maintenance Activities for Potential Loss of Reactor Coolant Inventory.
- 12 Verify that 1-OPT-RC-10.2, Reactor Coolant System Cold Shutdown Inventory Balance is complete (normally done on day shift with 1-PT-10, Reactor Coolant Leakage).
- 13 Verify that A and C Reserve Station Service supplies are in service.
- 14 Verify that the Cold Shutdown/Refueling Shutdown Minimum Equipment List is complete.
- 15 Verify that the batteries are not cross-tied.
- 16 Verify that EDG 1 and EDG 3 are operable.
- 17 IAW 1-OC-6, Boric Acid Flow Paths and Tech Spec Heat Trace Circuit Verification, verify that Flow Path 5 is available.
- 18 IAW 1-OC-6, verify that Flow Path 7, preferred LHSI flow path or Flow Path 6, acceptable LHS flow path, is available.
- 19 Verify that there are no plans to change the established flow paths defined in Steps 17 and 18

3 Outage Types & POSs

Table 3-12
Time to Mid-loop, and Duration of Mid-loop

Time to Mid-loop	Mean (Hour)	5%	50%	95%	EF
Pos 6 Refuel	191	72.2	167.6	388.8	2.32
Pos 10 Refuel	2619	833	968	4828	2.41
Pos 6 Drained	190	27.0	105	618	4.78

Duration of Mid-loop	Mean (hours)	5%	50%	95%	EF
Pos 6 Refuel	238	14.2	112	876	7.85
Pos 10 Refuel	444	6.3	151	2586	20.3
Pos 6 Drained	255	11.9	109	958	8.97

Table 3-13
Probability that the Initiating Event Occurs in the Time Windows

	WINDOW 1	WINDOW 2	WINDOW 3	WINDOW 4
Definition	<= 75 hours	> 75 hours and <= 240 hours	> 240 hours and <= 32 days	> 32days
Representative Decay Heat	13.23 MW(2days)	10 MW(5 days)	7 MW(12 days)	5 MW(32 days)
D6	0.117 (0.31)*	0.436 (0.454)	0.375 (0.21)	7.20E-02 (2.6E-02)
R6	1.7E-02 (5.82E-02)	0.543 (0.7)	0.41 (0.24)	3.4E-02 (1.48E-03)
R10	0.0	0.0	0.016 (2.2E-02)	9.84E-01 (0.98)

* Applicable only to RHR2A, over-draining event.

3 Outage Types & POSs

Table 3-14

**Probability that the RCS Loops Are Isolated So that
Reflux Cooling Is Unavailable or Ineffective**

	R6	R10	D6
W1	0.3	-	True
W2	0.7	-	False
W3	True	True	False
W4	True	True	False

Table 3-15

Probability that the Safety Valves on the Pressurizer Are Removed

	R6	R10	D6
W1	0.01	-	False
W2	0.05	-	False
W3	0.9	0.9	False
W4	0.3	0.3	False

4 INITIATING EVENT ANALYSIS

This chapter discusses the identification, categorization, quantification of initiating events, and determination of their applicability to the different plant operational states defined in Chapter 3. The scope of the initiating event analysis covers all POSs focussing on those events that may occur during mid-loop operations. Section 4.1 discusses the approach used in the initiating event analysis and summarizes the identified initiating events. Sections 4.2 to 4.11 gives a detailed analysis of each event, including the data base collected for their applicability to different POSs, their categorization of initiating events, and the impacts that the initiating events have on the plant. Point estimates of the initiating events were provided for all initiating-event categories. Probability distributions for the frequencies of loss of RHR categories and some support system failures were estimated, using the two-stage Bayesian approach. Section 4.12 summarizes the initiating events that are applicable to the mid-loop POSs. These initiating events are the starting points of the event tree analysis documented in chapter 7.

4.1 Approach and Summary

Table 4.1-1 summarizes the approach used to identify initiating events that may occur when the plant is operating at low power or shutdown conditions. Basically, we made a systematic search of actual events, as well as identified accident scenarios. A systematic search of all possible accident scenarios was not attempted, and was considered beyond the scope of the study. Methods that can be used in a systematic search are failure mode and effect analysis, hazard and operability analysis^[1], master logic diagrams^[2], and heat balance fault tree^[2]. The effort needed to apply these methods systematically was beyond our resources. Table 4.1-2 lists the initiating event categories or accident scenarios identified.

The initiating event frequency was quantified for each POS, basically using data collected for the initiating event categories. In principle, the rate of an initiating event varies with POSs. However, in many cases, there was insufficient information to determine the relative likelihood that an initiating event may occur in the POSs that it is applicable to; therefore, the same frequency was used for all applicable POSs. Depending on the type of data collected for the initiating event category, some what different statistical approaches were used. In the case of loss of RHR categories and loss of support-system initiating events, both population and plant specific data were collected, and the two-stage Bayesian approach^[3] was used. When only plant specific data was available, a simple Bayesian update was done. The prior distributions of the simple updating were taken from generic data sources, or determined by developing some simple fault trees for the events of interest. Appendix A summarizes the initiating event data base, and describes those events used in the quantification.

The frequencies are expressed in terms of hourly rate, and the conditional probability that an initiating event occurs in a POS is equal to the frequency times the duration of the POS. In chapter 9, past outage experience was used to estimate the duration of the POSs. The annual frequency that an initiating event occurs in a POS is equal to the frequency of the POS times the probability that the initiating event occurs given that the plant is in the POS. The frequency that an initiating event category, IE_k , occurs in a particular POS j of a particular type of outage, i , can be expressed as

Frequency (outage i) per year * Probability (IE_k | POS j of outage i), where
Probability (IE_k | POS j of outage i) = hourly rate (IE_k) * duration of POS j of outage i .

In the time window approach, the frequency that an initiating event occurs in a given time window, window ℓ , of a particular POS j of a particular type of outage type, i , is the above frequency multiplied by the

4 Initiating Event Analysis

conditional probability of the time window given that the initiating event occurred in the specified POS and outage type, i.e.,

Frequency (outage i) per year * Probability(IE_k | POS j of outage i) * Probability (window ℓ | IE_k in POS j of outage i).

In Chapter 9, the results of statistical analyses of time to, and duration of mid-loop were used to estimate the conditional probability of the time windows. This frequency is calculated using the fault tree for the first top event of the event trees. The rest of the event trees then are used to calculate the conditional probability of the accident scenarios, given that the initiating event category IE_k had occurred in window ℓ of POS j of outage i. With this formulation, the core damage frequency is expressed in units of per year, and is additive. (The sum of frequencies from different windows and POSs is meaningful). It represents the frequency that core damage occurs in the time window of the POS and accounts for the amount of time the plant is in the window and POS.

Table 4.1-2 summarizes the initiating event categories. Table 4.1-3 is a summary of the initiating events that are applicable to the POSs, and, Table 4.1-4 is the estimated frequencies of the initiating event categories.

The rest of this section discusses in more detail the approach and the resulting initiating events identified.

4.1.1 Review of Existing Shutdown Studies

We reviewed three existing studies to identify potential initiating events; NSAC-84^[4], Seabrook shutdown study^[5], and NUREG/CR-5015^[6]. NSAC-84 considered loss of RHR, loss of offsite power, LOCAs, and low temperature over-pressurization. The Seabrook shutdown study considered loss of RHR, loss of offsite power, loss of component cooling water, loss of service water, LOCAs, and low temperature over-pressurization. NUREG/CR-5015 considered loss of RHR, LOCAs, loss of offsite power, loss of service water, and loss of component water. Two French studies were completed on the core-damage risk while the reactor is at power or shutdown; however, only a summary report^[7] on the 900 MW plant was available to BNL at this time. Based on this report and the papers^[8-10] presented at the C.S.N.I. meeting, the French studies included LOCAs, ATWS, secondary line break, SGTR, transients loss of heat sink, loss of SG feedwater, and blackout. These initiating events are included in the list in Table 4.1-2.

4.1.2 Review of Procedures Used during Shutdown

Indices to various procedures were obtained from the Surry station, including operating procedures, periodic test procedures, abnormal procedures, maintenance procedures, operational check lists, and emergency procedures. Our main objective was to understand the activities going on during an outage. In reviewing the indices, those procedures that are considered relevant were identified. Table 4.1-5 lists the operating procedures that were reviewed in details by a team of nuclear engineers, and a former senior reactor operator. The procedures were discussed step by step, with questions raised and related information requested or collected. An outage plan for the refueling outage of Unit 1 in October 1990 also was obtained and compared with the related operating procedures. The control room log book for the refueling outage of unit 1 in 1986 was also reviewed line by line by the team, who achieved a common knowledge of the plant design and operations during the process. Potential initiating events that may occur in a given plant configuration also were discussed. However, no systematic approach was used to identify initiating events. During the review, the following initiating events, or scenarios, were recognized:

- (a) potential challenge to PORVs during the period when the pressurizer is solid,
- (b) an inadvertent depressurization of RCS with one or more reactor coolant pumps running may lead to RCP seal failure due to the loss of the required 300 psid across the seal,
- (c) there is a period in a refueling outage during which the thimble tubes are retracted and sealed with temporary seal, and the RCS may be closed; this configuration may be more vulnerable than the adverse configuration for mid-loop operations, so consideration should be given to the effect of bypass between cold and hot legs in the vessel,
- (d) potential challenge to RCS integrity and pressure relief capability in case of a loss of RHR event.

4.1.3 Review of Initiators for Power Operations

The generic transients for PWRs in NUREG/CR-4550, Volume 1, were reviewed for their applicability to low power and shutdown conditions. In most cases, they apply to conditions in which steam generators are used for heat removal (POSs 1,2,14,15). When RHR is in operation, some transient initiating events still apply, e. g., loss of component cooling. (Their categorization is discussed in sections 4.4 and 4.9).

The team also examined the subtle interactions considered in NUREG-1150 to determine their applicability to Surry shutdown conditions. Support system failures, and the failure mode and effect analysis performed for Surry in the NUREG-1150 study were also reviewed for their applicability to low power and shutdown conditions. Section 4.4 discusses the support system failures that may lead to an initiating event for low power and shutdown conditions.

Applicable initiating events were sought in the Surry Individual Plant Examination^[11]. Loss of emergency switchgear room cooling was identified as an important initiating event in the IPE, and was included in this study as an initiating event.

4.1.4 Review of NRC Generic Letters, Information Notices, Bulletin, and Circulars

NRC generic letters, information notices, bulletins, and circulars were reviewed to identify potential initiating events, and the potential degradation of systems that can be used to mitigate the consequences of initiating events. The objective was to identify NRC concerns and ensure the study will be able to address the issues identified. Table 4.1-6 summarizes the findings of the review and Appendix B gives more details on and describes the way the issues can be modeled.

4.1.5 Review of Other Documents

NUREG/CR-4999^[12] addresses the low temperature over pressurization (LTOP) issue that may occur in a shutdown. NUREG/CR-4982^[13] discusses a spent fuel pool accident and identifies failure of refueling cavity seals and fuel transfer cask drop as accident scenarios during a refueling outage. These scenarios are considered beyond the scope of the study, because they are accidents related to the fuel outside the vessel. Westinghouse identified the scenario^[14] that may happen in a mid-loop operation and could lead to core uncover in only few minutes if the cold leg is open and the hot leg is isolated. NUREG/CR-5368^[15] is a generic study of reactivity accidents for both PWR and BWR; it gives references to various accident scenarios that have been identified. The Surry specific design and operational considerations were used to judge the applicability of the scenarios. Two NUREG reports^[16,17] on incidents at Diablo Canyon and Vogtle were also reviewed. NUREG-1410 identified the potential vulnerability due to the use of temporary seals at the seal

4 Initiating Event Analysis

table during refueling. BNL is evaluating the more general question of the capability of the RCS to relieve pressure in different scenarios. NUREG-1410 also identified the issue of reflux cooling while the RCS is in a partially drained condition. The Diablo Canyon event can be considered a successful experiment on reflux cooling. NUREG/CR-5472^[18] addresses loss of instrument air events in nuclear power plants. The BNL review concentrated on identifying the events that can be considered total loss of this system in PWRs.

4.1.6 References

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5. Kiper, K.L., et al., "Seabrook Station Probabilistic Safety Study, Shutdown(modes 4,5, and 6)," New Hampshire Yankee, May 1988.
6. Chu, T.-L. et al., "Improved Reliability of Residual Heat Removal Capability in PWRs as Related to Resolution of Generic Issue 99," Brookhaven National Laboratory, NUREG/CR-5015, BNL-NUREG-52121, May 1988.
7. "A Probabilistic Safety Assessment of the Standard French 900 MWe Pressurized Water Reactor", Institute de Protection et de Surete Nucleaire, EPS 900, Main Report, April 1990.
8. Berger, J.P., (Project Manager of EFF EPS 1300), "Probabilistic Safety Assessment at EDF," Presented at the Meeting of Committee for Safety of Nuclear Installations, Santa Fe, New Mexico, September 1990.
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11. "Probabilistic Risk Assessment for the Individual Plant Examination", Final Report, Surry Units 1 and 2, Virginia Electric and Power Company, August 1991.
12. Hsu, C.J., et al., "Estimation of Risk Reduction from Improved PORV Reliability in PWRs," NUREG/CR-4999, BNL-NUREG-52101, March 1988.

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13. Sailor, V.L., et al., "Severely Accident in Spent Fuel Pools in Support of Generic Safety Issue 82," NUREG/CR-4982, BNL-NUREG-52093, July 1987.
14. Letter from R.A. Newton, Chairman Westinghouse Owners Group, to Westinghouse Owners Group Primary Representatives, on "Westinghouse Owners Group Early Notification of Mid-loop Operation Concerns," May 27, 1988.
15. Diamond, D.J., Hsu, C.J., and Fitzpatrick, R.G., "Reactivity Accidents" NUREG/CR-5368, January 1990.
16. "Loss of Residual Heat Removal System," Diablo Canyon, Unit 2, April 10, 1987, NUREG-1269, U. S. NRC, June 1987.
17. "Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle unit 1 on March 20, 1990," NUREG-1410, U.S. NRC June 1990.
18. DeMoss, G., et al., "A Risk-Based Review of Instrument Air Systems at Nuclear Power Plants," NUREG/CR-5472, BNL-NUREG-52220, January 1990.

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Table 4.1-1 Approach Used in Identifying Initiating Events

1. Loss of RHR Events

Review of Shutdown Incident Reports
NSAC-52, AEOD/C503, Seabrook Shutdown Study
Search of Computerized Data Base-Sequence Coding Search System

2. Review of Existing Shutdown Studies

NSAC-84, Seabrook, French Study, NUREG/CR-5015

3. Review of Procedures Used at Shutdown

Operating Procedure, Test Procedure, Maintenance Procedure

4. Review of Initiating Events for Power Operations

NUREG/CR-4550 Volume 1, Generic Transients for PWRs
NUREG/CR-4550 Volume 3, Support System Failures, Subtle Interactions
Surry Probabilistic Risk Assessment for the Individual Plant Examination

5. Review of NRC Generic Letters, Information Notices, Bulletin, circulars

6. Review of Other Studies That Identified Scenarios at Shutdown

NUREG/CR-4999 Low Temperature Over Pressurization
NUREG/CR-5368 Reactivity Accidents
NUREG-1269 Diablo Canyon Incident Augmented Investigation
Team Report
NUREG-1410 Vogtle Incident Investigation Team Report
WCAP-11916 Loss of RHRS While the RCS is Partially Filled
Westinghouse PRA of LOCAs in Modes 3 and 4
NUREG/CR-4407 Pipe Break Frequency Estimation for NPP

Table 4.1-2 Initiating Events Categories

I. Loss of RHR

- RHR1. Spurious Closure of RHR Suction Valves (R1)
- RHR2. Loss of RHR due to Low Vessel Inventory
  - A. overdraining during drain down (RA)
  - B. failure to maintain level (RB)
- RHR3. Total Non-recoverable Loss of RHR (R3)
- RHR4. Loss of operating Train of RHR (R4)
- RHR5. Recoverable Loss of RHR (R5)
- RHR6. Inability to Initiate RHR (R6)

II. Loss of Offsite Power (LOOP) and Station Blackout

III. Support System Failures

- Loss of a 4 kV Bus (4 K)
- Loss of a DC Bus (DC)
- Loss of a 120 V Vital AC Bus (VB)
- Loss of Instrument Air (AR)
- Loss of Component Cooling Water (CC)
- Loss of Service Water (SW)
- Loss of Emergency Switchgear Room Cooling (SR)

IV. LOCAs

- Pipe Ruptures in RCS
  - A: Large LOCA
  - S1: Medium LOCA
  - S2: Small LOCA
  - S3: Small-Small LOCA
- H LOCA-Diversion of Flow
- J LOCA-LOCAs in Connected Systems
- K LOCA-Maintenance Induced LOCAs

V. Interfacing System LOCA

VI. Steam Generator Tube Rupture (SGTR)

VII. Inadvertent Safety Feature Actuation (SI)

4 Initiating Event Analysis

Table 4.1-2 Initiating Events Categories (Continued)

VIII. Transients

- T2: Transient with loss of MFW (no challenge to RPS)
- T2a: Transient with loss of MFW (challenge to RPS)
- T3: Transient with MFW Available (no challenge to RPS)
- T3a: Transient with MFW Available (challenge to RPS)

IX. Pressurized Thermal Shock

X. Reactivity Accidents

- Addition of Diluted Accumulator Water
- Addition of Diluted RWST Water
- Dilution When Cleaning Cavity
- Dilution due to Steam Generator Maintenance
- Uncontrolled Boron Dilution from CVCS
- Boron Dilution via RHR
- Startup of RCP after Improper Boron Dilution
- Backfill Cooldown after STGR
- Rod Ejection
- Misloading of Fuel Assembly
- Uncontrolled Bank Withdraw

XI. Heavy Load Drop Accident

Table 4.1-3 Applicability of Initiating Events to Plant Operational States

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
I. Loss of RHR															
RHR1															
RHR2A, RHR2B						6				10					
RHR3			3	4	5	6	7	8	9	10	11	12	13		
RHR4			3	4	5	6	7	8	9	10	11	12	13		
RHR5			3	4	5	6	7	8	9	10	11	12	13		
RHR6			3												
II. Loss of Offsite Power															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
III. Support System Failures															
Loss of a 4 kV Bus (4 K)															
Loss of a DC Bus (DC)															
Loss of a 120 V Vital Bus (VB)															
Loss of Instrument Air-Outside Containment (AR)															
Loss of Component Cooling Water (CO)															
Loss of Service Water (SW)															
Loss of Emergency Switchgear Room Cooling (SR)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
IV. LOCAs															
LOCAs (pipe ruptures)															
A	1	2	3	4								12	13	14	15
S1	1	2	3	4								12	13	14	15
S2	1	2	3	4								12	13	14	15
S3	1	2	3	4								12	13	14	15
V	1	2	3	4								12	13	14	15
H-RECOVERABLE FLOW DIVERSION															
VIA RHR			3	4	5	6			9	10	11	12	13		
VIA CVCS	1	2	3	4	5	6			9	10	11	12	13	14	15
J-LOCAs IN CONNECTED SYSTEM															
VIA RHR			3	4	5	6			9	10	11	12	13		
VIA CVCS	1	2	3	4	5	6			9	10	11	12	13	14	15
K-MAINTENANCE INDUCED															
VIA RCS	1	2	3	4	5	6			9	10	11	12	13	14	15
VIA RHR			3	4	5	6			9	10	11	12	13		

4 Initiating Event Analysis

Table 4.1-3 (continued)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
VIA CVCS	1	2	3	4	5	6			9	10	11	12	13	14	15
V. Interfacing System LOCAs															
LPSI, RHR Suction and Discharge, RHR-CVCS, ACC	1	2												14	15
RHR-RWST			3	4								12	13		
VI. Steam Generator Tube Rupture (SGTR)															
	1	2	3	4								12	13	14	15
VII. Inadvertent Safety Feature Actuation (SI)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
LTOP			3	4								12	13		
VIII. Transient															
T2		2												14	
T2a	1														15
T3		2												14	
T3a	1														15
IX. Pressurized Thermal Shock															
	1	2												14	15
X. Reactivity Accidents															
ACCUMULATOR				4	5	6	7	8	9	10	11	12			
RWST				4	5	6	7	8	9	10	11	12			
CAVITY								8							
SG											11	12			
CVCS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
RHR			3	4	5	6	7	8	9	10	11	12	13		
RCP														14	15
SGTR	1	2												14	15
ROD EJECTION	1	2												14	15
REFUELING								8							
CONTROL BANK	1	2												14	15
French 1														14	
French 2						6				10					
XI. Heavy Load Drop Accident															
				4	5	6	7	8	9	10	11	12			

Table 4.1-4 Estimated Initiating Event Frequency

I. Loss of RHR

	Mean Value	Error Factor
	N.A.	
RHR2A	1.62E-02/DEMAND	1.97
RHR2B	1.220E-05/hr	3.27
RHR3	4.09E-06/hr	3.79
RHR4	5.28E-06/hr	3.82
RHR5	2.12E-05/hr	2.21
RHR6	1.29E-02/DEMAND	1.54

II. LOOP

POS 1,15 POS 2-14
 9.13E-6/hr 6.96E-6/hr

III. Support System Failures

	Mean	Error Factor
Loss of a 4 kV Bus (4 kV) POS 6,10	2.10E-05/hr	2.4
POS 3,4,5,8,9,11,12,13	2.63E-05/hr	2.14
Loss of a 120 V Vital	5.58E-06/hr	3.94
Loss of Instrument Air- Outside Containment	2.12E-06/hr	2.86
Loss of Component Cooling Water	3.76E-06/hr	6.35
Loss of Emergency Switchgear Room Cooling POS 6,10	1.81E-08/hr	4.0
POS 3,4,5,7,8,9,11,12,13	6.13E-08/hr	4.0

4 Initiating Event Analysis

Table 4.1-4 (continued)

IV. Loss of Coolant Accident

	POS 1 & 15	POS 2 & 14	POS 3,4,12,13
A	5.0E-4/y	2.5E-5/y	1.7E-5/y
S1	1.0E-3/y	5.0E-5/y	3.3E-5/y
S2	1.0E-3/y	6.0E-5/y	3.3E-5/y
S3	1.3E-3/y	6.5E-4/y	4.3E-4/y

H - Recoverable Flow Diversion

via RHR 5.0E-3/y

via CVCS 1.0E-3/y

Drain

Valves 1.0E-3/y

J - LOCAs in Connected System

via RHR 5.0E-3/y

via CVCS 3.0E-3/y

K - Maintenance Induced LOCA

via RCS 2.0E-3/y

via RHR 1.0E-3/y

V. Interfacing LOCA

	POS 1	POS 2	POS 14	POS 15
LPSI (CDF)	3.00E-10/y	8.90E-9/y	1.22E-08/y	1.00E-08/y
RHR Suction & Discharge (CDF)	3.2E-8/y	9.3E-7/y	1.28E-6/y	1.0E-6/y
RHR-CVCS (CDF)	3.2E-12/y	9.5E-11/y	1.3E-10/y	1.1E-10/y
ACC	1.8E-7/y	5.4E-6/y	7.4E-5/y	6.1E-6/y

Table 4.1-4 (continued)

	POS 3	POS 4	POS 12, 13
RHR-RWST (CDF)	2.38-8/y	2.92-7/y	9.15-7/y

VI. Steam Generator Tube Rupture

POSs 1,2,14,151.00E-02/yr

POSs 3,4,12,131.00E-03/yr

VII. Inadvertent Safety Feature Actuation Mean   Error Factor

1.06E-04/hr 1.15

VIII. Transients

T2   1.09E-3/hr

T2a   1.82E-3/hr

T3   1.24E-3/hr

T3a   8.3E-3/hr

MeanError Factor

LTOP   POS 3,4,12,131.06E-04/hr1.15

IX. Pressurized Thermal Shock (CDF)   1.05E-07/y**X. Reactivity Accidents (CDF)**

Accumulator8.0E-10/y

RWST   2.5E-10/y

CVCS (French)6.8E-08/y

RCP (French)2.8E-05/y

Refueling   1.2E-07/y

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Table 4.1-5 Operating Procedures that Were Reviewed Step by Step

GOP-2.1 (Rev. 1)
Unit Shutdown, Power Decrease from Maximum Allowable Power to 25% -30% Reactor Power

GOP-2.2 (Rev. 1)
Unit Shutdown, 25% - 30% Reactor Power to 2% Reactor Power

GOP-2.3 (Rev. 1) Unit Shutdown, 2% Reactor Power to HSD

GOP-2.4 (Rev. 1) Unit Shutdown, RCS Cooldown from HSD to 345°F - 350°F

GOP-2.5 (Rev. 1) Unit Shutdown, RCS Cooldown from 345°F - 350°F to 195°F

GOP-2.6 (Rev. 1) Unit Shutdown, RCS Cooldown from 195°F to Ambient

OP-RC-004 (Rev. 1) Draining the RCS to 5% Pressurizer Level (29.0 ft)

OP-RC-005 (Rev. 1) Draining the RCS from 5% Pressurizer Level (29.0 ft) to Mid- Nozzle (12.5 ft.)

OP-8.7 RCS Degasification

OP-14.1 Placing RHR in Service

MOP-5.3 Draining 1A Reactor Coolant LOOP

MOP-5.4 Draining 1B Reactor Coolant LOOP

MOP-5.5 Draining 1C Reactor Coolant LOOP

OP-4.1 Refueling Operations

OP-5.1.1 Filling the Reactor Coolant System

OP-5.1.2 Venting the Reactor Coolant System

OP-14.3 DE-Watering the Reactor Cavity Using RHR

OP-5.8.1 Raising the Reactor Vessel Level Using LHSI

OP-5.8.2 Raising the Reactor Vessel Level Using CVCS

GOP-1.1 (Rev. 2) Unit Startup, RCS Heatup from Ambient to 195°F

GOP-1.2 (Rev. 1) Unit Startup, RCS Heatup from 195°F to 350°F/450 psig

GOP-1.3 (Rev. 3) Unit Startup, RCS Heatup from 350°F/450 psig to HSD

GOP-1.4 (Rev. 2) Unit Startup, HSD to 2% Reactor Power

GOP-1.5 (Rev. 4) Unit Startup, 2% Reactor Power to 25% - 30% Reactor Power

Table 4.1-6
Summary of Review of NRC Information Notices, Bulletin, Generic Letters, and Circulars:
Potential Degradation of Systems that Can Be Used for Accident Mitigation

1. Due to the activities in an outage, transient material and debris may be taken inside the containment. They may clog up the suction from the containment sump in a LOCA. The operability of the low head injection system, inside containment recirculation system, and outside containment recirculation system will be affected. (IN 88-22) Use the June 16, 1988 event as failure data for recirculation pumps. (IN 89-77)
2. During startup, when the power is above 10%, the intermediate power level(25%) trip will be blocked. If the reactor power is lowered below 10%, and two of the four bistable switches fail to reset, then the reactor will not trip until 109%; this applies to both power range and intermediate range channels. Tech. Spec. allows one channel to be taken out of service. (IN 86-105)
3. Common-mode failure to open of four normally closed motor operated valves, that control the service water flow to the recirculation spray heat exchangers. (IN 83-46)

Potential Initiating Events

1. Inadvertent lifting of fuel assembly while lifting the upper internal, February 26, 1986 and Indian Point Oct. 90 ,(NSAC-129, IN88-92,IN 86-58) Damage to fuel assembly during refueling (IEC 80-13).
2. Inadvertent withdrawal of control rod. The events at Vermont Yankee on November 7, 1973 and Millstone 1 on November 12, 1976 can be used as a data.(IN 88-21)
3. Pressurizer surge line movement and deformation due to thermal stratification(IEB 88-11)

4 Initiating Event Analysis

4.2 Loss of RHR Events

The most important source of loss of RHR events is past experience. There are studies^[1-4] that compile and analyze shutdown data, covering the loss of RHR events from 1976 to 1986. Table 4.2-1 gives the period each study covers and the number of loss-of-RHR events included. A computerized system of licensee event reports (LERs), Sequence Coding Search System (SCSS),^[5] was used to search for more recent events (1987 to 1989). Table 4.2-1 also includes some events reported in NUREG-1410,^[6] the report on the Vogtle incident on March 20, 1990. The loss of RHR events from these sources were combined to eliminate duplications, and 266 events were entered into a data base^[7] on a personal computer using the DBASE IV software. Appendix A is a documentation of this data base. An abstract, a one-line summary and references, gives more detail information on the events, are provided for each event. Three hundred and fifty-one events are included in the appendix; the additional 85 events are events used in estimating the frequency of transients and LOCAs. The events are further separated into the categories in Table 4.2-2 and other initiating event categories, i.e., loss of support systems, transients and LOCAs. Appendix A also describes those initiating events that were in the quantification. The categorization of loss of RHR events was based on the Surry-specific design. For example, category RHR1 involves spurious closure of the RHR suction from the hot leg, which occurs as a result of the auto-closure of the valves upon a spurious signal. Surry's suction valves do not have the auto-closure feature. Therefore, such category is not applicable to Surry. The following descriptions define the loss of RHR categories, and their impact on systems that may be used to mitigate the initiating event.

RHR1- spurious closure of RHR suction valves

Surry does not have auto-closure interlock for the RHR suction valves; therefore, it is not applicable to Surry.

RHR2- loss of RHR due to low vessel inventory

This category is caused by failure to maintain inventory needed for RHR operation, while the reactor is in mid-loop operations. Two sub-categories are considered:

(A) over-draining during drain down

This subcategory occurs when the operator fails to stop the drain down process while the RCS is being drained to mid-loop. It occurs at the beginning of the mid-loop operation POS and is modelled as an event that occurs with a probability that can be estimated from experience data.

(B) failure to maintain level

This sub-category occurs during mid-loop operation, as a result of failure to maintain the level in the RCS. It is modelled as an event that may occur with an hourly rate while the RCS in mid-loop operation.

RHR3-This category represents events that lead to failure of the RHR system that is not recoverable within the time frame of the accident.

RHR4-This category represents events that cause failure of the operating train of the RHR system. The standby train of RHR is not affected by the initiating event, and can be put into service.

RHR5-This category represents events that interrupt the operation of the RHR system; it can be restored by restarting.

RHR6-Inability to initiate RHR system

This event happens at the beginning of POS 3 when RHR is expected to start operation.

Frequency of Loss of RHR Events

Table 4.2-2 summarizes the estimated failure rate and failure probability for the loss of RHR categories; using a two-stage Bayesian approach. Data from the PWR population were used to derive a prior distribution which was then updated using Surry-specific data. Table 4.2-3 lists the data used in the analyzing of those initiating events characterized by an hourly rate, including the number of occurrences at each plant, and the time base from which the data was collected. Table 4.2-4 lists the data used for those initiating events characterized by a demand failure probability, from January 1, 1979 to December 31, 1989. The gray book data base^[8] was used to determine the durations of the PWR outages that lasted more than 24 hours during this time period. The amount of time that the plant was on RHR was estimated by reducing the full duration by 57 hours, which is the mean value estimated from Surry data. The total number of hours RHR operation is approximately 1.4 million hours, or 160/year. The time base of Table 4.2-3 also is used in the frequency estimate of spurious safety feature actuation, and some support system failures.

4.2.1 References

1. "Residual Heat Removal Experience Review and Safety Analysis, Pressurized Water Reactors," NSAC-52, January 1983.
2. Ornstein, H., "Decay Heat Removal Problems at U. S. Pressurized Water Reactors," Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, December 1985.
3. Kiper, K.L., et al., "Seabrook Station Probabilistic Safety Study, Shutdown(modes 4,5, and 6)," New Hampshire Yankee, May 1988.
4. Chu, T.-L., et al., "Improved Reliability of Residual Heat Removal Capability in PWRs as Related to Resolution of Generic Issue 99," Brookhaven National Laboratory, NUREG/CR-5015, BNL-NUREG-52121, May 1988.
5. Sequence Coding and Search System, Office of Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission.
6. "Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle Unit 1 on March 20, 1990," NUREG-1410, USNRC, June 1990.
7. "Loss of RHR Data Base," a DBASE IV data base of Loss of RHR event at PWRs throughout the United States, Brookhaven National Laboratory, October 1990.
8. "Licensed Operating Reactors Status Summary Report," Office of Information Resources Management, U.S. N. R. C., NUREG-0020.

4 Initiating Event Analysis

Table 4.2-1 Sources of Loss of RHR Events

	Period Covered	Number of Events
NSAC-52	1978-1982	96
AEOD/C503	1982-1984	74
Seabrook	1982-1986	107
NUREG/CR-5015	1984-1986	46
SCSS LER Search	1987-1989	53
NUREG-1410	1973-1989	52
TOTAL	1973-1990	266

Table 4.2-2 Estimated Frequency of Loss of RHR

Category	Mean	5%	50%	95%	Error Factor
RHR1	Not Applicable				
RHR2A	1.62E-02/Demand	7.56E-03	1.49E-02	2.93E-02	1.97
RHR2B	1.22E-05/HR	2.88E-06	9.42E-06	3.08E-05	3.27
RHR3	4.09E-06/HR	7.78E-07	2.95E-06	1.17E-05	3.79
RHR4	5.28E-06/HR	4.91E-07	3.79E-06	1.45E-05	3.82
RHR5	2.12E-05/HR	8.53E-06	1.89E-05	4.18E-05	2.21
RHR6	1.29E-02/Demand	8.08E-03	1.25E-02	1.92E-02	1.54

4 Initiating Event Analysis

Table 4.2-3 Data Used in Two-Stage Bayesian Analysis

	Plant Name	RHR 2B	RHR 3	RHR 4	RHR 5	4 kV/P6	4 kV	VITAL 120 V	ESF/SSI	CCW	Time (Hour)
1.	Arkansas	0	1	3	2	0	3	0	0	0	4.680 E+04
2.	Beaver Valley	4	0	0	1	0	1	0	0	0	3.337 E+04
3.	Braidwood	0	0	0	0	0	0	0	0	1	3.631 E+03
4.	Byron	1	0	0	0	0	0	0	0	1	8.834 E+03
5.	Callaway	0	0	0	0	0	0	0	0	0	5.147 E+03
6.	Calvert Cliffs	0	2	0	3	1	1	5	0	0	4.4516 E+04
7.	Catawba	0	0	0	0	0	1	1	0	0	1.4490 E+04
8.	Cook	1	0	0	1	0	0	0	0	0	5.4935 E+04
9.	Crystal River	0	1	1	3	0	1	0	0	0	3.2564 E+04
10.	Davis-Besse	0	0	0	2	0	0	1	0	0	4.2621 E+04
11.	Diablo Canyon	1	0	0	0	1	1	2	0	0	1.2239 E+04
12.	Farley	0	1	1	3	1	1	0	0	0	3.1409 E+04
13.	Fort Calhoun	0	0	0	0	0	1	0	0	0	1.9873 E+04
14.	Ginna	0	0	0	1	0	0	0	0	0	1.9000 E+04
15.	Haddam Neck (Conn. Yankee)	0	0	0	2	0	0	0	0	0	1.9529 E+04
16.	Harris	0	0	0	0	0	0	0	0	0	3.348 E+03
17.	Indian Point	0	0	0	1	0	0	0	0	0	6.3922 E+04
18.	Kewanee	0	0	0	0	0	0	0	0	0	1.2470 E+04
19.	Maine Yankee	0	0	0	1	0	0	0	0	1	1.7016 E+04
20.	McGuire	0	1	1	0	0	1	2	0	0	2.6916 E+04
21.	Millstone	1	0	0	1	0	1	1	0	0	3.0983 E+04
22.	North Anna	4	0	3	2	1	4	3	0	0	4.2319 E+04
23.	Oconee	0	0	0	2	0	0	2	0	0	5.8494 E+04
24.	Palisades	1	0	0	1	0	0	0	0	0	4.2720 E+04
25.	Palo Verde	0	1	0	0	0	0	1	0	0	2.0935 E+04
26.	Point Beach	0	0	0	0	0	0	0	0	0	3.0050 E+04
27.	Prairie Island	0	0	0	0	0	0	0	0	0	8.561 E+03
28.	Rancho Seco	0	0	1	1	0	1	2	0	0	5.2877 E+04

Table 4.2-3 (continued)

	Plant Name	RHR 2B	RHR 3	RHR 4	RHR 5	4 kV/P6	4 kV	VITAL 120 V	ESFAS/SI	CCW	Time (Hour)
29.	Robinson	0	0	0	1	0	0	0	0	0	3.0525 E+04
30.	Salem	1	1	1	2	3	7	2	0	0	5.3117 E+04
31.	San Onofre	0	0	1	1	0	0	0	0	0	8.0292 E+04
32.	Sequoyah	3	0	0	0	0	0	0	0	0	7.0797 E+04
33.	South Texas	0	0	0	0	0	0	1	0	0	3.219 E+03
34.	St. Lucie	0	0	0	0	0	0	0	0	0	2.8737 E+04
35.	Summer	0	0	0	1	0	0	2	0	0	1.1015 E+04
36.	Three Mile Island	0	0	0	0	0	1	0	0	0	6.4135 E+04
37.	Trojan	1	0	0	0	0	0	0	0	0	3.1374 E+04
38.	Turkey Point	0	0	1	0	0	0	1	0	1	6.7856 E+04
39.	Vogtle	0	0	0	0	0	0	0	0	0	2.229 E+03
40.	Waterford	0	0	0	0	0	0	0	0	0	5.658 E+03
41.	Wolf Creek	0	0	0	0	0	1	0	0	0	7.008 E+03
42.	Yankee-Rowe	0	0	0	0	0	0	0	0	0	1.9546 E+04
43.	Zion	2	0	0	0	1	1	2	0	0	4.8319 E+04
44.	Surry	1	0	0	2	4	5	0	8	0	7.3292 E+04
	SUMMARY	21	8	13	34	12	32	26	22	4	

Table 4.2-4 Data Used in Two-Stage Bayesian Analysis

Demand Type Failures

	Plant Name	RHR 2A	Demand (RHR 2A)	RHR 6	Demand (RHR 6)
1.	Arkansas	1	46	0	123
2.	Beaver Valley	0	28	1	61
3.	Braidwood	0	9	0	20
4.	Byron	0	16	0	27
5.	Callaway	0	11	0	30
6.	Calvert Cliffs	0	46	0	123
7.	Catawba	1	18	0	74
8.	Cook	1	46	0	86
9.	Crystal River	0	23	3	69
10.	Davis-Besse	1	23	1	48
11.	Diablo Canyon	0	20	0	35
12.	Farley	0	41	0	83
13.	Fort Calhoun	0	23	0	25
14.	Ginna	1	23	2	31
15.	Haddam Neck (Conn. Yankee)	0	23	0	30
16.	Harris	0	6	0	17
17.	Indian Point	0	46	0	117
18.	Kewanee	0	23	0	21
19.	Maine Yankee	0	23	0	54
20.	McGuire	4	32	0	97
21.	Millstone	0	54	0	68
22.	North Anna	5	43	0	92
23.	Oconee	0	69	2	139
24.	Palisades	0	23	0	55
25.	Palo Verde	0	22	0	30
26.	Point Beach	0	46	0	53
27.	Prairie Island	0	46	0	25

Table 4.2-4 (continued)

	Plant Name	RHR 2A	Demand (RHR 2A)	RHR 6	Demand (RHR 6)
26.	Point Beach	0	46	0	53
27.	Prairie Island	0	46	0	25
28.	Rancho Seco	0	23	0	47
29.	Robinson	0	23	2	61
30.	Salem	0	41	0	139
31.	San Onofre	1	52	1	110
32.	Sequoyah	1	37	0	62
33.	South Texas	0	5	0	14?
34.	St. Lucie	0	37	0	54
35.	Sumner	0	15	0	39
36.	Three Mile Island	0	23	0	16
37.	Trojan	3	23	0	47
38.	Turkey Point	0	46	1	134
39.	Vogtle	0	7	0	31
40.	Waterford	3	10	0	31
41.	Wolf Creek	0	10	0	17
42.	Yankee-Rowe	0	23	0	31
43.	Zion	1	46	0	108
44.	Surry	0	46	0	86
	SUMMARY	23	1,296	13	2,660

4.3 Loss of Off-Site Power

In NUREG-1150, loss of off-site power/station blackout was the most dominant core-damage scenario for full power operations at Surry. In the low power and shutdown accident frequency program, we used an improved approach to that in NUREG-1150. In NUREG-1150 analysis of Surry, only one loss of offsite power event tree was included, and loss of offsite power was characterized by having only one 4 Kv bus energized. In this study, three loss of offsite power events, are defined designated by L1, L2, and L3. L1 represents a loss of offsite power with both 1H and 1J buses energized. L2 represents a loss of offsite power with 1H bus energized, 1J bus de-energized, and 2H bus energized; and in L3 the 1H bus energized and unit 2 has a blackout. Similar to NUREG-1150, two types of station blackout were analyzed, station blackout at unit one only(B1), and station blackout at both units(B2). Section 4.3.1 describes the statistical analysis for estimating the frequency of loss of off-site power and recovery of ac power. In Section 4.3.2, the model for calculating the conditional probabilities for each of these initiating events that may result from a loss of offsite power is discussed. The event trees for these initiators are presented in section 7.4.

4.3.1 Statistical Analysis of Loss of Offsite Power Frequency and Recovery

We used the same statistical methods for the frequency and recovery of off-site power as those in the NUREG-1150 study^[1,2]. For recovery of offsite power, the same computer code that was employed in NUREG-1150 was used. For the frequency of loss of offsite power, a separate two-stage Bayesian program^[3] written at BNL was used. The difference between the BNL program and NUREG-1150 approach is that the BNL program assumes a lognormal distribution, while the NUREG-1150 program assumes a gamma distribution.

The data base of NUREG-1150 for the loss of off-site power was updated by adding events that occurred in 1988, as documented in NSAC-144^[4]. Tables 4.3.1-1 and 4.3.1-2 list the data in the data base. Table 4.3.1-1 is events occurred while the plant is operating; Table 4.3.1-2 is category IV events that occurred while the plant is shutdown. Those events that occurred during power operations are further grouped into two categories, plant-centered events, and weather-grid events. The former are events caused by activities at the plant, and are assumed to be possible only when the plant is operating. The latter events are events that were caused by incidents outside the plant site, and occur regardless of the plant condition. Table 4.3.1-3 lists the input data used in the two stage Bayesian analysis of loss of offsite power frequency, and Table 4.3.1-4 summarizes the estimated frequencies of loss of offsite power during power operation and shutdown conditions. It is assumed that during power operations, plant-centered and weather-grid events can occur, and during shutdown conditions, category IV and weather-grid events can occur.

Similarly, two sets of recovery curves are derived, one for POSs 1 and 15 and the other for the remaining POSs (shown in Figures 4.3.1-1 and 4.3.1-2). A mean curve is obtained by assuming that the non-recovery probability is lognormally distributed with the uncertainty bounds given in the figures. The mean curves are tabulated in Tables 4.3.1-5 and 4.3.1-6.

RECOVERY CURVE FOR SURRY PC,GW,W (88 DATA)

Figure 4.3.1-1 Non-Recovery Curves for POS 1 and 15

RECOVERY CURVE FOR SURRY PC,G,W W/ CAT IV (88 DATA)

Figure 4.3.1-2 Non Recovery Curves for POS 2 to 14

4 Initiating Event Analysis

Table 4.3.1-1 Loss of Off-Site Power Data Base

No. Plant	SY	CAT	DATE	DURATION (hours)	FREQ	RECOV
1 Ano	2	PC	09/16/78	1,480	F	R
2 Beaver Valley	2	PC	07/28/78	0.280	F	R
3 Big Rock Point	3	G	01/25/75	0.333	F	R
4 Brunswick	2	PC	02/26/75	0.707	F	R
5 Calvert Cliffs	3	PC	07/23/87	1.970	F	R
6 Davis Besse	1	PC	11/29/77	0.002	F	R
7 Davis Besse	1	PC	10/15/79	0.430	F	R
8 Diablo Canyon	1	PC	07/17/88	0.633	F	R
9 Dresden	2	W	11/12/65	4.000	F	R
10 Dresden	2	PC	08/16/85	0.083	F	R
11 Farley	3	PC	09/16/77	0.900	F	R
12 Farley	3	PC	10/08/83	2.750	F	R
13 Fort Calhoun	3	PC	02/21/76	0.900	F	R
14 Fort Calhoun	3	PC	08/22/77	0.015	F	R
15 Fort St. Vrain	3	W	05/17/83	1.750	F	R
16 Ginna	2	PC	03/04/71	0.500	F	R
17 Ginna	2	PC	10/21/73	0.670	F	R
18 Haddam Neck	1	PC	04/27/68	0.480	F	R
19 Haddam Neck	1	PC	07/15/69	0.150	F	R
20 Haddam Neck	1	PC	07/19/72	0.017	F	R
21 Haddam Neck	1	PC	01/19/74	0.330	F	R
22 Haddam Neck	1	PC	06/26/76	0.270	F	R
23 Haddam Neck	1	PC	08/01/84	0.167	F	R
24 Indian Point	3	G	11/09/65	-	F	
25 Indian Point	3	G	07/20/72	0.920	F	R
26 Indian Point	3	G	07/13/77	6.470	F	R
27 Indian Point	3	PC	06/03/80	1.750	F	R
28 Indian Point	3	PC	06/03/80	0.500	F	R
29 McGuire	2	PC	08/21/84	0.334	F	R
30 Millstone	1	PC	07/21/76	0.080	F	R

4 Initiating Event Analysis

Table 4.3.1-1 (continued)

No. Plant	SY	CAT	DATE	DURATION (hours)	FREQ	RECOV
31 Millstone	1	W	08/10/76	5.000	F	R
32 Millstone	1	W	09/27/85	5.500	F	R
33 Monticello	1	PC	04/27/81	0.250	F	R
34 Nine Mile Point	1	PC	11/17/73	0.003	F	R
35 Nine Mile Point	1	PC	12/26/88	0.150	F	R
36 Oconee	1	PC	01/04/74	0.013	F	R
37 Oyster Creek	2	PC	09/08/73	0.003	F	R
38 Palisades	3	PC	09/02/71	0.930	F	R
39 Palisades	3	PC	09/24/77	0.500	F	R
40 Palisades	3	PC	07/14/87	7.430	F	R
41 Palo Verde	3	PC	10/03/85	0.400	F	R
42 Palo Verde	3	PC	10/07/85	0.200	F	R
43 Pilgrim	1	W	05/10/77	2.670	F	R
44 Pilgrim	1	W	02/06/78	8.900	F	R
45 Pilgrim	1	W	11/19/86	4.317	F	R
46 Pilgrim	1	W	11/12/87	11.000	F	R
47 Point Beach	2	PC	02/05/71	0.130	F	R
48 Point Beach	2	PC	04/27/74	0.020	F	R
49 Prairie Island	2	PC	07/15/80	1.030	F	R
50 Quad Cities	3	PC	11/06/77	1.150	F	R
51 Quad Cities	3	PC	06/22/82	0.570	F	R
52 River Bend	3	PC	01/01/86	0.767	F	R
53 Robinson	3	PC	01/28/86	1.667	F	R
54 San Onofre	3	PC	11/22/80	0.004	F	R
55 San Onofre	3	PC	11/21/85	0.067	F	R
56 St. Lucie	2	G	05/16/77	0.330	F	R
57 St. Lucie	2	G	05/16/77	1.500		R
58 St. Lucie	2	G	05/14/78	0.130	F	R
59 Susquehanna	1	PC	07/26/84	0.183	F	R

Table 4.3.1-1 (continued)

No. Plant	SY	CAT	DATE	DURATION (hours)	FREQ	RECOV
60 Turkey Point	2	G	04/03/73	0.300	F	R
61 Turkey Point	2	G	04/04/73	0.250	F	R
62 Turkey Point	2	G	04/25/74	0.330	F	R
63 Turkey Point	2	G	06/28/74	0.180	F	R
64 Turkey Point	2	G	05/16/77	1.030	F	R
65 Turkey Point	2	G	05/16/77	2.000	F	R
66 Turkey Point	2	PC	02/12/84	0.250	F*	R*
67 Turkey Point	2	PC	02/16/84	0.250	F	R
68 Turkey Point	2	G	05/17/85	2.083	F	R
69 Yankee Rowe	3	G	11/09/65	0.550	F	R

*This event is used in the LOSP calculation for power operation and startup only, not for the shutdown states.

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**Table 4.3.1-2 Loss of Off-Site Power Data Base Events Considered
as Category IV (Applicable to Shutdown States)**

No. PLANT	SY	CAT	DATE	DURATION (hours)	FREQ	RECOV
1 Brunswick	2	PC	04/26/83	0.283	F	R
2 Fitzpatrick	1	PC	04/10/78	0.004	F	R
3 Fitzpatrick	1	PC	03/27/79	0.050	F	R
4 Fitzpatrick	1	PC	10/31/88	1.000	F	R
5 Ft. Calhoun	3	PC	03/13/75	11.083	F	R
6 Indian Point	3	PC	11/16/84	0.233	F	R
7 Haddam Neck	1	PC	08/24/84	0.367	F	R
8 McGuire	2	PC	09/16/87	0.417	F	R
9 Monticello	1	PC	06/04/84	0.033	F	R
10 Oyster Creek	2	PC	11/14/83	4.000	F	R
11 Palisades	3	PC	01/08/84	2.683	F	R
12 Point Beach	2	PC	10/13/73	-	F	
13 Point Beach	2	PC	10/22/84	0.050	F	R
14 Quad Cities	3	PC	05/07/85	0.717	F	R
15 Salem	2	PC	06/05/84	2.000	F	R
16 San Onofre	3	PC	06/07/73	4.983	F	R
17 San Onofre	3	PC	04/22/80?		F	
18 Turkey Point	2	PC	04/29/85?		F	
19 Yankee Rowe	3	PC	05/03/84	0.117	F	R

4 Initiating Event Analysis

Table 4.3.1-3 Data Used in Estimating Loss of Offsite Power Frequency (up to 1988)

No.	Plant	Plant Centered		Grid and Weather			Class IV
		Number of Events	Number of Years	Number of Events	Number of Years	Number of Events	Number of Years
1	ARKANSAS NUCLEAR ONE ANO 2	1	10.35	0	14.09	0	5.82
2	BEAVER VALLEY BV 2	1	6.47	0	12.25	0	5.61
3	BIG ROCK POINT BRP 3	0	15.28	1	25.85	0	10.44
4	BROWNS FERRY BF 1	0	10.52	0	14.42	0	8.94
5	BRUNSWICK BRU 2	1	9.14	0	13.17	1	6.23
6	BYRON BYR 3	0	1.86	0	3.33	0	1.24
7	CALLAWAY CAL 3	0	3.28	0	4.08	0	0.91
8	CALVERT CLIFFS CC 3	1	12.21	0	13.68	0	3.68
9	CATAWBA CAT 2	0	2.94	0	3.58	0	1.25
10	COOK COK 1	0	11.06	0	13.42	0	4.63
11	COOPER COP 1	0	8.55	0	14.51	0	5.82
12	CRYSTAL RIVER CR 1	0	7.01	0	11.84	0	5.16
13	DAVIS-BESSE DB 1	2	4.00	0	10.51	0	6.31
14	DIABLO CANYON DC 1	1	2.83	0	3.67	0	1.10
15	DRESDEN DR 2	1	14.53	1	18.59	0	7.79
16	DUANE ARNOLD DA 0	0	7.52	0	13.92	0	6.25
17	FARLEY FAR 3	2	9.43	0	11.09	0	3.29
18	FITZPATRICK FIT 1	0	8.65	1	13.51	3	4.78
19	FORT CALHOUN FC 3	2	9.64	0	14.59	1	4.73
20	FORT ST. VRAIN FSV 3	0	1.34	1	9.51	0	8.20
21	GINNA GIN 2	2	13.47	0	18.51	0	4.91
22	GRAND GULF GG 1	0	2.41	0	3.5	0	1.10
23	HADDAM NECK HN 1	6	17.15	0	21.43	1	4.67
24	HATCH HAT 3	0	9.72	0	13.09	0	5.34
25	INDIAN POINT IP 3	2	11.21	3	14.42	1	5.59
26	KEWAUNEE KEW 3	0	11.78	0	14.59	0	2.71
27	LASALLE LAS 2	0	2.87	0	5	0	2.63
28	LIMERICK LIM 3	0	2.15	0	2.91	0	0.88

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Table 4.3.1-3 (continued)

No.	Plant		Plant Centered		Grid and Weather			Class IV
			Number of Events	Number of Years	Number of Events	Number of Years	Number of Events	Number of Years
29	MAINE YANKEE	MY 1	0	11.27	0	16.09	0	4.83
30	MCGUIRE	MCG 2	1	5.22	0	7.08	1	2.83
31	MILLSTONE	MIL 1	1	14.98	2	17.85	0	5.18
32	MONTICELLO	MON 1	1	12.67	0	17.59	1	4.98
33	NINE MILE POINT	NMP 1	2	11.11	0	19.09	0	7.81
34	NORTH ANNA	NA 3	0	8.77	0	10.59	0	4.08
35	OCONEE	OCO 1	1	14.53	0	15.51	0	5.09
36	OYSTER CREEK	OYC 2	1	10.40	0	19.09	1	8.71
37	PALISADES	PAL 3	3	8.23	0	17.09	1	9.78
38	PALO VERDE	PV 3	2	2.16	0	2.91	0	1.24
39	PEACH BOTTOM	PB 1	0	11.00	0	14.51	0	7.23
40	PILGRIM	PIL 1	0	7.71	4	16.09	0	8.64
41	POINT BEACH	PTB 2	1	16.62	0	18.09	2	3.46
42	PRAIRIE ISLAND	PI 2	1	14.25	0	15.09	0	3.11
43	QUAD CITIES	QC 3	2	13.79	0	15.92	1	5.48
44	RANCHO SECO	RS 2	0	5.60	0	13.76	0	8.28
45	RIVER BEND	RB 3	1	1.92	0	2.58	0	1.02
46	ROBINSON	ROB 3	1	11.32	0	17.85	0	6.37
47	SALEM	SAL 2	0	7.91	0	11.59	1	5.17
48	SAN ONOFRE	SO 3	2	12.49	0	21.01	2	10.15
49	SEQUOYAH	SEQ 1	0	4.31	0	7.5	0	5.03
50	ST LUCIE	STL 2	0	9.88	2	12.09	0	3.55
51	SHEARON HARRIS	SH 0	0	1.20	0	1.69	0	0.52
52	SUMMER	SUM 1	0	3.34	0	5	0	1.55
54	SUSQUEHANNA	SUS 1	1	4.74	0	5.59	0	1.68
55	THREE MILE ISLAND	TMI 3	0	5.49	0	14.34	0	8.50
56	TROJAN	TRO 2	0	7.29	0	12.67	0	5.63
57	TURKEY POINT	TP 2	2	13.64	7	16.09	1	5.95

Table 4.3.1-3 (continued)

No.	Plant	Plant Centered		Grid and Weather			Class IV
		Number of Events	Number of Years	Number of Events	Number of Years	Number of Events	Number of Years
58	VERMONT YANKEE VY 1	0	11.59	0	16.17	0	4.61
59	VOGTLE VOG 0	0	0.87	0	1.58	0	0.45
60	WASHINGTON NUCLEAR WN 1	0	2.19	0	4.08	0	1.75
61	WATERFORD WAT 2	0	2.44	0	3.33	0	0.84
62	WOLF CREEK WC 1	0	2.51	0	3.33	0	1.00
63	YANKEE-ROWE YR 3	1	20.87	1	28.18	1	7.21
64	ZION ZIO 2	0	12.28	0	15.09	0	6.29
53	SURRY SUR 3	0	12.80	0	16.09	0	6.55
	TOTAL	46	544.709	23	785.26	19	304.52

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Table 4.3.1-4

Estimated Frequency of Loss of Offsite Power
Using Data up to End of 1988

	Mean	Error Factor
Power Operation (POSS 1 and 15)	8.00E-02 per year (9.13E-06 per hour)	2.17
Shutdown (POSS 2 to 14)	6.10E-02 per year (6.96E-06 per hour)	3.23

Table 4.3.1-5 Mean Non-Recovery Curves for POSs 1 and 15

TIME (hours)		P (TIME $\geq$ T)
1	0.050000	0.88
2	0.100000	0.83
3	0.150000	0.79
4	0.200000	0.75
5	0.250000	0.72
6	0.300000	0.70
7	0.350000	0.67
8	0.400000	0.65
9	0.450000	0.62
10	0.500000	0.61
11	0.550000	0.59
12	0.600000	0.57
13	0.650000	0.55
14	0.700000	0.54
15	0.750000	0.52
16	0.800000	0.51
17	0.850000	0.49
18	0.900000	0.48
19	0.950000	0.46
20	1.000000	0.45
21	1.050000	0.44
22	1.100000	0.43
23	1.133000	0.42
24	1.200000	0.40
25	1.250000	0.39
26	1.283000	0.39
27	1.333000	0.38
28	1.400000	0.37
29	1.450000	0.36

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Table 4.3.1-5 (continued)

TIME (hours)	P (TIME $\geq$ T)
30 1.500000	0.35
31 1.550000	0.34
32 1.600000	0.33
33 1.650000	0.32
34 1.700000	0.32
35 1.750000	0.31
36 1.800000	0.30
37 1.850000	0.30
38 1.900000	0.29
39 1.950000	0.28
40 2.000000	0.28
41 2.050000	0.27
42 2.100000	0.27
43 2.150000	0.26
44 2.200000	0.25
45 2.250000	0.25
46 2.300000	0.24
47 2.350000	0.24
48 2.400000	0.23
49 2.450000	0.23
50 2.500000	0.22
51 2.750000	0.20
52 3.000000	0.18
53 3.167000	0.17
54 3.500000	0.15
55 3.750000	0.14
56 4.000000	0.13
57 4.250000	0.12
58 4.500000	0.11

Table 4.3.1-5 (continued)

TIME (hours)	P (TIME $\geq$ T)
59 4.750000	0.10
60 5.000000	0.10
61 5.250000	0.09
62 5.500000	0.09
63 5.750000	0.08
64 6.000000	0.08
65 6.250000	0.07
66 6.500000	0.07
67 6.750000	0.06
68 7.000000	0.06
69 7.250000	0.06
70 7.500000	0.05
71 7.750000	0.05
72 8.000000	0.05
73 8.250000	0.05
74 8.500000	0.05
75 8.750000	0.04
76 9.000000	0.04
77 9.250000	0.04
78 9.000000	0.04
79 9.750000	0.04
80 10.000000	0.03
81 13.300000	0.02
82 15.000000	0.02
83 16.000000	0.02
84 18.000000	0.01
85 23.000000	0.01
86 27.000000	0.01
87 27.000000	0.01

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Table 4.3.1-6 Mean Non-Recovery Curves for POS 2 to 14

TIME (hours)		P (TIME $\geq$ T)
1	0.050000	0.89
2	0.100000	0.84
3	0.150000	0.80
4	0.200000	0.77
5	0.250000	0.74
6	0.300000	0.72
7	0.350000	0.69
8	0.400000	0.67
9	0.450000	0.65
10	0.500000	0.63
11	0.550000	0.62
12	0.600000	0.60
13	0.650000	0.58
14	0.700000	0.57
15	0.750000	0.55
16	0.800000	0.54
17	0.850000	0.53
18	0.900000	0.51
19	0.950000	0.50
20	1.000000	0.49
21	1.050000	0.48
22	1.100000	0.47
23	1.133000	0.46
24	1.200000	0.45
25	1.250000	0.44
26	1.283000	0.43
27	1.333000	0.42
28	1.400000	0.41
29	1.450000	0.40

Table 4.3.1-6 (continued)

TIME (hours)	P (TIME $\geq$ T)
30 1.500000	0.40
31 1.550000	0.39
32 1.600000	0.38
33 1.650000	0.37
34 1.700000	0.36
35 1.750000	0.36
36 1.800000	0.35
37 1.850000	0.34
38 1.900000	0.34
39 1.950000	0.33
40 2.000000	0.32
41 2.050000	0.32
42 2.100000	0.31
43 2.150000	0.31
44 2.200000	0.30
45 2.250000	0.29
46 2.300000	0.29
47 2.350000	0.28
48 2.400000	0.28
49 2.450000	0.27
50 2.500000	0.27
51 2.750000	0.25
52 3.000000	0.23
53 3.167000	0.21
54 3.500000	0.19
55 3.750000	0.18
56 4.000000	0.17
57 4.250000	0.15
58 4.500000	0.14

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Table 4.3.1-6 (continued)

TIME (hours)	P (TIME $\geq$ T)
59 4.750000	0.14
60 5.000000	0.13
61 5.250000	0.12
62 5.500000	0.11
63 5.750000	0.11
64 6.000000	0.10
65 6.250000	0.09
66 6.500000	0.09
67 6.750000	0.08
68 7.000000	0.08
69 7.250000	0.07
70 7.500000	0.07
71 7.750000	0.07
72 8.000000	0.06
73 8.250000	0.06
74 8.500000	0.06
75 8.750000	0.06
76 9.000000	0.05
77 9.250000	0.05
78 9.500000	0.05
79 9.750000	0.05
80 10.000000	0.04
81 13.300000	0.03
82 15.000000	0.02
83 16.000000	0.02
84 18.000000	0.02
85 23.000000	0.01
86 27.000000	0.01
87 27.000000	0.01

4.3.2 Definition, Logical Model and Quantification of Categories of Loss of Offsite Power and Station Blackout Initiators

A loss of offsite power initiator is assumed to affect both Units at Surry site simultaneously, i.e. it would likely be an externally caused event. Depending upon availability and reliability of emergency diesel generators (EDGs) and various electrical buses in both units, several combinations of bus availabilities are possible (Table 4.3.2-1).

4.3.2.1 System Configuration

Here, we are interested in Unit 1, which is assumed to be in a mid-loop POS. Its emergency bus 1H is connected to the (assumed) operating RHR pump A. EDG #1 is designed to load onto this bus.

Emergency bus 1J is connected to RHR train B of Unit 1, and EDG #3 will provide backup power to this bus. This is the "swing" diesel, which will align itself with either 1J or 2J bus, depending on necessity or priority.

Unit 2 emergency buses, 2H and 2J are backed up by EDG #2 and #3, respectively. For charging cross-connection to Unit 1, 2H power is needed.

Emergency diesel generators #1 and #3 cannot be in maintenance due to constraints placed on mid-loop operation, nor can any other electrical equipment associated with emergency buses 1H and 1J. However, maintenance is possible on EDG #2. During maintenance on EDG #2, a loss of offsite power will lead to assignment of EDG #3 to Unit 2 J bus, as that would be the only source of power available to Unit 2.

4.3.2.2 LOSP Categories

There are several mutually exclusive categories of loss of offsite power (including station blackout) depending on the combinations of emergency buses that are available. These are shown in Table 4.3.2-1 and described below:

- 1) L1: Both emergency buses on Unit 1 (1H and 1J) have power. On Unit 2, bus 2J is down because EDG #3 is assigned to the 1J bus (or there may be hardware faults associated with bus 2J). This means there are two combinations in L1: either bus 2H is up or it is down. In the latter case, there is an SBO on Unit 2. In that case, something is wrong with the 2J bus, otherwise the operators would try to switch EDG #3 to Unit 2. The mirror image of this situation occurs in category SBO-U1, when Unit 2 has both buses available while Unit 1's buses are both down.
- 2) L2: Only one Unit 1 emergency bus has power, i.e. emergency bus 1H is up (1J is down) in various combinations with Unit 2 buses; or 1J is up (1H is down) and 2H is up (2J cannot be up because of the shared diesel). The combinations are: 1H and 2H up, 1J and 2J down; 1H, 2H and 2J up, 1J down; 1H, 2J up, 1J and 2H down; and 1J and 2H up, 1H and 2J down.
- 3) L3: One emergency bus on Unit 1 is up, while Unit 2 is having a station blackout (i.e. both emergency buses are down). The two combinations are: 1H up, while 1J, 2H and 2J are down; 1J up, while 1H, 2H and 2J are down.

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- 4) SBO-U1. Unit 1 is having a station blackout (neither emergency bus has power), while at least one Unit 2 emergency bus is up. The combinations are: 1H and 1J down, 2H and 2J up; 1H, 1J and 2J down, 2H up; 1H, 1J and 2H down, 2J up. (See comment under L1).
- 5) SBO-U1U2. Both Units are having a station blackout, i.e. all four emergency buses (1H, 1J, 2H, 2J) are down.

The above categories exhaust all combinations of failures of emergency buses to provide power after a LOSP. We note that both J buses cannot be up at the same time.

4.3.2.3 Fault Trees for Breakdown of LOSP Initiator Into Categories

Figures 4.3.2-1 through 4.3.2-4 present the fault trees for failure of emergency buses 1H, 1J, 2H, and 2J after a LOSP. These are the basic building blocks for the LOSP categories fault trees shown in Appendix H. The failure categories considered are failures of the bus itself, and emergency diesel generator failures. EDG failures could be due to maintenance, battery failures (for DC operated circuit breakers), failures to start (including common cause), and failure to run (including common cause). EDG#3 can be assigned only to one bus, so buses 1J and 2J cannot be both up at the same time. In addition, this diesel generator will be assigned to Unit 1 (bus 1J) first, unless something is wrong with that bus or the breakers. This is because Unit 1 is progressing toward core melt at the time. It is assumed that battery 1B is necessary for connecting EDG #3 to bus 1J, while battery 2B is necessary for connecting EDG #3 to bus 2J.

The mission time for emergency diesel generators is 6 hours and the initiator in the appropriate LOSP category is assumed to occur at time 0. (This is found to be an acceptable compromise between accuracy and the amount of resources expended for this task). According to the NUREG-1150 analysis for full power^[5] this assumption is a good alternative to the time-consuming task of integrating various failures, transitions between LOSP categories, and offsite power recovery over all times between zero and 24 hours (this would have to be done while running the whole PRA model). The Sandia study in the NUREG-1150 report has reported finding very good agreement between this approach and the "exact" method for several sample analyses run because, after 6 hours, failure to include additional diesel run-time failures is offset by a substantially increased probability of offsite power recovery.

Figures in Appendix H.1 show the fault trees for categories L1, L2, L3, SBO-U1, SBO-U1U2, and total LOSP which is an "OR" gate with the 5 categories as input.

4.3.2.4 Quantification

Fault trees in Appendix H.1 were quantified using the IRRAS code, with a cutset cutoff value of 1.E-8. The results are presented in Table 4.3.2-2, Showing the conditional probabilities of specific LOSP categories. The cutsets are shown in Appendix H.2.

The five categories' conditional probabilities add up to 0.996 (the expected value is 1.); The IRRAS algorithm is not very accurate at high failure probabilities. One cutset in L1 has a high probability (0.884). Also, when incoherent systems are quantified (and there are many complemented events in the cutsets shown in Appendix H.2), an upper bound is not necessarily obtained by the mincut upper bound method. Using the rare-event approximation for quantifying the five LOSP categories, results in a total LOSP conditional probability of 1.001.

The number of cutsets in the quantification of the total LOSP fault tree is equal to the summation of the number of cutsets in the other five fault trees, i.e. there is no overlap between the categories (they are

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mutually exclusive), as expected. The mincut upper bound for the total LOSP top event is 0.900, significantly below the value of 0.996 from summing the results of the five components of total LOSP, again reflecting the diminished accuracy of the algorithm when high failure probabilities are present and possible non-conservatism when there are many complemented events (i.e. incoherent systems).

However, the main assumption is that a LOSP event affects both Units simultaneously, although there are some internally generated LOSP events where this is not true.

The conditional probabilities of various types of electrical bus failures needed in the PRA model were also calculated. For instance, the conditional probability of failure of 1H bus in L2 (or L3) initiator is needed. Because some important systems may have one or the other train down for extended periods of maintenance (e.g. charging, LPI, recirculation sprays). Also, the conditional probability of (Unit 2) 2H bus failure in various initiator categories is needed because this bus is used for charging cross-connect from Unit 2, and also as a fallback option for cooling of charging pumps on Unit 1. These results are presented in Table 4.3.2-3; some of the fault trees used for generating the results are shown in Appendix H.3.

The hourly frequencies of the LOSP initiators are given in Table 4.3.2-4; they were obtained by multiplying the mincut upper bound results in Table 4.3.2-2 by the LOSP shutdown frequency of 6.96E-06/hr.

The uncertainty distribution in frequency of various LOSP initiator (needed for generating the uncertainty results) is obtained by analyzing the fault trees in Appendix H.4, and the resulting sample distributions in the frequencies (in units of /hr) are shown in Appendix H.5. These distributions are somewhat dependent on the random seed generated at the time of analysis, and are slightly different than the actual distributions used.

4.3.3 References

1. Hora, S.C., and Iman, R.L., "Bayesian Modelling of Initiating Event Frequencies at Nuclear Power Plants," Risk Analysis 10(1), March 1990.
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3. Chu, T.-L., "A Two-Stage Bayesian Analysis Program", Brookhaven National Laboratory.
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5. Bertuccio, R.C., and Julius, J.A., "Analysis of Core Damage Frequency: Surry, Unit 1, Internal Events Appendices", Appendix D.7, NUREG/CR-4550, Vol. 3, Rev. 1, Part 2, April 1990.

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ELECTRICAL POWER - MCC 1H1-1 (4KV1H) (4KV1H)

Figure 4.3.2-1 Fault Tree for Failure of 1H Bus

ELECTRICAL POWER — MCC 1J1-1 (EJ1)
(4KV1J)

Figure 4.3.2-2 Fault Tree for Failure of 1J Bus

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Figure 4.3.2-3 Fault Tree for Failure of 2H Bus

ELECTRICAL POWER (4KV2J)

Figure 4.3.2-4 Fault Tree for Failure of 2J Bus

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Table 4.3.2-1 LOSP/SBO Analysis Cases

LOSP/SB Case	DG #1 (1H Bus)	DG #2 (2H Bus)	DG #3	
			(1J Bus)	(2J Bus)
L1	S	F	S	
L1	S	S	S	
L2	S	S		S
L2	S	S	F	F
L2	S	F		S
L2	S	M		S
L2	F	S	S	
L3	S	F	F	F
L3	S	M		F
L3	F	F	S	
B1	F	S		S
B1	F	S	F	F
B1	F	F		S
B1	F	M		S
B2	F	F	F	F
B2	F	M	F	F

NOTES:

- F** — DG fails to start, fails to run, or fails to load onto the emergency bus
- M** — DG down for maintenance, only maintenance on DG 2 taken into account here, and in which case DG 3 is assumed to be aligned to 2 J bus
- S** — Success

Table 4.3.2-2 Quantification of LOSP Categories

Category	Mincut Upper Bound	Rare Event	No. Cutsets
L1	0.8839	0.8841	16
L2	0.1047	0.1098	24
L3	4.42-3	4.42-3	56
SBO-U1	2.18-3	2.18-3	79
SBO-U1U2	5.56-4	5.56-4	74
LOSP-TOTAL	.996*	1.001	249

*Sum of the above

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Table 4.3.2-3 Conditional Probabilities of Various Bus Failures

Type of Failure	Conditional (on LOSP Category) Probability
SBO on Unit 2 in L1	1.56-4
Bus 1H failed in L2	0.329
Bus 1H failed in L3	0.489
Bus 2H failed in L1	5.9-4
Bus 2H failed in L2	0.181
Bus 2H failed in L3	1.0
Bus 2H failed in B1	4.33-2

Table 4.3.2-4 LOSP Initiating Event Frequencies

LOSP Category	Frequency, Mean Values (/hr)	Frequency, Point Estimates (/hr)
L1	6.197-06	6.150-6
L2	7.368-07	7.290-7
L3	3.810-08	3.075-8
B1	1.952-08	1.514-8
B2	3.167-09	3.872-9

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4.4. Support System Failures

To determine a list of initiators associated with the loss of support systems in POSs (3) through (13), each support system was evaluated using the following criteria:

- (1) Does its failure affect the successful removal of decay heat,
- (2) Does its failure result in directly or indirectly an inventory loss of reactor coolant, or cause the dilution of its boron concentration.

For each systems which satisfied these criteria, a more detailed (trainwise) analysis of failure impact was carried out. Our purpose was to see how, and to what extent the failure results in preventing or interrupting any train of frontline systems required for safe shutdown operations.

The following are the systems failures for which more detailed impact analysis was performed:

- (1) Loss of 4.16 KV and 480 V AC Emergency Buses
- (2) Loss of 125 V DC Buses
- (3) Loss of 120 V AC Vital Buses
- (4) Loss of Instrument Air
- (5) Loss of Component Cooling Water (CCW)
- (6) Loss of Service Water
- (7) Loss of Emergency Switchgear Room Cooling
- (8) Loss of Charging Pump Cooling

The results of the impact analysis, together with the reasons for including or excluding a support system failure as an initiating event are summarized in the following subsections. These subsections (4.4.1 to 4.4.8) describe shortly also the method applied to determine the frequency of the selected initiating event and the results obtained. Table 4.1-4 lists the selected initiating event and the frequency results obtained. Table 4.4-1 and 4.4-2 list the input data used in the two-stage Bayesian analysis. Subsection 4.4-9 covers the treatment of recovery in the initiating events considered, the input data, and the non-recovery curves obtained.

