50-335

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 16, 1996

Mr. Thomas F. Plunkett
President, Nuclear Division
Florida Power and Light Company
Post Office Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: REVIEW OF PRELIMINARY ACCIDENT SEQUENCE PRECURSOR ANALYSIS OF OPERATIONAL CONDITIONS AT PLANT ST. LUCIE UNIT 1

Dear Mr. Plunkett:

Enclosed for your review and comment is a copy of the preliminary Accident Sequence Precursor (ASP) analysis of operational conditions which were discovered at St. Lucie Unit 1 on August 2, 1995 (Enclosure 1), and were reported in Licensee Event Report (LER) Nos. 335/95-004, -005, and -006. This analysis was prepared by our contractor at the Oak Ridge National Laboratory (ORNL). The results of this preliminary analysis indicate that these conditions may be a precursor for 1995. In assessing operational events, an effort was made to make the ASP models as realistic as possible regarding the specific features and response of a given plant to various accident sequence initiators. We realize that licensees may have additional systems and emergency procedures, or other features at their plants that might affect the analysis. Therefore, we are providing you an opportunity to review and comment on the technical adequacy of the preliminary ASP analysis, including the depiction of plant equipment and equipment capabilities. Upon receipt and evaluation of your comments, we will revise the conditional core damage probability calculations where necessary to consider the specific information you have provided. The object of the review process is to provide as realistic an analysis of the significance of the plant conditions as possible.

In order for us to incorporate your comments, perform any required reanalysis, and prepare the final report of our analysis of this event in a timely manner, you are requested to complete your review and to provide any comments within 30 days of receipt of this letter. We have streamlined the ASP Program with the objective of significantly improving the time after an event in which the final precursor analysis of the event is made publicly available. As soon as our final analysis of the operational conditions has been completed, we will provide for your information the final precursor analysis of the plant conditions and the resolution of your comments. In previous years, licensees have had to wait until publication of the Annual Precursor Report (in some cases, up to 23 months after an event) for the final precursor analysis of an event and the resolution of their comments.

We have also enclosed several items to facilitate your review. Enclosure 2 contains specific guidance for performing the requested review, identifies the criteria which we will apply to determine whether any credit should be given in the analysis for the use of licensee-identified additional equipment or specific actions in recovering from the conditions and describes the specific

information that you should provide to support such a claim. Enclosure 3 is a copy of LER Nos. 335/95-004, -005, and -006, which documented the conditions.

Please contact me at (301) 415-1495 if you have any questions regarding this request. This request is covered by the existing OMB clearance number (3150-0104) for NRC staff followup review of events documented in LERs. Your response to this request is voluntary and does not constitute a licensing requirement.

Sincerely,

Original signed by

Leonard A. Wiens, Senior Project Manager
Project Directorate II-3
Division of Reactor Projects-I/II
Office of Nuclear Reactor Regulation

Docket No. 50-335

Enclosures: 1. Preliminary ASP Analysis of Operational Conditions Discovered at St. Lucie Unit 1 on 8/2/95
2. Guidance For Licensee Review of Preliminary ASP Analysis
3. LER Nos. 335/95-004, -005, -006

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LER Nos. 335/95-004, -005, -006

Event Description: Failed PORVs, RCP seal failure, relief valve failure and subsequent SDC unavailability, plus other problems

Date of Event: August 2, 1995

Plant: St. Lucie 1

Event Summary

On August 1, 1995, St. Lucie 1 shut down to mode 3 in preparation for hurricane Erin. The next day reactor coolant pump (RCP) 1A2 lower seal stage failed. When operators attempted to restage the seal, two additional stages failed and resulted in a 2 gpm leak. The reactor coolant system (RCS) was cooled down and depressurized to replace the failed seal. The next day, while in mode 4, both PORVs were tested and subsequently determined to be failed, a result of incorrect reassembly during the fall 1994 refueling outage. The failed PORVs required the plant to be cooled down, depressurized, and placed in mode 5. During this cooldown, a thermal relief valve on the low pressure safety injection (LPSI) common discharge piping [part of the shutdown cooling (SDC) system] lifted and did not reseat. Discovery of the open valve was delayed for 2 h because normally-open floor drain valves were closed. Once the open relief valve was discovered, the SDC system was removed from service for about a day to replace the valve. During this time period only the steam generators were available for decay heat removal. The conditional core damage probability estimated for this event is 1.3×10^{-4}.

Event Description

On August 1, 1995, the National Hurricane Center predicted hurricane force winds from the passage of Hurricane Erin near the St. Lucie site. Both units were shut down and cooled down to an average temperature of 350°F to allow for enhanced steam generator heat removal capability with a steam-driven auxiliary feedwater (AFW) pump, and a storm crew was stationed on-site to support potential recovery efforts.

Hurricane Erin made landfall approximately 20 miles north of the site, and maximum wind speed on-site was less than 45 mph. The Unusual Event that had been declared because of the hurricane was terminated at 0542 on August 2, 1995, and a decision was made to return both units to service.

At 0805, while Unit 1 was in Mode 3 with an RCS pressure of 1550 psia, RCP 1A2 middle seal cavity pressure was observed to be approximately equal to RCS pressure; an indication that the lower seal stage had failed. A decision was made to "restage" the leaking seal - increasing the differential pressure across it by sequentially depressurizing the seal cavities from top to bottom.

During the restaging evolution, the RCP middle stage failed and the upper and vapor stage degraded. The licensee attributed these failures to the performance of the restaging procedure at RCS temperatures above 200°F and on a rotating pump. Twenty minutes after control room indication of the failed middle stage, at 1810 on August 2, 1995, operators began to cool down and depressurize the RCS. At 1840, RCP 1A2 was secured.

By 2018 on August 2, 1995, reactor cavity leakage had increased to about 2 gpm. This leakage decreased the next day due to the ongoing RCS cooldown and depressurization. The RCP 1A2 seal was subsequently replaced, as was the RCP 1A1 seal (due to degraded performance).

