REVIEW OF THE DCPRA: Letter Report-04/Rev.1

A REVIEW OF SYSTEM ANALYSIS IN THE DCPRA: AUXILIARY SALTWATER SYSTEM

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May 1989

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Prepared for
U.S. Nuclear Regulatory Commission
Washington, DC 20555
Contract No. DE-AC02-76CH00016
FIN A-3958

1. INTRODUCTION

1.1 Objectives

The main objective of this letter report is to summarize the results, to date, of reviewing the unavailability analysis of the auxiliary saltwater (ASW) system described in the DCPRA.[1] An additional objective is to determine a new value for the initiator "Total Loss of Auxiliary Saltwater (LOSW)" based on generic plant experience appropriately updated for Diablo Canyon with Bayesian techniques. This was done to compare with the currently used (PG&E) value obtained by calculating the total yearly failure frequency of the ASW system. All findings and insights listed in this report reflect BNL's current understanding of the DCPRA and as such must be considered interim results. Final results for this analysis will be provided in the NUREG/CR document to be issued at the end of the project and will reflect, at that time, any additional supporting input submitted by PG&E as well as any direct feedback on these preliminary findings.

1.2 Organization of the Report

Chapter 2 provides a brief description of the configurations and the functions, the dependency on support equipment, the surveillance and maintenance conditions, the unavailability modelling in the DCPRA, and the original PRA results. The purpose of this approach is to present to the reader stand alone documentation to which the review's findings can be directly compared. Chapter 3 contains the results of the BNL review and presents the current preliminary findings including a new value for the LOSW initiator.

For completeness, the documentation of the information used by BNL for determination of the initiator frequency (LOSW) is presented in Appendix A. In addition, the ranked cut sets of hardware unavailabilities (both independent and total) obtained by BNL for a representative condition (AS1) and the calculated initiator values are given in Appendix B.

2. UNAVAILABILITY MODELLING OF THE AUXILIARY SALTWATER SYSTEM IN THE DCPRA

2.1 System Description, Configurations and Functions

The function of the Diablo Canyon auxiliary saltwater (ASW) system is to provide cooling water to transfer heat from the component cooling water (CCW) system to the Pacific Ocean. The ASW system of Unit 1 consists of two trains. Each train includes the motor-operated ASW bay gate, an ASW pump, the discharge check and manual isolation valves, the secondary side of the Component Cooling Water (CCW) System heat exchanger, and the exhaust fan that supplies ASW pump room ventilation, when the pump is running.

Two normally open train-to-train crosstie valves insure that each pump can serve both CCW heat exchangers. If Unit 1 ASW pumps fail, Unit 2 pumps are able to provide flow to Unit 1 equipment through opening of a normally closed unit crosstie valve. Equipment that can be considered common to both ASW pump trains of Unit 1 are the traveling screen and the train-to-train crosstie valves.

The ASW system is normally operating with one pump running and one CCW heat exchanger in service. The non-operating ASW pump is in a standby mode. It starts automatically

a. on low header pressure,
b. bus transfer to startup power,
c. diesel generator start, or on
d. safety injection signal.

If the ocean temperature exceeds 64°F it is manually started. The ASW pump bay gates are normally open so the standby pump has an available suction source. ASW ventilation fans start automatically when the ASW pumps start and stop when the pumps stop.

2.2 Top Event Definition, Success Criteria

Associated with the unavailability of the ASW function, the DCPRA defines only one top event to be used in the support system event tree ("mechanical" part). The designator of this top event is: AS. It is evaluated for 14 boundary conditions depending on the initiator and/or the unavailability of ASW trains of Unit 1 and Unit 2. One of the boundary conditions, "Loss of ASW Supply to Unit 1 (designator: ASI)" was taken as an initiator among one of the initiator groups of the DCPRA called: "common cause initiating events." The name of the boundary condition as initiator is: "Total Loss of Auxiliary Saltwater (LOSW)" as was mentioned in Section 1.1. Its value is computed as: ASI = LOSW.

The AS model assumes that initially pumps 1-1 (Unit 1) and 2-1 (Unit 2) are the normally running pumps. The other two pumps are in standby.

The success criteria of the top event AS is described in Table 2.1 for post accident injection and recirculation phases, as well as for normal plant cooldown. For comparison, the success criteria for ASW required by the DCFSAR[2] are also indicated.

2.3 Logic Model, Dependency on Other Support Systems

The logic model of the top event AS describes the system configuration shown in Figures 2.1 and 2.2. The logic model is constructed from blocks (supercomponents) of AS components. The boundaries of the blocks are given in Figures 2.1 and 2.2.

The logic model itself is shown by the diagram in Figure 2.3. The diagram indicates the logic relationship among the blocks and the dependencies on trains or supercomponents of the plant (ac and dc) electrical systems. The start signal to the standby ASW pump is provided either by auto start circuitry or by the Solid State Protection System (SSPS) (discussed in Letter Report-01), given an event that generates such an actuation signal.

2.4 Boundary Conditions of Top Event AS

Top event AS was evaluated for 14 boundary conditions (including the initiating condition, ASI). The boundary conditions (except ASI) resulted from initiating events with and without offsite power available and the combination of the various states of the electrical systems of both Units 1 and 2. To be more specific, when offsite power was assumed to be available, only the auto start of the standby ASW pump on low discharge pressure was modelled and all Unit 2 support systems were taken to be available. In the case of loss of offsite power, the ASW pumps were required to restart automatically and function after the vital busses had been re-energized. In this case it was not assumed that all Unit 2 support systems were available.

Different operator failures were applied for modelling the opening of the inter-unit crosstie valve depending upon whether this operation required remote or local actions. The detailed list of the boundary condition definitions and the designators of the associated top event split fractions are given in Table 2.2.

2.5 Quantification of Top Event Split Fraction, AS

The methodology of systems analysis applied in the DCPRA requires that the top event "split fraction" (associated with a system under a given boundary condition) should reflect the notion that the system (or its portion) in question is in one of the following mutually exclusive alignments: 1) normal alignment, 2) testing alignment, 3) maintenance alignment, or 4) misalignment. Thus, the contribution to the system unavailability from a specific alignment is determined by the conditional system unavailability, given that the system is in that alignment multiplied by the fraction of time that the system spends in that alignment. That is the way that the DCPRA considers the constraints imposed by Technical Specifications which disallow simultaneous maintenance or test activities on redundant components and the human errors causing the system or its components (usually occurring after these activities) to be inoperable.

Table 2.3 lists the values of AS split fractions associated with the various boundary conditions quantified by PG&E. The table presents the total unavailabilities (TTL), along with the main contributors to the total unavailabilities, such as hardware (HW), maintenance (MN), test (TS), and human error (HE). At a given boundary condition the hardware contribution relates to the normal alignment, when no test or maintenance activities are being performed. To provide complete information, the table also indicates the two constituent parts of the hardware contribution to the unavailability: the independent (HWI) and the dependent (HWD, i.e., common cause) failures of the supercomponents.

The maintenance alignment is a significant contributor to the unavailability because it includes the demusseling and chlorination of the trains. Demusseling occurs every 60 days and takes four to five hours per train. During normal maintenance, only the pump of the train in maintenance is unavailable; the two heat exchangers still get cooling water from the running pump or through the crosstie to Unit 2. During demusseling, however, since the intertrain crosstie is closed, the train in maintenance would appear to become completely isolated and unavailable. In this case, the DCPRA changed the success criterion of the ASW system from 2/2 to 1/1. Unit 2 train demusseling and maintenance are modelled identically.

The test alignment is a small contributor to the unavailability because of the relatively short duration involved. During pump start testing the standby pump does not get a start signal if a low pressure condition develops on the discharge header (e.g., due to failure of the running pump) because the pressure sensor is isolated. The status of the ASW system in that case is equivalent to the case when a pump is in maintenance. The ASW pump operability test does not alter the normal configuration except once per year, when the vacuum breakers are tested. Vacuum breakers are used on this system to prevent the occurrence of water hammer (see more about this later in the report). During this test the intertrain crosstie is closed, and a situation similar to demusseling occurs.

Unavailability contributions due to operator failures to realign the system after test or maintenance were assumed to be negligible. This is because the crosstie valves and the motor-operated bay gates have position indicators in the control room and maintenance procedures require that the open status of the discharge isolation valve and the service readiness of the discharge pressure switch should be verified before an ASW pump would be returned to service.

2.6 Quantification of the Initiator: "LOSW"

The DCPRA models and quantifies the initiator LOSW as loss of all ASW supply to both of the Unit 1 CCW heat exchangers. The plugging of the ASW traveling screens is not included in the quantification, because given plugging the DCPRA assumes completely successful and timely mitigating actions.

Two fault trees were constructed by PG&E to determine the initiator frequency: one, describing the yearly failures of the ASW system during normal operation, and one describing the yearly failures of the system which occur when the running and the standby trains are rotated (26 times per year). The fault trees involve independent and dependent component failures of Unit 1 and Unit 2 trains as well as failures occurring during maintenance. The numerical results of the quantification obtained by PG&E are indicated at boundary condition ASI and denoted by "LOSW" in Table 2.3.

3. RESULTS OF THE BNL REVIEW

3.1 General

Special attention was directed by BNL to the review of the unavailability modelling and quantification of the auxiliary saltwater system based upon the following:

1. the DCPRA uses a "non-plant-specific experience-based" value for the LOSW initiator derived from a fault tree,

2. the system is exposed to rather harsh environmental effects (biological fouling, fast corrosion, etc.), and

3. it is an important support system impacting the safety of the majority of plant operations, including cold shutdown.

For the review, therefore, the following approach was used to check the adequacy of the DCPRA modelling for "system-specific" effects. BNL performed a survey of failure events involving the Service Water (SW) Systems at U.S. PWRs by using the RECON[3] data base and the NPE[4] operating events listing. After having determined the nature and characteristics of these failures, an evaluation was made as to how well the DCPRA model reflects this 'experience.' The evaluation was carried out by a thorough review of the failure modes involved in the AS top event logic diagram and by comparing the failure rates occurring in the associated fault trees (including those describing the initiator - LOSW) with failure rates used by the DCPRA in fault trees of standby systems. In order to check for calculational consistencies, all of the fault trees were requantified. (The fault trees are not reproduced here, they can be found in Chapter D.2.6 of the DCPRA.) Furthermore, sensitivity calculations were carried out to determine the impact of changes in the assumptions concerning the availability of the Unit 2 ASW trains. Finally, an attempt was made to independently determine a Diablo Canyon-specific LOSW initiator frequency based upon experience data.

3.2 Results of the Survey on SW Systems Failures

The results of the BNL survey on failures of SW systems at U.S. PWRs are presented in Appendix A. The failure events are classified into three groups;

a. operating events involving the total loss of the SW system due to component failures or due to environmental effects (Table A3),

b. operating events involving the total loss of the SW system due to system interactions (e.g., electrical failures) or other initiators (e.g., flooding) (Table A4), and

c. operating events involving the partial degradation of the SW system due to any cause (Table A5).

The results also revealed that partial degradation of the SW system is rather frequent and there are some dominant failure modes of the SW system as a result of proneness to failure of certain components. These dominant failure modes are:

a. Biological fouling and/or sediment deposition. This is an indication that the quality of the cooling water is not very well controlled since SW systems are typically of an open-cycle design. (Systems of open cycle design take and discharge cooling water from and to an ultimate heat sink such as; ocean, lake, river, pond, etc.) The affected components are generally strainers and heat exchangers which become clogged and restrict the flow of the cooling water.

b. Unusually high rate of corrosion of pipe walls, tubes, valves, and consequent leakage. Additionally, mechanical and electrical problems with the operation of the SW pumps.

Failures which lead to the complete loss of the SW function typically involve:

c. The unavailability of the intake structure due to
   1. problems associated with the traveling screens (clogging, corrosion, loss of motive power), and
   2. cold weather (icing) or flooding.

d. Loss of motive or control power to the operating train (systems interaction) associated with loss of redundancy owing to maintenance or procedural failures.

e. Mechanical or design failures of the SW pumps.

A significant failure mode of SW systems can occur with piping of steep slope. the steep slope creates a situation which may be conducive to water hammer, such as the event that happened at Diablo Canyon in 1982. The following is a quote from Diablo Canyon LER-275/82-10-07 (see Appendix A for further details).

> "the (Auxiliary Saltwater) system is susceptible to water hammer effects during anticipated operational transients. These transients include pump trip and restart sequences such as would occur following a loss of offsite power. The peak pressure observed during testing exceeded the 100 psig system design pressure specified in the FSAR. The cause of the system water hammer is believed to be water column separation and subsequent column recombination at a point of significant piping slope change."

The recovery times of the observed SW failure events (as estimated by examining the time evolution of the various events) indicate a distribution extending from a representative time period of 1-2 hours to more unpredictable time periods of a few hours or of even one or more days (weather, flooding).

It is noted that biological fouling and/or sedimentation do not tend to cause total loss of the SW system even though these are the dominant causes of partial degradation. This may be explained by the relatively long time

available for preventive actions after the failure is recognized for a given train or component.

3.3 Modelling of the ASW; Logic Diagrams, Fault Trees

The review of the unavailability modelling of the ASW system performed by BNL was based upon the latest version of the DCPRA information most recently provided by PG&E[5] and the data obtained from the BNL survey of SW failures described above. The information included the fluid flow diagrams with indication of the supercomponents, Technical Specifications, FSAR, as well as operating and surveillance test procedures relevant to the ASW system.

The review found that the DCPRA unavailability model of the ASW system only weekly reflects the industry-wide proneness of an SW train to be randomly blocked or to be prevented from functioning properly (e.g., by leaking) because of the environmental effects prevalent in such a system. Specific observations include:

1. Consider, e.g., the failure mode "Failure of the traveling screens, (ZTSC3P, plugging)." This is a common cause failure in the ASW unavailability model which one can take to be representative of some environmental effects. It was assumed in the DCPRA that this failure mode fails both trains at Unit 1 or both trains at Unit 2 but was not considered as a common mode failure for both units taken together. In other words, the cut set for common mode failure of the traveling screens for both units would be the Unit 1 common mode failure ANDED with the Unit 2 common mode failure. Even so, the DCPRA analysis identified it to be a leading contributor to the ASW systems' unavailability.
   In the initiator model, however, this failure mode was not included for Unit 1, on the basis that complete recovery was assumed. As was mentioned in Section 3.2, experience indeed gives some indication that these types of failures can be recovered (similar to loss of offsite power initiators). To neglect them completely, however, seems to be somewhat optimistic.