4.4.1 Loss of a 4.16 kV AC Emergency Bus

At Surry, each of the 4.16 kV AC Emergency Buses (1H, 1J) provides motive power directly to one train of Charging, Feedwater, Auxiliary Feedwater, RHR, and Component Cooling systems and indirectly, via the associated 480 V AC buses (1H1, 1H1-1, 1J1, 1J1-1, etc.) to one train of Safety Injection, Containment Spray, Recirculation Spray, Service Water, and Instrument Air Systems.

It is easy to see that a failure of a 4.16 kV Emergency Bus interrupts the operation of one train of systems participating in decay heat removal. Such an event can lead to core damage when the bus (or its stub bus) cannot be re-energized; i.e., when "bus blackout" occurs. Therefore, the event is considered to be a separate initiator, and its impact on core-damage frequency can be qualitatively evaluated in various POSs:

In POSs (6) and (10), when operational procedures (see Attachment 3 of 1-OP-RC-005) require that Reserve Station Service Supplies (A and C) to the emergency buses should be available, both diesel generators (DG1 and DG3) have to be operable, DC batteries should not be cross-tied and one high head and one low head safety injection train should be operable; it is expected then, that the contribution of the initiator to the core damage frequency will be small.

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In any other POSs, however, when maintenance/test activity on non-operating buses and associated loads is not constrained, the contribution of this initiator to the core-damage frequency is expected to be higher.

The loss of a 480 V AC Emergency Bus was not considered to be an initiating event because of the redundancy of these buses, and because of their loads. With the exception of the Charging Pump Service Water and Charging Pump Cooling Water System pumps, the pumps fed by these buses do not perform direct functions related to core cooling. All functions can be performed by alternate pumps.

Another effect, the loss of 480 V AC supply to an Uninterruptible Power Supply (providing power to an associated 120 V AC Vital Bus and a 125 V DC Charger) was not considered consequential because it does not lead to a direct loss of either the Vital Bus or the DC power supplies.

For the present study, the "Loss of a 4.16 kV AC Emergency Bus" event is defined as a bus failure from whatever reasons, causing a momentary loss of all its loads, and when the associated Diesel Generator still can be used within its load capacity to resupply the bus with emergency power.

To determine the frequency of the initiator, a large set of "Loss of 4.16 kV AC Bus" events that occurred under shutdown conditions was selected from the LER database. This set of data served to determine the initiating frequency for POSs other than POSs (6) and (10). A subset of the events screened by selection criteria corresponding to the more constrained conditions of POSs (6) and (10) (no maintenance/test activity on the emergency buses) was used to calculate the initiator frequency for POSs (6) and (10). Both initiator frequencies were determined, like the frequencies of the "Loss of RHR" initiating events, with two-stage Bayesian updating technique and using Surry-specific data. The results obtained are given below:

INITIATOR	FREQUENCY (hr ⁻¹)			
	MEAN	5%	50%	95%
Loss of 4.16 kV AC Emergency Bus				
POS: 3,4,5,7,8,9,11,12,13	2.63E-05	1.11E-05	2.37E-05	5.05E-05
POS: 6,10	2.10E-05	7.60E-06	1.82E-05	4.37E-05

4.4.2 Loss of a 125 V DC Bus

The 125 V DC buses (1A, 1B) provide control power to the Charging, Safety Injection, Containment Spray, Recirculation Spray, Feedwater, Auxiliary Feedwater, RHR, and Component Cooling Water Systems. They supply also the 4.16 kV and 480 V AC emergency switchgear.

Loss of a 125 V DC bus will not stop an operating decay-heat removal train, but will prevent its control. If the lost DC bus supplied the standby heat removal train, the event will prevent putting the train into operation. Since the "Loss of a 125 V DC Bus" does not affect successful decay-heat removal, the event was not considered as a separate initiator. Industrial experience seems to support this decision, because there was no LER event describing DC bus failure during shutdown conditions in the whole PWR population.

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4.4.3 Loss of a 120 V AC Vital Bus

Surry has four main vital (I,II,III and IV) and one semi vital 120 V AC instrument buses. Each of the main bus has branch line for redundancy.

Based on a detailed analysis to identify the impact of the loss of any of these vital buses on safety during various POSs, we concluded that such an event will reduce the redundancy of some safety-related instrumentation, and will interrupt the heat-removal function. In RHR operation, the loss of Vital Bus I would close the flow control valve 1-RH-HCV-1142 (RHR letdown flow), the isolation valve 1-TV-CC-109A (CCW return from RHR), and would render inoperable one of the two ultrasonic reactor vessel level sensors. The loss of vital bus II would close the isolation valve 1-TV-CC-109B (CCW return from RHR pump seal coolers). The loss of Vital Bus III would fail open the flow control valve 1-RH-HCV-1758 (RHR HX flow) with the potential of starting RHR pump runout. The very rare event, "Loss of two 120 V AC Vital Buses" would interrupt the RHR operation by closing the Component Cooling Water system isolation valves 1-TV-CC-109A (controlled by Vital Bus I) and 1-TV-CC-109B (controlled by Vital Bus II). (The effect of this double event would be equivalent to the effect of a spurious Containment Closure Signal CLS-Hi.) The same event (Loss of Vital Buses I and II) also would render inoperable both trains of in-core thermocouples (ICC-trains A and B) and the associated plasma display power supplies.

Therefore, we decided that the "Loss of a 120V AC Vital Bus" event would be considered as a separate initiator. However, since each Vital Bus has two independent power supplies, the frequency of simultaneous failure of multiple Vital Buses was deemed to be exceedingly small thus, this event was not included as a separate initiator.

The frequency of the initiator was determined for all POSs by using LER data and two-stage Bayesian updating technique. The frequency obtained is as follows:

INITIATOR	MEAN	FREQUENCY (hr ⁻¹)		
		5%	50%	95%
Loss of a 120V AC Vital Bus	5.58E-06	9.98E-07	1.14E-06	1.55E-05

4.4.4 Loss of Instrument Air

Loss of instrument air outside the containment is defined as a total loss of system pressure, so that operator actions are needed to restore the system and mitigate potential adverse effects. The occurrence of the initiating event causes the system pressure to decrease to all the instrument air loads. A review of the operating experience (reference [1]) showed that the dominant causes of loss of instrument air are air-line rupture or leak, mispositioning of valves, loss of compressors, and problems with the dryers. At Surry, it can be caused by any of these above modes of failure. If one of the latter three occurs, the operator can isolate the problem and start the service air or outage air compressors to restore the system. Also, after line ruptures or leaks are located, most lines can be isolated. Then the air pressure can be restored. Local loss of air supply usually has localized effect and is not considered a significant accident initiator. Depending on the plant operational state, the impacts of total loss of outside instrument air are different. The impacts are discussed in section 6.2.5 of the system analysis.

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For this study, we decided to use only total loss of instrument air events that led to reactor scram. Only PWR events were chosen, however, for all modes of plant operations. Reference 1 summarizes a study of all significant loss of air events identified from a review of more than 600 LERs covered in Reference 2, and in LERs from 1980 to 1987; 264 events were determined to be related directly to instrument air. By additional review, 38 events were found to be loss of IA with reactor scram. In this reduction, only events for 1984 - 1987 were used because the LER rule requiring full reports on all trips was issued in 1983 (before then, IA related trips were only occasionally reported). From these 38 events, only PWR IA total loss (or almost total loss) events were taken into account as summarized in Table 4.4-2 and the event data base given in Appendix A.

The potential for recovery from loss of IA events was taken into account in the event tree analysis considered in Section 7.5-4. The LERs were carefully reviewed to estimate the time available for recovery in the original LERs. Some LERs provided that information, but in all other cases, the recovery time was estimated based on the event description. Reference 2 was consulted in most of the events for this purpose. The recovery times chosen are shown in Table 4.4-2 and in Appendix A data base.

The results of the two-stage Bayesian analysis taking into account one event at Surry (based on Reference 1 finding) are as follows:

INITIATOR	FREQUENCY (hr. ⁻¹)			
	MEAN	5%	50%	95%
Loss of Instrument Air	2.12E-6	4.97E-7	1.63E-6	5.38E-6

The hourly failure frequency was multiplied by the length of time at each POS to obtain the initiator frequency for that POS.

A mean curve of the non-recovery probabilities were generated from the data of Table 4.4-2. The curve mean non-recovery probabilities are tabulated in Table 4.4-3.

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4.4.5 Loss of Component Cooling Water (CCW)

The Component Cooling Water System at Surry is a shared system providing Component Cooling Water. During shutdown of Unit 1, one of the system's main functions is to support decay heat removal; it supplies cooling water to the RHR heat exchangers and RHR pumps. In addition, in POSs when the Reactor Coolant Pumps are still operating, it provides cooling water to the RCP thermal barriers.

The event, a "Loss of CCW" will interrupt the removal of decay heat at Unit 1 in any POSs when the RHR is operating. Therefore, for the present study, it is considered a separate initiating event. (Such an event, alone however, does not fail the RCP seal injection flow nor any other system required to maintain the Unit in hot shutdown. To fail the RCP seals, the Charging Pumps also have to fail in conjunction with the loss of CCW. The Charging Pumps provide redundant cooling to the RCP seals.)

For further analysis, the event, "Loss of the CCW" must to be defined more precisely. An event caused by failures of components assigned only to the Unit 1 portion of the CCW system is not considered to be a unique initiator because these failures are recoverable using components belonging to Unit 2. Failures of system components disabling both the Unit 1 and Unit 2 portions of the CCW system are considered to be true initiating events. Such failures are: loss of the surge tank, suction and return line header breaks, common cause failures of CCW pumps, and heat exchangers.

An LER search identified four events in the PWR data base with a potential to cause a complete loss of the CCW system at Surry. Based on these events, the Bayesian updated frequency of the initiator is given below:

INITIATOR	FREQUENCY (hr ⁻¹)			
	MEAN	5%	50%	95%
Loss of Component Cooling Water	3.76E-06	3.16E-07	2.00E-06	1.27E-05

This frequency is assumed to be applicable to all POSs.

4.4.6 Loss of Service Water

The service water system at Surry supplies various loads by gravity flow from the canal. The service water lines branch off from the 96" circulating water lines to the condenser. After passing through the loads, service water is discharged to the discharge canal. The loads include component cooling water heat exchangers, bearing cooling water heat exchangers, recirculation spray heat exchangers, control room and relay room air conditioning-unit chiller condensers, and charging pump cooling service water subsystem. The control room and switch-gear room cooling system and the charging pump cooling system have their own service water pumps that take suction from the service water lines. The service water flow paths to all loads are normally open, except the flow to the recirculation spray-heat exchangers.

A total loss of service water can be caused by biofouling at the screen-well, rupture in the service water or circulating water line, or loss of offsite power and failure to isolate the circulating water lines. Biofouling requires failure of the traveling screens, and is considered very unlikely. The screens can also be unblocked manually. Therefore, biofouling is not considered as an initiating event. Rupture in the service/circulating water line is considered in the flooding analysis. Loss of offsite power will trip the circulating water pumps and cause automatic throttling of the condenser outlet valves, 1-CW-MOV-100A,B,C,D, to 25% open. As long as the circulating water lines are isolated in a loss of offsite power, the emergency service pumps can supply

makeup to the canal. Normally, the canal level is maintained between 25 to 30 feet. A low level alarm at 26 feet will be annunciated by LT-CW-101. Below 23.5 feet, automatic turbine trip and circulating water isolation will take place automatically by closing the condenser outlet isolation valves 1-CW-MOV-100A,B,C,D and inlet isolation valves 1-CW-MOV-106A, B, C, D. These isolation valves also close on a high containment pressure signal. The condenser inlet isolation valves also isolate when the water level in the basement of the turbine building basement reaches nine inches. Due to this elaborate arrangement to assure that the inventory in the canal is conserved, the only scenario in which canal inventory becomes a problem is that of a station blackout. It is modeled in the station blackout event tree.

Individual valve failures in the service water system can cause localized loss of service water. Such failures are not significant causes of accident initiators.

4.4.7 Loss of Emergency Switchgear Room Cooling (ESGR)

The Emergency Switchgear Room Ventilation at Surry is an HVAC system consisting of Chiller Condensers and Air Handling Units (AHUs), a closed cycle chilled Water System and its backup, a closed cycle Central Chilled Water Subsystem. This Ventilation System provides cooling and ventilation to the Emergency Switchgear Rooms at Units 1 and 2. The Chiller Condensers are cooled through an open system by service water driven by three pumps and taken from the intake canal.

The Surry IPE Study identified the importance of the availability of the ESGR Ventilation system to maintain the plant in operable state under any condition. Loss of the chillers or air handling units or the service water will eventually result in overheating of the ESGR, and will lead to a partial or complete Loss of the Emergency Power System; i.e. these failures of the Ventilation System represent a separate initiator affecting the operation of the plant as a Unit SBO event.

Since loss of ESGR cooling could occur during power operation, as well as during shutdown, the event was considered also as a separate initiator for the present study. (If ESGR cooling is lost there is no immediate impact on the unit. Eventually, as the room heats up, perturbations in the Vital power or DC power supply probably will occur. At power operation, the perturbations would cause a reactor trip; under shutdown conditions, however, they generate only some alarms. At this time the emergency power system is still operable, but only for a limited time. Cooling can be restored by cross-connecting chilled water from the Central Chilled Water Subsystem chillers, or by establishing cross air with fans from the Unit 2 ESGR before power is lost.)

The frequency of the Loss of ESGR cooling was estimated in the Surry IPE study from a fault tree. The success criterion of the fault tree was adjusted to allow (described above) mitigative actions. Hence, the success criterion of the fault tree required that 1 out of 3 Ventilation System Chillers, and 1 out of 2 Air Handling Units (AHUs) should be available to ensure sufficient ESGR cooling. For shutdown condition, the same success criteria were considered valid. The fault tree in its original form was re-quantified with the data set used in the present study, and the value obtained is assumed to be applicable to all POSs other than POSs (6) and (10). For POSs (6) and (10), the fault tree was somewhat modified (maintenance events were removed to reflect the conditions required by the operational procedure 1-OP-RC-005 (Attachment 3) and was requantified with BNL data. [For completeness, the fault tree is shown in Appendix 4.4.7, and a detailed description is given].

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The obtained frequencies are given below:

INITIATOR	MEAN	FREQUENCY (hr ⁻¹)		
		5%	50%	95%
Loss of ESGR Cooling				
POS: 3,4,5,7,8,9,11,12,13	6.13E-08	1.07E-08	4.30E-08	1.72E-07
POS: 6,10	1.81E-08	3.17E-09	1.27E-08	5.08E-08

4.4.8 Loss of Charging Pump Cooling

The Charging Pumps at Surry use two systems for cooling: The closed cycle Charging Pump Cooling Water System, which provides cooling to the mechanical seal coolers for the Charging Pumps, and the open Charging Pump Service Water System which provides cooling to the lube oil coolers and to the intermediate seal coolers. Service water is pumped to each Charging Pump by one of two pumps on two Service Water headers in parallel. Motor-and-gear-driven lube oil pumps circulate the lube oil.

Loss of Service Water cooling to the lube oil coolers or loss of the Charging Pump lubricating oil system eventually cause the loss of a running Charging Pump. Loss of all service water would lead to loss of all Charging Pumps, resulting in loss of RCP seal injection flow. Loss of the closed cycle cooling is not so important because plant experience, supported by calculation, shows that the Charging Pumps could operate for one day mission time without cooling the intermediate seal coolers.

While RCP seal cooling is required during cold shutdown by the Charging Pumps, the RCPs are idle in the majority of POSs. The Charging Pumps themselves have only an accident mitigating role during cold shutdown operations, and their failure does not interrupt directly successful decay-heat removal.

Therefore, the "Loss of Charging Pump Cooling" event was not considered as a separate initiator.

4.4.9 Non-Recovery Curves for Support System Failures

The LER data used to establish the loss of support system failure frequencies also was used to estimate the recovery time distribution associated with each initiator. The recovery curves were derived from all events for which there were recovery data. A mean curve was obtained by assuming that the recovery time is lognormally distributed. The mean curves are tabulated in Table 4.4-3.

4.4.10 References

1. DeMoss, G., Lofgren, E., Rothleder, B., Villeran, M. Ruger, C., "A Risk-Based Review of Instrument Air Systems at Nuclear Power Plants," NUREG/CR-5472, January 1990.
2. Nuclear Power Experience (NPE) abnormal events summaries.

Table 4.4-1 Data Used in Two-Stage Bayesian Analysis

	Plant Name	RHR 2B	RHR 3	RHR 4	RHR 5	4KV/P6	4 KV	VITAL 120V	ESFAS/SI	CCW	Time (Hour)
1.	Arkansas	0	1	3	2	0	3	0	0	0	4.680 E+04
2.	Beaver Valley	4	0	0	1	0	1	0	0	0	3.337 E+04
3.	Braidwood	0	0	0	0	0	0	0	0	1	3.631 E+03
4.	Byron	1	0	0	0	0	0	0	0	1	8.834 E+03
5.	Callaway	0	0	0	0	0	0	0	0	0	5.147 E+03
6.	Calvert Cliffs	0	2	0	3	1	1	5	0	0	4.4516 E+04
7.	Catawba	0	0	0	0	0	1	1	0	0	1.4490 E+04
8.	Cook	1	0	0	1	0	0	0	1	0	5.4935 E+04
9.	Crystal River	0	1	1	3	0	1	0	0	0	3.2564 E+04
10.	Davis-Besse	0	0	0	2	0	0	1	6	0	4.2621 E+04
11.	Diablo Canyon	1	0	0	0	1	1	2	01	0	1.2239 E+04
12.	Farley	0	1	1	3	1	1	0	0	0	3.1409 E+04
13.	Fort Calhoun	0	0	0	0	0	1	0	0	0	1.9873 E+04
14.	Ginna	0	0	0	1	0	0	0	0	0	1.9000 E+04
15.	Haddam Neck (Conn. Yankee)	0	0	0	2	0	0	0	0	0	1.9529 E+04
16.	Harris	0	0	0	0	0	0	0	0	0	3.348 E+03
17.	Indian Point	0	0	0	1	0	0	0	0	0	6.3922 E+04
18.	Kewancee	0	0	0	0	0	0	0	0	0	1.2470 E+04
19.	Maine Yankee	0	0	0	1	0	0	0	0	1	1.7016 E+04
20.	McGuire	0	1	1	0	0	1	2	0	0	2.6916 E+04
21.	Millstone	1	0	0	1	0	1	1	0	0	3.0983 E+04
22.	North Anna	4	0	3	2	1	4	3	1	0	4.2319 E+04
23.	Oconee	0	0	0	2	0	0	2	0	0	5.8494 E+04
24.	Palisades	1	0	0	1	0	0	0	0	0	4.2720 E+04

Table 4.4-1 (continued)

	Plant Name	RHR 2B	RHR 3	RHR 4	RHR 5	4KV/P6	4 KV	VITAL 120V	ESFAS/SI	CCW	Time (Hour)
25.	Palo Verde	0	1	0	0	0	0	1	0	0	2.0935 E+04
26.	Point Beach	0	0	0	0	0	0	0	0	0	3.0050 E+04
27.	Prairie Island	0	0	0	0	0	0	0	0	0	8.561 E+03
28.	Rancho Seco	0	0	1	1	0	1	2	0	0	5.2877 E+04
29.	Robinson	0	0	0	1	0	0	0	0	0	3.0525 E+04
30.	Salem	1	1	1	2	3	7	2	2	0	5.3117 E+04
31.	San Onofre	0	0	1	1	0	0	0	0	0	8.0292 E+04
32.	Sequoyah	3	0	0	0	0	0	0	1	0	7.0797 E+04
33.	South Texas	0	0	0	0	0	0	1	0	0	3.219 E+03
34.	St. Lucie	0	0	0	0	0	0	0	0	0	2.8737 E+04
35.	Summer	0	0	0	1	0	0	2	1	0	1.1015 E+04
36.	Three Mile Island	0	0	0	0	0	1	0	0	0	6.4135 E+04
37.	Trojan	1	0	0	0	0	0	0	0	0	3.1374 E+04
38.	Turkey Point	0	0	1	0	0	0	1	0	1	6.7856 E+04
39.	Vogtle	0	0	0	0	0	0	0	0	0	2.229 E+03
40.	Waterford	0	0	0	0	0	0	0	0	0	5.658 E+03
41.	Wolf Creek	0	0	0	0	0	1	0	0	0	7.008 E+03
42.	Yankee-Rowe	0	0	0	0	0	0	0	0	0	1.9546 E+04
43.	Zion	2	0	0	0	1	1	2	0	0	4.8319 E+04
44.	Surry	1	0	0	2	4	5	0	7	0	7.3292 E+04
	SUMMARY	21	8	13	34	12	32	26	22	4	

4 Initiating Event Analysis

Table 4.4-2 Data used in Two-Stage Bayesian Analysis for Loss of Instrument Air

PLANT NAME	YEARS CRITICAL 1/84-1/88	LOSS OF IA EVENTS	OTHER SYSTEMS AFFECTED	RECOVERY TIME	COMMENTS
Ano-1	3.04	0			
Ano-2	3.21	0			
Beav-1	3.23	1	FW	10 min	Estimated on Event Description
Beav-2	0.11	0			
Big RP	3.21	0			
Braidwood	0.35	0			
Byron-1	1.75	0			
Byron-2	0.27	0			
Callaway	2.51	1	FW	20 min	Estimated on Event Description
Calvert-1	3.02	1	FW	20 min	Time Specified
Calvert-2	3.19	0			
Catawba-1	1.73	1	RCPs, B-Dilution	15 min	Time Specified
Catawba-2	0.98	0			
Cook-1	2.76	1	FW	20 min	Estimated on Event Description
Cook-2	2.64	0			
Cry-3	2.48	0			
DBesse-1	1.82	1	-	31 min	Time Specified
Diablo-1	2.25	0			
Diablo-2	1.47	0			
Farley-1	3.44	0			
Farley-2	3.30	0			
Fermi-2	0.69	0			
FT Cal	3.08	0			
FT ST VR	0.86	0			
Ginna	3.47	0			
Haddon Neck	2.85	0			
Harris	0.51	1	FW	20 min	Estimated on Event Description
IP-2	2.82	0			
IP-3	2.84	0			

4 Initiating Event Analysis

Table 4.4-2 (continued)

PLANT NAME	YEARS CRITICAL 1/84-1/88	LOSS OF IA EVENTS	OTHER SYSTEMS AFFECTED	RECOVERY TIME	COMMENTS
Kewaunee	3.46	0			
Lacrosse	2.24	0			
Maine Yank	3.11	0			
MCG-1	2.78	1	FW	20 min	Estimated on Event Description
MCG-2	2.79	0			
MLS-2	3.18	0			
MLS-3	1.34	1	FW	20 min	Estimated on Event Description
North Anna-1	2.72	0			
North Anna-2	3.29	0			
Oconee-1	3.28	0			
Oconee-2	3.58	0			
Oconee-3	3.04	1	FW condensate	20 min	Judgement
Palisades	1.68	0			
Palo Verde-1	1.14	0			
Palo Verde-2	1.06	0			
Palo Verde-3	0.08	0			
Point Bch-1	3.28	0			
Point Bch-2	3.42	0			
Prairie-1	2.84	1	FW	20 min	Judgement
Prairie-2	3.65	0			
Ranch Seco	0.94	0			
Robinson	2.51	0			
Salem-1	2.80	0			
Salem-2	2.36	0			
San Onofre-1	2.06	0			
San Onofre-2	2.27	0			
San Onofre-3	2.50	0			
Sequoyah-1	1.14	0			
Sequoyah-2	1.33	0			
St. Lucie-1	3.21	0			
St Lucie-2	3.37	0			

Table 4.4-2 (continued)

PLANT NAME	YEARS CRITICAL 1/84-1/88	LOSS OF IA EVENTS	OTHER SYSTEMS AFFECTED	RECOVERY TIME	COMMENTS
Summer	2.21	0			
Surry-1	2.93	1		10 min	Estimated on Event Description
Surry-2	2.98	0			
TMI-1	1.69	0			
Trojan	2.68	0			
Turkey PT-3	2.47	0			
Turkey PT-4	2.35	0			
Vogtle	0.46	0			
Waterford	1.84	0			
Wolf Creek	1.77	0			
Yankee-Rowe	3.38	1		10 min	Estimated on Event Description
Zion-1	2.74	0			
Zion-2	2.92	0			
Total	170.75	13			

4 Initiating Event Analysis

Table 4.4-3 Mean Non-Recovery Curves for Support System Initiators

P (Time >T)	TIME (minutes)					
	4 kV/P6	4 kV	Vital 120 V	ESFAS/ SI	CCW	Instrument Air
0.95	0.33	0.28	0.33	0.86	7.1	9.3
0.90	0.62	0.50	0.60	1.4	8.9	10.7
0.85	0.96	0.73	0.90	1.9	10.3	11.7
0.80	1.3	1.0	1.2	2.5	11.7	12.6
0.75	1.8	1.3	1.7	3.1	12.9	13.4
0.70	2.3	1.6	2.1	3.8	14.2	14.2
0.65	3.0	2.1	2.7	4.5	15.5	14.9
0.60	3.8	2.5	3.3	5.4	16.8	15.7
0.55	4.7	3.1	4.1	6.4	18.1	16.4
0.50	5.9	3.8	5.1	7.6	19.6	17.2
0.45	7.3	4.6	6.2	8.9	21.2	18.1
0.40	9.2	5.7	7.7	10.6	22.9	19.0
0.35	11.5	7.0	9.6	12.6	24.9	19.9
0.30	14.7	8.7	12.1	15.1	27.1	21.0
0.25	19.1	11.0	15.5	18.4	29.7	22.2
0.20	25.7	14.4	20.6	23.0	33.0	23.6
0.15	36.1	19.6	28.4	29.7	37.2	25.4
0.10	55.5	28.9	42.7	41.1	43.2	27.8
0.05	104.9	51.5	78.1	66.3	54.1	31.9
Mean Value	29.1	13.8	21.3	18.7	27.7	18.6

Appendix 4.4.7.A

Fault Tree to Determine the Frequency of the Initiator "Loss of Emergency Switchgear Room (ESGR) Cooling" for POS (6) and (10).

The fault tree Figure 4.4.7.A-1 considers three subtrees contributing to the top event: "Frequency of Loss of Unit 1 ESGR Cooling Initiating Event". These are:

- (1) Subtree to calculate the frequency of the event, when the Unit 1 Air Handling Units (AHUs) fail. The subtree, called non-motor initiating event, includes the yearly failure frequency of the operating AHU, and the failure events of the standby AHU within a mission time of 7 days. The mission time was determined by Technical Specifications requirements.
- (2) Subtree to calculate the frequency of the event, when the Unit 1 AHU fan motors fail. The subtree, called fan-motor initiator, includes the yearly failure frequency of the operating AHU fan motor, and the failure events of the standby AHU fan motor during a mission time of 7 days.
- (3) Subtree to calculate the yearly frequency of the event, when all three chillers fail. The unit Technical Specifications restrict operation to 7 days with only 2 chillers operating, and to 6 hours (Technical Specification 3.0.1) with only 1 chiller operating. The fault tree models the 1-VS-E-4B chiller for the 7-day Action Statement (a 14-day mission is used to represent the probability of fault to either of the two running chillers in a 7-day period) and the 1-VS-E-4C chiller for the 6 hour Action Statement. The fault tree does not include recovery actions, and many faults that can be easily recovered, are not included, such as strainer plugging. During normal shutdown operation there is ample time and there is less stress on the operator allowing for a high probability of recovery. This makes recoverable events insignificant, so they are omitted.

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VENTILATION SYSTEM INITIATOR - POS6 (VSIN-P6)

Figure 4.4.7.A-1 Fault Tree for Initiating Event "Loss of Emergency Switchgear Room Cooling"

VENTILATION SYSTEM INITIATOR (VSIN-P6) (GTBA213P)

Figure 4.4.7.A-1 (continued)

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VENTILATION SYSTEM INITIATOR (VSIN-P6) (GTBA413P)

Figure 4.4.7.A-1 (continued)

VENTILATION SYSTEM INITIATOR (VSIN) (GTBA613)

Figure 4.4.7.A-1 (continued)

Figure 4.4.7.A-1 (continued)

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4.5 Loss of Coolant Accidents (LOCAs)

4.5.1 Introduction

Loss of Coolant Accidents can fall into several categories. We first discuss the ones covered in NUREG-1150^[1] and other full power PRAs, and follow this by describing the LOCAs unique to this study (i.e. low power/shutdown configuration).

Usually a leak is considered a LOCA if safety systems are challenged, i.e. the leak rate is greater than the makeup capacity of the CVCS. At Surry, this is about 110 gpm at normal reactor pressure (that is the setpoint for the high charging flow alarm; each charging pump can supply 150 gpm at operating pressure).

NUREG-1150 and other full power PRAs consider several pipe-break LOCA categories: large LOCA ("A" designation), medium LOCA ("S1"), small LOCA ("S2") and small-small LOCA ("S3"). This categorization is based on the ECCS success criteria. Below the size of the small-small LOCA, normal RCS makeup can maintain inventory.

The pipe rupture sizes are the following:

Large LOCA	——	> 6 in
Medium LOCA	——	between 2 in and 6 in
Small LOCA	——	between 0.5 in and 2 in
Small-small LOCA	——	< 0.5 in

These LOCA definitions may change in plant states other than 1 and 15 due to low pressure and temperature and changes in SI actuation logic.

4.5.2 LOCAs Unique to Shutdown States

To figure out the pathways for LOCAs when the plant is shut down, we looked for connections to the RCS. Such a connection is a possible way of losing RCS inventory. The RCS has connections to the RHR and the CVCS system, and to the Primary Drains Transfer Tank and the Primary Drain Tank of the Vents and Drains System via the loop drain valves. Three types of LOCAs have been identified for the shutdown condition: recoverable diversion of RCS coolant (H LOCA), LOCA in connected systems (J LOCA), and maintenance-induced LOCA (K LOCA).

The classical LOCA (the one involving a break in the RCS) is defined as having a leak rate exceeding the makeup capacity of the CVCS. At Surry, this is about 121 gpm based on the charging pump capacity, recirculation rate and RCP seal charging flow. Therefore, a break involving the RCS will be considered a LOCA if the out flow exceeds 121 gpm. For other LOCAs considered here, much smaller leak rates will be allowable as LOCA initiators (down to about 60 gpm). The reason for this is that in states 5-11, the inventory control is no longer automatic, i.e., the CVCS does not automatically maintain the pressurizer level in a narrow band. The duties of inventory control fall on the reactor operator. Some of the LOCAs considered involve a break in the CVCS, or failure of the automatic controller in POSs where it is used. Similarly, the automatic SI signal is disabled in POS 2-14 when the RCS pressure is below 2000 psi. The automatic isolation of letdown on SI signal or low pressurizer level will be on only in POS 1, 2, 14 and 15 (in other states the RHR letdown is used; its flow rate is 5-10 times smaller than that of regular letdown, i.e. 10-20 gpm). In states 3-13, the LTOP protection is in place, i.e., the standby charging pump is locked out. Thus, the operator is called on to diagnose and respond to a LOCA most of the time in shutdown condition. A break may go unnoticed, so smaller leak rates are considered than in classical LOCAs. The most vulnerable condition will be while draining to mid-loop, between the levels of top of the nozzle and the loop mid-plane. Here, a large drop in inventory (beyond the planned draindown rate) may go unnoticed, as the impact on level will be

minimal. As the top of the nozzle is uncovered, the steam generator tubes will start to drain, so the level will stay almost constant for a long time. Around the mid-plane, one inch in level corresponds to about 400 gal. Therefore, because a leak may go unnoticed, this is a very vulnerable condition from the standpoint of losing the RHR due to pump cavitation from inadequate coolant level. However, loss of inventory while in mid-loop will be considered as a RHR loss initiator, not as a LOCA initiator.

Following is a discussion of H, J, and K LOCAs:

- (a) H LOCA, or recoverable diversion of RCS coolant. This is an event that results from inadvertent transfer of reactor coolant out of the RCS; the transfer is recoverable as the coolant can be pumped back to the RCS. For example, there have been several instances industry wide where the RHR system was inadvertently aligned in such a manner that RCS coolant was transferred to RWST. For Surry, this diversion can be recovered by 1) stopping it, and 2) using the LPI pumps to transfer the coolant from the RWST back to the RCS, or using the makeup system (part of the CVCS).

At Surry, a diversion can happen in the following ways:

- (1) RHR transfer to RWST: this diversion can happen if both the manual valve RH-29 and MOV-100 were opened at the same time and would proceed at about 90 gpm. If the plant was in the refueling state with the refueling cavity filled, it would take about 50 hours to drain down to the reactor vessel flange, and more time to drain below the mid-loop, thus causing RHR pump cavitation and RHR failure (the failure of decay heat removal could occur before this time if RHR cold leg return valves MOV 1720A and MOV 1720B were inadvertently closed). Unless there was a long hiatus in refueling operations, the drop in the level of the refueling cavity would, presumably, be detected during this time (the level is also alarmed in the control room and there are hourly checks in the containment); this possibility probably can be discarded in the refueling state. In other configurations, there would be a varying time period available for recovery, depending on the volume of water available for transfer before the onset of problems with decay-heat removal. The most sensitive configuration is mid-loop condition, as there is very little margin for a decrease in level.
- (2) RL transfer to RWST: the RL system is used to purify refueling cavity water (by using certain parts of the CVCS). It can be used to drain the cavity to the RWST after the refueling is finished (again by going through the CVCS and opening the manual valves CH-208 and CH-210). It can only drain the coolant down to the bottom of the refueling cavity, therefore by itself it is not an initiator. It can be used in conjunction with RHR transfer to RWST to minimize the draindown time; if used alone, the cavity would take > 50 hours to drain. Again, the possibility of an inadvertent diversion going unnoticed is very small, and it will be discarded.
- (3) CVCS system imbalance between letdown and charging: this imbalance effectively transfers the RCS coolant to the boron recovery and primary grade water systems. It can occur by some malfunction in the charging or letdown systems, followed by a failure of letdown isolation valves to close on low pressurizer level (in POS 1-4, and 12-15) or on loss of charging, or failure of the operator to control the letdown and charging operation (in POS 5-11). The original malfunction could be a loss or decrease in the charging flow, an increase in the letdown flow, or loss of control over charging and letdown. The maximum letdown flow rate through the regenerative and non-regenerative heat exchangers is about 120 gpm, at 2250 psi; at lower pressures, the letdown flow will be smaller. Two letdown orifices can each pass a maximum flow of 60 gpm/orifice, and 45 gpm for the third. Normally, only one orifice is used (except during startup when letdown flow is maximized). The letdown flow is alarmed in the control room at 130 gpm. (The excess letdown can add very little, about 15 gpm). During RHR operation, the RHR letdown configuration is used which bypasses the orifices and the regenerative heat exchanger. The charging flow is alarmed below 30 gpm and above

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110 gpm, the maximum charging pump flow is 150 gpm at 2250 psi, which increases as the RCS pressure decreases. On loss of charging flow, the standby charging pump will automatically start if the plant is in states 1, 2, 14, or 15. If there is a loss of charging, letdown is automatically isolated by closure of the two letdown isolation valves.

In summary, this diversion requires some failure in the charging or the letdown system combined with the failure of an automatic or human controller, and combined with failure to alarm or to respond to the alarm (e.g. level alarm). The loss of inventory can be compensated by the makeup system or by injecting from the RWST by LPI or HPI (charging pumps).

- (4) Diversion through loop-drain valves with loop stop valves open or leaking. The maximum drain rate from all three loops is 15 gpm (the drained coolant goes into the Vents and Drains system and, after purification, becomes part of the boron recovery and the primary grade water systems). Normally, the loop drain valves would not be open deliberately unless the loop-stop valves were closed. The rate of draining is very small, but if left unchecked for a long time could cause RHR pump cavitation under certain conditions. Again, level alarms/checking would have to be disregarded for a long time (the most vulnerable plant condition would be mid-loop operation). Because of such a low leak rate, this is not a credible initiator; under normal plant conditions, this rate is well within the capacity of the makeup system. It will not be considered further as a LOCA initiator.
- (5) Failure of the refueling cavity seal. Failures of the inflatable type seals have been observed in the past, including an occurrence at Surry. This would be a recoverable failure, as the coolant would end up in the Vents and Drains system via the containment sump or in the containment sump. A complete refueling cavity draindown would leave the RCS level at the reactor vessel flange. A similar type event would be the inadvertent opening of the refueling cavity drain valve.
- (b) J LOCA or LOCA in connected systems. This is a LOCA that occurs in a system that is connected to the RCS, thereby indirectly challenging the maintenance of an adequate reactor coolant inventory. There have been several occurrences in PWRs with leaks in RHR and CVCS systems. (One RHR event was caused by a water hammer due to faulty maintenance (i.e., air left in line)—this event should probably be considered under "maintenance-induced LOCAs" (see below)). We consider J LOCAs in systems that are under stress (e.g., operating) and are connected to the RCS. The following are subcategories for this IE:
  - (1) LOCA in RHR
  - (2) LOCA in CVCS
  - (3) Failure of temporary seals around instrument thimble tubes. Temporary seals designed to withstand 40 psi, are made around the instrument tubes as they are retracted from the reactor vessel in preparation for refueling. In normal operation, the highest pressure they would encounter would be the head of water from the vessel flange (approximately) to the top of the refueling cavity, or less than 30 ft (about 15 psi). If this seal were to fail due to low quality material or improper maintenance, the reactor cavity would drain down to the vessel flange, which would not be a threat to the reactor core. Therefore, this is not an initiator. The concern with these seals is if a prolonged loss of RHR were to occur with the vessel head bolted on; then the buildup of pressure due to boiling in the core would eventually fail the seal, giving rise to a LOCA through the bottom of the reactor vessel. Therefore, this event is considered as part of scenarios following loss of RHR.
- (c) K LOCA or maintenance induced LOCA. This is a LOCA that occurs as a result of maintenance activity—e.g., due to improper valve lineup, the RCS coolant is directed toward an opening created by maintenance activities or improper maintenance results in a LOCA.

Many maintenance activities go on in parallel during shutdown, and sometimes they are not well coordinated; the plant can be in unusual configurations due to a lack of requirements, such as technical specifications, for these modes of operation. Finally, part of the RCS pressure boundary may be made of temporary materials that cannot withstand elevated pressures (tygon tubing, temporary seals around thimble tubes) or temperatures. Cold plugs may be used (for example, if RHR isolation valve MOV-1700 were to fail to open when RHR is started, it might have to be taken out for repair and a cold plug put in the 14" line at elevated temperature and pressure). The frequency of cold plug failure has been neglected in comparison to the frequency of other LOCA initiators. There has never been a cold plug failure at Surry. No moving parts or power are needed to sustain a cold plug, which is continuously monitored by the technician. During a cold plug job, there is always twice as much liquid nitrogen on site as is needed for duration of the job, and there is a supply of spare valves if needed. A typical 4" seal could take 4-5 hours to thaw if the nitrogen supply were cut off.

There have been several instances (in LERs) where openings were created through lack of coordination (e.g. in valve manipulation), or lack of understanding, improper maintenance (air left in lines creating a water hammer; valves not torqued down creating a leak) or rupture of temporary pressure boundary, such as tygon tubing. Maintenance activities on the RCS or the connected systems (CVCS and RHR) are of concern.

4.5.3 Applicability of LOCA Categories in Various Plant States

A, S1, S2, S3:   States 1 and 15
                               States 2 and 14 (reduced frequency)
                               States 3,4 and 12 & 13 (frequency further reduced)
 Comment: in all other states pressure too low (atmospheric)

H LOCA: via RHR: States 3-6, 9-13
 Comment: in States 7 and 8, the refueling cavity is either being filled or is full of borated water; due to checks and alarms on the level and the quantity of water any diversion can be discarded in these states, as it would be discovered quickly.

                              via CVCS: all except 7 and 8
 Comment: same as above.
 J LOCA: via RHR: States 3-13, except 7 and 8
                               via CVCS: all except 7 and 8

K LOCA: via RCS: all except 7 and 8
 Comment: a maintenance induced LOCA can occur in a different plant state than the one in which the maintenance was performed.

                              via RHR: 3-13, except 7 and 8
                               via CVCS: all except 7 and 8
 Refueling cavity seal failure: 8
 Refueling cavity drain valve left open: 7

The applicability of LOCA categories vs. plant states is given in Tables 4.5-1 and 4.1-3.

4.5.4 LOCA Frequencies

Full Power LOCA frequencies are taken from NUREG-1150 and adjusted.
     A: 5.0E-4/yr
     S1: 1.0E-3/yr

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S2: $1.0\text{E-}3/\text{yr}$

S3: $1.3\text{E-}2/\text{yr}$

For states 1 and 15, full power frequencies are used. For states 2 and 14, the full power frequencies for individual categories are divided by 20^[2]. For states 3, 4, 12 and 13, the full power frequencies are divided by 30. These ratios are derived from statistical considerations of structural mechanics in the case of the pressurizer surge line (large LOCA); it is assumed that the same ratios will hold for other piping and other break sizes. In the past, studies assumed that the frequency of LOCAs does not change with the mode^[4,5]. The frequencies given above are per full power year; the frequency in each plant state is calculated by pro-rating, based on fraction of time spent in that state (Table 4.5-2). The final frequencies are given in Tables 4.5-3 - 4.5-12.

Frequencies are given with and without the contribution from the ISL (interfacing system LOCA) analysis. We note that the S2 LOCA Tables given here do not include the substantial contribution from transfers from transient event trees. These are discussed in Appendix I in the sections on event tree analysis and quantification of the phase 1 analysis.

The frequency of other LOCAs was derived from LER reports, by dividing the number of LER occurrences by the number of PWR reactor years in the 10-year LER period, i.e., about 610 reactor years. The frequencies given below are per calendar year; frequency in each plant state is calculated by pro-rating, based on the fraction of time spent in that state (Table 4.5-2). The final numbers are given in Tables 4.5-3 - 4.5-12.

H LOCA:

via RHR: $0.005/\text{yr}$
via CVCS: $0.001/\text{yr}$
via drains: $0.001/\text{yr}$

J LOCA:

via RHR: $0.005/\text{yr}$
via CVCS: $0.003/\text{yr}$

K LOCA:

via RCS: $0.002/\text{yr}$
via RHR: $0.001/\text{yr}$

For H LOCAs via RHR, we did not use the LER generated number as the setup at Surry differs from a typical PWR. For this transfer to happen, both the manual valve RH-29 and the MOV-100 would have to be left open (i.e., this initiator is most likely in POS 10). The HEPs for these actions were calculated as 0.005 for RH-29 (i.e. simple action outside the control room), and 0.0002 for MOV-100 (simple action in the control room + >60 min for diagnosis). This gives us the initiator frequency of 10^{-6} .

For J and K LOCAs through the RHR, we use the LER generated number for S2 (small) LOCAs, as these represent problems with the RHR relief valves. This results in S2 LOCA frequency that is about 40% of the S2 LOCA frequency via the RCS in those POSs.

For A LOCAs (as most of the RHR piping is of large diameter), we take the Diablo Canyon rupture frequency (of RHR piping >3") of $1.5\text{E-}9/\text{hr}/\text{section}$. Conservatively, assuming 20 sections in the RHR system yields a calendar year frequency of $1.75\text{E-}4/\text{yr}$, or 35% of the RCS A LOCAs in the applicable POSs (this value needs to be multiplied by the fraction of time in the particular POS). The multipliers (40% for S2 and 35% for A) will be added on the final sequence quantification for S2 and A LOCAs to arrive at the total S2 and A LOCA quantification for sequences in these POSs.

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For the frequency of cavity seal failure we use 0.01 (2 failures, ~600 reactor years). For cavity drain valve failure, we conservatively use the same number (0.01).

One of the events in the J LOCA via CVCS category did not come from LERs but from a separate source^[5].

LISTING OF OCCURRENCES:

Plant	Docket	Year	LER	Classification
Sequoyah 1	327	1981	021	H via RHR
Sequoyah 2	328	1981	094	H via RHR
North Anna 1	338	1987	014	K via RCS
Plant	Docket	Year	LER	Classification
Trojan	344	1981	013	K via RCS
McGuire 1	370	1984	017	J via RHR
Waterford 3	382	1985	057	J via CVCS
Summer 1	395	1985	014	J via RHR
Beaver Valley 2				H via RCS drains
Catawba 1	413	1990	013	H via RHR
Braidwood 1	456	1988	008	J via RHR
Braidwood 1	456	1989	016	J via RHR
Yankee Rowe		1986	010	J via RHR
Robinson 2		1981	005	J via CVCS
Turkey Point 3		1988	002	H via CVCS
Maine Yankee		1990		H via RHR
Braidwood 2		1990		H via RHR
Braidwood 1		1990		K via RHR
Salem 2		1981	IDAHO	J via CVCS

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4.5.5 System Impact and Success Criteria

For classical LOCAs (A, S1, S2, S3), we assume that for states 1 and 15, the system impact and success criteria are the same as in NUREG-1150. For other states, manual actuation of safety features is necessary and the reactor is already scrammed. The success criteria for safety injection may be different than those at full power -- the leak rates may differ, and the break flow may be liquid instead of steam in some states. Thermal-hydraulic calculations are performed to confirm this.

For other LOCAs, manual actuation of safety injection may be necessary in states other than 1 and 15. If the RCS is depressurized and there is a vent path, gravity feed from RWST can be used (states 5-11). If RHR was part of the problem (e.g. RHR LOCA), reflux cooling can be used, if steam generators are in wet layup and available. If the CVCS was part of the problem (CVCS LOCA), seal cooling to RCPs may be lost in states 1-4 and 12-15, and cooldown/heatup will have to be stopped until the problem is repaired.

4.5.6 References

1. Bertucio, R.C., et al., "Analysis of Core Damage Frequency: Surry, Unit 1 Internal Events", Sandia National Laboratories, July 1987, NUREG/CR-4550, Rev. 1, Volume 3, Part 1.
2. Gresham, J.A., Bishop, B.A., Cassidy B.G., and Monty, B.S., "Core Damage Risk Associated with Loss of Coolant Accidents During Shutdown Operations," Proceedings of International Topical Meeting on Probability, Reliability and Safety Assessment, April 2-7, 1989, Pittsburgh, PA.
3. Berger, J.P., "Probabilistic Safety Assessments at EDF", presented at the Meeting of Committee for Safety of Nuclear Installations, Santa Fe, NM, September 1990.
4. Lanore, J.M., "The French 900 MWe PWR P/sa Results and Specificities", presented at the Meeting of Committee for Safety of Nuclear Installations, Santa Fe, NM, September, 1990.
5. Wright, R.E., Stevenson, J.A., and Zuroff, W.F., "Pipe Break Frequency Estimation for Nuclear Power Plants", EG&G Idaho, Inc., May 1987, NUREG/CR-4407.

Table 4.5-1 State Applicability of LOCAs

State	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
A															
A	X	X	X	X								X	X	X	X
S ₁	X	X	X	X								X	X	X	X
S ₂	X	X	X	X								X	X	X	X
S ₃	X	X	X	X								X	X	X	X
H															
Via RHR			X	X	X	X			X	X	X	X	X		
Via CVCS	X	X	X	X	X	X			X	X	X	X	X	X	X
J															
Via RHR			X	X	X	X			X	X	X	X	X		
Via CVCS	X	X	X	X	X	X			X	X	X	X	X	X	X
K															
Via RCS	X	X	X	X	X	X			X	X	X	X	X	X	X
Via RHR			X	X	X	X			X	X	X	X	X		
Via CVCS	X	X	X	X	X	X			X	X	X	X	X	X	X
Cavity Seal															
Cavity Seal								X							
Cavity Drain Valve															
Cavity Drain Valve							X								

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Table 4.5-2 Fraction of Time that the Plant Stays in the POSs

Outage Type →	R	D	N1	N2
POS				
1	3.83-5	9.58-5	9.13-6	1.53-4
2	1.53-3	2.07-3	1.12-3	4.11-3
3	7.32-4	1.86-3	1.53-3	
4	0.0106	0.0269	0.0117	
12	0.1259	0.0237		
13	2.33-3	1.37-3		
14	4.72-3	5.53-3	1.92-3	
15	3.84-3	1.74-3	1.70-3	2.69-3

Table 4.5-3 A LOCA Frequency vs. POS vs. Outage Type (Without ISL Contribution)

Outage Type → POS	R	D	N1	N2
1	1.92-8	4.79-8	4.57-9	7.65-8
2	3.82-8	5.18-8	2.80-8	1.03-7
3	1.24-8	3.16-8	2.60-8	
4	1.08-7	4.57-7	1.99-7	
12	2.14-6	4.03-7		
13	3.96-8	2.33-8		
14	1.18-7	1.38-7	4.80-8	
15	1.92-6	8.70-7	8.50-7	1.34-6

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**Table 4.5-4 A LOCAs Initiator Frequency as a Function of POSs
(Without ISL Contribution)**

POS	Frequency (/yr)
1	1.49-6
2	2.21-7
3	7.00-8
4	8.36-7
12	2.54-6
13	6.29-8
14	3.04-7
15	3.64-6

Table 4.5-5 A LOCAs Initiator Frequency With ISL Contribution

POS	Frequency (/yr)
1	1.49-6
2	1.25-6
3	7.00-8
4	8.36-7
12	2.54-6
13	6.29-8
14	1.72-6
15	5.4-6

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Table 4.5-6 S1 LOCA Initiator Frequency vs. POS vs. Outage Type (Without ISL Contribution)

Outage Type →	R	D	N1	N2
POS				
1	3.83-8	9.58-8	9.13-9	1.53-7
2	7.65-8	1.04-7	5.6-8	2.06-7
3	2.44-8	6.2-8	5.1-8	
4	3.53-7	8.97-7	3.9-7	
12	4.2-6	7.9-7		
13	7.77-8	4.57-8		
14	2.36-7	2.77-7	9.6-8	
15	3.84-6	1.74-6	1.7-6	2.69-6

Table 4.5-7 S1 LOCA Initiator Frequency as a Function of POSs

POS	Frequency (/yr)	
	w/o ISL Contribution	w/ISL Contribution
1	2.99-6	2.99-6
2	4.42-7	7.68-7
3	1.37-7	1.37-7
4	1.64-6	1.64-6
12	5.0-6	5.0-6
13	1.23-7	1.23-7
14	6.09-7	1.06-6
15	7.28-6	7.28-6

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Table 4.5-8 S2 LOCA Initiator Frequency vs. POS vs. Outage Type (Without ISL Contribution)

Outage Type →	R	D	N1	N2
POS				
1	3.83-8	9.58-8	9.13-9	1.53-7
2	7.65-8	1.04-7	5.6-8	2.06-7
3	2.44-8	6.2-8	5.1-8	
4	3.53-7	8.97-7	3.9-7	
12	4.2-6	7.9-7		
13	7.77-8	4.57-8		
14	2.36-7	2.77-7	9.6-8	
15	3.84-6	1.74-6	1.7-6	2.69-6

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Table 4.5-9 S2 LOCA Initiator Frequency as a Function of POSs

POS	R, D & N2 Outages		N1* Outages	
	without ISL	with ISL	without ISL	with ISL
1	2.99-6	1.98-5		
2	4.42-7	5.02-5		
3	1.37-7	1.37-7		
4	1.64-6	1.64-6		
12	5.0-6	5.0-6		
13	1.23-7	1.23-7		
14	5.13-7	5.74-5	9.6-8	1.08-5
15	5.58-6	3.69-5	1.7-6	1.12-5

* included in "R, D & N2 Outages" column unless a value appears

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Table 4.5-10 S3 LOCA Initiator Frequency vs. POS vs. Outage Type

Outage Type →	R	D	N1	N2
POS				
1	4.98-7	1.25-6	1.19-7	1.99-6
2	9.94-7	1.35-6	7.28-7	2.68-6
3	3.17-7	8.06-7	6.63-7	
4	4.59-6	1.17-5	5.07-6	
12	5.46-5	1.03-5		
13	1.01-6	5.94-7		
14	3.07-6	3.60-6	1.25-6	
15	4.99-5	2.26-5	2.21-5	3.50-5

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Table 4.5-11 S3 LOCA Initiator Frequency as a Function of POSs

POS	Frequency (/yr)	POS	Frequency (/yr)
1	3.89-5	12	6.49-5
2	5.75-6	13	1.60-6
3	1.79-6	14	7.92-6
4	2.14-5	15	9.46-5

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Table 4.5-12 Other LOCA Initiator Frequencies Considered in Report

IE	POS	Frequency (yr)
H-RHR	10	1.-6
JK-RHR-S2	3,4,12,13	40% of S2 in POS 3,4,12,13
JK-RHR-A	3,4,12,13	35% of A in POS 3,4,12,13
Cavity seal failure	8	0.01
Cavity drain valve open	7	0.01

4.6 Interfacing Systems LOCA

4.6.1 Extended Interfacing System LOCA Analysis

The Surry NUREG-1150 study identified an interfacing systems LOCA (ISLOCA) sequence during power operation as an important contributor to public health risk. In the present study, BNL extended the ISLOCA analysis with the primary objective of identifying additional potential sources of ISLOCA events

- (a) during (low) power and shutdown plant operational states, (POSSs), and
- (b) as a consequence of changes between these POSSs.

For item (a), we explored possible new ISLOCA pathways because of the changed hardware configuration and plant parameters. For item b) we looked for weak elements of man-machine interface when changing POSSs, such as potential human operational errors, procedural inconsistencies or nonexisting procedures, as well as failures in performing test and maintenance.

The secondary objective of the analysis was to determine the core damage contributions due to the ISLOCA sequences based on the latest developments in that area,^[1-3] including the possibility that the novel nonintrusive approach^[4] for monitoring the operation and condition of check valves in real time might be applied at Surry.

While BNL's ISLOCA analysis was more extended than that of Surry NUREG-1150, its scope is still more limited than a dedicated ISLOCA study, based on a full-fledged deep vertical slice ISLOCA inspection conducted by an NRC team.

4.6.2 Methodology

A screening review was performed on the piping configurations of the RCS and its interfacing fluid systems during both power and shutdown conditions to identify potential ISLOCA pathways. In particular, the RHRS was investigated, because during POSSs when the RHRS are not connected to the RCS, its piping could serve as a conduit through which reactor coolant could bypass containment ("V-events"), and also during POSSs when it is connected to the RCS, a breach of its pressure boundary bypassing containment directly also represents a V-event.

The screening process eliminated potential ISLOCA flow paths containing more than two pressure isolation valves in series, or where the expected flow rate was smaller than or around the makeup flow rate. For the remaining pathways, ISLOCA initiator models were constructed. These models, as well as their quantification involve the plant/system/operational-state/operational-process-specific conditions, and all the new information and failure data accumulated since of Surry NUREG-1150 was completed. All ISLOCA initiators that potentially lead to core damage were determined, and scenarios leading to ISLOCAs bypassing containment ("V-events") were identified for further health risk analysis.

The initiating frequency, as well as the eventual core-damage frequencies were obtained by point estimates.

4.6.3 ISLOCA Scenarios

The following ISLOCA scenarios were selected for detailed analysis:

- (1) The Low Pressure Safety Injection System V-Event Scenario.
- (2) Residual Heat Removal system ISLOCA Scenarios:

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- (a) ISLOCA Scenarios via the Suction and Discharge Lines of the RHRS and the associated V-Event Scenario through the RHRS-CVCS Letdown Line.
  - (b) V-Event Scenario through the RHRS-CVCS Letdown Line associated with Low Temperature Overpressurization (LTOP) of the RHRS.
  - (c) V-Event Scenario through the connecting line of the RHRS to the Refueling Water Storage Tank (RWST).
- (3) Accumulator Discharge Line ISLOCA Scenario.

The description of these scenarios as well as the relevant results of their analysis are presented in the subsequent sections.

4.6.3.1 Low Pressure Safety Injection System V-Event Scenario

The first ISLOCA scenario involves the failure of the LPI system discharge swing check valves (Velan) at their connection to the three RCS cold legs; this is the V-event identified in Surry NUREG-1150. In the scenario, we assumed that two of the check valves in a single connection line fail, leading to pressurization of the LPI piping or components outside the containment.

The LPI system is described in Section 6.2.10. Its schematic is shown in Fig. 4.6-1. The V-event check-valve pairs are: (CV-79, CV-241), (CV-82, CV-242) and (CV-85, CV-243). Heavy lines indicate the pressurized pipe segments in the figure in a V-event. (The piping is made out of Class 153 150 lb. type 304 stainless-steel lines. The pressure specifications of this piping are 95 psig at 350°F, 225 psig at 250°F, and 275 psig at 100°F). The high pressure (2580 psig)-low pressure piping boundaries are located just at the inlet sides of MOV-1890 A, B, and C. MOV 1890 A and B are normally closed during power operation. There are three relief valves in the system: RV-1845 A, B, and C. (Set points: 220 psig). However, they have only one common 1" dia. discharge line that relieves to the safeguard area. The check valves are subject to the individual leak-testing program ("Event-V Order").

At operating pressure and temperature, only massive leakage can cause LPI overpressurization or (via the 2" LPI miniflow line (Schedule 40S pipe) the RWST), a failure of the RWST. Smaller leaks (about 100 gpm) could be diverted to the RWST without LPI overpressurization. The scenario directly leads to core damage, because although initially the High Pressure Injection, (HPI) system provides cooling water make-up, loss of recirculation would result in late core damage.

The scenario can exist in POSs 1, 15, and also in POSs 2, and 14, because the normally open MOV on the single main-injection line (MOV 1890C) is closed during shutdown at the end of POS 2, and reopened only during startup at the beginning of POS 14. Since the plant configuration and plant parameters are similar, POSs 1 and 15, as well as POS 2 and 14 were considered to be practically symmetric with respect to potential ISLOCA generation.

The core damage frequency in Surry NUREG-1150 for the scenario was obtained by expert elicitation. BNL re-evaluated the scenario. BNL's scenario model was based, essentially, on all of the possible combinations of credible failure modes for the two check valves, and on the Technical Specification requirement that these pressure-isolation valves should pass a leak test at least once per nine-months ($T = .75$ yr intervals). The credible check valve failure modes were: "massive internal reverse leakage (rupture)", and "check valve fails to operate (to close) on demand (and stays undetected)".

Following the initiating frequency model derived in detail in Ref. 3 (Appendix B, Eq. (8) on p. B-9 of that Ref.) the average failure rate of two check valves in series over a time period T is given by the expression:

$$\langle \lambda, (1, 2, d_1, d_2) \rangle = \lambda_1 \lambda_2 T + \lambda_1 \lambda_d \left(\frac{d_2 T + 1}{2} \right) + \lambda_2 \lambda_d \left(\frac{d_1 T + 1}{2} \right) \quad (1)$$

where, $\lambda_1 = \lambda_2 = \lambda$, is the mean value of the large reverse leakage failure rate,

λ_d is the mean value of "check valve fails to operate (to close) on demand" failure rate,

d_1 and d_2 are the demand rates for check valves 1 and 2, respectively. The data for check valve failures are listed in Appendix 4.6.A. The demand rate for the first check valve (e.g., CV-79) is taken to be the frequency of inadvertent safety injections, $d_1 = 6.4 \text{ yr}^{-1}$. For the second check valve (e.g., CV-241), the demand rate was taken to be one demand during a period between two leak tests i.e., $d_2 = 1/T$. The demand could be generated by the monthly flow testing of the LPI pumps and discharge lines.

The average failure rate for one check-valve pair is:

$$\begin{aligned} \langle \lambda, (1, 2, d_1, d_2) \rangle &= 1.25-07 * .75 + (2.19-04) * (2.81-04) * \left\{ 1 + \frac{6.4 * .75 + 1}{2} \right\} \\ &= 9.375-08 + 2.40-07 = 3,34-07 \text{ per year.} \end{aligned} \quad (2)$$

Thus, for the three ISLOCA pathways, the total initiating (and core damage) frequency is:

1.00-06 per year.

(The expert elicitation core damage frequency value in Surry NUREG-1150 is: 1.60-06 per year). They are simply the frequency per year multiplied by the fractions of a year that the plant is in the POSs.

The core damage frequencies in the various POSs corresponding to BNL's value are given in Table 4.6-1. They are simply the frequency per year multiplied by the fractions of a year that the plant is in the POSs. Recently, novel non-intrusive methods were developed at Oak Ridge National Laboratory⁽⁴⁾ to monitor the operation and condition of check valves in real time. The methods are based on measuring the disk position of check valves in the field of external AC or external DC (permanent) magnets. As an example, the scheme of the DC magnet method is shown in Figures 4.6-2 and 4.6-3 which show that the application of disk position monitors of these types would substantially reduce "the check valve failure to close on demand (and stays undetected)" failure mode. From data on instrumentation failure, the reduction is expected to be at least two orders of magnitude. Thus, the average failure rate for one check valve pair would be:

$$\langle \lambda, (1, 2, d_1, d_2) \rangle = 9.375-08 + 2.4-09 = 9.62-08 \text{ per year,}$$

and the reduced total initiating (and core damage) frequency would be 2.89-07 per year.

Table 4.6-1 also contains the corresponding reductions in core damage frequencies in the various POSs. The advantage of applying real-time check valve disk position monitors is clear; the reduction factor in core-damage frequency is 3.5. (Its ultimate benefit can be evaluated only by estimating the reduction in health risk which would be expected to be considerably larger.)

4.6.3.2 Residual Heat Removal System ISLOCA Scenarios

To facilitate understanding of the ISLOCA scenarios associated with the RHR system, its hardware configurations interfacing with the RCS and other systems are discussed below.

4.6.3.2.1 Interfacing Configurations of the RHRS

The RHR system is designed to operate at pressures less than 450 psig and at temperatures less than 350°F. The material in the RHR System piping is: 600 lb., Class 602, Schedule 40 or 40S, TP 304 stainless steel.

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(The maximum operating specifications of the piping are: 650 psig at 600°F, 750 psig at 400°F and 950 psig at 200°F.) The associated flanges and gaskets are rated to stand a maximum pressure of 600 psig. Detailed descriptions are given in Section 6.2.13.

The RHRS is operated during plant cooldown and refueling to remove decay heat until the subsequent plant heatup approaches the systems limitations. It also is used to transfer water from the reactor refueling cavity and the fuel transfer canal to the Refueling Water Storage Tank (RWST) after a refueling operation. Furthermore, with the Chemical and Volume Control System (CVCS), it provides shutdown chemical control, volume control, and shutdown pressure control when the RCS is solid.

The following flow pathways are used in these operations:

- (1) RHR operation: RHR suction and discharge lines.
- (2) Coolant Transfer from Reactor Cavity to the RWST: RHR suction line and an "alternate" RHR connecting line to the RWST. (The RHR discharge lines are closed).
- (3) Chemical and Volume Control during Shutdown: standard CVCS charging line to the RCS, and an "alternate" RHR connecting line (letdown) to the CVCS.

The valve configurations in the lines are described below (the schematics of the RHRS and the ISLOCA pathways are shown in Fig. 4.6-4):

RHR Suction Line

The incoming 14" line from the RCS hot leg A to the RHR suction contains two motor operated double disk gate valves (MOV-1700 and MOV 1701) in a series configuration that are normally closed. The high-and low-pressure interface is located at the second MOV.

RHR Discharge Lines

Two 10" outlet lines pass the RHR discharge flow to the RCS cold legs (B and C) via the Safety Injection (SI) system accumulator discharge lines. In each of these RHR discharge lines there is a normally closed MOV. The MOV, together with one of the two check valves in an accumulator discharge line, represent a double pressure isolation configuration for the RHR piping. (The valve configurations in the lines to cold legs B and C are; SI-130, MOV-1720A and SI-147, MOV-1720B, respectively.) The high-and low-pressure interface is located at the MOV. The system's discharge side has a relief valve, RV-1721 which provides overpressure protection. Its set point is 600 psig and its relief capacity is 750 gpm. The discharge of the relief valve is directed to the Pressurizer Relief Tank, PRT, located also in the containment.

Connecting Line to the RWST

The connecting line from the RHR system to the RWST is 6" in diameter (Schedule 40S). It contains two valves in series: a manually operated valve (RH-29), and a motor-operated valve (MOV-RH-100). While RH-29 is located in the basement of the containment, MOV-RH-100 is located outside the containment on the second level of the Safeguards Valve Pit Building. These valves are normally shut but are opened when coolant is transferred from the reactor cavity to the RWST at the end of refueling.

The CVCS Charging Line

The charging flow pathway from the CVCS to the RCS is a high pressure line belonging to the CVCs. It is not considered within the scope of the present discussions.

Connecting Line to the CVCS

The 2" connecting line (Schedule 40S) to provide letdown flow during shutdown to the CVCS via the standard low pressure letdown line contains a normally open air operated globe valve, HCV-1142. Together with a similar valve in the CVCS, PCV-1145, it controls the letdown flow. The low pressure letdown line is protected from overpressurization by a relief valve, RV-1203. The relief valve is set to 600 psig (which is the design pressure of the Non-Regenerative Heat Exchanger), its capacity is about 180 gpm, and it discharges to the PRT. Outside the containment there is also a containment isolation solenoid valve on the letdown line, TV-1204, which closes upon receiving a Containment Isolation Signal, CIS.

4.6.3.2.2 RHR Suction Line and RHR Discharge Line ISLOCAs. V-Event Through the RHR-CVCS Letdown Line

The RHR system is located inside the containment. Therefore, ISLOCA events through the RHR suction and discharge lines (during POSs 1,2 and 14,15) do not represent direct V-events. However, they may result in core damage because of overpressurization and rupture of the RHR system. Furthermore, they may lead to "indirect V-events" by eventual pressurization and rupture of the connecting piping to other systems.

The most obvious candidate for such an indirect V-event is the one which may occur through the rupture of overpressurized letdown line to CVCS, where the normally open air-operated globe valve, HCV-1142, would close upon receiving CIS. (An "indirect V-event" to the RWST through the RWST connecting line was estimated to be negligible.) CIS is always generated because, given an RHR Suction Line or Discharge Line ISLOCA, both the RHR relief valve, RV-1721, and the letdown line relief valve, RV-1203, would be lifted and would discharge to the PRT. An interesting feature of these ISLOCA scenarios is that if the piping integrity of RHR was better preserved, the higher would be the chance for a "V-event" through the letdown line.

- The RHR suction line ISLOCA scenario assumes that both of the in-series MOVs would fail with a loss of RCS to RHR pressure boundary. The scenario initiating frequency was modeled by considering the following operating conditions of these valves:

- (a) During normal power operations and in POSs 1, 2 and 14, 15 power is removed from the motor operators (Limitorque) and the circuit breakers are locked in the open position. (However, the fuse disconnects are not kept open.)
- (b) Electrical interlocks prevent opening the MOVs until the RCS pressure has been reduced below approximately 460 psig. The interlock is governed by the output of RCS narrow range (0-1000 psia) pressure transmitters (PT1403 measures the RCS pressure in the hot leg of Loop C and governs the interlock of MOV 1700; PT1458A measures the RCS pressure in the pressurizer and governs the interlock of MOV1701).
- (c) If that the motor operator fails or power is lost, the valves can be manually opened by disengaging the motor clutch (locally) and using a handwheel on the motor operator. If this operation is undertaken, the open permissive interlock is defeated; thus, the operator must ensure that the RCS pressure is less than the interlock setpoint.

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- (d) The MOVs fail in the "as is" position.
- (e) The MOVs have limit switches inside the operator-housing on the drive gears (not on the valve stem) making the valve susceptible to the failure mode "MOV fails open but indicates closed". The gears that drive the valve closed become disengaged; the drive gear still turns and the limit switch indicates that the valve is closed, although it has not.
- (f) The position of a valve are indicated by red/green light indicators in the control room. If both lights are energized, the valve is in an intermediate position. Handswitches (open-close) control the operation.

In the initiating-event frequency model, therefore, the combinations of the following MOV failure modes were considered: "gross internal leakage" and "MOV fails open but indicates closed". The failure modes "MOV disk rupture" and "MOV transfers open" were not taken as credible, the former because the MOVs are of double-disk type and are stroke tested at each start up, which would uncover failure of disk integrity, and the second one because of conditions a) and b). "The external leakage/rupture" failure modes of the MOVs (representing a breach of the RCS) are essentially included in the "Small LOCA" initiating frequency. The average failure rate for the MOV pair is (Ref. 3, Appendix B, p. B-13, Eq. (12a)):

$$\langle \lambda, (1, 2, d) \rangle_{MOV} = \lambda_i^2 T + 2\lambda_i \lambda_d \left(\frac{DT+1}{2} \right) \quad (3)$$

where, λ_L and λ_D are the mean values of the failure rates: "gross internal leakage", and "MOV fails open but indicates closed", respectively.

d is the demand rate of the MOVs when the RHRS is used (the sum of the frequencies of outage types N₁, D, and R, i.e.. d = 2.6 yr⁻¹).

Because disk integrity/leak tests as well as gear-case and valve-stem inspections are performed on these MOVs during each refueling, the period between two leak tests is taken to be T = 1/R = 1/6 yr⁻¹ = 1.67 yr.

The initiating event model was evaluated using recent MOV failure data listed in Appendix 4.6.A. Thus the average failure rate of the MOV pair is:

$$\begin{aligned} \langle \lambda, (1, 2, d) \rangle_{MOV} &= (6.12-05) * 1.67 + (4.85-03) * (1.1-04) * (2.6 * 1.67 + 1) \\ &= 1.05-04 \text{ per year.} \end{aligned}$$

To obtain initiating frequencies for LOCAs inside the containment, the ISLOCA initiating event frequencies calculated for the various POSs were multiplied by the rupture probability of the RHR system. (The probability of RHR rupture was taken as .98, a representative value for RHR systems recently determined by the Idaho National Engineering Laboratory,^[1] see also Appendix 4.6.A.) BNL gave credit to the significantly lower RCS pressure during POSs 2 and 14, for generating a LOCA in the containment. We assumed that an ISLOCA through the RHR suction line leads 2/3 of the time to a medium and 1/3 of the time to a large LOCA in the containment. Table 4.6-2 shows the mean initiating frequencies for the containment of these types of LOCAs in the appropriate POSs.

- The RHR discharge line ISLOCA scenario assumes that both the check valve and the MOV fail with a loss of RCS to the RHR pressure boundary. The large size of the valves and the double pathway compelled us to analyze carefully the initiating event frequency of the scenario.

The initiating event model took into account that the check valve (in the accumulator discharge line) has a dedicated leak-monitoring piping system, through which the check valve is leak-tested during each start up. We also considered that a leak failure would be detected by an increased leakage into the constantly monitored accumulator. Thus, for this check valve, we eliminated "failure to reclose", and small and medium size "leak" failures; only the "large reverse leakage (rupture)" failure mode was retained.

The MOVs in the discharge line have the same properties and safety features as the MOVs in the suction line, except they do not have an electrical pressure interlock. Therefore, "MOV transfers open" and "MOV fails open but indicates closed" failure modes were taken to be credible for these valves.

The average failure of two check valve-MOV pairs is:

$$\langle \lambda_s(CV, MOV, d) \rangle = 2 \left[\lambda_i \lambda_L \frac{T}{2} + \lambda_i \lambda_T \frac{T}{2} + \lambda_i \lambda_D \left(\frac{dT+1}{2} \right) \right] \quad (5)$$

where, λ_i and λ_L are mean values of large, reverse, internal-leak failure rates for check valves and for MOVs, respectively. λ_T and λ_D are the mean values for "MOV transfers open" and "MOV fails open but indicates closed" failure modes. The interval between the periodic tests of disk integrity for the MOVs was taken as the refueling period ($T = 1.67$ yr). The demand rate, d , of the MOVs was taken to be the average frequency of the use of the RHRS, $d = 2.6 \text{ yr}^{-1}$.

The average failure rate of the two check valve-MOV pairs was evaluated with the check valve and MOV failure data (See Appendix 4.6.A). The result of the quantification:

$$\begin{aligned} \langle \lambda_s(CV, MOV, d) \rangle &= 2.19-04 * [1.67 * (4.85-03 + 8.1-04) + 1.1-04 * (2.6 * 1.67 + 1)] \\ &= 2.20-06 \text{ per year} \end{aligned}$$

Since the discharge lines are smaller than the suction line, we assumed that these ISLOCAs generate "Medium LOCAs" in the containment during POSs 1 and 15. During POSs 2 and 14, due to the lower RCS pressure, we assumed that 2/3 of the time "Small LOCAs" and 1/3 of the time "Medium LOCAs" are initiated. Table 4.6-2 shows the appropriate initiating frequencies.

We note that the frequencies of containment LOCAs generated through the RHR discharge lines are significantly smaller than those generated through the RHR suction line. To calculate their combined contribution to the total core damage frequency, their sum is also given in the Table. The associated small, medium and large LOCA event trees were evaluated in the phase 1 study documented in Appendix I.

- Given an ISLOCA through the RHR suction or discharge lines, a V-event may occur through the RHR-CVCS letdown line. The necessary condition for a happening is that the integrity of the RHR system would be preserved and the letdown line would be pressurized and ruptured outside the containment. BNL took the complementary value of the RHR rupture probability, (.98) to characterize the condition. In other words, we used a conditional probability of .02 that the RHRS would behave as a pressurized conduit to the letdown line. The probability that the letdown line will rupture, under pressurization was taken, conservatively, to be 5.0-03 (See Appendix 4.6.A). The whole scenario was assumed to lead directly to (late) core damage, because of the eventual loss of LPI recirculation. The mean core-damage frequencies for various POSs are listed in Table 4.6-3.