During the RCS depressurization and cooldown on August 3, 1995, the PORVs were also stroke tested. No increase in acoustical flow indication was observed. Because of apparent inconsistencies with other indications, the problem was initially attributed to the acoustic monitors, and further PORV testing was planned following replacement of the RCP seals. On August 9, 1995, the PORVs were again tested with unsatisfactory results, first at 260 psia, then in Mode 4 at 320 psia and with SDC secured, and finally at an RCS pressure of 475 psia.

The problem with both PORVs was caused by the improper installation of the main disc guides following overhaul during the 1994 fall refueling outage and by inadequate post-maintenance testing before returning the valves to service (only a seat leakage test was performed).

With both PORVs inoperable, Limiting Condition for Operation (LCO) 3.4.13 required the unit to be depressurized and a vent path established within 24 h. A cooldown and depressurization was begun.

At 0018 on August 10, 1995, with the unit at 278°F and 261 psia, the 1A LPSI pump was started to place the SDC system in service to continue the cooldown. Shortly after starting the pump, pressurizer level and letdown flow were observed to be decreasing. Since no annunciations associated with RCS leakage were received, no increases in reactor cavity sump flow or waste management system sump levels and tanks were detected, and no leakage was observed in the LPSI pump rooms and other auxiliary building areas, the operators concluded that the unexpected mismatch between charging and letdown flow was the result of the RCS cooldown. At 0105, the 1B LPSI pump was started and the remaining steps in the SDC normal operating procedure were completed.

At 0215 on August 10, 1995, water was discovered to be accumulating in the auxiliary building pipe tunnel. Both trains of SDC were secured (decay heat removal was provided by the steam generators). Pressurizer level and charging/letdown flow were observed to be stable, indicating that the leakage had stopped. The floor drain isolation valves to the safeguards pump room sump were found to be closed. When these valves were subsequently opened, high sump level annunciated. The safeguards pump room sump isolation valves had been stroke-tested in preparation for Hurricane Erin, and some of the seven valves controlled by a single switch had failed to close. Following trouble-shooting efforts the control switch had been left in the close position.

At 0611 on August 10, 1995, thermal relief valve V3439 was determined to have been the cause of the leakage. This valve is located in LPSI pump discharge piping that is common to both trains. During the event, the operating pressure of the SDC system immediately following LPSI pump start was within the relief valve's lift-pressure range, resulting in the valve opening. The SDC system operating pressure remained above the relief valve reseat pressure, which prevented the valve from closing. Approximately 4000 gal was discharged over the almost 2-h period that the valve was open.

Three and one-half hours after the relief valve leakage was identified both trains of the SDC system were removed from service for 22 h in order to replace the valve. RCS temperature was increased to 305°F, where the PORV Technical Specification was not applicable. Decay heat was removed using the steam generators, the only source of decay heat removal at that point. Following replacement of the relief valve, both SDC trains were restored to operable status and the RCS was cooled down and depressurized to repair the PORVs.

Three other reportable events occurred within the same time frame as the events described above. These events, which would not be selected as precursors, are summarized below in order to provide a more complete picture of the situation at St. Lucie 1 during the August 1995 time period.

While RCS temperature was being decreased on August 2, 1995, in response to the failed RCP seal, the main steam isolation signal (MSIS) block permissive annunciators alarmed and were acknowledged by an operator. That operator did not refer to the annunciator summary procedure but concluded that blocking MSIS was not required since all valves that would have been affected by an MSIS actuation were already in their actuated positions. The shift technical advisor subsequently questioned whether MSIS should be blocked, but the annunciator procedure was again not consulted. Six minutes after the block permissive annunciated, MSIS actuated and was then blocked and reset.

On August 11, 1995, the train A containment spray header flow control valve, FCV-07-1A, failed its stroke test and was declared inoperable. Since repair of the valve was expected to take a significant length of time, the valve was instead placed in its safeguard position (open), and repair was deferred until the next refueling outage. On August 16, 1995, a Unit 1 heatup was begun and the SDC system was secured. Unspecified maintenance on the LPSI system delayed performance of the emergency core cooling system venting procedure until 1756 on August 17, 1995, when the RCS was at 532°F and 1550 psia. As part of the venting procedure, the 1A LPSI pump was started and used to circulate refueling water tank (RWT) water through the SDC warmup line. The SDC heat exchanger inlet and outlet valves were then opened to circulate water through the heat exchanger. Because FCV-07-1A was open, this provided a direct path from the RWT to the "A" containment spray header. Three minutes later, at 1806, the control room received high reactor cavity leakage annunciation, multiple containment fire alarms, and rapidly increasing containment sump flow

indication, and entered the off-normal operating procedure for excessive RCS leakage. The 1A LPSI pump was stopped, the flow path through the spray header identified, the SDC heat exchanger isolation valves closed, and the venting procedure exited. Approximately 10,000 gal of borated water was sprayed into the containment. The containment fire detection system malfunctioned during the event; 90% of the containment smoke detectors either alarmed or faulted. In addition, an electrical ground occurred on one safety injection tank sample valve [Ref. 4].

On August 28, 1995, with the unit in Mode 5 with an RCS temperature of around 120°F and an RCS pressure of 250 psia, high pressure safety injection (HPSI) header stop valve V-3656 was opened and HPSI pump 1A was started to support an inservice leak test of header relief valve V-3417. This valve is the HPSI equivalent of the LPSI relief valve that opened on August 10, 1995. HPSI pump operation is prohibited at RCS temperatures below 236F. All four HPSI injection valves were shut and disabled at the time, so the RCS was not affected [Ref. 5].

Additional Event-Related Information

The PORVs provide three functions at St. Lucie: (1) low temperature overpressure protection (LTOP) when the RCS is below 305°F and not vented, (2) RCS pressure relief above normal operating pressure to minimize challenges to the pressurizer code safety valves, and (3) a bleed path for "once through cooling," (feed and bleed) in the event that secondary-side decay heat removal is unavailable.

The LPSI system at St. Lucie provides injection for large- and medium-break loss-of-coolant accidents (LOCAs). The system is secured at the start of the recirculation phase and the HPSI pumps are realigned and used to provide RCS makeup from the containment sump. The LPSI system also provides decay heat removal during normal plant shutdowns. Either LPSI pump can be used to circulate reactor coolant through a shutdown heat exchanger, returning it to the RCS via the low-pressure injection header.