2. Demusseling (and chlorination) is performed on average once per 60 days for about 4.5 hours per train and has been assumed to be so effective, that the DCPRA did not consider the blockage of the ASW trains as a conceivable failure mode. Neither the ASW unavailability model, nor the model of the component cooling water system takes into account the "plugging of the shell side of the CCW heat exchangers."

3. The ASW unavailability model does not contain failure events which would reflect the frequent leakage/rupture failure events caused by corrosion and observed at numerous other plants.

4. In the ASW model, the same values were taken for the rate of the failure mode "pump fails to start" and for the pump maintenance frequency and duration as those used for pumps of standby safety systems or systems operating in closed cycles and using treated water.

5. As a consequence of neglecting the higher failure rate data observed throughout the industry for SW train components, the unscheduled switchover frequency between running and standby trains and the unscheduled maintenance contribution to the system's overall unavailability may be somewhat underestimated.

As concerns other aspects of the modelling, the review identified the following items:

6. The DCPRA changed the success criteria from 2/2 to 1/1 during demusseling activities and during testing of the vacuum breakers in order to avoid the guaranteed failure condition during these periods.

7. The DCPRA assumes that when an ASW train at Unit 2 is unavailable (failure state or in maintenance/demusseling/test) the other train of Unit 2 can still provide enough cooling flow for the CCW heat exchangers of both units. Such flow sharing may be possible in principle, but it should be supported by engineering calculations.

8. The DCPRA considers only unscheduled maintenance for Unit 2 trains. Large train overhauls lasting over a protracted period of time performed when Unit 2 is in cold shutdown were not included in the model. During this time the full flow from the running pump of Unit 2 is needed for Unit 2. These periods of complete unavailability of Unit 2 (in terms of Unit 1) should have been represented in the ASW unavailability model, particularly in the fault trees for the LOSW initiator. Similarly, periods when Unit 2 goes to cold shutdown or during warm ocean water conditions (when two ASW trains per unit are required) were omitted from the determination of the initiator frequency.

Additional information/resolution of the above eight items will be necessary in order for BNL to complete the review.

The ASW unavailability model is tacit about the possible occurrence of waterhammer given loss of offsite power. According to PG&E, the plant eliminated this problem by applying vacuum breakers (see LER No.82-009-01T-1, quoted also in Appendix A).

3.4 Audit and Sensitivity Calculations

In order to scrutinize the quantified split fractions themselves, BNL performed audit calculations for each of the split fractions associated with each of the boundary conditions. In these calculations the same assumptions, input data, maintenance frequency and duration values were used as in the DCPRA. The SETS-code[6] and locally generated PC software were used for the computations. The use of the SETS code allowed the identification of the most important cut sets contributing to the hardware unavailabilities. These cut sets are not readily accessible for direct review in the DCPRA. Appendix B lists the ranked cut sets for AS1 and for the initiator, LOSW, as example calculations. The definition of the basic events appearing in the cut sets are identical to those given in Appendix D.2.6 of the DCPRA, except HW1, HW2, HW3, and HW11. The definition of the latter events are indicated in Appendix B.

The results obtained by the audit calculations are presented in Table 2.3, denoted by "BNL1," to be compared with the values given in the DCPRA (PG&E). BNL also performed a sensitivity calculation for all the boundary conditions to see the impact on the split fractions of abandoning the DCPRA's assumption that a Unit 2 ASW train would still be available for Unit 1 even if the other Unit 2 train had failed or was in maintenance/demusseling/test. The results of this sensitivity calculation are denoted by "BNL2" in Table 2.3. One can observe that this latter assumption results in a considerable increase in the split fractions associated with some boundary conditions.

Comments

The BNL review and calculations have resulted in the following comments.

1. In the expanded block level fault tree (offsite power available) given in Figure D.2.6-5 there are some inconsistencies:
   a. In the sheet 1 of 5 (page D.2.6-38) for the events :loss of flow to header 11 only" and "loss of flow to header 12 only" one should use "AND" gates, instead of "OR" gates, given in the figure.
   b. In the sheets 4 of 5 and 5 of 5 (pages D.2.6-41, 42) the failure modes of the running and standby pumps are reversed.

2. For the failure modes "pump fails to start," "pump fails to run," as well as for similar failure modes of the fans, the single failure rates used in the fault tree quantification are higher than the total failure rates.

3. The DCPRA fault trees describing the initiator LOSW do not include unavailability contributors due to
   a. failure of the Unit 1 train-to-train crosstie,
   b. the maintenance of the unit-to-unit crosstie,
   c. the demusseling of standby trains at both units,
   d. failure of the demusseling process, and
   e. failure of the traveling screen at Unit 1 (but was considered in block E for Unit 2).

4. While it was assumed for the LOSW fault trees that failures of the traveling screen at Unit 1 can be successfully mitigated, there was no maintenance duration defined with these actions.

The audit calculations denoted by BNL1 were corrected for items 1 and 2 above. BNL2 calculations include these corrections and involve (as discussed before) the assumption that a Unit 2 ASW train cannot provide water to Unit 1 CCW heat exchangers if the other Unit 2 train is down due to failure/maintenance/ demusseling/test. In addition, the BNL2 calculation for LOSW includes corrections for items 3 and 4 above as well as a provision addressing train rotations and some scheduled outages of Unit 2 trains resulting in an unavailability value (for both trains) of .07.

3.5 Determination of Initiator Frequency, LOSW Based on Industry Experience

In order to compare the LOSW initiator frequencies obtained in the DCPRA by using ASW unavailability models with values based on industry experience, BNL made an attempt to determine such Diablo-Canyon-specific values by applying a Bayesian technique.[7]

Two approaches were used in the calculations:

A. The first approach was based on the observed frequency of appropriately selected LOSW events whose potential occurrence was deemed possible at the Diablo Canyon plant. According to this approach, the mean initiator frequency of LOSW events (non-recoverable within some time t) can be calculated if the Unit 1 ASW trains were independent of the Unit 2 trains, by the expression:

$$LOSW_E^A(1) = .85 * LOSW(1) * P(T \geq t) \qquad (1a)$$

and if the Unit 1 trains are dependent on Unit 2 trains (actual case) by the formula:

$$LOSW_E^A(1,2) = .85 * LOSW(1) * P(T \geq t) * R_C(2|1) \quad (1b)$$

$$= LOSW_E^A(1) * R_C(2|1)$$

where LOSW(1) is the "posterior" mean frequency of the selected LOSW events. The selected events are counted independently; i.e., events in which two units were involved counted twice. $P(T \geq t)$ is the probability that the time to recover a LOSW event will last longer than some given time, t. $R_C(2|1)$ is the conditional probability that given loss of both ASW trains at Unit 1, the Unit 2 trains also become unavailable. This quantity can be calculated by an ASW unavailability model. And .85 is the assumed capacity factor of a Diablo Canyon plant unit.

B. The second approach derives the mean initiator frequency directly from the experienced frequency of selected LOSW events when all SW trains of two units were lost. The mean frequency of these events non-recoverable within some given time t can be obtained by the formula:

$$LOSW_E^B(1,2) = .85 * LOSW(1,2) * P(T \geq t) \quad (2)$$

where LOSW(1,2) is the "posterior" mean frequency of LOSW events experienced at twin units. The two other quantities in Eq.2 are the same as those defined above.

The advantage of Approach A (compared to Approach B) is that its "statistical basis" is better than that of Approach B. However, its disadvantage is that Eq.1b is a hybrid expression; it still needs the calculated quantity $R_C(2|1)$.

The posterior frequency distributions of the quantities (LOSW(1) and LOSW(1,2) occurring in the above equations were determined by two-stage Bayesian updating calculations.

The first seven events of Table A.3 and the reactor-years listed in Table A.1 (except those of Diablo Canyon Units 1 and 2) were taken as "experience,"

and zero number of LOSW events during the operation times of both Diablo Canyon units was taken as "evidence" for the LOSW(1) frequency updating calculation. By assuming lognormal prior and posterior frequency distributions and by using "best estimate" parameters for the prior of the second stage updating, the obtained Diablo Canyon specific posterior mean, median, standard deviation, 5th and 95th percentile values are presented in Table 2.4 (see "experience based values").

The calculation of the frequency distribution LOSW(1,2) is based on the San Onofre events, when Unit 2 and Unit 3 SW trains were lost, and on the (overlapping) reactor-years associated with multi-plants listed in Table A.2. The Diablo Canyon specific posterior values are also given in Table 2.4 (see also "experience based values").

In order to determine the recovery probability of LOSW events, all the events listed in Table A.3 were used. Event No.8 was also included in the sample to represent some fraction of LOSW events which are non-recoverable within (say) 12 hours. An exponential distribution was assumed for the recovery probability density function:

$$f(t) = \lambda e^{-\lambda t}, \ t \geq 0, \ \lambda \geq 0. \tag{3}$$

Thus, the distribution function

$$F(t) = P(T \leq t) = \int_{o}^{t} f(x)dx, \tag{4}$$

gives the probability that a LOSW event will be recovered within t hours, and

$$P(T \geq t) = 1-F(t) \tag{5}$$

provides the probability that the time to recover a LOSW event will be longer than some given time, t.

The cumulative distribution of the LOSW events as a function of the time to recover, the fitting curve, (Eq.5), as well as the ninety percent

uncertainty bounds are shown in semi-logarithmic representation in Figure 2.4. The maximum likelihood estimate of the parameter λ is given by the expression:

$$\lambda = N/\Sigma\ t_i = .271/\text{hour} \qquad (6)$$

where t_1, t_2, ..., t_N represent the sample data, and $1/\lambda = \bar{t}$ is the mean time to recovery.

Based on a rough estimate of the heat capacity of the water available in the CCW system given a LOSW ($t_1 \sim$ ½ hour) and the time necessary to develop a seal LOCA with appreciable leak rate given unavailable cooling ($t_2 \sim 1.5$ hours), the critical time for non-recovery of LOSW events was taken to be $t_1 + t_2 \sim 2$ hours. At this point in time the probability of non-recovery of an LOSW event was estimated from the best fitting curve in Figure 2.4 to be $P(T \geq 2) = .57$.

The conditional probability $R_C(2|1)$, that Unit 2 ASW trains become unavailable for Unit 1 CCW heat exchangers given loss of both ASW trains at Unit 1 was determined by the ratio:

$$R_C(2|1) = \frac{LOSW_C(1,2)}{LOSW_C(1)}\ , \qquad (7)$$

where $LOSW_C(1,2)$ denotes the calculated frequency of total loss of ASW trains at both Diablo Canyon units, Unit 1 and 2, and $LOSW_C(1)$ denotes the calculated frequency of total loss of ASW trains belonging only to Unit 1.

The value of $LOSW_C(1,2)$ is identical to the values of LOSW listed in Table 2.3 for the cases "BNL1" and BNL2". For the sake of completeness, however, they are again presented in Table 2.4 (see "model based values"). Table 2.4 also shows the corresponding values for $LOSW_C(1)$ and $R_C(0|1)$.

For comparison, a ratio based on the experienced data and defined as

$$R_E = \frac{LOSW(1,2}{LOSW(1)}$$

is also calculated and presented in Table 2.4. This value is indicative of the large dependence between the failures of the ASW trains at twin units.

After all the necessary quantities were determined, Eqs. 1a, 1b, and 2 were evaluated. The obtained mean values for the initiator frequencies, $LOSW_E^A(1)$, $LOSW_E^A(1,2)$ and $LOSW_E^B(1,2)$ are given in Table 2.4 (see "experience" and "experience and model" base values).

A comparison of the purely model-based initiator values with those obtained by experience or by "experience and model", shows that there is a satisfactory agreement between the following values:

a. If Unit 1 ASW trains were independent of Unit 2 trains:

$LOSW_C(1) = 5.16\text{-}3/ry$ ("BNL2") and $LOSW_E^A(1) = 4.14\text{-}3/ry$.

b. Actual situation:

$LOSW_C(1,2) = 5.62\text{-}4/ry$ ("BNL2") and $LOSW_E^A(1,2) = 4.51\text{-}4/ry$.

Since these values are higher than the initiator values ($LOSW_C(1,2)$) calculated by using the original PG&E assumptions (PG&E, BNL1) it appears that the DCPRA has underestimated the real value of the LOSW initiator by at least a factor of 5.

The underestimation is exacerbated if one compares the experience-based value, $LOSW_E^B = 2.23\text{-}3/ry$ with the frequencies given above at b., because even those values seem to underestimate the real value. According to BNL calculations, the "real" value of the LOSW initiator, $LOSW_R(1,2)$ lies in the interval:

$$LOSW_E^B(1,2) = 2.23\text{-}3/ry < LOSW_R(1,2) \leq LOSW_E^A(1,2) = 4.51\text{-}4/ry.$$

Fine-tuning this interval to yield the "real" value would require much more realistic modelling of both the inter-unit dependency and the ASW trains and using more accurate information about the unavailabilities of Unit 2 trains.

3.6 Conclusion

The BNL review identified several apparent discrepancies in the modelling of the ASW system in the DCPRA. If these apparent discrepancies are determined to be real discrepancies as the review progresses, it will mean that the top event split fractions for certain boundary conditions and the calculated initiator frequency associated with the total loss of the ASW system will have been underestimated in the DCPRA.

