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Interfacing Systems LOCA: Pressurized Water Reactors

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Prepared for
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Commission

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Interfacing Systems LOCA: Pressurized Water Reactors

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ABSTRACT

This report summarizes a study performed by Brookhaven National Laboratory for the Office of Nuclear Regulatory Research, Reactor and Plant Safety Issues Branch, Division of Reactor and Plant Systems, U.S. Nuclear Regulatory Commission. This study was requested by the NRC in order to provide a technical basis for the resolution of Generic Issue 105 "Interfacing LOCA at LWRs." This report deals with pressurized water reactors (PWRs). A parallel report was also accomplished for boiling water reactors. This study focuses on three representative PWRs and extrapolates the plant-specific findings for their generic applicability. In addition, a generic analysis was performed to investigate the cost-benefit aspects of imposing a testing program that would require some minimum level of leak testing of the pressure isolation valves on plants that presently have no such requirements.

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EXECUTIVE SUMMARY

This study was performed by the Risk Evaluation Group, Department of Nuclear Energy, Brookhaven National Laboratory for the Reactor and Plant Safety Issues Branch, Office of Nuclear Regulatory Research, USNRC. The objectives of this study are to investigate the vulnerability of current pressurized water reactor designs to an interfacing systems LOCA (ISL), identify any improvements that would significantly reduce the frequency of ISLs, determine the cost-benefit aspect of the improvements, and determine the effects and the cost-benefit relationship of instituting leak testing programs of the pressure isolation valves for those plants that do not currently have such a requirement.

The study is based upon the detailed examination of three plants (Indian Point 3, Oconee 3, and Calvert Cliffs 1) with the goal of taking the plant-specific findings and extrapolating the results to aid in the resolution of NRC Generic Issue 105. The examination applied a more advanced approach to the ISL analysis than any previous one performed with PRA methodology.

Overpressurization of low pressure systems due to reactor coolant system boundary failures may result in rupture of low pressure piping. This event, if combined with failures in the emergency core cooling systems (ECCS) and other systems that may be used to provide makeup to the reactor coolant system (RCS), could result in a core melt accident with the potential for release of radioactivity outside the containment. Some ECCS failures may be a direct result of the initial rupture and/or its environmental effects.

The results of the BNL core damage frequency (CDF) calculations indicate that the contributions from two groups of pipe lines, namely, the Residual Heat Removal suction and Low Pressure injection lines, dominate the CDF due to ISLs. The total contribution of ISL events to CDF is generally less than a few percent of the overall CDF. However, they can potentially be important contributions to risk if core damage occurs because ISLs may bypass the containment and allow fission product release directly to the environment.

A plant specific analysis of the effect of various corrective actions such as (a) application of continuous pressure (leak) monitoring devices and (b) increased frequency of valve leak testing indicates that they are capable of reducing the CDF due to ISLs by a factor of ~2 to 5.

One of the primary goals of the present study was to determine the cost-benefit relationship associated with requiring plants that do not currently have leak testing requirements on their pressure isolation valves to institute such a program. Core damage frequencies have been calculated to analyze the effect of leak testing of the pressure isolation valves. Large core damage and risk reductions due to a judiciously selected leak testing scheme have been calculated. The obtained cost-benefit relationship shows that the benefits derived from such testing schemes are cost-effective.

The most significant findings of this study are:

- Institution of a leak testing program of the pressure boundary isolation valves at plants that do not currently have such a requirement results in a definite net benefit in overall risk reduction. Based upon the results of a

sensitivity study, it would appear sufficient that such leak testing be performed at each refueling as well as after individual valve maintenance. In addition, the leak tests may be performed during descending from power at the beginning of the refueling period without significantly increasing the risk of an ISL event. This specific leak testing program was calculated to be capable of reducing the CDF by almost two orders of magnitude as compared to an assumed case without any provisions for leak testing.

The offsite risk benefit-to-cost ratio was calculated to be within the range of 78 to 46 depending on whether or not the break in the low pressure system was submerged under water. A submerged break would result in trapping of the aerosol fission products in the water and thus lower offsite consequences and hence a lower benefit-to-cost ratio. This indicates that in spite of uncertainty in predicting fission product release the benefits in risk reduction outweigh the cost of implementing such a leak testing program.

- The root cause analysis of experienced accumulator inleakage events revealed that the accumulator outlet check valve is rather prone to the "failure to operate (reseat) on demand" failure mode. Therefore, the preferred direction of an interfacing LOCA is expected to be through the accumulator and not through the LPI/HPI pathways. This is a particularly significant finding as the accumulator pathway represents an ISL inside containment.

In addition, the following technical results have been found:

- The results of this study with respect to initiator frequencies support the insight obtained by Pickard, Lowe & Garrick in their Seabrook EPZ sensitivity study,[1] that the relief valves of the low pressure systems have a definite role in reducing the frequency of overpressurization of low pressure piping.

- The failure analysis of low pressure piping performed by BNL indicates that, at least for the plants selected, given a breach of the pressure boundary between high and low pressure systems, hoop stresses are at yield stress or above in the low pressure piping. In certain pipe segments, the stresses are found to be near the ultimate material stress. At such stress levels pipe failure probabilities range from 2×10^{-3} at yield to almost certainty at the ultimate stress.

References

1. "Seabrook Station Risk Management and Emergency Planning Study," PLG-0432, December 1985.

1. INTRODUCTION

1.1 Scope/Objective

The term "interfacing system LOCA" (ISL) refers to a class of nuclear plant loss-of-coolant accidents in which the Reactor Coolant System (RCS) pressure boundary (isolation valve, piping wall, etc.) interfacing with a supporting system of lower design pressure is breached. A subclass of these accidents takes on special concern when the postulated flow path affects the availability of a safety system needed to mitigate the accident. This can occur by overpressurizing the system of lower design pressure and may further induce secondary ruptures outside the containment, thus establishing discharge of coolant directly to the environment. Depending on the configuration and accident sequence, the Emergency Core Cooling System (ECCS) as well as other injection paths may fail, resulting in a core melt with containment bypass.

The Reactor Safety Study, WASH-1400,[1] pointed out that a subclass of these types of accidents, called V-events, can be significant contributors to the risk resulting from core damage. (The V-events were defined for PWRs and involved the failure of two check valves in series or two check valves in series with an open motor-operated valve.) Further evaluations of ISL events in subsequent PRAs have found that their relative contribution to public health risk is even more pronounced compared with other sequences, because in recent PRAs more credit has been given to radionuclide retention in the containment for scenarios other than ISLs.

In spite of numerous analyses conducted in various PRAs, both the probability and the consequence estimates for interfacing system LOCA (ISL) sequences are subject to substantial uncertainties. Depending on assumed valve failure modes, common cause contribution, valve monitoring, test and maintenance strategies, and statistical data handling methods, the total core damage frequency due to ISL accidents may vary from 10^{-4} to 10^{-8}/reactor year. The radiological consequences are also subject to large variations due to plant-specific features, the location of the secondary break, and the radionuclide behaviour under the particular ISL sequence (e.g., break is below or above water level).

The ISL sequences have been a long standing concern for the NRC because of the considerable risk potential and the above-mentioned uncertainties. The NRC has taken steps to impose requirements to reduce the frequency of ISLs and has conducted a number of programs (analytical, experimental, inspection) to study various aspects of ISL accidents. Currently, intersystem LOCA at LWRs is a Generic Issue. The primary goals of the present project are (a) provide technical support to NRC, Reactor and Plant Systems Branch to resolve this issue, (b) investigate the frequency and the effects of ISLs, (c) identify any improvements that would significantly reduce the frequency of ISLs, (d) determine the cost-benefit aspect of the improvements, and (e) determine the effects and the cost-benefit relationship of instituting leak testing programs of the pressure isolation valves for those plants that do not currently have such a requirement. In order to accomplish these goals, a detailed analysis was conducted to:

- better understand the progression and effects of ISLs at PWRs,
- identify principal system dependencies involved in the ISL accident sequences,
- more realistically assess the initiating frequencies of ISLs at PWRs,
- identify corrective actions or methods for prevention, recovery or mitigation of ISLs with minimum change of existing design features,
- determine the corresponding core damage frequency and health risk reductions for each corrective measure, and
- evaluate the associated costs and benefits.

1.2 Methodology

The overall methodology of the project includes the following elements:

- From all the potential flow paths (at three representative PWR plants), pathways were identified by certain selection criteria, as candidates where ISLs may occur. The plants selected were: Indian Point 3 - representative of a Westinghouse plant, Oconee 3 - representative of a Babcock & Wilcox plant, and Calvert Cliffs 1 - representative of a Combustion Engineering plant.
- For the selected pathways, ISL initiator frequencies were calculated by utilizing all available information, including plant visits and new failure data obtained from root cause analysis of experienced pressure isolation valve failures.
- In the analysis, the relief valve capacities were considered in classifying ISL initiators leading to overpressurization of low pressure piping and small LOCAs.
- For each of the identified pathways, event trees were constructed assuming two types of initiators: overpressurization events leading to small or large LOCA and events without overpressurization resulting in small LOCA. The event trees describe the immediate plant response (status of frontline safety systems and support systems), the accident management (thermal hydraulic features of the accident and operator responses) and pipe rupture probabilities. The end states of the event trees were connected to plant specific PRA event trees through a conditional core damage frequency multiplier. Special attention was given to the estimate of pipe rupture probability.
- All accident scenarios resulting in core damage were computed. Scenarios leading to ISLs bypassing containment were further evaluated for health risk by using "scrubbed" and "nonscrubbed" source terms characterizing pipe ruptures below or above water level.
- The sensitivities of core damage frequency and corresponding risks were calculated for each of the scenarios assuming various corrective actions such as:
  - a. more frequent leak testing of check valves and MOVs,
  - b. application of permanent pressure sensors in the piping between valves,
  - c. ensuring the availability of alternate injection sources in addition to the standard ones (RWST, etc.),
  - d. improved operator training, and
  - e. implementation of all of the above (a. through d.).

- The sensitivities of core damage frequency and corresponding risks were calculated for each of the reference plants by removing the benefits of leak testing over a protracted period of time.
- Cost-benefit calculations were performed for each of the corrective actions using the risk data obtained with scrubbed and nonscrubbed source terms. Comparing the results strategies were suggested for determining the optimum method to decrease the occurrence of ISLs and/or mitigate their risk effects.
- A generic cost-benefit calculation was also performed to investigate the effect of instituting a leak testing program for plants that do not currently have such a requirement.

1.3 Organization of the Report

Section 2 provides detailed information on the interfacing lines (piping layouts, valve arrangements, immediate plant response) for three PWR plants specifically selected for the analysis. Section 3 summarizes the results of a Licensing Event Report (LER) survey conducted for ISL precursor events (overpressurization of interfacing lines or leakage through isolation boundary of RCS/support system of lower design pressure) which have occurred at PWRs. Section 4 contains the details and results of initiator frequency calculations for each of the potential ISL pathways identified in Section 2. Section 5 describes the event trees and provides the core damage frequencies corresponding the present status of operational conditions and valve testing policy of the selected reference plants. Section 6 discusses the sensitivity analysis of the core damage frequency for various corrective actions and for the generic "base case," when valves in the ISL pathways remain untested for leak failure over protracted periods of time. A generic "base case" was developed to represent plants that do not currently have specific requirements concerning leak testing pressure isolation valves (PIVs). This model had to be derived as all of the three reference plants do perform some level of leak testing. Section 7 presents the risk-based cost and benefit estimates for the proposed corrective actions and the generic base case. Section 8 summarizes the results obtained and the most important conclusions.

Numerous appendices contain the rather extensive support material for the main report. Appendix A describes the analysis of valve failure data. Appendix B contains the basic method and formalism for the initiator frequency calculation. Appendix C discusses the operator responses (accident diagnosis and post diagnosis performance of the operators). Appendix D presents the thermal-hydraulic aspects of ISLs. Appendix E contains the data analysis for the event trees based on the reference plant PRAs. Appendix F details a new ISL pipe break analysis with a critical review of previously performed work on this subject. Appendix G summarizes the sensitivity of core damage frequency on pipe break probability. Finally, Appendix H provides the results of the consequence analysis due to an ISL accident using the CRAC2 code.

1.4 References

1. "Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH-1400 (NUREG-75/914), USNRC, October 1975.

2. SURVEY OF POTENTIAL ISL PATHWAYS AT REPRESENTATIVE PWR PLANTS

2.1 Selection of Representative PWR Plants

In order to analyze the progression of ISL scenarios at PWR plants of different design, three representative PWRs were selected:

- Indian Point 3, a Westinghouse (W) design,
- Oconee 3, a Babcock & Wilcox (B&W) design, and
- Calvert Cliffs 1, a Combustion Engineering (CE) design.

Table 2.1 presents some useful characteristics of these plants with regard to ISL analysis.

The design features of the Emergency Core Cooling Systems have only minor differences, mainly in the design of the safety injection lines to the reactor vessels; in the B&W design, the Low Pressure Injection and Core Flooding Systems inject directly into the reactor vessel and not into the cold legs.

Most of the major components of the High and Low Pressure Injection Systems are located in the Auxiliary Buildings, except the LPI/RHR Heat Exchangers at Indian Point 3, which are inside the containment.

Since the detailed system designs vary from plant to plant, necessitating attention to specific plant features, a survey was carried out to identify potential ISL pathways at the selected plants.

The approach and criteria used to identify interfacing lines are discussed in Section 2.2. Sections 2.3, 2.4, and 2.5 contain the detailed information on the interfacing lines identified for Indian Point 3, Oconee 3, and Calvert Cliffs 1, respectively. These sections describe the piping layouts, valve arrangements and controls in the potential ISL pathways and the indication of overpressurization or pipe break.

Section 2.6 summarizes the additional information found necessary to assess overpressurization frequencies and to calculate the conditional ISL core damage probabilities.

2.2 Identification of Interfacing Lines in Selected PWRs

The plant surveys focused on all intersystem pathways where the boundary is represented by a high pressure/low pressure valve arrangement. Pathways, in which the isolation boundary is a pipe or coil wall (e.g., in heat exchangers or in reactor cooling pumps at seal cooling coils, etc.) were not considered.

The interfacing lines were identified as potential ISL pathways if they satisfied all of the following criteria:

- the line connects to the RCS,
- the interfacing system has a design pressure lower than that of the RCS,

- the path could be overpressurized by introduction of primary system pressure due to inadvertent valve opening or valve failure from any cause, and
- if so overpressurized, the path could produce a leakage rate of primary system coolant of sufficient magnitude to cause significant risk.

Note, that among the criteria there is none which would explicitly require that the lines penetrate the containment. Thus, this survey went beyond the identification processes that have been used in past studies, which involve the requirement for containment penetration.

The interfacing pathways were identified through a review of all the systems interfacing directly with the RCS. As part of the review process, all the containment piping penetrations were also surveyed, as a crosscheck to insure that at least all the interfacing systems having containment penetrations were not missed.

The main sources of information were the FSARs for the three plants.[1-2-3] Additional information was gained from the detailed system descriptions provided by the respective utilities. Useful information was also found in the PRAs[4-5-6] of these plants, as well as in a study[7] of light water reactor safety systems conducted at the Oak Ridge National Laboratory in 1981. The results of a recent V-event inspection[8] of the major "as built" interfacing paths at Indian Point 2 and Calvert Cliffs 1 plants conducted by NRC Region 1 personnel, also proved to be very helpful.

The major ISL pathways have been identified as the Low Pressure Injection/Residual Heat Removal, the High Pressure Injection and the Core Flooding Systems (see Table 2.1).

Isolable interfacing lines with diameters ranging up to two inches were not analyzed further. Their contribution to core damage was considered to be too small. This is because the expected flow through these lines is so limited that it is within the capacity of the normally operating charging and/or HPI pumps. Break sizes smaller than two inches were also not considered to have the potential for core uncovery in the FSAR's, for the three plants (see Chapter 14, Results of Small Break LOCA). Such lines were part of the RCS Drain, or RCS Sampling Systems.

The interfacing lines identified by the selection criteria and survey of available sources of information are described in the following sections. For each of the interfacing lines, the piping and instrumentation drawings (P&IDs) of the appropriate system were used to review the valve arrangements and the pipe sections that potentially can be overpressurized.

The type of information given for each of the lines is detailed below:

1. Line and pressure isolation valve characteristics (size, location, type, operator, normal and failed position).
2. Automatic and manual control of PIVs and the system they belong to.
3. Monitoring.
4. Surveillance requirements.

5. Boundaries (valves) of overpressurized pipe sections after failure of PIVs.
6. Potential alarms and indications of overpressurization or ISL.

2.3 Interfacing Lines at Indian Point 3

The interfacing lines satisfying all the selection criteria given in Section 2.2 at Indian Point 3 were the following:

1. Low Pressure Injection (LPI) Lines
2. Residual Heat Removal (RHR) Suction Line
3. High Pressure Injection (HPI) Lines
4. Core Flooding Tank (Accumulator) Outlet Lines
5. Letdown Line
6. Excess Letdown Line

The schematics of these lines are shown on Figures 2.3.1 through 2.3.6. Tables 2.3.1 through 2.3.6 provide additional information about the components involved.

2.3.1 Low Pressure Injection Lines

2.3.1.1 General

The LPI system at Indian Point 3 is designed to maintain core cooling during medium and large LOCAs. Following plant shutdown, when the pressure and temperature of the RCS are less than 450 psig and 350°F, respectively, its function is to remove residual heat (Residual Heat Removal, RHR System) from the core and reduce and maintain the temperature of the RCS. Figure 2.3.1 shows the flow paths during normal reactor operation, when the system configuration is that of the standby LPI system. The system fulfills its mission if at least one of the two pump-trains provides sufficient flow to keep the core covered after a large LOCA given that the two of three intact legs deliver flow to the core.

2.3.1.2 Operation and Control

In the standby configuration the valves of the system are lined up for automatic injection of borated water into the core from the RWST upon initiation of an SI signal.

The Technical Specifications require that:

a. Valves 882 and 744 in the suction and discharge lines, respectively, be open and their power supplies deenergized.
b. One LPI train (pump, heat exchanger with associate piping and valves) be operable.
c. Valve 883 in the RHR return line to the RWST be deenergized in the closed position.
d. The miniflow line (back to the suction of the LPI pumps) should be open with valves 1870 and 743 being open and their power supplies deenergized.

The RHR system purification path hand control valve (to the CVCS) HCV-133 is closed. The containment spray supply valves (from the RHR loop), 889A and B are closed. Similarly, the MOVs (1802A and B) to the recirculation pumps are closed. The recirculation path to the HPI suction (MOVs 888A and B), and to the containment suction (MOVs 885A and B) are closed. The RHR suction from the hot leg (loop 32) with MOVs 730, 731, and double disk valve 732 are also closed. The hydraulic control valves 638 and 640 are normally open. A crosstie ensures the balanced flow distribution to the four branch lines. These lines feed the discharge lines of the core flood tanks, which feed the four cold legs. The check valves in the core flood tank discharge lines (Series: 897A, B, C, D) and in the branch lines (Series: 838A, B, C, D) isolate the LPI from the RCS. There are also two normally open MOVs in each of the two trains (MOV 889A, MOV 746, MOV 899B, and MOV 747), which in principle can be closed by the operator if the PIVs fail. However, given PIV failure, the SI signal first opens these valves and during the resetting time (~3 minutes) the valves cannot be closed. The valves are of high pressure design so that they will withstand the full RCS pressure. If the valves can be closed, an ISL event would be stopped.

Each of the trains have a relief valve (RV733A, RV733B) set at 600 psig. The relief valve discharge is routed to the Pressurizer Relief Tank (PRT) which is inside the containment. Both relief valves are expected to lift together because of a crosstie. The aim of the design is to relieve low or medium sized leakage through the PIVs.

2.3.1.3 Indications of Overpressurization or ISL

A. Overpressurization

If a pair of check valves (from the groups 897 and 838) leaks moderately, that part of the LPI which is in the containment before check valve 741, will be overpressurized. The pressure would lift the relief valves and the discharge would flow to the PRT. Through HPI recirculation and the RHR miniflow lines the reactor coolant can bypass the containment and arrive to the LPI suction side.

Indication: a. "Auxiliary Building and Piping Trench Area High Temperature and Radiation (R-14) Alarms."
b. PRT level, temperature, pressure increase.
c. RHR heat exchanger outlet temperature increase.

B. Interfacing System LOCA

1. If the PIVs rupture, the pressure will, with high probability, break the heat exchangers or check valve 741 and lift the relief valves and thus become a LOCA inside the containment.

2. If the piping in the containment is resilient enough, the most severe scenario would be when the disk of check valve 741 ruptures and the pressure wave causes an ISL at the LPI pumps.

Indication: 1. There is an SI signal and injections from the HPI and soon from the LPI systems. The water level in the RWST decreases. If the sump water level increases and there are erratic LPI

branch line flow readings, the ISL is in the LPI system within the containment.

2. If the increase of the sump water level is not evident but the water level in the RWST decreases and also indications similar to a. and b. of case A occur with erratic LPI branch line flow readings the ISL is in the LPI system and the containment is bypassed.

3. The alarm indicating the start of the Auxiliary Building Sump Pump and high plant vent readings provide direct evidence for the ISL outside the containment.

Operator Actions: The operator would try to close MOV 744, then MOV 882 (to prevent draining RWST), and MOV 1869A and B (to isolate the HPI recirculation line with the miniflow to the LPI suction). The closing of RHR heat exchanger valves (MOV 747, MOV 899B, MOV 746, and MOV 899A) would also be attempted. (If the break is not isolated promptly, the motors for the isolation valve operator may overheat.) The RHR pumps would be shut off. Further actions would depend on system and plant responses.

If an ISL occurred which bypassed the containment through the pathway discussed above, the break would be above the flood level unless it were at the LPI pumps. Since the pumps are at the lowest level of the Auxiliary Building at elevation El.15'-0", a break at the pumps themselves would be flooded.

2.3.2 Residual Heat Removal Suction Line

2.3.2.1 General

The function of the RHR system during cold shutdown operations is described in Section 2.3.1.1. When the RHR system is lined up for these operations, the reactor coolant flows from the hot leg of loop 32 of the RCS to the RHR pumps through the RHR heat exchangers and back to the RCS through loops 31, 32, and/or 33 and 34. The heat load is transferred by the RHR heat exchangers to the Component Cooling Water System.

The RHR suction line has two MOVs: MOV-731 and MOV-730 and a double disk manual (N_2 operated) valve 732. These should be open under cold shutdown when the RHR is operating but should be tightly closed under normal reactor operation or hot shutdown. Figure 2.3.2 shows the valve arrangement under these operations. Table 2.3.2 gives some additional information on the valves.

2.3.2.2 Operation and Control

When these valves isolate the RHR suction line from the RCS (during normal reactor operation or hot shutdown), both of the MOVs are kept closed with the corresponding motor control center breakers locked in the off position. In addition, these valves are pressure interlocked. They get an automatic close signal if the RCS pressure increases to 550 psig. The motor of these valves is also specially designed. The motors are undersized such

that these valves cannot open against the large differential pressure which exists across the valve seat at power operation.

In order to secure the isolation of the RHR line, the double disk hand operated stop valve 732 is also locked. To avoid pressure buildup in the low pressure piping section, there is a relief valve (RV-1896) on a pipe segment of 2" diameter. The relief valve setpoint is at 600 psig. Its discharge is routed to the PRT.

The two MOVs are of crucial importance for the plant safety. Both these valves could conceivably be spuriously opened if individual shorts (e.g., because of fire) occur in the control cables of each MOV breaker that run between the respective motor control centers (2FM on MCC 36A and RFM on MCC 36B at El.55'-0" of the Auxiliary Building for MOV-730 and MOV-731, respectively) and the control room. To avoid this spurious operation, the fuse disconnect of both valves are normally kept open during normal plant operation, isolating the 480V ac power at the respective MCC cubicle. These valves are operated locally to align the RHR system for cold shutdown operation.

2.3.2.3 Indication of Overpressurization or ISL

A. Overpressurization

In the case that the isolation valves MOV-730, MOV-731, and manual (N_2 operated) valve 732 are leaking; the overpressurized zone will be that piping section which is bounded by the LPI pumps and check valve 881 in the line to the RWST. However, through the miniflow line, that part of the LPI system which is in the containment up to check valve 741 would also be overpressurized. The overpressurization may induce unstable conditions at the seating of the isolation check valves in the injection lines of the LPI. These conditions may then initiate an ISL.

The leakage is expected to lift the relief valve inside the containment.

Indication: The same as Indication a. and b. in Section 2.3.1.3.

B. Interfacing System LOCA

In the case where isolation valves MOV-730 and MOV-731 rupture or become fully open, an ISL can occur bypassing the containment at normally closed valve 732. If the body of this valve survives, an ISL can occur at the seals of the LPI pumps (assuming that the disk of check valve 881 is ruptured). In both cases a massive flood would occur in the auxiliary building, which would be exacerbated by an additional flow from the RWST.

Indication: Similar to that discussed in Section 2.3.1.3, Indication b.

It is expected that only breaks at the LPI pumps would be under flood level.

2.3.3 High Pressure Injection Lines

2.3.3.1 General

The HPI system at Indian Point 3 is designed to provide cooling water to the RCS in case of a small (less than two inches), or a medium (two to six inch) LOCA. It is also used in the case of a steam line break accident. While the design pressure (1500 psig) of its piping is significantly higher than that of the LPI (600 psig), it is nevertheless, only 60% of the design pressure of the RCS piping (2500 psig). The design pressure of the suction side piping of the HPI pumps is only 210 psig. Since the HPI has a very important role in the safety of the plant, it has been included in the analysis.

During normal reactor operation the system is lined up for safety injection. Figure 2.3.3 shows the flow paths for this case. The system fulfills its mission (medium LOCA) if two of three pumps provide cooling water to two of four injection legs. Two of the four injection paths are required to deliver water to the core. The system design incorporated the ability to isolate the safety injection pumps on separate headers such that full flow from at least one pump is ensured should a branch line break.

2.3.3.2 Operation and Control

The motor-operated valve to the RWST, MOV-1810 is normally open and kept deenergized. The MOVs in the discharge lines (series of MOV-856) to the cold legs are maintained in the open position. The motor-operators of MOV-856A,D,F, and K are electrically disconnected. Upon actuation of the SI signal, the valves MOV-856C,E,H, and J receive an open signal. The MOVs to the hot legs of RCS loop 1 and loop 3, MOV-856G and MOV-856B are signaled to open. Motor-operated valves MOV-1835A and B, as well as, MOV-1852A and B, on the Boron Injection Tank (BIT) line are also signaled to open. Pressure and flow indications, decreasing tank levels and alarms indicate the status of the system. There is a test line (diameter 3/4") relief valve (RV-855) to relieve any pressure above design to the PRT. The relief valve can pass about 15 gpm.

Each of the branch lines (diameter 2") of line 56 (except the hot leg line) feeds an accumulator discharge line. Thus, on each of these lines there are three isolation check valves (one 897 and two 857; e.g., to the cold leg of loop 1, 897A, 857A, and 857G). The cold leg branch lines (diameter 1.5") of line 16 join directly to the cold legs. On these lines there are only two isolation check valves (two from the series 857, e.g., to loop 1, 857E and 857L).

On each of the two branch lines feeding directly the hot legs (diameter 2") there are two 857 check valves and a closed MOV (a 856 valve).

Upon an SI signal, all the three HPI pumps start and the valves in line 16 open to allow flow through the BIT.

2.3.3.3 Indication of Overpressurization or ISL

A. Overpressurization

In the branch lines of line 56, three PIVs have to fail to cause overpressurization or ISL. These are either the three check valves in series (on the lines to cold legs) or the two check valves and a closed MOV (on the line to the hot leg). In this case the overpressurized part of HPI would be those pipe sections which are bounded by check valves 858B, 852A, 849A, and the locked closed valve 859A on the test line back to the RWST. The relief valve RV-855 will be opened, discharging to the PRT. The overpressurization disables only line 56 of the LPI.

In the branch lines of line 16, two PIVs have to fail to cause overpressurization. The overpressurized section would be limited by two normally closed MOVs (1835A and B), the locked closed manual valve 859A and the normally closed manual valve 1833A. The relief valve (RV-855) would also be lifted.

Indication: PRT level, temperature and pressure increase.

B. Interfacing System LOCA

In order to obtain an ISL at HPI pumps 31 or 32 via line 56, an additional check valve has to fail. If either check valve 852A or 894A failed, there would be an ISL in the auxiliary building. The relief valve RV-855 would be lifted. The pumps are at the El.34'-0" of the auxiliary building, so the flooding would be drained to lower elevations. The environmental conditions in the pump room, however, may fail the pumps.

Indication: SI signal. Erratic HPI branch line flows. RWST level decreases. No increase in containment sump water level. High temperature and radiation alarm in the piping trench area and in the auxiliary building. PRT level, temperature and pressure increase. High radiaton readings at the plant vents. Start of the automatic sump pump in the auxiliary building.

Operator Actions: Operator will try to isolate the line which has the break. Further actions depend on system and plant responses.

2.3.4 Core Flooding Tank (Accumulator) Outlet Lines

2.3.4.1 General

The core flooding tanks are pressure vessels filled with borated water and pressurized with nitrogen gas. They are designed to provide enough flow to initiate recovery of the core in the case of a large LOCA before the LPI starts to deliver flow. Injection occurs when the RCS pressure drops below the nitrogen gas pressure (650 psig) in the tanks. Each Core Flooding Tank Outlet Line is connected to an RCS cold leg pipe. The pressure in each tank is monitored by two pressure sensors. Low and high level alarms annunciate out-of-limit water levels. There is also a pressure relief valve for each accumulator. The relief valves discharge to the containment.

2.3.4.2 Operation and Control

There are two isolation check valves and a motor-operated valve in each outlet line (e.g., in loop 1; check valves 897A, 895A, and MOV-894A). The MOVs are normally deenergized open when the RCS pressure is higher than 1000 psig and receive signals to open upon a safeguards actuation signal. The valve arrangements of the lines are shown in Figure 2.3.4. Should the RCS pressure fall below the tank pressure, the check valves open after about 25 seconds and borated water is forced into the RCS. The check valves are specially made for boric acid operation. The check valves operate in the closed position with a nominal differential pressure across the disc of approximately 1650 psi.

2.3.4.3 Indication of Overpressurization or ISL

If the isolation valves in an accumulator outlet line fail, the line and the tank will be overpressurized. The liquid level will also increase . (Small leakage can be detected by chemical analysis of the boron concentration. The allowed leakage for an accumulator check valve is 2cc/hr/in of nominal pipe size.) The accumulator relief valves will first pass nitrogen gas and at higher inleakage would also pass water.

Indication: Accumulator pressure and level alarms. High radioactivity alarm in containment. Increasing containment sump level.

Rupture of the check valves would cause the loss of a tank and a large ISL in the containment.

2.3.5 Letdown Line

2.3.5.1 General

During plant startup, normal operation, load reductions and shutdowns reactor coolant flows through the letdown line from the cold leg of reactor coolant loop 1 via the CVCS volume control tank and holdup tanks to the suction side of the charging pumps. An excess letdown line is also provided (see Section 2.3.6).

The normal letdown line (diameter 3") is a normally open pathway penetrating the containment. It branches into three orificed lines (diameter 2") after going through the regenerating heat exchanger (to preheat incoming charging water). The reactor coolant pressure drops from 2235 psig to about 275 psig, when flowing to one of the orifices. The design pressure of the piping downstream of the orifices is 600 psig. The schematics of the line is shown on Figure 2.3.5.1.

2.3.5.2 Operation and Control

Each of the branch lines contains an air operated valve, inside the containment (200A, 200B, 200C). There are also two solenoid operated valves outside the containment, which are automatically closed by a containment isolation signal. The line has two remotely controlled air operated valves (LCV459, LCV460) and a relief valve (RV-203) with setpoint at 600 psig.

2.3.5.3 Indication of Overpressurization or ISL

If air operated valves 201 and 202 close (e.g., fire energizes the coils), coolant pressure downstream of the orifices will increase. This will lift the relief valve 203 which discharges to the PRT. If valves LCV-459 and LCV-460 cannot close and the low pressure piping breaks, the result would be an ISL within the containment.

Indication: Letdown Relief Valve High Temperature Alarm. PRT level, temperature and pressure increase. Automatic close signal on low pressurizer level to LCV-459 and LCV-460. SI signal.

If a rupture of the letdown line occurred outside the containment, the leakage would be restricted to the piping trench area and the auxiliary building. Any leakage would be collected by the building radioactive drains. The leakage would be within the makeup capacity of the charging pumps and could be readily isolated and the excess letdown line could be placed in service.

Indication: Auxiliary Building and Piping Trench Area High Temperature and Radiation Alarms. Start of Auxiliary Building Sump Pump.

2.3.6 Excess Letdown Line

2.3.6.1 General

Under certain plant conditions or when the normal letdown line is isolated, the excess letdown would be in service and it would transport reactor coolant to the CVCS volume control tank, via the RCP seal leakoff return path.

2.3.6.2 Operation and Control

The excess letdown line (diameter 1") is normally closed. The pipe arrangement is shown on Figure 2.3.6. There are three valves on the line (that fail in the closed position). One of the valves (HCV-123) utilizes an analog instrument signal for operation of the valve. This valve contains an orifice that regulates flow through the valve. The piping design pressure changes at the outlet of the valve.

2.3.6.3 Indication of Overpressurization or ISL

In order to spuriously open the valves, application of sustained voltage (hot shorts) would be required. The event is very unlikely. However, if spurious operation of these valves does occur, the low pressure piping would be overpressurized (leakage to the reactor coolant drain tank) or broken at valve 215. This latter event may cause RCP seal cooling loss.

Indication: Increasing level and pressure of reactor coolant drain tank. Typical signals of small LOCA within the containment.

2.4 Interfacing Lines at Oconee 3

The following lines have been identified at Oconee 3 that may be subjected to an interfacing system LOCA:

1. Low Pressure Injection Lines
2. Decay Heat Removal Suction Line
3. Core Flood Tank Outlet Lines
4. Low Pressure Auxiliary Pressurizer Spray Line
5. RCS Letdown to Coolant Treatment System

These lines are shown schematically in Figures 2.4.1 through 2.4.4 and Tables 2.4.1 through 2.4.5 list additional information.

2.4.1 Low Pressure Injection Lines

2.4.1.1 General

Under normal circumstances, the main purpose of the LPI system is to remove decay heat from the reactor core during shutdown. In emergency operation, the LPI is designed to maintain core cooling for large LOCA and to control boron concentration in the reactor vessel. There are two separate flow paths, as indicated on Figure 2.4.1; each includes one pump, one heat exchanger, and isolation valves.

2.4.1.2 Operation and Control

In the emergency mode, the LPI is automatically initiated by low reactor coolant system pressure or high containment pressure. Initially, the system is aligned such that the LPI pumps take suction from the borated water storage tank and the normally closed isolation valves LP-17 and LP-18 automatically open, allowing water to be injected into the reactor vessel. After the initial injection phase the LPI system is switched over to the recirculation mode by connecting the suction side either to the containment building emergency sump or to the normal decay heat suction line.

In the decay heat removal mode, after the RCS pressure is reduced to 255 psi, the LPI pumps are connected to the RC hot leg and discharged through the heat exchangers and the open isolation valves LP-17 and LP-18.

The LPI lines are connected to the reactor vessel and each injection loop is isolated by two check valves (CF-12, LP-47, and CF-14, LP-48) and normally closed MOVs (LP-17 and LP-18).

2.4.1.3 Indications of Overpressurization or ISL

In case the isolation valves fail, the low pressure piping downstream of LP-17 and LP-18 will be overpressurized. The low pressure piping includes the decay heat cooler and is bounded by valves LP-31, LP-33, LP-9, LP-10, LP-15, LP-16. A pressure relief valve is included in each injection line against relatively small leakages from the HPI system.

If overpressurization or interfacing LOCA occurs at the LPI lines, the following indications will be available to the operator:

1. High DHR Pump Discharge Pressure
2. High DHR Cooler Outlet Temperature
3. Injection Line Flow Indications
4. Auxiliary Building Vent High Radiation Alarm
5. RCS Pressure Indication

2.4.2 Decay Heat Removal Suction LIne

2.4.2.1 General

The LPI system is used in normal operation to remove decay heat from the reactor core during shutdown. DHR cooling is initiated when the reactor pressure is below the suction piping design pressure.

2.4.2.2 Operation and Control

The system is connected to the RC hot leg line (see Figure 2.4.2) by opening LP-1, LP-2, and LP-3 and delivers the water back to the reactor vessel through the LPI pumps and coolers. The isolation valves can be manually operated from the main control room. In addition, isolation valves LP-1 and LP-2 have interlocks to prevent their opening whenever the RCS pressure is above the design pressure of the suction piping. The motor-operated isolation valves are stroke tested at least quarterly in cold shutdown conditions.

2.4.2.3 Indications of Overpressurization or ISL

If the isolation valves fail, the low pressure piping that will be overpressurized, is bounded by the LPI pumps, valves LP-29, LP-30, LP-19, LP-20, BS-7, BS-9, and the RB spray pumps. There are two relief valves in the suction pipe. One inside the containment discharging to the emergency sump, and the other outside in the auxiliary building that discharges to the high activity waste tank.

The following indications will be available to the operator if overpressurization or interfacing LOCA occurs.

1. LP Suction Line Pressure and Temperature Indications
2. RB Normal Sump Level Indication/Alarm
3. High Activity Waste Tank Level Indication/Alarm
4. Auxiliary Building Vent Radiation Alarm
5. RCS Pressure Indications

2.4.3 Core Flooding Tank Outlet Line

2.4.3.1 General

The core flooding system is designed to provide core cooling in case of intermediate or large RCS pipe breaks. The system automatically floods the core when the RCS pressure drops below 600 psig.

2.4.3.2 Operation and Control

Each core flood tank outlet line is connected to the reactor vessel core flooding nozzle, and each line contains two isolation check valves (CF-11,12

and CF-13,14) and one MOV (CF-1 and CF-2), which is fully open during normal operation (see Figure 2.4.3). No operator action or automatic signal is required to initiate the operation of the core flooding system. The check valves are leak tested at each cold shutdown utilizing the test rig indicated on Figure 2.4.3. The stop MOVs are stroke tested simultaneously with the check valve leak test.

2.4.3.3 Indications of Overpressurization or ISL

If the isolation check valves (CF-11,12 and CF-13,14) fail, the core flood tank outlet line and the tank itself will be overpressurized. The flood tank has a pressure relief valve, which would open and relieve the pressure by discharging a portion of the nitrogen blanket to the atmosphere.

There are a number of indications available to the station operator indicating overpressurization or interfacing LOCA at the core flood system:

1. Core Flood Tank Level and Pressure
2. RCS Pressure
3. RB Emergency Sump Level
4. RB Vent High Radioactivity

2.4.4 Auxiliary Pressurizer Spray Line

2.4.4.1 General

The auxiliary pressurizer spray line (see Figure 2.4.3) is available to control RCS pressure during low pressure operation. Its use is limited and is not presently specified in any operational procedure.

2.4.4.2 Operation and Control

The auxiliary pressurizer spray line is normally closed off by two manual isolation valves in addition to the isolation check valve (LP-45, LP-62, LP-63, LP-46).

2.4.4.3 Indications of Overpressurization or Interfacing LOCA

The failure of the isolation check valve LP-46, together with manual isolation valves LP-62 or LP-63 would pressurize the LPI lines. If the containment isolation valves on these lines also fail (either LP-17 or LP-18), the LPI lines in the auxiliary building would be overpressurized. This is identical with the LPI failure mode discussed in Section 2.4.1.3. An interfacing LOCA through the auxiliary pressurizer spray lines (1.5" diameter) can be considered as a very small LOCA, not capable of core uncovery, since the makeup capacity of one HPI pump is sufficient to maintain RCS inventory with break sizes smaller than .04 ft^2. Therefore, the line is not analyzed further.

2.4.5 Letdown Line

2.4.5.1 General

The function of the letdown flow is to accommodate RC volume changes due to thermal expansion and the need for removing impurities as well as controlling boron concentration in the coolant (see Figure 2.4.4). The letdown flow is isolated from RCS pressure by a passive pressure reducing orifice.

2.4.5.2 Operation and Control

Each letdown cooler outlet line has one inboard motor-operated containment isolation valve. One pneumatic outboard containment isolation valve is provided upstream of the pressure reducing orifice (HP-3, HP-4, HP-5).

2.4.5.3 Indications of Overpressurization or ISL

Overpressurization or interfacing LOCA can occur in the letdown line only if a normally open valve downstream of the pressure reducing orifice (HP-8 or HP-195) is accidentally closed overpressurizing the low pressure line. If the line downstream of the pressure reducing orifice ruptures the result is a very small LOCA with restricted outflow from the RCS. This interfacing LOCA is not capable of core uncovery as was previously noted (see Section 2.4.4.3).

Indications available to the operator include:

1. Letdown Storage Tank Low Level Alarm
2. RCS Pressure Indication
3. High Radioactivity in Auxiliary Building

2.5 Interfacing Lines at Calvert Cliffs 1

The interfacing lines identified according to the selection criteria listed in Section 2.2 at Calvert Cliffs 1 are the following:

1. Low Pressure Injection Lines
2. Residual Heat Removal (Shutdown Cooling) Suction Line
3. High Pressure Injection Lines
4. Core Flooding Tank (Safety Injection Tank) Outlet Lines
5. Letdown Line

The schematics of these lines are shown in Figures 2.5.1 through 2.5.5. Tables 2.5.1 through 2.5.5 present additional information about the components involved.

2.5.1 Low Pressure Injection Lines

2.5.1.1 General

The LPI system is designed at Calvert Cliffs 1 to provide core cooling water during the injection and recirculation phases of a large LOCA. A second function of the system is to provide shutdown cooling flow through the core

and shutdown cooling heat exchangers. During plant operation with the RCS at normal operating pressures and temperatures, the LPI is maintained in a standby mode with all of its components lined up for emergency injection. The system lineup is shown on Figure 2.5.1. The success criterion of the system is that at least one of the two pump trains provides sufficient flow from the RWST via one or more of the four safety injection headers to keep the core covered after a large LOCA.

2.5.1.2 Operation and Control

Each of the two LPI pumps take suction from separate suction headers from the RWST. The LPI pumps discharge through check valves to a common discharge header (diameter 12"). The header pressure and flow are indicated in the control room (ranges: 0-600 psia for pressure and 0-6000 gpm for flow). There is an air operated flow control valve on the header, SI-306 which is locked open (Technical Specification requirement because of lack of redundancy). Relief valve SI-439 protects the header against overpressurization. The relief setpoint is 500 psig, the design pressure of the LPI piping.

The LPI header splits into four injection lines (diameter 6"). Each of the LPI lines has an MOV isolation valve controlled by a hand switch located in the control room (SI-615, SI-625, SI-635, SI-645). These MOVs can be throttled. Valve position indicators and line flowmeters are provided in the control room. The valves are normally closed. They open automatically upon receipt of an SI signal. They fail "as is."

After the MOVs there are two isolation check valves on each of the four branch lines (e.g., SI-114, SI-118). The HPI lines join in these pipe sections to form a common inlet to the outlet lines of the Core Flooding Tanks. Thus, the three injection systems, HPI, LPI, and the Core Flooding Tanks share four common injection paths into the RCS via common final isolation valves (see, e.g., SI-217). One isolation check valve on each branch line (e.g., SI-118) is of the "weighted closed" type to ensure the valve remains closed.

The LPI is automatically actuated by an SI signal. No operator action is required in the injection phase; the discharge line isolation valves are opened. If the RCS pressure drops below about 200 psig, the LPI starts delivering flow. The miniflow line back to the RWST with normally open motor operated valves (SI-659, SI-660) stays open during the injection phase (power is normally removed from the valve operators).

2.5.1.3 Indication of Overpressurization or ISL

In order to have an overpressurization or ISL three check valves and a motor operated valve have to fail. Due to the number of valves in series, the probability of these failures is very small. The overpressurized zone would be the whole LPI system. The break is expected to occur at the LPI pump seals.

Indication: In the case of small inleakage, relief valve SI-439 would open. In the case of an ISL, high temperature and high radiation alarms would be generated from the piping tunnel area, or from the ECCS pump rooms 11 and 12 in the auxiliary building.

2.5.2 Residual Heat Removal Suction Line

2.5.2.1 General

Following reactor shutdown and cooldown the LPI is used in the shutdown cooling mode for further cooling of the RCS when the coolant temperature drops below 300°F and coolant pressure falls below 270 psig. The system in this mode is called the Shutdown Cooling System at Calvert Cliffs 1. For this mode, the system is manually realigned and the LPI pumps take suction from the hot leg of coolant loop 2. The heat load is transferred by the shutdown cooling heat exchangers to the component cooling water system. The reactor coolant returns to the RCS through the LPI header.

The RHR suction line (diameter 14") has two motor operated isolation valves: SI-652 and SI-651. The two isolation valves are shut during safety injection operation, and are opened during shutdown cooling. The schematic of the valve arrangement with the suction side piping of the shutdown cooling system is shown in Figure 2.5.2.

2.5.2.2 Operation and Control

The first isolation valve, SI-652, is located inside the containment and is controlled by key operated hand-switch (1-HS-3652 on a control panel). The second isolation valve, SI-651, is located outside the containment and is also controlled by a key operated hand-switch (1-HS-3651). These valves are interlocked with pressurizer pressure such that the valves shut automatically when the pressure rises above 300 psia. During normal operation the valves are locked closed, both locally at the MCCs and on the control board. The keys are kept under administrative control to ensure that the valves cannot be opened inadvertently. In addition, with the help of newly installed redundant pressure signal channels, the opening control circuit of each valve is also interlocked. These interlocks represent independent and redundant means for preventing the opening of the valves. In the event of main control room evacuation, the necessary control functions are transferable to the auxiliary control room. The position of the MOVs are continuously indicated with lights on the control board.

The valves are specially made, double disk (flex wedge) MOVs with undersized motor operators, such that these valves cannot be opened against the large differential pressure which exists across the valve seat with the reactor at power. A relief valve (SI-469) is provided between the two valves to protect the piping between the valves from sudden pressure changes (e.g., due to sudden temperature increase in the containment). The setpoint is 2485 psig. A second relief valve (SI-468) is located on the suction line, to protect the line from overpressurization. The relief setpoint is 315 psig. The design pressure of the suction line is 300 psig. (The valve was originally sized to protect the line from overpressure due to simultaneous operation of the charging pumps and shutdown cooling with the pressurizer in a solid condition.)

2.5.2.3 Indication of Overpressurization or ISL

A. Overpressurization

If the first isolation valve (SI-652) leaks, the operator is alerted by the discharge through the first relief valve. If both isolation valves (SI-652 and SI-651) are leaking, an overpressurization zone would be generated. The zone would be bounded by the normally closed manual valves SI-441 (for LPI pump 11) and SI-440 (for LPI pump 12), isolation valve SI-399 of the recirculation line from the LPI injection header (normally shut) and manual (normally shut) isolation valve, 26M3-1 of the common inlet of the lines from the CVCS and from the Spent Fuel Pool Cooling System.

Indication: Both relief valves would cause considerable leakage and high temperature alarms would be triggered in the auxiliary building.

B. Interfacing System LOCA

If both of the MOVs rupture, a massive ISL would occur in the piping trenches and/or in the auxiliary building.

Indication: The event would be an extra-containment LOCA, with the associated consequences.

2.5.3 High Pressure Injection Lines

2.5.3.3 General

The HPI system at Calvert Cliffs 1 is designed to inject borated water from the RWST into the RCS to prevent the uncovering of the core in case of small or intermediate size LOCA. The system is capable of delivering borated water at discharge pressures up to 1275 psia. The design pressure of its piping (1600 psig) is much higher than that of the LPI (500 psia), but, it is only 64% of the design pressure of the RCS piping (2485 psia). The design pressure of the suction side piping of the HPI pumps is 300 psig. Thus, it has been included in the analysis.

The HPI system of Calvert Cliffs 1 is a two-train, three pump system which injects into the four RCS cold legs via four injection headers. Figure 2.5.3 shows the lineup of the system for injection. The system fulfills its mission, if one of three pumps provide flow through one of four headers to the RCS.

2.5.3.4 Operation and Control

Two separate suction headers supply the three HPI pumps with water from two possible sources: the RWST and the containment sump. The motor operated valves are normally open to the RWST. The three HPI pumps discharge through check valves to a common header. In this header there are two motor operated valves: SI-655 (normally open) and SI-653 (normally closed). The valves allow flexibility for pump realignment.

There are two HPI headers: the main header and the auxiliary header. The motor operated isolation valve for the main header is open and receives an

open signal when an SI signal is generated. Downstream of this valve there is a relief valve (SI-409) which protects the header (against pressure developed by a sudden temperature increase) and a pressure indicator (range = 0 to 200 psig, the indicator is not shown in the figure). The setpoint of the relief valve is 1485 psig.

The main header splits into four parallel lines. Each of the lines has a motor operated isolation valve (SI-616, SI-626, SI-636, SI-646) which is normally closed. These valves open automatically upon receipt of an SI signal. (These valves can be positioned from fully open to fully shut by hand switches, in order to throttle the lines' flow. Position indicators are available.) Each of the main lines joins to a respective auxiliary line (diameter 2") to form a common line which passes through a check valve (SI-113 respectively) and flow elements (range: 0 to 300 gpm, not shown). This line joins to a respective LPI line to form one of the four injection paths to the RCS.

The valve/instrumentation arrangement of the auxiliary header is the same.

The four injection paths enter the containment where they join the core flooding tank inlets to the RCS could legs (via a check valve and isolation valve, see Sections 2.5.1 and 2.5.4).

The system is actuated automatically upon receiving an SI signal. Operator action is required only for starting recirculation operation.

2.5.3.5 Indication of Overpressurization or ISL

In any injection line three check valves and one motor operated valve have to fail to generate an overpressurization or an ISL. The frequency of these events is very small.

A. Overpressurization

In the case of overpressurization, it is expected that only one of the two trains would be overpressurized, because the two trains are isolated.

Indication: The relief valve associated with the train which was overpressurized would relieve. Pressure sensors would indicate the pressure.

B. Interfacing System LOCA

In order to have an ISL at the suction side of an HPI pump, the shock wave would have to brake an additional check valve. If this happens, the ISL would be isolable, because the MOV (either SI-656 or SI-654) of the train in which the LOCA occurred, can be closed. This may succeed because the MOV (SI-656) is located in the high pressure section of the piping and the flow is limited by the size of the header branch lines (diameter is only 2").

Indication: The relief valve associated with the train would relieve. Pressure sensors would indicate the pressure. High temperature and radiation alarms would be in the auxiliary building, with

symptoms similar to a small-small LOCA. After an ISL one or two HPI pumps would not operate, because three pumps are located in two compartments.

2.5.4 Core Flooding Tank Outlet Lines

2.5.4.1 General

The Core Flooding Tanks are called Safety Injection Tanks (SITs) at Calvert Cliffs 1. They are sized to ensure that following an RCS depressurization caused by a design basis accident, three of the four tanks will inject sufficient borated water to cover the core until the safety injection pumps can provide water for core cooling. During normal plant operation the SITs are approximately half filled (total volume per tank is 2000 ft^3) with borated water and pressurized with nitrogen to between 200 and 250 psig. Each SIT is connected to an RCS loop cold leg through two check valves in series (see Figure 2.5.4) and are normally held shut by the higher RCS pressure. A motor operated gate valve is provided between the two check valves on the SIT outlet. This valve is normally open and is shut to isolate the SIT and prevent emptying it during plant cooldown and depressurization. The SITs have instrumentation and alarms which provide indication of the SIT level and pressure. The SITs are also provided with relief valves and can be vented to the atmosphere via air operated vent valves. The setpoint of the relief valves is 250 psig. The vent valves are normally shut and the vent lines are normally capped.

2.5.4.2 Operation and Control

The SITs are passive components and require no operator or control action to actuate. During normal plant operation the MOVs are locked open, their associated circuit breakers deenergized, and their position indication is checked by every shift from the control room. The two check valves serve to prevent the reactor coolant from entering the SITs.

A leakoff return line is used to send any leakage between the two SIT check valves to the reactor coolant drain tank or the RWST. Each SIT has an air operated isolation valve in its leakoff return line. They are normally shut and shut automatically (if open) for an SI signal. The four leakoff return lines join in a common return line. The isolation valve to the RC drain tank (SI-661) is a normally open air operated valve, which shuts automatically for an SI signal. To send leakoff flow to the RWST, two manual containment isolation valves (SI-463, SI-455) can be opened. There is a relief valve (SI-446) which has a setpoint at 360 psig, to protect the line from overpressurization during SIT check valve testing and relieves to the RCS quench tank.

For filling, draining, sampling, and correcting the boron concentration of the tanks additional miniflow lines are provided.

2.5.4.3 Indication of Overpressurization or ISL

In order to indicate potential isolation check valve failures, pressure indicators are used in the outlet lines between the isolation check valves and the SIT outlet check valves. The range of the pressure indicators extends

from 0 to 2500 psig. The pressure signal actuates an alarm at a setpoint of 300 psig.

Indication: Overpressurization of a SIT outlet line is indicated by "SIT Check Valve High Pressure" alarm. In leakage and/or overpressurization of a tank is signaled by "SIT Pressure/Level Hi" alarms (setpoints: 235 psig, 228 in). Check valve ruptures would cause an ISL within the containment resulting in the usual symptoms. A simultaneous rupture of an isolation check valve and an air operated valve failure on the leakoff return line may cause also a small ISL inside the containment.

2.5.5 Letdown Line

2.5.5.1 General

In order to control coolant chemistry, minimize corrosion and compensate for coolant expansion due to temperature changes, during most of normal plant operations, coolant flows from the cold leg of a reactor coolant loop (loop 12-A) to the suction side of the charging pumps.

The letdown line (diameter 2") first passes though the tube side of the regenerative heat exchanger (where the temperature is reduced to 260°F) then it flows through the letdown control valves, purification filters, ion exchangers into the volume control tank of the CVCS. The charging pumps take suction from the volume control tank. Figure 2.5.5 shows the flow schematic of the letdown line. The pressurizer level control system regulates the letdown flow by adjusting the letdown control valves (I-CV-110P, I-CV-110Q), so that the letdown flow plus the reactor coolant pump controlled bleed off matches the input from the operating charging pumps. The valves reduce the pressure of the letdown fluid from the regenerative heat exchanger from about 2250 psig to 460 psig. The valves are pneumatically operated and fail closed. Flashing of the hot liquid between the letdown control valves and the letdown heat exchanger is prevented by controlling back pressure with a pressure control valve downstream of the letdown heat exchanger. The design pressure of the piping downstream of the letdown control valves is 650 psig.

A spring loaded excess flow check valve (diameter 2") on the letdown line inside the containment serves to shut in the event that the flow through the letdown line reaches 200 gpm as would occur in the event of a letdown pipe break, thus limiting the letdown flow in the auxiliary building (its design pressure is 2485 psig). There are also two isolation valves (I-CV-515 and I-CV-516) of the letdown line inside the containment upstream of the regenerative heat exchanger.

2.5.5.2 Indication of Overpressurization or ISL

A break or crack in the letdown line will result in flashing of the blowdown released in the piping penetration room (west) or letdown heat exchanger room in the auxiliary building. The ISL will cause compartment pressurization. Four pressure sensors are installed in the west piping penetration room and letdown heat exchanger room to detect the rise in ambient pressure. The pressure signal generated by the sensors will automatically close the letdown isolation valves. Pressure relief for the letdown heat

exchanger room is provided by an open blockout connecting to the west piping penetration room. Pressure in the penetration room will be gradually decay. No excessive amounts of water will be released, because the excess flow check valve will seat and terminate blowdown. An ISL with more coolant loss may occur if

a) a break occurs in that part of the piping where feedback signals cannot be generated to the isolation valves and/or to the excess flow check valve,
b) these valves are unavailable for some reason, or
c) charging pump(s) continue to work.

Following rupture of the letdown line in the auxiliary building, the applicable emergency operating procedures would be implemented.

2.6 References

1. Indian Point 3, Nuclear Power Plant, Power Authority of the State of New York, "Final Safety Analysis Report," July 1982.

2. Oconee Nuclear Station, Units 1, 2, and 3, Duke Power Company, "Final Safety Analysis Report," December 1981.

3. Calvert Cliffs 1 and 2, Baltimore Gas and Electric Company, "Final Safety Analysis Report," July 1985.

4. "Indian Point Probabilistic Safety Study," Power Authority of the State of New York and Consolidated Edison Company of New York, 1982.

5. "Oconee PRA," NSAC-60, June 1984.

6. A. C. Payne, Jr., "Interim Reliability Evaluation Program: Analysis of the Calvert Cliffs Unit 1 Nuclear Power Plant," NUREG/CR-3511/1 of 2, SAND83-2086/1 of 2, May 1984.

7. F. A. Heddleson, "Summary Report on a Survey of Light Water Reactor Safety Systems," Oak Ridge National Laboratory, NUREG/CR-2069, October 1981.

8. "Special Inspection Regarding Potential Overpressurization of ECCS," Memorandum by R. W. Starostecki, Director, Division of Reactor Projects, USNRC, Region I, April 2, 1985.

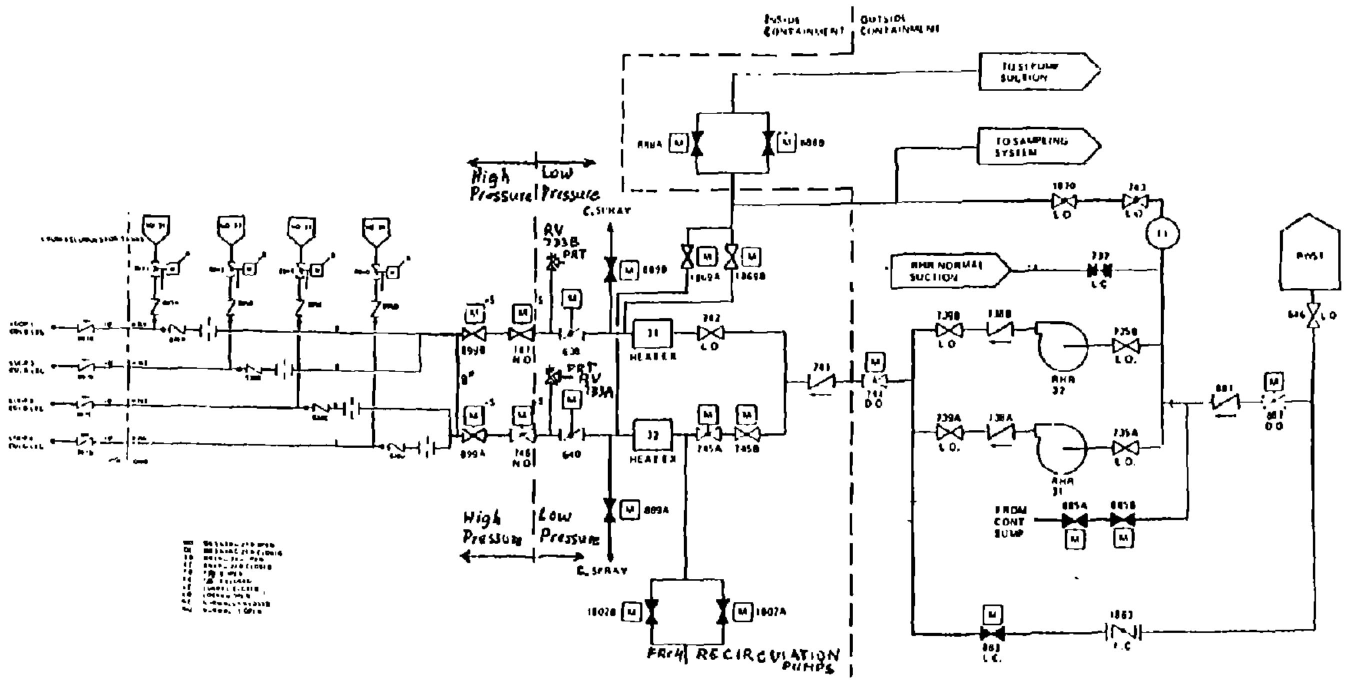


Figure 2.3.1   Low pressure injection lines, Indian Point 3.

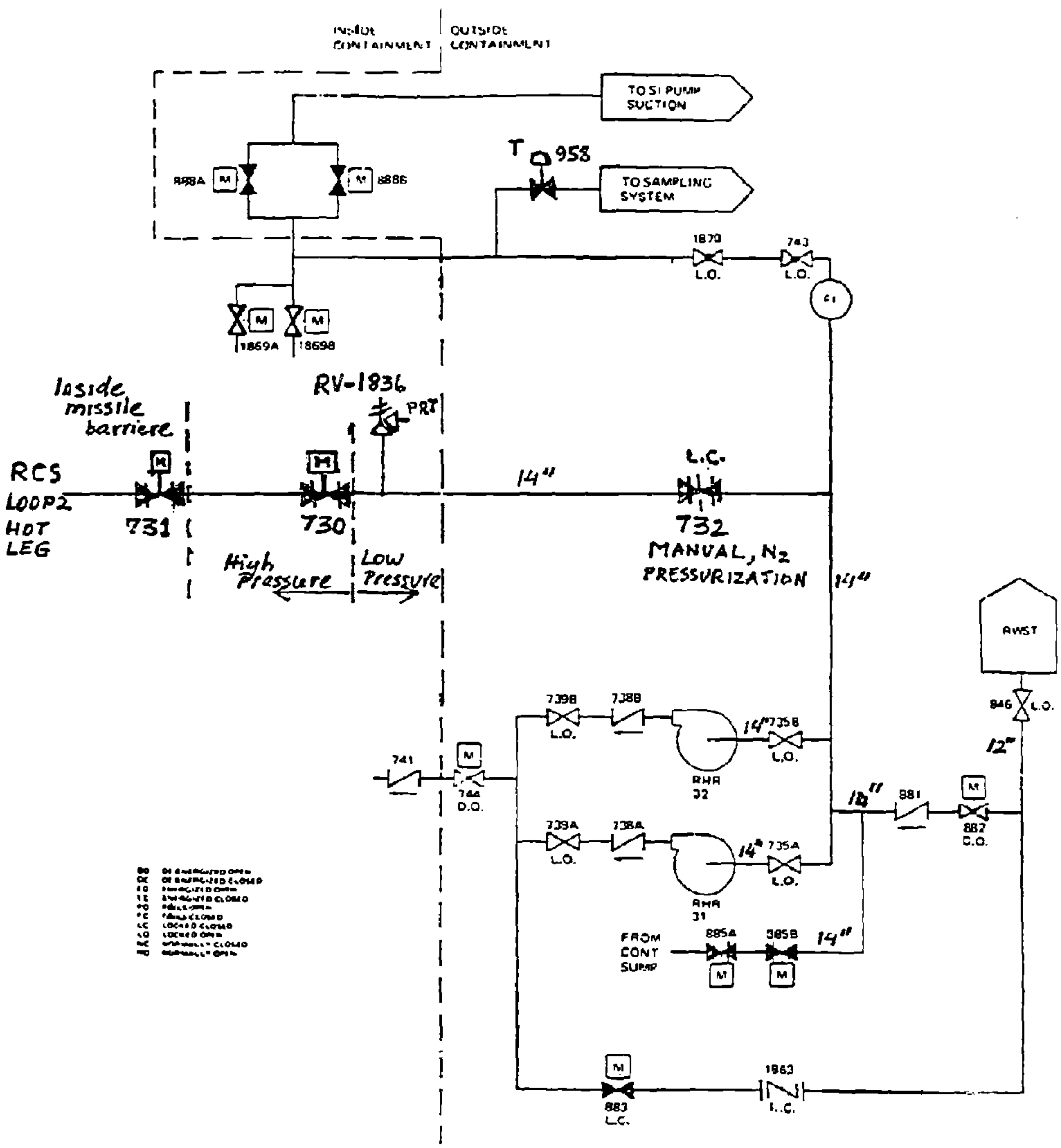


Figure 2.3.2 Residual heat removal suction line, Indian Point 3.

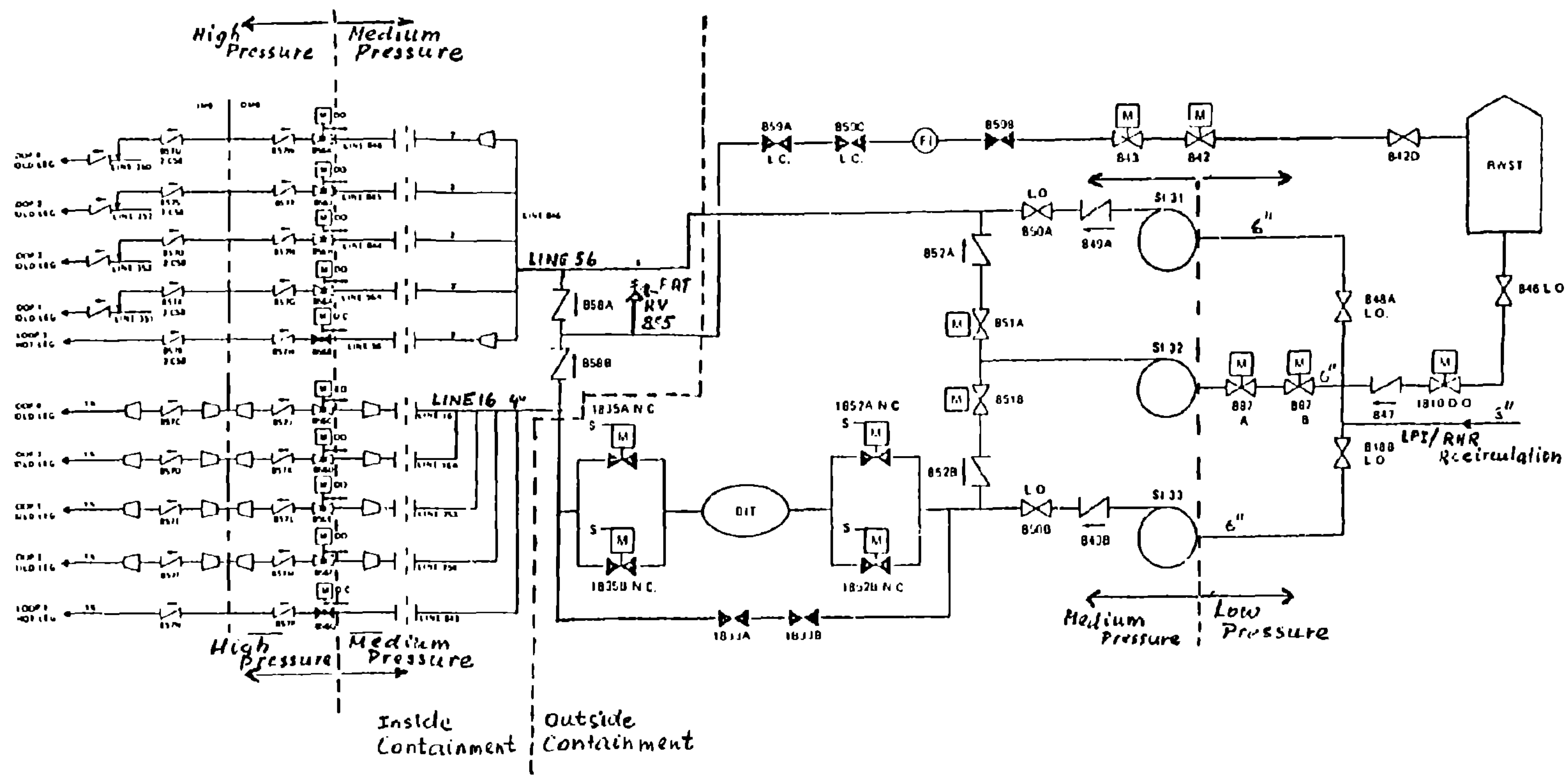
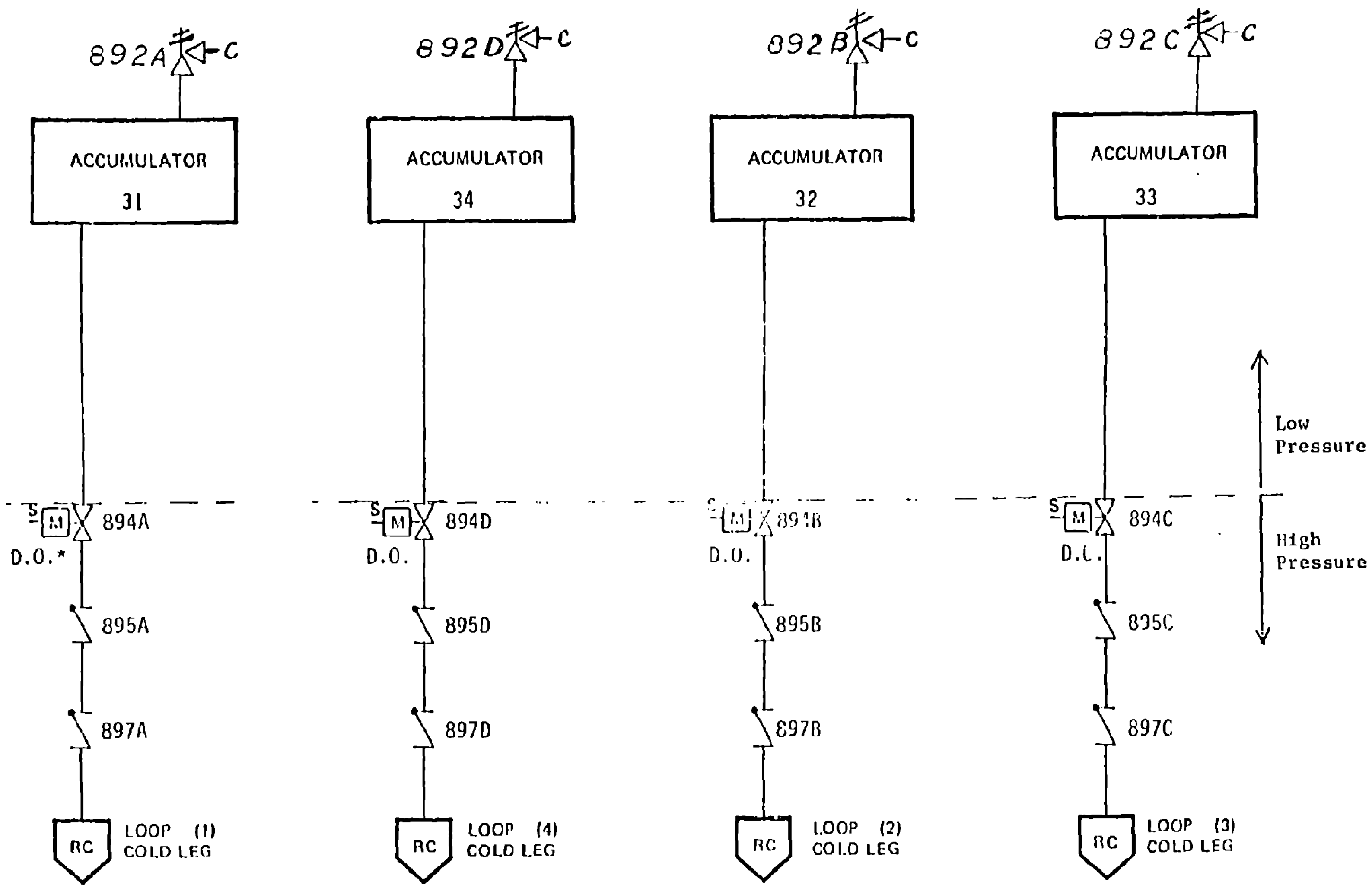


Figure 2.3.3 High pressure injection lines, Indian Point 3.



*D.O. ⇒ . Deenergized open.

Figure 2.3.4 Core flooding tank (accumulator) outlet lines, Indian Point 3.

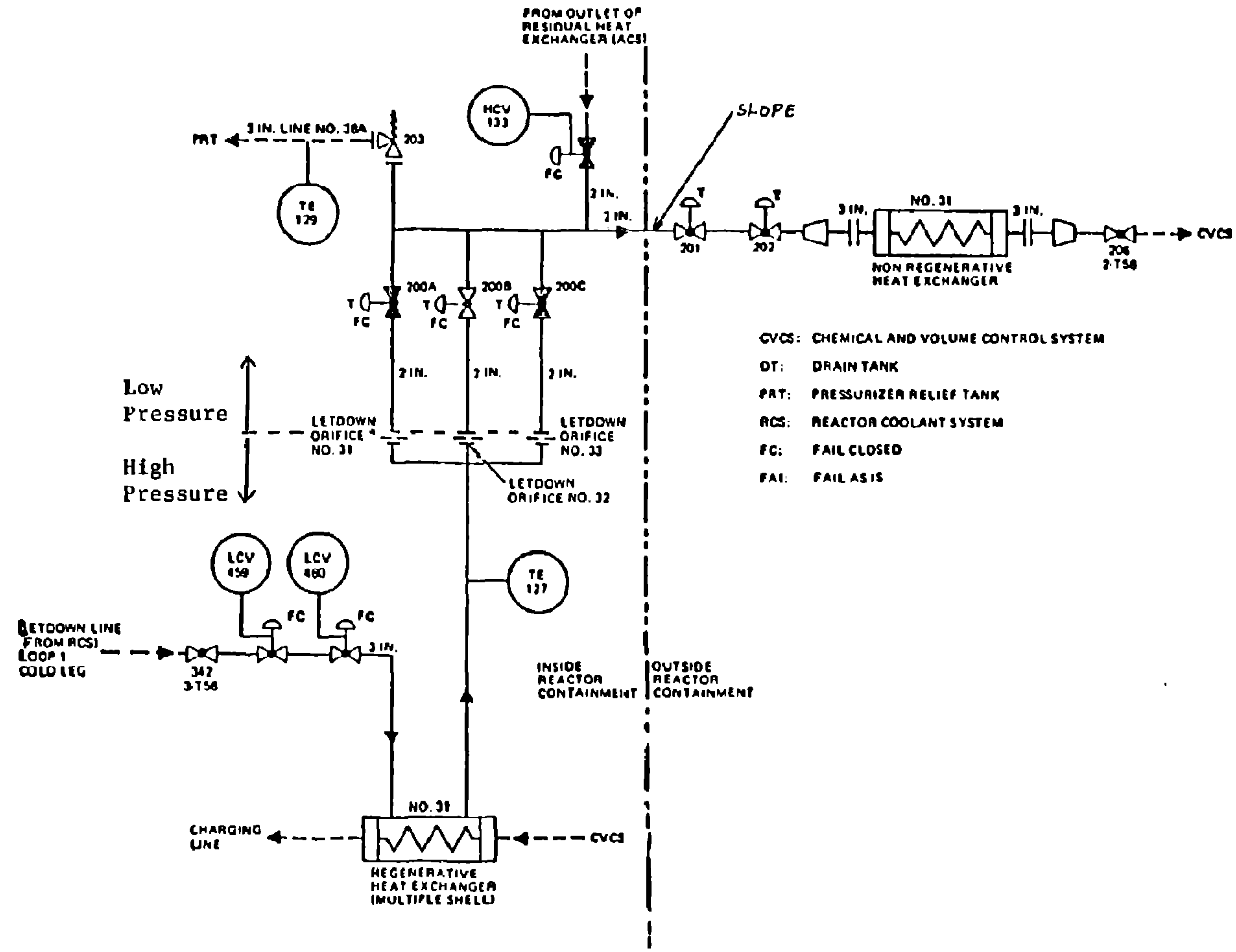


Figure 2.3.5 Letdown line, Indian Point 3.

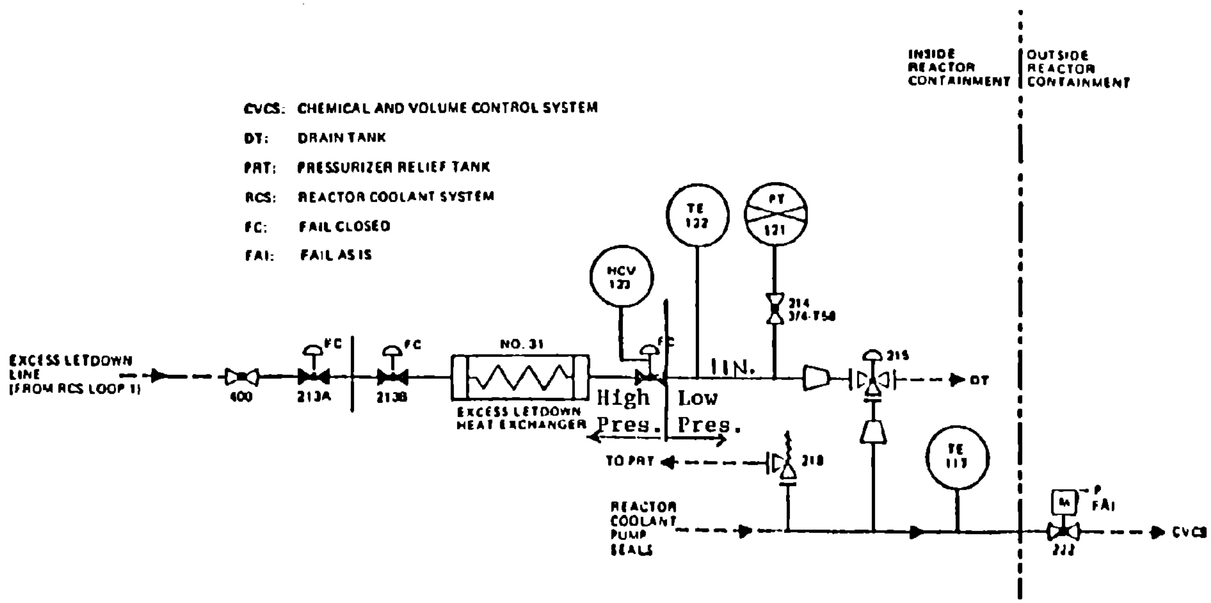


Figure 2.3.6 Excess letdown line, Indian Point 3.