Modeling Assumptions

The combined event has been modeled as (1) an unavailability of both PORVs from the time St. Lucie 1 returned to power following its Fall 1994 refueling outage, (2) a potential RCP seal LOCA resulting from the two failed seal stages, and (3) a 22 h unavailability of the SDC system for decay heat removal. The failure of the operator to block the MSIS, inadvertent spray-down of the containment, and HPSI pump start at low temperature, while problematic, did not substantially impact core damage sequences and were not addressed.

PORV unavailability. St. Lucie 1 returned to power on December 1, 1994, and the failed PORVs were discovered on August 3, 1995. During this period (approximately 5840 h), the PORVs were unavailable for both pressure relief and for feed and bleed. To reflect the unavailability for feed and bleed, basic events for failure of the valves to open, PPR-SRV-CC-1 and PPR-SRV-CC-2, were set to TRUE.

The ASP models do not specifically address failure of relief valves to open for pressure relief; a sufficient number of valves are assumed to open to prevent overpressure. Since the two PORVs were failed, the pressurizer code safety valves (SVs) would have been demanded in the event of high RCS pressure. Because SVs cannot be isolated, failure of an open valve to close would result in an unisolatable small-break LOCA. The potential for the SVs to be challenged instead of the PORVs was reflected in the model by setting the basic events for failure of the PORVs to close (PPR-SRV-OO-1 and PPR-SRV-OO-2) to FALSE and adding a basic event (PPR-SRV-OO-SRVS) to represent the potential that an open SV will fail to close.

The relief valve challenge rate used in the model was not revised to reflect the fact that the SVs would be challenged on high RCS pressure instead of the PORVs. The SV lift pressure is 100 psi greater than the PORV lift pressure, and fewer transients are expected to reach this pressure. This should result in fewer SV challenges and therefore a lower challenge rate. Unfortunately, because PORVs are usually available, operational data on SV challenges does not exist. The significance of impacted sequences (primarily transient sequences 5, 7, and 8 in Fig. 1), is therefore potentially overestimated in the analysis. However, these sequences do not significantly contribute to the overall results even with the conservative SV challenge rate.

Potential RCP seal LOCA. The seal on RCP 1A2 could have degraded further and failed, resulting in a small-break LOCA. The probability of a small-break LOCA, given the degraded seal, was estimated from Byron-Jackson RCP seal data in Tables 4 and B-3 of NUREG-1275, Vol. 7 [Ref. 6]. These tables list actual RCP seal degradations (such as the failure of a stage or increased controlled bleed-off flow) in which plant operation was allowed to continue for some period of time in accordance with operating procedures.

Most of the data in Tables 4 and B-3 of Ref. 6 were from the Nuclear Plant Reliability Data System (NPRDS) and excluded the names of the plants at which the events occurred. However, data was listed for Arkansas Nuclear One (ANO), Units 1 and 2. This data was compared with the seal history data included for these two units in Appendix A of Ref. 6 to determine the fraction of events in Tables 4 and B-3 that were unrelated to the seal degradation observed during this event —primarily seal degradations caused component cooling water transients, weld cracks, and end-of-life failures. Approximately one-third of the ANO degradations were determined to be unrelated to this event. Assuming this fraction is applicable to all of the data in Tables 4 and B-3, 25 instances of seal degradation have occurred which appear to be relevant to the failure observed during this event and in which RCP operation continued. None of these 25 instances proceeded to a catastrophic seal failure.[1] Using a Chi-square approach[2] with zero observed seal failures in these 25 demands, a probability of 0.028 is estimated for a subsequent RCP seal failure and a small-break LOCA, given an observed seal degradation (stage failure).

The probability of a small-break LOCA resulting from further degradation of the RCP 1A2 seal was reflected in the ASP model by revising basic event IE-SLOCA to 0.028. Consistent with the analysis of the failed PORVs, PPR-SRV-CC-1 and PPR-SRV-CC-2 were set to TRUE to reflect the unavailability of the PORVs

[1] One catastrophic seal failure was included in Table B-3, but was excluded from the set of seal degradations relevant to this event. That event occurred at ANO 1 and followed a LOOP and a deliberate isolation of seal injection during a test.

[2] The use of a Chi-square distribution, a standard approach to estimate failure probabilities for small numbers of events, is described in Chapter 5 of NUREG/CR-2300, *PRA Procedures Guide*.

for feed and bleed cooling, and PPR-SRV-OO-1 and PPR-SRV-OO-2 were set to FALSE to reflect the unavailability of the PORVs for pressure relief.[3]

SDC unavailability for 22 h. During the 22 h that the SDC system was removed from service to repair failed thermal relief valve V3439, the only source of decay heat removal was via the steam generators, since feed and bleed was unavailable due to the failed PORVs. The analysis for this case assumed that both motor-driven AFW pumps were available for use, and that if both failed, RCS heatup would allow use of the turbine-driven AFW pump as well. The analysis also assumed that the AFW system had been returned to its pre-initiation state prior to the discovery of the stuck-open relief valve and that component failure probabilities applicable following a typical reactor trip from power were applicable in this situation as well.[4]

The LPSI system was removed from service nine days after St. Lucie was shut down for hurricane Erin, when decay heat was approximately one-eighth of its nominal post-trip value. This lower decay heat level would substantially extend the time available to recover the AFW system, if it failed, and eliminate the requirement to provide an alternate AFW suction source, since the CST would not be expected to be emptied during the 22-h LPSI unavailability. This was reflected in the model by reducing the probability of not recovering AFW as described in the following paragraph, setting the basic event representing the failure of the operator to provide an alternate water source upon depletion of the CST, AFW-XHE-XA-CST2, to FALSE, and utilizing a 22-h mission time.[5]

The ASP models utilize a probability of 0.26 for failing to recover an initially failed AFW system within about 0.5 h following a reactor trip from power (basic event AFW-XHE-NOREC). Assuming the time available to recover AFW is proportional to the decay heat load, 4 h would be available if AFW had failed

[3] Since high RCS pressure would not exist following a postulated small-break LOCA, model changes were not actually required to reflect the unavailability of the PORVs for pressure relief.