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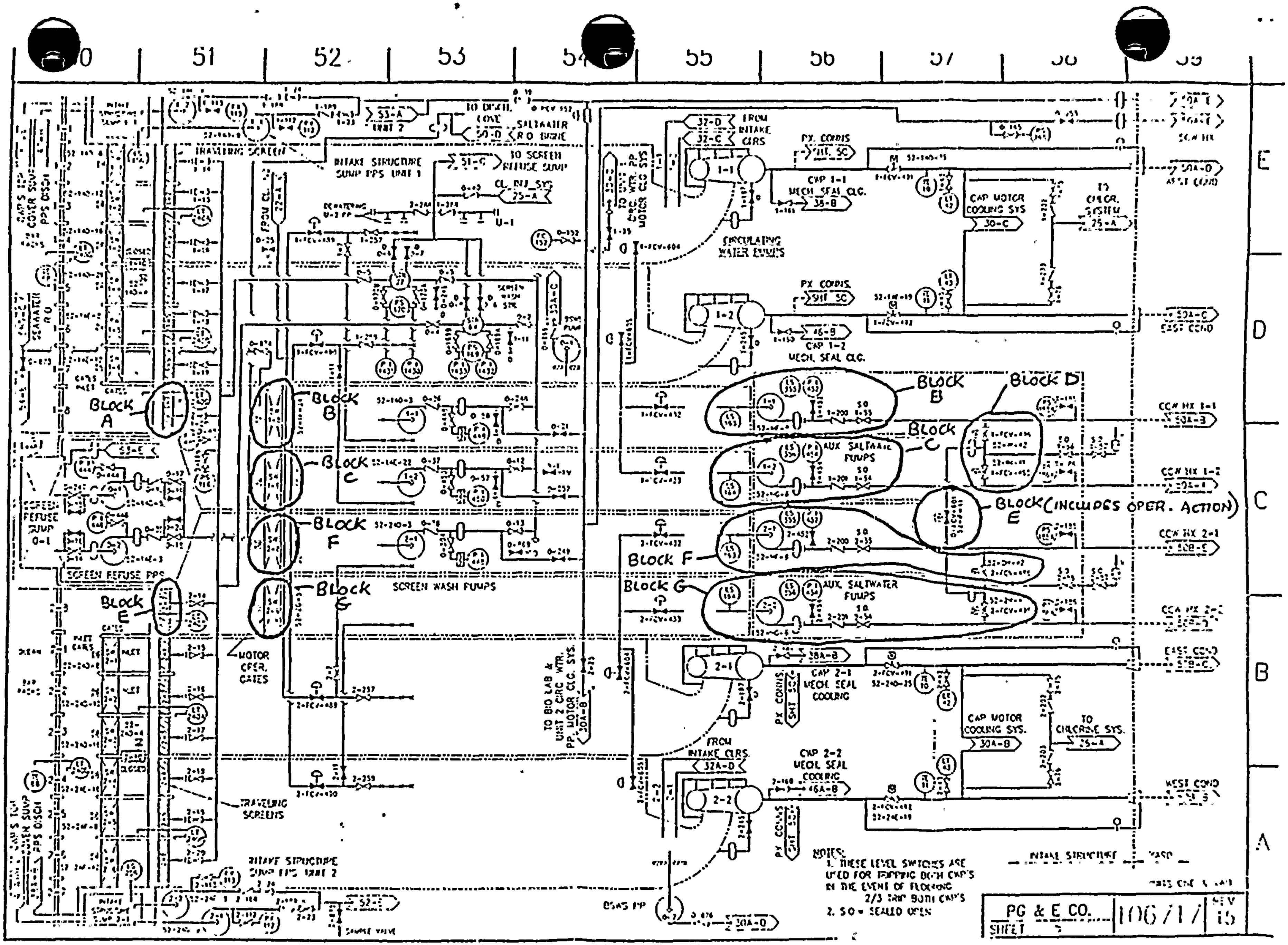


Figure 2.1. Top event, AS - Supercomponents. Auxiliary Saltwater System.

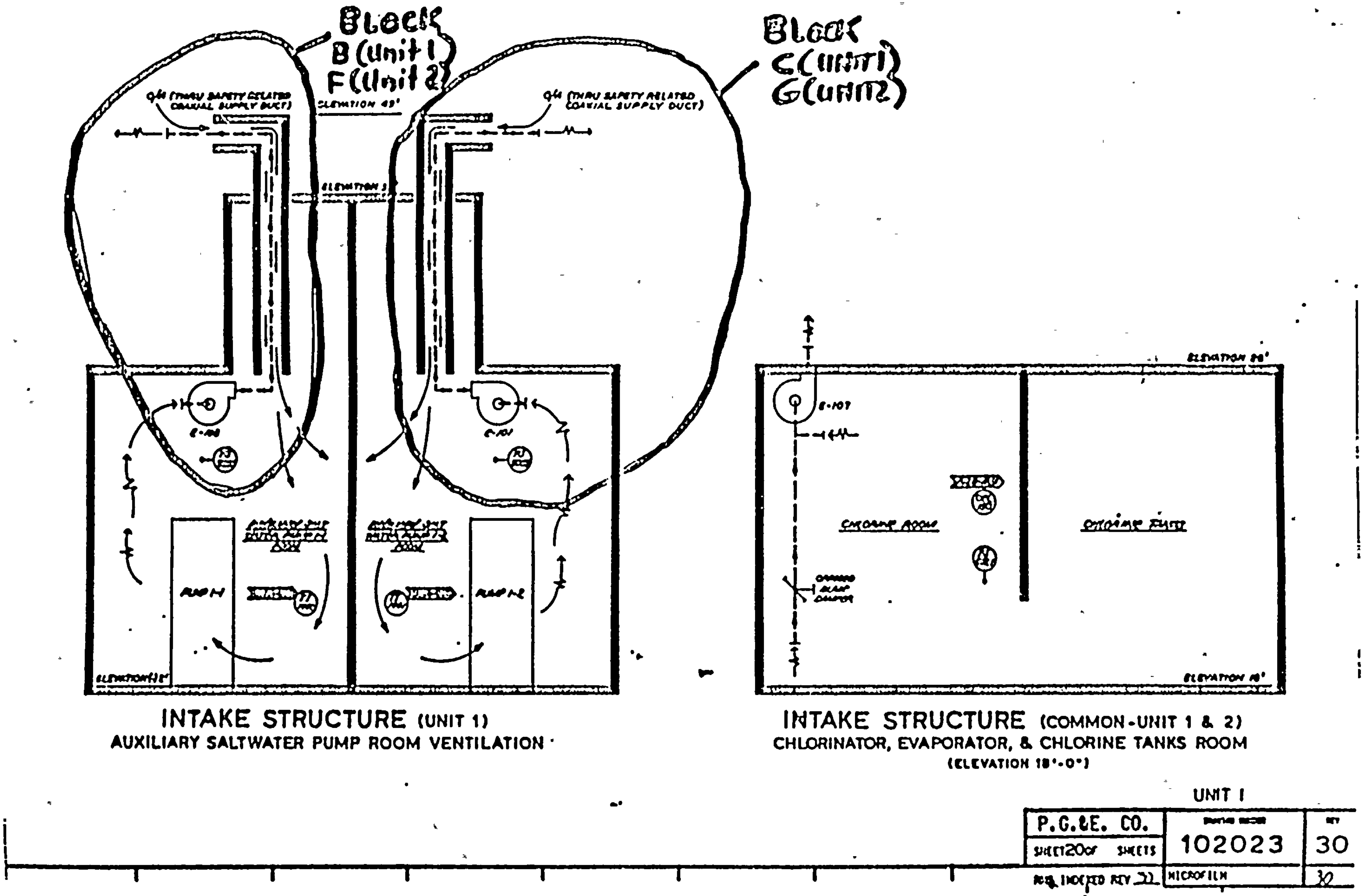
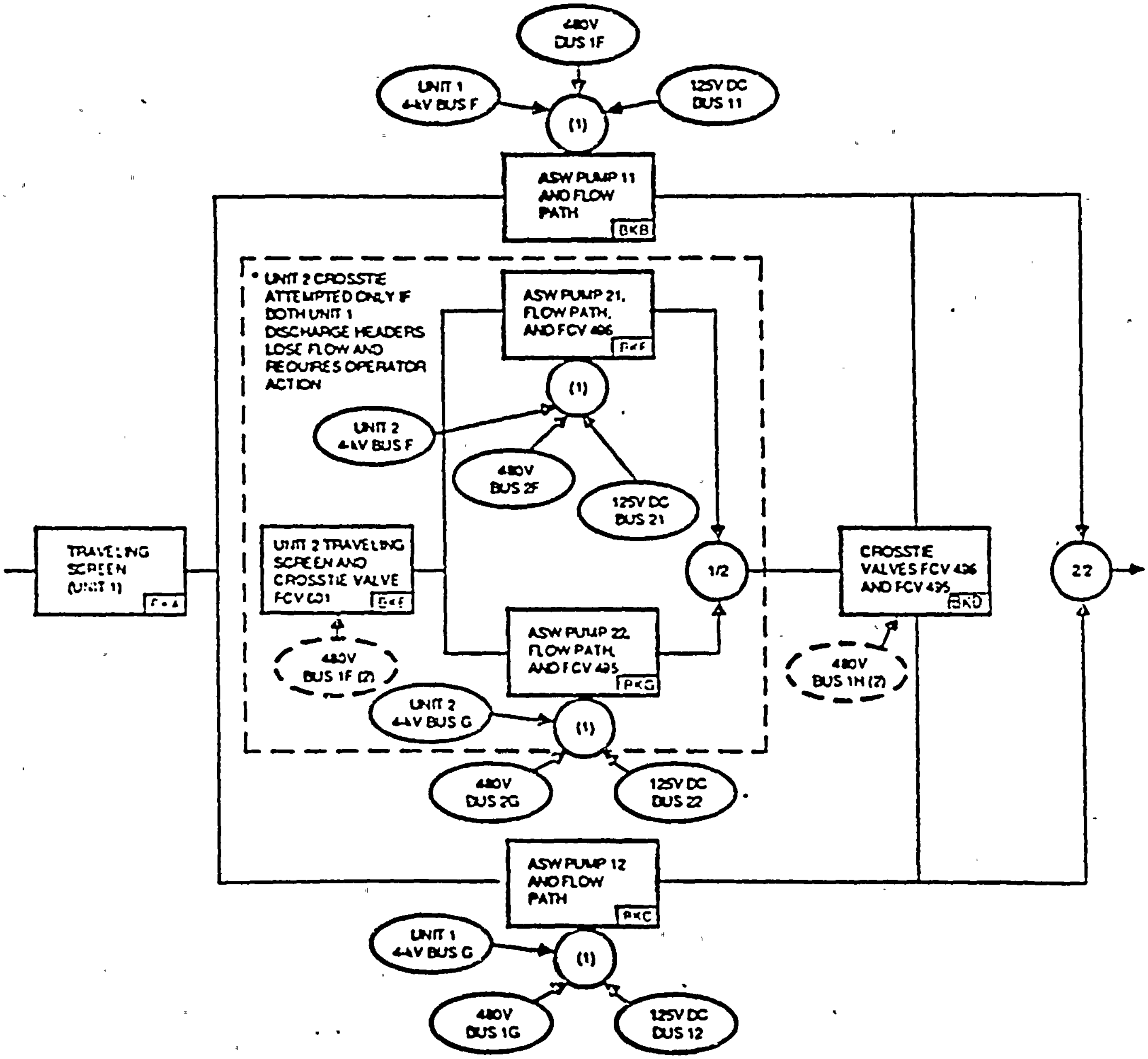


Figure 2.2. Top event, AS - Supercomponents. Auxiliary Saltwater System.



NOTES:

(1) DC AND 4kv POWER REQUIRED TO START STANDBY PUMPS

(2) DASHED LINES INDICATE SUPPORT SYSTEMS THAT ARE NOT REQUIRED

Figure 2.3. Logic diagram for top event, AS and initiator, LOSW.

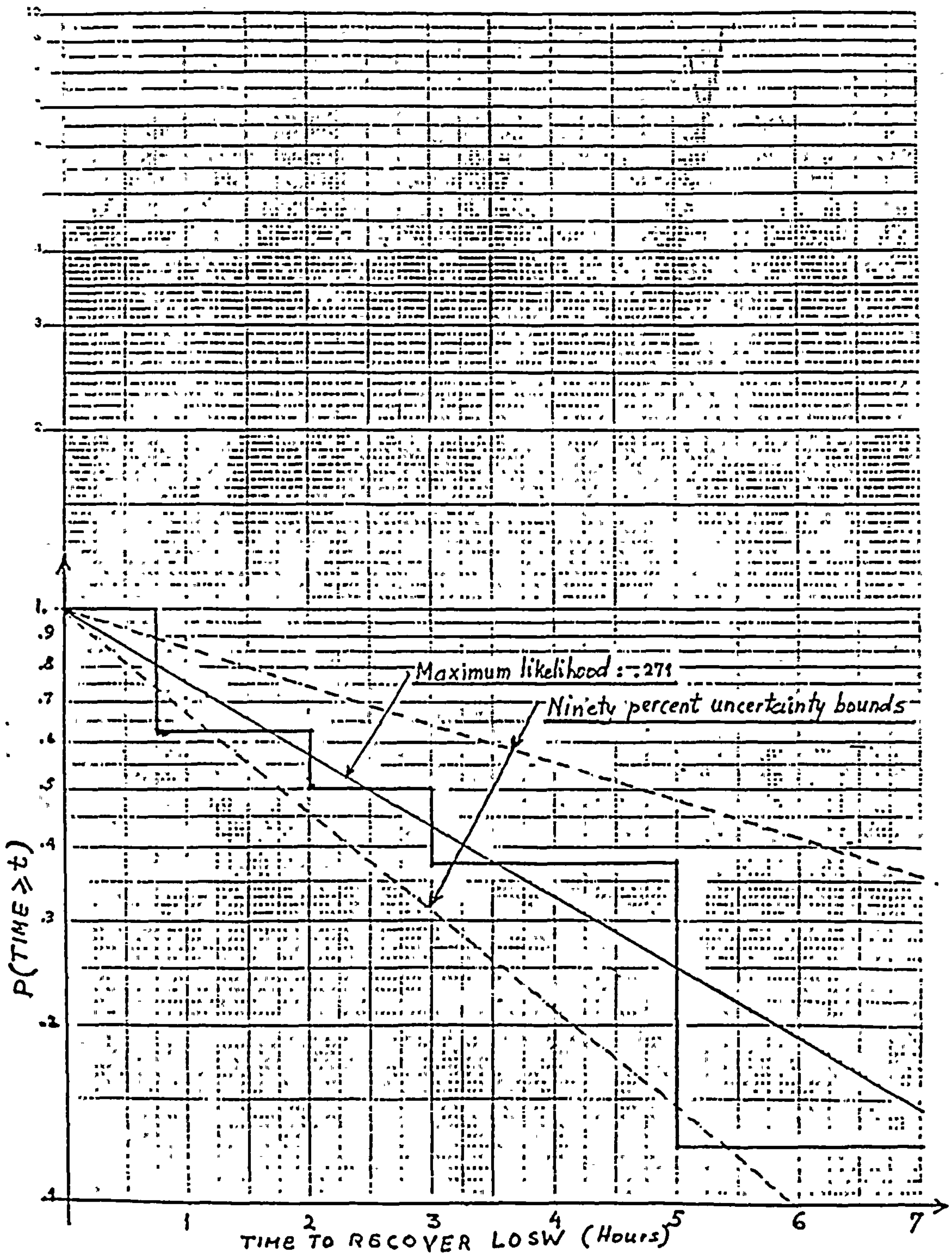


Figure 2.4. Exponential model for non-recovery of LOSW events.