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4.6.3.2.3 V-Event through the RHRS-CVCS Letdown Line Associated With the Low Temperature Overpressurization (LTOP) of the RHRS

A V-event similar to that described in the previous section may happen in POSs (12 + 13) and also in POSs 3 and 4 in connection with an RHR Low Temperature Overpressurization (LTOP). Sections 4.2.6 and 6.8.2 of the phase 1 study respectively, describe the LTOP scenario and its initiating frequency. They are provided in Appendix I.

The V-event scenario would occur if, because of an LTOP event, the letdown line ruptured instead of the RHRS. The initiating event frequency can be estimated as follows:

$$(V-LTOP)^{Letdown} = LTOP * I_{RHRS} * P_R$$

where, LTOP is the initiating frequency of LTOP events during the total time fraction of POSs (3 + 4 + 12 + 13). LTOP = 3.0-08 per year (from Section 6.8.2 of phase 1 study provided in Appendix I.). I_{RHRS} is the probability that the RHRS integrity is preserved under an overpressurization, and P_R is the probability of rupture of the overpressurized letdown pipe.

With $I_{RHRS} = .6$ and $P_R = 5.0-04$ at an overpressure of ~1000 psig (See Appendix 4.6.A) the initiating frequency is: $(V-LTOP)^{Letdown} = 2.4-11$ per year. The event again is assumed to lead directly to core damage. Since this is also a letdown line V-event, the core damage frequency also is listed in Table 4.6-3.

4.6.3.2.4 V-Event Through the RHRS-RWST Connecting Line

A "V-event" through the RHRS-RWST connecting line might occur if the two in-series isolation valves (the manual valve RH-29 and MOV-RH-100) simultaneously failed while the RHRS (connected to the RCS) is operating and still pressurized, i.e. when the plant is in POSs 3,4,12, or 13. (When the RHR is isolated from the pressurized RCS, the scenario may also occur, given an ISLOCA through the RHR suction or discharge lines. However, as discussed, the occurrence frequency of this scenario was found to be negligible.) The event would divert the coolant from the RCS to the RWST, or, given a massive external leakage (rupture) of MOV-RH-100, the RCS coolant would flow into the Safeguard Valve Pit.

The scenario initiating frequency was modeled by taking into account the following operating conditions of the MOV-RH-100:

The MOV is controlled in the control room by a two-position handswitch (Close, Open) that has red/green position lights. After operation, a spring returns the switch into a neutral position. The valve has an automatic shutting feature, operated by a level switch (LS-102-2), which measures the level of the RWST. If the RWST level reaches 99 percent, the MOV shuts automatically, preventing overfilling of the RWST. Therefore, such MOV failure modes which would not be able to recover by an automatic closure signal were included in the initiating event model. These were: "massive internal leak (disk rupture)", "massive external leak (at the valve bolted bonnet or body rupture)", "MOV transfers open", "MOV fails to operate on demand", and "MOV fails open, while indicating closed". (The corresponding failure rates are denoted, respectively, as: λ_L , λ_E , λ_T , λ_O , λ_D). The "MOV inadvertently left open by the operator" failure mode was not included in the model, since it is recoverable.

For the manual valve, we considered the failure modes "massive internal leakage (disk rupture)", "valve fails to close", and "valve inadvertently left open by the operator". (The corresponding failure rates are denoted, respectively, as: λ_{LL} , λ_C , λ_H).

Concerning recovery actions, closing of the manual valve by the operator was taken to be a credible action. (The failure of the recovery action is denoted by N_R). However, the other possibility for recovery was not taken to be credible, namely, to isolate the RHRS from the RCS by closing one of the two RHR suction line MOVs, which are locked open during these POSs, without an adequate accident management procedure, .

If the event cannot be recovered, it, directly leads to core damage because of a probable loss of the RWST integrity and/or eventual loss of LPI recirculation.

The average failure rate of the manual valve-MOV pair is:

(a) Flow to the RWST.

$$\begin{aligned} \langle \lambda_s(MV, MOV, d) \rangle^{RWST} &= \lambda_{LL} \lambda_L T + \lambda_{LL} \lambda_T \frac{T}{2} + \\ &+ \left(\lambda_{LL} \lambda_D + \lambda_{LL} \lambda_O + \lambda_L \lambda_C + \lambda_L \lambda_{HN_R} + \lambda_T \lambda_{HN_R} \right) \left(\frac{dT+1}{2} \right). \end{aligned} \quad (4a)$$

(b) Flow to the Safeguard Building.

$$\langle \lambda_s(MV, MOV, d) \rangle^{SB} = \lambda_{LL} \lambda_E \frac{T}{2} + (\lambda_C \lambda_E + \lambda_H \lambda_E N_R) \left(\frac{dT+1}{2} \right). \quad (4b)$$

Where the λ_s denote the mean failure rates of the described valve failure modes. T is the average time between periodic uses of the RHRS. The demand rate of the RHRS is,

$$d = 2.6 \text{ yr}^{-1} \text{ and } T = 1/d = .38 \text{ yr.}$$

By using the data on failure rate listed in Appendix 4.6.A, Equations (4a) and (4b) can be quantified as:

$$\begin{aligned} \langle \lambda_s(MV, MOV, d) \rangle^{RWST} &= 4.38-04 * (4.85-03 * .38 + 8.1-4 * .19) + [4.38-04 * (1.1-04 + 3.0-03) + 4.85-03 * \\ &* (5.0-04 + 5.0-03^2) + 8.1-04 * (5.0-04 + 5.0-03^2)] = 8.7535-07 + 4.337-06 \\ &= 5.21-06 \text{ per year.} \\ \langle \lambda_s(MV, MOV, d) \rangle^{SB} &= 1.23-03 * [4.38-04 * .19 + 5.0-04 + 5.0-03^2] \\ &= 7.48-07 \text{ per year.} \end{aligned}$$

The values for core damage frequency obtained by quantifying the model for the appropriate POSs are shown in Table 4.6-4. The frequencies of the V-event scenarios (the one with flow to the RWST, and the one with flow to the Safeguard Building) are shown separately.

4.6.3.3 Accumulator Discharge Line ISLOCA Scenario

Each of the three 12" accumulator discharge lines at Surry has two check valves (and a normally open MOV) in a series configuration. The I.D. Numbers of the check valves are the following: SI-109 and SI-107 in the line of Accumulator 1, SI-130 and SI-128 in the line of Accumulator 2, and SI-147 and SI-145 in the line of Accumulator 3. All the check valves are of swing-design and manufactured by Darling. (Figure 4.6-5 is a schematic of the potential pathways for ISLOCA).

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As discussed, in a recent BNL study on ISLOCA at PWRs^[3], the accumulator lines may represent preferred pathways for ISLOCAs. These accidents do not lead to "V-events", but as small, medium or large LOCAs may significantly contribute to the total core damage frequency.

BNL's study^[3] suggested that the accumulator discharge lines are preferred pathways for ISLOCAs because of the combined effects of the harsh, corrosive boric-acid environment and the proneness of the accumulator outlet check valve "to chatter". The chattering is caused by the valve's unstable position between two differently pressurized regions; the nitrogen-filled accumulator with a nominal pressure of 650 psig, and the pressurized pipe section between the two check valves. The pressure levels of these regions frequently vary i.e., there is no constant positive differential pressure across the valve disk. With each opening of the valve as it is chattering, the chance increases that it will fail to reseal when a sudden leakage of the first check valve demands it. Thus, an "effective probability" of the valve fails to operate (reseal) on demand failure mode will characterize this valve. This effective probability may increase rapidly after the valve has passed a leak test.

To model the initiating frequency of ISLOCAs of this type at Surry, the following system features and conditions were taken into account:

- (1) The accumulator check valves have a dedicated leak-monitoring piping system, through which the valves are leak- tested during each start-up, when there is about 120 psi differential pressure across the valves.
- (2) The volume of an accumulator is 1450 cubic feet, of which 975 cubic feet (53.3%) is filled with borated water. The status of the accumulator (pressure, level) and the boric acid concentration of its water are continuously monitored. Thus, there is a high potential for early discovery of an excessive accumulator in-leakage and for taking preventive actions.
- (3) The design pressure of the accumulator is 700 psig. The accumulator has a relief valve to prevent overpressurization. However, this vents to the containment; its setpoint is at 700 psig.
- (4) The normally open MOV in the discharge line is closed at the end of POS 2 during cooldown, and opened at the beginning of POS 14 during start-up.

Because of the features, we can use the accumulator ISLOCA model developed in Ref. [3]. The model expresses the average failure rate of the two check valves in the accumulator discharge line as:

$$\langle \lambda_s(1,2) \rangle^{ACC} = \lambda_1 C \quad (5)$$

where λ_1 is the mean value of the "large reverse leak" failure rate of the first check valve, and C is the mean value of an "effective probability" for the valve fails to operate (reclose) on demand failure mode of the second check valve. Its experienced generic mean value was determined in Ref. [3] as $C = .93$.

Taking for λ_1 the same numerical value as in previous cases, and considering that there are three accumulator lines, the frequency of accumulator ISLOCAs was obtained as:

$$\langle \lambda_s(1,2) \rangle^{ACC} = 3 * 2.19-04 * .93 = 6.11-04 \text{ per year.}$$

In POSs 1 and 15 these ISLOCAs were classified as "Medium LOCA" initiators judging the valve's size and the leak flow rate associated with the leak failure rate used (for the latter, see the exceedance leak failure rate of check-valves as a function of leak flow rate in Fig. A.2 of Ref. [3]). As in the previous calculations, in POSs 2 and 14, credit was given to the fact that the RCS pressure, on average, is substantially lower than in POSs 1 and 15 which influences the leak flow- rate. Therefore, we assumed, that in these POSs, the

accumulator ISLOCAs lead 2/3 of the time to "Small LOCAs", and 1/3 of the time initiate "Medium LOCAs" in the containment. By assuming certainty for the loss of the accumulator integrity, the mean initiating frequencies were calculated for the various containment LOCAs in the appropriate POSs (Table 4.6-5).

The same table also shows the initiating frequencies in the case when real-time check-valve disk position monitors were assumed to be applied to the check valves of the accumulator outlet. Since the disk position monitors are expected to reduce the "effective probability" for the valve fails to reclose on demand failure mode by a factor of two orders of magnitude, the initiating frequencies in the table are essentially the original values reduced by this amount.

The associated small and medium LOCA event trees were evaluated in Section 6.4 of the phase 1 study provided in Appendix I.

Conclusions

The extended ISLOCA analysis at Surry gave the following results:

- New potential pathways were identified for "V-events" during low power operation and shutdown over those in Surry NUREG-1150.
- The contribution to core-damage frequency of the individual V-events are small. However, their sum is comparable with the "V-event" core damage frequency during power operation. The dominant contributor is a potential "V-event" through the RHRS-RWST pathway during start-up operations in POSs (12 + 13).
- The contributions to core-damage due to ISLOCAs (not V-events) are comparable with those of other types of LOCAs during low power operation and shutdown.
- The application of real-time check-valve disk position monitors for check valves in the LPI and accumulator discharge lines significantly reduces the initiating frequencies of ISLOCAs through these pathways.

4.6.4 References

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2. Kelly, D.L., Auflick, T.L., and Haney, L.N., "Assessment of ISLOCA Risks - Methodology and Application: Westinghouse Four-Loop Ice Condenser Plant", EGG-SSRE-9557, February 1991.
3. Bozoki, G.E., Kohut, P., and Fitzpatrick, R.G., "Interfacing Systems LOCA: Pressurized Water Reactors", NUREG/CR-5102, February 1989.
4. Haynes, H.D., "Recent Improvements in Check Valve Monitoring Methods", Proc. of Eighteenth Water Reactor Safety Information Meeting, NUREG/CP-0114, Vol. 3., p. 403, April 1991.
5. Chu, T.-L., Stoyanov, S. and Fitzpatrick, R.G., "Interfacing Systems LOCA: Boiling Water Reactors", NUREG/CR-5124, February 1989.

Figure 4.6-1 Schematic of the Low Pressure Safety Injection System V-Event Pathway

Figure 4.6-2 Schematic of the External Nonintrusive dc Magnet
Check Valve Monitoring Method

Figure 4.6-3 Disc Position and Motion Diagram of a 10-inch Carbon Steel Check Valve Monitored by the External dc Magnet Method.

Figure 4.6-4 Schematic of the Residual Heat Removal System ISLOCA/V Event Pathways

Figure 4.6-5 Schematic of the Accumulator ISLOCA Pathways

Table 4.6-1 Core Damage Frequency in Various POSs due to the LPIS V-Event Scenario

CDF (yr ⁻¹)				
POS (1)	POS (2)	POS (14)	POS (15)	TOTAL
(.0003)*	(.0089)*	(.01218)*	(.010)*	(.0314)*
3.0-10	8.9-09	1.22-08	1.00-08	3.14-08
8.7-11 ⁺	2.6-09 ⁺	3.5-09 ⁺	2.9-09 ⁺	9.1-09 ⁺

*Time fraction of POS.

⁺Value obtained by assuming that real time check valve disk position monitors are applied.

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Table 4.6-2 Initiating Frequencies for Small, Medium and Large LOCAs Inside Containment due to ISLOCAs through RHR Suction and Discharge Lines
RHR Rupture Probability: 0.98

ISLOCA Pathway	Type of LOCA	LOCA Initiating Event Frequency (yr ⁻¹)			
		POS (1)	POS (2)	POS (14)	POS (15)
RHR Suction Line	Medium	—	6.04-07	8.27-07	—
	Large	3.09-08	3.11-07	4.26-07	1.03-06
RHR Discharge Lines	Small	—	1.27-08	1.73-08	—
	Medium	6.5-10	6.52-09	8.92-09	2.15-08
Total	Small	—	1.27-08	1.73-08	—
	Medium	6.5-10	6.11-07	8.36-07	2.15-08
	Large	3.09-08	3.11-07	4.26-07	1.03-06

Table 4.6-3 Core Damage Frequencies due to V-Events through the RHR-CVCS Letdown Line

Type of V-Event	CDF/ (yr ⁻¹)					
	POS (1)	POS (2)	POSs (3+4+12+13)	POS (14)	POS (15)	TOTAL
RHS Suction/Discharge ISLOCA Induced Letdown Line V-Event	3.2-12	9.56-11		1.31-10	1.10-10	3.60-11
LTOP Induced Letdown Line V-Event			2.40-11			

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Table 4.6-4 Core Damage Frequencies Due to V-Events Through the Connecting Line to the RWST

Type of V-Event	CDF (yr ⁻¹)		
	POS (3) (.004)*	POS (4) (.049)*	POS (12+13) (.1535)*
V-Event to the RWST	2.08-08	2.55-07	8.00-07
V-Event to the Safeguard Valve Pit Building	3.00-09	3.67-08	1.15-07
Total	2.38-08	2.92-07	9.15-07

*Fraction time of POS.

**Table 4.6-5 Initiating Frequencies for Small and Medium LOCAs Inside Containment Due to ISLOCAs Through the Accumulator Discharge Lines
Probability for the Loss of Accumulator Integrity: 1.0**

Type of ISLOCA	Type of Containment LOCA	LOCA Initiating Event Frequency (yr ⁻¹)			
		POS (1)	POS (2)	POS (14)	POS (15)
Without Real Time Check Valve Disk Position Monitors	Small	—	3.59-06	4.91-06	—
	Medium	1.83-07	1.85-06	2.53-06	6.11-06
With Real Time Check Valve Disk Position Monitors	Small	—	3.59-08	4.94-08	—
	Medium	1.83-09	1.85-08	2.53-08	6.11-08

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APPENDIX 4.6.A - List of Component Failure Rates Used in the ISLOCA Analysis

This Appendix contains the component failure rate data used in the ISLOCA analysis. The data were taken from the most recent studies on ISLOCAs at INEL and BNL (Refs. [1,2] and [3]).

4.6.A1 Check Valve Failure Rates

4.6.A1.1 Check Valve, Large Reverse Leakage

Ref. 1 (Appendix B, B1, p. B-35) lists 110 reverse-leak failure events for check valves during 212,951,708 check valve-hours associated with Emergency Core Cooling Systems of PWRs. It states also that 3% of these represent large internal leaks.

Based on this data, a yearly failure rate of large internal reverse leakage is:

$$.03 * (5.1655 \times 10^{-7} \text{ hr}^{-1}) * 8760 \frac{\text{hrs}}{\text{yr}} = 1.36 \times 10^{-4} \text{ yr}^{-1}.$$

This value can be taken as the median for an underlying lognormal distribution. With a range factor of $RF = 5$, the mean and the mean square of the large internal reverse-leak failure rate, are:

$$\lambda_1^{\text{Mean}} = 2.19 \times 10^{-4} \text{ yr}^{-1},$$

$$\langle \lambda_1^2 \rangle = (\lambda_1^{\text{Mean}})^2 + \text{Var}_1 = 1.25 \times 10^{-7} \text{ yr}^{-2}$$

The "mean unavailability" value given in Surry NUREG-1150 for rupture of an individual LPI check valve is $3.64 \times 10^{-5} \text{ yr}^{-1}$. This value was obtained by combining the results of various expert elicitations in 1988.

4.6.A1.2 Check Valve Failure to Operate (to Close) on Demand

- (a) The rate for check valve failure for "failure to operate on demand (and remain undetected)" failure was taken from Appendix B, B2 (p. B-55) of Ref. [1]. This failure rate (λ_d) was originally determined by BNL in Ref. [3] utilizing Bayesian updating as:

$$\lambda_d^{\text{Mean}} = 2.81 \times 10^{-4} \text{ per demand.}$$

The median value was:

$$\lambda_d^{\text{Median}} = 1.72 \times 10^{-4} \text{ per demand, with a range factor, } RF = 5.$$

The "mean unavailability" value used for this failure in Surry NUREG-1150 was 3.0×10^{-3} per demand. The value was also obtained by combining the results of various expert elicitations in 1988.

- (b) For the accumulator outlet check valves in Ref. [3] a generic mean "effective probability" was determined for the valve fails to operate (to close) on demand failure. (This failure results from adverse environmental conditions and chattering of the valve disk). Based on experienced accumulator inleakage data, its generic mean value was: $C = .93$.

4.6.A2 MOTOR Operated Valve Failure Rates

4.6.A2.1 MOV Internal Leakage

The value for this failure rate was taken also from Ref. [1] (Appendix B, B2, p. B-62) and Ref. [3], where it was originally determined; it also gives a conservative upper limit for "MOV disk rupture" failure rate. MOV disk rupture has not been experienced at PWRs.

The median, range factor, mean and mean square values of the failure rate are:

$$\lambda_L^{Median} = 3.0-03 \text{ per year, } RF \approx 5,$$

$$\lambda_L^{Mean} = 4.85-03 \text{ per year,}$$

$$\langle \lambda_L^2 \rangle = (\lambda_L^{Mean})^2 + Var_L = 6.12-05 \text{ per year}^2.$$

4.6.A2.2 MOV Disk Fails Open While Indicating Closed

The value used is the same that is listed in Ref. [1] (Appendix B, B2, p B-61) and Ref. [3]:

$$\lambda_D^{Mean} = 1.10-04 \text{ per demand.}$$

4.6.A2.3 MOV Transfers Open

This failure describes the MOV failure when a closed MOV inadvertently opens due to failures of valve control circuits/power supplies, or due to human errors during test/maintenance of these components.

From Ref. [1] (Appendix B, B2, p. B-61) and Ref. [3], the value used is;

$$\lambda_T^{Mean} = 8.10-04 \text{ per year.}$$

4.6.A2.4 MOV Failure to Operate (to Close and Stay Closed)

This failure represents MOV failures to close and stay closed, such as when a closed MOV suddenly opens upon demand (e.g., due to shocks from pressure waves or sudden increases in stress due to mechanical or thermal causes).

From Ref. [1], the recommended values (Appendix B, B2, p. B-60) are:

$$\lambda_o^{Mean} = 3.0-03 \text{ per demand, } RF = 5,$$

$$\lambda_b^{Median} = 1.9-03 \text{ per demand.}$$

4.6.A2.5 MOV External Rupture

The value for mean failure rate was taken from Ref. [1] (Appendix B, B2, p. B-63). The value originally was determined by BNL in Ref. [5].

$$\lambda_E^{Mean} = 1.23-03 \text{ per year.}$$

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4.6.A3 Manual Valve Failure Rates

4.6.A3.1 Manual Valve Massive Internal Leakage

From Ref. [1] (Appendix B, B2, p. B-60) the recommended failure rate was used:

$$\lambda_{LL}^{Mean} = 4.38-04 \text{ per year, } RF = 10,$$

$$\lambda_{LL}^{Median} = 1.66-04 \text{ per year.}$$

4.6.A3.2 Manual Valve Fails to Close

From Ref. [1] (Appendix B, B2, p. B-59) the recommended value was used for this failure rate:

$$\lambda_C^{Mean} = 5.0-04 \text{ per demand, } RF = 10,$$

$$\lambda_C^{Median} = 1.9-04 \text{ per demand.}$$

4.6.A3.3 Manual Valve Inadvertently Left Open by the Operator. Failure of Its Recovery

To close a manual valve outside containment was considered to be a simple action. The assigned time to accomplish this task was estimated to be 20 minutes. Thus the mean failure rate to make the error was estimated to be:

$$\lambda_H = 5.0-03 \text{ per demand.}$$

Similarly, to make the error (later) again; i.e., to fail to recover was also estimated to be the same value:

$$N_R = 5.0-03 \text{ per demand.}$$

4.6.A4 RHRS Rupture Probability

Recently, in Ref. [1], new calculations were made for the probability of rupture of an RHRS as a function of the overpressurization (RCS pressure). The calculation gave the probabilities for "large", and "small" ruptures, and the probability for a complete "survival" (no leak). Table 4.6.A1 reproduces the data from Table 17 of Ref. [1]. From this table, the probabilities can be determined, of preserving the integrity of RHRS, given an overpressurization from an ISLOCA through the RHRS suction/discharge lines or from an LTOP event.

The characteristic pressure value for ISLOCA events occurring in POSs 1, 2, 14, and 15 was taken to be 1600 psig. The corresponding "large" rupture probability is .98. Thus, in this case the probability of preserving the integrity of the RHRS is .02.

The characteristic pressure value for LTOP events occurring in POSs 3, 4, (12 + 13) was taken to be 1000 psig. At this pressure, the probability of preserving the RHRS integrity is .6. (In both cases, we disregarded "small" ruptures, because they do not prevent the overpressurization of the RHRS-CVCS letdown line.)

Table 4.6.A1 RHR System Rupture Probabilities as a Function of RCS Pressure
(Pipe failure pressure log-std-dev = 0.36)

RCS Pressure (psig)	System Rupture Probability		
	Large	Small	No-Leak
2200	1	0	0
2100	0.999	0.001	0
2000	0.997	0.003	0
1900	0.995	0.005	0
1800	0.994	0.006	0
1700	0.991	0.009	0
1600	0.983	0.017	0
1500	0.964	0.036	0
1400	0.920	0.080	0
1300	0.836	0.164	0
1200	0.705	0.295	0
1100	0.551	0.449	0
1000	0.403	0.597	0.0001
900	0.281	0.718	0.001
800	0.178	0.810	0.012
700	0.100	0.809	0.091
600	0.050	0.580	0.370
500	0.021	0.193	0.786
400	0.007	0.012	0.981

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4.6.A5 Rupture Probability of the RHRS-CVCS Letdown Line

In Ref. [3] (Appendix F, Fig. 3 p. F-11), the rupture probability of piping made of 304 SS steel was determined as a function of pressure. From this curve, the rupture probability of the RHR-CVCS letdown line was determined at pressures of 1600 psig and 1000 psig as $5 \cdot 10^{-3}$ and $5 \cdot 10^{-4}$, respectively.

4.7 Steam Generator Tube Rupture (SGTR)

The steam generator tube rupture (SGTR) accident is a unique small LOCA accident that has the potential to release primary coolant outside the containment. The pressure boundary of the primary system is breached by rupturing one or more tubes in one of the steam generators. The random or consequential rupture of the steam generator tubes initiates a small LOCA accident, where primary system volume leaks into the secondary system overpressurizing it.

Overpressurization of the secondary side may cause the relief valves to open and potentially cause additional ruptures. An unmitigated leak of the primary system through a secondary side opening may result in a core-damage scenario where the containment is bypassed and a direct pathway may exist to the outside environment.

The initiating event is defined as the complete double-ended rupture of one single steam generator tube. The initial outflow at the break may be up to 600 gpm, depending on the pressures in the primary and secondary system. The initial outflow is expected to require makeup flow in excess of the charging pump capacity. After the initial rupture of the tube, the pressure in the primary system decreases as the system's inventory is depleted.

In operating states POS 1 and 15, a reactor trip may result on either low pressurizer pressure or overtemperature delta-T. When the outflow is small, the operator may manually trip the reactor before its automatic trip, due to the slowly developing scenario. The decrease in the RCS pressure results in a low pressurizer-pressure safety injection (SI) signal, but even the SI signal may be manually initiated by the operator before automatic actuation.

In POS 2-4 and 12-14, the reactor is already scrammed and the SI signal is blocked and requires manual initiation. The normal feedwater flow is automatically terminated on SI signal, and auxiliary feedwater is delivered to all steam generators. Further action by the operator is required to adjust the auxiliary feedwater flow to maintain the water level in the unfaulted steam generators and terminate flow to the faulted generators.

The operator is expected to follow the general procedures valid for operating states, and will attempt to identify and isolate the faulted steam generator. The isolation of the ruptured steam generator involves closing the MSIV, AFW inlet valve, isolating the blowdown line and the turbine driven AFW pump steam inlet valve. Complete isolation will not occur until the RCS pressure is reduced to equal or less than the faulted SG pressure.

In POS 1 and 15, the secondary side pressure may increase to the level where the steam generator safety valves are lifted, releasing steam to the atmosphere. In the other states, the safety valves are not expected to be challenged due to the lower pressure in the primary system (POS 2,14 - 350 to 1000 psig, POS 3,4 and 12,13 - 300 psig).

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Initially, pressure in the secondary side may be controlled by initiating steam dump to the main condenser using the unfaulted steam generators. The safety-injection flow is expected to begin refilling the pressurizer and increase the RCS pressure until the injection flow equals the break flow, achieving an equilibrium pressure that depends on the size of the break and the temperature.

The main action of the operator is related to the cooldown and depressurization of the RCS, using the good steam generators and the pressurizer sprays. The operator has to identify the ruptured steam generators relying primarily on the indications of the generator's water level. For large size ruptures, a high water level is expected which can readily be identified. For small tube ruptures, the water-level indication may not be reliable, and possibly a high radiation alarm due to a release of radioactivity on the secondary side may be necessary before the ruptured steam generators can be definitively identified.

When the faulted steam generator is identified, it is manually isolated to maintain its pressure higher than the unfaulted generators and to minimize any releases of radioactivity. Auxiliary feedwater flow is terminated to the ruptured SG, and using the steam dump, the temperature of the primary system is reduced.

Once cooldown is achieved, the RCS is depressurized using the normal pressurizer spray system. If this fails or is ineffective, then opening one pressurizer PORV may reduce the pressure in the primary system.

Once the reactor is depressurized below the pressure in the ruptured SG, the outflow from the RCS will terminate and the reactor is in a stable condition. The operator then places the reactor in cold shutdown by placing the RHR system in operation. The preferred method of achieving cold shutdown is through a backfill procedure.

In this method, the ruptured steam generator is depressurized by draining auxiliary feedwater through the ruptured SG tube into the RCS. The RCS pressure is stabilized by the pressurizer spray and heater, if necessary, and reduced to the pressure of the faulted SG. The RCS system is cooled down to cold shutdown conditions using the RHR system, and also by dumping steam from the intact SGs. The faulted SG is refilled using the AFW system, allowing it to drain into the RCS.

This particular method of placing the reactor in cold shutdown by backfilling from the faulted SG may potentially cause local dilution of the RCS and a consequent reactivity accident scenario (discussed next). During the backfill process, unborated water is supplied by the AFW system into the faulted SG, which eventually drains back to the RCS through the ruptured tube.

The introduction of unborated water into the RCS is considered as a relatively minor dilution flow as long as the reactor coolant is circulated by the RCPs. The decrease in boron concentration is very small as compared to the whole volume of the RCS. The large flow rate of the coolant, even with only one RCP in operation, assures that instantaneous mixing occurs.

However, if the RCPs are not available, due to variety of reasons, the unborated water is introduced through the ruptured tube into the RCS where natural circulation is used to remove decay heat. When the faulted SG is isolated, its temperature will be equal to the saturation temperature of the RCS, and consequently, there will be no thermal head driving the flow in the damaged loop. This may lead to a local boron dilution scenario; that is, the reactor coolant in the damaged loop may be diluted by the backfill or unborated auxiliary feedwater flow.

In the backfill procedure, the operator is instructed to periodically verify the shutdown margin by obtaining water-chemistry samples from the RCS hot leg, pressurizer, and the faulted SG. However, the dilution flow is assumed to accumulate in the cold leg of the SG, and this sampling procedure would not indicate any

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localized dilution effects. After sufficient time unborated water accumulates in the cold leg, which could be transported to the core by restarting the RCP, so leading to a reactivity accident.

The SGTR accident scenario is applicable to operating states with pressure in the primary system higher than the secondary system, POS 1 through 4 and 12 through 15. The specific conditions in each POS will be discussed at the applicable event trees. In general, in all the POSs, the operator must isolate the faulted steam generator, must introduce safety injection flow to maintain the primary system's volume, and must cooldown and depressurize the RCS to terminate the breakflow. If the level of the decay heat is low, then the use of the secondary side system may not be necessary, and the RHR is sufficient to achieve cold shutdown.

4.7.1 SGTR Initiating Frequency

The initiating frequency of SGTR accidents for full power operations were established in NUREG-1150 at

$$\text{SGTR} = 1.0\text{E-}02/\text{yr},$$

which is based on five events over ~500 reactor years of operation. This value is assumed to be valid for POS 1, 2, 14 and 15, due to the potential high differential pressures between the primary and secondary side ($\Delta p \sim 1000$ psi). The other states, where the potential for tube rupture exists - POS 3, 4, 12, and 13, have operating pressures and temperatures of 300 psig and 200/140°F and the differential pressure through the SGs is about 180 psig.

In these states, the initiating frequency is adjusted to reflect the lower differential pressure by lowering the full power value by a factor of ten. The final initiating frequencies are:

$$\text{SGTR (POS 1,2,14,15)} = 1.0\text{E-}02/\text{yr}$$

$$\text{SGTR (POS 3,4,12,13)} = 1.0\text{E-}03/\text{yr}$$

The initiating frequencies are given for a full year, which are adjusted by a relative time factor to take into account the relative length of each particular operating POS, i.e.,

$$\text{SGTR-POS} = \text{SGTR (POS)}/\text{yr} * \text{RELATIVE TIME (POS)}$$

Table 4.7-1 lists the final initiating frequencies in each POS with the respective relative time fractions.

4.7.2 Success Criteria

The primary functions required in response to a SGTR accident are the removal of core heat, capability of the operator of controlling RCS pressure, and in POS 1 and 15, the reactor scram. In all POSs when the level of decay heat power is high (except in POS 12, 13, and 14 R and D states), the function of heat removal is accomplished by using the unfaulted steam generators (success criteria 1/2 SG), and the RHR system (1/2 trains) in certain POS (3, 4, 12, 14). The use of the SGs requires auxiliary feedwater supply (success criteria 1/3 AFW pumps).

The depressurization function is accomplished either by using the pressurizer spray or opening the PORV. In POS 3, 4, 12, and 13 the need for the pressurizer spray or PORV is diminished (operating pressure 300 psig) and is not required for depressurization, because the RCS is expected to be quickly depressurized through the tube break.

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Table 4.7-1 SGTR Initiating Frequency

State	Initiating Frequency/Yr.	Relative Time Fraction	Initiating Frequency/Yr.
POS 1	1.0E-02	2.96E-04	2.96E-06
POS 2	1.0E-02	8.83E-03	8.83E-05
POS 3	1.0E-03	4.12E-03	4.12E-06
POS 4	1.0E-03	4.92E-02	4.92E-05
POS 12 ¹	1.0E-03	1.50E-01	1.50E-04
POS 13 ²	1.0E-03	3.70E-03	3.70E-06
POS 14 ³	1.0E-02	1.22E-02	1.22E-04
POS 15	1.0E-02	9.97E-03	9.97E-05

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¹R and D outages only - N1 and N2 outages included in POS 4

²R and D outages only - N1 and N2 outages included in POS 3

³R and D outages only - N1 and N2 outages included in POS 2

4.8 Spurious Emergency Safety Features Actuation Signals (SI, CLS, RMT)

Under normal power operation at Surry three electronic systems automatically operate the Reactor Trip and Engineered Safeguard systems to mitigate an accident. The three systems are:

- (1) The Reactor Protection System (RPS),
- (2) The Engineered Safeguard Actuation System (ESFAS), and
- (3) The Recirculation Mode Transfer System (RMTS)

The ESFAS System consists of two subsystems:

- (a) The Safety Injection Activation System (SIAS), and
- (b) The Consequence Limiting Safeguard System (CLS).

Although the RPS is independent of the ESFAS and RMT, the last two depend upon signals derived from the RPS through isolation amplifiers. The design approach is to use measurements of unit sensors more efficiently, for both protection and safeguards. In addition to this signal dependency among the systems, each system depends on the Emergency Power System:

The RPS and the ESFAS depend on the Vital 120 V AC instrumentation, and the 125 V DC buses for power to the primary sensors and to the relay logic network, respectively. The RMT depends only on the Vital AC instrumentation buses to the (RWST level) sensors and to the relay logic.

During shutdown, the reactor protection logic matrices of the RPS are not operating and several signals that actuate the ESFAS are manually blocked by permissive interlocks (e.g., the signal that actuates SI due to low-low pressurizer pressure). However, the safeguard logic matrices of the RPS, are continuously operating and the associated safeguard signals, such as Undervoltage, SI, CLS-Hi, CLS-Hi-Hi, and the RMT signals are available.

Because of this condition, spurious SI, CLS-Hi, CLS-Hi-Hi, and RMT signals could be generated alone or in conjunction with spurious undervoltage signals by maintenance and testing (mainly by electrical shorts) on the sensors, the systems themselves, or on the supporting AC/DC buses. Also, operators could generate these signals inadvertently by their actions.

An impact analysis of the various spurious signals identified that the following ones interrupt the decay-heat removal function at Surry:

- Spurious SI, CLS-Hi signals close the containment isolation valves 1-CC-TV-109A and 1-CC-TV-109B. The closure isolates the CCW flow from the RHR heat exchangers.
- Spurious SI, CLS-Hi, and CLS-Hi-Hi signals alone start the Diesel Generators but do not cause Emergency Bus transfer and load shed: i.e. the trip of stub bus, RHR pump and CCW pump breakers. To interrupt the removal of the heat by emergency bus transfer and load shed, these signals have to coincide with spurious undervoltage on the 4.16 kV AC Emergency Buses.
- Spurious CLS-Hi-Hi signal together with a Loss of Offsite Power signal isolates the Service Water cooling to the Component Cooling System Heat Exchangers. A spurious low canal level (≤ 18 feet) signal generated by two, independent level sensors in coincidence does the same.

A spurious RMT signal changes only the lineup of the ECCS from injection to recirculation. It does not affect the successful operation of decay-heat removal. Similarly, a spurious CLS-Hi-Hi signal prevents only the cooling of the RCP thermal barrier and cooler (by closing the trip valve 1-CC-TV-107), but does not affect the removal of decay-heat function.

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From this list of signals, the spurious SI and CLS-Hi signals (the first ones) were deemed to have non-negligible frequencies and potential to start accident scenarios which may lead to core damage. These signals not only interrupt the operation of decay-heat removal, but, in POSs when the PORVs are closed, they may cause inadvertent RCS overpressurization by isolating the RHR discharge and by starting high and/or low head safety injection. To prevent spurious safety injection during mid-loop operations the breakers of the standby charging pumps, the low-head and AFW pumps usually are required to be in PTL (pull-to-lock) position. (Because of human errors some of the breakers may not be in the correct position.)

Therefore, we selected failure events involving spurious SI and CLS-Hi signals to represent a separate initiating-event category the "Spurious ESFAS Signal" initiator.

The frequency of the initiator was determined (for all the POSs) by using appropriate events from the LER data base. By applying the previously described two-stage double Bayesian updating approach, the frequency of the initiator was determined to be:

INITIATOR	FREQUENCY (hr ⁻¹)			
	MEAN	5%	50%	95%
Spurious ESFAS Signal	1.06E-04	9.15E-05	1.06E-04	1.22E-04

4.9 Transients-Turbine Trips and Loss of Main Feedwater

4.9.1 Identification and Grouping of Transient Initiating Event

We identified and grouped the transient initiating events at low power/shutdown conditions into generic transient event categories in accordance with the methodology in the NUREG-1150 study. Potentially significant initiators were identified by reviewing the PWR initiator categories defined in NUREG/CR-3862 that are applicable to the different plant operational states (POSs) at low power and shutdown. Each of the 41 potential initiators was categorized into transient event groups based on similar plant response and similar success criteria for successful initiator mitigation. Depending on the impact on plant operation, these 41 initiators were grouped into generic transient categories (e.g., T₂ or T_{2a}) which challenge the reactor protection system. For example, the T₂ transient category represents a transient with loss of feedwater that does not challenge RPS availability. The T_{2a} transient category represents the transient with loss of feedwater that challenge RPS availability. Table 4.9-1 shows the initiating event categorization for the Surry plant at low/power shutdown states.

4.9.2 Estimation of Transient Initiating Event Frequencies

Plant-specific information was reviewed to determine initiating event frequencies for the various transient groups in Table 4.9-1. The sources of information were licensee event reports (LERs), control room operating logs, and NRC Gray Books and Annual Summaries of Operating Experience.

LER data over a ten-year operating experience of the Surry plant (January 1, 1980 through December 31, 1989) were evaluated to identify transient event occurrences at low power and shutdown conditions. The plant specific transient events found in the LER data base were grouped according the applicable initiator categories and the frequency count of each specific transient event indicated on Table 4.9-1. Using the outage data on the durations of various POSs shown on Table 4.9-2, we estimated the occurrence rates of generic transients T_2 , T_{2a} , T_3 , and T_{3a} in frequency per hour (Tables 4.9-3). The overall estimations of transient initiating event frequencies are summarized in Table 4.9-4.

Table 4.9-1 Initiating Event Categorization for Surry Plant At Low Power/Shutdown States

Trans- Category	Title	Initiating Event Category	Operational States							Event Count		
			1	2	3	4-12	13	14	15	NUREG/ CR-3862	Su 1	Su 2
1	Loss of RCS flow (1 loop)			T ₃				T ₃		14		
2	Uncontrolled Rod Bank Withdrawal		T _{3a}	T _{3a}				T _{3a}	T _{3a}	2		
3	CRDM Problems/Rod Drop		T ₃						T ₃	25	1	
4	CR Leakage		T ₃	T ₃				T ₃	T ₃	1		
5	Leakage in Primary System		T ₃	T ₃				T ₃	T ₃	4		
6	Low Pressurizer Pressure		T ₃						T ₃	4		
7	Pressurizer Leakage		T ₃	T ₃				T ₃	T ₃	1		
8	Hi Pressurizer Pressure		T _{3a}	T ₃				T ₃	T _{3a}	4		
9	Inadvertent SI Signal		T _{2a}	T ₂				T ₂	T _{2a}	4	3	
10	Containment Pressure Problems		T ₂	T ₂				T ₂	T ₂	0		
11	CVCS Malfunction - Boron dilution		T ₃					T ₃	T ₃	1	2	
12	Pressure/Temp. Imbalance		T ₃						T ₃	12		
13	Startup of 1 RCP									0		
14	Total Loss of RCS Flow		T ₃	T ₃				T ₃	T ₃	5		
15	Loss of FW (1 Loop)		T _{2a}	T ₂				T ₂	T _{2a}	180		
16	Loss of FW (All Loops)		T _{2a}	T ₂				T ₂	T _{2a}	13		
17	Partial Closure of MSIV (1 Loop)		T ₂	T ₂				T ₂	T ₂	6		
18	Closure of All MSIV		T ₃						T ₃	0		
19	Increase in FW (1 Loop)		T _{2a}	T ₂				T ₂	T _{2a}	64	2	
20	Increase in FW (All Loops)		T _{2a}	T ₂				T ₂	T _{2a}	5		
21	FW Instability - Operator Error		T ₃	T ₃				T ₃	T ₃	108		
22	FW Instability - Mechanical Causes		T ₃	T ₃				T ₃	T ₃	53		
23	Loss of 1 Condensate Pump		T ₂	T ₂				T ₂	T ₂	2		

Table 4.9-1 (continued)

Trans- Category	Title	Initiating Event Category	Operational States							Event Count		
			1	2	3	4-12	13	14	15	NUREG/ CR-3862	Su 1	Su 2
24	Loss of All Condensate Pumps		T ₂	T ₂				T ₂	T ₂	0		
25	Loss of Condenser Vacuum		T ₃	T ₃				T ₃	T ₃	11		
26	SG Leakage		T ₂	T ₂				T ₂	T ₂	0		
27	Condenser Leakage		T ₃	T ₃				T ₃	T ₃	6		
28	Secondary System Leakage - Misc.		T _{2a}	T ₃				T ₃	T _{2a}	5	2	2
29	Spurious Opening of SRVs		T _{2a}	T ₃				T ₃	T _{2a}	1		
30	Loss of Circulating Water		T ₃	T ₃				T ₃	T ₃	0		
31	Loss of Component Cooling	Special								2		
32	Loss of Service Water	Special								0		
33	Turbine trip, TCV close, EHC problems	None								110		
34	Generator Trip	None								23		
35	Loss of Offsite Power	T ₁								11		
36	Pressurizer Spray Failure		T ₃						T ₃	3		
37	Loss of Power to Plant Systems		T ₃						T ₃	2		
38	Spurious Trip		T ₃						T ₃	5	1	
39	Auto Trip - No Transient		T ₃						T ₃	91	1	5
40	Manual Trip - No Transient		T ₃						T ₃	44		1
41	Fire Within Plant	None								0		

Note: T₂: Transient with no reactor SD
T_{2a}: Transient with reactor SD
T₃: Transient with reactor SD
T_{3a}: Transient with reactor SD (States 1,15)

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Table 4.9-2 Total Durations of POSs During 1980-1989

Types of Outages	Plant Operational States			
	1	2	14	15
Non-drained Maintenance with RHR	1.6	196.8	336.0	297.6
Non-drained Maintenance without RHR	26.9	720.0	*	476.6
Drained Maintenance	16.8	362.4	969.6	304.8
Refueling	6.72	267.6	828.0	673.2
Total	52.0	1546.8	2133.6	1752.2

* Included as part of POS 2

Table 4.9-3 Frequency Transient Categories

Event Category	Title	Estimated Frequency (Per Hour) at Applicable POSs
3	CRDM Problems/Rod Drop	5.54E-4
9	Inadvertent SI Signal	5.47E-4
11	CVCS Malfunction-Boron Dilution	5.08E-4
19	Increase in FW (1 Loop)	3.65E-4
28	Secondary System Leakage-Misc.	7.29E-4
38	Spurious Trip	5.54E-4
39	Auto Trip - No Transient	3.33E-3
40	Manual Trip - No Transient	5.54E-4

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Table 4.9-4 Estimates of Transient Frequencies

Transient Category	Description	Estimated Frequency (Per Hour)			
		1	2	14	15
T_2	Transient with loss of MFW (Events 9 & 19)	1.07E-4*	9.12E-4	9.12E-4	1.07E-4*
T_{2a}	Transient with loss of MFW that require shutdown (Events 9, 19 & 28)	1.64E-3	N/A	N/A	1.64E-3
T_3	Transient without loss of MFW (Events 3, 11, 28, 38, 39 & 40)	5.5E-3	7.29E-4	1.24E-3	5.5E-3
T_{3a}	Transient without loss of MFW that require shutdown (Events 2 & 8)	8.33E-4*	N/A	N/A	8.33E-4*

*NUREG-1150 Transient Frequencies

$T_2=0.94/\text{year}=1.07\text{E-}4/\text{hr}$

$T_3=7.3/\text{year}=8.33\text{E-}04/\text{hr}$

4.10 Estimate of Core Damage Frequency Due to Pressurized Thermal Shock

4.10.1 The Pressurized Thermal Shock Phenomenon

The classical thermal shock transient was long ago identified^[1] as a credible mechanism to cause the integrity of a PWR reactor vessel to fail. During such a transient, thermal stresses are created in the vessel wall as its inner surface is overcooled rapidly. It was believed that for PWRs, a large LOCA initiated the most severe thermal shock that a reactor vessel would be required to withstand. In this type of accident, emergency core coolant at room temperature floods the reactor vessel and rapidly cools its inner surface. In the corresponding models of stress-build-up, pressure stresses were not taken together with the thermal stresses, because it was expected that during a large-break LOCA the RCS would remain at low pressure.

However, the 1978 Ranch Seco event demonstrated that there are transients (not large-LOCA types) when rapid cooldown could be accompanied by repressurization of the RCS, so that pressure stresses would be superimposed on the thermal stresses (hence, Pressurized Thermal Shock, PTS). If there were faults (cracks) in the overcooled surfaces (mainly in the downcomer region), the additional stresses could significantly contribute to overcoming the fracture resistance of the wall material and could cause the cracks to propagate. If the fast-neutron fluence had caused the fracture resistance of the wall material to gradually deteriorate, the additional stresses might be even sufficient to cause through-the-wall cracks (TWCs), which might lead to catastrophic rupture of the reactor vessel.

Rupture of the reactor vessel would be a LOCA; if it occurred in the so-called beltline region (the area just across from the core), there would be no possibility of reflooding the core; i.e., it would directly damage the core. The welds in the beltline region cause particular concern because the copper contaminant in the weld material is prone to radiation damage, and the accumulated fast-neutron fluence is the highest in this region. Radiation damage decreases the ductility of the weld material; therefore, here crack propagation is expected to be high.

This description of the PTS phenomenon suggests that the probability of reactor-vessel failure depends on three major factors:

- (1) The copper content of the wall/weld material,
- (2) The accumulated fast-neutron fluence in the beltline wall and welds, and
- (3) The frequency and the severity profile of the overcooling transients.

4.10.2 The Assessment of Core Damage Frequency due to PTS in the Surry NUREG-1150 Study

To assess the core damage frequency due to PTS, the Surry NUREG/1150 Study^[2] determined the most important parameter in the fracture-mechanism of the PTS: the reference temperature for transition to nil-ductility (RTND). This is the temperature below which the metal-phase transition to nil-ductility (i.e., to a brittle condition) is of minimal concern. The RTND for Surry Unit 1, at the end of licensed life (ELO = 32 effective full power years), was 269°F or 260°F, depending upon whether it was calculated in accordance with 10 CFR 50.61 or with Reg. Guide 1.99, Rev. 2, respectively.

These values are near to that obtained (270°F) for the reactor vessel of the H.B. Robinson Unit 2 nuclear plant for which a detailed PTS analysis^[1] was performed recently (NUREG/CR-4153). (The reactor vessel used in Ref. [1] is a hypothetical one, with an increased copper content in its welds for which the RTND at

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the EOL was calculated to be 270°F. The copper content of the actual Robinson vessel was so low that it was not possible to estimate a statistically significant PTS core-damage frequency for it.)

Since the Robinson plant is of similar design to Surry, the Surry NUREG-1150 study assumed that the frequency and severity profiles of overcooling transients at Surry are also similar, and used the Robinson PTS core damage frequency as a representative value. The Robinson study derived two values for the PTS core-damage frequency at the above RTND;

- (a) a best (point) estimate "median" value of: $1.5 \cdot 10^{-8} \text{ yr}^{-1}$, and
- (b) a simulation "mean" value of: $8.4 \cdot 10^{-6} \text{ yr}^{-1}$.

The latter includes an extensive uncertainty analysis performed on some key variables, such as the flaw density in the vessel's wall and welds, the parameter RTND, water mixing and the associated final temperature in the downcomer region, the measure of nonlinearity of the fracture-mechanics, and operator's actions in the overcooling event sequences.

Based on the Robinson best estimate value, $1.5 \cdot 10^{-8} \text{ yr}^{-1}$ and the condition that the calculated RTND values for Surry are somewhat less than 270°F, the NUREG-1150 study concluded that the core damage frequency due to PTS is a small contributor to the total core damage ($< 1\%$) and a negligible contributor to risk. Thus, the Surry NUREG-1150 study did not include PTS and associated reactor vessel rupture as an initiator.

4.10.3 Assessment of PTS Core Damage Frequency During Low Power Operation and Shutdown at Surry

At the review meeting of the present project in January, 1991, it was brought to the team's attention that the Surry NUREG-1150's conclusion to neglect the PTS core-damage contribution was based on the Robinson study's point estimate of "median" core damage frequency instead of the mean value. It was suggested that for the assessing the contribution of PTS to core damage frequency during low power operation and shutdown, the Robinson study's mean value should be considered.

In the Robinson study, it was shown that the downcomer region can be overcooled by the following mechanisms:

- (a) an injection of cold water into the vessel inlet lines,
- (b) a net removal of energy from the RCS via the steam generators, and
- (c) a breach in the primary system, with subsequent RCS depressurization.

Also, it was shown that the initiating events (and essentially, many of the associated event sequences) leading to one of these cooling mechanisms result in varying temperature profiles on the walls. Furthermore, the wall's temperature profiles depend upon whether the initiating event occurred during power operation or when the reactor was at 0% power in hot shutdown. During the latter some overcooling events were more severe than at full power because in hot shutdown (of longer duration) the decay heat level is low and there is no heatup to compensate cooling, and consequently, there is no water circulation or mixing as is available following a scram at full power.

To fully utilize the results of the Robinson study for Surry, the following approach was used:

- (A) Conditional core-damage probabilities were calculated for each initiator that contributed significantly to the PTS core damage frequency during full power operation and in hot shutdown at the Robinson plant.

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(B) For the Surry plant, plant operational states (POSs) were selected during which PTS could occur, and a compatible set of initiating events was determined for each.

(C) Surry specific PTS core damage frequencies were calculated for each initiator in each. To ensure more statistical accuracy and conservatism, the initiating event frequencies during power operation were considered. They were taken from the Surry NUREG-II50 Study; If some initiating frequency was not given explicitly, the Robinson values were used. The POS frequencies were essentially those which were determined elsewhere in the present study.

The mean core-damage frequencies and conditional PTS core-damage probabilities due to various initiating events for the Robinson plant are listed in Table 4.10-1 according to their importance to the total PTS core-damage frequency. These mean frequencies, together with mean hot shutdown time, were taken from Table 7.1 of Ref. [1]. The core-damage frequencies were obtained by summing the mean core damage frequencies of dominant individual sequences appearing in the event tree of an initiating event. The number of sequences in a sum is indicated in the fifth column of the Table. The mean sequence frequency values (not shown) were determined originally in the Robinson study by uncertainty analysis.

The conditional PTS core-damage probabilities characterize the plant's nonmitigation probability against PTS, given the occurrence of an initiating event. We note that the severity profiles of Large Steam Line Break and Small Break LOCA initiators are worse during hot shutdown than during power operation.

For the Surry reactor vessel, PTS is of concern in POSs 1,2,14, and 15. In POSs 3 through 13, the pressure and temperature of the RCS are much lower than under full power operation or in the above POSs. In these POSs, an overcooling scenario and associated stress build-up in the reactor vessel wall/welds is likely to be mild; the probability of developing TWCs seems to be negligible.

Table 4.10-2 gives the results of the PTS core damage frequency calculations for POSs 1,2, 14, and 15.

In spite of the differences in the level of decay heat in these calculations during cold shutdown and start up, POSs 1 and 15, and POSs 2 and 14 are considered to be symmetric as regards PTS generation. Thus, in the table shows the combined time fraction of POSs (1 + 15). For POSs (2 + 14), the time is divided into two parts; a part containing plant states ($N_2 + R$), and a part containing plant states ($N_1 + D$). Here, N_2 and R denote "Non-Drained Maintenance (w/o RHRS)" and "Refueling", respectively, while N_1 and D stand for "Non-Drained Maintenance (w.RHRS)" and "Drained Maintenance". The first part is taken to characterize the time fraction of "hot-shutdown-like" states, and the second part characterizes the time fraction of reactor "ramp down/up" states.

(A distinction between these two types of states must be made, because of the different conditions for PTS generation. In a "hot shutdown" state, water mixing is slow, thermal stratification may occur, and the rate of pressure and temperature change is at its minimum, thus the potential for PTS generation is high. In reactor "ramp down/up" states, the rate of pressure and temperature changes is higher, and water mixing is forceful. Safety injection cannot cause extreme overcooling, i.e. the initiator for PTS generation is suppressed).

In the calculations of core-damage frequency for POSs (1 + 15), the Robinson core-damage during power operation were used, while for POSs (2 + 14), when available, the Robinson conditional core-damage probabilities for hot shutdown were used.

In Table 4.10-2, the PTS contributions to core-damage frequency from POSs (1 + 15), and from POSs (2 + 14) are shown separately. For completeness, and to see the sensitivity of the results, the potential PTS

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contribution from the "ramp down/up" states also are given (in parentheses). Finally, Table 4.10-2 shows the total PTS core damage frequency for Surry, which is:

$$PTS = 1.05 \times 10^{-7} \text{ yr}^{-1}.$$

This value, which is obtained in a simple, straightforward way, is a satisfactory estimate of the PTS core-damage frequency, reflecting the uncertainties in the TWC probabilities, the uncertainties of the initiating events and associated sequences, and partially, the uncertainties of the POS time fractions.

4.10.4 References

1. Selby, D.L., et al., "Pressurized Thermal Shock Evaluation of the H.R. Robinson, Unit 2 Nuclear Power Plant", Oak Ridge National Laboratory, Sept. 1985, NUREG/CR-4153.
2. Bertuccio, R.C., et al., "Analysis of Core Damage Frequency: Surry, Unit 1 Internal Events", Sandia National Laboratories, July 1987, NUREG/CR-4550, Rev. 1, Volume 3, Part 1.

**Table 4.10-1 Mean Conditional Core Damage Probabilities due to PTS
for Various Initiating Events at Robinson Unit 2 Power Plant**

RTND = 270° F at EOS = 32 Effective Full Power Years

	Initiator	Mean Initiating Frequency (yr ⁻¹)	PTS CDF (yr ⁻¹)	Number of Sequences	Importance (%)	Conditional PTS Core-Damage Probability
1.	Reactor Trip at Full Power	8.5	7.90-06	32	94.36	9.29-07
2.	Small Steam Line Break at Full Power	2.0-02	2.73-07	5	3.67	1.36-05
3.	Loss of Main Feedwater	3.0-01	4.10-08	1	.49	1.37-07
4.	Large Steam Line Break at Full Power	1.2-03	1.93-08	4	.23	1.61-05
5.	Small Break LOCA at Full Power	8.9-03	1.27-08	3	.15	1.43-06
6.	Loss of Service Water	1.0-02	8.60-09	1	.10	8.60-07
	Subtotal		8.25-06	46	98.59	
7.	Small Steam Line Break at Hot 0% Power	(2.0-02)* .25 = 5.0-03	6.54-08	3	.78	1.31-05
8.	Large Steam Line Break at Hot 0% Power	(1.2-03) * .019 = 2.28-05	2.69-08	4	.32	1.18-03
9.	Small Break LOCA at Hot 0% Power	(8.9-03) * 9.02-02 = 8.03-04	2.6-08	2	.31	3.24-05
	Sub Total		1.18-07	9	1.41	
	Total		8.37-06	55	100.00	

**Table 4.10-2 PDS Core Damage Frequencies due to Various Initiating Events
During Low Power Operation and Shutdown at Surry Unit 1 Power Plant**

	Initiator	Mean Initiating Frequency (yr ⁻¹)	Mean Fraction of Time for POSs (1+15)	PTS CDF in POSs (1+15) (yr ⁻¹)	Mean Fraction of Time for (N ₂ +R) and (N ₁ +D) ⁺⁺ of POSs (2+14)	PTS CDF in POSs (2+14) (yr ⁻¹)
1.	Reactor Turbine Trip, T ₃	7.3	.0103	6.99-08	.0122 (.0066)	—
2.	Small Steam Line Break	2.0-02*	.0103	2.82-09	.0122 (.0066)	3.19-09 (1.73-09)
3.	Loss of Main Feedwater, T ₂	9.2-01+	.0103	1.30-09	.0122 (.0066)	1.54-09 (8.32-10)
4.	Large Steam Line Break	1.2-03*	.0103	1.99-10	.0122 (.0066)	1.73-08 (9.35-09)
5.	Small and Very Small LOCAs, S ₂ + S ₂	1.4-02	.0103	2.06-10	.0122 (.0066)	5.53-09 (2.99-09)
6.	Rupture of SG Tube, T ₇ **	1.0-02	.0103	1.40-09	.0122 (.0066)	1.60-09 (8.65-10)
	Subtotals			7.58-08		2,92-08 (1.57-08)
	Total CDF due to PTS					1.05-07 (1.21-07)

Footnotes: * Robinson Values

+ In Ref. ¹, T₂ = 9.4-01 yr⁻¹, because it includes the Steam Line Break frequencies.

** Steam Generator Tube Rupture did not contribute significantly to the Robinson is PTS Core Damage Frequency, therefore, for this calculation the Small Steam Line Brake Conditional Core Damage Frequencies were used.

++Nomenclature: N₂ = Non Drained Maintenance (w/o RHRS), N₁ = Non Drained Maintenance (with RHRS);
R = Refueling; D = Drained Maintenance

4.11 Reactivity Accidents

4.11.1 General Comments

The following discussion of reactivity events during shutdown is based on the plant information available to BNL during the phase 1 study. We understand how certain events may occur and what the consequences may be, but our knowledge is very general and sometimes based on analyses done for foreign reactors. There is a dearth of information on the specific systems and procedures at Surry that determine the sequences, and also a lack of analysis or data on the response of systems during an event. In addition, the events discussed may not be a complete set, as there is a need to ensure that all potential sources of unborated water at Surry have been identified.

The outcome of these events may either be acceptable or lead to core damage. It is necessary to differentiate the potential for catastrophic core damage (i.e., rapid changes in geometry) from that type of damage that has been considered as a severe accident in the past because the evolution of a severe accident after rapid core damage may be quite different.

Most reactivity events in a PWR are due to a boron dilution. This dilution may cause a power rise in one of three different ways, and more analysis is needed of the fuel damage and pressure rise during these events. One type of dilution is a relatively slow uncontrolled one in which the boron concentration changes slowly but steadily throughout the entire core. This type of accident requires a large volume of diluted water. It is relatively easy to analyze as the increase in power will be determined by a linearly increasing reactivity mitigated by feedback effects until stopped by the action of an operator or melting of the fuel.

A second type of excursion occurs when diluted water accumulates in the bottom of the vessel to the extent that the bottom of the core becomes critical and power increases. This power increase causes an increase in the natural circulation flow rate, which draws the diluted water up from the bottom of the vessel into the core. This autocatalytic power excursion needs to be analyzed to understand the consequences. The third type of dilution is caused by a slug of diluted water rapidly entering the core; this also needs to be analyzed to understand the consequences. This type of dilution is more scenario-specific than the previous two as it depends on whether the slug of water comes from the start of one or more reactor coolant pumps, or the blowdown of the accumulator, or some other cause. We note, too, that the analysis required for the latter two types of dilutions is non-trivial and that they require less diluted water to cause a problem than the first type of dilution discussed.

The following discussion of reactivity events categorizes the events according to some distinguishing feature. In most cases, it is the most important system in the sequence, e.g., the accumulator, the reactor coolant pumps, or the chemical and volume control system. Later, we will categorize these events so that they are consistent with the initiating event used in the event tree defining the sequence.

4.11.2 Addition of Diluted Accumulator Water

4.11.2.1 Description of Event

If the boron in the water in an accumulator has become sufficiently diluted, and if that water enters the vessel during shutdown, then a reactivity event can occur. For sufficient water to get from the accumulator to the vessel, the vessel would have to be depressurized below the pressure of the accumulators which are kept at approximately 625 psia. Hence, for these types of events to occur the plant would have to be in cold shutdown (pressure less than 300 psia) which corresponds to Plant Operational States (POS) 4-12. We consider first the process of diluting the accumulator, and then the sequences by which the core would become diluted.

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There are three ways in which the accumulator can become diluted; The first is that the accumulator is filled with water having too little boron. The water comes from the refueling water storage tank (RWST), and hence, the paths by which this source could become diluted must be considered. The boron concentration in the accumulator must be verified within hours after refilling, and is re-verified at monthly intervals. Because of these requirements as well as surveillance requirements on the RWST (weekly boron concentration test), this is not expected to be the most probable means of dilution (for a four-loop plant this is true^[1]).

The more likely cause of having a dilution is via inleakage of reactor coolant through the check valves that isolate the accumulators from the reactor coolant system (RCS) during normal operation when the RCS pressure is higher than the accumulator pressure. The leakage would be important at the end of the fuel cycle when the RCS boron concentration is low and there is a short time until a refueling outage. The Licensee Event Reports^[2] and the Nuclear Power Experience data base^[1] show that there have been many instances of this type of dilution (including incidents at Surry 1 and 2), although none large enough to cause a reactivity accident. For the dilution to remain undetected until shutdown, instruments which would detect the overfilling of the accumulator would have to fail, and/or operator errors take place. The operator's errors might be surveillance errors, errors in recognizing the inleakage, or in taking action to correct it.

A third way of diluting the accumulator would result from any flushing of the accumulator piping with fresh water. Some plants do this to cope with the buildup of boric acid salts on the valves.

The boron concentration in the Surry accumulators is supposed to be at least 1950 ppm. To understand the boron concentration in the core that might lead to a problem, consider a beginning-of-cycle core which is critical at hot full power with all rods out and a boron concentration of 1300 ppm. (This concentration is generally limited by the requirements for the moderator temperature reactivity coefficient and higher concentrations are not expected. At the end-of-cycle, the boron concentration at which a power excursion can take place is lower.) Based on a simple conservative analysis^[1] for a significant power excursion to occur requires the injection of water with a boron concentration of less than 1050 ppm. It assumes that the water is mixed throughout the core, that the core would be 1.77% subcritical with all rods in at hot zero power (the Technical Specification minimum requirement), and that only \$1 of excess reactivity would lead to core damage. This value corresponds to changing the accumulator boron concentration by approximately 900 ppm. A more precise figure could be obtained if the sequences were calculated with the appropriate codes.

Assuming that an accumulator has become diluted, the core then could become diluted in one of three ways. The most serious situation probably would result from a blowdown of the accumulator. There is a motor-operated valve (MOV) that isolates the accumulator from the RCS before the reactor pressure vessel (RPV) falls below 650 psia. This MOV then is deenergized at some point during the cooldown. If this valve is not deenergized and then inadvertently opens, the accumulator will blow down into the cold leg and a slug of diluted water could rapidly enter the vessel, causing a power excursion which would damage the fuel.

Another possibility is for the water to slowly leak past the MOV into the vessel. If the water mixed with that in the vessel, then the shutdown margin would slowly be lost and the source-range neutron monitors should alert the operators to this fact, allowing them time to take corrective action. (There may not be enough water in the accumulator to cause criticality if it is mixed with all the water in the vessel.) However, if the residual heat removal system (RHR) was not in operation and there was minimal decay heat in the core (e.g., after refueling and if shut down for a reasonable period of time), then the leaking accumulator water could collect at the bottom of the vessel. When diluted water filled the lower plenum, the lower part of the core would become critical; if no corrective action was taken, the increase in power would increase the flow rate through the core, thereby bringing more of the diluted water from the lower plenum into the core. This autocatalytic process could lead to widespread core damage.

To be more certain of the consequences, detailed neutronic and thermal-hydraulic calculations are necessary. These calculations would not be easy because multidimensional flow patterns, low flows, stratification, and boron transport are involved, and each can be difficult to model. The calculations would help determine the mixing of the diluted slug of water with the vessel water during blowdown, core neutronic behavior with the boron concentration changing in space and time, and would determine natural circulation flow rates to allow for stratification, and then for entrainment.

4.11.2.2 Probabilistic Analysis

Two sequences were analyzed probabilistically for a Westinghouse four-loop plant ^[1]. For the sequence with rapid blowdown of the accumulator, the frequency of occurrence was estimated to be $6.9\text{E-}10/\text{RY}$. For the sequence which results in an autocatalytic excursion after diluted water has collected in the lower plenum, the estimated frequency of occurrence was $4.1\text{E-}9/\text{RY}$. These results are based on detailed fault trees to obtain the probability of an undetected dilution of the accumulators, and simple event trees to define the sequences.

These numbers could be regenerated taking into account the actual systems and instrumentation at Surry and refinements to the assumptions used in the original analysis. This was done and the results are presented in Appendix I.6 of this report.

4.11.3 Addition of Diluted RWST Water

4.11.3.1 Description

If the boron concentration of the water in the refueling water storage tank (RWST) becomes sufficiently diluted and if water enters the vessel during shutdown, then a reactivity event can occur. One sequence of this type occurs with the inadvertent actuation of the safety-injection system which is assumed to lead to a rapid power excursion, causing immediate, extensive core-damage. This event could occur while the reactor pressure vessel (RPV) is at a low pressure and while safeguards are still in service during cooldown or startup. The high-pressure safety injection is blocked during POS 2 and low pressure injection during POS 3. The low-pressure and high-pressure systems then are unblocked during POS 13 and 14, respectively.

Another type of sequence in which RWST water can get into the RPV involves the incorrect opening/closing of valves. Water would flow under the influence of gravity into the vessel. (An incident like this occurred at Surry 1.^[2]) The sequence then could be as described in Section 1.1 for accumulator water, i.e., either a slow return to power or the collection of diluted water in the lower plenum followed by an autocatalytic power excursion; it is expected that this could occur during POS 4-12.

If the RWST is diluted, it is also possible to slowly dilute the core when the cavity is filled for refueling during POS 7. Then the water flows into the hot leg and it is not expected to collect at the bottom of the vessel. The concern would be if the operator does not recognize the slow return to criticality and takes no action to stop the continuing dilution of the core.

For each of these sequences, it is necessary to assume that the RWST water has become diluted to the levels discussed in Section 1.1. This situation may occur when the tank is filled, or it may occur by erroneously introducing unborated water. Dilution also requires the failure of the weekly surveillance which takes place on a weekly basis.

4.11.3.2 Probabilistic Analysis

Two sequences were analyzed probabilistically^[1] for a Westinghouse four-loop reactor. The sequence involving inadvertent safety injection was estimated to have a frequency of occurrence of $3.7\text{E-}8/\text{RY}$. The sequence with

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slow leakage of the RWST resulting in diluted water collecting in the bottom plenum followed by an autocatalytic power excursion has a frequency of occurrence of $1.5\text{E-}8/\text{RY}$. The analysis was done using a detailed fault tree for the probability of the RWST becoming diluted without being detected. The probability for this situation was estimated as $2.8\text{E-}5$.

These numbers could be regenerated taking into account the actual systems and instrumentation at Surry and refinements to the assumptions used in the original analysis. Since the original work was done for a Westinghouse plant the basic events were almost be the same. The results requantified for Surry are discussed in Appendix I.6 of this report.

4.11.4 Boron Dilution Due to Maintenance Problems

4.11.4.1 Description of Events

4.11.4.2 Dilution When Cleaning Cavity

The refueling cavity is hosed down with unborated water after refueling. If this water is not turned off, water in the vessel will be diluted. Without the operator's intervention, the core would become critical and increase in power slowly; it is assumed that this would then lead to core damage. This cleaning procedure may take place at Surry; during POS 8, 9, or 10.

A precursor to this sequence occurred at a French plant^[3]. The dilution occurred after refueling was completed and work was proceeding simultaneously on draining the reactor cavity and decontaminating the cavity walls with an automatic system supplied with demineralized water. The original boron concentration in the core of 2110 ppm was diluted 1770 ppm before the situation was corrected. Human errors originally had left the system delivering a constant supply of unborated water.

In that incident, the boron meter, which continuously monitors the boron concentration of the reactor coolant, was undergoing calibration and was inoperable. Consequently, there was no alarm to warn the operator that the boron concentration was below the 1950 ppm setpoint. Furthermore, although operating procedures stipulate that the boron concentration should be checked once every eight hours when the meter is unavailable, the procedure had been postponed because of another situation.

While the reactor coolant was being diluted, the count level indicated by the source channels had risen rapidly and almost doubled; however, since this parameter is recorded on a logarithmic scale, the increase went unnoticed by the operators. In addition, the two "high flux count during shutdown" alarms failed to trip because their setpoint had been set at three times the normal flux level.

The incident was terminated after more than 12 hours of dilution when a boron concentration test was finally completed and operators became aware of a 340 ppm dilution.

4.11.4.3 Dilution due to Steam Generator Maintenance

If the steam generator tubes are cut either purposely or inadvertently during modifications to the steam generator, and no repairs are made before the secondary side is brought back into service, then unborated water can leak into the primary. Two such events were reported^[4] between June 1969 to January 1981. These dilutions were both detected early and RCS boron concentration fell less than 100 ppm.

4.11.4.4 Probabilistic Analysis

The POSs during which the secondary is refilled are not yet known for Surry. If cavity cleaning could cause a dilution sequence then a detailed probabilistic analysis could be done to determine the estimated frequency of occurrence. Consideration also will be given to a sequence involving the leakage of secondary water into the RCS after maintenance. After discussions with VEPCO personnel, it was concluded that the risk significance of these sequences is rather small.

4.11.5 Uncontrolled Boron Dilution from CVCS

4.11.5.1 Description of Event

The chemical and volume control system (CVCS) is normally used to maintain the proper boron concentration in the core. Many system failures and human errors could cause a malfunction and dilute the boron. The system is designed to limit the rate of dilution even under various failure modes, so that the operator could take corrective action after getting an indication of the dilution on various instruments and alarms. However, if the operator does not take corrective action, then a recriticality during shutdown is possible followed by an increase in power which could damage the core. A malfunction could occur during POS 1-15.

As of the end of 1984, there had been 25 reported instances of inadvertent boron dilution due to the CVCS during maintenance and refueling,^[5] none of which resulted in criticality. (An incident at Surry 2^[6] was caused by problems in the blending system.) The NRC made this a generic issue. The NRC and their contractors determined that a return to power would not lead to core damage. However, this conclusion is probably based on the assumption that the dilution would be terminated. Their analysis also considered radiological consequences based on the release of gap activity from any leak that may already exist and the pathways to the surrounding population. In combination with a cost estimate, this analysis allowed a value/impact assessment to be made. The conclusion was that no new requirements were established, and the generic issue was categorized as "RESOLVED".

4.11.5.2 Probabilistic Analysis

The previous NRC analysis,^[5] was based on a generic PWR, determined the frequency of criticality from an unplanned boron dilution as $2.0\text{E-}4/\text{RY}$. This number is the product of two factors. Using information from the events that did occur, and extrapolating to the point where the shutdown margin is reduced to zero results in a frequency of $2.0\text{E-}3/\text{RY}$. This value is multiplied by a human-error probability of 0.1 for the failure of the operator to take action. This takes into account that neutron flux alarms will come into play at some point and then the operator can still prevent criticality by stopping the dilution and/or reborating the RCS.

To apply the generic analysis to Surry and the possibility that the dilution could continue until core damage occurs, the length of time between criticality and core damage would have to be estimated, also considering that the additional alarms either failed or were ignored while the reactor power increased. This was done for the CESSAR PRA and the (proprietary) result is that the frequency is significant. For Surry, the probabilistic analysis of reactivity accidents due to boron dilution from CVCS was centered on those which are assumed to occur when the RCS is under mid-loop operation.

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4.11.6 Boron Dilution via the RHR

4.11.6.1 Description of Event

The residual heat removal system (RHR) is turned on during the cooldown of the reactor. This system is a potential source of unborated water during POS 3-13. The sequences involve dilution as a result of either getting demineralized water into the RHR or from ruptures of the heat exchanger tubes. Dilution could have occurred before startup of the RHRS or during operation.

This type of relatively slow dilution (and others like it) involves the incoming water mixing with all the water in the vessel, as opposed to some sequences when it is a slug of diluted water that is of concern. Therefore, the speed at which the dilution takes place is increased with less water in the vessel and hence, mid-loop operation is more of a concern than other shutdown plant operational states.

4.11.6.2 Probabilistic Analysis

Belgian work^[7] gives an "extremely low probability" for the CDF, but the analysis is not clear making it difficult to assess the relevancy to Surry. French workers^[8] claim that the CDF due to the startup of a previously diluted RHR is $1.0\text{E}-8/\text{YR}$, but no details are given.

4.11.7 Startup of RCP after Improper Boron Dilution

4.11.7.1 Description of Event

There are several sequences during shutdown wherein dilution may not be excessive if mixing takes place with all the water in the vessel. However, these sequences may be a problem if the diluted water collects in one region of the primary loop, and then starting one or more reactor coolant pumps (RCPs) sends a slug of this diluted water into the core. For this to happen, the plant must be in an operational state which allows for the start of an RCP. Although this is most likely during POS 14, it could occur during POS 1-3 or POS 13-15 depending on the particular scenario.