[4] This is most likely conservative since at least some of the AFW components had recently operated and non-demand, standby failures would therefore not substantially contribute to these component failure probabilities.

[5] Certain basic events in the ASP models address both failure to start and failure to run. The probabilities for these basic events were not revised to reflect the 22-h mission time. This has less than a 2 percent impact on these basic event probabilities.

during the LPSI relief valve repair. AFW-XHE-NOREC was revised to 0.12 to reflect this greater recovery time. This value is the demand-related AFW nonrecovery probability developed in *Faulted Systems Recovery Experience*, NSAC-161 [Ref. 7] (Fig. 3.1-2) at 2 h, the longest nonrecovery duration addressed in that document. This probability is conservative for 4 h, but consistent with the data-based approach summarized in NUREG/CR-4834, Vol. 2 [Ref. 8], the data in Fig. 3.1-2 of Ref. 7 was not extrapolated.

The probability that AFW would have failed during the 22-h that the SDC system was removed form service is estimated to be 3.0×10^{-5} using the St. Lucie ASP model modified as described above. If the AFW system had failed, the condensate system could have been used for SG makeup. In addition, if the AFW system had failed when initially demanded following isolation of the SDC system (failure at this time is more likely than failure following a successful demand), the SDC system could have been returned to service with the leaking relief valve until the AFW system had been restored to operation. The probability that both of these alternatives would fail is estimated to be well below 0.03, which reduces the overall conditional probability for the 22-h SDC unavailability to less than 1.0×10^{-6}, the truncation limit for documentation in the ASP program. Because the conditional probability for the 22-h SDC unavailability is estimated to be less than 1.0×10^{-6}, it was not analyzed further.

Analysis Results

The conditional core damage probability (CCDP) estimated for this event is 1.3×10^{-4}. About 95% of the CCDP is contributed by the unavailability of the PORVs. The remaining 5% of the CCDP is associated with a postulated RCP seal LOCA initiating event. Only the conditional assessment of the unavailability of the PORVs is discussed below. The dominant core damage sequence, highlighted as sequence number 21 on the event tree in Fig. 1, contributes about 41% to the conditional probability estimate and involves:

- a postulated reactor trip during the 5840 h period that the PORVs were unavailable,
- nonrecoverable failures of MFW and AFW, and
- ability to feed and bleed is lost due to the unavailability of the PORVs.

The second highest core damage sequence, which contributes about 20% of the CCDP, is similar to sequence number 21 on Fig. 1, but involves a postulated LOOP instead of a transient. Sequence 16 involves:

- a successful reactor trip given a loss-of-offsite power with emergency power available,
- the AFW system fails,
- operators successfully recover offsite power within 6 hours, and
- ability to feed and bleed is lost due to the unavailability of the PORVs.

Definitions and probabilities for selected basic events are shown in Table 1. The conditional probabilities associated with the highest probability sequences for the condition assessment are shown in Table 2. Table 3 lists the sequence logic associated with the sequences listed in Table 2. Table 4 describes the system names associated with the dominant sequences for the condition assessment. Minimal cut sets associated with the dominant sequences for the condition assessment are shown in Table 5.

Acronyms

AFW	Auxiliary Feedwater
ANO	Arkansas Nuclear One
ASP	Accident Sequence Precursor
CCDP	Conditional Core Damage Probability
CST	Condensate Storage Tank
HPSI	High Pressure Safety Injection
LCO	Limiting Condition for Operation
LOCA	Loss-of-Coolant Accident
LOOP	Loss-of-Offsite Power
LPSI	Low Pressure Safety Injection
LTOP	Low Temperature Overpressure Protection
MFW	Main Feedwater
MSIS	Main Steam Isolation Signal
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RWT	Refueling Water Tank

PORV	Power Operated Relief Valve
SBO	Station Blackout
SDC	Shutdown Cooling
SG	Steam Generator
SV	Safety Valve

References

1. LER 335/95-004, Rev. 0, "Hurricane Erin at St. Lucie," August 27, 1995.
2. LER 335/95-005, Rev. 0, "Pressurizer Power Operated Relief Valves (PORV) Inoperable due to Personnel Error," August 22, 1995.
3. LER 335/95-006, Rev. 0, "Loss of Reactor Coolant Inventory through a Shutdown Cooling Relief Valve due to Lack of Design Margin," August 22, 1995.
4. LER 335/95-007, Rev. 0, "Inadvertent Containment Spray via 1A Low Pressure Safety Injection Pump while Venting the Emergency Core Cooling System During Startup due to Inadequate Procedure," August 27, 1995.
5. LER 335/95-008, Rev. 0, "High Pressure Safety Injection Pump Operation During Plant Conditions Not Allowed by Technical Specifications due to Personnel Error," September 27, 1995.
6. *Operating Experience Feedback Report - Experience with Pump Seals Installed in Reactor Coolant Pumps Manufactured by Byron Jackson*, L.G. Bell and P.D. O'Reilly, NUREG-1275, Vol. 7, U.S. Nuclear Regulatory Commission, September 1992.
7. *Faulted Systems Recovery Experience*, H.R. Booth, F.J. Mollerus, and J.L. Wray, NSAC-161, Nuclear Safety Analysis Center, May 1992.
8. *Recovery Actions in PRA for the Risk Methods Integration and Evaluation Program (RMIEP), Volume 2: Application of the Data-Based Method*, D.W. Whitehead, NUREG/CR-4834, Vol. 2, Sandia National Laboratories, 1987.