Table 2.1
Top Event Definition and Success Criteria
Auxiliary Saltwater Function

Top Event Designator	Top Event Definition	Top Event Success Criteria
AS	ASW provides cooling water to Unit 1 CCW heat exchangers during 24 hours following an initiating event.	1. Post accidental injection and recirculation phases. Cooling water is required to be available to both CCW heat exchangers of Unit 1 for all initiating event (of course, except LOSW). Even if both Unit 1 ASW pump trains fail, top event AS still succeeds if the operator aligns a Unit 2 ASW pump train to supply the Unit 1 CCW heat exchangers by opening a crosstie valve. 2. Under normal plant cooldown conditions. Two operable ASW pump trains to two CCW heat exchangers are required for success (trains are operated separately). The unavailability of CCW heat exchangers is modelled in the CCW analysis.

FSAR Success Criteria:

Applicability: Modes: Power operation, 1; Startup, 2; Hot standby, 3; Hot shutdown, 4. At least two auxiliary saltwater trains shall be operable.

Action: With only one ASW train operable, restore at least two trains to operable status within 72 hours or be in at least hot standby within the next six hours, in cold shutdown (Mode 5) within the following 30 hours.

[illegible]

Table 2.2
Boundary Conditions for Top Event, AS

Split Fraction ID	Boundary Condition
AS1	No LOSP. All pump trains available (2 running, 2 standby). Power at Unit 1 available for 4.16kV Busses F and G and 125V DC Bus 12. Open crosstie valve, remotely: OP1.
AS2	No. LOSP. Three pump trains available (Train 11 fails). 4.16kV Bus F failed at Unit 1. Open crosstie valve, manually: OP2.
AS3	No LOSP. Three pump trains available (Train 12 fails). 4.16kV Bus G or 125V DC Bus 12 failed at Unit 1. OP1.
AS4	No LOSP. Two pump trains available (Trains 11 and 12 fail). 4.16kV Bus F and 4.16k Bus G or 125V DC Bus 12 failed at Unit 1. OP2.
AS5	LOSP. Three pump trains available (Train 11 fails). 4.16kV Bus at Unit 1 fails. OP2.
AS6	LOSP. Three pump trains available (Train 21, Unit 2, fails). 4.16kV Bus at Unit 2 fails. OP1.
AS7	LOSP. Two pump trains available (Trains 11 and 12 fail). 4.16kV Busses F and G failed. OP2.
AS8	LOSP. Two pump trains available (Trains 11 and 21 or 22 fail). 4.16kV Bus F at Unit 1 and 4.16kV Busses F or G at Unit 2 failed. OP2.
AS9	LOSP. Two pump trains available (Trains 12 and 21 failed). 4.16kV Bus G at Unit 1 and 4.16kV Bus F at Unit 2 failed. OP1.
ASA	LOSP. Two pump trains available (Trains 21 and 22 failed). 4.16 Busses F and G at Unit 2 failed. Useless operator action to open crosstie valve, because both Unit 2 trains are unavailable, OPF.
ASB	LOSP. One pump train available (Trains 11, 12 and 21 or 22 failed). 4.16kV Busses F and G failed at Unit 1 and 4.16kV Busses F or G at Unit 2 failed. OP2.
ASC	LOSP. One pump train available (Trains 11 or 12 and 21 and 22 failed). 4.16k Busses F or G at Unit 1 and 4.16kV Busses F and G at Unit 2 failed. OPF.
ASI	Initiator. Total loss of ASW for Unit 1.
ASF	Guaranteed failure.

Table 2.3
Unavailability Values (Split Fractions) for the Auxiliary Saltwater System Function

Top Event	Case	Calc.	TTL	HW	HWI	HWD	MN	TS	HE	Comment #
AS	AS1	PG&E	1.849-6	1.598-6	1.574-6	2.406-8	2.459-7	4.811-9	----	
		BNL1	1.809-6	1.555-6	1.531-6	2.340-8	2.493-7	4.774-9		
		BNL2	3.256-6	1.555-6	1.531-6	2.340-8	1.666-6	3.505-8		
	AS2	PG&E	3.550-4	2.458-4	2.452-4	6.438-7	1.068-4	2.531-6	----	
		BNL1	3.614-4	2.480-4	2.474-4	6.340-7	1.108-4	2.579-6		
		BNL2	4.532-4	2.480-4	2.474-4	6.340-7	2.014-4	3.779-6		
	AS3	PG&E	1.224-4	2.349-5	2.344-5	5.028-8	9.778-5	1.151-6	----	
		BNL1	1.631-4	2.361-5	2.356-5	5.000-8	8.722-5	5.226-5		
		BNL2	2.617-4	2.361-5	2.356-5	5.000-8	1.796-4	5.847-5		
	AS4	PG&E	1.686-2	1.664-2	1.664-2	5.223-7	2.189-4	5.233-6	----	
		BNL1	1.666-2	1.644-2	1.644-2	5.200-7	2.215-4	5.222-6		
		BNL2	2.944-2	1.644-2	1.644-2	5.200-7	1.291-2	3.044-4		
	AS5	PG&E	3.582-4	2.481-4	2.453-4	2.804-6	1.083-4	1.909-6	----	
		BNL1	3.637-4	2.502-4	2.474-4	2.800-6	1.115-4	1.943-6		
		BNL2	4.968-4	2.502-4	2.474-4	2.800-6	2.438-4	2.837-6		
	AS6	PG&E	7.857-6	5.321-6	2.912-6	2.408-6	2.499-6	3.518-8	----	
		BNL1	7.068-6	4.573-6	2.191-6	2.382-6	2.460-6	3.500-8		
		BNL2	4.559-5	4.573-6	2.191-6	2.382-6	4.008-5	9.316-7		
	AS7	PG&E	1.693-2	1.667-2	1.665-2	1.424-5	2.595-4	4.651-6	----	
		BNL1	1.674-2	1.647-2	1.646-2	1.410-5	2.629-4	4.648-6		
		BNL2	3.166-2	1.647-2	1.646-2	1.410-5	1.291-2	2.283-3		
	AS8	PG&E	4.709-4	2.806-4	2.660-4	1.461-5	1.881-4	2.324-6	----	
		BNL1	4.685-4	2.780-4	2.635-4	1.450-5	1.881-4	2.343-6		
		BNL2	1.082-2	4.193-3	4.157-3	3.647-5	6.511-3	1.142-4		
	AS9	PG&E	2.741-4	1.016-4	8.702-5	1.455-5	1.705-4	2.007-6	----	
		BNL1	2.635-4	9.549-4	8.124-5	1.425-5	1.661-4	1.963-6		
		BNL2	1.065-2	4.023-3	3.987-3	3.650-5	6.510-3	1.142-4		
	ASA	PG&E	1.834-4	1.315-4	1.172-4	1.424-5	5.104-5	9.113-7	----	
		BNL1	1.799-4	1.271-4	1.130-4	1.409-5	5.190-5	9.171-7		
		BNL2	1.799-4	1.271-4	1.130-4	1.409-5	5.190-5	9.171-7		
	ASB	PG&E	2.699-2	2.063-2	2.060-2	3.674-5	6.369-3	1.141-4	----	
		BNL1	2.697-2	2.053-2	2.049-2	3.647-5	6.457-2	1.142-4		
		BNL2	1.000	1.000						

Table 2.3 (Continued)

Top Event	Case	Calc.	TTL	HW	HWI	HWD	MN	TS	HE	Comment #
	ASC	PG&E	1.065-2	4.171-3	4.134-3	3.674-5	6.369-3	1.141-4	----	
		BNL1	1.179-2	4.193-3	4.157-3	3.647-5	6.457-3	1.141-4		
		BNL2	1.179-2	4.193-3	4.157-3	3.647-5	6.457-3	1.141-4		
LOSW	ASI	PG&E	9.734-5	9.734-5	9.004-5	6.975-6	----	----	----	
		BNL1	9.588-5	9.588-5	8.894-5	6.943-6				
		BNL2	5.616-4	5.616-4	5.411-4	2.038-5				
	ASF	PG&E	1.0							
		BNL	1.0							

Table 2.4
Unavailability Model and Experience Based Frequencies of the LOSW Initiator
Unit capacity factor: .85
Probability of non-recovery of LOSW, P(T≥2) = .57

Quantity		Frequency [LOSW Events/ry] Mean	Standard Deviation or Variance	5th Percentile	Median	95th Percentile	$R = \frac{LOSW(1,2)}{LOSW(1)}$
1. Model based values Loss of ASW trains at Unit 1 (they are assumed to be independent of Unit 2 ASW trains)							
$LOSW_C(1)$	BNL1	2.48-3					
	BNL2	5.16-3					
Loss of ASW trains at Units 1 and 2 (see also Table 2.3)							
$LOSW_C(1,2)$	PG&E	9.73-5	1.89-8,V.	2.47-5	6.23-5	1.97-4	
	BNL1	9.56-5					.039
	BNL2	5.62-4					.109
2. Experience based values Loss of SW trains at Unit 1 ("posterior"), LOSW(1)		8.55-3	7.55-1,S.D.	2.01-3	6.60-3	2.16-2	
Eq.1a, initiator, $LOSW_E^A(1)$		4.14-3					
Loss of SW trains at Units 1 and 2 ("posterior"), LOSW(1,2)		4.60-3	7.07-1,S.D.	1.14-3	3.60-3	1.14-2	.538
Eq.2, initiator, $LOSW_E^B(1,2)$		2.23-3					

Table 2.4 (Continued)

Quantity		Frequency [LOSW Events/ry] Mean	Standard Deviation or Variance	5th Percentile	Median	95th Percentile	$R = \frac{LOSW(1,2)}{LOSW(1)}$
3. <u>Experience and model based values</u> Loss of ASW trains at Units 1 and 2							
Eq.1b, $LOSW_E^A(1,2)$	BNL1	1.68-4					
	BNL2	4.51-4					

APPENDIX A: Information on Failures of the Service Water System

This appendix provides the documentation of information used to analyze the nature of failures occurring at the Service Water Systems of US PWRs and to determine the frequency of the initiator "Total Loss of Auxiliary Saltwater, LOSW" for Diablo Canyon based on generic plant experience.

The information includes:

a. the total time exposure of service water systems (SWS) at US PWRs (Table A.1),
b. the classification of SWSs for multi unit PWR sites (Table A.2),
c. a list of failure events obtained by a survey of the RECON data base[3] and the NPE operating event listings[4] when the SWS is completely lost for one or more units due to failures of the system itself or due to certain activities at the unit which is down (Table A.3),
d. a list of failure events when the SWS is completely lost or susceptible to fail due to systems interaction (Table A.4),
e. a detailed description of the events listed in Tables A.3 and A.4, and
f. a list of failure events when the SWS becomes partially degraded (Table A.5).

Table A.1
Total Time Exposure of Service Water Systems at U.S. PWRs

Plant Name	Start of Commercial Operation	Number of Years to End of 1988
Calvert Cliffs 1	5/75	14.27
Calvert Cliffs 2	4/77	12.5
Haddam Neck	1/68	21.5
Indian Point 2	7/74	15.0
Beaver Valley 1	4/77	12.3
Beaver Valley 2	11/87	1.7
Three Mile Island 1	9/74	14.8
Three Mile Island 2	12/78	5.8
Main Yankee	12/72	16.0
Indian Point 3	8/76	12.9
Millstone 2	12/75	13.0
Millstone 3	4/86	3.3
Salem 1	6/77	12.1
Salem 2	10/81	7.8
Robert E. Ginna	3/70	19.3
Yankee	6/61	28.1
Zion 1	12/73	15.6
Zion 2	9/74	14.8
Byron 1	9/85	3.8
Byron 2	8/87	1.9
Braidwood 1	3/88	.3
Braidwood 2	9/88	.1
Palisades	12/71	17.6
Donald C. Cook 1	8/75	13.9
Donald C. Cook 2	7/78	11.0
Prairie Island 1	12/73	15.6
Prairie Island 2	12/74	14.6
Fort Calhoun 1	9/73	15.8
Davis-Besse 1	11/77	11.7
Callaway 1	4/85	4.3
Point Beach 1	12/70	18.6
Point Beach 2	10/72	16.8
Kewaunee	6/74	15.1
Wolf Creek	9/85	3.8
Joseph M. Farley 1	12/77	11.6
Joseph M. Farley 2	7/81	8.0
Arkansas Nuclear One 1	12/74	14.6
Arkansas Nuclear One 2	3/80	9.3
Robinson 2	3/71	18.3
Shearon Harris	5/87	2.2
Oconee 1	7/73	16.0
Oconee 2	9/74	14.8
Oconee 3	12/74	14.6
McGuire 1	12/81	7.6

Table A.1 (Continued)

Plant Name	Start of Commercial Operation	Number of Years to End of 1988
McGuire 2	3/84	5.3
Catawba 1	6/85	4.1
Catawba 2	8/86	2.9
Turkey Point 3	12/72	16.6
Turkey Point 4	9/73	15.8
St. Lucie 1	12/76	12.6
St. Lucie 2	8/83	5.9
Crystal River 3	3/77	11.7
Vogtle 1	5/87	2.2
Waterford 3	9/85	3.8
Virgil C. Summer 1	1/84	5.5
Sequoyah 1	7/81	8.0
Sequoyah 2	6/82	7.1
Surry 1	12/72	16.6
Surry 2	5/73	16.2
North Anna 1	6/78	11.1
North Anna 2	12/80	8.6
Palo Verde 1	1/86	3.5
Palo Verde 2	9/86	2.8
Palo Verde 3	2/88	0.4
South Texas Project 1	3/88	0.3
Diablo Canyon 1	5/85	4.2
Diablo Canyon 2	3/86	3.3
Trojan	5/76	13.2
Rancho Seco	4/75	14.3
San Onofre 1	1/68	21.5
San Onofre 2	8/83	5.9
San Onofre 3	4/84	5.3

Total: PWR (72) = 751.4 Reactor Years

Note: Use of the commercial operation date precludes an indeterminate amount of system operation time prior to that point. An attempt has been made to correlate the reported failures to this same time frame.