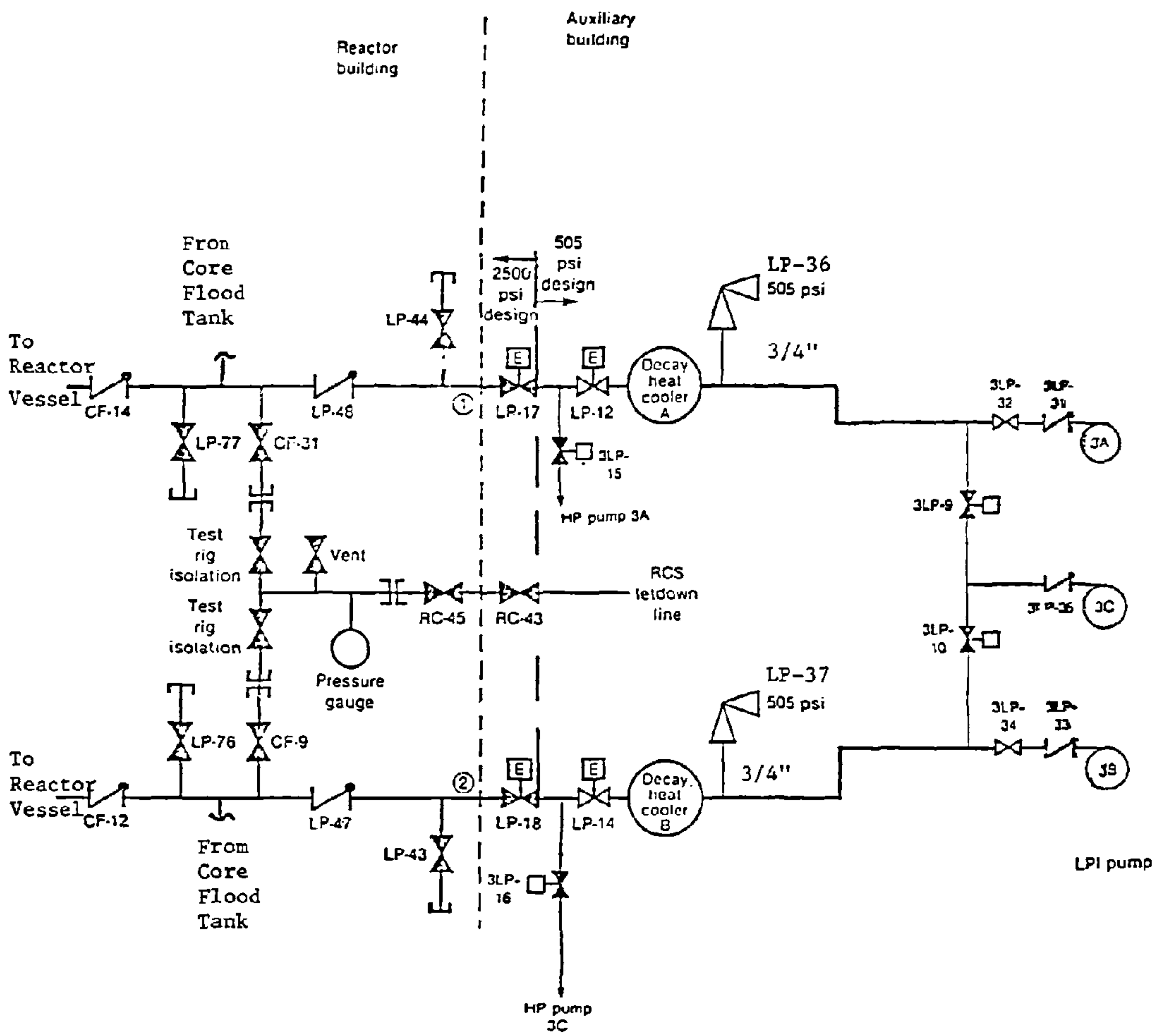


Figure 2.4.1 Low pressure injection lines, Oconee 3.

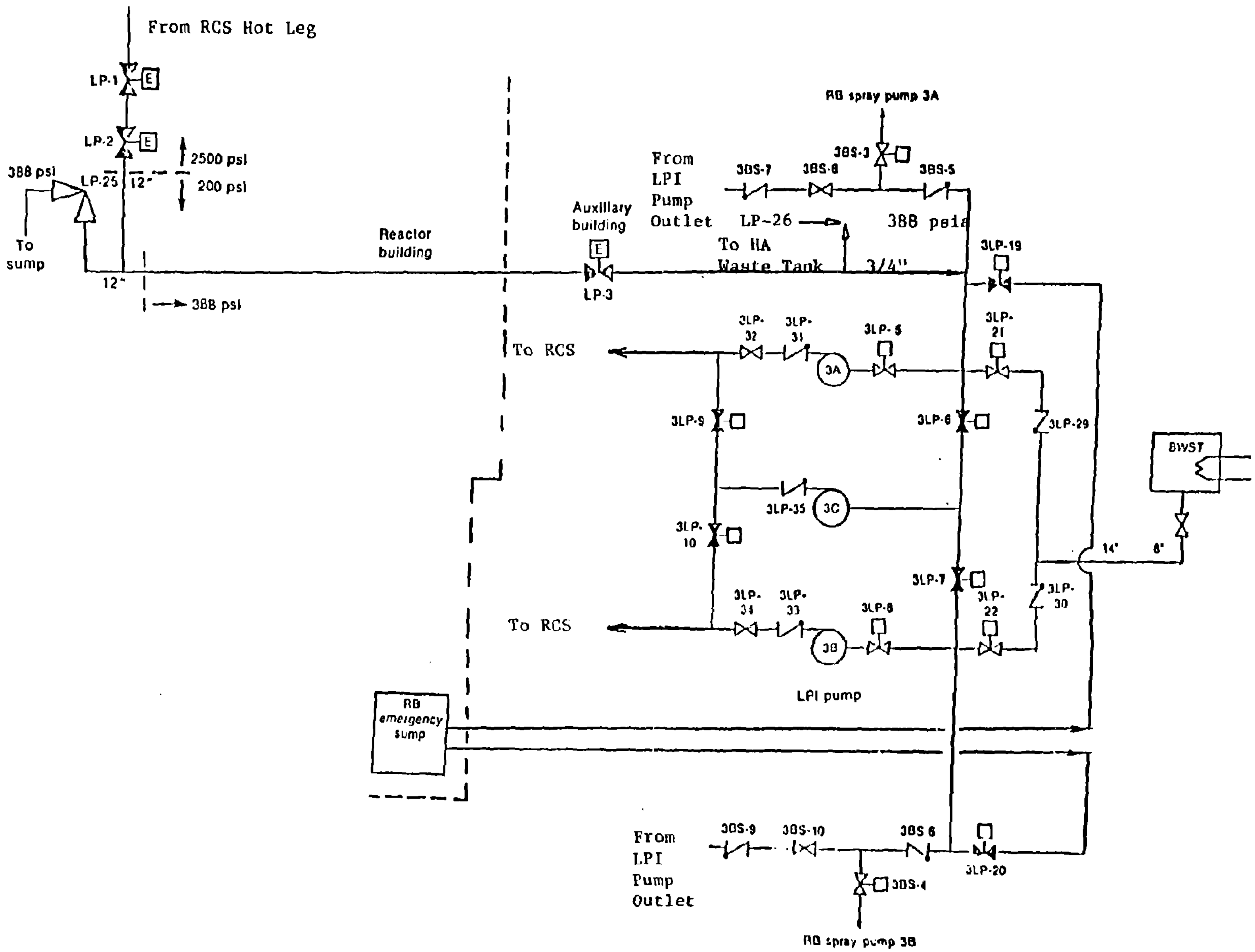


Figure 2.4.2 Decay heat removal suction line, Oconee 3

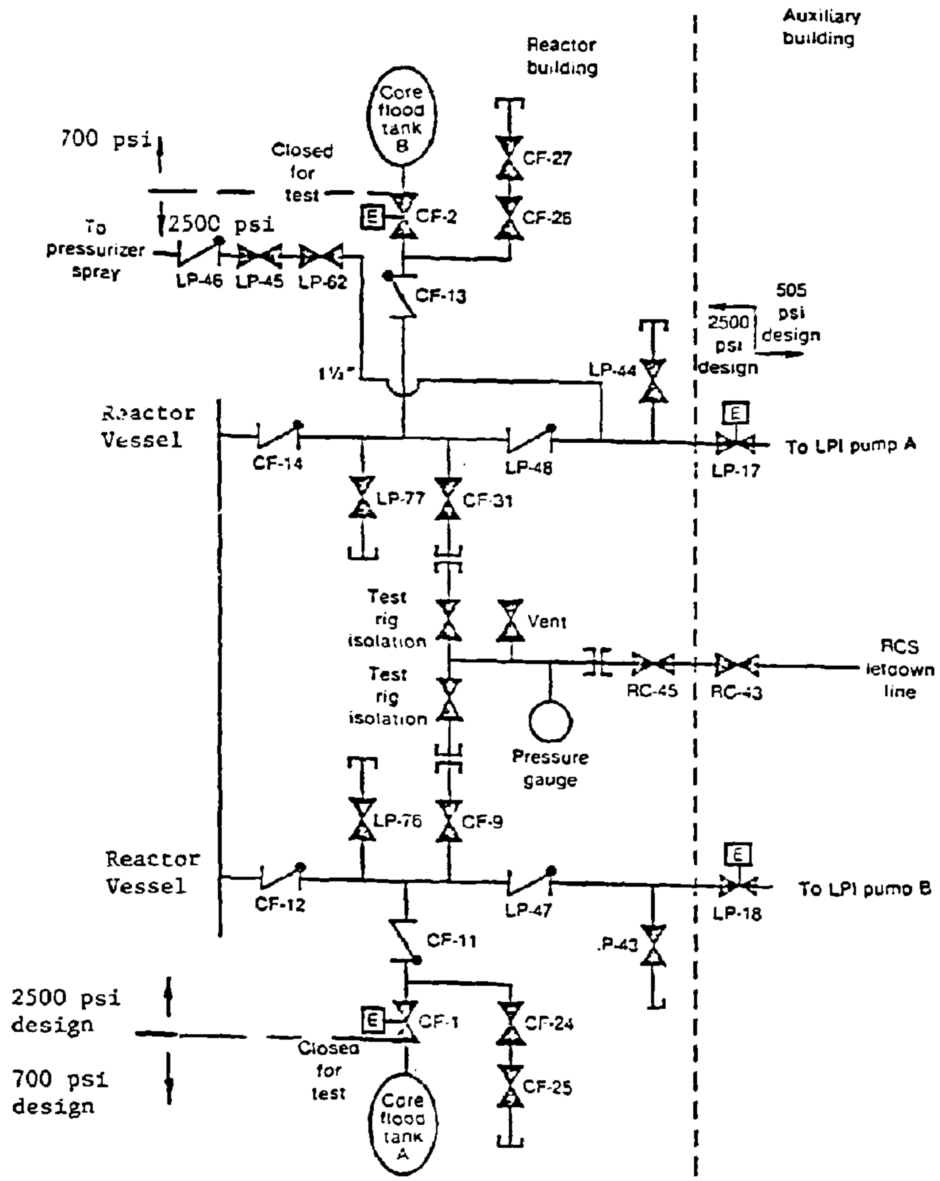


Figure 2.4.3 Core flooding system, Oconee 3.

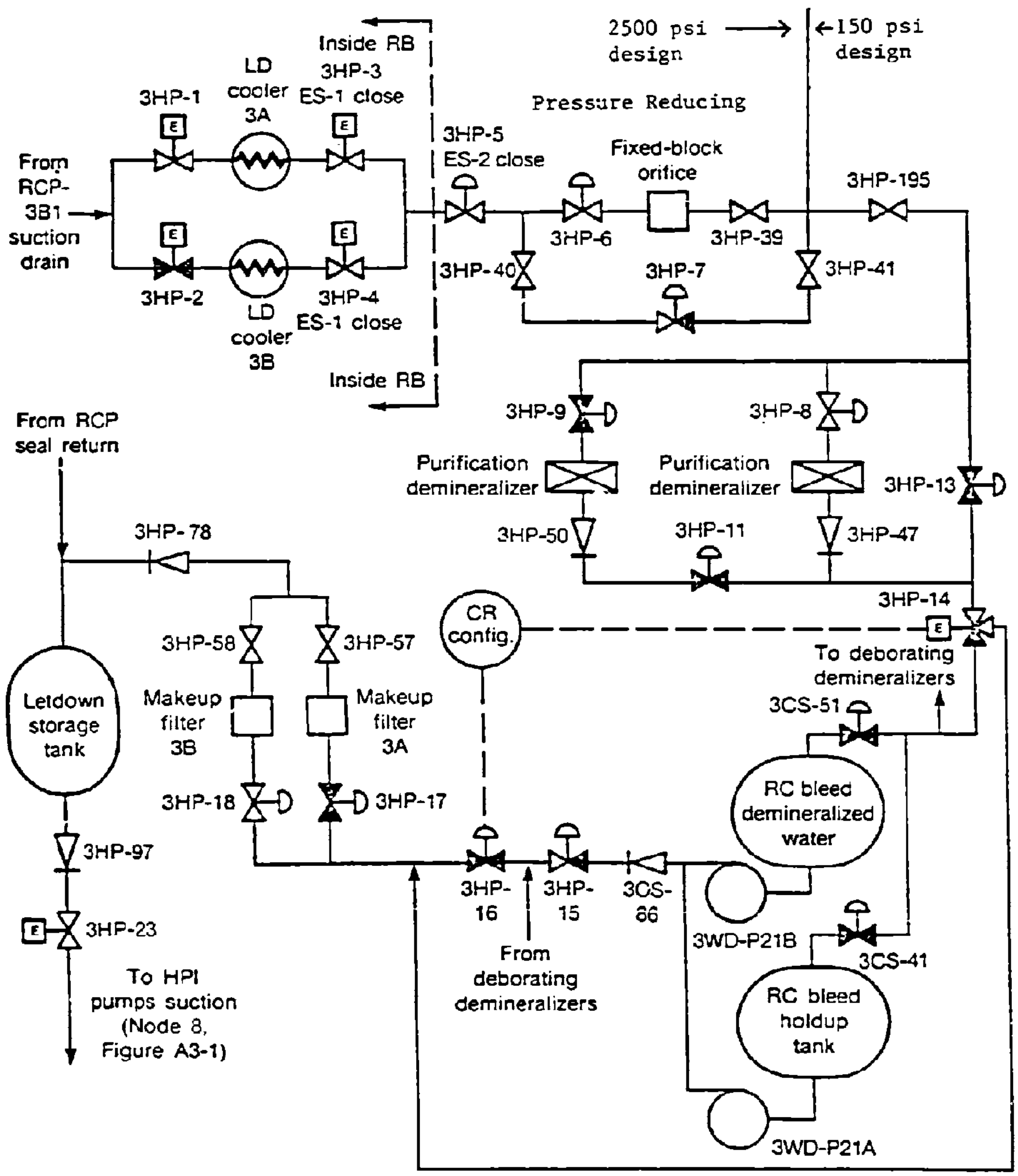
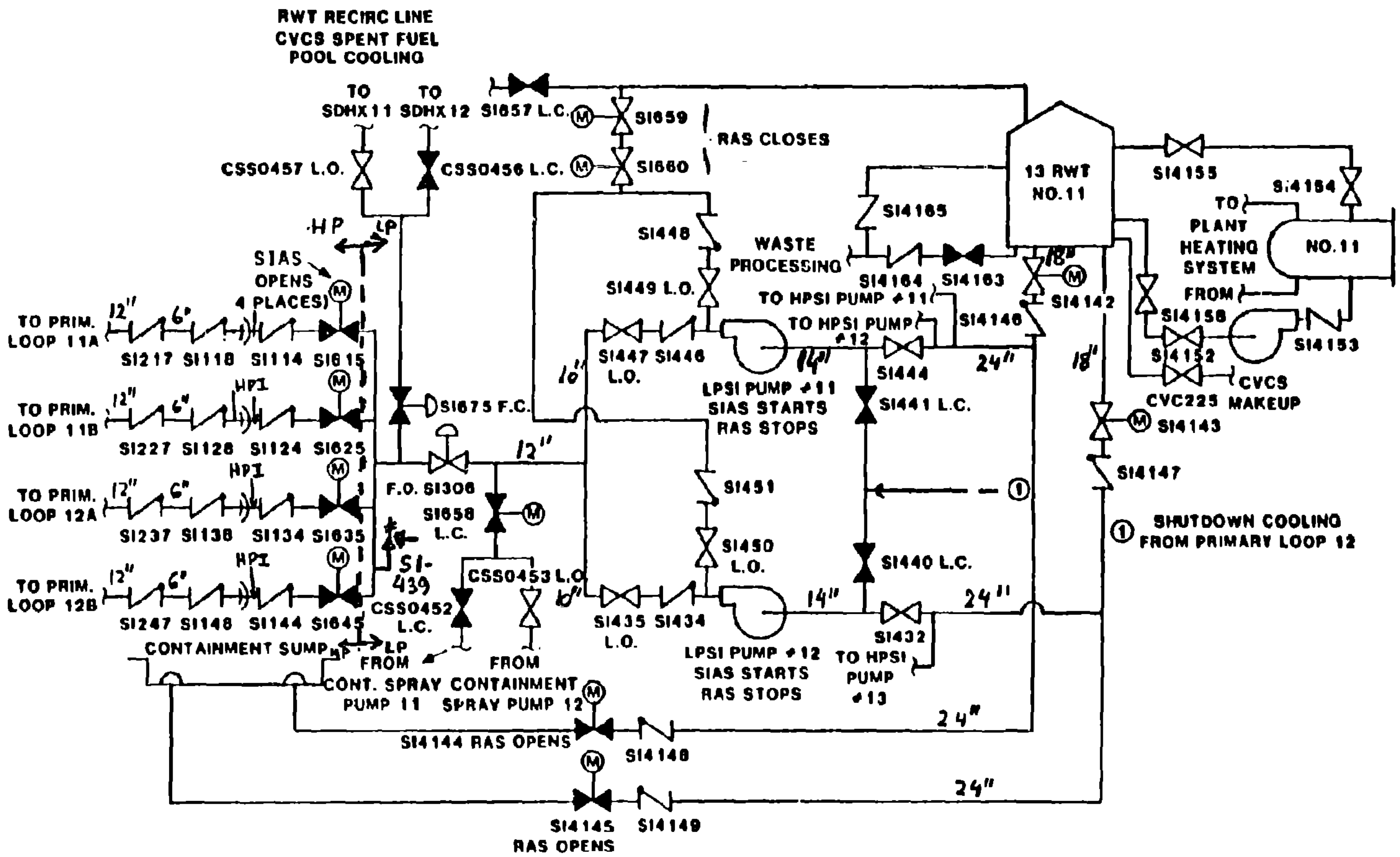
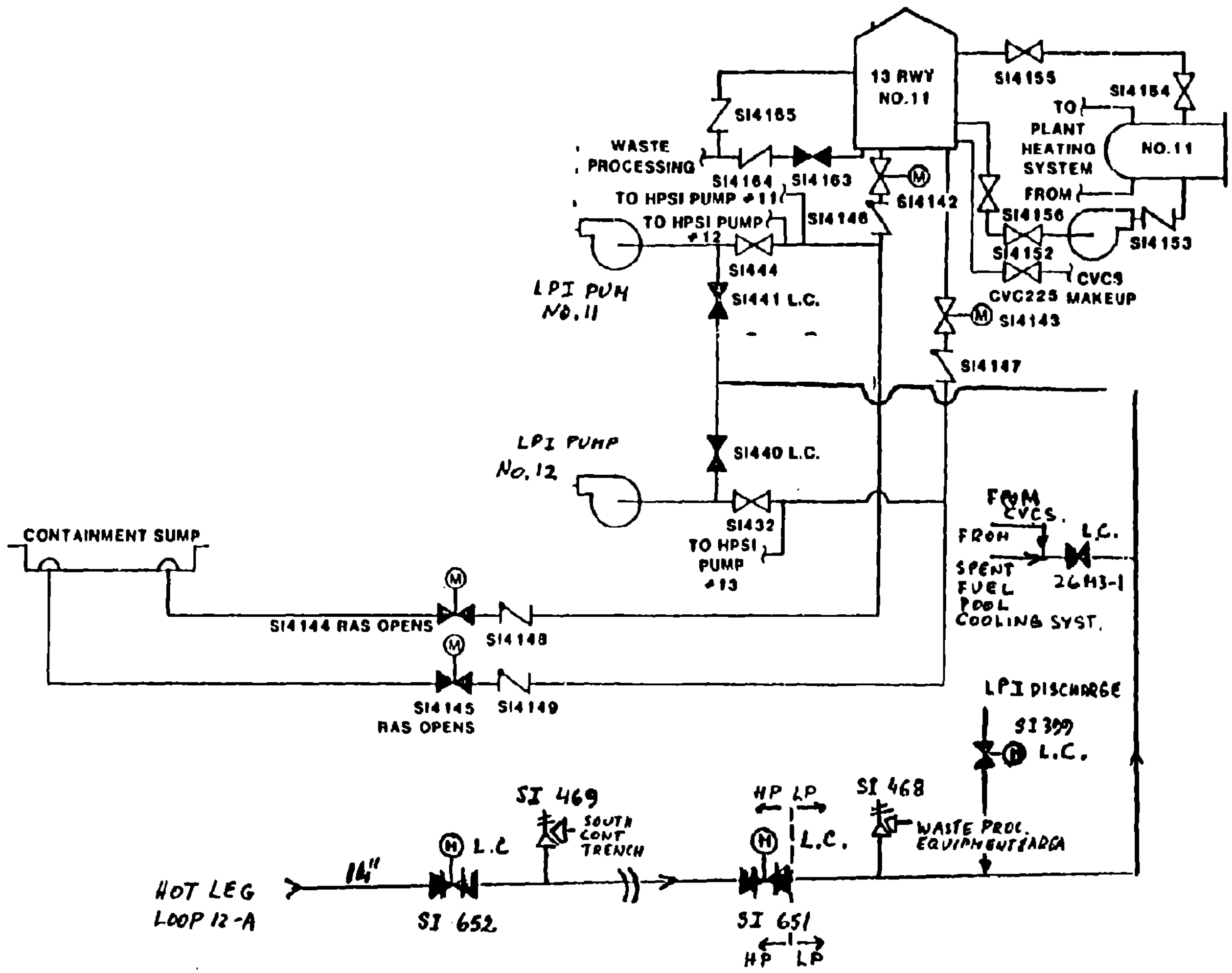


Figure 2.4.4 RCS letdown.



SIAS = Safety Injection Actuation Signal
RAS = Recirculation Actuation Signal
L.C. = Locked Closed
L.O. = Locked Open
FAI = Fails "as is"
HP = High Pressure
LP = Low Pressure

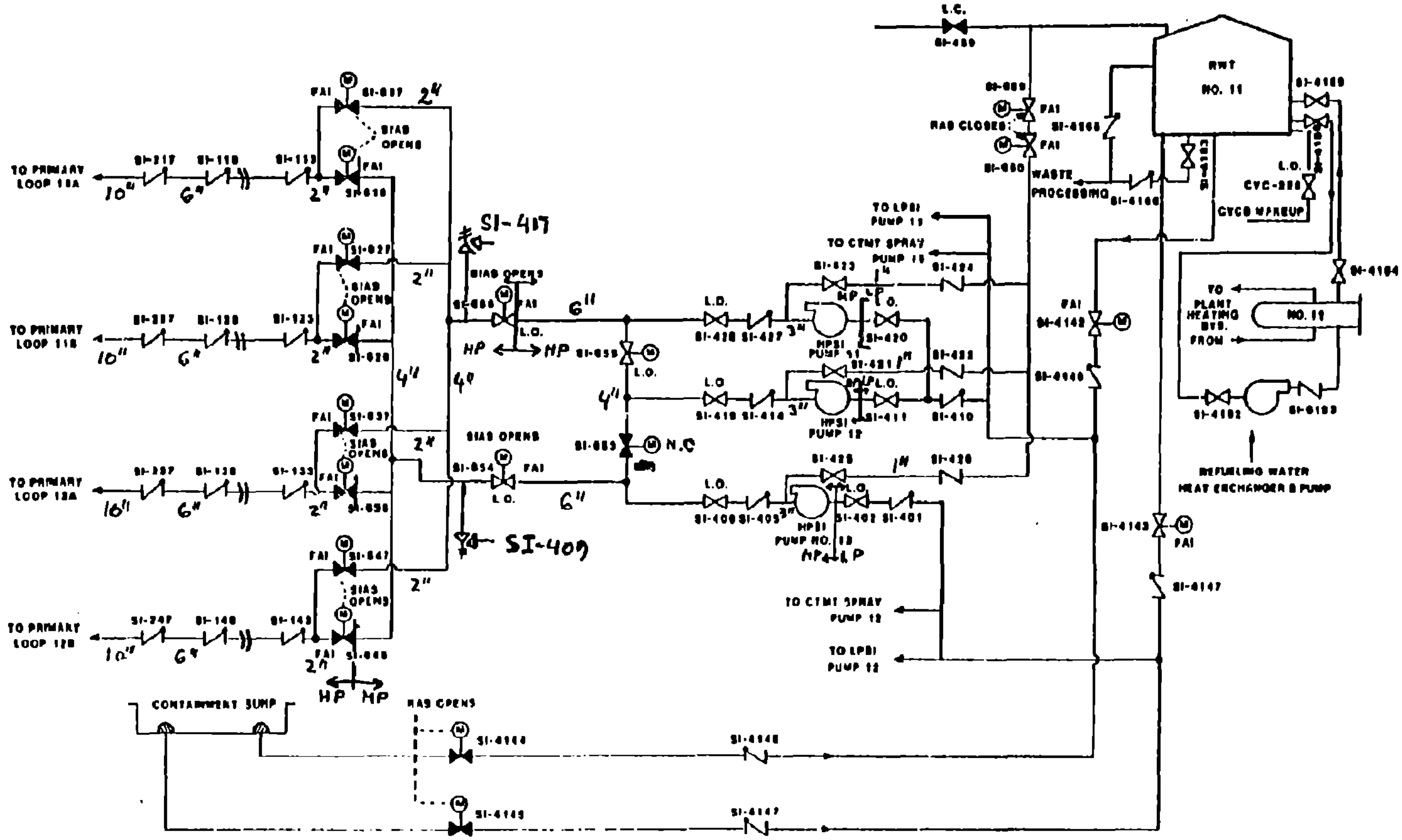
Figure 2.5.1 Low pressure injection lines, Calvert Cliffs 1.



RAS = Recirculation Actuation Signal
L.C. = Locked Closed

HP = High Pressure
LP = Low Pressure

Figure 2.5.2 Residual heat removal (Cold Shutdown Cooling System) suction line, Calvert Cliffs 1.

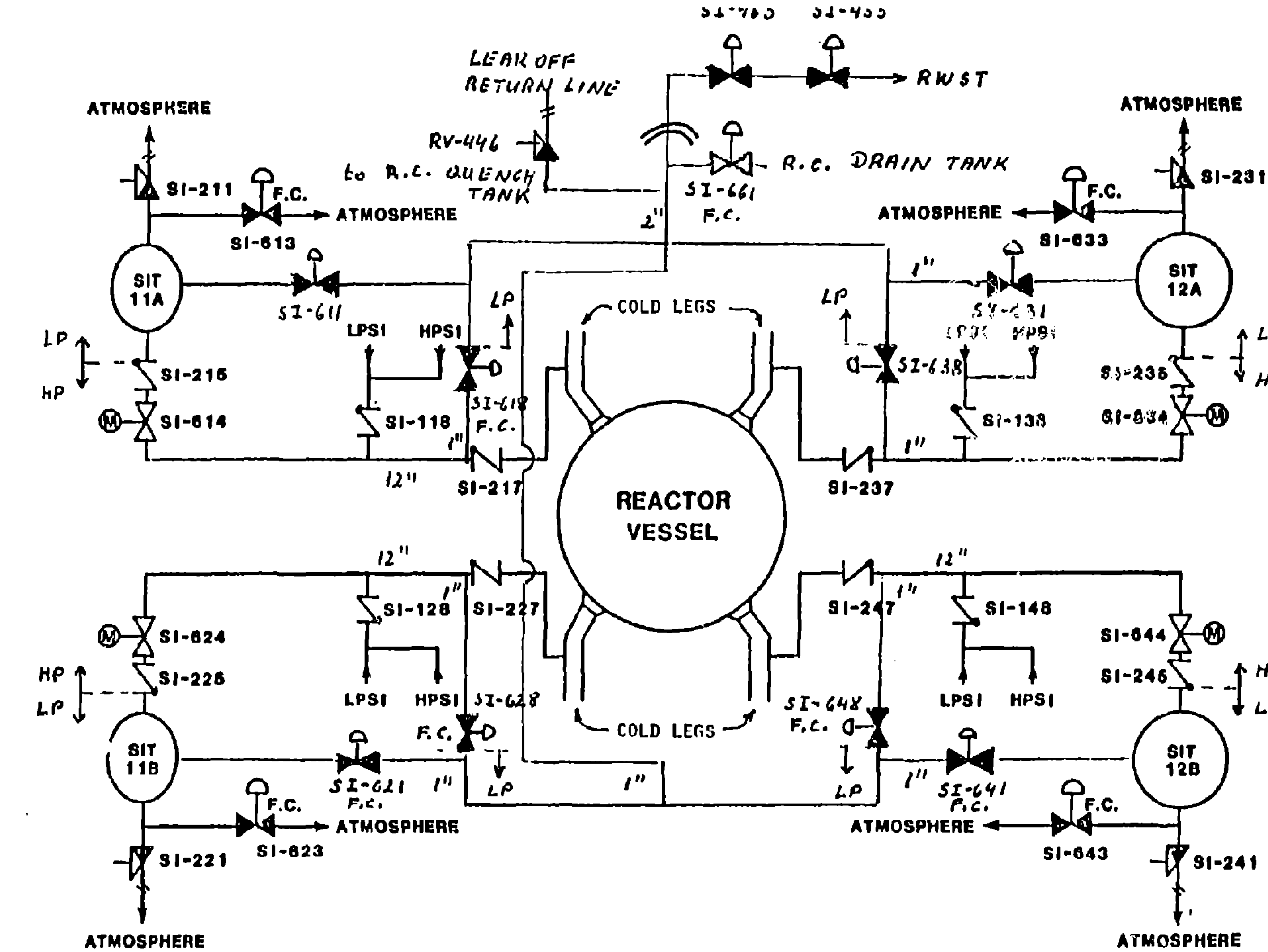


SIAS = Safety Injection Actuation Signal
RAS = Recirculation Actuation Signal
L.C. = Locked Closed

L.O. = Locked Open
HP = High Pressure
MP = Medium Pressure

LP = Low Pressure
FAI = Fails "as is"

Figure 2.5.3 High pressure injection lines, Calvert Cliffs 1.



HP = High Pressure   F.C. = Fails to Close   HPSI = HPI
LP = Low Pressure   LPSI = LPI

Figure 2.5.4 Core flooding tank (safety injecttion tanks) outlet lines, Calvert Cliffs l.

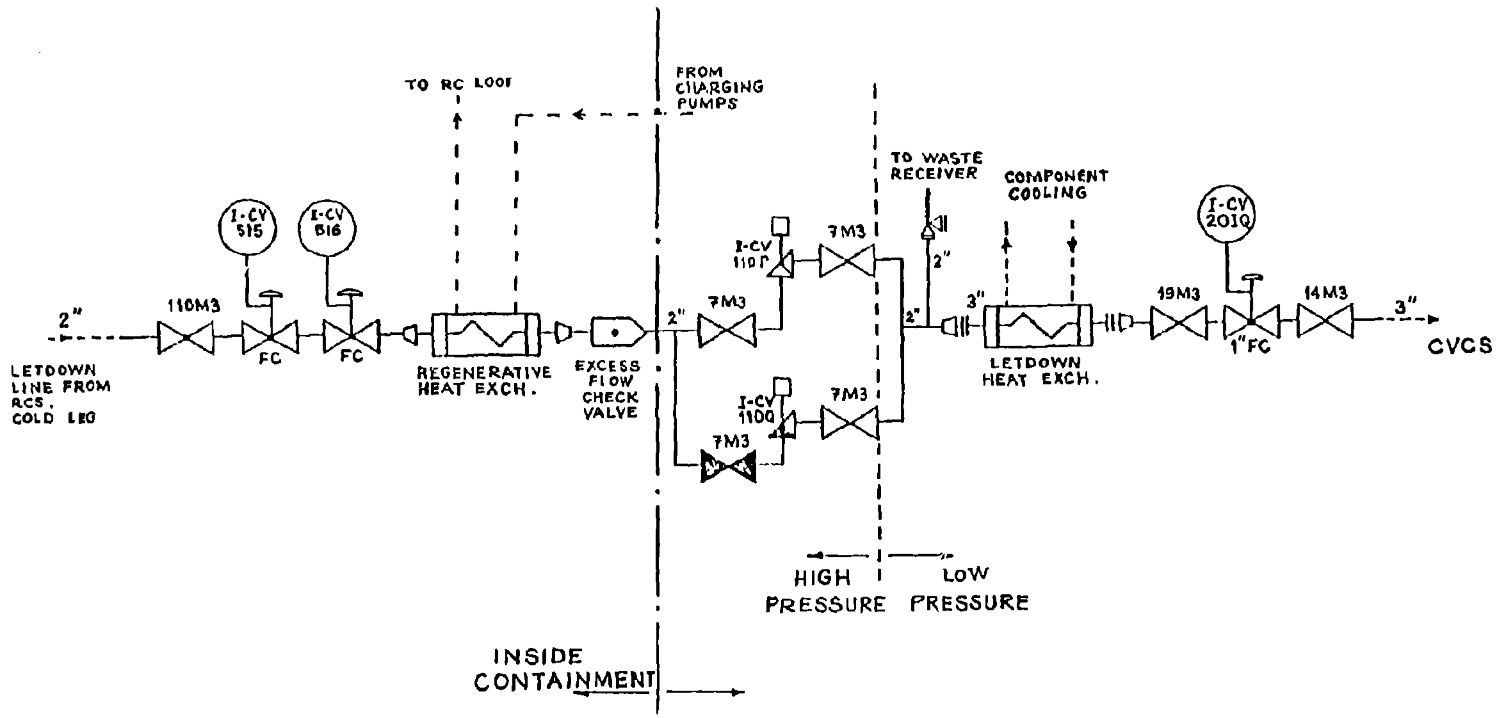


Figure 2.5.5 Letdown line, Calvert Cliffs-1.

Table 2.1
Characteristics of Selected PWRs

	Indian Point 3	Oconee 3	Calvert Cliffs 1
Reactor Vendor	Westinghouse	Babcock & Wilcox	Combustion Engineering
Design Power:			
(MWt)	3025	2568	2700
(MWe)	965	886	800
Architectural Engineer	WEDCO/United Engineers & Constructors	Bechtel Power Co. Duke Power Co.	Bechtel Power Co.
Commercial Operation	8/1976	12/1974	5/1975
Containment:			
Free Vol. (ft^3)	$2.8x10^6$	$1.9x10^6$	$2.0x10^6$
Design Pres. (psig)	47	59	65 (50)
Cavity Condition	Dry	Dry	Dry
Reactor Coolant System (RCS):			
Loops	4	2 Hot Legs 2 Parallel Cold Legs Per Loop	2 Hot Legs 2 Parallel Cold Legs Per Loop
Operating Pressure (psia)	2250	2185	2250
Low Pressure Injection System, Residual Heat Removal System (LPI/RHR):			
Pumps	2	2 (a third pump is available, it is normally valved out and is load shed)	2
Pump Location	Auxiliary Bldg.	Auxiliary Bldg.	Auxiliary Bldg.
Injection Location	Cold Legs, via Injection Lines Common With HPI, CFS	Vessel, via 2 Core Flooding Nozzles	Cold Legs, via Inlets Common With HPI, CFS
Recirculation, RHR HEXRs	2	2	2 (Part of Containment Spray System)
HEXR Location	Containment	Auxiliary Bldg.	Auxiliary Bldg.

Table 2.1 (Continued)

	Indian Point 3	Oconee 3	Calvert Cliffs 1
LPI Discharge Cross Connection	Yes	No	Yes
Containment Penetrations	2 (1 for recirculation)	2	4
LPI Injection	Upon RCS pressure below 450 psig	Upon RCS pressure below 500 psig	Upon RCS pressure below 600 psig
RHR Hot Leg Suction Line Containment Penetration	1	1	1
High Pressure Injection System (HPI):			
Pumps	3	3	3
Pump Location	Auxiliary Bldg.	Auxiliary Bldg.	Auxiliary Bldg.
Injection Location	Cold legs, via 4 separate and 4 common injection line with LPI, CSF. Also, 2 hot leg injection possibilities.	Cold Legs, via 4 injection line.	Cold Legs, via inlets common with LPI/CFS.
Containment Penetrations	2	2	4 (Those of LPI)
Actuation	Upon RCS Pressure of 1720 psig or containment pressure of 3 psig.	Upon RCS pressure of 1500 psig or containment pressure of 4 psig.	Upon RCS pressure below 1750 psig or containment pressure of 2.8 psig.
Core Flooding System (CFS):			
Tanks	4	2	4
Injection Location	Cold legs, via injection lines common with HPI/LPI.	2 Vessel nozzles common with LPI.	Cold legs, via inlets common with HPI/LPI.
Actuation	Upon RCS pressure below 650 psig.	Upon RCS pressure below 600 psig.	Upon RCS pressure below 200 psig.
Chemical and Volume Control System (CVCS, Charging Mode) Charging Pumps	3 (Of three cylinder positive displacement type)	3 (HPI pumps servicing also for the Coolant Makeup System)	3 (Of three cylinder positive displacement type)

Table 2.1 (Continued)

	Indian Point 3	Oconee 3	Calvert Cliffs 1
Maximum Makeup Flow Rate Independent of RCS Pressure	98 gpm	~100 gpm in CMS Mode	132 gpm
Containment Penetrations	2	2	2

Table 2.3.1
LPI (RHR) Injection Lines†
Indian Point 3

Number of Lines	4		
Line Size	6"		
Valve Number	838A,B,C,D	MOV899A,B	MOV746,747
Valve Location	I	I	I
Type	Check	MO Gate	MO Gate
Operator	—	AC	AC
Normal Position	Closed	Open	Open
Power Failure Position	—	Open	Open
Automatic Signals	—	Opened on SI Signal††	Opened on SI signal††
Normal Flow Direction	In	In	In
Surveillance Requirement	*	**	**
Relief Valves	733A,B set at LPI design pressure: 600 psig.		
Associated Pump Surveillance	Manually started monthly, flow tested at cold shutdown and refueling.		

†Information on check valves from the series 897 is given on Table 2.3.4.
††May be closed manually for isolation.
*Flow and leak tested at each RCS depressurization. Test for gross leakage at every refueling and midway between refuelings.
**Position verification weekly, stroke tested quarterly, flow tested (holding required position) at each shutdown and refueling.

Table 2.3.2
Residual Heat Removal Suction Line
Indian Point 3

Number of Lines	1		
Line Size	14"		
Valve Number	MOV-731	MOV-730	732
Valve Location	I	I	O
Type	MO Gate (special design)	MO Gate (special design)	Manual Block (double disk)
Operator	AC	AC	Manual, Locked Closed
Normal Position	Closed	Closed	Closed
Power Failure Position	Closed	Closed	—
Automatic Signals	RC pressure interlock†	RC pressure interlock†	—
Normal Flow Direction	Out	Out	Out
Surveillance Requirement	*	*	**
Relief Valves	1896 Setpoint: 600 psig.		
Associated Pump Surveillance	Manually started monthly, flow tested at cold shutdown and refueling.		

†RHR operation is not indicated.
*Disk integrity (leak) and stroke tests at each cold shutdown. Automatic isolation and interlock action test at each refueling. If not done during 18 months, the check will be performed during the next cold shutdown.
**Operability test through one complete cycle of full travel at each refueling.

Table 2.3.3
High Pressure Injection Lines
A. Branch Lines of Line 56†
Indian Point 3

Number of Lines	5			
Line Size	2"			
Valve Number	857A,B,G,H, Q,R,S,T,U,W	MOV-856J,H	MOV-856A,K	MOV-856B
Valve Location	I	I	I	I
Type	Check	MO Gate	MO Gate	MO Gate
Operator	---	AC	AC#	AC†††
Normal Position	Closed	Open	Open	Closed
Power Failure Position	---	Open	Open	Closed
Automatic Signals	---	Opened on SI signal	---	---
Normal Flow Direction	In	In	In	In
Surveillance Requirement	*	**	††	***
Relief Valves	RV-855, set at HPI design pressure, 1500 psig.			
Associated Pump Surveillance	HPI pumps started and run monthly, HPI system test at each refueling.			

†Information on check valves from the series 897 is given in Table 2.3.4
††Verify open quarterly.
†††Deenergized.
*Full stroke tested at each cold shutdown (RCS is drained). Leak tested at every refueling.
**Verify open quarterly, stroke at each cold shutdown.
***Verify closed quarterly, stroke at each cold shutdown.
#Motor operator disconnected.

Table 2.3.3 (Continued)
High Pressure Injection Lines
B. Branch Lines of Line 16
Indian Point 3

Number of Lines	5			
Line Size	To cold legs: 1.5", to hot leg: 2".			
Valve Number	857C,D,E,F,J K,L,M,N,P	MOV-856C,E	MOV-856D,F	MOV-856G
Valve Location	I	I	I	I
Type	Check	MO Gate	MO Gate	MO Gate
Operator	---	AC	AC#	AC†††
Normal Position	Closed	Open	Open	Closed
Power Failure Position	---	Open	Open	Closed
Automatic Signals	---	Opened on SI signal	---	---
Normal Flow Direction	In	In	In	In
Surveillance Requirement	*	**	††	***
Relief Valves	See Table A.			
Associated Pump Surveillance	See Table A.			

*Partial stroke tested at each cold shutdown (RCS is drained). Leak tested at every refueling.
**Verify open quarterly, stroke at each cold shutdown.
***Verify closed quarterly, stroke at each cold shutdown.
††Verify open quarterly.
†††Deenergized.
#Motor operator disconnected.

Table 2.3.4
Core Flooding Tank (Accumulator) Outlet Lines
Indian Point 3

Number of Lines	4		
Line Size	10"		
Valve Number	897A,B,C,D	895A,B,C,D	MOV-894A,B,C,D
Valve Location	I	I	I
Type	Check	Check	MO Gate
Operator	---	---	AC
Normal Position	Closed	Closed	Open
Power Failure Position	---	---	Open
Automatic Signals	---	---	Open safeguard actuation signal
Normal Flow Direction	In	In	In
Surveillance Requirement	*	*	**
Relief Valves	892A,B,C,D		

*Flow and leak tested at each RCS depressurization. Test for gross leakage at every refueling and midway between refuelings.
**Cycled and verify open every RCS depressurization. Tested open every refueling.

Table 2.3.5
Letdown Line
Indian Point 3

Number of Lines	1			
Line Size	2"			
Valve Number	LCV459	LCV460	200A,B,C	201,202
Valve Location	I	I	I	O
Type	Globe	Gate	Globe	Globe/ Solenoid
Operator	118V ac air	118V ac air	Air	118V ac
Normal Position	Open	Open	B open, A and C closed	Open
Power Failure Position	Closed	Closed	Closed	Closed
Automatic Signals	Close on low pressurizer level		---	*
Normal Flow Direction	Out	Out	Out	Out
Surveillance Requirement	Not yet identified			
Relief Valves	RV 203, setpoint at 600 psig.			

*Trip to close on containment isolation signal, phase A.

Table 2.3.6
Excess Letdown Line
Indian Point 3

Number of Lines	1	
Line Size	1"	
Valve Number	213A,B	HCV123
Valve Location	I	I
Type	Globe	Globe
Operator	Air 118V ac	Analog instrument, 118V ac
Normal Position	Closed	Open
Power Failure Position	Closed	Closed
Automatic Signals	—	—
Normal Flow Direction	Out	Out
Surveillance Requirement	Not yet identified	
Relief Valves	—	

Table 2.4.1
LPI Injection Lines
Oconee 3

Number of Lines	2		
Line Size	10"		
Valve Number	CF-12,14	LP-47,48	LP-18,17
Valve Location	I	I	O
Type	Check	Check	MOV
Normal Position	Closed	Closed	Closed
Power Failure Position	---	---	Closed
Automatic Signals	---	---	Low RCS Pressure High RB Pressure
Normal Flow Direction	In	In	In
Surveillance Requirement	*	*	**
Relief Valves Setpoint: 505 psia	LP-36, LP-37	***	

*Leak tested after a cold shutdown, at least once every nine months.
**Stroke tested quarterly, at cold shutdown only.
***Flow tested at each cold shutdown.

Table 2.4.2
Decay Heat Removal Suction Line
Oconee 3

Number of Lines	1	
Line Size	12"	
Valve Number	LP-1,2	LP-3
Valve Location	I	O
Type	MOV	MOV
Normal Position	Closed	Closed
Power Failure Position	Closed	Closed
Automatic Signals	RC pressure interlock	---
Normal Flow Direction	Out	Out
Surveillance Requirement	Stroke Test*	Stroke Test**
Relief Valves Setpoint: 388 psia	LP-25, LP-26	

*Once per cold shutdown.
**Once every three months.

Table 2.4.3
Core Flood Tank Outlet Line
Oconee 3

Number of Lines	2		
Line Size	14"		
Valve Number	CF-11,13	CF-12,14	CF-1,2
Valve Location	I	I	I
Type	Check	Check	MOV
Normal Position	Closed	Closed	Open
Power Failure Position	Closed	Closed	Open
Automatic Signals	—	—	—
Normal Flow Direction	—	—	—
Surveillance Requirement	*	*	**

*Leak test at cold shutdown.
**Stroke test simultaneously with check valve leak test.

Table 2.4.4
Auxiliary Spray Line
Oconee 3

Number of Lines	2	
Line Size	1 1/2"	
Valve Number	LP-45,62,63	LP-46
Valve Location	I	I
Type	Manual Gate	Check
Normal Position	Closed	Closed
Power Failure Position	—	—
Automatic Signals	—	—
Normal Flow Direction	In	In
Surveillance Requirement	*	*

*Not identified.

Table 2.4.5
Letdown Line
Oconee 3

Number of Lines	1	
Line Size	2 1/2"	
Valve Number	HP-3,4*	HP-5*
Valve Location	I	O
Type	MOV	AOV
Normal Position	Open	Open
Power Failure Position	As is	Open
Automatic Signals	SI	SI
Normal Flow Direction	Out	Out
Surveillance Requirement	**	**

*These are containment isolation valves. The pressure boundary is the pressure reducing flow orifice and the pipe schedule changes at valve HP-39.
**Local leak rate test during each shutdown.

Table 2.5.1
Low Pressure Injection Lines†
Calvert Cliffs 1

Number of Lines	4		
Line Size	6"		
Valve Number	SI-118,128, 138,148	SI-114,124, 134,144	SI-615,625, 635,645
Valve Location	I	O	O
Type	Check***	Check	MO Gate
Normal Position	Closed	Closed	Closed
Power Failure Position	---	---	As it is
Automatic Signals	---	---	Open on SI
Normal Flow Direction	In	In	In
Surveillance Requirement	**	*†	*
Relief Valves	SI-439, setpoint is 500 psig.		
Associated Pump Surveillance	Manually started monthly, flow tested at cold shutdown and refueling.		

†Information on check valves SI-217, 227, 237, 247 is given in Table 2.5.4.
*Verifying closed position at least once per month after cycling upon SI signal. Quarterly stroke (operability) test.
**Full flow and leak test during refueling outages (cold shutdown) (inboard checks).
*†Full flow test during refueling outages (cold shutdown), leak test quarterly during plant operation (outboard checks).
***These check valves are of "weighted closed" types.

Table 2.5.2
Residual Heat Removal (Shutdown Cooling System) Suction Line
Calvert Cliffs 1

Number of Lines	1	
Line Size	14"	
Valve Number	SI-652	SI-651
Valve Location	I	O
Type	MO Gate* (Special design)	MO Gate (Special design)
Normal Position	Closed	Closed
Power Failure Position	Closed	Closed
Automatic Signals	RCS pressure interlock†	RCS pressure interlock†
Normal Flow Direction	Out	Out
Surveillance Requirement	**	**
Relief Valves	SI-469, setpoint: 2485 psig, SI-468, setpoint: 315 psig	
Associated Pump Surveillance	See Table 2.5.1	

†RHR operation is not indicated.
*Continuous leak surveillance. Disk integrity (leak) and stroke tests at each refueling.
**Disk integrity (leak) and stroke tests at each refueling.

Table 2.5.3
High Pressure Injection Lines†
Calvert Cliffs 1

Number of Lines	4 (per train)		
Line Size	2"		
Valve Number	SI-113,123, 133,143	SI-616,626, 636,646 (main header	SI-617,627,637, 647 (auxiliary header)
Valve Location	O	O	O
Type	Check	MO Gate	MO Gate
Operator	—	AC	AC
Normal Position	Closed	Closed	Closed
Power Failure Position	---	Fails as is	Fails as is
Automatic Signals	---	Open on SI	Open on SI
Normal Flow Direction	In	In	In
Surveillance Requirement	**	*	*
Relief Valves	SI-409, SI-417, setpoints @ 1485 and 2505 psig, respectively		
Associated Pump Surveillance	Manually started monthly, flow teted at cold shutdown and refueling.		

†Information on check valves: SI-217, etc. and SI-118, etc. is given in Table 2.5.4 and 2.5.1, respectively.

*Continuous position surveillance (alarm panel). Verifying closed position at least once per month after cycling upon SI signal. Quarterly stroke (operability) test.

**Leak test quarterly during plant operation (outboard checks). Full flow test during refueling outages (cold shutdown).

Table 2.5.4
Core Flooding Tank ("SIT") Outlet Lines
Calvert Cliffs 1

Number of Lines	4		
Line Size	12"		
Valve Number	SI-217,227, 237,247	SI-614,624, 634,644	SI-215,225,235 245
Valve Location	I	I	I
Type	Check	MO Gate (Globe)	Check
Operator	—	AC†	—
Normal Position	Closed	Open	Closed
Power Failure Position	—	Open	—
Automatic Signals	—	—	—
Normal Flow Direction	In	In	In
Surveillance Requirement	**	*	*†
Relief Valves	SI-211,221,231,241 setpoint: 250 psig, this is also the design pressure of the SITs (Size: 1").		

†Locked open, deenergized.
*Valve position in every 12 hours. Verifying open position within four hours prior increasing RCS pressure above 1750 psig.
**Valve seat leakage is monitored continuously. Full flow test during refueling outages (cold shutdown).
*†Full flow and reverse leakage test during refueling outages (cold shutdown).

Table 2.5.5
Letdown Line
Calvert Cliffs 1

Number of Lines	1			
Line Size	2"			
Valve Number	110M3	I-CV-515	I-CV-516	
Valve Location	I	I	I	I
Type	Gate	Gate	Gate	Excess Flow
Operator	Manual	Air/dc	Air/dc	Check
Normal Position	Open	Open	Open	Open
Power Failure Position	—	Closed	Closed	—
Automatic Signals	Pressure signals from the Auxiliary Building.			
Normal Flow Direction	Out	Out	Out	Out
Surveillance Requirement	Continuous			

3. SURVEY OF OPERATING EXPERIENCE FOR ISL PRECURSOR EVENTS AT PWRs

3.1 Survey of Operational Events and Causes of Failures

Operating experiences regarding pressure boundary interfaces are embedded in various extensive data bases, which include events dating back to the 1970's. BNL has performed a search for ISL precursor events at PWRs by using the RECON[1] data base and the NPE operating events listing.[2] The available information mostly consists of LER submittals and, in the NPE, additional component engineering and failure reports are listed. The data bases have been systematically searched for isolation boundary component failures in systems connected to the RCS. All operational events involving pressure boundary isolation valves have been collected and reviewed.

Even though the actual configuration may vary greatly between systems, plants, and vendors, the isolation boundary generally consist of a number of check valves and/or motor-operated isolation valves, which may normally be closed or open depending on the particular design.

Based on the above, the failure events can be classified as (a) failures involving isolation check valves, (b) motor-operated valve failures, and (c) procedural or management problems.

Both the check valves and the motor-operated valves may fail to perform their intended function in a variety of ways. However, the review of the operating events has indicated that there are one or two dominant failure modes for each class of isolation valves.

a. Check Valves - Leakage across the seat interface is the most typical failure mode for the check valves. A less frequent class of events involve operational failures of the check valves. These failures prevent the check valves from reseating after opening.

b. Motor-Operated Valves - The improper operation of the electrical control circuitry and various problems with the limit and torque switches seem to be the principle causes of failures for motor-operated valves.

In the following sections the collected operating events are discussed. A more detailed description of some of the events are given in Appendix A.3.

3.1.1 Events Involving Isolation Check Valves

Reported operating events involving pressure boundary isolation check valve failures were classified according to the two main types of failure modes: leak and demand related operational failure modes. The events are listed in Tables 3.1 and 3.2, respectively. Special attention was given to the leakage failure events. For, it was recognized at the start of the present study that in spite of the fact that various nuclear industry data sources provide failure rates for the leak failure mode, the available data are not suitable for ISL analysis. The available data are related to a conglomerate of check valves of different type, size and make, which are built into various reactor systems. Also, the leak and reseat failures are typically treated together. However, for the ISL analysis, the knowledge of that specific failure frequency which correctly describes the leak failures of

check valves located in the RCS/ECCS interface is required. It was also recognized that small or large leakage flow rates will result in markedly different accident developments. Therefore, it was clear that specific information was needed about the frequency of leak failures exceeding certain leakage flows through the valves and that that information had to be extracted from available data.

In order to obtain as accurate data sample as possible, the event selection has been cross-checked by comparing the events found separately in the RECON and the NPE data bases. An additional comparison of the resultant event list was made with a similar list of events selected in an independent search conducted at Pickard, Lowe and Garrick, Inc. for the Seabrook Station Risk Management and Emergency Planning Study (PLG-0432).[3]

The events of Table 3.1 are presented in a format that further serves the leak failure frequency analysis (see Section Appendix A.1). The table contains the NPE number for facilitating better event identification, the name of the specific ECCS system involved (Accumulator, LPI, HPI) and direct or indirect information about the leak rate. The latter involves such evidences as: the rate of boron concentration changes and rate of pressure reduction in the accumulators. The table also contains the estimated leak rates. The approach used to estimate the leak rate was essentially similar to that of Ref.3: the utilization of the direct or indirect flow rate information. If there were no such information available, the similarity to other occurrences for which the leak rates were known was applied.

An inspection of Table 3.1 shows that the majority of failure events are failures of the check valves in the accumulator outlet lines. This apparent bias in the occurrence frequency might be due to the continuous monitoring of the accumulators, or it might reflect a particularly severe environment acting on the valves.

It also can be seen that an accumulator cannot easily be overpressurized by small back leakages from the RCS, since it is a relatively large reservoir of water capable of relieving pressure through relief valves. In addition, increasing water level in the tank (and dilution of boron concentration) can easily be detected allowing ample time for the operator to take the appropriate action.

The remaining events occurred rather evenly between the LPI and HPI systems.

The operational failure events given in Table 3.2 also represent a fairly accurate set of data for a new estimate of the operational failure probability of check valves in the RCS/ECCS boundary. The events reveal that the environmental effects of boric acid (e.g., boron solidification) and other corrosion and aging processes are deteriorating the proper operation of the check valves.

In both of the tables there are events involving valve disk separation or stuck open failures yielding a total loss of the pressure isolating function of that valve. It is reassuring, however, that no real check valve rupture was reported and none of the events led to actual overpressurization, because

of additional pressure boundary barriers, i.e., other check valves or closed motor-operated isolation valves prevented it.

It is important to note that a number of the operating events were discovered during interfacing system LOCA testing, which is designed to detect any deterioration of the pressure boundary isolation function.

In general, the multiple pressure boundary concept has functioned as designed, especially against single failure of the isolation boundary.

3.1.2 Events Involving Motor-Operated Isolation Valves

Reported operating events involving failures of motor-operated isolation vales are shown in Table 3.3. Only the fail-to-close failure mode has been included in this tabulation, since this mode would make an interfacing LOCA unisolable. There are numerous designs where the primary pressure boundary is a normally closed motor-operated valve. The nonmechanical failure of these valves (fail-to-open) would maintain the integrity of the pressure boundary and is therefore not considered further. Most of these events have occurred in the HPI systems which are generally designed to have a number of normally open isolation valves. The major causes of failure involved either some component failure in the electrical control circuitry or the improper operation of the motor operator torque or limit switches.

There are only three events (marked with asterisk) involving the "MOV internal leakage" failure mode. It is interesting that all three occurred in MOVs in RHR suction lines. Mechanical failure does not seem to be a major problem.

3.1.3 Events Involving Procedural or Other Problems

The pressure boundary isolation function can be lost through mechanical and/or electrical failure of the isolation components. In addition, human errors or procedural management problems can also lead to the deterioration or even loss of integrity of the pressure boundary. All events listed in Table 3.4 involve some form of human error or procedural deficiency, which may have caused or could have led to an ISL. The total number of events in Table 3.4 is so small that no particular trend can be observed from the data.

3.2 References

1. DOE/RECON, Nuclear Safety Information Center (NSIC), File 8, 1963 to present.

2. Nuclear Power Experience, NPE, Published by the S.M. Stoller Corp.

3. "Seabrook Station Probabilistic Assessment," PLG-0300, December 1983.

Table 3.1
Summary of Operating Events, Emergency Core Cooling System, Isolation Check Valves, Leakage Failure Mode

Reference (NPE #)	Plant	Date	ECCS System	Event Description	Number of Check Valves Failed	Estimated Leak Rate (gpm)
VII.A.13	Palisades	5/72	ACC	Leakage into SI tank. The internals of a check valve on the outlet of an SI tank was incorrectly assembled.	1	$\gamma<5$
VII.A.25	Main Yankee	12/72	ACC	Leakage into SI tank. A small piece of weld slag had lodged under the seal of the outlet check valve allowing back leakage. Dilution: 1700 ppm (limit is 1720 ppm).	1	$\gamma<5$
VII.A.32	Turkey Point	5/73	HPI	One of the three check valves in the SI lines developed a leakage of 1/3 gpm. Two other check valves showed only slight leakage. Failure of soft seats.	3	$\gamma\leq.33$
VII.A.63	Ginna	9/74	ACC	Leakage of a check valve caused boron dilution in ACC. "A" (from 2250 ppm to 1617 ppm).	1	$\gamma<20$
VIII.A.85	Surry 1	8/75	ACC	Check valve did not seat. ACC ("IC") level increased. Leakage rate: ≈6 gpm.	1	$\gamma<10$
VII.A.126	Zion 2	10/75	ACC	Wrong size gasket installed in the check valve for ACC. "A". Leak rate: ≈.25 gpm.	1	$\gamma\leq.25$
VII.A.105	Robinson 2	1/76	ACC	Accumulator ("B") inleakage through leaking outlet check valve.	1	$\gamma<20$
V.A.122	Zion 1	6/76	ACC	Inleakage to ACC. "1D" from RCS.	2	$\gamma<20$
VII.A.114	Surry 1	7/76	ACC	Two check valves in series (1-SI-128, 130) leaked causing boron dilution in ACC. "B".	2	$\gamma<10$
VII.A.120	Surry 2	8/76	ACC	Boron dilution (from 1950 ppm to 1893) in SI ACC. "C" caused by leaking check valves (2-SI-145, 147).	2	$\gamma<10$
VII.A.225	Millstone 2	4/77	ACC	Inleakage of RC through outlet check valves to SI tank "4". Low boron concentration. Five occurrences in 1977.	2x6	$\gamma<20$
VIII.A.182	Calvert Cliffs 2	9/78	ACC	Outlet check valves for SI tanks 21B and 22B leaked. Boron concentration reduction from 1724 and 1731 ppm to 1652 and 1594 ppm in one month period.	4	$\gamma<10$ $\gamma<10$

Table 3.1 (Continued)

Reference (NPE #)	Plant	Date	ECCS System	Event Description	Number of Check Valves Failed	Estimated Leak Rate (gpm)
VII.A.262	Crystal River 3	7/80	ACC	Check valve CFV-79 to core flood tank failed. The isolation valve to the N_2 system was open for N_2 mixing. ≈500 gallon liquid entered the N_2 system and ≈20 gallons was released. The corresponding activity released estimated as 1.07 mCi.	1+1	$100<\gamma<200$
VII.A.273 IE Info. Notice 80-41	Davis Besse 1	10/80	ACC	RHR system isolation check valve CF-30 leaked back excessively. Valve disk and arm had separated from the valve body. Bolts and locking mechanism were missing. Core flood tank overpressurized.	2	$50<\gamma<100$
VII.A.291	Surry 2	1/81	ACC	Accumulator ("C") boron diluted. Check valve (1-SI-144) leaked. Flushing system improperly set up, resulting in charging system pressure to exist on the downstream side of the check valve.	1	$\gamma<10$
VII.A.301	Palisades	3/81	ACC	Leakage of RC into the SI tank (T-823).	2	$\gamma<5$
VII.A.306	McGuire 1	4/81	ACC	Accumulator "A" outlet check valves IN-159 and IN-160 were leaking. RCS pressure: 1800 psig. Acc. pressure: 425 psig. Water level above alarm setpoint.	2	$\gamma<10$
VII.A.307	McGuire 1	4/81	ACC	Similar events with Accs. "C" and "D".	2x2	$\gamma<10$ $\gamma<10$
VII.A.343	Point Beach 1	10/81	LPI	RCS/LPI isolation check valve (1-853C) leaks in excess of acceptance criteria (>6 gpm).	1	$\gamma<10$
VII.A.384	Calvert Cliffs 1 & 2	7/82	ACC	Acc. outlet check valve at Unit 1 leaked due to deterioration of the disk sealing o-ring. The o-ring material has been changed on all check valves of Unit 1 and 2 1/2 SI-215, 225, 235, and 245.	2	$\gamma\leq200$
VII.A.403	Surry 2	9/82	ACC	Acc. outlet check valve (2-SI-144) leaked RCS water into tank "C" during a pipe flush resulting in low boron concentration.	1	$\gamma<20$
VII.A.396	Palisades	9-12/82	ACC	Minor leakage into SI tank (compounded by level indication failure) via check valve leakages.	2	$\gamma<5$

Table 3.1 (Continued)

Reference (NPE #)	Plant	Date	ECCS System	Event Description	Number of Check Valves Failed	Estimated Leak Rate (gpm)
VII.A.407	McGuire 1	5/83	ACC	RCS water inleakage through outlet check valves 1N-170 and 1N-171, resulting in low boron concentration in CLA "B".	2	$20<\gamma<50$
VII.A.437	Farley 2	9/83	LPI/ HPI	SI check valve to loop 3 cold leg was excessively leaking, incomplete contact between the valve disk and seat.	1	$50<\gamma<100$
LER 84-001	Oconee 1	3/84	ACC	Accumulator ("A") inleakage through leaking valves. Administrative deficiency, no management control over a known problem (since 8/83).	2	$\gamma<5$
V.F.0043 LER 84-012	Palisades	7/84	ACC	Accumulator inleakage through leaking check valves CK-3146 and CK-3116.	2	$\gamma<5$
VII.A.452	St. Lucie 2	12/84	ACC	Inleakage to SI tank. Seal plate cocked, valve seat compensating joint ball galled.	2	$20<\gamma<50$
VII.A.456	Calvert Cliffs 1 & 2	1/85	ACC	Inleakage to safety injection tanks through check valve, o-ring material degradation (Unit 1 = 1.6 gpm, Unit 2 = 27.2 gpm).	2	$\gamma<5$ $20<\gamma<50$
VII.A.457	McGuire 1	4/85	ACC	Low accumulator boron concentration.	2	$\gamma<5$
LER 85-007	Palisades	6/85	ACC	Inleakage from the RCS. Low level boron concentration.	2	$\gamma<5$
VII.A.474	Palisades	11/85	ACC	Accumulator (SIT-82D) inleakage from RCS Boron dilution (see Note 1).	2	$\gamma<5$

Note 1: The Palisades unit has a chronic accumulator inleakage problem.

Table 3.2
Summary of Operating Events, Emergency Core Cooling System, Isolation Check Valves, "Failure to Operate on Demand" Failure Mode

Reference (NPE #)	Plant	Date	ECCS System	Event Description	Number of Check Valves Failed
VII.A.175	San Onofre 1	5/78	LPI	Tilting disk check valve failed to close with gravity. It was installed in a vertical rather than a horizontal pipeline.	1
VII.A.270	Sequoyah 1	9/80	HPI	SI check valve 63-635 was found to be stuck open. It was caused by interference between the disk nut lockwire tack weld and the valve body.	1
VII.A.285	Salem 1	12/80	HPI	SI check valve failed to close during a test. It is an interface between RCS hot leg and SI pumps. Valve was found to be locked open due to boron solidification during the last refueling.	1
VII.A.294	Oconee 1	2/81	LPI	Reactor vessel LPI loop "B" isolation valve (GCF-12) leaked excessively during LOCA leak test. The valve disk had become frozen at the pivot in a cocked position. Buildup of deposit in the gap between the hinge and disc knob caused the freezing.	1
VII.A.302	Oconee 3	3/81	LPI	Similar to event at Unit 1 (valve involved is 3 CF-13).	1
VII.A.310	McGuire 1	5/81	ACC	Leak test damaged acc. check valves - seal type changed.	2
VII.A.311	McGuire 1	5/81	ACC	Acc. check valves failed.	2
VII.A.315	Point Beach 1	7/81	LPI	RCS/LPI isolation check valves 1-853 C and D were found to be stuck in the full open position. High leakage rate.	2
VII.A.392	ANO-2	10/82	HPI	SI isolation check valves 2 SI-13C and 2 SI-13B stuck in the open position during test requested by IE Notice 81-30. Disk stud protruded above nut, disk misaligned.	2

Table 3.3
Summary of Operating Events
Motor-Operated Isolation Valves

Plant	Date	System Involved	Description
Turkey Point	6/72	RHR*	RHR suction valve had cracks in the valve lower retainer. The retainer cracked due to over travel, operational control improperly designed.
Robinson 2	/73	RHR*	RHR pump suction valve from RCS had leaked due to seat wear.
Oconee 1 Docket 50-269	1/74	LPI/RHR	LPI containment isolation valve failed to close. A control power fuse blew.
Cook 1	8/75	LPI/RHR	LPI discharge isolation valve could not be closed. Misaligned electrical switch.
Trojan Docket 50-344	2/76	ACC	The accumulator outlet isolation valves reopened after the operator closed them. There was a design error in the control wiring.
Calvert Cliffs 1 LER 76-8/3L	5/76	HPI	HPI loop isolation valve failed to operate. A control circuit fuse had blown.
Crystal River 3 LER 78-006	2/78	HPI	HPI isolation valve inadvertently opened and tagged out of service.
ANO 2 Docket 50-368	4/78	HPI	HPI header isolation valve failed due to flow conditions and check valve failure.
Davis-Besse 1 LER 79-015	1/79	ACC	Core flooding tank isolation valve failed to close remotely. Mechanical component failure.
Davis-Besse 1 LER 79-036	3/79	HPI	HPI isolation valve inadvertently opened due to electrical component failure in the control logic circuitry.
North Anna 1	4/79	RHR	RHR isolation valve failed to close automatically. Misaligned limit switch contact.
Cook 1	10/79	LPI/RHR	RHR discharge isolation valve failed to close. Valve operator torque switch failed due to condensation.
Robinson 2 LER 80-029	12/80	RHR*	RHR pump suction isolation valve from RCS hot leg leaked through due to normal wear.

Table 3.3 (Continued)

Plant	Date	System Involved	Description
Millstone 2 LER 82-004	1/82	RHR	The pressure interlock setpoint for the RHR suction valve was set above the limits. Pressure transmitter had electrical problems.
Yankee Rowe LER 82-022	7/82	ACC	Accumulator isolation valve failed to operate. Motor operator was disabled due to grounding conditions.
Millstone 2 LER 82-037	9/82	RHR	RHR isolation valve would not close. Torque switch was found to be out of adjustment.
San Onofre 3 LER83-017	2/83	HPI/ACC	HPI isolation valve leaked through. Accumulator level increased. Tank relief valve lifted and failed to reseat.
Main Yankee LER 83-016	5/83	HPI	HPI isolation valve failed to close. Excessive tightening due to limit switch misadjustment.

*Events selected for calculation of "MOV internal leakage" failure frequency (see Section Appendix A.2.2).

Table 3.4
Summary of Operating Events
Procedural or Other Problems Involving Isolation Valves

Plant	Date	System Involved	Description
Crystal River 3 LER 78-006	2/78	HPI	HPI isolation valve was inadvertently opened and tagged out of service. Technicians cleared the wrong breaker.
Sequoyah 1 LER 81-099	7/81	RHR	RHR check valves were not tested within the required time period.
Salem 1 LER 83-005	1/83	RHR	The RHR automatic isolation function had not been tested prior to placing the RHR in operation.
Davis-Besse 1	1/83	RHR	Pressure interlock for RHR suction valve (from RCS hot leg) was bypassed. Operator error and design deficiency.
Oconee 1 LER 84-001 (Listed also in Table 3.1)	3/84	ACC	Accumulator inleakage through leaking valves. Administrative deficiency no management control over a known problem.

4. INITIATOR FREQUENCIES OF ISLs FOR VARIOUS PATHWAYS IN REPRESENTATIVE PWR PLANTS

4.1 Introduction

This section describes one of the most important parts of the present study; the determination of the initiator frequencies of ISLs through the various pathways identified in Section 2. It also analyzes the sensitivity of these frequencies to certain administrative measures (e.g., changes in valve testing policy) or design changes (e.g., application of permanent pressure sensors in spaces between valves) envisioned to decrease the likelihood of ISLs. It also discusses the hypothetical situation ("base case"), in which valves in the pathways remain untested for leak failure over protracted periods of time. As discussed previously, it was necessary to construct a base case model with no leak testing provisions as the three reference plants all have various leak testing requirments already in place.

4.2 Basic Approach

In the modeling of ISL initiators for the various pathways, the following approach was applied. A generic system failure model was developed for valve configurations consisting of increasing numbers of valves in series. Then the model was adapted to the specific valve arrangements for the representative plants.

The generic failure model of valve arrangements is based on the simple, well-known multiple sequential standby system model. This simplified model has been selected instead of a somewhat more accurate Markovian approach because the latter becomes rather complicated and cumbersome with increasing numbers of valves and failure states and the incremental accuracy was judged not to be cost-effective for the present purpose. The simplified model describes the basic mechanism of accident initiation in the same way as a Markovian model. The difference is that simplifications are used to describe the effects of operational, test and surveillance conditions on the valve failures, which in a Markovian model can be treated in a more sophisticated and exact way. The great advantage of the simplified model lies in its flexibility in considering the plant-specific features of the valve arrangements. It allows one to relatively easily compare the effects of the plant-specific features for the reference plants and to study the sensitivity of the failure frequency of valve systems to the aforementioned administrative measures and possible design changes.

In the model, three basic valve configurations; two-, three- and four-unit series systems, are considered. The results of the modeling with some calculational details are presented in Appendix B. The formulas obtained for generic cases were applied to the individual valve systems located in the pathway groups given below:

a. Accumulator Lines
b. HPI Lines
c. LPI Lines
d. RHR Suction Lines

The letdown lines are analyzed separately because their function and design require specific treatment.

4.3 Calculation of Initiator Frequencies for Accumulator, LPI, and HPI Pathways

At the majority of PWRs, the LPI injection lines and the accumulator outlet lines have a common inlet header to the RCS. At PWRs of Westinghouse and Combustion Engineering designs this inlet header is also shared with the HPI system. At PWRs of Babcock and Wilcox design the HPIS injects to the reactor vessel via separate lines.

In all previous analyses of ISLs through the LPI (or HPI) lines the effect of the common inlet header was not taken into consideration and the ISL initiator frequencies were estimated assuming the LPI pathways to be independent from the accumulator system.

A thorough analysis of the check valve failure events occurring in the LPI/accumulator injection lines (for details see Appendix A.1) revealed that the second (downstream) check valve in an accumulator injection line is rather prone to the "failure to operate (reseat) upon demand" failure mode. The proneness to failures of this type is due to the combined effects of boric acid corrosion, boron deposition, and the valve being initially in an unstable (neutral) position when both sides of its disk are exposed to the accumulator pressure. Since the differential pressure across its disk is almost zero ($\Delta p \approx 0$) and the accumulator is subject to many small pressure changes, the valve is expected to be open frequently. With each opening, the chance that it will fail to reseat upon a demand due to a leak in the first valve, increases.

The result of the process is, that the second valve behaves like a "safety valve" with respect to the overpressurization of the common inlet header. That is, whenever the first (upstream) isolation check valve to the RCS leaks (or in the worst case ruptures), in the majority of the cases, the second check valve will not completely prevent completely the propagation of the leakage (or pressure wave) to the accumulators.

Based upon the results of the check valve failure analysis, it was concluded that in any study of ISLs involving common injection inlet pathways, the proneness of the accumulator outlet check valve to the "failure to operate (reseat) on demand," failure mode has to be taken into account. It has been inferred that the nature and frequency of ISLs through the LPI/HPI pathways will be significantly different depending upon the state of this check valve (whether it is capable of reseating or not) and upon the rate of the backflow through the first check valve. One of the following two situations may arise.

a. If the valve is seated (or it is capable of reseating), there will be no inleakage (in the above terminology "safety valve effect") to the accumulators. ISLs through the LPI/HPI pathways, even with a moderate leak rate, may cause core damage. That is, leaks that are larger than the total charging capacity (~100 gpm) but smaller than the total capacity of LPI/HPI relief valves, will depressurize the RCS to drain collecting tanks (e.g., the Pressurizer Relief Tank) inside or outside the containment. When, these drain collecting

tanks fail, a small LOCA arises. Leaks that exceed the total relief valve capacity of the LPI/HPI systems have of course, more potential risk impact since they cause overpressurization with the potential of a large LOCA.

b. If the valve is open and fails to reseat, the preferred direction of an ISL will be through the accumulator (in the above terminology there will be a "safety valve effect") and not through the LPI/HPI pathways. Should an ISL with a moderate leakage flow rate (i.e., smaller than the total capacity of LPI/HPI relief valves) still occur through these pathways, it will only lead to small LOCAs through the relief valves in addition to leakage into the accumulator. Since the accumulators are continuously monitored, leaks through the first check valve and the concomitant small LOCAs through the relief valves will have high potential for early discovery and preventive actions. In the case of an ISL a with high leak rate (e.g., check valve ruptures), neither the open accumulator check valve nor the relief valves will prevent the overpressurization of the low pressure piping and large LOCA may happen outside the containment. (The relief valves will be open but choked.) While a LOCA through an accumulator may potentially increase confusion in the accident management, due to the unexpected location, it will have the beneficial effect of rendering a large part of the RCS inventory available for recirculation and immersing the containment sump. The advent of core damage would be delayed and the source term would be reduced through the decontamination potential of a submerged release.

The structure of the calculation of ISL initiator frequencies through the shared Accumulator/LPI/HPI inlet to the RCS is shown schematically in a flow chart presented in the form of an event tree in Figure 4.1. Multiple valve failures for piping with individual (not shared) inlets to the RCS should be understood in the chart as falling into the event category "w/o accumulator inleakage."

The relationship between leak failure frequency and leak rate magnitude for check valves is discussed in Appendix A.1.