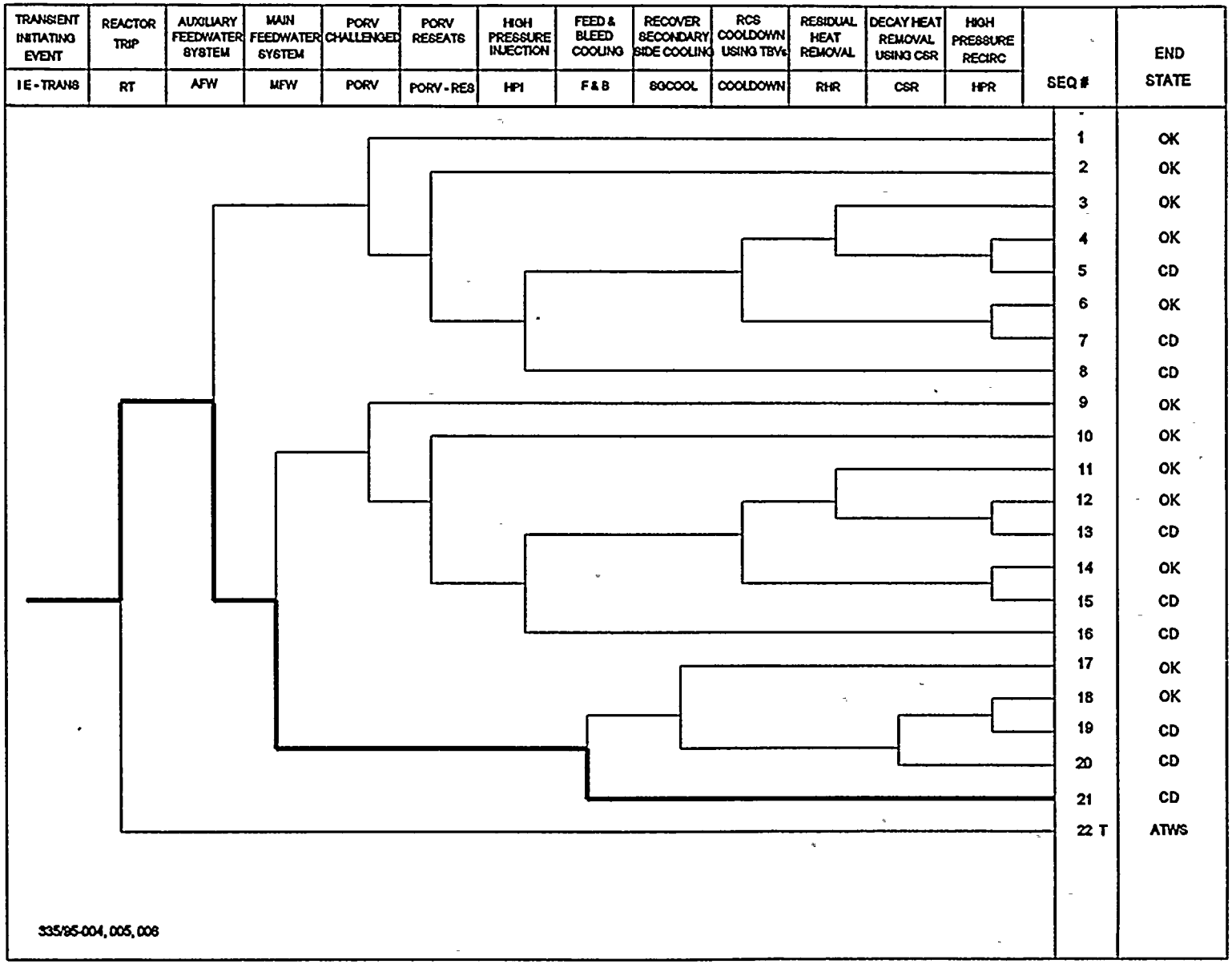

Fig. 1 Dominant core damage sequence given a transient for LER Nos. 335/95-004, -005, -006.