Table A.2
Classification of Service Water Systems for Multi-Unit PWR Sites

Multi-Unit Plants	Service Water Pumps/1 Unit	Success Criterion for Highest Load	Separate Water Source (Or Intake)
ANO 1 & 2	2 + 1 Swing	1 of 2	Yes
Beaver Valley 1 & 2	2 + 1 Swing	1 of 2	
Braidwood 1 & 2	2	1 of 2	
Byron 1 & 2	2	1 of 2	
Calvert Cliffs 1 & 2	3	2 of 3	
Catawba 1 & 2	2	1 of 2	Yes
Cook 1 & 2	2	1 of 2	
Diablo Canyon 1 & 2	2	1 of 2	
Farley 1 & 2[1]	2	1 of 2	
Indian Point[2]	9	3 of 9	Yes - two separate intakes from the same source.
McGuire 1 & 2	2	1 of 2	Yes
North Anna 1 & 2[3]	2	1 of 2	Yes
Oconee 1 & 2	1 + 1 Swing	1 of 1	
Oconee 3	2	1 of 2	
Palo Verde 1, 2 & 3[4]	2	1 of 2	
Point Beach 1 & 2	3 (6/2 units)	3 of 6 (2 units)	
Prairie Island 1 & 2	2 + 1 Swing	1 of 2	Yes - two separate intakes from the same source.
Salem 1 & 2	6	4 of 6	
San Onofre 1, 2 & 3[5]	4	1 of 4	
Sequoyah 1 & 2	4	2 of 4	
South Texas 1 & 2	3	2 of 3	
St. Lucie 1 & 2	2 + 1 Swing	1 of 2	Yes
Surry 1 & 2[6]	3/2 units	2 of 3/2 units	
Turkey Point 3 & 4	3	2 of 3	
Vogtle 1 & 2	6 (3/trains)	2 of 3/trains	
Watts Bar 1 & 2	4	2 of 4	
Zion 1 & 2	3	1 of 3	

[1] SW pumps take suction from the SW wet pit, which is directly supplied by 5 pumps/1 unit from the ultimate heat sink (river) and the success criteria for these pumps are 2-out-of-5.
[2] Both essential and non-essential loads are included.
[3] Two auxiliary SW pumps are available. However, the power supply for these pumps are non-safety related.
[4] The ESW system is on standby during normal operation. There is no crossties between the units.
[5] Each SW train has two pumps, but only one is powered during normal operation.
[6] The SW pumps (3/2 units) are only for emergency purposes. The normal supply is by gravity flow from the circulating water system.

Table A.3
Total Loss of the Service Water System

Event	Plant	Reference	Recovery	Description
1	San Onofre 1	LER-206/80-06	~45 Min.	One ESW pump shaft sheared due to excessive vibration, the discharge valve of the standby pump didn't open and the auxiliary pump lost suction.
2	TMI-2	LER-320/81-11	≥2 Hours*	One ESW pump lost due to vibration other pump unavailable.
3	Salem 2	LER-311/83-32	~1 Hour	Flooding in ESW bay due to a gasket failure.
4,5	San Onofre 2 & 3	LER-361/83-72	>5 Hours*	Traveling screens were damaged, CCW heat exchangers clogged.
6	Catawba 1	LER-413/85-68	~45 Min.	Both ESW trains declared inoperable due to torque switch problems on the discharge valves.
7	Crystal River	LER-302/86-02	≥3 Hours*	All ESW pumps are shut down, two divers drowned.
8	Oconee 1	LER-269/86-11	---	Loss of LPSW suction due to inadequate design.

*Estimated.

Description of Operating Events Involving the Total Loss of the SW System Function (Table A.3).

1. San Onofre 1 - LER-206/1980-006

During normal operation, the south salt water cooling pump (SCP) discharge pressure dropped sharply. The north salt water cooling pump (NCP) automatically started on low pressure. However, its discharge POV failed to open. The auxiliary salt water cooling pump (ACP) was then started but flow could not be established. As a result of (1) excessive vibration, the shaft of the (SCP) sheared, (2) mechanical failure, the (NCP) POV did not open, and (3) apparent inadequate prime, the (ACP) lost suction. The POV on the (NCP) was manually opened and the (ACP) regained suction.

2. TMI 2 - LER-320/1981-001

On April 23, 1981, the "A" nuclear service river water pump was started for operation. The pump exhibited high vibrations and high current readings. An evaluation showed that the pump should be declared inoperable to prevent further damage. The inoperable status resulted in a violation of Tech Spec since the "B" pump had been declared inoperable in October 1979. The cause of this event was most likely due to excessive clearance at the bottom of the pump which caused excessive vibration leading to damage. Procedures were rewritten to ensure that backup pumps are powered to provide cooling water to operating diesels.

3. Salem 2 - LER-311/1983-032

On June 23, 1983, during routine shutdown operation, an equipment operator performing routine surveillance discovered a large leak in the No. 2 service water bay. Due to the accumulation of approximately six feet of water in the bay, and an apparently continuing rise in the water level following an initial attempt to isolate the leak, all service water pumps were stopped, resulting in the loss of flow to the boron injection, residual heat removal and diesel generator system. Investigation revealed that the leakage was due to a failed

gasket in the joint downstream of check valve 225; the gasket failure was attributed to an isolated problem in installation related to poor access to the joint. The connection had recently been opened then remade during cleaning of the No. 21 nuclear header. Related problems with the bay sump pumps and alarms will be corrected by a design change.

4,5. San Onofre 2 & 3 - LER-361/1983-072, LER-362/1983-041

On July 6, 1983 at 0030 while Unit 2 was in mode 5 and Unit 3 was in mode 4 operator observed that the Unit 3 circulating water system traveling screen water level differential pressure was off scale indicating clogging of the screens. The screen wash system was actuated to clear the screens of marine debris. The screen wash system failed to clear the screen. The inability to clear the screens resulted in high CCW heat exchangers (Unit 2 train A and Unit 3 trains A and B) differential pressure being alarmed in the control room at 0210 on July 6, 1983, and at 0227 SCW flow was reduced to the point that the heat exchangers were declared inoperable. This resulted in exceeding limiting condition for operation (LCO) 3.7.4 for Unit 3, only, since the LCO is applicable to modes 1 through 4 and Unit 2 was in mode 5. Exceeding LCO 3.7.4, for Unit 3, resulted in invocation of LCO 3.0.3. Visual inspection of the traveling screens after the incident revealed that several screen panels were dislodged from their housings either before or during this event resulting in marine debris to be carried into the circulating water pump forebay. To preclude concurrent fouling of both trains of CCW heat exchangers during excessive marine debris buildup in a single intake structure, C system operating procedure is being revised.

6. Catawba 1 - LER-413/1985-068

On November 25, 1985, the in service test on the nuclear service water (RN) header 1B supply isolation valve was performed. While stroking the valve, it stopped in the intermediate position. Train B of RN was declared inoperable and train A of RN was placed in service. Upon starting RN pump 1A, the discharge isolation valve also stopped in the intermediate position. Train A of RN was declared inoperable and Technical Specification 3.0.3 was entered due

to the simultaneous inoperability of both trains of RN. Both trains of RN were inoperable for 43 minutes until the RN header 1B supply isolation valve was opened and train B of RN was declared operable. Investigation revealed that the torque switches for the valves were set at the low end of the allowable tolerance. These settings did not allow the valves to open completely. Therefore, this incident is classified as a design deficiency. Unit 1 was at 45% power.

7. Crystal River - LER-302/1986-002

On January 10, 1986, Crystal River Unit 3 was in mode 5 during an outage. The intake structure was being cleaned and inspected by two contract divers. At 1615, one diver failed to reappear following his dive. The second diver attempted to locate and rescue the missing diver but was himself drowned. When the second diver was reported to be in trouble, all seawater pumps taking suction at the intake structure were secured, thus disabling both trains of the decay heat removal system. The body of the second diver was recovered shortly thereafter. The first diver was found to have been drawn into the 48" suction line of the 'A' emergency nuclear services and decay heat seawater system pumps (both pumps were running at the start of the event). The body of the first diver was recovered in the auxiliary building. All seawater pumps were voluntarily secured and/or disabled in an attempt to prevent loss of life.

8. Oconee 1 - LER-269/1986-011

On October 1, 1986, with Units 1 and 3 at 100% full power, and Unit 2 shutdown for refueling, a load shed test on Unit 2 was performed. Suction to the low pressure service water (LP) pump was lost about one hour into the test. The loss prime in the condenser circulating water (CCW) siphon flow (or emergency CCW) system was the cause for the loss of the LP pumps. The emergency condenser circulating cooling water (ECCW) system is required to provide water through the main condenser for decay heat removal during loss of all ac power event (station blackout). The immediate corrective action was to analyze the failures that occurred during the load shed test, and shut down Oconee Units 1 and 3. Subsequent corrective actions included redesign of the

CCW pump flanges and determination of the design basis of the ECCW system. The root cause of this event is the inadequate design and testing of the ECCW system. This led to a failure of the ECCW system to perform the intended function as described in the final safety analysis report (FSAR).

Events not included in the statistics.

San Onofre 3 LER-362/1986-011

Power level - 100% at 1550 on August 4, 1986, saltwater cooling (SWC) flow through train a component cooling water heat exchanger (CCWHX) decreased, due to fouling with marine growth, to below the postulated design basis flow rate required for removal of CCW heat loads (critical CCW loop), and was therefore declared inoperable. At this time Train B CCWHX was operating with reverse SWC flow to remove similar fouling which had previously taken place. At 1605, operators commenced realignment of Train B CCWHX SWC flow to the normal direction in order to return one train of CCW to its design configuration and thereby increase heat removal capability of that train. During the realignment, both trains of the SWC system were considered to be inoperable contrary to technical specification limiting condition for operation (LCO) 3.7.4, and LCO 3.0.3 was entered. Train B SWC system was returned to operable status within thirty minutes, and at 1635, LCO 3.0.3 was exited. As corrective action, operating procedures will be revised to minimize the effect of marine fouling on the operability of the SWC system.

Table A.4
Total Loss of Service Water Due to Other Initiators

Event	Plant	Reference	Recovery	Description
1	Salem 1	NPE/PWR-2 VIII-110, 1976	Few days*	Winter storm shuts down the ESW system. Traveling screens blocked by ice.
2	Farley 1	NPE/PWR-2 VIII-155, 78	~3 Days	Flooding of the intake structure.
3	Salem 1	LER-272/82-15	~1 Hour	Vital bus 1A tripped, operating ESW train is lost, other train in maintenance.
4	Calvert Cliffs	LER-318/82-54	~30 Min.	Power was lost on a 4 kV bus resulting in the loss of ESW pump on the operating loop. Other train in maintenance.
5	Palisades	LER-255/84-01	~1 Hour	Offsite power removed, no operable service water pump supplied by the operating diesel.
6	Salem 1	LER-272/84-14	~1 Hour	Vital bus 1A failed, bus 1B in maintenance, bus 1C didn't energize, loss of ESW system.

Description of Operating Events Involving the Total Loss of the SW System Due to Systems Interaction (Table A.4.).

1. Salem 1 - NPE/PWR2, VIII-110, 1976

Numerous problems were experienced with the plant service water system. The first serious problem was noted in January 1976 when a winter storm shut down the system. Icing due to wind whipped spray and screen wash spray created four inches of ice on the operating deck of the structure making it hazardous to operators and caused the traveling screens in operation to ice-over thereby restricting flow to the pumps. Screens which were out of service froze in their tracks causing shear pins to fail when the screen was started. The eventual buildup of ice and debris resulted in the shutting down of the remaining pumps due to low flow. Some modifications were made to the system, however, the major improvement, a heated protective housing, had not yet been installed.

2. Farley 1 - NPE/PWR-2, VIII-155, 1978

At ~2100 hours on January 25th, 600V load centers 1H and 1J, which were located in the river water structure, were de-energized when flooding of this structure occurred. The flooding was the result of high Chattahoochee River levels following heavy rains. The water level in the train A side of the river water structure was ~1 ft. The river level at this time was ~110 feet mean sea level (MSL). The river water pumps were still operable. They set up temporary sump pumps to supplement the permanently installed pumps. The Tech Specs required that load centers 1H and 1J be operable, energized, and aligned to an operable DG.

At 2300 hours a 50% reduction in turbine load was initiated. Power to river water pumps 8A, 9A, 10A was racked out at 2330 hours. At 0007 hours on January 26th, the unit was at 40% reactor power and 430 MWe. At 0040 hours a further load reduction was initiated at 5 MW/min to place the unit in hot standby as required by the Tech Specs. At 0045 hours power to river water pumps 4B and 5B was racked out, and the rate of load reduction was increased to

10 MW/min to have the unit in hot standby within the required one hour. At 0055 hours emergency service water recirculation flow to the pond (ultimate heat sink) was initiated. At 0135 hours the unit was taken off line and at 0136 hours the reactor was manually tripped. The water level in the river water structure train A section reached ~5 feet; train B section reached 2 feet. The river reached a maximum level of ~115 feet MSL at the river water structure.