4.3.1 ISL Initiator Frequencies for Accumulator Pathways

In order to determine the ISL initiator frequencies for the accumulator pathways, the frequency per year of experienced accumulator inleakage events exceeding certain leakage flow rate (see Table A.2 and Section A.1.1 of Appendix A) is plotted in Figure 4.2. The plot is fitted with a "best" straight line (on a log-log scale) using regression techniques. The line is taken to represent the median values of a postulated lognormal leak failure frequency distribution describing the uncertainty of the data. The figure also shows curves representing the 5th and 95th percentiles and the mean values of the lognormal distribution. The curves for the percentiles were obtained by statistical confidence band estimates of the parameters describing the best fit line. The curve describing mean exceedance frequency values can be taken as a direct estimator of the ISL initiator frequencies.

The application of a straight line fit to the observed values is supported by generic experience: there are more small leaks than large, more

small pipe breaks than large, etc. Exceedance frequencies of these types usually follow a power law. They belong to the family of Pareto's distributions (see, e.g., E. J. Gumbel: "Statistics of Extremes," page 151, Columbia University Press, 1958).

To estimate ISL initiator frequencies for a specific plant by using the mean curve in Table 4.2, the most important parameter is to choose an appropriate leak flow rate value at which the estimate is to be evaluated. For that purpose a reasonable choice is that leakage flow rate that fills up the "free volume" of an accumulator within a "critical time" deemed to be required for operator actions to safely mitigate an accumulator inleakage. Table 4.1 presents the free volumes of the accumulators for the selected PWRs. The table also shows, for convenience, some other relevant design characteristics of the accumulators.

Table 4.2 lists the filling time of the free volumes for various leak rates. (The filling times presented in the table are conservative because it does not take into account the delay in the filling due to the compression of the N_2 gas.) Ten minutes was selected as the critical time for all the plants. This time was deemed to be long enough for the operator to respond to the specific accumulator alarms (high pressure, high level) and to take successful corrective actions. Table 4.3 gives the corresponding leak rates and the mean values of the leak rate exceedance frequencies per accumulator line per year. The leak rate exceedance frequencies were obtained simply by reading-off from the curve providing mean values in Figure 4.2.

The value which is directly read off from the curve at the appropriate leakage flow rate is essentially to be identified with the left hand side of Eq. (10) in Appendix B:

$$\langle \lambda_s^T(1,2) \rangle = \lambda_1 C \quad , \qquad (1)$$

where λ_1 is the mean annual frequency of exceeding the appropriate leakage rate due to the leakage failure mode of the check valves.
C = .93 denotes the "effective operating (reseat) failure probability" of the accumulator outlet check valve (see also Section A.1 of Appendix A).

In order to determine the plant-specific ISL initiator frequencies, the exceedance frequencies read off from the curve above should only be adjusted according to the plant specific parameters given in Table 4.3. The sizes of the lines are not important parameters because the experienced curve is based on failure events representing a relatively homogeneous sample of pipe sizes (8"-14" diameter). Using these data, the total initiator frequencies were calculated for each plant. The values obtained are presented in Table 4.3.

Since these initiator frequencies relate to the exceedance of given leak rates, it should be appreciated that they may cause either type of accidents; "small LOCA, through the accumulator relief valves" or "accumulator overpressurization."

In order to determine the total frequencies of initiators leading only to "accumulator overpressurization," one has to read off the leak exceedance curve at the leak rate which just exceeds the relief valve capacity of the accumulators and to apply the plant specific parameters.

The initiator frequencies obtained in this way are also given in Table 4.3. Both initiator frequencies for "small LOCA through the accumulator relief valve or accumulator overpressurization" and for "accumulator overpressurization" only, serve as inputs to the accumulator ISL event trees. The event trees are discussed in Section 5.

It is interesting to note that the initiator frequencies through the accumulator lines are essentially not affected by the plant specific test and surveillance conditions of the check valves. The reason for this is associated with the fact that the accumulators are among the best and continuously monitored plant components. Any anomalous leakage, even those which result in only minor boron concentration changes, can be detected. Accumulator inleakages usually cause immediate plant shutdowns and/or investigation of the condition of the accumulator check valves. A left open first check valve (after cold shutdown operations) associated with accumulator inleakage, therefore, is considered to be a failure detectable during start up or shortly after start up in the initiator analysis.

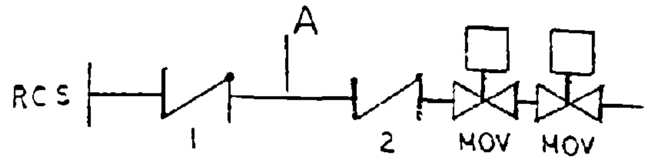
As a consequence of the constant surveillance of the accumulators and the high effective reseat failure probability of the accumulator outlet check valve, one would expect that these check valves are tested/maintained regularly. In fact, it was found that each of the reference plants is practicing an accumulator valve testing policy which is best suited to their particular experience; e.g., at Calvert Cliffs 1, the seat leakage of the first check valve is continuously monitored with a pressure sensor placed in the pipe section between the first and second check valves. This plant experienced accumulator inleakages in the past (see Table 3.1). The causes were found to be seal failures of the second check valves due to the harsh boric acid environment. At Indian Point 3 the check valves are leak/seat tested after each RCS depressurization (~3 time/year) and at Oconee 3 once per nine month interval.

An upper limit on the time period without test/maintenance can be estimated from the exceedance frequency curve of accumulator inleakage events (Figure 4.2). The estimate is based on calculating the mean time to failure (MTTF) values for leakage events with small flow rates expected to occur frequently (e.g., leaks with flow rate higher than or equal to 1.5 gpm). The MTTF values obtained for the plants selected are given in the last row of Table 4.3. They are in the time range of 7 to 18 years. These time periods will be used in the next section as reasonable time limits for calculating ISL frequencies for the LPI systems via the shared inlet under "base case" (no leak test after cold shutdowns over a protracted period of time) conditions.

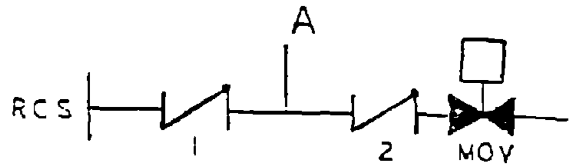
4.3.2 ISL Initiator Frequencies for LPI Pathways

The check valve arrangements on the interfacing LPI lines of the representative plants have the following basic configurations:

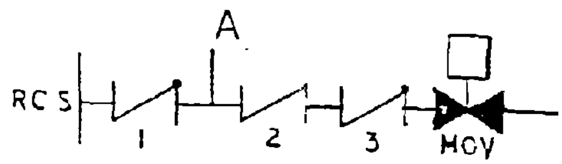
a. Indian Point 3.
Two check valves and two open MOVs.
(Valve descriptions are given in Tables 2.3.2 and 2.3.4)
Number of paths: 4



b. Oconee 3.
Two check valves and a closed MOV. (Valve descriptions are given in Tables 2.4.2)
Number of paths: 2



c. Calvert Cliffs 1.
Three check valves and a closed MOV. (Valve descriptions are given in Table 2.5.1 and 2.5.4)
Number of paths: 4



The ISL initiator frequencies for the LPI pathways are calculated by using

a. the formalism for the appropriate valve configuration developed in Appendix B,
b. the dependency of the leakage failure frequency on the leak flow rate given in Figure A.2,
c. the condition that the accumulator check valve is frequently in the failed state, and
d. the assumptions that (1) ISLs with leakage flow less than the total relief valve capacity of the injection side of the LPI system do not lead to overpressurization of the low pressure piping, but contribute to the small LOCAs through the relief valve, and (2) ISLs with leakage flow below the total capacity of the charging system are easily treatable and are therefore negligible events.

4.3.2.1 <u>Calculation of ISL Frequencies for LPI Lines at Indian Point 3</u>

The ISL frequencies for LPI lines at Indian Point 3 are calculated for three cases:

a. the standard case which corresponds to the present status of operational conditions and check valve test policy,
b. an improved case where the improvement is the application of a permanent pressure sensor between check valves 1 and 2, and
c. a base case corresponding to a hypothetical condition in which the check valves are untested for leakage failure over a protracted period of time.

At Indian Point 3, the check valves in the LPI lines are flow and leak tested after each cold shutdown. This test policy should preclude the check valves being left in an open position. (This assessment should be understood such that the check valves are accepted to be seated if their leakage flow

is smaller than a limiting flow rate defined in the Technical Specifications and test requirements.)

Since the current leak test policy at Indian Point 3 is optimal concerning leak test frequency, a calculation was performed only to see the effect of a permanent pressure sensor.

The relevant average failure frequency formulas to be used to demonstrate the calculational process in this simple case are derived in Section B.1 of Appendix B. They will be repeated here for convenience. The average failure frequencies for double check valve failures are:

a. for the standard case, (Eq. (6) of Appendix B):

$$\langle\lambda_s^T(1,2)\rangle = \lambda_l^2 T + 2\lambda_l\lambda_d, \tag{2}$$

b. for the case of pressure sensor, PS; (Eq. (9) of Appendix B);

$$\langle\lambda_s^T(1,2)\rangle_{PS} = \lambda_l^2 \frac{T}{2} + \lambda_l\lambda_d, \tag{3}$$

c. for the base case, (Eq. (8a) of Appendix B);

$$\langle\lambda_s^T(1,2,d)\rangle = \lambda_l^2 T + 2\lambda_l\lambda_d\left(\frac{dT + 1}{2}\right) \tag{4}$$

In these formulas,

λ_l is the mean frequency of the leak failure mode,
λ_d is the mean probability of the "failure to operate (reseat) on demand" valve failure mode,
d is the demand (opening) rate of the check valves, and
T is the time interval between leak tests of the check valves.

The formulas can be applied directly to calculate the total average frequency of double check valve failure events unaccompanied by check valve failure in the accumulator line, denoted $(1,2,\overline{A})$. The application can be performed simply by multiplying the formulas (2) through (4) by the term, (1-C), where C is the "effective probability" that the accumulator outlet check valve will not operate (reseat) upon demand. The term, (1-C) expresses the probability that the accumulator outlet check valve will reseat on demand.

The formulas obtained [Eq. (2b) through 4b)] are listed in Table 4.4. In the formulas the factor 2.88 accounts for the condition that there are four similar LPI lines and the capacity factor of the reactor is: .72. The capacity factor was determined from the plant's history given in NPE.[1]

If the accumulator outlet check valve is stuck open, a left open first check valve, as well as leakage failures developing randomly in time through either check valve 1 or 2, would be detected by pressure/level/concentration changes at the continuously monitored accumulator. The monitoring role of the accumulator is reflected in the formula (Eq. (2a) of Table 4.4) describing the total average failure frequency of double check valve failure events accompanied by check valve failure in the accumulator line, (1,2,A).

Clearly, a pressure sensor will not "discover" more failures than will a monitored accumulator, given an open outlet check valve. Thus, the average failure frequency (Eq. (3a)) will not change given the presence of the pressure sensor compared to the previous case.

The base case considers the hypothetical "worst case condition," that in spite of the accumulator outlet check valve being stuck open after an operation, the untested second check valve may stick open and remain undetected (Eq. (4a)) until the first check valve fails and an accident occurs.

Quantification of the Double Valve Failure Formulas (Table 4.4)

The formulas in Table 4.4 were evaluated as a function of the leakage flow rate through the shared LPI/HPI/Accumulator inlet using the leakage failure frequency exceedance curve (mean values) given in Figure A.2 of Appendix A. The mean frequency of the "valve failure to operate (reseat) on demand" failure mode was taken to be λ_d = 2.81(E-4)/demand (see Appendix A.1.2). In the "standard" case and in the case of the application of a permanent pressure sensor, the time parameter (T) was taken to be 1/3 year, the average time between cold shutdowns. In the base case, the time parameter was chosen to be T = 8 years (see Table 4.3) and the demand rate for the check valves (cold shutdowns) to be d = 3/year.

For the numerical evaluation, a PC computer program was developed. From the results obtained, Figures 4.3a and 4.3b show the ISL frequency exceedance curves related to the "standard" and the "pressure sensor" cases for comparison with similar results for other plants.

One has to emphasize that the curves represent total initiator frequencies exceeding certain leakage flow rates through the shared inlet. In order to obtain final initiator frequencies in an appropriate form for the "small LOCA without overpressurization" and "overpressurization" event trees of the low pressure system, the frequency values have to be read from the curves (or calculated) at certain characteristic leakage flow rates.

The question arises as to which double valve failure events should be classified as "small LOCAs without causing overpressurization" and which as "overpressurization" events? Clearly, the answer is dependent upon whether or not there is simultaneous inleakage to the accumulator. Consider the situation in which there is no inleakage:

I. In this case, double check valve failure events in which the leakage flow rate is larger than the maximum makeup flow (~98 gpm), but less than the total capacity of the LPI relief valves on the injection side (740 gpm), result only in small LOCAs through the relief valves and do not cause piping overpressurization.

II. In contrast, double check valve failure events in which the leakage flow rate is larger than the total capacity of the LPI relief valves (740 gpm) on the injection side result in piping overpressurization.

If there is inleakage into the accumulator, the situation is somewhat more complicated because now two pathways are open, one to the accumulator and one through the LPI relief valve(s):

III. In order to avoid double counting of LOCA initiators through relief valves and through the accumulator, the only failure events assumed to result in a small LOCAs whose leakage flow rate lies between two values: the leakage flow rate value required to exceed the total charging capacity given a simultaneous accumulator inleakage (272 gpm, see its calculation below), and the leakage flow rate value required to exceed the accumulator leakage flow rate given flow diversion to the relief valves (~470 gpm).

IV. Double valve failure events are assumed to result in overpressurization events if the leakage flow rate at the shared inlet exceeds the capacity of the LPI relief valves in spite of flow diversion to the accumulator (this occurs at a flow rate of ~2100 gpm).

(Note: The core damage frequency through overpressurization of low pressure piping is calculated by use of event trees (for LPI or HPI systems) that differ from that associated with LOCAs simultaneously occurring through the accumulator. Thus, the core damage frequencies obtained from the accumulator and e.g., an LPI event tree are essentially double counted contributions from the same initiator. This does not cause any significant bias in the total core damage values because the core damage contributions from the overpressurization event trees of low pressure piping are usually much smaller than that from the accumulator event tree.)

The sum of the frequencies of events I and III, and the sum of the frequencies of events II and IV, are taken as inputs to the "small LOCA without overpressurization" and "overpressurization" event trees of low pressure systems, respectively.

Table 4.5 lists the frequency of events in the above discussed leakage flow ranges (I through IV) for the standard, the pressure sensor, and the base cases. Those values which are calculated as inputs for event trees are listed in the last two columns of the table.

The leakage flow rates at the shared LPI/HPI/Accumulator inlet required to exceed certain critical values were estimated by assuming that only a fraction, F, of the incoming flow reaches the relief valves or the accumulators if both pathways are open. The fraction is the flow diversion ratio defined as the ratio of the cross sections of the LPI and accumulator lines:

$$F = \left(\frac{6''}{10''}\right)^2 = .36$$

Thus,
- the flow required to exceed the total charging flow (98 gpm) going through the LPI relief valves given accumulator inleakage is: 98 gpm/.36 = 272 gpm,
- the flow required to exceed the accumulator flow rate (300 gpm) at the initial time given flow diversion to the relief valves is: 300 gpm/.64 = 470 gpm, and

- the flow required to exceed the capacity of the relief valves given accumulator inleakage is: 740 gpm/.36 = 2100 gpm.

4.3.2.2 Calculation of ISL Frequencies for LPI Lines at Oconee 3

The ISL frequencies for the LPI lines at Oconee 3 are calculated for the following cases:

a. the standard case which corresponds to the present status of operational conditions and check valve test policy,
b. an improved case where the improvement is the application of a permanent pressure sensor between check valves 1 and 2,
c. an improved check valve test policy which involves performing stroke and leak testing of check valves after each cold shutdown,
d. simultaneous application of b and c,
e. application of a "relaxed" check valve leak testing policy (leak test requirement only at each refueling to determine the effects and the cost-benefit relationships of instituting leak testing programs of pressure isolation valves for those plants that do not currently have such a requirement), and
f. a base case corresponding to the hypothetical condition that the check valves are not tested for leak failure over a long period of time.

An ISL would occur through an LPI line at Oconee 3 if two check valves and a normally closed MOV were in an "open" failure state. The frequency of these events can be calculated by applying Eq. (19) of Section B.2 of Appendix B. In applying the formula, one has to use the appropriate failure modes of both types of valves (check valves and MOVs) and the specific testing policy of the valves. The testing policy of the valves is discussed first.

At Oconee 3, there is leak testing equipment (a rig) to carry out the ISL tests at nine month intervals. These tests, which are intended to verify that the check valves of the ECCS system properly reseat after cold shutdown, have been judged to be efficient after having studied the procedure and discussed it with plant personnel. However, there are usually two additional cold shutdowns during the nine month leak testing period when the LPI lines are flow tested and the MOVs are stroked. After these cold shutdowns the check valves may stick open and the MOVs may remain in failed state such that they would not operate on demand. The MOVs are never tested for leaks. These conditions are taken into account in the calculation of the initiator frequencies.

The calculational procedure (see Section B.2.1.c) is similar to that followed for the LPI lines at Indian Point 3.

Step 1. Eq. (19) of Appendix B.2 is adapted to the "two check valves and one normally closed MOV" configuration.

Step 2. The new equation is appropriately modified to describe the various cases previously defined. In each case the possibilities that the accumulator outlet check valve is stuck open was also taken into account. The formulas obtained (listed in Table B.4) reflect the

beneficial effects of leak tests after each cold shutdown and the application of a permanent pressure sensor.

Step 3. The formulas are evaluated numerically as a function of the leakage flow rate through the shared LPI/HPI/Accumulator inlet.

Quantification

In the formulas, a factor of 1.72 accounts for the two similar LPI lines and that the capacity factor of the plant is 0.86. The capacity factor was determined from the plant's history given in NPE.[1]

The check valve leakage and demand failure data are the same as those applied in Indian Point 3 calculation.

The total mean frequency of MOV failures, λ_3, leading to the inadvertent open state of the normally closed MOV is obtained from the following contributors:

a. MOV disk rupture (A.2.1)	1.20×10^{-3}/year
b. MOV internal leakage (A.2.2)	4.85×10^{-3}/year
c. MOV transfer open (A.2.4)	8.1×10^{-4}/year
d. Inadvertent SI signal	6.4×10^{-2}/year*
	$= 7.1 \times 10^{-2}$/year

(*This value is taken from the Indian Point 3 PRA[2] as a generic value for estimating the frequency of an inadvertent SI signal. The Oconee PRA[3] assumes a more moderate value of 1×10^{-2}/year.)

The mean frequency of the failure mode "MOV disk fails open while indicating closed," λ_{d3}, is taken to be 1.07×10^{-4}/demand (see Sections A.2.3 and A.2.5).

In the various cases the time periods for leak tests (T) and demand rates for check valves (d) and for MOVs (d_3) are the following:

- Standard case and in the case of application of a pressure sensor: $T = 3/4$ year, $d = d_3 = 4$/year.
- In the cases of "leak test of check valves at each cold shutdown," and "leak test plus pressure sensor:" $T = 1/4$ year, $d_3 = 4$/year.
- "Relaxed" check valve leak testing policy (leak tests at each refueling): $T = 1.5$ year, $d = d_3 = 4$/year.
- Base case (for the time period chosen see also Table 4.3): $T = 16$ year, $d = d_3 = 4$/year.

Figures 4.3a and 4.3b show the ISL frequency exceedance curves obtained for the standard and improved cases. More precise ISL initiator frequency values at the relevant leakage flow rates for each of the cases discussed are listed in Table 4.5. (The numbers given in brackets show the results if one

gives credit for the possibility that leakage through the second check valve and MOV is discoverable given a stuck open accumulator outlet check valve.) The values not in the brackets are used as inputs to the "small LOCA without overpressurization" and "overpressurization" event trees.

At Oconee 3 the flow diversion ratio is defined as the ratio of the cross sections of the LPI and accumulator lines:

$$F = (\frac{10"}{14"})^2 = .51 \quad .$$

Thus,
- the flow required to exceed the total charging flow (100 gpm) going through the LPI relief valves given accumulator inleakage is: 100 gpm/.51 = 200 gpm,
- the flow required to exceed the accumulator flow rate (280 gpm) at the critical time given flow diversion to the relief valves is: 280 gpm/.49 = 570 gpm, and
- the flow required to exceed the capacity of a relief valve (~330 gpm) given accumulator inleakage is: 330 gpm/.51 = 650 gpm (at Oconee 3 each line has its own independent relief valve).

The difference between Oconee 3 and Indian Point 3 concerning small LOCAs through the relief valves is that at Oconee 3 the relief valves drain to a high activity waste collecting tank located outside the containment while at Indian Point the relief valves relieve to the pressurizer relief tank located inside the containment.

4.3.2.3 Calculation of ISL Frequencies for LPI Lines at Calvert Cliffs 1

The ISL frequencies for LPI lines at Calvert Cliffs 1 are calculated for the following cases:

a. the standard case corresponding to the present status of operational conditions and check valve test policy, and
b. a base case corresponding to a hypothetical condition in which the check valves are not tested for leakage failure over a long period of time.

At Calvert Cliffs an ISL occurs through the LPI lines if three check valves and a normally closed MOV are in an open failure state. The frequency of the events can be calculated by applying Eq. (24) of Section B.3 of Appendix B to the case. In applying this formula, one has to use the appropriate failure modes of both types of valves (check valves and MOVs).

The check valve testing policy of Calvert Cliffs 1 is diverse; continuous leak/pressure indication of the first check valve by a permanent pressure sensor as well as an additional safety valve and leak test on each inboard check valve at each refueling outage. A leak test is performed quarterly during plant operation and a flow test during refueling outages on the outboard check valves. The MOVs are stroke tested quarterly and cycled once per month.

The high valve redundancy in that configuration, as well as the use of a permanent pressure sensor, leaves little scope for considering additional improvement in this valve arrangement. Therefore, beyond the standard case, improved cases were not considered. Only a base case was analyzed as defined above.

The calculational procedure is similar to those the for previously considered plants.

Step 1. Eq. (24) of Appendix B is adapted to the "three check valve and one normally closed MOV" configuration where leakage through the first check valve is monitored continuously.

Step 2. The new equation is appropriately modified to describe the standard and base cases for the conditions that the accumulator outlet check valve is stuck open or not.

Step 3. The formulas obtained (listed in Table B.5) are evaluated numerically as a function of the leakage flow rate through the shared LPI/HPI/Accumulator inlet.

Quantification

In the formulas, a factor of 3.52 accounts for the four similar lines and the plant capacity factor, which is taken to be 0.88. The capacity factor is determined from the plant's history given in NPE.[1]

The check valve leakage and demand failure data are the same as those applied to Indian Point 3 and Oconee 3. The MOV failure data are the same as those listed for Oconee 3.

Since the test interval for the components ranges from zero to 1.5 years, in quantification of the standard case, the basic time period (T) over which the average multiple valve failure frequency is calculated, is chosen to be T = 1/4 year. The demand rate of the second check valve (opening) is taken to be, d_2 = 4/year. The demand rate of the MOV is d_4 = 12/year.

In the base case, the time period during which no leak test is assumed to be performed for all the check valves except the first one (which is constantly monitored) is taken to be: T = 8 years (see Table 4.3). The demand rate of the check valves was assumed to be, d = 4/year (four cold shutdowns) and the demand rate of the MOV, is taken to be the same as before: d_4 = 12/year. Figures 4.3a and 4.3b show the ISL frequency exceedance curves obtained for the standard case. More precise ISL initiator frequency values at the relevant leak flow rates for both the standard and base cases are listed in Table 4.5.

The values given in the table are used as inputs to the "small LOCA without overpressurization" and "overpressurization" event trees. (The numbers given in brackets show the results if one gives credit for the possibility that leakage through the second and third check valves as well as through the MOV is discoverable, given stuck open accumulator check valves.)

At Calvert Cliffs 1 the flow diversion ratio is defined as the ratio of the cross sections of the LPI and accumulator lines:

$$F = (\frac{6''}{12''})^2 = .25 \quad .$$

Thus,
- the flow required to exceed the total charging flow (132 gpm) going through the LPI relief valve given accumulator inleakage is: 132 gpm/.25 = 530 gpm,
- the flow required to exceed the accumulator flow rate (665 gpm) at the critical time flow diversion to the relief valve is: 665 gpm/.75 = 890 gpm, and
- the flow required to exceed the capacity of the relief valve given accumulator inleakage is: 330 gpm/.25 = 1320 gpm.

Since the LPI relief valve relieves to a drainage collecting tank located outside the containment, the small LOCA at Calvert Cliffs 1 is also a containment bypass ISL as in the case of Oconee 3.

4.3.3 ISL Initiator Frequencies for HPI Pathways

The basic valve arrangements of the interfacing HPI lines do not differ from those already described for the LPI. Thus, the calculation of average multiple valve failure frequencies for individual lines essentially repeats the approach applied for the LPI calculations. A small complication arises for those systems where certain valve arrangements occur together as in the HPI system of Indian Point 3.

4.3.3.1 Calculation of ISL Frequencies for HPI Lines at Indian Point 3

The HPI system in this plant has the following groups of valve arrangements:

A. Four lines whose valve arrangement is of the type: three check valves and an open MOV. The lines have shared inlets to the cold legs of the RCS with the LPI/Accumulator System.

B. Four lines whose valve arrangement is of the type: two check valves and an open MOV. The lines have no shared inlets with the accumulator.

C. Two lines whose valve arrangement is of the type: two check valves and a closed MOV. The lines have no shared inlets with the accumulator.

There is a relief valve for these lines with a setpoint of 150 psia and an estimated capacity of 580 gpm. Valve descriptions are given in Table 2.3.3.

The ISL frequencies are calculated for the following cases:

a. the standard case which corresponds to the present status of operational conditions and check valve test policy (the test policy is somewhat different for each of the above groups),
b. application of permanent pressure sensors between check valves 1 and 2,

c. more frequent check valve leak tests (performed at each cold shutdown),
d. simultaneous application of b. and c., and
e. a base case, corresponding to a highly hypothetical condition in which the check valves are not tested for leak failures over a long period of time.

1. Calculation of average multiple check valve failure frequencies for Group A lines from above.

The leak and stroke tests of the individual check valves on these lines are different. The first check valve (upstream) common with the LPI/Accumulator line is stroke and leak tested at each cold shutdown. The other check valves are stroke tested at each cold shutdown, but leak tested only at every refueling. The average valve failure frequencies per line were calculated for both the cases without and with accumulator inleakage.

The calculation is based on applying Eq. (19) of Section B.2 of Appendix B to valve configuration A and to the particular cases, a. through e. discussed above. The relevant formulas are listed in Table B.3. The formulas are evaluated numerically as a function of the leakage flow rate through the shared HPI/LPI/Accumulator inlet.

In the formulas, a factor of 2.88 accounts for the four similar A lines and the capacity factor of the reactor, which is taken to be: .72 (4x.72 = 2.88).

The frequencies of the check valve failures are the same as those used in all the previous cases.

The time periods and demand rates are the following:

For the standard and pressure sensor cases, the time period of leak testing was taken to be the refueling period, T = 1.5 year. The demand rate for the check valves (stroke tested at each cold shutdown) is taken to be, d = 3/year. It is assumed that stuck open first check valve is detected by inleakage to the accumulator given stuck open accumulator outlet check valves. However, stuck open second and third check valves are assumed to remain undetected (the setpoint of the HPI relief valves is 1500 psia, a much higher pressure than the operating pressure of the accumulator), given even a stuck open accumulator outlet check valve.

For the "more frequent leak testing" and "more frequent leak testing plus application of pressure sensor" cases, the time period of leak testing is, T = 1/3 year. Other assumptions are the same as in the previous cases.

Base Case – The HPI injection system is a standby safety system compared to the LPI/RHR system which is used at each cold shutdown. Thus, the time period during which leak tests on the associated check valves are not carried out is assumed to be T = 30 years (in contrast with T = 8 years, chosen for the check valves on the LPI lines). The demand rate of the check valves (stroke tests) is taken to be the same as above, d = 3/year.

The ISL frequency exceedance curves for the various cases (except the base case) are plotted as a function of the leakage flow rate through the shared HPI/LPI/Accumulator inlet in Figures 4.3a and 4.3b.

Numerical values that provide input to the "small LOCA without overpressurization" and "overpressurization" event trees are given in Table 4.5. The table also presents the leakage flow rates used to distinguish between "small LOCA" and "overpressurization" events. The same leakage flow rate values are used in each of the cases a. through e. in Table 4.5, therefore, they are indicated only once in the "standard case."

The relevant leakage flow rates for Group A lines are obtained by the following consideration. The flow diversion ratio for the Group A lines can be calculated from the pipe sizes as:

$$F = \left(\frac{2''}{10''}\right)^2 = .04 \quad .$$

Thus, the flow required to exceed the total charging flow (98 gpm) going through the HPI relief valve given accumulator inleakage is: 98 gpm/.04 = 2450 gpm. This flow rate is higher than the flow rate required to exceed the accumulator flow rate (300 gpm) at the critical time given flow diversion to the relief valve, which is: 300 gpm/.96 = 312 gpm. Therefore, the "small LOCA" initiator is evaluated for flow rates between 2450 gpm and the flow rate required to exceed the capacity of HPI relief valve (580 gpm) given accumulator inleakage. This latter value is: 580 gpm/.04 = 14500 gpm and is the threshold leakage flow rate for overpressurization of the HPI piping, given accumulator inleakage.

2. Calculation of average multiple check valve failure frequencies for Group B lines.

The lines have no shared inlet with the accumulator. Consequently, Eqs. (2) through (4), multiplied with a constant factor, can be used directly to calculate the total average frequencies of double valve failures on these lines.

In the quantification the following parameters are used: A constant factor of 2.88 (4 lines x .72, where .72 is the capacity factor of the reactor).

Under the present operational conditions, the check valves on these lines are stroke and leak tested only at each refueling period. In the standard and "application of pressure sensor" cases, therefore, the time parameter used is, T = 1.5 year. It is assumed that during this time period the valves have not been opened.

In the cases of more frequent testing, and also when a pressure sensor is used, the time period is taken to be T = 1/3 year.

In the base case, the time period is T = 30 years. The frequency of valve openings without subsequent leak test is assumed to be d = 2/3 per year.

Figure 4.3c shows the ISL frequency exceedance curves for the various cases (except the base case) as a function of the leakage flow rate through the inlet of the HPI lines.

Numerical values for input to the "small LOCA without overpressurization" and "overpressurization" event trees are listed in Table 4.5. The table also shows the leakage flow rates used to distinguish between "small LOCA" and "overpressurization" events.

3. Calculation of average multiple check valve failure frequencies for Group C lines.

Similar to Group B lines, Group C lines have no shared inlet with the accumulator either. The total average failure rate for these lines can be obtained from application of Eqs. (17) and (19) of Appendix B.2.

Since there are only two lines, the multiplication constant in the equations is: 2x.72 = 1.44, where .72 is the capacity factor of the reactor.

The MOVs of these valve configurations are locked closed during normal operation. Therefore, only the "MOV disk rupture," "MOV internal leakage" and "MOV failure to operate (hold) on demand" failure modes were selected as credible MOV failures. In the quantification of the equations, the rounded sum of the frequencies of the first two failure modes is used for the numerical value of, λ_3; λ_3 = 6.1(E-3)/year. As for the demand failure mode, the value λ_{d3} = 1.07(E-4)/demand is applied (see Sections A.2.1 through A.2.2.6 for MOV failure rates).

The check valves on the Group C lines are stroke and leak tested at each refueling period. Thus, the time interval in the standard and the "pressure sensor" cases is taken to be T = 1.5 year. The time period for the cases of more frequent leak test and leak test plus pressure sensor cases is that of the cold shutdowns: T = 1/3 year.

The time period for the base case is T = 30 years. During this time interval the check valves are assumed to have no leak testing performed.

The ISL frequency exceedance curves are shown in Figure 4.3a as a function of the leakage flow rate through the inlet of these lines.

Numerical values for inputs to the "small LOCA without overpressurization" and "overpressurization" event trees are listed in Table 4.5. The table also indicates those leakage flow rates which were used to distinguish between "small LOCA" and "overpressurization" events.

4.3.3.2 Calculation of ISL Frequencies for HPI Lines at Calvert Cliffs 1

The valve arrangement of the HPI lines at Calvert Cliffs 1 is similar to that of the LPI lines: three check valves and a closed MOV. (The valve descriptions are given in Table 2.5.3.) The number of lines is four.

The testing policy for the isolation check valves is also similar to LPI: continuous leak pressure indication of the first check valve (in common with the accumulator and LPI lines), leak test quarterly during plant operation of

an outboard check valve and flow testing during refueling outages. Additionally, leak tests are performed on each inboard check valve at each refueling.

The position of the MOVs is under continuous surveillance. They are stroke tested quarterly and their closed position is physically verified monthly. There is also a relief valve at the header of the branch lines with a setpoint of 1485 psia and an estimated capacity of about 580 gpm.

The same leak/frequency parameter values used for the LPI analysis to calculate the multiple valve failure frequencies were used here also. An exception is the base case, where the time period of leak testing is assumed to be T=30 years. The ISL frequency exceedance vs. leakage flow rate curves in Figures 4.3a and 4.3b relate not only to the LPI but also to the HPI system.

Since the relief valve setpoints and capacities are different, the leakage flow requirements will be also different for the LPI and HPI systems. Correspondingly, the selected values for "small LOCA without overpressurization" and "overpressurization" initiators will be different. These values are presented in Table 4.6.

The flow diversion ratio for the HPI lines can be calculated from the pipe sizes:

$$F = \left(\frac{2''}{14''}\right)^2 = .02 \quad .$$

Thus, the flow required to exceed the total charging flow (132 gpm) going through the HPI relief valve given accumulator inleakage is: 132 gpm/.02 = 6600 gpm. This flow rate is higher than the flow rate required to exceed the accumulator flow rate (665 gpm) at the critical time, which is: 665/.98 = 678 gpm. Therefore, the small LOCA initiator is evaluated for flow rates between 6600 gpm and the flow rate required to exceed the capacity of the HPI relief valve (580 gpm) given accumulator inleakage. This latter value is: 580 gpm/.02 = 29000 gpm. It is the threshold leakage flow rate for overpressurization of the HPI piping, given accumulator inleakage.

4.4 ISL Initiator Frequencies For RHR Suction Paths

At all the plants selected, the RHR design includes a single suction line (Tables 2.3.3, 2.4.2 and 2.5.2). The line is separated from the RCS by two specially built MOVs in series. The basic failure model for two valves in series described in Section B.1.2 of Appendix B can be applied to calculate the average failure frequency of each of these valve arrangements provided the MOV failure modes are appropriately selected. Since some of the valve arrangements preclude certain failure modes, and test policies and practices are also different at each plant, the initiator frequencies are calculated on a plant-specific basis.

Leak failure exceedance frequency data as a function of leakage flow rate are not available for MOVs. The approach applied for the check valves, therefore, when initiator frequencies are evaluated as a function of leak

rate, cannot be applied. Under these circumstances the role of the suction side relief valves in the development of an ISL accident is problematic.

In order to overcome the problem, the following approach has been adopted in the calculation of initiator frequencies:

At plants where the suction side relief valve capacity is equal or larger than 1000 gpm (Indian Point 3 and Calvert Cliffs-1), failure combinations involving the MOV internal leakage failure mode are considered to represent double valve failure events, where the leakage into the RHR system is equal to or less than the relief valve capacity and therefore results only in "small LOCAs." Failure combinations, however, involving "MOV disc rupture" with other MOV failure modes (not with MOV internal leakage) are taken to contribute to the "overpressurization" of the RHR suction line (in other words, leakage into the suction line is assumed to be higher than the relief valve capacity).

In the case of Oconee 3, where the relief capacity on the suction side of the RHR system is smaller than 1000 gpm, a fraction of "small LOCA" events are assumed also to contribute to the "overpressurization" event frequency. These small LOCA events represent valve failures where the leakage is higher than the relief valve capacity. The fraction was estimated by using the leakage frequency exceedance curve for the check valves.

The frequencies of ISLs through the suction lines are calculated for various "cases," in a similar way to the procedure used for the injection lines. The cases are as follows:

a. The standard case corresponding to the present status of operational conditions and MOV test policy.
b. An improved case, where the improvement is the application of a permanent pressure sensor between MOVs 1 and 2.
c. An improved MOV test policy involving stroke and leak (disk integrity) testing after each cold shutdown.
d. Simultaneous application of b and c.
e. A "relaxed" MOV testing policy. (Stroke and disk integrity testing required only at each refueling. This case is calculated simply to determine the effects and cost-benefit relationship of instituting leak testing programs of pressure isolation valves for those plants that do not currently have such a requirement).
f. A base case corresponding to a hypothetical condition in which the MOVs are not tested for leak (disk integrity) failure over a long period of time.

4.4.1 Calculation of the Frequency of ISLs Through the RHR Suction Line at Indian Point 3

At Indian Point 3 the MOVs are stroke and leak (disk integrity) tested at each cold shutdown. The leak test rules out the possibility of leaving the valve open even though the control room has a signal indicating a closed position. (If both valves had failed open valve disks, that condition would be detected during plant startup.) The MOV transfer open failure mode cannot happen because at this plant the MOV circuit breakers are locked in the off position and the fuse disconnect is normally kept open during normal plant

operation. Both MOVs are located inside the containment. The gross external leakage failure mode would result in a LOCA inside the containment with the HP and LP recirculation paths remaining open. This would not cause an overpressurization. The frequency of this failure mode (Appendix A.2.6) is rather small, so its failure frequency contribution was assumed to be negligible.

Since the capacity factor of Indian Point is .72, the frequencies of double MOV failures, I_s resulting in "small LOCAs" and "overpressurization" events are calculated by use of Eqs. (11a) and (11b) of Section B.1.2 of Appendix B for the standard and "permanent pressure sensor" cases:

$$I_s \text{ (Small LOCA)}^{\text{Standard}} = .72\ (\lambda_L^2 T + \lambda_R \lambda_L T + 2\lambda_L \lambda_d) \qquad (5)$$

$$I_s \text{ (Overpressurization)}^{\text{Standard}} = .72\ (\lambda_R^2 T + 2\lambda_R \lambda_d) \qquad (6)$$

$$I_s \text{ (Small LOCA)}^{PS} = .72\ (\lambda_L^2 \frac{T}{2} + \lambda_R \lambda_L \frac{T}{2} + \lambda_L \lambda_d) \qquad (7)$$

$$I_s \text{ (Overpressurization)}^{PS} = .72\ (\lambda_R^2 \frac{T}{2} + \lambda_R \lambda_d) \qquad (8)$$

where λ_L, λ_R and λ_d denote the mean frequencies of the 1) MOV internal leakage, 2) MOV disk rupture, and 3) MOV fails open while indicating closed failure modes (the numerical values of these failure frequencies are given in Appendix A.2).

The time period, $T = 1/3$ year, is the average time between cold shutdowns.

For the base case calculation, it was assumed that during $T_L = 30$ years of operation there is no leak test performed on the MOVs. It was also assumed that the stroke test performed at each refueling ($T_R = 1.5$ year) would reveal disk rupture.

The formulas used to calculate the average failure frequencies (see Eq. (12a) of Section B.1.2 of Appendix B) are:

$$I_s \text{ (Small LOCA)}^{\text{Base Case}} = .72\ [\lambda_L^2 T_L + \lambda_R \lambda_L T_L + 2\lambda_L \lambda_d\ (\frac{dT_L+1}{2})]\ , \qquad (9)$$

and

$$I_s \text{ (Overpressurization)}^{\text{Base Case}} = .72\ [\lambda_R^2 T_R + 2\lambda_R \lambda_d\ (\frac{dT_R+1}{2})\ , \qquad (10)$$

where the demand rate of the MOVs is $d = 3$/year.

The results of the quantification of Eqs. (5) through (10) are presented in Table 4.7 for comparison with other initiator frequencies obtained for

other plants under various operation and testing conditions. The values listed in the table are used as inputs to the "small LOCA" and "overpressurization" event trees.

4.4.2 Calculation of the Frequency of ISLs Through the RHR Suction Line at Oconee 3

At Oconee 3, the MOVs of the RHR suction line are located inside the containment, thus the "MOV external leakage" failure mode is not included in the analysis. As was mentioned in the description of the MOVs at Indian Point 3, this failure mode would result in an inside containment small LOCA of very small occurrence frequency. The simultaneous occurrence of "MOV fails open, while indicating closed" failure events are expected to be recognized during plant heatups and are not further considered.

At Oconee 3 the two MOVs are:

- stroke tested at each cold shutdown and
- leak (disk integrity) tested every nine months.

Since the leak tests are carried out less frequently than the stroke tests, the "MOV fails open, while indicating closed" (demand type) failure mode would increase after each cold shutdown during the nine month period between the two leak tests. The failure mode "MOV internal leakage" and "MOV disk rupture" are also included in the analysis.

Electrical power is not disconnected from the MOVs, therefore "MOV transfer open" failure events may arise at Oconee 3. This particular failure mode affects only the second (downstream) MOV. The first (upstream) valve is always subjected to the full RCS pressure, and these valves are designed in such a way that the normal torque capability of their motors cannot open the valves against such a high differential pressure.

Calculations were carried out for all the cases listed from a) to f) in the introduction (Section 4.4).

Both frequencies, those of "small LOCA" and of "overpressurization," are determined by use of Eqs. (11a), (11b), (12a), and (12b) of Section B.1.2 of Appendix B. The equations are adapted to the specific failure modes identified for Oconee 3.

The form of the Eqs. obtained are very similar to those given for Indian Point 3. Therefore, they are not presented here. They are listed in Table B.1 of Appendix B. Here, information on the numerical values of parameters used in the quantification are detailed:

The frequencies of relevant MOV failure modes can be found in Section A.2. The capacity factor of the plant is: .86.

In the standard and "pressure sensor" cases the time period between leak tests is T_L = 3/4 year. The demand rate for MOV openings (cold shutdowns) is d = 4/year. The given time period relates to the "small LOCA" events. The time period for "overpressurization" events is taken to be, T_R = 1/4 year,

because it is assumed that stroke testing at cold shutdowns will reveal disc rupture.

In the cases of "increased leak test frequency" and "increased test frequency + pressure sensor," the time periods are $T_L = T_R = 1/4$ year.

In the case of a "relaxed" MOV testing policy, stroke and disk integrity testing is assumed to be carried out at each refueling, $T_L = T_R = 1.5$ year. The demand rate for MOV openings (cold shutdowns) is d = 4/year.

In the base case it is assumed that no leak test is performed during the period $T_L = 30$ years, a stroke test however is assumed to be carried out at each refueling period $T_R = 1.5$ year. The demand rate of MOV openings (cold shutdowns) is d = 4/year.

The fraction of "small LOCAs" which may cause "overpressurization" events is estimated to be about ~13% in all of the cases. This estimation is based on the assumption that the leakage failure frequency of MOVs follows the same trend as the leakage frequency exceedance curve of the check valves as a function of the leak rate.

The results of the quantification are listed in Table 4.7. The values indicated serve as inputs to the "small LOCA" and "overpressurization" event trees for this plant.

4.4.3 Calculation of the Frequency of ISLs Through the RHR Suction Line at Calvert Cliffs-1

The isolation valve arrangement on the RHR suction line at Calvert Cliffs 1 (Shutdown Cooling Line) is different from those of the other two reference plants. One of the isolation MOVs is located outside the containment. This requires consideration of the "MOV external leakage" failure mode for that valve because such a failure event would lead to an ISL bypassing the containment even though overpressurization would not occur.

An interesting feature of the Calvert Cliffs isolation valve system is that a relief valve is located between the two MOVs, inside the containment. While this relief valve has the potential for continuous leak monitoring, its set point (~2495 psia) is much higher than the normal operating pressure of the RCS (~2250 psia). Therefore, in the present study no credit is given to this possibility.

The MOVs are stroke and leak tested at every refueling. There are, on the average, about four cold shutdowns per year.

After cold shutdown, in order to eliminate the "MOV failing open while indicating closed" failure mode, manual checks are carried out as to whether the valves are indeed closed by using a calibrated torque wrench. A maintenance crew (consisting of two technicians) performs the checking. Credit is given for this plant procedure in the "standard" and "application of pressure sensor" cases.

The fuse disconnects of the MOVs at Calvert Cliffs 1 are normally not kept open. Consequently, the "MOV transfer open" failure mode was considered

to be credible for the second (downstream) MOV whose disc is not exposed to high differential pressure.

The failure frequency of the valve arrangements is calculated for all cases from a) to e) listed in the introduction to Section 4.4. "Small LOCA" and "overpressurization" event frequencies are determined by use of Eqs. (11a), (11b), (12a), and (12b) of Section B.1.2 of Appendix B through adapting them to the failure modes occurring at Calvert Cliffs 1 ("MOV internal leakage" and "MOV disc rupture" failure modes are also assumed to occur). The forms of the equations are similar to those given for Indian Point 3 and therefore are not presented here. They can be found listed in Table B.2 of Appendix B. Information concerning some relevant parameters used in the quantification is presented here.

The capacity factor of the plant is: .88.

In the standard and pressure sensor cases, the time period of stroke and leak tests is $T_R = T_L = 1.5$ year (refueling period). The demand rate of MOV openings (cold shutdown) is $d = 4$/year.

In the cases of "increased test (stroke and leak) frequency" and "increased test frequency plus pressure sensor," the chosen time period is the time interval between cold shutdowns $T_R = T_L = 1/4$ year.

In the base case, it was assumed that no leak test is performed during $T_L = 30$ years and no credit was given to the torque test procedure. Stroke tests, however, were assumed to be efficiently carried out to discover disc rupture at each refueling period $T_R = 1.5$ year. The demand rate of MOV openings was taken to be $d = 4$/year.

In all cases when calculating the frequency of ISLs bypassing the containment due to MOV external leakage, it was assumed that the time period during which an external leakage of the MOV located in the Auxiliary Building may escape detection is 8 hours/day. This is believed to be a conservative estimate.

The results of quantifying Eqs. (11) and (12) in Section B.1.2 for the frequencies of "small LOCA" and "overpressurization" events are presented in Table 4.7. In the table, external leakage contributions to the small LOCA frequencies are indicated separately. The data presented serve as inputs to the "small LOCA" and "overpressurization" event trees of the plant.

4.5 Letdown

The letdown line is used to continuously remove reactor coolant for level control and/or RC chemistry treatment.

4.5.1 Indian Point 3

Reactor coolant is withdrawn from the intermediate leg of the RC piping through a manual and two air-operated fail closed stop valves, LCV-459 and LCV-460. Three letdown orifices are provided to reduce the letdown flow pressure from RCS operating pressure (2235 psig) to the CVCS operating pressure (225-275 psig). Normally, one orifice is in operation allowing

normal letdown flow at optimum level. One of the other two orifices is for backup and the other is to increase letdown flow, when required, to the maximum capacity of the CVCS. A relief valve is provided on the inside containment section of the low pressure piping to protect it in either the event that the letdown control valves fail open resulting in rupture of the flow orifice or in the event of any of the low pressure block valves (201, 202) failing in the closed position. These failure modes combined with the failure of the relief valve may result in a pipe rupture. In case that the relief valve opens, the result would be a small LOCA inside the containment. A failure rate for air-operated valves failing to remain open or failing in the open position has been obtained from the data base included in the Oconee PRA[3] and has the value of $\lambda_{Valve} = 2.01(-03)$/year. The orifice rupture rate has been obtained from the data base provided in the Calvert Cliffs PRA,[4] $\lambda_{Orifice} = 2.63(-4)$/year. Similarly, the failure rate for a relief valve to open on demand is $\lambda_{RV} = 3.0(-4)$/d. The total average failure rate at Indian Point-3 resulting in a pipe rupture is

$$\langle\overline{\lambda}_{Letdown}\rangle = (\lambda_{Valve} + \lambda_{Orifice}) * \lambda_{RV} = 6.82(-7)/\text{year} .$$

The opening of the relief valve results in a small LOCA inside the containment and its average failure rate is

$$\langle\overline{\lambda}_{Letdown}\rangle = \lambda_{Valve} + \lambda_{Orifice} = 2.28(-3)/\text{year} .$$

4.5.2 Oconee 3

The letdown flow from the RCS is routed through the normally used 3A LD cooler. The MO block valves HP-1 and HP-3 are provided on this line inside the containment. There is a redundant cooler and associated block valves (3B, HP-2 and HP-4). Outside the containment there are two air-operated HP stop valves (HP-5, HP-6) upstream of the pressure reducing orifice and a letdown flow control valve (HP-7) parallel with the orifice. The HP/LP boundary is located outside the containment including the relief valve on the LP piping. Failures, such as orifice rupture, demineralized inlet valves failing closed or the letdown flow control valve failing open leading to overpressurization of the LP piping, result in a small LOCA outside the containment, even if the relief valves open. The failure modes to be considered are the same as previously discussed in Section 4.5.1.

$$\lambda_{Valve} = 2.01(-3)/\text{year}$$
$$\lambda_{Orifice} = 2.63(-4)/\text{year} .$$

The average failure rate for the letdown system including small LOCA events due to overpressurization and consequent opening of the relief valve is

$$\langle\overline{\lambda}_{Letdown}\rangle = \lambda_{Valve} + \lambda_{Orifice} = 2.28(-3)/\text{year} .$$

4.5.3 Calvert Cliffs 1

Coolant letdown from the cold leg first passes through the regenerative heat exchanger and then through the letdown control valves. The valves, controlled by the pressurizer level control system, control the letdown flow

to maintain proper pressurizer level. An excess flow check valve is installed before the control valves to limit the letdown flow in abnormal circumstances. RC pressure is reduced to CVCS operating pressure in one of the air-operated letdown control valves. A relief valve on the low pressure side prevents overpressurization of the LP piping.

The average failure rate of the letdown system can be obtained using general valve and orifice failure data as provided in the previous section and is estimated as:

$$\langle \bar{\lambda}_{\mathrm{Letdown}} \rangle = 2.28(-3)/\mathrm{year} \;.$$

4.6 References

1. Nuclear Power Experience, NPE, published by the S. M. Stoller Corp.
2. "Indian Point Probabilistic Safety Study," Power Authority of the State of New York and Consolidated Edison Company of New York, 1982.
3. "Oconee PRA, A Probabilistic Risk Assessment of Oconee Unit 3," NSAC-60, June 1984.
4. "Interim Reliability Evaluation Program: Analysis of the Calvert Cliffs Unit 1 Nuclear Power Plant," NUREG/CR-3511, Vol. 1, May 1984.

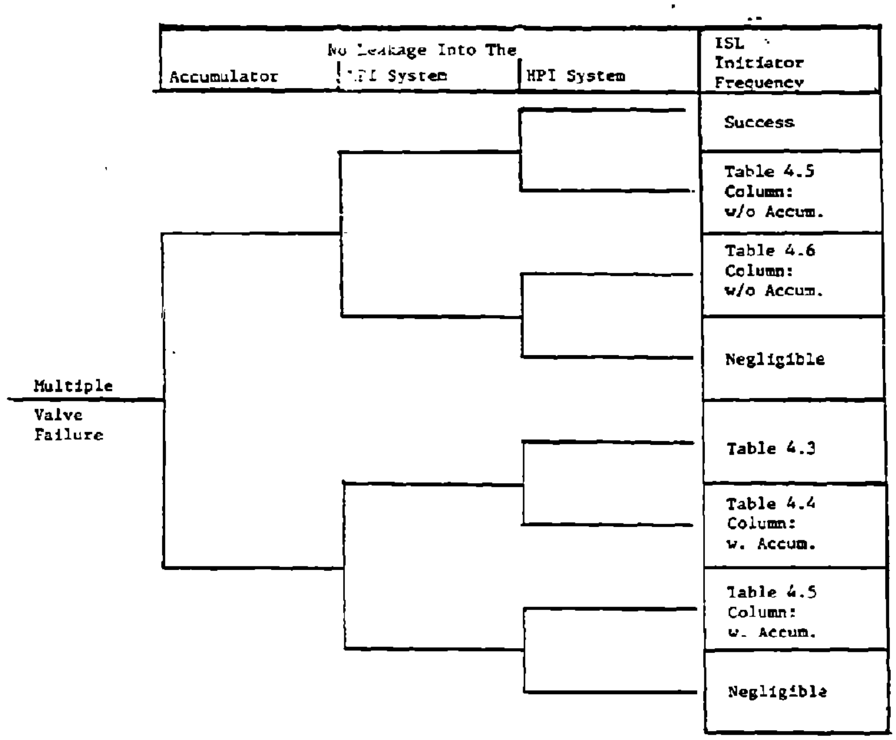


Figure 4.1 Schematics of ISL initiator frequency calculation for accumulator, LPI, and HPI injection lines.

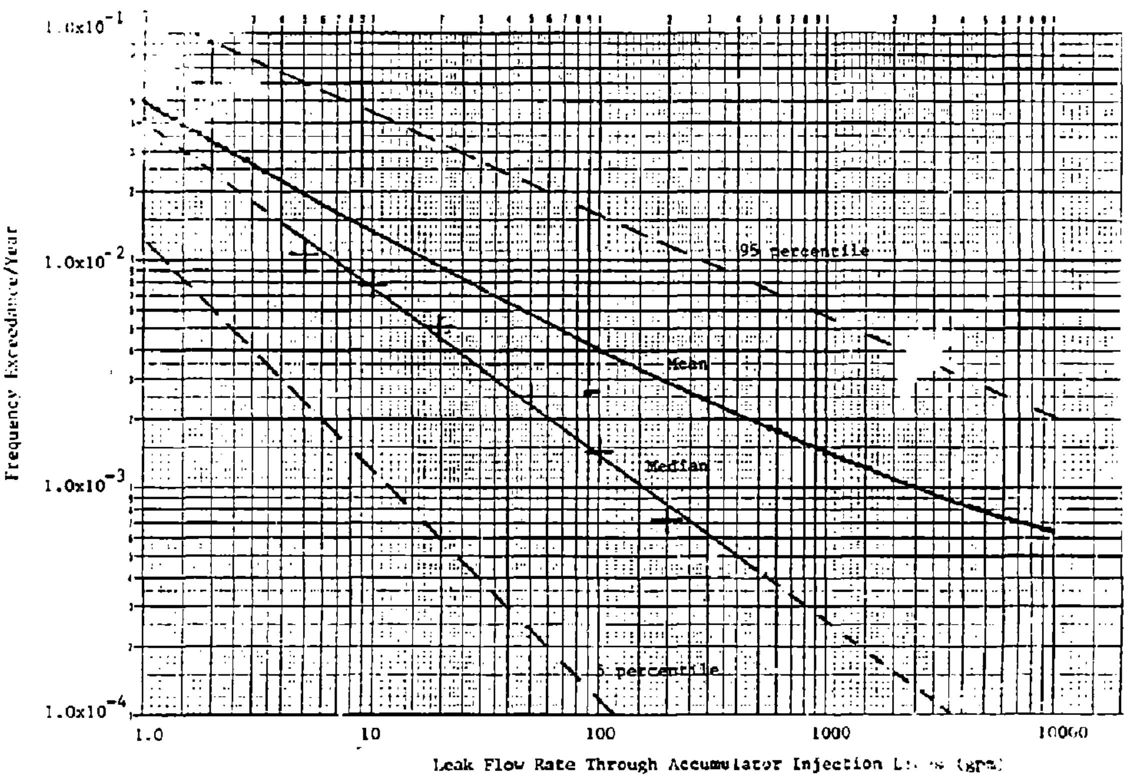


Figure 4.2 Frequency of accumulator inleakage events.

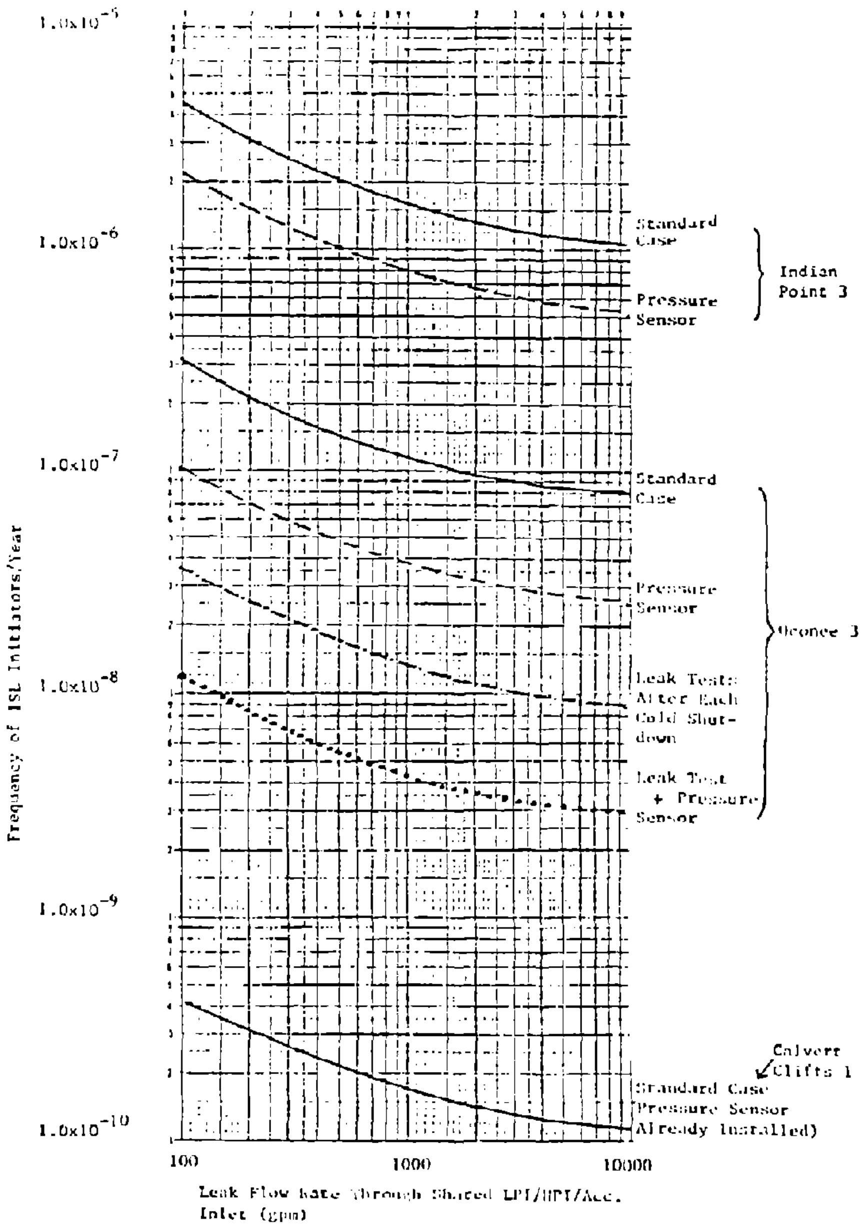


Figure 4.3a Frequency of ISL initiators through LPI lines without accumulator inleakage vs. leak flow rate.

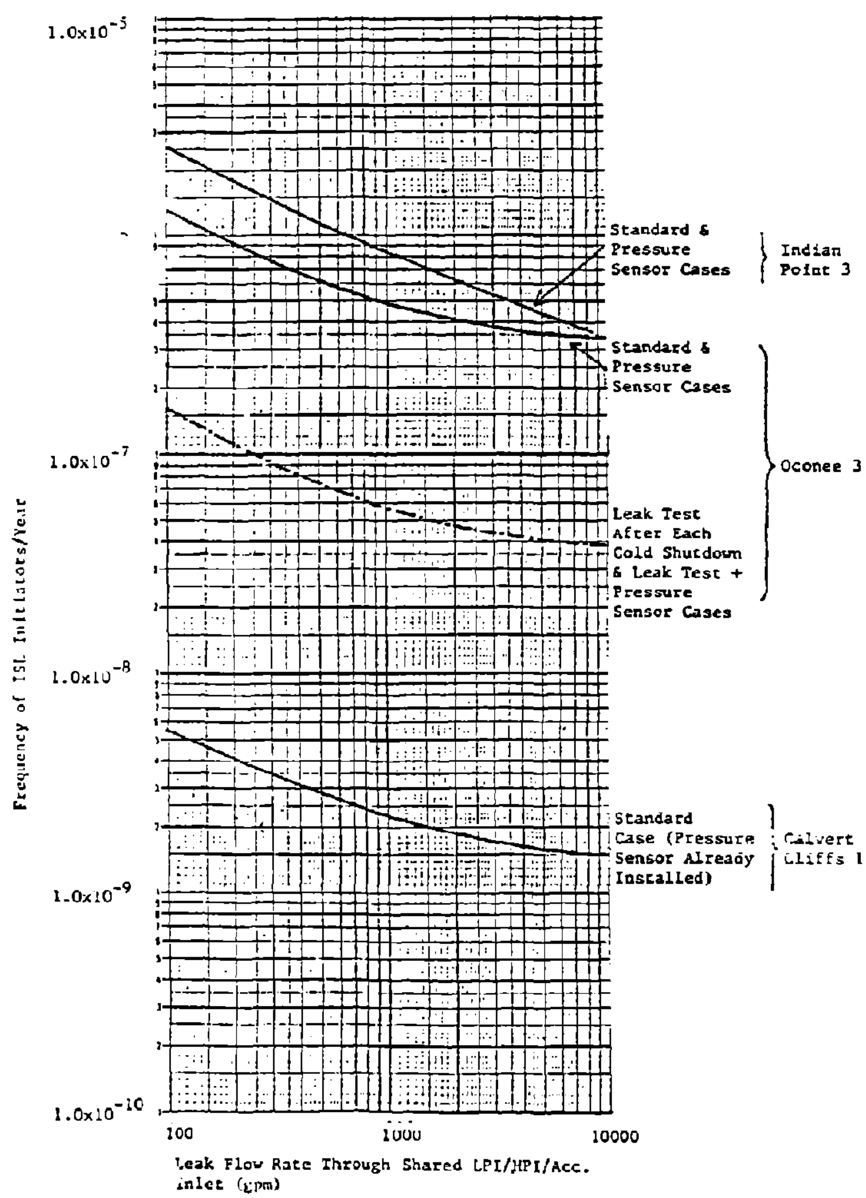


Figure 4.3b Frequency of ISL initiators through LPI lines with accumulator inleakage vs. leak flow rate.

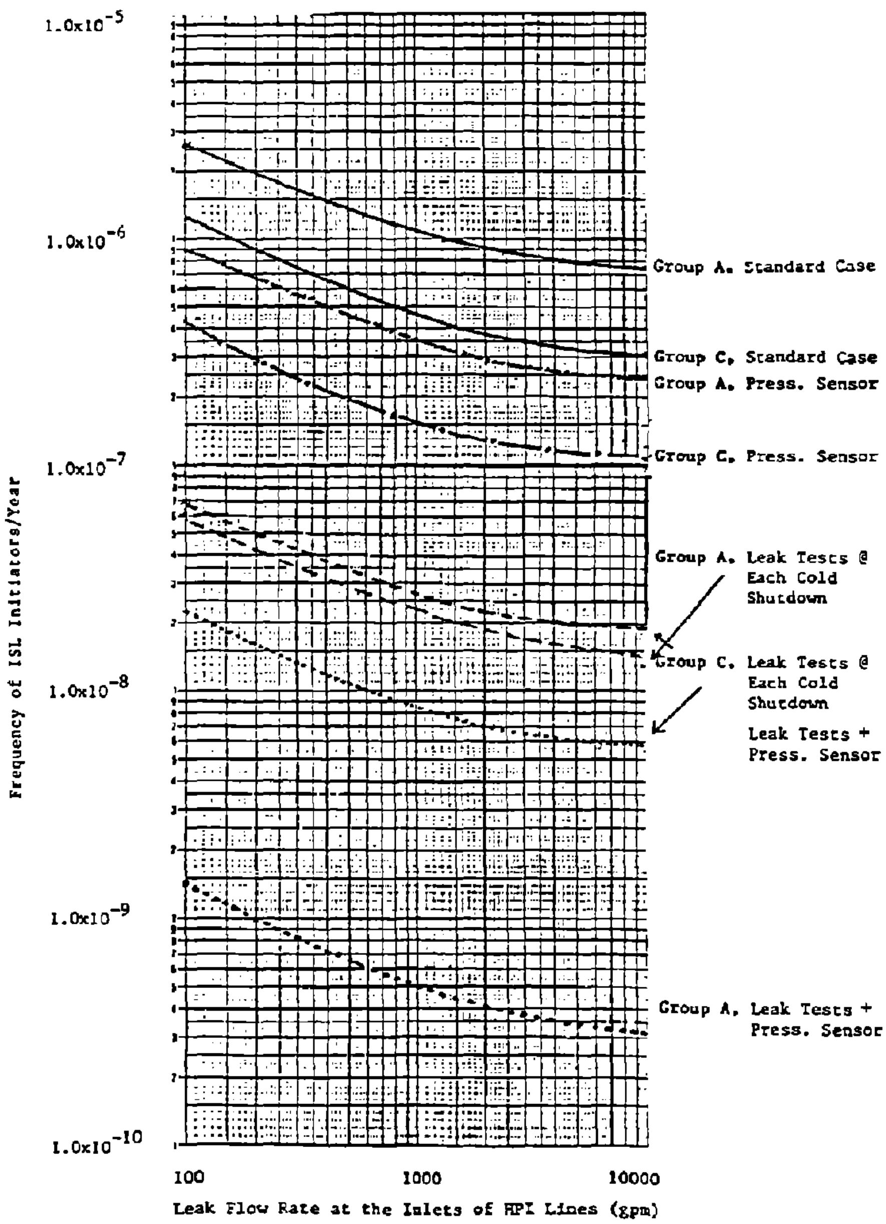


Figure 4.4a Frequency of ISL initiators through HPI lines (Groups A and C) vs. leak flow rate - Indian Point 3. Case: Without accumulator inleakage.

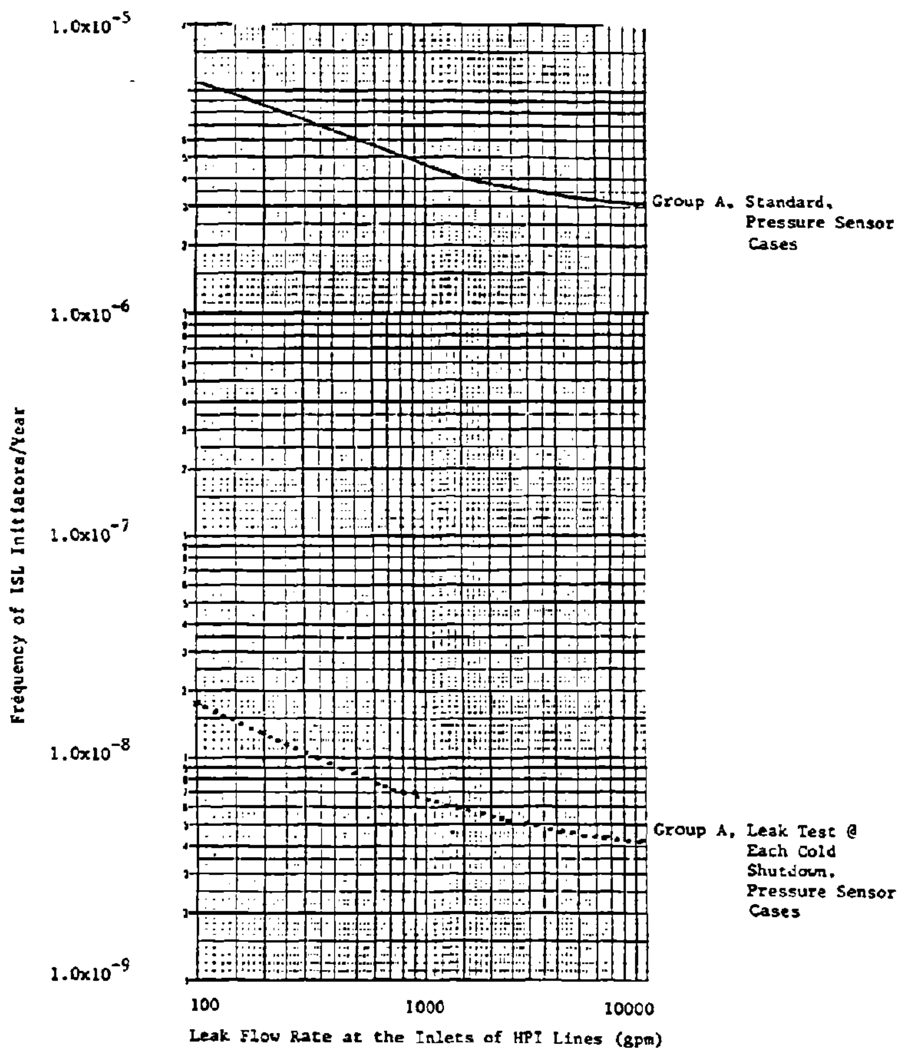


Figure 4.4b Frequency of ISL initiators through HPI lines (Group A) vs. leak flow rate - Indian Point 3. With accumulator inleakage.

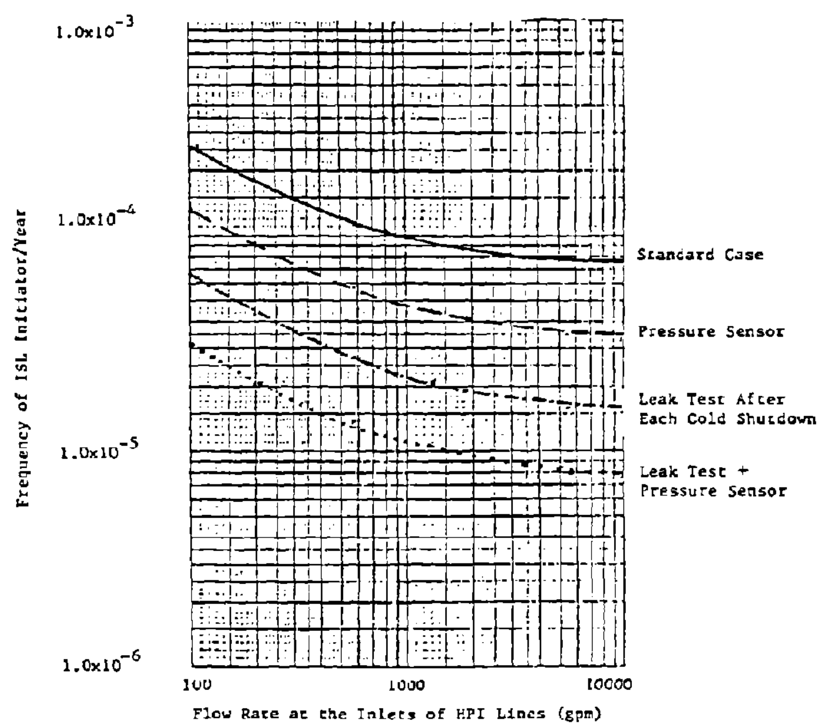


Figure 4.4c Frequency of ISL initiators through HPI lines (Group B) vs. leak flow rate - Indian Point 3.

Table 4.1
Some Design Characteristics of The Accumulators
(Core Flooding Tanks) at The Selected PWRs

Design Characteristics	Indian Point-3	Oconee-3	Calvert Cliffs-1
Number of accumulators	4	2	4
Design pressure (psig)	700	700	250
Operating pressure (psig)	650	600	200
Tank total volume (gallon)	8230	10547	14960
Water volume (gallon)	5240	7780	8325
"Free" volume (gallon)	~3000	~2800	~6650
Number of relief valves	1	1	1
Relief valve size	1"	1"	1"
Relief valve setpoint	700	~700	250
Relief valve capacity (est.) (gpm)	710	710	425
Drain line (accessible) and size (inch)	1 (1")	1 (1")	1" (1")
Drainage capacity (gpm)	~1250	~1250	~1250

Table 4.2
Filling Time of Accumulator's "Free" Volumes
For Various Leak Rates*

Indian Point-3		Oconee-3		Calvert Cliffs-1	
Leak Rate (gpm)	Time (min)	Leak Rate (gpm)	Time (min)	Leak Rate (gpm)	Time (min)
100	30	100	28	100	66
200	15	200	14	200	33
300	10	280	10	300	22
500	6	467	6	500	13
740	4	700	4	665	10
1000	3	1000	~3	1000	~7

*Leak rates underlined correspond to the "critical time" necessary to the operator to take successful corrective actions.

Table 4.3
ISL Initiation Frequencies For Accumulator Pathways and Mean Time to Leakage Into the Accumulators

	Indian Point-3	Oconee-3	Calvert Cliffs-1
Reactor at power	.72	.86	.88
Number of lines, Size (inch)	4 10	2 14	4 12
Leak rate (gpm) at the "critical time, 10 min.,"	300	280	665
Leak failure exceedance frequency at above leak rate (per line-year)	2.45(-3)	2.5(-3)	1.75(-3)
ISL initiation frequency at above leak rate: "small LOCA through the accumulator relief valve or accumulator overpressurization" (per year)	7.05(-3)	4.30(-3)	6.15(-3)
ISL frequency at accumulator relief valve capacity: "overpressurization" (per year)	4.90(-3) (710 gpm)	2.93(-3) (710 gpm)	*
Leak failure exceedance frequency at leak rate of 1.5 gpm (per line year)	3.9(-2)	3.9(-2)	3.9(-2)
Maximum frequency of accumulator inleakage (per year)	1.1(-1)	5.6(-2)	1.4(-1)
Mean time to failure, MTTF (year)	9.0	17.9	7.1

*Not calculated (relief valve capacity is smaller than 665 gpm).

Table 4.4
Formulas to Calculate Initiator Frequencies for ISL Through LPI Lines at Indian Point 3

Cases	Frequency of Double Valve Failures: With Accumulator Inleakage		Without Accumulator Inleakage	
Standard Case $T = 1/3$ year	$2.88(\lambda_1\lambda_d)C$	(2a)	$2.88[\langle\lambda_s^T(1,2)\rangle](1-C)$	(2b)
Application of Pressure Sensor	Same as above	(3a)	$2.88[\langle\lambda_s^T(1,2)_{PS}](1-C)$	(3b)
Base Case	$2.88(\lambda_1\lambda_d)(\frac{dT+1}{2})C$	(4a)	$2.88[\langle\lambda_s^T(1,2,d)\rangle](1-C)$	(4b)

Table 4.5
ISL Initiation Frequencies for LPI Pathways*

Plant	Number of Lines	Case	Leak Rate @ The Shared LPI/HPI/Accum. Inlet (gpm)	LPI Inleakage Frequencies: With Accumulator Inleakage (Per Year)	LPI Inleakage Frequencies: Without Accumulator Inleakage (Per Year)	I_{LPI} Initiator Frequencies Selected For Further Analysis (Per Year): Small LOCA+	I_{LPI} Initiator Frequencies Selected For Further Analysis (Per Year): Overpres-surization++
Indian	4	Standard	Between 98				
Point			and 740		2.71(-6)	3.06(-6)	
3			Between 272				
			and 470	3.53(-7)			
			>740		1.78(-6)		
			≥2100	6.11(-7)			2.39(-6)
		Pressure	Between 98				
		Sensor	and 740		1.36(-6)		
			Between 272				
			and 470	3.53(-7)		1.71(-6)	
			>740		8.90(-7)		
			≥2100	6.11(-7)			1.50(-6)
		Base	Between 98				
		(No Leak	and 740		6.20(-5)		
		Test in 8	Between 272				
		Years)	and 470	1.27(-5)		7.47(-5)	
			>740		4.10(-5)		
			≥2100	2.20(-5)			6.30(-5)
Oconee	2	Standard	Between 100				
3			and 330		1.40(-7)	4.81(-7)	
			Between 200	3.41(-7)		[1.40(-7)]	
			and 570	[2.92(-10)]			
			≥330		1.72(-7)		
			≥650	5.71(-7)			7.43(-7)
				[4.25(-10)]			[1.72(-7)]
		Pressure	Between 100				
		Sensor	and 330		4.59(-8)		
			Between 200	3.41(-7)		3.87(-7)	
			and 570	[2.92(-10)]		[1.40(-7)]	
			≥330		5.61(-8)		6.27(-7)
			≥650	5.71(-7)			[5.65(-8)]
				[4.25(-10)]			
		Leak	Between 100				
		Test	and 330		1.64(-8)		
		After	Between 200	4.00(-8)		5.64(-8)	
		Each	and 570	[8.60(-11)]		[1.65(-8)]	
		Cold	≥330		2.01(-8)		8.63(-8)
		Shutdown	≥650	6.62(-8)			[2.14(-8)]
				[1.31(-9)]			

Table 4.5 (Continued)

Plant	Number of Lines	Case	Leak Rate @ The Shared LPI/HPI/Accum. Inlet (gpm)	LPI Inleakage Frequencies: With Accumulator Inleakage (Per Year)	LPI Inleakage Frequencies: Without Accumulator Inleakage (Per Year)	I_{LPI} Initiator Frequencies Selected For Further Analysis (Per Year): Small LOCA+	I_{LPI} Initiator Frequencies Selected For Further Analysis (Per Year): Overpressurization++
Oconee	2	Leak	Between 100		5.38(-9)		
3		Test	and 330				
		and	Between 200	4.00(-8)		4.53(-8)	
		Pressure	and 570	[8.60(-11)]		[5.46(-9)]	
		Sensor	≥330		6.52(-9)		
			≥650	6.62(-8)			7.27(-8)
				[1.31(-9)]			[7.83(-9)]
		Leak	Between 100		5.64(-7)		
		Test at	and 330				
		Each	Between 200	1.29(-6)		1.85(-6)	
		Refueling	and 570				
			≥330		6.86(-7)		2.87(-6)
			≥650	2.18(-6)			
		Base	Between 100		6.37(-5)		
		(No	and 330				
		Leak	Between 200	1.47(-4)		2.11(-4)	
		Test	and 570	[9.40(-8)]		[6.38(-5)]	
		in 16	≥330		7.73(-5)		
		Years)	≥650	2.47(-4)			3.24(-4)
				[1.38(-7)]			[7.36(-5)]
Calvert	4	Standard	Between 132		1.41(-10)	5.91(-10)	
Cliffs		(Pressure	and 330				
1		Sensor	Between 530	4.5(-10)		[1.41(-10)]	
		Installed)	and 890	[2.6(-13)]			
			≥330		2.52(-10)		2.31(-9)
			≥1320	2.06(-9)			[2.53(-10)]
				[8.54(-13)]			
		Base	Between 132		4.54(-6)	1.89(-5)	
		(No Leak	and 330				
		Test in	Between 530	1.44(-5)		[4.54(-6)]	
		8 Years)	and 890	[1.90(-9)]			
			≥330		8.06(-6)		7.42(-5)
			≥1320	6.61(-5)			[8.07(-6)]
				[6.06(-9)]			

*The numbers in brackets correspond to the case that leakage through the second (and third) check valve, as well as through the MOV, is detected given stuck open accumulator check valve.