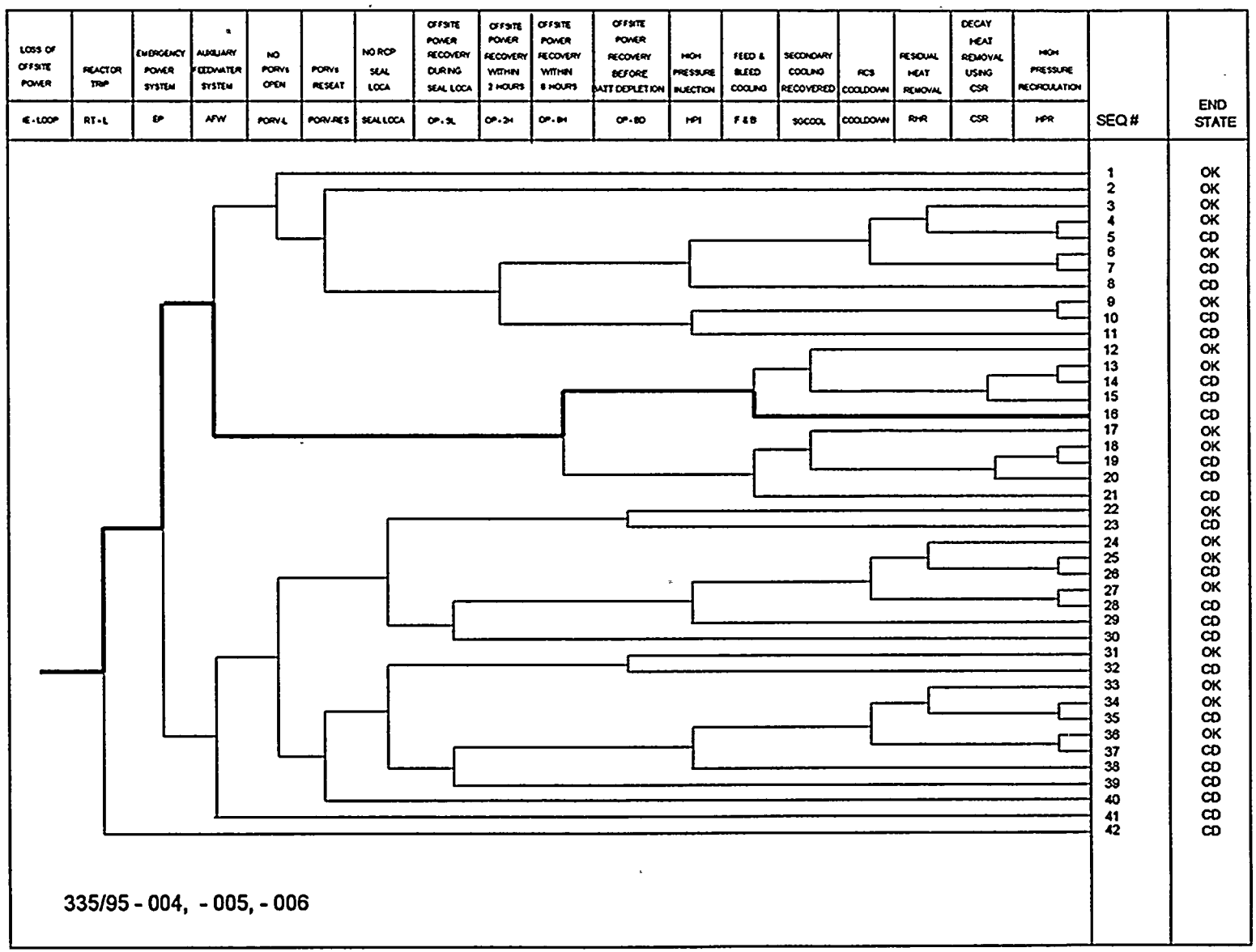

Fig. 2 Dominant core damage sequence given a LOOP for LER Nos. 335/95-004, -005, -006.

Table 1. Definitions and probabilities for selected basic events for LER Nos. 335/95-004, -005, -006

Event name	Description	Base probability	Current probability	Type	Modified for this event
AFW-MOV-CF-SGALL	Common Cause Failure of all Steam Generator Motor-Operated Valves	5.5 E-005	5.5 E-005		No
AFW-PMP-CF-ALL	Common Cause Failure of all AFW Pumps	1.7 E-004	1.7 E-004		No
AFW-TDP-FC-1C	AFW Turbine Driven Pump 1C Fails	3.2 E-002	3.2 E-002		No
AFW-XHE-NOREC	Operator Fails to Recover AFW System	2.6 E-001	2.6 E-001		No
AFW-XHE-NOREC-EP	Operator Fails to Recover AFW During a Station Blackout	3.4 E-001	3.4 E-001		No
AFW-XHE-NOREC-L	Operator Fails to Recover AFW During LOOP	2.6 E-001	2.6 E-001		No
AFW-XHE-XA-CST2	Operator Fails to Initiate Backup Water Source	1.0 E-003	1.0 E-003		No
AFW-XHE-XA-CST2E	Operator Fails to Initiate Backup Water Source During a Station Blackout	1.0 E-003	1.0 E-003		No
AFW-XHE-XA-CST2L	Operator Fails to Initiate Backup Water Source During a LOOP	1.0 E-003	1.0 E-003		No
EPS-DGN-CF-AB	Common Cause Failure of Diesel Generators	1.6 E-003	1.6 E-003		No
EPS-DGN-FC-DGA	Diesel Generator A Failures	4.2 E-002	4.2 E-002		No
EPS-DGN-FC-DGB	Diesel Generator B Failures	4.2 E-002	4.2 E-002		No
EPS-XHE-NOREC	Operator Fails to Recover Emergency Power	8.0 E-001	8.0 E-001		No
HPI-MDP-CF-ALL	Common Cause Failure of HPI Motor-Driven Pumps	1.0 E-004	1.0 E-004		No
HPI-MOV-CF-DISAL	Common Cause Failure of all HPI Injection Valves	5.5 E-005	5.5 E-005		No

Table 1. Definitions and probabilities for selected basic events for LER Nos. 335/95-004, -005, -006

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPI-TNK-FC-RWST	RWST and Water Supply Valve Failures	2.7 E-006	2.7 E-006		No
MFW-SYS-TRIP	Main Feedwater System Trips	2.0 E-001	2.0 E-001		No
MFW-XHE-NOREC	Operator Fails to Recover Main Feedwater	3.4 E-001	3.4 E-001		No
OEP-XHE-NOREC-6H	Operator Fails to Recover Offsite Power Within 6 Hours	5.7 E-002	5.7 E-002		No
OEP-XHE-NOREC-BD	Operator Fails to Recover Offsite Power Before Batteries Are Depleted	1.1 E-002	1.1 E-002		No
OEP-XHE-NOREC-SL	Operator Fails to Recover Offsite Power (Seal LOCA)	6.0 E-001	6.0 E-001		No
PCS-PSF-HW	Hardware Failures Causing Failure to Depressurize	1.0 E-005	1.0 E-005		No
PCS-XHE-SM-SG	Operator Fails to Initiate RCS Depressurization	4.0 E-004	4.0 E-004		No
PPR-SRV-CC-1	PORV 1 Fails to Open on Demand	2.0 E-003	1.0 E+000	TRUE	Yes
PPR-SRV-CC-2	PORV 2 Fails to Open on Demand	2.0 E-003	1.0 E+000	TRUE	Yes
PPR-SRV-CO-SBO	PORVs Open During SBO	1.0 E+000	1.0 E+000		No
PPR-SRV-CO-TRAN	PORVs Open During Transient	4.0 E-002	4.0 E-002		No
PPR-SRV-OO-PRV1	PORV 1 Fails to Reclose After Opening	2.0 E-003	0.0 E+000	FALSE	Yes
PPR-SRV-OO-PRV2	PORV 2 Fails to Reclose After Opening	2.0 E-003	0.0 E+000	FALSE	Yes
PPR-SRV-OO-SRVS	At Least One Safety Valve Fails to Reclose After Opening	0.0 E+000	9.0 E-002		Yes
RCS-MDP-LK-SEALS	RCP Seals Fail Without Cooling and Injection	3.4 E-002	3.4 E-002		No

Table 2. Sequence conditional probabilities for LER Nos. 335/95-004, -005, -006

Event tree name	Sequence name	Conditional core damage probability (CCDP)	% Contribution
TRANS	21	5.1 E-005	40.8
LOOP	16	2.6 E-005	21.3
LOOP	40	1.9 E-005	15.7
LOOP	30	4.4 E-006	3.5
LOOP	39	4.4 E-006	3.5
SGTR	05	3.9 E-006	3.1
LOOP	41	2.5 E-006	1.9
LOOP	23	2.4 E-006	1.9
LOOP	32	2.4 E-006	1.9
LOOP	21	1.5 E-006	1.2
SGTR	06	1.5 E-006	1.2
TRANS	08	1.3 E-006	1.0
Total (all sequences)		1.2 E-004	

