1.0 INTERNAL INITIATING EVENT ANALYSIS

The initial task of a plant risk assessment is to determine the accident initiators to be used to quantify accident sequences. This section identifies the initiators for the APWR probabilistic safety study which have the potential to trigger a sequence of events which could lead to core damage during plant power operation. The initiating event categories are defined to form a complete set in the sense that any internal initiator that could hypothetically result in core damage must cause one of the event categories to occur. The resultant categories are comprised of specific initiating events that were derived and identified from various reference sources. The frequencies with which these initiating event categories occur, due only to internal plant considerations and the plant's electric grid, are subsequently determined.

Initiating events occurring during controlled shutdowns, cold shutdown and refueling are not included in this study as initiating events. They are not addressed because of the low potential for core damage due to the redundancy of systems and long operator response times given that a failure has occurred when compared with the events initiated at power.

Accidents due to external causes such as earthquakes, fires and floods are also excluded. Additionally, sabotage events, internally or externally initiated, are excluded. External initiating events are not included for the following reasons:

- Detailed knowledge of the site is unavailable and would be necessary to determine the frequency and severity of related external events.

- Detailed knowledge of the plant layout is unavailable.

- For the most part, these events relate to the design and layout of the safety buildings and not necessarily to the safety systems.

However, it is estimated that the APWR systems would have an advantage with respect to external events because of their greater redundancy and diversity. In addition, the plant layout provides a greater degree of separation between safety trains A and B and between safety equipment and control equipment.

1.1 INTERNAL INITIATING EVENT CATEGORIZATION

All internal initiating events which could lead to core damage are systematically categorized. Core damage will occur if an insufficient core cooling event or an excess core power event occurs.

Loss of core cooling can occur either due to a primary coolant boundary failure or due to insufficient heat removal and subsequent failures of essential safeguards systems. Primary coolant boundary failure results from loss of coolant accident (LOCA) discharges inside or outside of containment. Insufficient heat removal can occur because of inadequate core or Reactor Coolant System (RCS) heat removal or because of loss of secondary system heat removel capability.

Excess core power is directly initiated by a core power excursion event. The internal initiating event categories are defined logically. These categories are broken down into the ten initiating event categories shown on Table 1.1-1. The event categories are logically categorized in such a manner that any internal initiator is included in at least one of the categories.

This section describes the basis for selection of the initiating events included in each category. The selection of initiating events for the categories identified on Table 1.1-1 is an iterative process between the first categorization of initiators, the determination of normal plant response sequences and the construction of event trees.

Event tree and fault tree methodology is employed to determine the contribution to core damage frequency of each category. Each category is analyzed as a separate initiator and bounds, from the point of view of core damage state probability, the entire range of the initiating events categorized.

The loss of DC power is not considered as an initiating event for the following reasons:

i) If AC power is available when Vital DC is lost, the running pumps will continue to run and other pumps can be started locally if needed. Since loss of Vital DC is a rare event, it has no appreciable impact on plant risk.

ii) If station blackout occurs following loss of a DC power circuit, the turbine driven emergency feedwater pumps and back-up seal injection system will still be operable. Thus, such an event will progress like a station blackout. However, the frequency of loss of DC power is orders of magnitude lower than a station blackout event and is considered to be accounted for in the station blackout accident sequence. Loss of Vital DC power is included in the failure of the Integrated Protection System (IPS) which generates the safety injection and other signals following an initiating event. It is estimated that the loss of DC power would make up more than 90% of the IPS failures. Thus, loss of DC power concurrent with an initiating event is accounted for in the present model.

In conclusion, the loss of Vital DC power event is not deemed to result in a dominant accident sequence. Failure of the IPS, which includes loss of vital DC power, is accounted for in the station blackout event sequence.

1.1.1 TRANSIENTS

Transient events can be simply defined as non-LOCA initiating events. However, it is not a simple task to identify all possible transient initiators and analyze their consequences. Transient events, as defined in 10 CFR 50, Appendix A, are of two different types: anticipated transients and unanticipated transients or postulated accidents. EPRI NP-2230 (Ref. 3) was used as a basis for the identification of anticipated transients and WASH-1400 (Ref. 1) was used for the unanticipated transients. Additional sources were used in reviewing the completeness of the lists of transient initiators (Refs. 2, 4, 5).

The listings of transient initiators included in this analysis are presented in Tables 1.1-2 and 1.1-3. Each transient initiator listed in these tables should be recognized as representing a group of similar transient initiators. To illustrate this point, there are a variety of equipment malfunctions such as low suction pressure, overspeed, low feedwater pump bearing oil pressure, etc., that can cause a feedwater pump trip and all are represented by the loss of feedwater flow initiator.

Except for the transients marked as included in another initiating event category, the transient initiators presented in Tables 1.1-2 and 1.1-3 have been traditionally classified based on plant response, signal actuation, systems required for mitigation and subsequent plant related effects. For continuity and completeness, the traditional transient initiating event classifications are presented in Table 1.1-4. Whenever applicable, unanticipated transients are grouped together with anticipated transients.

Because the plant response behavior is essentially the same for all of the transient initiating event classifications, all transients have been analyzed with one event tree in this study. Any minor differences that may exist between the classifications do not affect the accident sequence as modeled in the transient category event tree.

Breaks of small steam and feedwater branch lines, small leaks in secondary piping and spurious failure of steam generator relief or safety valves to the open position comprise small secondary side breaks. None of these postulated events results in a need for safety injection. These events are therefore treated differently than large ruptures of secondary system piping. Recovery from small secondary side breaks is similar to recovery from a transient. System operability and parameters will be identical following isolation of either the leak or the affected steam generator. The most likely event in this category is the spurious opening of an atmospheric dump valve. However, these valves are provided with automatically-actuated motor-driven block valves. These valves close on low steamline pressure, thus isolating the open valve following reactor trip and the associated reduction in secondary side steam flow. For these reasons, small secondary side breaks are analyzed in the transient event tree.

The introduction of the automatic steam generator overfill protection system may increase the number of transients due to inadvertent opening of one of the overfill protection valves. However, this potential increase is judged to be small compared to the number of transients assumed for this study.

1.1.2 LOSS OF OFFSITE POWER

This category was developed due to the unique effect that this transient has on the plant. A loss of offsite power event can be caused by either a complete loss of the offsite grid power accompanied by a turbine trip or loss of the onsite AC distribution system.

1.1.3 STEAM GENERATOR TUBE RUPTURE (SGTR)

Although this category could be included with small LOCAs, it is separated due to its unique effect on the plant. If steam generator safety or relief valves fail, a steam generator tube rupture may result in direct bypass of the containment boundary and, therefore, must be analyzed separately. Also, included in this category are all abnormal leakages from the RCS into one steam generator which are in excess of the charging pump make up capacity and would result in actuation of the ECCS. Multiple tube ruptures in a single SG have a low frequency of occurrence, and due to the inclusion of the steam generator overfill system, plant recovery would not proceed differently from the single tube rupture event.