In one such sequence suggested by French workers,^[9] the reactor is in the startup state being deborated (POS 14). The RCPs are tripped but deboration is assumed to continue. The diluted water is assumed to collect at the bottom of the vessel and the RCPs are restarted causing a slug of unborated water to enter the core and damage the fuel. As in several other sequences, it is necessary to assume that the natural circulation flow rate is low enough so that mixing is negligible. This sequence was analyzed probabilistically by French workers,^[9] but the information is very general. No deterministic calculations seem to have been done to support their assumptions although related experimental work is being carried out.

Another sequence suggested by French workers starts with a loss of power, and failure of equipment involved in the procedure to start for an hour. Next is the restarting of one steam-generator auxiliary feedwater pump followed by electrical power becoming available and the start of the RCPs. Preliminary calculations^[10] showed that the sequence first leads to boiling, and then when the aux feed comes on, to condensation so that diluted water accumulates in the crossover leg. Finally, when the RCP comes on, there is the possibility of diluted water being pumped into the core. Although this sequence was considered during startup (POS 14) by French workers, it may also be possible during other states.

One sequence studied in great detail by Swedish workers^[11] is initiated by a steam generator tube rupture (SGTR). The plant is either shutdown initially or at hot zero power and there is a coincident loss of offsite power or some other means of tripping the RCPs. Secondary water then can get into the primary system if

the operators use backfill cooldown. This unborated water is assumed to collect in the stagnant part of the loop and then the RCP in that loop is assumed to start, forcing the slug of water into the core. POS 1, 2, 14, and 15 are relevant and the Surry procedures must be examined to see when backfill is possible.

Calculations showed that the boron concentration in the core could go from 850 ppm to a minimum of 163 ppm in 10s, but did not show any immediate fuel damage due to the energy deposition. However, the calculations are claimed to be inconclusive, and it is clear that further neutronics and thermal-hydraulics calculations are needed. As a result of this analysis, Westinghouse, in 1990, recommended to the Westinghouse Owners Group that the Emergency Response Guidelines are changed regarding the procedures after a SGTR.

Other sources of unborated water during shutdown that could cause a problem if an RCP was started include the RCP seal water flow or a leaking thermal barrier. However, Swedish workers determined that these were less important than the SGTR sequence.

A situation that is similar to a pump restart is the opening of a loop-stop valve when pumps are running. Westinghouse^[12] calculated the consequences of a startup of an inactive unborated loop without consideration of how the loop became diluted. The event starts from hot zero power (HZP) and hence, the reactivity addition is mitigated by the insertion of control rods. Rather than the restart of an RCP, the calculation assumes the opening of loop stop-valves for the loop while all RCPs are running. In the worst case considered, they calculate that approximately 3% of the fuel experiences clad rupture and <0.5% melts-completely. No calculations are known for situations other than this HZP case. Surry does not use stop valves except during shutdown to isolate a steam generator for maintenance.

4.11.7.2 Probabilistic Analysis

The French study^[9] showed that the CDF is $1.3\text{E-}6/\text{RY}$ for the sequence wherein the RCPs are tripped during deboration and then restarted later after deborated water has accumulated in the lower part of the vessel. This number resulted from taking into account corrective actions that were recommended when the study was first done. Such actions would cause the charging flow to automatically switch to the RWST if the pumps were tripped. The CDF is 2% of the total CDF (including both shutdown and normal operation) and significantly higher before the corrections were taken into account.

The French results are an incentive to look closely at this sequence. Hence, a series of questions were addressed to VEPCO to determine what happens to the dilution process when there is a loss of offsite power. The information obtained from VEPCO was incorporated into the detailed analysis presented in Appendix I.6 of this report.

The distillation sequence involving first, the boiling of water and then, condensation in one loop should be considered. If it seems physically possible, then the probabilistic analysis should be done. We note that if the French analyzed this sequence in detail for their recent PRAs, there is no mention of it as a significant contributor.

The sequence in which SGTR is followed by dilution from the secondary and startup of the RCP in the affected loop has a CDF of $1.4\text{E-}7/\text{RY}$ ^[12]. The French study claims the probability of occurrence of RCP startup with one loop diluted to be $1.0\text{E-}11/\text{RY}$ ^[8]. Information has been obtained from VEPCO regarding cooldown by backfill. The analysis performed for Surry is discussed in section 6.4.3.2.6 of the Phase 1 report (see Appendix I.6 of this report).

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4.11.8 Rod Ejection Accident

4.11.8.1 Description of Event

The design-basis rod ejection accident (REA) is defined as the mechanical failure of a control rod mechanism housing so that the pressure in the reactor coolant system (RCS) ejects a rod cluster control assembly and drive shaft to a fully withdrawn position. This requires a complete, instantaneous circumferential rupture of the control element drive mechanism (CEDM) housing or of the CEDM nozzle. The accident can occur whenever pressure in the plant is elevated and is critical or not significantly shut down. Hence, in the present study, the event is of interest in POS 1, 2, 14, or 15.

The consequence of the ejection is a localized power excursion with the potential for fuel damage and/or damage to the RCS pressure boundary. However, for a PWR to be licensed, it must be shown that the consequences are within acceptable limits. Of concern in the present study are any beyond-design-basis variants of the REA which might lead to unacceptable damage to either the core or the pressure boundary.

The reactivity addition, and hence, the severity of the accident, would be increased if there were additional failures which lead to higher-than-expected rod worths or the ejection of multiple rods. However, for hot zero power, the REA is already analyzed assuming a configuration which would lead to the maximum rod cluster reactivity worth. For two or more rod clusters to have an additive or synergistic effect, they must be ejected almost simultaneously from nearby locations because the power excursion is over in less than 100 ms. If they are not, then the fuel behavior in each assembly will be independent, and hence, acceptable in terms of the criteria for the design-basis accident. Therefore, the REA is not expected to have any risk significance.

4.11.8.2 Probabilistic Analysis

There is no known probabilistic analysis for an REA at any plant. The only sequence that might lead to an excessive power excursion requires the simultaneous ejection of two or more rod clusters. A common-cause mechanism could be postulated due to the dropping of a heavy load on top of the vessel, but the probability is reduced by procedures which place the missile shield above the vessel, and prohibit the movement of heavy loads when the vessel is pressurized. However, of most significance is that the ejection of each rod would have to be almost simultaneous to create the possibility of exceeding the acceptance criteria for the design-basis accident. Since this scenario is not expected to have a significant probability, the conclusion is that the REA is not expected to have any risk significance. If a quantitative upper bound is desired, an estimate could be made of the frequency of dropping a heavy load on the vessel when it is pressurized.

4.11.9 Misloading of Fuel Assemblies

4.11.9.1 Description of Event

Fresh fuel assemblies have relatively high reactivity worths when they do not contain control rods. If these high worth assemblies are loaded into the core incorrectly so that they are clustered together without control rods, then there is the possibility of a reactivity excursion. If a cluster was just subcritical because of a misloading and no action was taken when the count rate increased, then the loading of the next adjacent assembly would cause a fast insertion of reactivity which would likely result in localized core damage. This event could occur in POS 8.

4.11.9.2 Probabilistic Analysis

The probability of misloading fresh fuel without control rods into clusters was calculated for a Combustion Engineering plant at BNL as part of the NRC-sponsored study of PWR loss of shutdown margin.^[13] This work was extrapolated to the Surry plant and the results are presented in Appendix I.6 of this report.

4.11.10 Uncontrolled Bank Withdrawal

4.11.10.1 Description of Event

This event is of concern when the core has been shut down and all rods are inserted, or during startup when either all rods are in or the shutdown bank is withdrawn. The latter case, with the possibility of scram, is a design-basis event and Westinghouse has shown that the consequences are acceptable. Westinghouse also analyzed the case without scram and showed that the fuel cannot be damaged. French workers^[9] claim that there are credible beyond-design-basis withdrawals that lead to core damage. A check of bank worths for Surry should indicate how serious this event might be starting from shutdown conditions, and further consideration will be given to finding beyond-design-basis situations.

4.11.10.2 Probabilistic Analysis

No analysis has been found. It would have to be determined whether there are credible sequences which lead to core damage before this event could be analyzed probabilistically.

4 Initiating Event Analysis

4.11.11 References

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4.12 Initiating Events That Are Applicable to the Mid-Loop POSs

Table 4.12-1 lists the initiating events that are applicable to the mid-loop POSs, i.e., POSs 6 and 10, together with the frequencies and probabilities of the initiating events.

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Table 4.12-1 Initiating Events that Are Applicable to the Mid-Loop POSs

		Mean	Error Factor
1.	Loss of RHR		
	RHR2A-Over Draining	1.62E-02/Demand	1.97
	RHR2B-Failure to Maintain Level	1.22E-05/hr	3.27
	RHR3-Non-Recoverable Loss of RHR	4.09E-06	3.79
	RHR4-Non-Recoverable Loss of Operating Train of RHR	5.28E-06/hr	3.82
	RHR5-Recoverable Loss of RHR	2.12E-05/hr	2.21
2.	LOOP-Loss of Offsite Power	6.96E-06/hr	3.23
3.	4 kV-Loss of 4 kV Bus	2.10E-05/hr	2.40
4.	VITAL-Loss of Vital Bus	5.58E-06/hr	3.94
5.	AIR-Loss of Outside Instrument Air	2.12E-6/hr	2.86
6.	CCW-Loss of CCW	3.76E-06/hr	6.35
7.	SWGR-Loss of Emergency Switchgear Room Cooling	1.81E-08/hr	4.00
8.	ESFAS-Inadvertent Safety Feature Actuation	1.06E-04/hr	1.15
9.	Dilute-Boron Dilution (CDF)	2.00E-07/hr	—

5 SUPPORTING THERMAL HYDRAULIC ANALYSIS

The main purpose of the thermal hydraulic analysis is to support the development of the event trees and quantification of the accident sequences. In a coarse screening study^[1] undertaken at BNL as part of the low power and shutdown program, preliminary calculations based on simplified assumptions were used to estimate the time that the plant might reach potential core damage. The study identified alternate cooling methods which could prevent core damage following the loss of RHR, but did not further evaluate the feasibility of these alternate cooling methods. More detailed analyses are required to confirm the preliminary findings^[1].

In this chapter, the thermal-hydraulic behavior in the reactor coolant system (RCS) during mid-loop operation after the loss of RHR is discussed. Three alternate cooling methods, i.e., gravity feed from the RWST, reflux cooling, and feed-and-bleed were investigated. Gravity feed was analyzed by using the MELCOR code^[2] for a few different decay-power levels between 1 day to 29 days after reactor shutdown. The assessment of reflux cooling is largely based on studies by Idaho National Engineering Laboratory, and the Westinghouse Company. Feed-and-bleed operation was analyzed for a large range of initial operating conditions using simplified models developed for this program. For all the three cooling methods, we attempted to identify the conditions under which the operation would be successful.

5.1 Gravity Reflood Via the RWST

In the event of a loss of RHR transient during mid-loop operation, one method available for plant recovery is to connect the RWST to the RHR lines. Since the primary side is vented through the process vent during mid-loop operation, and is, therefore, essentially at atmospheric pressure, the difference between the liquid levels in the RWST and reactor vessel results in a net gravity head which will drive water from the RWST into the primary circuit.

Gravity reflood from the RWST as a method of core recovery after a loss of decay-heat removal was discussed in the coarse screening study^[1] for the low power and shut-down program in which the results of hand calculations were presented to indicate the requirements for a successful recovery of the plant under various assumptions. This section takes that analysis further, and describes the results of several MELCOR calculations.

The MELCOR computer code^[2] was used exclusively in this analysis on the grounds that:

- (1) A MELCOR input deck for Surry already existed at Brookhaven National Laboratory.
- (2) The results of the level 1 thermal-hydraulic calculations would be directly comparable with the source term calculations performed as part of the level 2/3 study.

5.1.1 The MELCOR Model

Figure 5.1-1 shows the plant operational state to be modeled. The plant is in mid-loop operation, with the primary circuit open to the atmosphere, and a maximum coolant temperature of 140°F. All six loop isolation valves are closed, which both minimizes the primary circuit inventory and precludes the use of reflux cooling as a recovery procedure. A Tygon tube connects the upper head vent to the pressurizer relief tank, and at least one pressurizer SRV is assumed to have been removed, which provides a vent path to the containment.

5 Supporting Thermal Hydraulic Analysis

The MELCOR nodalization scheme is shown in Figure 5.1-2. The RHR system was modeled using a single, large thermal-hydraulic control volume, with control functions to maintain the required inlet/outlet conditions. The RWST tank remained at atmospheric pressure throughout the transient, and the containment was assumed to be closed to maximize the pressure increase experienced by the primary circuit as vapor from the boiling core is vented into the containment.

The pipe-work between the RWST and the primary circuit was modeled with a notional geometry. These lines contain a number of components including reducers, elbows, tees, diffusers, and valves. Each component has an associated irrecoverable head loss, which may be influenced by interactions between closely spaced components where the flow path length was insufficient to establish a fully developed flow. Rather than attempt to model these losses explicitly, an irrecoverable forward flow loss of 10 velocity heads was used to represent all components in the flow paths connecting the RWST and primary circuit. The actual irrecoverable loss would not be expected to exceed this value, and since mass flows were generally low, this assumption did not provide an undue degree of conservatism. Flow reversal was prevented by including large reverse loss coefficients in the RWST lines.

All calculations began with 5000 seconds running in quasi-steady state conditions, which was sufficient for the MELCOR model to approach a close approximation to a steady state. A careful choice of control logic enabled the liquid levels in the primary circuit to equilibrate to within approximately one inch of the reference mid-loop elevation (26.54ft), consistent with the findings of the Westinghouse report on flow gradients (see ref [3]). Depending upon the level of decay heat, the temperature of the primary circuit coolant ranged between 124°F in the cold legs to 144°F in the hot legs.

The transient was initiated by closing the RHR flow paths to simulate a loss of RHR, and all timings referred to here begin with this time in the calculation. For the base-case calculations, 30 minutes transient time was assumed to elapse before the lines connecting the primary circuit to the RWST were opened.

The standard ANS decay heat curve, programmed into MELCOR, was used throughout to provide a best-estimate rate of heat generation. The initial decay-heat levels for all but the lowest value were selected by the 'time window' approach (section 5.4), where success criteria based on thermal-hydraulic considerations, such as the availability of reflux cooling or feed-and-spill, were used to identify the levels of interest. The limiting lower value was obtained from scoping calculations, using MELCOR, to determine the maximum generation rate of decay heat at which gravity reflood from the RWST could provide sufficient core cooling to prevent core damage with the 24-hour mission time.

A peak clad temperature of 1340°F indicated the onset of core damage. Above 1340°F, phenomena such as clad oxidation and ballooning affect core behavior. At the low levels of decay heat typical of shutdown operations, the exothermic Zircaloy oxidation reaction, which is modeled by MELCOR, provides a significant additional source of heat leading to a marked increase in the rate of core heat-up. However, MELCOR does not model clad ballooning and its associated impact on heat transfer, which would be anticipated if rod temperatures exceeded 1340°F for long. Furthermore, the core model uses three radial rings, so that the rod's peak temperature represents an average behavior for 1/3 of the core; we expect that some rods will be appreciably hotter than this average value just as some will be lower. Therefore, once rod temperatures exceed 1340°F, there is a significant potential for both severe distortion of the fuel rod, inhibiting easy removal of fuel from the core, and clad rupture, with its subsequent release of active species. We anticipated that the PRA analysis would exhibit a limited sensitivity to the choice of core-damage criteria since only the time differences between core damage with and without gravity reflood were used to identify successful sequences.

The abnormal procedure for Decay Heat Removal Capability, AP 27.00 Rev. 4^[4], provided by Virginia Power, requires the RWST to be aligned with the cold legs. This configuration is the most efficient method of core recovery following a loss of RHR during mid-loop operation since, for hot leg injection, much of the cold RWST water injected into hot leg C is diverted into the pressurizer surge line by the flow of water and vapor from the vessel. For cold leg injection, all the RWST water must first pass through the core before it flows into the pressurizer and vents to the containment. This behavior was confirmed by a preliminary series of MELCOR calculations.

The abnormal procedure AP 27.00 also requires the RWST flow to be throttled to maintain core subcooling with core exit temperatures between 180-200°F. Control functions were used in MELCOR to provide the required throttling of the flow from the RWST.

Twenty-four MELCOR calculations were performed in this analysis. They are summarized in Table 5.1-1. The minimum equipment list for mid-loop operation requires the removal of one pressurizer SRV and a base-case series of calculations were made with this assumption. However, past shutdown operations logs uncovered instances when all three pressurizer SRVs were removed for maintenance testing during mid-loop operation. We determined the impact of this increased vent flow path area on plant response. A series of sensitivity calculations investigated the ability to recover the core at later times, after a period of boil-down and subsequent heat-up of the core. Cases with gravity reflood initiated when rod temperatures exceeded 620°F and 980°F were calculated to determine the impact of delayed injection on the time to core damage.

The latest released version of MELCOR (version 1.8.2) was used, which includes several major improvements and corrections. For this study, the most significant update to the code is the correction to the inter-phase drag correlation. In previous versions, this correlation contained an extra term which over-predicted inter-phase momentum exchange, with a consequent under-prediction in counter-current flow limitation.

5.1.2 Results

Case 3, which assumes cold leg injection initiated 30 minutes after loss of RHR, one pressurizer SRV removed and an initial decay heat level of 10 MW, showed the typical plant response to gravity reflood from the RWST, and is be used to illustrate the major phenomena involved.

The collapsed liquid levels in the vessel and pressurizer are shown in Figure 5.1-3 (the bottom of the vessel is the reference elevation). Boiling in the core commenced approximately 1000 seconds after the loss of RHR, producing a level swell which forced a two-phase vapor/liquid mixture into the pressurizer. However, the increase in primary side pressure (see Figure 5.1-4), caused by liquid hold-up in the pressurizer (~52ft), was still much less than the gravity head of the RWST (initial liquid level 86.75ft), which commenced injection at 1800 seconds, and filled the primary circuit rapidly. (The anomalous pressure spikes in the upper plenum pressure response seen in Figure 5.1-4 at approximately 15,300, 19,700 and 22,300 seconds were caused by problems in MELCOR and do not represent physical behavior.)

Figure 5.1-5 shows the mass flow rate into the cold legs from the RWST. The flow peaked briefly approximately 400 lbm/s before the core-exit temperature fell below 180°F (Figure 5.1-6), and the control block modeling the flow throttling began to reduce the flow path opening fraction (Figure 5.1-7). As the level in the RWST approached the top of the pressurizer (Figure 5.1-8), the throttling of the RWST flow was gradually reduced, until approximately 10,000 seconds, when the flow paths were once more fully open. The

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mass flow rate from the RWST continued to fall from this point in the transient with the decrease in driving head until 12,500 seconds, when it virtually ceased.

The decreasing flow from the RWST removed progressively less heat from the core, and the fuel rod temperatures gradually increased until saturation was achieved, boiling commenced, and a vapor bubble formed in the upper plenum. Figure 5.1-4 demonstrates the impact on vessel pressure of liquid hold-up in the pressurizer, with the water column developing a gravity head of typically 15 psid. Therefore, as the expanding vapor bubble and the residual flow of water from the RWST combined to force saturated water from the vessel into the pressurizer, some of this now superheated liquid flashed to vapor, producing a level swell and briefly forcing two phase fluid through the SRV manifold. This rising mass flow (Figure 5.1-9) increased the pressure drop across the SRV manifold, and the primary circuit pressure began to rise (Figure 5.1-4).

The vapor bubble in the upper plenum began to vent through the pressurizer surge line at approximately 14,500 seconds, reducing primary circuit pressure, which allowed further flow from the RWST.

This cycle of events was repeated twice, with the reduction in pressurizer inventory being reinforced by brief periods of counter-current flow of liquid from the pressurizer into the hot leg (Figure 5.1-10: negative flow is from the pressurizer into the hot leg.)

Eventually, the liquid level in the RWST fell sufficiently that it could no longer drive reflood water into the primary circuit. This occurred at approximately 24,600 seconds after which, apart from two brief periods of low flow, the core began its final heat-up with rod temperatures exceeding 1340°F at 30,200 seconds.

The response of the containment is shown in Figures 5.1-11 and 5.1-12, which plot temperatures and pressures in various parts of the containment building. The intermittent peaks in the temperature of the pressurizer cubicle associated with periods of venting of the vapor from the vessel, when vapor flow rates through the SRV manifold into the pressurizer cubicle rose significantly. This, in turn, produced sharp rises in containment pressure. However, the pressure remained low throughout the transient, and did not challenge the containment integrity.

The response of the plant at other initial levels of decay heat was broadly similar; the results are summarized in Table 5.1-2. They demonstrate that gravity reflood cannot sufficiently cool the core to prevent damage for 24 hours when initial levels of decay heat are greater than 5 MW (23.5 hours was considered acceptably close to the 24 hour mission time, bearing in mind the conservative definition of core damage used). At higher levels of decay heat the time to core damage was correspondingly shorter, with only 5.25 hours available to execute alternative recovery actions at the highest initial level of 15.8 MW.

One noticeable feature of the results in Table 5.1-2 is the lack of consistent trends for end-time conditions. For example, the end-time RWST inventory shows a general trend towards lower inventory for longer transient times, although it is marginally less for case 1 than for case 2. Even for the longest transient, the RWST discharges less than 53% of its initial inventory (387,200 US gallons).

Comparing the base-case results with Table 5.1-3 shows that with no gravity reflood, the core was damaged between 0.85 and 4.9 hours after a loss of RHR during mid-loop operation, depending upon the time after shutdown. Containment temperatures and pressures also were lower, as a result of the shorter transient times

combined with the reduced liquid inventory available for vapor production since only the initial, mid-loop vessel inventory was available for core cooling.

Table 5.1-4 shows the impact of a greater flow path area with 3 pressurizer SRVs removed to vent the primary circuit to the containment. Compared with the base-cases with 1 pressurizer SRV removed, the increased vent path flow area extends the time to core damage. For this plant configuration, core damage occurred 6.85 hours after a loss of decay heat removal for case 11, with an initial decay heat level of 15.8 MW, and core damage was averted for the mission time of 24 hours for initial decay heat levels less than 6 MW. These cases exhibit a more marked randomness in RWST end-time inventory than the base-case calculations. However, the general trend of lower end-time RWST inventories for these cases, when compared with the base-case results, is consistent with the improved venting of the primary circuit and the extended times to core damage.

These calculations all assumed that gravity reflood was established 30 minutes after loss of RHR whilst the rods were still experiencing high heat-transfer rates, typical of the nucleate boiling regime, and surface temperatures of the rods were close to saturation. However, if the start of gravity reflood was delayed further, the upper elevations of the core could dry-out, causing the temperatures of the rods to rise as the liquid inventory in the core decreased.

MELCOR was not intended to calculate detailed heat transfer as do codes such as TRAC and RELAP5. Consequently, the modeling of core heat transfer, and, in particular, the phenomenon of reflood of a core at elevated temperatures, is necessarily simplified. Therefore, the results of such calculations should only be used for general guidance.

To assess the impact of elevated rod temperatures on the ability of the RWST to recover the core, we made two sets of calculations with gravity reflood initiated when rod temperatures exceeded 620 and 980°F. The lower temperature was selected since reflood of a core at and below such temperatures would be expected to quench all fuel rods immediately. The higher temperature accounted for the possibility of the hotter surfaces remaining unquenched for longer after reflood had commenced.

The results of these two series of calculations are shown in Table 5.1-5, which indicates that there is little impact of delayed reflood on the times to core damage for all situations except case 17, with the highest initial decay-heat level 13.23 MW, and injection commencing when rod temperatures exceed 920°F. Here, the higher generation rate of decay heat, combined with the greater stored heat in the core, generated a sufficiently high vapor volumetric flow in the vessel to choke at the SRV manifold. The resultant increased pressure drop across the manifold prevented prolonged reflood from the RWST, which ceased after an initial period lasting less than 300 seconds, and was insufficient to flood the core.

Figure 5.1-13 compares the pressurizer pressure for cases 2 and 17, which clearly shows the impact of choking at the SRV manifold. The cliff-edge effect is highlighted in Figure 5.1-14, which indicates that choking occurred at the SRV manifold shortly after 2,000 seconds in case 17, when the rods began to heat-up. Figure 5.1-15 highlights the subsequent marked reduction in RWST flow.

Two calculations were performed assuming all three SRVs were removed for the case of 13.23 MW initial decay heat to assess the impact of the increased vent path on the ability of the RWST to reflood the core at elevated temperatures. Table 5.1-6 compares the times to core damage with case 12, where RWST gravity reflood began 30 minutes after loss of RHR. The similar behavior for all three cases confirms that the increased area of vent path flow area was sufficient to prevent choking at the SRV manifold.

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5.1.3 Discussion

The 'time window' approach identified a set of initial levels of decay heat of interest. Successful recovery, defined as 24 hours of sufficient high heat transfer to prevent core damage, using either reflux cooling, or feed-and-spill, identified all but the lowest decay-heat level in this set, demarcating the lower limit by the ability of gravity reflood via the RWST to provide 24 hours of core cooling. The analysis was made on a discrete number of decay heat levels, covering a wide range of times to core damage under various assumptions, and identifying the major phenomena governing the ability of the RWST to reflood the core.

pressure before the start of the transient. The long-term behavior of the plant then was governed by the gradual reduction in this driving head, as the RWST level fell, balanced by the various phenomena that increase the primary circuit pressure. A feature of these results is the apparent random variance in some end-time conditions, most notable in the cases of a large vent path (11-15). This variance is considered to stem from the gravity reflood mechanism which becomes particularly sensitive to the interplay between several competing effects as conditions approach mechanical equilibrium. Coupled with numerical inaccuracies in the method as small time-steps are taken, this sensitivity may cause the code logic to follow different calculational paths for otherwise similar transients. We do not consider this to be a severe limitation because a sensitivity study indicated a minor impact on times to core damage, and only the cases of large vent path significantly vary from the expected trend of lower RWST inventory with longer transients.

In most cases, the hold-up of water in the pressurizer was the major contribution to the primary circuit pressure. After the initial reflood from the RWST had ceased, the pressurizer was almost full of water at saturation conditions; Figure 5.1-8 shows the gradual fall in the collapsed liquid level during a transient. The dominant phenomenon governing this reduction in liquid level occurred when saturated liquid in the hot leg was driven into the lower pressure, saturated liquid in the pressurizer, either by RWST flow or the expanding vapor bubble trapped in the upper plenum. The increased thermal energy of the fluid caused flashing, which, in turn, produced a level swell in the pressurizer volume. The rise, coupled with the increased volumetric flow rate of the vapor, entrained liquid in the vapor flow vented through the SRV manifold.

The lumped parameter approach of the MELCOR model undoubtedly had an effect on the detailed behavior of this phenomenon. In the plant, fluid experiences a continuous change in static pressure as it flows from the hot leg into, and up through, the pressurizer, whereas MELCOR models a step change in pressure. Therefore, vapor generation would be a more gradual process in the plant than predicted by MELCOR. However, the energy balance, and hence, the volumetric vapor generation rate calculated by MELCOR is a function of the pressure drop and is not affected by the step change; we anticipate that the general behavior of the plant under these circumstances will not differ substantially from the MELCOR prediction.

Some drain-down of the pressurizer into the hot leg occurred when vapor began to vent from the vessel through the surge line, but this was generally short-lived and the resultant decrease in pressurizer liquid inventory was not significant. Boil-off in the pressurizer, caused by superheated vapor venting through the surge line, did not contribute significantly to the reduction in pressurizer inventory before core damage because vapor temperatures in the hot leg remained at or near saturation until rod temperatures had begun their final temperature excursion. This is illustrated in Figure 5.1-16, which plots the vapor temperatures for the hot leg and pressurizer for case 3.

Smaller contributions to the primary circuit pressure arose from the back pressure of the containment, which was assumed closed throughout, and the pressure drop across the SRV manifold. Only in extreme cases,

involving generation of high decay heat and high core temperatures, did choking at the SRV manifold occur and the increased pressure drop contribute significantly to the primary circuit pressure. However, as previously noted, the pressure drop across the pressurizer SRV manifold did affect the stability of the calculation as mechanical equilibrium was approached towards the end of each period of reflood. This view is supported by the more consistent trend in the end-time RWST inventories for the base-case calculations compared with the large vent cases.

During the first vapor bubble formation in the upper plenum there was little evidence of a drain-down of the upper head. This finding should not be confused with the 'liquid levitation' problem first encountered in earlier versions of MELCOR, which was caused by an error in the flooding correlation so over-predicting of inter-phase drag. This error was corrected in the version of the code (1.8.2) we used. The, apparently anomalous, behavior exhibited in case 3 was largely the result of the geometry of the flow path, which connected the upper head to the upper plenum and represented the control-rod drive housings. This flow path had an opening height spanning elevations 25.4 to 27.7ft within the upper plenum so that, as vapor flowed into the upper plenum from the boiling core, it remained trapped, pressurizing the vessel, until the liquid level in the upper plenum fell below 27.7ft.

At this point in the transient, drain-down of the upper head would be expected to occur. However, MELCOR calculates the gravity head between two components based on change in elevation multiplied by the average fluid density in the two connected volumes, rather than the actual density within the flow path itself. Thus, as vapor began to enter this flow path, the pressure drop between the upper head and upper plenum remained largely unchanged and did not fall sharply as expected. Further, the pressure in the upper plenum continued to rise, the vapor that entered the upper head was condensed in the subcooled fluid, and a large flow resistance was input for this flow path. The combined effect is that drain-down from the upper head was delayed for approximately 300 seconds until venting of vapor through the pressurizer reduced the upper plenum pressure, shortly before gravity reflood from the RWST commenced and refilled the vessel. This behavior, coupled with the coarseness of the graphical output from MELCOR, was responsible for the apparent lack of drain-down of the upper head. A detailed examination of the output from the calculation during this phase of the transient indicated a brief period of liquid drain-down from the upper head before injection from the RWST refilled the vessel. The impact on the overall plant behavior of this delay is considered to be small since, in all cases, the upper head had drained down completely before the upper plenum and core were substantially voided.

All base-case calculations demonstrated that the initial flow of water from the RWST was sufficient to recover core subcooling within 400 seconds at the highest rates of heat generation, and almost immediately at the lowest levels. The behavior of the control block modeling the throttling of the RWST flow is shown in Figure 5.1-17 for the base-case calculations. Whilst we recognize that the control function used was an idealization of the operator's action, the low decay-heat levels during shutdown operations, and the passivity of the reflood mechanism result generally in long time constants for system response. Therefore, we consider that, to a reasonable approximation, the operator's actions would have the same effect on plant response.

Throughout these calculations, it was assumed that the SRVs were open to the containment. The exact type of any covering on the SRV manifolds was not clear, but the analysis assumed that the initial flow of vapor/liquid from the pressurizer would have sufficient momentum to clear the flow path to the containment. If the covering was sufficiently robust, it might impede venting of the primary side, and hence, gravity reflood from the RWST may be compromised.

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Another point not considered was the availability of the RWST from Unit 2. At the Surry plant, these can be cross-connected to supply an additional reflood water. Such an action would extend the period before core damage occurs, although the governing factor in the amount of water available would be the technical specification requirements for the minimum RWST level required for operating Unit 2.

5.1.4 Conclusions

Several MELCOR calculations were made to assess the thermal-hydraulic behavior of Surry Unit 1 following a loss of RHR, with subsequent recovery by gravity reflood from the RWST. The following conclusions are drawn.

- (1) Gravity reflood from one full RWST, with appropriate throttling of the flow, prevented core damage for 24 hours for times after shutdown when initial levels of decay heat were less than 5 MW with 1 pressurizer SRV removed, and 6 MW with 3 pressurizer SRVs removed.
- (2) In all cases, the initial driving head of water from the RWST was sufficient to recover core cooling, with throttling of the flow required shortly thereafter, assuming compliance with the abnormal procedure for loss of decay-heat removal.
- (3) Liquid hold-up in the pressurizer was the dominant phenomenon in reducing the effectiveness of gravity reflood, with liquid entrainment in the vapor vented through the SRV manifold the governing factor in the reduction of pressurizer inventory.
- (4) For the base-case accident sequences, a 'cliff-edge' effect occurs at levels of decay heat above approximately 13.23 MW, with one pressurizer SRV removed, owing to the limited time available before the enthalpy rise in the core is sufficient to choke the SRV manifold, which increases the pressure of the primary circuit above the limiting threshold for successful gravity reflood.
- (5) Before core damage, containment temperatures and pressures remain low and do not challenge the containment.
- (6) The sensitivity of gravity reflood near mechanical equilibrium, coupled with numerical inaccuracy of the solution method resulted in some random variance in predictions, most notably the end-time RWST inventory, although predictions of core damage were largely unaffected.

Figure 5.1-2 Melcor Noding

Figure 5.1-3 Case 3 - Primary Circuit Collapsed Liquid Levels (ft)

Figure 5.1.4 Case 3 - Primary Circuit Pressure (psia)

Figure 5.1.5 Case 3 - RWST Mass Flow (lbm/s)

Figure 5.1-6 Case 3 - Rod Temperatures (F)

Figure 5.1.7 Case 3 - RWST Flow Path Fraction Open

Figure 5.1-8 Case 3 - Pressurizer and RWST Liquid Levels (ft)

Figure 5.1-9 Case 3 - SRV Manifold Mass Flow (lbm/s)

Figure 5.1-10 Case 3 - Surge Line Mass Flow (lbm/s)

Figure 5.1-11 Case 3 - Containment Vapor Temperatures (F)

Figure 5.1-12 Case 3 - Containment Pressures (psia)

Figure 5.1-13 Impact of Delayed Injection - Pressurizer Pressure (psia)

Figure 5.1-14 Impact of Delayed Injection - SRV Manifold Flow Velocity (ft/s)

Figure 5.1-15 Impact of Delayed Injection - RWST Mass Flow (lbm/s)

Figure 5.1-16 Case 3 - Hot Leg C and Pressurizer Vapor Temperatures (F)

Figure 5.1-17 Base Cases - RWST Flow Path Fraction Open

Table 5.1-1 - Summary of Cases Analyzed

Initial Decay Heat (MW)	Base Cases Cold Leg Injection 1 Press. SRV Removed	No Injection 1 Press. SRV Removed	Cold Leg Injection 3 Press. SRVs Removed	Delayed Cold Leg Injection		
				1 Pressurizer SRV Removed		3 Pressurizer SRVs Removed
				Rods>620°F	Rods>980°F	Rods>620°F Rods>980°F
15.8	Case 1	Case 6	Case 11	-	-	-
13.23	Case 2	Case 7	Case 12	Case 16	Case 17	Case 23 Case 24
10.0	Case 3	Case 8	Case 13	Case 18	Case 19	-
7.0	Case 4	Case 9	Case 14	Case 20	Case 21	-
6.0	-	-	Case 15	-	-	-
5.0	Case 5	Case 10	-	-	Case 22	-

**Table 5.1-2 - Base Case Results. Cold Leg Injection after 30 minutes,
1 Pressurizer SRV Removed.**

Case	Initial Decay Heat (MW)	Core Damage (Rods>1340°F) (hours)	Containment End-Time Pressure (psia)	Containment End-Time Temperatures (°F)	RWST End-Time Level* (ft)	RWST End-Time Inventory (US gal.)
1	15.8	5.25	18.3	122-174	69.9	243,700
2	13.23	5.69	18.0	120-169	70.4	248,000
3	10.0	8.39	18.1	122-169	68.2	229,800
4	7.0	15.3	20.0	136-174	67.9	227,100
5	5.0	23.52	19.0	133-165	62.8	183,700

* Reference = bottom of vessel: mid-loop = 26.54ft, top of pressurizer = 76.31ft.

Table 5.1.3 - No Injection, 1 Pressurizer SRV Removed

Case	Initial Decay Heat (MW)	Core Damage (Rods > 1340°F) (hours)	Containment End-Time Pressure (psia)	Containment End-Time Temperatures (°F)	RWST End-Time Level* (ft)	RWST End-Time Inventory (US gal.)
6	15.8	0.85	16.2	104-162	86.8	387,200
7	13.23	1.36	16.2	106-154	"	"
8	10.0	1.89	16.9	108-162	"	"
9	7.0	3.33	17.0	109-158	"	"
10	5.0	4.87	16.6	109-149	"	"

* Reference = bottom of vessel: mid-loop = 26.54ft, top of pressurizer = 76.31ft.

**Table 5.1-4 - Cold Leg Injection after 30 minutes,
3 Pressurizer SRVs Removed.**

Case	Initial Decay Heat (MW)	Core Damage (Rods>1340°F) (hours)	Containment End-Time Pressure (psia)	Containment End-Time Temperatures (°F)	RWST End-Time Level* (ft)	RWST End-Time Inventory (US gal.)
11	15.8	6.85	17.6	122-149	61.7	174,200
12	13.23	8.24	17.6	122-151	60.8	166,300
13	10.0	11.82	17.7	125-154	58.1	143,500
14	7.0	17.48	20.1	138-174	63.6	190,000
15	6.0	23.5	19.8	136-171	58.2	144,700

* Reference = bottom of vessel: mid-loop = 26.54ft, top of pressurizer = 76.31ft.

**Table 5.1-5 - Effect of Delayed Cold Leg Injection,
1 Pressurizer SRV Removed.**

Case	Initial Decay Heat (MW)	Cold Leg Injection Begins		Core Damage (Rods > 1340°F) (hours)	Base Case Core Damage Time (hours)
		Time After Loss of RHR (minutes)	At Peak Rod Temperature (°F)		
16	13.23	40	620	5.26	5.69
17		50	980	1.41	
18	10.0	58	620	7.68	8.39
19		79	980	7.94	
20	7.0	102	620	15.49	15.3
21		143	980	15.98	
22	5.0	220	980	24+	23.5

3 Pressurizer SRVs Removed.

Case	Initial Decay Heat (MW)	Cold Leg Injection Begins		Core Damage (Rods > 1340°F) (hours)	Base Case (12) Core Damage Time (hours)
		Time After Loss of RHR (minutes)	At Peak Rod Temperature (°F)		
23	13.23	41	620	7.92	8.24
24		54	980	7.82	

5.2 Primary Feed and Spill

5.2.1 Introduction

During mid-loop operation, the RCS is often isolated so that the reflux cooling mode of heat transfer to the steam generators is not available following a loss of RHR capability. If RCS venting is inadequate, the RCS could be pressurized once boiling occurs in the core region. Pressurization could prevent the makeup of water inventory via gravity feed from the RWST, as discussed in Section 5.1. In this situation, interim cooling could be provided by the feed and spill operation.

In this section, we examine the feasibility of the feed-and-spill mode of heat transfer. The thermal-hydraulic behavior in the RCS is analyzed under various levels of decay power. Four cases are considered:

Case 1.

Bleed only. The RCS bleeding is provided by the vessel head vent and the two pressurizer PORVs. The vent paths are connected to the pressure relief tank. This is the base case which provides the basic thermal-hydraulic conditions if makeup of coolant is not available.

Case 2.

Bleed only. This case is the same as Case 1, but assumes that only one pressurizer PORV is open to evaluate the effect of higher pressurization.

Case 3.

Bleed only. This case is the same as Case 1, but assumes that the 3 SRVs are removed so that the RCS is considerably depressurized.

Case 4.

Feed-and-spill. This case considers the forced coolant makeup to the RCS and spillage via the open PORVs or removed SRVs at a rate high enough to suppress core boiling.

The RCS configuration considered includes the reactor pressure vessel (RPV), the pressurizer (PZR), and the pressure relief tank (PRT). The configuration assumes that 1) RCS is intact, 2) all loop-stop valves are closed, and 3) the RHR system is isolated. Most of the geometric data of the RCS used in the analysis are from the MELCOR input deck prepared for the Surry plant, but part are from References [5,6,7]. Figure 5.2-1 is a diagram of the RCS.

5.2.2 Analysis

The analysis considers a parametric study involving variations of the level of decay power over the first 29 days after shutdown. These decay powers are modified from the ANS - 5.1 1979 decay-heat curve and were used in reference [6], except that at 29 days which is reduced to reflect the replacement of 1/3 of the fuel rods by fresh rods. These decay power levels are slightly higher than that used in MELCOR as reported in Section 5.1. The parametric study assumes an initial water temperatures of 100°F for each decay-power level, which is lower than the 140°F assumed in Reference [5].

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The basic assumptions of the analysis are summarized below:

- (1) The quantity of water involved in heatup and boiling is an important parameter in the analysis. It is assumed in Reference [6] that the effective water volume for initial heatup consists of core volume, the section of upper plenum below the mid-loop level, and one-third of the hot leg. Once boiling occurs, convective forces will promote good mixing in the reactor vessel. Hence, water in the downcomer and the baffle/barrel regions are available for the boil-off calculation^[6]. In the present analysis, similar assumptions are adopted for the estimate of effective water volume for heatup. Furthermore, for the case of feeding, all water in the RCS, including the amount of water injected into the core, are included in the heatup calculation.
- (2) The two pressurizer PORVs and the vessel head vent are assumed as the venting paths. In estimating the vent flow, we assumed that the flow rate through the PORVs is controlled by the valve's orifice. The effective flow area of each PORV is 0.01485 ft² as given in Reference [6]. A maximum flow rate of 210,000 lb/hr at 2350 psia [7] is used to obtain the ratio of the choked flow rate at lower pressures. The flow rate is determined by the smaller of the two calculations^[8]:

$$\text{Choked Flow: } W = 2 \times (210,000/60) \sqrt{\frac{P_1 \rho}{2350 \times 6.849}}$$

$$\text{Unchoked Flow: } W = 5778 \times 0.583A \sqrt{\rho(P_1 - P_2)}$$

where W = flow rate, lbm/min

A = PORV valve orifice area, ft²

P_1 = pressurizer pressure, psia

P_2 = pressure relief tank pressure, psia

ρ = fluid density in pressurizer, lbm/ft³

6.849 = saturated steam density at 2350 psia

5778 = unit conversion factor

0.583 = orifice discharge coefficient

For the reactor vessel head vent, it is assumed that the flow rate is controlled by the long tube connecting the head vent to the pressurizer release line. The tube is 0.75 inches in diameter with an assumed length of 100 ft. The flow rate is estimated by the smaller of the two calculations^[8]:

$$\text{Choked Flow: } W = 2798A \sqrt{P_1 \rho}$$

where W = flow rate, lbm/min

A = vent tube area, ft²

P_1 = reactor vessel pressure, psia

$$\text{Unchoked Flow: } W = 5778A \sqrt{\rho(P_1 - P_2) \frac{D}{L} \cdot \frac{1}{f}}$$

- ρ = fluid density in upper plenum, lbm/ft³
 P_2 = pressure in PRT, psia
 D/L = diameter/length ratio of the vent tube
 f = friction coefficient, assumed to be 0.04.

It is further assumed that the tygon tube of the vent line would fail when the pressure in the reactor vessel reaches 40 psia. After the rupture, the flow rate is estimated by the orifice flow correlation, similar to that used for the PORVs.

In addition to the above two venting paths, the impact of the removal of the three SRVs was considered. The size of each SRVs is 4 inches. The PRT is not included in the analysis when the SRVs are removed, because the pressurizer would be depressurized to nearly atmospheric pressure.

- (3) Both the steam and nitrogen are assumed to follow the ideal gas law. The gases are in thermal equilibrium with the water pool. After the start of boiling, the gases are at the steam saturation temperature.
- (4) In computing the water heatup and boiling, we considered only the heat capacities of water and fuel rods. Steel structures in the reactor vessel, hot leg, and pressurizer were not included. This assumption is conservative with respect to the timing of core uncover. The mass of fuel rods, i.e. 175,000 lbm of UO₂ and 36,300 lbm of Zr, was obtained from the MELCOR input data prepared for the Surry plant. The heat-capacity correlations given for UO₂ and Zr by the MELCOR code [2] were used.
- (5) The PRT volume is 1300 ft³ and it is assumed that 70% of the tank is occupied by water (i.e. 910 ft³) at 120° F. Neither the water volume nor temperature was varied in the parametric study. Gases in the relief tank are released through a 0.75 -inch diameter tube of 100 feet long to the outside of the containment. The rupture disk of the PRT is assumed to fail at 100 psia. It is assumed that gases and water released from the PORVs will enter the PRT even after the rupture of the tygon tube which is connected to the release line.
- (6) The feed capacity is determined by the decay power level and the water is at 60° F. The feed capacity represents a minimum requirement to maintain the RCS water temperature at about 200°F. The water temperature is that assumed for the RWST. The capacity and water temperature of the feed flow were not included in the parametric study.
- (7) Core damage is defined as the initiation of cladding failure. A limited MELCOR calculation shows that failure is likely to occur when the water level in the core region is reduced to about 2.5 ft above the bottom of the core. However, the Virginia Power Company (VPC)[6] assumes that the time of core damage generally corresponds to a water level at about 3.5 ft above the bottom of the core. This level represents the criterion of inadequate core cooling used in the development of the Westinghouse Emergency Response Guidelines (ERGs). Because the Westinghouse criterion is more conservative than the MELCOR calculation we used in the present study.

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- (8) The fuel rods and core are divided into 10 axial nodes. The power factors of the 10 nodes, from the top to the bottom of the fuel, are 0.7, 0.9, 1.05, 1.15, 1.2, 1.2, 1.15, 1.05, 0.9, and 0.7 (obtained from the MELCOR input data for Surry). The axial power distribution determines the boiling rate of the water after uncover of the core. It is assumed that only the fraction of decay power associated with nodes in the region covered by water contributes to the heating and boiling. The fraction of decay power associated with nodes in the uncovered region contributes to the heating of steam and nitrogen, which affects the pressurization in the RCS.

5.2.3 Discussion of Results

Case 1

This is the base-case in which only RCS bleeding is assumed, provided by the two PORVs in the pressurizer and the reactor head vent. Twenty nine cases with different levels of decay power were analyzed. The results summarized in Table 5.2-1 show the following:

- (1) Depending on the level of decay power, boiling in the core region could start from about 12 to 55 minutes. The boiling time predicted in this analysis is longer than that predicted by the VPC^[6]. For example, the boiling time for the first 3 days after shutdown are 4.6, 5.6, and 6.4 minutes according to the VPC, and are 12, 15, and 16 minutes in this analysis. This is caused by differences in modeling and initial conditions. The VPC assumed an initial water temperature of 140°F and used all the decay power for heating water in the core region. In this analysis, the initial water temperature was 100°F, and the decay power was used to heat the water in the core region and the fuel mass.
- (2) The generation of steam following the loss of RHR pressurizes the RCS and causes the tygon tube in the head vent path to fail at about 18 to 89 minutes, depending on the level of decay power. The failure of the tygon tube releases radioactive gases directly into the containment.
- (3) Continued pressurization eventually raises the RCS pressure to 165 psia, which is the LHSI shutoff point. The time to reach 165 psia varies from 33 to 352 minutes (Table 5.2-1). Beyond this time, the low head pumps are unable to inject water into the RCS and the high head pumps must be used.
- (4) Times for core uncover vary from about 101 to 394 minutes, and for core damage from about 180 to 839 minutes. The latter is comparable to that predicted by the MELCOR analysis. For example, MELCOR shows that cladding failure occurs at about 100, 140 and 230 minutes after core uncover for decay-power levels at 1, 3, and 10 days after shutdown, respectively. In this analysis, core damage occurs at about 80, 112, and 187 minutes after core uncover for the three corresponding levels of decay power. MELCOR predicts cladding failure when the water level is reduced to about 2.5 ft above the bottom of the core, but in this analysis, damage is assumed when the water level is at 3.5 ft above the bottom. Furthermore, MELCOR uses a slightly lower decay power correlation, as stated in Section 5.2.2.
- (5) The time to core damage predicted by this analysis is considerably longer than that predicted by the VPC^[6]. For example, the VPC predicted core damage time is about 100 minutes for the decay power level at 5 days after shutdown. The corresponding value we predicted is about 300 minutes. The difference is caused mainly by the decay power used for the water boiloff calculation. Our analysis used only the fraction of total decay power which is associated with fuel nodes in the water-covered region

to calculate the water boiloff; the VPC considers the total decay power for water boiloff even if the core is uncovered and a large section of the fuel rod is not in the water region.

- (6) As pressure is built up in the RCS, nitrogen is forced to flow through the PORVs into the pressure relief tank (PRT). Nitrogen will pass through the water pool, enter the upper gas region, and be released through the relief valve to the outside of the containment. However, when boiling occurs in the core region, steam is released into the PRT and condenses in the water pool. Condensation causes a rapid increase of the pool's temperature. As soon as the pool reaches saturation, the generation of steam yields a pressure spike in the PRT which fails the rupture disk at 100 psia, causing a direct release of steam into the containment. The failure time of the PRT rupture disk varies from 45 to 129 minutes (Table 5.2-1). In many cases, the PRT fails after the RCS pressure has reached 165 psia because of a large pressure drop across the PORV orifice as the flow is choked under the critical flow condition.

The RCS pressurization is shown in Figures 5.2-2 to 5.2-4 for three representative cases (1, 2, and 29 days after shutdown). With the opening of two PORVs and the failure of the tygon tube, the peak pressures in the RCS are below the setpoint of the RHR suction relief valve (615 psia). Thus, the high head pumps could be used before the core is damaged to initiate the feed-and-spill operation for core cooling.

Case 2

This case is the same as Case 1, but assumes that only one PORV in the pressurizer is open; this greatly reduces the venting capacity and increases the pressurization in the RCS. The results are summarized in Table 5.2-2, and some representative graphs are shown in Figures 5.2-5 to 5.2-7. In general, times of boiling, tygon tube failure, core uncover, and core damage are similar to that of Case 1, in which two PORVs are open. However, the limited venting capacity of one PORV results in a more rapid pressurization in the RCS. The RCS pressure reaches 165 psia much sooner than in Case 1. Hence, the operators would have less time to initiate the LHSI for coolant makeup. The results also show that the RCS pressure could reach the setpoint of the RHR suction relief valve (615 psia) at about 75 and 145 minutes, respectively, for decay powers at 1 and 2 days after shutdown. Thus a late restoration of the LHSI pumps may not be able to provide core injection during the first two days after shutdown if only one PORV is available for venting.

Case 3

This case is the same as Case 1, but assumes that three SRVs are removed. The diameter of each SRV is 4 inches and the total area is 0.2618 ft². With such an opening in the pressurizer, the RCS is largely depressurized. The low RCS pressure implies a relatively low saturation temperature, hence, water boiling and core damage occur sooner (Table 5.2-3). The low RCS pressure due to the removal of three SRVs would allow the actuation of the LHSI system if the feed-and-spill operation is required.

Case 4

This case involves the feed-and-spill operation recommended by the Virginia Power Company^[6]. It was assumed that water can be provided by the RWST at a temperature of 60°F. The water injection rate is determined by the level of decay power so that the RCS water temperature is limited to about 200°F. The selection of 200°F ensures that 1) sub-cooled water is maintained in the RCS to suppress any boiling, and 2) there will be no flashing when water is spilled into the containment, so that containment sprays are not needed

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to condense the steam. As the RCS is filled with water, the system has to be pressurized to spill out the same amount of water added to the core to remove the decay heat. The required system pressures for spillage through PORVs and the upper head vent are summarized in Table 5.2-4. In computing the system pressure, the orifice discharge coefficient was adjusted from 0.583 to 0.443 (See assumption 2 in Section 5.2.2) so that the flow equation used in the BNL analysis is equivalent to that used in the VPC report^[6] with a loss coefficient of 5. We note that the assumed loss coefficient of 5 is probably too high, and the predicted pressure differentials are too conservative.

From Table 5.2-4, the following observations can be made:

- (1) The RCS pressure was less than the LHSI shutoff head (165 psia) for most cases, except for those cases during the first four days with only 1 PORV available for spillage. Hence, the LHSI can be used for feed-and-spill for times greater than the first four days when only one PORV is open.
- (2) For the first six days after shutdown, the required flow rates to suppress boiling are more than 440 gpm, which exceed the capacity of the HHSI pumps. According to the VPC report^[6], the HHSI delivery capacity is about 400 to 434 gpm if the RCS pressure is between 335 and 29 psia. Therefore, two HHSI pumps are required for the feed-and-spill operation for the first six days after shutdown if the LHSI is not available.
- (3) All feed-and-spill operations using the LHSI pumps must be initiated early during the accident, i.e., before boiling or core uncover. As shown in Tables 5.2-1 and 5.2-2, steam generation rapidly pressurizes the RCS and prevents the coolant injection using the low head pumps. The RCS pressures needed to deliver the required flow rates are very close to those given by the VPC^[6]. The comparison is illustrated below:

SOURCE	1 HHSI Pump		1 LHSI Pump	
No. of PORVs	1	2	1	2
Required Decay Times, Hours				
VPC	138	129	107	13
BNL	144	144	120	24

Note that the results of the VPC analysis is based on hours, but the BNL analysis starts from the first day after shutdown and uses days as the time increment. There was no analysis for decay times earlier than 24 hours. The BNL estimated 144 hours (6 days) could be 138 hours (5.75 days), or 129 hours (5.375 days). The BNL estimated 24 hours (1 day) could be 13 hours.

The VPC also reported that the high head injection flow can be throttled from the Surry control room, but the low-head injection flow is much more difficult to control. Therefore, operators might attempt to use the full capacity of the LHSI pumps. At low pressures, the full capacity of the LHSI pump is about 2000 gpm, which could exceed the critical flow rate. For example, at 42 psia, the VPC LHSI flow rate is 2250 gpm^[5] and the critical flow rate, based on 1 PORV, is about 1900 gpm. (The critical flow rate was estimated using functions given in the RETRAN-02 code^[9].) Thus, the critical flow condition could limit the feed-and-spill operation using the full capacity of the LHSI pump at low pressures. At higher pressures (above 78 psia), the critical flow rate is above 2000 gpm, based on 1 PORV, and the low head pump delivery capacity is below 2000 gpm. Hence, the critical flow condition would not limit the feed-and-spill operation at higher pressures if the full capacity of the low head pump is used.

The computed times of filling the RCS and depleting the RWST are summarized in Table 5.2-5. It is noted that:

- (1) The RCS will be filled within 0.7 to 3.4 hours depending on the decay time. Although filling of the RCS will rupture the tygon tube, most of the water spilled out of the PORVs is expected to enter the PRT. Since 70% of the PRT is originally filled with water under normal operation conditions, its gas volume is only about 390 ft. With a spillage rate from 784 to 167 gpm (Table 5.2-5), this volume would be quickly filled up within 37 to 178 minutes. Filling of the PRT will cause the rupture disk to fail, and spilling water on the containment floor.
- (2) For the first 22 days after shutdown, the RWST will be depleted within 24 hours when the feed-and-spill operation is applied. (Depletion of the RWST occurs when 100% of the water has been used.) Thus, either re-circulation or cross connection to the other unit's RWST is needed to provide continuous cooling for 24 hours. However, re-circulation is necessary for the first three days, because water provided by the other unit's RWST would not be sufficient for 24 hours of continuous cooling.
- (3) For feed-and-spill operations applied after 22 days, water from one RWST is sufficient to provide continuous cooling for at least 24 hours. Neither re-circulation nor a cross connection to the other unit's RWST is needed.
- (4) MELCOR analysis shows that saturated water spilled out of the pressurizer and collected in the cavity and basement areas could be cooled to about 140°F by losing heat to the surroundings. Recirculation of this hot water may not provide sufficient core cooling unless the flow rate is increased significantly over that for feed-and spill operation. A large flow rate could increase the RCS pressure above the LHSI shutoff head. Thus, the heat exchanger in the recirculation spray system seems to be necessary to remove heat from the water pool in the containment. This finding implies that the recirculation spray must be available for a successful feed-and-spill operation under the recirculation mode.
- (5) In the event of no recirculation and no cross-tie for the first 22 days, the termination of feed due to the depletion of the RWST will eventually lead to core damage. A simplified model was developed to estimate the times at which water boiling, core uncover, and core damage would occur after the depletion of the RWST. The model assumes that steam generated in the core will rise to the top of the reactor vessel and expel water out of the pressurizer PORVs, which, in turn will reduce the RCS water inventory. As the water level is decreased to the hot-leg level, the release of water stops and steam is released directly out of the PORVs. These estimates are included in Table 5.2-5, in which

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the opening of two PORVs is assumed. It appears that core damage is unlikely to occur within 24 hours for accidents initiated after 10 days following plant shutdown.

Finally, the feed-and-steam operation could be considered as an alternate method of core cooling. Table 5.2-4 shows that for the first five days after shutdown, the high injection rate needed for the feed-and-spill operation requires two HHSI pumps if i) only one PORV is open, or ii) two PORVs are open but the LHSI is unavailable. Thus, the feed-and-spill operation will not be feasible for the first five days if only one HHSI pump is available. Then, core cooling could be provided by feed-and-steam because the injection rate needed for removing the decay power is very small and one HHSI pump is sufficient to cool the core. An analysis made for the first five days after shutdown and summarized in Table 5.2-6 shows that using the latent heat of water to remove the decay power reduces the injection rate considerably. At the end of 24 hours, only a 1/3 to 1/4 of the RWST water was used. Thus, recirculation or a RWST cross-tie should not be necessary for the feed-and-steam operation. Another advantage of this operation is that it can be implemented under the recirculation mode after the depletion of the RWST following the feed-and-spill operation. Since the feed-and-steam operation is based on saturated water, the operation does not require the heat exchanger of the recirculation spray system.

5.2.4 Summary

A preliminary analysis was made of feed-and-spill cooling during a mid-loop operation covering a wide range of decay power levels. The results show the following:

- (1) For the case of no feed, the loss of RHR will lead to core boiling, RCS pressurization, failure of the tygon tube, core uncover, and eventually core damage. The timing of these events are summarized in Tables 5.2-1. to 5.2-3. The Virginia Power Company⁽⁶⁾ also presented the times of core boiling and core damage at various decay times. Those results differ from the BNL results due to differences in modeling and initial conditions. In general, the BNL analysis provides a more realistic estimation because the VPC analysis made some conservative assumptions.
- (2) For the case of no feed and with the opening of 1 or 2 PORVs, RCS pressurization could rupture the tygon tube in about 18 to 90 minutes, depending on the level of decay heat.
- (3) For the case of no feed and with the opening of 1 or 2 PORVs, core damage could occur from 178 to 847 minutes depending on the level of decay heat. The core damage times predicted by BNL are comparable to those predicted by the MELCOR code, but are much longer than those given by the VPC.
- (4) For the case of no feed and with the opening of 1 or 2 PORVs, the RCS pressure would eventually reach the LHSI shutoff point (165 psia) at about 35 to 352 minutes (except for the case of 29 days after shutdown with 2 open PORVs). Above this shutoff point, the low-head pumps will not be able to initiate the feed-and-spill operation.
- (5) For the case of no feed and with the opening of both PORVs, the predicted RCS pressures for all the 29 decay levels are less than the setpoint of the RHR suction relief valve (615 psia). Thus, the high-head pumps could provide the feed-and-spill operation. However, with the opening of only one

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PORV, the RCS pressure could reach the 615 psia level at about 75 and 145 minutes for decay times at 1 and 2 days, respectively. Then, the high-head pumps could not provide core injection.

- (6) The removal of the SRVs has no significant effect on the timing of boiling and core damage. The low RCS pressure will permit the initiation of the LHSI for all the 29 decay heat levels.
- (7) For the feed-and-spill operation, the required minimum injection rates for all the 29 decay times were determined based on the consideration of removal of decay heat and the maintenance of a subcooled water in the core region. The BNL estimates are comparable to that given by the VPC. For the first 5 days after shutdown, the required minimum flow rates exceed the capacity of the high head pump. Either two high head pumps or a low head pump is required for the first six days.
- (8) For the feed-and-spill operation, the BNL estimates of the RCS pressure heads needed to spill out the required injection flow for all the 29 decay heat levels are very close to those given by the VPC, as shown below:

SOURCE	1 HHSI Pump		1 LHSI Pump	
No. of PORVs	1	2	1	2
Required Decay Times, Hours				
VPC	138	129	107	13
BNL	144	144	120	24

- (9) For the feed-and-spill operation, the times to fill up the RCS for all the 29 decay times varies from 0.7 to 3.4 hours. It is assumed that after the RCS is filled, water spilled from the PORVs will enter the PRT, which, in turn, would cause the PRT rupture disk to fail.
- (10) For the feed-and-spill operation, the times of depleting the RWST were estimated for all the 29 days. For the first 22 days after shutdown, the RWST will be depleted within 24 hours. Core damage is likely to occur within 24 hours for the first 10 days if coolant is not added after the RWST is depleted. After the first 10 days, water remaining in the RCS can maintain sufficient core cooling for 24 hours.
- (11) Either re-circulation or cross connection to the RWST of the other unit is needed for the first 10 days to maintain continuous core cooling for 24 hours. According to the MELCOR analysis, the heat exchanger in the recirculation spray system is needed to remove heat from the water pool in the containment. Thus, the success of feed-and-spill operation under the recirculation mode requires the availability of the recirculation spray system.
- (12) During the first three days, recirculation is necessary because the large injection rates required can deplete the two RWSTs within 24 hours.

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- (13) Feed-and-steam could be used for the first five days after shutdown if only one HHSI pump is available. RWST water is sufficient to provide core cooling for more than 24 hours. If the feed-and-steam operation is implemented later during the recirculation mode following the feed-and-spill operation, the heat exchanger of the recirculation spray system is not needed. Because of the High RCS pressure due to steam generation, the LHSI pumps cannot be used for this operation unless the SRVs are removed. The fine control of the RCS makeup flow during this operation also presents an operational challenge as reported by the VPC^[6].

Figure 5.2-1 Diagram of RCS and Pressurizer

SURRY/MID-LOOP/LOSS OF RHR/ BLEED ONLY/ SRV CLOSED/ 2 PORVs OPEN

DECAY TIME - 1 DAY, INITIAL WATER TEMPERATURE-100F

Figure 5.2-2 PRV Pressure at Decay Time of 1 Day and with the Opening of 2 PORVs

SURRY/MID-LOOP/LOSS OF RHR/ BLEED ONLY/ SRV CLOSED/ 2 PORVs OPEN

DECAY TIME - 2 DAY, INITIAL WATER TEMPERATURE-100F

Figure 5.2-3 PRV Pressure at Decay Time of 2 Days and with the Opening of 2 PORVs

SURRY/MID-LOOP/LOSS OF RHR/ BLEED ONLY/ SRV CLOSED/ 2 PORVs OPEN

DECAY TIME - 29 DAY, INITIAL WATER TEMPERATURE-100F

Figure 5.2-4 PRV Pressure at Decay Time of 29 Days and with the Opening of 2 PORVs

Figure 5.2-5 PRV Pressure at Decay Time of 1 Day and with the Opening of 1 PORV

Figure 5.2-6 PRV Pressure at Decay Time of 2 Days and with the Opening of 1 PORV

SURRY/MID-LOOP/LOSS OF RHR/ BLEED ONLY/ SRV CLOSED/ 1 PORV OPEN

DECAY TIME - 29 DAY, INITIAL WATER TEMPERATURE-100F

Figure 5.2-7 PRV Pressure at Decay Time of 29 days and with the Opening of 1 PORV

Table 5.2-1 Summary of Case 1 (Bleed Only-2 PORVS Open-SRV Closed)

TIME, MINUTES							
DAYS	BOILING	TYGON TUBE RUPTURE	RCS AT 165 PSTA	CORE UN- COVERY	CORE DAMAGE	RCS AT 615 PSIA	PRT FAILURE
1	12	18	33	101	180	-	45
2	15	23	41	120	219	-	51
3	16	26	50	133	245	-	55
4	18	28	56	145	271	-	59
5	20	31	63	157	297	-	63
6	21	32	65	166	316	-	65
7	22	33	85	175	336	-	68
8	23	37	105	182	353	-	70
9	25	38	123	190	369	-	73
10	26	39	209	197	384	-	74
11	26	42	221	203	398	-	76
12	27	43	227	209	411	-	76
13	28	45	232	214	421	-	79
14	29	45	239	219	432	-	81
15	29	46	251	224	443	-	82
16	30	47	260	229	455	-	84
17	31	49	267	235	468	-	85
18	32	51	280	239	479	-	86
19	32	49	287	243	488	-	87
20	33	53	293	247	496	-	89
21	34	53	308	251	506	-	90
22	34	55	308	256	516	-	91
23	35	55	322	260	526	-	92
24	35	57	327	263	532	-	93
25	36	56	332	265	538	-	94
26	36	55	343	268	544	-	94
27	37	58	350	270	550	-	95

Table 5.2-1 (continued)

TIME, MINUTES							
DAYS	BOILING	TYGON TUBE RUPTURE	RCS AT 165 PSTA	CORE UN- COVERY	CORE DAMAGE	RCS AT 615 PSIA	PRT FAILURE
28	37	59	352	273	557	-	96
29	55	89	-	394	839	-	129

Table 5.2-2 Summary of Case 2 (Bleed Only-1 PORV Open-SRV Closed)

TIME, MINUTES							
DAYS	BOILING	TYGON TUBE RUPTURE	RCS AT 165 PSTA	CORE UN- COVERY	CORE DAMAGE	RCS AT 615 PSIA	PRT FAILURE
1	12	19	35	107	178	75	50
2	15	23	43	129	217	145	56
3	17	26	49	142	242	-	60
4	18	28	54	155	269	-	64
5	20	31	60	177	314	-	71
6	21	32	63	177	314	-	71
7	22	35	72	188	335	-	74
8	23	35	74	195	351	-	77
9	25	39	78	204	368	-	79
10	26	37	81	211	383	-	81
11	26	41	83	217	397	-	83
12	27	43	89	224	410	-	85
13	28	44	94	229	421	-	87
14	29	45	97	234	432	-	88
15	29	44	90	239	443	-	90
16	30	47	97	245	456	-	84
17	31	49	94	251	469	-	94
18	32	49	95	256	479	-	95
19	32	52	96	260	488	-	96
20	33	52	98	265	497	-	98
21	34	52	99	269	507	-	99
22	34	55	130	274	517	-	100
23	35	55	102	279	528	-	102
24	35	56	103	282	534	-	103
25	36	55	104	285	540	-	104
26	36	57	146	287	546	-	104
27	37	57	105	290	553	-	105

Table 5.2-2 (continued)

TIME, MINUTES							
DAYS	BOILING	TYGON TUBE RUPTURE	RCS AT 165 PSTA	CORE UN- COVERY	CORE DAMAGE	RCS AT 615 PSIA	PRT FAILURE
28	37	90	147	424	847	-	144
29	55	90	144	424	847	-	144

Table 5.2-3 Summary of Case 3 (Bleed Only-SRVS & 2 PORVS Open)

TIME, MINUTES						
DAYS	BOILING	TYGON TUBE RUPTURE	RCS AT 165 PSTA	CORE UN- COVERY	CORE DAMAGE	RCS AT 615 PSIA
1	11	12	-	73	179	-
2	14	14	-	89	218	-
3	16	51	-	100	243	-
4	17	74	-	110	269	-
5	19	105	-	121	294	-
6	20	149	-	128	313	-
7	21	157	-	137	333	-
8	22	197	-	143	349	-
9	23	169	-	150	366	-
10	24	224	-	156	380	-
11	26	230	-	162	394	-
12	26	235	-	167	407	-
13	27	237	-	171	417	-
14	27	239	-	175	428	-
15	28	-	-	180	439	-
16	29	-	-	185	451	-
17	30	-	-	190	464	-
18	30	-	-	194	474	-
19	31	-	-	198	483	-
20	31	-	-	202	492	-
21	32	-	-	206	505	-
22	33	-	-	210	512	-
23	33	-	-	214	522	-
24	34	-	-	217	529	-
25	34	-	-	219	534	-
26	34	-	-	221	540	-

Table 5.2-3 (continued)

TIME, MINUTES						
DAYS	BOILING	TYGON TUBE RUPTURE	RCS AT 165 PSTA	CORE UN- COVERY	CORE DAMAGE	RCS AT 615 PSIA
27	35	-	-	224	546	-
28	35	-	-	226	553	-
29	53	-	-	343	839	-

Table-5.2-4 RCS Pressure for the Feed and Spill Operation

DAYS	MW	GPM	DP, psi			
			1 PORV	2 PORV	1 PORV AND UPPER HEAD VENT	2 PORV AND UPPER HEAD VENT
1	16.10	784	441	110	303	91.
2	13.23	644	298	74	205	61.
3	11.84	576	239	60	164	49.
4	10.72	522	196	49	134	40.
5	9.80	477	164	41	112	34.
6	9.22	449	145	36	99	30.
7	8.64	421	127	32	87	26.
8	8.26	402	116	29	80	24.
9	7.88	383	106	26	73	22.
10	7.58	369	98	24	67	20.
11	7.31	356	91	23	63	19.
12	7.09	345	85	21	59	18.
13	6.91	336	81	20	56	17.
14	6.74	328	77	19	53	16.
15	6.56	319	73	18	50	15.
16	6.39	311	69	17	48	14.
17	6.21	302	66	16	45	13.
18	6.08	296	63	16	43	13.
19	5.97	290	61	15	42	12.
20	5.85	285	58	15	40	12.
21	5.74	280	56	14	39	12.
22	5.63	274	54	13	36	11.
23	5.52	269	52	13	52	11.
24	5.45	265	51	13	35	10.
25	5.39	262	50	12	34	10.
26	5.34	260	48	12	33	10.
27	5.28	257	47	12	33	10.

Table 5.2-4 (continued)

DP, psi						
DAYS	MW	GPM	1 PORV	2 PORV	1 PORV AND UPPER HEAD VENT	2 PORV AND UPPER HEAD VENT
28	5.22	254	46	12	32	10.
29	3.44	167	20	5	14	4.

Table 5.2-5 RCS Fill Time and RWST Depletion Time (Time in Hours)

DAYS	MW	GPM	TIME TO FILL RCS	TIME TO DEplete RWST	WATER BOILING	CORE UN- COVERY	CORE DAMAGE
1	16.1	783.7	0.7	8.2	8.4	9.9	11.2
2	13.2	643.8	0.9	10.0	10.2	12.0	13.7
3	11.8	576.3	1.0	11.2	11.4	13.4	15.2
4	10.7	521.8	1.1	12.4	12.6	15.1	17.2
5	9.8	477.0	1.2	13.5	13.7	16.0	18.3
6	9.2	448.5	1.3	14.4	14.6	17.3	19.8
7	8.6	420.6	1.4	15.3	15.6	18.6	21.3
8	8.3	401.9	1.4	16.1	16.3	19.0	21.8
9	7.9	383.4	1.5	16.8	17.0	20.2	23.1
10	7.6	368.9	1.6	17.5	18.7	21.3	24.4
11	7.3	355.9	1.6	18.1	18.3	21.6	24.8
12	7.1	344.8	1.7	18.7	18.9	22.8	26.1
13	6.9	336.3	1.7	19.2	19.4	22.9	26.4
14	6.7	327.8	1.8	19.7	19.9	23.1	26.6
15	6.6	319.3	1.8	20.2	20.4	24.3	27.9
16	8.4	310.8	1.9	20.8	21.0	24.5	28.2
17	6.2	302.2	1.9	21.3	21.6	25.8	29.6
18	6.1	295.7	1.9	21.8	22.0	26.0	29.9
19	6.0	290.3	2.0	22.2	22.4	26.1	30.1
20	5.8	284.7	2.0	22.7	22.9	27.5	31.6
21	5.7	279.5	2.1	23.1	23.3	27.6	31.8
22	5.6	274.1	2.1	23.5	33.7	27.8	32.1
23	5.5	268.7	2.1	24.0	24.2	29.3	33.6
24	5.5	265.4	2.2	24.3	24.5	29.4	33.8
25	5.4	262.5	2.2	24.8	28.5	34.0	104
26	5.3	259.6	2.2	24.9	25.1	29.7	34.2
27	5.3	256.7	2.2	25.1	25.3	29.8	34.4

Table 5.2-5 (continued)

DAYS	MW	GPM	TIME TO FILL RCS	TIME TO DEplete RWST	WATER BOILING	CORE UN- COVERY	CORE DAMAGE
28	5.2	253.8	2.3	25.4	25.6	29.9	34.6
29	3.4	167.2	3.4	38.6	38.8	46.2	53.6

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Table 5.2-6

**Summary of Feed-and-Steam Operation
(Time in Minutes)**

Days	MW	Boiling Tygon Tube			PRT	% of RWST
		GPM Failure	GPM Failure	GPM Used*		
1	16.1	115	12.4	18.1	53.6	33
2	13.2	95	14.8	22.8	60.5	29
3	11.8	84	16.7	25.4	65.1	25
4	10.7	76	18.2	28.8	69.4	23
5	9.8	70	19.9	30.9	73.4	23

* % of RWST water used at the end of 24 hours

5.3 Reflux Cooling

Analyses of loss of RHR events show that the reflux condensation mode of cooling is a very effective way of removing heat from the system. Both INEL and Westinghouse analyzed the strategy of maintaining core cooling via this method. Their results are described in this section.

5.3.1 INEL Analysis

INEL performed detailed analyses of reflux condensation behavior during reduced inventory operations using the Piston Model [10] and the RELAP5/MOD3 code [11]. Of particular concern is the RCS pressure that would be reached in establishing a stable refluxing condition. If this pressure is too high, it may cause the failure of temporary closures such as nozzle dams or thimble tube seals, which could lead to a loss of inventory. High pressure may also prevent the initiation of gravity cooling via the RWST.