Table 3. Sequence logic for dominant sequences for LER Nos. 335/95-004, -005, -006

Event tree name	Sequence name	Logic
TRANS	21	/RT, AFW, MFW, F&B
LOOP	16	/RT-L, /EP, AFW-L, /OP-6H, F&B-L
LOOP	40	/RT-L, EP, /AFW-L, PORV-SBO, PRVL-RES
LOOP	30	/RT-L, EP, /AFW-L, /PORV-SBO, SEALLOCA, OP-SL
LOOP	39	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, SEALLOCA, OP-SL
SGTR	05	/RT, /AFW-SGTR, /HPI, RCS-SG
LOOP	41	/RT-L, EP, AFW-L-EP
LOOP	23	/RT-L, EP, /AFW-L, /PORV-SBO, /SEALLOCA, OP-BD
LOOP	32	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, /SEALLOCA, OP-BD
LOOP	21	/RT-L, /EP, AFW-L, OP-6H, F&B-L
SGTR	06	/RT, /AFW-SGTR, HPI
TRANS	08	/RT, /AFW, PORV, PORV-RES, HPI

Table 4. System names for LER Nos. 335/95-004, -005, -006

System name	Logic
AFW	No or Insufficient AFW Flow
AFW-L	No or Insufficient AFW Flow During LOOP
AFW-L-EP	No or Insufficient AFW Flow During Station Blackout
AFW-SGTR	No or Insufficient AFW Flow During a Steam Generator Tube Rupture
EP	Failure of Both Trains of Emergency Power
F&B	Failure to Provide Feed and Bleed Cooling
F&B-L	Failure of Feed and Bleed Cooling During a LOOP
HPI	No or Insufficient Flow from HPI System
MFW	Failure of the Main Feedwater System
OP-6H	Operator Fails to Recover Offsite Power Within 6 h
OP-BD	Operator Fails to Recover Offsite Power Before Batteries are Depleted
OP-SL	Operator Fails to Recover Offsite Power (Seal LOCA)
PORV	PORVs Open During Transient
PORV-RES	PORVs Fail to Reseat
PORV-SBO	PORVs Open During Station Blackout Event
PRVL-RES	PORVs and Block Valves Fail to Reclose [Electric Power (EP) succeeds]
RCS-SG	Failure to Lower RCS Pressure to Less Than the Steam Generator Relief Valve Setpoint
RT	Reactor Fails to Trip During Transient
RT-L	Reactor Fails to Trip During LOOP
SEALLOCA	RCP Seals Fail During LOOP

Table 5. Conditional cut sets for higher probability sequences for LER Nos. 335/95-004, -005, -006

Cut set No.	Percent Contribution	Conditional Probability[a]	Cut sets
TRANS Sequence 21		5.1 E-005	
1	80.2	4.1 E-005	AFW-XHE-NOREC, AFW-XHE-XA-CST2, MFW-SYS-TRIP, MFW-XHE-NOREC
2	14.2	7.2 E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC
3	4.4	2.2 E-006	AFW-MOV-CF-SGALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC
LOOP Sequence 16		2.6 E-005	
1	79.0	2.1 E-005	AFW-XHE-XA-CST2L, AFW-XHE-NOREC-L
2	14.0	3.6 E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC
3	4.4	1.1 E-006	AFW-MOV-CF-SGALL, AFW-XHE-NOREC-L
LOOP Sequence 40		1.9 E-005	
1	52.4	1.0 E-005	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-SRVS
2	47.6	9.0 E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-SRVS
LOOP Sequence 30		4.4 E-006	
1	52.4	2.3 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
2	47.6	2.1 E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
LOOP Sequence 39		4.4 E-006	
1	52.4	2.3 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
2	47.6	2.1 E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL

Table 5. Conditional cut sets for higher probability sequences for LER Nos. 335/95-004, -005, -006

Cut set No.	Percent Contribution	Conditional Probability[a]	Cut sets
SGTR Sequence 05		3.9 E-006	
1	97.6	3.8 E-006	PCS-XHE-XM-SG
2	2.4	9.4 E-008	PCS-PSF-HW
LOOP Sequence 41		2.5 E-006	
1	50.2	1.3 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, AFW-TDP-FC-1C, AFW-XHE-NOREC-EP
2	45.5	1.1 E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, AFW-TDP-FC-1C, AFW-XHE-NOREC-EP
3	1.6	4.0 E-008	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, AFW-XHE-XA-CST2E, AFW-XHE-NOREC-EP
4	1.4	3.5 E-008	EPS-DGN-CF-AB, EPS-XHE-NOREC, AFW-XHE-XA-CST2E, AFW-XHE-NOREC-EP
LOOP Sequence 23		2.4 E-006	
1	52.4	1.3 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, OEP-XHE-NOREC-BD
2	47.6	1.1 E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, OEP-XHE-NOREC-BD
LOOP Sequence 32		2.4 E-006	
1	52.4	1.3 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, OEP-XHE-NOREC-BD
2	47.6	1.1 E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, OEP-XHE-NOREC-BD
LOOP Sequence 21		1.5 E-006	
1	79.0	1.2 E-006	AFW-XHE-NOREC-L, AFW-XHE-XA-CST2L, OEP-XHE-NOREC-6H
2	14.0	2.1 E-007	AFW-PMP-CF-ALL, AFW-XHE-NOREC-L, OEP-XHE-NOREC-6H
3	4.4	6.6 E-008	AFW-MOV-CF-ALL, AFW-XHE-NOREC-L, OEP-XHE-NOREC-6H

Table 5. Conditional cut sets for higher probability sequences for LER Nos. 335/95-004, -005, -006

Cut set No.	Percent Contribution	Conditional Probability[a]	Cut sets
SGTR Sequence 06		1.5 E-006	
1	62.7	9.4 E-007	HPI-MDP-CF-ALL
2	34.7	5.2 E-007	HPI-MOV-CF-DISAL
3	1.7	2.6 E-008	HPI-TNK-FC-RWST
TRANS Sequence 08		1.3 E-006	
1	62.7	8.2 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-SVRS, HPI-MDP-CF-ALL
2	34.7	4.5 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-SVRS, HPI-MOV-CF-DISAL
3	1.7	2.2 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-SVRS, HPI-TNK-FC-RWST
RCP Seal LOCA		5.9 E-006	
Total (all sequences)		1.3 E-004	

a. The conditional probability for each cut set is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per hour basis), and t is the duration time of the event (in this case, 5840 h). This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are: $\lambda_{TRANS} = 4.0 \times 10^{-4}$/h, $\lambda_{LOOP} = 1.4 \times 10^{-5}$/h, and $\lambda_{SGTR} = 1.63 \times 10^{-6}$/h.