Based on historical plant operational data, the event of coincident tube rupture in multiple steam generators has an extremely low frequency, not only as a random occurrence but also if considered as a consequence of other initiating events. The frequency of tube rupture in multiple steam generators is about two percent of the frequency of multiple tube ruptures in one steam generator. For this reason it is not included in this category.

1.1.4 LARGE SECONDARY SIDE BREAK

Many of the transient initiators from Tables 1.1-2 and 1.1-3 were grouped to form this initiating event category. It includes secondary line breaks both inside and outside of containment and multiple stuck open steam valves. The transient initiators included in the Large Secondary Side Break category are shown on Table 1.1-5 and described in the following subsections.

1.1.4.1 SECONDARY SIDE BREAKS UPSTREAM OF MSIVS OR DOWNSTREAM OF MFWIVS

Initiators included in this category are transients that begin with a secondary side break upstream of the MSIVs. Also considered among these initiators are breaks located downstream of the MFWIVs. This category was developed due to the effect of having an unisolatable secondary side break that could lead to a severe cooldown of the reactor coolant system. Included in this category are unanticipated random pipe ruptures and failures of two or more unisolated steam generator relief or safety valves.

1.1.4.2 SECONDARY SIDE BREAKS DOWNSTREAM OF MSIVS OR UPSTREAM OF MFWIVS

This category considers all transients that begin with a secondary side break downstream of the MSIVs. Also included are breaks located upstream of the MFWIVs. As opposed to secondary side breaks upstream of the MSIVs, these breaks can be quickly isolated without significant steam generator depressurization. Included under this category are random pipe ruptures and failures of two or more steam dump valves.

1.1.5 SMALL LOSS OF COOLANT ACCIDENTS (< 6")

Loss of coolant accidents can be defined as any accident involving the rupture or failure of the reactor coolant boundary including piping, valves, pressure vessel and interconnecting systems. Reactor coolant pump seal failures are also categorized under LOCA initiators. The loss of coolant accident initiators consider loss of primary inventory inside and outside the containment structure.

This category considers random ruptures of the RCS piping in the range from 3/8 inch to 6 inches in diameter. Also considered in this category are reactor coolant pump seal LOCAs, failure of one or multiple power-operated relief valves or safety valves and small LOCAs from ruptured control rod drive housing and instrument line failures. Although initiators resulting in breaks of less than 3/8 inches in diameter are within the capability of the normal makeup system, if normal technical specification limits are exceeded, a reactor trip may be manually initiated. For this reason these small leakages from the RCS are categorized in reactor trip category.

1.1.6 LARGE LOCA (> 6")

This category considers any random ruptures of the reactor coolant system ranging from a 6-inch diameter break up to the double-ended rupture of the largest pipe in the system. The large LOCA category includes failures of the reactor pressure vessel that do not exceed the capability of the emergency core cooling system.

1.1.7 ANTICIPATED TRANSIENT WITHOUT SCRAM (ATWS)

Anticipated Transient Without Scram (ATWS) is not an internal initiating event, but is a consequential failure resulting from other events. Therefore, ATWS is included as an initiating event category and has a detailed event tree analysis performed to determine core damage frequency.

1.1.8 INTERFACING SYSTEMS LOCA

This category considers RCS supporting systems that have direct piping connections to the RCS. Piping and/or valve ruptures associated with these systems have the potential to cause a LOCA with severe consequences which could disable the Emergency Core Cooling System (ECCS) functions and bypass the containment. The limiting factors in this type of event are possible loss of primary coolant outside the containment boundary and a direct release path to the environment.

Initiating events included in this category are vessel injection line failure, hot leg injection line failure, RHR letdown line failure and pipe ruptures outside of containment in other interfacing systems.

1.1.9 VESSEL FAILURE

This initiator category considers all catastrophic reactor vessel failures. The leakage due to these failures is assumed to exceed the Emergency Core Cooling System capability to maintain core cooling. Thus, since severe core damage is assumed due to the progression of this type of accident, it is categorized separately.

1.1.10 TOTAL LOSS OF AUXILIARY COOLING

During the process of categorizing the transient initiators, it was apparent that certain transient initiators need special attention based on the effects that could arise. These transients can occur as a result of loss of either the Component Cooling Water System (CCW) or the Essential Service Water (ESW) System.

Component Cooling Water (CCW) is used to cool a number of plant systems, many of which are safety-related mitigation systems such as safety injection and the containment heat removal systems.

The main systems cooled by the CCW are as follows:

- Reactor Coolant Pumps
- Containment Spray Pumps
- High Head ISS (HHSI) pumps, Residual Heat Removal (RHR) pumps, RHR heat exchangers
- Containment Fan Coolers
- Centrifugal Charging Pumps

The CCW System consists of two independent 100 percent capacity trains, each of which has a main and a back-up pump. Under normal conditions, only one pump in each train is operating. If, for any reason, the running train becomes unavailable, the back-up CCW pump is started. The switchover is automatically initiated by low CCW pressure. At the same time, the ESW is automatically realigned so that the CCWS is properly cooled. If the switchover to the second train fails, a total loss of CCW specific transient is generated.

Because of the design connections between the CCW/ESW and various primary systems including the reactor coolant pumps/motors and the charging pumps, the loss of this cooling will result in reactor trip due to failure of one of these components.

TABLE 1.1-1

APWR INITIATING EVENT CATEGORIES

Event Tree No.	Symbol	Initiating Event Category
1	TRA	Transients
2	LSP	Loss of Offsite Power
3	SGR	Steam Generator Tube Rupture
4	SSB	Large Secondary Side Break
5	SLO	Small LOCA < 6"
6	LLO	Large LOCA > 6"
7	ATW	ATWS
8	ISL	Interfacing Systems LOCA
9	VEF	Vessel Failure
10	LC1	Total Loss of Auxiliary Cooling

TABLE 1.1-2

ANTICIPATED TRANSIENT INITIATOR LIST
FROM EPRI NP-2230

EPRI NP-2230 Number	Title
1	Loss of RCS flow (1 loop)
2	Uncontrolled rod withdrawal
3	CRDM problems and/or rod drop
4	Leakage from control rods
5	Leakage in primary system
6	Low pressurizer pressure
7	Pressurizer leakage
8	High pressurizer pressure
9	Inadvertent safety injection signal
11	CVCS malfunction - Boron dilution
12	Pressure/Temperature/Power imbalance-rod position error
13	Startup of inactive coolant pump
14	Total loss of RCS flow (all loops)
15	Loss of reduction in feedwater flow (1 loop)
16	Total loss of feedwater flow (all loops)
17	Full or partial closure of MSIV (1 loop)
18	Closure of all MSIVs
19	Increase in feedwater flow (1 loop)
20	Increase of feedwater flow (all loops)
21	Feedwater flow instability - Operator error
22	Feedwater flow instability - Misc. mechanical causes
23	Loss of condensate pump (1 loop)
24	Loss of all condensate pumps (all loops)
25	Loss of condenser vacuum
27	Condenser leakage

TABLE 1.1-2 (Continued)