+Events without overpressurizing the LPI system.

++Event overpressurizing the LPI system. (For a more precise definition of the above events see the text (e.g., pgs. 4-12, 4-13).)

Table 4.6
ISL Initiation Frequencies for HPI Pathways

Plant	Case	Line Group Name & No. of Lines in the Group	Leak Rate @ The Shared LPI/HPI/Accum. Inlet (gpm)	LPI Inleakage Frequencies: With Accumulator Inleakage (Per Year)	LPI Inleakage Frequencies: Without Accumulator Inleakage (Per Year)	I_{HPI} Initiator Frequencies Selected For Further Analysis (Per Year): Small LOCA+	I_{HPI} Initiator Frequencies Selected For Further Analysis (Per Year): Overpressurization++
Indian	Standard	A	Between 98				
Point		4	and 580		1.35(-6)		
3			Between 2450				
			and 14500	5.31(-7)			
			≥580		1.28(-6)		
			≥14500	3.30(-6)		1.59(-4)	1.22(-4)
		B	Between 98	No shared	1.57(-4)		
		4	and 580	inlet			
			≥580		1.17(-4)		
		C	Between 98	No shared	7.13(-7)		
		2	and 580	inlet			
			≥580		5.47(-7)		
	Pressure Sensor					7.79(-5)	6.22(-5)
	Leak Test After Each Cold Shutdown					3.65(-5)	2.78(-5)
	Leak Test + Pressure Sensor					1.82(-5)	1.39(-5)
	Base (No Leak Test During 30 Years)					4.05(-3)	4.36(-3)
Calvert	Standard	4	Between 132		1.92(-10)		
Cliffs	(Pressure		and 580				
1	Sensor		Between 6600	3.40(-12)			
	Installed)		and 29000			1.95(-10)	1.74(-9)
			≥580		2.01(-10)		
			≥29000	1.54(-9)			

Table 4.6 (Continued)

Plant	Case	Line Group Name & No. of Lines in the Group	Leak Rate @ The Shared LPI/HPI/Accum. Inlet (gpm)	LPI Inleakage Frequencies: With Accumulator Inleakage (Per Year)	LPI Inleakage Frequencies: Without Accumulator Inleakage (Per Year)	I_{HPI} Initiator Frequencies Selected For Further Analysis (Per Year): Small LOCA+	I_{HPI} Initiator Frequencies Selected For Further Analysis (Per Year): Overpressurization++
	Base (No Leak Test During 30 Years)		Between 132 and 580		3.24(-4)		
			Between 6600 and 29000	5.50(-5)			
			≥580		3.40(-4)	3.79(-4)	2.95(-3)
			≥29000	2.61(-3)			

+Events without overpressurizing the HPI system.
++Event overpressurizing the HPI system. (For a more precise definition of the above events see the text (e.g., pgs. 4-12, 4-13).)

Table 4.7
ISL Initiator Frequencies for RHR Suction Pathways*

Operational & Test Conditions of MOVs (Cases)	Indian Point-3 Frequency (per year) Small LOCA	Indian Point-3 Frequency (per year) Overpres-surization	Oconee-3 Frequency (per year) Small LOCA	Oconee-3 Frequency (per year) Overpres-surization	Calvert Cliffs-1 Frequency (per year) Small LOCA	Calvert Cliffs-1 Frequency (per year) Overpres-surization
Stroke and leak tests at each cold shutdown and application of permanent pressure sensor. At Indian Point-3: $T_R=T_L=1/4$ year. Disconnected fuses. At Oconee-3 and Calvert Cliffs-1: $T_R=T_L=1/4$ year. Connected fuses. At Calvert Cliffs-1 direct external leakage.	8.40(-6)	3.30(-7)	8.08(-6)*	4.36(-7)	7.81(-6) Ext. leakage: 1.95(-7) Total: 8.01(-6)	3.34(-7)
Stroke and leak tests at each cold shutdown. Standard case at Indian Point-3. At Indian Point-3: T=1/3 year. Disconnected fuses. At Oconee-3 and Calvert Cliffs-1: T=1/4 year. Connected fuses. At Calvert Cliffs-1 direct external leakage.	1.68(-5)	6.79(-7)	1.42(-5)*	7.67(-7)	1.52(-5) Ext. leakage: 7.78(-7) Total: 1.60(-5)	5.61(-7)
Application of permanent pressure sensor. Oconee-3: Leak tests at each nine month period: $T_L=3/4$ year. Stroke test: $T_R=1/4$ year (at cold shutdown). Connected fuses. Calvert Cliffs-1: Leak and stroke tests at each refueling: $T_L=T_R=1.5$ years. Credit is given to torque test after each cold shutdown. Direct external leakage. Connected fuses.	---	---	2.38(-5)*	5.47(-7)	4.68(-5) Ext. leakage: 1.17(-6) Total: 4.80(-5)	2.00(-6)
Standard cases at Oconee-3 and Calvert Cliffs-1. Oconee-3: Leak tests at each nine month period: $T_L=3/4$ year. Stroke test: $T_R=1/4$ year (at cold shutdown). Connected fuses. Calvert Cliffs-1: Leak and stroke tests at each refueling: $T_L=T_R=1.5$ years. Credit is given to torque test after each cold shutdown. Connected fuses. Direct external leakage.	---	---	4.63(-5)*	9.90(-7)	9.11(-5) Ext. leakage: 4.67(-6) Total: 9.58(-5)	3.36(-6)
"Relaxed" MOV Testing Oconee 3: Leak and stroke test at each refueling. $T_L=T_R=1.5$ year Cold shutdowns: d=4/year Connected fuses.	---	---	9.22(-5)*	4.06(-6)	---	---

Table 4.7 (Continued)

Operational & Test Conditions of MOVs (Cases)	Indian Point-3 Frequency (per year) Small LOCA	Overpressurization	Oconee-3 Frequency (per year) Small LOCA	Overpressurization	Calvert Cliffs-1 Frequency (per year) Small LOCA	Overpressurization
Base Case Stroke test at each refueling: T_R=1.5 years. Leak test at each 30 years: T_L=30 years. Cold shutdowns: d=3/year Indian Point-3 d=4/year Oconee-3 Calvert Cliffs-1 Connected fuses for Oconee-3 and Calvert Cliffs-1. No credit is given to torque test at Calvert Cliffs-1. Direct external leakage.	1.36(-3)	1.06(-5)	1.69(-3)*	1.66(-5)	1.73(-3) Ext. leakage: 9.94(-5) Total: 1.83(-3)	1.70(-5)

*13% of the small LOCA frequency value may contribute to the overpressurization frequency because of the small relief valve capacity.

Notes: The table is organized in order of less constraining MOV test policy.

"Small LOCA" defines double MOV failures where the leak rate is smaller than the capacity of suction side relief valve.

"Overpressurization" defines double MOV failures were the leak rate is higher than the relief valve capacity.

Estimated Relief Valve Capacities: Indian Point-1: 2600 gpm (Setpoint: 600 psia, Pipe Dia.: 2").
Oconee-3: 300 gpm (Setpoint: 388 psia, Pipe Dia.: 3/4").
Calvert Cliffs-1: 1100 gpm (Setpoint: 315 psia, Pipe Dia.: 1.5").

5. CORE DAMAGE FREQUENCIES AND EVENT TREES

The event trees have been constructed in such a way that, for any given initiator, the end states correspond to an initiating event of the respective PRA study of the particular reference plant.[1-2-3] In this manner, all events are classed as small or large LOCAs, inside or outside the containment building with a respective conditional core damage frequency derived from the plant PRAs. The effect of ISL on safety systems required to mitigate a LOCA has also been considered in determining the conditional core damage frequency. Table 5.1 lists all conditional core damage frequencies as derived from the plant-specific PRA studies. The main results of this study, the core damage frequencies due to ISLs, are listed in a summary format in Tables 5.2 through 5.6 for the three plants.

In order to mitigate LOCAs bypassing the containment, the operator has to rely on the water supply available in the RWST. Once the RWST is depleted, an additional source of water must be found. The time available to establish makeup to the RWST varies depending on the size of the break and the available equipment and could range from 3-4 minutes (~6" break no LP, no HP systems), to a few (~12) hours (~1" break HP available).[4] The makeup to the RWST would be based on an "ad hoc" arrangement, and consequently was not modelled. Core damage was assumed to occur when the RWST has been depleted and makeup has not been established. One of the important parmeters in the event trees is the probability of a major pipe rupture in case of an overpressurization event. A summary of pipe failure probabilities, calculated based on the methods presented in Appendix F, are listed in Table 5.7.

In Sections 5.1 through 5.5 the event trees for all interfacing systems are discussed along with the additional assumptions used to establish the core damage frequencies. Section 5.6 briefly describes the method used to derive the conditional core damage frequencies from the plant-specific PRAs. The core damage frequencies are presented in Section 5.7. In Appendix C, assumptions used to quantify operator performances are discussed and Appendix D presents a brief summary of the thermal-hydraulic aspect of ISL events. In Appendix E a more detailed discussion is presented regarding the derivation of the plant-specific conditional core damage frequencies. A detailed analysis of the pipe rupture probability is presented in Appendix F.

5.1 LP Injection

The event trees for the three reference plants are shown on Figures 5.1 and 5.2.

An overpressurization event of the LP injection lines at Calvert Cliffs & Oconee cannot be isolated; causing a LOCA bypassing the containment. Even though at Oconee one LP injection train might be unaffected, the loss of recirculation capability leads to core damage once the RWST water supply runs out. The Indian Point arrangement is different from the other plants, because a large portion of the system is routed inside the containment and, in addition, there is isolation capability on each injection line. It is very likely that an overpressurization event of the LP injection line at Indian Point will result in a LOCA inside the containment. The injection line is designed such, that the operator has the capability to terminate the blowdown of the primary coolant by closing at least one of the two high-pressure-rated

MOVs. In addition to the major pipe break event, the top events are (a) pipe break location (inside/outside containment building) and (b) operator diagnoses the event and attempts to terminate it. The probability of a major pipe break due to an overpressurization event has been determined in Appendix F and the numerical values used in the event tree are listed in Table 5.7. In case of a small break, the probability of a pipe break inside the containment was estimated at .9. This probability was based on engineering judgment after reviewing the piping design and actual layout of the LP injection piping. In case of a small break inside the containment, the primary concern is that, depending on the actual break location, the HP recirculation capability might be disrupted increasing the core damage frequency due to an unisolated small LOCA without recirculation.

Thermal-hydraulic calculations[4] have indicated (see Appendix D for a brief summary) that there is ample time available (2-3 hours) to the operator to diagnose a small LOCA event. It is assumed that at least one of the two isolation MOVs would operate and would terminate the blowdown of the primary coolant.

The NREP cognitive error function (see Appendix C) has been used to determine the probability of an operator error ($2x10^{-3}$) having ~2 hours available to recognize and isolate a small LOCA through the LP injection lines.

The core damage frequency for terminated small LOCAs has been determined using the unavailability of the HP injection system.

A small break outside the containment on the recirculation line connecting the LP outlet to the suction side of the HP pumps would disable the normally closed isolation valves. The RWST would drain through the pipe break and the HP pumps would be unavailable, leading to core damage regardless of the isolation capability.

A large LOCA inside the containment would disable one LP injection line making the LP pumps unavailable, leading to core damage. It is assumed that the isolation capability would be lost during a large LOCA, because the isolation MOVs are not designed for high flow and high temperature conditions.

5.2 SI Discharge

The event tree (Figure 5.3), for the safety injection (SI) line overpressurization event is relatively simple at Calvert Cliffs. There is no isolation capability, therefore, a pipe break (small LOCA) would eventually lead to core damage, when the RWST water supply is depleted and makeup cannot be established.

At Indian Point, some low pressure portions of the SI piping are inside the containment making the event tree somewhat more complicated (Figure 5.4). In addition, an open MOV on each injection line can isolate a LOCA event. Given an overpressurization accident, the relief valve common to both trains will open leading to a small LOCA inside the containment. If the leak does not exceed the relief valve capacity, then the core damage frequency is that associated with a small LOCA. The integrity of both injection trains is intact and they can be used to mitigate the accident. If the leak is larger

than the relief valve capacity, the integrity of the piping boundary may be lost. The pipe rupture probability has been estimated in Appendix F and is listed in Table 5.7. If the pressure boundary is damaged at the train isolating check valves (858A or B), then the other train may loose enough flow through the break making the HP system unavailable. This leads to core damage even if the blowdown is terminated by the operator (no makeup capability).

If the pipe break is located outside the containment (with a probability of .1) and is not terminated, core damage will result, because of the lost recirculation capability. In addition, the RWST would most likely be drained through the damaged train making the progress of this accident much faster (reduced RWST inventory). In order to terminate the accident outside the containment on the HP pump discharge line, the operator has to (a) be able to diagnose the problem, (b) terminate the RC blowdown with the SI high pressure isolation MOV, and (c) be able to isolate the damaged HP train and stop the RWST drain. The available time is judged to be 30-60 minutes. Considering the complexity of the accident and the short available time, the probability of an error in the operator's action is taken as .1.

The core damage frequency associated with the small LOCA outside containment, terminated by the operator has been calculated using HP system unavailability with one train in a failed mode.

5.3 RHR Suction

The event trees for all three reference plants are very similar and are shown in Figures 5.5 and 5.6. The main difference at Calvert Cliffs is that the pressure isolation boundary is located outside the containment leading to LOCAs that always bypass the containment. At Indian Point and Oconee the initiator or overpressurization event may cause a pipe break either inside or outside the containment. The first top event is to decide if the event is a small (<6") or large break. The major pipe rupture probability has been derived in Appendix F and is listed in Table 5.7. The location of the pipe break is of utmost importance and the second top event determines if this is a break inside the containment or bypassing it. The probability of a pipe break outside the containment at Indian Point has been based on field observations and was estimated at .1. The LP piping inside the containment is ~5 times longer than the outside segment with numerous pipe turns and bends with all supports inside containment and only one pipe support outside. The low probability of an outside pipe break has also been supported by the results of a detailed V-sequence analysis[5] completed for the Indian Point RHR piping. At Oconee, the line just beyond LP-2 is schedule 10 (wall thickness of .18") and outside the containment is schedule 20 (wall thickness of .25"). There is also a relief valve (388 psi setpoint), which could not relieve the full pressure. The relief valve and the schedule 10 line are the most likely failure points. The probability that pipe break occurs inside the containment was estimated, based on these considerations at .9. If the overpressurization is such that the relief valve is lifted and the leak does not exceed the relief valve capacity the end result is a small LOCA inside the containment. Each plant has an additional low-pressure-rated normally closed valve on the suction line after the two closed MOVs. The assumption has been made that a major pipe break outside the containment would disable this valve. However, for small breaks, this third isolation valve would maintain the pressure

boundary. Large LOCAs outside the containment eventually lead to core damage, because recirculation is unavailable and the RWST water supply is limited.

5.4 Letdown Lines

Figures 5.7 and 5.8 show the event trees for the letdown lines. The first top event determines whether the relief valve opens or fails in the closed position. Its failure rate (3×10^{-4}) has been estimated using generic data from Reference 3. The primary top event asks whether the operator can recognize the nature of the accident and what action might be taken. The time available, even when the HP system is unavailable, is about 1-2 hours before the RWST water supply runs out. The blowdown can be terminated by closing the high-pressure-rated letdown stop valves. The probability of the operator not being able to recognize and terminate the accident (5×10^{-3}) was determined from the NREP cognitive error function (Appendix C). In this accident a substantial amount of primary coolant may be lost requiring makeup capability using the HP pumps. The core damage frequency associated with terminated small LOCAs reflects the unavailability of the HP system.

At Indian Point, in addition to operator action, a top event representing inside or outside break location is also included. The probability of a letdown pipe rupturing outside the containment (.5) has been estimated as previously described in Section 5.3.

5.5 Accumulators

The event tree for the accumulator system is shown on Figure 5.9. The accumulators are well instrumented including high pressure and high-low level alarms. The operator can easily recognize and diagnose a small ISL event with ample time available to terminate it. Therefore, the ISL's are essentially non-events below a certain critical leak rate (see Section 4.3.2.1). If the leak rates are above the critical level, the time available for operator action is on the order of a few minutes. It has been assumed that, initially, the operator would try to maintain the water level in the accumulator by draining the excess leakage. The operator error associated with the draining action is based on the lower bound HEP values of Figure C.1 (Appendix C). For Oconee, no remote draining capability has been identified; eliminating the possibility of this action. If the back-leakage is in excess of the drain and relief capacity, a major pipe rupture may occur. The probability of a major pipe rupture has been derived in Appendix F and is listed in Table 5.7. The operator may be able to terminate the ISL event by closing the high-pressure-rated MOV on the accumulator outlet lines, which is deenergized-open in normal operation and thus would require local action at the valve MCC. The probability of an operator error, including the probability of an MOV failure to close on demand, has been estimated at 3.0×10^{-3} using generic MOV data with the error recognition function. In case of a major pipe or tank rupture, the event is equivalent to the large LOCA design basis accident (DBA) of the FSAR with one accumulator not being available. All three reference plant PRAs discuss and quantify this event.

5.6 Conditional Core Damage Frequencies (CCDF)

The CCDF values have been derived from the plant-specific PRAs[1-3] and are fully explained in Appendix E. All ISL events result in a small or large

LOCA, inside or outside the containment. In addition, the effect of the initiating event (ISL) on some of the safety systems required to mitigate the accident has also been considered.

5.6.1 Indian Point, Unit 3

In the following events, the operator is unable to isolate the primary coolant leak and a failure in one of the required safety systems leads to core damage. For detailed discussion see Appendix E, Chapter E.1.

1. Large LOCA Inside Containment - 8.4-03.

   This sequence is basically dominated by sequences AEFC and ALFC, which reflects the failure of the LP injection or recirculation functions (see Appendix E.1.3.1).

2. Small LOCA Inside Containment - 4.5-03.

   The Indian Point PRA has three LOCA classes (large, medium, and small). In this study, medium and small LOCA have been grouped together (small loca <6"). In this case, the dominant sequences are again related to the injection and recirculation functions (see Appendix E.1.3.2).

3. Large LOCA Outside Containment - 1.0

   In case of a pipe break larger than 6", the available time is very limited before core damage starts. Thermal-hydraulic studies, documented in Appendix D, indicate that core damage may be prevented if the safety injection system is available. However, these calculations analyzed the first six minutes of the accident and there are indications that other heat removal mechanisms may be required to prevent fuel melting. In this study, no credit has been given for these limited thermal-hydraulic calculations and it was assumed that once a large ISL bypassing the containment occurs core damage is certain, i.e., $CCDF_{LOCA} = 1.0$.

4. Small LOCA Outside Containment - 4.5-03.

   In case of a small interfacing system LOCA bypassing the containment, the operator has to use a basically once-through cooling method supplying water from the RWST. Even though the available water supply is limited in the RWST, the operator has, in most cases, other sources of water to establish additional makeup, if needed. The dominant failure modes are a) HP system unavailability and b) operator error in establishing or finding other sources of cooling water. The first function is identical to the failure of the injection function in the case of an inside LOCA. It was assumed that the other failure mode, operator error in the makeup phase, is similar to the failure of the recirculation mode.

ISL events terminated by the operator result in core damage only if the makeup capability to the RCS is lost.

5. Small LOCA Inside/Outside, Terminated - 1.7-04.

   In this case the operator is able to terminate the loss of primary coolant, but it is assumed that makeup is still required to prevent core damage using the HP injection system. This value essentially represents the HP system unavailability (see Appendix E.1.3.3).

6. Small LOCA Inside/Outside HP Train Affected - 5.74-03.

   The ISL event may affect one HP injection train. In this case, unavailability of the HP system may be recalculated in terms of the unavailabilities of the dominant contributors with one train in a failed mode (see Appendix E.1.3.4 for details).

5.6.2 Oconee, Unit 3

1. Large LOCA Inside Containment - 1.03-02.

   Large break LOCA events are contained in Bin V and VI.[2] Bin V sequences include all those initiating events where core melt results due to failure in the injection phase (AU sequence). Bin VI corresponds to failures in the recirculation phase (AX sequence). The dominant cutset listing for Bins V and VI, including the initiators, are presented in Appendix E.2.3.1.

2. Small LOCA Inside/Outside Containment - 2.1-03.

   The dominant sequences leading to core melt are primarily related to the unsuccessful operation of the HP injection and/or recirculation system. These sequences are contained in Bin I (SU_s and SY_sX_s) and Bin II (SX_s). Again, the dominant cutsets along with the initiators are listed in Appendix E.2.3.1.

3. Large LOCA Outside Containment - 1.0

   The value of the conditional core damage frequency, 1.0, reflects the assumption that core damage is certain to occur if there is a large ISL outside the containment (see Section 5.6.1).

4. Terminated Small LOCA Inside/Outside - 1.6-04.

   The HP system unavailability has been derived using the SU_s sequence of Bin I (see Appendix E.2.3.2).

5.6.3 Calvert Cliffs, Unit 1

1. Large LOCA Inside - 2.8-02.

   The quantification of all large LOCA sequences, indicated on Figure E.3.1 of Appendix E, is discussed in Section E.3.3.1. The CCDF due to large LOCA has been calculated based on the initiator value listed in Table E.3.3 of Appendix E.

2. Small LOCA Inside/Outside - 1.3-03.

   Similarly to the previous case, the quantified sequences, which are listed in Table E.3.3, were renormalized using the initiator value from the same table. The numerical values of the sequence probabilities are discussed in Chapter E.3.3.2 of Appendix E.

3. Large LOCA Outside Containment - 1.0

   In case of a large interfacing system LOCA bypassing the containment the value of the CCDF, 1.0, reflects the assumption that core damage is certain to occur (see Section 5.6.1).

4. Terminated, Small LOCA Inside/Outside - 7.5-05.

   The HP system unavailability has been derived using the S_2D'' sequence with the corresponding initiator (see Appendix E.3.3.3).

5.7 Core Damage Frequency (CDF)

The plant and system-specific CDFs are listed in Tables 5.2a through 5.4b. In Tables 5.2a, 5.3a, and 5.4a, only ISL events resulting in overpressurization are shown. If the system is equipped with a relief valve, then overpressurization occurs only if the leak is in excess of the capacity of this valve. The opening of the relief valve results in a small LOCA inside/outside the containment and the associated CDF values are listed in Tables 5.2b, 5.3b, and 5.4b.

A summary of the total CDF due to ISL, both inside and outside the containment, is shown in Table 5.5 with the respective CDF values (due to LOCAs) from the plant-specific PRAs.

Some of the most important results of this study, CDF due to ISLs bypassing containment, are listed in Table 5.6.

The first column lists CDF values with and without overpressurization of the low pressure interfacing systems (corresponding to all ISL events including those where a relief valve opens and no overpressurization occurs). The second column lists the CDF values corresponding to only those ISL events which overpressurize the low pressure system in addition to bypassing the containment.

At Indian Point and Oconee stations the total CDF with overpressurization is dominated by the contributions from two sequences. A large LOCA on the RHR suction side piping contributes 50% (IP), 12% (OC) of the total CDF, and an ISL event on the LP injection side is 39% (IP), 88% (OC) of the total. At Calvert Cliffs the ISL event sequence leading to a large LOCA on the RHR suction side is the dominant contributor (99%).

5.8 References

1. "Indian Point Probabilistic Safety Study," Power Authority of the State of New York and Consolidated Edison Company of New York, 1982.

2. "Oconee PRA, A Probabilistic Risk Assessment of Oconee Unit 3," NSAC-60, June 1984.

3. "Interim Reliability Evaluation Program: Analysis of the Calvert Cliffs Unit 1 Nuclear Power Plant," NUREG/CR-3511, Vol. 1, May 1984.

4. "Dominant Accident Sequences in Oconee-1 Pressurized Water Reactor," NUREG/CR-4140, April 1985.

5. "Source Term Safety Assessment, Appendix A: Analysis of the V-Sequence at Indian Point 3," Risk Management Associates and New York Power Authority, July 10, 1984.

Overpressurization (Initiator)	Major Pipe Rupture		Conditional Core Damage Multiplier (CCDF) Oconee	Calvert Cliffs
		Small LOCA/Out	2.1-03	1.3-03
	1.0	Large LOCA/Out	1.0	1.0

Figure 5.1 ISL Event Trees - LP injection, Oconee and Calvert Cliffs stations.

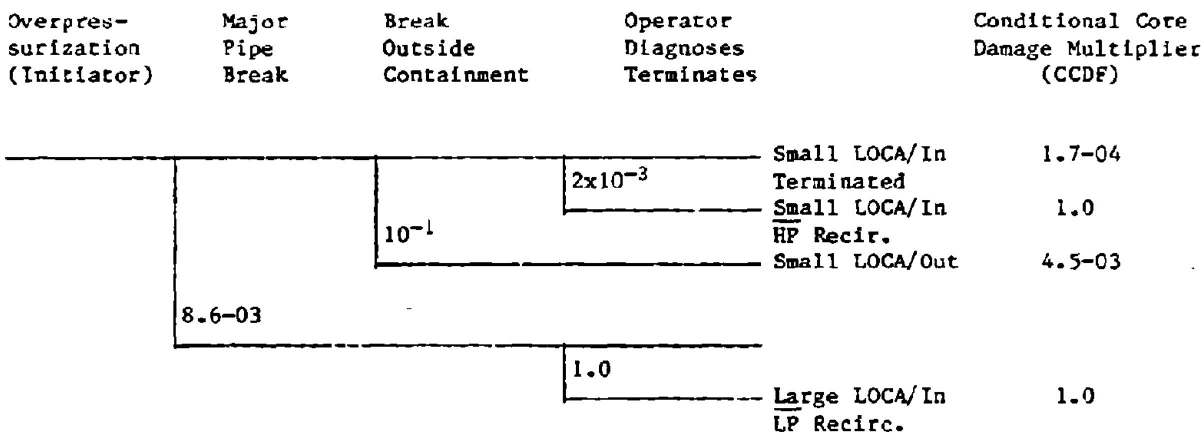


Figure 5.2 ISL Event Trees - LP injection, Indian Point Station.

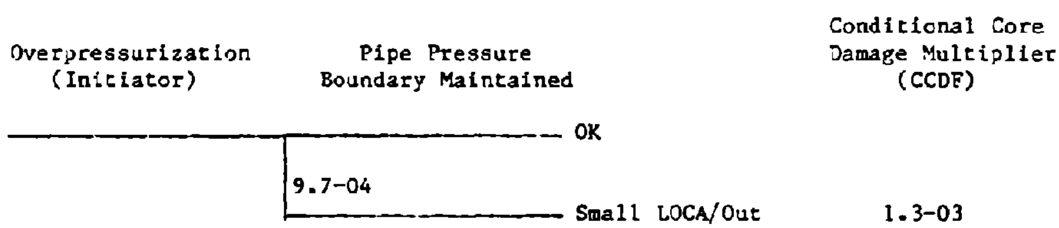
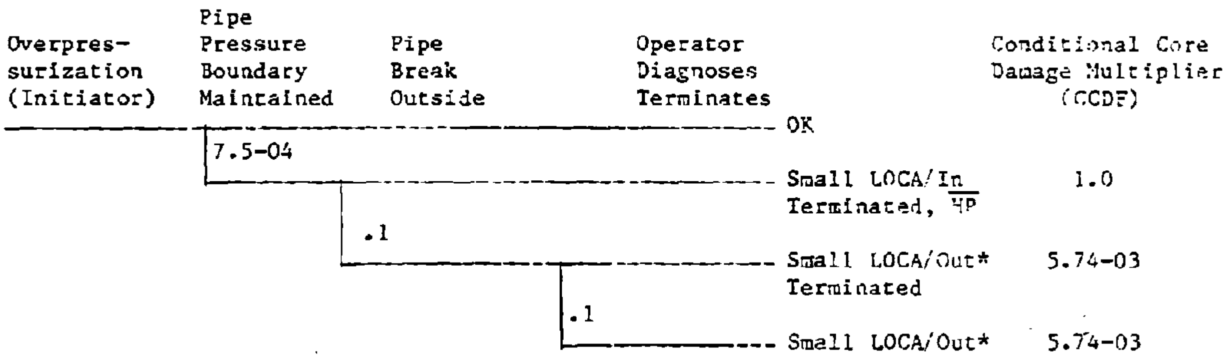


Figure 5.3 ISL event tree - SI discharge, Calvert Cliffs Station.



*CCDF calculated with one side in failed mode.

Figure 5.4 ISL event tree - SI discharge, Indian Point Station.

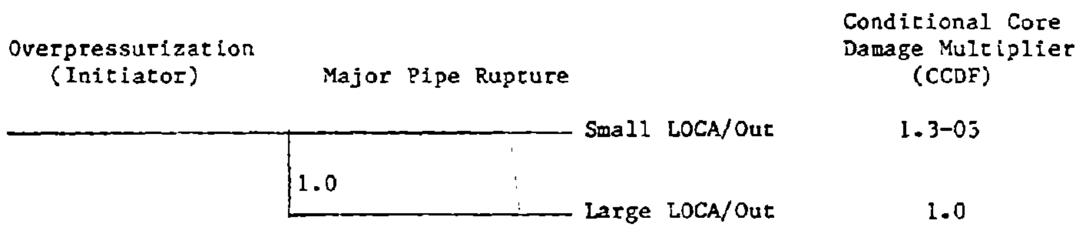


Figure 5.5 ISL event trees - RHR suction, Calvert Cliffs Station.

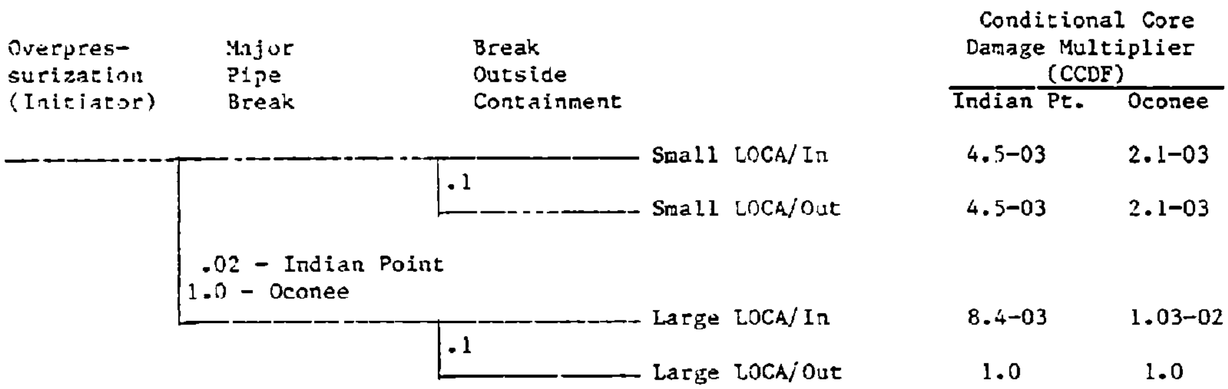


Figure 5.6 ISL event trees - RHR suction, Indian Point and Oconee Stations.

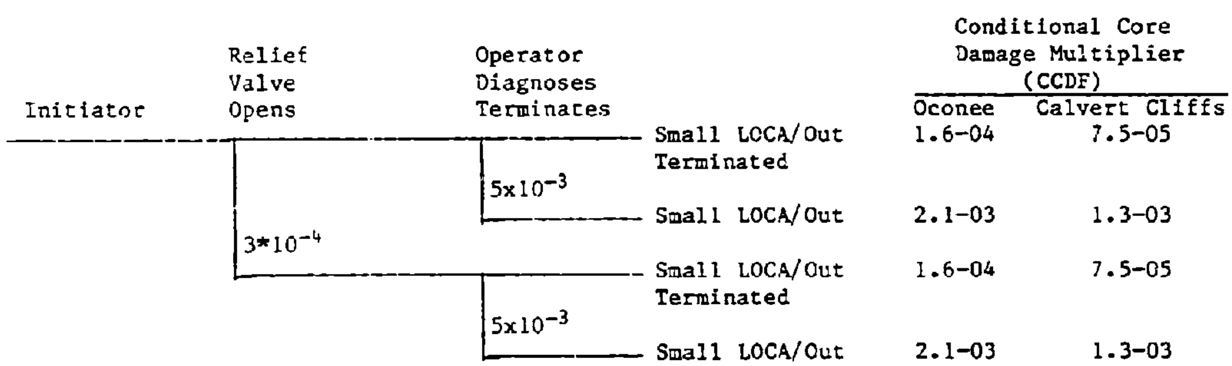


Figure 5.7 ISL event trees - Letdown lines, Oconee and Calvert Cliffs Stations.

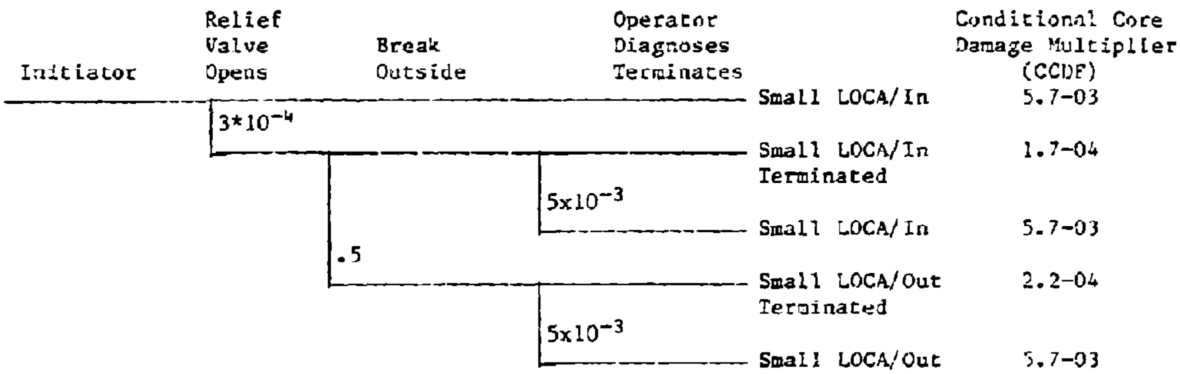
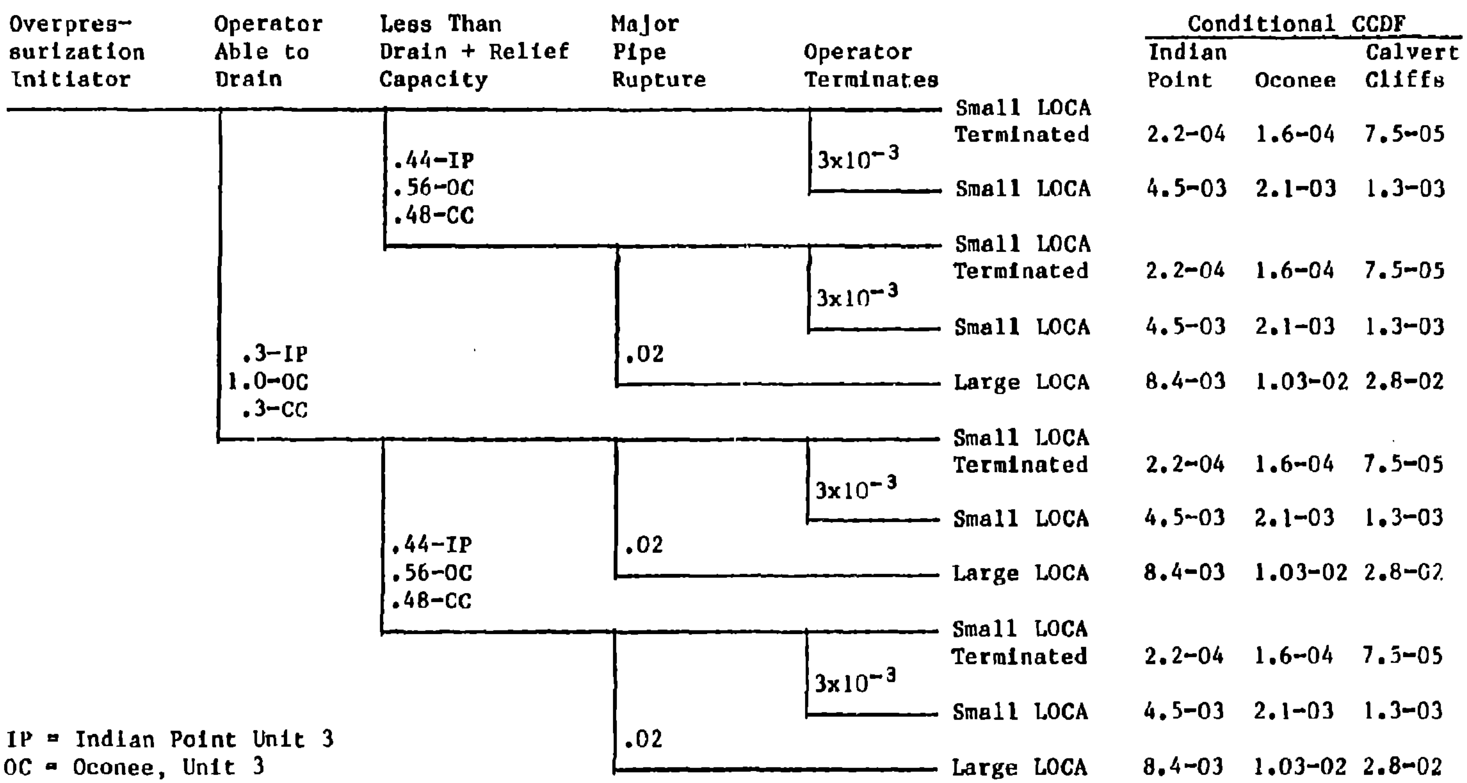


Figure 5.8 ISL event trees - Letdown lines, Indian Point.



IP = Indian Point Unit 3
OC = Oconee, Unit 3
CC = Calvert Cliffs, Unit 2

Figure 5.9 ISL event trees - Accumulators.

Table 5.1
Conditional Core Damage Frequencies for LOCAs

	Indian Point	Oconee	Calvert Cliffs
No Operator Action			
Large LOCA Inside Containment	8.4-03	1.03-02	2.8-02
Small LOCA Inside	4.5-03	2.10-03	1.3-03
Large LOCA Outside	1.0	1.0	1.0
Small LOCA Outside	4.5-03	2.10-03	1.3-03
LOCA Terminated by Operator			
Small LOCA Inside	2.2-04	1.6-04	7.5-05
Small LOCA Outside	2.2-04	1.6-04	7.5-05
Special Case			
Small LOCA Inside One Train of HP System Not Available	5.74-03		

Table 5.2a
Core Damage Frequency
Indian Point

System	Overpressurization Initiator	P(Rupture)	CCDF (Including ISL Event Trees)	CDF/Year
LPI	2.39-06	8.6-03	1.10-02	2.64-08
SI*	1.22-04	7.5-04	6.75-04	8.24-08
RHR Suction	6.79-07	2.00-02	6.56-03	4.46-09
Letdown*	6.82-07	1.00	4.50-03	3.07-09
Accumulators	4.90-03	2.00-02	3.32-04	1.63-06
TOTAL (CDF due to overpressurization)				1.75-06

Note: P(Rupture) = Probability of a major pipe rupture.
*For this system P(Rupture) = Probability of pipe pressure boundary NOT maintained.

Table 5.2b
Core Damage Frequency Without Overpressurization
Indian Point

System	Initiator*	CCDF (Small LOCA)	CDF/Year
LPI	3.06-06	4.5-03	1.38-08
SI	1.59-04	4.5-03	7.16-07
RHR	1.68-05	4.5-03	7.56-08
Letdown	2.28-03	4.5-03	1.03-05
Total (CDF w/o over-pressurization)			1.11-05

*No overpressurization, relief valves open.

Table 5.3a
Core Damage Frequency
Oconee

System	Overpressurization Initiator	P(Rupture)	CCDF (Including ISL Event Trees)	CDF/Year
LPI	7.43-07	1.00	1.00	7.43-07
RHR Suction	9.90-07	1.00	1.09-01	1.08-07
Letdown*	2.28-03	1.00	5.09-08	1.16-10
Accumulators	2.93-03	2.00-02	3.69-04	1.08-06
TOTAL (CDF due to over-pressurization)				1.93-06

Note: P(Rupture) = Probability of a major pipe rupture.
*For this system P(Rupture) = Probability of pipe pressure boundary NOT maintained.

Table 5.3b
Core Damage Frequency Without Overpressurization
Oconee

System	Initiator*	CCDF (Small LOCA)	CDF/Year
LPI	4.81-07	2.1-03	1.01-09
RHR	4.63-05	2.1-03	9.72-08
Letdown	2.28-03		3.87-07
Total (CDF w/o over-pressurization)			4.85-07

*No overpressurization, relief valves open.

Table 5.4a
Core Damage Frequency
Calvert Cliffs

System	Overpressurization Initiator	P(Rupture)	CCDF (Including ISL Event Trees)	CDF/Year
LPI	2.31-09	1.00	1.00	2.31-09
SI*	1.74-09	9.7-04	1.26-06	2.19-15
RHR Suction	3.36-06	1.00	1.00	3.36-06
Letdown* (Includes relief valve opening)	2.28-03	1.00	2.43-08	5.55-11
Accumulators	6.15-03	2.00-02	4.34-04	2.67-06
TOTAL (CDF due to over-pressurization)				6.03-06

Note: P(Rupture) = Probability of a major pipe rupture.
*For this system P(Rupture) = Probability of pipe pressure boundary NOT maintained.

Table 5.4b
Core Damage Frequency Without Overpressurization
Calvert Cliffs

System	Initiator*	CCDF (Small LOCA)	CDF/Year
LPI	5.91-10	1.3-03	7.68-13
SI	1.95-10	1.3-03	2.53-13
RHR	9.50-05	1.3-03	1.24-07
Letdown	2.28-03		1.85-07
Total (CDF w/o overpressurization)			3.08-07

*No overpressurization, relief valves open.

Table 5.5
Core Damage Frequency
Summary

Plant	Total CDF Due to Overpressurization	Total CDF Without Overpressurization	Total CDF/Year	CDF* in PRA (/Year)
Indian Point	1.75-06	1.11-05	1.29-05	1.18-04
Oconee	1.93-06	4.85-07	2.42-06	1.59-05
Calvert Cliffs	6.03-06	3.08-07	6.34-06	3.34-05

*Due to LOCA only.

Table 5.6
Core Damage Frequency Due to ISL
Bypassing Containment

Plant	Total CDF/Year ISL Outside Containment With/Without Over-pressurization	Total CDF/Year ISL Outside Containment With Overpressurization	CDF* in PRA (/Year)
Indian Point	2.78-09	2.78-09	1.18-04
Oconee	1.23-06	8.42-07	1.59-05
Calvert Cliffs	3.69-06	3.38-06	3.34-05

*Due to LOCA only.

Table 5.7
Pipe Rupture Probabilities

Plant	System	Pipe Size (Inch)	Pipe Schedule	Failure Probability (Corroded)
Indian Point	LPI	6	40	8.6-03
	RHR	14	N.A.	2.0-02*
	HPI	2	N.A.	7.5-04*
	Accumulator	10	40	2.0-02
Oconee	LPI	10	20	1.00
	RHR	12	10s	1.0
	Accumulator	14	40s	2.0-02
Calvert Cliffs	LPI	12	40s	1.0
	RHR	14	10	1.0
	HPI	6	80s	9.7-04
	Accumulator	12	40	2.0-02

N.A. - Not available.
*Estimated.

6. EFFECTS OF CORRECTIVE ACTIONS AND LEAK TESTING ON CORE DAMAGE FREQUENCY

In order to reduce the core damage frequency due to ISLs, numerous options appear to be available. From these options, however, corrective actions within the perspective of implementation are rather limited. In the present section, those corrective actions will be discussed which have been deemed to be implementable without excessive difficulties.

The corrective actions considered are essentially plant specific ones. The reason for this is that one or two plants already have certain safety features against ISLs, while others do not.

In the following calculations, the effects of the remedial actions on the initiator frequencies of LOCAs and overpressurization, as well as on the core damage frequencies are presented.

All three reference plants have already instituted certain testing procedures in order to preclude ISL. These various leak and/or stroke testing procedures (verifying the conditions of the pressure isolation devices) are not uniformly required for all PWRs. In Section 6.4 the effects of leak testing are quantified with respect to CDF.

The sensitivity calculations found in the succeeding sections list a number of different CDF values based on the location and size of the pipe break. In the following, a brief description of these CDFs are given:

1. Total CDF with Overpressurization - Total CDF due to ISL events occurring inside and outside the containment building that overpressurizes the low pressure system. (The capacity of the relief valves are exceeded.)

2. Total CDF Without Overpressurization - Total CDF to ISL events occurring inside and outside the containment where the capacity of the relief valves are not exceeded. (The low pressure system is not overpressurized.)

3. Total CDF - This includes all inside and outside ISL events with and without overpressurization (sum of Items 1 and 2).

4. Total CDF Outside - Total CDF due to only those ISL events which bypass the containment. (This includes both overpressurization events and those without overpressurization due to relief valve opening.)

5. Total CDF Outside with Overpressurization - Total CDF due to only those ISL events which bypass the containment and overpressurize the low pressure system.

6.1 Corrective Actions at Indian Point 3

At Indian Point 3, leak tests are performed on the pressure isolation valves (check valves as well as MOVs) after each cold shutdown. Thus, there is no compelling reason to investigate an increase in the frequency of leak

tests. However, as the calculations below demonstrate, there is room for some improvement by implementing the following corrective actions.

1. Leak testing of the HPI check and motor-operated isolation valves at each cold shutdown.

2. Application of pressure sensors (or equivalent continuous leak sensor devices) between the first (RCS side) and second pressure isolation valves on each of the LPI/HPI/RHR pathways. (This is a feature which can be found at the common LPI/HPI/Accumulator inlet at Calvert Cliffs 1.)

3. Improving the ability of operators to recognize ISLs and manage such accidents.

4. Establishing a procedure for RWST makeup in case of an ISL.

Table 6.1 presents the results for Indian Point 3 to be compared with the results of each potential corrective action taken separately and then combined.

6.1.1 Leak Test of the HPI Isolation Valves

The possibility of leaving the HPI check valve and MOVs open can be eliminated by performing leak testing after each cold shutdown period when RCS pressure is being increased to operating level. Table 6.2 lists the results of these calculations.

6.1.2 Application of Permanent Pressure Sensor Between The First Two Isolation Valves on Each LPI/HPI/RHR Line

The advantage of the pressure sensor is that whenever the first isolation valve leaks, an overpressurization alarm would call the attention of the operator to take preventive action. The effect of this potential corrective action causes the time dependent terms to vanish in the expressions describing initiator frequencies. Table 6.3 shows the pathway by pathway results if permanent pressure sensors would be implemented. (The results reflect the assumption that the pressure sensors will perform as intended.) The last column gives the core damage reduction values relative to the existing plant. The effect of continuous leak testing is to reduce the total CDF associated with ISL bypassing the containment by a factor of ~2.

6.1.3 Improving The Ability of Operators For ISL Management

Following the plant visit to Indian Point 3 and study of the LOCA procedure, it was felt that it would be very useful to improve the ability of operators to manage an ISL accident. This would seem to be easily achieved by training on control room simulators. However, Table 6.4 shows that the effect of considering improved operator actions in the ISL event trees is negligible. This reflects the fact that the CDF due to ISL is dominated by sequences where either the pipe break cannot be isolated (RHR) or the recirculation capability may be impaired (RHR, HPI) reducing the effectiveness of any action by the operator.

6.1.4 Establishing RWST Makeup Procedure

In case of an interfacing LOCA bypassing the containment, the operator has to rely on the water supply available in the RWST. The makeup to the RWST is generally based on "ad hoc" arrangements depending on the type of accident and any other available water supplies. If this procedure were to be formalized with respect to the various ISL scenarios, the CDF associated with small LOCA outside containment would be greatly reduced (effectively reflecting only HPI unavailability and typically a conditional CDF-10^{-4}).

Table 6.5 lists the corresponding CDF values and the total CDF for ISL outside containment is reduced by a factor of -2.

Table 6.6 provides the results if all of the above corrective actions would be implemented. A comparison with the results for the existing plant shows a significant advantage by implementing all of the above corrective actions.

6.2 Corrective Actions at Oconee 3

At Oconee 3 the leak tests of the isolation check valves and MOVs are performed at nine month intervals. After cold shutdown (there are two assumed during the leak test period) the isolation valves may remain in failed states (open). Therefore, for this plant the simplest remedial action is to increase the frequency of the leak testing. In addition, there are other options. A list of possibilities are:

1. Leak testing of the isolation valves (check and MOVs) after each cold shutdown.

2. Application of permanent pressure sensors between the first and the second isolation valves on each LPI/RHR pathway.

3. Improving the ability of the operators with respect to ISL recognition and accident management.

4. Establishing an RWST makeup procedure.

Table 6.7 provides the results for Oconee 3 to be compared with the results of each potential corrective action taken separately and then combined.

6.2.1 Leak Testing of The Isolation Valves After Each Cold Shutdown

With the implementation of leak testing after each cold shutdown, the possibility of leaving the isolation valves open can be eliminated.

The appropriate initiators and the results of the calculations are listed in Table 6.8.

6.2.2 Application of Permanent Pressure Sensors Between The First and Second Isolation Valves on Each LPI/RHR Pathway

The application of pressure sensors (or other equivalent leak sensor devices) has the same effect as was explained for Indian Point 3 (Section 6.1.2). Table 6.9 shows the results for each pathway.

6.2.3 Improving The Ability of Operators For ISL Recognition and Accident Management

Table 6.10 presents the results of this potential corrective action.

6.2.4 RWST Makeup Procedure

Establishing an RWST makeup procedure has a slight effect in reducing total CDF for ISLs outside containment. Table 6.11 lists the results of this corrective action.

The combined effect of corrective actions 1, 2, 3, and 4 is shown in Table 6.12.

6.3 Corrective Actions at Calvert Cliffs 1

At Calvert Cliffs there is a permanent pressure sensor at the common LPI/HPI/Accumulator inlet.

Thus, for Calvert Cliffs the list of corrective actions is as follows:

1. Application of permanent pressure sensors between the two MOVs in the RHR suction line.

2. Leak and stroke tests of the RHR suction MOVs.

3. Improving the ability of the operators with respect to ISL recognition and accident management.

4. RWST makeup procedure.

Table 6.13 summarizes the results for Calvert Cliffs 1 to be compared with the results of each potential corrective action taken separately and then combined.

6.3.1 Application of Additional Permanent Pressure Sensors

In the calculations for the existing plant, full credit was given to the effect of the pressure sensor at the shared inlet of LPI/HPI lines. No credit was given to the effect of the relief valve between the two MOVs on the RHR suction line.

Table 6.14 contains the results of the calculations if the additional permanent pressure sensors would be implemented.

6.3.2 Leak and Stroke Tests of the RHR Suction MOVs

The time period of the leak and rupture failure modes can be reduced by periodic testing. Table 6.15 lists the results assuming leak and stroke tests are performed in each cold shutdown period.

6.3.3 Improvement of The Ability of Operators For ISL Recognition and Accident Management

Table 6.16 shows the results of this potential corrective action.

6.3.4 RWST Makeup Procedure

Table 6.17 presents the results of calculations including the effects of a formalized RWST makeup procedure.

The combined effect of corrective actions 1, 2, 3, and 4 is shown in Table 6.18.

6.4 Effect of Leak Testing on CDF

The operators of commercial nuclear power plants are, in most cases, required to perform periodic tests on valves that isolate the primary reactor coolant system from interfacing safety systems. These in-service tests are intended to demonstrate the operability of the valves and to identify leakage due to valve degradation. The identification of valves to be tested, test methods, and acceptance criteria are generally specified in the plant Technical Specifications and in most cases refer to the appropriate section of the ASME boiler and pressure vessel code. However, these periodic testing requirements are not uniformly applied across the PWR population (e.g., older PWRs are not required to specifically test all pressure isolation valves to ensure the structural and leak-tight integrity of these components). In this section the results of calculations demonstrating the effects of leak testing requirements on CDF are presented.

The three reference plants have all instituted certain periodic test procedures to preclude ISL accidents. The calculated initiator frequency values of the ISL sequences are all based on these plant-specific test practices and are discussed in more detail in Section 4.

The effect of leak testing on the core damage frequency can be calculated by appropriately modifying the initiator frequency values of the ISL sequences by increasing the testing interval to the lifetime of the plant. These modifications, the removal of leak testing from the initiator frequency values, are documented and discussed in Section 4.

The core damage frequency, calculated with new initiators that reflect no leak testing during the lifetime of the plants, are presented in Tables 6.19 through 6.21 for the three reference plants. In the following, two CDFs are discussed. The first, CDF_1, is the total CDF including all ISL events inside and outside the containment. The second, CDF_2, is the total CDF with an ISL event bypassing the containment and overpressurizing an interfacing safety system.

In general, the effect of no leak testing on CDFs is to increase their values by at least one or two orders of magnitude. At Indian Point, the initiators of the dominant contributors are all increased by about a factor of 20, and this is directly reflected in the increased value of the CDFs, CDF_1 by a factor of ~4 and CDF_2 by ~20. At Oconee, the dominant contributor to CDF is an ISL sequence on the LPI line. The initiator frequency of this sequence is increased by two orders of magnitude and correspondingly both CDFs are similarly increased. The increase in CDF_1 is somewhat less reflecting the relative increase of the contributions from the other sequences. At Calvert Cliffs the dominant sequence is an ISL event on the RHR suction line. The initiator of this sequence is increased by a factor of ~5 and for the other nondominant sequences the increase was even higher. This is reflected in the higher values of both CDF_1 and CDF_2, which are increased by about the same order of magnitude.

In summary, leak testing of isolation components at interfacing system boundaries is very effective and the core damage frequency associated with ISL events bypassing the containment may be reduced by one or two orders of magnitude.

Table 6.1
Core Damage Frequency - Indian Point
Existing Plant

System	Initiator	CDF/Year Base
<u>A - Overpressurization</u>		
LPI	2.39-06	2.64-08
SI	1.22-04	8.24-08
RHR Suction	6.79-07	4.46-09
Letdown	6.82-07	3.07-09
Accumulators	4.90-03	1.63-06
<u>B - Without Overpressurization</u>		
LPI	3.06-06	1.38-08
SI	2.73-04	1.23-06
RHR	1.68-05	7.56-08
Letdown	2.28-03	1.03-05
<u>Total CDF</u>		
A - Overpressurization		1.75-06
B - Without Overpressurization		1.16-05
A and B		1.34-05
Total CDF With ISL Outside With Overpressurization		2.78-09

Table 6.2
Core Damage Frequency - Indian Point
With Leak Test After Each Cold Shutdown

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change		2.64-08	1.00
SI	2.78-05	1.88-08	8.24-08	.23
RHR Suction	No change		4.46-09	1.00
Letdown	No change		3.07-09	1.00
Accumulators	No change		1.63-06	1.00
B - Without Overpressurization				
LPI	No change		1.38-08	1.00
SI	3.65-05	1.64-07	1.23-06	.13
RHR	No change		7.56-08	1.00
Letdown	No change		1.03-05	1.00
Total CDF				
A - Overpressurization		1.69-06	1.75-06	.96
B - Without Overpressurization		1.06-05	1.16-05	.92
A and B		1.23-05	1.34-05	.92
Total CDF With ISL Outside With Overpressurization		2.74-09	2.78-09	.99

Table 6.3
Core Damage Frequency - Indian Point
With Continuous Leak/Pressure Monitoring

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	1.50-06	1.65-08	2.64-08	.63
SI	6.22-05	4.20-08	8.24-08	.51
RHR Suction	3.30-07	2.17-09	4.46-09	.49
Letdown	No change		3.07-09	1.00
Accumulators	No change		1.63-06	1.00
B - Without Overpressurization				
LPI	1.71-06	7.69-09	1.38-08	.56
SI	7.79-05	3.51-07	1.23-06	.29
RHR	8.40-06	3.78-08	7.56-08	.50
Letdown	No change		1.03-05	1.00
Total CDF				
A - Overpressurization		1.69-06	1.75-06	.97
B - Without Overpressurization		1.07-05	1.16-05	.92
A and B		1.24-05	1.34-05	.92
Total CDF With ISL Outside With Overpressurization		1.50-09	2.78-09	.54

Table 6.4
Core Damage Frequency - Indian Point
With Enhanced Operator Training

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change	2.21-08	2.64-08	.84
SI	No change		8.24-08	1.00
RHR Suction	No change		4.46-09	1.00
Letdown	No change		3.07-09	1.00
Accumulators	No change	1.43-06	1.63-06	.88
B - Without Overpressurization				
LPI	No change		1.38-08	1.0
SI	No change		1.23-06	1.0
RHR	No change		7.56-08	1.0
Letdown	No change		1.03-05	1.0
Total CDF				
A - Overpressurization		1.54-06	1.75-06	.88
B - Without Overpressurization		1.16-05	1.16-05	1.00
A and B		1.31-05	1.34-05	.97
Total CDF With ISL Outside With Overpressurization		2.78-09	2.78-09	1.00

Table 6.5
Core Damage Frequency - Indian Point
With RWST Makeup Procedure

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change	2.53-08	2.64-08	.96
SI	No change		8.24-08	1.00
RHR Suction	No change	4.17-09	4.46-09	.94
Letdown	No change		3.07-09	1.00
Accumulators	No change		1.63-06	1.00
B - Without Overpressurization				
LPI	No change		1.38-08	1.00
SI	No change		1.23-06	1.00
RHR	No change		7.56-08	1.00
Letdown	No change		1.03-05	1.00
Total CDF				
A - Overpressurization			1.75-06	1.00
B - Without Overpressurization			1.16-05	1.00
A and B			1.34-05	1.00
Total CDF With ISL Outside With Overpressurization		1.47-09	2.78-09	.53

Table 6.6
Core Damage Frequency - Indian Point
With All Four Corrective Actions

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	1.50-06	1.33-08	2.64-08	.50
SI	1.39-05	9.39-09	8.24-08	.11
RHR Suction	3.30-07	2.03-09	4.46-09	.46
Letdown	6.82-07		3.07-09	1.00
Accumulators	4.90-03	1.43-06	1.63-06	.88
B - Without Overpressurization				
LPI	1.71-06	7.69-09	1.38-08	.56
SI	1.82-05	8.19-08	1.23-06	.07
RHR	8.40-06	3.78-08	7.56-08	.50
Letdown	2.28-03		1.03-05	1.0
Total CDF				
A - Overpressurization		1.46-06	1.75-06	.83
B - Without Overpressurization		1.04-05	1.16-05	.90
A and B		1.19-05	1.34-05	.89
Total CDF With ISL Outside With Overpressurization		7.06-10	2.78-09	.25

Table 6.7
Core Damage Frequency - Oconee
Existing Plant

System	Initiator	CDF/Year Base
A - Overpressurization		
LPI	7.43-07	7.43-07
RHR Suction	9.90-07	1.08-07
Letdown	2.28-03	1.16-10
Accumulators	2.93-03	1.08-06
B - Without Overpressurization		
LPI	4.81-07	1.01-09
RHR	4.63-05	9.72-08
Letdown	2.28-03	3.87-07
Total CDF		
A - Overpressurization		1.93-06
B - Without Overpressurization		4.85-07
A and B		2.42-06
Total CDF With ISL Outside With and Without Overpressurization		1.23-06
Total CDF With ISL Outside With Overpressurization		8.42-07

Table 6.8
Core Damage Frequency - Oconee
With Leak Test After Each Cold Shutdown

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	8.63-08	8.63-08	7.43-07	.12
RHR Suction	7.67-07	8.38-08	1.08-07	.78
Letdown	No change		1.16-10	1.00
Accumulators	No change		1.08-06	1.00
B - Without Overpressurization				
LPI	5.64-08	1.18-10	1.01-09	.12
RHR	1.42-05	2.98-08	9.72-08	.31
Letdown	No change		3.87-07	1.00
Total CDF				
A - Overpressurization		1.25-06	1.93-06	.65
B - Without Overpressurization		4.17-07	4.85-07	.86
A and B		1.67-06	2.42-06	.69
Total CDF With ISL Outside With and Without Overpressurization		5.50-07	1.23-06	.45
Total CDF With ISL Outside With Overpressurization		1.63-07	8.42-07	.19

Table 6.9
Core Damage Frequency - Oconee
With Continuous Leak/Pressure Testing

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	6.27-07	6.27-07	7.43-07	.84
RHR Suction	5.47-07	5.98-08	1.08-07	.55
Letdown	No change		1.16-10	1.00
Accumulators	No change		1.08-06	1.00
B - Without Overpressurization				
LPI	3.87-07	8.13-10	1.01-09	.80
RHR	2.38-05	5.00-08	9.72-08	.51
Letdown	No change		3.87-07	1.00
Total CDF				
A - Overpressurization		1.76-06	1.93-06	.91
B - Without Overpressurization		4.38-07	4.85-07	.90
A and B		2.20-06	2.42-06	.91
Total CDF With ISL Outside With and Without Overpressurization		1.07-06	1.23-06	.87
Total CDF With ISL Outside With Overpressurization		6.82-07	8.47-07	.81

Table 6.10
Core Damage Frequency - Oconee
With Enhanced Operator Training

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change		7.43-07	1.00
RHR Suction	No change		1.08-07	1.00
Letdown	No change	4.80-08	1.16-10	.94
Accumulators	No change	1.06-06	1.08-06	.99
B - Without Overpressurization				
LPI	No change		1.01-09	1.0
RHR	No change		9.72-08	1.0
Letdown	No change	3.65-07	3.87-07	.94
Total CDF				
A - Overpressurization		1.91-06	1.93-06	.99
B - Without Overpressurization		4.63-07	4.85-07	.96
A and B		2.37-06	2.42-06	.98
Total CDF With ISL Outside With and Without Overpressurization		1.21-06	1.23-06	.98
Total CDF With ISL Outside With Overpressurization		8.42-07	8.42-07	1.00

Table 6.11
Core Damage Frequency - Oconee
With RWST Makeup Procedure

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change		7.43-07	1.00
RHR Suction	No change		1.08-07	1.00
Letdown	No change	1.09-10	1.16-10	.94
Accumulators	No change		1.08-06	1.00
B - Without Overpressurization				
LPI	No change	7.70-11	1.01-09	.08
RHR	No change		9.72-08	1.00
Letdown	No change	3.65-07	3.87-07	.94
Total CDF				
A - Overpressurization		1.93-06	1.93-06	1.00
B - Without Overpressurization		4.62-07	4.85-07	.95
A and B		2.39-06	2.42-06	.99
Total CDF With ISL Outside With and Without Overpressurization		1.21-06	1.23-06	.98
Total CDF With ISL Outside With Overpressurization		8.42-07	8.42-07	1.00

Table 6.12
Core Damage Frequency - Oconee
With All Four Corrective Actions

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	7.27-08	7.27-08	7.43-07	.01
RHR Suction	4.36-07	4.76-08	1.08-07	.44
Letdown	2.28-03	1.09-10	1.16-10	.94
Accumulators	2.93-03	1.06-06	1.08-06	.99
B - Without Overpressurization				
LPI	7.27-08	1.16-11	1.01-09	.01
RHR	8.08-06	1.70-08	9.72-08	.18
Letdown	2.28-03	3.65-07	3.87-07	.94
Total CDF				
A - Overpressurization		1.18-06	1.93-06	.61
B - Without Overpressurization		3.82-07	4.85-07	.75
A and B		1.56-06	2.42-06	.65
Total CDF With ISL Outside With and Without Overpressurization		4.81-07	1.23-06	.40
Total CDF With ISL Outside With Overpressurization		1.16-07	8.42-07	.14

Table 6.13
Core Damage Frequency - Calvert Cliffs
Existing Plant

System	Initiator	CDF/Year Base
A - Overpressurization		
LPI	2.31-09	2.31-09
SI	1.74-09	2.19-15
RHR Suction	3.36-06	3.36-06
Letdown	2.28-03	5.55-11
Accumulators	6.15-03	2.67-06
B - Without Overpressurization		
LPI	5.91-10	7.68-13
SI	1.95-10	2.53-13
RHR	9.50-05	1.24-07
Letdown	2.28-03	1.85-07
Total CDF		
A - Overpressurization		6.03-06
B - Without Overpressurization		3.08-07
A and B		6.34-06
Total CDF With ISL Outside With and Without Overpressurization		3.69-06
Total CDF With ISL Outside With Overpressurization		3.38-06

Table 6.14
Core Damage Frequency - Calvert Cliffs
With Continuous Leak/Pressure Monitoring

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change		2.31-09	1.00
SI	No change		2.19-15	1.00
RHR Suction	2.00-06	2.00-06	3.36-06	.60
Letdown	No change		5.55-11	1.0
Accumulators	No change		2.67-06	1.0
B - Without Overpressurization				
LPI	No change		7.68-13	1.00
SI	No change		2.53-13	1.00
RHR	4.78-05	6.21-08	1.24-07	.50
Letdown	No change		1.85-07	1.00
Total CDF				
A - Overpressurization		4.67-06	6.03-06	.77
B - Without Overpressurization		2.47-07	3.08-07	.80
A and B		4.92-06	6.34-06	.78
Total CDF With ISL Outside With and Without Overpressurization		2.26-06	3.69-06	.61
Total CDF With ISL Outside With Overpressurization		2.02-06	3.38-06	.60

Table 6.15
Core Damage Frequency - Calvert Cliffs
With Leak After Each Cold Shutdown Test

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change		2.31-09	1.00
SI	No change		2.19-15	1.00
RHR Suction	5.61-07	5.61-07	3.36-06	.17
Letdown	No change		5.55-11	1.00
Accumulators	No change		2.67-06	1.00
B - Without Overpressurization				
LPI	No change		7.68-13	1.00
SI	No change		2.53-13	1.00
RHR	1.60-05	2.08-08	1.24-07	.17
Letdown	No change		1.85-07	1.00
Total CDF				
A - Overpressurization		3.23-06	6.03-06	.54
B - Without Overpressurization		2.06-07	3.08-07	.67
A and B		3.44-06	6.34-06	.54
Total CDF With ISL Outside With and Without Overpressurization		7.84-07	3.69-06	.21
Total CDF With ISL Outside With Overpressurization		5.78-07	3.38-06	.17

Table 6.16
Core Damage Frequency - Calvert Cliffs
With Enhanced Operator Training

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change		2.31-09	1.0
SI	No change		2.19-15	1.0
RHR Suction	No change		3.36-06	1.0
Letdown	No change	5.13-11	5.55-11	.93
Accumulators	No change	2.12-06	2.67-06	.79
B - Without Overpressurization				
LPI	No change		7.68-13	1.0
SI	No change		2.53-13	1.0
RHR	No change		1.24-07	1.0
Letdown	No change	1.71-07	1.85-07	.93
Total CDF				
A - Overpressurization		5.48-06	6.03-06	.91
B - Without Overpressurization		2.95-07	3.08-07	.96
A and B		5.78-06	6.34-06	.91
Total CDF With ISL Outside With and Without Overpressurization		3.66-06	3.69-06	.99
Total CDF With ISL Outside With Overpressurization		3.36-06	3.38-06	.99

Table 6.17
Core Damage Frequency - Calvert Cliffs
With RWST Makeup Procedure

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	No change		2.31-09	1.00
SI	No change	1.27-16	2.19-15	.05
RHR Suction	No change		3.36-06	1.00
Letdown	No change	5.13-11	5.55-11	.92
Accumulators	No change		2.67-06	1.00
B - Without Overpressurization				
LPI	No change	4.43-14	7.68-13	.06
SI	No change	1.46-14	2.53-13	.06
RHR	No change	7.13-09	1.24-07	.06
Letdown	No change	1.71-07	1.85-07	.92
Total CDF				
A - Overpressurization		6.03-06	6.03-06	1.00
B - Without Overpressurization		1.78-07	3.08-07	.58
A and B		6.21-06	6.34-05	.98
Total CDF With ISL Outside With and Without Overpressurization		3.54-06	3.69-06	.96
Total CDF With ISL Outside With Overpressurization		3.36-06	3.38-06	.99

Table 6.18
Core Damage Frequency - Calvert Cliffs
With All Four Corrective Actions

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	2.31-09		2.31-09	1.00
SI	1.74-09	1.27-16	2.19-15	.06
RHR Suction	3.34-07	3.34-07	3.36-06	.10
Letdown	2.28-03	5.13-11	5.55-11	.92
Accumulators	6.15-03	2.12-06	2.67-06	.79
B - Without Overpressurization				
LPI	5.91-10	4.43-14	7.68-13	.06
SI	1.95-10	1.46-14	2.53-13	.06
RHR	8.00-06	6.00-10	1.24-07	.005
Letdown	2.28-03	1.71-07	1.85-07	.92
Total CDF				
A - Overpressurization		2.45-06	6.03-06	.41
B - Without Overpressurization		1.72-07	3.08-07	.55
A and B		2.62-06	6.34-06	.41
Total CDF With ISL Outside With and Without Overpressurization		5.08-07	3.69-06	.14
Total CDF With ISL Outside With Overpressurization		3.36-07	3.38-06	.10

Table 6.19
Core Damage Frequency - Indian Point
Assuming No Leak Testing During Lifetime of the Plant

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	6.30-05	6.95-07	2.64-08	26.4
SI	4.36-03	2.94-06	8.24-08	35.7
RHR Suction	1.06-05	6.95-08	4.46-09	15.6
Letdown	No change		3.07-09	1.0
Accumulators	No change		1.63-06	1.0
B - Without Overpressurization				
LPI	7.47-04	3.36-06	1.38-08	244.0
SI	4.05-03	1.82-05	1.23-06	14.8
RHR	1.36-03	6.12-06	7.56-08	81.0
Letdown	No change		1.03-05	1.0
Total CDF				
A - Overpressurization		5.34-06	1.75-06	3.1
B - Without Overpressurization		3.80-05	1.16-05	3.3
A and B		4.33-05	1.34-05	3.2
Total CDF With ISL Outside With Overpressurization		5.58-08	2.78-09	20.1

Table 6.20
Core Damage Frequency - Oconee
Assuming No Leak Testing During Lifetime of the Plant

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	3.24-04	3.24-04	7.43-07	436.0
RHR Suction	1.66-05	1.81-06	1.08-07	18.1
Letdown	No change		1.16-10	1.0
Accumulators	No change		1.08-06	1.0
B - Without Overpressurization				
LPI	2.11-04	4.43-07	1.01-09	439.0
RHR	1.69-03	3.55-06	9.72-08	36.5
Letdown	No change		3.87-07	1.0
Total CDF				
A - Overpressurization		3.27-04	1.93-06	169.0
B - Without Overpressurization		4.38-06	4.85-07	9.0
A and B		3.31-04	2.42-06	137.0
Total CDF With ISL Outside With and Without Overpressurization		3.26-04	1.23-06	265.0
Total CDF With ISL Outside With Overpressurization		3.26-04	8.42-07	387.0

Table 6.21
Core Damage Frequency - Calvert Cliffs
Assuming No Leak Testing During Lifetime of the Plant

System	Initiator	CDF/Year Perturbed	CDF/Year Base	CDF Pert / CDF Base
A - Overpressurization				
LPI	7.42-05	7.42-05	2.31-09	3.21+04
SI	2.95-03	3.72-09	2.19-15	1.70+06
RHR Suction	1.70-05	1.70-05	3.36-06	5.1
Letdown	No change		5.55-11	1.0
Accumulators	No change		2.67-06	1.0
B - Without Overpressurization				
LPI	1.89-05	2.46-08	7.68-13	3.20+04
SI	3.79-04	4.93-07	2.53-13	1.94+06
RHR	1.83-03	2.38-06	1.24-07	19.3
Letdown	No change		1.85-07	1.0
Total CDF				
A - Overpressurization		9.38-05	6.03-06	15.6
B - Without Overpressurization		3.08-06	3.08-07	10.0
A and B		9.69-05	6.34-06	15.3
Total CDF With ISL Outside With and Without Overpressurization		9.43-05	3.69-06	25.6
Total CDF With ISL Outside With Overpressurization		9.12-05	3.38-06	27.0

7. REGULATORY ANALYSIS

7.1 Introduction

This entire section of the report is formatted according to the guidelines of NUREG/BR-0058, Regulatory Analysis Guidelines of the USNRC.[1]

Statement of Problem

Interfacing system LOCAs have been identified as significant contributors to the risk resulting from core melt. Even though Probabilistic Risk Assessments (PRAs) have shown that the expected core damage frequency due to ISLs is typically a few percent or less of the overall CDF, it can be expected to dominate the risk associated with core melt accidents.

Objectives

The primary objective of this study is to investigate in detail the interfacing LOCAs at pressurized water reactors. The further objectives are to find and analyze any key improvements that would significantly aid in further reducing the frequency of ISLs and/or mitigate their consequences.

Alternatives

In order to provide a range of alternatives within the study, four models including three actual plants were investigated. The fourth, a specific base case has also been studied to focus on the cost-benefit consideration of the effects of placing leak testing requirements on plants that do not currently have testing requirements on their pressure isolation valves. The reference plants were also investigated for other possible improvements that could further reduce their specific vulnerabilities to overpressurization events and ISLs. A number of alternative actions have been identified for each of the models. All proposed actions have undergone a cost-benefit analysis documented in the following subsections.

Consequences

There are three basic concerns to be considered in the consequence analysis for any proposed corrective action. These concerns are (1) the cost-benefit considerations, (2) the potential impact on other NRC requirements, and (3) any constraint that may have to be placed upon the implementation of a given proposed corrective action. The cost-benefit considerations are discussed in detail in the following subsection and impacts on other requirements are addressed in the succeeding subsections. In terms of constraints (as defined in NUREG/BR-0058), we have not identified any such considerations that would impact the proposed corrective actions.

7.2 Cost-Benefit Considerations

Approach for Determining Costs

The implementation of the corrective actions discussed in Section 6 requires revisions of existing procedures, development of new procedures, improvement in operator training and application of additional

instrumentation. In order to obtain accurate estimates of the costs involved and to solicit comments on the study, copies of the first five sections of this report were sent to the plants being studied and the utility companies that own the plants.

This section describes the costs involved in implementing each of the proposed corrective actions for each plant. Cost estimates are provided based on the information from the plants where available. In all the other cases the cost estimates are based partially on previously collected data, engineering judgement, and other generic methods. Tables 7.1 to 7.3 summarize the cost-benefit analysis for each of the reference plants. The costs and benefits are expressed in units of dollars. A man-rem is assumed to be equivalent to $1000.[2] An acute fatality is assumed to be equivalent to $5,000,000.[3] Costs that recur over the years, e.g., costs of performing leak tests, are discounted using a discount rate of 10% per year[1] to determine their present value.

Approach for Determining Benefits

Benefits are divided into two major categories, i.e., those derived from lowering the predicted core damage frequency and those associated with lowering the frequency of overpressurization events. The latter category does not lead to core damage but does result in replacement power costs, clean up costs, and occupational doses. The reduction in core damage frequency and the reduction in overpressurization frequency are calculated using the results of Section 6. They are expressed in units of per calendar year. It is assumed that one calendar year is equal to 0.7 reactor year (i.e., the expected amount of time a plant will be operating during a given year).