The principal assumption of the INEL Piston Model [10] is that the noncondensable gas is transported and compressed into the non-condensing section of the steam generators by steam produced in the core. The transport of noncondensable gas into a reduced volume by steam is similar to the effect of a piston compressing a gas in a cylinder. Based on this model, INEL made a detailed analysis of the thermal-hydraulic behavior in the reactor coolant system, pressurizer, and steam generator under various conditions, including the time after shutdown, RCS inventory, secondary pressure, number of active steam generators, and number of loops containing nozzle dams.

The analyses were performed for the H.B. Robinson plant, which is a 3-loop Westinghouse plant similar to the Surry plant as indicated by comparing the design features related to the reflux cooling mechanism:

	Surry	Robinson	Surry/Robinson ratio
Thermal Power, MW	2441	2200	1.11
Core Volume, ft ³	934	934	1.0
Core average power density, MW/ft ³	2.61	2.35	1.11
Steam generator volume, ft ³			
Primary side	1080	944	1.14
Secondary side	5868	4580	1.28

Because of their similarity, the results obtained for the Robinson plant should be applicable to the Surry plant. Since Surry uses stop valves rather than the nozzle dams to isolate the loops, high RCS pressure may not be a major concern for the Surry plant.

The basic assumptions of the Piston Model are given below:

- (1) The reactor coolant system is closed from the containment.
- (2) One or more of the steam generators is in wet layup, and nozzle dams may or may not be in place in one, but not all loops.
- (3) After boiling occurs in the core, steam expands into the primary coolant system and eventually reaches the steam generators.
- (4) Nitrogen or air above the RCS water level is swept out of the reactor vessel and is compressed into the steam generator tube and downstream spaces sufficiently to allow enough of the surface area of the steam generator tubes to cause the steam to condense.

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- (5) This condensate drains back into the hot leg and eventually into the reactor vessel. The transfer of heat into the secondary coolant causes the secondary temperature to gradually increase. The temperature and pressure of the primary vapor also increase with time.
- (6) Secondary coolant starts to boil and steam is released through a vent path. A pseudo-steady condition then prevails in which the primary pressure remains stable as long as there is sufficient secondary coolant to cover the condensing length of the tube.

The significant results from the INEL analysis are:

- (1) The final RCS pressure is relatively insensitive to the time after shutdown when the loss of RHR begins. The analysis covered four shutdown times, from 2 days to 30 days. The results show that the variation of RCS pressure is within 3 psi over the 30 days, as long as the noncondensable gas can be compressed into the steam generator.
- (2) The final RCS pressure is insensitive to the number of steam generators whose secondary sides are filled when nozzle dams are not installed. The RCS pressure is less than 45 psia over the range of 30 days in cases of one (without dams) and three steam generators. In the case of one steam generator available with two installed nozzle dam pairs, the final RCS pressure is increased to about 60 psia because a large mass of gas must be compressed into the one active steam generator.
- (3) The final RCS pressure is sensitive to the venting and feedwater supply capacities available to the steam generators. If a vent path is available and the secondary side of the steam generator is maintained at atmospheric pressure with continued feedwater-supply, the RCS pressure is below 45 psia. The RCS pressure could increase to above 75 psia if the secondary pressure is at 44 psia.
- (4) The RCS pressure is affected by the behavior of the pressurizer during the noncondensable compression phase. The Piston Model used in the analysis allows various assumptions to be made on the exchange of noncondensable gas between the pressurizer and RCS. Depending on the assumptions, the RCS pressure could increase by about 97% for one steam generator and by about 37% for three steam generators. Since the behavior of pressurizer has not been verified experimentally, the interpretation of the results must be cautious.

In addition to the Piston Model analysis, INEL also performed RELAP5/MOD3 calculations for the Robinson plant^[11]. A one-loop nodalization was used to simulate the isolation of the other two loops through the use of nozzle dams in the hot and cold leg piping. Two cases were analyzed for the mid-loop operation with decay power levels corresponding to one day and 7 days after shutdown. In both cases, the initial water temperature was at 90°F. The secondary side of the steam generator was started with water at 90°F, and upon the initiation of secondary boiling, a vent path was assumed to be available to maintain secondary pressure and temperature near atmospheric conditions. The addition of auxiliary feedwater also was assumed. The results show that a peak pressure of 41 psia occurred at about 117 minutes when the decay power is at the 1-day level. The peak pressure becomes 38 psia at about 200 minutes when the decay power is at the 7-day level. The study suggests that a relatively low pressure could be reached in the RCS when only one steam generator is available for reflux cooling.

In summary, INEL analyses using either the Piston Model or the RELAP5 code indicate that the RCS pressurization is mainly caused by the compression of air into the steam generator. Hence, the peak pressure in the RCS is relatively insensitive to the level of decay power. The initiation of boiling, and consequently, the time of reaching the peak pressure are simply delayed at lower decay powers. For the H. B. Robinson plant, the peak pressure is between 40 to 45 psia when only one steam generator is available; this is due to the high heat transfer used in the RELAP code and in the Piston Model, which is sufficient to remove the decay heat if feed water is provided to the steam generator and the secondary side is maintained at about atmospheric condition. Because of the similarity between the Robinson and Surry plants, reflux cooling using one steam generator should also be adequate for the Surry plant following the loss of RHR during a mid-loop operation.

5.3.2 Westinghouse Analysis

Westinghouse analyzed the effects of condensation on the RCS heatup and pressurization rates following the loss of RHR during a mid-loop operation^[3]. Seven analyses were performed, among which only two analyses were suitable for the Surry plant (3-loop plant) (The others are for Ginna (1-loop) and Diablo Canyon (4-loop)). The variable considered for the Surry plant was the number of steam generators available for steam condensation. The effect of time after shutdown was considered only for the 4-loop plant. The major concern of the analysis is the RCS pressurization which can be used to determine whether the RCS pressure can be maintained at a low level for a long time, and whether the operator has sufficient time to realign flow paths to provide gravity feed from the RWST and recover RCS inventory. Thus, the success of reflux cooling is evaluated as the number of steam generators required to maintain the RCS pressure below the RWST gravity feed pressure for an extended period.

The Westinghouse analyses used the computer program TREAT-NC, which is an interactive engineering simulation program based on first principles describing a two-component, two-phase system. It is assumed that the RCS initial pressure and temperature are 15 psia and 140° F, respectively. The initial water level in the secondary side of the steam generator is at 5% narrow range level, i.e. tubes covered. The only operator action required for the reflux cooling operation is to open the steam generator PORVs (if not open initially) to reduce the pressurization rate in the steam generator. The PORVs are assumed to be capable of relieving enough steam to match the generation of decay heat in the core.

The effects of the number of steam generators on RCS pressurization are summarized below (decay power at 48 hours):

NO. of S.G.	Time to 40 psia (min).	Long range stable pressure (psia)
0	20	Not reached
1	36	~80
2	57	50~60

Thus, increasing the number of steam generators available for condensation increases the time to reach 40 psia and decreases the quasi-stable pressure. For the decay power at the 48-hour level, two steam generators are required to maintain the RCS pressure at a relatively low level for a long time.

The effect of decay power for 48 and 120 hours on RCS pressurization was investigated for the Diablo Canyon (4-loop) plant. The results show that the smaller decay power yields a 12 minutes delay before RCS pressure reaches the typical RWST gravity feed limit of 40 psia when a steam generator is not available for condensation. The delay time is 15 and 36 minutes with one and four steam generators available, respectively. The effect of decay power on RCS peak pressure is reported only for the case in which four steam generators are available; the smaller decay power yields a peak pressure of about 44 psia, and the larger decay power 41 psia. The small difference in peak pressure agrees approximately with that predicted by the INEL analysis.

Based on the Westinghouse analysis, the Virginia Power Company recommended a criterion that the ratio of SGs to decay power should exceed 0.171 SG/MWt (or less than 5.85 MWt/SG). Based on this criterion, adequate reflux capability could be maintained so that the RCS is at a relatively low pressure level. The following number of steam generators are recommended for the Surry plant, if the reflux condensation is selected as a backup cooling method^[6]:

- (1) Three for decay times less than 75 hours,

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- (2) Two for decay times of 75 to 475 hours,
- (3) One for decay times greater than 475 hours.

To implement the reflux condensation, it is required that

- (1) the steam generator secondary side water level is greater than the 5% narrow range;
- (2) the AFW makeup capability is equivalent to a MD AFWP;
- (3) the secondary side of the steam generators is vented by opening the PORVs or steam dump to the condenser.

5.3.3 Summary and General Remarks

Both the INEL and Westinghouse analyses reveal that reflux condensation is an effective cooling method to maintain the RCS pressure at a relatively low level over a long period. However, implementation of reflux condensation must be cautious.

(1) The success of reflux cooling is based on the assumption of a closed system. According to the INEL and Westinghouse analyses, the peak pressure in the RCS is likely to reach 40 psia for the Surry plant. This pressure could rupture the tygon tubing along the upper head vent path and cause a direct loss of coolant inventory. For the Surry plant, the tygon tube is about 0.75-inch in diameter and the orifice of the vent valve is about 0.375 inches. With these small openings, the leakage rate of saturated steam at 40 psia is about 4 lbm/min. It would take about 190 hours to lose enough coolant to uncover the core. Therefore, the rupture of the tygon tube does not have a significant impact on reflux cooling.

(2) Reflux cooling also requires the closure of all pressurizer PORVs and SRVs during the mid-loop operation. Opening of a vent path has two effects on reflux cooling: a) there may not be an adequate temperature difference between the primary and secondary systems to promote heat transfer across the steam generator tubes; and b) a direct loss of coolant inventory may uncover the core. VPC^[6] showed that there is sufficient temperature difference to promote effective reflux cooling even with the opening of two PORVs. However, leakage from the PORVs will eventually lead to core uncover. BNL analysis shows that with only one PORV open, the uncover times are approximately 12, 10, and 8 hours for RCS pressures at 35, 40, and 45 psia, respectively. This interval should give operators sufficient time to initiate other alternate cooling methods.

(3) To implement reflux condensation, sufficient water should be provided to the secondary side of the steam generator so that the steam generator can be maintained as a heat sink. RELAP5 analyses^[10,11] indicate that the effective condensing length along the steam generator tubes is about 10 ft above the tube sheet; this may be considered as the minimum water level that must be maintained in the secondary side to provide an adequate reflux cooling. Assuming an initial water volume in each of the steam generator as 3582 ft³, BNL estimated the water boil-off time for 29 decay-power levels after shutdown (Table 5.3-1). The time to boil-off 75% of the water inventory corresponds approximately to the minimum water level needed to maintain an adequate reflux cooling. The operators have at least 10 hours to initiate alternate water supply to the secondary side of the steam generator.

(4) Both INEL and Westinghouse assumed that a nearly atmospheric condition in the secondary side of the steam generator should be maintained through proper venting. The Surry steam-generator relief system has five code safety relief valves (SRV) and one power-operated relief valve (PORV) for each steam generator. The PORV is expected to be used for removing decay heat in reflux cooling. Assuming the initial volumes of steam and water in each steam generator are 1977 and 3582 ft³, respectively, and the PORV size is 3.86 inches (MELCOR input), BNL analyses show that a quasi-steady state could be reached in about 500 minutes and the pressure in the secondary side is about 30 psia. The analyses are based on the criterion of 5 MW/SG as the capability for decay-heat removal. Although this pressure is about twice the atmospheric pressure, the higher pressure in the RCS could probably still have sufficient temperature difference between the primary and secondary systems for removing heat. Surry also is equipped with steam dump valves for extracting steam from steam generators to control heat removal from the RCS. The valves are situated in four groups of two and discharge to the main condenser. Based on the capacity of 4.256E6 lb/hr for the 8 valves, the size of each valve is computed as about 4 inches. Since the dump valve is larger than the PORV, the opening of the dump valves will be sufficient to depressurize the secondary side of the steam generator.

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Table 5.3-1 Steam Generator Secondary Water Boil-Off Time

(Time in Minutes)				
DAYS	MW	NO. OF SG	% of Water Boil-off	
			100%	75%
1	16.1	3	787.	611.
2	13.2	3	958.	743.
3	11.8	3	1070.	830.
4	10.7	2	788.	611.
5	9.8	2	862.	669.
6	9.2	2	917.	711.
7	8.6	2	978.	759.
8	8.3	2	1023.	794.
9	7.9	2	1073.	832.
10	7.6	2	1115.	865.
11	7.3	2	1156.	897.
12	7.1	2	1193.	925.
13	6.9	2	1223.	949.
14	6.7	2	1254.	973.
15	6.6	2	1288.	999.
16	6.4	2	1323.	1027.
17	6.2	2	1361.	1056.
18	6.1	2	1391.	1079.
19	8.0	2	1416.	1099.
20	5.8	2	1444.	1121.
21	5.7	1	736.	571.
22	5.6	1	750.	582.
23	5.5	1	765.	594.
24	5.5	1	775.	601.
25	5.4	1	783.	608.
26	5.3	1	792.	614.
27	5.3	1	801.	621.
28	5.2	1	810.	628.
29	3.4	1	1229.	954.

5.4 Summary of Results and Their Application to PRA Assumptions

In this section, the results of the previous sections are summarized and their use in the PRA analysis is described. This PRA study used a mission time of 24 hours; that is, it is assumed that if the operators can prevent core damage during the first 24 hours after an initiating event, then damage can be avoided due to the additional help that would become available. Thermal hydraulic calculations are used to determine the success criteria of the various systems or mitigation functions based on this mission time. In addition, the calculations determine the timing of the accident scenarios and the time available for the operators to perform the needed actions.

Table 5.4-1 summarizes the success criteria as a function of the decay heat. Table 5.4-2 summarizes the success criteria for the time windows and the timing of the important events that determine the time available for operator actions. Table 5.4-2 differs from Table 5.4-1 in the success criteria for feed-and-bleed; the latter shows the conservative success criteria based on Virginia Power technical report 865^[6] which is intended to maintain subcooling in the RCS to allow restoration of RHR. The success criteria in Table 5.4-2 are more realistic and were, therefore, used in the PRA analysis.

Gravity feed from RWST Gravity feed from the RWST is established by opening the low head injection flow path from the RWST to the RCS cold legs or hot legs. The RCS must be vented by removing the SVs on the pressurizer so that gravity flow can be established. Depending on the level of decay heat and the number of SVs removed, gravity feed may or may not provide 24 hours of cooling after the initiating event. The analysis documented in section 5.1 found that with 1 SV removed at approximately 32 days after shutdown (5MW decay heat), core damage was predicted to occur after 24 hours. Therefore, 32 days was chosen to be one of the boundaries between the time windows. In the PRA model, for an initiating event that takes place after 32 days after shutdown, gravity feed from the RWST assumed to be sufficient to terminate the accident. For accidents that start before 32 days after shutdown, gravity feed from the RWST would provide some additional time for operators to restore failed mitigation systems; this additional period for each time window is listed in Table 5.4-2. These times are the estimated delays in core damage based on the MELCOR modeling of gravity feed, and the amount of time that subcooling is maintained as estimated in attachment 9 of AP 27.00^[4]. Operator recovery using these times is modeled as recovery actions in the event-tree analysis. The time available for the operators to establish gravity feed is assumed to be the same as the time to core uncover.

Feed and Spill Section 5.2 documents the determination of success criteria for feed-and-spill operation; discussing both the Virginia Power Technical Report 865 and the BNL analysis. Table 5.4-1 summarizes the success criteria. The criteria are based on the Virginia Power Technical Report 865 which is the basis of AP 27.00. In AP 27.00, LHSI to the hot legs is the preferred method for feed-and-spill. If this is not available, then cold leg injection is used. If LHSI is not available, then HHSI is used. HHSI hot-leg injection is preferred to cold leg injection. The needed number of PORVs is specified as a function of the time after shutdown. The operators are expected to throttle the injection flow to maintain 200°F at the core exit thermal couple.

We note that the success criteria in the Virginia Power technical report is intended to maintain subcooling in the RCS. In reality, much more relaxed success criteria are sufficient to prevent core damage. For example, the report requires that 2 charging pumps and 2 PORVs are needed for feed-and-spill during the first 129 hours. If only 1 charging pump and 1 PORV are available, feed-and-bleed should be sufficient to keep the core covered as long as water is available in the RWST. The success criteria given in Table 5.4-2 were used in this study.

To account for the low shut-off head of the LHSI pumps, the time at which the RCS pressure reaches 165 psia was determined and used as the time available for the operator to use LHSI. For HHSI, it was assumed that the time to core damage is the time available. In the high level fault trees, two separate human error events were used.

Recirculation Table 5.4-2 lists the time to RWST depletion for each time window. As the level in the RWST becomes low, the operators are instructed to establish either a RWST cross connect or high head recirculation.

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Section 5.2 estimated that approximately 10 days after shutdown, recirculation is not needed. With successful feed-and-spill, core damage will not occur within 24 hours after the loss of RHR. Therefore, high pressure recirculation is needed only during the first 10 days after shutdown. Ten days is used to define the boundary of time windows 2 and 3. In window 1, both RWSTs cannot support 24 hours of feed- and-spill operation and therefore, recirculation is needed. In window 2, cross-connect of the RWST provides 24 hours of feed-and-spill operation. In the fault trees, credit is taken in time window 2 for cross-connection of the RWSTs.

AP27.00 provides instructions on how high-pressure recirculation can be established, and states the possible need for the spray recirculation heat exchangers. High-pressure recirculation is achieved by using the low pressure injection pump to take suction from the containment sump, and discharge to the suction of the high pressure injection system. In this mode of recirculation, both a high head pump and a low head pump are needed. In the fault-tree analysis, two alternative methods of recirculation were also modeled. The methods are low pressure feed-and-steam taking suction from the containment sump, and low pressure feed-and-spill taking suction from the sump. In both, only low head injection is needed. The feed-and-steam mode requires that the safety valves are removed to provide sufficient vent path, and does not require cooling of the sump water. The feed-and-spill operation requires operation of the spray recirculation systems to cool the water in the sump, so that subcooling in the reactor vessel can be established.

Spray Recirculation In section 5.2, it is estimated that during the first 10 days after shutdown the RWST inventory is not sufficient for feed-and-spill and recirculation is needed. Recirculation would introduce steam into the containment, and with this, the potential for containment failure. In this study, it is assumed that if spray recirculation is not available, then the containment would fail. The impact of containment failure on recirculation is that there is a small probability, 0.02, that the low head pumps would lose their needed net positive suction head. This failure cause is similar to the failure mode considered in NUREG-1150. That is, failure of recirculation is modeled as a potential failure mode of the low-head injection pumps.

Another function of the spray recirculation systems is to support the low-pressure feed-and-spill mode of low-pressure recirculation by taking suction from the containment sump. It cools the containment sump water making it possible to maintain subcooling in the reactor vessel.

Reflux Cooling The success criteria for reflux cooling was based on Virginia Power Technical Report 865, and also specified in AP 27.00. The number of steam generators needed is specified as a function of decay heat. It is known that the success criteria are conservative. Because it is specified in the procedure, it is assumed that the operators would follow the procedure. To establish reflux cooling, the operators are supposed to close the vessel head vent and PORVs to ensure there is no inventory loss through these openings. In section 5.3, it was estimated that the leakage through the tygon tube connected to the vessel head is insignificant. If the PRT rupture disks are ruptured, the leakage through an open PORV is large enough to lead to core damage in a few hours. If reflux cooling is established before the PRT is ruptured, the PRT becomes a part of the RCS boundary, and no significant loss of inventory is expected. Therefore, if the operators can establish reflux cooling by venting the secondary side of the SGs before the PRT rupture disks rupture, then there is no need to close the PORVs. If reflux cooling is established after the PRT ruptures, then the PORVs must be closed to prevent inventory loss. It is assumed that reflux cooling is sufficient to remove decay heat if it is established before the core is uncovered. If reflux cooling is established, the SG inventory is sufficient for approximately 10 hours (Table 5.4-2). Feeding the steam generator after the SG inventory becomes low is modeled as a long-term operator actions.

Table 5.4-1 Success Criteria for Mitigating Features

Feature	Time Window	Success Criteria	
		Short Term	Long Term
Reflux Cooling			
	< 75 hours	3 SGs	AFW to 3 SGs
	>= 75 hours and < 475 hours	2 SGs	AFW to 2 SGs
	>= 475 hours	1 SG	AFW to 1 SG
Feed and Spill	< 107 hour	1LHSI * (SV removed + 2PORV)	
	> 107 hours	1LHSI *(SV removed + 1 PORV)	
	< 129 hours	2HHSI*(SV removed + 2 PORV)	
	> 129 and < 138 hours	1HHSI*(SV removed + 2 PORV)	
	>= 138 hours	1HHSI * (SV removed + 1 PORV)	
Gravity Feed	< 70 hours	at least 1 SV removed , less than 1 hour of subcooling	
	> 70 hours and < 150 hours	at least 1 SV removed, 2 hours of subcooling	
	> 150 hours and less than 768 hours	at least 1 SV removed, 3 hours of subcooling	
	>= 768 hours	at least 1 SV removed, sufficient for 24 hours	
Recirculation	< = 3 days	needed	
	> 3 days and <=10 days	not needed if RWSTs are cross tied, otherwise needed	
	> 10 days	not needed	
Spray Recirculation	<= 3 days	needed to prevent recirculation failure	
	> 3 days and <=10 days	not needed if RWSTs are cross tied, otherwise needed to prevent recirculation failure	
	> 10 days	not needed	

5 Supporting Thermal Hydraulic Analysis

Table 5.4-2 Definition and Characterization of Time Windows

	WINDOW 1	WINDOW 2	WINDOW 3	WINDOW 4
Definition	<= 75 hours	> 75 hours and <= 240 hours	> 240 hours and <= 32 days	> 32days
Representative Decay Heat	13.23 MW(2days)*	10 MW(5 days)	7 MW(12 days)	5 MW(32 days)
Success Criteria				
Reflux Cooling	3 SGs	2 SG	2 SG	1 SG
Feed and Bleed				
LHSI	1LHSI*(SV removed + 2 PORV)	1LHSI*(SV removed + 2 PORV)	1LHSI *(SV removed + 1PORV)	1LHSI *(SV removed + 1PORV)
HHSI	1HHSI*(SV removed + 1 PORV)	1HHSI*(SV removed + 1 PORV)	1HHSI*(SV removed + 1 PORV)	1HHSI*(SV removed + 1 PORV)
Gravity Feed	1 SV removed * LHSI flow path provides 4.3 hours for operator actions (with less than 2 hours of subcooling)	1 SV removed * LHSI flow path provides 6.5 hours for operator actions (with 2 hours of subcooling)	1 SV removed * LHSI flow path provides 12 hours for operator actions (with 2 hours of subcooling)	1 SV removed * LHSI flow path provides sufficient cooling for 24 hours (with more than 3 hours of subcooling)
Recirculation	needed(HPR + LPF&Steam + LPF&Spill)	1 RWST,needed	not needed	not needed
		2 RWST, not needed		
Recirculation Spray	needed	1 RWST,needed	not needed	not needed
		2 RWST,not needed		
Probability that IE Occurs in the Window				
D6	0.117 (0.31)*	0.436 (0.454)	0.375 (0.21)	7.20E-02 (2.6E-02)
R6	1.7E-02 (5.82E-02)	0.543 (0.7)	0.41 (0.24)	3.4E-02 (1.48E-03)
R10	0.0	0.0 ~	0.016 (2.2E-02)	9.84E-01 (0.98)
Decay Heat	13.23 MW(2days)	10 MW(5 days)	7 MW(12 days)	5 MW(32 days)

Table 5.4-2 (continued)

	WINDOW 1	WINDOW 2	WINDOW 3	WINDOW 4
Time to Boiling	15 min.	20 min.	27 min.	37 min.
Time to Tygon Tube Rupture(40 psia)	23 min.	31 min.	43 min.	59 min.
Time to PRT Rupture(100 psig)	51 min.	63 min.	78 min.	96 min.
Time to 165 psia	41 min. with 2 PORV 43 min. with 1 PORV	63 min. with 2 PORV 60 min. with 1 PORV	227 min. with 2 PORV 89 min. with 1 PORV	352 min. with 2 PORV 147 min. with 1 PORV
Time to 615 psig	145 min. with 1 PORV - with two	-	-	-
Time to RWST Depletion	10 hrs	13.5 hrs	18.7 hrs	38.6 hrs
Time to AFW Initiation(with 25% SG inventory remaining)	743 min.	669 min.	925 min.	628 min.
Time to Core Uncovery	120 min.	157 min.	209 min.	273 min.
Time to Core Damage	219 min.	297 min.	411 min.	557 min.

*Applicable to RHR2A only, based on time to mid-loop

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6 SYSTEM DESCRIPTIONS AND FAULT TREE ANALYSIS

6.1 System Analysis Approach and Scope

The approach used in the system analysis is summarized as follows:

- (a) The fault trees developed in NUREG/CR-4550 were reviewed in detail. The dependency of front line systems on support systems was examined to ensure all dependency is modeled. Common-cause failures documented in NUREG/CR-4550 were modeled in the IRRAS version of the model. The resulting fault trees are applicable to those POSs that represent low power, and possibly, hot shutdown or intermediate shutdown conditions.
- (b) In a cold shutdown condition, many systems are placed in a different configuration from that during power operations. These configurations were identified by reviewing the operating procedures, and system training manuals, and in discussions with system engineers at Virginia Power. The fault trees that are applicable to the shutdown configurations were developed by modifying those developed for low power conditions.
- (c) Three new system fault trees were developed; instrument air system, steam generator recirculation transfer system, and emergency switchgear room cooling system. The instrument air system supplies much equipment throughout the plant, and was found to be important in some PRAs. The steam-generator recirculation transfer system can potentially be used to remove decay heat when the RHR system is lost. The emergency switchgear room cooling system was found to be an important system in the Surry IPE. In developing these new fault trees, the same assumptions were made as those in the NUREG-1150 study, e.g., the database of component failures of NUREG/CR-4550. In addition, we modeled the dependencies of the CCW heat exchangers, charging pump cooling system, and emergency switchgear room cooling system on the service water system by extending the boundaries of these systems to include the valves in the service water system.
- (d) Four control system fault trees of NUREG/CR-4550, the consequence limiting control system, reactor protection system, recirculation mode transfer system, and safety injection system were not greatly modified. The models/boolean expressions developed in NUREG/CR-4550 were converted into fault trees and used.

Table 6.1-1 lists the system fault trees, their top event names, and the applicable plant operational states. In the computer model, the same naming scheme of basic events as that used in NUREG/CR-4550 was used. Table 6.1-2 lists the identifiers of systems, components, and events. Table 6.1-3 lists the identifiers of failure modes. The system fault trees are included in Appendix C. They contain basic events that represent human errors and maintenance unavailabilities of equipment. In general these events depend on the accident scenarios as well as plant operational states, and their quantification was specialized accordingly.

Surry is a two-unit plant, and some systems are shared between the units. Consistent with the NUREG/CR-4550, the system analysis of this study modeled unit 1 systems only. For example, if a component in the model gets its power from a unit 2 bus, e.g. the chiller in the switchgear room-cooling system, the unit 2 bus was modeled as a basic event whose probability was estimated from the model for the corresponding bus at unit 1. The modeling of the potential interactions between the two units is summarized below:

- (1) Instrument air system

6 System Description and Fault Tree Analysis

The service air system is common to both units, and normally supplies all instrument air loads outside the containments through the instrument air-flow paths. Each unit has one train of instrument air that is normally on standby. The instrument air-flow headers of two units are normally isolated by closed manual valves. If the instrument air manifold pressure drops below 90 psig, the instrument air compressor will start automatically, and the service air system will be isolated from the instrument air vital loads by a check valve. A simplified fault tree for the system was developed to model the service air compressors, instrument air compressor of unit one and the associated valves. Depending on the accident scenario, cross-connecting the instrument air headers of both unit can be modeled as a recovery action.

(2) Emergency Diesel Generators

Three diesel generators (DGs) are available for the two units. DGs 1 and 2 are dedicated to Unit 1 and 2, respectively, and DG 3 is a swing DG. They are demanded during a loss of offsite power. Given a loss of offsite power, NUREG-1150 developed boolean expressions for the probabilities of one unit and two unit station blackout, by evaluating the availabilities of the DGs. These expressions were reviewed and used in the LP&S program.

(3) CCW system

The CCW system consists of 4 CCW pumps and 4 CCW HXs shared by both units. The discharges of the pumps and HXs are headered together with isolation valves configured to separate the system into two parts. Each part consists of two pumps and two HXs serving one unit. The fault-tree model of CCW includes only the part that is associated with unit 1. Cross tie to unit 2 CCW can be used as a recovery action. The boolean expression developed in NUREG/CR-4550 was reviewed, and converted into a fault tree.

(4) Charging pumps

The discharges of the charging pumps at two units can be cross connected by local aligning of the valves manually. This procedure is included in the abnormal procedures for loss of decay-heat removal, i.e., AP 27.00. Credit is also taken for it in a unit 1 blackout. The boolean expression developed in NUREG/CR-4550 for the charging pump at unit 2 was reviewed and converted into a fault tree.

(5) AFW

The discharge headers of the AFW pumps at the two units can be cross connected. Cross connection is modeled in station blackout scenarios. The boolean expressions developed in NUREG/CR-4550 were modified, and converted into a fault tree.

(6) Charging Pump Cooling

The charging pumps at each unit of Surry have a dedicated closed-loop cooling system whose heat exchangers are cooled by dedicated charging-pump service water pumps. For each unit, these pumps take suction from the condenser inlet lines of both unit 1 and 2. In this sense, the two units interact. The fault-tree model for charging pump service water system of unit 1 includes the flow path from the circulating water line of unit 2.

(7) Service Water

The service water system is a gravity-feed system, providing cooling to spray recirculation heat exchangers, CCW heat exchangers, and bearing cooling water heat exchangers. In addition, the charging pump service water subsystem uses pumps to cool the charging pump cooling system. Pumps also are used to provide cooling to the three control room and relay room air conditioning unit chiller condensers. The charging pump service water subsystems of the two units are shared in that the 10A pumps at both units take a suction from the unit 1 screenwell, and the 10B pumps take a suction from the unit 2 screenwell.

NUREG/CR-4550 for Surry modeled the valves in the flow path to the spray recirculation heat exchangers, and the charging pump service water system. Valves in the flow path to the CCW heat exchangers were not modeled. Bearing cooling water system and control room and relay room chillers were not modeled. Among other loads, the bearing cooling water system provides cooling to the service air and instrument air compressors.

In addition to what was modeled in NUREG/CR-4550, in this study, the dependence of CCW heat exchangers and relay room chillers on service water was modeled by modeling the service water valves in the flow paths from the screenwells. Bearing cooling water system was modeled as a basic event.

(8) Circulating Water System

The circulating water system and the intake canal are shared by both units. Due to the large inventory in the canal, redundancy in the emergency service water pumps, and automatic isolation of the lines on low level in the canal, it was judged that the only way to have a problem with canal inventory is when a loss of offsite power or station blackout occurs. This is modeled in the event trees for loss of offsite power and station blackout.

6 System Description and Fault Tree Analysis

Table 6.1-1 System Fault Trees and Their Applicable POSs

<u>Fault Tree Top Event</u>	<u>Applicable POSs</u>
Accumulators	
D5 -Accumulators	1,2,14,15
Auxiliary Feedwater System	
L -AFW to 1 of 3 SGs, All Transients except SBO	1,2,14,15
L2 -AFW to 2 of 3 SGs, ATWS	1,2,14,15
L3 -AFW to 1 of 2 SGs, SG Tube Rupture	1,2,14,15
SBOU1L -AFW to 1 of 3 SGs, SBO at Unit 1	1,2,14,15
SBU1U2L -AFW to 1 of 3 SGs, SBO at Unit 1 and 2	1,2,14,15
LSW1 -AFW to 1 of 3 SGs, Time Window 1	3-13
LSW23 -AFW to 1 of 3 SGs, Time Window 2 and 3	3-13
LSW4 -AFW to 1 of 3 SGs, Time Window 4	3-13
LS3 -AFW to 1 of 2 SGs, SG Tube Rupture	3-13
SBOU1LS -AFW to 1 of 3 SGs, SBO at Unit 1	3-13
SBU1U2LS -AFW to 1 of 3 SGs, SBO at Unit 1 and 2	3-13
Charging Pump Cooling System	
CPCA -CPC to charging pump 1A	1-15
CPCB -CPC to charging pump 1B	1-15
CPCC -CPC to charging pump 1C	1-15
Component Cooling Water System	
CCW1 -CCW to 1-RH-E-1A	1,2,14,15
CCW2 -CCW to 1-RH-E-1B	1,2,14,15
CCW3 -CCW to RHR Pump Cooler, 1-RH-E-2A	1,2,14,15
CCW4 -CCW to RHR Pump Cooler, 1-RH-E-2B	1,2,14,15
CCW5 -CCW to RCP Thermal Barriers	1-4,12-15
CCW1S -CCW to 1-RH-E-1A	3-13
CCW2S -CCW to 1-RH-E-1B	3-13
CCW3S -CCW to RHR Pump Cooler, 1-RH-E-2A	3-13
CCW4S -CCW to RHR Pump Cooler, 1-RH-E-2B	3-13
Compressed Air System	
TIA -Turbine Building Instrument Air	1,2,3,13,14,15
CIA -Containment Instrument Air	1,2,3,13,14,15
TIA-CSD -Turbine Building Instrument Air	4-12
Containment Spray System	
C -Containment Spray System	1,2,14,15
CLPSD -Containment Spray System	3-13
Emergency Power System	
4KV1H -4 Kv Bus 1H	1-15
4KV1J -4 Kv Bus 1J	1-15
ESTB1H -Stub Bus 1H	1-15
ESTB1J -Stub Bus 1J	1-15
EH1 -MCC1H1-1	1-15
EH2 -MCC1H1-2	1-15
EJ1 -MCC1J1-1	1-15

Table 6.1-1 (continued)

EJ2 -MCC1J1-2	1-15
E4801H -480 v Bus 1H	1-15
E4801J -480 v Bus 1J	1-15
E1I -Vital Bus 1-I	1-15
E21II -Vital Bus 1-II	1-15
E31III -Vital Bus 1-III	1-15
E41IV -Vital Bus 1-IV	1-15
E1A -125 v DC Bus 1A	1-15
E1B -125 v DC Bus 1B	1-15
Emergency Switchgear Room Cooling System	
VS1 -Emergency Switchgear Room Ventilation	1-15
High Pressure Injection/Recirculation	
D1 -HPI in Automatic Mode	1,2,14,15
D2 -HPI in Manual Mode	1,2,14,15
D3 -HPI to RCP Seals	1,2,14,15
D4 -Emergency Boration Using HPI	1-15
HPR-H2 -HPI in Recirculation Mode	1-15
D2-C -HPI in Manual Mode	3-13
D2HLG-HPI to Hot Leg	3-13
D3-C -HPI to RCP Seals	3-13
FSW12H -HPI System, Time Windows 1 and 2	3-13
FSW34H -HPI System, Time Windows 3 and 4	3-13
Low Pressure Injection/Recirculation	
D6 -LPI Automatic	1,2,14,15
D6-C -LPI Manual	3-13
LPIHLG -LPI to Hot legs	3-13
HAS -LPI in Recirculation Mode	1-15
HASHLG -LPI Hot Leg Recirculation	3-13
H1 -LPI in Support of HPR	1-15
FSW12L -LPI System, Time Windows 1 and 2	3-13
FSW34L -LPI System, Time Windows 3 and 4	3-13
Primary Pressure Relief	
P1 -Failure of 1 of 2 PORVs	1-15
P -Failure of 2 of 2 PORVs	1-15
PORV1 -Failure to close both PORVs	3-13
PORV2 -PORV fails to open on demand	3-13
Recirculation Spray Systems	
F1 -Inside Recirculation Spray	1,2,14,15
F2 -Outside Recirculation Spray	1,2,14,15
F1LPSD -Inside Recirculation Spray	3-13
F2LPSD -Outside Recirculation Spray	3-13

6 System Description and Fault Tree Analysis

Table 6.1-1 (continued)

Residual Heat Removal System	
W3 -Residual Heat Removal	1,2,14,15
W3-S -Residual Heat Removal	3-13
Steam Generator Recirculation and Transfer System	
SGRT-Steam Generator Recirculation and Transfer	3-13
Steam Generator Secondary Relief	
SSHW1 -Secondary Side Heat Removal Time Window 1	3-13
SSHW23 -Secondary Side Heat Removal Time Window 2 and 3	3-13
SSHW4 -Secondary Side Heat Removal Time Window 4	3-13
Consequence Limiting Control System	
CLCS-A -CLCS Train A	1-15
CLCS-B -CLCS Train B	1-15
Reactor Protection System	
RPS -Reactor Protection System	1,15
Recirculation Mode Transfer System	
RMT-A -RMT Train A	1-15
RMT-B -RMT Train B	1-15
Safety Injection Actuation System	
SIA-A SIA Train A	1,2,14,15
SIA-B SIA Train B	1,2,14,15

Table 6.1-2 System, Component, and Event Identifiers
Part 1: System Identifiers

SYSTEM IDENTIFIER	SYSTEM NAME
ACC	Accumulators
ACP	AC Power System
ARF	Air Return Fan System
ADS	Automatic Depressurization System
AFW	Auxiliary Feedwater System or Emergency Feedwater System
CPC	Charging Pump Cooling System
CHP	Charging Pump System
CIA	Containment Instrument Air System
CVC	Chemical and Volume Control System
CHW	Chilled Water System
CSC	Closed Cycle Cooling System
CCW	Component Cooling Water System
CDS	Condensate System
CLS	Consequence Limiting Control System
CCU	Containment Atmosphere Cleanup
CGC	Containment Combustible Gas Control
CFC	Containment Emergency Fan Cooler System
CIS	Containment Isolation System
CSR	Containment Spray Recirculation System
CSS	Containment Spray System
CRD	Control Rod Drive System
DCP	DC Power System
DWS	Drywell (Wetwell) Spray Mode of RHR System
EHV	Emergency Heating, Ventilation, and Air Conditioning System
ESF	Engineered Safety Feature Actuation System
ESW	Essential Service Water System
FHS	Fuel Handling System
HCI	High Pressure Coolant Injection System

6 System Description and Fault Tree Analysis

Table 6.1-2 (continued)

SYSTEM IDENTIFIER	SYSTEM NAME
HCS	High Pressure Core Spray System
HPR	High Pressure Recirculation System
HPI	High Pressure Safety Injection System
HSW	High Pressure Service Water System
ICS	Ice Condenser System
ISR	Inside Containment Spray Recirculation System
IAS	Instrument Air System
ISO	Isolation Condenser System
LCI	Low Pressure Coolant Injection System
LCS	Low Pressure Core Spray System
LPR	Low Pressure Recirculation System
LPI	Low Pressure Safety Injection System
MCW	Main Circulating Water System (main condenser cooling water)
MFW	Main Feedwater System
MSS	Main Steam System
NHV	Normal Heating, Ventilation, and Air Conditioning System
OEP	Onsite Electric Power System
OSR	Outside Containment Spray Recirculation System
PCS	Power Conversion System
PPS	Primary Pressure Relief System (PORV/SRV)
RGW	Radioactive Gaseous Waste System
RLW	Radioactive Liquid Waste System
RBC	Reactor Building Cooling Water System
RCS	Reactor Coolant System
RCI	Reactor Core Isolation Cooling System
RPS	Reactor Protection System
RMT	Recirculation Mode Transfer System
RHR	Residual Heat Removal System
SAS	Service Air System

Table 6.1-2 (continued)

SYSTEM IDENTIFIER	SYSTEM NAME
SGRT	Steam Generator Recirculation & Transfer System
SIS	Safety Injection Actuation System
SWS	Service Water System
SDC	Shutdown Cooling Mode of RHR
SGT	Standby Gas Treatment System
SLC	Standby Liquid Control System
SPC	Suppression Pool Cooling System (or Suppression Pool Cooling Mode of the RHR System)
SPM	Suppression Pool Makeup System
TBC	Turbine Building Cooling Water System

6 System Description and Fault Tree Analysis

Table 6.1-2 System, Component, and Event Identifiers
Part 2: Component Identifiers

COMPONENT IDENTIFIER	COMPONENT NAME
ACX	Air Cooling Heat Exchanger
	Sensor/Transmitter Units:
ASF	Flow
ASL	Level
ASO	Physical Position
ASP	Pressure
ASR	Radiation
AST	Temperature
ASX	Flux
CRB	Circuit Breaker
CAL	Calculational Unit
CBL	Electrical Cable
CND	Signal Conditioner
	Control Rods:
CRH	Hydraulically Driver
CRM	Motor Driven
DCT	Ducting
MDC	Motor-Driven Compressor
FAN	Motor-Driven Fan
FUS	Fuse
DGN	Diesel Generator
HRU	Hydrogen Recombiner Unit
HTX	Heat Exchanger
INV	Inverter
ISO	Electrical Isolation Device
ACU	Air Cleaning Unit
LOD	Load/Relay Unit
LOG	Logic Unit

Table 6.1-2 (continued)

COMPONENT IDENTIFIER	COMPONENT NAME
LPS	Local Power Supply
MGN	Motor-Generator Unit
MOD	Motor-Operated Damper
	Pumps:
EDP	Engine-Driven
MDP	Motor-Driven
TDP	Turbine-Driven
XSW	Manual Control Switch
REC	Rectifier
TSW	Transfer Switch
TFM	Transformer
TNK	Tank
TXX	Bistable Trip Unit
AHU	Air Heating Unit
BDC	Electrical Bus - DC
BAC	Electrical Bus - AC
XDM	Manual Damper
PND	Pneumatic/Hydraulic Damper
BAT	Battery
	Valves:
CKV	Check Valve
HDV	Hydraulic Valve
SRV	Safety Relief Valve
SOV	Solenoid-Operated Valve
MOV	Motor-Operated Valve
XVM	Manual Valve
AOV	Air-Operated Valve
TCV	Testable Check Valve
EFV	Explosive Valve

6 System Description and Fault Tree Analysis

Table 6.1-2 (continued)

COMPONENT IDENTIFIER	COMPONENT NAME
FLT	Filter
ICC	Instrumentation and Control Circuit
STR	Strainer
HTR	Heater Element
PSF	Pipe Segment Fault
PTF	Pipe Train Fault
ACS	Actuation Segment Fault
ACF	Actuation Train Fault
TAC	AC Electrical Train Fault
TDC	DC Electrical Train Fault
XHE	Human Error
CCF	Common Cause Fault
VFC	Miscellaneous Aggregation of Faults
PHN	Phenomenological Events

Table 6.1-3 Failure Mode Codes*

CODE	FAILURE MODE
	Valves, Contacts, Dampers
FT	Fail to Transfer
OO	Normally Open, Fail Open
OC	Normally Open, Fail Closed (Position)
CC	Normally Closed, Fail Closed
CO	Normally Closed, Fail Open
	Valves, Filters, Orifices, Nozzles
PG	Plugged
	Pumps, Motors, Diesels, Turbines, Fans, Compressors
FS	Fail to Start
FR	Fail to Continue Running
	Sensors, Signal Conditioners, Bistable
HI	Fail High
LO	Fail Low
NO	No Output
	Segments, Trains and Miscellaneous Agglomerations
LF	Loss of Flow, No Flow
FC	Loss of Function
FA	Actuation Fails
LP	No Power, Loss of Power
VF	Failure (for miscellaneous fault agglomerations not based on segments or trains)
HW	Hardware
	Battery, Bus, Transformer
LP	No Power, Loss of Power
ST	Short
OP	Open

6 System Description and Fault Tree Analysis

Table 6.1-3 (continued)

CODE	FAILURE MODE
	Tank, Pipes, Seals, Tubes
LK	Leak
RP	Rupture
	Human Errors
FO	Fail to Operate
MC	Miscalibrate
RE	Fail to Restore from Test or Maintenance
	Normal Operations (unavailable due to planned activity):
MA	Maintenance
TE	Test
TM	Test and Maintenance

* Events or components shown are only suggestions. The failure modes listed may be used for any applicable event or component type.

6.2.1 Accumulator System

The accumulators provide rapid refilling of the lower core plenum in the event of a large break in the Reactor Coolant System (RCS). Each accumulator is a pressurized vessel containing borated water covered with pressurized nitrogen gas. Should the RCS pressure fall below the accumulator pressure during power operation, the borated water is forced into the RCS. The accumulators are considered passive components of the safety injection (SI) system, since they can function without operator action, component repositioning, or need of electric power. The following sections describe the accumulators, identify their interfaces and dependencies with other front-line and support systems, list any operational constraints, describe their shutdown configuration, and discuss the fault-tree model developed for the accumulators in the NUREG/CR-4550 report and its applicability to the present study.

6.2.1.1 Accumulator Description

The Surry Safety Injection system has three accumulators, 1A, 1B, and 1C. Following a large LOCA, two of the three accumulators refill the reactor inlet plenum, downcomer, lower core basket, and half of the active core with borated water. The third accumulator is assumed to be dumped out of the break. Each accumulator is a pressure vessel of 1450 cubic feet in volume that is filled with at least 975 cubic feet of 2250 ppm (parts per million) borated water and pressurized with nitrogen gas to 600 to 650 psig. Remote accumulator pressure and level indication is provided in the Main Control Room. Figure 6.2.1-1 is a simplified schematic of the accumulators.

Each accumulator is connected to an RCS cold leg through a motor-operated, accumulator discharge isolation valve and two swing-check valves. For accumulator 1A, they correspond, respectively, to MOV-1865A, CV107 and CV109 (Fig. 6.2.1-1). The accumulator isolation valve prevents emptying of the accumulator during normal plant cooldown and depressurization or during check-valve testing. All accumulator isolation valves are opened during RCS pressurization when the pressure is above 1000 psig. When RCS pressure exceeds 2000 psig, power is removed from the valve operators and the breakers are locked open.

The accumulator check valves are normally held shut by the high RCS pressure of 2235 psig. During a LOCA, when RCS pressure drops below the nitrogen pressure in the accumulator, the check valves open to discharge the contents of the accumulator into the RCS. Upstream of each check valve, a connection is provided to permit testing the check valves for seal leakage during RCS pressurization when a differential pressure of about 120 psi exists across them. Any leakage is directed by the test connections to the accumulator test line, which, in turn, directs any leakage to the RWST.

A hydrostatic test pump initially fills the accumulators by drawing borated water from the refueling water storage tank (RWST). The water passes through a makeup header check valve and a pneumatically operated control valve. The water level may be lowered by draining each accumulator to the primary drain transfer tank through accumulator tank drain valves. Samples of the boric acid solution in the accumulators are taken periodically at the sampling station to check the boron concentration.

The accumulators are pressurized with nitrogen from the nitrogen supply header. A pressure control valve situated on the supply header supplies 657 psig nitrogen to the accumulator vent and supply line, which is connected to the accumulator through an accumulator vent and supply valve. Each accumulator is protected by a relief valve, which has a setpoint of 700 psig and vents to the containment atmosphere.

6.2.1.2 Accumulator Interfaces and Dependencies

The accumulators depend on the nitrogen system to maintain a head. Nitrogen is supplied by dedicated nitrogen bottles located outside the auxiliary building. Each accumulator has redundant level and pressure indications. Each pressure transmitter provides indication on a pressure gage and inputs to the High/Low

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Accumulator Tank Pressure alarms. Each level transmitter provides level indication and inputs to the High/Low Accumulator Tank Level alarms. Because of the small fault exposure time (four hours), the dependency of the accumulators on the nitrogen system was not explicitly modeled in the fault tree in NUREG/CR-4550.

6.2.1.3 Accumulator Operational Constraints

Technical specifications require that, during normal power operations, all three accumulators are operable. If one accumulator becomes inoperable due to, for example, low water level or low pressure, it must be restored within four hours. Technical specifications also require that accumulator's water level and pressure indicators are verified at each shift, and that level and pressure instruments are calibrated at each refueling shutdown following procedures for instrument calibration and subsequent valve alignment. The boron concentration in the accumulators is verified monthly and after any coolant makeup to the system.

All of the accumulator isolation valves should be closed if RCS pressure falls below 1000 psig and must be closed below 700 psig, during normal cooldown, to preclude inadvertent discharge into the RCS. The breakers must be locked open. The accumulator isolation valves must be open if RCS pressure is above 1000 psig, and the breakers locked open.

6.2.1.4 Accumulators Shutdown Configuration

During POS 1, the RCS pressure is essentially maintained at the normal operation condition, i.e., 2235 psig. All three of the accumulator discharge isolation MOVs, i.e., MOVs-1865 A/B/C, therefore, are kept open with power to the valve operators removed and the breakers locked open. Following a reactor shutdown and during POS 2, the reactor is cooled down from RCS temperature and pressure of 543°F and 2235 psig to 345° F and 345 psig, respectively. When RCS pressure is reduced to less than 1000 psig, the operator is instructed to unlock and close the breakers for all of the accumulator discharge isolation MOVs; then, the operator is further instructed to lock open their breakers to preclude inadvertent discharge of the accumulator contents into the RCS when reactor is at cold shutdown.

This accumulator configuration is maintained throughout cold shutdown, except for possible planned maintenance and testing activities, such as draining and refilling the accumulators, or calibration of their level and pressure instruments. During POS 14, when the reactor is started up and the RCS pressure is increased from 345 psig to about 1000 psig, all of the accumulator discharge isolation MOVs are opened and then their opening power is removed. Their breakers are also locked open.

6.2.1.5 Accumulator System Logic

The adequacy and suitability of the fault trees (D5) for the accumulators in the NUREG/CR-4550 report was examined. In the NUREG/4550 model, the success criterion for the accumulators following a large LOCA (conservatively assumed to be a cold leg break) was the injection of the contents of the two accumulators associated with the intact cold legs into the RCS. For a medium LOCA, the success criterion is injection of the contents of two or more accumulators into the RCS.

For a large LOCA, the model assumes that the cold leg break occurs in Loop 1, failing its associated accumulator immediately. The only faults considered in the fault tree model were demand-type faults, such as the failure of the swing-check valves to open or the plugging of the accumulator discharge isolation MOVs. We considered the accumulator fault trees were adequate for the present study without any modification for POSs 1, 2, 14, and 15. Since the accumulators are disabled during POSs 3 through 13 because their discharge isolation MOVs are closed, the unavailability of the accumulators during these POSs is taken as unity in the present study.

Figure 6.2.1-1 Accumulator System Simplified Sketch

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6.2.2 Auxiliary Feedwater System

6.2.2.1 Auxiliary Feedwater System Description

The auxiliary feedwater (AFW) system supplies the reserve source of feedwater to the steam generators (SG) to remove core heat from the primary system after a reactor trip. The normal source of AFW is the emergency condensate storage tank. Alternate sources of water are from the condensate storage tank, auxiliary feedwater from the opposite reactor unit, the emergency makeup tank via the auxiliary feedwater booster pumps, and finally, a connection to the Fire Protection System is available.

The AFW system is provided by three feedwater pumps; two electric-motor-driven pumps and one steam-turbine-driven pump. The former have a capacity of 350 gpm, and the turbine-driven AFW pump has a capacity of 700 gpm. Each pump draws a suction through an independent line from the 110,000 gallon condensate storage tank (CST). Additionally, a 300,000 gallon CST, a 100,000 gallon emergency makeup tank, and the fire main can supply water for the AFW pumps. Each AFW pump discharges to two parallel headers, each of which can provide auxiliary feedwater flow to any or all of the three steam generators. Flow from each header to any one SG is through a normally open motor-operated valve (MOV) and a locked open manual valve in series, paralleled with a line from the other header. These lines feed one line containing a check valve which joins the main feedwater line to a steam generator. Once the AFW system is initiated, the normally open motor operated valves (FW151A-F, see Figure 6.2.2-1) are throttled to reduce the flow rate and to maintain the level in the SGs.

The diversity of the piping and valves on the discharge side of the AFW pumps permits any pump to supply feedwater to any steam generator. A simplified schematic of the AFW system is presented in Figure 6.2.2-1.

6.2.2.2 Auxiliary Feedwater System Interfaces and Dependencies

During power operation and in POS 1, 2 and 14, 15, the motor-driven AFW pumps automatically start on receiving a safety-injection actuation signal, trip of main feedwater pumps, low-low steam generator level in any steam generator, or loss of reserve station power. The turbine-driven AFW pump automatically starts on receipt of indication of low-low steam generator level in two of the three steam generators, or under voltage on two 4160 VAC station service buses (loss of the RCS pumps) by opening the steam inlet valves (MS-102 A,B). These signals also ensure that the system MOVs are in the correct position; the AFW discharge valves FW-151A-F open in addition to MS-102 A,B.

The AFW system depends on the AC power buses for motive power to the AFW motor-driven pumps, and motive and control power to the AFW MOVs. The pump and valve motors are powered from the 4160 VAC H or J emergency buses. The AFW system also depends on the DC power buses for control power to the electric-motor-driven AFW pumps, and the SIAS for actuation of the AFW pumps. The turbine-driven pump turbine inlet valves require instrument air and DC power for control. However, on loss of either instrument air or DC power, the valves fail open allowing steam to flow to the pump turbine. Table 6.2.2-1 lists the status and dependency of the AFW components.

There are individual oil-lubrication systems for each AFW pump. A shaft-driven oil pump provides the motive force to circulate oil to the pump bearings. The heat from the lube oil is transferred to a small portion of the AFW flow coming from the AFW pump discharge through the recirculation line.

The steam exhaust from the turbine of the steam driven AFW pump is directed to the atmosphere and does not have an auxiliary condenser.

6.2.2.3 Auxiliary Feedwater System Operating Constraints

During power operations, the Technical Specifications require both motor-driven feedwater pumps to be operable at all times and the turbine-driven pump to be operable when the reactor is above 10 percent power. However, one pump may be removed from service for maintenance for a short period (72-hour AOT before commencing hot shutdown in the following 12 hours). Technical Specifications also require that when Unit 1(2) is at power operation, one of three Unit 2(1) AFW pumps must be operational.

The testing requirements specified in the Surry Tech. Specs. for the AFW system are as follows:

- (a) Each motor-driven AFW pump and the turbine-driven AFW pump are flow tested monthly for at least 15 min. to demonstrate their operability. The AFW pump discharge valves are exercised monthly.
- (b) During periods of extended shutdown, only one of three AFW pumps is flow-tested for a minimum of 15 min. to demonstrate its operability, provided the required components are tested before plant startup.

In addition, the following precautions are observed when the AFW system is in operation:

- (1) During normal operation, the AFW pump discharge valves (FW-151A-F) must remain open at all times.
- (2) Having either motor-driven AFW pump control switch in the MCR or the ASP in the Pull-to-Lock position defeats the start function of the AFW pumps.
- (3) The turbine-driven AFW pump cannot be operated until RCS temperature is greater than 400°F and is not normally operated below 547°F.

6.2.2.4 Auxiliary Feedwater System Shutdown Configuration

The AFW system provides emergency makeup to the SGs and is normally in standby during operation. Its basic function is also maintained in shutdown, that is, it is an emergency standby system for removing heat in transients and accidents. The essential difference is in the availability and the controlling logic of the various components.

In POS 1, 2 and 14, 15, the operation of the AFW system is similar to the configuration in power operation and is initiated automatically. The pumps are on standby status and the discharge MOVs (FW151A-F) are open. The steam inlet MOVs (MS-102A,B) are closed, but fail open upon loss of instrument air or DC power. In POS 3-13, the automatic start logic of the AFW system is defeated and the system is under full manual control.

The control switches for the two motor-driven pumps are placed in Pull-to-Lock position, preventing their starting on any automatic signal. The discharge MOVs (FW-151A-F) are closed and their breakers are opened. The AFW system may still be started up, but only by the operator, requiring that at least one motor-driven AFW pump is started and one of the six discharge MOVs is opened to direct flow into at least one SG.

The steam-driven AFW pump is effectively unavailable in POS 3-13, because the RCS temperature is below 400°F and the rate of steam generation in the SG and its quality is not sufficient to start up the Terry turbine.

6.2.2.5 Auxiliary Feedwater Logic Model

In POS 1, 2, 14, and 15, the AFW system is on standby. The NUREG/CR-4550 model was modified to include the additional failure modes:

- (1) Common-cause failure mode for all components not already in the model was added.
- (2) The plugging failure mode of the normally locked open manual valve MS-196 at the Terry turbine inlet line was added.

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The SBO conditions are different from other transients and the possibility of connecting the Unit 2 AFW supply was explicitly modelled; this is similar to the treatment in NUREG/CR-1150, where a specific equation was derived in Appendix B. The logic module developed includes the Unit 1 AFW system together with the turbine driven AFW pump of Unit 2. The motor-driven pumps of the AFW system are assumed to be made unavailable through the built-in dependency through AC power; this was explicitly modelled and these components eliminated from the logic structure.

The cross connect of the AFW system of the two units is modelled similarly to the NUREG-1150 model. The cross-connect valves FW160A or B are powered from unit 2 and are without power in a two unit SBO. The valves may be opened manually and the various actions related to the cross-connect function are reflected in the human error probabilities.

The use of the Unit 2 AFW pump cross connect, the 300,000 gallon CST, the emergency makeup tank, or the fire main as a backup to the CST were considered as recovery actions and were not included in the fault trees directly. The exception is the SBO fault trees, where the Unit 2 cross-connect is explicitly modelled. The potential backup source provided by the 300,000 gallon CST (TNK-2) is also included in a specific subtree (discussed below) to account for sequences where the SG relief valve is stuck open.

Two separate modules describe the specific features of the SBO scenario; one for the case when there is SBO at Unit 1, but not at Unit 2 (SBOU1L), and the other for the two unit SBO conditions (SBU1U2L).

The SBO event may result in the scenario of a stuck open SG relief valve in POS 1/2, 14/15. Then, the flow requirement from the turbine-driven AFW pump is increased and the normal supply from the CST may not be sufficient, so that the operator has to cross-connect TNK-1A (normal supply) to TNK-2. This action is represented by the basic event AFW-XHE-FO-CST2. A specific subtree was developed to account for this situation for both one and two unit SBO scenarios. In one unit SBO, the tree is SBOU1LQ and is intended for sequences where the SG relief valve is stuck open (in SBO); for two unit SBO, the tree is SU1U2LQ. Both trees are to be used as alternate top events for the specific sequences (stuck open SG relief valve).

The modified AFW logic modules are (DLS files):

POS 1, 2, 14, and 15

- L - AFW flow to 1 of 3 SGs; all transients except SBO
- L2 - AFW flow to 2 of 3 SGs; ATWS
- L3 - AFW flow to 1 of 2 SGs; SG tube rupture
- SBOU1L - AFW flow to 1 of 3 SGs, SBO at Unit 1
- SBU1U2L - AFW flow to 1 of 3 SGs, SBO at Unit 1 and 2

POS 1, 2, 14, and 15

Alternate top event trees/Stuck open SG PORV

- SBOU1LQ - AFW flow to 1 of 3 SGs, SBO at Unit 1 stuck open SG relief valve
- SU1U2LQ - AFW flow to 1 of 3 SGs, SBO at Unit 1&2 stuck open SG relief valve

LOGIC MODELS FOR TIME WINDOW REPRESENTATIONS

The success criterion of the AFW system depends on the SGs. Accordingly, three logic models were developed for non-SBO cases:

- Time Window 1 - LSW1
- Time Window 2 & 3 - LSW23
- Time Window 4 - LSW4

For SBO situations, only the cross connection to unit 2 is modeled, SBOU1LS and SBU1U2LS.

The following modifications were made in POS3-13 to reflect the operating conditions of the AFW system:

- (1) The AC dependence of the discharge MOVs were added, because the valves are not open in these POSs. Additional failure modes to account for the failure to open and common-cause failures were added.
- (2) AFW logic modules were developed for the SBO conditions.

The following is the list of the AFW system logic modules to be used in POS 3-13:

POS 3-13

- LSW1 - AFW to 1 of 3 SGs, Time Window 1
- LSW23 - AFW to 1 of 3 SGs, Time Windows 2 & 3
- LSW4 - AFW to 1 of 3 SGs, Time Window 4
- SBOU1LS - AFW flow to 1 of 3 SGs, SBO at Unit 1
- SBU1U2LS - AFW flow to 1 of 3 SGs, SBO at Unit 1 and 2

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Figure 6.2.2-1 AFW System
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Table 6.2.2-1 AFW System Component Status and Dependency Summary AFW System

COMPONENT	NORMAL STATUS		ACTUATION		DEPENDENCIES
PUMPS	POS 1, 2, 14, 15	POS 3-13	POS 1, 2, 14, 15	POS 3-13	
1-FW-P-2	Standby	Not Available	2/3 Lo SG Level, Under voltage on two 4160 VAC Station Service Buses	-----	Main Steam
1-FW-P-3A	Standby	Standby	SIS-A, Loss of MPW, Lo SG Level, Loss of Reserve Power	R. Manual	4160 Bus 1H, DC Bus 1A
1-FW-P-3B	Standby	Standby	SIS-B, Loss of MPW, Lo SG Level, Loss of Reserve Power	R. Manual	4160 Bus 1J, DC Bus 1B
MOVs					
151A	NO/FAI	NC/FAI	Open signal same as Pump 3A Act.	R. Manual	MCC-1H1-2
151B	NO/FAI	NC/FAI	Open signal same as Pump 3B Act.	R. Manual	MCC-1J1-2
151C	NO/FAI	NC/FAI	Open Signal same as Pump 3A Act.	R. Manual	MCC-1H1-2
151D	NO/FAI	NC/FAI	Open Signal same as Pump 3B Act.	R. Manual	MCC-1J1-2
151E	NO/FAI	NC/FAI	Open Signal same as Pump 3A Act.	R. Manual	MCC-1H1-2
MOVs	POS 1, 2, 14, 15	POS 3-13	POS 1, 2, 14, 15	POS 3-13	
151F	NO/FAI	NC/FAI	Open Signal same as Pump 3B Act.	R. Manual	MCC-1J1-2
160A	NC/FAI	NC/FAI	R. Manual	R. Manual	MCC-2H1-2
160B	NC/FAI	NC/FAI	R. Manual	R. Manual	MCC-2J1-2
260A	NC/FAI	NC/FAI	R. Manual	R. Manual	MCC-1H1-2
260B	NC/FAI	NC/FAI	R. Manual	R. Manual	MCC-1J1-2
AOVs					
MS102A	NC/FO	NC/FO	2/3 SG low level or LOSP to station service buses	-----	Instrument Air DC Bus 1A*
MS102B	NC/FO	NC/FO	2/3 SG low level or LOSP to station service buses	-----	Instrument Air DC Bus 1B*

* On loss of instrument air and DC power, valves fail in safe position (i.e., open) resulting in steam flow to AFW pump turbine. N₂ bottles provided for control of AFW pump in the event of loss of air.

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6.2.3 Charging Pump Cooling System

The Surry charging pump cooling (CPC) system is a support system which has two specific functions, seal cooling and lube-oil cooling, for the three charging pumps in the high pressure injection/recirculation (HPI/HPR) system. Figure 6.2.3-1 is a simplified sketch of the system. The Surry CPC system consists of two subsystems, the charging pump cooling water system and the charging pump service water system. The former is a closed-cycle system which provides cooling to the charging pump seal coolers. The latter is an open-cycle cooling system which provides cooling to the lube-oil coolers and to the intermediate seal coolers in the charging pump cooling water system. The following section gives details of the CPC system.

6.2.3.1 CPC System Description

The charging pumps employ mechanical seals, equipped with cyclone separators to remove abrasive particles. The mechanical seals have external cooling from the Component Cooling Water System (CCWS) via charging pump seal coolers. Heat generated in the mechanical seals is transferred to processed reactor coolant, which is passed through the tube-side of the coolers. The charging pump cooling water system has two pumps which circulate component cooling water through the shell-side of the charging pump seal coolers to remove heat from the tube-side coolant. The charging pump also has a radial bearing and a thrust bearing. The lubrication system for each charging pump includes an oil cooler, a gear-driven main oil pump, a motor-driven auxiliary oil pump, a pressure gage, and a pressure switch to control the operation of the auxiliary oil pump. The lubricating oil to the charging pump bearings is normally supplied by the gear-driven oil pump. When oil pressure decreases to 6 psig, the auxiliary oil pump automatically starts; it stops automatically when the pressure reaches 7 psig. The lubricating oil is cooled by circulating service water through the oil coolers. The motive force for circulating the service water is provided by the two pumps in the charging-pump service water system.

The charging pump cooling water system is a closed-cycle system composed of two 100%-capacity pump trains. Each train contains a charging pump cooling water pump, an intermediate seal cooler, a check valve, and several manual valves. One pump normally runs continuously and the other pump is on standby, but will start automatically on low discharge header pressure (25 psig). Each pump is a single-suction, vertically split, closed impeller, centrifugal unit that can be installed directly in the pipe line. These pumps are designed to deliver 90 gpm (per pump) at a head of 115 feet and are driven by 480 VAC, 5 HP motors. The intermediate seal coolers have a compact design, about 13 inches deep and 15 inches wide. From information obtained at a BNL-VEPCO staff meeting at Surry on February 6, 1992, the recently revised Technical Specifications now require both intermediate seal coolers to be operating normally.

Each charging pump cooling water pump draws suction from the outlet of either of the two intermediate seal coolers and discharges to a common header which provides flow to the seal coolers for each charging pump. Two seal coolers in parallel are provided for each charging pump. Each seal cooler is compact in design, with one continuous coiled tube enclosed inside a housing that forms the shell of the cooler. The seal coolers transfer the heat generated in the charging pump mechanical seals to the charging pump cooling water system. The discharge of the seal coolers is returned to the intermediate seal coolers where it is cooled by the charging pump service water system. Makeup to the system to account for seal leakage is given by a surge tank, which receives makeup flow from the component cooling water system. The charging-pump seal cooling surge-tank has a capacity of 20 gallons and operates at atmospheric pressure. It accommodates thermal expansion and contraction in the charging pump cooling water system and satisfies the NPSH requirements of the charging pump cooling water pumps.

The charging pump service water system is an open-cycle system composed of two 100% capacity pump trains, each containing a charging pump service water (SW) pump which provides flow to one intermediate seal cooler and all three charging pump lube oil coolers. Service water to the charging pump service water system is supplied from both units' SW systems (screenwells 1B and 2A) through valves 1-SW-11 and 2-SW-11. In

addition, SW can be provided by way of Crosstie Valve 1-SW-474 from 1D screenwell, and Crosstie Valve 2-SW-474 from 2C screenwell. Service water from these crosstie valves goes through a common header to supply the charging pump service water system. Flow from each unit's screenwell passes through separate, motor-operated self-cleaning strainers (STR1A and STR1B). The flow also passes duplex strainers (STR2A and STR2B) before reaching the suction of the charging pump SW pumps (MDPSW10A and MDPSW10B). Each pump discharges through two check valves. The two discharge lines from these pumps can be cross-connected to those of the other unit. Downstream of the check valves, the flow is split, with a portion of the flow directed to an intermediate seal cooler (HXSW1A or HXSW1B) and the other portion directed to a common header feeding the lube-oil coolers (HXCH5A, HXCH5B, and HXCH5C). From this header, flow is directed through the lube oil coolers for the operating charging pumps. Temperature control valves are adjusted to control the SW flow through the lube-oil coolers to maintain the lube oil at the proper temperature. The return flows from each of the lube oil coolers join to form a single return line, which directs service water to the Unit 1 Discharge Canal.

One of the charging pump SW pumps and one of the charging pump cooling water pumps are normally in operation. Upon indication of low discharge pressure of the operating pump, the parallel pump receives a signal to start automatically. With the exception of the pumps and the lube-oil cooler temperature control valves, all other components in the system are manually actuated.

6.2.3.2 Charging Pump Cooling System Interfaces and Dependencies

Table 6.2.3-1 summarizes the component status and dependency of the CPC system. The CPC system interfaces with the HPI/HPR system at the charging pumps. The CPC system depends on the AC power buses for motive and control power to the charging pump service water pumps and cooling water pumps; it also depends on the component cooling water system for the ultimate makeup to the charging pump seal cooling surge tank. The surge tank is located so that gravity flow of component cooling water into it would take place even if there was loss of the component cooling water system. The temperature control valves of the lube oil cooler require instrument air as well as DC power for control; however, on loss of either the valves will fail open allowing flow to the lube-oil coolers. The CPC service water system depends on sufficient level in the service water intake canal.

6.2.3.3 CPC System Operational Constraints

Since one charging pump is in operation at all times, one charging pump service water pump, one charging pump cooling water pump and the associated coolers must also be in operation. Technical specifications require that a reactor cannot be critical, or RCS pressure and temperature cannot exceed 450 psig or 350°F unless two service water paths to the charging pump SW system are available. However, this requirement may be modified to allow the reactor to operate with one operable path. The requirement must be met in full within 24 hours or the reactor will be placed in hot shutdown. If the requirement cannot be met in an additional 48 hours, the reactor must be placed in cold shutdown. Technical specifications also require that makeup water from the Component Cooling Water (CCW) subsystem is always available, and further, that two charging pump cooling water pumps (24-hour AOT), two charging pump service water pumps (24-hour AOT), and two charging pump intermediate seal coolers (48-hour AOT) are operational. The operability of the CPC pumps is verified quarterly.

6.2.3.4 CPC System Shutdown Configuration

During POSs 1, 2, 14 and 15, one charging pump service water pump (MDPSW10A), one charging pump cooling water pump (MDPCC2A), and two intermediate seal coolers (HXSW1A and HXSW1B) are in operation: two intermediate seal coolers are now required by the recently revised Technical Specifications to be normally operating. The remaining charging pump SW pump (MDPSW10B), and charging pump coolant water pump (MDPCC2B) are on standby. Therefore, the manual valves, XV780 and XV785, downstream of the intermediate seal coolers are open. Since only Charging pump A is actually running

6 System Description and Fault Tree Analysis

(Charging pumps B and C are in standby), the charging pump SW pump supplies water only to charging pump A lube oil cooler (HXCH5A). The temperature control valve, TCVSW108A, therefore, is partially open and both TCVSW108B and TCVSW108C are closed. On the other hand, the operating charging pump cooling water pump (MDPCC2A) supplies component cooling water to the seal coolers of all three charging pumps. During POSs 3 through 13, the control switches of both Charging pumps B and C are placed in the Pull-To-Lock position. One of the charging pumps (presumably Charging pump A), however, is usually stopped early in the outage, but it remains available (as opposed to operable) to support the opposite unit with a 7-day clock applicable to the operating unit during unavailability. Therefore, the CPC configuration remains unchanged from that described above.

6.2.3.5 CPC System Logic Model

In the NUREG/CR-4550 report, three separate fault trees were developed for the CPC system, each having a fault-tree top event defined as follows:

CPCA -	Insufficient CPC to charging pump CH1A: SW to lube	oil/CC to seal cooler
CPCB -	Insufficient CPC to charging pump CH1B: SW to lube	oil/CC to seal cooler
CPCC -	Insufficient CPC to charging pump CH1C: SW to lube	oil/CC to seal cooler

These top events represent the modeled interfaces of the CPC system with the fault trees of the HPI/HPR system discussed in Section 6.2.9. The adequacy, completeness, and applicability of each fault tree to the present shutdown study was scrutinized. The following section briefly summarizes the major findings and the modifications required so that the fault trees can be used in this study.

(1) Logic Model for CPCA (Insufficient CPC to charging pump CH1A: SW to lube oil/CC to seal cooler)

The configuration of the CPC system in this fault tree model is that both the A-train of the charging pump service water system and the A-train of the charging pump cooling water system and its associated intermediate seal cooler, HXSW1A, are operating. The B-train of each system is on standby. It is also assumed that charging pump A is the only running charging pump at the onset of the accident (B and C are in standby). The temperature control valve, TCVSW108A, on the charging pump A lube oil cooler is open, while the temperature control valves for the other two lube oil coolers are closed. If the B charging pump or C charging pump is started, the associated temperature control valve will open as the pump lube-oil heats up to generate a temperature signal. As pointed out previously, the recently revised Technical Specifications now require that both of the intermediate seal coolers (i.e., HXSW1A and HXSW1B) are put into operation, even though only one charging pump cooling water pump is running. To comply, the manual valves, XV780, XV785, XV131, and XV132, must normally be kept open to allow flows through both the tube- and the shell-sides of the intermediate seal coolers. The flows discharged into the common header from the seal coolers of the charging pumps are split into two streams, each of which flows through the shell-side of the intermediate seal cooler where its heat is removed by service water. The cooled two streams merge before entering manual valve XV786 located at the suction side of the charging pump cooling water pump, MDPCC2A.

One assumption made, based on operating experience, is that charging pump service water to the intermediate seal cooler is considered unnecessary for successful operation of the charging pump seal coolers. Therefore, in developing the fault-tree logic for the failure to supply sufficient flow through the seal coolers, failure of heat exchange at the intermediate seal coolers was not modeled. Because of this assumption, we note that the new Technical Specifications requirement on the use of both intermediate seal coolers has virtually no impact on the fault-tree model.

Cross connection with the Unit 2 CPC system was not modeled in the fault tree, because it was considered as a recovery action in the accident-sequence analysis.