Water had entered the structure through a hole in each river water pump baseplate and through the gland seal leakoff line on each pump. Additional leakage occurred through compression type cable penetrations of structure.

3. Salem 1 - LER-272/1982-015

Number 1A vital bus tripped resulting in a loss of component cooling water (CCW) and service water (ESW) flows; the redundant CCW and pumps were tagged out for maintenance. All charging pumps, boron injection flow paths, residual heat removal (RHR) loops and diesel generators were declared inoperable due to no CCW or flow. A wire to the TD5 undervoltage relay had shorted to the feeder cubicle door, causing the 1A vital bus infeed breaker to trip without automatic transfer. CCW and flows were restored.

4. Calvert Cliffs 2 - LER-318/1982-054

At 0547, during normal shutdown operation in mode 6, power was lost to 24 4kV bus resulting in the loss of 22 saltwater pumps and 22 LPSI pumps, thereby disabling the only operable shutdown cooling loop. Power was restored to 24 4kV bus and shutdown cooling flow restored at 0605. The redundant shutdown cooling loop was out of service for maintenance. Vendor failure report indicated the cause of the power supply failure to be cracked printed circuit board.

5. Palisades - LER-255/1984-001

On January 8, 1984, the Palisades Nuclear Plant experiences a complete loss of all normal communications links between the plant, the NRC and state/local authorities. The event was precipitated by the need to isolate a faulty switchyard breaker. To accomplish the isolation, it was necessary to interrupt the offsite power supply to the plant. At the time of the event, Palisades was in a refueling outage with all fuel removed from the reactor and one diesel generator inoperable. While operating procedures require two operable diesel generators prior to removing offsite power, the shift supervisor proceeded with the evolution after determining the safety of the fuel would not be jeopardized. In preparing for the evolution, the operators failed to realize that there would be no operable service water pumps supplied by the operating diesel. Consequently, after 50 minutes the diesel overheated due to lack of cooling water and was manually tripped. The resulting loss of onsite ac power caused a loss of all plant telephones and radios for 45 minutes. Onsite power was subsequently re-energized from the switchyard, resulting in the restoration of normal communications.

6. Salem 1 - LER-272/1984-014

On June 5, 1984, during a refueling outage, 1A vital bus was de-energized when the 1A vital bus infeed breaker failed to close during breaker testing. Since 1B vital bus was de-energized for inspection at the time, a blackout loading signal started 1A and 1C diesels and opened the 1C vital bus infeed breaker, de-energizing 1C vital bus. 1A diesel loaded, but because the 1C 125V dc bus was de-energized for maintenance, the 1C safeguards equipment cabinet (SEC) was completely de-energized. This prevented 1C diesel from loading. 1C vital bus remained de-energized, resulting in a loss of service water cooling. Numerous control room indicators failed to mid-scale, leading the shift to believe that the 1C vital bus was still energized. As a result, the diesels ran for an extended period of time without cooling water; although, no diesel damage occurred. The root cause of this event was the lack of adequate procedural and/or administrative controls to ensure sufficient electrical systems remained in an operable status during a period when the plant was in a configuration which was not covered by the Tech Specs (i.e., defueled).

Diablo Canyon - LER-275/82-10-18

Testing performed on the auxiliary saltwater (ASW) system has revealed that the system is susceptible to water hammer effects during anticipated operational transients. These transients include pump trip and restart sequences such as would occur following a loss of offsite power. The peak pressure observed during this testing exceeded the 100 psig system design pressure specified in the FSAR. The cause of the system waterhammer is believed to be water column separation and subsequent column recombination at a point of significant piping slope change. Further evaluation of the event and ASW system design is being conducted. Results of the evaluation will be reported in a revision to this LER.

Diablo Canyon - LER-275/84-03-02

Prior to fuel load, testing on the Auxiliary Saltwater (ASW) System has shown that the system is susceptible to water hammer effects during anticipated operational transients. These transients include pump trip and restart sequences which would occur following a loss of offsite power. Peak pressures observed exceeded the 100 psig system design pressure specified in the FSAR and some valve damage did occur.

The cause of ASW System water hammer is water column separation and subsequent column recombination at a point of significant piping slope change. Corrective actions included the replacement of damaged valves, additional engineering analysis, the installation of vacuum breakers and further testing to ensure system operability.

Pacific Gas and Electric Company, Diablo Canyon Unit 1, Docket No.50-275, LER 82-009-01T-1 - Supplemental Information

Engineering analysis has shown the root cause of the ASW system water hammer to be water column separation (resulting in vacuum formation) and subsequent column recombination at the point of significant piping slope change. A detailed inspection of the Auxiliary Saltwater (ASW) System was

conducted after the pressure transients to inspect for damage. This inspection also included the ASW pump discharge check valves. There was no evidence of deformation in system piping due to the water hammer (pressure transient). Two butterfly valves, the ASW Pump 1-2 discharge isolation valve and the Component Cooling Water heat exchanger 1-1 inlet isolation valve, suffered damaged valve discs. These valves were replaced. In 1983, vacuum breakers were installed in the ASW system to reduce the pressure transients of subsequent column recombination. Further testing conducted after vacuum breaker installation verified that, for all operating conditions of the ASW system, pressure transients greater than maximum allowable system pressure will not occur.

Table A.5
Operating Events Involving the Degradation of the Service Water System

Plant	Reference	Description
San Onofre 1	LER-206/80-01	Pipe support installation error in SW system.
	/80-08	Pipe support corroded on one SW pump.
	/80-31	Discharge valve on pump failed to open automatically.
	/81-09	HX partially blocked, marine growth.
	/82-07	Pressure switch failed, pump discharge valve closed.
	/82-15	Intake structure flooded to dangerous levels, inadequate maintenance procedures.
	/82-22	One pump bearing degraded, other pump out for maintenance, auxiliary SW pump put in service.
	/82-24	Discharge valve opens, reverse flow through pump resulting in damage.
	/84-08	Corrosion of the intake structure.
Haddam Neck	LER-213/83-01	SW leak in fan cooler due to corrosion.
	/83-10	SW filter plugged.
	/86-09	SW flood protectors are ineffective.
Ginna	LER-244/83-01	SW valve failed to open to AFW pump.
Indian Point 2	LER-247/80-16	SW leak in fan cooler coils.
	/81-09	SW pipe wall thinning.
	/81-10	Valve seat problem, reduces pump capacity.
	/81-11	Pipe wall thinning, corrosion.
	/81-21	SW pipe leak.
	/82-13	SW pump vibration excessive.
	/82-26	Impeller wear of three SW pumps.
	/82-31	SW leak in containment.
	/82-33	SW leak in fan coolers.
	/82-37	SW leak in fan coolers.
	/83-07	Strainer plugged.
	/83-10	Pump inoperable, rope tied the impeller.
	/84-11	Leak into the CCW pump.
	/84-21	SW pump discharge valves leak.
	/85-13	SW leak in fan coolers.
	/87-11	SW pumps fail performance tests, vortexing.
Turkey Point 3	LER-250/86-08	SW system design deficiency.
	/86-18	SW system design deficiency.
	/86-24	SW pump inoperable.
Turkey Point 4	LER-251/84-18	Strainer removed for longer period as allowed.

Table A.5 (Continued)

Plant	Reference	Description
	LER-251/87-16	SW pump tripped, electrical problems.
	/87-28	Two of three SW pumps are inoperable.
Palisades	LER-255/82-24	SW design problem.
	/86-24	Loss of coolers, SW valve problems.
	/86-36	SW pumps performs below requirements.
H. B. Robinson 2	LER-261/81-19	SW booster pump tripped, bearing and breaker problems.
	/82-13	SW pump failed to restart, blown fuse.
	/83-03	Leak in the CF cooler.
	/83-05	Two of four SW booster pumps lost.
	/83-06	SW pump and its replacement fails, longer in AOT than allowed.
	/83-14	SW leak at CF cooler.
	/83-22	SW leak at CF cooler.
	/83-27	SW leak at CF cooler.
Oconee 1	LER-269/80-02	HPSW inoperable, motor insulation broke down.
	/80-04	HPSW inoperable, motor cooler leakage.
	/80-24	Automatic initiation of HPSW was affected by construction.
	/80-30	Valve failed to close in SW system.
	/81-14	HPSW pumps A and B had no control powers, breakers were open, jockey pump used in place.
	/86-02	Seismic design deficiency in LPSW system.
	/87-04	SW heat exchanger capacity reduced, biological fouling.
Oconee 2	LER-270/80-10	SW valves fail in closed position.
	/81-01	Improper alignment of SW valves.
Salem 1	LER-272/80-22	SW solenoid valve failure isolates CFCU coil.
	/80-23	SW flow reduced to CFCU, inoperable flow transmitter.
	/80-24	Solenoid on SW line failed, no flow to CFCU.
	/80-39	Solenoid on SW line failed, no flow to CFCU.
	/80-49	SW piping leak at charging pump.
	/80-60	SW valve mispositioned, all DG inoperable.
	/81-03	SW pipe leak, CCW HX removed from service.
	/81-10	SW pipe leak, CF coil inoperable.

Table A.5 (Continued)

Plant	Reference	Description
	/81-11	SW pipe leak, CF coil inoperable.
	/81-12	SW hose leak.
	/81-31	SW pipe leak, CFCU inoperable.
	/81-39	SW pipe leak, CFCU inoperable.
	/81-46	SW valve failure blocks flow to CFCU.
	/81-64	SW pipe leak at CFCU.
	/81-67	SW valve failure reduces flow to CFCU.
	/81-69	SW valve failure reduces flow to CCW HX.
	/81-71	SW flow XMTR line plugged.
	/81-76	SW pipe leak at CFCU.
	/81-77	SW pipe leak at CFCU.
	/81-80	SW pipe leak at CFCU.
	/81-83	SW pipe leak, charging pump operation affected.
	/81-90	SW pipe leak, CCW HX.
	/81-94	SW pipe leak, CFCU.
	/81-96	SW pipe leak, CFCU.
	/81-114	SW pipe leak, CFCU.
	/81-119	SW pipe leak, charging pump.
	/81-121	SW pipe leak, CFCU.
	/82-18	SW valve leaks in containment.
	/82-22	SW flow control valve fails, reduces flow to CFCU.
	/82-24	SW flow control valve fails, reduces flow to CFCU.
	/82-29	SW flow control valve fails, reduces flow to CFCU.
	/82-37	SW flow control valve fails, reduces flow to CFCU.
	/82-41	SW pipe leak, charging pump affected.
	/82-69	SW pipe leak, charging pump affected.
	/82-91	SW leak, CCW HX.
	/83-15	SW valve malfunction, DG inoperable.
	/83-26	SW valve plugged, CFCU inoperable.
	/83-68	SW line freezes - fire OG inoperable.
	/84-06	SW line leak, CFCU.
	/84-08	SW pipe corrosion near CCW HX.
	/84-27	SW pipe leak at CFCU.
	/85-06	SW pipe leak at CFCU.
	/85-08	SW pipe leak at CFCU.
	/86-14	SW valve to turbine lube oil fails, reactor trip.
Surry 1	LER-280/80-54	SW MOV failed to cycle.
	/80-65	SW MOV failed due to marine growth.
	/82-100	Loss of one SW pump due to personnel error.

Table A.5 (Continued)

Plant	Reference	Description
	/82-124	SW inlet valve to RS HX was inadvertently closed, loss of one train.
	/83-42	SW strainer clogged.
	/86-24	SW lines in chillers are clogged.
	/86-30	SW lines clogged, marine growth.
	/86-31	SW strainer malfunction, personnel error.
	/86-34	SW strainer clogged.
	/87-02	SW valve malfunction, chiller affected.
	/87-03	SW valve malfunction, chiller affected.
	/87-05	SW strainer malfunction, chiller affected.
	/87-06	SW low flow to chiller, electrical trouble.
	/87-07	SW leak at chiller.
	/87-08	SW valve malfunction affecting chiller.
	/87-18	SW strainer clogged.
	/87-21	SW strainer clogged.
	/88-07	SW flow problems (manual control).
Surry 2	LER-281/80-28	Check disk missing in SW subsystem.
	/80-37	SW strainer clogged, charging pump affected.
	/81-21	SW strainer clogged, charging pump affected.
	/81-34	SW strainer clogged, charging pump affected.
	/81-47	SW MOV breaker open at CCW HX.
	/81-51	SW MOV failed to close.
	/81-73	SW MOV malfunction.
	/81-76	SW MOV malfunction.
	/82-02	SW check valve failed on booster pump discharge.
	/82-09	SW valve failure, flow obstructed.
	/82-39	SW MOV flooded.
	/82-45	SW MOV breaker open - CCW HX.
	/82-49	SW strainer leaking.
	/82-50	SW strainer clogged, booster pump lost.
	/82-52	SW flow indicator fails, reduces flow.
	/82-54	SW MOV flooded.
	/83-25	SW MOV malfunction.
	/83-26	SW MOV breaker open.
	/83-50	SW strainer clogged.
	/85-02	Improper alignment of SW flow to HX.
	/86-06	SW leak in containment spray HX.
Prairie Island 1	LER-282/83-18	Intake device fails, some SW pumps tripped.
	/83-21	SW isolation MOV failed.
	/85-03	SW valve inadvertently closed.