The CRAC2 code was used to estimate the consequences of a LOCA event that bypasses containment. Two CRAC2 runs were made. The first assumes a release without the benefit of being submerged and the second including the benefit of a submerged release. A decontamination factor of 10 was applied to all but the noble gases in the submerged case. These two runs are considered to bound the public health effects.

As discussed previously, the goal of this study is to provide a generic perspective to interfacing LOCAs at pressurized water reactors. To that end, this regulatory analysis is being based upon a so-called generic 1000 Mw PWR situated on a generic site within the United States. The two CRAC2 runs were made using these generic input data with respect to power level and plant-site, meteorology, population, etc. The consequence analysis is documented in Appendix H.

The following items will be constant for the succeeding cases given an ISL resulting in core damage:

- Public Health Effects
  Nonsubmerged Release
  (2.18×10^6 man-rem) ($1000/man-rem) = $$2.18\times10^9$
  (6×10^{-3} acute fatalities) (5×10^6/acute fatality) = 3.00×10^4
  Submerged Release
  (1.08×10^6 man-rem) ($1000/man-rem) = $$1.08\times10^9$
  Zero acute fatalities = $0.0

- Occupational Health Effects (Best estimates of Ref. 2)
  Immediate Dose (1000 man-rem) ($1000/man-rem) = $\$10^6$
  Long-Term Dose (20,000 man-rem) ($1000/man-rem) = $\$2x10^7$
- Onsite Cleanup Costs (Estimated based on TMI experience[4])
  $1x10^8$/year for 10 years
- Land Interdiction w/o Decontamination
  Nonsubmerged Release $\$1.26x10^9$
  Submerged Release $\$2.76x10^8$

Concept of Discounting

In evaluating the economic consequences of a potential accident that can occur any time in the life of a plant, we must sum terms for costs occurring over a period of many years. The value of the present cost as projected to future years has to be discounted with a rate representing the depreciation as the function of time. In addition, it also has to be considered that the cost might be a one time only expense or a periodically occurring item lasting either through a fixed period or the whole time of interest. The following discounting formulas, taken from Ref. 5, are applicable to different types of consequences or costs of an accident.

Consequences that the formulas applied to:

$C_o f \frac{1-e^{-rt_f}}{r}$ Health effects, offsite property damage. (7.1)

$\frac{C_o f}{r^2} (1-e^{-rt_f}) (1-e^{-rt_M})$ Cleanup expense. (7.2)

$\frac{C_o f}{r} (\frac{1-e^{-rt_f}}{r} - e^{-rt_f} t_f)$ Replacement power. (7.3)

where C_o = present cost of a consequence
f = frequency of accident
t_f = end of plant life
r = discount rate
M = duration of an expense that recurs for several years.

Basically, the formulas are used to determine the multiplier of $C_o f$. For example, in the case of a core damage accident, a cleanup expense of $100,000,000 per year for 10 years is comparable to current estimates of the cleanup costs for the TMI accident.[4] For a plant with 30 years of remaining plant life, the discounted cost of cleanup over 30 years can be calculated using the second formula, i.e.,

$$\frac{100*10^6*f}{0.1^2} (1-e^{-0.1*30}) (1-e^{-0.1*10}) = 6*10^9*f = 60*C_o f$$

where the discount rate is taken to be 0.1 which is the suggested value by the Regulatory Analysis Guideline.[1]

7.3 Cost Estimates for the Proposed Corrective Actions

The risk due to interfacing systems LOCA could potentially be reduced by implementing any or a combination of the various corrective actions discussed in Section 6.

In this section a generic analysis of the costs involved in implementing each corrective action is presented. The cost estimates are based partially on previously collected data, discussion with engineering personnel at BNL and engineering judgement using generic cost estimates. A cost-benefit analysis has been completed for each representative plant and includes plant specific cost estimates where available.

The costs involved in implementing the various corrective actions consist of engineering design changes, modification of test procedures, application of additional instrumentation and improvement in operator training. In order to obtain plant-specific cost estimates, appropriate portions of this report were sent to the three reference plants being studied with requests for their input.

All costs are reduced to the present worth of dollars. A man-rem is assumed to be equivalent to \$1000,[2] and all costs are averaged through the plant lifetime.

The benefit associated with any particular corrective action is primarily measured by a reduction in core damage frequency and is calculated using the results of Section 6. Tables 6.1 through 6.19 of Section 6 list various CDF values; 1) total due to overpressurization, 2) total without overpressurization, 3) the sum of total with and without overpressurization, and 4) total CDF with ISL bypassing containment (see Section 6 for a more detailed description). In the (cost-benefit calculations, only the total CDF with ISL outside containment with and without overpressurization) is used as a measure of benefit, since the other CDFs may not reflect a similar reduction in the risk associated with ISLs.

7.3.1 Generic Cost Estimates for Corrective Actions

In Section 6, plant-specific corrective actions have been identified which could potentially be implemented without excessive difficulties. In the following, cost estimates for each of those corrective actions are given and applied to each plant to complete a cost-benefit analysis. Discounting is applied only in the plant-specific calculations, since it depends on the remaining plant lifetime.

7.3.1.1 Application of Pressure Sensors (Continuous Leak Monitoring Device) Between Isolation Valves

This corrective action requires the installation of a pressure sensing device with associated tubing, fittings, supports and cables. In addition, control board modification is also required for alarm or indicating functions. The pressure connections are generally located in pipe segments

inside the containment. In most cases, test connections are already in place and could be utilized to connect the permanent pressure sensors.

The average cost of the installation of a pressure instrument is estimated to be $5000 (including materials, the instrument itself, 30 man-hours for design, 16 man-hours for installation, and .2 man-rem). It is estimated that the cost of a man-hour is $40 and a man-rem is $1000. The control board modification is estimated to cost 30 engineering man-hours for design and 50 man-hours for installation and wiring or $3200. The total cost is $5000 + $3200 = $8200 per pressure instrument to be averaged over the plant lifetime. It is also estimated that the instrument will be maintained once every year at the annual cost of 10 man-hours and .2 man-rem or $600/year.

7.3.1.2 Additional Leak Tests of the Isolation Valves

All of the reference plants in this study already perform leak tests of the pressure boundary isolation valves at regular intervals. Increasing the frequency of these tests could help eliminate certain failure modes. The costs of performing a test is estimated to be about 20 man-hours and .3 man-rem or $1100 per test. Since test procedures are already in place for each of the reference plants no additional costs are assumed. The leak tests are presently performed in the "critical path" (extending the length of the outage) and other means of replacing the electrical generation has to be found for this time period. It is estimated that the replacement cost of power is ~ $500,000 per day.[6]

7.3.1.3 Improvement in Operator Training

The operator's ability to identify explicit ISL scenarios and thereby improve his response can be enhanced by additional training and using more explicit written procedures. The additional training cost is estimated to be 30 man-hours or $1200/year. The cost of additional procedures to cover specific ISL accidents is about 300 man-hours including analyzing, writing, reviewing, and typing or $12,000 over the plant lifetime.

7.3.1.4 Formalized RWST Makeup Procedure

In case of an ISL event which bypasses the containment, the operator has to rely on the water supply available in the RWST as no water will reach the containment sump for recirculation. The makeup procedure to the RWST should be explicitly formalized with regard to the various ISL accident scenarios.

The cost of analyzing ISL accidents in relation to water inventory is estimated at 250 man-hours. Based on this analysis a formalized makeup procedure may be produced at an additional cost of 250 man-hours. The total estimated cost of this corrective action is 500 man-hours or equivalently $20,000 over the plant lifetime.

7.3.1.5 Summary of Generic Cost Estimates

A summary of the cost estimates for each of the corrective actions are given below for further reference.

1. Application of pressure sensors:
   Installation $8,200/instrument
   Maintenance $ 600/year and instrument

2. Additional leak testing:
   Test $1,100/test
   Downtime Plant-specific

3. Operator training:
   Training $1,200/year
   Procedural $ 300/year
   Total = $1,200 + $300 = $1500/year

4. RWST makeup procedure: $450/year

These generic cost estimates have been used in the plant-specific calculations.

7.4 Plant-Specific Cost-Benefit Estimates

7.4.1 Indian Point, Unit 3

7.4.1.1 Costs

The remaining licensed plant lifetime is assumed to be 32 calendar years. The estimated cost of replacement power is ~$500,000[6] per day.

1. Additional Leak Tests - The plant model assumed that leak tests are performed for the LPI/RHR lines at each cold shutdown. In addition, the HPI interface boundaries are tested at refueling only. The test frequency of the HPI system may also be increased to test at each cold shutdown, requiring on the average three additional leak tests per year. The replacement power cost is estimated at $500,000/day.
   Test: $\$1.1 \times 10^3$ per test
   Downtime (5 hours): $\$1.04 \times 10^5$ per test
   Discounting the annual cost using Eqs. (7.1) and (7.3) (r=.1, $t_f = 32$)
   Test = 9.6 * $\$1.1 \times 10^3 = \$1.06 \times 10^4$
   Downtime = 82.9 * $\$1.04 \times 10^5 = \$8.64 \times 10^6$
   Total (3 Tests + Downtimes) = $\$2.59 \times 10^7$

2. Pressure Sensors - There are 11 lines with two or more isolating valves in the LPI/HPI/RHR systems. The costs of installing and operating the pressure instruments are
   11*[($8200/32)+$600] = $9,400/year.
   Discounting using Eq. (7.1)
   Total = $9,400 * 9.6 = $\$9.02 \times 10^4$

3. Operator Training - The cost is estimated at $1,500/year.
   Discounted cost is (Eq. (7.1)) = $\$1.44 \times 10^4$

4. RWST Makeup Procedure - $450/year.
   Discounted cost is (Eq. (7.1)) = $\$4.32 \times 10^3$

5. Combination of all corrective actions -
$\$2.59x10^7 + \$9.02x10^4 + \$1.44x10^4 + \$4.32x10^3 = \$2.60x10^7$

7.4.1.2 Benefits

For core damage events, the benefit of a reduction in core damage frequency can be expressed as follows:

$Benefit_{CD} = \Delta f_{CD}$ (man rem + replacement power + cleanup costs + land interdiction)

Replacement power costs are dependent upon the region of the United States in which the plant is located.[6] For the Indian Point Unit 3 replacement power costs on a yearly basis is:

$500,000/day = $\$1.83x10^8$/year.

Discounting the various benefits yields the following:

- Public Health + Occupational Health
  (Nonsubmerged Case)
  $\$2.18x10^9 + \$3.00x10^4 + \$10^6 + \$2x10^7 = \$2.20x10^9$/accident
  Discounting using Equation 7.1 (with $r=0.1$, $t_f=32$) = 9.6
  $\$2.20x10^9 * 9.6 = \$2.11x10^{10}$
  (Submerged Case)
  $\$1.08x10^9$ + Zero + $\$10^6 + \$2x10^7 = \$1.10x10^9$/accident
  $\$1.10x10^9 * 9.6 = \$1.06x10^{10}$

- Replacement Power - $\$1.83x10^8$/year
  Discounting using Equation 7.3 ($r=0.1$, $t_f=32$) = 82.9
  $\$1.83x10^8 * 82.9 = \$1.52x10^{10}$

- Cleanup Costs - $\$10^8$ for 10 years
  Discounting using Equation 7.2 ($r=0.1$, $t_f=32$, $t_m=10$) = 60.6
  $\$1x10^8 * 60.6 = \$6.06x10^9$

- Land Interdiction
  Discounting using Equation 7.1 = 9.6
  (Nonsubmerged Case)
  $\$1.26x10^9 * 9.6 = \$1.21x10^{10}$
  (Submerged Case)
  $\$2.76x10^8 * 9.6 = \$2.65x10^9$

For overpressurization events that result in the introduction of primary coolant outside the containment but without core damage, the benefit of a reduction in the frequency of overpressurization can be expressed as follows:

$Benefit_{OP} = \Delta f_{OP}$ * (replacement power costs)

Other costs have not been included because the replacement power costs totally dominate this type of event. We have broken this category of events into two parts. One part addressing events that are isolated rather quickly and thus limit the spill and cleanup time and the other part addressing those

that are not isolated until the spill represents hundreds of thousands of gallons of primary coolant. Our model is shown as follows:

```
             1
             ┌─────────────── (5 days) limited spill
OP ──────────┤
             └─────────────── (60 days) large spill
            10^-2
```

$500,000/day * 5 days = $2.50x10^6
$500,000/day * 60 days = $3.00x10^7

$\text{Benefit}_{OP} = \$2.50\times10^6 + (10^{-2} * \$3.00\times10^7) = \$2.80\times10^6/\text{OP}$
Discounting using Equation 7.1
$\$2.80\times10^6/\text{OP} * 9.6 = \$2.69\times10^7$

The overall benefit of the design changes can be calculated based upon the foregoing input as follows:

$\text{Benefit}_{TOT} = \Delta f_{CD}$ (man rem + replacement power + cleanup + land interdiction) + Δf_{OP} (replacement power)

(For Nonsubmerged Case)

$$= \Delta f_{CD}\,(2.11\times10^{10} + 1.52\times10^{10} + 6.06\times10^9 + 1.21\times10^{10}) + \Delta f_{OP}\,(2.69\times10^7)$$
$$= \Delta f_{CD} * 5.45\times10^{10} + \Delta f_{OP} * 2.69\times10^7$$

(For Submerged Case)

$$= \Delta f_{CD}\,(1.06\times10^{10} + 1.52\times10^{10} + 6.06\times10^9 + 2.65\times10^9) + \Delta f_{OP}\,(2.69\times10^7)$$
$$= \Delta f_{CD} * 3.45\times10^{10} + \Delta f_{OP} * 2.69\times10^7$$

7.4.1.3 Results

There are four separate proposed corrective actions and a fifth which includes all of them from Section 6 based upon the Indian Point design, namely:

1. Additional leak tests.
2. Installation of pressure sensors.
3. Improved operator training.
4. RWST makeup procedure.
5. Implementation of all of the above.

The estimated costs and benefits for the above five items are presented in Table 7.1. In general, the proposed corrective actions for Indian Point 3 are largely ineffective, as shown by the cost-benefit calculations. A comparison of cost-benefits for the first corrective action indicates that the single most important cost factor is the replacement power, which dominates the costs and overwhelms all benefit considerations. It also suggests that testing may in general be much more cost beneficial when performed not in the critical path. This alternative will be examined in more detail for the generic base case.

7.4.2 Oconee, Unit 3

7.4.2.1 Costs

The remaining plant lifetime would be 31 calendar years.

1. Increased Frequency of Leak Tests - Oconee plant personnel have provided plant-specific cost estimates to be used in the analysis. The replacement of electrical power due to shutdowns is estimated to cost $300,000/day. The duration of the leak test is estimated to be 25 man-hours (5 men/5 hours) with 1 man-rem total exposure. There are two isolation boundaries where increased test frequency is suggested in the LPI/RHR systems. It is estimated that in each nine month period there are on the average three cold shutdowns. If Oconee were required to perform leak tests at each cold shutdown, this could entail two additional tests per nine months or three additional tests per calendar year.

Downtime:	5 hours	-	$60,000
Man-hours:	25 hours	-	$1,000
Man-rem:	1 rem	-	$1,000
Total			$62,000/Test

   The additional cost of three tests per year is 3 * $62,000 = $186,000/year.

   Discounting the annual cost using Eq. (7.1) (r=.1, t_f=31) and Eq. (7.3).
   Test = 9.6 * ($1,000 + $1,000) = $\$1.92 \times 10^4$
   Downtime = 81.5 * $\$6.00 \times 10^4$ = $\$4.89 \times 10^6$
   Total (3 Tests per year) = $\$1.47 \times 10^7$

2. Pressure Sensors - There are three lines in the LPI/RHR system where continuous leak monitoring may be installed at a total cost of 3x[($8200/31)+$600] = $2,600/year.

   Discounting using Eq. (7.1)
   Total = 9.6 * $2,600 = $\$2.50 \times 10^4$

3. Operator Training - Estimated cost is $1,500/year.
   Discounted cost is $\$1.44 \times 10^4$

4. RWST Makeup Procedure - Estimated cost is $500/year.
   Discounted cost is $\$4.8 \times 10^3$

5. Combination of all of these corrective actions -
   $\$1.47 \times 10^7 + \$2.50 \times 10^4 + \$1.44 \times 10^4 + \$4.8 \times 10^3 = \$1.47 \times 10^7$

7.4.2.2 Benefits

For core damage events, the benefit of a reduction in core damage frequency can be expressed as follows:

$Benefit_{CD} = \Delta f_{CD}$ (man rem + replacement power + cleanup costs + land interdiction)

Replacement power costs are dependent upon the region of the United States in which the plant is located. For the Oconee plant the replacement power costs on a yearly basis is (~\$300,000/day):

$300,000/day * 365 days/year = $1.10x10^8$/year.

Discounting the various benefits yields the following:

- Public Health + Occupational Health
  (Nonsubmerged Case)
  $\$2.18x10^9 + \$3.00x10^4 + \$10^6 + \$2x10^7 = \$2.20x10^9$/accident
  Discounting using Equation 7.1 (with r=0.1, t_f=31) = 9.6
  $\$2.20x10^9 * 9.6 = \$2.11x10^{10}$
  (Submerged Case)
  $\$1.08x10^9$ + Zero + $\$10^6 + \$2x10^7 = \$1.10x10^9$/accident
  $\$1.10x10^9 * 9.6 = \$1.06x10^{10}$

- Replacement Power - $\$1.10x10^8$/year
  Discounting using Equation 7.3 (r=0.1, t_f=31) = 81.5
  $\$1.10x10^8 * 81.5 = \$8.97x10^9$

- Cleanup Costs - $\$10^8$ for 10 years
  Discounting using Equation 7.2 (r=0.1, t_f=31, t_m=10) = 60.4
  $\$1x10^8 * 60.4 = \$6.04x10^9$

- Land Interdiction
  Discounting using Equation 7.1 = 9.6
  (Nonsubmerged Case)
  $\$1.26x10^9 * 9.6 = \$1.21x10^{10}$
  (Submerged Case)
  $\$2.76x10^8 * 9.6 = \$2.65x10^9$

For overpressurization events that result in the introduction of primary coolant outside the containment but without core damage, the benefit of a reduction in the frequency of overpressurization can be expressed as follows:

$Benefit_{OP} = \Delta f_{OP}$ * (replacement power costs)

Other costs have not been included because the replacement power costs totally dominate this type of event. We have broken this category of events into two parts. Using the model described in Section 7.4.1.2 we have the following:

$300,000/day * 5 days = $\$1.50x10^6$
$300,000/day * 60 days = $\$1.8x10^7$

$Benefit_{OP} = 1.50x10^6 + (10^{-2} * 1.8x10^7) = \$1.68x10^6$/OP
Discounting using Equation 7.1
$\$1.68x10^6$/OP * 9.6 = $\$1.61x10^7$

The overall benefit of the design changes can be calculated based upon the foregoing input as follows:

$Benefit_{TOT} = \Delta f_{CD}$ (man rem + replacement power + cleanup + land interdiction) + Δf_{OP} (replacement power)

(For Nonsubmerged Case)

$$= \Delta f_{CD}\ (2.11\times10^{10} + 8.97\times10^{9} + 6.04\times10^{9} + 1.21\times10^{10}) + \Delta f_{OP}\ (1.61\times10^{7})$$
$$= \Delta f_{CD} * 4.82\times10^{10} + \Delta f_{OP} * 1.61\times10^{7}$$

(For Submerged Case)

$$= \Delta f_{CD}\ (1.06\times10^{10} + 8.97\times10^{9} + 6.04\times10^{9} + 2.65\times10^{9}) + \Delta f_{OP}\ (1.61\times10^{7})$$
$$= \Delta f_{CD} * 2.83\times10^{10} + \Delta f_{OP} * 1.61\times10^{7}$$

7.4.2.3 Results

There are four distinct proposed corrective actions as well as a fifth one which includes implementing all four from Section 6 based upon the Oconee Unit 3 design, namely:

1. Additional leak tests.
2. Installation of pressure sensors.
3. Improved operator training.
4. RWST makeup procedure.
5. Implementation of all of the above.

The estimated costs and benefits for the above corrective actions are presented in Table 7.2. Based on the cost-benefit considerations the proposed corrective actions are basically ineffective. The effect of replacement power costs is similar to that previously discussed for the Indian Point design. The placement of testing in the noncritical path will be discussed in the generic base case calculations.

7.4.3 Calvert Cliffs, Unit 1

7.4.3.1 Costs

The remaining licensed plant lifetime is assumed to be 33 calendar years. The estimated cost of the replacement power is ~\$400,000[6] per day.

1. Pressure Sensors - There are eight lines with multiple isolation boundary valves in the LPI/HPI systems with a total cost of 8*[(\$8200/33)+\$600] = \$6,800/year.

   Discounting using Eq. (7.1)
   Total = 9.6 * \$6,800 = $\$6.53\times10^4$

2. Increased Frequency of Leak and Stroke Testing - Three additional leak tests have been suggested. Each test duration is estimated at ~5 hours with .3 man-rem exposure.
   Test: $\$1.1\times10^3$
   Downtime: $\$8.33\times10^4$

Discounting using Eq. (7.1) ($r=.1$, $t_f=33$) and Eq. (7.3)
Test = 9.6 * $\$1.1x10^3$ = $\$1.06x10^4$
Downtime = 84.1 * $\$8.33x10^4$ = $\$7.01x10^6$
Total (3 Tests) = $\$2.11x10^7$

3. Operator Training - Estimated cost is \$1,500/year.
   Discounted cost is $\$1.44x10^4$

4. RWST Makeup Procedure - Estimated cost is \$400/year.
   Discounted cost is $\$3.84x10^3$

5. Combination of all of the corrective actions -
   $\$6.53x10^4 + \$2.11x10^7 + \$1.44x10^4 + \$3.84x10^3 = \$2.12x10^7$

7.4.3.2 Benefits

For core damage events, the benefit of a reduction in core damage frequency can be expressed as follows:

$Benefit_{CD} = \Delta f_{CD}$ (man rem + replacement power + cleanup costs + land interdiction)

Replacement power costs are dependent upon the region of the United States in which the plant is located. For the Calvert Cliffs plant the replacement power costs on a yearly basis is:

\$400,000/day * 365 days/year = $\$1.46x10^8$/year.

Discounting the various benefits yields the following:

- Public Health + Occupational Health
  (Nonsubmerged Case)
  $\$2.18x10^9 + \$3.00x10^4 + \$10^6 + \$2x10^7 = \$2.20x10^9$/accident
  Discounting using Equation 7.1 (with $r=0.1$, $t_f=33$) = 9.6
  $\$2.20x10^9 * 9.6 = \$2.11x10^{10}$
  (Submerged Case)
  $\$1.08x10^9$ + Zero + $\$10^6 + \$2x10^7 = \$1.10x10^9$/accident
  $\$1.10x10^9 * 9.6 = 1.06x10^{10}$

- Replacement Power - $\$1.46x10^8$/year
  Discounting using Equation 7.3 ($r=0.1$, $t_f=33$) = 84.1
  $\$1.46x10^8 * 84.1 = \$1.23x10^{10}$

- Cleanup Costs - $\$10^8$ for 10 years
  Discounting using Equation 7.2 ($r=0.1$, $t_f=33$, $t_m=10$) = 60.9
  $\$1x10^8 * 60.9 = \$6.09x10^9$

- Land Interdiction
  Discounting using Equation 7.1 = 9.6
  (Nonsubmerged Case)
  $\$1.26x10^9 * 9.6 = \$1.21x10^{10}$
  (Submerged Case)
  $\$2.76x10^8 * 9.6 = \$2.65x10^9$

For overpressurization events that result in the introduction of primary coolant outside the containment but without core damage, the benefit of a reduction in the frequency of overpressurization can be expressed as follows:

$\text{Benefit}_{OP} = \Delta f_{OP}$ * (replacement power costs)

Other costs have not been included because the replacement power costs totally dominate this type of event. We have broken this category of events into two parts. Using the model described in Section 7.4.1.2 we have the following:

$400,000/day * 5 days = $\$2.00\text{x}10^6$
$400,000/day * 60 days = $\$2.40\text{x}10^7$

$\text{Benefit}_{OP} = \$2.00\text{x}10^6 + (10^{-2} * \$2.40\text{x}10^7) = \$2.24\text{x}10^6/\text{OP}$
Discounting using Equation 7.1
$\$2.24\text{x}10^6/\text{OP} * 9.6 = \$2.15\text{x}10^7$

The overall benefit of the design changes can be calculated based upon the foregoing input as follows:

$\text{Benefit}_{TOT} = \Delta f_{CD}$ (man rem + replacement power + cleanup + land interdiction) + Δf_{OP} (replacement power)

(For Nonsubmerged Case)

$$= \Delta f_{CD}\ (2.11\text{x}10^{10} + 1.23\text{x}10^{10} + 6.09\text{x}10^{9} + 1.21\text{x}10^{10}) + \Delta f_{OP}\ (2.15\text{x}10^{7})$$
$$= \Delta f_{CD} * 5.16\text{x}10^{10} + \Delta f_{OP} * 2.15\text{x}10^{7}$$

(For Submerged Case)

$$= \Delta f_{CD}\ (1.06\text{x}10^{10} + 1.23\text{x}10^{10} + 6.09\text{x}10^{9} + 2.65\text{x}10^{9}) + \Delta f_{OP}\ (2.15\text{x}10^{7})$$
$$= \Delta f_{CD} * 3.16\text{x}10^{10} + \Delta f_{OP} * 2.15\text{x}10^{7}$$

7.4.3.3 Results

The following represents the proposed corrective actions derived for the Calvert Cliffs design in Section 6:

1. Installation of additional pressure sensors.
2. Additional stroke and leak testing.
3. Improved operator training.
4. RWST makeup procedure.
5. Implementation of all of the above.

The estimated costs and benefits for the above corrective actions are presented in Table 7.3. From this table, it can be seen that the corrective action establishing an RWST makeup procedure is the only clearly effective one from the cost-benefit considerations. The corrective action requiring the installation of additional pressure sensors falls within the benefit range, however, it is felt to be marginal at best. The results for the second corrective action again indicate that, based only on cost/benefit considerations, additional critical path leak testing is not cost effective.

7.5 Base Case Model

As discussed previously, the three reference plants selected for this study all perform some level of leak testing for their pressure isolation valves. One of the major goals of this study was to determine the cost-benefit relationship of requiring a plant that does not perform leak testing of the pressure isolation boundaries to do so. NRC guidance in defining this base case included the provision that those who voluntarily test the pressure isolation boundaries but are not required to, would also fall into this category.

In order to construct a representative generic base case plant, the previously developed Oconee plant model was selected and modified to remove the credit given for the current leak testing provisions. The details of the model with respect to the initiators are discussed in Section 4.

In order to cover the various possibilities with respect to test frequency and placement of testing, three cases were analyzed and evaluated. Initially, two leak testing schemes with different time periods of testing were calculated in detail. The first was to perform leak testing every nine months and the second was every refueling period (~18 months). Both of these cases include the requirement to perform the leak testing in the critical path. Since the cost of replacement power dominated the total cost estimate for the first two proposed leak testing schemes and greatly reduced the effectiveness of the tests with regard to cost-benefit considerations, a third case has also been analyzed where leak testing would be performed in each refueling outage, but not in the critical path. The results of the first two cases, the reduction in the frequency of core damage due to leak testing of the pressure isolation boundaries, are presented in Table 7.5.

7.5.1 Costs

The various costs for performing leak tests of the pressure isolation boundaries can be estimated using those previously estimated for the three reference plants. The cost of performing the leak tests of the various systems, such as LPI, HPI, RHR, etc., is estimated assuming the tests to last about five hours requiring about 50 man-hours with one man-rem exposure. If the leak test is performed in the critical path, the cost of the replacement power should also be included in the total estimate. The generic base case represents a typical PWR plant and consequently the replacement power cost is estimated at an average rate of ~ $400,000/day.[6] The generation of the appropriate test procedures, distribution, typing, and other costs is estimated at ~700 man-hours. Assuming that the plants have not been originally designed to accommodate periodic leak testing: test taps, valves, test tubing, etc., may not be available. The installation of the necessary test connections and other accessories and the associated documentation is estimated to cost ~$150,000 (based on discussion with plant personnel).

One Time Expenses

Test Procedures = 700 man-hours * $40 = $ 28,000
Test Taps, Installation, Etc. = $150,000

Periodic Expenses

Test Man-Hours = 50 man-hours * \$40 = \$2,000
Test Man-Rem = 1 man-rem * \$1,000 = \$1,000
Total Test = \$2,000 + \$1,000 = \$3,000
Replacement Power (5 Hours) = $\$8.33\times10^4$

Discounting the periodic cost of testing and replacement power by Eq. (7.1) ($r=.1$, $t_f=31$) and Eq. (7.3).

Test = 9.6 * \$3,000 = $\$2.88\times10^4$
Replacement Power = 81.5 * $\$8.33\times10^4$ = $\$6.79\times10^6$

Total cost - 9 months testing in critical path:
\$150,000 + \$28,000 + 12/9 * ($\$2.88\times10^4$ + $\$6.79\times10^6$) = $\$9.27\times10^6$

Total cost - 18 months testing in critical path:
\$150,000 + \$28,000 + 12/18 * ($\$2.88\times10^4$ + $\$6.79\times10^6$) = $\$4.72\times10^6$

Total cost - 18 months testing <u>not</u> in critical path:
\$150,000 + \$28,000 + 12/18 * ($\$2.88\times10^4$ + 0.0) = $\$1.97\times10^5$

7.5.2 Benefits

By assuming that the base case plant physically resembles Oconee, we are able to use the two benefit equations developed in Section 6.2.1. These two equations are:

(Nonsubmerged Case)
$\text{Benefit}_{TOT} = \Delta f_{CD}*4.82\times10^{10} + \Delta f_{OP}*1.61\times10^7$
(Submerged Case)
$\text{Benefit}_{TOT} = \Delta f_{CD}*2.83\times10^{10} + \Delta f_{OP}*1.61\times10^7$

These formulas require the calculation of explicit core damage frequencies. By comparing the periodic leak testing cases to the generic base case Δf_{CD}'s may be derived. The two leak testing programs with different time periods of testing in the critical path have been analyzed in detail and the results of these CDF calculations are presented in Table 7.5. The CDF due to ISL events bypassing the containment (see Item 4 in Table 7.5) may be reduced by approximately two orders of magnitude by performing periodic leak testing (the ratio of $CDF_{No\ Leak\ Test}/CDF_{Leak\ Test}$ is 265 for 9 months and 90 for 18 months). It is important to note that the reduction in CDF between the two different time periods of testing is only about a factor of three. This indicates that a leak testing program with 18 months test frequency may be almost as effective in reducing the CDF as a program with more frequent tests.

The benefits due to leak testing have been calculated using the results of the CDF analysis of the two leak testing programs and the formulas listed above.

The core damage frequency of the third case, which includes periodic testing every 18 months but not in the critical path, may be derived from the case where the test is performed with the same time period, but in the

critical path, by adding a component representing the incremental risk increase due to the placement of the testing (critical vs. noncritical path). This risk increment may be included in the base model by appropriately changing the initiator frequencies. However, noting that the difference in Δf_{CDF}'s of the two critical path testing schemes are almost negligible (less than 1%, see Table 7.4; $\Delta = (3.25-3.22)\times10^{-4}$) and knowing that this difference represents a definite risk differential, the following simplified approach has been used to model the incremental risk. An upper bound of this risk component may be estimated using the difference in CDFs of the two critical path testing programs. The rationale for this assertion follows.

The difference between the leak testing program with the 18 months time period as compared to the 9 months period (both in the critical path) represents an increase in risk due to the following factors:

1. In the time period between the 9th and 18th months an average of ~3 additional cold shutdowns occur during the normal operation of a typical plant. In the shutdown period there may be a number of demands to open the PIVs for maintenance or other reasons and in the case of the RHR system the RCS isolation valves definitely experience at least one demand to open, since residual heat removal must be provided to maintain safe operation. The important aspect of this demand cycle from the ISL point of view is that at the end of the shutdown period these valves are not tested for reclosure, thus somewhat increasing the probability of an ISL event. This component of the total risk represents essentially the demand type failure modes for the isolation boundaries during the shutdown period.

2. In addition, there is a small contribution from a continuous type of leakage failure mode due to the extended time between testing, since the leak test is performed now less frequently every 18 instead of 9 months.

In general, maintenance and other activities are more complex in a refueling period than in a single cold shutdown and consequently the operating demands (open/reclose) on the isolation valves may be somewhat higher. We have made the assumption that the risk due to ~3 cold shutdowns with respect to the demand type failure modes is equivalent with the risk due to one refueling period and is represented by the difference in CDFs of the two critical path testing programs (Δf (refueling) = $f(18) - f(9)$). In fact, this difference serves as an upper bound on the incremental risk, since a leakage type failure component is also included, but its contribution is relatively small as compared to the demand type component.

Based on the above arguments the Δf_{CD}'s for the noncritical path testing scheme have been derived in the following manner.

The CDF component due to the difference between critical and noncritical path testing is approximated as (f_{CD}'s are listed in Table 7.5):

$$\Delta(\Delta f_{CD}) \begin{bmatrix} \text{CD component} \\ \text{due to non-} \\ \text{critical path} \\ \text{testing} \end{bmatrix} \approx f_{CD} \begin{bmatrix} \text{Critical} \\ \text{path 18} \\ \text{months} \\ \text{testing} \end{bmatrix} - f_{CD} \begin{bmatrix} \text{Critical} \\ \text{path 9} \\ \text{months} \\ \text{testing} \end{bmatrix}$$

$$\Delta(\Delta f_{CD}) = (3.67-06) - (1.23-.06) = 2.44-06.$$

The CDF for the noncritical path testing scheme is derived by adding this CDF component to f_{CD}(critical):

$$f_{CD}\begin{bmatrix}\text{Noncritical} \\ \text{path 18} \\ \text{months testing}\end{bmatrix} = f_{CD}\begin{bmatrix}\text{Critical} \\ \text{path 18} \\ \text{months} \\ \text{testing}\end{bmatrix} + \Delta(\Delta f_{CD})$$

$$f_{CD}[\text{noncritical}] = (3.67-06) + (2.44-06) = 6.11-06.$$

Finally, the Δf_{CD} corresponding to the leak testing program with noncritical path testing is:

$$\Delta f_{CD})\begin{bmatrix}\text{Noncritical} \\ \text{path 18} \\ \text{month testing}\end{bmatrix} = f_{CD}\begin{bmatrix}\text{Base} \\ \text{case} \\ \ \end{bmatrix} - f_{CD}\begin{bmatrix}\text{Noncritical} \\ \text{path 18} \\ \text{month testing}\end{bmatrix}$$

$$\Delta f_{CD} = (3.26-04) - (6.11-06) = 3.19-04.$$

The Δf_{OP} numbers have been similarly derived.

Based on these considerations the benefits for the noncritical path testing scheme have been derived using the previous benefit formulas with the appropriate Δf_{CD}'s and Δf_{OP}'s.

7.5.3 Results

The cost and benefits for the three proposed alternative leak test programs are presented in Table 7.4. The first two columns represent the results when leak tests are performed in the critical path. Based on cost-benefit considerations, the leak tests are not very effective in the 9 months cycle and only marginally beneficial in the 18 months scheme due to the very high cost of the replacement power. The important fact to notice is that if the leak tests are performed only in refueling periods the associated costs can almost be halved without appreciably affecting the benefits. This suggests that the frequency of leak testing should coincide with the refueling period.

The third column represents the results when the leak tests are performed in the refueling period, but not in the critical path. The costs of this testing program are reduced by an order of magnitude, since the cost of the replacement power is eliminated. It is obvious that this leak testing program is a very effective method of reducing the risks from the cost-benefit considerations.

These results suggest that leak testing of the pressure isolation valves should be performed after maintenance and at each refueling. In addition, the leak tests may be performed during descending from power at the beginning of

the refueling period without significantly increasing the risk of an ISL event.

The main purpose of the leak test is to examine whether the conditions of the PIVs have deteriorated to such an extent that specific maintenance actions are required. If such maintenance has to be performed (which definitely occurs with some frequency throughout the plant lifetime), the cost of such actions should also be accounted for in the total cost estimate. Even though the previous cost estimates did not include this component, it is apparent that performing such maintenance in the critical path would significantly increase the already high cost of those leak testing programs that include critical path testing requirements due to the high cost of replacement power.

In light of this, a leak testing program without the critical path testing requirement has the additional advantage that maintenance of the PIVs, if required, does not have to be performed in the critical path, but rather in the refueling period with significantly less costs and in a time period when other regular maintenance activities are already taking place.

It should be emphasized that the individual leak test of the PIVs is especially effective in finding the failures of one element of a multiple pressure boundary. One important advantage of the leak test is that it provides information on the condition of the individual elements of the pressure boundary irrespective of the particular failure mode. Even though the leak tests are very useful to find and correct failures that have already occurred, the tests are somewhat ineffective in predicting possible future failures. The exception is a slowly developing leakage failure mode, where a trend in subsequent leak tests could indicate a potential future failure of the PIV.

7.6 Impact on Other Requirements

We have identified two established NRC programmatic functions that could be impacted by incorporating the recommendations of this study. The two programmatic functions are the In-Service Testing and Inspection Program and the Technical Specifications. In each case the impact would be to add certain pressure isolation valves to the existing programs.

We have also identified an ongoing NRC program that interacts with the Interfacing System LOCA issue. BNL is in the finalizing stages of a study concerning Generic Issue 99.[7] This issue deals with the risk involved with PWR RHR system performance with the plant at shutdown. The proposed corrective actions derived from this ISL study do not impact the resolution of the RHR generic issue. However, there is one proposed corrective action in the RHR study that potentially impacts upon the ISL issue.

One of the main concerns in the RHR study is loss of the RHR function and one of the major contributions to loss of this function is the spurious closure of an RHR suction valve. Furthermore, the main contributor to closure of an RHR suction valve is spurious or false actuation via the automatic closure interlock. The purpose of the interlock is to ensure that the suction valves are closed when the primary system is pressurized and thereby preclude an interfacing LOCA.

One of the RHR study's proposed corrective actions is to eliminate or modify the auto-closure interlocks. It must be stressed that this trade-off results in a reduction in overall plant risk. The removal of the auto-closure interlock results in a significant reduction in the loss-of-cooling initiator frequency and somewhat more modest reduction in core damage frequency. In terms of ISL initiator frequency, the increase is not considered significant because the removal of the interlock in the proposed corrective action is to be accompanied by other means to compensate, such as detailed operating procedures, alarms, etc. to ensure manual closure of these valves as primary pressure is increased during startup.

7.7 References

1. "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission," NUREG/BR-0058, January 1983.

2. S. W. Heaberlin et al., "A Handbook for Value Impact Assessment," NUREG/CR-3568, December 1983.

3. ACRS, "An Approach to Quantitative Safety Goals for Nuclear Power Plants," NUREG/-0739, October 1980.

4. USGAO, Three Mile Island: The Financial Fallout, EMD-80-89, July 1980.

5. David R. Strip, "Estimates of the Financial Consequences of Nuclear Power Reactor Accidents," NUREG/CR-2723, November 1982.

6. "Inside NRC," March 16, 1987.

7. T-L. Chu et al., "Improved Reliability of Residual Heat Removal Capability in PWRs as Related to Resolution of Generic Issue 99," NUREG/CR-5015, May 1988.

Table 7.1
Cost-Benefit Estimates Based Upon the Indian Point Unit 3 Design

	Corrective Actions				
	1	2	3	4	5
Δf_{CD} (per calendar year)	4.00×10^{-11}	1.28×10^{-9}	0.0	1.30×10^{-9}	2.10×10^{-9}
Δf_{OP} (per calendar year)	3.03×10^{-4}	2.07×10^{-4}	0.0	0.0	3.60×10^{-4}
Benefits					
Nonsubmerged Release	$\$8.15\times10^{3}$	$\$5.64\times10^{3}$	\$0.0	$\$7.09\times10^{1}$	$\$9.80\times10^{3}$
Submerged Release	$\$8.15\times10^{3}$	$\$5.61\times10^{3}$	\$0.0	$\$4.49\times10^{1}$	$\$9.76\times10^{3}$
Costs	$\$2.59\times10^{7}$	$\$9.02\times10^{4}$	$\$1.44\times10^{4}$	$\$4.32\times10^{3}$	$\$2.60\times10^{7}$

Table 7.2
Cost-Benefit Estimates Based Upon the Oconee Unit 3 Design

	Corrective Actions				
	1	2	3	4	5
Δf_{CD} (per calendar year)	6.80×10^{-7}	1.60×10^{-7}	2.08×10^{-8}	2.0×10^{-8}	7.49×10^{-7}
Δf_{OP} (per calendar year)	3.34×10^{-5}	2.32×10^{-5}	0.0	0.0	3.99×10^{-5}
Benefits					
Nonsubmerged Release	$\$3.33\times10^{4}$	$\$8.09\times10^{3}$	$\$1.00\times10^{3}$	$\$9.64\times10^{2}$	$\$3.67\times10^{4}$
Submerged Release	$\$1.98\times10^{4}$	$\$4.90\times10^{3}$	$\$5.89\times10^{2}$	$\$5.66\times10^{2}$	$\$2.18\times10^{4}$
Costs	$\$1.47\times10^{7}$	$\$2.50\times10^{4}$	$\$1.44\times10^{4}$	$\$4.80\times10^{3}$	$\$1.47\times10^{7}$

Table 7.3
Cost-Benefit Estimates Based Upon the Calvert Cliffs Design

	Corrective Actions				
	1	2	3	4	5
Δf_{CD}	$1.43x10^{-6}$	$2.91x10^{-6}$	$3.00x10^{-8}$	$1.50x10^{-7}$	$3.18x10^{-6}$
Δf_{OP}	$4.86x10^{-5}$	$8.18x10^{-5}$	0.0	0.0	$9.00x10^{-5}$
Benefits					
Nonsubmerged Release	\$7.48x10^4	\$1.52x10^5	\$1.55x10^3	\$7.74x10^3	\$1.66x10^5
Submerged Release	\$4.62x10^4	\$9.37x10^4	\$9.48x10^2	\$4.74x10^3	\$1.02x10^5
Costs	\$6.53x10^4	\$2.11x10^7	\$1.44x10^4	\$3.84x10^3	\$2.12x10^7

Table 7.4
Cost-Benefit Estimates Based Upon the Base Case Design

	Leak Tests In Critical Path		Leak Test Not In Critical Path
	9 Months**	18 Months**	18 Months**
Δf^*_{CD}	$3.25x10^{-4}$	$3.22x10^{-4}$	$3.19x10^{-4}$
Δf^*_{OP}	$2.19x10^{-3}$	$2.14x10^{-3}$	$2.09x10^{-3}$
Benefits			
Nonsubmerged Release	$1.57x10^7$	$1.56x10^7$	$1.54x10^7$
Submerged Release	$9.23x10^6$	$9.15x10^6$	$9.06x10^6$
Costs	$9.27x10^6$	$4.72x10^5$	$1.97x10^5$

*Note: $\Delta f = f^{\text{Without Leak Test}} - f^{\text{With Leak Test}}$

**Time period when tests are performed.

Table 7.5
Core Damage Frequency Reduction Generic Plant
Base Case

Item*	Core Damage Frequency: Base Case No Leak Test	Leak Test: 9 Months	Leak Test: 18 Months
1. Overpressurization	3.27-04	1.93-06	4.39-06
2. W/O Overpressurization	4.38-06	4.85-07	5.84-07
3. Sum of 1 + 2	3.31-04	2.42-06	4.97-06
4. With ISL Outside With and Without Overpressurization	3.26-04	1.23-06	3.67-06
5. With ISL Outside With Overpressurization	3.26-04	8.42-07	3.28-06

*Notes for Items

1. Total CDF due to ISL events occurring inside and outside the containment building that overpressurizes the low pressure system. The capacity of the relief valves are exceeded.

2. Total CDF due to ISL events occurring inside and outside the containment where the capacity of the relief valves are not exceeded. The low pressure system is not overpressurized.

3. The sum of Items 1 and 2.

4. Total CDF due to only those ISL events which bypass the containment. It includes both overpressurization events and those without overpressurization due to relief valve opening.

5. Total CDF due to only those ISL events which bypass the containment and overpressurize the low pressure system.

8. RESULTS AND CONCLUSIONS

The purpose of this section to highlight some of the results obtained and to present the most important conclusions.

The initiation, progression, core damage, and health risk aspects of ISL accidents at PWRs have been completely reexamined at BNL. All the potential ISL pathways at three reference plants representing three different reactor vendors were included in the analysis. The reexamination applied a more advanced approach to the ISL analysis than any previous one performed with PRA methodology. The new analysis utilized:

a. new valve failure rate data determined, by detailed root cause study, the failure of experiences of pressure isolation valves,
b. flow rate dependent leak failure frequencies which allowed the consideration of relief valve capacities in modelling of the accident and in classifying ISL initiators leading to small LOCAs and overpressurization of low pressure piping,
c. more accurate multiple valve failure model,
d. the results of a detailed investigation of valve testing procedures, practices and maintenance records including clarifying discussions with plant personnel on some problematic aspects of these activities,
e. newly constructed event trees based on all available information, including among others the results of an inquiry concerning emergency operating procedures, operator actions with respect of plant response and accident management,
f. reanalyzed failure probabilities of low pressure piping,
g. scrubbed and unscrubbed source terms characterizing pipe ruptures below and above water level, and
h. generic site consequence model with a ten mile evacuation.

8.1 Technical Results and Conclusions

The reexamination of the ISLs provided the following important results that may be used for future analyses of ISLs at PWRs:

1. In all former studies of ISLs through the LPI pathways the analysis did not consider the fact that the inlet header of the LPI to the RCS is shared with the accumulator and also with HPI lines at Westinghouse and Combustion Engineering plants. This shared inlet header may have an appreciable effect on the development of the ISLs through the affected pathways. The root cause analysis of experienced accumulator inleakage events revealed that the accumulator outlet check valve is rather prone to the "failure to operate (reseat) on demand" failure mode. Therefore, the preferred direction of the ISLs is expected to be through the accumulator and not through the LPI/HPI pathways. One can conclude, that in any future study of ISLs through the common injection inlet, this effect and its consequences have to be taken into account.

2. The results on the initiator frequencies support the insight obtained by PLG in their Seabrook EPZ sensitivity study, that the relief valves have a definite role in reducing the frequency of overpressurization of low pressure piping. (In the present study the sensitivity of initiator frequencies to various relief valve capacities can be easily evaluated, since the initiator

frequencies through the injection lines are given in graphical form as a function of check valve leak flow rates.)

3. The failure analysis of low pressure piping performed at BNL indicates that, at least for the plants selected, given a breach of the pressure boundary between high and low pressure systems, hoop stresses are at the yield stress or above in the low pressure piping. In certain pipe segments, the stresses are found to be near the ultimate material stress. At such stress levels pipe failure probabilities range from $2x10^{-3}$ at yield to almost certainty at the ultimate stress.

8.2 Results on Core Damage Frequency

The results of the core damage frequency (CDF) calculations indicate that the contributions from two groups of lines, the RHR suction and LPI injection lines, dominate the CDF due to ISLs. In particular, at the Indian Point and Oconee plants the total CDF with overpressurization is dominated by the contributions from two sequences. A large ISL on the RHR suction side piping contributes 50% (IP), 12% (OC) of the total CDF, and an ISL event on the LP injection side is 39% (IP), 88% (OC) of the total. At Calvert Cliffs an ISL event sequence leading to a large LOCA on the RHR suction side is the dominant contributor (99%). The total contribution of ISL events to CDF is generally less than a few percent of the overall CDF. However, they can potentially be important contributions to risk if core damage occurs because ISLs may bypass the containment and allow fission product release directly to the environment. These results are in agreement with previous findings.

8.3 Results and Conclusions From the Analysis of the Effects of Corrective Actions

A comparative plant specific analysis of the effect of various corrective actions on the CDF due to ISL lead to the following results: Corrective actions, such as (a) application of continuous pressure (leak) monitoring devices and (b) increased frequency of valve leak testing are capable of reducing the CDF due to ISLs by a factor of ~2 to 5 depending on plant specific valve arrangements.

However, the results obtained from the cost-benefit calculations for the three reference plants have indicated that additional leak testing and installation of pressure monitoring instruments (which are the most effective corrective actions for reducing the CDF) are rendered largely ineffective when replacement power costs are considered in the analysis. The other proposed corrective actions showed little reduction in the CDF and consequently the resulting benefits are negligible.

8.4 Results of the Generic Base Case Analysis

One of the primary goals of the present study was to determine the cost-benefit relationship associated with requiring plants that do not currently have leak testing requirements on their pressure isolation valves to institute such a program. All of the reference plants already had various requirements in this area. Therefore, the Oconee design model was selected and modified to represent those plants which presently have no leak testing requirements. Core damage frequencies have been calculated for the following

cases: (a) leak testing of the pressure isolation valves is not performed ("base case"), (b) leak testing would be required to be performed at each refueling during startup and therefore in the critical path (18 months), (c) leak testing would be required to be performed every nine months also in the critical path, and (d) Leak testing would be required to be performed at each refueling (18 months), but not in the critical path.

In general, the leak testing programs are capable of reducing the CDF due to ISL by two orders of magnitude depending on the specific test arrangements. The ratio of $CDF_{No\ Test}/CDF_{Leak\ Test}$ is 265, 90 and 53 for Cases B, C, and D, respectively. It is important to note that the difference between the 18 months noncritical path testing (Case D) and the 9 months critical path testing (Case B) is only about a factor of five suggesting that a program with 18 months test frequency may be almost as effective in reducing the CDF as a program with more frequent tests.

The obtained cost-benefit relationship shows that the benefits associated with the large core damage frequency and risk reduction due to a judiciously selected leak testing scheme could potentially outweigh the cost of implementing such a program.

8.5 Final Conclusions

- Institution of a leak testing program of the pressure boundary isolation valves at plants that do not currently have such a requirement results in a definite net benefit in overall risk reduction. It is suggested that leak testing be performed at each refueling and after specific valve maintenance. In addition, the leak tests may be performed during descentfrom power at the beginning of the refueling period without significantly increasing the risk of an ISL event. This specific leak testing program is capable of reducing the CDF by almost two orders of magnitude as compared to a case without provisions for leak testing, $CDF_{No\ Leak\ Test} = 3.26\times10^{-4}$ and $CDF_{Leak\ Test} = 6.11\times10^{-6}$. The offsite risk benefit-to-cost ratio was calculated to be within the range of 78 to 46 depending on whether or not the break in the low pressure system was submerged under water. A submerged break would result in trapping of the aerosol fission products in the water and thus lower offsite consequences and hence a lower benefit-to-cost ratio. This indicates that inspite of uncertainty in predicting fission product release the benefits in risk reduction outweigh the cost of implementing such a leak test program.

- The root cause analysis of experienced accumulator inleakage events revealed that the accumulator outlet check valve is rather prone to the "failure to operate (reseat) on demand" failure mode. Therefore, the preferred direction of an interfacing LOCA is expected to be through the accumulator and not through the LPI/HPI pathways. This is a particularly significant finding as the accumulator pathway represents an ISL inside containment.

- The results of this study with respect to initiator frequencies support the insight obtained by Pickard, Lowe & Garrick in their Seabrook EPZ sensitivity study,[1] that the relief valves of the low pressure systems have a definite role in reducing the frequency of overpressurization of low pressure piping.

- The failure analysis of low pressure piping performed by BNL indicates that, at least for the plants selected, given a breach of the pressure boundary between high and low pressure systems, hoop stresses are at yield stress or above in the low pressure piping. In certain pipe segments, the stresses are found to be near the ultimate material stress. At such stress levels pipe failure probabilities range from $2x10^{-3}$ at yield to almost certainty at the ultimate stress.

APPENDIX A: Analysis of Valve Failure Data

This appendix provides the documentation of valve failure data used to calculate the initiator frequencies of Interfacing System LOCAs (ISLs) in various pathways. It describes the approach used in the derivation of new failure rates and gives the sources for those which were previously determined. In addition it presents the description of some representative operating events involving pressure boundary isolation failure.

A.1 Check Valve Failure Rates

In the initiation of an ISL through ECCS injection lines, the following check valve failure modes are considered:

1. Leak failure (gross reverse leakage).
2. Disk rupture.
3. Failure to operate (reseat) on demand.
4. Failure to operate (hold) on demand.

Before entering into the discussion of the data sources for the rates of these failure modes some general comments are made about them.

1. Leak Failure Mode - The current usage combines actual leak events and reseat failure events. The experienced data include the failures of all the check valves in nuclear power plants. These data are not too appropriate to derive ISL initiators. In the present analysis, the leak failure events of isolation check valves in the RCS/ECCS interface (see Section 3 of the main text) alone serve as data base to derive new leak exceedance frequencies which are more appropriate for ISL analysis.

2. Disk Rupture Failure Mode - Disk rupture failure mode of check valves has not been experienced so far in the nuclear industry. (Our operating event search mentioned in Section 3 corroborated this general belief.) Therefore, in the failure frequency formulas this failure mode is not shown explicitly. However, since the formulas are quantified with leak exceedance frequencies, the disk rupture failure mode is implicitly included in the calculated ISL initiator frequencies.

3. Failure to Operate (Reseat) on Demand - The failure mode is identical to the "valve stuck open" failure mode. It acts essentially at valve openings, but if it stays undetected, it leads to an ISL when another isolation valve fails and demand occurs for the operability of the check valve to reseat.

The situation concerning the usefulness of the available data sources was similar to that discussed above (and in Section 3.1.1 of the main text) for the (reverse) leak failure mode. In various data bases failure events representing reseat failures either were classified as leak failures or if they were treated separately as "operating failures," the "failure to open," and "failure to reseat" modes were not distinguished.

In the present study, therefore a new frequency is calculated for the "failure to operate (reseat) on demand" failure mode by using appropriately selected failure events for check valves at the RCS/ECCS pressure boundary.

4. Failure to Operate (Hold) Upon Demand - The failure mode has been introduced by Pickard, Lowe and Garrick (PLG) in the "Seabrook Station Risk Management and Emergency Planning Study,"[1] to characterize the failure of a check valve against a flow and/or pressure perturbance resulting from a sudden failure of another preceding valve. However, neither PLG nor BNL could find operating events to be classified as representatives of the failure mode.

The failure mode formally plays a similar role in the multiple valve failure combinations of failure frequency formulas as the previous demand type failure mode (for details, see Appendix B). Thus, the frequency of "check valve failure to operate (reseat) upon demand" is used in the analysis as a substitute for the frequency of "check valve failure to operate (hold) failure mode.

From these preliminaries it can be seen that essentially two failure frequencies are used in the quantification of failure frequency formulas for various systems: the exceedance frequency of the "leak (rupture)" failure mode and the frequency of "valve failure to operate (reseat) on demand"failure mode.

The following subsections discusses further the details of the event analysis for the check valves.

A.1.1 Leak Failure Mode

A.1.1.1 Event Analysis

The operational events selected to obtain leak exceedance failure frequencies are listed in Table 3.1. The search and selection process of the events are shortly discussed in Section 3 of the main text. In this section more details are given about the event analysis.

A.1.1.1.1 Event Categories

The failure events of Table 3.1 were grouped into four categories:

1. Events whose description contains evidence of RC leakage into the accumulators. These events are considered to be accumulator inleakages through two failed check valves in series; A(2). The total number of A(2) events is: $N_{A(2)} = 28$. (The sample of events represents 56 check valve failures.)

2. Accumulator leakage events, whose description contains evidence only about one leaking check valve; A(1). (The water source is assumed not to be the RCS.) The total number of A(1) events is: $N_{A(1)} = 8$.

3. Leakage events of check valves in the common injection header of accumulator, LPI and HPI lines. Accumulator inleakages are not associated with these events. The leakages are directed into the LPI/HPI systems. These events are denoted by: LP. The total number of check valves in LP events is: $N_{LP} = 2$.

4. Leakage events of check valves on other HPI lines not associated with the accumulator injection header. These events are denoted by HP. There is

only one such event in Table B.1; representing three check valve leakage failures: $N_{HP} = 3$.

In order to clarify the causes of the high occurrence frequency of failure events associated with the accumulators, the events in the first three groups were subjects to the following analyses.

A.1.1.1.2 Interpretation of Accumulator Leakage Events, A(2)

To understand the possible origins of events A(2) one has to look into the operation of the accumulator check valves. For that purpose the schematic of the check valve arrangements at the RCS/Accumulator, LPI, HPI interface is presented in Figure A.1. The figure indicates the pressure conditions at the interface under ideal normal reactor operations when the check valves are perfect. P_1, P_2, and P_3 denote the pressures in the RCS, in the accumulator and in the LPI, HPI systems, respectively.

We are interested in the pressure conditions in the piping section between the check valves CV1, CV2, and CV3. (An additional check valve CV4 is also there if the design is such that the HPI line joins the LPI header downstream from CV3.)

It is easy to see that, when the check valves are operating, the pressure between the valves is that of the accumulator, P_2. Since $P_1 > P_2 > P_3$, (where P_2, the pressure of N_2 filling in the accumulator is much higher than P_3, the hydrostatic pressure of the RWST) the pressure differences across the check valves CV1 and CV3 (and CV4) keep these valves closed. However, the accumulator outlet check valve, CV2 is essentially open. Consequently, the seat of this check valve is exposed to various damaging affects of the highly borated water of the accumulator. Under unfavorable temperature conditions boron can be deposited onto the seat or hinges of the valve disc. The affects of boric acid are different at the other check valves. At CV1, whose temperature is about the same as that of the RCS, boric acid stays in solution. At CV3 (and CV4), the effect of boric acid is much smaller than at CV2, because these check valves are closed.

Consider now what happens when a back-leakage develops through CV1. (An original "disk failing open" failure mode of CV1 must be excluded from consideration, because CV1 and other similar isolation check valves are leak tested after RCS depressurization to ensure disc seating.) The sudden, ruling pressure in the space between the valves will become P_1, and the valve CV2 will close. CV3 (and CV4) will close even tighter because of the increased pressure difference across their disks. CV1 will have RCS pressure on both sides of its disc. At the same time, the check valves CV2 and CV3 (and CV4) will be exposed to the RC temperature. This is the situation, when CV2, CV3, and CV4 are operating. Due to the damaging effects of boric acid or boron deposition it is highly probable, however, that CV2 will not be able to reseat.

The environmental effect of the boric acid under unfavorable conditions may significantly enhance the probability of the other check valve failure mode "valve failure to operate (reseat) on demand" for CV2. The effect of boric acid on CV3 (and CV4) is expected to be much less, because CV3 (and CV4) are always kept closed (unless they fail).

If CV2 recloses, it may develop backward leakage randomly in time with the same failure rate as previously CV1 had, because its disc is exposed now to the same differential pressure as previously CV1 was.

The level, pressure, temperature, and boric acid concentration of the accumulator is under constant surveillance. CV2 has high probability that is will not reclose completely upon demand. Consequently, even small leaks through CV1, have high potential for discovery.

Thus, it can be concluded, that the combination of two effects, the constant surveillance of the accumulators and the high probability that CV2 fails to operate (reseat) on demand because of boric acid effects, provides a reasonable explanation for the high occurrence frequency of accumulator events, A(2).

The frequency of these events can be described by the expression given below (for more details see Eq. (10) in Appendix B, Section B.1.1.d and Section 4.3.1 of the main text, discussing the determination of ISL initiator frequencies for LPI pathways):

$$\lambda_{A(2)} = \lambda_1 \left[\lambda_1 T + \lambda_d + \lambda_{d2} \left(\frac{d_2 T + 1}{2}\right)\right] \equiv \lambda_1 C \quad (1)$$

where, λ_1 denotes the (gross backward) leak failure rates of check valves CV1 and CV2,

λ_{d2} is the enhanced failure probability of CV2 to operate (reseat) on demand and d_2 is the demand ("chattering") frequency of CV2,

λ_d is the (standard) failure probability of CV1 to operate on demand,

T usually denotes the time interval between the leak tests of CV1, when there is no other means to discover valve failures. Since the accumulators are constantly monitored, T is "an effective time period" to detect a significant accumulator inleakage.

The quantity C may be considered as "an effective probability" of "valve failure to operate on demand" failure mode for CV2.

A.1.1.1.3 Interpretation of Accumulator Leakage Events, A(1)

In order to interpret the origin of these events we refer again to the valve configuration shown in Figure A.1. Consider the case, when CV1 is perfectly seated. Leakage into the accumulator through CV2 still can occur, if:

a) for some reasons, the N_2 pressure in the accumulator, P_2 falls below the hydrostatic pressure of the RWST, P_3 (i.e., $P_3>P_2$) and CV2 does not reclose upon this challenge, or

b) for some reasons, e.g., due to inadvertent initiation of the HPI pumps the pressure in the space between the valves suddenly increases such that $P_3>P_2$ and CV2 does not operate upon this demand. Since these failure events are not associated with RC inleakage into the accumulators they are not analyzed further.

A.1.1.1.4 Interpretation of Leakage Events, LP

For the interpretation of these events we refer again to Figure A.1. We recall the situation described in Section A.1.1.1.2, when CV1 leaks and CV2 is operating. i.e., CV2 recloses upon demand and does not develop leakage randomly. If there is no safety valve connected to the space between the valves, the overpressurization of the space between the valves is hard to detect. Only leak tests on CV1 lead to the discovery of the failure.

Consider now the case when both check valves, CV1 and CV2 are operating, but CV3 or CV4 leaks ($P_2>P_3$). It is hard to detect the failure because successive check valves upstream in the injection lines will probably reclose. As in the former case, leak tests leads to the discovery of the failures.

The frequency of LP events, i.e., the frequency of single check valve back leakage failures which are not accompanied by check valve failure in the accumulator line, can be described by the expression:

$$\lambda_{LP} = \lambda_1(1-C), \qquad (2)$$

where λ_1 is the leak failure rate of the individual check valves (considered to be about the same for each check valve, CV1, CV3, or CV4) and C is the "effective operating failure probability of CV2" defined in expression (1).

Additional failure combinations of CV1 and CV3, or CV1 and CV4 are discussed in Section 4.3, of the main text, where the ISL initiator frequencies are calculated.

A.1.1.2 Data Reduction

A.1.1.2.1 General

The following approach has been applied in the data reduction:

1) Expressions (1) and (2) are equated to the maximum occurrence frequencies of events A(2) and LP. The obtained system of equations is solved for the "effective operating failure probability," C of the accumulator check valve, CV2.

2) Expressions (1) and (2) are equated to the experienced frequences of events A(2) and LP in various leak rate groups. By solving the equations for the leak failure rate, a leak exceedance frequency versus leak rate curve is calculated.

A.1.1.2.2 Determination of the Effective Operating (Reseat) Failure Probability, C for the Accumulator Check Valve, CV2

The maximum occurrence frequencies (frequency/hour) of events A(2) and LP are determined by using expressions (1) and (2), respectively, as follows:

$$\lambda^{max}_{A(2)} = \lambda^{max}_{1} C = \frac{N_{A(2)}}{T_A} \qquad (I)$$

and

$$\lambda_{HP}^{max} = \lambda_1^{max}(1-C) = \frac{N_{LP}}{T_{LP}} , \qquad (II)$$

where λ_1^{max} denotes the maximum LP leakage failure frequency,
$N_{A(2)}$ and N_{LP}, are the total number of failure events of event categories (1) and (3) (see Section A.1.1.1.1),
T_A and T_{LP} the total number of check valve-hours for check valve populations in accumulator and LPI lines at all PWRs, respectively.

The solution of the system of equations (I) and (II) for C, is:

$$C = \frac{N_{A(2)}}{N_{A(2)} + kN_{LP}} , \qquad (III)$$

where $N_{A(2)} = 28$, $N_{LP} = 2$ (from Section A..1.1.1.1), and $k = T_{A(2)}/T_{LP}$.

The total number of check valve hours, $T_{A(2)}$ and T_{LP} are given in Table A.1, as:

$T_{A(2)} = 2.316 \times 10^7$ and $T_{LP} = 2.287 \times 10^7$, $k = 1.012$.

Additional details about the determination of the total number of check valve hours are discussed in Section A.1.1.2.4.

From the data above the "effective operating (reseat) failure probability" of the accumulator check valve, CV2 is:

$$C = .93 \qquad (III')$$

The value is high because of the presence of the boric acid.

The significance of the high value of C for the initiation of ISLs through LPI lines is important. It means that CV2 behaves as a kind of "safety valve" with regard to the shared Accumulator/LPI/HPI inlet and the preferred direction of an ISL will be through the accumulator and not through the LPI (or HPI) pathways.

A.1.1.2.3 Calculation of a Leak Exceedance Frequency Versus Leak Flow Rate

The leakage events, A(2) and LP, were grouped into five leak flow ranges. For each group, a frequency per hour value is calculated by using the total check valve hours given above. By equating expressions (1) and (2) to the frequencies of the i-th leak flow range one obtains the following system of equations:

$$\lambda_{A(2)}^{(i)} = \lambda_1(i)C = \frac{n_{A(2)}^{(i)}}{kT_{LP}} \qquad (I')$$

$$\lambda_{LP}(i) = \lambda_1(i)(1-C) = \frac{n_{LP}(i)}{2T_{LP}} \qquad \text{(II')}$$

Here, $\lambda_1(i)$ denotes the leakage failure frequency of a check valve in the i-th leak flow range and $n_{A(2)}(i)$ and $n_{LP}(i)$ are the number of leakage events of event categories (1) and (3) in the i-th leak flow range.

Solving the system of equations (I') and (II') for $\lambda_1(i)$, one obtains (k=1.0):

$$\lambda_1(i) \approx \frac{1}{T_{LP}} \left[n_{LP}(i) + n_{A(2)}(i)\right] \qquad \text{(III')}$$

Table A.2 shows the sum of leakage events and the leakage failure frequencies calculated according to formula (III') for the five leak flow ranges as well as the corresponding cumulative frequency values for single check valves, λ_1. Table A.2 shows also the cumulative frequencies of the accumulator inleakages, $\lambda_{A(2)}$. The cumulative frequency values are also plotted as a function of the leak flows in Figure A.2 and Figure 4.2 (of the main text) for single check valve and for accumulator inleakages, respectively.

The cumulative frequency values for single check valves are fitted with a straight line (on a log-log scale) by using the least square method. The line represents the median values of an assumed underlying lognormal leak failure frequency distribution. The figure shows lines representing the 05 and 95 percentiles of the distribution obtained by statistical band estimate. The corresponding mean and mean square curves are also presented to facilitate inter- or extrapolation. The mean and mean square frequency curves are used in the quantification of formulas for ISL initiators.

The application of straight line fit to the observed values is supported by the generic experience that exceedance frequencies of many naturally occurring phenomena (like earthquakes, income of people, pipe break sizes, etc.) follow a kind of power low (Pareto's distribution).

It has to be recognized that the experienced values and their best fit curve represent only a first approximation for a more precise "leak exceedance frequency versus relative leak rate" curve. This is because the experienced data are originated overwhelmingly from accumulator inleakages. Accumulator inleakages from the RCS involve leakage through two check valves in series, where the less leaking valve dominates (the other valve may even be wide open). The leak flow rate values derived from RC leakage into the accumulators are correct for a two check valve system, but are lower limits for single check valves.

A precise leak exceedance frequency versus leak rate curve should be based on single valve leak data and homogeneous check valve size.

A.1.1.2.4 Total Exposure Times of Check Valves in Accumulator and LPI Lines

This section provides some additional information about the determination of total exposure times for check valves in the accumulator and LPI lines.

Table A.1 details the accumulator and LPI check valve hours for each PWR considered and presents the total exposure times, $T_{A(2)}$ and T_{LP}. Usually the FSARs of various PWRs were used to obtain the number of check valves in the relevant lines. The total time from start of commercial operation of the individual plants was taken as "time of exposure per check valve." This was done because corrosion effects (e.g., corrosion due to boric acid) continuously degrade the internals of the valves.

A.1.2 Check Valve Failure to Operate (Reseat) on Demand

A.1.2.1 Event Analysis

The search process for operating events selected as representations for this failure mode was shortly discussed in Section 3 of the main text. In this section more details are given about the event analysis.

The relevant events were already listed in Table 3.2. From all the events, however a subset consisting of events designated as LPI or HPI events, are taken only to estimate the probability of the failure mode.

The total number of failed check valves involved in that subset is: 9.

The corresponding success (number of demand) data are developed on the LPI check valve population and plant age. The HPI check valve population in the interfacing lines is assumed to be equal to that of the LPI. For the success estimate, an average of 10 system-wide demands per year is assumed.

A.1.2.2 Data Reduction

The total number of check valve-years for LPI check valves from Table A.1 is $2.611\text{x}10^3$. Based on the above considerations this value results in the following total number of check valve demands in the LPI and HPI interfacing lines: Check valve demands (LPI and HPI) = $2\text{x}10\text{x}2.611\text{x}10^3 = 5.222\text{x}10^4$.

Assuming an underlying lognormal distribution the median value of the probability of check valve failure to operate (reseat) on demand is:

$$\lambda_d^{Median} = \frac{9}{5.222\text{x}10^4} = 1.72\text{x}10^{-4} \text{ per demand.}$$

With a Bayesian updating process for the average range factor characterizing the distribution a value of RF = 5 obtained.

Thus, the values for the mean and mean square are:

$\lambda_d^{Mean} = 2.81\text{x}10^{-4}$ per demand, and

$$\langle\lambda_d^2\rangle = (\lambda_d^{Mean})^2 + var. = 2.05x10^{-7} \text{per demand}^2 ,$$

respectively.

The result obtained is in agreement with the value obtained in Ref. 1 applying different basic data for this type of failure mode, which is:

λ_d(Median) = $1.58x10^{-4}$ per demand.

A.1.3 Check Valve Disk Rupture

Besides, what has been told previously about this failure mode, the following is remarked:

Till the end of 1985 the nuclear industry had not reported any check valve disk rupture events. The closest failure event to this category is what happened at Davis Besse-1 (NPE # VII.A.273, IE Info. Notice 80-41) when a disk and arm had separated from the body in an LPI isolation check valve. The PSA Procedures Guide[2] lists an estimated value based on expert opinions for the disk rupture failure rate, as $1.0x10^{-7}$/hour (i.e., $8.76x10^{-4}$/year). The guide's value practically coincides with the exceedance frequency of the maximum experienced leak flow (200 gpm) in Figure A.2. Since there is no experienced event for this failure made in the nuclear industry, the leak failure rates applied in this study are considered as conservative upper bounds for the disk rupture frequency.

A.2 Motor-Operated Valve Failure Rates

The following failure modes of MOVs are considered in the calculation of ISL initiator frequencies:

1. MOV disk rupture.
2. MOV internal leakage.
3. MOV disk failing open while indicating closed.
4. MOV transfer open.
5. MOV failure to close on demand.
6. MOV gross (external) leakage.

The subsections below discuss the data sources for each of the failure modes.

A.2.1 MOV Disk Rupture

Available data sources had no data on this catastrophic MOV failure mode based on experienced events. An LER search conducted by BNL for this failure mode at PWRs could not identify any such event. However, a similar search conducted also by BNL for the study of ISLs at BWR[3] identified five events in which valve disk was separated from the stem. Based on these events the MOV disk rupture failure rate (mean value) estimated in that study is: $1.20x10^{-3}$ per year. This value is applied also in the present calculations.

A.2.2 MOV Internal Leakage

This failure mode represents failures in which MOV leaks because of seat wear or other reasons. The failure mode is assumed to result in limited leakage through the valve. An LER search performed to identify such failures resulted in three events at RHR suction side valves (see Table 3.3). The suction side valves are specially built with double disks. The total number of RHR suction valve-hours was calculated by using the number of reactor years of Table A.2 and RHR suction valve population of two or four per reactor for plants starting commercial operation before or after 1981. The total number of RHR suction valve-hours is 8.743×10^6.

Assuming lognormal distribution and by using a Bayesian updating process one obtains the following values for the median, range factor, mean and mean square of the failure frequency:

$$\lambda^{Median}_{MOV\ Int.\ leak} = 3.0 \times 10^{-3} \text{ per year}, \qquad RF \approx 5,$$

$$\lambda^{Mean}_{MOV\ Int.\ leak} = 4.85 \times 10^{-3} \text{ per year, and the expectation of its square:}$$

$$\langle \lambda^2_{MOV\ Int.\ leak} \rangle = (\lambda^{Mean})^2 + Var. = 6.12 \times 10^{-5} \text{ per year}^2 .$$

A.2.3 MOV Disk Failing Open While Indicating Closed

This type of failure mode may arise at MOVs, which are not equipped with stem-mounted limit switches from gear drive disengagement. At valves which are equipped with limit switches it arises from failure of the stem or other internal connections or failure of a limit switch (including improper maintenance such as reversing indication). The failure may occur after the valve being opened. As a result, the valve is leaking while the indication in the control room signals that the valve is closed. It is expected, that this failure mode is giving rise small leakage.

The failure rate applied in this study is taken from the Seabrook PSA,[4] where it was obtained from data reported in NPE. The mean frequency of "failure of an MOV to close on demand and indicate closed" is 1.07×10^{-4}/demand.

A.2.4 MOV Transfers Open

"MOV transfers open" failure mode defines such MOV failure, when a closed MOV inadvertently opens due to failures of valve control circuits and power supplies or due to human errors during test or maintenance.

In the Seabrook PSA[4] the main failure rate of this failure mode was estimated by using generic data to be 8.10×10^{-4} per year. For quantification of the initiator formulas in the present study that value is applied.

A.2.5 MOV Failure to Operate on Demand

MOV failure to operate on demand represents MOV failures in which a closed MOV suddenly opens upon demand, e.g., as various kind of shocks like

pressure wave, sudden stress increases due to mechanical or thermal causes. This failure mode of MOV is a failure mode of "dependent" type and different from the retainer rupture failure mode of MOVs, which is a failure mode of random type.

An LER search to identify such events was futile. Therefore, in the calculation of ISL initiator frequencies "MOV disk failing open while indicating closed" failure rate (1.07×10^{-4}/demand) is used.

A.2.6 MOV External Leakage/Rupture

This failure mode of the MOVs is the most visible and detectable. The failure rate is given in various data sources. The data sources, however, do not provide information about the exceedance frequency of the failure as a function of the leak flow rate. A cursory review of some failure event reports showed that there is no appropriate information in the event descriptions about the leak rate. The LER search for failures of MOVs in the interfacing lines did not detect the occurrence of this failure mode. Thus, for the present report the generic value given in NUREG/CR-1363[5] for PWRs is taken. The mean failure frequency of MOV external leakage/rupture mode is 8.76×10^{-4} per year. As first approximation to the variation of this value with the leak flow rate, the exceedance frequency vs. leak flow rate curve for check valves (Section A.1.1.2.3) is used.

A.3 Description of Representative Operating Events Involving Pressure Boundary Isolation Failure

In this section, some of the previously listed and briefly discussed operating events (Chapter 3) are discussed in more detail.

A.3.1 Events Involving Isolation Check Valves

A.3.1.1 Oconee 1 and 3 (LER 81-015)

A check valve (14" Crane, steel, swing check valve) in the LPI system was found to be leaking excessively during the performance of a LOCA leak test. The leaking valve was the final valve in the LPI loop before reaching the reactor vessel. The valve disc had a cylindrical knob on its back which was inserted through a hole in the hinge arm and then had a retainer ring welded onto it to hold in the hinge arm. By pivoting, the disc was allowed to find its seat properly should the mating surfaces become slightly altered. A manufactured tolerance of 3 to 11 mil between the disc knob and the hinge at the pivot prevented the disc from swaying too freely. Examination of the valve disc-hinge assembly showed that the disc had become frozen at the pivot in a cocked position. Consequently, only ~1/2 of the disc was seating. The "freezing" of the disc at the pivot was apparently caused by a buildup of deposits in the gap between the hinge and the disc "knob" on the side of the knob closest to the hinge pin. While there was flow through the valve, the disc was normally in a cocked position, and it was postulated that the flow could carry deposits into the pivot gap area, where they could accumulate. The accumulation of deposit could then cause the disc to remain slightly cocked when the flow was stopped. During examination of the valve disc, the retaining ring was removed and unsuccessful attempts were made to remove the disc from the hinge. Both the hinge and disc were made of the same type of SS

and under the high temperature of unit operation, some galling could have occurred. At that time, the disc was still connected to the hinge.

Prior to the testing, two backup check valve had been leak tested and both had shown zero leakage. This valve was the 1st valve, out of a total of 18 of the same type of valve leak tested at Oconee, which had shown any leakage problem. Another check valve of the same type was found to be leaking on Unit 3.