The fault tree can be divided into two major sub-trees, one delineating the logic of failing to provide sufficient service water flow to charging pump A lube oil cooler, and the other depicting the failure to provide sufficient component cooling water flow through charging pump A seal coolers. The dependencies of the charging pump SW pumps, MDPSW10A and MDPSW10B, on their respective 480 VAC MCC buses are properly modeled. Common-cause failures modeled on train level include CPC-CCF-LF-STRAB (common mode loss of flow strainers STR2A and STR2B), MCW-CCF-VF-INLVL (insufficient intake canal level). On the other hand, common-cause failure of motor-operated self-cleaning strainers STR1A and STR1B, was not modeled, nor was the dependency of these strainers on power supply explicitly modeled. Back flow through train-A pipe segment, PS100 (upstream of manual valve XV116) is considered to induce a common-cause failure of the coolant flow through train-B pipe segment, PS101 (upstream of manual valve XV119). Typographical errors were found in the definition of a few fault-tree events. CPC-MDP-FR-SW10A is defined as "MDPCC2A fails to run as long as charging pumps." Here, however, MDPCC2A should be changed to MDPSW10A. Similarly, MDP CC2B in the definition of CPC-MDP-FR-SW10B should be changed to MDPSW10B.

In our study, the CPC system fault trees were modified by eliminating some events modeling the pipe segments, PS100 and PS101. The fault tree for the remaining pipe segments was then interfaced with that of the service water system through a transfer gate. The charging pump lube-oil cooling system has two trains, Train-A and Train-B. The pipe segment extending from the screen-well up to and including manual valve XV302 (PS3 in Train-A) and that extending from the screen-well up to and including manual valve XV306 (PS4 in Train-B) are shared by both the service water system and the charging pump cooling system. Since the fault tree for these pipe segments was constructed as part of the service water system fault trees, it was used to model the CPC system.

To implement these modifications, the following alterations were made to the fault tree, CPCA :

- (i) From CPC1 of CPCA, eliminate CPC-STR-PG-STR1A (Strainer 1A plugged) and replace MCW-CCF-VF-INLVL (Insufficient intake canal level) by a transfer-gate, GCW1813 (Insufficient SW supply flow from Pipe SEGs PS3 or PS4).
- (ii) Add the transfer-gate, GCW1813, to the intermediate event CPC2.
- (iii) From CPC9, eliminate the basic event, MCW-CCF-VF-INLVL.
- (iv) From CPC5, eliminate the following 3 basic events:
  - CPC-XVM-PG-XV305 (Manual valve XV305 plugged)
  - CPC-STR-PG-STR1B (Strainer 1B plugged)
  - CPC-XVM-PG-XV306 (Manual valve XV306 plugged)

In the NUREG/CR-4550 modeling of the subtree depicting the logic of failing to provide sufficient flow through the seal coolers of charging pump A, attention focused mainly on the various possible causes of failing to provide sufficient flow through pipe segments, PS111 and PS118. Since the charging pump cooling pump, MDPCC2A, is assumed to be initially operating, failure to provide sufficient flow in pipe segment PS118 is considered to occur only when the pump itself fails (to run long enough) or of the 480 VAC MCC 1H1-1 bus fails, which provides motive power to the cooling pump.

For failure to provide sufficient flow through pipe segment PS111 using the standby charging pump cooling water pump, MDPCC2B, the dependencies of the cooling pump on an actuation signal and 480 VAC MCC 1J1-1 bus are both modeled properly. The unavailability of the cooling water pump due to testing and maintenance, failures of the pump to start as well as to run for sufficient period of time, and plugging of the manual valves are also modeled. No modification of these subtrees was necessary.

The corrected and modified fault tree model discussed in this subsection is applicable to all POSs, i.e., POS 1 through POS 15, since one charging pump (pump A) is presumed to be always running when the reactor is in shutdown.

- (2) Logic Model for CPCB (Insufficient CPC to charging pump CH1B: SW to lube oil/CC to seal cooler)

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This fault tree was constructed in the NUREG/CR-4550 report to delineate the logic of failing to provide sufficient CPC flows to charging pump B, which is normally on standby. The main difference between the fault tree structures of CPCB and CPCA is that the flow paths of the charging pump service water to the lube oil coolers of the two charging pumps are different. Modeling of the closed-cycle component cooling water flow paths to the charging pump seal coolers, however, remains identical to that described previously for CPCA. Whenever possible, the logic model for CPCB uses the events that have been logically developed and discussed above in (1) for CPCA. In fact, the fault tree CPCB interfaces with the fault tree, CPCA, at the following four developed events:

- CPC1 - Insufficient flow through CPC pipe segment PS100
- CPC2 - Insufficient flow through CPC pipe segment PS101
- CPC3 - Insufficient flow through CPC pipe segment PS111
- CPC4 - Insufficient flow through CPC pipe segment PS118

The logic models of these four events were discussed in connection with the fault tree for CPCA. The corrections and modifications made to these models, discussed earlier, are applicable here. Since charging pump B is normally on standby, a signal is required to actuate the cooling of its lube oil following its startup. This dependency is modeled in the fault tree. The pipe segment, PS105, which is a flow path unique to charging pump lube oil cooler, HXCH5B, contains five manual valves and one temperature control valve, TCVSW108B. Plugging of these manual valves and the failure of TCVSW108B to open on demands are all modeled properly.

This fault-tree model was found to be applicable to POSs 1 through 15 without further modification.

(3) Logic Model for CPCC (Insufficient CPC to charging pump CH1C:SW to lube oil/CC to seal cooler)

Structurally speaking, this fault tree, which depicts the logic for failing to supply sufficient CPC flows to charging pump C, is virtually identical to that described above in (2) for CPCB. The only difference lies in distinguishing the paths of service water flow to the charging pump lube oil coolers. No particular modeling change is required for the component cooling water flow paths to the charging pump seal coolers. As in the case of CPCB, the fault tree interfaces with the fault tree of CPCA at the same four developed events, CPC1, CPC2, CPC3, and CPC4. Since charging pump C is considered to be normally on standby, an actuation signal is required to begin lube-oil cooling following its startup. This dependency is properly modeled. The pipe segment, PS106, which is a flow path unique to charging pump lube oil cooler, HXCH5C, contains five manual valves and one temperature control valve, TCVSW108C. The model considers plugging of these manual valves and the failure of TCVSW108C to open on demand.

This fault tree model was found to be applicable to POSs 1 through 15 without further modification.

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Table 6.2.3-1 CPC Component Status and Dependency Summary

COMPONENT	NORMAL STATUS		ACTUATION	DEPENDENCIES
Pumps:	POS 1, 2, 14, 15	POS 3-13		
1-SW-P-10A	operating	operating		MCC-1H1-1
1-SW-P-10B	standby	standby	Starts on low header pressure	MCC-1J1-1
1-CC-P-2A	operating	operating		MCC-1H1-1
1-CC-P-2B	standby	standby	Starts on low header pressure	MCC-1J1-1
AOVs:				
TCVSW108A	open	open		
TCVSW108B	closed	closed	Open on increased lube oil temperature. Valves fail open on loss of DC power or instrument air.	
TCVSW108C	closed	closed		
Strainers:				
1-VS-S-1A	operating	operating		1H1-2S
1-VS-S-1B	operating	operating		2H1-1

6.2.4 Component Cooling Water System

6.2.4.1 System Configuration and Description

The Component Cooling Water (CCW) system is a closed-cycle cooling system providing cooling to various heat loads at both Surry units, Unit 1 and Unit 2 under any operational conditions. Its major components are a surge tank, four motor pumps and four heat exchangers to reject heat to the Service Water System, crosstie among the discharge headers of the pumps, crosstie among the heat exchangers, and a coolant distributing piping manifold. Makeup water to the CCW is supplied from either unit's Main Condensate System.

The Unit 1 CCW system, as defined for this analysis, includes only that portion of CCW system which provides cooling water to Unit 1 Residual Heat Removal (RHR) system, the Reactor Coolant Pump (RCP) thermal barriers, and provides makeup to the Charging Pump Cooling Water Subsystem (CPCS). That portion consists of the surge tank, two parallel CCW pumps, two parallel CCW heat exchangers, and two CCW distribution headers; 1A and 1B. Its simplified flow diagram is shown in Figs. 6.2.4-1a and 6.2.4-1b.

The 1A header supplies cooling water to RHR heat exchanger, 1-RH-E-1A.

The 1B header supplies to the following heat loads:

- RHR heat exchanger, 1-RH-E-1B,
- RHR pump seal coolers; 1-RH-E2A, and 1-RH-E2B,
- RCP thermal barriers; 1-RCP-1A, 1-RCP-1B and 1-RCP-1C.

When needed, this header provides makeup water to the CPCS.

The CCW pumps (1-CC-P-1A and 1-CC-P-1B) take suction from an 18-inch inlet header that is supplied with water from the component cooling return headers and the surge tank. For each unit, one CCW pump and one heat exchanger are used normally when both units are in operation. The two standby pumps supply 100 percent backup capability to each Unit.

The standby pump for each reactor unit automatically starts on low discharge pressure; they are designed to deliver 9000 gpm with a discharge pressure about 85 psig. The discharge pressure is monitored by pressure sensor; 1-PS-CC-101A. The required NPSH is met by the CC surge tank mounted approximately 30 feet above the suction level of the pumps (about 15 psig). Each CCW pump is a horizontally mounted, single-stage, double-suction, centrifugal pump. Pump friction, radial and axial misalignment is minimized by using two radial sleeve bearings and a thrust bearing. The bearings are oil-lubricated and self-cooled. The pumps employ a single mechanical seal which also requires no external cooling. The discharge from the CC pumps is directed to the CCW heat exchangers: 1-CC-E-1A and 1-CC-E-1B.

The heat exchangers act as a heat-transfer medium between the CCW and the Service Water system. (They also serve as a barrier against the leakage of radioactivity into the Service Water system). The heat exchangers are designed to transfer 50.3×10^6 BTU/hr under normal conditions. Screenwells 1B and 1D supply SW to the tube sides of the CCW heat exchangers through two normally open MOVs: 1-SW-MOV-102A and 1-SW-MOV-102B. Each heat exchanger has a manual inlet and outlet isolation valve: 1-SW-37, 1-SW-39 for 1-CC-E-1A and 1-SW-33, 1-SW-35 for 1-CC-E-1B. (Service water also is supplied to the Turbine Building SW subsystem via the above MOVs.)

If an operating heat exchanger fails, the standby heat exchanger must be valved in manually. The discharge header from the Unit 1 heat exchangers supplies CC water to the 18-inch Unit 1A and B distribution headers.

The CCW lines to each RHR heat exchanger (Fig. 6.2.4-2 is a schematic of the RHR system's cooling) contain two manual isolation valves and a relief valve: 1-CC-178, 1-CC-181, 1-CC-RV-119A and 1-CC-182, 1-CC-185, 1-CC-RV-119B. Containment isolation trip valves CC-TV-109A and 1-CC-TV-109B are located

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downstream of the RHR heat exchangers. The trip valves are operated from the MCR and are designed to shut automatically upon initiation of Phase I containment isolation (Safety Injection).

The mechanical seals of the RHR pumps are cooled by CC water in the seal coolers, each of which has inlet and outlet manual isolation valves (1-CC-122, 1-CC-118 and 1-CC-116, 1-CC-112).

Inlet CCW flow to the RCP thermal barriers penetrates the containment through three, 6-inch lines (the simplified flow diagram of the RCP thermal barrier cooling is shown in Fig. 6.2.4-3). Each line has a relief valve (1-CC-RV-116A, B, and C). The thermal barrier discharge lines are equipped with isolation trip valves (1-CC-TV-120 A,B and C), which go closed on a high CCW flow signal after a 10-second delay designed to prevent spurious trips. The three discharge lines from the thermal barriers join to form a common line having containment isolation trip valves 1-CC-TV-104A inside the containment and 1-CC-TV-104B outside. Containment isolation automatically isolates this line by shutting the trip valve on a High-High CSL Phase III signal.

A standby CCW pump starts automatically, provided all of the following conditions exist:

- (1) Low discharge pressure, as sensed by 1-PS-101A
- (2) Associated control switch in START or AUTO position (additional switch positions are: STOP and PULL-TO-LOCK)
- (3) Appropriate breaker racked-in
- (4) No ground/phase overcurrent condition; i.e. normal voltage on the associated bus.

If a CCW pump trips because of an electrical fault (loss of offsite power, ground or phase overcurrent) the pump cannot be restarted without resetting the lockout relay. This is reset by placing the control switch in the STOP/PULL-TO-LOCK position and only after, manually or automatically, can the power to the pump be restored. (The degraded and under-voltage protection relays trip open the CCW pump breaker, RHR pump breaker, and stub bus breaker. Power from stub bus will remain unavailable once its breaker is opened, until the degraded condition clears and an operator closes the breaker).

The relief valves protecting the CCW system piping are all set to lift at approximately 150 psig, except the relief valves for the RCP thermal barriers which lift at 2485 psig.

The trip valves associated with the CCW system are all pilot solenoid, air-actuated control valves operated from the MCR. The valves are designed to fail shut on loss of vital 120 V AC electrical power to the pilot solenoid or loss of instrument air pressure, except for RCP thermal barrier TVs which fail open. The RHR heat exchanger trip valves CC-TV-109A/B are equipped with quick-disconnect instrument air fittings so they can be locally operated with a portable air source. This feature was required for decay-heat removal according to the (fire) regulations of Appendix R to 10CFR 50.

6.2.4.2 Dependency on Other Support Systems

The CCW system primarily depends on the Service Water System, and on the AC and DC power buses for motive and control power to the CCW pumps. Also, it depends on the instrument air system and the 120V Vital AC System for motive and control power to the trip valves. The thermal barrier throttle valves are dependent on the instrument air system for motive power and on the semi-vital 120V and AC bus for control power. These dependency and specific train assignments are summarized in Table 6.2.4-1.

6.2.4.3 CCW System Operating Constraints

Technical Specifications require that two CCW pumps and two CCW heat exchangers are operable (24 hour AOT before hot shutdown and additional 48-hour AOT before cold shutdown) for any one unit to operate. During unit cooldown the two pumps, two heat-exchanger operation is designed to reduce the temperature

of the RCS to 140°F within 20 hours, based on a service water temperature of 95°F. Cooldown is possible with one pump and one heat exchanger operating for one unit; however, the time will extend beyond 20 hours.

The surveillance requirements for CCW pumps are that operability tests be performed every three months. During CCW system operation, samples are required to be taken on the service water flowing through the tube side of the heat exchangers. These samples are used to detect a CCW to SW leak through the heat-exchanger tubes. A sample must be taken on each of the in-service heat exchangers once per shift, with a maximum time between samples of 12 hours. Preventive maintenance of the CCW pumps and heat exchangers is usually performed during refueling outages.

6.2.4.4 Fault Tree Modeling of the CCW System

In the NUREG-1150 study, a single fault tree was developed to model the potential loss of CCW flow to the RCP thermal barrier. This fault tree was applied also to describe the loss of CCW to the CCW cooled components of the RHR System; that is, the RHR heat exchangers and the RHR pump seal coolers.

In the present study, a different fault tree was developed for each of the plant components cooled by the CCWs, so that asymmetric hardware and operational features (and their changes while the plant goes through various operational states, POS) could be modeled, as well as trainwise dependencies of the CCW systems components on other support systems.

Table 6.2.4.2 defines the fault tree top events, and the identifier in the various POSs of their variants and gives the number of the POSs, when the variant is used in the event-tree quantification.

The fault trees do not model the possibility that the Unit 1 portion of the CCW system can be cross-tied to the Unit 2 portion, because cross-ties are rarely used for only a small fraction of time. However, in the case of Unit station blackout (SBO) accident, the failure of Unit 2 CCW to provide continued cooling flow to the Unit 1 RCP thermal barriers and RHR system components was modeled, as appropriate Boolean expressions. These Boolean expressions will be converted into fault trees and used in the station blackout analysis.

6.2.4.5 Assumptions in the Fault Tree Models

The system-specific assumptions made in the fault tree analysis are as follows:

- (a) The A CCW pump and heat exchangers (1-CC-P-1A and 1-CC-E-1E) are operating. The B CCW pump and heat exchanger may be in test/maintenance in any time independently whether Unit 1 is in operation or in shutdown.
- (b) When Unit 1 is "operating," i.e., in POSs 1, 2, 14, 15 usually the RHR heat exchanger 1-RH-E-1A is lined up to be used. It is CCW isolated only by the closed trip valve 1-CC-TV-109A. Its CCW discharge valve 1-CC-181 is not closed, only throttled. The other RHR heat exchanger 1-RH-1B is CC isolated by the closed manual valve 1-CC-185.
In the fault trees for the RHR heat exchangers, these conditions are reflected by including the event "Trip Valve 1-CC-TV-109A in Unscheduled Maintenance" (e.g. Top Event CCW1) and by using standby (i.e., elevated) failure rates for potential plugging of some manual valves in the branchlines leading to the RHR heat exchangers.
- (c) With a CLS-I (real or inadvertent SI) signal, the trip valve 1-CC-109B closes, allowing some faults that would not occur without a containment closing signal. These faults involve 1-CC-109B and check valve 1-CC-176 failing closed, and for the operator failing to open 1-CC-109B. When SI/CLSI signal occurs, the house event SP-SI-CLSI-HE should be set equal to 1 in the models.

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- (d) When the RHR system is put into operation, (i.e. in POS 3) the trip valve 1-CC-TV-109A, and the manual valves 1-CC-181 and 1-CC-185 are opened. In modeling, this fact excludes the event of unscheduled maintenance of the trip valve, 1-CC-TV-109A and results in operational (smaller) failure rates for plugging of these manual valves. The model considers also the possibility that during RHR operation (POSs 3 through 13) the trip valves 1-CC-109A and B, as well as the check valves 1-CC-176 and 177 may fail closed if an inadvertent SI/CLS-I signal was generated; the house event SP-SI-CLSI-HE, again, should be set equal to 1 in the models.
- (e) The cross-tie between the A&B and Unit 2 C&D CCW pump discharge lines is assumed to be isolated by the four valves 1-CC-572, 573, 589, and 590.

Similarly, the cross-tie between the A&B and Unit 2 C&D CCW heat exchanger discharge lines is assumed to be isolated by the two valves 1-CC-588 and 595.

Figure 6.2.4-1 Simplified Flow Diagram. Component Cooling Water System, Pumps & Heat Exchangers

Figure 6.2.4-2 Simplified Flow Diagram. Component Cooling Water System

CCW2.DWG

Figure 6.2.4-3
Simplified Flow Diagram. Component Cooling Water System, RC Pump Thermal Barrier Cooling

Table 6.2.4-1 Component Dependency of the CCWS

Component	Motive Power	Control Power	Auto Actuation
1-CC-P-1A	4.16kV AC Stub 1H, BKR:15H10	125V DC Bus 1A	1-PS-CC-101A
1-CC-P-1B	4.16kV AC Stub 1J, BKR:15J10	125V DC Bus 1B	1-PS-CC-101A
1-CC-TV-140A 1-CC-TV-140B	Inst. Air Through Solenoid CC-SOV-107	120V AC Vital Bus 1-I, BKR: 13	CLS-2A (Hi-Hi) CLS-2B closes TV-107
1-CC-TV-109A	Inst. Air Through Solenoid CC-SOV-109A	120V AC Vital Bus 1-I, BKR: 16	CLS-I closes TV-109A
1-CC-TV-109B	Inst. Air Through Solenoid CC-SOV-109B	120V AC Vital Bus 1-II, BKR: 21	CLS-I closes TV-109B
1-CC-TV-120A	Inst. Air, fails open	Semi-vital 120V AC BKR: 3	Closes on Hi CCW flow signal (from FT- 107A)*
1-CC-TV-120B	Inst. Air, fails open	Semi-vital 120V AC BKR: 3	Closes on Hi CCW flow signal (from FT- 107B)*
1-CC-TV-120C	Inst. Air, fails open	Semi-vital 120V AC BKR: 3	Closes on Hi CCW flow signal (from FT- 107C)*

Table 6.2.4-1 (Continued)

Component	Motive Power	Control Power	Auto Actuation
1-SW-MOV-102A	1G1-1 480VAC, fails, as is	Stepdown transformer from 480 V AC MCC	Closes on Low Intake Canal Level (see note 1)
1-SW-MOV-102B	1J1-1 480VAC, fails, as is	Stepdown transformer from 480 V AC MCC	Closes on Low Intake Canal Level (see note 2)
1-CC-E-1A HXER	Tube side cooling: Service Water System		
1-CC0E-1A HXER	Tube Side cooling: Service Water System		

Table 6.2.4.2 Top Event Definition and Identifiers for CCWS

Top Event Definition	Identifier	No. of POSs
Insufficient CC Water to RHR HX, 1-RH-E-1A	CCW1 CCW1S	1, 2, 14, 15 3 through 13
Insufficient CC Water to RHR HX, 1-RH-E-1B	CCW2 CCW2S	1, 2, 14, 15 3 through 13
Insufficient CC Water to RHR Pump Cooler, 1-RH-E-2A	CCW3 CCW3S	1, 2, 14, 15 3 through 13
Insufficient CC Water to RHR Pump Cooler, 1-RH-E-2B	CCW4 CCW4S	1, 2, 14, 15 3 through 13
Insufficient CC Water to any of the three RCP Thermal Barriers	CCW5	1, 2, 3, 4, 12, 13, 14, 15

6.2.5 Instrument Air System

6.2.5.1 Instrument Air System Description

Surry's Instrument Air System has four subsystems: the Service Air (SA) System, the low-level intake structure instrument air system, the Turbine Building Instrument Air (IA) System, and the Containment Instrument Air (CIA) System. The low-level instrument air system is not needed in mitigating an accident and is not modeled. The other three systems are shown in Figures 6.2.5-1 to 3. During POS 1, 2, 3, 13, 14, and 15 each unit's containment vital air loads are supplied by an independent CIA System. All vital air loads outside the containment are supplied by the common SA System, with an independent IA System compressor train for each unit in reserve standby. During POS 4 thru 12, the CIA System is secured and the containment's vital air loads also are supplied by the SA System by opening two manual isolation valves (446 & 447 for Unit #1).

The SA system consists of three large-capacity air receivers and five compressors, the service-air compressors 1-SA-C-1 and 2-SA-C-1, outage compressors 1-SA-C-2A and 1-SA-C-2B, and a mobile outage-air compressor 1-SA-C-2C. The service-air compressors can supply 100% of the stations (units 1&2) IA requirements. Normally, one compressor is running and the other is on standby. The outage compressors are used only if the demand for non-critical outage air (e.g., pneumatic tools) becomes large; they are controlled locally at the compressor. The mobile compressor (Sullaire model 750DTQ CAT) is an air-cooled, two-stage, diesel-driven, oil-filled, rotary screw compressor with a capacity of 750 SCFM at 125 psig. In the abnormal procedure for loss of off-site power, AP 10, the operators are instructed to use this compressor. SOV-SA-124 and 175 are valves in the service-air system that can be used to isolate the service-air loads from the service-air receivers. This allows the latter to be used by the instrument air system. When problems arise in the service air system, check valves 1/2-SA-5 in the flow paths from the service air receivers to the instrument air-receivers prevent back flow to the service-air system.

The turbine building instrument air system (IA) consists of one compressor (1-IA-C-1) and one air receiver (1-IA-TK-1) per unit. It is powered from MCC-1J1-2 and depends on cooling water supply for the bearings of the compressor and intercooler. On an S signal, valves MOV-101A&B in the bearing cooling water line close, isolating this cooling train. This system is normally always in a standby mode. If the air receiver pressure drops below 90 psig, the compressor automatically starts and loads after a 15-second delay. On loss of electric power, valve IA-TV-126, which is normally closed, will fail open ensuring a flow path from the air receivers to the vital air loads bypassing the dryer assembly, even though that air may have a very high moisture content. The normal flow path is through the dryer assembly for both SA or IA and is controlled by valve IA-TV-125 which is normally open but fails closed on loss of electric power to the solenoid or a high DP in the upstream dryer train.

The CIA system consists of two 100% capacity compressors (1-IA-C-4A and B) and two common air receivers (the air receivers are located inside containment). This system is powered by the non-emergency buses and depends on both the primary grade water system for operating the compressor and CCW for cooling the seal. Normally, one compressor will start automatically when the containment instrument air pressure reaches 95 psig, and will trip at 105 psig. The other compressor will start at 90 psig and trip at 100 psig. During POS 4 thru 12, this system is secured. If available, it can be used during these POSs, but the compressor(s) must be manually started locally. On loss of electric power, TV-IA-100 fails closed, thereby isolating the system from the containment's vital air loads. The air supply for the compressors is normally from the containment, but when containment pressure is high TV-IA-101A&B close, and AOV-IA-103, which is normally closed, will open. On loss of power, AOV-IA-103 will fail as is.

6 System Description and Fault Tree Analysis

6.2.5.2 Instrument Air System Interfaces and Dependencies

Table 6.2.5-1 lists the components and dependency of the instrument air system.

6.2.5.3 Instrument Air System Operating Constraints

The instrument air system is normally operating. Although there is no technical specification requirement on the system, loss of air can lead to a reactor trip with loss of main feedwater or a loss of removal of decay heat depending on the plant's condition. The system has significant redundancy and cross-tie capability that ensures its reliability.

6.2.5.4 Instrument Air System Shutdown Configuration

When the reactor system reaches cold shutdown (less than 200°F) the integrity of the containment is no longer required; this corresponds to leaving POS 3 and entering POS 4. The containment's vacuum is broken at this point, and its instrument air system is supplied by the service air system receivers via the instrument air system by opening manual valves 446 and 447. After verifying their proper alignment, the containment's instrument air compressors are shutdown. During the beginning of the heatup phase, POS 12, containment integrity is re-established (see OP 1.1 step 5.52). Before reaching 200°F, the instrument air compressors are put online and valves 446 and 447 manually reclosed; this corresponds to leaving POS 12 and entering POS 13. Therefore, as far as the containment instrument air supply for the containment loads is concerned, the following is assumed:

<u>POS</u>	<u>Air Supply</u>
1-3	Containment Instrument Air System
4-12	Service Air/Instrument Air System
13-15	Containment Instrument Air System

Abnormal procedure, AP 10, for loss of offsite power direct the operator to fire main cooling to the instrument air compressors. This action is necessary because the bearing cooling water system that provides cooling to the compressors is not on the emergency bus.

Abnormal procedure, AP. 40.00, for non-recoverable loss of instrument air system, does not distinguish between loss of containment instrument air and loss of outside instrument air. However, loss of both seems to be accounted for. If the unit is on RHR when the loss occurs, the operators are instructed to use a portable air tank to reopen TV-CC-109A or B to restore CCW to the RHR heat exchangers and locally throttle outlet valve for the in-service HX. Meanwhile, attempts are made to restore the instrument air systems of the turbine building and the containment using the mobile Sullair air compressor. The containment instrument air can be restored by opening IA-446 and 447 to connect to the outside instrument air.

6.2.5.5 Instrument Air System Logic Model

Table 6.2.5-2 summarizes the impacts of loss of these two systems. The impacts A and B in the table can be imposed on different POSs, based on how the containment's instrument loads are supplied. We note that the

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configuration of the air system depends on whether the plant is at cold shutdown: this differs from some other systems, whose configuration depends on whether the RHR system is in service.

Initiator	POS	Impact
Loss of Containment air	1-3	B
	4-12	N/A
	13-15	B
Loss of Instrument Air	1-3	A
	4-12	A and B
	13-15	A

For POS 1 to 3 and 13 to 15, two new fault trees were developed for the instrument air system, one for the turbine building instrument air system (top event name TIA) and one for the containment instrument air system (top event name CIA); these trees were not in the NUREG/CR-4550 study. For the turbine building instrument air system, we assumed either one of the two service air compressors or the instrument air compressor can provide all air load. For the containment instrument air system, either of the two compressor can supply the loads. These compressors should operate automatically. Use of other compressors requires operator action and is considered recovery action. It is assumed that manual valves and check valves that are normally open have insignificant contributions to the availability of the system: For example, plugging of the valves is considered less likely than that of the dyer.

For POS 4-12, one fault tree was developed for the turbine building instrument air system.(Top event name TIA-CSD) This fault tree is similar to fault tree TIA except that it is assumed that one outage compressor and one service air compressor are normally operating, and two compressors are needed to supply all the service air and instrument air loads. That is, failure of either compressor will demand the instrument air compressor to start. Once it is started, it can supply all instrument air loads.

Common-mode failures of the service air compressors and containment instrument air compressors to continue running are modeled as basic events with a beta factor of 0.1. The dependence of the containment instrument air compressors on primary grade water and bearing cooling water is modeled with basic events. The impacts of consequence-limiting control signals (CLS-H and CLS-HH) are modeled as house events in the fault trees.

6 System Description and Fault Tree Analysis

COMPRESSED AIR SYSTEM

Figure 6.2.5-1 Compressed Air System
6-44

Graphics No: CB720A

Figure 6.2.5-2 Instrument Air System

Table 6.2.5-1 Instrument Air System Component Status and Dependency

COMPONENT	NORMAL STATUS		DEPENDENCIES
	POS 1-3,13-15	POS 4-12	
Compressors:			
Service Water			
1-SA-C-1	running	running	14C2-6(480v bus 1C2)
2-SA-C-1	running	running	24A2-2(480v bus 2A2)
Outage Air			
1-SA-C-2A	standby	running	24A2-1(480v bus 1A2)
1-SA-C-2B	standby	standby	24A2-1(480v bus 1A2)
1-SA-C-2C	standby(mobile)	standby(mobile)	diesel
Instrument Air			
1-IA-C-1	standby	standby	MCC-1J1-2 BKR 2A BCW*
2-IA-C-1	standby	standby	MCC-2J1-1 BKR 2-1 BCW
Containment Air			
1-IA-C-4A	running	secured	MCC-1A1-1 PGW* CCW
I-IA-C-4B	standby	secured	MCC-1B1-2 PGW CCW
Instrument Air Dryers			
1-IA-D-1	running	running	MCC-1J1-2
2-IA-D-1	running	running	MCC-2J1-1
Valves			
Service air			
PCV-SA-101 (removed,check valve 1-SA-5 isolates SA from IA)			

6 System Description and Fault Tree Analysis

Table 6.2.5-1 (continued).

COMPONENT	NORMAL STATUS		DEPENDENCIES
	POS 1-3,13-15	POS 4-12	
PCV-SA-20 (removed,check valve 2-SA-5 isolates SA from IA)			
Instrument Air			
MOV-101A	NO/FAI	NO/FAI	MCC 1H1-1
MOV-101B	NO/FAI	NO/FAI	MCC 1J1-1
IA-TV-126	NC/FO	NC/FO	IA 1J1-2 BKR 1D-2
IA-TV-125	NO/FC	NO/FC	IA 1J1-2 BKR 1D-1
Containment instrument air			
AOV-1A-103	NC/FAI	not used	CIA non-vital bus
IA-TV-101A	NO/FC	not used	close on H CLS VB1-I CIA
IA-TV-101B	NO/FC	not used	close on H CLS VB1-IV CIA
TV-IA-100	NO/FC	not used	close on H HCLS VB1-IV CIA
446	closed	open	manual
447	closed	open	manual

*BCW = Bearing Cooling Water System
PGW = Primary Grade Water System

Table 6.2.5-2 Impacts of loss of Turbine Building Instrument Air System and Containment**Instrument Air System****A. Impacts of loss of turbine building instrument air:**

1. Loss of CCW to containment
 Valves TV-CC-109A & B close, resulting in a loss of cooling to the RHR pump seal coolers, and excess letdown coolers inside the containment.
 Valve TV-CC-107 closes resulting in loss of RCP thermal barrier cooling.
 Valve HCV-CC-108 closes resulting in loss of cooling to the excess letdown heat exchanger.
 Valve TV-CC-105A,B,C close resulting in the loss of cooling to RCP stator and lube oil cooling.
 Valves TV-101A,B,C fail closed, HCV-101A fails open resulting loss of heat removal to the containment air recirculation coolers.
2. A false low SG water level signal is generated.
3. A false low SW canal level signal indication is generated (see AP 40.00 attachment 1).
4. MFW regulator and bypass valves fail closed.
5. Steam admission valves to the turbine driven AFW pump fail open, thereby allowing the pump to start if steam is available.
7. Atmospheric dump valves for the secondary side of the SG's will be unavailable.
8. Dumping of steam to condenser will be unavailable because the Main Steam Trip Valves (MSTVs) fail closed.

Essentially, RHR will be unavailable, with possible pump failure. If the RHR was in operation, bleeding of the secondary side of the steam generators can be only done by manually opening the bypass valves around the MSTVs locally.

B. Impacts of loss of containment instrument air:

1. Loss of RHR flow control.
 Letdown flow control valve 1-RH-HCV-1142 fails closed.
 RHR HX Flow control valve 1-RH-HCV-1758 fails open.
 RHR HX BYP flow control valve 1-RH-FCV-1605 fails closed.
2. Loss of Pressurizer auxiliary spray capability/flow path. HCV-1311 fails closed.
3. Excess letdown HX discharge valves HCV-1137 and HCV-1389 fail closed.
4. Letdown isolation valves LCV-1460A&B fail closed.
5. Letdown orifice isolation valves 1200A,B&C fail closed.
6. Letdown containment isolation valve TV-1204A fails closed.
7. Normal charging flow to loop B, HCV-1310 fails open.
8. Charging flow control valve FCV-1122 fails open.

Basically the RHR system has full flow capability through the RHR heat exchangers, but no control. Letdown is isolated with charging at full flow to the loop B cold leg. Depending on RCS configuration, this could result in a LTOP event.

6 System Description and Fault Tree Analysis

6.2.6 Containment Spray System

6.2.6.1 Containment Spray System Description

The CSS diagrams are shown in Figs. 6.2.6-1 and 6.2.6-2.

The containment spray system provides initial cooling of the containment's atmosphere following a containment-pressurizing accident (e.g. a LOCA). It takes the cool (45°F) borated water from the RWST and sprays it inside the containment to condense the steam. NaOH from the chemical addition tank (CAT) is added to the spray water to scavenge out the (radioactive) iodine from the atmosphere, thus reducing the offsite consequences and helping to maintain long-term stability of the pH of the containment sump.

The containment spray system consists of two 100% capacity trains, each is connected to a separate spray ring; and there is an additional ring shared by both trains. The spray pattern from the rings covers about 73% of the containment's atmosphere. The pumps take suction through two normally open MOVs (MOV-CS-100A and B) and discharge through four normally closed MOVs (two valves in parallel for each pump: MOV-CS-101A, B, C, & D). Each of the latter valves receives open signals from opposite CLS trains to ensure that at least one valve opens on a CLS signal. The valves cannot be shut manually until the CLS signal is reset and the respective CS pump is stopped. The CAT is connected to the CSS pump suction via normally closed MOV-CS-102A & B (in parallel) and normally open MOV-CS-103A, B, C, & D. The latter four valves were welded open in 1991, so they are no longer controllable. The original purpose of these valves was to prevent the NaOH from being drawn into the RWST should an operating CSS pump fail (the corresponding valves would close in that case); subsequent evaluations determined that there is no need for this. There are drain lines (going to the containment sump) in each CSS pipe downstream of the weight-loaded containment isolation check valves. These lines drain any liquid trapped in the system after testing; the flow loss through these lines during actual CSS operation would be negligible.

The CAT contains (by Tech Specs) about 4200 gallons of 17-18% NaOH solution. A recirculation pump keeps the solution mixed. The RWST tank contains (by Tech Specs) between 387,100 and 398,000 gallons of 2300-2500 ppm borated water. The proper boron concentration is maintained by the CVCS during RWST makeup. The RWST can be made up by using the spent-fuel pool purification system (each SFP pump can put out 150 gpm). Following refueling, the RWST water is cooled down to 45°F by the chilled water system. Thereafter, the RWST refrigeration units maintain the temperature between 43-45°F. The RWST is insulated, which limits the rise in temperature to 0.5°F per day should the refrigeration units fail. There are two RWST recirculation pumps for each unit; one pump is in AUTO, the other is OFF. The operating pump (in normal plant operation) takes suction from the upper, warmer part of the RWST and recirculates (at low speed) should the RWST temperature rise above 43°F. It shuts off when the temperature drops below 40°F. After refueling, the pump operates at high speed, and takes suction from the bottom of the RWST (to aid in NPSH requirements at such speed) to speed up cooldown via the heat exchangers. Each spray pump also has a recirculation line to the RWST (opened by normally closed manual valves) that is used for testing the CSS pumps. The spray pump discharge is split into two paths: the major portion goes directly into the RWST, while a small part is diverted through test nozzles inside the RWST; the test nozzles are identical to the ones inside the spray rings, hence, the RWST water is tested for any particulates that may plug the nozzles.

Each spray pump can put out about 3200 gpm of flow. When the RWST supply is exhausted (it provides borated water to both the CSS and the LPI/HPI), the CSS has to be manually secured by the operator; the recirculation spray systems are started by timers a few minutes after the CSS start, so that enough water has accumulated in the sump. Therefore, the CSS and ISR/OSR will be operating in parallel for some time. This relationship is somewhat different from that between the LPI and the LPR systems, where the RMT system

provides automatic switchover (backed up by operator action) when the RWST level drops to about 20%. The CSS is a support system for the OSR (outside spray recirculation system), as part of the CSS flow (about 300 gpm) is diverted to the suction of the OSR pumps to provide the minimum NPSH (net positive suction head) by cooling the sump water in that area.

6.2.6.2 Containment Spray System Interfaces and Dependencies

The CSS system depends on the CLS to provide the start signal on containment high-high pressure (23 psi), and on the RWST for fluid inventory. The assumption is that RWST cooling is not needed (and may not be available) in POS 3-13. The CSS is also dependent on the 480V emergency a.c. power buses 1J and 1H for power to the CSS pumps and for control (via stepdown transformers) and motive power (via motor control centers 1H1-2 and 1J1-2) to the MOVs. It depends on the 125V DC power buses 1A and 1B for control to the CSS pumps. The dependencies are shown in Table 6.2.6-1.

6.2.6.3 Tech Specs and Minimum Equipment List

The requirements on the CSS are for > 350 F, 450 psig. There are no requirements below these limits. While the reactor is operating, both CSS trains must be operable; otherwise, the AOT is 24hrs and the reactor must be placed in hot shutdown 6 hours after AOT expiration and in cold shutdown within an additional 48 hours. Before, exceeding 350°F, 450 psig, on the ramp up to power, both CSS trains must be available. Therefore, in POSs 1, 2, 14 and 15, at least one train is available (but there is a small chance that both trains are unavailable due to AOT requirements). The RWST must contain at least 387,100 gal of 2300 ppm boric acid (but not to exceed 398,000 gal of 2500 ppm) and must be colder than 45°F. All four containment pressure transmitters must be operable. If one channel is inoperable, it may be placed in the tripped condition within 6 hours and the minimum operable channels requirement is met. The CAT must have between 4200 and 4330 gal of 17-18% NaOH solution.

There are no tech specs for this system below 350° F, 450 psig, i.e. in POSs 3-13, although, informally, the availability is relatively high (75%) on the pumps. However, the RWST cooling has no requirements in those conditions (and more than half the RWST water may be inside the containment, during refueling). However, due to the less stringent requirements, and the fact that the CSS and ISR/OSR operate in parallel, credit will be given to the CSS if at least one pump is available in those conditions.

6.2.6.4 Testing, Maintenance and Shutdown Configuration

Testing for the CSS is done per the following schedule: quarterly for the pumps (while at power); every 5 years for the spray nozzles and the check valves (during a refueling outage); and MOV tests are done at unspecified intervals while at power.

There are no set times when the maintenance is done on the CSS system components, other than the fact it can be done at any time when the system is below 350° F, 450 psig. Hence, in POSs 3-13, there are no rules for configuration of the CSS system.

6.2.6.5 Modifications to the 1150 Fault Trees

The modified fault trees are shown in Appendix C.6. The modified trees are named CLPSD (the top event fault tree to be used in the event trees), CSS1N115, CSS1N313, and CSS2N115. The trees CSS1N115 and CSS2N115 are used for POSs 1, 2, 14 and 15, while the tree CSS1N313 is used in POSs 3-13. A house event (HOUSE-POS313) and its complement select the appropriate trees according to the POS. HOUSE-POS 313

6 System Description and Fault Tree Analysis

The following are the changes made:

POS 1, 2, 14 and 15

Manual actuation of the CSS (if the CLCS fails) is given credit for. To manually actuate it, the operator has to press two buttons in the MCR simultaneously. Therefore, there is no separate actuation of train A vs. train B. The event CLS-ACT-OP-CLS2 represents this manual actuation. In the 1150 report it is stated that this action is taken credit for in the fault trees (rather than in the sequence cut sets as a recovery action would be) because it is a skill-based, simple action which the operator would memorize and there would be indications in the MCR that it is needed (startup of SI and/or the other CLS train). However, the appropriate events (CLS-XHE-FO-MAN-A, CLS-XHE-FO-MANS1 and CLS-XHE-FO-MANS2) never appear in the fault trees.

We note that, for Level 1 work, the availability of CAT and associated components is immaterial and is not included in the fault trees; however, this will be important in Level 2/3 analyses.

POS 3-13

In addition to the appropriate changes from the above, the following changes are also implemented: One CSS train is always unavailable for maintenance, and the other is also unavailable 25% of the time for maintenance. (The RWST is assumed available as in the discussion above). Event CSS-TRA-MA denotes the maintenance unavailability of train A when shutdown, while train B is assumed down all the time in these POSs, as discussed with Surry personnel.

Since the automatic actuation of CSS is disabled in these POSs, an event is added that asks the question of operator manually starting the two CSS trains. This event is CSS-MDP-OP-AB. The event CLS-ACT-FA-CLS2A (and B) is deleted, as it represents CLCS failure in POS 1,2,14 and 15.

Maintenance event CSS-MDP-MA-CS1A is deleted, as event CSS-TRA-MA already takes into account maintenance on level of train A (train B is assumed down as per discussion above).

Figure 6.2.6-1 CS System Simplified Diagram

Figure 6.2.6-2 CS System Diagram (Sheet 1)

Table 6.2.6-1

**CS
Dependency Matrix¹**

Component	Motive Force	Control Power	Auto Actuation
1-CS-P-1A	480 VAC Bus 1H CKT-14HS	125 VDC A	CLS-2A
1-CS-P-1B	480 VAC Bus 1J CKT-14JS	125 VDC B	CLS-2B
1-CS-MOV-100A	480 VAC MCC-1H1-2S CKT-CS130A BRKR 32	480 Volt stepdown transformer	CLS-2A2
1-CS-MOV-100B	480 VAC MCC-1J1-2W CKT-100B BKR 31	480 Volt stepdown transformer	CLS-2B2
1-CS-MOV-101A	480 VAC MCC-1H1-2S CKT-CS101A BKR 11	480 Volt stepdown transformer	CLS-2A2
1-CS-MOV-101B	480 VAC MCC-1J1-2W CKT-CS101B BKR-51	480 Volt stepdown transformer	CLS-2B2
1-CS-MOV-101C	480 VAC MCC-1H1-2S CKT-CS101C BKR-22	480 Volt stepdown transformer	CLS-2A4
1-CS-MOV-101D	480 VAC MCC-1J1-2W CKT-CS101D BKR-41	480 Volt stepdown transformer	CLS-2B4

¹ For all components, component cooling is not provided,
and room cooling is not required.
There are no interlocks

6 System Description and Fault Tree Analysis

Table 6.2.6-2

New Events for CSS

Event Name	Description	Probability	Error Factor
CLS-ACT-OP-CLS2	No operator actuation CLCS initiation of ESFAS	1.4 E-3 ^a	10.0 ^b
CSS-MDP-OP-AB	No operator actuation CSS system, POS 3-13	1.4 E-3 ^a	10.0 ^b
CSS-TRA-MA	Unavailability of TRAIN A (maintenance)	0.25 ^c	10.0 ^b
HOUSE-POS313	HOUSE POS 3-13	1	1.0

^aTaken from Surry IPE submittal

^bEngineering judgement (taken from similar type events in 1150)

^cBased on discussions with plant personnel at Surry

6.2.7 Emergency Power System

The Emergency Power System distributes power to components that are needed to protect the reactor and the public during accident conditions. The EPS is a support system that interfaces with nearly all front line systems and other support systems.

6.2.7.1 EPS Description

The simplified diagram of the EPS is presented in Figures 6.2.7-1 to 3. The figure shows the EPS as part of the Basic Electrical Distribution System of the plant.

The Basic Electrical Distribution System is composed of two major areas: the Switchyard and the Plant Electrical Distribution System. The latter is divided into three parts: 1.) The Power Generation System, 2.) the Station Service Electrical Distribution System, and 3.) the Emergency Power System.

The purpose of the Switchyard is to transmit electrical power to 11 substations by eight 230 KV and three 500 KV transmission lines. The switchyard provides power to the EPS and to the units when one or both units are not producing any electrical power.

The output of each Unit's generator is connected to the Station Service Electrical Distribution System through three Station Service Transformers (SSTs) which step the voltage down from 22 KV to 4160 V. The generators are also connected to the switchyard through the main transformers (MTs) which step the voltage up from 22 KV to 230 KV (Unit 1) or 500 KV (Unit 2). A set of removable links in the generator output leads allows the generator to be electrically separated from the MTs and SSTs; this feature allows the Station Service Buses (1A,1B,1C) to be powered by backfeed from the switchyard through the MTs when the unit is off the line.

The Station Service Electrical Distribution System supplies power to the components in the station that are not necessary for protection of the reactor and the public, therefore, it is not analyzed further.

The EPS itself at each Unit consists of two 4160 VAC buses, four 480 VAC buses, four 120 VAC vital instrumentation buses, two 125 VDC buses, one dedicated and one shared diesel generator, and their associated motor control centers, breakers, transformers, uninterruptable power supplies, and batteries. (The busworks at the two units are symmetrical, therefore, the description is equally applicable for both units with the appropriate change of a designator: 2H for 1H, 2J for 1J).

RSS Transformers

The normal or "preferred" source of power to the Emergency Buses is H and J from the three Reserve Section Service Transforms (RSS A, RSS B, RSS C) and the associated Transfer Buses (D, E, F), with an emergency power source from the diesel generators. The RSSTs are supplied by the 34.5 KV switchyard buses 5 and 6: Bus 5 supplies power to RSS A and RSS B, Bus 6 supplies power to RSS C.

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The RSS transformers are three-phase, step-down, 34.5 KV to 4160 VAC transformers and are located south of the Turbine Building. RSS transformers A and B provide power to 4160 emergency buses 1J and 2H through transfer buses D and E. RSS transformer C provides power to 4160 VAC emergency buses 2J and 1H through transfer bus F. The cables from RSS transformer C are kept separate from those of A and B to minimize the possibility of a single accident causing the loss of both emergency trains for either unit.

(The switchyard buses 5 and 6 feed also the "Screenwell" transformers A and B, respectively. The associated Screenwell buses supply the circulating water pumps at the Low Level Water Intake. The details of these switchyard features are not shown in Figure 6.2.7.1).

Transfer Buses

The transfer buses are located in the Unit 1 Switchgear Room in the Service Building. Each transfer bus has breakers that connect the bus to the following:

1. an RSS transformer
2. two bus ties to the associated normal 4160 VAC buses, and
3. an emergency bus (two emergency buses for transfer bus F).

During normal plant operations, the transfer buses supply power only to the EPS. During plant shutdown and loss of power situations, the transfer buses may be required to supply power to part or all of the Basic Electrical Distribution System. Two automatic systems, load shed and auto-start inhibit, protection against overloading the transfer buses. The scheme for load shed reduces the electrical loading on RSS transfer buses D, E, and F during events which necessitate two-unit simultaneous loading on an individual transfer bus. The auto-start inhibit scheme ensures that adequate power is available during a Safety Injection or Consequence Limiting Safeguards actuation by delaying the automatic starting of some of the plant loads (60 sec. after SI, and 315 sec. after CLS Hi-Hi signal).

- The largest electrical load on the station service bus is the Reactor Coolant Pump. If it is not running, then in all likelihood the bus will not experience excessively high amperage. Therefore, by procedure, load shed is enabled when both units are running or soon will be running RCPs. This is regardless of which transformers are supplying the buses, because a unit trip will cause the station service buses to load into the RSSTs automatically.

When load shed is activated, the following equipment trips automatically:

1. one main feed pump on each unit,
  2. one condensate pump on each unit,
  3. both high and low pressure reactor drain pumps on each unit and some other loads.
- The equipment that is affected upon initiation of the auto-start inhibit scheme is as follows:
    1. component cooling water system pumps
    2. condensate pumps
    3. high pressure heater drain pump, and
    4. bearing cooling pumps.

4160 VAC Emergency Buses

The 4160 VAC emergency buses 1H and 1J are located along the north end of the Unit 1 Emergency Switchgear and Relay Rooms in the basement of the Service Building. The emergency buses are color-coded orange for bus 1H and purple for bus 1J, and are separated by a cement wall.

The 4160 VAC emergency buses are physically divided into two panels, each consisting of cubicles that house various breakers and are arranged to form a passageway between the two panels. Air circuit breakers (ACB) 15H9 and 15J9 are called stub bus breakers. They connect a short bus, called the "stub bus", to the main bus bars in the emergency panels. On emergency bus 1H, the stub bus consists of the breaker cabinets for ACB 15H9, 15H10, and 15H11. The 1J stub bus is similar. The purpose of the stub bus is to quickly reduce the amount of load on the bus in an undervoltage situation.

The 4160 VAC emergency buses can be interconnected by a breaker that is normally removed from its cubicle, located on the H bus. The ability to interconnect the two emergency buses provides a second source of power to an emergency bus if the normal source (and diesel) is not available. This breaker is under strict operational supervision of the station's supervisory staff to prevent an inadvertent interconnection of the two emergency trains, and is there for maintenance purposes only. The 4160 VAC buses provide power to the large pumps, such as the high pressure injection pumps, the stub buses which each power one CCW and Residual Heat Removal pump, and the 480 VAC buses through transformers. The stub bus is shed on undervoltage on the main bus.

Emergency Diesel Generators

Surry has three diesel generators which supply power to both units. Diesel Generators 1 and 2 are dedicated to the H train at each unit. Diesel Generator 3 is a swing diesel that can align to the J train at either unit. The swing diesel will preferentially load onto the unit that has an SI or CLS Hi-Hi signal present. Otherwise, it will load onto the unit whose breaker closes first. If no SI signal is present at either unit, the diesel can be manually realign from one unit to the other. Both units cannot be fed from Diesel 3 at the same time.

Diesel Description

Each diesel generator is a self-contained 2850 KW generating unit. The diesels are self-cooled (water cooled with water-air radiators), have self contained starting batteries that suction directly on outside air (an air start system), and have a separate day tank and two fuel oil transfer pumps. The only dependency with other plant systems is that DC power required to close the diesel output breaker is supplied from the station vital batteries. However, if this battery is unavailable, the diesel can be loaded onto the emergency buses manually with spring-loaded jacking mechanisms.

480 VAC Emergency Buses

The 4160 VAC emergency buses provide power to four 480 VAC emergency buses: 1H, 1H1, 1J, 1J1. The 480 VAC emergency buses are located south of their respective 4160 VAC bus in the Unit 1 Emergency Switchgear and Relay Rooms. Each bus houses its own 4160/480 VAC transformer and major load breakers.

6 System Description and Fault Tree Analysis

The following description applied to the 1H related buses. Because the 1H and 1J related buses are symmetrical, the description is equally applicable to the 1J related buses with the appropriate changes to the designators.

The 1H 480 VAC bus is primarily used to power pumps such as the A train low pressure injection pump. The 1H-1 480 VAC bus feeds two motor control centers (MCCs). MCC 1H1-1 and 1H1-2, that provide power to a multitude of motor operated valves (MOVs) and small pumps, such as the charging pump cooling pumps. MCC 1H1-1 and 1H1-2 also power the two Uninterruptible Power Supplies used to charge DC battery 1A, and the 1-I and 1-III 120 VAC vital instrumentation buses.

125 V DC Emergency Buses

The 1A 125 VDC bus provides control power to the switchgear for the pumps powered from the 1H buses. The 1A 125 VDC bus is powered from a 480 VAC bus, as noted above, and if the AC power source is lost, from DC battery 1A.

There are two emergency related 125 VDC, 60-cell, lead-calcium batteries per unit. 1A and 1B batteries are contained in an individual, missile-protected room with its own ventilation fan. The Battery Rooms are located in the Unit 1 Emergency Switchgear and Relay Rooms. Each room contains two smoke detectors and a temperature detector.

Battery capacities are rated on an ampère-hour basis (their ability to deliver a certain number of ampères for a specified number of hours before the cell voltage drops to a specified minimum value). The station batteries have a design discharge rate of 677 ampères for 1 minute, followed by 119 amperes for 119 minutes and a capacity of 1650 ampère-hours. During discharge, every battery has a minimum or final cell voltage at which the battery no longer produces any useful power, which for the station batteries is 1.75 volts (total battery voltage of 105 VDC). Battery capacity is measured periodically under the Periodic Test (PT) program.

The batteries supply power only if the battery charge (in the UPS s) fail, or if the demand exceeds the capacity of the chargers. The batteries are good for a minimum of 2 hours.

Uninterruptible Power Supplies (UPS)

There are two uninterruptible power supplies per 125 VDC bus. Each UPS consists of a rectifier/charger, inverter, static switch, manual bypass switch and a regulating line conditioner, in one unit.

The rectifier/charger converts AC to DC to supply the DC bus and provides a continuous charge on the station batteries. The inverter converts DC to AC for use on the vital buses.

The static switch is an electronic one with a transfer time of about 1/4 cycle (about 1/240th of a second) between the inverter and the alternate source.

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The manual bypass switch allows either power source to be isolated for maintenance. It is a make-before-break switch, so the two power sources must be "in sync" before closing it. The sources are normally synchronized by the UPS, and a red indicating light on the front panel verifies this.

The regulating line conditioner is designed to accept a widely varying AC input and produce a well-regulated, filtered, single-phase, 120 VAC output.

The UPS will automatically transfer to its alternate source of power on a loss of its normal power source or a failure of any component in line with its normal source. It can be transferred to and from its alternate source by pushbuttons located on the front of the panel.

The UPS can be set up to retransfer back to its normal source by means of a retransfer control toggle switch, located inside the UPS on the Static Switch control circuit board. In the "on" position, the Static Switch will retransfer back to its normal source after a 30 second time delay provided the condition which caused the transfer has cleared. If the switch is in the "off" position, no retransfer will occur until the operator does it manually.

120 VAC Vital Buses

There are four main (and four branch) 120 VAC vital buses per unit located in the MCR, Computer Room and Emergency Switchgear Room, which are constructed like a typical lighting panel. Each load has a light switch-type circuit breaker with an ON/OFF position and trips to a middle position on an electrical fault. The four color-coded vital buses and their branch lines (in parentheses) are as follows:

1. vital bus 1-I (and I-IA)
2. vital bus 1-II (and 1-IIA)
3. vital bus 1-III (and 1-IIIA)
4. vital bus 1-IV (and 1-IVA)

The 120 VAC vital buses provide uninterruptible power to vital instruments and equipment to eliminate spurious shutdowns. They also are used to control and protect the primary and secondary plant.

6.2.7.2 EPS Interfaces and Dependencies

The EPS interfaces with almost all of the systems required for safe shutdown of the reactor following an abnormal event and during shutdown. The specific dependencies of these systems on the EPS are described in applicable sections.

Table 6.2.7-1 summarizes the normal and alternate power source for each EPS bus and component, and identifies any dependencies for the EPS subsystems. The EPS design does not require load sequencers to reload the buses after loss of offsite power because time delays are included in the start circuitry for many required pumps.

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Table 6.2.7-2 shows the dependence of the 4160 VAC emergency power breakers on motive and control powers, actuation and component cooling.

The 4160 and 480 VAC breakers are controlled by local or remote, two-position (OPEN/CLOSE) handswitches. The breaker operates between the open and close position by means of two springs. The closing spring, which moves the breaker from the open position to the closed position, is the larger of the two, thus ensuring that the breaker can always be closed with or without control power. When the handswitch is taken to either position, the breaker is unlatched and the spring forces the breaker to switch positions. As the breaker closes, the opening spring is compressed by the momentum of the breaker. A motor then compresses the closing spring. As the breaker opens, the opening spring provides the motive force for the breaker operation and is left in the non-compressed state. The use of the springs for breaker operation ensures that, on loss of DC control power, every breaker may be cycled at least once.

The 4160 VAC breakers are operated by 125 VDC power supplied by the battery chargers under normal conditions, and supplied by the batteries under loss of power conditions. The power for the H bus breakers comes from battery 1A, and the J bus breakers are powered from battery 1B. Control power is fused by two sets of fuses inside the breaker cabinets, one for closing power and the other for trip power. The trip power fuses also supply the indicator lights.

6.2.7.3 Technical Specifications and Periodic Tests

Technical Specifications 3.9 and 3.16 give the required conditions for the EPS. The surveillance and test requirements are listed in Technical Specification 4.6.

When the Reactor Coolant System pressure and temperature exceed 450 psig and 350° F, respectively, the TSS require that:

1. Two Diesel Generators (the unit DG and the swing DG) with associated subsystems must be operable, with each generator's day tank having at least 290 gallons of fuel and with a minimum onsite supply of 35,000 gallons of fuel available. Two operable flowpaths to provide fuel to each DG must be also available. However, one DG may be taken out of service, provided the operability of the other DG is demonstrated daily. The Allowed Outage Time for a DG is 7 days before cold shutdown. For failure of the fuel oil path, the AOT is 1 day. For subsystem failure (e.g. DC control failure) there is no AOT before hot shutdown.
2. Two 4160 V and two 480 VAC emergency buses must be energized. Also, two offsite transmission lines must be available to feed these buses, one line permanently, the other within 8 hours.
3. One battery may be inoperable for one day before hot shutdown, provided the DC bus associated with the other battery is fed by the operable battery charger.

The minimum requirements for the periodic testing of emergency power sources are:

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- a) Monthly test of 30 minutes on each diesel generator that is started manually to verify proper operation of the emergency power source. The availability of the fuel-oil transfer system also is verified in conjunction with this monthly test.
- b) The automatic start of each DG in response to a simulated loss of off-site power together with a simulated safety injection signal is tested during reactor shutdown for refueling.
- c) Each battery undergoes a simulated load test without battery charges during normal refueling shutdown.
- d) The battery charger is turned off for about 5 min. every six months during normal operation to test its voltage and current.

The surveillance requirements are:

- a) Each DG is given a thorough inspection for preventive maintenance during each refueling.
- b) The specific gravity, electrolytic temperature, cell voltage of the pilot cell in each 60-cell battery, and DC bus voltage of each battery are measured weekly.
- c) The voltage of each battery cell in each 60-cell battery is measured monthly.
- d) The specific gravity of each battery cell, the temperature reading of every fifth cell, the height of electrolytes in each cell, and amount of water added to any cell are measured every 3 months.

6.2.7.4 Fault Tree Modeling

6.2.7.4.1 General Description

A thorough review of the NUREG 1150 fault tree models of the EPS showed that the level and assumptions used in the 1150, with slight modifications, are applicable to the present study. The modifications involved including the DG output breaker dependency on the battery, DG common cause failures, and also several unavailability events related to maintenance of electrical components, such as bus bars, chargers/inverters.

Since the interfaces of the EPS with plant systems requiring electrical power were modeled to the motor control center level in the NUREG 1150, the top events of the fault trees in the present study also correspond to the definitions and identifiers used in the NUREG 1150 (Table 6.2.7-3):

The EPS model listed above relates only to the part of the Surry EPS at Unit 1 with the dedicated DG 1 and the swing DG 3 included. This model is used as the "basic" model of the EPS, in conjunction with the other system fault trees used in the present study. Some relevant part of the EPS associated with Unit 2 (essentially DG 2) however, is also used to develop the model of the Station Blackout (SBO) initiating events at Unit 1 and at Units 1 and 2 and to calculate their frequencies. (The associated Boolean equations and their

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quantifications will be discussed in the section describing the SBO accidents.) The specific assumptions made to develop the EPS fault trees are included in the following section.

6.2.7.4.2 Assumptions in the Fault Tree Model of the EPS

The specific assumptions made in developing the EPS fault trees are as follows:

1. Diesel Generators

- a) The Emergency Diesel Generators were modeled as a separate system to provide alternate AC power to the 4160 volt emergency buses. The fault tree for DG and G3 was transferred into the fault tree for failure of the 4160 VAC buses.
- b) Actuation failures for diesel generators were not explicitly included. The failure probability for DG fail to start was considered to include actuation failures.
- c) The DG support systems such as starting air, DG batteries, fuel oil, lubricating oil, air intake, exhaust, and engine cooling were not explicitly modeled. These DG subsystems are considered essential to the successful operation of the DGs, and are thus included in their component boundaries. Failure of a support system will cause failure of the DG to start or run for six hours (DG mission time). Such failures are well-documented events which provide sufficient data to determine DG reliability.
- d) The dependency of the DG output breakers on DC power is included in the fault tree as a demand loss of DC power (an independent and a common-cause DC power failure) associated with a house event, IHOS-LOOP. (The dependency was not modeled as an external transfer to DC power to prevent circular logic between the DG tree and electrical power fault tree). The house event should be set equal to 1, if the accident initiator is a LOOP.
- e) DG 1 and DG 3 have similarly structured fault trees. (For SBO events affecting both units, DG 3 is not available to one unit (Unit 1) because the other unit (Unit 2) has priority). For the Surry Unit 1 model, this logic means that DG 3 will not be available to Unit 1 if there are simultaneous undervoltages on both 1J and 2J and Unit 2's output breaker closes first, or if an undervoltage is not present on either 1J or 2J and Unit 2 has a SI or CLS condition. (This assumption is conservative because if DG 2 failed to run, but had a successful start, then DG 3 could have been aligned to Unit 1 initially.)
- f) Four common-cause failure basic events are used in the DG fault trees. These events are the common cause failure related to all three DGs, or common cause failures related to the combination of any two diesels (e.g. DG 1 & 2, 2 & 3, or 1 & 3).

2. 4160 V and 480 AC Buses

- a) Loss of the normal power supply to an emergency bus is automatically recovered by the degraded/undervoltage protection circuitry which opens the normal supply breakers, starts the DG, and

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closes the diesel output breaker. Failure to perform these actions is included in the DG start failure rate as it was mentioned as assumption b) at the DG modeling.

- b) The 4160V stub buses will become de-energized due to a degraded/undervoltage conditions on the emergency bus. Power from the stub bus will remain unavailable once its breaker is opened until power is restored to the main emergency bus and an operator closes the feeder breaker of the stub bus.
- c) Control Room and Emergency Switchgear Room cooling system dependencies were not included in the fault trees.
- d) The failures of the large Reserve Station Service Feeder Breakers (15D1, 15F1) are included in the associated buswork failures.

The failures of the 4160V and 480V AC bus breakers, indicated in Fig. 6.2.7-3 were explicitly modeled. Breakers below the level of MCCs were not represented in the fault trees of the buses, but were included in the appropriate failure modes of the loads.

3. 125 V DC Buses

- a) Battery depletion time was assessed to be 4 hours; it is modeled in the SBO event trees.
- b) The cross tie breaker between A and B DC bus is not included in the DC fault trees.

4. 120 VAC Vital Buses

- a) The uninterruptible power supplies (UPSs) are assumed to be powered from their normal power supply. The alternate power supply breaker is assumed to close and the normal supply breaker open whenever there is a loss of the normal power supply. This is an automatic, fast transfer of power supplies.
- b) The branch 120 VAC Vital Buses: 1-IA, 1-IIA, 1-IIIA and 1-IVA are not modeled.

5. Assumptions for all the Buses of the EPS:

- a) Cross-connecting buses was not considered.
- b) Shorts in buses and motor-control centers were postulated to fail only their respective bus or MCC, and not fail the power source to the bus or MCC.
- c) To avoid circular logic, the dependency of EPS equipment (UPSs, etc.) located in the Emergency Switchgear Room on the Ventilation System is not modeled, but is represented in the event trees.

The detailed fault trees of the EPS are shown in Appendix X. The fault trees are presented in the order of the top events listed in Table 6.2.7-3.

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6.2.7.5 Modifications in the Line-Up of the EPS during Scheduled Maintenance of Main Components

During scheduled maintenances of main components of the EPS, performed while Unit 1 is in refueling shutdown, the basic line-up of the EPS changes. Depending on the length of the maintenance, these changes may significantly affect the reliability of the EPS and may require to be taken into account in the fault tree of the EPS in certain POSs.

By using procedures for shutdown operations and maintenance activities it was identified, that in POS 6, i.e. during mid-loop operation, the basic EPS line-up is required (see checklist in Attachment 3 to Proc.: 1-OP-RC-005); however, in other POSs the following line-up changes may occur:

1) Change of EPS Line-up During Maintenance of Reserve Station Service

Transformers

(Procs: 1-EMP-C-EPH-84; 2-EMP-C-EPH-82)

The change in EPS line-up during the maintenance of RSS Transformer "C" and its associated breakers 4KV ACB 15F1 and 34.5KV OCB 262 is as follows:

The 1H bus is powered by the S.S. Transformer "1C" via the 1C bus and the (normally open) breaker 15C1. The RSS Transformer "C" and the breakers ACB 15F1 and OCB 262 are isolated from the transfer bus F and the switchyard bus #6 and de-energized. Since the Unit 1 generator does not work the S.S. Transformer "1C" is operating in "backfeed" mode.

If Unit 2 is in cold shutdown and the RSS transformer "1C" is in maintenance, the 1H bus is "backfed" from S.S. transformer "2C" via the "2C" bus and the closed 25C1 breaker.

The maintenance of the transformer RSS "A" proceeds similarly by backfeeding the emergency 1J bus from S.S. transformer 1A via bus 1A with closed breaker 15A1 when Unit 1 is in cold shutdown, or from S.S. transformer 2A via bus 2A with closed breaker 25A1 when Unit 2 is in cold shutdown.

2) Change of EPS Line-up During Maintenance of S.S. Transformer "C" and RSS

Transformer C.

(No appropriate Procedure is available).

We identified, from the present outage schedule of the plant, that simultaneous maintenance/tests on RSS Transformer "C" and S.S. Transformer "C" render the feeding of 1H bus by the 1C bus unavailable. Then, the 1H bus is powered by the emergency 1J bus by closing the otherwise normally open breaker 15H1. If a LOOP occurs and breaker 15H1 fails to open, the starting voltage/current requirements may cause both buses (1H and 1J) to fail when the DGs try to load both buses.

3) Change of EPS Line-up During Maintenance of 4160/480 VAC

Transformers 1H and 1H-1

(Procs.: 1-MOP-26.5, 1-MOP-26.6)

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Unit 2 is considered to be operating. Before putting the 4160/480 VAC Transformers 1H and 1H-1 into maintenance the operator ensures that all the trains and equipment fed by 1J and 1J-1 buses are operable. In the same time, the loads associated with the buses 1H and 1H-1 are taken off. The operator ensures that the heaters of the Boric Acid Tanks A and B are fed from Unit 2 buses 2H1-2 and 2J1-2 (and also, that some common equipment shared with Unit 2 is also operating with Unit 2 electrical power).

During maintenance, the EPS line-up changes as follows:

- a) DC Buses 1A and 1B are connected by closing the (normally open) tie breaker 1A-22.
- b) Battery chargers 1A-1 and 1A-2 are removed from operation.
- c) Vital Buses 1-I and 1-III are set to operate with inverters (i.e. they are fed by DC power)
- d) The breakers 15H1, 14H1, 14H15, 14H14, and 14H13 are open.

Putting back the transformers into service, and subsequently testing the breakers of all the equipment is a prolonged task which may represent a source of leaving some equipment (MOVs) in misalignment.

4. Change of EPS line-up During Maintenance of the Undervoltage Relays of Bus "1J"

(Proc: 1-EMP-P-RT-52)

During the maintenance of the undervoltage relays of bus 1J, it is powered from bus 1H by closing the breaker 15H1.

Other Changes: Circuit breakers associated with this bus are removed from the "Connect" position. Several breakers, like 15H6 (Charging Pump 1C), 15J3 (DG 3), 15J5 (Charging Pump 1B), and 15J8 (Feed from transfer bus "D") are put in "exercise" position together with the "autoexercise" switch of DG3. (These precautions ensure that bus 1J does not get false undervoltage through faulty breakers).

The test of the relays and associated logic and electrical circuits ensure that DG 3 and other equipment should start properly if an undervoltage occurred on the bus.

The test itself and the realignment of the breakers to the "connect" position may be a source of misalignment failures.

The maintenance of the undervoltage relays on bus 1H causes symmetric line-up change in the EPS.

5. Change of EPS line-up During Maintenance of the Uninterruptible Power Supplies (UPSs)

(Proc: 1-EMP-C-EPDC-169)

The maintenance of the subsystems (charger inverter, SOLA Transformer) of the uninterruptible power supplies (UPSs) were deemed to cause non-significant changes in the line-up of the EPS.

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Figure 6.2.7-1 Simplified Diagram showing the EPS (Unit 1) as part of the Basic Electrical Distribution System
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Figure 6.2.7-2 Plant 4160 VAC Electrical Distribution System (Unit 1 and Unit 2)

Figure 6.2.7-3 Detailed Diagram of the EPS (Unit 1)

Table 6.2.7-1 AC/DC Power Supplies and Dependencies

Bus/Component	Normal Feed	Alternate Feed	Dependency/Comments
4160V - 1A 1B 1C	Station Generator	Offsite grid, via RSS transfer from A, B, C.	None of the EP systems are provided power by these buses. Not included in the EPS model.
4160V - 1H (Orange Bus)	Offsite grid, via RSS transfer from C	DG 1	Switchgear Power provided by DC battery A.
4160V 1H-Stub	4160-1H	None	Stub bus contains 1 CCW pump and 1 RHR pump. Bus is shed from main bus on Under Voltage on main bus.
4160V 1J (Purple Bus)	Offsite grid, via RSS transfer A	DG 3	Switchgear power provided by DC battery B. DG 3 may be required by Unit 2.
4160V 1J-Stub	4160V-1J	None	Stub bus contains 1 CCW pump and 1 RHR pump. Bus is shed from main bus on UV on main bus.
DG 1, DG 3	NA	NA	DG 1 Auto actuation upon undervoltage on 1H, CLS or SI signal on Train A, Unit 1. DG 3 Auto actuation upon: undervoltage on 1J, CLS or SI Signal on Train B of Unit 1 or undervoltage on 2J, CLS or SI signal on Train B of Unit 2. No Dependencies. DGs are self contained. Each DG has a dedicated battery to start it. Self cooled. Upon LOSP, DG 3 will align to either unit, depending on whose breaker closes first. If SIS or CLS Hi-Hi signal exists at a unit, that unit will get DG 3.
480V - 1H 480V - 1H1	4160V 1H 4160V 1H	None None	Switchgear for pumps is supplied by DC battery A.
480V - 1J 480V - 1J1	4160 1J 4160 1J	None None	Switchgear for pumps is supplied by DC battery B.
MCC 1H1-1, MCC 1H1-2	480V 1H1	None	
MCC 1J1-1, MCC 1J1-2	480V 1J1	None	
120V AC Vital Bus 1-I	MCC 1H1-1, MCC 1H1-2 DC Bus A	None	Vital bus supplied by an uninterruptable power supply fed by three sources. Whichever source has the highest voltage will power the vital bus.

Table 6.2.7-1 (continued)

Bus/Component	Normal Feed	Alternate Feed	Dependency/Comments
120V AC Vital Bus 1-II	MCC 1J1-1, MCC 1J1-2, DC Bus B	None	Vital bus supplied by an uninterruptable power supply fed by three sources. Whichever source has the highest voltage will power the vital bus.
120V AC Vital Bus 1-III	MCC 1H1-1, MCC 1H1-2, DC Bus A	None	Vital bus supplied by an uninterruptable power supply fed by three sources. Whichever source has the highest voltage will power the vital bus.
120V AC Vital Bus 1-IV	MCC 1J1-1, MCC 1J1-2 DC Bus B	None	Vital bus supplied by an uninterruptable power supply fed by three sources. Whichever source has the highest voltage will power the vital bus.
DC Bus A	MCC 1H1-1, MCC 1H1-2 via uninterruptable power supplies 1A1, 1A2	Battery A	
DC Bus B	MCC 1J1-1, MCC 1J1-2 via uninterruptable power supplies 1B1, 1B2	Battery B	

Table 6.2.7-2 Dependency Matrix of 4160 VAC Breakers¹

Component	Motive Force	Control Power	Auto Actuation	Room Cooling	Interlocks
1-E-BKR-15D1 NC	Charged Springs	1-EE-Bus-1A DC 125 VDC	1-EE-Bus-1J under voltage or degraded voltage opens breakers	None	
1-E-BKR-15E1 NC	Charged Springs	1-EE-Bus-1B DC 125 VDC	2-EE-Bus-2H under voltage or degraded voltage opens breakers	None	
1-E-BKR-15F1 NC	Charged Springs	1-EE-Bus-1B DC 125 VDC	1-EE-Bus-1H or 2-EE-Bus-2J under voltage or degraded voltage opens breaker	None	
1-EE-BKR-15H1 NO	Charged Springs	1-EE-Bus-1A DC 125 VDC	None	Control Room & Em. Switchgear room cooling	1H and 1J must be synchronized to close breaker
1-EE-BKR-15H3 NO	Charged Springs	1-EE-Bus-1A DC 125 VDC	Closes on UV or DV after 15H8 has been open for 2 sec.	Control Room & Em. Switchgear room cooling	Must be synchronized if manually closed
1-EE-BKR-15H8 NC	Charged Springs	1-EE-Bus-1A DC 125 VDC	Open on UV or DV on 1H	Control Room & Em. Switchgear room cooling	Buses 1H and 1F must be synchronized
1-EE-BR-15J3 NO	Charged Springs	1-EE-Bus-1B 125 VDC	Closes on UV or DV after 15J8 has been open 2 sec.	Control Room & Em. Switchgear room cooling	EDG must be synchro- nized if manually closed. 25J3 must be open.
1-EE-BKR-15J8 NC	Charged Springs	1-EE-Bus-1B 125 VDC	Opens on UV or DV on 1J	Control Room & Em. Switchgear room cooling	Buses 1J and 1D must be synchronized.