Table A.5 (Continued)

Plant	Reference	Description
	/85-16	SW leak at CFCU.
	/87-07	SW booster pump fails due to deposition.
	/87-08	SW booster pump air bound, procedural error.
Fort Calhoun 1	LER-285/81-05	Relay problems in the starting circuit.
	/87-01	Three SW pumps are unavailable for two hours.
Indian Point 3	LER-286/81-04	SW supply to non-essential HDR lost, both supply pumps are in maintenance.
	/83-06	Seismic restraining plates removed, possible failure during a DBA.
	/87-07	Pipe snubbers failed.
Oconee 3	LER-287/81-10	SW valve air line break.
	/83-08	SW valve failed, CFCU affected.
TMI-1	LER-289/80-15	SW RTD failed.
Zion 1	LER-295/80-18	SW valve failed, AFW pump affected.
	/80-24	SW pump failed to start, electrical switch problem.
	/81-07	SW pipe section made to non-safety specifications.
	/83-32	SW MOV failure.
	/84-04	SW leak at CFCU.
	/85-39	SW crosstie valve between two units cycled, loss of SW, standby pump started.
	/86-01	SW valves inadvertently closed, isolates AFW for three weeks.
Crystal River 3	LER-302/84-11	SW pump discharge check valve stuck open.
	/85-24	Cracked pipe support pedestal at CCW HX.
	/85-35	Design deficiency, fire may affect various pumps.
	/87-20	Design discrepancy in SW system temperatures.
Zion 2	LER-304/80-17	SW pump disabled due to electrical fault at dc bus.
	/80-30	SW MOV failure.
	/81-14	SW MOV failure.
	/81-17	SW valve inoperable, loss of initiating signal.

Table A.5 (Continued)

Plant	Reference	Description
	/81-36	SW valve inoperable, loss of initiating signal.
	/82-09	SW valves fail, silt deposition.
	/83-29	SW valves fail, electrical problems.
	/83-40	SW valves fail, electrical problems.
	/83-45	SW leak at CFCU.
	/84-13	SW leak, tube degradation.
	/85-04	Control valve malfunction.
Kewaunee	LER-305/80-35	SW pump fail to start.
	/81-01	SW valve failure, CFCU inoperable.
	/81-07	SW pump failed to start.
	/82-05	SW pump failed to start.
	/82-33	SW MOV failed to open.
	/83-05	SW MOV malfunction.
	/83-21	SW pump unavailable, strainer tested.
	/83-24	SW pump failed.
	/83-25	Flow indicator failed, SW pump unavailable.
	/83-27	Pipe leak due to corrosion at CCW HX.
	/83-37	SW strainer leaked, SW pump unavailable.
	/84-18	Silt deposition in CFCU coils reduces flow.
	/86-15	SW valve failed in closed position.
Prairie Island	LER-306/80-32	Intake area isolated for one unit, causing a loss of SW pump on the other unit.
Maine Yankee	LER-309/81-07	SW cooling to SCC interrupted due to overload.
	/83-15	SW pump tripped, redundancy reduced.
	/83-17	SW MOV failed to operate.
	/83-33	SW MOV failed to operate.
Salem 2	LER-311/81-04	SW pipe leak at CFCU.
	/81-10	SW pump failed, another in maintenance.
	/81-38	SW leak at CFCU.
	/81-64	SW leak at CFCU.
	/81-90	SW leak at CFCU.
	/81-94	SW leak at CFCU.
	/81-99	Instrument line clogged with silt, valve inoperable.
	/81-114	SW leak at CFCU.
	/81-115	SW leak at CFCU.
	/81-117	Line clogged with silt, limit SW failure on MOV.
	/81-118	SW leak.
	/82-06	Valve stuck closed at CFCU.
	/82-17	Valve stuck closed, line clogged with silt.

Table A.5 (Continued)

Plant	Reference	Description
	/82-28	Sw leak at CFCU.
	/82-35	SW valve inoperable.
	/82-39	SW leak at CFCU.
	/82-40	SW leak at CFCU.
	/82-41	Marine growth reduces flow to CFCU.
	/82-46	Oysters reduce flow to CFCU.
	/82-49	Oysters reduce flow to CFCU.
	/82-50	Oysters reduce flow to CFCU.
	/82-58	Oysters reduce flow to CFCU.
	/82-63	One vital bus lost, diesel didn't load.
	/82-65	Valve failure stopped flow to CFCU.
	/82-70	SW leak at CFCU.
	/82-73	SW leak at CFCU.
	/82-74	SW leak at CFCU.
	/82-75	SW leak at CFCU.
	/82-77	SW leak at CFCU.
	/82-78	SW leak at CFCU.
	/82-80	SW leak at CFCU.
	/82-83	Oysters reduce flow to CFCU.
	/82-84	SW leak at CFCU.
	/82-86	One train of SW lost, one pump failed, other maintenance.
	/82-88	Low flow to CFCU due to valve problems.
	/82-89	SW leak at CFCU.
	/82-91	SW leak at CFCU.
	/82-92	SW leak at CFCU.
	/82-93	SW leak at CFCU.
	/82-96	Silt buildup in line reduces flow to CFCU.
	/82-98	Silt buildup in line reduces flow to CFCU.
	/82-99	Silt buildup in line reduces flow to CFCU.
	/82-100	Silt buildup in line reduces flow to CFCU.
	/82-101	Silt buildup in line reduces flow to CFCU.
	/82-105	Silt buildup in line reduces flow to CFCU.
	/82-109	Silt buildup in line reduces flow to CFCU.
	/82-112	SW leak at CFCU.
	/82-113	SW leak at CFCU.
	/82-115	SW leak at CFCU.
	/82-117	Oysters block SW valve.
	/82-119	SW leak due to corrosion from silt.
	/82-120	SW leak due to corrosion from silt.
	/82-122	SW leak due to corrosion from silt.
	/82-123	Flow controller setpoint is incorrect, low flow.
	/82-128	SW leak due to silt buildup.
	/82-130	Reduced flow to CFCU, silt buildup.
	/82-135	SW leak at CFCU.

Table A.5 (Continued)

Plant	Reference	Description
	/82-136	SW leak at CFCU.
	/82-146	SW strainer plugged, one train lost.
	/82-155	Valve problem reduces flow to CFCU.
	/85-01	SW air-operated valve failure to DG cooling.
	/85-18	Valve failed to open, both CCW HX unavailable.
	/85-19	SW leak at CFCU.
	/87-09	Design deficiency, cable separation didn't satisfy Appendix R requirements.
	/88-02	SW pump leaked, a number of pumps unavailable.
	/88-15	SW pipe leaked, centrifugal changing pumps lost.
Rancho Seco	LER-312/80-19	SW pump breaker didn't close.
	/81-16	Lube oil cooler malfunction.
	/81-52	Sw pump tripped, no apparent cause.
	/83-05	SW pump failed to start.
	/83-16	Snubbers failed in the SW system.
	/83-33	Incorrect personnel actions in tests.
	/85-14	SW pump breaker not properly documented.
	/87-11	Snubbers and pipe system in operation in spite of incorrect acceptance criteria.
	/87-36	Pipe to spray pump bearing plugged.
	/87-41	Incorrect level switches could prevent the starting of the SW pumps.
ANO-1	LER-313/81-01	Deficiency in SW pipe system design.
	/83-05	Deficiency in SW pipe system design.
Cook 1	LER-315/80-29	MOVs are tested not in accordance with requirements.
	/81-04	MOV failed.
	/81-15	Relays lead to malfunction of SW pump circuitry.
	/82-06	MOV failed to close at CCW HX.
	/82-09	SW leak at CCW HX.
	/82-43	SW pump discharge valve failed, loop unavailable.
	/82-48	SW MOV failed at CCW HX.
	/82-94	MOV leaked.
	/82-95	SW valve left in closed position, containment spray HX unavailable.
	/83-14	Silt buildup in strainer.

Table A.5 (Continued)

Plant	Reference	Description
Cook 2	LER-316/81-03	Strainer shut down, enabling SW pump.
	/82-02	Sw MOV tested less frequently as required.
	/82-11	SW pipe leak at CCW HX.
	/82-80	SW valve leak at CCW HX.
	/83-97	SW MOV electrical ground problem.
Calvert Cliffs 1	LER-317/80-27	Air bound due to instrument air cooler tube leak.
	/80-32	Valve failed, corrosion causes seizure.
	/80-41	Cooler failed.
	/80-52	SW leak, HX tube failed.
	/81-04	SW MOV failed open at CFCU discharge.
Calvert Cliffs 2	LER-317/81-10	SW valve malfunction.
	/81-29	Pipe support design deficiency.
	/81-63	SW valve operator failed at CCW HX.
	/81-77	Solenoid valves in SW are underrated.
	/82-32	SW MOV electrical trouble.
	/83-67	Valve failed at ECCS pump room air cooler.
	/83-74	Operator disconnected, SW pump lost, one train inoperable.
Calvert Cliffs 2	LER-318/80-17	SW HX leaked.
	/81-09	SW MOV didn't operate, electrical trouble.
	/81-53	Reduced SW flow due to valve problem.
	/82-34	SW valve failed, HX inoperable.
	/82-35	Valve broken, leak at SW HX.
	/82-51	SW loop degraded due to valve failure.
	/83-17	Power on valves lost, one train unavailable.
TMI-2	LER-320/80-08	SW pump locked out, not on standby.
	/81-02	SW unavailable to DG, improper operator action.
	/81-37	SW pump lost, mechanical trouble.
	/82-03	SW pump failed to start, loose connections.
Sequoyah 1	LER-327/80-75	SW pump failed, personnel error.
	/81-72	SW pipe hanger removed, not reinstalled.
	/81-95	Strainer failed.
	/81-97	Protective device not installed to prevent SW system damage from a steam line break.
	/81-101	Inadequate flow to safety equipments.
	/82-17	Inoperable snubbers.
	/82-27	Clams block flow to CS HX.
	/82-35	Solenoid valve failed closed to air compr. HX.

Table A.5 (Continued)

Plant	Reference	Description
	/83-10	SW valve failed to DG.
	/83-26	SW valve failed to DG.
	/83-182	Relay failure in SW electrical system.
	/84-69	SW valve overload improperly set.
	/85-05	SW pipe inadequately supported for seismic event.
	/86-28	Design deficiency in SW pump instruments.
	/86-29	SW pump failed to meet test acceptance criteria.
	/86-41	Misaligned valve, improper flow to DG.
	/87-08	SW valves are not tested as required by TS.
	/87-11	SW valves are not tested as required by TS.
	/87-27	SW valves are not tested as required by TS.
	/87-37	Inadequate calculations, design deficiency on coolers.
	/87-45	Inadequate design for traveling screen speed SW.
	/87-51	SW valves are not tested as per TS.
	/87-64	SW spool pieces out of tolerances.
	/87-65	Screen wash pumps are not tested regularly.
	/87-71	Electrical interlock on strainers disabled.
Sequoyah 2	LER-328/82-47	Reduced flow to CS HX, valve position adjusted.
	/85-06	SW valve in closed position, indicator plate mislabelled.
Beaver Valley 1	LER-334/80-27	SW check valve eroded to DG.
	/80-42	Pipe line improperly restrained for seismic event.
	/80-65	SW pipe over-stressed, design deficiency.
	/80-68	Check valves installed backwards.
	/82-19	SW leak at CS HX.
	/82-60	Starter on MOV failed.
St. Lucie 1	LER-335/81-54	SW pump not tested as required.
Millstone 2	LER-336/80-24	SW pump A seized, C unavailable.
	/80-38	Strainer leaked.
	/81-10	Strainer drive motor had loose mounting bolts.
	/81-23	SW strainer leaked.
	/81-24	Solenoid failed, DG inoperable.
	/82-10	SW pipe leaked.
	/82-52	SW pump leaked.
	/82-53	Misalignment of HX components.

Table A.5 (Continued)

Plant	Reference	Description
	/83-06	SW pump/strainer leaked.
	/83-31	Pipe hangers undersized.
	/85-12	Strainer plugged, loss of one header.
	/86-01	Pipe hanger failed.
	/86-20	SW pump failed to start on loss of offsite power.
	/86-22	SW pump failed to start.
	/87-06	Improperly positioned control valve.
	/88-05	SW pump manually started on loss of offsite power. sequencer failed.
North Anna 1	LER-338/80-22	Increased stresses on pipe/valve supports.
	/80-10	Increased stresses on pipe/valve supports.
	/80-16	Increased stresses on pipe/valve supports.
	/81-24	SW pipe leaked.
	/81-46	SW pipe leaked.
	/81-71	SW pipe leaked.
	/81-83	SW pipe leaked.
	/82-06	SW pipe leaked.
	/82-81	SW pipe leaked.
	/83-04	SW MOV failed, trouble with operator.
	/83-48	SW pipe leaked.
	/85-04	SW supply line not adequately covered against tornados.
	/87-18	MOV operator didn't have proper documentation.
North Anna 2	LER-339/82-81	SW MOV breaker open.
	/83-07	SW pipe leaked.
	/83-14	SW pipe leaked.
Trojan	LER-344/80-14	Incorrectly installed pipe restrain.
	/82-19	SW valves not surveyed as required.
	/84-02	Sediment accumulation in SI lube oil HX.
	/84-21	Partial plugging of strainers, reduced flow to both trains.
Davis Besse	LER-346/80-38	SW relief valve failed.
	/81-57	SW pipe leaked to ECCS room air coolers.
	/82-28	SW check valve didn't operate.
	/82-32	Valve out of position, personnel error.
	/86-01	Inadequate SW pump room ventilation.
	/87-11	SW pump failed to start.
Farley 1	LER-348/80-07	SW pump failed to start.
	/80-69	Design error, inadequate train separation.