ANTICIPATED TRANSIENT INITIATOR LIST
FROM EPRI NP-2230

EPRI NP-2230 Number	Title
28	Misc. leakage in secondary system
29*	Sudden opening of steam relief valves (Dump valves)
30	Loss of circulating water
31**	Loss of component cooling
32**	Loss of service water systems
33	Turbine trip, throttle valve closure, EHC problems
34	Generator trip or generator-caused faults
35+	Total loss of offsite power
36	Pressurizer spray failure
37	Loss of power to necessary plant systems
38	Spurious trips cause unknown
39	Auto trip - no transient condition (Hardware error)
40	Manual trip - no transient condition (Operator error)

* One Valve Failed Open Included in Transient Category; Two Valves Failed Open Included in Secondary Side Break Category

** Included in Total Loss of Auxiliary Cooling Category

\+ Included in Loss of Offsite Power Category

TABLE 1.1-3

UNANTICIPATED TRANSIENT LIST

1	Control rod ejection
2	Reactor coolant pump locked rotor
3	Reactor coolant pump shaft failure
4*	Feedwater line break downstream of MFWIV
5*	Feedwater line break upstream of MFWIV
6*	Steam line break downstream of MSIVs
7*	Steam line break upstream of MSIVs
8**	One or two steam generator relief valves fail open and unisolated
9**	One or two steam generator safety valves fail open
10*	Multiple steam dump valves fail open
11*	Multiple steam generator relief valves fail open and unisolated
12*	Multiple steam generator safety valves fail open

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* Included in Secondary Side Break Category

** One Valve Failed Open Included in Transient Category; Two Valves Failed Open Included in Secondary Side Break Category

TABLE 1.1-4

TRANSIENT INITIATING EVENT CLASSIFICATIONS

1. Loss of Reactor Coolant Flow

   Loss of RCS flow (1 loop)
   Total Loss of RCS flow
   Reactor Coolant Pump Locked Rotor
   Reactor Coolant Pump Shaft Failure

2. Loss of Main Feedwater Flow

   Total Loss of Feedwater Flow
   Feedwater Flow Instability - Operator Error
   Feedwater Flow Instability - Miscellaneous Mechanical Causes
   Loss of Condensate Pump (1 loop)
   Loss of All Condensate Pumps
   Condenser Leakage

3. Primary to Secondary Power Mismatch

   Full or Partial Closure of One or More MSIVs
   Increase in Feedwater Flow in One or More Loops
   Loss or Reduction in Feedwater Flow (1 loop)

4. Turbine Trip

   Closure of all MSIVs
   Miscellaneous Leakage in Secondary System
   Loss of Condenser Vacuum
   Loss of Circulating Water
   Turbine Trip, Throttle Valve Closure, - EHC Problems
   Generator Trip or Generator-Caused Faults

TABLE 1.1-4 (Continued)

TRANSIENT INITIATING EVENT CLASSIFICATIONS

5. Reactor Trip

Control Rod Drive Mechanism Problems and/or Rod Drop
High or Low Pressurizer Pressure
Pressurizer Spray Failure
Spurious Trips - Cause Unknown
Manual Trip - Operator Error
Auto Trip - Hardware Error
Pressure, Temperature or Power Imbalance - Rod Position Error
Loss of Power to Necessary Plant Systems
Leakage from Control Rods
Leakage in Primary System
Pressurizer Leakage

6 Core Power Excursion - Uncontrolled Rod Withdrawal and Boron Dilution

Uncontrolled Rod Withdrawal
Control Rod Ejection
Startup of an Inactive Coolant Pump
CVCS Malfunction - Boron Dilution

7. Spurious "S" Signal

Inadvertent Safety Injection Signal

8. Small Secondary Side Breaks

One Steam Generator Relief Valve Fails Open and Unisolated
One Steam Generator Safety Valve Fails Open
One Steam Dump Valve Fails Open and Unisolated by MSIVs

TABLE 1.1-5

SECONDARY SIDE BREAK INITIATING EVENT CLASSIFICATIONS

1. Seconda , Side Breaks Upstream of MSIVs or Downstream of MFWIVs

   Steam Line Break Upstream of MSIVs
   Feedwater Line Break Downstream of MFWIV
   Multiple Steam Generator Safety Valves Fail Open
   Multiple Steam Generator Relief Valves Fail Open and Unisolated

2. Secondary Side Breaks Downstream of MSIVs or Upstream of MFWIV

   Steam Line Break Downstream of MSIVs
   Feedwater Line Break Upstream of MFWIV
   Multiple Steam Dump Valves Fail Open

1.2 INTERNAL INITIATING EVENT FREQUENCY QUANTIFICATION

This section discusses the methods employed in deriving the frequency of occurrence of initiating events as categorized in Section 1.1 and listed in Table 1.1-1. The resultant initiating event frequencies are summarized in Table 1.2-1.

Because the plant is at the design stage, no plant-specific operating experience is available for incorporation into the data analysis. Due to the lack of plant-specific data for the initiating events, estimates of the initiating event frequency distribution are based on USA PWR experience. An exception is the steam generator tube rupture data which was derived from an extensive review of Westinghouse-manufactured plants, both in the USA and abroad.

Sources utilized in the analysis include an Electric Power Research Institute compilation of transient data, EPRI NP-2230, (Ref. 3), a Brookhaven Laboratory memorandum which comments on the Zion Probabilistic Safety Study (Ref. 7) and WASH-1400 (Ref. 1). Other sources have been also examined, such as NUREG/CR-2815 (Ref. 12) and NUREG/CR-2497 (Ref. 13). In EPRI NP-2230, data from 36 operating pressurized water reactors (PWRs), representing 201 operating years, is assimilated into 41 transient categories.

Reference PWR event data are presented in Table 1.2-2 by plant versus initiating event. Table 1.2-3 lists the plants and operational years included in the data base. With the exception of the small loss of coolant accidents, the data presented in Tables 1.2-2 and 1.2-3 is taken from EPRI NP-2230. The small LOCA event is noted in a Brookhaven Laboratory memorandum (Ref. 7) which refers to a random reactor coolant pump seal failure at the H. B. Robinson Plant. This event has been confirmed by a review of the plant operating history (Ref. 8). Large LOCAs and all the unanticipated transients have not been observed in the reference PWR experience and treatment of these rare events is discussed in Sections 1.2.4 and 1.2.6. For the loss of offsite power initiator a frequency derived from operating experience has been used.

The initiating event data for Indian Point Unit 1, although included in EPRI NP-2230, is excluded from the calculations in Tables 1.2-3 and 1.2-4. It was excluded because the plant experience is not representative of current operational practices and of initiating event causes expected to occur in a newer generation of plants. Indian Point Unit 1 has already been decommissioned. Its initiating event data also shows marked differences from other plants in the data base. Additionally, Indian Point Unit 1 is a non-Westinghouse plant.

The quantification of each initiating event frequency is discussed in the following paragraphs.

1.2.1 FREQUENCY OF TRANSIENT EVENTS

From Table 1.2-3, the average transient event frequency per plant is calculated as:

$$f_1 = \frac{360.2}{35} = 10.3/\text{year}$$

In EPRI NP-2230, the transient occurrence rate for Westinghouse plants is estimated as:

$$f_1 = 9.71/\text{year}$$

For this analysis, the following estimate is used for the mean value of transient events:

$$f_1 = 10/\text{year}$$

The variance is calculated by assuming a lognormal distribution and an error factor of 3 ($EF = X_{95}/X_{05}$) as:

$$V_1 = 56/\text{year}^2.$$

This should be very conservative for the WAPWR because of its ambitious availability goals (<3% forced outages between refuelings) will result in reduced trip frequency.