The unit was returned to cold shutdown so that the valve could be repaired. The valve seat was lapped and the internals (disc, hinge, and hinge pin) were replaced with new parts. The valve was then retested and there was zero leakage by the seat. An analysis was to be performed on the substance in the pivot gap of the valve to determine its origin. Extreme contamination of the internals, however, had made examination of these parts undesirable at that time with respect to personnel exposure. At Unit 3 a spectrum analysis was performed on the deposits from the pivot and they were determined to be from the RCS.

A.3.1.2 Palisades

On 9 September, during modification of the LPSI system piping to add leak testing capability, excessive wear to the valve internals was discovered in the LPSI swing check valves. The disk nut, disk nut washer and the disk nut pin were missing and severe wear was observed on the valve body, clapper arm, disk clapper arm shaft and clapper arm support for two (CK 3100 and 3148) of the four LPSI valves. The disks were still attached to their clapper arms and the valves were operational; however, valve set and disk sealing surfaces were damaged and the valves could have been leaking. An NRC order dated April 20, 1981 involved check valves that formed the interface between an HP system connected to the RCS and an LP system whose piping went outside containment. CK 3133 and 3148 formed the boundary between the LPSI and HPSI systems and failure of the valves could have resulted in overpressurization of the LPSI system and the loss of some HPSI flow. The inspection of the valves was the first in ~10 years of operation. It was subsequently discovered that the remaining two valves had also failed in a similar fashion. The LPSI check valves were manufactured by Alloy Steel Products Company (ALOYCO) in 1968. They were six inch swing type check valves with weld ends for attachment to piping. All four valves were mounted vertically with flow directed upward.

The valves were of an in-line configuration with a ballooned or expanded area in the valve body for movement of the flapper-type (see Figure A.1). The disk was substantially larger than the pipe and if the disk had separated from the clapper arm, it would have been trapped within the expanded portion of the valve body.

Operation of the valve resulted in the threaded shaft on the back of the valve disk striking the valve body as it opened to the full flow position. The valve body was the ultimate limit for disk opening. In full flow operation, it was presumed the disk generated sufficient turbulence to cause chatter against the valve body. Where these valves were used for extended periods of operation, they exhibited about a 1/2" of wear (above the disk nut) of the threaded portion of the disk shaft. Although the disk nuts had been

worn away, none of the disks had separated from their clapper arm because of the peening action on the shaft.

The design of ALOYCO swing check valves was such that the threaded shaft acted as the striking surface to limit clapper travel. This design was not used universally by other manufacturers. In other valve designs, the possibility of the threaded shaft acting as the striking surface had been eliminated by providing an alternate raised surface on the valve disk to contact the valve body.

A.3.1.3 Arkansas One 2

On 18 October, SI check valve (Velan) 2SI-12C stuck in the open position when stroked by hand. The hand stroking operation was initiated as a result of recommendations of IE Notice 81-30. The hand stroking operation was performed when the bonnet was removed during maintenance activities. The three counterpart valves (2SI-13A, 2-SI-13B, and 2SI-13D) were inspected and hand stroked. Valve 2SI-13B also stuck when hand stroked. These valves were the first of two check valves between the HPSI header shutoff valve and the injection nozzles. Investigation revealed that the valve disc stud for 2SI-13C protruded far enough above the disc nut to interfere with the body and hold the disc assembly in the open position. The vendor drawing showed the disc stud to be flush with the top of the disc out. The portion of the disc stud that protruded above the nut was filed off leaving the top for the stud flush with the top of the disc nut. Valve 2SI-13B stuck because the disc was misaligned and allowed the disc to stick against the side of the body. The interference resulted from the bushings being improperly positioned. The bushings were repositioned so the valve functioned properly with no sticking throughout its full stroke.

A.3.1.4 Point Beach 1 (LER 81-010)

On July 31, 1981, Wisconsin Electric Power Company reported (LER 81-010/01T-0) that on July 14, 1981, while a check valve leakage test at the Point Beach Nuclear Plant, Unit 1, was being performed, the check valves closest to the reactor coolant system in the low head safety injection lines were found to be leaking more than allowed by the leakage acceptance criteria. The valves are Velan six inch 1500 psig ASA swing check valves (Velan Drawing No.78704).

The valves were disassembled and the disks were found to be stuck in the full-open position due to interference between the disk nut lockwire (disk wire) and the valve body. The disk nut and its shaft can rotate freely, and, in certain random rotational positions, this interference is likely to occur.

The licensee has replaced the disk wire with a cotter pin that will not cause interference with the valve body for any rotational position. Subsequent inspection of the other check valves in the low head safety injection lines was performed. These valves were found to be closed. The lock wires were nevertheless replaced with cotter pins.

A.3.1.5 Davis-Besse Unit 1

On October 9, 1980, the resident inspector at the Davis-Besse facility was informed that the licensee had performed leak rate tests and identified excessive leakage through Decay Heat Removal System check valve CF-30. Valve CF-30 is the inboard one of two in series check valve that is used to isolate the reactor coolant system from the low pressure decay heat removal system. On further investigation the licensee found that the valve disc and arm had separated from the valve body and was lodged just under the valve cover plate. The two 2-5/8" x 5/8" bolts and locking mechanism for the bolts that holds the arm to the valve body were missing and have not been located. The CF-30 valve is a 14" swing check valve manufactured by Velan Valve Corporation. The cause of the failure has not been identified.

A.3.1.6 Main Yankee

Following power escalation testing the reactor was tripped and the plant cooled to 400°F for investigation of noted leakage into SI Tank No. 1. Samples taken from this tank were analyzed and the boron concentration found to be 1700 ppm (limit is 1720).

All SI Tanks (SIT) were filled and sampled ~7 weeks earlier and initial physics testing initiated. At this time all tanks were at 1750 ppm. These tests were followed by the Power Escalation Tests. About 2 1/2 weeks earlier, while performing these tests, inleakage to SIT No. 1 was noted. The noted leakage into SIT No. 1 was drained periodically. As the boron concentration in the RCS and therefore the charging system averaged ~800 ppm, any inleakage decreased by a small amount the boron concentration in SIT No. 1.

Following the cooldown the soft seat check valve between SIT No. 1 and the high pressure SI header was opened for inspection. A small piece of weld slag had lodged under the seat of the check valve allowing back leakage into SIT No. 1 from the high pressure SI header. The slag was removed, the seat and disk were smoothed and the "o" ring seal on the disk replaced. The valve was reassembled and tested satisfactorily.

A.3.2 Events Involving Motor-Operated Isolation Valves

A.3.2.1 Davis-Besse 1

Davis-Besse 1 - January 1979 - Hot Standby

During a shutdown on 17 January they attempted to close the Core Flood (CF) Tank 1-2 Isolation Valve CF1A using the Limitorque motor operator. The valve could not be closed with the motor operator and was manually closed. During investigation of the failure, it was determined that during a unit startup in December 1978, valve CF1A would not open using the motor operator and had been manually opened. The valve was manually opened prior to RCS pressure exceeding 800 psig on 29 December 1978 as required by the Tech. Specs.

The CF Tanks Isolation Valves are opened the entire time RCS pressure is >800 psig, and the power removed from the motor operators to prevent an inadvertent closure from rendering the CF Tank inoperable. Whenever RCS

pressure is <700 psig, the isolation valves are closed, and the power removed from the motor operators to prevent inadvertently opening the valve and discharging from the CF Tank.

The apparent cause of the failure of the motor operator for CF1A was a fabrication error. The motor operator of CF1A was found to have a cracked motor pinion gear. This was a small gear on the end of the motor shaft which supplied the initial torque to the operator. The set screw which held the gear to the shaft came loose. This allowed the key which kept the gear rotating with the shaft to travel downward and catch on the casting of the housing. This in turn bent the key and caused the gear to crack. The crack in the gear then permitted the key to fall completely out and prohibited the pinion gear from turning with the motor shaft. This caused the operator to be inoperative in either direction. The pinion gear and the associated key were replaced.

A.3.3 Events Involving Other Problems

A.3.3.1 Davis-Besse 1

The plant was in the process of a normal cooldown in accordance with the plant shutdown and cooldown procedure. As a part of the procedure, the decay heat suction isolation valves, DH11 and DH12, were required to be opened just prior to entering Mode 4 (hot shutdown). Pressure switch PSH-RC2B4 was required to close its contacts at 266 psig decreasing to allow DH12 to be opened. The switch functioned properly to open at 266 psig increasing to prevent opening DH12; however, the deadband in the switch prevented the switch from resetting within the pressure band required for simultaneous decay heat pump and RCP operation. A Facility Change Request (FCR) had been implemented to correct problems with this pressure switch and its deadband; however, the FCR changes did not correct the problems with PSH-RC2B4. Therefore, each time DH12 was required to be opened, a jumper was installed per plant procedure to defeat PSH-RC2B4 thereby allowing the valve to be opened.

On 23 August 1982, during a plant cooldown, the shift supervisor had the jumper installed to open DH12. The cooldown procedure required that the jumper be removed after DH12 was opened. The shift supervisor stated that he had called the electrical shop to remove the jumper; however, the jumper was never removed. The unit was returned to service and in operation until a plant shutdown on 18 January 1983. During the subsequent cooldown on 19 January, it was discovered that the jumper for PSH-RC2B4, installed on 23 August 1982, was still in place. DH12 was opened, the jumper removed as required by procedure and the cooldown continued.

It was determined that the cause for the event were two-fold. First, the shift supervisor did not verify that the jumper had been removed which was considered a lack of proper administrative control in following written procedures. The second cause was considered to be design error because had the pressure switch reset properly there would have been no need for the jumper to be installed.

A.4 References

1. "Seabrook Station Risk Management and Emergency Planning Study," PLG-0432, December 1985.

2. R. A. Bari et al., "Probabilistic Safety Analysis Procedures Guide," NUREG/CR-2815, Vols. 1 and 2, Rev. 1, August 1985.

3. T-L. Chu, S. Stoyanov, R. Fitzpatrick, "Interfacing Systems LOCA at BWRs," Draft Letter Report, July 1986.

4. "Seabrook Station Probabilistic Safety Assessment," PLG-0300, December 1983.

5. W. H. Hubble, C. F. Miller, "Data Summaries of LERs of Values," June 1980.

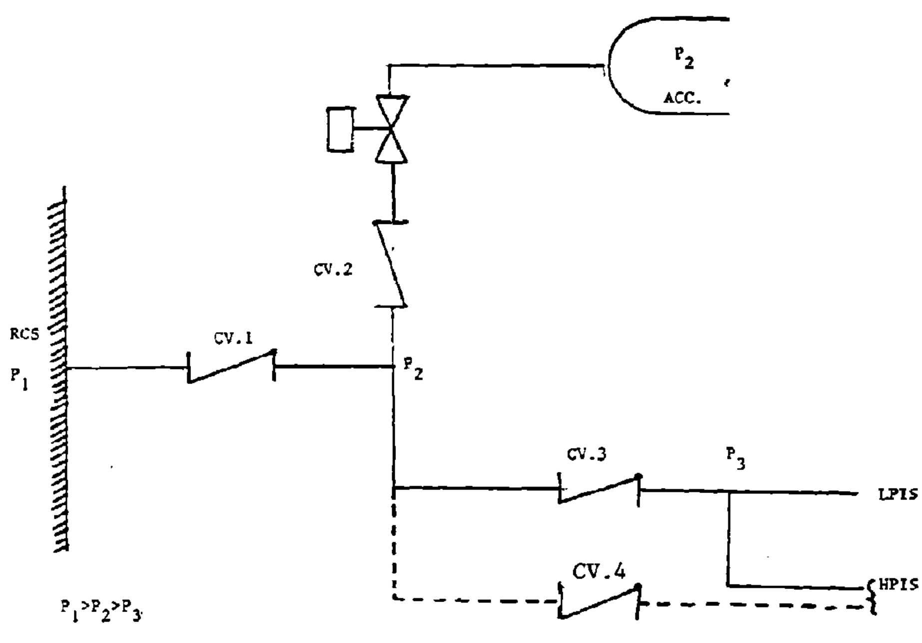


Figure A.1 Schematic of the valve arrangement at the RCS/ Accumulator, LPIs, HPIs interface. (An alternative joint of the HPI line to the LPI header is indicated by a broken line.)

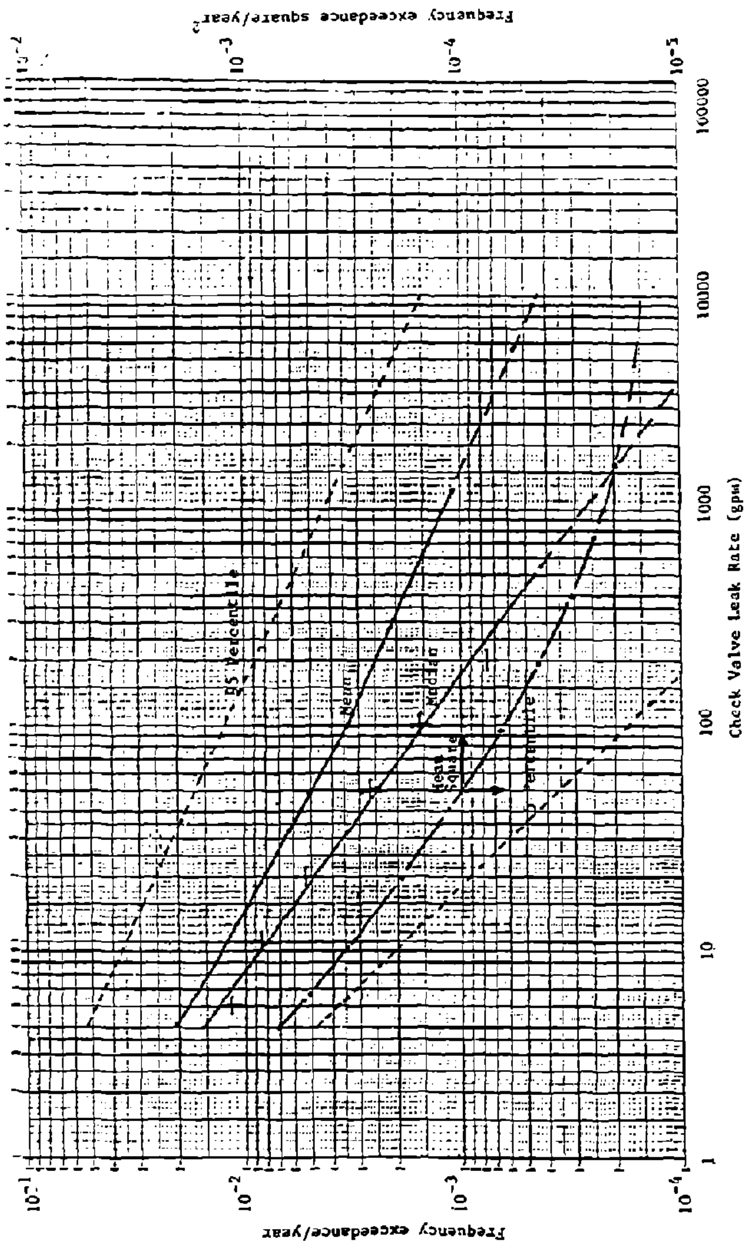


Figure A.2 Leak failure exceedance frequency of RCS/Accumulator, LPI pressure isolation check valves.

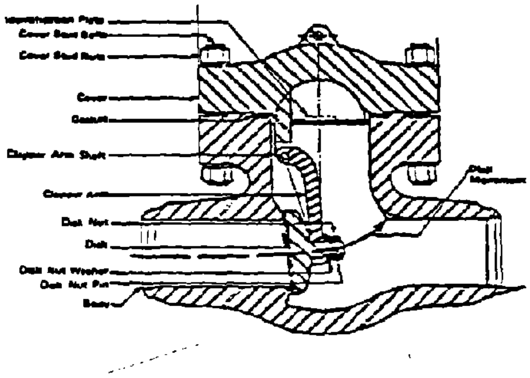


Figure A.3.1 Cross section of an ALOYCO swing check valve showing disk movement.

Table A.1
Accumulator and LPI Check Valve Exposure Data

Plant Name	Start of Commercial Operation	Number of Years	Number of Accumulator Check Valves	Total Number of Accumulator Check Valve-Hrs. (10^5 Hours)	Number of LPI Check Valves	Total Number of LPI Check Valve-Hrs. (10^5 Hours.)
Arkansas Nuclear One 1	December 1974	11.08	4	3.882	4	3.882
Crystal River 3	March 1977	8.83	4	3.094	4	3.094
Davis-Besse 1	November 1977	8.16	4	2.859	4	2.859
Oconee 1	July 1973	12.50	4	4.380	4	4.380
Oconee 2	March 1974	11.83	4	4.145	4	4.145
Oconee 3	December 1974	11.08	4	3.882	4	3.882
Rancho Seco	April 1975	10.75	4	3.767	4	3.767
Three Mile Island 1	September 1974	11.33	4	3.970	4	3.970
Three Mile Island 2	December 1978	7.08	4	2.481	4	2.481
Arkansas Nuclear One 2	March 1980	5.83	8	4.086	8	4.086
Calvert Cliffs 1	May 1975	10.67	8	7.478	12	11.217
Calvert Cliffs 2	April 1977	8.75	8	6.132	12	9.198
Fort Calhoun	September 1973	12.33	8	8.641	2	2.160
Millstone 2	December 1975	10.08	8	7.064	16	14.128
Maine Yankee	December 1972	13.08	6	6.875	9	10.312
Palisades	December 1971	14.08	8	9.867	2	2.467
St. Lucie 1	December 1976	7.08	8	4.962	8	4.962
Beaver Valley 1	April 1977	8.75	6	4.599	6	4.599
D. C. Cook 1	August 1975	10.42	8	7.302	4	3.651
D. C. Cook 2	July 1978	7.50	8	5.256	4	2.628
Indian Point 2	July 1974	11.50	8	8.059	9	9.067
Indian Point 3	August 1976	9.42	8	6.602	9	7.427
Joseph M. Farley 1	December 1977	8.08	6	4.247	6	4.247
Kewaunee	June 1974	11.58	4	4.058	4	4.058
North Anna 1	June 1978	7.58	6	3.984	8	5.312
Prairie Island 1	December 1973	12.08	4	4.233	3	3.175
Prairie Island 2	December 1974	11.08	4	3.882	3	2.912
Point Beach 1	December 1970	15.08	4	5.284	3	3.963
Point Beach 2	October 1972	13.25	4	4.643	3	3.482
R. E. Ginna 1	March 1970	15.83	4	5.547	-	—
H. B. Robinson 2	March 1971	14.83	6	7.795	2	2.598
Salem 1	June 1977	8.50	8	5.957	6	4.468
Surry 1	December 1972	13.08	6	6.875	6	6.875
Surry 2	May 1973	12.67	6	6.659	6	6.659
Trojan	May 1976	9.67	8	6.777	6	5.083
Turkey Point 3	December 1972	13.08	6	6.875	2	2.292
Turkey Point 4	September 1973	12.33	6	6.481	2	2.160
Yankee Rowe	June 1971	14.50	2	2.540	-	—
Zion 1	December 1973	12.08	8	8.466	14	14.816
Zion 2	September 1974	11.33	8	7.940	14	13.895
McGuire 1	December 1981	4.08	8	2.859	14	5.003
Sequoyah 1	July 1981	4.50	10	3.942	14	5.519
Sequoyah 2	June 1982	3.58	10	3.136	14	4.390
San Onofre	January 1968	18.0	-	—	3	4.730
Haddam Neck	January 1968	18.0	-	—	3	4.730
TOTAL				2.316(2)		2.287(2)

Table A.2
Statistical Data on Leakage Events of Pressure Isolation Check Valves to Accumulators and LPI Systems

Leak Rate (gpm)	Number of Leakage Events (A(2) + LP)	Frequency of Occurrence (per hour)	Frequency of Exceedance (per hour)	Frequency of Exceedance (per year)	Accumulator Inleakage Frequency Exceedance (per year)
5	8	3.50(-7)	1.31(-6)	1.15(-2)	1.07(-2)
10	8	3.50(-7)	9.62(-7)	8.43(-3)	7.85(-3)
20	7	3.06(-7)	6.12(-7)	5.36(-3)	5.00(-3)
50	3	1.31(-7)	3.06(-7)	2.68(-3)	2.50(-3)
100	2	8.74(-8)	1.75(-7)	1.53(-3)	1.43(-3)
200	2	8.74(-8)	8.74(-8)	7.66(-4)	7.15(-4)

APPENDIX B: Modeling of Multiple Failures of Valves in Series

This appendix discusses the modeling of ISL initiators for the valve arrangements in the various pathways. In the modeling, three valve configurations, two-, three-, and four-unit series systems are considered. The formulae obtained can be adapted and evaluated easily under the operating and test and surveillance conditions of a specific plant.

B.1 Two Valves in Series

B.1.1 Check Valves

Consider two check valves in series. The valves are denoted by 1 and 2. Valve 1 is assumed to be the first (high pressure side) isolation valve of the interfacing system.

In general, the failure frequency of the events, when both valve fail, can be written as:

$$\lambda_s(1,2) = \lambda_1 * P(2|1) + \lambda_2 * P(1|2) \quad (1)$$

where λ_1 and λ_2 denote the independent failure frequencies of valves 1 and 2, respectively. $P(2|1)$ and $P(1|2)$ denote the conditional probabilities that valve 2 fails, given valve 1 failed and valve 1 fails, given valve 2 failed, respectively.

The independent failure frequencies λ_1 and λ_2 represent the frequencies of the "leak" (rupture) failure mode, which occurs randomly in time. Both conditional probabilities $P(2|1)$ and $P(1|2)$ involve an independent, random type failure component and a dependent, demand type failure component. The independent, random type failure component is the frequency of the "leak" failure mode and the dependent demand type failure component includes the probabilities of the "valve failure to operate (to hold on pressure challenge) on demand" and the "valve failure to operate (reseat) on demand" failure modes (see more details about these failure modes in Appendix A).

a. Initially Leak Tested Check Valves

Following the WASH-1400 treatment of the V-events in many PRAs only the first term of Eq. (1) has been the subject of more detailed analysis. The reason for it was the general belief that if a check valve is not exposed to a high differential pressure its leak failure frequency must be much smaller than that of a check valve which is exposed to a high differential pressure. Since, it was assumed that if valve 1 is perfectly seated, valve 2 would not be exposed to high differential pressure, the leak failure frequency would be much smaller than that of valve 1, and, thus, the second term can be neglected.

From the results of the root cause analysis of the pressure isolation check valve failures (Section 3), however, one can infer that pressure isolation check valves directly not exposed to high differential pressure deteriorate due to harsh environmental effects (presence of boric acid, vibration, corrosion, aging, etc.) and not due to the high differential pressure. Exposure to high differential pressure of an already corroded valve

disk may cause only the last shock for a check valve failure. This view is supported by the facts that check valve deterioration is experienced quite frequently in plant fluid systems, where the disks of the valves are not exposed to high differential pressure and disk rupture in pressure isolation check valves has never been experienced at PWRs. Therefore, it was concluded that the leak failure frequency of a check valve not exposed to high differential pressure cannot be neglected relative to the leak failure frequency of check valve, which is exposed to high differential pressure and in Eq. (1) both terms have to be evaluated. It was also concluded that the evaluation should reflect the condition that a small leakage through valve 1 sooner or later pressurizes the space between the valves leading to somewhat complex failure mechanism.

The evaluation is based on (a) analyzing the influence of the presence or absence of RCS pressure in the space between the valves to the mechanism of multiple valve failures and (b) the application of simple sequential failure model.

The presence or absence of RCS pressure between the check valves can be formally taken into account in Eq. (1), if it is written as:

$$\lambda_s(1,2) = (1-p)*\lambda_1*P(2|1) + p*\lambda_1'*P'(2|1) + (1-p)*\lambda_2'*P'(1|2) + p*\lambda_2*P(1|2), \quad (1a$$

where p is the pressurization probability of the space between the valves due to small inleakage through valve 1,

- λ_1, λ_2, and λ_1', λ_2' are the leak (rupture) failure frequencies of the valves with and without high differential pressure across their disks, respectively.
- $P(2|1)$ and $P'(2|1)$ are the conditional probabilities that valve 2 fails, given valve 1 failed with and without high differential pressure across the disk of valve 1, respectively.
- $P(1|2)$ and $P(1|2)$ are the conditional probabilities that valve 1 fails given valve 2 failed with and without high differential pressure across the disk of valve 2, respectively.

The mechanism of multiple failure events is illustrated by a failure event flow diagram shown in Figure B.1. The initial conditions of the valves and the failure event flow diagram are detailed below.

The check valves are located in such pipe segment which contains no branch line to other check valves (e.g., to the outlet check valve of the accumulator). The check valves are leak and seat tested before reactor startup. Their disk integrity are found to be in order and the disks are believed to be seated. This assessment should be understood such that the check valves are accepted to be seated if their leak flow is found to be smaller than a limiting flow rate defined in the technical specifications and test requirements. This condition is important, because it is equivalent with the statement that pressure is present in the space between the check valves right away after start up. Therefore, the valve system can be after the start up in one of the following two states:

I. A state when the differential pressure across the disks of the first and second check valves are: $\Delta p_1 >> o$ and $\Delta p_2 \approx o$, respectively. In this state

the disk of valve 1 is firmly seated and the disk of valve 2 is seated only by its own weight in an "unstable" position. The state is denoted in the flow diagram as a "closed-unstable," "CU" state. The probability that the system is in that state is: (1-p).

II. A state when the differential pressure across the disks of the first and second check valves are: $\Delta p_1 \approx o$ and $\Delta p_2 >> o$, respectively. In this state the disk of valve 1 is in an "unstable" position and the disk of valve 2 is seated firmly. The state is denoted in the flow diagram as a "unstable-closed," "UC" state. The probability that the system is in that state is: p.

A. Transitions from the state, "CU."

When the system is in the state, "CU" transitions may occur to other system states:

1. Should a massive leak develop randomly in time through valve 1, the system would transit into an "open valve 1 - closed valve 2," state; "OC." Transition probability is proportional to the leak failure rate of valve 1; λ_1.

2. The second valve may fail to hold upon the sudden pressure challenge. If it fails the system transits immediately from the state, "OC" into a complete failure state, defined by two open check valves: "OO." The transition proceeds with the probability of the "valve failure to operate (hold) upon demand" failure mode; λ_d^*.

3. If valve 2 does not suffer sudden catastrophic failure, later a leak (rupture) failure may develop through it (it became exposed to the full RCS pressure; $\Delta p_2 >> 0$). In this case the transition probability from state "OC" to the catastrophic failure state, "OO" is proportional to the leak failure rate; $\lambda_2 \approx \lambda_1$.

4. There is also a possible transition from state "CU" to "OO" via the "closed valve 1 - open valve 2 state; "CO" (see the broken transition line in Figure B.1). In the "CU" state, the unstable second check valve may open due to vibration or other small pressure disturbances. The pressure disturbances could be generated by monthly tests of associated pumps or other plant activities. As a consequence the system may transit with a relatively high transition probability (occurrence probability of the pressure disturbances, $d_2^* >> 0$) from the state "CU" to the state, "CO." One has to realize, however, that an open valve 2 in itself does not represent failure of the valve system. System failure occurs, if after valve 2 having been opened valve 1 develops a massive leakage, (λ_1) and valve 2 "fails to reseat" upon this demand, (λ_d). The total transition probability from the state, "CU" to the state, "OO" can be taken as proportional to; $d_2^* \lambda_d \lambda_1 \approx \lambda_d \lambda_1$.

5. While the system is in the state "CU," there is also a "CU-CO-OO" transition initiated by a leak failure of valve 2. The transition probability from the state, "CU" to the state, "CO" is proportional

to the leak failure frequency of, valve 2 when its disk is not exposed to high differential pressure; λ_2. From the state, "CO" then a subsequent randomly developing leak failure would transit the system into the catastrophic state, "OO." Transition probability is proportional to; λ_1.

B. Transitions from the state, "UC."

In the state, "UC" valve 1 is unstable and valve 2 is assumed to be firmly closed. Therefore, from this state the following transitions may occur:

1. If in valve 2 a massive leak develops and upon this challenge valve 1 would tightly reseat the system would transit to the "closed valve 1 - open valve 2" state, "CO.". The transition probability is proportional to the leak failure rate of valve 2; λ_2.

2. From the state, "CO" then a subsequent leak failure developing randomly in valve 1 would transit the system into the catastrophic state, "OO." Transition probability is proportional with the leak failure rate of valve 1; λ_1.

3. The other mechanism of the system failure is due to the possibility that in the state, "UC" the unstable valve 1 opens and given a massive leakage in valve 2 (λ_2) it fails to reseat (λ_d). Since valve 1 is assumed to be slightly leaking the differential pressure across its disk may become so small that vibration being usually very high at the RCS pressure boundary can open the valve completely. The system transits from the state, "UC" to the state, "OC" (see the other broken transition line in Figure B.1). The transition probability is the occurrence probability of vibration strong enough to open the valve; (d^*_1>>0). The total transition probability from the state, "UC" via state, "OC" to the failure state, "OO" can be taken as proportional to: $d^*_1\lambda_d\lambda_2 \approx \lambda_2\lambda_d$.

4. While the system is in the state, "UC" the slightly leaking valve 1 may begin to leak profusely. The system would transit from the state, "UC" to the state, "OC." The transition probability is proportional to the leak failure frequency of valve 1 when its disk is not exposed to high differential pressure; λ'_1. This transition may be then followed by a massive leakage randomly developing in valve 2 (λ_2), which transits the system into the failure state, "OO."

The next step in the analysis is to evaluate the four terms in Eq. (1a) by a sequential failure model. The process is essentially equivalent with the calculation of complete transition frequencies from initial states to the final one in the failure mechanism diagram discussed above.

The probability of sequential failure of two valves, Q_{12} starting by the failure of valve 1 over a time interval t can be calculated by the following integrals (exponentials are approximated by first order terms):

1. Transition between states, "CU" and "OO," via state, "OC."

$$T_1 = (1-p) \left\{\int_o^t \lambda_1 dt' \left(\int_{t'}^{t} \lambda_2 dt'' + \lambda_d^*\right)\right\} = (1-p) \left[\lambda_1 \lambda_2 \frac{t^2}{2} + \lambda_1 \lambda_d^* t\right], \quad (2a)$$

2. Transition between states, "CU" and "OO," via state, "CO."

$$T_2 = (1-p) \int_o^t \lambda_1 \lambda_d dt' = (1-p)\left[\lambda_1 \lambda_d t\right] , \quad (2b)$$

3. Transition between states, "UC" and "OO," via state, "OC."

$$T_3 = p \int_o^t \lambda'_1 dt' \left(\int_{t'}^{t} \lambda_2 dt''\right) = p\left[\lambda_1' \lambda_2 \frac{t^2}{2}\right] , \quad (2c)$$

Their sum is:

$$Q_{12} = T_1 + T_2 + T_3 .$$

The probability of sequential failure of two valves, Q_{21} starting by the failure of valve 2 over a time interval t can be calculated by integrals similar to the above equations. The results are given as follows:

1. Transition between states, "UC" and "OO," via state, "CO."

$$T_1' = p \left[\lambda_2 \lambda_1 \frac{t^2}{2}\right] , \quad (2d)$$

2. Transition between states, "UC" and "OO," via state, "OC."

$$T_2' = p\left[\lambda_2 \lambda_d t\right] , \quad (2e)$$

3. Transition between states, "UC" and "OO," via state, "CO."

$$T_3' = (1-p)\left[\lambda_2' \lambda_1 \frac{t^2}{2}\right] . \quad (2f)$$

Their sum is:

$$Q_{21} = T_1' + T_2' + T_3' .$$

Note that replacing λ_d^* or λ_d in these expressions by a beta factor, β, one arrives at expressions similar to the classical common mode failure formula. In sequential system, the demand failure mode is similar to a β factor. Indeed, the time interval between a failure causing a demand and the second failure can be infinitely small. In this sense, two subsequent failures are equivalent with two really simultaneous failures. That is the

reason why common mode failure is not explicitly indicated in the present simple model.

The probability Q_{12}, is used to derive the failure (or hazard) rate for two valves starting with the failure of valve 1:

$$\lambda'_{12}(t) = \frac{-1}{(1-Q_{12})}\frac{d}{dt}\left[1-Q_{12}\right] = \frac{1}{1-Q_{12}}\frac{d}{dt}Q_{12} \approx \frac{d}{dt}Q_{12},(Q_{12}<<1),$$

$$= (1-p)\left[\lambda_1\lambda_2 t + \lambda_1\lambda_d^* + \lambda_1\lambda_d\right] + p\left[\lambda'_1\lambda_2 t\right] . \quad (3a)$$

The average failure rate over a time period, T is given by:

$$\langle\lambda'_{12}\rangle = \frac{1}{T}\int_0^T \lambda'_{12}(t)dt = (1-p)\left[\frac{\lambda_1\lambda_2 T}{2} + \lambda_1\lambda_d^* + \lambda_1\lambda_d\right] + p\left[\frac{\lambda'_1\lambda_2 T}{2}\right] . \quad (4a)$$

Similarly, starting with the failure of valve 2 one obtains for the failure rate the expression:

$$\lambda'_{21}(t) = p\left[\lambda_2\lambda_1 t + \lambda_2\lambda_d\right] + (1-p)\left[\lambda'_2\lambda_1 t\right] \quad (3b)$$

and for its average:

$$\langle\lambda'_{21}\rangle = p\left[\frac{\lambda_2\lambda_1 T}{2} + \lambda_2\lambda_d\right] + (1-p)\left[\frac{\lambda'_2\lambda_1 T}{2}\right] . \quad (4b)$$

By equating the terms of Eq. (1a) to the terms on the right side of Eqs. (4a) and (4b), respectively, one obtains the failure frequency of two check valves in series averaged over a time period, T:

$$\langle\lambda_S^T(1,2)\rangle = \langle\lambda'_{12}\rangle + \langle\lambda'_{21}\rangle . \quad (5a)$$

For the failure frequencies, one can assume with confidence, that the following relationships are valid: $\lambda_1\lambda_2 \approx \lambda_2\lambda_1$, $\lambda'_1\lambda_2 \approx \lambda'_2\lambda_1$, $\lambda_1\lambda_d \approx \lambda_2\lambda_d$.

Thus, Eq. (5a) can be written as:

$$\langle\lambda_S^T(1,2)\rangle = \frac{\lambda_1\lambda_2 T}{2} + \frac{\lambda'_2\lambda_1 T}{2} + (1-p)\lambda_1\lambda_d^* + \lambda_2\lambda_d . \quad (5b)$$

One can expect also that $\lambda_2 \geq \lambda'_2$, and after plant start up, the probability, p that the space between the valves is pressurized is not at all certain, so the term $(1-p)\lambda_1\lambda_d^*$ is not small. It is conservative, therefore, to use in Eq. (5b) the upper bound: $\lambda_1\lambda_d^* \geq (1-p)\lambda_1\lambda_d^*$.

As a consequence of these approximations, the average failure frequency of two check valves in series can be written as:

$$\langle\lambda_S^T(1,2) \leq \lambda_1\lambda_2 T + \lambda_1\lambda_d^* + \lambda_2\lambda_d \ . \qquad (5c)$$

There are no experienced data for the probability, λ_d^*. Therefore, as a substitute value, the probability of the other demand type failure mode, λ_d is used. With this substitution, Eq. (5c) goes over into a particularly simple form:

$$\langle\lambda_s^T(1,2)\rangle \leq \lambda_1^2 T + 2\lambda_1\lambda_d \ . \qquad (6)$$

This expression is used in further applications.

It is interesting to notice that in spite of the fact that the model started with seated check valves, due to the combination of pressure dynamics, the effects of different failure modes and the approximations used, the analysis ended up with a formula which could have been obtained by postulating simply that the check valves have two failure modes characterized by λ_1 and λ_d. Then, in Eq. (1) complete symmetry would have been obtained, i.e., $\lambda_1^* P(2|1) = \lambda_2^* P(1|2)$. Thus, one could get immediately:

$$\langle\lambda_s^T(1,2)\rangle \leq 2(\lambda_1^2 \frac{T}{2} + \lambda_1\lambda_d) \ .$$

However, by referring to this simplistic (but conservative) approach the whole physical process of the system failure would have been covered up.

b. Periodically Operated Check Valves Without Subsequent Leak Testing

There are power plants, where check valves are leak tested only at each refueling period. If the valves are operated during this time period (cold shutdowns, safety injections, etc.), and after each operation are not leak tested, the chances that they would stuck open and fail to reseat upon demand would increase with every occurrence of operation. (Check valves simultaneously stuck open would be detected at reactor startup, therefore, they are not taken into consideration).

The contribution of the stuck open and undetected check valve failures to the average failure frequency is estimated as follows:

Let n_1-1 and n_2-1 denote the number of occasions (cold shutdowns) when check valves 1 and 2 are operated without subsequent leak testing. Let t_1 and t_2 denote the corresponding time intervals between these occasions. Let us assume, that the valves are tested to be seated only after the time period $T = n_1t_1 = n_2t_2$. If $d_1 = 1/t_1$ and $d_2 = 1/t_2$ denote the rates of demand of individual check valves to open (refuelings included), then $d_1T = n_1$ and $d_2T = n_2$.

The periodic operation of check valve is equivalent in the failure event diagram (figure B.1) with a transition from state, "UC" to state "OC" with transition frequency d_1 or from state "CU" to state, "CO" with transition frequency, d_2.

These transitions involve "valve failure to reseat on demand" failure mode. Therefore, their failure rate contributions will effect only those failure rate terms in the average multiple failure frequency formulas, which involve demand type failure modes.

From Eqs. (3a) and (3b) the sum, S of these terms can be written as:

$$S = (1-p)[\lambda_1\lambda_d^* + \lambda_1\lambda_d]t + p[\lambda_2\lambda_d]t \ .$$

Since $\lambda_1 = \lambda_2$;

$$S = (1-p)[\lambda_1\lambda_d^* t] + \lambda_2\lambda_d t \ .$$

As it was previously emphasized, in the first time period after refueling the probability that the space between the valves in pressurized is finite, but far from certain. It would be, therefore, not right to neglect the first term in S. Just the opposite, engineering prudence requires to use the upper bound of this term:

$$\lambda_1\lambda_d^* t \geq (1-p)[\lambda_1\lambda_d^* t] \ .$$

Thus, S will be written as:

$$S \geq \lambda_1\lambda_d^* t + \lambda_2\lambda_d t \ .$$

Remembering, that the substitute value of λ_d^* is λ_d; thus

$$S \geq \lambda_1\lambda_d t + \lambda_2\lambda_d t \ .$$

Therefore, in the first time period after refueling the failure rate contributions for the time intervals t_1 and t_2 can be written as:

$$Q'_{12}(t) = \lambda_1\lambda_d t_2 \ , \text{ and } Q'_{21}(1) = \lambda_2\lambda_d t_1 \ .$$

After the first cold shutdown (without subsequent leak test):

$$Q'_{12}(2) = 2\lambda_1\lambda_d t_2 \ , \text{ and } Q'_{21}(2) = 2\lambda_2\lambda_d t_1 \ ,$$

$$\vdots \qquad\qquad \vdots$$

and after the n_1-th and n_2-th cold shutdown (without subsequent leak test):

$$Q'_{12}(n_2) = n_2\lambda_1\lambda_d t_2 \text{ and } Q'_{21}(n_1) = n_1\lambda_2\lambda_d t_1 \ .$$

The failure rate contributions averaged over the time period, T are:

$$\langle\lambda_s^{T = n_2 t_2}(1,2)\rangle = \frac{1}{T}\,[Q'_{12}(1) + Q'_{12}(2) + \ldots + Q'_{12}(n_2)]$$

$$= \frac{1}{T} [\lambda_1 \lambda_d t_1 \sum_{i=1}^{n_2} i]$$

$$= \frac{1}{T} \lambda_1 \lambda_d \frac{n_2 t_2 (n_2 + 1)}{2}$$

$$= \lambda_1 \lambda_d (\frac{n_2 + 1}{2}) = \lambda_1 \lambda_d (\frac{d_2 T + 1}{2}) \ , \qquad (7a)$$

and similarly,

$$\langle \lambda_s^{T = n_1 t_1} (1,2) \rangle = \lambda_2 \lambda_d (\frac{d_1 T + 1}{2}) \qquad (7b)$$

The total failure rate of the system averaged over a time period T, (during which individual check valves were operated with demand rate d_1 and d_2 without subsequent leak tests) can be calculated by incorporating Eqs. (7a) and (7b) into Eq. (5) as:

$$\langle \lambda_s^T (1,2,d_1,d_2) \rangle = \lambda_1 \lambda_2 T + \lambda_1 \lambda_d (\frac{d_2 T + 1}{2}) + \lambda_2 \lambda_d (\frac{d_1 T + 1}{2}) \ , \qquad (8)$$

Since $\lambda_1 \approx \lambda_2$ and assuming that the two valves are operated with the same demand rate, $d_1 = d_2 = d$, Eq. (8) can be written in simplified form:

$$\langle \lambda_s^T (1,2,d) \rangle = \lambda_1^2 T + 2\lambda_1 \lambda_d (\frac{dT + 1}{2}) \ . \qquad (8a)$$

If the valves are used only once at the beginning of a time period, T, (i.e., the demand rate of the valves is $d = 1/T$) and tested, Eq. (8a) reduces to Eq. (6), as it is expected.

Eqs. (8) and (8a) are used to study the effect of certain measures (like application of permanent pressure sensors) envisioned to reduce the frequency of ISL initiators and for "base case" initiator frequency calculations.

c. Application of Permanent Pressure Sensors

If a permanent pressure sensor was used to monitor the pressure condition of the space between the valves, the average failure rate of the valve system would decrease significantly.

It is easy to see that the sensor would eliminate the following failure combinations a) the failure combination, when leakage of valve 1 is followed the leakage of valve 2 and b) the failure combination, when valve 1 is stuck open and would not reseat upon the demand generated by a leak failure of valve 2.

The equations describing the average failure rates in this case are the followings:

$$\langle\lambda_s^T(1,2)\rangle_{PS} = \lambda_1^2 \frac{T}{2} + \lambda_1\lambda_d \ , \tag{9}$$

when leak tests are performed after each opening of the valves, and

$$\langle\lambda_s^T(1,2,d)\rangle_{PS} = \lambda_1^2 \frac{T}{2} + \lambda_1\lambda_d(\frac{dT + 1}{2}) \ , \tag{9a}$$

when leak tests are not performed after operations of the valves during a time period, T.

Comparing Eq. (9) with Eq. (6) and Eq. (9a) with Eq. (8a), one sees that the application of pressure sensor reduces the failure rate of a valve system consisting of two check valves in series by a factor of 2.

d. Check Valves in the Accumulator Injection Line

The failure mechanism of the check valves in the shared inlet of accumulator, LPI and HPI system is an important variant of the model discussed. A detailed analysis of the experienced failure events of valves of this type are presented in Appendix A.1.1.1.2. The purpose of the short discussion here is to complete the analysis of the two check valve systems and to emphasize certain aspects of the failure mechanism in this interesting case.

The accumulator is a pressurized system whose pressure is subject to frequent changes due to various operational reasons. The frequency of changes in any case is expected to be much higher than the pressure changes in other interfacing lines leading to the RWST. The failure mechanism of the accumulator check valves, therefore, can be taken to be very similar to that of a check valve system periodically operated without subsequent leak testing of its second check valve.

According to this model it is reasonable to assume that the accumulator valve system will transit from its initiating state "CU" into a "CO" state (see Figure B.1 and previous description of the "CU-CO-OO" transition) after start up with a demand ("chattering") frequency, d_2.

While the system is in the "CO" state, the seat, disk, hinge or seal of valve 2 are exposed to the corrosive effect of boric acidic water. Under unfavorable temperature conditions boron is expected even to be deposited to the surface of these components. The environmental effect of the boric acid results in a significant enhancement of the probability of the "valve failure to reseat on demand" failure mode. For distinction from the normal probability, λ_d, the enhanced failure probability is denoted by λ_{d2} ($\lambda_{d2} >> \lambda_d$).

Therefore, if valve 1 begins to leak, the average transition frequency from the state "CU" to the complete failure state, "OO" will be:

$$\lambda_1\lambda_{d_2} \left[\frac{d_2T + 1}{2}\right] ,$$

where T is now an "effective time period to detect a significant accumulator inleakage." (The accumulator is continuously monitored for inleakage.)

From Eq. (8), one obtains the average failure frequency of two check valves in the accumulator line by taking for the demand rate of check valve 1, $d_1 = 1/T$, as follows:

$$\langle\lambda_s^T(1,2)\rangle_{\text{Accumulator}} = \lambda_1\lambda_2\,\frac{T}{2} + \lambda_1\lambda_{d2}\left(\frac{d_2T + 1}{2}\right) + \lambda_2\lambda_d\ .$$

Assuming as before, that the leak failure frequencies of the valves are approximately equal, $\lambda_2 = \lambda_1$, can be written as:

$$\langle\lambda_s^T(1,2)\rangle_{\text{Accumulator}} = \lambda_1\left[\lambda_1 T + \lambda_d + \lambda_{d2}\left(\frac{d_2T + 1}{2}\right)\right] \equiv \lambda_1 C \qquad (10)$$

In this equation, C may be considered as an "effective probability for valve failure to operate (reseat) on demand" failure mode, characteristic to the check valve systems in accumulator lines.

Since the accumulator is under constant surveillance, and the experienced effective probability for reseat failure, C=1., it is expected that an application of permanent pressure sensor in the space between its check valves will not be too effective in reducing the frequency of ISLs through this pathway.

The application of a permanent pressure sensor in the shared inlet of the accumulator, LPI and HPI system has meaning in reducing the frequency of ISLs toward the LPI and HPI systems.

B.1.2 Motor-Operated Valves

The formulas providing the average failure frequency of two MOVs in series are very similar in mathematical structure to those of two check valves. The reason is that the simple sequential failure model is also applicable to the description of the failure mechanism of MOVs. Differences arise only from the different failure modes of the MOVs compared to those of check valves and from the conditions how they are acted upon by operating, surveillance, testing, and maintenance practices and procedures.

The "two-MOVs in series, without check valve" configurations can be found in the suction line of the RHR system. The following considerations, therefore, will focus to the failure possibilities of these specifically built MOVs.

In the discussion generic formulae are presented to a hypothetical worst case valve arrangement. The emphasis here is to see the effect of tests or other actions (like application of permanent pressure sensors) envisioned to reduced the frequency of ISLs through the RHR suction lines. If specific valve arrangement or other conditions preclude certain failure modes they will be discussed at the applications in subsection c.) and in Section 4.4 of the main text.

The relevant failure modes of the MOVs and their frequency notations are listed below (more details about the MOV failure modes and their frequencies are given in Section Appendix A.2).

Random Type Failure Modes

1. Internal leakage, λ_L (unlike the case of check valves, data are not available to generate failure frequencies exceeding certain leak rates).

2. Rupture, λ_R.

3. Transfers open, λ_T.

4. Gross external leakage, λ_O.

Demand Type Failure Modes

1. MOV failing open while indicating closed, λ_d.

2. MOV fails to operate on demand, λ_g. (There are no experienced data concerning this failure mode. Conservatively, in the numerical evaluations the identity, $\lambda_g = \lambda_d$ is used. An additional role of this failure mode in the subsequent formulas is to pick up previously undetected common mode failures.)

a. MOVs Operated With Initial Leak Testing

The hypothetical MOV system assumed here is such a configuration, where MOV 1 (nearest the RCS) is located in the containment and MOV 2 is located outside of it (similar to the valve arrangement of the RHR suction line at Calvert Cliffs 1). The disks of the valves are assumed to be stroke and leak (disk integrity) tested upon start up. The test is repeated at each cold shutdown. Between cold shutdowns the time period is T.

It is assumed, furthermore, that:

a. the MOVs are not equipped with stem mounted limit switches (the assumption involves the failure mode "MOV failing open while indicating closed" may occur),

b. fuse connections are not in the off position, power breakers may or may not be disconnected (this assumption involves the failure mode "MOV transfers open" may occur), and

c. both MOVs have identical failure frequencies for each of the failure modes.

Under these conditions the average frequency of ISL over a time interval T, for this hypothetical valve arrangement is given by:

$$\langle\lambda_s(1,2)\rangle_{MOV} = (\lambda_L^2 + \lambda_R^2 + \lambda_R\lambda_L)T + (\lambda_L\lambda_O + \lambda_R\lambda_O + \lambda_L\lambda_T + \lambda_R\lambda_T)\frac{T}{2}$$

$$+ 2\lambda_L\lambda_d + 2\lambda_R\lambda_d \tag{11a}$$

However, if both MOVs are located inside the containment, the fuse disconnects are kept open and a permanent pressure sensor is applied in the space between the MOVs, the average failure frequency would reduce to:

$$\langle\lambda_s(1,2)\rangle^{PS}_{MOV} = (\lambda_L^2 + \lambda_R^2 + \lambda_R\lambda_L)\frac{T}{2} + \lambda_L\lambda_d + \lambda_R\lambda_d \tag{11b}$$

b. MOVs Operated Without Leak Testing

Consider now the case when the hypothetical MOV system is operated under such condition that the MOVs are stroke and leak tested only at each refueling period. During this period, T, there is n-1 cold shutdowns, such that n t = T (t is the average time interval between cold shutdowns, d = 1/t denotes the number of MOV demands per year, such that dT = n). After each cold shutdown the chances that one of the valves "will fail open but indicated closed" will increase.

A calculation similar to that performed previously for check valves gives the average frequency of ISLs through MOV configuration discussed first as:

$$\langle\lambda_s^T(1,2,d)\rangle_{MOV} = (\lambda_L^2 + \lambda_R^2 + \lambda_R\lambda_L)T + (\lambda_L\lambda_O + \lambda_R\lambda_O + \lambda_L\lambda_T + \lambda_R\lambda_T)\frac{T}{2}$$

$$+ 2\lambda_L\lambda_d\left[\frac{dT+1}{2}\right] + 2\lambda_R\lambda_d\left[\frac{dT+1}{2}\right] . \tag{12a}$$

Under similar change of conditions, as above, Eq. (12a) reduces to:

$$\langle\lambda_s^T(1,2,d)\rangle^{PS}_{MOV} = (\lambda_L^2 + \lambda_R^2 + \lambda_R\lambda_L)\frac{T}{2} + \lambda_L\lambda_d\left[\frac{dT+1}{2}\right] + \lambda_R\lambda_d\left[\frac{dT+1}{2}\right] . \tag{12b}$$

c. Application of Failure Rate Formulas of Two MOVs

The application of the formulas (Eqs. (11a), (11b), (12a), and (12b) for the RHR suction side valve arrangement of Indian Point 3 is described in detail in Section 4.4.1 of the main text. In this place the application of the formulas to the valve arrangements at Oconee 3 and Calvert Cliffs 1 is presented.

Tables B.1 and B.2 list the formulas obtained for Oconee 3 and Calvert Cliffs 1, respectively. The first column of the table contains the "cases" representing various operational test and surveillance policies on the MOVs. Notice that at Calvert Cliffs 1 ISL may arise through direct leakage from the MOV located outside the containment. More details about the criteria used for the classification of valve failure events (failure combinations) into "small LOCA" and "Overpressurization" initiator groups and about the numerical values of the parameters in the equations can be found in Sections 4.4.2 and 4.4.3 of the main text.

B.2 Three-Valves in Series

The following failure analyses of valve arrangements consisting of three valves in series will be completely generic in that sense that it will not treat separately configurations consisting of only check valves or only MOVs. The reason for that is that the three-valve systems occurring in the possible ISL pathways of the selected plants either are consisting of three check valves or two check valves and a MOV in series. The failure analysis of two

valve systems has shown also, that a generic analysis is possible by using independent, random and dependent, demand type failure modes, in a simple sequential failure model. These failure modes and their applicability then are specified for the various valve configurations.

Consider now a configuration of three valves (1,2,3) in series. Again, valve 1 is assumed to be the first isolation valve. The failure frequency of the events, when three valves fail is:

$$\begin{aligned}\lambda_s(1,2,3) = {} & \lambda_1{*}P(2|1)P(3|12) + \lambda_2{*}P(1|2){*}P(3|21) + \\ & \lambda_1{*}P(3|1){*}P(2|13) + \lambda_2{*}P(3|2){*}P(1|23) + \\ & \lambda_3{*}P(1|3){*}P(2|31) + \lambda_3{*}P(2|3){*}P(1|32) \ ,\end{aligned} \tag{13}$$

where λ_1, λ_2, λ_3 are the independent, random failure frequencies of valves 1, 2, and 3, respectively.
$P(2|1)$ denotes the conditional probability that valve 2 failed given valve 1 failed. Similar terms denote similar events.
$P(3|12)$ is the conditional probability that valve 3 failed given valves 1 and 2 failed. Similar terms denote similar events.

The conditional probabilities involve two components: independent, random and dependent demand type failure components.

Eq. (13) can be evaluated by considering the effects of the initial valve tests and the pressure in the interval spaces to the valve failure modes and their frequencies. The evaluation can be performed for each of the terms in a straightforward way by the sequential model. As an example, the calculation of the term $\lambda_1{*}P(1|1){*}P(3|12)$ is shown below.

Let λ_1, λ_2, λ_3 denote the random type leak failure frequencies of valves 1, 2, and 3, respectively. Let λ_{d2} and λ_{d3} denote the demand type (e.g., valve fails to reseat on demand) failure probabilities of valves 2 and 3, respectively. Then, the probability of simultaneous failures of three valves over a time interval t can be calculated by the following integral (exponentials are approximated by first order terms):

$$Q_{123} = \int_o^t \lambda_1 dt' \ \{ \int_{t'}^t \lambda_2 dt'' \ [\int_{t''}^t \lambda_3 dt'' + \lambda_{d3}] + \lambda_{d2} \ [\int_t^t \lambda_3 dt'' + \lambda_{d3}]\}$$

$$= \frac{\lambda_1\lambda_2\lambda_3 t^3}{6} + \frac{\lambda_1\lambda_2\lambda_{d3}t^2}{2} + \frac{\lambda_1\lambda_{d2}\lambda_3 t^2}{2} + \lambda_1\lambda_{d2}\lambda_{d3}t \ . \tag{14}$$

The failure (hazard) rate is:

$$\lambda'_{123}(t) = \frac{d}{dt} Q_{123} = \frac{1}{2}\lambda_1\lambda_2\lambda_3 t^2 + \lambda_1\lambda_2\lambda_{d3} + \lambda_1\lambda_{d2}\lambda_3 + \lambda_1\lambda_{d2}\lambda_{d3} \ . \tag{15}$$

The failure rate averaged over a time period, T, is given by:

$$\langle\lambda'_{123}\rangle = \frac{1}{T}\int_0^T \lambda'_{123}(t)dt = \frac{\lambda_1\lambda_2\lambda_3 T^2}{6} + \frac{\lambda_1\lambda_2\lambda_{d3}T}{2} + \frac{\lambda_1\lambda_{d2}\lambda_3 T}{2} + \lambda_1\lambda_{d2}\lambda_{d3} \ . \quad (16)$$

This average can be equated to the term $\lambda_1 * P(2|1) * P(3|12)$. Each of the the other five terms can be calculated similarly. The sum of the six terms yields the total failure frequency of three valves in series averaged over a time period, T, which is given by:

$$\langle\lambda_s^T(1,2,3)\rangle = \lambda_1\lambda_2\lambda_3 T^2 + \lambda_1\lambda_2\lambda_{d3}T + \lambda_1\lambda_{d2}\lambda_3 T + \lambda_{d1}\lambda_2\lambda_3 T + 2\lambda_1\lambda_{d2}\lambda_{d3} + 2\lambda_{d1}\lambda_2\lambda_{d3} + 2\lambda_{d1}\lambda_{d2}\lambda_3 \quad (17)$$

If $\lambda_1 = \lambda_2 = \lambda_3$ and $\lambda_{d1} = \lambda_{d2} = \lambda_{d3}$, one arrives at the simplified expression:

$$\langle\lambda_s^T(1,2,3)\rangle = \lambda_1^3 T^2 + 3\lambda_1^2\lambda_d T + 6\lambda_1\lambda_d^2 \ . \quad (18)$$

Eqs. (17) and (18) are easily adaptable to calculate specific valve configurations, when the valves are tested after each operation (opening).

If the valves are not tested after use the chances that they will be left open will accumulate with each operation. As it was shown in the case of the two valve system one can calculate the average failure frequency of untested three valve systems by using the well known addition formula of arithmetic series. The result for the unsimplified expression is:

$$\langle\lambda_s^T(1,2,3,d_1,d_2,d_3)\rangle = \lambda_1\lambda_2\lambda_3 T^2 + \lambda_1\lambda_2\lambda_{d3}T\left[\frac{d_3T+1}{2}\right] + \lambda_1\lambda_{d2}\lambda_3 T\left[\frac{d_2T+1}{2}\right] + \lambda_{d1}\lambda_2\lambda_3 T\left[\frac{d_1T+1}{2}\right] + 2\lambda_1\lambda_{d2}\lambda_{d3}\left[\frac{d_2T+1}{2}\right]\left[\frac{d_3T+1}{2}\right] + 2\lambda_{d1}\lambda_2\lambda_{d3}\left[\frac{d_1T+1}{2}\right]\left[\frac{d_3T+1}{2}\right] + 2\lambda_{d1}\lambda_{d2}\lambda_3\left[\frac{d_1T+1}{2}\right]\left[\frac{d_2T+1}{2}\right] , \quad (19)$$

where d_1, d_2, and d_3 denote the demand frequencies of the individual valves. The number of operations of the valves (number of cold shutdowns; refueling included) during the time interval, T, are: $n_1 = d_1T$, $n_2 = d_2T$, and $n_3 = d_3T$, respectively. All the other quantities have been defined previously.

The result for the simplified expression, given the valves are operated simultaneously (i.e., $d_1 = d_2 = d_3 = d$) is:

$$\langle\lambda_s^T(1,2,3,d)\rangle = \lambda_1^3 T^2 + 3\lambda_1^2\lambda_d T\left[\frac{dT+1}{2}\right] + 6\lambda_1\lambda_d^2\left[\frac{dT+1}{2}\right]^2 \ . \quad (20)$$

These formulas are adapted to study the effects of various test conditions and certain improvements envisioned to reduce the average frequency of ISLs and for "base case" calculations.

B.2.1 Application of Failure Rate Formulas of Three Valves

In this section application of formulas Eq. (18), (19), and (20) is presented briefly to valve configurations in the Group A and Group C lines of the HPI system at Indian Point 3 and in the LPI lines at Oconee 3. Details about the operational, test, and surveillance conditions as well as about the calculational parameters applied in various "cases" can be found in Sections 4.3.2 and 4.3.3 of the main text.

The valve configurations are:

a. HPI Group A Lines: Three check valves. The lines have shared inlets with the LPI/Accumulator lines.
b. HPI Group C Lines: Two check valves and a closed MOV. The lines have no shared inlets.
c. LPI Lines: Two check valves and a closed MOV. The lines have shared inlets with the accumulator lines.

a. Group A Lines (HPI, Indian Point 3)

The average failure rate of the system for the standard case can be calculated from Eq. (19). It is assumed, that after stroke test at each cold shutdown stuck open second and third check valves stay undetected during a refueling period.

The assumption involves that $d_1=1/T$, $d_2=d_3=d$, and according to the configuration $\lambda_2=\lambda_3=\lambda_1$. Correspondingly, Eq. (19) can be expressed as:

$$\langle\lambda_s^T(1,2,3,d)\rangle^{\text{Standard}} = \lambda_1^3 T^2 + \lambda_1^2\lambda_d T\left[(dT + 1) + 1\right] + 2\lambda_1\lambda_d^2\left[\left(\frac{dT + 1}{2}\right)^2 + (dT + 1)\right] . \tag{20a}$$

In case of a pressure sensor or stuck open accumulator outlet check valve, a leaking or stuck open first check valve is detectable. The corresponding failure combinations will not contribute to the failure rate. Thus, Eq. (20a) will be further reduced to:

$$\langle\lambda_s^T(1,2,3,d\rangle^{PS} = \frac{1}{3}\lambda_1^3 T^2 + \lambda_1^2\lambda_d T\left(\frac{dT + 1}{2}\right) + 2\lambda_1\lambda_d^2\left(\frac{dT + 1}{2}\right)^2 . \tag{20b}$$

It is easy to see that if leak test is performed after each stroke test, Eq. (20a) transits to Eq. (18). Frequent leak test and application of a pressure sensor will cause that Eq. (20b) will be transformed to:

$$\langle\lambda_s^T(1,2,3)\rangle^{PS} = \frac{1}{3}\lambda_1^3 T^2 + \lambda_1^2\lambda_d T + 2\lambda_1\lambda_d^2 . \tag{20c}$$

In the "base case" a stuck open accumulator outlet check valve changes Eq. (20) to the following form:

$$\langle\lambda_s^T(1,2,3)\rangle^{\text{Base Case}} = \frac{1}{3}\lambda_1^3 T^2 + \lambda_1^2\lambda_d T\left(\frac{dT + 1}{2}\right) + 2\lambda_1\lambda_d^2\left(\frac{dT + 1}{2}\right)^2 . \tag{20d}$$

Since the valve system has a common inlet with the accumulator, in the final formulas this condition is also reflected. The final formulas for the Group A lines are summarized in Table B.3. In the formulas C denotes the "effective probability" that the accumulator outlet check valve will not operate (reseat) upon demand.

b. Group C Lines (HPI, Indian Point 3)

Let us apply Eqs. (17) and (19) for the valve configuration in the Group C lines. For the check valves, one can write: $\lambda_2=\lambda_1$, $\lambda_{d1}=\lambda_{d2}=\lambda_d$. For the MOV one can keep the notation: λ_3, λ_{d3}. The MOV is locked closed during normal operation. Stroke and leak test are performed at each refueling. Correspondingly, the expression for the average failure rate of the valve system for the standard case is the following (disregarding from a non-indicated common multiplication factor which is 1.44):

$$\langle\lambda_s^T(1,2,3)\rangle^{\text{Standard}} = \{\lambda_1^2\lambda_3T^2 + (\lambda_1^2\lambda_{d3} + 2\lambda_1\lambda_d\lambda_3)T + 4\lambda_1\lambda_d\lambda_{d3} + 2\lambda_d^2\lambda_3\} \tag{20f}$$

More frequent test at each cold shutdown does not modify the form of Eq. (20f). The time parameter, however, will change from T=1.5 to T=1/3 year. The effect of a pressure sensor is that a leaking (or stuck open) first check valve would be detected. The average failure rate expression (same for both time parameters, T=1.5 year and T=1/3 year) disregarding from a non-indicated common multiplication factor is:

$$\langle\lambda_s^T(1,2,3)\rangle^{PS} = \{\tfrac{1}{3}\lambda_1^2\lambda_3T^2 + (\lambda_1^2\lambda_{d3} + \lambda_1\lambda_d\lambda_3)\tfrac{T}{2} + 2\lambda_1\lambda_d\lambda_{d3}\} \ . \tag{20g}$$

In the base case one assumes that the valves may stay open after refuelings if leak tests are not performed. The corresponding time parameter is, T=30 years and d=2/3 per year. The appropriate formula by using Eq. (19) is:

$$\langle\lambda_s^T(1,2,3)\rangle^{\text{Base Case}} = \{\lambda_1^2\lambda_3T^2 + (\lambda_1^2\lambda_{d3} + 2\lambda_1\lambda_d\lambda_3)T(\frac{dT+1}{2}) + 2(2\lambda_1\lambda_d\lambda_{d3} + \lambda_d^2\lambda_3)(\frac{dT+1}{2})^2\} \tag{20h}$$

c. LPI Lines (at Oconee-3)

Eq. (19) is taken as a starting formula to obtain average failure frequencies for the valve arrangements on the LPI lines at Oconee-3. For the check valves, as in the previous case, one can write: $\lambda_2=\lambda_1$, $\lambda_{d2}=\lambda_{d1}=\lambda_d$. For the MOV one can keep the notation: λ_3, λ_{d3}. The demand rate of check valves and MOVs are different, $d\neq d_3$. Thus, in the standard case the average failure frequency is written in the following form:

$$\langle\lambda_s^T(1,2,3,d,d_3)\rangle^{\text{Standard}} = \lambda_1^2\lambda_3T^2 + \lambda_1^2\lambda_{d3}T(\frac{d_3T+1}{2}) + 2\lambda_1\lambda_d\lambda_3T(\frac{dT+1}{2})$$

$$4\lambda_1\lambda_d\lambda_{d3}\left(\frac{dT + 1}{2}\right)\left(\frac{d_3T + 1}{2}\right) + 2\lambda_d^2\lambda_3\left(\frac{dT + 1}{2}\right)^2 . \tag{20i}$$

In case of a pressure sensor or stuck open accumulator outlet check valve, a leaking or stuck open first check valve will be detected. The corresponding failure combinations will not contribute to the failure rate. Eq. (20i) will be reduced to the form:

$$\langle\lambda_s^T(1,2,3,d,d_3)\rangle^{PS} = \lambda_1^2\lambda_3\,\frac{T^2}{3} + \lambda_1^2\lambda_{d3}\,\frac{T}{2}\left(\frac{d_3T + 1}{2}\right) + \lambda_1\lambda_d\lambda_3\,\frac{T}{2}\left(\frac{dT + 1}{2}\right) +$$

$$2\lambda_1\lambda_d\lambda_{d3}\left(\frac{dT + 1}{2}\right)\left(\frac{d_3T + 1}{2}\right) . \tag{20j}$$

Assuming leak tests at each cold shutdown, Eqs. (20i) and (20j) formally transit into Eqs. (20f) and 20g), respectively.

The formula to be used in the case of application of "relaxed" check valve test policy (i.e., leak test at each refueling) and in the base case if the accumulator outlet check valve is seated is identical with Eq. (20i). If the accumulator outlet check valve is stuck open, the formula to be used is Eq. (20j).

The final formulas for the LPI lines are summarized in Table B.4. In the formulas, as usual, C denotes the "effective probability" that the accumulator outlet check vale will not operate (reseat) on demand.

B.3 Four Valves in Series

The configuration "four valves in series" is applied in the LPI and HPI system at Calvert Cliffs 1. Notwithstanding that somewhat tedious, it is educative to calculate the average failure frequency of such valve systems.

It is easy to show that for four valves in series the failure frequency when four valves fail, can be written as:

$$\lambda_s(1,2,3,4) = \lambda_1 * P(2|1)(P(3|12) * P(4|123) + \text{23 similar combinational terms of four valves,} \tag{21}$$

where λ_1 is the independent failure frequency of the valve 1. $P(2|1)$, $P(|12)$, and $P(4|123)$ are conditional probabilities that a subsequent valve fails given that the preceding valves already failed. The conditional probabilities involve two kinds of components; an independent, random, and a dependent, demand type failure component.

The integral which describes the probability of simultaneous failures of four valves over a time interval t is given by:

$$Q_{1234} = \int_o^t \lambda_1 dt' \int_{t'}^t \lambda_2 dt'' \int_{t''}^t \lambda_3 dt'''(\int_{t'''}^t \lambda_4 dt'''' + \lambda_{d4}) +$$

$$\int_o^t \lambda_1 dt' [\int_{t'}^t \lambda_2 dt'' \lambda_{d3} (\int_{t''}^t \lambda_4 dt''' + \lambda_{d4})] +$$

$$\int_o^t \lambda_1 dt' \lambda_{d2} \ [\int_{t'}^t \lambda_3 dt'' (\int_{t''}^t \lambda_4 dt''' + \lambda_{d4})] +$$

$$\int_o^t \lambda_1 dt' \lambda_{d2} \lambda_{d3} \ (\int_{t'}^t \lambda_4 dt'' + \lambda_{d4}) = \frac{1}{24} \ \lambda_1 \lambda_2 \lambda_3 \lambda_4 t^4 +$$

$$\frac{1}{6} (\lambda_1 \lambda_2 \lambda_3 \lambda_{d4} t^3 + \lambda_1 \lambda_2 \lambda_{d3} \lambda_4 t^3 + \lambda_1 \lambda_{d2} \lambda_3 \lambda_4 t^3) +$$

$$\frac{1}{2} (\lambda_1 \lambda_2 \lambda_{d3} \lambda_{d4} t^2 + \lambda_1 \lambda_{d2} \lambda_3 \lambda_{d4} t^2 + \lambda_1 \lambda_{d2} \lambda_{d3} \lambda_4 t^2) +$$

$$\lambda_1 \lambda_{d2} \lambda_{d3} \lambda_{d4} t \quad , \qquad (22)$$

where λ_1, λ_2, λ_3, and λ_4 denote the random type (leak) failure frequencies of valves 1, 2, 3, and 4, respectively. λ_{d2}, λ_{d3}, λ_{d4} denote the demand type (valve failure to reseat on demand) failure probabilities of valves 2, 3, and 4, respectively.

In the same way as it was shown for the two and three valve configurations, the average failure rate, $\langle \lambda'_{1234} \rangle$ can be derived from Eq. (22) and equated with the first term of Eq. (21):

$$\langle \lambda'_{1234} \rangle = \lambda_1 {*} P(2|1) {*} P(3|12) {*} P(4|123) \quad .$$

Similar expressions can be written also for the other 23 terms in Eq. (21). After summation of all the 24 terms, the average failure frequency of four valves in series averaged over a time period, T, can be calculated as:

$$\langle \lambda_s^T(1,2,3,4) \rangle = \lambda_1 \lambda_2 \lambda_3 \lambda_4 T^3 + [\lambda_1 \lambda_2 \lambda_3 \lambda_{d4} + \lambda_1 \lambda_2 \lambda_{d3} \lambda_4 + \lambda_1 \lambda_{d2} \lambda_3 \lambda_4 +$$

$$\lambda_{d1} \lambda_2 \lambda_3 \lambda_4] T^2 + 2[\lambda_1 \lambda_2 \lambda_{d3} \lambda_{d4} + \lambda_1 \lambda_{d2} \lambda_3 \lambda_{d4} + \lambda_1 \lambda_{d2} \lambda_{d3} \lambda_4 +$$

$$\lambda_{d1} \lambda_2 \lambda_3 \lambda_{d4} + \lambda_{d1} \lambda_2 \lambda_{d3} \lambda_4 + \lambda_{d1} \lambda_{d2} \lambda_3 \lambda_4] T + 6[\lambda_1 \lambda_{d2} \lambda_{d3} \lambda_{d4} +$$

$$\lambda_{d1} \lambda_2 \lambda_{d3} \lambda_{d4} + \lambda_{d1} \lambda_{d2} \lambda_3 \lambda_{d4} + \lambda_{d1} \lambda_{d2} \lambda_{d3} \lambda_4] \ . \qquad (23)$$

Eq. (23) describes the case when the valves are leak tested after valve operation.

If the valves are not tested for leak failures after openings or only some of them are tested (e.g., inboard valves are tested only at each refueling, outboard valves are tested only after each cold shutdown and MOVs opened quarterly) the applicable average failure frequency formula somewhat even more complicated. An appropriate formula should reflect the different demand rates of the individual valves. Such formula is shown below.

Let d_1, d_2, d_3, and d_4 denote the demand frequency of valves 1, 2, 3, and 4, respectively. Then, the number of occasions when the valves are operated (number of cold shutdowns; refueling included) during a time interval, T, are: $n_1 = d_1T$, $n_2 = d_2T$, $n_3 = d_3T$, and $n_4 = d_4T$, respectively. For this rather generic case the average failure frequency is given by:

$$
\begin{aligned}
\langle\lambda_s^T(1,2,3,4,d_1,d_2,d_3,d_4)\rangle = {} & \lambda_1\lambda_2\lambda_3\lambda_4T^3 + [\lambda_1\lambda_2\lambda_3\lambda_{d4}(\frac{d_4T+1}{2}) + \\
& \lambda_1\lambda_2\lambda_{d3}\lambda_4(\frac{d_3T+1}{2}) + \lambda_1\lambda_{d2}\lambda_3\lambda_4(\frac{d_2T+1}{2}) + \lambda_{d1}\lambda_2\lambda_3\lambda_4(\frac{d_1T+1}{2})]T^2 + \\
& 2[\lambda_1\lambda_2\lambda_{d3}\lambda_{d4}(\frac{d_3T+1}{2})(\frac{d_4T+1}{2}) + \lambda_1\lambda_{d2}\lambda_3\lambda_{d4}(\frac{d_2T+1}{2})(\frac{d_4T+1}{2}) + \\
& \lambda_1\lambda_{d2}\lambda_{d3}\lambda_4(\frac{d_2T+1}{2})(\frac{d_3T+1}{2}) + \lambda_{d1}\lambda_2\lambda_3\lambda_{d4}(\frac{d_1T+1}{2})(\frac{d_4T+1}{2}) + \\
& \lambda_{d1}\lambda_2\lambda_{d3}\lambda_4(\frac{d_1T+1}{2})(\frac{d_3T+1}{2}) + \lambda_{d1}\lambda_{d2}\lambda_3\lambda_4(\frac{d_1T+1}{2})(\frac{d_2T+1}{2})]T + \\
& 6[\lambda_1\lambda_{d2}\lambda_{d3}\lambda_{d4}(\frac{d_2T+1}{2})(\frac{d_3T+1}{2})(\frac{d_4T+1}{2}) + \lambda_{d1}\lambda_2\lambda_{d3}\lambda_{d4}(\frac{d_1T+1}{2}) \\
& (\frac{d_3T+1}{2})(\frac{d_4T+1}{2}) + \lambda_{d1}\lambda_{d2}\lambda_3\lambda_{d4}(\frac{d_1T+1}{2})(\frac{d_2T+1}{2})(\frac{d_4T+1}{2}) + \\
& \lambda_{d1}\lambda_{d2}\lambda_{d3}\lambda_4(\frac{d_1T+1}{2})(\frac{d_2T+1}{2})(\frac{d_3T+1}{2})] \, . \qquad (24)
\end{aligned}
$$

This latter formula is adapted below to the plant specific conditions at Calvert Cliffs 1.

B.3.1 Application of Failure Rate Formulas of Four Valves

Eq. (24) can be easily applied to the operating conditions of the valve system on the LPI/HPI lines at Calvert Cliffs 1. The valve system consists of three check valves and a normally closed MOV. A permanent pressure sensor is installed after the first check valve to monitor the status of this check valve.

The effect of the pressure sensor in the system model is that in Eq. (24) all of the failure combinations, where the leakage through the first check valve is not the last occurring event in a sequence of valve failures are eliminated. Similarly, combinations in which stuck open first check valve occurs, also vanish.

Lets introduce the notation, $\lambda_2=\lambda_3=\lambda_1$, $\lambda_{d2}=\lambda_{d3}=\lambda_d$ and $d_2=d$, $d_3=1/T$. Then, for the standard cases the average frequency of quadruple valve failures can be written as:

$$\langle\lambda_s^T(1,2,3,4,d,d_4)\rangle_{SC} = 3.52\Big[\frac{1}{4}\lambda_1^3\lambda_4T^3 + \frac{1}{3}\lambda_1^3\lambda_{d4}T^2\left(\frac{d_4T+1}{2}\right) + \frac{1}{3}\lambda_1^2\lambda_d\lambda_4T^2\left(1+\frac{dT+1}{2}\right) + \lambda_1^2\lambda_d\lambda_{d4}T\left(1+\frac{dT+1}{2}\right)\left(\frac{d_4T+1}{2}\right) + \lambda_1\lambda_d^2\lambda_4T\left(\frac{dT+1}{2}\right) + 6\lambda_1\lambda_d^2\lambda_{d4}\left(\frac{dT+1}{2}\right)\left(\frac{d_4T+1}{2}\right)\Big] . \qquad (25)$$

In the base case, one can assume that $d_2=d_3=d$ (i.e., inboard and outboard check valves are simultaneously operated without leak test). Therefore, Eq. (24) will have the form:

$$\langle\lambda_s^T(1,2,3,4,d,d_4)\rangle_{BC} = 3.52\Big[\frac{1}{4}\lambda_1^3\lambda_4T^3 + \frac{1}{3}\lambda_1^3\lambda_{d4}T^2\left(\frac{d_4T+1}{2}\right) + \frac{2}{3}\lambda_1^2\lambda_d\lambda_4T^2\left(\frac{dT+1}{2}\right) + 2\lambda_1^2\lambda_d\lambda_{d4}T\left(\frac{dT+1}{2}\right)\left(\frac{d_4T+1}{2}\right) + \lambda_1\lambda_d^2\lambda_4T\left(\frac{dT+1}{2}\right)^2 + 6\lambda\,\lambda_d^2\lambda_{d4}\left(\frac{dT+1}{2}\right)^2\left(\frac{d_4T+1}{2}\right)\Big] . \qquad (25')$$

The factor 3.52 accounts for the four similar LPI lines and the capacity factor of the reactor which is taken to be 0.88.

The final formulas describing the effect of the accumulator outlet check valve, are presented in Table B.5. In the formulas, C denotes the "effective probability" that the accumulator outlet check valve will not operate (reseat) upon demand.