Table A.5 (Continued)

Plant	Reference	Description
	/80-72	Relays malfunction in pump starting circuitry.
	/81-45	One train inoperable, MOV failed.
	/83-03	Valves failed to open, DG inoperable.
	/86-14	Clogged coolers to charging pumps.
	/87-09	RHR room cooler valves closed, personnel error.
San Onofre 2	LER-361/82-148	SW pump failed, grounding of electrical wire.
	/82-174	Mechanical binding prevents valve to open.
	/83-89	Pump suction costs due to debris.
	/84-46	Improper instrument readout.
Farley 2	LER-364/80-01	Inadequate train separation.
	/82-28	Mislabeling of SW valves.
	/82-39	One train unavailable, valve failed.
	/83-34	SW valves left in closed position.
	/83-68	MOV failed, DG inoperable.
	/86-11	SW trains removed for maintenance, operation on the other unit affected.
	/87-02	Inadequate train separation.
ANO 2	LER-368/80-27	SW pipe hanger fails.
	/80-54	SW CV failed.
	/80-70	Control valve and pressure switch improperly set.
	/80-72	Clam buildup on CFCU HX.
	/81-35	Reduced flow through seal water cooler of SI pump.
	/81-43	SW MOV, breaker open.
	/82-03	Reduced flow through seal water cooler of SI pump.
	/83-06	Improper switch and valve settings.
	/83-27	Over-tight SW valve failed to operate.
McGuire 1	LER-369/81-138	SW system leak.
	/83-21	Valve actuator replaced incorrectly.
	/83-84	SW pump inoperable, one train unavailable.
	/85-30	Valve locked in incorrect position.
	/86-06	SW system no fully tested.
	/86-19	SW valve not tested as per requirements.
	/87-09	Improperly positioned valve.
	/87-18	Inadequate test performance of SW pumps.
	/88-03	Mispositioned control valve at CCW HX.

Table A.5 (Continued)

Plant	Reference	Description
McGuire 2	LER-370/85-01	Valve not locked open as per requirements.
	/87-14	One SW pump tripped, other in maintenance.
	/87-17	Both SW trains are in maintenance.
St. Lucie 2	LER-389/83-54	SW pipe leak.
	/86-01	SW pipe leak.
Summer 1	LER-395/82-30	Check valve stuck closed.
	/83-33	Speed switch failed, one train inoperable.
	/83-49	Check valve failed to close on reverse flow.
	/85-14	SW pump lost during DG test, RHR transient.
	/86-12	SW pump failed to start, faulty relay.
	/87-10	Screen pump failed to start, loose connections.
Shearon Harris	LER-400/87-59	Travelling screen didn't start at loss of offsite power.
	/88-06	SW valves failed, debris.
	/88-08	Emergency SW pump unavailable due to test.
Catawba 1	LER-413/85-04	Loss of SW to RCP motor, improper airline design.
	/85-26	Loss of suction to SW pumps, incorrect valve operation.
	/85-32	SW intake aligned to standby source, personnel error.
	/86-24	Misalignment of SW intake.
	/86-27	Misalignment of SW intake.
	/86-53	Misalignment of SW intake.
	/86-57	SW MOV torque switches improperly set.
	/87-08	Tornado missile cover missing on SW pipe manways.
	/87-35	Incorrect procedures could prevent SW train operation.
	/87-36	Incorrect crossover supply alignment.
Millstone 3	LER-423/86-56	No flow to SI HX, valve closed.
	/87-01	SW low pressure causes turbine/reactor trip.
Vogtle 1	LER-424/87-03	Incorrect sealant used in penetrations.
Seabrook	LER-443/87-25	Incorrect test monitoring for Sw pump vibrations.
Byron 1	LER-454/86-31	Both SW strainers improperly tested.

Table A.5 (Continued)

Plant	Reference	Description
Byron 2	LER-455/87-03	SW makeup pumps out of service.
Braidwood 1	LER-456/87-16	Incomplete test of SW systems.
Wolf Creek	LER-482/85-12	SW MOV didn't close properly.
	/85-69	Travelling screens collapse due to plant growth.
	/86-44	SW valve failed to operate.
Callaway 1	LER-483/87-24	SW valve not tested as required.
South Texas 1	LER-498/87-03	SW pump tripped, discharge check valve stuck closed.
	/87-18	SW pipe leak, one train inoperable.
	/88-20	Screen wash booster pump inoperable.
	/88-23	Test on screen wash booster pump performed not as frequently as required.
Palo Verde 1	LER-528/86-14	SW pump failed to start, faulty relays.
	/86-37	SW pump failed to start.
Crystal River 3	LER-302/87-20	On September 3, 1987, Crystal River Unit 3 (CR3) was operating at approximately 63% rated thermal power. An NRC audit of plant cooling water systems revealed that the ultimate heat sink (UHS) temperature exceeded the maximum value assumed in the plant design basis. Also, the plant Tech. Spec. limit for UHS temperature was higher than the design basis. This event was the result of an inadequate plant design specification. The maximum seawater temperature specified for plant design was 85°F, while actual temperatures exceed this value during the summer months. The Tech. Spec. error appears to have been caused by inadvertently selecting a temperature limit from a closed cycle cooling loop rather than the UHS design specification. Analyses indicate that the nuclear services closed cycle cooling system 105°F. Temperature limit can be met with seawater temperatures as high as 92.4°F. FPC continues to evaluate the past operability of the decay heat closed cycle cooling

Table A.5 (Continued)

Plant	Reference	Description
		system when the seawater temperature exceeded 85°F. The results of the evaluation are due to be submitted to the NRC in a separate report by July 29, 1988.

APPENDIX B: Hardware Unavailability Cut Sets for the Auxiliary Saltwater System.
Top Event: AS
Initiator: LOSW

Top Event AS

Boundary condition designator: AS1

Hardware unavailability cutsets due to dependent and independent failure; HW =

1	1.2962E-04	BKA * BKE1 +
2	1.3552E-07	HW11 +
3	4.9457E-03	BKD * BKC * /BKB * /G4PP * /D4PP12 * /D4PP13 * /D4PP14 * /T4PP123 * /T4PP124 * /T4PP134 +
4	3.6275E-04	BKE1 * BKA * BKC +
5	1.6176E-04	G4PP +
6	8.9495E-03	BKD * BKB * /BKC * /G4PP * /D4PP12 * /T4PP123 * /T4PP124 * /G4PV * /D4PP23 * /D4PP24 * /D4PV23 * /D4PV24 * /D4PV12 * /T4PP234 * /T4PV234 * /T4PV123 * /T4PV124 +
7	5.8375E-03	BKE1 * D4PP12 +
8	3.4400E-03	PIPE1 +
9	1.2472E-09	BKA * BKD +
10	2.6959E-11	BKA * BKF * BKG +
11	1.7070E-10	BKE1 * T4PP124 +
12	1.7070E-10	BKE1 * T4PP123 +
13	1.3023E-10	BKD * D4PV24 * /BKE * /G4PP * /D4PP12 * /D4PP13 * /D4PP14 * /T4PP123 * /T4PP124 * /T4PP134 +
14	1.3023E-10	BKD * D4PV12 * /BKE * /G4PP * /D4PP12 * /D4PP13 * /D4PP14 * /T4PP123 * /T4PP124 * /T4PP134 +
15	1.3023E-10	BKD * D4PV23 * /BKE * /G4PP * /D4PP12 * /D4PP13 * /D4PP14 * /T4PP123 * /T4PP124 * /T4PP134 +

HW11 = BKBT*ZTVCOD

Top Event AS

Boundary condition designator: AS1
Hardware unavailability cutsets due to independent failures; HWI =

1	1.2962E-06	BKA * BKE1 +
2	1.3552E-07	HW11 +
3	4.9457E-08	BKD * BKC * 7BKB +
4	3.6275E-08	BKE1 * BKB * BKC +
5	8.9697E-09	BKC * BKB * 7BKC +
6	3.4400E-09	PIPE1 +
7	1.2472E-09	BKA * BKD +
8	2.5989E-10	BKA * BKF * BKG +

HW11 = BKBT*ZTVCOD

Initiator: LOSW
1 - During Normal Operation, BNL1 Calc.

Hardware unavailability cutsets due to dependent and independent failure; HW =

1	3.6893E-05	HW1 +
2	2.5614E-05	PIP +
3	1.7057E-05	BKBX * MFDC * BKEX +
4	9.0116E-06	BKBX * BKCX * BKEX +
5	5.0186E-06	G4PL +
6	1.5967E-06	D4PL12 * BKEX +
7	4.6689E-08	T4PL124 * BKEX +
8	4.6689E-08	T4PL123 * BKEX +
9	2.6596E-08	T4PL134 * MFDC +
10	2.6596E-08	T4PL123 * MFDG +
11	2.6126E-08	BKBX * D4PV12 * BKEX +
12	2.6126E-08	BKEX * D4PV23 * BKEX +
13	2.6126E-08	BKBX * D4PV24 * BKEX +
14	1.4064E-08	T4PL123 * BKGX +
15	1.4051E-08	T4PL134 * BKCX +
16	1.2795E-08	HW2 +
17	1.0640E-08	D4PL13 * MFDC * BKEX +
18	1.0640E-08	D4PL14 * MFDC * BKEX +
19	6.0511E-09	D4PL13 * MFDC * MFDG +
20	5.6213E-09	D4PL13 * BKCX * BKEX +

HW1 = BKBXT*ZTVCOD
HW2 = BKBXT*(BKKT*ZTVCOD)

Initiator: LOSW
1 - During Normal Operation, BNL 1 Calc.

Hardware unavailability cutsets due to independent failure; HWI =

1	3.6893E-05	HW1 +
2	2.5614E-05	PTF +
3	1.7057E-05	BKBX * MFDC * BKEX +
4	9.0116E-06	BKBX * BKCX * BKEX +
5	1.2795E-08	HW2 +
6	3.3978E-09	BKBX * MFDC * MFDG * BKFX +
7	1.7967E-09	BKBX * MFDC * BKGX * BKFX +
8	1.7951E-09	BKBX * BKCX * MFDG * BKFX +
9	9.4923E-10	BKBX * BKCX * BKGX * BKFX

HW1 = BKBXT*ZTVCOD
HW2 = BKBXT*(BKCT*ZTVCOD)

Initiator: LOSW
1 - During Normal Operation, BNL2 Calc.

Hardware unavailability cutsets due to dependent and independent failure; HW =

1	1.3155E-04	BKBX * MFDC * COLD +
2	5.2221E-05	BKBX * BKCX * COLD +
3	3.7329E-05	BKBX * MFDC * BKEX +
4	3.6893E-05	HW1 +
5	3.6490E-05	BKBX * MFDC * MFDG +
6	2.5614E-05	PIP +
7	1.0177E-05	BKBX * BKCX * BKEX +
8	9.9431E-06	BKBX * BKCX * MFDG +
9	9.2523E-06	D4PL12 * COLD +
10	8.7873E-06	BKBX * MFDC * BKDM +
11	5.0186E-06	G4PL +
12	3.2833E-06	BKA * COLD +
13	2.3958E-06	BKBX * BKCX * BKDM +
14	1.8031E-06	D4PL12 * BKEX +
15	1.7626E-06	D4PL12 * MFDG +
16	6.3984E-07	BKA * BKEX +
17	6.2546E-07	BKA * MFDG +
18	4.2448E-07	D4PL12 * BKDM +
19	2.7055E-07	T4PL123 * COLD +

HW1 = BKBXT*ZTVCOD

Initiator: LOSW
1 - During Normal Operation, BNL2 Calc.

Hardware unavailability cutsets due to independent failure; HWI =

1	1.9155E-04	BKBX * MFDC * COLD +
2	5.2221E-05	BKBX * BKCX * COLD +
3	3.7329E-05	BKBX * MFDC * BKEX +
4	3.6893E-05	HW1 +
5	3.6490E-05	BKBX * MFDC * MFDG +
6	2.5614E-05	PIP +
7	1.0177E-05	BKBX * BKCX * BKEX +
8	9.9481E-06	BKBX * BKCX * MFDG +
9	8.7878E-06	BKBX * MFDC * BKDM +
10	3.2833E-06	BKA * COLD +
11	2.3958E-06	BKBX * BKCX * BKDM +
12	6.3984E-07	BKA * BKEX +
13	6.2546E-07	BKA * MFDG +
14	1.5063E-07	BKA * BKDM +
15	2.2169E-08	BKBX * MFDC * BKDC +
16	1.2795E-08	HW2 +
17	6.0439E-09	BKBX * BKCX * BKDC +

HW1 = BKBXT*ZTVCOD
HW2 = BKBXT*(BKCT*ZTVCOD)

Initiator: LOSW
2 - During Pump Rotation, BNL1 Calc.

Hardware unavailability cutsets due to dependent and independent failure; HW =

1	1.2972E-08	BKCY * BKBY * BKEX +
2	1.8744E-10	HW3 +
3	4.1754E-11	D4FV12 * BKBY * BKEX +

Hardware unavailability cutsets due to independent failure; HWI =

1	1.2972E-08	BKCY * BKBY * BKEX +
2	1.8744E-10	HW3 +

HW3 = BKCYT*BKBYT*ZTVCOD

Initiator: LOSW
2 - During Pump Rotation, BNL2 Calc.

Hardware unavailability cutsets due to dependent and independent failure; HW =

1	3.2933E-06	BKA * COLD +
2	6.3984E-07	BKA * BKEX +
3	6.2546E-07	BKA * MFDG +
4	1.5063E-07	BKA * BKDM +
5	7.5169E-08	BKCY * BKBY * COLD +
6	1.4649E-08	BKCY * BKBY * BKEX +
7	1.4320E-08	BKCY * BKBY * MFDG +
8	3.4486E-09	BKCY * BKBY * BKDM +
9	3.8000E-10	BKA * BKDC +
10	2.4196E-10	D4PV12 * BKBY * COLD +
11	2.4196E-10	D4PV23 * BKBY * COLD +
12	2.4196E-10	D4PV24 * BKBY * COLD +
13	1.8744E-10	HW3 +

HW3 = BKCYT*BKBYT*ZTVCOD

Initiator: LOSW
2 - During Pump Rotation, BNL2 Calc.

Hardware unavailability cutsets due to independent failure; HWI =

1	3.2833E-06	BKA * COLD +
2	6.3984E-07	BKA * BKEX +
3	6.2546E-07	BKA * MFDG +
4	1.5063E-07	BKA * BKDM +
5	7.5169E-08	BKCY * BKBY * COLD +
6	1.4649E-08	BKCY * BKBY * BKEX +
7	1.4320E-08	BKCY * BKBY * MFDG +
8	3.4486E-09	BKCY * BKBY * BKDM +
9	3.8000E-10	BKA * BKDC +
10	1.8744E-10	HW3 +

HW3 = BKCYT*BKBYT*ZTVCOD