1.2.2 FREQUENCY OF LOSS OF OFFSITE POWER EVENT

The loss of offsite power event frequency is taken from EPRI NP-2301 (Reference 15). It is based on 45 loss of offsite power occurrences which occurred over the 370 years of plant operation for all of the plants included in the report. This frequency is:

$$f_2 = 0.12/\text{year}$$

with a variance of:

$$V_2 = 8.1 \times 10^{-3}/\text{year}^2$$

which is calculated by assuming a lognormal distribution and an error factor of 3.

1.2.3 FREQUENCY OF STEAM GENERATOR TUBE RUPTURE EVENT

Due to its unique effects on the plant the steam generator tube rupture initiating event frequency was calculated based on a detailed review of historical tube rupture data from domestic and foreign Westinghouse-manufactured plants and from Westinghouse licensee plants. This data, summarized on Table 1.2-4, totals over four million tube years since commercial operation. Because the data assumes continuous operation since the beginning of commercial operation, it is discounted 10 percent to 3.6×10^6 tube years to account for outages for steam generator replacement, plugged tubes and any other prolonged period of non-operation such as licensing action for seismic analysis.

TUBE FAILURE RATE

Table 1.2-5 presents a list of the five tube rupture events that have occurred in Westinghouse steam generators. Assuming there will be four advanced steam generators with 5626 tubes each, the point estimate for the frequency of steam generator tube rupture is calculated as:

$$f_3 = \frac{5}{3.6 \times 10^6} \times (5626)\ (4) = 3.1 \times 10^{-2}/\text{year}$$

This estimate is conservative for the present design due to the modifications for design and operation improvements in steam generators, as described below.

The variance is:

$$V_3 = 5.4 \times 10^{-4}/\text{year}^2$$

which is calculated by assuming a lognormal distribution and an error factor of 3.

MODIFICATIONS FOR DESIGN AND OPERATION IMPROVEMENTS

Because of improvements in the design, operation, and inspection of steam generators, it is believed that experience in the Model F plants will be significantly better than that observed to date. Cogent reasons can be given as to why certain of the five tube ruptures experienced should not occur in the Model F's since the operating conditions are not applicable, or why the occurrence rate should be substantially less because of such design and inspection improvements. These are described below.

At Point Beach 1 in February 1975, phosphate wastage had thinned tubes in a zone just above the tubesheet where sludge had collected. In addition to thinning, some stress corrosion cracking was also present. The events at Surry 2 in September 1976 and Doel 2 in June 1979 show some similarities. In both cases, the tubes had suffered stress corrosion cracking starting from the

primary side. At Surry, this was due to denting accompanied by "hour glassing" of the flow slots. At Doel, the affected tube had excessive ovality which led to high stresses at the bend. The two remaining events, at Prairie Island 1 in October 1979 and Ginna in January 1982, were both due to foreign objects fretting against the tube and wearing it thin along one side. Due to improvements in the design of Model F steam generators and in current maintenance procedures, some of these incidents can be expected to be reduced in frequency. The problem of phosphate wastage, for example, has been eliminated since phosphates will not be used.

Denting of tubes, if it occurs at all, will develop much more slowly and with more limited extent than at previous stations due to:

- use of an improved tube support plate material (stainless steel type 405) which is less susceptible to corrosion and promotes less oxide growth than carbon steel;

- new hole profiles which allow less concentration of salts;

- elimination of copper and decrease in chloride concentrations compared to other plants.

Stress corrosion cracking (SCC) for the APWR is very unlikely due to the following improvements:

- new thermal treatment of tubing which makes it less sensitive to caustic SCC and intergranular attack (IGA);

- absence of copper which reduces the rate of SCC by minimizing the corrosive environment;

- improved design which minimizes crevices between the tube and tubesheet, including hydraulic expansion of tubes, to reduce the concentration of alkaline salts in overlying sludge.

In addition, tube degradation will most likely be identified before rupture occurs due to extensive In-Service Inspection (ISI) which includes: eddy current testing, ultrasonic techniques, profilometer probes, full inspection of all tubes before the plant is put into operation, and continuous monitoring of water quality, radioactivity, leakage rates, etc.

One type of tube failure, wear due to foreign objects, was responsible for the two largest tube rupture events which have occurred and is not affected by design improvements. However, due to rigorous quality assurance procedures as well as monitoring for loose parts, this type of tube failure is judged to be much less likely than historical frequency indicates.

1.2.4 FREQUENCY OF LARGE SECONDARY SIDE BREAK EVENT

Because safety injection is not required for success, small secondary side break events are considered as transients. The remaining large secondary side breaks are rare events. The frequency of such events is estimated as the same as large LOCA events (Section 1.2.6). The frequency of large LOCA is multiplied by 2 to account for both steam and feedwater line breaks.

$$f_4 = 8 \times 10^{-4}/\text{year}$$

$$V_4 = 4 \times 10^{-6}/\text{year}^2$$

1.2.5 FREQUENCY OF SMALL LOCA EVENT

The small LOCA initiating event frequency is estimated from Table 1.2-2 as:

$$f' = \frac{1 \text{ event}}{201 \text{ years}} = 0.005$$

for 0 to 2 inch breaks.

The 2-6 inch breaks (traditionally classified as medium LOCAs) are included in the small LOCA category since the plant success criteria is identical to that for small LOCAs. The frequency of the "medium" LOCA is estimated similar to

large LOCA estimation of Section 1.2.6. The resulting freqency is calculated to be:

$$f^* = 6.0 \times 10^{-4}/\text{year}$$

$$V^* = 1.3 \times 10^{-6}/\text{year}^2$$

The total frequency of small LOCA events (0-6 inches) is

$$f_5 = 5.0 \times 10^{-3} + 6.0 \times 10^{-4} = 5.6 \times 10^{-3}/\text{year}.$$

The variance is calculated to be

$$V_5 = 1.8 \times 10^{-5}/\text{year}^2$$

by assuming a normal distribution and an error factor of 3.

This estimate reflects only those events that are randomly initiated as small LOCAs. The consequential LOCAs that will follow transients are modeled as nodes in the event trees. The consequential LOCAs are estimated to be about 20% of the 0-2 inch LOCAs. Thus, in the event trees, a consequential LOCA probability of 1×10^{-4} is used. When multiplied with 10 transients a year, this results in 0.001 consequential small LOCAs per year.