If one assumes that leakage through the last three valves can be detected by the accumulator or by the relief valve in the LPI system given stuck open accumulator check valve, all the time dependent terms will vanish in Eqs. (25) and (25').

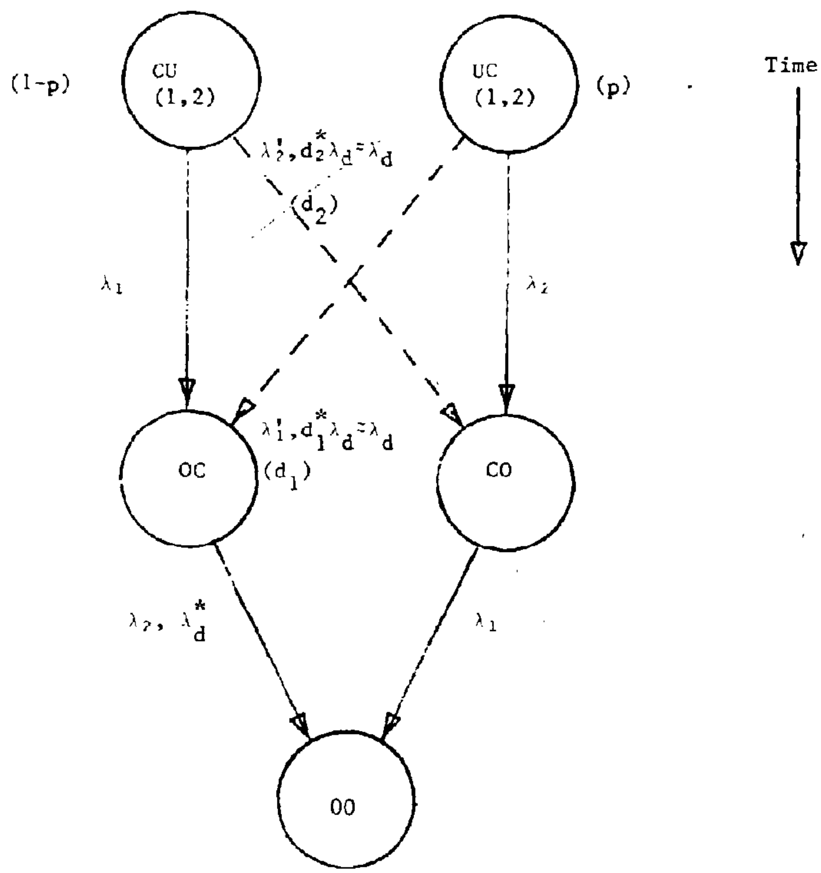


Figure B.1. Failure event flow diagram for two check valves in series (for explanation of notation see the text).

Table B.1
Formulas to Calculate Initiator Frequencies for ISL Through RHR Suction Lines at Oconee 3 (Capacity Factor: .86)

<u>Case</u> – Standard: T_L = 3/4 year, T_R = 3/4 year, d = 4/year

Small LOCA:

$$[(\lambda_L^2 + \lambda_L\lambda_R)T_L + \lambda_L\lambda_T \frac{T_L}{2} + 2\lambda_L\lambda_d(\frac{dT_L + 1}{2})] \quad (12c)$$

Overpressurization:

$$[(\lambda_R^2 T_R + \lambda_R\lambda_T \frac{T_R}{2} + 2\lambda_R\lambda_d(\frac{dT_R + 1}{2})] \quad (12d)$$

<u>Case</u> – Pressure Sensor (same parameters as above)

Small LOCA:

$$[(\lambda_L^2 + \lambda_L\lambda_R + \lambda_L\lambda_T) \frac{T_L}{2} + \lambda_L\lambda_d(\frac{dT_L + 1}{2})]$$

Overpressurization:

$$[(\lambda_R^2 + \lambda_R\lambda_T) \frac{T_R}{2} + \lambda_R\lambda_d(\frac{dT_R + 1}{2})]$$

<u>Case</u> – Leak Test at Each Cold Shutdown: T_L = T_R = 1/4 year

Small LOCA:

$$[(\lambda_L^2 + \lambda_L\lambda_R)T_L + \lambda_L\lambda_T \frac{T_L}{2} + 2\lambda_L\lambda_d]$$

Overpressurization:

$$[(\lambda_R^2 T_R + \lambda_R\lambda_T) \frac{T_R}{2} + 2\lambda_R\lambda_d]$$

<u>Case</u> - Leak Test at Each Cold Shutdown + Pressure Sensor:
T_L = T_R = 1/4 year

Small LOCA:

$$[(\lambda_L^2 + \lambda_L\lambda_R + \lambda_L\lambda_T) \frac{T_L}{2} + \lambda_L\lambda_d]$$

Table B.1 (Continued)

Overpressurization:

$$\left[(\lambda_R^2 + \lambda_R\lambda_T)\,\frac{T_R}{2} + \lambda_R\lambda_d\right]$$

<u>Case</u> - MOV leak and stroke test at each refueling: $T_L = T_R = 1.5$ year, $d = 4$/year,

Small LOCA: Eq. (12c)

Overpressurization: Eq. (12d)

<u>Case</u> - Base: $T_L = 30$ year, $T_R = 1.5$ year, $d = 4$/year,

Small LOCA: Eq. (12c)

Overpressurization: Eq. (12d)

Table B.2
Formulas to Calculate Initiator Frequencies for ISL Through RHR Suction Lines at Calvert Cliffs-1 (Capacity Factor: .88)

Case - Standard: $T_L = T_R = 1.5$ year, $T_L' = T_{L/3}$, d = 4/year

Small LOCA:

$$[(\lambda_L^2 T_L + \lambda_L \lambda_R T_L + \lambda_L \lambda_T \frac{T_L}{2} + (\lambda_L \lambda_o + \lambda_R \lambda_o) \frac{T_L}{2} + (\lambda_o \lambda_L + \lambda_o \lambda_R)^2 \frac{T_L'}{2}] \qquad (12e)$$

Overpressurization:

$$[\lambda_R^2 T_R + \lambda_R \lambda_T \frac{T_R}{2}] \qquad (12f)$$

Case - Pressure Sensor (same parameters as above)

Small LOCA:

$$[(\lambda_L^2 + \lambda_L \lambda_R + \lambda_L \lambda_T) \frac{T_L}{2} + (\lambda_o \lambda_L + \lambda_o \lambda_R) \frac{T_L'}{2}] \qquad (12g)$$

Overpressurization:

$$[(\lambda_R^2 + \lambda_R \lambda_T) \frac{T_R}{2}] \qquad (12h)$$

Case - Leak Test at Each Cold Shutdown: $T_L' = T_{L/3}$, $T_L = T_R = 1/4$ year

Small LOCA: Eq. (12e)

Overpressurization: Eq. (12f)

Case - Leak Test at Each Cold Shutdown + Pressure Sensor: $T_L' = T_{L/3}$, $T_L = T_R = 1/4$ year

Small LOCA: Eq. (12g)

Overpressurization: Eq. (12h)

Case - Base: $T_L = 30$ year, $T_R = 1.5$ year, d = 4/year, $T_L' = T_{L/3}$, $T_R' = T_{R/3}$

Small LOCA:

$$[(\lambda_L^2 T_L + \lambda_L \lambda_R T_L + \lambda_L \lambda_T \frac{T_L}{2} + \lambda_L \lambda_o \frac{T_L}{2} + \lambda_o \lambda_L \frac{T_L'}{2} + \lambda_R \lambda_o \frac{T_R}{2} + \lambda_o \lambda_R \frac{T_R'}{2})]$$

Overpressurization: Eq. (12f)

Table B.3
Formulas to Calculate Initiator Frequencies for ISLs
Through Group A HPI Lines at Indian Point-3

Cases	Frequency of Triple Valve Failures (per year) Multiplication Factor: 2.88	
	w/Accumulator Inleakage	w/o Accumulator Inleakage
Standard T = 1.5 year $d_2 = d_3 = d = 3$/year $d_1 = 1/T$	From Eq. (20b): $\langle\lambda_s^T(1,2,3,d)\rangle^{PS}C$	From Eq. (20a): $\langle\lambda_s^T(1,2,3,d)\rangle^{Standard}(1-C)$
Application of Pressure Sensor T = 1.5 year d = 3/year	Same as above.	From Eq. (20b): $\langle\lambda_s^T(1,2,3,d)\rangle^{PS}(1-C)$
Leak Test at Each Cold Shutdown T = 1/3 year d = 1/T	From Eq. (20c): $\langle\lambda_s^T(1,2,3)\rangle^{PS}C$	From Eq. (18): $\langle\lambda_s^T(1,2,3)\rangle(1-C)$
Leak Test + Pressure Sensor T = 1/3 year d = 1/T	Same as above.	From Eq. (20c): $\langle\lambda_s^T(1,2,3)\rangle^{PS}(1-C)$
Base T = 30 years $d_1 = d_2 = d_3 = d = 3$/year	From Eq. (20c): $\langle\lambda_s^T(1,2,3,d)\rangle^{Base\ Case}C$	From Eq. (20): $\langle\lambda_s^T(1,2,3,d)\rangle(1-C)$

Table B.4
Formulas to Calculate Initiator Frequencies for ISL Through LPI Lines at Oconee-3

Cases	Frequency of Triple Valve Failures (per year) Multiplication Factor: 1.72 w/Accumulator Inleakage	w/o Accumulator Inleakage
Standard T = 3/4 year d = 3/year d_3 = 4/year	From Eq. (20j): $\langle\lambda_s^T(1,2,3,d,d_3)\rangle^{PS}C$	From Eq. (20i): $\langle\lambda_s^T(1,2,3,d,d_3)\rangle^{Standard}(1-C)$
Application of Pressure Sensor T = 3/4 year d = 3/year d_3 = 4/year	Same as above.	From Eq. (20j): $\langle\lambda_s^T(1,2,3,d,d_3)\rangle^{PS}(1-C)$
Leak Test at Each Cold Shutdown T = 1/4 year	From Eq. (20g): $\langle\lambda_s^T(1,2,3)\rangle^{PS}C$	From Eq. (20f): $\langle\lambda_s^T(1,2,3)\rangle^{Standard}(1-C)$
Leak Test + Pressure Sensor T = 1/4 year	Same as above.	$\langle\lambda_s^T(1,2,3)\rangle^{PS}(1-C)$
Leak Test at Each Refueling T = 1.5 year d = d_3 = 4/year	Same as in the Standard Case.	Same as in the Standard Case.
Base T = 16 years d = d_3 = 4/year	Same as in the Standard Case.	Same as in the Standard Case.

Table B.5
Formulas to Calculate Initiator Frequencies for ISL
Through LPI/HPI Lines at Calvert Cliffs-1

Cases	Frequency of Quadruple Valve Failures (per year)	
	w/Accumulator Inleakage	w/o Accumulator Inleakage
Standard T = 1.5 year d = 4/year d_4 = 12/year	$\langle\lambda_s^T(1,2,3,4,d,d_4)\rangle_{SC}C$, or $3.52[6\lambda_1\lambda_d^2\lambda_{d4}(\frac{dT+1}{2})(\frac{d_4T+1}{2})]C$	$\langle\lambda_s^T(1,2,3,4,d,d_4)\rangle_{SC}(1-C)$
Base T = 8/year d = 4/year d_4 = 12/year	$\langle\lambda_s^T(1,2,3,4,d,d_4)\rangle_{BC}C$, or $3.52[6\lambda_1\lambda_d^2\lambda_{d4}(\frac{dT+1}{2})^2(\frac{d_4T+1}{2})]C$	$\langle\lambda_s^T(1,2,3,4,d,d_4)\rangle_{BC}(1-C)$

APPENDIX C: Operator Diagnosis and Post-Diagnosis Performance

Human behavior in response to an event, especially an abnormal event in a nuclear power plant, can be considered in three phases of activity: (1) observation of the event, (2) recognizing and/or diagnosing it, and (3) responding to it. Errors in each of these phases can be considered separately. However, there is much interaction between the various phases. In particular, phases 1 and 3 are very much controlled by phase 2 - the diagnosing stage. Failures in this stage are the most significant and basically constitute failures in cognitive behavior. The term cognitive behavior refers to the behavior that comprises structuring information, conceptualizing root causes and developing a response.

In regard to an abnormal event in a nuclear power plant, cognitive behavior on the part of the operator consists of identifying the nature of the event, identifying the necessary safety-related responses and deciding how those responses can be implemented in terms of system operation. The main basis for estimating the reliability of operator action is primarily determined by the available time for that particular event before core damage occurs.

The three phases of activity (observation, diagnosis, and response) can be represented in the operator action tree shown on Figure C.1a. However, the action tree is not a very good representation of how an operator thinks, since in practice there is a considerable iteration between making a diagnosis, searching for more information, and correctly responding to the abnormal event. The tree identifies three potential failure states that can result in operators failing to take timely and correct action in response to an accident events.

In the ISL study this process was not modelled in this detailed descriptive way, rather an estimate of overall failure to take action was derived and was used in the event trees. The simplified event tree corresponding to this overall approach is shown in Figure C.1b. The simplified event tree may be derived from Figure C.1a by assuming that recognition and diagnosis may be combined to a single event and that correct diagnosis implies that appropriate actions will always be taken.

The numerical models for diagnosing an abnormal event by the control room team and carrying out the appropriate activities has been based on work described in Reference 1 (Handbook of HRA). Figure C.2 shows the basic diagnosis model: the probability of operations team diagnosis error in case of an abnormal event. The median joint human error probability (HEP) shows the probability of a team not diagnosing an abnormal event by a given elapsed time. The other lines represent the lower and upper error factors. The probability vs. time curve was developed on the basis of a clinical speculation presented in Reference 2 at a National Reliability Evaluation Program data workshop. A hypothetical response time probability curve has been constructed using the general approach suggested in Reference 3 assuming lognormality for time to diagnosis as opposed to assuming that the probability of failure is a logarithmic function of time.

In case the event is generally not practiced by the operators except in the initial training, the handbook[1] recommends the use of the upper bound joint HEP curve.

In this study a combination of upper bound HEP_{UB} and median HEP_M has been used ($HEP_{UB} + HEP_M/2$) reflecting that, even though LOCA events are well practiced, ISL events are not specifically recognized in the written procedures especially nor in the system level.

It is certain that actions will always be taken by the operators in response to an abnormal event, but only after the condition has been diagnosed will the operators refer to the appropriate written procedures (if any) to cope with the event.

In case of an ISL, the initial signals can be somewhat misleading indicating either a typical inside or outside LOCA event. The determination of the particular location of the break due to the ISL is extremely important, since systems required to mitigate the LOCA event might be affected.

In general, system specific ISL procedures are not available to the operator, but the loss-of-coolant phase is covered by the LOCA procedures.

References

1. A. D. Swain, H. E. Guttmann, "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications, Final Report," NUREG/CR-1278, August 1983.

2. J. R. Fragola, A. J. Oswald et al., "Human Error Probability vs Time, Generic Data Base for Data and Models in NREP Guide," EGG-EA-5887, June 1982.

3. J. Wreathall, "Operator Action Trees, An Approach to Quantifying Operator Error Probability During Accident Sequences," NUS Report #4159, July 1982.

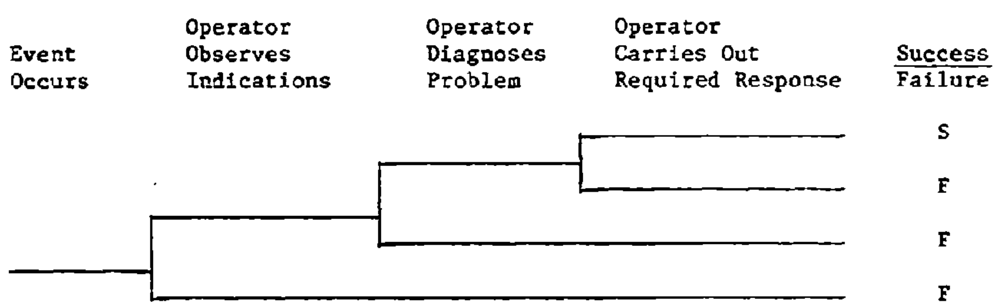


Figure C.1a Basic operator action tree.

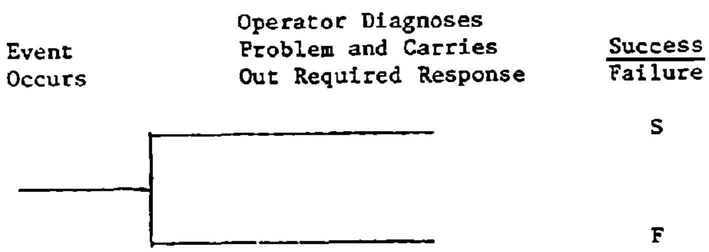


Figure C.1b ISL operator action tree.

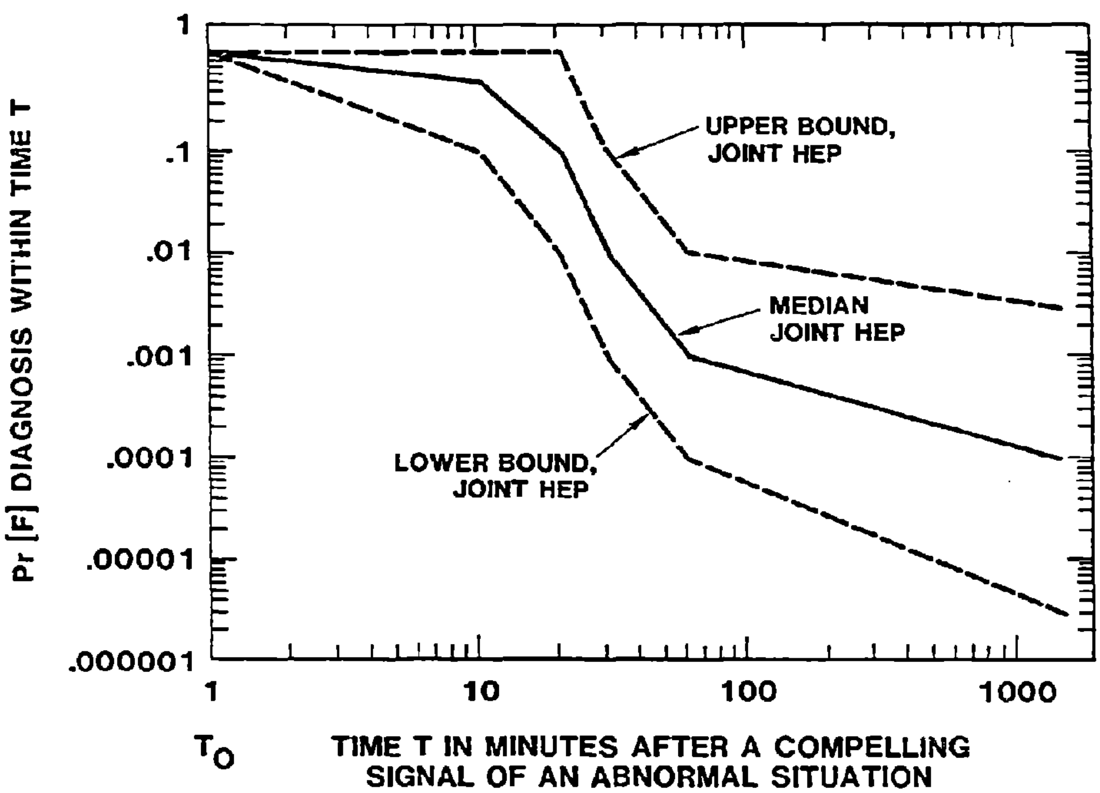


Figure C.2 Time curve for operator action.

APPENDIX D: Thermal-Hydraulic Aspects of Interfacing LOCAs

Interfacing LOCA bypassing the containment has been deterministically studied for typical cases[1] to assess the effect on core damage.

The LOCA sequence assumes the failure of the pressure boundary at isolating check valves and/or motor-operated gate valves. The low pressure system is overpressurized by the primary coolant and the system boundary fails outside the containment (pipe rupture or pump seal blowout, etc.). Depending on the mode of failure and its particular location, a large or small break LOCA can occur. In the following, a brief summary of the deterministic calculations is given for these types of accident sequences. All figures have been reproduced from Reference 1.

D.1 Large and Medium LOCA (>2")

The transient is initiated by a large low pressure pipe break resulting in an extremely severe accident sequence.[1] Figures D.1 through D.3 describe the thermal-hydraulic history of this accident. Four parametric cases have been calculated. The base case indicates an accident sequence where no ECC injection is available. If the failure is such that pumped ECC injection is prevented, core damage is certain as indicated on Figure 2 even if accumulators are available. Core damage would occur at ~8 minutes after the break. The other parametric cases indicate that stable core cooling can be established with a minimum of one HPI pump available until the RWST inventory is depleted, which is in the order of 1-12 hours (Figure D.3). Long term cooling is a major concern since the water supply from the RWST is limited. In addition, recirculation system may be unavailable due to the postulated failure in the low pressure RHR system.

D.2 Small LOCA (<2")

The primary system in accident sequences with initial break size less than 2" in diameter will remain pressurized by one HPI pump (see Figure D.4). The reactor coolant system is refilled and subcooling is achieved. Core average temperature is determined by system-wide energy balance (Figure D.5) and in all cases the system would slowly cool until the RWST water supply is exhausted, which may be extended by throttling the HPI flow. Conditions for low pressure recirculation cooling are not met before the RWST supply runs out (8-15 hours). Long term cooling may also be of some concern, because the postulated failure could affect the capability of the HP and/or LP recirculation system.

References

1. J. F. Dearing et al., "Dominant Accident Sequences in Oconee-1 PWR," NUREG/CR-4140, Los Alamos National Laboratory, April 1985.

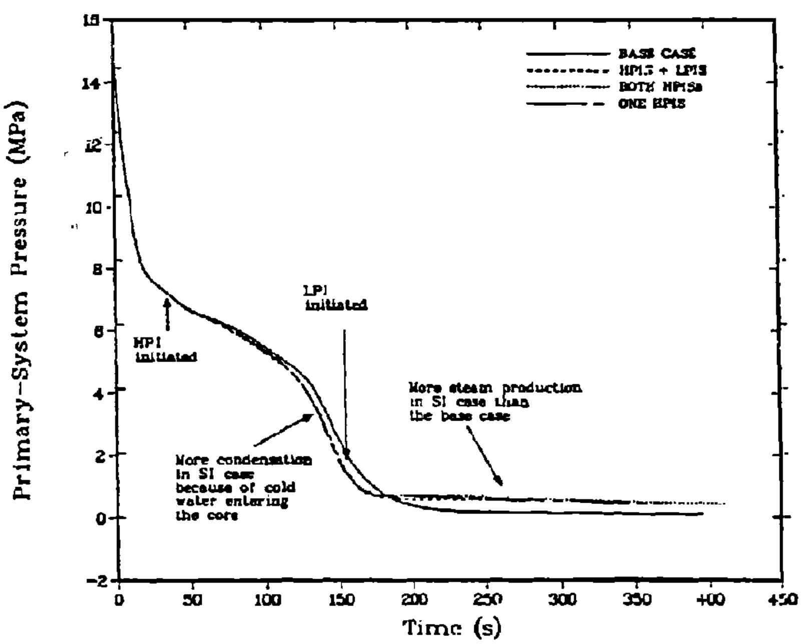


Figure D.1 Primary system pressure during V sequence base and parametric cases.

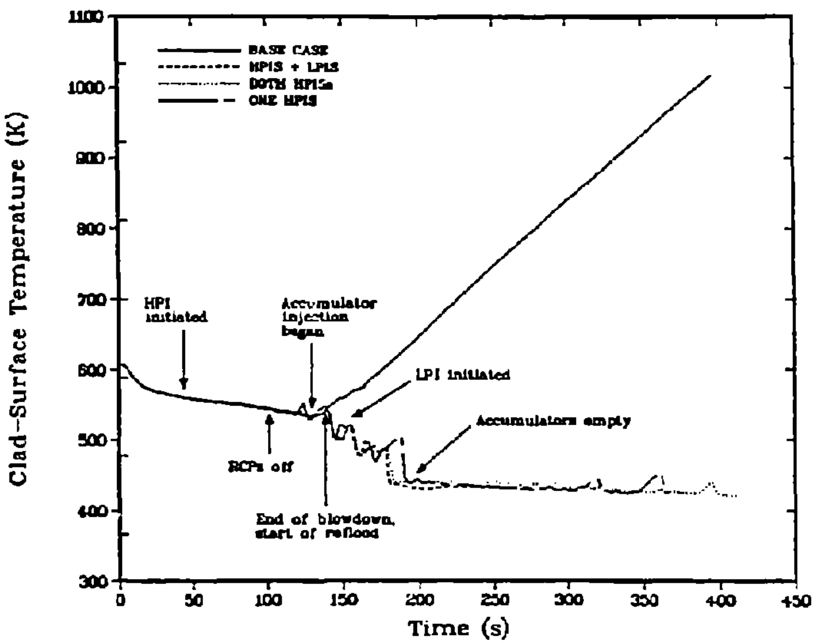


Figure D.2 Maximum cladding temperature of average rod during V sequence base and parametric cases.

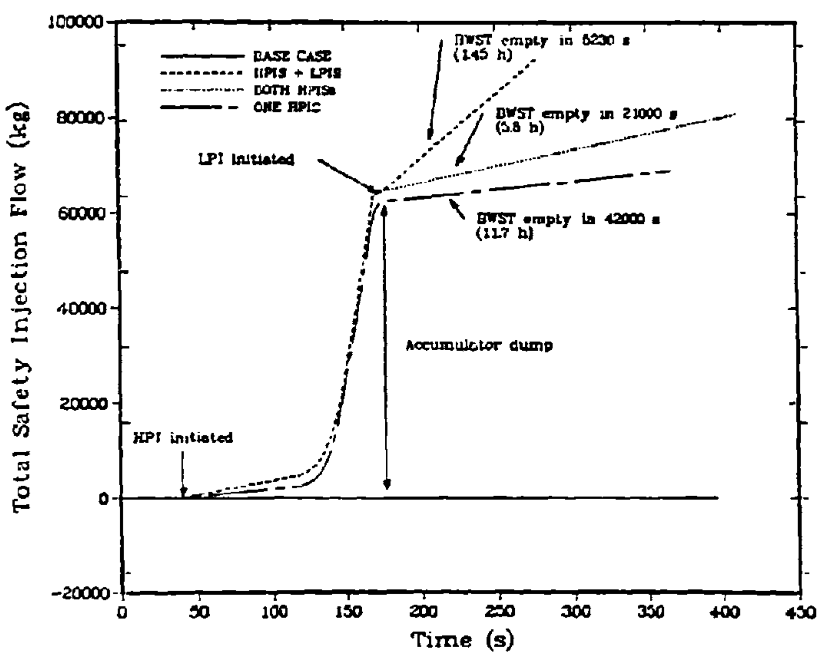


Figure D.3 Duration of effective core cooling during V sequence base and parametric cases.

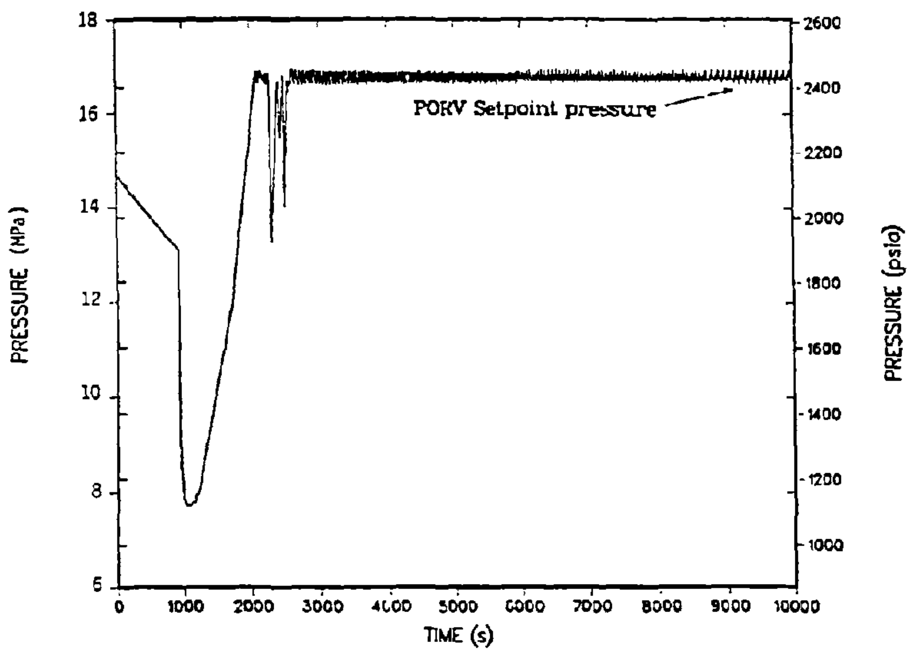


Figure D.4 Pressurizer pressure, 11-mm diam. (0.43") break case.

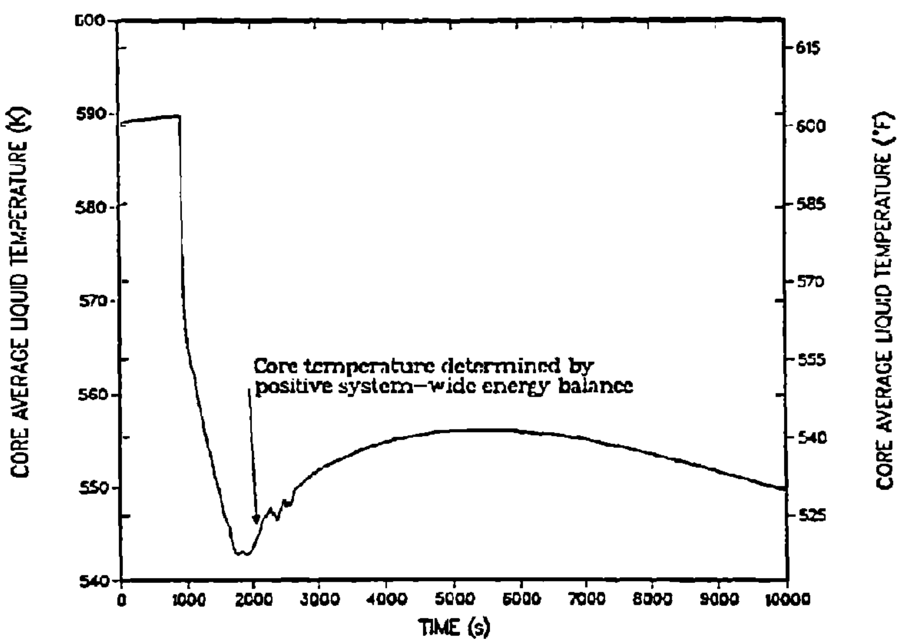


Figure D.5 Core average liquid temperature, 11-mm diam. (0.43") break case.

APPENDIX E: Conditional Core Damage Frequencies: Summary of Plant PRAs

E.1 Indian Point Unit 3

E.1.1 Introduction

In the following, a brief summary of the quantitative results of the Indian Point Unit 3 PRA is presented as it relates to the ISL study.

The Indian Point PRA was performed to quantify the physical response of the plant to all considered initiating accident events. The plant analysis was divided into various phases. First, initiating events were identified and classed into various categories based on experiences and operating records. For each initiating event including LOCAs, plant event trees were constructed. The exit or final states were grouped into appropriate plant event categories, which served as input states for the containment analysis.

In the next phase, a plant-specific data base was developed using Bayesian updates with plant data to prior probability distributions. After establishing the data base, unavailabilities of the plant systems were analyzed by modelling each key system and covering a complete range of plant conditions and success criteria as specified for each event tree. The plant analysis was competed by combining the quantified initiating vector with the system unavailabilities.

The "Master Logic Diagram," presented in Figure E.1.1 is used to define in general the initiating event categories. Categories 1, 2, and 3 representing LOCA initiators are the relevant ones to interfacing system LOCA events. In these cases the pressure boundary between a low/high pressure interface breaks down and the low pressure system will be overpressurized leading to the degradation in the primary coolant boundary and the loss of coolant resulting in core damage.

The specific event trees for each initiating event were constructed using general functional plant response logic. The functional event trees so developed describe the basic functions that are necessary to avoid core melt and/or minimize the possibility of offsite release. In the following sections, the LOCA event trees are briefly reviewed and finally the quantification and conditional core damage frequencies (CCDFs) are presented.

E.1.2 Event Trees

E.1.2.1 Large LOCA

The large LOCA event tree, shown on Figure E.1.2 is applicable to all reactor coolant boundary ruptures equivalent to double-ended circumferential pipe breaks of six inches or above. The event is an extremely severe accident in which the coolant blowdown occurs in a matter of minutes. The cooling of the reactor core is accomplished by the RHR recirculation system. The top event RWST, represents the availability of borated water supply for injection, recirculation, and also for containment spray. The safety injection signal is a prerequisite for the LPI system operation as modelled in the PRA. The containment spray and cooling functions are present in the event tree to

differentiate between the various exit modes that are the input to the containment analysis.

E.1.2.2 Small LOCA

The PRA has three LOCA categories based on the assumed size of the pipe break. The medium (2"-6"0 and small (<2") LOCA categories correspond to the category of small LOCA in the present ISL study. The CDFs of the two categories have to be properly averaged using the corresponding initiators. The small LOCA initiator (2.1-02) is so large compared to the medium LOCA initiator (2.16-03) that the average CCDF due to small and medium LOCAs will be almost entirely dominated by the small LOCA CCDF. The dominant small LOCA event tree is presented in Figure E.1.3. It can be seen that to prevent core damage the emergency coolant injection system must be operable.

The reactor trip function is present, since in most of the small LOCA events the RCS will not depressurize sufficiently to initiate the automatic reactor trip function. In addition, heat removal through the letdown system may not be sufficient requiring the operation of either the secondary side (steam generator, AFWS) or the use of the so-called feed and bleed cooling mode. The high pressure recirculation may be utilized for long term cooling. If depressurization is possible the low pressure recirculation system may also be used.

E.1.3 Quantification of Sequences

E.1.3.1 Large LOCA

The initiator for this accident sequence is listed in Table E.1.1. The dominant sequences of the large LOCA event tree are listed in Table E.1.2. The two most important sequences, AEFC and ALFC, contribute ~99% of the total. These sequences represent failures of the LP system in the injection (AEFC) and the recirculation (ALFC) phases. The conditional core damage frequency is the sum of all the sequence conditional frequencies in Table E.1.2 and is

$$CCDF_A = 8.4\text{-}03/\text{year}.$$

E.1.3.2 Small LOCA

The initiators for the two categories of LOCAs (medium and small) are shown in Tables E.1.3 and E.1.4. The dominant sequences for each event tree are shown in Tables E.1.5 and E.1.6. Again, the two most dominant sequences, SEFC and SLFC, represent the loss of cooling capability either in the injection or recirculation phase. By appropriately averaging the two classes of conditional frequencies with the respective initiators, the average conditional CDF for a small LOCA is found to be

$$\overline{CCDF}_S = \sum I_i \times CCDF_i / \sum_i I_i = 4.5\text{-}03/\text{year}$$

I_i = initiator

$CCDF_i$ = conditional CDF in group i.

E.1.3.3 Terminated Small LOCA

An ISL event may be terminated by the operator in time if there are isolation valves available and operable. Even though the primary coolant blowdown is stopped by the closure of the isolation valve, it is assumed that make-up to the reactor coolant inventory is still required to prevent core damage. If the primary coolant make-up capability is lost through the unavailability of the HPI system, core damage may occur.

The CCDF value associated with this event may be obtained by using the conditional frequency of the sequence SEFC, which essentially represents the failure of the HP injection function. Again, averaging over the medium and small LOCA numbers the results is

$CCDF_{Term}$ = 2.2-04/year.

E.1.3.4 Small LOCA, One Train of HP System Unavailable

In one of the ISL event scenarios, as a result of the overpressurization of the HPI lines, one train of the HPI system becomes unavailable, reducing the make-up capability. In the following, the unavailability of the HPI system with one train unavailable is calculated based on the methods used in the PRA.

The system unavailability is derived as the sum of the mean values of the dominant contributors (in Table E.1.7 relevant pages from the Indian Point PRA are reproduced for convenience).

The expression for the mean unavailability of the HPI system in terms of the dominant components is:

$$Q_{HPIS} = Q_{Single} + Q_{Pump\ Trains} + Q_{Bit} + Q_{Test} + Q_{Maintenance} + Q_{Other}$$

Below each of the dominant contributors are explained, examined, and modified according to the postulated condition of one train being unavailable. It is assumed for simplicity that Train B is the one incapacitated by an ISL event.

1. Q_{Single} – Represents single event cutset or single failure contribution. These are essentially valve failures in the RWST feed line to HP pumps suction side. No modification is necessary.

2. $Q_{Pump\ Train}$ – There are three blocks (B, C, and D) and B and C are identical.
   $Mean_B = 1.0$ – unavailable as the result of the ISL event
   $Mean_C = 1.49 \times 10^{-3}$ – see page 1.6-462 in Table E.1.7
   $Mean_D = 1.53 \times 10^{-3}$
   $Q_{Pump\ Train} = (B \cdot C) + (B \cdot D) + (C \cdot D) = C + D + C \cdot D$
   Since B = 1.0
   $Q_{Pump\ Train} = 3.02 \times 10^{-3}$

3. Q_{Bit} – No change.

4. Q_{Test} – Represents the contribution to unavailability due to test.
   $Mean_{Test} = Mean_T \times Mean_{2B} = 1.1 \times 10^{-4}$

Since there are three pumps
$\text{Mean}_{3\ \text{Pumps}} = 3{*}\text{Mean}_{\text{Main}} \times \text{Mean}_{2B} = 3{*}8.13\text{x}10^{-4}{*}1.0 = 2.44\text{-}03$

5. Q_{Other} - No change.

The total system unavailability is the sum of the dominant contributors

$Q_{HPIS} = 5.74\text{x}10^{-3}$

with one train affected by an ISL event. A summary of the changes are presented in Table E.1.8.

E.2 Oconee Unit 3

E.2.1 Introduction

In this section a brief summary of the quantitative results of the Oconee PRA are presented. The PRA was performed to obtain estimates of the frequency of internally and externally initiated accident events that may lead to severe core damage. In addition, estimates were calculated of the frequency and characteristics of radionuclide releases and the magnitude of the resulting public heath risk.

In this brief review, results pertaining to internally initiated loss of coolant accidents are presented to the extent relevant to the ISL study.

In order to obtain core damage sequences the event tree/fault tree methodology was utilized. In the so-called small event tree/large fault tree method employed in the Oconee PRA, a supporting logic or functional fault trees have been developed for each top event function. For each initiating event (LOCA, transients, etc.) a functional event tree was developed where the top events represent the safety functions necessary to avert core damage.

In general, the functional event tree starts with the initiator followed by the subcriticality function (failure at this point transfers the event to an ATWS event tree). The next function is the preservation of the RCS integrity leading directly to the LOCA functional event trees. The next functions are associated with heat removal from the reactor core, transfer of heat from the RCS and long term core cooling. The end points of the functional event trees are classified as different classes of core damage, Bin I through Bin VI. The core damage bins relevant to the ISL study are listed in Table E.2.1.

E.2.2 Functional Event Trees

The relevant functional event trees for the ISL study are the large and small LOCA trees.

E.2.2.1 Large LOCA Event Tree

In the large LOCA event tree (Figure E.2.1), the first question is the availability of injection (U_A), and its failure leads to core damage. With successful injection, the failure of the low pressure recirculation (X_A) also results in core damage.

E.2.2.2 Small LOCA Event Tree

The first top event in the small LOCA event tree, Figure E.2.2 refers to the subcriticality function (K). If this function fails, a small LOCA ATWS occurs.

At the next top event the availability of the HPIS (U_S) is ascertained. If the HPI fails, core damage occurs.

If HPIS is successful ($\overline{U_S}$), the function "failure to maintain RCS makeup supply" (Y_S) is analyzed. If this function fails, either because the RBCS fails or because the operator fails to terminate the RBSS, the inventory in the BWST will be depleted in about two hours and the operators must start the high pressure recirculation. Failure of this function (X_S) results in core damage.

If function Y_S is successful, the inventory in the BWST will be depleted in about 12 hours; at this time, a failure of high pressure recirculation and low pressure recirculation results in core damage.

E.2.3 Quantification of Sequences

E.2.3.1 Large and Small LOCAs

The quantification of accident sequences relevant for ISL events are presented in this section. Based on the functional event trees the following approach was used to quantify the accident sequences.

Core damage fault trees (CDFT) were constructed for each core damage bin using the previously described functional event trees. Supporting logic and system fault trees were used as inputs to these CFDTs and the quantification of the accident sequences for each bin was accomplished by calculating dominate cutsets using the SETS code.

The final result of the quantification is shown in Table E.2.2. However, this form of breakdown of the core melt frequency is not very useful for the ISL study. In Table E.2.3a a further breakdown is provided using the dominant small and large LOCA contributors to each core damage bin.

Average conditional core damage frequencies for each LOCA sequence can be derived by averaging the sum of the sequence core melt frequency with the appropriate initiator. The final results are shown in Table E.2.3b and

$\overline{CCDF}_{\text{Large LOCA}} = 1.03\times10^{-2}$/year

$\overline{CCDF}_{\text{Small LOCA}} = 2.1\times10^{-3}$/year.

E.2.3.2 Terminated Small LOCA

If an ISL event occurs, the operator might be able to terminate the primary coolant blowdown by closing isolation valves (if available). In this case core damage may occur if the makeup capability through the HPI system is lost. In a small LOCA event the primary system slowly depressurizes preventing the use of the LPI system before the RWST runs out.

The core damage associated with this sequence represents the unavailability of the HPI system or the SU_s sequence (see Figure E.2.2). From Table E.2.3a the CCDF may be calculated as:

$$CCDF_{\substack{\text{Terminated}\\\text{Small LOCA}}} = CMF_{SU_s}/s = 4.65x10^{-7}/3x10^{-3} = 1.6x10^{-4}$$

E.3 Calvert Cliffs Unit 1

E.3.1 Introduction

In this section a brief summary of the interim reliability evaluation program (IREP) analysis of the Calvert Cliffs Unit 1 is given. The analysis was performed[3] as part of the IREP program to identify those accident sequences which dominate the risk. The analysis used the fault tree/event tree modelling to evaluate the risk due to a core melt at Calvert Cliffs.

Core melt sequences initiated by one of three break size LOCAs or one of six categories of transients were evaluated. The most significant sequences contributing to the core melt frequency are listed in Table E.3.1. There are three small LOCA sequences S-50, S-52, and S-59 initiated by the loss of the integrity of the primary system pressure boundary, and the other dominant sequences are all initiated by one of the different categories of transients.

This present study is primarily concerned with events initiated by the breakdwon in pressure isolation function resulting in an interfacing LOCA possibly leading to a core melt. In this study the initiators for this type of accidents have been specifically calculated (see Section 4) for each interfacing line.

The core damage frequency can be obtained by multiplying the initiator value with the conditional core damage frequency (CCDF) for that particular accident scenario. The results of the IREP study can be easily adapted to derive the required CCDFs.

In the following, first the event trees are briefly reviewed, then the quantification and conditional core damage frequencies are presented.

E.3.2 LOCA Systemic Event Trees

Three LOCA initiators are defined as "Large" ($D^*>4.3$ inches), "Small" (1.9 inches $\leq$ 4.3 inches), and "Small-small" (0.30 inches $< D^* \leq 1.9$ inches) breaks, where D^* is the equivalent diameter of the break. A Large LOCA results in rapid depressurization of the primary system allowing the use of the high-volume, low-pressure portions of the Safety Injection System (SIS) to reflood the core. A Small LOCA involves a relatively slow depressurization of the primary system, but the rate of flow of coolant through the break and consequent makeup by High Pressure Safety Injection (HPSI) allows adequate decay heat removal without depending on the secondary (i.e., steam, condensate, and feedwater) systems. In a Small-small LOCA, the rate of flow of coolant through the break is greater than the capability of the normal reactor coolant makeup system, and HPI is initiated based on a low pressurizer pressure signal. However, the rate of flow of coolant through the Small-small

break is insufficient to remove enough decay heat to lower the pressure to the HPI shutoff head and, therefore, secondary heat removal is required.

The Large LOCA systemic event tree is shown in Figure E.3.1 and the Small and Small-small LOCA systemic trees are shown in Figures E.3.2 and E.3.3, respectively. Table E.3.2 lists the mitigating systems and defines their success criteria.

The major difference between the Large LOCA and the Small or Small-small LOCA event trees lies in the treatment of the reactor subcriticality function. For the Large LOCA, success of the reactor subcriticality function is inherent in the design of the reactor and in the nature of the accident. The reactor is automatically rendered subcritical due to core voiding during the blowdown phase and is maintained subcritical during the subsequent core reflood by borated water from the Safety Injection System (SIS).

E.3.2.1 Large LOCA (A)

The Large LOCA initiating event is a random rupture of the RCS piping having a greater break area than a 4.3 inch diameter circular break. This break size was selected because the primary system will depressurize rapidly for breaks of this size, resulting in a demand on the high volume, low pressure portions of the Safety Injection System (SIS). In addition, because of the rapid core voiding, the reactor subcriticality function is not required for this event.

The frontline systems required to mitigate a Large LOCA include the Low Pressure Safety Injection (LPSI) System, the Safety Injection Tanks (SIT), the Containment Air Recirculation and Cooling (CARC) System, the Containment Spray System in the injection mode (CSSI), the Containment Spray System in the recirculation mode (CSSR), the Shutdown Cooling Heat Exchangers (SDHX), and the High Pressure Safety Recirculation (HPSR) System.

E.3.2.2 Small LOCA (S_1)

The Small LOCA initiating event is a random rupture of the RCS piping having a break area greater than that of a 1.9 inch diameter circular break but less than or equal to that of a 4.3 inch diameter circular break. A Small LOCA involves a relatively slow depressurization of the primary system, such that the low pressure portions of the Safety Injection System (SIS) will not be activated, but the rate of flow of coolant through the break and consequent makeup by High Pressure Safety Injection (HPSI) allows adequate reactor heat removal without depending on the secondary systems (i.e., steam, condensate and feedwater systems). Success of the reactor subcriticality function is dependent on the successful operation of the Reactor Protection System (RPS).

The frontline systems required to mitigate a Small LOCA comprise the headings of the Small LOCA systemic event tree (Figure E.3.2) and include the Reactor Protection System (RPS), the High Pressure Safety Injection (HPSI), the Containment Air Recirculation and Cooling (CARC) System, the Containment Spray System in the injection mode (CSSI), the Containment Spray System in the recirculation mode (CSSR), the Shutdown Cooling Heat Exchangers (SDHX), and the High Pressure Safety Recirculation (HPSR) System.

E.3.2.3 Small-Small LOCA (S_2)

The Small-small LOCA initiating event is a random rupture of the RCS piping or a reactor coolant pump seal having a break area greater than that of a 0.3 inch diameter circular break but less than or equal to that of a 1.9 inch diameter circular break. In a Small-small LOCA, the rate of flow of coolant through the break is greater than the capability of the normal reactor coolant makeup system, and HPSI is initiated based on a low pressurizer pressure signal. However, the rate of coolant loss through the Small-small break is insufficient to remove enough decay heat to prevent a core melt and, therefore, secondary heat removal is required. Success of the reactor subcriticality function is dependent on the successful operation of the Reactor Protection System (RPS).

The frontline systems required to mitigate a Small-small LOCA comprise the headings of the Small-small LOCA systemic event tree (Figure E.3.3) and include the Reactor Protection System (RPS), Secondary System Relief with Auxiliary Feedwater (SSR with AFW), the High Pressure Safety Injection (HPSI) System, the Containment Air Recirculation and Cooling (CARC) System, the Containment Spray System in the injection mode (CSSI), the Containment Spray System in the recirculation mode (CSSR), the Shutdown Cooling Heat Exchangers (SDHX), and the High Pressure Safety Recirculation (HPSR) System.

E.3.3 Quantification of Sequences

E.3.3.1 Large LOCA

Table E.3.3 lists the frequency and probability values obtained in the IREP study for each of the sequences leading to core melt. The sum of the leading large LOCA sequences A-1 through A-13 results in a conditional core damage frequency of $CCDF_A = 2.8*10^{-2}$/year due to a large LOCA.

E.3.3.2 Small LOCA

Table E.3.3 lists the conditional event probability for both Small (S_1) and Small-small (S_2) LOCA sequences. In the present ISL study, these two classes of LOCAs were combined into a single small LOCA group. An average $CCDF_S$ has been calculated by first summing the dominant sequences S_2-50, S_2-52, and S_2-59 leading to $CCDF_{S2} = 1.2x10^{-3}$ including the recovery factor. $CCDF_{S1}$ has also been calculated by summing the major S_1 sequences (S_1-26 through S_1-37). An average $\overline{CCDF}$ has been calculated by the weighted average of the individual $CCDF_{S1}$ and $CCDF_{S2}$ and their respective initiators. The result is an average small LOCA $\overline{CCDF_S} = 1.3x10^{-3}$/year.

E.3.3.3 Terminated Small LOCAs

In this scenario, after an interfacing small LOCA event the operator is successfully able to terminate the primary coolant blowdown by closing the isolation valves, if available. It is assumed that coolant makeup to the primary system will be required using the HPI system and water supply from the RWST. If the HPI system is unavailable, the makeup capability is lost since the primary system pressure remains relatively high, preventing the operation of the LPI system and thus leading to core damage.

The CCDF associated with this sequence effectively represents the unavailability of the HPSI system. One of the dominate sequences S_2-59 (S_2D'') represents exactly this event and the CCDF can be calculated by dividing the core damage frequency due to S_2D'', $1.6x10^{-6}$ (after recovery, from Table E.3.1) with the initiator, $2.1*10^{-2}$. The result is

$$CCDF_{\substack{\text{Terminated}\\\text{Small LOCA}}} = 7.5x10^{-5}/\text{year.}$$

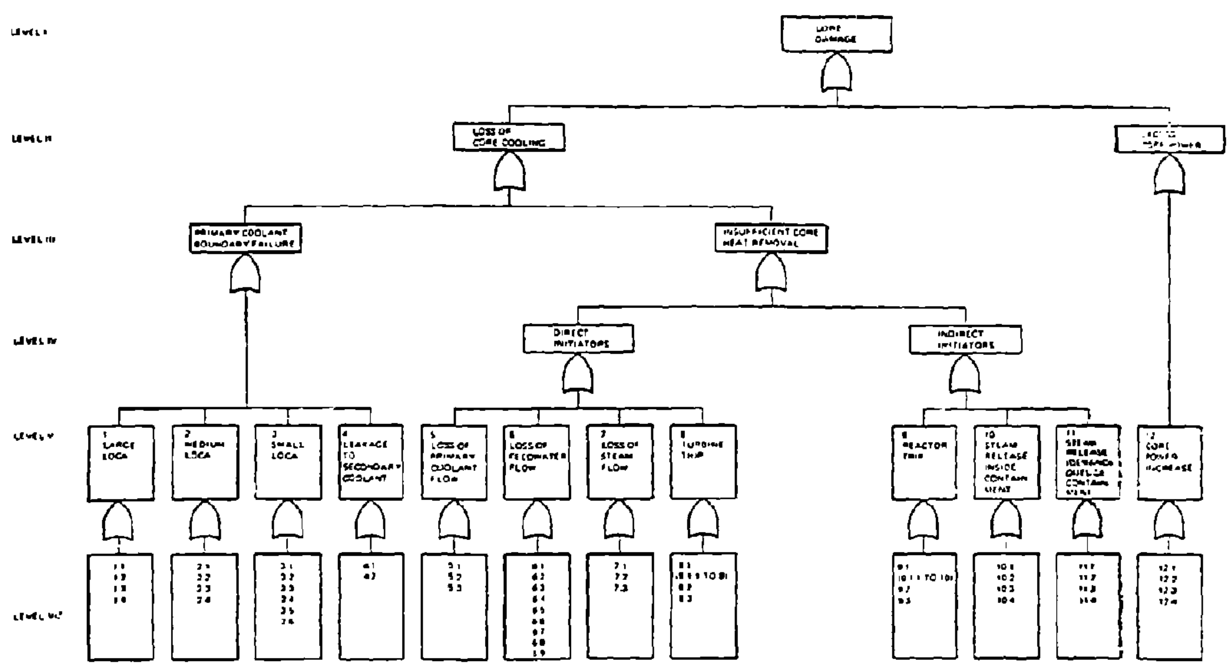


Figure E.1.1 Indian Point core damage master logic diagram.

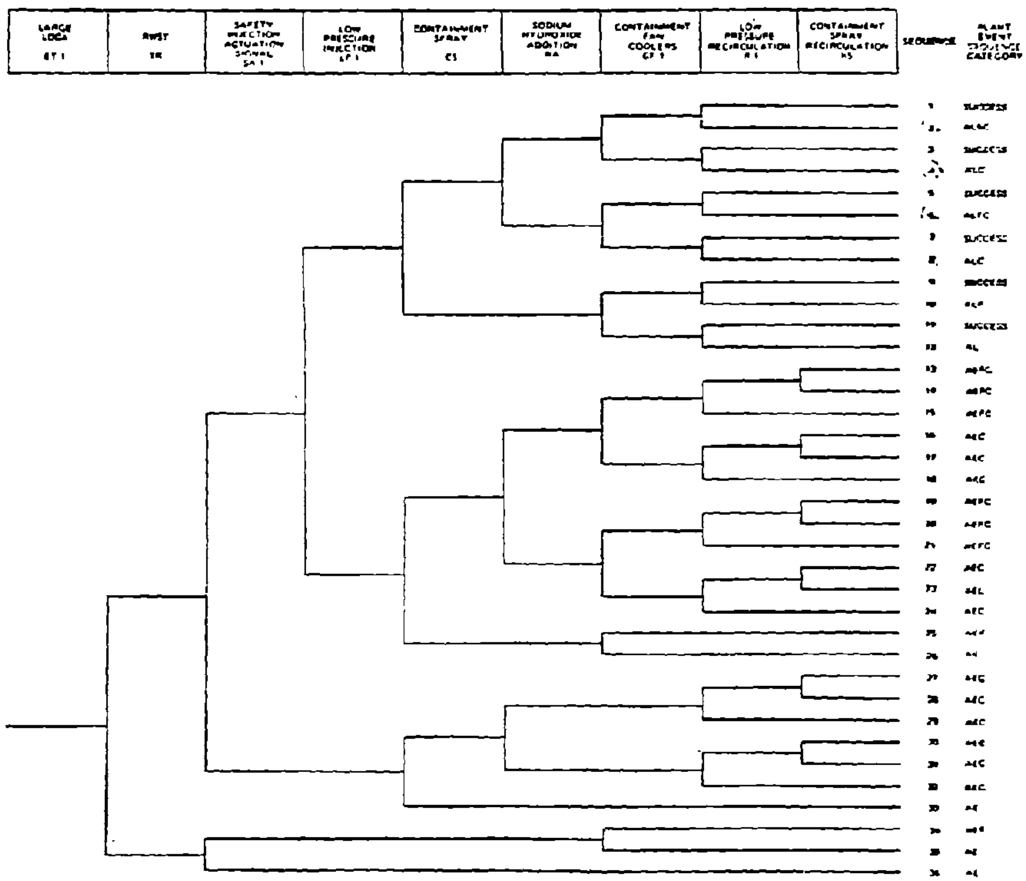


Figure E.1.2 Large LOCA - Event Tree. Indian Point Unit 3.

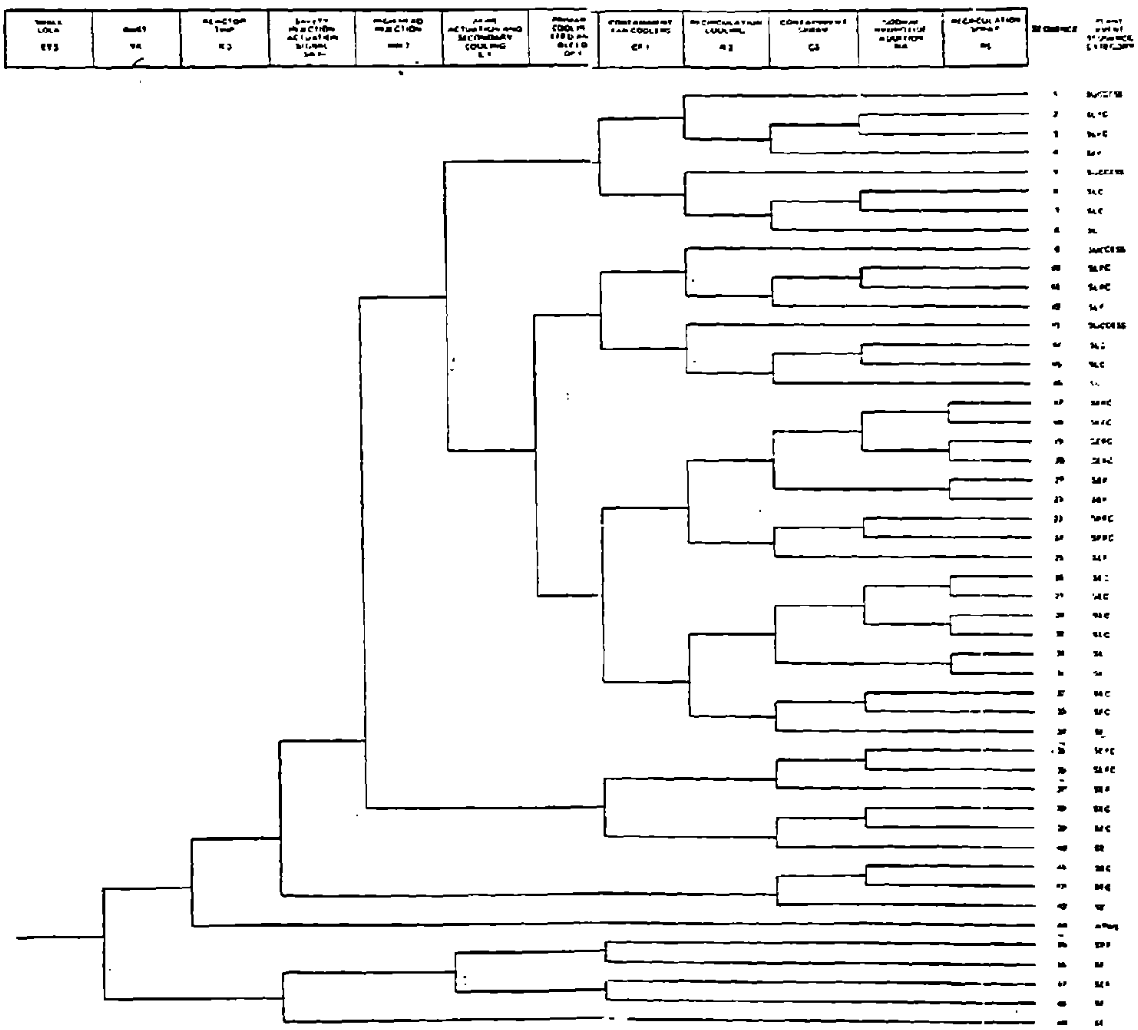
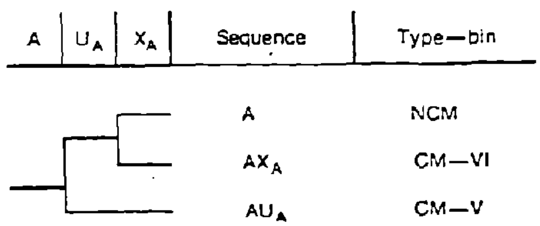


Figure E.1.3 Small LOCA - Event Tree. Indian Point Unit 3.



Event	Description
T	Occurrence of a transient initiating event.
K	Failure of the RPS to trip the reactor.
Q	Loss of RCS integrity.
B	Failure of RCS heat removal via the steam generators.
P	Failure to provide RCS pressure relief.
U	Failure of core-heat removal by HPI cooling.
Y	Failure to maintain RCS makeup supply.
L	Failure to recover RCS heat removal.
W	Failure to reestablish RCS integrity.
X	Failure to maintain long-term core-heat removal.
A	Large LOCA initiator.
S	Small LOCA initiator.

Figure E.2.1 OPRA event tree for large-break LOCA events. Oconee 3.

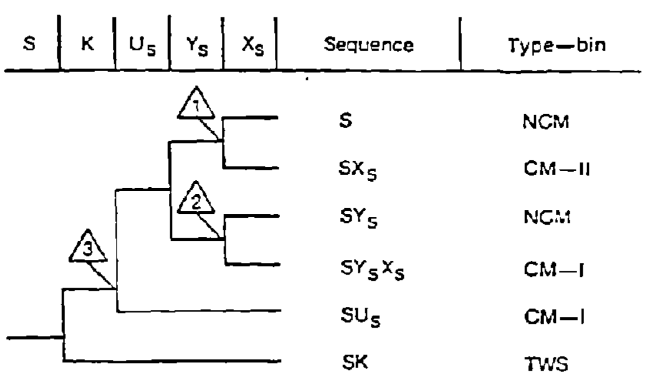
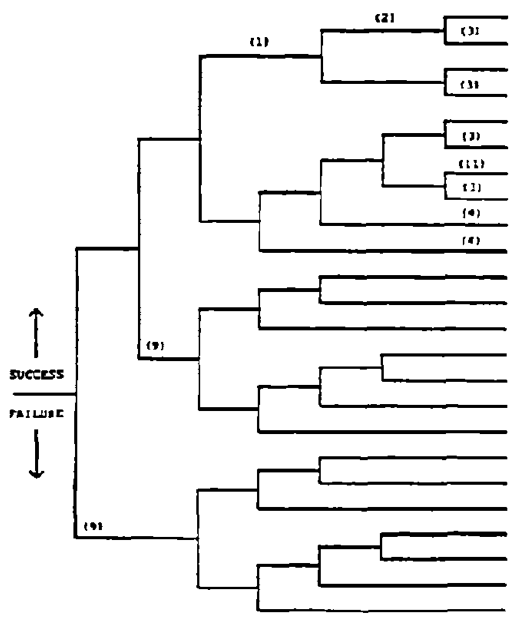


Figure E.2.2 OPRA event tree for small-break LOCA events. Oconee 3.

Initiating Event	Mitigating Systems Response						
Large LOCA	LPSI[9]	SIT[9]	CARC	CSSI	CSSR	SDHX	HPSR
A	D'	D	C	C'	F	G	H



Sequence No.	Sequence Designator	REMR INJ	REMR REC	CNHR INJ	CNHR REC	CHRR INJ	CHRR REC	RCS Status	NOTES
1	A							SAFE	1,2
2	AH		x					CM	1,2,3
3	AF							SAFE	1
4	AFH		x				x	CM	1,3
5	AC							SAFE	
6	ACH		x					CM	3
7	ACG		x		x			CM	11
8	ACGH		x		x			CM	3
9	ACF		x		x		x	CM	4
10	ACC'		x	x		x		CM	4
11	AD	x						CM	9
12	ADF	x					x	CM	9
13	ADC'	x				x		CM	9
14	ADC	x						CM	9
15	ADCG	x			x			CM	9
16	ADCF	x			x		x	CM	9
17	ADCC'	x		x		x		CM	9
18	AD'	x						CM	9
19	AD'F	x					x	CM	9
20	AD'C'	x				x		CM	9
21	AD'C	x						CM	9
22	AD'CG	x			x			CM	9
23	AD'CF	x			x		x	CM	9
24	AD'CC'	x		x		x		CM	9

Figure E.3.1 Large LOCA (A) Systemic Event Tree. Calvert Cliffs 1.

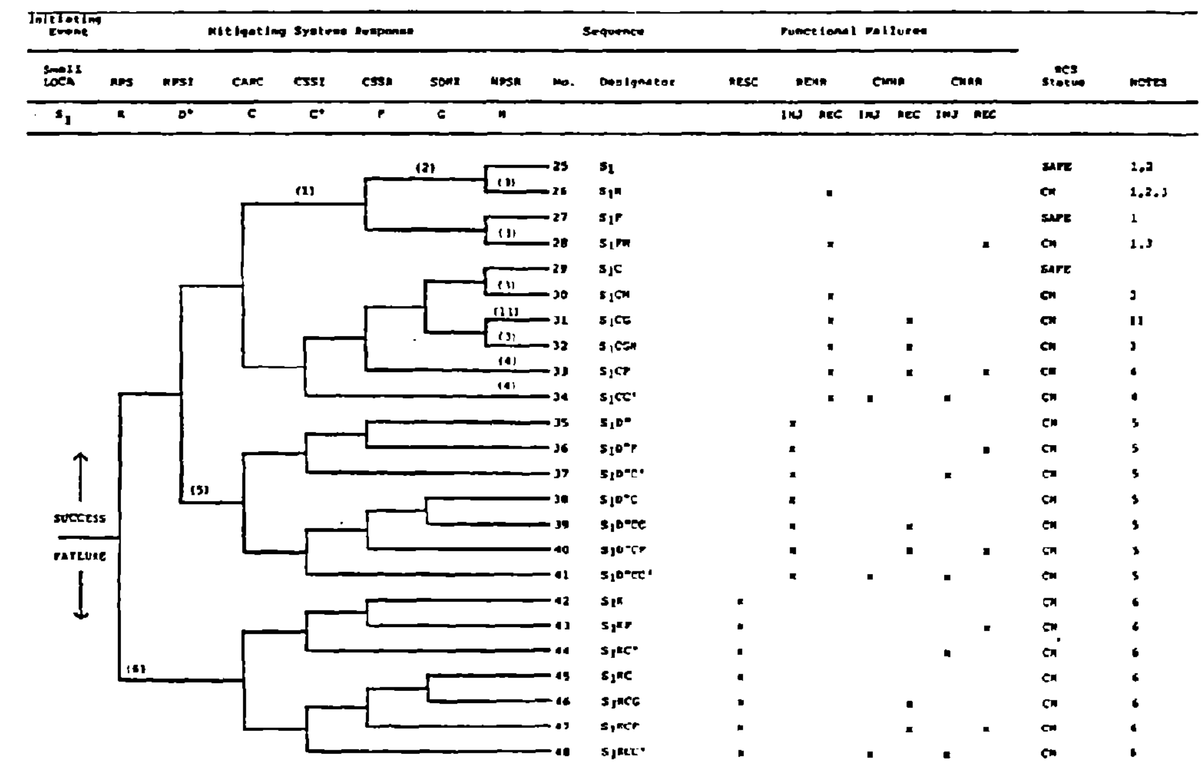


Figure E.3.2 Small LOCA (S_1) Systemic Event Tree. Calvert Cliffs 1.

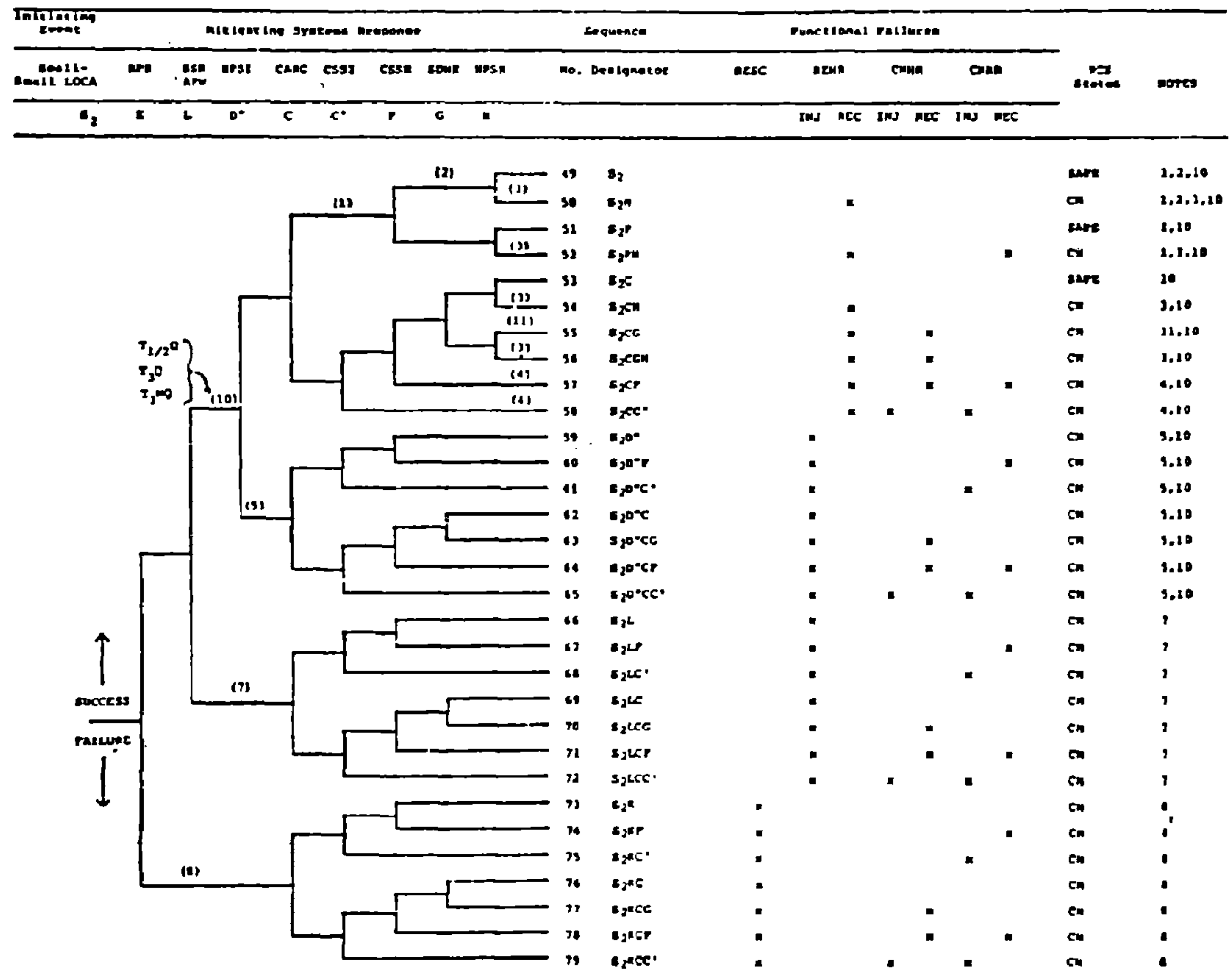


Figure E.3.3 Small-Small LOCA (S_2) Systemic Event Tree. Calvert Cliffs 1.

Table E.1.1
Large LOCA Initiating Event and Electric Power Data
Indian Point Unit 3

Description	5%	Median	95%	Mean
ϕ_1- Large LOCA (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_1):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

Table E.1.2
Large LOCA Event Tree Dominant Sequences
Indian Point Unit 3

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
AEFC	3.01-3	2,3,5,6	13	LP-1	2.98-3
AEF	1.33-7	2,3,5,6	25	LP-1, CS	1.08-7
		2,3,5,6	34	TK	2.40-8
AEC	7.19-6	2,3,5,6	27	SA-1	6.15-6
		5,6	16	LP-1, CF-1	9.10-7
AE	1.26-7	No Power	26		1.20-7
ALFC	5.34-3	2,3,5,6	2	R-1	5.29-3
ALF	1.97-7	2,3,5,6	10	CS, R-1	1.90-7
ALC	1.87-7	5,6	4	CF-1, R-1	1.63-7
		6	4	R-1	1.87-8
AL	3.78-7	2,3	12		3.78-7

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11 x 10^{-5}.

Table E.1.3
Medium LOCA Initiating Event and Electric Power Data
Indian Point Unit 3

Description	5%	Median	95%	Mean
ϕ_2- Medium LOCA (Annual Frequency)	1.07-6	1.17-4	6.66-3	2.16-3
AC Power Available at Buses (Given ϕ_2):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

Table E.1.4
Small LOCA Initiating Event and Electric Power Data
Indian Point Unit 3

Description	5%	Median	95%	Mean
ϕ_3- Small LOCA (Annual Frequency)	1.03-4	1.11-2	5.43-2	2.01-2
AC Power Available at Buses (Given ϕ_3):				
2A, 3A, 5A, 6A	9.97-1	9.99-1	1.00+0	1.00+0
2A, 3A, 6A	3.42-7	5.18-6	5.87-5	1.31-5
2A, 3A, 5A	2.75-7	4.89-6	5.69-5	1.26-5
5A, 6A	5.09-4	1.27-3	2.75-3	1.48-3
2A, 3A	6.26-9	1.37-7	1.07-6	3.77-7
6A	3.99-8	2.05-7	2.87-6	4.33-7
5A	3.42-7	7.80-7	1.82-6	9.63-7
None	3.97-8	9.64-8	2.84-7	1.19-7

Note: Values are presented in an abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

Table E.1.5
Medium LOCA Event Tree Dominant Sequences
Indian Point Unit 3

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences: Sequence and AC Buses Available — Bus No. A	Seq.	Failed Branch Points	Conditional Frequency
AEFC	1.00-3	2,3,5,6	31	LP-2	8.03-4
		2,3,5,6	13	HH-1	1.78-4
AEF	6.10-8	2,3,5,6	43	LP-2, CS	2.90-8
		2,3,5,6	70	TK	2.40-8
		2,3,5,6	25	HH-1, CS	6.43-9
AEC	7.62-6	2,3,5,6	63	SA-1	6.15-6
		6	16		4.06-7
		5	52		9.10-7
AE	5.06-7	2,3	30		3.79-7
		No Power	62		1.20-7
ALFC	5.35-3	2,3,5,6	2	R-1	5.29-3
ALF	1.97-7	2,3,5,6	10	CS, R-1	1.91-7
ALC	1.68-7	5,6	4	CF-1, R-1	1.62-7
AL	1.23-11	2,3,6	12	CS, CF-1, R-1	6.36-12
		5,6	12	CS, CF-1, R-1	5.86-12

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

Table E.1.6
Small LOCA Event Tree Dominant Sequences
Indian Point Unit 3

Plant Event Sequence Category	Conditional Frequency	Dominant Sequences			
		Sequence and AC Buses Available		Failed Branch Points	Conditional Frequency
		Bus No. A	Seq.		
SEFC	1.40-4	2,3,5,6	35	HH-2	1.40-4
SEF	2.91-8	2,3,5,6	45	TK	2.40-8
		2,3,5,6	37	HH-2, CS	5.04-9
SEC	6.22-6	2,3,5,6	41	SA-1	6.19-6
SE	4.77-9	2,3(3)[1]	40		3.40-9
		NP(3)[2]	40		1.10-9
SLFC	·4.11-3	2,3,5,6	2	R-2	4.10-3
SLF	1.49-7	2,3,5,6	4	R-2, CS	1.48-7
SLC	3.73-8	2,3,5,6	6	CF-1, R-2	2.58-9
		5,6	6	CF-1, R-2	3.44-8
SL	2.56-12	2,3,6	8	CF-1, R-2, CS	1.22-12
		5,6	8	CF-1, R-2, CS	1.24-12
ATWS	3.91-5	2,3,5,6	44	K-3	3.90-5

Note: Values are presented in abbreviated scientific notation, e.g., 1.11-5 = 1.11×10^{-5}.

1. Initially power at 2A and 3A, power not recovered in 3 hours.
2. Initially no power, power not recovered in 3 hours.

Table E.1.7
Indian Point Unit 3

1.6.2.3.1.4 Quantification: Boundary Condition, Electric Power Available on Buses 2A, 5A, and 6A.

1.6.2.3.1.4.1 Quantification of Single Failures.

1.6.2.3.1.4.1.1 Hardware contribution. Each single-event cutset is analyzed using plant specific data:

- Manual valve (MV) 846 on the feed line from the RWST is tested monthly on the recirculation pump test. Therefore, one-half of 30 days is used as the average time period of unknown valve condition.

$$\text{Mean}_{MV} = 9.15\times10^{-8}/\text{hour} \times 30 \text{ days}/2 \times 24 \text{ hours/day}$$

$$= 3.29\times10^{-5}$$

$$\text{Variance}_{MV} = 1.01\times10^{-14}/\text{hour}^2 \times (360 \text{ hours})^2$$

$$= 1.31\times10^{-9}$$

- Motor-operated valve (MOV) 1810 is flow tested monthly and is deenergized open so it has the same characteristics as the manual valve.

Mean_{MOV}: 3.29×10^{-5}

Variance_{MOV}: 1.31×10^{-9}

- Check valve (CV) 847 is flow tested monthly.

Mean_{CV}: 6.91×10^{-5}/demand

Variance_{CV}: 1.03×10^{-8}

- The total hardware contribution for single failures is a serial addition of the components' unavailability in block A.

$$\text{Mean}_{Singles} = \text{Mean}_{MV} + \text{Mean}_{MOV} + \text{Mean}_{CV}$$

$$= 3.29\times10^{-5} + 3.29\times10^{-5} + 6.91\times10^{-5}$$

$$= 1.35\times10^{-4}$$

$$\text{Variance}_{Singles} = 1.30\times10^{-8}$$

1.6.2.3.1.4.1.2 Test and maintenance contribution. Neither of these two valves is stroked during the quarterly test. The monthly flow test does not change the position of the valves, but verifies flow through each one. This ensures there will be no contribution to unavailability due to testing.