¹ No CCW cooling is required for any component.

Table 6.2.7-3 Top Event Definitions and Identifiers for the EPS

Top Event Definition:	Identifier
Failure of 4160 VAC Bus 1H	4KV1H*
Failure of 4160 VAC Bus 1J	4KV1J**
Failure of 4160 VAC Stub Bus 1H	ESTB1H
Failure of 4160 VAC Stub Bus 1J	ESTB1J
Failure of 480 VAC MCC 1H1-1	EH1
Failure of 480 VAC MCC 1H1-2	EH2
Failure of 480 VAC MCC 1J1-1	EJ1
Failure of 480 VAC MCC 1J1-2	EJ2
Failure of 480 VAC Bus 1H	E4801H
Failure of 480 VAC Bus 1J	E4801J
Failure of 120 VAC Vital Instrumentation Bus 1-I	E1I
Failure of 120 VAC Vital Instrumentation Bus 1-II	E21II
Failure of 120 VAC Vital Instrumentation Bus 1-III	E31III
Failure of 120 VAC Vital Instrumentation Bus 1-IV	E41IV
Failure of 125 VDC Bus 1A	E1A
Failure of 125 VDC Bus 1B	E1B

* Contains the fault tree of DG 1.

** Contains the fault tree of DG 3.

6.2.8 Emergency Switchgear Room Ventilation Systems

The Emergency Switchgear Rooms (ESGR) of Units 1 and 2 have a shared Air Conditioning System to maintain the electrical equipment in operable state and prevent the rooms overheating. The Normal Air Conditioning chilled Water System supplies chilled water to the Air Conditioning System. The heat sink for the normal ESGR chillers is the Service Water System. Backup chilled water is supplied by the Backup Air Conditioning Chilled Water System (also called the Service Building Chillers). Heat sinks for the backup chillers are evaporative condensers and air fans.

The Surry IPE PRA pointed out that a loss of ESGR ventilation for long periods would cause the temperature in the ESGR to rise (during four hours, a temperature of about 120° F) so that it would have deleterious effects on the electrical equipment. The three most prominent effects were that relays would spuriously transfer, the thermal overload margin in the load breakers would be lost causing tripping of the load breakers, and the solid state components in the UPS power supplies would become inoperable. The temperatures at which each of these effects would occur was not specifically determined. Heat-up times for combinations of heat loads and ventilation equipment availability made for licensing purposes were available for use in the IPE. Heat-up times were compared with the 24-hour mission times used in the IPE and success criteria for the ventilation function were developed.

The loss of ESGR ventilation has the same deleterious effect on the electrical equipment during unit shutdown. That is the basic reason why we analyzed the ventilation systems and included them in the present study. We noted that, at shutdown, a significant source of cool air is the turbine building, as the TB/ESGR door can be opened.

The description of the ESGR Ventilation Systems is given below:

6.2.8.1 Normal Air Conditioning Chilled Water System

The normal ESGR chilled water source is three 50% capacity chillers, 1-VS-E-4A, 4B, and 4C (100% capacity if water temperature <70°F). The chiller units are typical freon refrigerant units arranged in parallel, and located in Mechanical Equipment Room #3. The chillers are rated at 50% for design conditions which include no room heatup and peak heat leaks (due to electrical equipment operation) over long periods. For the Surry analysis, some heating up of the room and some shedding of the heat load can be assumed, so that the chillers are assumed to be at 100% capacity for long term cooling, and only one operating chiller is required for system success.

Each of the normal ESGR chillers has a Service Water (SW) side as a final heat sink, and a chilled water side to supply chilled water to the ESGR and Main Control Room (MCR) Air Handling Units (AHU). The schematics of the SW side piping are shown in Figure 6.2.8-1.

SW is provided from both units' SW Systems (Screenwells 1B and 2A), through valves 1-and 2-SW-11. In addition, SW can be obtained by way of crosstie valve 1-SW-474 from 1D screenwell and crosstie valve 2-SW-474 from 2C screenwell. Flow from each unit passes through separate, motor-operated self-cleaning strainers or Rotating Strainers (1-VS-S-1A and -1B). A backup duplex strainer can to bypass self-cleaning strainer 1A if it malfunctions. Each strainer has a local differential pressure indication. The outlet of the strainers join via the air-operated control valve 1-SW-163 into a common header to supply the chiller condensers (and the Charging Pump Service Water Subsystem, See Section 6.2.3). Flow from the common header supplies the suction of each Condenser Service Water Pumps (1-VS-P-1A, B, and C), which supply the 90-ton air conditioner chiller condensers, where heat is transferred to the SW from the freon as it condenses. The pumps also supply backwash flow to the self-cleaning strainers. A local pressure gage indicates discharge pressure.

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Pressure control valves PCV-SW-100A/B/C and -101A/B/C work together to maintain proper flow through the chiller condensers. Each pair of valves is controlled by its associated chiller unit. The air operated control valve 1-SW-263 automatically closes and will alarm on the VSP annunciator panel in the control room on the following conditions:

1. Smoke or fire in either the pump room in Unit 2 turbine building or in the Mechanical Equipment Room #3.
2. Loss of power to Fire Detection panel for the Charging Pump Service Water Pumps.
3. Trouble or alarm on the Fire Detection Panel for the charging Pump Service Water Pumps.

An alarm will also be received if 1-SW-263 is closed, but can be manually overridden.

On the chilled water side, each chiller train consists of a pump taking suction from common header, the chiller, and valves to isolate the train (see Figure 6.2.8-2). The chillers normally supply one of two groups of air handling units. Each group has 1 AHU each for the Unit 1 MCR, the Unit 1 ESGR, the Unit 2 MCR, and the Unit 2 ESGR. Currently, only one ESGR AHU for Unit 1 must be operating when Unit 1 is critical or in shutdown and similarly for the Unit 2 ESGR AHUs. Also, two of three chillers must be operable when any unit is critical or in shutdown; two chillers are assumed to be operating although only one chiller is required for system success. The ESGR AHUs have been restored to the original UFSAR design configuration, with each AHU having 100% capacity for heat removal for its associated room.

6.2.8.2 Backup Air Conditioning (Central) Chilled Water System

To resolve the concerns in Appendix R, a backup chilled water supply is provided by the Central Chilled Water subsystem chillers, 1-VS-E-3A and 3B. These chillers, are located elsewhere, and can be powered from the 1J and 2H Emergency Buses by a manual switchover (normal power is from station service). These backup chillers are also rated at 50% capacity, and can be cross-tied to a single MCR/ESGR AHU group by opening two manual valves (supply and discharge). The backup chillers 1-VS-E-3A and 3B and their cross-tie to the ESGR AHUs is shown in Figure 6.2.8-3. Only one group of 4 AHUs can be connected to the Service Building chillers, so that only one Unit 1 ESGR AHU (or one Unit 2 AHU) can be supplied by this backup source of chilled water.

The service building chillers have a different heat sink than the ESGR chillers. Evaporative condensers using water sprays and air fans dump heat to the atmosphere, outside the service building. Makeup water for the central evaporative condensing system is supplied from the Domestic Water System by way of a float-operated valve and backflow preventer valve. An emergency backup supply from the fire main is provided in case these chillers are being used to supply cooling for the Main Control Room/Emergency Switchgear Room.

6.2.8.3 Emergency Switchgear and Relay Rooms Air Conditioning Subsystem

Two cross-connected, 100% capacity air cooling systems are provided per ESGR, for a total of four (see Figure 6.2.8-2). Each cooling system consists of an air handler and a chiller supply. For the Unit 1 ESGR, these are

1. air handler 1-VS-AC-6, and
2. air handler 1-VS-AC-7.

For the Unit 2 ESGR, these are:

1. air handler 2-VS-AC-6, and
2. air handler 2-VS-AC-7.

Each cooling system has sufficient capacity for the total cooling load.

In an emergency, the normal outside breathing air supply and exhaust are automatically isolated. The MCR and ESGR doors are lined with a gasket seal, and sliding missile shields are provided.

6.2.8.4 Interfaces and Dependencies

Table 6.2.8-1 shows the dependency of the components of the Ventilation systems on other support systems.

6.2.8.5 Fault Tree Modeling

The loss of ESGR ventilation was modeled by a fault tree with top event "VS1". The success criteria for the ESGR ventilation were 1 of 3 chillers and 1 of 2 AHV's during all accident conditions.

The assumptions and conditions used for the fault tree modeling are described below:

1. Both Unit 1 and Unit 2 SW headers are assumed to be operating with the Unit 1 DS-3 strainer isolated. There is a bypass line around Unit 2 rotating strainer 1-VS-S-1B, but this flow path is ignored as human interaction is needed to operate this path.
2. The rotating strainers 1-VS-S-1A and B are modeled with plugging faults and by failure of the electric power supplied to rotate the strainer baskets. It is also considered that the baskets can be rotated with a handcrank.
3. The SW supply header cross-connect piping can be isolated by 1-SW-263, an air operated valve. 1-SW-263 fails closed on loss of Instrument Air and loss of 120V AC control (lighting) power. This control power is essentially supplied from the non-emergency bus, 1C. On Loss of Offsite power (LOOP), control power to solenoid valve 1-FSV-SWO1 is assumed to be lost, resulting in 1-SW-263 failing closed (solenoid valve 1-FSV-SWO1 controls air to 1SW-263). This LOOP dependency is modeled with a house event, IHOS-LOOP which will fail the cross-connect between Unit 1 and 2 SW supply headers when the LOOP occurs. It is also considered that the closure of 1-SW-263 can be manually overridden.
4. The assumed operating and standby components at the start of the accident are:
  - Normal chiller trains: 1-VS-E-4A and 4C are operating (1-VS-E-4B is in standby)
  - Backup chiller trains: 1-VS-E-3A and 3B are operating, powered from the station service 2buses.
  - Unit 1 ESGR AHU: 1-VS-AC-7 is operating.
5. For the standby B chiller train, it is assumed that the following valves are initially closed:
1-SW-PCV-100B

The B chiller train has a backup power source with manual switchover which is also modeled. The manual isolation valves 1-VS-285 and 286 are closed.

6. The Air Handling Units (AHUs) are assumed to be passive except for the fan motors. A loss of function fault fans, tube leaks, tube plugging, air flow blockage and other faults. The AHUs are controlled by the Group 1 and 2 switches. Current Technical Specifications allow one group to be in standby, so only one group is assumed to be operating. With one group switched off, a switch fault is possible upon startup of the standby group.
7. Loss of control power to a chiller train fails the active components in the train due to the control configuration.
8. When Unit 1 is shutdown, the VS system is often cross connected to the Backup (Central) Chilled Water (Service Building) subsystem via valves 1-VS-247 and 1-VS-251. This cross connect is required when the

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Unit 1 Bearing Cooling Water system is removed from service, as this BC system supplied makeup to the Backup (Central) Chilled Water subsystem.

9. VS makeup is provided by the Unit 2 BC system. VS is not isolated from Unit 2 BC and the flow path does not include check valves to prevent flow from VS to BC.

Figure 6.2.8-2 Emergency Switchgear Room Ventilation System Chilled Water Side

Figure 6.2.8-3 Central Chilled Water System Support for Emergency Switchgear Room Ventilation System Chilled Water Side

Table 6.2.8-1 Dependency Matrix of ESGR Ventilation System

Component	Motive Force	Control Power	Auto Actuation	Component Cooling	Room Cooling	Interlocks
1-VS-AC-6	1J1-1 480VAC	Step Down transformer from 480VAC MCC	None	None Provided	None Required	
1-VS-AC-7	1H1-1 480VAC	Interlock to 3-4A Step down transformer from 480 VAC MCC	None	None Provided	None Required	
1-VS-E-4A	1H1-1 480VAC	Interlock to 3-4A step down transformer from 480 VAC MCC	None	None Provided	None Provided	VB 1-III
1-VS-E-4B	1J1-1 480VAC	Interlock to 3-4B step down transformer from 480 VAC MCC	None	None Provided	None Provided	VB 1-IV
1-VS-E-4B Backup Power	2J1 480VAC		None	None Provided	None Provided	VB 2-IV
1-VS-E-4C	2H1-1 480VAC	Interlock to 3-4C step down transformer from 480 VAC MCC	None	None Provided	None Provided	VB 2-III
1-VS-P-1A	1H1-1 480VAC	Interlock to 3-4A step down Transformer from 480 VAC MCC	None	None Provided	None Provided	1-VS-E-4A Interlock VB-1-III
1-VS-P-1B	1J1-1 480VAC	Interlock to 3-4B step down transformer from 480 VAC CC	None	None Provided	None Provided	1-VS-E-4B Interlock VB 1-IV

Table 6.2.8-1 (continued)

Component	Motive Force	Control Power	Auto Actuation	Component Cooling	Room Cooling	Interlocks
1VS-P-1B Backup Power	2J1-1 480VAC		None	None Provided	None Provided	1-VS-E-4B
1-VS-P-1C	2H1-1 480VAC	Interlock to 3-4C Step down transformer from 480 VAC MCC	None	None Provided	None Provided	
1-VS-P-2A	IH1-1 480VAC	Interlock to 3-4A Step Down transformer from 480 VAC MCC	None	None Provided	None Provided	
1-VS-P-2B	1J1=1 480VAC	Interlock to 3-4B Step down transformer from 480 VAC MCC	None	None Provided	None Provided	
1-VS-P-2B Backup Power	2J1-1 480VAC		None	None Provided	None Provided	1-VS-E-4B Interlock VB 2-IV
1-VS-P-2C	2H1-1	Interlock to 3-4C Step Down transformer from 480 VAC MCC	None	None Provided	None Provided	1-VS-E-4C Interlock VB 2-III
1-PG-MOV-107A	1H1-1 480VAC	Interlock to 3-4AX Step down transformer from 480 VAC MCC	None	None Provided	None Provided	1-VS-E-4A Interlock VB 1-III
1-PG-MOV-107B	1J1-1 480VAC	Interlock to 3-4BX Step down transformer from 480 VAC MCC	None	None Provided	None Provided	1-VS-E-4B Interlock VB 1-IV

Table 6.2.8-1 (continued)

Component	Motive Force	Control Power	Auto Actuation	Component Cooling	Room Cooling	Interlocks
1-PG-MOV 107B Backup Power	2J1-1 480VAC		None	None Provided	None Provided	1-VS-E-4B Interlock VB 2-IV
1-PG-MOV 107C	2H1-1 480VAC 3B	Interlock to 3-4CX Step down transformer from 480 VAC MCC	None	None Provided	None Provided	1-VS-E-4C Interlock VB 2-III
1-SW-PCV- 100A	Instrument Air	None	1-VS-E-4A Refrigerant Pressure	None Provided	None Provided	Fails open
1-SW-PCV 100B	Instrument Air	None	1-VS-E-4B Refrigerant Pressure	None Provided	None Provided	Fails open
1-SW-PCV- 100C	Instrument Air	None	1-VS-E-4C Refrigerant Pressure	None Provided	None Provided	Fails open
1-SW-PCV- 101A	Instrument Air	None	1-VS-E-4A Refrigerant Pressure	None Provided	None Required	Fails Close
1-SW-PCV- 101B	Instrument Air	None	1-VS-E-4B Refrigerant Pressure	None Provided	None Required	Fails Close
1-SW-PCV- 101C	Instrument Air	None	1-VS-E-4C Refrigerant Pressure	None Provided	None Required	Fails Close
1-VS-S-1A	1H1-2S 480VAC	Step down transformer from 480 VAC MCC	None	None Provided	None Required	

Table 6.2.8-1 (continued)

Component	Motive Force	Control Power	Auto Actuation	Component Cooling	Room Cooling	Interlocks
1-VS-S-1B	2H1-2S 480VAC	Step down transformer from 480 VAC MCC	None	None Provided	None Required	
1-SW-263	Instrument Air Fails Closed	Fire Detection Panel 1SW01 from Lighting Panel 2T3 (fed from Bus "1C") CKT:8,	Closes upon fire detection inputs	None Provided	None Provided Space	Solenoid Valve 1-FSV-SW01 controls air to 1SW-263
1-VS-E-3A	1J1-1 (1) 480 VAC	Step down transformer from 480 VAC MCC	None	None Provided	None Provided	
1-VS-E-3B	2H1-1 (2) 480 VAC	Step down transformer from 480 VAC MCC	None	None Provided	None Provided	
1-VS-E-1A	1J1-1 (1) 480 VAC	Step down transformer from 480 VAC MCC	None	None Provided	None Provided	Interlocked with chilled 1-VS-E-3A
1-VS-E-1B	2H1-1 (2) 480 VAC	Step down transformer from 480 VAC MCC	None	None Provided	None Provided	Interlocked with chilled 1-VS-E-3B
1-VS-P-3A	1J1-1 (1) 480 VAC	Step down transformer from 480 VAC MCC	None	None Provided	None Provided	Interlocked with chilled 1-VS-E-3A
1-VS-P-3B	2H1-1 (2)	Step down	None	None	None	Interlocked
	480 VAC	transformer from		Provided	Provided	with chilled
		480 VAC MCC				1-VS-E-3B

(1) Normal power from 1B2-1, emergency power from 1J1-1. Only emergency power considered.

(2) Normal power from 1C1-2, emergency power from 2H1-1. Only emergency power considered

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6.2.9 High Pressure Injection/Recirculation System

6.2.9.1 High Pressure Injection/Recirculation System Description

The Surry high pressure injection/recirculation (HPI/HPR) system consists of three centrifugal charging pumps and associated pipings and valves. During normal operations, the charging pumps provide normal RCS coolant makeup and cooling flow to the reactor coolant pump (RCP) seals. Following an accident, the charging pumps provide primary coolant injection and recirculation as well as maintaining flow to the RCP seals. The charging pumps are one of the three major components of the Safety Injection (SI) System; the other two are accumulators and low pressure injection pumps. The primary purposes of the SI system are: (i) to inject borated water into the RCS to flood and cool the core following a LOCA; and (ii) to remove heat from the core for extended periods following a LOCA. The HPI system also delivers boric acid to the RCS from the boric acid transfer system if emergency boration is required. The HPI/HPR system is a front-line system designed to provide coolant makeup, early and late removal of core heat or emergency boration for reactor shutdown.

Under normal operating conditions, one of the three charging pumps provides RCS makeup and cooling to the RCP seals by taking suction from the volume control tank (VCT) through a supply header containing two motor operated isolation valves (MOVs) in series. The charging pumps normally discharge to RCS loop B cold leg. The RWST is used as a backup supply of water for the charging pumps if the water level in the VCT falls to a low-low level. The VCT supply header and the RWST supply header combine into a common HPI pump suction header.

The charging pumps are horizontal, nine-stage, centrifugal pumps, each designed to have a pumping capacity of 150 gpm at 130° F and 2235 psig. The actual pumping capacity, however, depends on pump discharge pressure. For example, the pump flow rate increases to 300 gpm if the discharge pressure is lowered to 1000 psig, while the flow rate is zero if the discharge pressure is 2750 psig. Each charging pump is equipped with a self-contained oil lubrication system. The charging pump is driven by a 600 HP, 1769 rpm motor that rotates the pump at 6018 rpm through a speed-increasing gearbox. Charging pump 1A is powered from 4160 VAC bus 1H, while charging pump 1B is powered from 4160 VAC bus 1J. Charging pump 1C, which can be used as an alternate pump for either SI train, can be powered from either the 1H or the 1J bus and is normally aligned to the 1H bus. However, when pump 1C is powered from the 1J bus, it does not start automatically.

To protect the charging pumps from overheating when they are operated at a shutoff head, each has a mini-flow recirculation line. After being discharged to the seal water heat exchanger, the recirculation flow is directed back to the suction of the charging pumps. Following a LOCA, when RCS pressure drops below 1600 psig, the isolation valves of the recirculation line is manually isolated to maximize charging pump flow. The valve is reopened if RCS pressure rises above 2000 psig.

Upon indication of a loss of RCS coolant or break in the steam line (i.e., low pressurizer pressure, high containment pressure, high pressure differential between any steam generator header and the steam line, or high steam flow coincident with either low RCS average temperature or low-low steam line pressure), the safety injection actuation system (SIAS) generates an emergency signal. Upon receipt of this signal, the charging pumps suction and the discharge flow path is automatically realigned for safety injection. The low

pressure injection (LPI) pumps also start, but do not provide flow to the RCS until its pressure falls below the discharge pressure of the LPI pump.

The high-pressure emergency coolant injection differs from normal coolant makeup in three ways. First, the suction source of the charging pumps is the refueling water storage tank (RWST) rather than the volume control tank (VCT). Second, the pump discharge is directed to the RCS cold legs instead of the Loop B cold leg. Finally, the emergency injection flow is from all available charging pumps, and is not throttled. The SIAS signals the normal charging line isolation valves to close, the standby charging pumps to start, the valves from the VCT to close, and a parallel set of normally closed MOVs to open to provide suction from the RWST. The SIAS signal also causes a parallel set of normally closed MOVs to open to provide flow from the pump discharge header to the three RCS cold legs. An additional path is available to the RCS cold legs through a manually operated, normally closed MOV. The line to the RCP seals remains open throughout the transient. The HPI system may also be employed in the "feed and bleed" mode of cooling for the early removal of removal core heat. The only difference between this mode of operation from that discussed above is that a SIAS signal is not necessarily generated, so that the HPI system must be manually placed in service.

Before the RWST content is exhausted, the Engineered Safety Features (ESF) system automatically initiates a recirculation mode transfer (RMT) signal. The operator can also terminate the injection mode and initiate the recirculation mode by manually repositioning the required valves. In the recirculation mode, the HPR provides core-heat removal late in an accident sequence. The charging pumps draw suction from the discharge of the low-pressure safety injection pumps in the low pressure recirculation (LPR) system. The RMT signal causes the charging pump suction valves from the RWST to close and the suction valves from the LPR pump discharges to open. In the recirculation mode, the LPR pumps take suction from the containment sump and deliver a large quantity of water for long-term core cooling to the RCS cold legs via two paths. If RCS pressure is below the LPR pump discharge pressure, the LPR pumps deliver water directly to the RCS cold legs. The LPR pumps also deliver water to the RCS cold legs via the charging pumps at any RCS pressure. Therefore, in the recirculation mode, the LPR pumps provide both water and net positive suction head (NPSH) to the charging pumps.

The recirculation mode provides flow to the RCS cold legs for approximately 16 hours. Thereafter, the recirculation flow is alternated roughly every 24 hours to either the hot leg or the cold leg. This and cold leg alteration assists in terminating boiling, collapsing voids in the vessel head, and backflushing boron that may have plated out on the core.

In the emergency boration mode, the HPI system is used for emergency shutdown of the reactor. The HPI system functions as described above, except that the boric-acid transfer pumps must deliver boric acid solution from the boric acid storage tanks (BASTs) to the charging pump suction header. To do this, the operator must switch the normally operating boric acid transfer pump to fast speed, and open the emergency boration valve, MOV-1350, allowing boric acid solution to flow into the charging pump suction header. The MOV can be operated from the control room or from the auxiliary shutdown panel. When the valve is open, the discharge of the boric acid transfer pump is linked directly to the charging pump suction header via a check valve. To increase the addition of boric acid to the RCS, the emergency procedure calls for the RCS power-operated relief valves be opened to reduce RCS pressure. Also, a locally operated emergency boration valve

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(1-CH-228) is available. To direct concentrated boric acid solution to the suction of the charging pumps, however, the boric acid-to-blender flow control valve must be open.

6.2.9.2 HPI/HPR System Interfaces and Dependencies

Figure 6.2.9-1 is a simplified sketch of the system, and Table 6.2.9-1 summarises its component status and dependency. The HPI system interfaces with the low pressure injection system and the containment spray system at the common RWST via a shared valve. The HPR system interfaces with the low pressure recirculation system at the recirculation suction valves for the high pressure recirculation.

The HPI system depends on various systems (or support systems) to operate, which include:

- (i) The RWST for fluid inventory
- (ii) The charging pump cooling system for charging pump seal cooling and lube oil cooling
- (iii) AC power buses for motive power to the HPI pumps and motive and control power to the MOVs in the HPI system
- (iv) DC power buses for control power to the HPI pumps
- (v) The Safety Injection Actuation System (SIAS) for actuation of the HPI components, such as the HPI pumps or some of the MOVs

In addition, for the emergency boration mode of HPI operation, the system depends on the primary pressure relief system to reduce RCS pressure sufficiently to allow for the timely injection of boric acid solution.

On the other hand, the HPR system has dependency on the following systems (or, support systems):

- (i) The low pressure recirculation system for fluid inventory
- (ii) The charging pump cooling system for charging pump seal cooling and lube oil cooling
- (iii) AC power buses for motive power to the HPR pumps and motive and control power to the MOVs in the HPR system
- (iv) DC power buses for control power to the HPR pumps
- (v) The recirculation mode transfer (RMT) generated by the Engineered Safety Features (ESF) system for switching over from HPI to HPR mode of operation

6.2.9.3 HPI/HPR System Operational Constraints

The RWST is a vertical, cylindrical tank with an usable capacity of 398,000 gallons. Technical specifications require that, during normal plant operations, the RWST should contain at least 387,100 gallons of borated water between 2000 ppm and 2300 ppm concentration. For a single-unit operation, two charging pumps must be operable per technical specifications and action statements are entered when fewer than two (of three) are operable. One charging pump may be unavailable due to testing or maintenance. Under normal operations, two boric-acid transfer pumps also must be operable, with the boric-acid tanks (normal unit tank and the common tank) containing a minimum of 6000 gallons of between 7 and 8.5% boric-acid solution at least 112° F. Technical specifications also require that when Unit 1 is at power, at least one HPI/HPR pump at Unit

2 must be available (7-day AOT for charging pumps in opposite unit before hot shutdown in 6 hours, and cold shutdown within the next 30 hours).

During normal plant operations, the charging pumps are lined up to charge to the RCS with one of the three pumps running and the other two pumps are placed in the auto position. When safety injection is actuated, all three pumps receive an auto-start signal.

To minimize the possibility of accidentally overpressurizing the RCS, technical specifications require that whenever T_{avg} is less than 350° F, the following charging pump conditions must be maintained: (i) a maximum of one charging pump operable; and (ii) two charging pumps must be demonstrated inoperable at least every 12 hours by verifying that their circuit breakers are racked out or that their control switches are in the pull-to-lock position.

The surveillance requirements specify that a complete systems test is performed during refueling shutdown to demonstrate the correct response to an activation of the safety injection signal. During reactor operation, the instrumentation which is depended on to initiate safety injection is checked daily, and the active components, such as pumps and valves, are tested quarterly, as required by ASME Section XI.

6.2.9.4 HPI/HPR System Shutdown Configuration

During POS 1, all three charging pumps are lined up for normal charging, with only pump A actually running. Pump B and C are maintained in standby and in auto condition. Charging pump A takes suction from the VCT and discharges to RCS cold leg B through the normal charging line at a flow rate of 129 gpm. The motor-operated VCT isolation valves, MOV-1115 C and E, and the isolation valves, MOV-1289 A and B, in the normal charging line are open. MOV-1370 is also open to divert part of the charging flow for RCP seal injection. On the other hand, MOV-1115 B and D which lie between the RWST and the charging pump suction header, and MOV-1867 C and D on the discharge line to the cold legs are closed.

During POS 2, the RCS is cooled down from hot shutdown (HSD) conditions of 543° F and 2235 psig to 345°F using the steam generators. Initially, the CVCS is setup to borate the RCS to cold shutdown (CSD) concentration. Two RCPs (B and either A or C) are tripped to aid the RCS cooldown, which is accomplished by controlling main turbine steam bypass to the main condenser and by placing pressurizer spray control in manual. The maximum RCS cooldown rates are 100° F/hr for >440° F and 50° F/hr from 440° F to 200° F, while the maximum cooldown rate for the pressurizer is 200° F/hr. As RC pressure decreases, letdown flow is maintained by opening the letdown pressure control valve (PCV-1145) and verifying that all letdown orifice isolation valves (HCV-1200 A/B/C) are open. RCP seal injection flow is also maintained at between 6.5 and 13 gpm per RCP.

During the RCS cooldown when the low T_{avg} and the low pressurizer pressure (less than 2000 psig) permissives are received, automatic safety injection (SI) initiation is blocked from HI STEAM FLOW & LO TAVG OR LP SI and LO PRZR PRESS STM HDR/LINE P SI, respectively. When RC pressure falls below 1000 psig, the SI accumulator discharge isolation MOVs are closed and their breakers locked open. When RC temperature decreases to 350° F, the control switches of the non-operating charging pumps are put in pull-to-lock to protect against overpressurization; all charging pumps except the running pump A are in pull-to-

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lock. When the RC pressure is reduced below 345 psig, the Low Temperature Overpressurization Protection (LTOP) system is manually enabled.

During POS 3, cooldown of the shutdown reactor and the RCS is continued from 345°F to cold shutdown conditions of <200° F by controlling main turbine steam bypass (while still having SG pressure) and by establishing and maintaining Residual Heat Removal (RHR). Before the cooldown, the engineered safeguards pumps (such as low pressure SI pumps, recirculation spray pumps and containment spray pumps, with the exception of one charging pump) will be prevented from operating by placing their control switches in pull-to-lock. Meanwhile, the Low Pressure Safety Injection (LPSI) and AFW discharge valves are closed. The maximum cooldown rate is 50° F/hr to 200° F, and 40° F/hr from 200° F to 170° F.

While setting up the RHR, the RCS is cooled down by using the SGs and main turbine steam bypass. The RHR setup includes system fill via alignment to CVCS letdown, starting up of one RHR pump and system heatup to 345° F via RCS interface (by opening the RHR series supply valves MOV-1700 and 1701 and discharging through HCV-1142 to CVCS). This change establishes flow from the RCS hot leg A through RHR system to the letdown line. Before placing the RHR in service (by opening the MOV-1720 A/B on the RHR discharging lines to RCS loop B and C cold legs), it must be ascertained that RHR boron concentration is equal or larger than that of the RCS.

Once RHR is in service, SG steaming and RHR cooling are used together to continue the cooldown until SG pressure decreases to 5 to 15 psig (RC temp 228° to 250° F). Then, the main turbine steam bypass valves are closed and the SG secondary sides are isolated. To prevent intrusion of oxygen, nitrogen gas must be delivered to maintain positive pressure in the SGs before the RC temperature falls below 212°F.

During POS 4, cooldown of the RCS is continued to 140° F by controlling low through the RHR heat exchanger using HCV-1758. The cooldown rate is <40°F/hr to 170°F, and <20°F/hr from 170°F to 140°F. Throughout this POS, coolant pressure in the reactor is maintained at approximately 345 psig with a bubble in the pressurizer. The total RHR flow is automatically controlled at 3500 gpm, while maintaining component cooling water (CCW) return from the operating RHR heat exchangers at 100-120° F.

The RCS is drained to mid-loop during POS 5. Starting with RCS temperature and pressure of about 140°F and 345 psig, respectively, and with a bubble in the pressurizer, the only operating RCP (1A or 1C) and pressurizer heaters are secured.

In addition, protection of the equipment is enhanced by the tagout and lockout of all pressurizer heater groups and the rack out of all RCP breakers. RCP seal bypass isolation valve (HCV-1307) and the three RCP seal leakoff isolation valves (HCV-1303 A/B/C) also are closed. The RCS then is depressurized by spraying down the pressurizer and filling it. The charging flow is introduced to the pressurizer by opening auxiliary spray isolation valve (HCV-1311), while closing charging line to Loop B cold leg isolation valve (HCV-1310). To cooldown the pressurizer, it is filled with charging line flow by closing the letdown pressure control valve (PCV-1145) and adjusting the charging line flow control valve (FCV-1122). Before the pressurizer level reaches 85%, the pressurizer PORVs and their isolation valves are opened. The pressurizer is full when the level increase in the Pressurizer Relief Tank (PRT). The charging and letdown flows are then balanced until pressurizer temperature <212° F before opening HCV-1310 and closing HCV-1311.

After the pressurizer is filled and then pressurized by a 5-30 psig nitrogen-gas blanket on the RCS via the PRT, the RCS is drained cautiously to the "referenced" midloop (9 inches above the actual midloop level) while RHR continues to remove decay heat. Draining is accomplished by opening the pressurizer spray valves, closing charging line flow control valve (FCV-1122), and after verifying that HCV-1142 is open, maximizing the discharge pressure of the RHR pump for optimum drainage. Meanwhile, the letdown pressure control valve (PCV-1145) is opened and letdown flow is verified. The operator should also verify that pressurizer level is decreasing and that LCV-1115A just upstream of the volume control tank (VCT) is diverting the drained reactor coolant to the Boron Recovery Tanks.

During Mid-loop Operations I (POS 6), the RC loops may be isolated by closing the loop isolation valves and drained completely for loop maintenance or SG tube inspection. The RCS temperature, meantime, is maintained at $<140^{\circ}\text{F}$ by controlling the RHR heat exchanger flow. Part of the RHR flow is still diverted to the letdown flow line through HCV-1142.

The Refueling Cavity is filled in preparation for refueling during POS 7. Starting with the POS 6 mid-loop conditions, the water level in the reactor vessel is first raised to just below the head flange, using either the CVCS or the LPSI system. If CVCS is to be used, the operator must first verify that at least one charging pump is operating. The charging flow is then increased so that it is greater than letdown flow (placing FCV-1122 in manual). If necessary, makeup to the VCT is added to maintain the level. During the makeup, the operator must verify that the flow of boric acid and of primary grade water are in accordance with blended flow nomograph. When the desired level is reached, the charging and letdown flows are balanced; PCV-1122 put to AUTO.

After installing the reactor Refueling Cavity seal, the reactor head is lifted as the water level is raised to flood the open reactor vessel up into the Refueling Cavity. The refueling cavity is filled with the RWST water is achieved by using the LPHI system (discussed in Section 6.2.10.4).

POS 8 is allocated exclusively to refueling activities, such as removing spent fuel assemblies from the reactor core, possibly shuffling control element assemblies (CEAs), or adding new fuel assemblies to the core; the RCS temperature is maintained below 140°F throughout by the RHR heat exchangers. Part of the RHR flow is diverted to letdown flow line through HCV-1142.

After refueling is completed, the upper internals structure is restored to the reactor vessel. The refueling cavity is then drained by pumping the water back to the RWST using the RHR (and RL) pumps. When the water level decreases below the flange of the reactor vessel, draining is suspended while the vessel head is reattached and head bolt tensioned. The RHR heat exchanger maintains the RCS temperature at $>80^{\circ}\text{F}$ with the reactor head bolts tensioned. Then, the RCS is cautiously drained, if necessary, once again to "referenced" midloop following the procedures described above for POS 5. All of these operations are performed during POS 9.

Any uncompleted loop maintenance work and/or SG tube inspection is done during POS 10 when the RCS is drained a second time to "referenced" midloop. During this POS, RCS temperature is still maintained at $<140^{\circ}\text{F}$ by the RHR heat exchangers.

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Following the second mid-loop operation is completed, POS 11 begins by raising the water level in the reactor vessel using CVCS delivering borated water containing >2000 ppm of boron. After verifying that Low Temperature Overpressurization (LTOP) protection is in effect, filling of the RCS is continued using CVCS (one charging pump) with normal injection and RCP seal water rate of <150 gpm. We note that, when raising the water level using CVCS, charging flow must be larger than letdown flow and makeup to the VCT must be made to maintain the proper the VCT water level. When the pressurizer is full, as indicated by increasing Pressurizer Relief Tank (PRT) level, the injection rate from the charging pump is reduced and RC pressure is maintained at less than 100 psig by automatic letdown pressure control until RCS pressure is stabilized. With the pressurizer full, the RCS is vented by closing the PORVs with LTOP, pressurizing the RCS to 300-345 psig, jogging a RCP and then reducing pressure to <125 psig and venting the reactor vessel. Repeating the cycle of pressurization-RCP jog-depressurization-head vent will eventually cause the RCS to be filled solid at a RC pressure of <125 psig, ready for commencing a solid RCS heatup.

Heating the solid RCS and drawing a bubble in the pressurizer are performed during POS 12. In preparation for starting a RCP (either A or C) to heat up the RCS, the solid RCS is repressurized and maintained at about 345 psig by charging flow. Then, the RCP is started with the pressurizer heaters energized to heat up the pressurizer. This, along with controlling the RHR heat exchanger flow, can heatup the RCS to 175° F at the rate of <40° F/hr. AT 175° F, the RCS temperature is stabilized for a "chemistry hold" until the concentration of certain chemicals (such as oxygen, chlorine or Li) in the RCS is within specified limits. The VCT gas space is then purged with hydrogen gas and preparation for drawing a bubble begins by energizing all pressurizer heaters, closing the pressurizer spray valves, and placing the letdown pressure control valve (PCV-1145) in "automatic" at about 300 psig. The RCS heatup to 190-195°F is continued, controlled at <40° F/hr, while the pressurizer heatup is controlled by the heaters at <100° F/hr. While awaiting the formation of bubbles, RCS pressure must be manually controlled so as not to fall below 300 psig (the minimum pressure to support RCP operation) yet not rise so high as to challenge the PORV set point for the LTOP. Bubble formation will be indicated by the letdown pressure control valve (PCV-1145) continuing to open in automatic, with a corresponding increase in letdown flow while there is no increase in charging flow. The rate of bubble formation can be increased by decreasing the charging flow and reducing the setpoint for PCV-1145. When the pressurizer level is reduced to the normal setpoint (approximately 22%), pressurizer level control is switched from manual to automatic while the charging line flow control valve (FCV-1122) is also placed in "auto" position. RCS pressure is maintained at about 345 psig using the pressurizer spray valves. This satisfies the 200 psig minimum RCP seal delta-P as well as the 300 psig minimum RCS pressure required for the operation of a RCP.

During POS 13, RCS is heated up to 350° F. When the prerequisites (such as completing the containment integrity checklists) for RCS temp >200° F are met, the other two RCPs are started to help the RCS heatup. The rate of heatup is maintained at <40° F/hr by controlling RHR heat exchanger flow if necessary. Before the RC temperature reaches 212° F, the SGs are prepared for steaming. When steaming begins, the SGs and Main Steam System will be prepared to control RC temperature by using main turbine steam bypass. The heatup is stopped when the RC temperature reaches 350° F.

At the beginning of POS 14, the pressurizer level is automatically controlled and maintained at normal operating level by CVCS. Its pressure is manually controlled by pressurizer spray and heaters. Meanwhile, RCS temperature is manually controlled at 350° F by RHR heat exchanger flow and main turbine steam

6 System Description and Fault Tree Analysis

bypass control. Before continuing the heatup, RHR is secured and isolated from the RCS. The engineered safeguards systems are also enabled, including changing the control switches of the non-operating charging pumps from Pull-To-Lock to AUTO position.

The operator has to verify that the control switches of all 3 charging pumps are in AUTO position. In this configuration, all three charging pumps are lined up to charge to the RCS, with one pump (pump A) running, one pump (pump B) on standby, and one pump (pump C) in Pull-To-Lock. LTOP protection also is disabled by placing the key switches of the reactor vessel's overpressurization mitigating system to the DISABLE position. The heatup is continued at the rate of $<40^{\circ}\text{F/hr}$ and the pressurization increased in accordance with the pressure-temperature curve. All of the accumulator isolation valves are opened during RCS pressurization when the pressure reaches about 1000 psig. Above 2000 psig, power to the isolation valve operators is removed and the breakers are locked open. When the normal operating RC temperature and pressure (543°F and 2235 psig) are reached, the pressure is put into automatic control whereas temperature is controlled by automatic SG pressure control with the main turbine steam bypass.

POS 15 begins with the reactor maintained at stable hot shutdown conditions with boron concentration of 2300 ppm. Before starting up the reactor, the RCS must be cautiously diluted by CVCS to a critical boron concentration after fully withdrawn status of the control rod assembly shutdown bank is verified. The RCS is deborated using the charging pump (pump A) to inject into cold leg B the primary grade water pumped into the volume control tank (VCT) by the primary grade water supply pumps. The letdown flow, in the meantime, is diverted to the Boron Recovery System. For Surry, deboration is estimated to take about 4 to 5 hours. After completing the boron dilution, the reactor is brought to criticality by withdrawing the appropriate control bank. Reactor power then is increased by manual control bank withdrawal to $<10\%$ to warmup, rollup, and place the turbine generator on the grid.

6.2.9.5 HPI/HPR System Logic Model

The following fault tree models were developed, based on the NUREG/CR-4550 report, to delineate the different modes of operation of the HPI/HPR system. They include:

- D1: Failure of high pressure flow to cold legs from three charging pumps (Automatic)
- D2: Failure of high pressure flow to cold legs from three charging pumps (Manual)
- D3: Insufficient flow from all charging pumps to the RCP seals
- D4: Insufficient emergency boration flow
- HPR-H2: Insufficient flow from three charging pumps in the recirculation mode
- D3U2 Cross-tie of unit 2 charging pumps

The following fault trees were developed to represent the different requirements in the various time windows corresponding to different success criteria:

Time Window 1 & 2	-	FSW12H - Feed & Spill Logic
		D223 - Cold leg Injection
		D2HLG23 - Hot leg Injection
Time Window 3 & 4	-	FSW34H - Feed & Spill Logic

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We scrutinized the logical soundness and applicability of these fault tree models to the analysis of reactor operations under shutdown conditions. Our findings and the modifications needed in order to use these models are summarized for each operating mode.

(1) Logic Model for D1 (Failure of HP Flow to Cold Legs from Three Charging Pumps, Automatic Initiation)

This fault tree model was essentially developed for normal power operation. All three charging pumps are modeled to inject into the charging line with Pump A actually running, Pump B and C on standby.

The dependencies of the three charging pumps on the AC bus, DC bus, SIS signal and CPC system, and those of MOVs (i.e., MOV-1115 B/C/D/E, MOV-1269 A, MOV-1270 A, MOV-1286 B/C and MOV-1867 C/D) on the AC bus, SIS signal and RMT, shown in Table 6.2.9-1, are all properly modeled in the fault tree. Common-cause failures treated in the fault tree include the following:

HPI-CCF-FS-CH1BC:	common cause failure to start charging pumps B and C
RWT-TNK-LF-RWST:	insufficient water available from the RWST
HPI-CCF-FT-115BD:	common cause failure of MOVs 1115B and 1115D
HPI-CCF-FT-867CD:	common cause failure of HPI MOVs 1867C and 1867D

The fault tree, D1, was modified to include possible failure of motor-operated dampers for charging pumps B and C. The following two basic events and two transfer-gates were added, which link the two basic events to their supporting electrical power system.

HPI-MOD-FT-101B (Motor-operated damper MOD-101B fails to open)
HPI-MOD-FT-101C (Motor-operated damper MOD-101C fails to open)
E21II (Failure of 120V AC power to vital bus 1-II)
E1I (Failure of 120V AC power to vital bus 1-I)

To account for a possible common-cause failure of the check valves located on the cold-leg injection lines, a basic event, CKV-CCF-FT-CLDLG (Common cause failure of CV79, CV82 and CV85) was also added. The modified fault tree is applicable to POSs 1,2,14, and 15.

During POSs 3-13, only charging pump A is assumed to be running, and the control switches of both charging pumps B and C are placed in Pull-TO-Lock position. The automatic safety injection signals are also disabled. Therefore, the following further modifications to the D1 fault tree were necessary:

- a. Add a new basic event, "operator fails to manually initiate high pressure injection flow to cold legs" to the OR-gate under the fault tree top event, D1. The modified tree was stored as D1-C. The operator actions required include changing the position of the control switch of both Pump B and Pump C from Pull-To-Lock to Start, and realigning the flow path so that the charging pumps take suction from the RWST rather than the VCT, and the injection flow enters the RCS through the injection lines to the cold legs rather than the normal charging line to cold leg B. The

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operator, therefore, must manually close the VCT isolation valves, MOV-1115 C/E, and MOV-1289 A/B on the normal charging line, and manually open MOV-1115 B/D on the pump suction line leading to the RWST and MOV-1867 C/D on the injection line to the cold legs.

- b. Set the basic-event probability of both SIS-ACT-FA-SISA (no signal from SIS train A) and SIS-ACT-FA-SISB (no signal from SIS train B) to zero, which is tantamount to disabling the automatic safety-injection signals. The probability of the basic event, HPI-XHE-FO-PLLCK (Operator fails to remove pull lock condition) also should be changed to zero.
- c. For accidents involving loss of RHR system, it is sometimes preferable to inject high-pressure coolant into the RCS through hot legs. The system fault tree, D1, therefore, was further modified so that charging pump flow can be injected this way rather than through the cold legs. The operator has to realign flow paths, including opening the motor-operated valves, MOVs-1869 A/B, leading to hot legs. The pull-to-lock condition of the charging pumps also must be removed and the charging pump started. The modified fault tree, with the following six new events, was stored as D1HLG.

HPI-XHE-FO-HOTLG (Operator fails to manually initiate HPI flow to hot legs)

HPI-MOV-PG-1869A (MOV-1869A plugged)

HPI-MOV-PG-1869B (MOV-1869B plugged)

HPI-MOV-FT-1869A (MOV-1869A fails to open on demand)

HPI-MOV-FT-1869B (MOV-1869B fails to open on demand)

HPI-CCF-FT-869AB (Common-cause failure of HPI MOVs, 1869A, 1869B)

The CCF basic event, CKV-CCF-FT-CLDLG, was eliminated because it does not apply.

Failures of the check valves located on the hot-leg injection lines prevent successful injection. Therefore, the D1HLG fault tree was further modified to include possible failure of the individual check valve, as well as common-cause failures of check valves arranged in parallel. The following two basic events were added:

CKV-CCF-FT-HTLG1 (Common cause failure of CV88, CV91 & CV94)

CKV-CCF-FT-HTLG2 (Common cause failure of CV238, CV239 & CV240)

A new sub-tree, NFWHLG (No flow to hot legs due to check valve failures), containing the following six basic events, was also constructed.

LPI-CKV-FT-CV88 (Check valve CV88 fails to open)

LPI-CKV-FT-CV91 (Check valve CV91 fails to open)

LPI-CKV-FT-CV94 (Check valve CV94 fails to open)

LPI-CKV-FT-CV238 (Check valve CV238 fails to open)

LPI-CKV-FT-CV239 (Check valve CV239 fails to open)

LPI-CKV-FT-CV240 (Check valve CV240 fails to open)

- (2) Logic Model for D2 (Failure of HP Flow to Cold Legs From Three Charging Pumps, Manual)

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The only difference between this mode of operation and that of D1 is that the high-pressure injection is initiated manually by the operator rather than automatically by a safety injection signal. This situation occurs if the operator decides to establish "feed-and-bleed" operation to remove the decay heat. The fault tree model for D2 is essentially identical to that for D1, except that it does not contain the basic events for the safety injection signals and that the fault tree top event contains an additional basic event, HPI-XHE-FO-FDBLD under an OR-gate (operator fails to establish feed and bleed operation). As in fault tree D1, the fault tree D2 was modified to include the failure of motor-operated dampers for charging pumps B and C. Common-cause failures of the check valves located on the cold-leg injection lines were also modeled. The modified D2 fault tree is applicable to POSs 1,2, 14, and 15.

For POSs 3 through 13, the fault-tree structure remains valid. However, the probability of the additional basic event, HPI-XHE-FO-FDBLD, must be re-evaluated by considering the additional needs for the operator to change the position of the control switches of charging pumps B and C from Pull-To-Lock to Start, and to manually realign the flow path, as described above for D1. Meanwhile, the probability of the basic event, HPI-XHE-FO-PLLCK (operator fails to remove pull lock condition), assigned to Charging pump C should be set to zero.

The system fault tree, D2, was further modified so that, for feed-and-bleed operation, the high pressure charging pump flow can be injected into the RCS through hot legs rather than cold legs. The operator has to manually establish the feed-and-bleed operation by manually realigning the flow paths, including opening MOVs 1869 A/B, removing the pull lock condition of the charging pumps, and starting the charging pump. The modified fault tree with the new basic event, HPI-XHE-FO-FBHLG (Operator fails to establish feed and bleed through hot legs), was stored as D2HLG.

The CCF basic event, CKV-CCF-FT-CLDLG, was eliminated because it does not apply. To take into account possible failure of hot leg injection due to check-valve failures on the hot-leg injection lines, the relevant check valve failure events, identical to those described for D1HLG, were added to the D2HLG fault tree.

(3) Logic Model for D3 (Insufficient Flow From All Charging Pumps to the RCP Seals)

This fault tree was developed to estimate the probability of having no RCS seal injection flow from all the three charging pumps. The NUREG/CR-4550 analysis assumes that the normal flow line to the RCS pump seal is normally in use and that the valves, even they fail, will fail in the position that allows flow to the seals. It further postulates that there is always sufficient flow from charging pump suction header for seal injection. Therefore, the motor-operated valves and manual valves on the seal injection line, were not modeled. The fault tree constructed for D3 differs from that for D1 in the following three respects:

- (i) Automatic safety injection signals from train-A and train-B are not modeled because they are irrelevant.
- (ii) The motor-operated valves, MOV-1867 C/D and check valve, CV225, located on the injection line to the cold legs are not modeled because they are irrelevant.
- (iii) The event, HP19 (insufficient flow from charging pump suction header) is not included.

The charging pumps are normally aligned to take suction from the VCT. In this study, the fault tree D3 was modified by adding events that take into account possible failures of motor-operated dampers for charging pumps B and C; these changes were described in modeling the fault tree D1. The modified tree is applicable to POSs 1,2,14, and 15.

For POSs 3 through 13, only charging pump A is running and the control switches of both charging pumps B and C are placed in the PULL-TO-LOCK position. Therefore, we added another basic event, HPI-XHE-FO-PLLCK (operator fails to remove pull lock condition), to the OR-gate under the event, HPI500 (insufficient flow through pipe segment PS12). The modified tree was stored as D3-C. We note that charging pump B is located on PS12, and that the basic event, HPI-XHE-FO-PLLCK, is already modeled to account for the possible failure of charging pump C. This basic event, therefore, acts as a common-cause failure for both pumps B and C.

(4) Logic Model for D4 (Insufficient Emergency Boration Flow)

Fault tree D4 was developed in the NUREG/CR-4550 report to estimate the probability of failing to provide sufficient emergency boration flow when needed. For an emergency boration, the operator must open a RCS PORV, open the emergency boration valve, MOV-1350, and manually start the boric acid transfer pump so that concentrated boric acid solution can be pumped to the charging pump suction header. The modeling mainly focused on the makeup subsystem containing the path for transporting boric-acid solution from the Boric Acid Storage Tank (BAST) to the suction of the charging pump and the primary pressure relief system containing the PORVs and their block valves.

Both the boric-acid transfer pump (1-CH-P-2A) and MOV-1350 depend on 480 VAC MCC-1H1-2S, and they are properly modeled in the fault tree. The dependencies of PORVs on DC buses (PCV-1455C on DC bus 1A and PCV-1456 on DC bus 1B) for control power, as well as those of the PORV block valves on the 480 VAC buses (MOV-1535 on MCC-1H1-2 and MOV-1536 on MCC-1J1-2) for control and motive power are also modeled. Although the PORVs depend on containment air for motive power, it was not modeled because the PORVs have air bottles sized to provide approximately 80 openings of each valve. Besides the dependencies, common cause failure of the two PORV block valves and common cause failure of the two PORVs to open are also modeled.

For failure to provide sufficient flow of boric acid solution to the charging pump suction, the only event considered is failure of the boric acid transfer pump to run for one hour. We decided to add two more basic events to account for the possible failures of boric-acid storage tank heaters and heat tracings. The fault tree, D4, is modified by adding the following two basic events to the OR-gate, CVC1 (insufficient flow-boric acid transfer pump to charging pump suction):

- (i) BAT-HTR-VF-STANK (boric acid storage tank heater fails and is not detected)
- (ii) BAT-HTR-FC-TRACE (heat tracing fails and is not detected)

The modified fault tree is applicable to POSs 1,2,14, and 15. For POSs 3 through 13, the structure of the fault tree remains applicable. Changing the control switch of charging pump B from Pull-To-Lock to Start position,

6 System Description and Fault Tree Analysis

and realigning the charging pump discharge path, if required, can be taken care of by re-evaluating the failure probability of the basic event, PPS-XHE-FO-EMBOR (operator fails to correctly perform emergency boration); the operator's failure to remove the pull lock condition of Charging pump C is already modeled in D3, which appears as a sub-tree to D4.

(5) Logic Model for HPR-H2 (Insufficient Flow from Three Charging Pumps in the Recirculation Mode)

The fault tree model for HPR-H2 presupposes that the high pressure injection system has been activated and in operation for a period before a RMT (recirculation mode transfer) signal is generated due to low water level in the RWST. The configuration of the HPSI system, therefore, is such that all three charging pumps are aligned to inject into the cold legs. Upon receiving of a RMT signal, LPSI MOVs-1863 A/B automatically open to admit flow from the discharge lines of low head SI pumps 1A and 1B to the suction headers of the charging pumps, thus providing water and NPSH to the charging pumps. Therefore, the HPR-H2 fault tree, interfaces with the LPSI system through events LPR-HHA (insufficient flow from LPR MOV-1863A) and LPR-HHB (insufficient flow from LPR MOV-1863B), which will be discussed in subsection 5.1.10.5, under item (3).

The fault tree structure of HPR-H2 differs from that of D1 mainly in the following respects:

- (i) Faults on the injection lines to the cold legs are not modeled (because the system has been operating in the injection mode).
- (ii) The flow path connecting the RWST and the charging pump suction header is not modeled (because the charging pumps now rely on the flow from the LPSI pumps into the suction header through MOVs-1863 A/B for their source of water).
- (iii) A new event is added, insufficient flow to charging pump suction header from LPSI MOVs-1863 A/B.
- (iv) Plugging of MOV-1269 A is neglected. To block the flow path on the suction side of charging pump B, both MOV-1269A and MOV-1269B must be plugged; the likelihood is negligibly small. Similarly, plugging of MOV-1270A is neglected.
- (v) The charging pumps are required to run for 18 hours.

As in the case of D1, the dependencies of the charging pumps on the AC bus, DC bus, and CPC system are all modeled properly. Common cause failure to start charging pumps B and C is also modeled.

Possible failures of motor-operated dampers for charging pumps B and C were added to the HPR-H2 fault tree. The required changes were discussed in the section describing fault tree D1. The modified fault tree is applicable to POSs 1,2,14, and 15.

For application to POSs 3 through 13, it must be assumed that the HPI system has been manually actuated by the operator and operating in the injection mode for a period. This implies that the flow paths for the charging pumps have already been manually realigned to take suction from the RWST and inject into the cold legs. Furthermore, the operator has removed the Pull-To-Lock condition from charging pumps B and C. One modification needed is to change the probability of each of the following basic events to zero:

SIS-ACT-FA-SISA (No signal from SIS train A)
SIS-ACT-FA-SISB (No signal from SIS train B)
HPI-XHE-FO-PLLCK (Operator fails to remove pull lock condition)

6. Logic Model for D3U2 (Cross-tie of Unit 2 Charging Pumps)

A fault-tree model was developed to represent the hardware failure modes associated with the operation and availability of the cross-tie of the charging system between the two units. The model primarily includes the failure modes of the unit 2 charging pumps, strainers, and valves. The dependency on unit 2 electrical power supplies were modeled as simple basic events and their values were determined by assuming the same unavailability for these components as for the corresponding unit 1 components.

This particular fault tree is primarily used in the station blackout event trees and is discussed in more detail in the section 7.4.

LOGIC MODELS FOR TIME WINDOW REPRESENTATION:

Time Window 1 & 2 - the feed-and-spill operation requires the success of 2 HPI pumps injecting either to the cold or hot legs. 2/3 logic was developed;

Cold leg injection - D223
Hot leg injection - D2HLG23

The failures of the HPI system are combined with the unavailability of the safety valves or PORVs, which represent the spill function (opening in the RCS).

Feed & Spill Logic - FSW12H

Time Window 3 & 4 - The main difference in this time window is the reduced flow requirement and 1 HPI pump may provide sufficient flow. It is assumed that 1 PORV path is open, satisfying the spill function.

Feed & Spill Logic - FSW34H

Figure 6.2.9-1 HPI/HPR System Simplified Sketch

Figure 6.2.9-1 HPI/HPR System Simplified Sketch

Table 6.2.9-1 HPI/HPR Component Status and Dependency Summary

COMPONENT	NORMAL STATUS		ACTUATION	DEPENDENCIES
Pumps:	POS 1-2, 14-15	POS 3-13		
1-CH-P-1A	Operating	Operating	SIS-A	4160V Bus 1H, SIS-A, DC Bus 1A, CPS System
1-CH-P-1B	Standby	Pull-to-lock	SIS-B	4160V Bus 1J, SIS-B, DC Bus 1B, CPC System
1-CH-P-1C	Standby	Pull-to-lock	SIS-A,B	4160V Bus 1H, 1J, SIS-A,B, DC Bus 1A,1B, CPC-System
MOVs:				
1115B	NC/FAI	NC/FAI	SIS-A,RMT-A	MCC1H1-2N,SIS-A,RMT-A
1115D	NC/FAI	NC/FAI	SIS-B,RMT-B	MCC1J1-2E,SIS-B,RMT-B
1115C	NO/FAI	NO/FAI	SIS-A,	MCC1H1-2N,SIS-A
1115E	NO/FAI	NO/FAI	SIS-B,	MCC1J1-2E,SIS-B
1267A	NO/FAI	NO/FAI	R. Manual	MCC1H1-2S
1269A	NO/FAI	NO/FAI	R. Manual	MCC1J1-2W
1270A	NO/FAI	NO/FAI	R. Manual	MCC1H1-2S
1267B	LO/FAI	LO/FAI	R. Manual	MCC1H1-2S
1269B	LO/FAI	LO/FAI	R. Manual	MCC1J1-2W
1270B	LO/FAI	LO/FAI	R. Manual	MCC1J1-2W
1286A	NO/FAI	NO/FAI	R. Manual	MCC-1H1-2S
1287A	NO/FAI	NO/FAI	R. Manual	MCC-1H1-2S
1286B	NO/FAI	NO/FAI	R. Manual	MCC-1J1-2W
1287B	NO/FAI	NO/FAI	R. Manual	MCC-1J1-2W
MOVs	POS1-2,14-15	POS 3-13		
1286C	NO/FAI	NO/FAI	R. Manual	MCC-1H1-2S
1287C	NO/FAI	NO/FAI	R. Manual	MCC-1J1-2W
1370	NO/FAI	NO/FAI	R. Manual	MCC-1H1-2N

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Table 6.2.9-1 (continued)

COMPONENT	NORMAL STATUS		ACTUATION	DEPENDENCIES
1289A	NO/FAI	NO/FAI	SIS-A	MCC-1H1-2N,SIS-A
1289B	NO/FAI	NO/FAI	SIS-B	MCC-1J1-2E,SIS-B
1867C	NC/FAI	NC/FAI	SIS-A	MCC-1H1-1,SIS-A
1867D	NC/FAI	NC/FAI	SIS-B	MCC-1J1-1,SIS-B
1842	NC/FAI	NC/FAI	R. Manual	MCC-1H1-2
1869A	LC/FAI	LC/FAI	R. Manual	MCC-1H1-1
1869B	LC/FAI	LC/FAI	R. Manual	MCC-1J1-1
1863A	NC/FAI	NC/FAI	RMT-A	MCC-1H1-2N,RMT-A
1863B	NC/FAI	NC/FAI	RMT-B	MCC-1J1-2E,RMT-B
AOVs:				
TVSI-102A	NC/FO	NC/FO	R. Manual	Instrument Air, DC Bus 1A
TVSI-102B	NC/FO	NC/FO	R. Manual	Instrument Air, DC Bus 1B

6.2.10 Low Pressure Injection/Recirculation System

6.2.10.1 Low Pressure Injection/Recirculation System Description

The primary function of the low pressure injection/recirculation system is to provide emergency coolant injection and recirculation following a loss of coolant accident (LOCA) when the reactor coolant system (RCS) depressurizes below 180 psig. During recirculation, after the refueling water storage tank (RWST) has drained to a low-low level, the LPR discharge also provides the net positive suction head (NPSH) for the high-pressure recirculation system. Figure 6.2.10-1 is a simplified drawing of the system.

The LPI/LPR system consists of two 100% capacity pump trains. During normal operations, the low-pressure injection pumps are in standby, lined up to pump borated water from the RWST to the RCS cold legs. Each LPI pump is a vertical, two-stage, mixed-flow enclosed impeller, centrifugal pump. Each pump has a capacity of 3250 gpm at 300°F and 300 psig, with a design head of 225 ft; the actual capacity of the pump, depends on its discharge pressure.

Upon indication of a loss of RCS coolant or a main steam line break (i.e., low pressurizer pressure, high containment pressure, high pressure differential between any steam generator header and the steam line, or high steam flow coincident with either low RCS average temperatures or low-low steam line pressure), the safety injection actuation system (SIAS) initiates LPI operation. On receiving a safety-injection signal from the SIAS, the LPI pumps automatically start and deliver large quantities of borated water to the RCS provided that RCS pressure is reduced below the LPI pump shutoff head; otherwise, they will discharge to the RWST through two normally open minimum flow recirculation lines until the RCS pressure is sufficiently reduced to allow inflow.

During normal operations and the injection mode, the LPI pump trains are lined up to receive water from the RWST through a common suction header. Each LPI pump draws suction from the header through a normally open motor-operated isolation valve MOV-1862(A or B), check valve, and locked open manual valve in series. Each pump discharges through a check valve and a normally open MOV-1864(A or B) in series to a common injection header which contains a locked-open MOV-1890C and branches to three separate lines, one to each cold leg. Each line to the cold legs has two check valves in series isolate it from the high pressure RCS.

The LPI pumps have tandem seals, the inboard seal being cooled from the discharge of the pump and the outboard seal cooled by the action of a pumping ring and air cooler circuit. To prevent the pump overheating when operating at shutoff head and also for testing, each pump has a minimum flow bypass line to recirculate fluid to the RWST. The recirculation line is automatically isolated during the recirculation mode following a LOCA. The maximum cold leg flow of the LPI pumps is limited to 3425 gpm by cavitating venturi.

The LPI pumps also can be aligned to inject borated water into the RCS hot legs. In the hot-leg injection mode, the operation of the system is identical to that described above, except that the normally open cold leg injection valve, MOV-1890C, must be remote-closed manually, and one or more normally closed hot-leg recirculation valves, MOV-1890 A (and or B), must be remote opened manually.

Upon receipt of a low-low RWST level (about 19.5% level), an recirculation mode transfer (RMT) signal is initiated to automatically realign safety injection to the recirculation lineup. The RMT signal causes the low pressure pump suction valves (MOV-1862 A/B) from the RWST and the valves in the minimum flow bypass lines to the RWST (MOV-1885 A/B/C/D) to close, and the suction valves from the containment sump (MOV-1860 A/B) to open. The discharge of the LPI pump also automatically aligns to the HPI pump suction through MOV-1863 A/B.

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In the recirculation mode, the low-pressure pump trains draw suction from the containment sump through a parallel arrangement of suction lines to a common header. Each suction line contains a motor-operated valve (MOV-1860 A or B) and a check valve in series. The discharge is directed to either the cold legs through the same lines used for injection, or to a parallel set of headers which feed the charging pumps, depending on the RCS pressure.

Approximately 16 hours after the inception of the postulated accident, the emergency procedures call for a switchover from cold-leg to hot-leg recirculation. The operator must restore power to motor-operated valves MOV-1890 A,B, and C (since the breakers for these valves are normally kept in the open position), open MOV-1890 A/B, and close MOV-1890 C.

6.2.10.2 LPI/LPR System Interfaces and Dependencies

The component status and dependency of the components of the LPI/LPR system are summarized in Table 6.2.10-1.

1. The LPI system interfaces with the high pressure injection system at the common RWST via a shared valve. The LPR system interfaces with the high pressure recirculation system at the recirculation suction valves for the HPR.

Operation of the LPI system depends on the following:

- (i) The RWST for fluid inventory
- (ii) The Safety Injection Actuation System (SIAS) to actuate the LPI components
- (iii) AC power buses for motive power to the LPI pumps, and for motive and control power to the MOVs in the LPI system
- (iv) DC power buses for control power to the LPI pumps

Meanwhile, operation of the LPR system depends on the following:

- (i) The injection systems for sump inventory
- (ii) The RMT signal generated by low-low level in the RWST to actuate of the LPR switchover from the injection mode
- (iii) AC power buses for motive power to the LPR pumps, and motive and control power to the MOVs in the LPR system
- (iv) DC power buses for control power to the LPR pumps

6.2.10.3 LPI/LPR System Operational Constraints

Technical specifications require the pumps, valves, piping and interlocks of the LPI/LPR system to be operable always (24-hour AOT for one LPI subsystem before hot shutdown, and an additional 48-hour AOT before cold shutdown). The surveillance requirements specify that each LPI pump is tested quarterly to verify satisfactory recirculation flow in accordance with ASME Section XI.

6.2.10.4 LPI/LPR System Shutdown Configuration

During POSs 1 and 2, the two low-pressure safety-injection pumps are placed in standby, lined up to pump borated water from the RWST to the cold legs. The two LPI suction valves, MOV-1862 A/B, and the two LPI discharge isolation valves, MOV-1864 A/B, located, respectively on the suction lines and discharge lines of the two LPI pumps are kept open. The LPI discharge isolation valve, MOV-1890C, located on the common discharge header leading to the cold legs also is kept open with its power removed. Meanwhile, the two LPI discharge valves, MOV-1890 A/B, located on the discharge lines leading to the hot legs are maintained closed with their power removed. The four LPI recirculation isolation valves, MOV-1885 A/B/C/D, located on the minimum flow bypass leading to the RWST, are normally kept open.

Before the RCS cooldown using the RHR in POS 3, the two LPI pumps are prevented from operating by placing their control switches to Pull-To-Lock position. After restoring power to the LPI discharge valve, MOV-1890C, by closing its breaker, MOV-1890C is also closed to prevent inadvertent injection into the RCS cold legs. The LPI/LPR system is essentially maintained in this configuration for POS 3 throughout POS 13, except for POS 7, when the LPI system may be used to fill the refueling cavity.

The reactor's refueling cavity is usually filled through the hot legs to prevent the reactor core being flushed into the reactor refueling cavity. Before filling the reactor cavity, the Heat Tracing System must be in service, the LPI pump seal tanks must be full, and communications between the control room and the containment must be established. The LPI system is verified to be in the proper lineup and the RMT keyswitches are placed in the REFUEL position. The operator must verify that the LPI suction valves, MOV-1862 A/B are open, leading to the RWST and the LPI recirculation isolation valves, MOV-1885 A/B/C/D, in the minimum flow recirculation line, and must also verify the LPI discharge isolation valves, MOV-1864 A/B and MOV-1890C are closed. Both LPI pumps are started and flow is throttled using MOV-1890 A and B by maintaining the flow rate at < 3500 gpm. When the desired water level in the reactor cavity is reached, both LPI pumps are secured and MOV-1890 A and B are closed.

Before the RCS heatup (from 350° F) is continued in POS 14, RHR is isolated from the RCS and the engineered safeguards systems, are enabled including the LPI/LPR system. The operator must realign the LPI system so that injection from the RWST to the cold legs can be done when a SI signal is received. Also, the control switches for the two LPI pumps must be put in AUTO. The LPI discharge valve, MOV-1890C, must also be opened and its power removed by opening its breaker. The LPI/LPR system is kept in this configuration during POS 15.

6.2.10.5 LPI/LPR System Logic Model

In the NUREG/CR-4550 report, the following three fault trees are developed to delineate the logic for failing the LPI/LPR system in different operating modes:

- D6:   Insufficient flow from two low pressure SI pumps to cold legs (injection mode)
- LPR-LH: Insufficient flow from low pressure SI pumps to cold legs (recirculation mode)
- LPR-HH: Insufficient flow from LPSI pumps to charging pump suction header

The following fault trees were developed to represent the requirements in the various time windows corresponding to different success criteria:

- For Feed & Spill Function
  - Time Window 1 & 2 - FSW12L
  - Time Window 3 & 4 - FSW34L

- For Gravity Feed Function
  - All Windows   - D6 - CG

The third fault tree (LPR-HH) interfaces with the high pressure SI system and can be considered as a sub-tree to the fault tree, HPR-H2, discussed in subsection 6.2.9.5. It depicts the logic for failing to provide sufficient LPSI pump flow to the suction header of the charging pumps to support the function of the high pressure SI system in recirculation mode.

We reviewed the adequacy and applicability of the NUREG-1150 fault trees to the present shutdown study. The required modifications are summarized next for each of these fault trees:

- (1) Logic Model for D6 (Insufficient Flow from Two Low Pressure SI Pumps to Cold Legs, Injection Mode)

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Under normal plant operation, the configuration of the LPI system is such that, upon receipt of a SI signal, the two LPI pumps can automatically take suction from the RWST and inject borated water into the cold legs through a common discharge header containing a motor-operated valve, MOV-1890 C. An insufficient inventory of water in the RWST or plugging of MOV-1890 C alone can, thus, directly cause the LPI system operation to fail. This logic is properly modeled in the fault tree. The rest of the fault tree models the failure to provide sufficient flow to or from MOV-1890 C. The injection flow downstream of MOV-1890 C eventually branches off and is directed into three separate flow paths, each connected to a cold leg. Each path contains two check valves in series, failure of any one of which to open can block the injection flow to the cold leg. The NUREG/CR-4550 analysis assumes that a large LOCA occurs at one of the three cold legs, so that only two cold legs are available for low pressure injection.

In the fault tree D6 developed in the NUREG/CR-4550 report, failure to provide sufficient flow to all three cold legs from MOV-1890 C (i.e., event LPI1) is modeled so that all four check valves (CV 242, CV 82, CV243, and CV 85) must fail to open on demand. We believe this to be a modeling error. We note that only two flow paths (PS44 and PS45) are considered available for the injection, and that each contains two check valves in series (CV 242 and CV 82 on flow path PS44, and CV 243 and CV 85 on flow path PS45). Failure of either CV 242 or CV 82 to open on demands can, thus, block flow path PS44. Similarly, failure of either CV 243 or CV 85 to open on demands can block flow path PS45. The fault tree was modified to reflect these changes in logic.

To handle certain special situations that might arise during plant shutdown, the fault trees were further modified so that all three cold legs (rather than two) can be used for safety injection. For this, the basic event, ALOCA (Occurrence of a large LOCA), is replaced by a transfer gate, LPPS43 (Failure of coolant flow through pipe segment 43). A new subtree, was also constructed with LPPS43 as the top event. LPPS43 is an OR-gate, containing a house event, ALOCA, and an OR-gate, NFWPS43 (NO flow through PS43 due to check valve failures). NFWPS43, which is an OR-gate, contains two basic events, LPI-CKV-FT-CV241 (Check valve CV241 fails to open), and LPI-CKV-FT-CV79 (Check valve CV79 fails to open).

Modeling of the event, LPI2 (insufficient flow to MOV-1890 C) focuses mainly on failures of LPSI pumps to start and run, plugging of motor-operated valves and manual valves, failure of check valves to open, and failure of safety injection signals. The dependencies of the two LPSI pumps on the AC-bus, DC-bus and SI signals, (Table 6.2.10-10), as well as the common-cause failure of the two LPSI pumps are modeled properly. The modified fault tree is applicable to POSs 1,2,14, and 15. For POSs 3 through 13, the basic event probability for SIS-ACT-FA-SISA and SIS-ACT-FA-SISB must be set to zero. Also, a new basic event, LPI-XHE-FO-COLD (Operator fails to manually initiate the LPI system), must be added to the fault tree top event, LPI, under OR-gate. To manually activate the LPI system during these POSs, the operator must change the control switches of both LPSI pumps from Pull-To-Lock to Start, and also remotely open MOV-1890C. Further, under the OR-gate, LPI, it is necessary to replace LPI-MOV-PG-1890C (MOV-1890C plugged) by LPI-MOV-FT-1890C (MOV-1890C fails to open on demands), and add a transfer gate EH2 (Failure of 480 VAC MCC1H1-2). The modified tree was stored as D6-C.

The system fault tree, D6, also was modified so that low pressure injection flow into the RCS can take place through hot legs rather than cold legs. The modified fault tree, which contains a new basic event, LPI-XHE-FO-HOTLG (Operator fails to manually initiate LPI flow to hot legs), was stored as LPIHLG. The operator has to realign the flow paths, restore power to the relevant valves before opening or closing them, remove the pull lock condition of the low pressure injection pumps, and start the LPI pump.

The fault tree, LPIHLG, was further modified to include possible failures of check valves located on the hot-leg injection lines. The required changes were discussed previously in the section describing the logic model of D1HLG, the fault tree for high pressure injection through hot legs.