1.2.6 FREQUENCY OF LARGE LOCA EVENT

For the large LOCA, 2-6 inch LOCA and Large Secondary Side Break events which have not occurred, a Bayesian estimate of event frequency has been generated. For these events, prior distributions have been developed from WASH-1400 distributions. The 5^{th} and the 95^{th} percentiles of the WASH-1400 lognormal distributions have been taken as the 20^{th} and 80^{th} percentiles of the prior distributions in order to express greater uncertainty in the pipe failure rates. The prior distribution was then updated based on the observation of zero occurrences in the total number of operating years in the

data base (201 reactor years). The posterior mean and variance are calculated as:

$$f_6 = 4.0 \times 10^{-4}/\text{year}$$

$$V_6 = 1.0 \times 10^{-6}/\text{year}^2$$

1.2.7 FREQUENCY OF ATWS EVENT

The ATWS initiating event frequency is calculated as a fraction of all transients which challenge the reactor protection system. Based on Reference 15, the unavailability of the reactor trip, including signal generation and insertion of the control rods is assumed to be 3.0×10^{-5} per demand. The expected number of challenges per year can be estimated by the number of transients. Thus, the initiating event frequency is estimated as:

$$f_7 = 10 \times \ 3 \times 10^{-5} = 3 \times 10^{-4}/\text{year}$$

The variance is calculated as

$$V_7 = 5.1 \times 10^{-8}/\text{year}^2$$

assuming a lognormal distribution and an error factor of 3.

1.2.8 FREQUENCY OF INTERFACING SYSTEMS LOCA EVENT

The interfacing systems LOCA (ISL), Event V as described in WASH-1400, is postulated for those large piping systems that connect to the Reactor Coolant System and also pass through containment. Such connections have the potential to cause a LOCA in which the containment and containment safeguards radionuclide protective barriers are bypassed. In addition, there is the potential for those piping failures to render the ISS ineffective or inoperable since most of these piping connections involve the ISS.

Three possible ISL-initiation scenarios have been identified for detailed analysis and are discussed and quantified in the following paragraphs. These scenarios are:

- o Disk rupture of the two series motor-operated valves in the letdown piping of the Residual Heat Removal System.

- o Disk rupture of check valves and disc rupture or transfer open of motor-operated valves in the reactor vessel injection lines.

- o Disk rupture of check valves and disc rupture or transfer open of motor-operated isolation valves in the hot leg injection lines.

These scenarios have been identified through a review of containment piping penetrations that was conducted in order to insure that all interfacing systems have been considered.

Several CVCS and other system penetrations for which an interfacing systems LOCA might be postulated are not considered in detail in this analysis. Rupture of the piping in the CVCS charging and RCP seal injection lines upstream of the RCS pressure boundary is judged to be extremely unlikely for several reasons. First, the piping in these lines is qualified to pressures higher than normal RCS pressures and thus this piping should not rupture if exposed to existing RCS pressure. Second, the piping runs range from two to four inches in diameter, so that the consequences of an interfacing systems LOCA via any of these paths would be less severe than the other scenarios under analysis. Third, these paths are similar in valve configuration to the low and high pressure injection paths which are analyzed, and shown to be minor contributors to the ISL-initiation frequency in the following paragraphs.

Other paths not considered in detail are the back-up seal injection and CVCS letdown lines. The back-up seal injection line is similar to the normal seal injection line. The CVCS letdown line is excluded from detailed analysis because orifices before the containment penetration reduce the flow outside containment if postulated rupture of piping is assumed. In this case, the

,c) maximum flow rate is [ ] gpm; centrifugal charging pumps are of sufficient capacity to make up this flow rate. Thus, the consequences of an interfacing systems LOCA via this path would be less severe than the other scenarios under analysis. The less frequent and less severe paths associated with these charging systems are, therefore, judged to be insignificant contributors to plant risk and are not considered further in this analysis.

ISL - RHR SUCTION PATH

There are four RHR suction lines, each of which contains two series motor-operated valves. These RHR lines are used during plant shutdown conditions when the RHR system is in operation.

Failure combinations involving disc rupture of two series motor-operated valves (MOV) are included in this analysis. Other valve failure modes have been judged inapplicable based on system characteristics.

Disk failure to close is defined as a failure of a valve disc to return to the closed position upon demand. If both valves in any line had disks which failed to close, this condition would become apparent within a short period of time during the subsequent RCS startup, and corrective action would be taken. Thus, the event initiators involving disk failure to close in two series MOVs are excluded from further consideration, because of the very low probability of failure to detect and correct this situation.

Combinations involving an inadvertently open disk in the first MOV and subsequent rupture of the second MOV downstream of the first valve are also eliminated from consideration because the positions of these valves are indicated in the control room. Therefore, failure to close the initial valve in any line would be detected during a normal shift. In addition, it is assumed that the operator would detect the initial valve misposition and take corrective action, to depressurize the RCS and close the valve, within 24 hours after startup, during which time the second valve would not be exposed to pressures that could reasonably be postulated to induce disc rupture.

Further, because this is such a short period, the conditional probability of the second valve rupture is very small.

The valve transfer open (spurious opening) failure mode is also excluded from quantification, in part because of the ability of the operators to detect changes in valve position from the control room. More importantly, these valves would have to transfer open against existing RCS pressure. There is an extremely low probability, given the valve motor capabilities, that such valves could change position under such a large pressure differential. In addition, these valves are interlocked against opening unless RCS pressure is less than RHR operating pressure, and are electrically racked out at the motor control center.

Based on the information and assumptions above, the following expression has been developed for the frequency of an interfacing systems LOCA initiating via the RHR suction path:

$$F(ISL_R) = 4\,[F(V1) \times P(V2/V1)]$$

where:

$F(ISL_R)$ = frequency of RHR suction ISL

$F(V1)$ = frequency of initial valve failure

$P(V2/V1)$ = conditional probability of 2nd valve failure

V1, V2 refers to the two normally closed MOVs

4 = number of RHR suction paths

The failure rate distribution associated with MOV and check valve disc rupture/catastrophic leakage is taken from the NREP Procedures Guide (NUREG/CR-2815) and is lognormal with the following characteristics:

Mean = 1.0×10^{-7}/hour

Variance = 1.0×10^{-14}/hour^2

Component failure probability is the product of the component failure rate and the exposure interval. Thus, the probability of the first valve failure is given by

$$q_1 = \lambda_1 t$$

where

q_1 = failure probability for the first MOV

λ_1 = failure rate per unit time for the first MOV

t = exposure interval (time to failure) such that $0<t<T$

T = maximum exposure interval considered; for this analysis $T = 1$ year to obtain an annual frequency, since the valves are not tested on a more frequent basis.

The probability of the second valve failure is then

$$q_2 = \lambda_2 (T-t)$$

because the second valve cannot fail until after the first valve fails but must fail within the time interval under consideration. The combined probability of the two valves failing is then

$$F(ISL_R) = 4\ q_1\ q_2 = 4 \times \lambda_1 t \times \lambda_2 (T-t)$$

and, because the valves are identical,

$$F(ISL_R) = 4\ \lambda^2 t(T-t)$$

The mean value of $F(ISL_R)$ is then determined by averaging over t

$$F(ISL_R) = 4 \times \frac{\lambda^2 \int_o^T (tT - t^2)dt}{\int_o^T dt} = \frac{2\lambda^2 T^2}{3} .$$

With the previously stated value of T (1 year, = 8760 hr.) and λ (mean = 1.0×10^{-7}, variance = 1.0×10^{-14}), the resulting ISL-initiation probability distribution is described by

$$f_8 = 1.0 \times 10^{-6}/\text{year}$$
$$V_8 = 1.0 \times 10^{-11}/\text{year}^2$$

Note that this reflects the fact that the mean value of the square of a probability is given by the square of the mean, plus the variance.