GUIDANCE FOR LICENSEE REVIEW OF PRELIMINARY ASP ANALYSIS

Background

The preliminary precursor analysis of an operational event that occurred at your plant has been provided for your review. This analysis was performed as a part of the NRC's Accident Sequence Precursor (ASP) Program. The ASP Program uses probabilistic risk assessment techniques to provide estimates of operating event significance in terms of the potential for core damage. The types of events evaluated include actual initiating events, such as a loss of off-site power (LOOP) or loss-of-coolant accident (LOCA), degradation of plant conditions, and safety equipment failures or unavailabilities that could increase the probability of core damage from postulated accident sequences. This preliminary analysis was conducted using the information contained in the plant-specific final safety analysis report (FSAR), individual plant examination (IPE), and the licensee event report (LER) for this event.

Modeling Techniques

The models used for the analysis of 1995 and 1996 events were developed by the Idaho National Engineering Laboratory (INEL). The models were developed using the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) software. The models are based on linked fault trees. Four types of initiating events are considered: (1) transients, (2) loss-of-coolant accidents (LOCAs), (3) losses of offsite power (LOOPs), and (4) steam generator tube ruptures (PWR only). Fault trees were developed for each top event on the event trees to a supercomponent level of detail. The only support system currently modeled is the electric power system.

The models may be modified to include additional detail for the systems/components of interest for a particular event. This may include additional equipment or mitigation strategies as outlined in the FSAR or IPE. Probabilities are modified to reflect the particular circumstances of the event being analyzed.

Guidance for Peer Review

Comments regarding the analysis should address:

- Does the "Event Description" section accurately describe the event as it occurred?
- Does the "Additional Event-Related Information" section provide accurate additional information concerning the configuration of the plant and the operation of and procedures associated with relevant systems?
- Does the "Modeling Assumptions" section accurately describe the modeling done for the event? Is the modeling of the event appropriate for the events that occurred or that had the potential to occur under the event conditions? This also includes assumptions regarding the likelihood of equipment recovery.

Appendix H of Reference 1 provides examples of comments and responses for previous ASP analyses.

Criteria for Evaluating Comments

Modifications to the event analysis may be made based on the comments that you provide. Specific documentation will be required to consider modifications to the event analysis. References should be made to portions of the LER, AIT, or other event documentation concerning the sequence of events. System and component capabilities should be supported by references to the FSAR, IPE, plant procedures, or analyses. Comments related to operator response times and capabilities should reference plant procedures, the FSAR, the IPE, or applicable operator response models. Assumptions used in determining failure probabilities should be clearly stated.

Criteria for Evaluating Additional Recovery Measures

Additional systems, equipment, or specific recovery actions may be considered for incorporation into the analysis. However, to assess the viability and effectiveness of the equipment and methods, the appropriate documentation must be included in your response. This includes:

- normal or emergency operating procedures,*
- piping and instrumentation diagrams (P&IDs),*
- electrical one-line diagrams,*
- results of thermal-hydraulic analyses, and
- operator training (both procedures and simulator),* etc.

Systems, equipment, or specific recovery actions that were not in place at the time of the event will not be considered. Also, the documentation should address the impact (both positive and negative) of the use of the specific recovery measure on:

- the sequence of events,
- the timing of events,
- the probability of operator error in using the system or equipment, and
- other systems/processes already modeled in the analysis (including operator actions).

For example, Plant A (a PWR) experiences a reactor trip, and during the subsequent recovery, it is discovered that one train of the auxiliary feedwater (AFW) system is unavailable. Absent any further information regrading this event, the ASP Program would analyze it as a reactor trip with one train of AFW unavailable. The AFW modeling would be patterned after information gathered either from the plant FSAR or the IPE. However, if information is received about the use of an additional system (such as a standby steam generator feedwater system) in recovering from this event, the transient would be modeled as a reactor trip with one train of AFW unavailable, but this unavailability would be

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* Revision or practices at the time the event occurred.

mitigated by the use of the standby feedwater system. The mitigation effect for the standby feedwater system would be credited in the analysis provided that the following material was available:

- standby feedwater system characteristics are documented in the FSAR or accounted for in the IPE,
- procedures for using the system during recovery existed at the time of the event,
- the plant operators had been trained in the use of the system prior to the event,
- a clear diagram of the system is available (either in the FSAR, IPE, or supplied by the licensee),
- previous analyses have indicated that there would be sufficient time available to implement the procedure successfully under the circumstances of the event under analysis,
- the effects of using the standby feedwater system on the operation and recovery of systems or procedures that are already included in the event modeling. In this case, use of the standby feedwater system may reduce the likelihood of recovering failed AFW equipment or initiating feed-and-bleed due to time and personnel constraints.

Materials Provided for Review

The following materials have been provided in the package to facilitate your review of the preliminary analysis of the operational event.

- The specific LER, augmented inspection team (AIT) report, or other pertinent reports.

- A summary of the calculation results. An event tree with the dominant sequence(s) highlighted. Four tables in the analysis indicate: (1) a summary of the relevant basic events, including modifications to the probabilities to reflect the circumstances of the event, (2) the dominant core damage sequences, (3) the system names for the systems cited in the dominant core damage sequences, and (4) cut sets for the dominant core damage sequences.

Schedule

Please refer to the transmittal letter for schedules and procedures for submitting your comments.

References

1. L. N. Vanden Heuvel et al., Precursors to Potential Severe Core Damage Accidents: 1994, A Status Report, USNRC Report NUREG/CR-4674 (ORNL/NOAC-232) Volumes 21 and 22, Martin Marietta Energy Systems, Inc., Oak Ridge National Laboratory and Science Applications International Corp., December 1995.