Table E.1.7 (Continued)

Any maintenance on these valves will cause the plant to shut down if the valves are removed or placed into a nonnormal open position.

1.6.2.3.1.4.1.3 Human error contribution. No significant human error is envisioned for valves because flow tests ensure an open flow path after any vale manipulation that may occur at refueling. In addition, MOV 1810 is deenergized open with redundant position indication in the CCR. Each week, MOV 1810 and MV 846 are verified to be locked open.

Table 1.6.2.3.1-8 summarizes the unavailability contributors for single failures.

1.6.2.3.1.4.2 Quantification of Double Failures.

1.6.2.3.1.4.2.1 Hardware contribution. Two element cutsets are determined as noted in Section 1.6.2.3.1.3.3 by combinations of any two pump trains not providing flow to the injection headers. These trains are referred to as block B or C for train 31 or 33 and block D for train 32.

Some elements in each train are flow tested each month so the average of 30 days/2 will apply to those valves in each of the trains. Other valves are only flow tested at refueling even though motor-operated valves 851A and 851B are stroked during the monthly test. Each of the following valves will be evaluated to determine the average time since a flow test verified the proper position of the gate within the valve.

The block B pump train element evaluation is shown below:

		Mean	Variance
• SI pump 31 fails to start.	P	1.36×10^{-3}	1.22×10^{-6}
• Manual valve 848A fails closed (30 days/2 x 24 hours/day x 9.15×10^{-8} = 3.29×10^{-5}).	MV1	3.29×10^{-5}	1.31×10^{-9}
• Check valve fails to open.	CV	6.91×10^{-5}	1.03×10^{-8}
• Manual valve 850A fails closed (30 days/2 x 24 hours/day x 9.15×10^{-8} = 3.29×10^{-5}).	MV2	3.29×10^{-5}	1.31×10^{-9}

The mean unavailability of the block B is then:

$$\text{Mean}_B = \text{Mean}_P + \text{Mean}_{MV1} + \text{Mean}_{CV} + \text{Mean}_{MV2}$$

$$= 1.36\times10^{-3} + 3.29\times10^{-5} + 6.91\times10^{-5} + 3.29\times10^{-5}$$

$$= 1.49\times10^{-3}$$

$$\text{Variance}_B = 1.05\times10^{-6}$$

Table E.1.7 (Continued)

Block C has the same values because the two blocks are symmetrical. However, block D has several different components which yield the following block values.

		Mean	Variance
• SI pump 31 fails to start.	P	1.36×10^{-3}	1.22×10^{-6}
• MOV 887A transfers closed (30 days/2 x 24 hours/day x 9.15×10^{-8} = 3.29×10^{-5}).	MOV1	3.29×10^{-5}	1.31×10^{-9}
• MOV 887B transfers closed	MOV2	3.29×10^{-5}	1.31×10^{-9}
• MOV 851A transfers closed (30 days/2 x 24 hours/day x 9.15×10^{-8} = 3.29×10^{-5}).	MOV3	3.29×10^{-5}	1.31×10^{-9}
• Check valve 852A fails to open.	CV	6.91×10^{-5}	1.03×10^{-8}

The mean unavailability of block D is then:

$$\begin{aligned}\text{Mean}_D &= \text{Mean}_P + \text{Mean}_{MOV1} + \text{Mean}_{MOV2} + \text{Mean}_{MOV3} + \text{Mean}_{CV}\\ &= 1.36\times10^{-3} + 3.29\times10^{-5} + 3.29\times10^{-5} + 3.29\times10^{-5} + 6.91\times10^{-5}\\ &= 1.53\times10^{-3}\end{aligned}$$

$$\text{Variance}_D = 1.06\times10^{-6}$$

The block D evaluation used the flow path to line 56, but the alternate path to line 16 has a similar set of valves. The pumps failing to start represents the majority of the contribution to unavailability. Consequently, the two types of trains have nearly equivalent values of unavailability.

Using discrete probability distribution (DPD) arithmetic for the three combinations of two trains failing coincidently yields the following:

$$\begin{aligned}\text{Mean}_{\text{Pump Trains}} &= (\text{B and C}) + (\text{B and D}) + (\text{C and D})\\ &= 7.85\times10^{-6}\end{aligned}$$

$$\text{Variance} = 7.57\times10^{-11}$$

There are two 2-event cutsets (Section 1.6.2.3.1.3.3) involving the valves in block M at each end of the BIT. If both valves in a pair fail to open, the line remains blocked. Because either of the two pairs can block the flow and the valves are from the same distribution, the following calculation using DPD arithmetic gives:

Table E.1.7 (Continued)

$$\text{Mean}_{BITMOV} = 1.51\times10^{-3}$$

$$\text{Variance}_{BITMOV} = 2.64\times10^{-6}$$

$$\text{Mean}_{BIT} = 2 \times (\text{Mean}_{BITMOV})^2$$

$$= 9.48\times10^{-6}$$

$$\text{Variance}_{BIT} = 1.70\times10^{-9}$$

Together, the hardware double failures are computed to be:

$$\text{Mean}_{doubles}\text{:}\ 1.73\times10^{-5}$$

1.6.2.3.1.4.2.2 Test contribution. During the monthly test, the system remains in normal configuration except for 2-3/4" test lines where manual valves are opened to allow recirculation to the RWST and to bypass the BIT on line 6. These lines being open is not considered a system failure on safety injection because the normal lines are 6"-4", respectively, on lines 56 and 16. Sufficient flow would still be available even with the test lines open.

MOV 851 and 851B are stroked during the test of pump 32. The valve being out of position in the line requiring flow is given by the following consecutive calculations showing five minutes during the stroke test where the system would be unavailable to the correct line.

Unavailability
due to tests: 5 minutes/(60 minutes/hour/720 hours/month)

$$\text{Mean}_T\text{:}\ 1.1\times10^{-4}$$

Using an estimated standard deviation value of three minutes yields the following:

$$\text{Variance}_T = (3/60)^2/(720)^2$$

$$= 4.8\times10^{-9}$$

With train 32 (block D) unavailable, the other trains must both operate to meet the required two pumps operating. Therefore, each element in blocks B and C becomes a single element cutset, and for both blocks, the following values are obtained (using values from Section 1.6.2.3.1.4.2.1):

$$\text{Mean}_{2B} = 2\ \text{Mean}_B$$

$$= 2 \times (1.49\times10^{-3})$$

$$= 2.99\times10^{-3}$$

Table E.1.7 (Continued)

Then the unavailability due to these tests is:

$$\text{Mean}_{\text{Test}} = \text{Mean}_{2B} \times \text{Mean}_{T}$$

$$= 2.99\times10^{-3} \times 1.1\times10^{-4}$$

$$= 3.29\times10^{-7}$$

1.6.2.3.1.4.2.4 Maintenance contribution. Valve maintenance was considered to be performed during nonoperating hours or with the valves in their normal injection system position. However, observation of pump maintenance during the past four years leads to the following unavailability of a pump train due to maintenance during operating hours.

$\text{Mean}_{\text{Maintenance}}$: 8.13×10^{-4}

$\text{Variance}_{\text{Maintenance}}$: 6.22×10^{-8}

With three pump trains, there are three ways to have maintenance unavailability because each pump is equally likely to require maintenance. The failure of two pumps is given in Section 1.6.2.3.1.4.2.2.

$\text{Mean}_{\text{3Pump Maintenance}} = 3 \times \text{Mean}_{\text{Maintenance}} \times \text{Mean}_{2B}$ (see Section 1.6.2.3.1.4.2.2)

$$= 3 \times 8.13\times10^{-4} \times 2.99\times10^{-3}$$

$$= 7.29\times10^{-6}$$

1.6.2.3.1.4.2.4 Human error contribution. Because the system starts automatically on a safety injection signal, human interaction does not become a major factor until the recirculation phase. The procedures of the monthly and quarterly tests appear to minimize human error (i.e., such as opening and then closing each valve before proceeding to the next valve). Therefore, no significant contribution to system unavailability was envisioned for this system.

1.6.2.3.1.4.2.5 Other causes. Most of the observed coupled failures in the industry involved motor- or air-operated valves that had to change position on demand. The frequency partial and full refueling system tests indicate that an unforeseen common cause failure is of low frequency. This state of knowledge is expressed by taking a β-factor with range 1.0×10^{-3} to 5.0×10^{-2} which yields a mean and variance of:

Mean: 1.4×10^{-2}

Variance: 6.1×10^{-4}

This β-factor is assessed for the common cause failure of the trains failing coincidently.

Table E.1.7 (Continued)

Mean = $1.4\times10^{-2} \times 1.53\times10^{-3}$ (see Section 1.6.2.3.1.4.2.1)

$= 2.14\times10^{-5}$

1.6.2.3.1.4.2.6 Double failure contributions. Table 1.6.2.3.1-9 summarizes the double failure contributions.

1.6.2.3.1.4.3 Triple failures. From Section 1.6.2.3.1.4.2.2, it was found that the mean unavailability of two injection paths being blocked while a third was being tested yielded a triple failure. If the third path fails coincident with the testing of the other two, the calculated unavailability is approximately:

$$Mean_{3Legs}: (1.53\times10^{-3})^3 = 1.03\times10^{-8}$$

Other triple failures of interest are those discussed in Section 1.6.2.3.1.3.3 for injection paths.

A single path is first quantified:

$$Mean_E: 2\ Mean_{Check\ Valve} + Mean_{MOV856}$$

Even though the MOVs are checked visually each quarter, the flow path is not verified. Given that the flow path is verified at refueling and assuming a 12 month refueling cycle, MOV 856 being closed is given by:

Mean: 9.15×10^{-8}

Variance: 1.01×10^{14}

For an average of 1/2 year we compute:

$$Mean_{MOV856} = 9.15\times10^{-8}/\text{hour} \times 8{,}760/2$$

$$= 4.00\times10^{-4}$$

$$\text{Variance} = 1.92\times10^{-7}$$

$$Mean_E = 2 \times (6.91\times10^{-5}) + 4.00\times10^{-4}$$

$$= 5.38\times10^{-4}$$

To have a system failure, three out of four of these blocks like E must block flow. Because there are four ways this can occur

$$\text{Mean Path Unavailability} = 4 \times (Mean_E)^3$$

$$= 6.23\times10^{-10}$$

Because this is a small contribution compared to single and double failures, triple failures will be carried no further.

Table E.1.7 (Continued)

1.6.2.3.1.4.4 System Unavailability. Table 1.6.2.3.1-10 shows the results that have been derived for the mean values of the dominant contributors to HPIS unavailability. These contributors are the basis for the uncertainty analysis. The mathematical expression for the unavailability of the system, in terms of the unavailabilities of the dominant contributor, is:

$$Q_{HPIS} = Q_{Single} + Q_{Pump\ Trains} + Q_{BIT} + Q_{Test} + Q_{Maintenance} + Q_{Other}$$

Using DPD arithmetic, we find for Q_{HPIS}:

Mean:	$1.81x10^{-4}$
Variance:	$1.39x10^{-8}$
5th Percentile:	$6.37x10^{-5}$
Median:	$1.48x10^{-4}$
95th Percentile:	$5.49x10^{-4}$

The requirement of only one pump train to be operative for a small LOCA and either line (16 or 56) delivering flow reduces the dominant unavailabilities to the single failures unavailability because all three trains must fail to fail the system, given that power is available on all buses.

The associated system unavailability distribution for this case using DPD arithmetic is:

Mean:	$1.34x10^{-4}$
Variance:	$1.20x10^{-8}$
5th Percentile:	$3.20x10^{-5}$
Median:	$9.70x10^{-5}$
95th Percentile:	$3.41x10^{-4}$

Table E.1.8
HPI System Unavailability
One Train (B) Effected by ISL
Indian Point Unit 3

Dominant Contributor	PRA (Three Blocks B, C, D)	One Block B Effected by ISL
Q_{Single}	1.35×10^{-4}	No change
$Q_{Pump\ Train}$	7.85×10^{-6}	3.02×10^{-3}
Q_{BIT}	9.48×10^{-6}	No change
Q_{Test}	3.29×10^{-7}	1.1×10^{-4}
Q_{MainT}	7.29×10^{-6}	2.44×10^{-3}
Q_{Other}	2.14×10^{-5}	No change
Total Q_{HPIS}	1.81×10^{-4}	5.74×10^{-3}

Table E.2.1
Summary of Core Melt Bins
Oconee 3

Bin	Sequence Characteristics
I	RCS pressure and leakage rates associated with small-break LOCAs, with early melting of the core (i.e., within about two hours after the break occurs).
II	RCS pressure and leakage rates associated with small-break LOCAs, with late melting of the core (i.e., after about 12 hours from when the break occurs).
III	Transient initiator.
IV	Transient initiator.
V	Large rates of leakage from the RCS and low pressure; associated with large-break LOCAs with failure of core injection.
VI	Large-break LOCA conditions with failure of coolant recirculation.

Table E.2.2
Summary of Contributors to Core-Melt Frequency
Oconee 3

CM bin	Internal events: Initiating event	Internal events: Core-melt frequency	External Events: Initiating event	External Events: Core-melt frequency
I	Pipebreak- and transient-induced small LOCA	6.5-6[a]	Earthquake	1.1-5
			Tornado	2.2-6
			Fire	6.5-6
	SGTR	1.3-6	Turbine-building flood	2.0-3
	TWS	1.8-8		
	Total bin I	7.8-6		2.0-3
II	Pipebreak- and transient-induced small LOCA	1.1-6	Earthquake	2.6-6
			External flood	2.5-5
	SGTR	1.4-6		
	TWS	1.8-8		
	Total bin II	2.5-6		2.8-5
III	Transients	2.7-5	Earthquake	4.6-5
	TWS	2.8-6	Fire	3.6-6
			Tornado	1.1-5
			Turbine-building flood	4.5-3
	Total bin III	3.0-5		4.5-3
IV	Transients	1.9-7		
	Total bin IV	1.9-7		
V	Large LOCA	1.4-6	Earthquake	3.2-6
	TWS	1.7-6		
	Total bin V	3.1-6		3.2-6
VI	Large LOCA	8.3-6	Earthquake	1.6-8
	TWS	1.5-6		
	Total bin VI	9.8-6		1.6-8
	Interfacing systems LOCA	1.4-7		
	Subtotal	5.4-5		6.5-3
Total core-melt frequency			6.6-3	

[a]Notation: 1.0-7 = 1.0 x 10^{-7}.

Table E.2.3a
Summary of Dominant Contributors to Core Melt Frequency
(Large and Small LOCA Only)
Oconee 3

Core Damage Bin	Sequence	Initiator	Core Melt Frequency (/Year)
I	SY_sX_s	3.0×10^{-3}	5.03×10^{-6}
	SU_s	3.0×10^{-3}	4.65×10^{-7}
II	SX_s	3.0×10^{-3}	6.90×10^{-7}
V	AU-Type A	1.1×10^{-6}	1.10×10^{-6}
	Type B	9.3×10^{-4}	2.70×10^{-7}
	Other		1.40×10^{-7}
VI	AX_A-Type A	9.3×10^{-4}	3.30×10^{-6}
	Type B	9.3×10^{-4}	4.80×10^{-6}
	Type C	9.3×10^{-4}	5.60×10^{-8}
	Other		1.50×10^{-7}

Table E.2.3b
Conditional Core Damage Frequency
Oconee 3

$\overline{CCDF}$	$\overline{CCDF} = \sum_i CMF_i/I$	
		$\overline{CCDF}$
Small LOCA	$(SY_sX_s + SU_s + SX_s)/S$	2.1×10^{-3}
Large LOCA	$(AU + AX_A)/(A_1 + A_2)$	1.03×10^{-2}

<u>Legend</u>: S - Small LOCA initiator = 3×10^{-3}
A_1 - Large LOCA initiator = 1.1×10^{-6}
A_2 - Large LOCA initiator = 9.3×10^{-4}

Table E.3.1
Final Calvert Cliffs Dominant Accident Sequences

SEQUENCE	DESCRIPTION	IREP FREQUENCY BEFORE RECOVERY (/YR)	IREP FREQUENCY AFTER RECOVERY (/YR)	% TOTAL CM FREQUENCY
ATWS(PSF)	----	2.8E-5	2.8E-5	20
T_{DC}-82	$T_{DC}L$	4.9E-4	2.1E-5	16
S_2-50	S_2H	5.1E-5	1.4E-5	11
S_2-52	S_2FH	5.7E-5	1.1E-5	9
T_2-82	T_2L	1.8E-4	7.1E-6	6
T_4-173	T_4KU	6.7E-6	6.7E-6	5
T_4-147	T_4ML	3.4E-4	6.3E-6	5
T_1-81-65	T_1Q-D"CC'	1.3E-5	5.3E-6	4
T_1-82	T_1L	2.4E-5	4.9E-6	4
Blackout	----	2.4E-4	4.4E-6	3
T_4-152	T_4KQ	4.3E-6	4.3E-6	3
T_3-139	T_3KU	3.7E-6	3.7E-6	3
T_3-118	T_3KQ	2.3E-6	2.3E-6	2
T_3-113	T_3ML	8.5E-5	1.7E-6	1
S_2-59	S_2D"	2.8E-6	1.6E-6	1
T_1-85	T_1LCC'	5.9E-5	1.0E-6	1
Sequences below cutoff	----	----	7.8E-6	6
Total	----	----	1.3E-4	100

E.3.2
LOCA Event Definition and Mitigating Systems
Success Criteria for Calvert Cliffs Unit 1

LOCA Size[1]	Mitigating Function[2]						
	Reactor Subcriticality (RESC)	Injection Phase			Recirculation Phase		
		Reactor Heat Removal (REHR)	Containment Atmospheric Heat Removal (CNHR)	Containment Radioactivity Removal (CNRR)[3]	Reactor Heat Removal (REHR)	Containment Heat Removal (CNHR)	Containment Radioactivity Removal (CNRR)[3]
Small-Small .3"<D"≤1.9"	RPS	1/3 HPSI AND SSR AND 1/2 AFW	1/2 CSSI OR 1/4 CARC[4]	1/2 CSSI	1/3 HPSR	1/2 CSSR with 1/2 SDHX OR 1/4 CARC	1/2 CSSR
Small 1.9"<D"≤4.3"	RPS	1/3 HPSI	1/2 CSSI OR 1/4 CARC[4]	1/2 CSSI	1/3 HPSR	1/2 CSSR with 1/2 SDHX OR 1/4 CARC	1/2 CSSR
Large D"<4.3"	None Required[5]	3/4 SITs AND 1/2 LPSI	1/2 CSSI OR 1/4 CARC	1/2 CSSI	1/3 HPSR	1/2 CSSR with 1/2 SDHX OR 1/4 CARC	1/2 CSSR

Table E.3.3
Summary Results of Screening Quantification
Calvert Cliffs 1
Key to Accident Sequence Symbols

EVENT TREE SYMBOL	FRONT LINE SYSTEM FAILURE
A	LARGE LOCA
C	CONTAINMENT AIR RECIRCULATION AND COOLING SYSTEM (CARCS)
C'	CONTAINMENT SPRAY SYSTEM (INJECTION) (CSSI)
D	SAFETY INJECTION TANKS (SIT)
D'	LOW PRESSURE SAFETY SYSTEM INJECTION (LPSI)
D"	HIGH PRESSURE SAFETY SYSTEM INJECTION (HPSI)
F	CONTAINMENT SPRAY SYSTEM (RECIRCULATION) (CSSR)
G	SHUTDOWN COOLING HEAT EXCHANGERS (SDHX)
H	HIGH PRESSURE SAFETY SYSTEM (RECIRCULATION) (HPSR)
K	REACTOR PROTECTION SYSTEM (RPS)
L	AUXILIARY FEEDWATER SYSTEM (AFW) AND SECONDARY STEAM RELIEF (SSR)
M	POWER CONVERSION SYSTEM (PCS) AND SECONDARY STEAM RELIEF (SSR)
P	RELIEF VALVES DEMANDED
Q	RELIEF VALVES RECLOSE
S_1	SMALL LOCA
S_2	SMALL-SMALL LOCA
T_1	LOSS OF OFFSITE POWER (LOSP)
T_2	LOSS OF POWER CONVERSION SYSTEM (PCS)
T_3	TRANSIENTS REQUIRING PRIMARY SYSTEM PRESSURE RELIEF
T_4	REMAINING TRANSIENTS REQUIRING REACTOR TRIP
T_{DC}	LOSS OF DC BUS II
T_{SRW}	LOSS OF SERVICE WATER TRAIN 12
U	CHEMICAL VOLUME AND CONTROL SYSTEM (CVCS)

Table E.3.3 (Continued)

A: Large LOCA

SEQUENCE NUMBER	SEQUENCE DESCRIPTION	TRANSIENT FREQUENCY/YR	UNDEVELOPED EVENTS PROBABILITY	DEVELOPED EVENTS PROBABILITY	SEQUENCE FREQUENCY
A-2	AH	2.3E-4	-	2.5E-3	ε
A-4	AFH	2.3E-4	-	2.8E-3	ε
A-6	ACH	2.3E-4	-	≦2.3E-3	ε
A-7	ACG	2.3E-4	-	≦2.3E-3	ε
A-8	ACGH	2.3E-4	-	≦2.3E-3	ε
A-9	ACF	2.3E-4	-	≦2.3E-3	ε
A-10	ACC'	2.3E-4	-	≦2.3E-3	ε
A-11	AD	2.3E-4	-	≦3.7E-3	ε
A-12	ADF	2.3E-4	-	≦3.7E-3	ε
A-13	ADC'	2.3E-4	-	≦3.7E-3	ε
A-14	ADC	2.3E-4	-	≦7.8E-6	ε
A-15	ADCG	2.3E-4	-	≦7.8E-6	ε
A-16	ADCF	2.3E-4	-	≦7.8E-6	ε
A-17	ADCC'	2.3E-4	-	≦7.8E-6	ε
A-18	AD'	2.3E-4	-	8.2E-4	ε
A-19	AD'F	2.3E-4	-	≦8.2E-4	ε
A-20	AD'C'	2.3E-4	-	≦8.2E-4	ε
A-21	AD'C	2.3E-4	-	≦1.3E-4	ε
A-22	AD'CG	2.3E-4	-	≦1.3E-4	ε
A-23	AD'CF	2.3E-4	-	≦1.3E-4	ε
A-24	AD'CC'	2.3E-4	-	≦1.3E-4	ε

Table E.3.3 (Continued)

S_1: Small LOCA

SEQUENCE NUMBER	SEQUENCE DESCRIPTION	TRANSIENT FREQUENCY/YR	UNDEVELOPED EVENTS PROBABILITY	DEVELOPED EVENTS PROBABILITY	SEQUENCE FREQUENCY
S_1-26	S_1H	2.4E-4	-	2.4E-3	ε
S_1-28	S_1FH	2.4E-4	-	2.7E-3	ε
S_1-30	S_1CH	2.4E-4	-	≤8.1E-4	ε
S_1-31	S_1CG	2.4E-4	-	≤8.1E-4	ε
S_1-32	S_1CGH	2.4E-4	-	≤8.1E-4	ε
S_1-33	S_1CF	2.4E-4	-	≤8.1E-4	ε
S_1-34	S_1CC'	2.4E-4	-	≤8.1E-4	ε
S_1-35	S_1D''	2.4E-4	-	≤1.3E-4	ε
S_1-36	$S_1D''F$	2.4E-4	-	≤1.3E-4	ε
S_1-37	$S_1D''C'$	2.4E-4	-	≤1.3E-4	ε
S_1-38	$S_1D''C$	2.4E-4	-	≤3.9E-5	ε
S_1-39	$S_1D''CG$	2.4E-4	-	≤3.9E-5	ε
S_1-40	$S_1D''CG$	2.4E-4	-	≤3.9E-5	ε
S_1-41	$S_1D''CC'$	2.4E-4	-	≤3.9E-5	ε
S_1-42	S_1K	2.4E-4	3.0E-5	N/A	ε
S_1-43	S_1KF	2.4E-4	3.0E-5	N/A	ε
S_1-44	S_1KC'	2.4E-4	3.0E-5	N/A	ε
S_1-45	S_1KC	2.4E-4	3.0E-5	N/A	ε
S_1-46	S_1KCG	2.4E-4	3.0E-5	N/A	ε
S_1-47	S_1KCF	2.4E-4	3.0E-5	N/A	ε
S_1-48	S_1KCC'	2.4E-4	3.0E-5	N/A	ε

Table E.3.3 (Continued)

S_2: Small-Small LOCA

SEQUENCE NUMBER	SEQUENCE DESCRIPTION	TRANSIENT FREQUENCY/YR	UNDEVELOPED EVENTS PROBABILITY	DEVELOPED EVENTS PROBABILITY	SEQUENCE FREQUENCY
S_2-50	S_2H	2.1E-2	-	2.4E-3	5.1E-5
S_2-52	S_2FH	2.1E-2	-	2.7E-3	5.7E-5
S_2-54	S_2CH	2.1E-3	-	6.6E-7	ϵ
S_2-55	S_2CG	2.1E-2	-	2.2E-6	ϵ
S_2-56	S_2CGH	2.1E-2	-	6.7E-6	ϵ
S_2-57	S_2CF	2.1E-2	-	1.3E-5	ϵ
S_2-58	S_2CC'	2.1E-2	-	2.0E-6	ϵ
S_2-59	S_2D"	2.1E-2	-	1.3E-4	2.8E-6
S_2-60	S_2D"F	2.1E-2	-	3.0E-6	ϵ
S_2-61	S_2D"C'	2.1E-2	-	1.9E-6	ϵ
S_2-62	S_2D"C	2.1E-2	-	5.8E-7	ϵ
S_2-63	S_2D"CG	2.1E-2	-	≤1.0E-8	ϵ
S_2-64	S_2D"CF	2.1E-2	-	9.0E-8	ϵ
S_2-65	S_2D"CC'	2.1E-2	-	3.2E-5	ϵ
S_2-66	S_2L	2.1E-2	-	2.3E-4	4.8E-6
S_2-67	S_2LF	2.1E-2	-	7.4E-8	ϵ
S_2-68	S_2LC'	2.1E-2	-	5.0E-7	ϵ
S_2-69	S_2LC	2.1E-2	-	8.0E-7	ϵ
S_2-70	S_2LCG	2.1E-2	-	≤1.0E-8	ϵ
S_2-71	S_2LCF	2.1E-2	-	≤1.0E-8	ϵ
S_2-72	S_2LCC'	2.1E-2	-	6.3E-6	ϵ
S_2-73	S_2K	2.1E-2	3.0E-5	N/A	ϵ
S_2-74	S_2KF	2.1E-2	3.0E-5	N/A	ϵ
S_2-75	S_2KC'	2.1E-2	3.0E-5	N/A	ϵ
S_2-76	S_2KC	2.1E-2	3.0E-5	N/A	ϵ
S_2-77	S_2KCG	2.1E-2	3.0E-5	N/A	ϵ
S_2-78	S_2KCF	2.1E-2	3.0E-5	N/A	ϵ
S_2-79	S_2KCC'	2.1E-2	3.0E-5	N/A	ϵ

APPENDIX F: Interfacing LOCA Pipe Break Probability

An estimate of the likelihood that the low pressure piping in a particular plant will fail when subjected to overpressurization is an essential item needed to assess the core damage frequency resulting from an interfacing system LOCA. The purpose of this appendix is to establish a reasonable pipe rupture probability associated with interfacing LOCA in both BWRs and PWRs. This pipe failure probability estimate is based on the limited amount of data available in this area and on a good deal of engineering judgement.

Review of Industry Estimates of Pipe Failure During Interfacing LOCA

As an initial step, the sections dealing with pipe rupture of three industry documents on the subject of interfacing LOCA were reviewed:

1. "Seabrook Station Risk Management and Emergency Planning Study," PLG-0432, December 1985.

2. Fauske & Associates, Inc., "Evaluation of Containment Bypass and Failure to Isolate Sequences for the IDCOR Reference Plants," Draft Report FAI/84-9, July 1984.

3. Draft of GE Report, "BWR Owners Group Assessment of Emergency Core Cooling System Pressurization in Boiling Water Reactors," by Mehta and Howard.

For convenience, these reports are referred to as Seabrook, IDCOR, and BWROG in the subsequent discussion.

Section 3 of Seabrook, entitled "SSPSA Plant Model Update," briefly discusses the Seabrook RHR piping strength and rupture probability. Seabrook states that the piping involved is Schedule 40, 304 stainless steel piping with a maximum diameter of 16 inches on the suction side. While the pipe is designed for a pressure of 600 psig, during an interfacing LOCA it may experience a pressure of 2,250 psia. Seabrook proceeds to model the overpressurization as quasi-static, based on the arguments made in the IDCOR report (discussed here later). The conclusion stated in Seabrook is that, with a 2250 psia pressure, the hoop stress σ_h will approach the yield stress of 35 ksi (kilopounds per square inch). (This can be easily verified. For a Schedule 40, 16 inch pipe

$$\sigma_h = \frac{2{,}250 \text{ psi } (15.5)}{2\ (.5)} = 34.88 \text{ ksi}) .$$

To obtain a failure probability, Seabrook assumes a log-normal distribution for which the probability of failure at yield is .01 and at the ultimate stress is 0.99. The calculated hoop stress, slightly below yield, then corresponds to a failure probability of 0.006. Seabrook also assumes a 'flat' distribution of a 10^{-3} failure probability to account for such things as undetected design errors, material defects, etc. In other words, independent of the magnitude of the internal pressure, the pipe rupture probability is never less than 0.001.

The following observations can be made regarding the Seabrook method: First, the yield stress of 35 ksi cited above, may be nonconservative for the 500 to 600°F temperature the pipe experiences. A standard reference work on stainless steels[1] gives a value of 24 ksi as the yield for 304 SS at 500°F. If the same criteria for a probability distribution were used as before, i.e., log normal with a .01 failure probability at yield, then the calculated hoop stress of 34.88 ksi would lead to a probability of failure considerably greater then .01. No reduction of pipe thickness due to corrosion was considered. Finally, like the other two references, Seabrook treats the problem only quasi-statically.

The IDCOR document considers interfacing system LOCA in four reference plants: Peach Bottom, Grand Gulf, Zion and Sequoyah. No probabilistic analysis is made regarding pipe breaks. Instead, hoop stresses are compared to pipe strength in a deterministic way with the conclusion that low pressure piping would remain intact long after the shaft seals of the RHR pumps fail. For Peach Bottom, IDCOR describes 20 inch piping made of ASTM A106 B with a wall thickness of 0.95 cm (0.375 in.). According to IDCOR, this piping could be exposed to pressures approaching 7 MPa (megapascals) (1,000 psia). The subsequent stress calculations in IDCOR are difficult to make sense of: For the pipe described at 7 MPa of internal pressure, IDCOR cites a hoop stress of 375 MPa. This is clearly wrong. The correct stress is only

$$\frac{7 \text{ MPa } (49.85 \text{ cm})}{2 \; (.95 \text{ cm})} = 184 \text{ MPa } (26.6 \text{ ksi}) .$$

However, IDCOR also cites the yield stress for A-106 Grade B as 414 MPa (60 ksi) but this value is actually the ultimate stress of this material. The yield stress is only 241 MPa (35 ksi) at room temperature and more like 186 MPa (27 ksi) for 500°F temperature service. Therefore the calculated hoop stress, 184 MPa, is about 99% of the yield stress of 186 MPa. No allowance for corrosion has been made and no dynamic effects are considered.

For Zion, IDCOR considers a 14 inch, Schedule 40 pipe of 316 stainless steel with an inside diameter of 0.33 m and a wall thickness of 1.1 cm. This low pressure piping could be exposed to 15.5 MPa (2,250 psia) according to IDCOR. The resulting hoop stress is correctly cited as 233 MPa (33.8 ksi) but the yield stress for 316 SS is given by IDCOR as 552 MPa (80 ksi). This again is an ultimate stress not a yield stress. 316 SS has a yield[1] of about 276 MPa (40 ksi) at room temperature and about 173 MPa (25.1 ksi) at 500°F. Therefore the hoop stress is likely to be above yield even without allowance for corrosion which is not considered. Again dynamic effects are dismissed.

For the Grand Gulf calculation IDCOR refers back to the Peach Bottom discussion. Sequoyah is considered similar to Zion.

Of all three documents, document number 3, the BWROG report, has the most extensive sections dealing with pipe failure. Piping integrity is evaluated using three different criteria:

1) Hoop stress versus burst margins.
2) Limiting axial flaw length in the piping.
3) Pipe rupture probability at a circumferential butt weld.

probabilistic and BWROG cites the probability calculated via the third method as the overall piping failure probability. This approach is inconsistent. The other two criteria should be applied probabilistically also, and all indications are they would produce higher pipe failure probabilities than the third method, which BWROG relies on.

For the first criteria, comparison of pipe hoop stress during overpressurization with burst margin, typical pipes from the Core Spray, RCIC, HPCI and RHR systems are analysed in BWROG. Pipe size ranges from 6 to 24 inch OD. Hoop stresses at 1,050 psi internal pressure are calculated for these various size pipes and compared to a burst hoop stress of 54 ksi which is based on results reported by General Electric from a series of burst tests.[2] All pipes are assumed to be made of A-106 Grade B steel, for which BWROG correctly cites 27 ksi as yield and 60 ksi as ultimate stress at 550°F. An allowance of .08 inches in wall thickness, regardless of diameter, due to corrosion is also made. The hoop stress calculations in BWROG show the following values:

Pipe Size (in.)	Hoop Stress at 1,050 psi (ksi)
6	16.3
14	23.9
16	27.4
20	34.5
24	28.9

Since none of the calculated hoop stresses exceeds 54 ksi, the conclusion in BWROG is that pipe failure will not occur, i.e., has zero probability. This is an inappropriate approach. Both the burst hoop stress and the actual total stress in the pipe should be considered as statistical variables which can take on a range of values. For instance, three of the hoop stresses above are higher than the yield stress of 27 ksi. A probabilistic approach such as that used by Seabrook, discussed earlier, where a hoop stress equal to the yield stress means a .01 failure probability, would imply that the failure probabilities of the 16, 20 and 24 inch pipes are all greater than 0.01!

The application of the second criteria in BWROG, limiting axial flaw length calculated via a limit load approach, suffers from the same inconsistencies as the hoop stress comparison just discussed: A deterministic application of the equations involved reaches the conclusion that the smallest crack length which will lead to failure is 2.4 inches and, since this is too large to remain undetected, failure cannot occur. Without even discussing the question of whether a 2.4 inch flaw will always be detected in time, the approach used can be again termed inconsistent: If the flow stress and hoop stress used in the theory were treated as statistical quantities, a range of crack lengths, some considerably less than 2.4 inches, would result. Failure probabilities associated with the different crack sizes could then be computed.

It is difficult to evaluate the method used in BWROG for obtaining the probability of pipe rupture at a circumferential weld of the piping, i.e., the third criteria used for establishing piping integrity. Since the method involves a complicated computer code, PRAISE, which was not reviewed by us,

essential ingredients of the method remain unknown. A failure probability of 10^{-7} per weld is calculated. When such small probabilities are the result of mathematical models using various assumed inputs to describe a physical process, one wonders to what order of magnitude the result is valid. BWROG assumes 300 welds per piping system and uses the resulting probability of $3x10^{-5}$ for the weld calculation to represent the total piping failure probability during an interfacing LOCA. This seems a very questionable way to obtain an overall piping failure probability, especially when one remembers that Seabrook assumed a base line failure probability of 10^{-3} due only to manufacturing defects, design errors, construction errors, and other random factors.

To summarize: The Seabrook document has perhaps the most reasonable approach but may still be non-conservative because it neglects corrosion, elevated temperature material effects, and dynamic loading considerations. The IDCOR TR uses only a deterministic comparison in which it grossly overstates yield strengths, neglects corrosion, temperature effects and dynamic consequences. Most of the hoop stresses calculated in the IDCOR TR are actually above the correct yield stresses of the pipe material and so are likely to lead to significant failure probabilities, at least according to the assumptions made by Seabrook. The BWROG document, accounts for corrosion and high temperature but not dynamic loads. It inappropriately uses two deterministic and one probabilistic approach to evaluate different phenomena related to pipe integrity and erroneously concludes that the probabilistic approach used for weld failures gives results which cover all three pipe integrity considerations.

None of the industry reports reviewed above ascribe any importance to the dynamic aspects of the loading on low pressure piping caused by a sudden overpressurization. This neglect of dynamic effects is justified in an appendix of the IDCOR TR and by a related calculation in a PL&G memorandum which show that the maximum pressure in the low pressure pipe cannot exceed the primary system pressure, i.e., no dynamic "pressure spike" is generated which would result in a higher hoop stress than is calculated in a quasi-static manner. The IDCOR and PL&G calculations are reasonable for the assumptions made, namely that the piping system is completely rigid. This may not be true in practice. While no dynamic increases in the local hoop stress may occur, the forces caused by the high pressure wave at elbows and area changes in a flexible piping system can generate bending and torsional moments which add to the total pipe stress. To quote from NUREG-0582, Water Hammer in Nuclear Power Plants; ".... local pressure increase is not the only cause of water hammer damage .... most of the reported damage can be attributed to forces produced during the transient at pipe bends and flow area changes. These forces can cause pipe 'jump' and result in axial forces and bending and torsional moments." While we are not dealing with a classical water hammer problem, the interfacing system LOCA causes a transient to occur, in which a high pressure wave has to travel around elbows and through area changes of a piping system. If the overpressurization is caused by the inadvertent gradual opening of a valve or the slow failure of some valve components the pressure rise will be slow enough so that the problem can be treated quasi-statically. Normal isolation valve opening times on the order of 10's of seconds would allow one to neglect dynamic effects. But if a sudden disintegration of the internals of a valve separating high and low pressure systems occurs, the

dynamic effects on the piping system may be significant.* Exact times for classifying 'fast' versus 'slow' overpressurization depend on the systems involved.

If a sudden overpressurization does occur, the nature and magnitude of the stresses imposed on the pipe due to dynamic effects are dependent on the time history of the force and on the individual piping segment in question. Not only piping material, thickness and diameter but the spatial configuration of the pipe, the location and kind of restraint provided by hangers, equipment attached or suspended from the pipe, location of welds, etc. are all important in determining the response of the piping system to dynamic loading and calculating the resulting forces and moments and corresponding stresses. Obviously no generic calculations are possible and the many piping system and even segment specific calculations needed would be extremely costly, especially since differences in assumptions regarding pressure rise time or hanger idealizations will yield different results. Despite such difficulties, when estimating the pipe break probability, one must keep in mind the possibility of adding significantly to the pipe stress if the overpressurization is fast enough to elicit a dynamic response from the piping system.

BNL Estimate of Pipe Failure Probabilities During Interfacing LOCA

In order to estimate the probability of low pressure piping failure due to overpressurization, we want to incorporate the limited data available, our engineering judgement, and the insights provided by previous work in this area, i.e., the documents just reviewed.

Ideally, every possible mechanism which could lead to pipe failure, would be investigated, modelled, and its contribution to total pipe failure probability assessed. Such a comprehensive analysis is well beyond the scope of our task here. Given the uncertainty associated with our present state of knowledge for many of these mechanisms, the estimate from such a detailed study may be no more precise than that obtained with the more general method we propose here.

Since almost all failure mechanisms are in some way related to pipe stress, we will estimate a failure probability which depends on the maximum stress level in the piping system.

We will avoid a dependence of our estimate on piping length by assuming, similar to the Seabrook approach discussed above, that the estimated probability applies to the particular piping system in question (RCIC, RHR, etc.) as a whole. Stress levels in the piping system depend on the imposed pressure and on the material and geometric properties of the pipe. If a particular piping system contains segments of different properties, we will assume the segment with the highest stress level to be the major contributor to the systems failure probability and use this probability as representative of the overall piping system failure probability.

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*A striking example of such dynamic effects was shown in an Indian Point calculations recently provided to us, but which arrived too late to be included in more detail in this review.

Earlier we discussed the approach used by Seabrook, which assumed a lognormal cumulative failure distribution whose parameters were determined by assigning percentile constraints at σ_y, the yield stress and σ_u, the ultimate stress. Seabrook took these constraints to be $P(\sigma_y) = 0.01$ ($P(\sigma_y)$ represents the cumulative failure probability at the yield stress) and $P(\sigma_u) = 0.99$. The 0.99 value at σ_u seems reasonable since one can expect failure at σ_u with almost certainty. However, assigning a failure probability of 0.01 at the yield stress appears very arbitrary without some supportive data. This arbitrary constraint occurs at the most sensitive part of the probability distribution curve for our calculations: During overpressurization many pipe stresses in BWR low pressure designed systems will be near the yield stress, while in PWRs these systems will experience stresses at or above yield. An assignment of $P(\sigma_y) = 0.001$ for instance, which seems just as defensible (or indefensible) as Seabrook's $P(\sigma_y) = 0.01$ without data, will shift failure probabilities by an order of magnitude on that part of the distribution curve of most interest to us.

By assuming a lognormal distribution with the constraints indicated above, Seabrook has also implicitly assumed that the mean and the median failure stress lie approximately halfway between the yield and ultimate stress. (For Seabrook's lognormal calculations, with $\sigma_y = 35$ ksi and $\sigma_u = 80$ ksi, the mean failure stress is 55.5 ksi and the median 54.6 ksi.) This is not due to the symmetry of the constraints at yield and ultimate, but rather to the nature of the lognormal distribution employed over a relatively narrow variable range between the constraints. For instance, Figure 1 shows a lognormal distribution for ASTM A106 B constrained by $P(\sigma_y) = 0.001$ and $P(\sigma_u) = 0.99$, where $\sigma_y = 27$ ksi and $\sigma_u = 60$ ksi at 500°F. The mean of this distribution corresponds to 42.1 ksi and the median to 41.7 ksi while $(\sigma_y + \sigma_u)/2$ equals 43.5 ksi. These values of mean and/or median failure stress relative to σ_y and σ_u do not agree with the limited data we do have on pipe overpressurization, i.e., the burst tests conducted by General Electric on ASTM A106 B pipe[2] mentioned in BWROG.

Specifically, General Electric conducted burst tests on seamless A106 B pipes ranging in size from 4-to-12 inches and in diameter to thickness (D/t) ratios from 13.3 to 27.5. A106 B is the material used in BWRs for much of the low pressure piping affected by a postulated interfacing LOCA. During the GE tests the actual yield and ultimate stress of the pipe material used for each test specimen was determined. The average burst hoop stress of unflawed pipe specimens was found to be at approximately 90% of the ultimate stress independent of the pipe size. This indicates that, when constructing a failure probability distribution, the stress corresponding to the distribution mean should be closer to the ultimate stress than the yield stress. Both intuition and theoretical calculations support the concept that the material ultimate stress has a greater influence than the yield stress on the value of the average burst stress. A lognormal distribution determined by specifying the 1st and 99th percentile probability values, as Seabrook has used, is conservative in its estimation of what stress corresponds to the mean failure probability and is not a good choice for the type of "best estimate" we are interested in.

The question of what would constitute a good distribution choice remains. The most defensible distribution is one which reflects only our state of knowledge and no more, i.e., does not add unwarranted assumptions.

Two conclusions which we feel sure enough about to couch as constraints for our distribution are the following:

First, the mean failure stress is approximately at 90% of the ultimate stress. This information is based on tests done on a series of unflawed pipe specimens of A106 B steel.[2] We of course want to include flawed as well as unflawed pipes in our distribution. However, since we expect flawed specimens to be relatively rare, it is reasonable to assume that the first moment of our distribution is similar to the first moment of a distribution for unflawed pipe failures. (Of course, we would expect the variance to be very different for the two distributions.) The other reasonable constraint is to assign the failure probability at the ultimate stress a value close to one: We will use 0.99 as the failure at σ_u.

Therefore, we want to construct a failure probability constrained to have its first moment at 90% of σ_u and its 99th percentile at σ_u. We also will limit the range of the stresses to lie between 1.0 and 100 ksi. We are not interested in negative stresses and an upper limit of 100 ksi at 500°F is quite adequate for the three materials of interest: ASTM A106 B, 304SS, and 316SS. We also assume that the average failure stress will be 0.90 of σ_u for 304 and 316 stainless steel just as it is for ASTM A106 B, even though the test data is only for ASTM A106 B.

The most defensible distribution we can assume is one which reflects the greatest degree of uncertainty given the specified constraints. Assuming any other distribution would mean we have implicitly adopted additional assumptions not supported by the available knowledge. Based on information theory, certain axioms for measuring uncertainty can be established[3] and used to find a maximum uncertainty (sometimes referred to as maximum entropy) distribution. When only the range of a variable is known, a uniform distribution maximizes the entropy. If the range of a variable is unlimited and the first two moments are known, the entropy is maximized by a normal distribution.[4]

For our problem we have a finite variable range and we presume to know the first moment and one percentile constraint. To find the appropriate probability function under these conditions we have used a computer code developed by Unwin,[5] which uses information theory principles to generate that probability distribution over some specified parameter range, given a finite number of constraints, which reflects the maximum degree of uncertainty consistent with those constraints.

Figures 2, 3, and 4 show the cumulative probability functions calculated by the code for the three materials of interest. The ultimate stress values at 500°F for all three steels used to determine the probability curves shown are listed in Table 1. Yield stresses at 500°F are also shown. A qualitative check on the reasonableness of our distributions can be made by examining the predicted failure probabilities at normal design conditions and at the material yield stress. For 304SS the failure probability at yield shown in Figure 3 is 2.5×10^{-3}, a factor of four lower than the value at yield assumed by Seabrook to quantify its lognormal distribution even though Seabrook used a room temperature yield of 35 ksi compared to our 24 ksi corresponding to 500°F. The 316SS failure probability is 2.0×10^{-3} at yield (Figure 4) while

for A106 B failure at yield is up to 8.1×10^{-3} (Figure 2) - not surprising since A106 B has a considerably lower σ_u than the two stainless steels.

During normal operating conditions these piping systems are stressed in the range of 10 to 15 ksi. As the figures show, failure probabilities here are typically an order of magnitude less than at yield. At 10 ksi 304SS has a cumulative failure probability of 2.3×10^{-4}; for 316SS it is 2.0×10^{-4} and for A106 B the value is 5.4×10^{-4}. These values are all almost an order of magnitude lower than Seabrook's 10^{-3} flat cutoff and appear more appropriate for a best estimate calculation than the conservative higher Seabrook value. In our engineering judgement, the cumulative failure probabilities shown in the figures at both yield and design seem reasonable based on the limited information available.

We believe that Figures 2, 3, and 4 provide reasonable estimates of pipe failure probability vs. pipe stress during an interfacing system LOCA.

If the overpressurization of the piping occurs "slowly" enough so that pipe motion and associated dynamic effects can be neglected, the stress in the pipe can be taken equivalent to the hoop stress due to the internal pressure. Since only the very sudden disintegration of the internals of a valve would lead to "fast" overpressurization, the "slow" situation due to inadvertent openings or gradual failure would appear to be the more usual scenario. If the stress in Figures 2 through 4 is only a hoop stress, then it is directly proportional to the diameter to thickness ratio of the pipe, D/t, and to the internal pressure. For a fixed D/t, the abscissa in Figures 2, 3, and 4 can be used to plot internal pressure, or, for a particular pressure, values of D/t can be used on the horizontal axis. Both situations are shown in all the figures.

If dynamic effects and, therefore, bending and shear stresses can be neglected, the figures can be used to relate failure probabilities directly to D/t for a given pressure, or to pressure for a particular D/t. Tables 2, 3, and 4 list the failure probabilities due to hoop stress of a number of typical pipe sizes for expected maximum overpressures as derived from the probability curves in Figures 2, 3, and 4. Table 2 and Figure 2 are for BWRs with 106 Grade B carbon steel and 500°F. Tables 3 and 4 as well as Figures 3 and 4 are for PWRs. Table 3 and Figure 3 are for 304 stainless steel at 500°F. Table 4 and Figure 4 are for 316 stainless steel at 500°F.

References

1. Handbook of Stainless Steels, edited by Pecker and Bernstein, McGraw-Hill, 1977.

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3. Ash, R., Information Theory, Interscience, 1965.

4. Goodman, J., "Structural Fragility and Principle of Maximum Entropy," Structural Safety, Vol. 3, pp 37-46, 1985.

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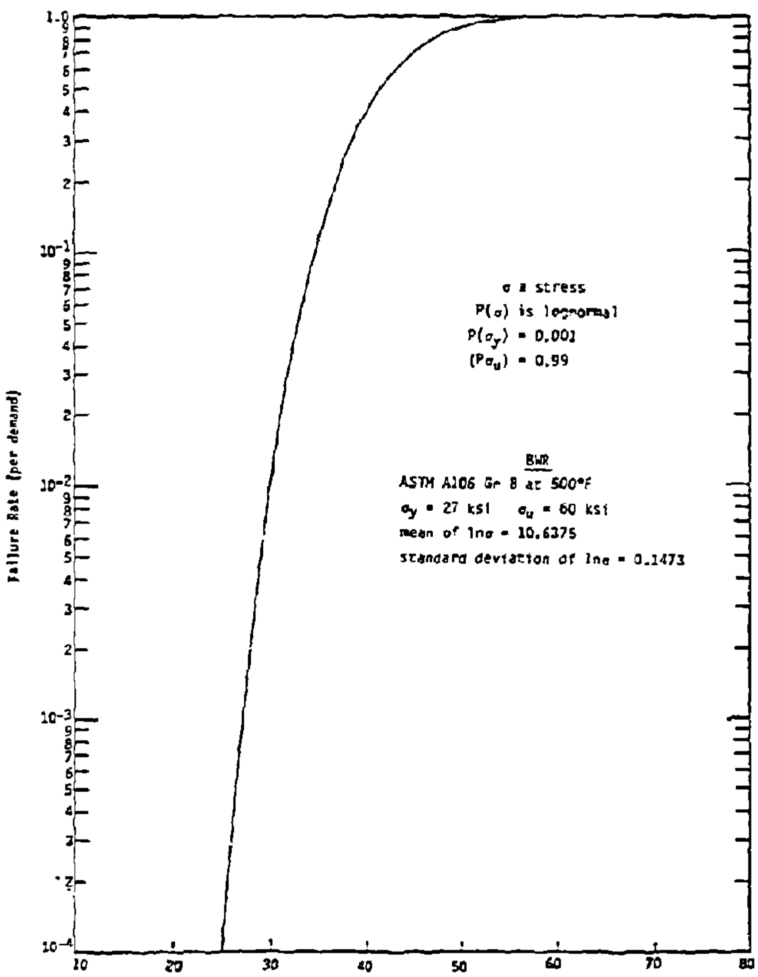

Figure 1. BWR pipe failure probability - lognormal distribution.

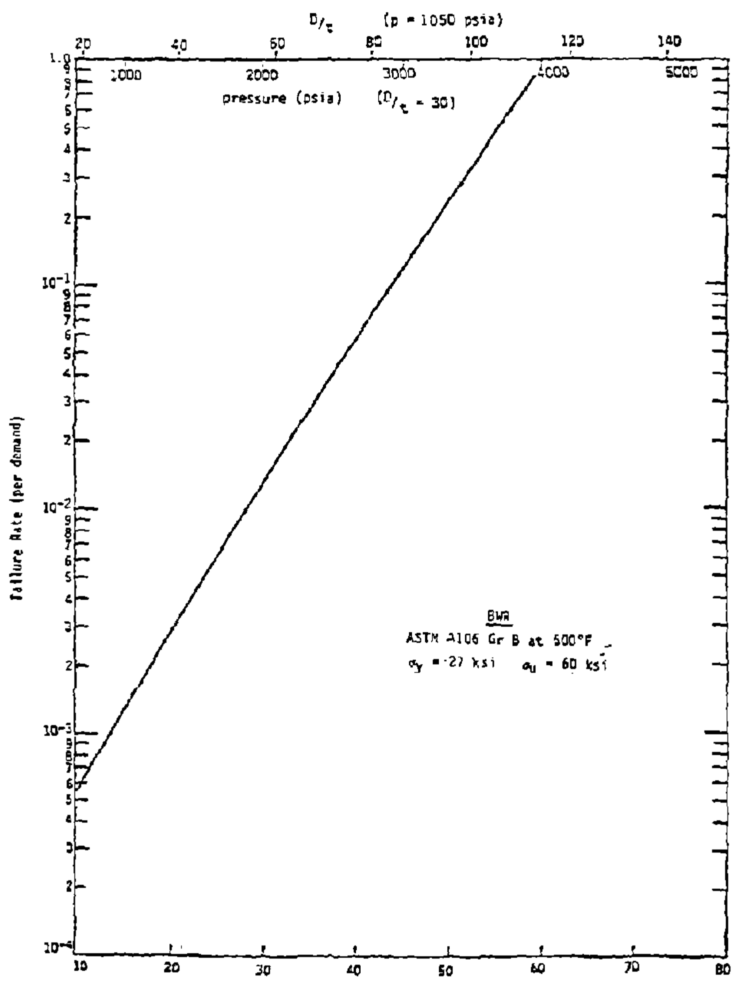

Figure 2. BWR pipe failure probability — maximum entropy distribution.

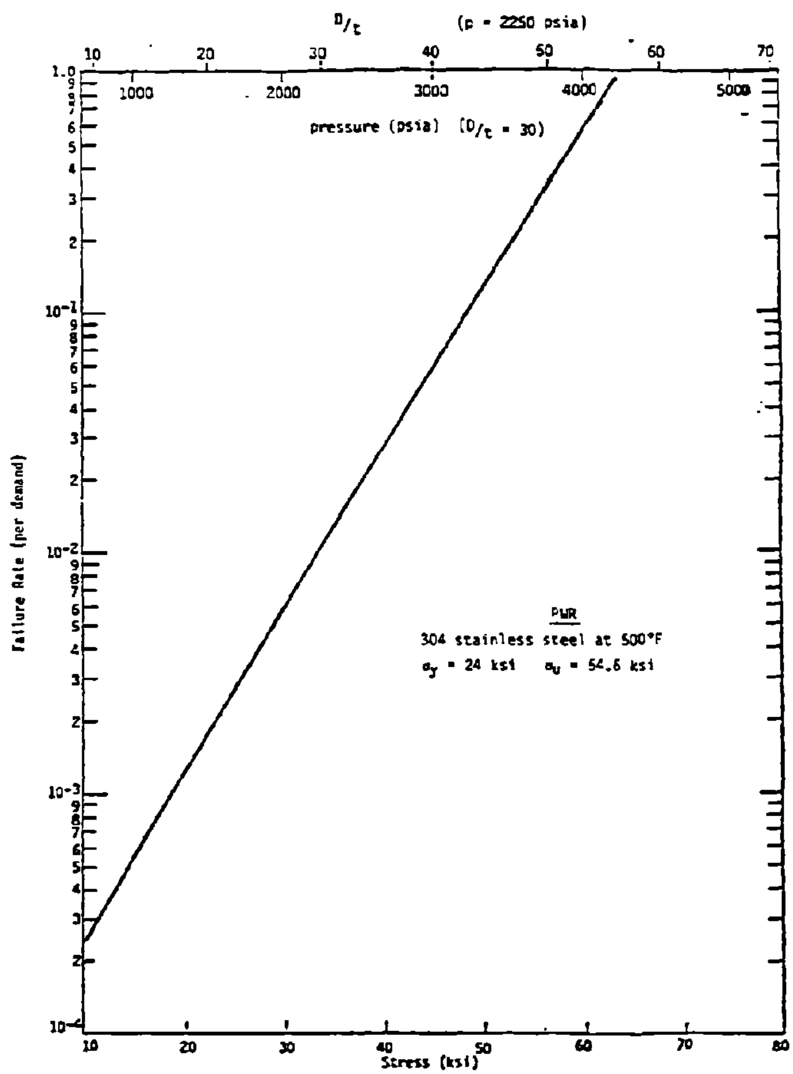

Figure 3. PWR pipe failure probability – 304SS – maximum entropy distribution.

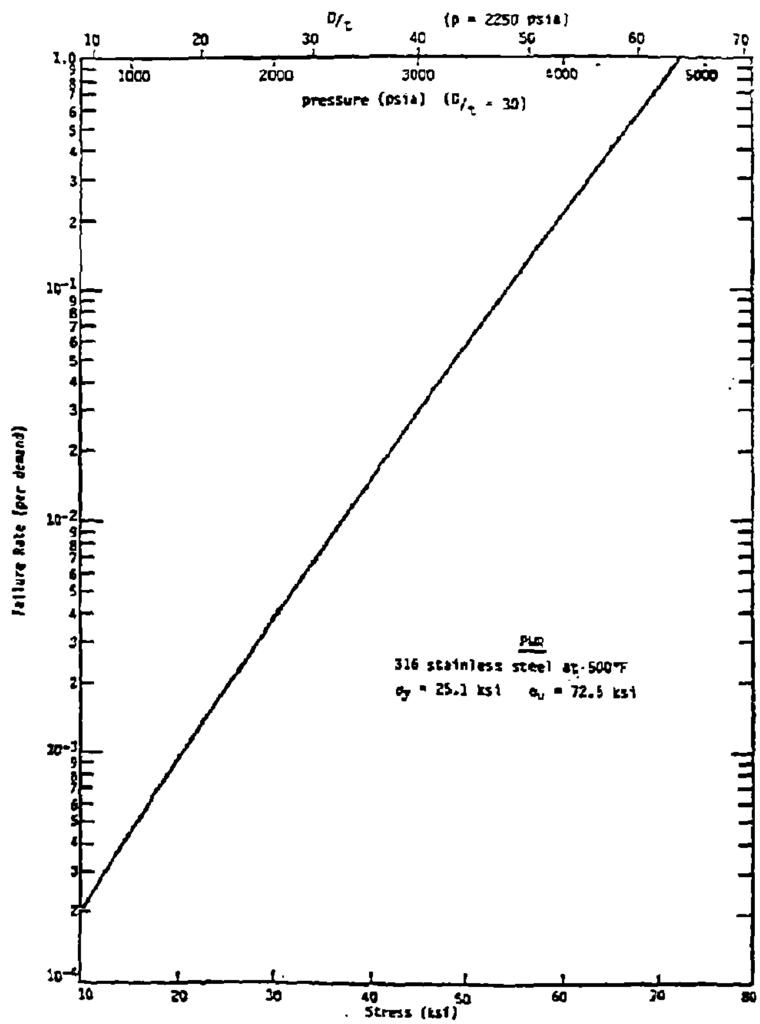

Figure 4. PWR pipe failure probability - 316SS - maximum entropy distribution.

Table 1
Steel Properties at 500°F

Steel	Yield Stress ksi	Yield Stress (MPa)	Ultimate Stress ksi	Ultimate Stress (MPa)
A106 GrB Carbon*	27	(186.2)	60	(413.7)
304 Stainless**	24	(165.5)	64.6	(445.4)
316 Stainless**	25.1	(173.1)	72.5	(499.9)

*From BWROG document and Metals Handbook Ninth Edition, AMS, 1978.
**From Reference 1.

Table 2
Failure Probabilities for Some BWR Pipes at Maximum Overpressure

Material: A106 GrB Carbon Steel
Properties at 500°F: $\sigma_y = 27$ ksi $\sigma_u = 60$ ksi
Internal Pressure: 1050 psia

Nominal Pipe Size (in.)	Schedule	As Built D/t	As Built Hoop-stress (ksi)	As Built Failure Probability	Corroded* D/t	Corroded* Hoop-stress (ksi)	Corroded* Failure Probability
3	Std.	15.20	7.98	3.62-4	24.74	12.99	9.23-4
4	Std.	17.99	9.44	4.86-4	27.66	14.52	1.19-3
6	Std.	22.66	11.90	7.63-4	32.13	16.86	1.74-3
8	Std.	25.79	13.54	1.01-3	34.64	18.19	2.14-3
8	XS	16.25	8.53	4.05-4	19.54	10.26	6.07-4
8	—	24.59	12.91	9.10-4	32.56	17.09	1.81-3
10	Std.	28.45	14.94	1.28-3	36.72	19.28	2.54-3
12	Std.	33.00	17.32	1.88-3	42.22	22.16	3.95-3
14	Std.	36.33	19.08	2.46-3	46.46	24.39	5.52-3
16	Std.	41.67	21.88	3.78-3	53.24	27.95	9.34-3
16	XS	31.00	16.28	1.59-3	37.10	19.48	2.63-3
18	Std.	47.00	24.68	5.76-3	60.02	31.51	1.58-2
18	XS	35.00	18.38	2.21-3	41.86	21.98	3.84-3
18	30	40.19	21.10	3.36-3	49.42	25.94	6.94-3
20	Std.	52.33	27.48	8.74-3	66.80	35.07	2.65-2
20	XS	39.00	20.48	3.07-3	46.62	24.48	5.60-3
20	40	32.73	17.18	1.83-3	37.99	19.94	2.81-3
20	60	23.63	12.41	8.36-4	26.32	13.82	1.06-3
24	Std.	63.00	33.08	1.98-2	80.36	42.19	7.48-2
24	XS	47.00	24.68	5.76-3	56.14	29.48	1.17-2
24	60	23.79	12.49	8.48-4	26.03	13.66	1.03-3
30	30	47.00	24.68	5.76-3	54.05	28.37	9.96-3

*All wall thickness reduced by 0.08 inches for corrosion allowance regardless of pipe size.

Table 3
Failure Probabilities for Some PWR Pipes at Maximum Overpressure

Material: 304 Stainless Steel
Properties at 500°F: σ_y = 24 ksi σ_u = 64.6 ksi
Internal Pressure: 2250 psia

		As Built			Corroded*		
Nominal Pipe Size (in.)	Schedule	D/t	Hoop-stress (ksi)	Failure Proba-bility	D/t	Hoop-stress (ksi)	Failure Proba-bility
2	80S	9.89	11.13	2.93-4	16.21	18.24	9.58-4
2.5	10S	22.96	25.83	3.13-3	70.88	79.73	~1.0
3	80S	10.67	12.00	3.34-4	14.91	16.77	7.54-4
4	80S	12.35	13.90	4.66-4	16.51	18.57	1.01-3
6	40S	22.66	25.49	2.98-3	32.13	36.14	1.50-2
6	80S	14.34	16.13	6.78-4	17.82	20.05	1.27-3
8	40S	25.79	29.01	5.08-3	34.64	38.97	2.29-2
10	20	42.00	47.25	7.99-2	62.24	70.01	~1.0
12	10S	69.83	78.56	~1.0	126.50	142.31	~1.0
12	20	50.00	56.25	3.09-1	74.00	83.25	~1.0
14	10	55.00	61.88	7.21-1	81.35	91.52	~1.0
14	30	36.33	40.88	3.07-2	46.46	52.26	1.70-1
14	40	31.04	34.92	1.24-2	38.22	42.99	4.21-2
14	140	10.20	11.48	3.05-4	10.97	12.34	3.56-4

*All wall thickness reduced by 0.08 inches for corrosion allowance regardless of pipe size.

Table 4
Failure Probabilities for Some PWR Pipes at Maximum Overpressure

Material: 316 Stainless Steel
Properties at 500°F: σ_y = 25.1 ksi σ_u = 72.5 ksi
Internal Pressure: 2250 psia

Nominal Pipe Size (in.)	Schedule	As Built D/t	As Built Hoop-stress (ksi)	As Built Failure Probability	Corroded* D/t	Corroded* Hoop-stress (ksi)	Corroded* Failure Probability
2	80S	9.89	11.13	2.49-4	16.21	18.24	7.52-4
2.5	10S	22.96	25.83	1.90-3	70.88	79.73	~1.0
3	80S	10.67	12.00	2.88-4	14.91	16.77	6.06-4
4	80S	12.35	13.90	3.91-4	16.51	18.57	7.89-4
6	40S	22.66	25.49	2.08-3	32.13	36.14	8.68-3
6	80S	14.34	16.13	5.51-4	17.82	20.05	9.73-4
8	40S	25.79	29.01	3.34-3	34.64	38.97	1.26-2
10	20	42.00	47.25	3.78-2	62.24	70.01	7.60-1
12	10S	69.83	78.56	~1.0	126.50	142.31	~1.0
12	20	50.00	56.25	1.24-1	74.00	83.25	~1.0
14	10	55.00	61.88	2.61-1	81.35	91.52	~1.0
14	30	36.33	40.88	1.63-2	46.46	52.26	7.33-2
14	40	31.04	34.92	7.38-3	38.22	42.99	2.15-2
14	140	10.20	11.48	2.65-4	10.97	12.34	3.05-4

*All wall thickness reduced by 0.08 inches for corrosion allowance regardless of pipe size.

APPENDIX G: Sensitivity of the CDF to Interfacing LOCA Pipe Break Probability

G.1 Introduction

Appendix F contains a discussion of a method to establish a best estimate pipe rupture probability due to an overpressurization event. The determination of the best estimate pipe rupture probability is particularly important in order to assess the core damage frequency resulting from an interfacing system LOCA event that leads to an overpressurization of a low pressure piping system. In Appendix F it was also indicated that the best estimate failure probabilities are based on rather limited amount of data and extensive engineering judgement. For this reason sensitivity calculations have been undertaken to determine the effect of pipe rupture probability on the core damage frequency.

G.2 Results of the Analysis

The pipe rupture probabilities have been parameterized in order to study their effect on the core damage frequency. The parametric values, .1, 1.0-03, and 3.0E-05, have been chosen to span the expected values of the rupture probabilities. The core damage frequency was calculated by uniformly using the parametric rupture probabilities in the event trees.

The results are listed in Tables G.1 through G.3 for the three reference plants. The effect of varying the rupture probabilities depends on the interfacing system affected, the physical arrangement of that particular system and other factors, such as isolation capabilities and operator intervention. At Indian Point the dominant sequences are the ones affecting the LPI, SI, and RHR systems. The contribution to CDF from the LPI and SI systems are reduced by two orders of magnitude when the rupture probability is changed from .1 to 1.0-03. Further decrease does not appreciably changes the CDF indicating that the contribution to CDF from other sequences became dominant. The RHR system behaves similarly except the effects are less pronounced.

The total CDF shows a similar tendency of decreasing sensitivity as the pipe rupture probability is lowered. For an initial decrease of two orders of magnitude, .1 to 1.0-03, the total CDF is reduced by about an order of magnitude, but further reductions in the rupture probabilities have negligible effect. At Oconee, the dominant sequences, the LPI and RHR, are reduced by an order of magnitude initially but further reduction has no appreciable effects. At Calvert Cliffs, an ISL on the RHR suction side dominates the CDF bypassing the containment and the initial sensitivity is very large, almost linear with the pipe rupture probability. Further reduction again demonstrates that other, initially nondominant sequences become more important.

In general, the sensitivity of CDF to pipe rupture probability decreases rapidly as the value of the rupture probability is lowered. If the rupture probability for a given system is in the range of ~1.0 to 1.0-03 the effect on the CDF/system may be very large. If the rupture probability is below ~1.0-03 the effect or sensitivity of the CDF/system is almost negligible.

In summary, systems that have high rupture probabilities, >.01, are the most important ones to investigate and best estimate studies should concentrate on the high range of the rupture probabilities to determine better estimates of the likelihood of pipe failures as was done in Appendix F.

Table G.1
Core Damage Frequency
Indian Point

System	Overpressurization Initiator	P(Rupture)	Sum of Event*CCDF	CDF/Year
LPI	2.39-06	1.00-01	1.02-01	2.44-07
		1.00-03	3.45-03	8.23-09
		3.00-05	2.48-03	5.92-09
SI*	1.22-04	1.00-01	9.01-02	1.10-05
		1.00-03	9.01-04	1.10-07
		3.00-05	2.70-05	3.30-09
RHR Suction	6.79-07	1.00-01	1.48-02	1.01-08
		1.00-03	4.60-03	3.13-09
		3.00-05	4.50-03	3.06-09
Letdown*	6.82-07	1.00	4.50-03	3.07-09
Accumulators	9.79-03	1.00-01	7.29-04	7.14-06
		1.00-03	2.38-04	2.33-06
		3.00-05	2.33-04	2.28-06
TOTAL		1.00-01		1.84-05
(CDF due to over-		1.00-03		2.45-06
pressurization)		3.00-05		2.30-06
TOTAL		1.00-01		1.49-08
(CDF with ISL out-		1.00-03		1.52-09
side containment)		3.00-05		1.39-09

Note: P(Rupture) = Probability of a major pipe rupture.
*For this system P(Rupture) = Probability of pipe pressure boundary NOT maintained.

Table G.2
Core Damage Frequency
Oconee

System	Overpressurization Initiator	P(Rupture)	Sum of Event*CCDF	CDF/Year
LPI	7.43-07	1.00-01	1.02-01	7.57-08
		1.00-03	3.10-03	2.30-09
		3.00-05	2.13-03	1.58-09
RHR Suction	9.90-07	1.00-01	1.28-02	1.27-08
		1.00-03	2.21-03	2.19-09
		3.00-05	2.10-03	2.08-09
Letdown*	2.28-03	1.00	5.09-08	1.16-10
Accumulators	5.85-03	1.00-01	1.18-03	6.90-06
		1.00-03	1.76-04	1.03-06
		3.00-05	1.66-04	9.72-07
TOTAL		1.00-01		6.99-06
(CDF due to over-		1.00-03		1.03-06
pressurization)		3.00-05		9.76-07
TOTAL		1.00-01		8.59-08
(CDF with ISL out-		1.00-03		2.72-09
side containment)		3.00-05		1.91-09

Note: P(Rupture) = Probability of a major pipe rupture.
*For this system P(Rupture) = Probability of pipe pressure boundary NOT maintained.

Table G.3
Core Damage Frequency
Calvert Cliffs

System	Overpressurization Initiator	P(Rupture)	Sum of Event*CCDF	CDF/Year
LPI	2.31-09	1.00-01	1.01-01	2.34-10
		1.00-03	2.30-03	5.31-12
		3.00-05	1.33-03	3.07-12
SI*	1.74-09	1.00-01	1.30-04	2.26-13
		1.00-03	1.30-06	2.26-15
		3.00-05	3.90-08	6.79-17
RHR Suction	3.36-06	1.00-01	1.01-01	3.40-07
		1.00-03	2.30-03	7.72-09
		3.00-05	1.33-03	4.47-09
Letdown*	2.28-03	1.00	2.43-08	5.55-11
Accumulators	1.23-02	1.00-01	1.85-03	2.28-05
		1.00-03	9.64-05	1.19-06
		3.00-05	7.92-05	9.74-07
TOTAL (CDF due to over-pressurization)		1.00-01		2.32-05
		1.00-03		1.19-06
		3.00-05		9.79-07
TOTAL (CDF with ISL out-side containment)		1.00-01		3.55-07
		1.00-03		2.25-08
		3.00-05		1.93-08

Note: P(Rupture) = Probability of a major pipe rupture.
*For this system P(Rupture) = Probability of pipe pressure boundary NOT maintained.

APPENDIX H: Consequence Analysis

The consequences were calculated using the CRAC2[1] computer code. The consequences of principal interest are person-rem, deaths, and decontamination area.

The techniques of consequence analysis are discussed in the Reactor Safety Study (WASH-1400) and the PRA Procedures Guide, and, therefore, the details are omitted here.

The consequence codes consider five processes that account for most of the ways in which people can accumulate a radiation dose after radioactivity has been released to the atmosphere from an accident:

a. Inhalation;
b. Cloudshine (external exposure from passing cloud);
c. Groundshine (external exposure from deposited material);
d. Ingestion; and
e. Inhalation of resuspended material.

The first three mechanisms are by far the most important in contributing to potential high-dose early effects. Lower doses leading to latent effects can come from any of the pathways, especially if interdiction does not preclude ingestion and cleanup does not reduce contamination.

In CRAC2, the dose response is piece-wise linear due to irradiation of the bone marrow, lung, and GI tract. The total risk is then:

$$R = R_1 + (1-R_1)R_2 + (1-R_1)(1-R_2)R_3$$

where R_1, R_2, and R_3 are the risks to the three organs, respectively.

Site Data

A "generic" site was considered using the average U.S. population density of about 100 people per square mile. The plant was assumed to be a 3000 MWt PWR.

The weather data consists of hourly weather observations of wind speed, wind direction, stability class, and precipitation. The data is not taken from a single year, but is averaged in a manner that represents the long-term average weather behavior. The code sorts this data into 20 weather categories (called bins), as discussed in the CRAC2 Model Manual, so that low probability weather conditions can be adequately sampled.

The site weather input was taken to be that for Indian Point simply for calculational convenience. Other site data would yield somewhat different numberical results, however, it is important to note that the relative magnitudes and relationships of the consequence analysis results would be expected to hold. The weather summaries for Indian Point are given in Tables H.1. The stability is ranked in six categories (A, B, C, D, E, F) ranging from the most dispersive to the least dispersive. Category A, with rapid dispersion, represents a sunny afternoon with low wind speeds. Category F, with little spread of the plume with distance, would occur late at night or

just before dawn if wind speeds were very low. In addition, there are weather bins for rain conditions, both at time of release and at later times, and for changing wind condition which produces a slowing down of the plume. Both of these conditions could produce higher doses at greater distances than would otherwise occur.

Source Terms

The characterization of a given release category is called the source term. The factors of interest are the timing and duration of the release, the release fractions, and the plume energy. The timing of the release is used for radioactive decay. The duration of release is used in CRAC2 to account for continuous releases by adjusting for horizontal dispersion because of wind meander (CRAC2 considers only puff releases). The release fractions are for groupings of isotopes that have similar chemical characteristics. The energy of the release is used to calculate plume rise.

In spite of the different vendors and balance of plant designs, the three representative reactors and Reactor Coolant Systems (RCS) are sufficiently similar from a fission product transport standpoint that one expects comparable results for the RCS portions of the source terms. The source terms shown in Table H.2 represent radiological releases associated with an interfacing system LOCA in a PWR with subatmospheric containment. They were taken from NUREG/CR-4629 for a dry and flooded break location for an event V in the Surry plant. The first column represents the release corresponding to an assumed break above the water level (unscrubbed) while the second column assumes a scrubbing of the release due to water above the break location. It should be noted that the scrubbing considerably reduces the release fractions.

The release was assumed to occur 0.5 hour after scram with a five hour duration. The energy of the release was 30 MW for the unscrubbed case and 1 MW for the scrubbed case.

Results of the Consequence Calculations

Results were calculated assuming a realistic public response to an evacuation within 10 miles one half hour after the release. The results are given in Table H.3 for deaths, injuries, persom-rem within 50 miles, and predicted costs due to contaminated land area.

H.1 References

1. Ritchie, L. T. et al., "Calculations of Reactor Accident Consequences Version 2. CRAC2: Computer Code Users Guide," NUREG/CR-2326, February 1983.

Table H.1
One Year of New York City Meteorological Data
Summarized Using Weather Bin Categories

Weather Bin	Number of Sequences	Percent
1. R(0)	697	7.96
2. R(0-5)	12	.14
3. R(5-10)	62	.71
4. R(10-15)	102	1.16
5. R(15-20)	75	.86
6. R(20-25)	67	.76
7. R(25-30)	61	.70
8. S(0-10)	24	.27
9. S(10-15)	16	.18
10. S(15-20)	18	.21
11. S(20-25)	14	.16
12. S(25-30)	18	.21
13. A-C 1,2,3	168	1.92
14. A-C 4,5	892	10.18
15. D 1	0	0.00
16. D 2	61	.70
17. D 3	226	2.58
18. D 4	948	10.82
19. D 5	3325	37.96
20. E 1	0	0.00
21. E 2	27	.31
22. E 3	167	1.91
23. E 4	682	7.79
24. E 5	270	3.08
25. F 1	0	0.00
26. F 2	116	1.32
27. F 3	310	3.54
28. F 4	402	4.59
29. F 5	0	0.00
	8760	100.0

R = Rain starting within indicated interval (miles).
S = Windspeed slowdown occurring within indicated interval (miles).
A-C, D,E,F = Stability categories.
1(0-1), 2(1-2), 3(2-3), 4(3-5), 5(GT 5) = Wind speed intervals (meters/second).

Table H.2
Comparisons of Environmental Releases
For Dry and Flooded Break Locations

Species	Dry	Flooded
I	2.9E-1	4.4E-2
Cs	2.6E-1	4.0E-2
Te	5.4E-2	8.6E-3
Sx	4.7E-3	9.6E-4
Ru	2.2E-7	3.7E-8
La	2.5E-4	5.0E-5
Ce	3.7E-4	7.2E-5
Ba	3.4E-3	6.8E-4

Table H.3
Results of Consequence Calculations

	Deaths	Injuries	Person-Rem	Total Land Cost W/O Decontamination ($)
V(Unscrubbed)	6.00-03	7.83+00	2.18+06	1.26+09
V(Scrubbed)	0.0	0.0	1.08+06	2.76+08