ISL - VESSEL INJECTION PATHS

The vessel injection lines consist of four trains, each of which contains several paths incorporating low-pressure piping. Each of these paths contains at least three check valves or two check valves and two normally-closed motor-operated valves. Several of these paths lead only to release inside containment (i.e., LOCA) and are not evaluated further for this analysis.

The frequency of an ISL initiation via the vessel injection paths is dominated by the following sequence:

$$F(ISL_v) = 4\ [F(V1)P(V2/V1)P(V3/V1,V2)]$$

where

F(V1) = frequency of first check valve rupture
P(V2/V1), P(V3/V1,V2) = conditional probability of 2nd and 3rd check valve ruptures

It has been determined, based on consideration of possible failure modes in the context of this analysis, that valve failure to close, excessive valve back leakage and valve transfers open are not credible failure modes for the check valves in the vessel injection lines. These check valves are tested for leakage during RCS repressurization, after system use (RHR mode) and prior to reactor startup. The tests confirm the proper seating of each valve disc and

verify that each valve can independently sustain differential pressure across its valve disc.

Disk rupture, therefore, is the sole failure mode applicable to the check valves in the vessel injection lines. Because disc rupture is more reasonably postulated for valves exposed to relatively high (e.g., RCS) pressures, the accident progression as modeled here involves failure of the last series check valve (i.e., the one farthest downstream) and the sequential failure of the three valves upstream of the initial valve failure. Scenarios involving disc rupture of valves not exposed to RCS pressure are judged to have extremely remote associated frequencies and are eliminated from further consideration on those grounds.

Quantification of this vessel injection path results in a negligibly small contribution to the frequency of an interfacing systems LOCA (mean $\simeq$ 2×10^{-9}/yr).

ISL - HOT LEG INJECTION PATHS

The hot leg injection lines consist of four trains, each of which contains three check valves and one normally closed motor-operated valve. An interfacing systems LOCA via this path would involve sequential disc rupture of the check valves and disc rupture or transfer open of the MOV. Quantification of scenarios involving four valve failures shows a negligible contribution to the overall frequency of an interfacing systems LOCA.

SUMMARY

In summary, the two injection path scenarios are of low frequency. The suction path is dominant in terms of frequency and cannot be isolated. The total mean frequency for initiation of an ISL is 1.0×10^{-6} per year with a variance of 1.0×10^{-11} per year^2.

1.2.9 FREQUENCY OF VESSEL FAILURE EVENT (LARGE LOCA BEYOND ECCS CAPABILITY)

The mean frequency of a reactor vessel failure is estimated as 1×10^{-7}/year.

A vessel integrity failure is defined as a disruptive failure. This is characterized as a breaching of the vessel by failure of the shell, head, nozzles or bolting accompanied by a rapid release of a large volume of reactor coolant. "Large" is defined as beyond the capacity of the ECCS System to keep the core covered or reflood the core after initial uncovery. This event includes all challenges to vessel integrity during emergency and fault conditions.

Two classes of large LOCAs that may be beyond ECCS capability have been identified; simultaneous rupture of two or more large pipes and a very large reactor vessel rupture.

Independent, simultaneous large ruptures are so unlikely that they cannot be contributors to core melt or risk. No internal dependencies (e.g., pipe whip damage following a large LOCA) have been identified that would contribute substantially to risk.

Catastrophic reactor vessel ruptures that are beyond the capability of ECCS were analyzed in WASH-1400. The WASH-1400 estimate of such failure is:

5th percentile: 1.0×10^{-8}/year
Median: 1.0×10^{-7}/year
95th percentile: 1.0×10^{-6}/year

Significant additional work has been performed since WASH-1400 and is summarized below. Due to the expected low frequency of vessel failure (there has not been a nuclear vessel failure to date), two basic approaches have been taken to characterize this frequency:

(i) Consideration was given to the operating experience of non-nuclear pressure vessels. Such experience must be critically examined to decide whether the reported failures are relevant to nuclear pressure vessels. In addition, an appraisal must be made of the considerable differences between non-nuclear and nuclear vessel practice regarding design, fabrication, materials, operation and in-service inspection. Into this data base is included the operating experience of commercial and military nuclear reactor pressure vessels. However, the contribution of nuclear experience is small since a statistically significant data base will not exist for at least 20 more years for commercial nuclear pressure vessels.

(ii) Calculation of a theoretical probability of failure by particular identified mechanisms.

Several studies have been completed using these methods in the US and UK (References 16, 17 and 18) with the results in agreement. These studies surveyed the pressure vessel data and extrapolated the results to nuclear applications. These are summarized below:

FREQUENCY PER YEAR OF DISRUPTIVE FAILURE

	WASH-1318 (Reference 16)	MARSHALL COMMITTEE (Reference 17)
ASME Section I Boilers	6.3×10^{-6}	1.0×10^{-5}
ASME Section III Boilers	6.3×10^{-7}	1.0×10^{-6}

There are several major cautions in utilizing these results:

(i) These results are on a yearly basis and do not provide a knowledge of what type of "challenges" to vessel integrity occurred. Thus, a failure per challenge must be cautiously inferred.

(ii) No disruptive vessel failures have occurred in Section III type vessels, thus, the probability has been assessed in a highly conservative manner.

(iii) In both reports these values represent at least a 99 percent confidence level, whereas this study utilizes "best estimate" values. Thus, these values are highly conservative within the context of defining risk. These values were therefore assumed to be 95 percent confidence levels.

It is judged that items (ii) and (iii) far outweigh the concerns of (i). Thus, a value of ~ 1.0×10^{-7} failure per year is judged a reasonable mean estimate of vessel rupture frequency.

Another method to verify the above result is to calculate the theoretical probability of failure by identified mechanisms (stress intensity, crack detection, crack location, etc.). Calculations performed in Reference 18 assessed a disruptive failure rate of 1.0×10^{-4} per demand with an expected vessel failure of 1.0×10^{-6} to 1.0×10^{-8} per vessel year given that vessel integrity challenges occur at a frequency of 1.0×10^{-2} to 1.0×10^{-4} per year. Several issues must be considered:

(i) The failure rate per year is consistent with the conservative data assessment made above.

(ii) This assessment of probability is highly conservative for the following reasons:

a. All cracks are assumed to be pre-existing lines rather than semi-elliptical cracks. Semi-elliptical cracks are less limiting by a factor of 10 to 100 (Reference 2), however, semi-elliptical cracks are the most probable (due to the difficulty of UT_{NDT} detection).

b. Thermal transients are induced at the most limiting set of conditions (zero power, no decay heat for steam breaks). This condition exists for less than one percent of core life.

c. Cooldown conditions are the most adverse with respect to RCS and SI flow. By assuming low RCS flow Reactor Coolant Pump (RCP) trip, the vessel inner wall is subjected to very low temperature SI water as a result of low mixing with the reactor coolant. This maximizes vessel wall temperature gradients (thermal stresses). However, in most cases the RCPs will not be tripped. Thus, SI flow will be completely mixed with the reactor coolant which would reduce vessel wall/reactor coolant ΔTs. This would reduce the thermal stress and reduce the probability of initiation.