- (2) Logic Model for LPR-LH (Insufficient Flow from Low Pressure Safety Injection Pumps to Cold Legs-Recirculation Mode)

The model presupposes that the LPSI system had been operating in the injection mode for a period, when the need arose to switch to the recirculation mode due to low RWST level. Upon receipt of a RMT signal, the suction lines of the two LPSI pumps automatically realign to allow the two pumps to take suction from the containment sump rather than the RWST. For this, both MOV-1862 A and MOV-1862 B must be closed, while opening both MOV-1860 A and MOV-1860 B. The model accounts for the dependencies of these motor-operated valves on the 480 VAC MCC buses and the RMT signal. Common-cause failure of MOVs-1862 A/B to close and that of MOVs-1860 A/B to open are also modeled. Other common cause failures modeled in the fault tree include LPR-CCF-PG-SUMP (plugging of the containment sump) and RMT-CCF-FA-MSCAL (common cause failure of RMT due to miscalibration).

Since the RMT signal is required to close MOV-1862 A and open MOV-1860 A, it is more appropriate to move the two events, RMT-ACT-FA-RMTSA (no signal from RMTS train-A) and RMT-CCF-FA-MSCAL from OR-gate LPR8 to OR-gate LPR9. Similarly, the two events, RMT-ACT-FA-RMTSB (no signal from RMTS train B) and RMT-CCF-FA-MSCAL, were moved from OR-gate LPR10 to OR-gate LPR11.

To account for possible failure of MOV-1890C to close when switching from cold-leg to hot-leg recirculation, an intermediate OR-gate, LPRM1, was added to the OR-gate LPR4 (failure to switch to hot leg recirculation at 16 hours). This new OR-gate contains one new basic event, LPI-MOV-OO-1890C (MOV-1890C fails to close) and a transfer gate, EH2 (Failure of 480V AC MCC 1H1-2). The review also uncovered a typographical error. The event, LPR5, was corrected to read "failure to provide flow through pipe segments PS46 and PS47." To take into account the possible failure of coolant flow due to failures of the check valve when switching to hot-leg recirculation, the sub-tree, LPR4 (Failure to switch to hot leg recirculation at 16 hours), was modified to include the relevant check valve failure events. These events were listed in the section describing the D1HLG fault tree that models high pressure injection through hot legs. The modified tree is applicable to POSs 1,2,14, and 15.

For application to POSs 3 through 13, however, the probability of the basic event, LPR-XHE-FO-HOTLG (operator fails to align the system for hot leg recirculation) must be re-evaluated to reflect the manual actions required to close MOV-1890 C, while opening MOVs-1890 A/B.

A new fault tree, HASHLG, also was constructed by modifying the system fault tree, LPR-LH (HAS), so that it can be used in combination with the fault tree, LPIHLG, discussed in section (1) above for low pressure injection to hot legs. The model assumes that low pressure SI flow into the RCS through hot legs has been taking place for some time before switching to the recirculation mode. Further, it assumes that the switchover to recirculation mode is actuated by a RMT (recirculation mode transfer) signal.

(3) Logic Model for LPR-HH (Insufficient Flow from LPSI Pumps to Charging Pump Suction Header)

This fault tree depicts the logic of the failure of LPSI pumps to provide sufficient flow to the suction header of charging pumps upon receipt of a RMT (recirculation mode transfer) signal. The two events, LPR-HHA (insufficient flow from LPR MOV-1863 A) and LPR-HHB (insufficient flow from LPR MOV-1863 B), defined near the top of this fault tree, interface with the fault tree, HPR-H2, (discussed in subsection, 6.2.9.5, item (5)). In their injection modes, both the charging pumps and the LPSI pumps take suction from the RWST. When the water level in the RWST falls to a low-low level, a RMT signal is generated, causing the suction source of the LPSI pumps to automatically switch from the RWST to the containment sump by closing MOVs-1862 A/B and opening MOVs-1860 A/B. At the same time, MOVs-1863 A/B are automatically opened to supply flow to the suction header of the charging pump.

Besides the mechanical failures of MOVs-1863 A or B, the modeling focused on the failures to provide sufficient flow through the individual LPSI pump train or via the discharge connection. Common-cause failures considered include LPR-CCF-FT-863AB (CCF failure of MOV-1863 A/B), LPI-CCF-FS-SI1AB (CCF of MDPs SI1A and SI1B), LPR-CCF-FT-860AB (CCF of MOVs 1860 A/B to open), LPR-CCF-FT-862AB (CCF of MOVs 1862 A/B to close), RMT-CCF-FA-MSCAL (CCF of RMT due to miscalibration), and LPR-

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CCF-PG-SUMP (plugging of the containment sump). The dependencies of the two LPSI pumps on their respective AC buses and DC buses are properly modeled, (Table 6.2.10-1). The dependencies of MOVs-1860 A/B, MOVs-1862 A/B and MOVs-1863 A/B on the RMT signal and on the 480 VAC MCC buses also are modeled. It is more appropriate, however, to transfer the two events, RMT-ACT-FA-RMTSA (no signal from RMTS train A) and RMT-CCF-FA-MSCAL from OR-gate LPR-HH3 to OR-gate LPR-HH5. By the same reasoning, the three events, RMT-CCF-FA-MSCAL, RMT-ACT-FA-RMTSB (no signal from RMTS train B), and LPR-CCF-PG-SUMP are transferred from OR-gate LPR-HH6 to OR-gate LPR-HH8. These are the only modifications made to this fault tree. The modified fault tree is applicable to POSs 1, 2, 14, and 15. For POSs 3 through 13, the fault tree is valid provided that, both the HPI and the LPI systems have been manually actuated by the operator before switching to the recirculation mode, and that the RMT signal is not disabled.

Logic Models for Time Window Representation:

Time Window 1 & 2 - The feed and spill function may be accomplished by using the LPI system injecting into their cold or hot legs. The RCS must be opened by removing the safety valves or insuring that the PORV pathways (2) are open. The LPI cold leg injection is contained in the D6-C fault tree, and the hot leg injection model is in the LP1HLG. PORV2 represents the failure to establish an opening in the RCS.

Feed & Spill Logic - FSW12L

Time Window 3 & 4 - The main difference between this time window and the ones previously discussed is that one PORV pathway is sufficient to insure the spill function.

Feed & Spill Logic - FSW34L

The gravity-feed fault tree was developed by modifying the existing D6 tree removing all pump-related failures. In addition, the possibility of using the hot legs (to inject) was included.

Gravity Feed Function

All time windows - D6-CG

Figure 6.2.10-1 LPI/LPR System Simplified Sketch

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Table 6.2.10-1 LPI/LPR Component Status and Dependency Summary

COMPONENT	NORMAL STATUS		ACTUATION	DEPENDENCIES
Pumps:	POS 1-2,14-15	POS 3-13		
1-SI-P-1A	standby	pull-to-lock	SIS-A	480V Bus 1H, DC Bus 1A, SIS-A
1-SI-P-1B	standby	pull-to-lock	SIS-B	480V Bus 1J, DC Bus 1B, SIS-B
MOVs:				
1860A	NC/FAI	NC/FAI	RMT-A	MCC-1H1-2N, RMT-A
1860B	NC/FAI	NC/FAI	RMT-B	MCC-1J1-2E, RMT-B
1862A	NO/FAI	NO/FAI	RMT-A	MCC-1H1-2N, RMT-A
1862B	NO/FAI	NO/FAI	RMT-B	MCC-1J1-2E, RMT-B
1863A	NC/FAI	NC/FAI	RMT-A	MCC-1H1-2N, RMT-A
1963B	NC/FAI	NC/FAI	RMT-B	MCC-1J1-2E, RMT-B
1864A	NO/FAI	NO/FAI	R. Manual	MCC-1H1-2N
1864B	NO/FAI	NO/FAI	R. Manual	MCC-1J1-2E
1885A	NO/FAI	NO/FAI	RMT-A	MCC-1H1-2S, RMT-A
1885B	NO/FAI	NO/FAI	RMT-B	MCC-1J1-2W, RMT-B
1885C	NO/FAI	NO/FAI	RMT-A	MCC-1H1-2S, RMT-A
1885D	NO/FAI	NO/FAI	RMT-B	MCC-1J1-2E, RMT-B
1890A	NC/FAI	NC/FAI	R. Manual	MCC-1H1-2N
1890B	NC/FAI	NC/FAI	R. Manual	MCC-1J1-2E
1890C	NO/FAI	NC/FAI	R. Manual	MCC-1H1-2N

6.2.11.1 Primary Pressure Relief System

The system diagram is shown in Figure 6.2.11-1. The primary pressure relief system (PPRS) protects the primary system from overpressurization to ensure that integrity is maintained. The PPRS also provides the means to reduce the pressure of the reactor coolant system (RCS) if its necessary. The PPRS is designed to control pressure and aid in removing core heat during "feed and bleed" cooling. It is composed of three code safety-relief valves (SRV) and two power operated relief valves (PORVs). The PORVs provide RCS pressure relief at a set point below the SRVs, and discharge to the pressurizer relief tank. Each PORV has a motor-operated block valve. The PORVs automatically open on high RCS pressure or are manually opened at the discretion of the operator. The block valves are normally open unless a PORV is leaking.

6.2.11.2 Dependencies

The PPRS depends on the 480 V safety AC power buses 1H and 17 for motive (via MCCs 1H1-2 and 191-2) and control power to the PORV block valves, DC power for control power to the PORVs from buses 1A and 1B, and the containment air system for motive power to the PORVs. However, the PORVs have air bottles sized to open each valve approximately 80 times. The SRVs have no dependencies on any other plant system. The dependencies are shown in Figure 6.2.11-2 and in Table 6.2.11-1.

6.2.11.3 Tech Specs and Minimum Equipment List

Technical Specifications require that the three pressurizer safety valves and two PORVs be operable (1-hour AOT for one or more PORVs before hot shutdown within 6 hours, and cold shutdown within the following 30 hours). Technical Specifications also require that the pressurizer and pressurizer heaters be operable (72 hour AOT before hot shutdown within 6 hours and intermediate shutdown in the following 12 hours). If the pressurizer is inoperable, the reactor must be in hot shutdown within 6 hours, and intermediate shutdown within the following 12 hours.

6.2.11.4 Test and Maintenance

The surveillance requirements specify that each pressurizer PORV be demonstrated to be operable by an instrument channel functional test every month, and a channel calibration every 18 months. The PORV also must be demonstrated to be operable on a quarterly basis by operating the valve through one complete cycle of full travel. The safety valve setpoints are tested and set at each refueling shutdown.

6.2.11.5 Fault Tree Modifications

Fault tree P2, representing the failure of the PPRS system (including both PORVs and SRVs) in ATWS was not modified, as ATWS is of concern only in POSs 1 and 15. Fault trees P1 (failure of 1 of 2 PORVs) and P (failure of 2 of 2 PORVs) were modified to account for the possibility of the PORVs being incorrectly set in POSs 3-13 (when the lifting pressure setpoint is reduced to ~400 psi). The new event is PPS-OP-SET-SD (operators do not reduce the PORV setpoint) and is "Anded" with House-POS 313 which is set to 1 in POS 3-13 and to 0 otherwise. In POSs 5-11 (in which the RCS may be open, or the PORVs are open or the safety valves are taken out) the fraction of time when the PPRS is needed is included in the event trees. The modified fault trees appear in Appendix C.11. Table 6.2.11-2 lists the new basic events used in this system.

Two additional fault trees were developed:

- PORV 1 - Failure to close both PORVs
- PORV 2 - One PORV fails to open upon demand

These fault trees are used to mode the various success criteria related to the Feed-and-Spill function.

Figure 6.2.11-1 PPRS System Simplified Sketch12

Figure 6.2.11-2
Primary Pressure Relief System
Dependency Diagram

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Table 6.2.11-1
PPRS Component Status and Dependency Summary

Component	Normal Status	Actuation	Dependencies
PORVs:			
PCV-1445C	Closed	Opens on high RCS pressure, or at discretion of operator.	DC bus 1A, Containment air
PCV-1456	Closed		DC bus 1B, Containment air
MOVs:			
1535	Normally open, unless PORV is leaking. 1 block valve closed 30% of time	R. Manual	MCC-1H1-2
1536		R. Manual	MCC-1J1-2
SRVs:			
1551A	NC	Automatic	None
1551B	NC	Automatic	None
1551C	NC	Automatic	None

Table 6.2.11-2
New Events for PPRS

Event Name	Description	Probability	Error Factor
PPS-OP-SET-SD	Operators do not reset PORV pressure setting POS 3-13	2.7 E-3 ^a	10. ^b
HOUSE-POS313	Set to one in POS 3-13, otherwise zero	1.0	1.0

^a1150 data

^bEngineering judgement (taken from events of a similar type events)

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6.2.12 The Recirculation Spray Systems -- Inside (ISR) and Outside (OSR)

The ISR/OSR diagrams are shown in Figs. 6.2.12-1 and 6.2.12-2.

The ISR and OSR systems provide the long-term containment cooling and pressure reduction following an accident. At Surry, these systems also provide long-term core cooling, as the recirculation core cooling systems (LPR/HPR) do not have heat exchangers, i.e. they depend on the sump water being sufficiently cool.

Each of the two systems contains two independent pump trains, each train drawing suction from the containment sump and discharging through a separate heat exchanger (there are four heat exchangers, a separate one for each train) that are cooled by service water. Each ISR or OSR train has a separate 180 degree spray ring (there are 4 spray rings for the RS). Two recirculation spray trains (in any combination) are sufficient for long term cooling following a LOCA.

Both systems are started by the CLCS system after a few minutes' delay following receipt of a high-high containment pressure signal. The ISR system actuation is delayed (by an agastat timer) for 2 minutes and the OSR system is delayed (by an agastat timer) for 5 minutes. The delay gives time for enough water to collect in the sump. The ISR pumps' delay being shorter is because the ISR inlet piping is shorter (because the pumps are inside the containment), hence, the fluid friction losses are lower. In case of loss of offsite power, the ISR pumps are delayed for 20 sec following reenergization of the emergency bus, and the OSR pumps are delayed 10 sec.

The containment sump is divided into two equal halves, each 65 square feet in area (it is so divided in case of one half of the mesh screen is plugged). The smaller, aerated drains sump, which is used in normal operation for minor containment spillage, overflows into the big recirculating systems' sump.

The NPSH for the OSR pumps is ensured by diverting a little CSS water to the OSR suction, whereas the ISR NPSH is ensured by diverting some discharge flow from the appropriate ISR heat exchangers to the ISR suction.

The inside recirculation spray pumps are located inside the containment and are qualified for the harsh post-accident environment. They provide about 3500 gpm of flow. The pump motors are air cooled. RS pump 1A is powered from the 480V ac bus 1H, whereas pump 1B is powered from the 480V ac bus 1J. About 350 gpm of discharge flow from the RS coolers is recirculated back to the suction of the ISR pumps to ensure NPSH. The recirculation line forms a ring header which distributes water to four lines leading to the pump suction. Remote pump discharge pressure and motor current are indicated in the main control room (MCR).

The inside recirculation pumps cannot be stopped from the control room while the CLCS signal is still present; this is opposite to the situation with the OSR pumps, which can be stopped and isolated. The reason is that there may be a need to isolate the outside spray pumps due to leakage of highly radioactive water outside the containment.

The outside recirculation pumps each provide about 3500 gpm of flow. They have tandem mechanical seals. The inboard ring is cooled from the discharge of the pump and the outboard seal is cooled by a pumping ring and an air-cooler circuit. Water from the seal passes through a finned, air-cooled coil and back to the seal. A seal head tank is filled with primary grade water and provides a 1 psi positive pressure to the seal. A low

level alarm on the seal's head tank, annunciated in the control room, indicates seal leakage by design. The same seal tank design is installed on the LHSI pumps.

RS pump 2A is powered from the 480V ac bus 1H, and RS pump 2B is powered from the 480V ac bus 1J. The suction lines between the containment sump and the outside RS pumps are cross-connected to ensure a supply of water to each pump if one side of the containment suction screens becomes clogged. The suction lines contain normally open isolation MOVs, RS-155A and B, which receive open signals in the event of a CLS.

The recirculation coolers are normally empty, both on the shell and the tube side. The supply header on the service-water side is filled with chemically treated water to prevent onset of turbulent flow upon RS initiation. (Turbulent flow detaches marine organisms from the walls of the service water system and transports them to the inside of the RS cooler tubes, which then become plugged). The sump water is at a higher pressure than the service water; hence, the borated water cannot be diluted should the cooler tubes leak. However, radioactive water can escape outside. We note that the suction/discharge MOVs on the service-water side can be isolated, even if the CLS signal is present. Leakage of the sump water into the service water is detected by radiation monitors in the service-water system. The RS coolers' service water inlet and outlet valves open upon receipt of a CLS signal.

6.2.12.2 Support System Dependencies

The RS system depends on the CSS and/or the safety injection system for sufficient sump inventory. It relies on the engineered safety features (ESF) actuation subsystem of the reactor protection system (RPS) to generate the CLS initiation signal for the RS system. (The CLCS signal is generated when 3 out of 4 pressure channels indicate a containment high-high condition ($p > 23$ psia)). The service water system is called upon to provide the ultimate heat sink for the RS system. The 480V ac 1H and 1J safety buses provide the motive power for the recirculation spray pumps. DC buses 1A and 1B provide control power to the pumps RS-P-1A (inside)/RS-P-2A (outside) and RS-P-1B (inside)/RS-P-2B (outside), respectively. The 480V ac safety buses also supply motive (via MCCs 1H1-2 and 1J1-2) and control (via stepdown transformers) power to the normally open MOVs (i.e. the outside recirculation spray pump suction MOVs RS155A (from MCC 1H1-2) and RS155B (from MCC-1J1-2) and the outside recirculation spray pump discharge MOVs RS156A (from MCC-1H1-2) and RS156B (from MCC-1J1-2)). The inside spray recirculation system does not have such valves. The pumps and the valves can be operated by handswitches off benchboard 1-1, as long as the appropriate breakers are closed.

The system's function is ultimately performed by the service water system, and the part of the SW system that feeds the RS heat exchangers is included in the ISR/OSR fault trees (this includes the intake canal water availability and all the MOVs in the path). The normally closed MOVs 103A,B,C,D, 104A,B,C,D and 105A,B,C,D receive CLCS signal to open. The motive power is supplied through 480V safety buses 1H and 1J, via MCCs 1H1-1 and 1J1-1 (for SW-103 MOVs) and 1H1-2 and 1J1-2 (for SW-104 and 105 MOVs). The control power comes also from the 480V buses, via stepdown transformers, and these valves can be operated by handswitches off benchboard 1-1.

For CLCS system automatically start the RS pumps, the appropriate handswitch has to be in "AUTO" and there should be no motor overload indication. Below the 350/450 setpoint, the handswitch may be in "PULL TO LOCK". Also below this setpoint, the CLCS may be unavailable. Then, the RS system can be manually

6 System Description and Fault Tree Analysis

started by pushing two buttons on the MCR console simultaneously (in addition, the handswitches have to be in the right position, and the appropriate breakers have to be closed).

Table 6.2.12-1 shows the dependency matrix.

Operator Actions Required

1. Manual CLCS signal generation (if applicable).
2. Opening/closing of valves (e.g. if OSR pumps leak).
3. Shutting off parts of the system when the containment is subatmospheric (long term cooling can be accomplished with one train).
4. Monitoring the flow of service-water through the RS heat exchangers, and shutting off individual heat exchangers, if necessary. With vacuum priming, the RS HXs can pass about 35,000 gpm (24,000 without vacuum priming).
5. Monitoring radiation and closing off parts of the system, as needed.

Motor current and discharge pressure is indicated in the MCR for the pumps and the level and temperature is indicated in the MCR for the RS coolers and the containment sump water.

6.2.12.3 Tech Specs and Minimum Equipment List

The requirements on the RS system are for > 350°F, 450 psig; there are no requirements below these limits. Above 350/450, all 4 trains must be available. If one outside RS subsystem is out of service, the AOT is 24 hrs; if one inside RS train is out of service, the AOT is 72 hours. If the AOT is exceeded, the time to hot/cold shutdown is 6/48 hrs.

There are no tech specs for these systems below 350 F, 450 psig, i.e. in POSs 3-13. Informally, the availability of at least one train is high (75%). It is not clear how the tagging of "unneeded" equipment at shutdown affects their availability.

6.2.12.4 Testing and Maintenance of the RS system

Both the inside and outside recirculation pumps are tested quarterly, including the MOVs. The ISR pumps are tested each refueling, the OSR pumps are tested quarterly. For the inside pumps, a temporary dike is installed in the containment sump to provide a suction volume and a temporary elbow is installed in the inside pump piping. The inside pumps are run and a blue rotation light is observed in the control room, indicating rotation flow. The appropriate motor current is verified. The outside pumps are run on recirculation, and verification is made that the proper discharge pressure has been reached. Other components are also tested (MOVs, check valves, spray nozzles). The spray nozzles are feather or thermographically tested. Maintenance is done when needed, and below the 350/450 setpoint (or according to the LCO concerns).

6.2.12.5 Modifications to the 1150 Fault Trees

The modified fault trees are shown in Appendix C.12.

The ISR modified trees are named F1LPSD (the top event fault tree used in the event trees), ISR1N115, ISR2N115, and ISR1N313 (the latter tree and only that one is for POS 3-13). The OSR trees are F2LPSD

(the top event fault tree), OSR1N115, OSR2N115, OSR1N313 (the only one specifically for POSs 3-13), OSR5, and OSR6. The associated service water trees are SWS5, SWS6, SWS9, SWS10, SWS12, and SWS13. The house event HOUSE-POS313 and its complement select the appropriate subtrees and basic events, based on the POS in question.

The 1150 fault trees for ISR/OSR have been modified as follows:

POS 1, 2, 14, and 15

The dependence of the OSR system on the CSS was removed (i.e. the transfer to the appropriate CSS fault trees). While the OSR depends on the CSS for NPSH requirements (and additionally, both ISR and OSR depend on the injection systems for sump inventory), it is logically incorrect to include these dependencies in the fault tree in the context of the event trees in question, i.e., if the CSS system is successful (as this question is first asked in the event trees), then its failure cannot be included as one of the mechanisms for failure of the OSR. If the CSS fails, then the OSR question is not asked in the event trees. Dependency of OSR train A's NPSH solely on CSS train A (and vice versa for trains B -- as is done in 1150) cannot be included as the OSR suction lines are cross connected and the whole CSS system would have to fail (not just a particular train) in order to disable either (and both) train(s) of the OSR.

The other modification applied to the 1150 fault trees (before considering separate POSs) was that the SW MOVs' power supplies (MCCs 1H1-1 and 2 and 1J1-1 and 2) are now included in the fault trees (i.e. for normally closed SW valves 103A,B,C,D, 104A,B,C,D and 105A,B,C,D). These are transfers to fault trees EH1, EH2, EJ1 and EJ2, respectively.

The 1150 trees include maintenance of certain SW valves (i.e. 103 A,B,C,D) but not others (i.e. the 104 and 105 series), because of lack of data. In Phase 1 work, maintenance of valve SW-MOV-104D was added, as additional POS-dependent data became available. However, maintenance of the other valves is not treated due to lack of data (as is the case for circuit breakers for pumps and MOVs).

Additionally, credit is given for manual actuation of ISR/OSR, should CLCS actuation fail. The event CLS-ACT-OP-CLS2 was added to describe failure of the operator to push two buttons simultaneously in the MCR (main control room) to initiate the CLS (consequence limiting systems which also includes the CSS). In addition, the operator has to check the service-water side (per procedure attachment) to verify flow and, if necessary, open the above mentioned SW MOVs manually (via handswitches). Failure to do so is described by event SWS-MOV-OP-RSFP. In the 1150 report, it is stated that credit for the actuation of CLS by the operator is taken in the fault trees (as it is a simple skill based action) rather than as a recovery action in sequence cutsets. However, the appropriate events (CLS-XHE-FO-MAN-A, CLS-XHE-FO-MANS1, CLS-XHE-FO-MANS2) do not appear in the fault trees.

Event MCW-CCF-VF-INLVL describes loss of service water cooling due to loss of intake canal level and appears in the original 1150 fault trees (SWS5, SWS6, ISR1 and ISR2). It is assigned a low probability (1.E-9). In this study, the intake canal level loss is modeled by additional events represented by a combination of a loss of power to circulating water pumps (through an initiating event such as loss of offsite power or station blackout, or a basic event such as a loss of power subsequent to an initiator and failure of operator to remedy the situation. We added these events because such a loss of power will quickly drain the intake canal through the normally open (even at shutdown) condenser inlet valves. The operator's action of closing these valves (either from the control room in case of LOSP or manually in case of SBO) is modeled as a recovery action

6 System Description and Fault Tree Analysis

in 1150 (i.e. on sequence cutset level). We decided to put this event (MCW-CCF-VF-SBO) in the fault trees as a skill-based action because a visit to the plant indicated that this would be a high priority action, and that the operators are well aware of it. The basic event LO SP appears in the fault trees elsewhere. The new events are HOUSE-LO SP, HOUSE-SBO1 and HOUSE-SBO2 which describe initiating event LO SP, one unit SBO, and two units SBO, respectively.

POS 3-13

As described above, the CSS dependence was deleted and dependence on the MCCs 1H1-1, 1H1-2, 1J1-1 and 1J1-2 (for SW MOVs) was added. The change in the intake canal level is kept in these POSs as well.

Maintenance events ISR-MDP-MA-RS1A and OSR-MDP-MA-RS1A were deleted when creating the ISR1N313 and OSR1N313 fault trees. Instead, train level maintenance (for train A) was added to top event trees F1LPSD and F2LPSD via events ISR-TRA-MA and OSR-TRA-MA, respectively. (Trains B are assumed down in these POSs, as discussed above). However, maintenance of 103 SW valves was kept, as these are not train-dependent.

The "AND"ing of events CLS-ACT-OP-CLS2 (the operator initiation of the CLS in POSs 1, 2, 14 and 15) and CLS-ACT-FA-CLS2A(B) (CLCS actuation of the CLS) in fault trees ISR1N115, ISR2N115, OSR1N115, and OSR2N115) is replaced by events ISR-MDP-OP-1AB and OSR-MDP-OP-2AB in trees ISR1N313 and OSR1N313. These events describe the operator's action of starting the ISR/OSR systems when no CLCS signal is anticipated (and certain breakers may be in PTL). Similarly, the event SWS-MOV-OP-RSFP, for opening SW MOVs in absence of the CLCS signal, is replaced by event SWS-MOV-OP-RSS (in fault trees I(O)SR1N313 only).

Figure 6.2.12-1 RS System Simplified Diagram

Figure 6.2.12-2 Recirculation Spray System

Table 6.2.12-1
RS Dependency Matrix

Component	Motive Force	Control Power	Auto Actuation	Component Cooling	Room Cooling	Interlocks
1-RS-P-1A	480 V CKT-14H4	125 VDC A	CLS-2A	None	None	Cannot be stopped manually if CLS signal is present
1-RS-E-1A (shell side)	None	None	None	None	None	None
1-RS-P-1B	480 V CKT-14J4	125 VDC B	CLS-2B	None	None	Cannot be stopped manually if CLS signal is present
1-RS-E-1B (shell side)	None	None	None	None	None	None
1-RS-P-2A	480 V CKT-14H7	125 VDC A	CLS-2A2	None	None	Pump can be stopped with CLS present
1-RS-MOV-156A	480 V MCC-1H1-2	480 Volt stepdown transformer	CLS-2A3	None	None	Can be closed with CLS signal present. Valve must be fully open before it can be manually closed.
1-RS-E-1C (shell side)	None	None	None	None	None	None
1-RS-MOV-155A	480 V MCC-2H1-2	480 V Step down	CLS-2A2	None	None	Can be closed with CLS signal present. See MOV-156A
1-RS-P-2B	480 V CKT-24J8	125 VDC B	CLS-2B2	None	None	Pump can be stopped with CLS present

Table 6.2.12.1 (continued)

Component	Motive Force	Control Power	Auto Actuation	Component Cooling	Room Cooling	Interlocks
1-RS-MOV-156B	480 V MCC-2J1-2	480 V Stepdown transformer	CLS-2B3	None	None	Can be closed with CLS signal present. See MOV-156A
2-RS-MOV-155B	480 V MCC-2J1-2	480 V Stepdown transformer	CLS-2B2	None	None	Can be closed with CLS signal present. See MOV-156A
2-RS-E-1D (shell side)	None	None	None	None	None	None
1-SW-MOV-101A	480 V MCC-2H1-1	480 V Step down	CLS-2A1	None	None	Close on loss of reserve power. Close on Hi-Hi CLS
1-SW-MOV-101B	480 V MCC-2J1-1	480 V Step down	CLS-2A1	None	None	See 1-SW-101A
1-SW-MOV-103A	480 V MCC-2H1-1	480 V Step down	CLS-2A1	None	None	Can't close unless fully open. Open on CLS signal can override CLS
1-SW-MOV-103B	480 V MCC-2J1-1	480 V Step down	CLS-2B1	None	None	See 1-SW-MOV-103A
1-SW-MOV-103C	480 V MCC-1J1-1	480 Volt stepdown transformer	CLS-2B3	None	None	See 1-SW-MOV-103A
1-SW-MOV-103D	480 V MCC-1H1-1	480 Volt stepdown transformer	CLS-2A3	None	None	See 1-SW-MOV-103A

Table 6.2.12.1 (continued)

Component	Motive Force	Control Power	Auto Actuation	Component Cooling	Room Cooling	Interlocks
1-SW-MOV-104A	480 V MCC-1H1-2	480 Volt stepdown transformer	CLS-2A4	None	None	Can override CLS. Open on CLS signal
1-SW-MOV-104B	480 V MCC-1J1-2	480 Volt stepdown transformer	CLS-2B2	None	None	See 1-SW-MOV-104A
1-SW-MOV-104C	480 V MCC-1H1-2	480 Volt stepdown transformer	CLS-2A4	None	None	See 1-SW-MOV-104A
1-SW-MOV-104D	480 V MCC-1J1-2	480 Volt stepdown transformer	CLS-2B3	None	None	See 1-SW-MOV-104A
1-SW-MOV-105A	480 V MCC-1H1-2	480 Volt stepdown transformer	CLS-2A5	None	None	Open on CLS. Hi-Hi signal can override CLS
1-SW-MOV-105B	480 V MCC-1J1-2	480 Volt stepdown transformer	CLS-2B5	None	None	See 1-SW-MOV-105A
1-SW-MOV-105C	480 VAC MCC-1H1-2	480 Volt stepdown transformer	CLS-2A5	None	None	See 1-SW-MOV-105A
1-SW-MOV-105D	480 VAC MCC-1J1-2	480 Volt stepdown transformer	CLS-2B5	None	None	See 1-SW-MOV-105A

6 System Description and Fault Tree Analysis

6.2.13 Residual Heat Removal System

6.2.13.1 Residual Heat Removal System Description

The residual heat removal (RHR) system provides shutdown cooling when the reactor coolant system (RCS) depressurizes below 450 psig and cools below 350°F. Figure 6.2.13-1 is a simplified drawing of the system. Figure 6.2.13-2 shows the component cooling water supply to the loads inside the containment, including the RHR heat exchangers, and RHR pumps. The CCW system is discussed more fully in section 6.2.4. The RHR system is a front line system (although non-safety grade) that provides long-term removal of decay heat. The RHR system has two pumps and two RHR heat exchangers in parallel. The RHR pumps take suction from the RCS loop A hot leg through two motor operated valves (MOVs) that are normally shut, MOVs 1700 and 1701. The discharge of the pumps is headered together and feeds two heat exchangers arranged in parallel. The RHR pumps and heat exchangers are cooled by component cooling water (CCW). An air-operated valve (AOV), FCV-1605, controls bypass flow around the heat exchangers. Another AOV, HCV-1758, controls flow through the heat exchangers. The two AOVs work together to control the cooldown rate of the RCS. The discharge of the flow control valves feeds into the SI/Accumulator piping and is delivered to the RCS loop B and loop C cold legs. A relief valve, RV-1721, is located on the discharge piping; it has a capacity of 750 gpm at its set point of 600 psig which also is the design pressure of the RHR system. Each path has a normally shut MOV isolating the RHR from the high pressure RCS during normal operations. Make-up to the RHR system is provided by the RCS.

The RHR system has two pumps and two heat exchangers. However, they do not constitute two redundant trains. There are single failures that can disable the whole system, as for example, the suction valves 1700 and 1701, and flow control valve HCV-1758. The RHR pump seal is cooled by a single cooling path, supplied by two CCW headers. Therefore, a single failure in the cooling path can cause loss of cooling to both RHR pumps. Switching from one CCW header to the other to re-establish CCW to the pump seal coolers requires local manual operation of manual valves inside the containment.

The RHR system at Surry is not an engineered safeguards system and is located inside the containment. A separate low-head injection system is used for emergency core cooling. The RHR suction MOVs, 1700 and 1701, do not have an auto-closure inter-lock that would close the valves automatically on a high RCS pressure signal. The RHR is manually initiated. An interlock prevents the RHR isolation MOVs opening until RCS pressure is below 450 psig. One RHR pump and heat exchanger are normally in operation. If either component fails, the parallel component is manually placed in service. After a loss of offsite power, the stub buses powering the RHR pumps are shed from the emergency buses and must be manually reconnected to restore power to the RHR pumps.

Two level instrumentations are available during mid-loop operations:

1. Permanent Standpipe A permanent standpipe arrangement (Fig. 6.2.13-3) was installed in the containment to replace the temporary poly hose arrangement previously used to monitor level in the reactor vessel. The range of the standpipe is 13 feet-6 inches, extending from EL. 10'-6" to EL. 24'-0", and is connected to a line off the top of the pressurizer and to the drain line on the C' loop. A magnetic flag indicator mounted on the standpipe indicates the local level. A level transmitter mounted on the standpipe will operate a level indicator (LI-RC-100A) and a SHUTDOWN COOLING LO LVL annunciator in the main control room. The level indicator in the MCR will be labeled the "cold shutdown coolant" indicator because it will be used during the

cold shutdown mode. During other modes of operation, an "enable-disable" key selector switch will be used that is behind the main in control board. Power to the level transmitter is provided by a semi-vital bus.

2. Ultra-sonic Level Indicator (1-RC-LT-105)

An ultra-sonic level instrumentation is installed in loop "B" hot leg, and gives a redundant indication of the level inside the loop. The ultrasonic level transducer, 1-RC-LT-105, is strapped onto the bottom exterior of the RCS "B" loop hot leg to sense the level of reactor coolant within. The transducer along with its associated signal processing electronics modules, provide an output signal which is proportional to the measured level. The measured range of level is from hot leg center line (elevation 11'9-15/16") to top of the pipe. The control room recorder has a graduated scale of 0" to 15" which corresponds to the actual measured level above the hot leg centerline. A low level alarm is set to actuate at 8" above the hot leg centerline. During drain down of the RCS, the RHR pumps may introduce air if the level in the "A" loop hot leg falls below 4.0" above the centerline. The alarm set point takes into account the worst-case difference in levels between the "A" and "B" loop hot legs. This new level channel is used only during RCS drain down and refueling operations. At all other times, the level channel will be de-energized and unavailable for use by the operators. The power supply for the instrumentation is VB-1-IVA, circuit breaker 16.

6.2.13.2 Residual Heat Removal System Interfaces and Dependencies

Table 6.2.13-1 lists the status and dependency of the RHR system component. The RHR system depends on AC power for motive power for the RHR pumps and the MOVs, and the DC buses for control power to the RHR pumps and the heat exchanger throttle valves. Additionally, the RHR system requires the instrument air system for motive power to the heat exchanger throttle valves. These valves fail in the safe positions. Based on the special test procedure, 1-STP-241, loss of control power from VBI-III causes HCV-1758 to fail open and possibly causes RHR pump runoff. This scenario is modeled as a cause of failure of the RHR system. CCW system cools the RHR heat exchangers and pumps. The RHR system depends on the RCS to supply sufficient net positive suction head.

6.2.13.3 Residual Heat Removal System Operating Constraints

Technical Specifications require that two RHR pumps, two RHR heat exchangers, and component cooling water system piping and valves which establish a flow path to RHR components are operable before the reactor is made critical (14-day AOT for one RHR train before shutdown). Before placing the RHR system in service, RCS pressure must be below 450 psig and temperature must be below 350°F. Following a loss of offsite power, the stub buses which power the RHR pumps are automatically shed and must be manually reloaded on to the main bus by the operator to restore power to the pumps.

When the average temperature in the reactor coolant loop is less than or equal to 350°F, one loop of RHR system must be operable, and can be removed from operation for one hour per 8 hours during core alterations or surveillance inspections of the reactor vessel. The surveillance requirements are for RHR system operability tests during cold shutdown, and for RHR MOVs to be cycled each time the system is placed in service.

6 System Description and Fault Tree Analysis

6.2.13.4 Residual Heat Removal System Shutdown Configuration

When RHR system is not in operation, i.e., POSs 1-2 and 14-15, it is isolated from the RCS by closed valves 1700, 1701, 1720A, and 1720B. To keep the system filled, HCV-1142 is kept open, i.e., the RHR system is connected to the letdown line of the CVCS.

When the conditions for RHR operation are reached, i.e., end of POS 2, it is placed into service. First, CCW to RHR heat exchanger 1A is established by opening TV-CC-109A. The second CCW pump is expected to start automatically with the increased load. Then, the RHR system is verified filled, and one RHR pump is started. RHR system is heated up by opening suction valves 1700 and 1701, establishing flow from the RCS through RHR system to the letdown line. When the RHR and RCS temperatures are almost equal the boron concentration in both systems is sampled to ensure that in the RHR system is greater than or equal to that of the RCS, before the MOVs, 1720A and 1720B, on the discharge to the RCS are opened. During the initial period of the outage, both RHR pumps and both RHR heat exchangers may be in service, later, only one RHR pump and one RHR heat exchanger are used. Approximately 4000 gpm of CCW flow is provided to the operating RHR heat exchanger. On the RHR side, HCV-1758 is used to manually control the rate of cool down.

At the end of refueling, POS 8, the reactor cavity is drained by opening manual valve RH-29 and MOV-RH-100 (operated as a manual valve with motor operator disabled) in the line to the RWST until the level in the cavity reaches the vessel lip, when these valves are closed again.

When the plant is ready to commence plant heatup, at end of POS 13, the RHR system must be removed from service before temperature and pressure in the RCS exceed the RHR limitations. When ready to remove RHR from service, the outlet valves, 1720A and 1720B, are shut while make up is maintained by HCV-1142 (at 20% position). The RHR system is cooled by recirculating coolant within the system and controlling the cooldown rate with HCV-1758. The pumps are stopped and TV-CC-109A is shut.

Abnormal procedure AP 27.00, is the only one that was written specifically for accidents that may occur when the plant is shutdown. It informs the operators on how to restore RHR and use of other means to mitigate a loss of RHR event (discussed in detail in chapter 7).

6.2.13.5 Residual Heat Removal System Logic Model

In POSs 1,2,14, and 15, the RHR system is on standby. The NUREG/CR-4550 model was modified, and used. The same top event name "W3" as in NUREG-1150 is used. In POSs 3-13, the RHR is initially running, so that more extensive modification was needed to model this configuration. For this, a new fault tree with a top event name "W3-S" was created.

Modifications to 1150 Model-

Modifications Applicable to POSs 1-15

- a. Dependency on CCW: In NUREG/CR-4550, the CCW fault tree developed for cooling the RCP thermal-barrier was used in RHR fault tree to model the dependence of RHR on CCW. In this study, four fault trees were specific developed for loss of CCW to the 2 RHR pumps and 2 RHR heat exchangers, named CCW1, CCW2, CCW3, and CCW4. Section 6.2.4 documents this further.

6 System Description and Fault Tree Analysis

- b. Upon initiation of the RHR system, it is assumed that, RHR pump A and RHR heat exchanger A are put into service from the control room. RHR pump B is on standby and can be started from the control room. RHR heat exchanger B is isolated on the RHR side by closed manual valves RH-20 and RH-24, and on the CCW side by closed manual valve 1-CC-185. In order to swap from heat exchanger A to B, it is necessary to enter the containment to re-align the valves. Failure of RH-20 and RH-24 to open are modeled as additional failure modes.
- c. We included an additional failure mode of the system due to failure open of HCV-1758. It is assumed that such failure causes RHR pump runoff and failure of the system. Loss of vital bus VBI-III and loss of instrument air are modeled as causes of such failure mode.
- d. The valve IDs for the check valves in the RHR return lines to cold legs B and C were corrected. The corresponding basic events are ACC-CKV-FT-CV130 and ACC-CKV-FT-CV147.

Modifications Applicable to POSs 3-13

The 1150 fault tree for RHR was modified for POSs(3-13) in which the RHR is initially running by developing a separate fault tree with top event "W3-S". In these POSs, the RHR suction valves(1700,1701) and cold leg return valves(1720A,B) are normally open. Therefore, failure to open is not a valid failure mode for these valves. They were removed from the 1150 fault tree for RHR. One event related to maintenance of the 1720A valve was used to model maintenance of the valve. It is assumed that RHR pump A is normally running, and pump B is on standby, and also that both RHR heat exchangers are in service with discharge to both loop B and C. It is assumed that RHR is initially running, and a loss of RHR occurred. This fault tree models the recovery of RHR subsequent to the initiating event, which is assumed to be a spurious trip of the running RHR pump, i.e., no actual failure of the system. The impacts of other initiating events will have to be modeled by failing part of all of the system. For example, an event "HOUSE-RHR5A" was added (to RHR11 and RHR4) to permit modeling loss of one train of the system as a result of the initiating event. If this event is set to "true", RHR pump A and RHR heat exchanger A will be failed. The human error probability associated with operator action is not included in the fault tree, but will be included at the level of the event tree sequence.

Figure 6.2.13-1 Simplified Drawing of the RHR System

Figure 6.2.13-2 Component Cooling Water Supply to Loads Inside the Containment

ATTACHMENT 1

(Page 1 of 1)

HEAD VENT AND STANDPIPE DIAGRAM

NOTE: The valve designators are for location only.
They **DO NOT** indicate valve position.

Figure 6.2.13-3 Head Vent and Standpipe Diagram

Table 6.2.13-1 RHR System Component Status and Dependency Summary

COMPONENT	NORMAL STATUS		DEPENDENCIES
	POS 1-2,14-15	POS 3-13	
Pumps:			
1-RH-P-1A	Standby	Running	4160V Stub 1H 1A DC Bus CCW
1-RH-P-1B	Standby	Standby	4160 V Stub 1J 1B DC Bus CCW
MOVs:			
1700	NC/FAI	NO/FAI	MCC-1H1-2
1701	NC/FAI	NO/FAI	MCC-1J1-2
1720A	NC/FAI	NO/FAI	MCC-1H1-2
1720B	NC/FAI	NO/FAI	MCC-1J1-2
RH-100*	NC/FAI (all POSs except 9) NO/FAI(POS9)		MCC-1B1-2 MCC-1B1-2
AOVs:			
FCV-1605	NO/FC	NO/FC	Instrument Air VB1-III and VB1- IIA
HCV-1758	NO/FO	NO/FO	Instrument Air VB1-III
HCV-1142	NO/FC	NO/FC	Instrument Air VB1-I

* closes automatically when RWST level sensed by level switch LS-102-2 reaches 99%.
All are activated manually

6 System Description and Fault Tree Analysis

6.2.14 Service Water System/Circulating Water System

6.2.14.1.1 Service Water System Description

Figure 6.2.14-1 is a simplified drawing of the service water system/circulating water system that provides cooling to the following loads:

1. component cooling water heat-exchangers;
2. recirculation spray heat-exchangers;
3. bearing-cooling water coolers;
4. control room and relay room air-conditioning unit chiller condensers; and
5. charging-pump cooling service water subsystems.

The source of water for the service water system is the James river, via the circulating water pumps in the low-level intake canal, and the circulating water system intake piping. The James river is the ultimate heat sink for the Surry power station. The first three loads of the service water system are fed by gravity, and the remaining loads above have their own service water pumps that take suction from the service water lines. Table 6.2.14-1 lists the flow rates of these service water loads.

The service water system has three diesel-driven emergency service water pumps that can take suction from James river and discharge to the intake canal. In addition, 1-SW-P-1A may be driven by a 4160 motor, receiving power from the 1G bus. The pumps can be manually controlled from the control room. When operated simultaneously, the three pumps can supply 45,000 gpm to the canal. Thus, except for extremely abnormal conditions, such as station blackout on both units, the three diesel-operated emergency SW pumps per unit can meet various SW needs.

6.2.14.1.2 Service Water System Interfaces and Dependency

Table 6.2.14-2 lists the power supply of the emergency service water pumps. The dependency of the valves in the service water lines on instrument air or ac power was modeled in the fault tree for each of the service loads discussed in section 6.2.14.5.

6.2.14.1.3 Service Water System Operational Constraints

Limiting Conditions for Operations(LCO) 3.14 specifies the requirement on the service water system.

Any time fuel is loaded in the reactor, at least one operable SW flow path to and from a control room and relay room A/C chiller condenser must be available.

A reactor can not be critical, nor can the RCS pressure and temperature exceed 450 psig or 350 degree F unless the following minimum requirements are met:

1. Intake canal water level greater than 23 feet;
2. piping and valves capable of establishing flow to and from one bearing cooling water cooler, and two component-cooling heat exchangers for one unit operation, or three component-cooling water heat-exchangers for two unit operation;
3. two circulating water pumps operating or operable;

4. two emergency service water pumps operable;
5. two service water flow paths to the charging pump service water subsystem; and
6. two service water flow paths to the recirculation spray heat exchangers.

6.2.14.1.4 Service Water System Shutdown Configurations

The service water system operates in the same way, regardless of plant condition; there is no known shutdown configuration that differs from that during power operation.

6.2.14.1.5 Logic Models of Service Water System

The dependency of the service water loads listed in section 6.2.14.1 (except bearing cooling water system) on service water is modeled by extending the boundary of the fault tree models to include the service water system components that are in the flow path from the circulating water lines to the service water loads. Bearing cooling water system is modeled as a basic event. It provides cooling to the instrument air compressors.

The only way to have a complete loss of service water is a loss of canal inventory due to a loss of offsite power with failure to close the circulating water valves, or a station blackout. This is modeled in Section 7.4: Loss of Offsite Power and Station Blackout Event Tree.

6.2.14.2.1 Circulating Water System Description

The largest load demands on the Intake Canal, are the circulating water flow to the main condensers of both units. The Intake Canal is part of the flow path for river water from the discharge of the Circulating Water Pumps (CWPs) to both the main condenser and the SW system. Service water lines tap off the 96-inch circulating water pipes to the condenser inlets (see Figure 6.2.14-1, sheet 3). Water level in the Intake Canal is normally kept at an elevation of approximately 25 to 30 feet, tantamount to 45 to >70 million gallons in capacity. Circulating water flows through the condenser by gravity, with Vacuum Priming establishing and maintaining a siphon. If adequate intake canal inventory cannot be maintained, unnecessary flowpaths of circulating water and service water through the station can be automatically isolated, provided that AC power is available.

There are four CWPs per unit (CW-P-1A, -1B, -1C, -1D), each has a capacity of 210,000 gpm at a 28-foot total dynamic head, and driven by a 2000 HP, 4.16 KV AC, squirrel cage induction motor. Thus, the four CWPs per unit supply 840,000 gpm of circulating/service water to the main condenser and the SW system. These CWPs have no automatic start features, but are manually started, stopped, and controlled remotely from the main control room or from the Low Level Control House. Automatic trip features, however, are provided.

Each of the four condenser inlet lines on each unit has an motor-operated isolation valve (CW-MOV-106 A, B, C, D). The 5-HP motors are powered by emergency bus Motor Control Centers (MCCs) and controlled from the main control room. Essentially identical MOVs (CW-MOV-100 A, B, C, D) are installed in the outlet lines. These inlet and outlet CW isolation valves are required to function under certain accident conditions, so they are powered by emergency buses (described in Section 6.2.14.2.2).

Each condenser isolation MOV also has a hand wheel so that the operator can manually isolate them as an alternate means, when necessary.

6 System Description and Fault Tree Analysis

Outlet water from the main condenser is directed to the discharge tunnel via the four outlet lines on each unit; each unit has its own discharge tunnel that has a vacuum-breaking vent valve which can be manually opened to minimize water flow through the tunnel. Such an action could conserve the Intake Canal level when abnormal conditions, such as a station blackout, should occur to both Surry units.

6.2.14.2.2 Circulating Water System Interfaces and Dependency

On each CW line, one valve is powered by a Bus H MCC (e.g., 1H1-1) and the other is powered by a Bus J MCC (e.g., 1J1-1A). The power supplies are listed in Table 6.2.14-3. For example, the inlet valve (MOV-106A) of line A is powered by a Bus H MCC, and the outlet valve (MOV-100A) is powered by a Bus J MCC. Also, the power supplies are staggered: two inlet valves are powered by the Bus H MCC and the other two are powered by the Bus J MCC. In contrast, four CW MOVs are powered by MCC 2H1-1 and the other four are powered by MCC 1J1-1A. In other words, four CW MOVs on each unit are powered by MCC 1J1-1A. This MCC normally gets power from 480 V Switchgear 1J1, but its power supply switches automatically to MCC 2J1-1 when the normal power supply is lost. This arrangement ensures that, if all offsite power is lost but emergency AC power is available, at least one MOV in each of the eight CW lines in the Surry station can be closed electrically to conserve Intake Canal level.

6.2.14.2.3 Circulating Water System Operational Constraints

The inlet and outlet isolation MOVs automatically close when either of the following signals is received:

- Intake Canal level less than 23.5 feet elevation (closes CW valves on both units);
- High-high Consequence Limiting Signal (i.e., high-high containment pressure, indicative of a LOCA) coupled with a loss of the transfer buses that feed the emergency buses.

These signals help ensure that there is adequate inventory in the Intake Canal to allow the Recirculating Spray System to depressurize and cool the containment in the wake of a major LOCA.

In addition, on a loss-of-station-transfer-buses signal, the outlet isolation valves automatically close to the 25% open position (75% closed), provided emergency AC power is available. (If a loss-of-station-transfer-buses signal is received, the design assumption is that power to the CWP's also has been lost.) This reduces flow through the station and allows the operators time to attempt corrective actions before the low Intake Canal level signal is received.

Figure 6.2.14-1 Service Water System

Figure 6.2.14-1 (continued)

6 System Description and Fault Tree Analysis

Table 6.2.14-1 SW System Operating Flow Rates

Components (Design Requirements)	Normal Operation		Shutdown of One Unit (i.e., cooling down of one unit)	
	Unit 1	Unit 2	Shutdown Unit	Operating Unit
CC heat exchangers (9,000 gpm each)	9,000	9,000	18,000	9,000
BC heat exchangers (12,000 gpm each)	24,000	24,000	24,000	24,000
Charging pump SW pump (90 gpm each)	90	90	90	90
Control and Relay Room (AC unit (330 gpm)	330	330	330	330
Mechanical chillers (1,800 gpm)	1,800	1,800	1,800	1,800
RS heat exchangers (6,000 gpm each)	-	-	-	-

Table 6.2.14-2
Power Supply of the Emergency Service Water Pumps

<u>Pump</u>	<u>Power Supply</u>
1-SW-P-1A	4KV BUS 1G and Dedicated Diesel
1-SW-P-1B	Dedicated Diesel
1-SW-P-1C	Dedicated Diesel

6 System Description and Fault Tree Analysis

Table 6.2.14-3 Power Supplies for Circulation Water Inlet and Outlet Isolation Valves

Component	Power Supply	Breaker
Motor Operated Valves:		
MOV-CW		
100A	MCC1J1-1A	3A
100B	MCC 1H1-1	8A
100C	MCC 1J1-1A	3B
100D	MCC1H1-1	7A
106A	MCC 1H1-1	7C
106B	MCC 1J1-1A	3C
106C	MCC 1H1-1	6B
106D	MCC 1J1-1A	3D
200A	MCC 1J1-1A	4D
200B	MCC 2H1-1	8A
200C	MCC 1J1-1A	4E
200D	MCC 2H1-1	7A
206A	MCC 2H1-1	7C
206B	MCC1J1-1A	5A
206C	MCC 2H1-1	6B
206D	MCC 1J1-1A	5D

6.2.15 Steam Generator Recirculation and Transfer System

6.2.15.1 Steam Generator Recirculation and Transfer System Description

The Steam Generator Recirculation and Transfer (SGRT) system recirculates water in the steam generator during wet layup to ensure that the SG water chemistry remains homogeneous and protects the internals of the SG from corrosion. The SGRT system may also be used to transfer water between SGs and to the river, pumping down the SG for maintenance.

The SGRT also may be used to reduce the SG temperature to avoid RCS overpressure when a RCP is started with a water solid plant. The system is designed to reduce the SG temperature from 212°F to 140°F in 12 to 16 hours. This capability for heat removal may also be used given a loss of RHR event transferring heat from the SG to the CCW system, providing an alternate means for removing decay heat.

A wet layup of the SG is achieved by filling it with deoxygenated, chemically treated feedwater. A nitrogen blanket is placed on the SG through a connection on the main steam lines. The SGRT system thoroughly mixes of the chemicals in the SG, preventing corrosion.

Each recirculation loop has a recirculation and transfer pump RT-P-1A (B, C), which recirculates the SG during wet layup or pump water between the SGs and/or to the Liquid Waste System. The SG temperature may be reduced by transferring heat to the CCW system through the recirculation cooler RT-E-1A (B, C), which is cooled by chilled water from the Component Cooling System.

During recirculation, the pump takes suction from the upper most portion of the SG and discharges into the blowdown line for that SG. Therefore, the water level in the SG must be greater than 95% to prevent cavitation in the pump. Figure 6.2.15-1 shows a schematic flow diagram of the SGRT system.

The recirculation cooler located in the SG's recirculation line reduces and maintains the SG temperature at less than 150°F after plant cooldown has been completed. The flow path for the recirculation process starts at the SG (see Figure 6.2.15-1, valve RT-1) and leaves the containment, providing the suction for the recirculation pump.

The line contains a relief valve, which is set at 1085 psig. The pump discharge line is connected to a common header with the other SGRT systems. The return path contains isolation valves, the recirculation cooler and a flow element. The water is returned to the SG through the blowdown trip valves TV-BD-100B and -100A and the isolation valves BD-1, 2 and 4.

The SGRT is manually operated and is not an engineered safeguard system and there are no applicable Technical Specification requirements. If RHR function is lost, the SGRT may be used to remove decay heat by manually placing it in service: this involves locally aligning the appropriate valves, insuring that cooling is available for the recirculation cooler, SG level is in the 95-100% narrow range, and eliminating any potential trip signal on the blowdown trip valves.

6 System Description and Fault Tree Analysis

6.2.15.2 Steam Generator Recirculation and Transfer System Interfaces and Dependencies

Table 6.2.15-1 lists the status and dependency of the SGRT system components. The SGRT pumps depend on AC power to operate. The blowdown trip valves TV-BD-100A, B, C, D, E, F are operated by instrument air, and the air lines are equipped with a solenoid valve which are powered from vital bus 1-I and 1-II, respectively. Upon loss of power from the vital buses or loss of instrument air pressure, the valves trip to isolate the blowdown line and prevent recirculation through the SGRT system, since the valves fail in the closed position.

The recirculation cooler is dependent on the chilled water supply from the CCW system. The SGRT pump is also dependent on SG level (between 95-100%), because the suction line is connected to its upper region.

6.2.15.3 Steam Generator Recirculation and Transfer System Operating Constraints

The SGRT system is placed in operation by local manual actions and there are no applicable Technical Specifications. However, it has the following standard precautions and limitations in each of the Operating Procedures that must be observed.

- 1 - The SGRT system should not be operated with primary RCS temperature above 150°F. This is an operating caution, and not necessarily a design limitation. The SGRT is designed to lower SG temperature from 212°F to 140°F.
- 2 - Water level in the SG must be maintained in a 95-100% narrow range when the SGRT is in operation.

6.2.15.4 Steam Generator Recirculation and Transfer System Shutdown Configuration

The SGRT system (SGRT A described, B and C are similar) is normally isolated from the SG by closed manual valves RT-1, 2, and 6. The discharge line is also isolated from the blowdown line by closed manual valves RT-18 and 19. If the system is placed in operation, the flow path is established by opening these closed valves and, in addition, BD-150 and the two blowdown trip valves TV-BD-100A and B are opened.

When the plant is in cold shutdown, both MFW pumps are turned off, which generates an automatic trip signal for the blowdown trip valves. To bypass the auto-closure signal, these valves have a local switch on the Containment Isolation Control Station, which must be placed in the permissive position to allow the valves to open (bypassing the closure signal).

The heat-removal capability of the SGRT system is limited due to the flow capacity of the pumps. Therefore, the success criterion depends on the level of decay-heat present in the core, and is as follows:

- 1 - Two SGRT coolers will be effective in removing core decay-heat 35 hours after shutdown.
- 2 - One cooler is sufficient to remove decay heat after 200 hours in shutdown.

6.2.15.5 Steam Generator Recirculation and Transfer System Logic Model

A logic model was developed for the SGRT system considering the two success criteria. The model assumes that all three SGs are available for recirculation. However, maintenance or other actions that make any SG unavailable are modelled by appropriately placed house events.

The interconnection between the SGRT of the different SGs was not modelled, because it is used exclusively to transfer water between the SGs and cannot be used for removing heat. For each recirculation loop, a human error probability was assigned that reflects a variety of operator actions associated with placing the SGRT systems into operation. These include the proper opening and aligning of the normally closed manual isolation valves, opening and bypassing the closure signal for the blowdown trip valves, insuring that there is secondary cooling available for the recirculation cooler (provided by chilled water from the CCW system), and finally, that the SG water level is in the 95-100% range.

If the RHR function is lost and the SGRT must be put in operation, the time available to perform the required actions is limited. Even though Operating Procedures caution the operator not to operate the SGRT system when the RCS temperature is above 150°F, it is assumed that in an emergency the system will be operated up to its design temperature (212°F of the SG). This would allow the operator about 30 minutes to 1 hour to set up the system and start operating the recirculation loop. The actual available time has to be determined in each case separately considering the elapsed time in shutdown (decay heat level) and the temperatures in the primary RCS and the secondary side.

The dependency of the recirculation cooler on the CCW system is explicitly modelled by transferring to the appropriate CCW logic modules. The recirculation pumps are powered from the non-safety related MCC 1A2, which is powered ultimately from the non-vital 4kV bus 1A. This portion of the electrical system is assumed to be always available ($P(\text{success})=0.$) except in a LOOP or SBO event, when it becomes unavailable ($P(\text{failure})=1.$) and modelled through an appropriate house event; this also implies that the SGRT system may not be used during this type of occurrence.

The electrical and instrument air dependency of the blowdown trip valves are explicitly modelled and any trip signal (containment isolation or AFW initiation) may also be included, if required.

The logic models for the two top events representing the SGRT system are given in Appendix C.15.

SGRT1 - 2 out of 3 SGRTs must fail corresponding to the first success criterion, where 2 coolers are required to remove decay heat.

SGRT2 - corresponding to the success criterion when 1 of 3 SGRT is sufficient to remove heat.

Figure 6.2.15-1 Steam Generator Recirculation and Transfer Systems

Table 6.2.15-1
Steam Generator Recirculation and Transfer Systems
Component Status and Dependency Summary

COMPONENT	NORMAL STATUS POS 1-15	ACTUATION	DEPENDENCIES
PUMPS			
RT-P-1A	STANDBY	LOCAL, MANUAL	MCC 1A2-1 BREAKER 45
RT-P-1B	STANDBY	LOCAL, MANUAL	MCC 1A2-1 BREAKER 23
RT-P-1C	STANDBY	LOCAL, MANUAL	MCC 1A2-1 BREAKER 42
AOVs			
TV-BD-100A TV-BD-100C TV-BD-100E	NO/FC	REMOTE - MCR ¹ LOCAL - CIVCS ² CONTAINMENT ISOLATION, AFW INITIATION, HIGH BLOWDOWN FLOW	INSTRUMENT AIR, VITAL BUS 1-I BREAKER 15
TV-BD-100B TV-BD-100D TV-BD-100F	NO/FC	REMOTE - MCR LOCAL - CIVCS CONTAINMENT ISOLATION, AFW INITIATION	INSTRUMENT AIR, VITAL BUS 1-II BREAKER 21

¹ - MAIN CONTROL ROOM

² - CONTAINMENT ISOLATION VALVE CONTROL STATION

6 System Description and Fault Tree Analysis

6.2.16 Steam Generator Secondary Relief System

6.2.16.1 Steam Generator Secondary Relief System Description

The power conversion system (PCS) can provide feedwater and remove heat from the steam generators following a transient. Two different aspects of the PCS were modeled for this study: The steam generators (SG) secondary side relief system, and selected portions of the main steam system related to the steam dump function.

The SG relief system is expected to be used for removing decay heat removal in reflux cooling mode.

The SG relief system is composed of five code safety relief valves (SRV) and one power operated relief valve (PORV) for each steam generator. The PORVs provide SG pressure relief at a set point below the SRVs. Each PORV has a manually operated block valve which is normally open unless a PORV is leaking. The PORVs automatically open on high SG pressure or are manually opened by the operator. All of the relief valves are upstream of the main steam header containment isolation valves, and all discharge directly to atmosphere outside the containment.

A portion of the main steam system (steam dump) was analyzed for the operator depressurization and cooldown fault trees. That portion consisted of two separate steam flowpaths: steam dumped to the main condensers and steam dumped to the atmosphere. Steam flows to the main condenser via one of two turbine bypass valves during cooldown. The atmospheric cooldown path uses the SG PORV, or the decay heat release valve, which is common to all three SGs.

The major components modeled in the study are briefly described below. Figures 6.2.16-1 and 2 are simplified diagrams of the steam generator secondary side relief and the steam dump system, respectively.

Decay heat release valve

The decay heat release valve (HCV-104), which is normally shut, is common to all three Main Steam lines. When in use, the valve allows steam to be extracted from the Main Steam System at a variable rate to assist in cooling the RCS. The HCV-104 can release sufficient steam to remove residual heat from the core approximately 30 minutes after shutdown. The valve also is used during system startup to control heatup of the plant if the main condensers are not ready to receive steam. The steam is released through a 4-inch line to the atmosphere, passing through an 8-inch sleeve in the top of the Safeguards Building.

The 4-inch air-to-open globe valve is designed to pass sufficient flow to remove 100 percent of the decay heat approximately 30 minutes after shutdown from full power. It is mounted on the top floor of the Safeguards Building, next to the Main Steam Safety Valves. Operation of the valve is controlled from MCR at the Steam Dump Control station. There is a manual station controller to position the valve. The valve also can be controlled from the Auxiliary Shutdown Panel with a manual station controller.

Atmospheric Relief Valve (PORV)

Each Main Steam header is provided with one atmospheric relief valve (MSRV-101 A/B/C) (or power-operated relief valve), sized to pass approximately 10 percent (373,000 lbm/hr) of the maximum calculated steam flow from each Steam Generator. The pneumatically operated (air-to-open), modulating valve is controlled with a manual/automatic station controller mounted on MCR benchboard 1-2. The PORV can control plant cooldown or heatup in conjunction with the decay-heat release valve.

Each PORV is supplied with instrument air, via a seismically qualified line. The relief setpoint is adjustable between 250 and 1100 psig; the PORVs are normally set to relieve at approximately 1035 psig. This setpoint is below the setpoint of the lowest set Main Steam Safety Valve, to avoid chattering of the safety valve. The valve is located on the top floor of the Safeguards Building and discharges to the atmosphere via a 10-inch line extending through the roof.

Main Steam Non-Return Valves and Steam Dump Valves

These valves are in the flow paths for the alternate steam relief to the condenser. The main steam non-return valves are normally closed during shutdown. There are eight Steam Dump Valves (TCV-105A/B, -106A/B, -107A/B, and -108A/B) that extract steam from the Steam Generators to control heat removal from the RCS. The design allows a 50 percent reduction in load without causing a reactor trip. The valves are situated in four groups of two and discharge to the main condenser. The groups together can dump 40 percent of the full steam load (approximately 4.256×10^6 lbm/hr) to the main condenser; rod movement handles the remaining 10 percent. Each 8-inch electropneumatic globe valve passes a flow of 532,000 lbm/hr. Four valves pass flow to the condenser tube bundle, and four flow to the hotwell.

6.2.16.2 Steam Generator Secondary Relief System Dependencies

The atmospheric relief valves (PORVs) depend on instrument air and DC power for their operation. The steam dump valves also depend on the same power sources, instrument air for motive force and DC power for control power. The Main Steam Trip Valves (MSTV) are operated by compressed air and DC power is required to operate the trip solenoids. The main steam non-return valves (NRVs) are motor operated check valves powered from the 4kv 1A, 1B, and 1C buses. Table 6.2.16.-1 lists the dependency of the system component.

6.2.16.3 Steam Generator Secondary Relief System Operational Constraints

No operational constraints were identified, except that the condenser is available for operation of the steam dump; this requires the operation of the gravity-fed circulating water system and a closed main condenser.

6.2.16.4 Steam Generator Secondary Relief System Shutdown Configuration

The setpoint on the PORVs may be lowered by the operator. The main steam trip valves and non-return valves are normally closed in shutdown, and have to be opened to enable steam dump.

6 System Description and Fault Tree Analysis

6.2.16.5 Steam Generator Secondary Relief Logic Model

The logic model was developed to take into account the number of potential relief pathways on the secondary side. In the reflux cooling mode, the heat transferred to the secondary side is relieved through the atmospheric dump valves (PORVs), or transferred to the circulating water system by dumping steam to the main condenser.

The following number of steam generators are needed to support reflux cooling depending on the decay time

Success Criterion	Time-After Shutdown
3 out of 3 SGs	0 - 75 Hrs.
2 out of 3 SGs	5 - 475 Hrs.
1 out of 3 SGs	475 Hrs.

It is assumed that 1 of 2 steam dump valves is sufficient to remove all decay heat.

The DC power-dependency of the STVs trip solenoids was not included in the model, since they are energized to trip the valves. On loss of DC power, the MSTVs may be opened, if air pressure is available. If DC power is available, then the solenoids may be positioned to allow compressed air to open the trip valves.

Three logic models were developed to represent the different success criteria in the time windows:

Time Window 1	-	SSHW1
Time Window 2 & 3	-	SSHW23
Time Window 4	-	SSHW4

The RCS system must be closed to prevent steam loss through the openings; this is modelled in fault tree PORV1, which represents the failure of closing the PORV pathways (2).

Figure 6.2.16-2 Simplified Flow Diagram
Main Steam Condenser Steam Dump Valves

Table 6.2.16-1
Steam Generator Secondary Relief System
Component Dependency

COMPONENT	MOTIVE FORCE	CONTROL POWER
1-MS-TCV-107A	Instrument Air	125 V DC at W Misc Rack 1
1-MS-TCV-107B	Instrument Air	125 V DC at W Misc Rack 1
1-MS-TCV-108A	Instrument Air	125 V DC at W Misc Rack 1
1-MS-TCV-108B	Instrument Air	125 V DC at W Misc Rack 1
1-MS-RV-101A	Instrument Air	Semi-vital Bus
1-MS-RV-101B	Instrument Air	Semi-vital Bus
1-MS-RV-101C	Instrument Air	Semi-vital Bus
1-MS-TCV-105A	Instrument Air	125 V DC at W Misc Rack 1
1-MS-TCV-105B	Instrument Air	125 V DC at W Misc Rack 1
1-MS-TCV-106A	Instrument Air	125 V DC at W Misc Rack 1
1-MS-TCV-106B	Instrument Air	125 V DC at W Misc Rack 1

6 System Description and Fault Tree Analysis

Table 6.2.16-1 (continued)

Component	Motive Force	Power Supply
Trip Valve Solenoids		
TV-101A	Instrument Air	
A		DC PNL 1-1
B		DC PNL 1-1
C		DC PNL 1-1
D		MCC 1J1-1
E		MCC 1H1-1
TV-101B	Instrument Air	
A		DC PNL 1-1
B		DC PNL 1-1
C		DC PNL 1-1
D		MCC 1J1-1
E		MCC 1H1-1
TV-101C	Instrument Air	
A		DC PNL 1-1
B		DC PNL 1-1
C		DC PNL 1-1
D		MCC 1J1-1
E		MCC 1H1-1
Non Return Valves		
NRV-101A		MCC 1A1-1 west
NRV-101B		MCC 1B1-2 west
NRV-101C		MCC 1C1-1 west

6.2.17 Consequence Limiting Control System

The consequence limiting control system (CLCS) automatically actuates the containment safeguards systems on receipt of indicated hi-hi (25 psia) containment pressure. It is a support system for the Containment Spray, Inside Spray Recirculation, and Outside Spray Recirculation front line systems. The CLCS has four containment pressure sensors, each sensor feeding a signal comparator whose output is input into two separate, three out of four logic trains. These logic trains automatically actuate the containment safeguards system components.

The CLCS depends on the vital instrumentation buses and the DC buses to operate the primary sensors and the relay logic network. Specific components in the Containment Spray, Inside Spray Recirculation, Outside Spray Recirculation, and containment spray Service Water Systems depend on the CLCS for automatic actuation. The Safety Injection Actuation system also uses some of the CLCS sensors.

The CLCS has no specific operational constraints. The surveillance requirements for the containment pressure sensors are daily checks of instrument channels for "instrumentation drift", and calibration of the sensors during reactor refueling. In addition, the isolation valve signal and spray signal of the CLCS are tested monthly.

The boolean expressions of the NUREG/CR-4550 model were converted into two simple fault trees for the two CLCS trains. The fault trees have top events "CLCS-A" and "CLCS-B".

6.2.18 Reactor Protection System

The reactor protection system (RPS) automatically scrams the reactor after receiving indications of abnormal conditions. The RPS is an actuation system that receives signals from several different types of sensors, which are combined in various logic matrices to trip the control rod drive mechanisms' supply circuit breakers, (also called the scram breakers). In addition, a circuit is installed that allows the scram breakers to be manually tripped from the control room. For redundant protection, the Surry manual scram circuit also trips the motor generator set which is the power source to the scram breakers.

The RPS system depends on the vital AC instrumentation and DC buses for power to the sensors and logic network. The combinations of bus failures required to fail the RPS is negligible compared to the unavailability of RPS system. The only components dependent on the RPS system are the scram breakers which supply power to the control-rod drive mechanisms.

Technical Specifications require that minimum number of reactor-trip-system instrumentation channels for various process variables (e.g. overpower delta temperature, low and high pressurizer pressure, lo-lo steam generator water level) are operable (48-hour AOT for one channel less than the minimum operable channel requirement before hot shutdown within the following 6 hours). Technical Specifications also require that a minimum number of reactor trip-breakers are operable (48-hour AOT for one breaker before hot shutdown within 6 hours), and that a breaker is not bypassed when one diverse trip feature (under voltage or shunt trip device) is inoperable, except for the time required for maintenance to restore the breaker.

6 System Description and Fault Tree Analysis

The surveillance requirements specify that the reactor trip system instrumentation channels are checked for "drift errors" during each shift, tested every month or before startup, and calibrated at refueling. The reactor trip breakers are tested monthly to verify operability of the undervoltage and shunt-trip attachments.

The fault tree of the NUREG/CR-4550 study was used in this study. It is a simple fault tree with one basic event with probability 6×10^{-5} .

6.2.19 Recirculation Mode Transfer System

The recirculation mode transfer (RMT) system automatically initiates the switchover of the suction of the low pressure injection pumps from the refueling water storage tank (RWST) to the containment sump when the RWST level is low. The RMT also automatically switches over suction of the high pressure injection pumps from the RWST to the low-pressure injection pump discharges on low RWST level. The RMT system has four independent RWST level sensors, each feeding two separate two-out-of-four relay matrices. These two matrices automatically actuate the components required switch over to the recirculation mode of the low and high pressure systems.

The RMT system depends on the vital AC instrumentation buses for power to the level sensors and to the relay logic. Specific components in the low and high pressure injection/recirculation systems depend on the RMT system for automatic actuation to their recirculation position.

There are no operational constraints for the RMT system. However, surveillance requirements specify that the RMT logic signal for automatic switchover to recirculation of low and high pressure systems is tested monthly.

The boolean expressions that were used in the NUREG/CR-4550 study were converted into two simple fault trees named "RMT-A" and "RMT-B".

6.2.20 Safety Injection Actuation System

The safety injection actuation system (SIAS) automatically initiates the high- and low pressure injection systems following an indication of the need for primary coolant makeup. The SIAS is composed of two independent trains used to automatically actuate the low- and high-pressure injection systems and the motor-driven AFW pumps. The signals which actuate SIAS are indications of: (i) low pressurizer level, (ii) high containment pressure, (iii) high differential pressure between main steam header and any steam line, or (iv) high steam flow in 2/3 lines coincident with low T_{avg} in 2/3 loops or low steam line pressure in 2/3 lines.

The SIAS depends on the AC vital instrumentation buses and the DC buses to operate the relay logic network. Specific components in the low- and high-pressure injection systems and the motor-driven AFW pumps are dependent on the SIAS for automatic actuation.

6 System Description and Fault Tree Analysis

Technical Specifications require that the minimum number of SIAS instrumentation channels for the various initiating functions are operable. If there is one channel less than the minimum requirement, the reactor is brought to cold shutdown. The surveillance requirements specify that SIAS instrumentation channels are checked each daily shift, tested monthly, and calibrated at refueling.

The boolean expressions of NUREG/CR-4550 study were converted into two fault trees named "SIA-A" and "SIA-B" representing failures of the two trains of the system.

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