These types of assumptions are appropriate in assuring a high confidence that a bounding (99 percent assurance) calculation has been produced.

(iii) The cooldown transient frequencies in this study are not equivalent to the transients considered in Reference 17. For example, 90 to 95 percent of steam breaks are a single steam generator PORV or steam dump valve. These do not represent a vessel challenge as verified by the Westinghouse Owner's Group 12/81 submittal (Reference 19). However, the initiator frequencies used do not make this distinction.

Based on several of the arguments in items (ii) and (iii), failure probability is assessed at 3.0×10^{-7} per indicated vessel integrity challenge. The derivation of this value for transient events is as follows: 1.0E-04 based on Reference 19, a reduction of 100 based on item (ii) and an additional reduction of 10 based on item (iii). This range of values is also consistent with the NRC assessment of Pressurized Thermal Shock (Reference 20).

In SECY-82-465 (Reference 20) issued in 1982, the staff proposed RT_{NDT} screening criteria of 270°F for longitudinal welds and 300°F for

circumferential welds. These values were established based upon the staff evaluation, as discussed below.

The NRC approach for the selection of these RT_{NDT} screening criteria during 1982 used a deterministic fracture mechanics algorithm to calculate the value of RT_{NDT} for which assumed pre-existing flaws in the reactor vessel would be predicted to initiate (grow deeper into the vessel wall) assuming occurrence of one of the severe overcooling events that have been experienced in domestic PWR's. These values of RT_{NDT} were related to the expected frequency of the experienced severe overcooling events based upon the available data base, consisting of eight events in 350 reactor-years of operation. However, this approach did not reflect low frequency events that have not occurred and could pose a greater potential risk to the integrity of the vessel.

To address this concern, the NRC considered a wide spectrum of postulated overcooling events that could occur. These events were grouped into categories, estimates were made of their expected frequency, and stylized characterizations of the temperature and pressure time histories were developed for each category. The estimates were based on a generic study of Westinghouse - designed PWR systems. These estimates were used by the NRC to better understand the residual risks inherent in the use of the screening criteria approach for further evaluations and resolution of the PTS issue.

The proposed NRC rule for PTS: (1) established the RT_{NDT} screening criteria; (2) requires licensees to submit present and projected values of RT_{NDT}; (3) requires early analysis and implementation of such irradiation flux reduction programs as are reasonably practicable to avoid reaching the screening criteria; and (4) requires plant-specific PTS safety analyses before a plant is within 3 calendar years of reaching the screening criteria, including analyses of alternatives to minimize the PTS concern.

In addition, the WAPWR has several improvements that should reduce the probability of vessel failure such as improved vessel material, reduced vessel fluence, and increased SI temperatures (EWST).

Thus, the following frequency estimate is used for catastrophic vessel failure beyond ECCS capacity:

$$f_9 = 1.0 \times 10^{-7}/\text{year}$$

The variance is calculated by assuming a lognormal distribution and an error factor of 10:

$$V_9 = 6.1 \times 10^{-14}/\text{year}^2.$$

1.2.10 TOTAL LOSS OF AUXILIARY COOLING

The total loss of essential service water or component cooling water cooling capabilities is treated as an initiating event. The initiating event frequency for this category is estimated to be 2.0×10^{-5}/year.

To estimate the failure probability of ESW or CCW systems with 2 running and 2 standby pumps, a period of twelve months is considered. The failure is modeled as the failure of both running pumps to operate and the failure of both standby pumps to start:

$$q = (q_R^2 + B_R\, q_R)\ (q_S^2 + B_S\, q_S)$$

where

q_R = failure to run = $\lambda_R \times 8760$ (8760 hr mission time)

q_S = failure to start on demand = λ_S (8760)

β = common cause beta factor

Alternation of various pumps in and out of service is not addressed, since the minimum number of pumps (1 ESW and 1 CCW) will be running at all times during the yearly period of interest. For ESW and CCW pumps, the data is taken from Section 3.0 of this report, as follows:

	SW or CCW
Pump fail to run/hr	2.47×10^{-5}/hour
Pump fail to start/demand	1.34×10^{-3}/demand
Beta factor for run	.10
Beta factor for start	.10

For ESW or CCW:

$$q = \{[(2.47 \times 10^{-5})(8760)]^2 + 0.1\ (2.47 \times 10^{-5})(8760)\}$$
$$\{(1.34 \times 10^{-3})^2 + 0.1\ (1.34 \times 10^{-3})\}$$

$$= (6.85 \times 10^{-2})\ (1.36 \times 10^{-4})$$

$$= 9.3 \times 10^{-6}$$

To take into account other failures, such as strainers, valves and unavailability due to maintenance, the initiating event frequency will be estimated by $f = 1 \times 10^{-5}$/year for each system. Thus, the frequency of loss of either system will be:

$$f_{10} = 2 \times 10^{-5}/\text{year}$$

$$V_{10} = 2.2 \times 10^{-10}/\text{year}^2$$

The variance is calculated by assuming a lognormal distribution and an error factor of 3.

1.2.11 REFERENCES

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

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10. NRC "Evaluation of Steam Generator Tube Rupture Events," NUREG-0651, March 1980.

11. Westinghouse Electric Corporation, "Report on Small Break Accidents for Westinghouse NSS System," WCAP-9601, June 1979.

12. Nuclear Regulatory Commission, "National Reliability Evaluation Program (NREP) Procedures Guide," NUREG/CR-2815, January 1983.

13. Nuclear Regulatory Commission, "Precursors to Potential Severe Core Damage Accidents: 1969-1979, A Status Report," NUREG/CR-2497, June 1982.

14. Electric Power Research Institute, "Loss of Off-Site Power at Nuclear Power Plants: Data and Analysis," EPRI NP-2301, March 1982.

15. Nuclear Regulatory Commission, "Anticipated Transients Without Scram for Light-Water Reactors," NUREG-0460, April 1978.

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17. United Kingdom Atomic Energy Authority, "An Assessment of the Integrity of PWR Pressure Vessels," October 1976.

18. "Report on the Integrity of Reactor Vessels for Light-Water Power Reactors by Advisory Committee on Reactor Safeguards," WASH-1285, January 1974.

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20. Meyer, T. A., "Summary Report on Reactor Vessel Integrity for Westinghouse Operating Plants," WCAP-10019, December 1981.

TABLE 1.2-1

PROBABILITY DISTRIBUTIONS FOR INITIATING EVENT OCCURRENCE FREQUENCIES

Initiating Event	Mean (events/year)	Variance
1. Transients	10	56
2. Loss of Offsite Power	.12	8.1×10^{-3}
3. Steam Generator Tube Rupture	3.1×10^{-2}	5.4×10^{-4}
4. Large Secondary Side Break	8.0×10^{-4}	4.0×10^{-6}
5. Small LOCA (< 6")	5.6×10^{-3}	1.8×10^{-5}
6. Large LOCA (> 6")	4.0×10^{-4}	1.0×10^{-6}
7. ATWS	3.0×10^{-4}	5.1×10^{-8}
8. Interfacing Systems LOCA	1.0×10^{-6}	1.0×10^{-11}
9. Vessel Failure	1.0×10^{-7}	6.1×10^{-14}
10. Total Loss of Auxiliary Cooling	2.0×10^{-5}	2.2×10^{-10}

TABLE 1.2-2

PWR POPULATION EVENT DATA

Plant Name	Small LOCA	Loss of RCS Flow	Loss of Main Feedwater Flow	Primary to Secondary Power Mismatch	Turbine Trip	Reactor Trip	Core Power Excursion	Spurious "S" Signal
1) YANKEE ROWE	0	10	1	5	14	44	0	0
2) SAN ONOFRE	0	1	1	2	15	19	0	1
3) HADDAM NECK	0	5	3	13	17	26	0	0
4) R.E. GINNA	0	1	0	16	9	7	0	0
5) POINT BEACH 1	0	0	0	11	12	17	0	0
6) H.B. ROBINSON	1	4	3	61	32	59	1	4
7) PALISADES	0	1	2	10	8	20	0	0
8) POINT BEACH 2	0	2	0	4	14	16	0	0
9) SURRY 1	0	2	6	34	20	23	1	2
10) MAINE YANKEE	0	1	1	5	3	7	1	0
11) SURRY 2	0	0	0	29	14	7	0	0
12) OCONEE 1	0	2	7	11	25	15	1	0
13) INDIAN POINT 2	0	8	10	92	21	37	1	2
14) PRAIRIE ISLAND 1	0	1	3	24	8	10	0	1
15) ZION 1	0	4	12	23	13	22	3	0
16) KEWAUNEE	0	1	1	23	17	30	0	0
17) FORT CALHOUN	0	3	1	3	5	7	0	0
18) THREE MILE ISLAND 1	0	0	0	0	3	2	0	0
19) OCONEE 2	0	1	6	6	11	10	0	0
20) ZION 2	0	5	10	43	8	24	1	0
21) OCONEE 3	0	2	2	4	15	8	1	0
22) ARKANSAS 1	0	0	1	4	11	15	0	0
23) PRAIRIE ISLAND 2	0	1	2	17	9	11	0	0
24) RANCHO SECO	0	0	3	10	6	6	2	0
25) CALVERT CLIFFS 1	0	4	5	12	16	11	1	0

TABLE 1.2-2 (Continued)

PWR POPULATION EVENT DATA

Plant Name	Small LOCA	Loss of RCS Flow	Loss of Main Feedwater Flow	Primary to Secondary Power Mismatch	Turbine Trip	Reactor Trip	Core Power Excursion	Spurious "S" Signal
26) COOK 1	0	2	0	14	6	18	0	0
27) MILLSTONE 2	0	3	1	14	22	17	0	0
28) TROJAN	0	3	1	17	7	16	0	2
29) INDIAN POINT 3	0	0	0	7	0	2	0	0
30) CALVERT CLIFFS 2	0	1	1	9	11	5	0	0
31) SALEM 1	0	1	2	12	16	12	0	0
32) DAVIS-BESSE 1	0	5	4	7	10	12	0	0
33) FARLEY 1	0	6	6	25	15	3	0	0
34) NORTH ANNA	0	2	0	6	1	4	0	0
35) COOK 2	0	0	1	13	10	5	0	0
Total no. of events	1	82	96	586	424	548	13	12

TABLE 1.2-3

PLANTS AND OPERATIONAL YEARS INCLUDED IN PWR DATA BASE

Plant Name	Number of Transients*	Number of Years	Number of Transients/Year*
1) Yankee Rowe	74	17.66	4.2
2) San Onofre	39	12.32	3.2
3) Haddam Neck	64	12.42	5.2
4) R. E. Ginna	33	9.10	3.6
5) Point Beach 1	40	9.28	4.3
6) H. B. Robinson	165	9.27	17.8
7) Palisades	41	3.82	10.7
8) Point Beach 2	36	7.50	4.8
9) Surry 1	88	6.00	14.7
10) Main Yankee	18	3.12	5.8
11) Surry 2	50	5.61	8.9
12) Oconee 1	61	7.47	8.2
13) Indian Point 2	171	6.55	26.1
14) Prairie Island 1	49	5.92	8.3
15) Zion 1	77	4.28	18.0
16) Kewaunee	72	6.58	10.9
17) Fort Calhoun	19	5.49	3.5
18) Three Mile Island 1	5	1.73	2.9
19) Oconee 2	34	6.31	5.4
20) Zion 2	91	3.57	25.5
21) Oconee 3	32	6.04	5.3
22) Arkansas 1	31	5.39	5.8
23) Prairie Island 2	40	4.92	8.1
24) Rancho Seco	27	5.71	4.7
25) Calvert Cliffs 1	49	4.92	10.0
26) Cook 1	38	5.35	7.1
27) Millstone 2	57	4.43	12.9
28) Trojan	46	4.20	11.0

TABLE 1.2-3 (Cont.)

PLANTS AND OPERATIONAL YEARS INCLUDED IN PWR DATA BASE

Plant Name		Number of Transients*	Number of Years	Number of Transients/Year*
29)	Indian Point 3	9	0.34	26.5
30)	Calvert Cliffs 2	27	3.00	9.0
31)	Salem 1	43	3.51	12.3
32)	Davis-Besse 1	38	3.11	12.2
33)	Farley 1	55	2.28	24.1
34)	North Anna 1	13	1.72	7.6
35)	Cook 2	29	2.50	11.6
	Total	1761	201.42	360.2**

* From Table 1.2-2

** Average

TABLE 1.2-4

SUMMARY OF STEAM GENERATOR TUBE EXPERIENCE

	No. of Plants	Plant-Years	Tube-Years
Westinghouse (Inconel Tube)			
US plants	31	233.4	2,456,000
Foreign plants	10	69.8	491,000
Subtotal	41	303.2	2,947,000
Westinghouse Licensee plants			
MHI	7	41.8	328,000
FRA	20	54.9	555,000
Miscellaneous W Licensee Plants	3	23.5	181,000
Subtotal	30	120.2	1,064,000
TOTAL	71	423.4	4,011,000

TABLE 1.2-5

TUBE RUPTURE EXPERIENCES SUMMARY

Event No.	Occurrence Date	Plant (startup date)	Attributed Cause	Estimated Leak Rate
1	Feb. 26, 1975	Point Beach 1 (Oct. 70)	Phosphate Wastage + SCC	125 gpm (1)
2	Sept.15, 1976	Surry 2 (Jan. 73)	Denting + SCC	80 gpm (1)
3	June 25, 1979	Doel 2 (June 75)	Ovality + SCC	135 gpm (1)
4	Oct. 2, 1979	Prairie Island (Aug. 73)	Loose Part (spring)	390 gpm (1)
5	Jan. 25, 1982	Ginna (Sept. 69)	Loose Part (plate)	634 gpm (2)

Ref.

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