October 23, 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 EVENT AT ST. LUCIE PLANT, UNIT 1

Dear Mr. Plunkett:

Enclosed for your information is a copy of the final Accident Sequence Precursor (ASP) analysis of the operational event at St. Lucie Plant, Unit 1, reported in Licensee Event Report (LER) Nos. 335/95-004, -005 and -006. This final analysis (Enclosure 1) was prepared by our contractor at the Oak Ridge National Laboratory (ORNL), based on review and evaluation of your comments on the preliminary analysis and comments received from the NRC staff and from our independent contractor, Sandia National Laboratories (SNL). Enclosure 2 contains our responses to your specific comments. Our review of your comments employed the criteria contained in the material which accompanied the preliminary analysis. The results of the final analysis indicate that this event is a precursor for 1995.

Please contact me at (301) 415-1495 if you have any questions regarding the enclosures. We recognize and appreciate the effort expended by you and your staff in reviewing and providing comments on the preliminary analysis.

Sincerely,

oOriginal signed by
Leonard A. Wiens, Senior Project Manager
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Division of Reactor Projects-I/II
Office of Nuclear Reactor Regulation

Docket No. 50-335
Enclosures: 1. Final ASP Analysis
2. Responses to Comments
cc w/enclosures: See next page

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

Event Description: Failed Power Operated Relief Valves (PORVs), Reactor Coolant Pump (RCP) seal failure, relief valve failure and subsequent Shutdown Cooling (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 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 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. After the open relief valve was discovered, the SDC system was removed from service for about a day to replace the valve. During this time, only the steam generators were available for decay heat removal. The conditional core damage probability (CCDP) estimated for the PORV unavailability is 1.1×10^{-4}. This is an increase of 9.3×10^{-5} over the nominal core damage probability for the same period. The CCDP associated with the potential RCP seal LOCA is 5.6×10^{-6}. The increase in core damage probability (CDP) associated with the removal of the SDC system from service to replace the thermal relief valve is less than the Accident Sequence Precursor (ASP) program screening value of 1.0×10^{-6}.

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 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 seal failed and the upper and vapor seal degraded. The licensee attributed these failures to the performance of the restaging procedure at RCS temperatures above 200°F and on a rotating pump. At 1810 on August 2, 1995, twenty minutes after control room indication of the failed middle seal, operators began to cooldown 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 because of the ongoing RCS cooldown and depressurization. The RCP 1A2 seal was subsequently replaced, as was the RCP 1A1 seal (because of degraded performance).

During the RCS depressurization and cooldown on August 3, 1995, the PORVs also were 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 again were 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. Because 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 because 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 closed position.

At 0611 on August 10, 1995, thermal relief valve V3439 was determined to have been the cause of the leakage. The valve is located in LPSI pump discharge piping, which 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 of reactor coolant was discharged during the almost 2-h period 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 approximately 20 h 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 relief valve replacement, 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 during the same time frame as the events described previously. These events, which would not be selected as precursors, are summarized 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 were 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 because 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 again was not consulted. Six minutes after the block permissive annunciated, the annunciator for MSIS actuation alarmed. Before operator action could be taken, MSIS actuated and was subsequently 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. Because repair of the valve was expected to take a significant length of time, the valve was 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 warm-up 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, a direct path from the RWT was provided 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 approximately 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 236°F. 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 when the RCS temperature 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 5880 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 Accident Sequence Precursor (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. Because 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, which should result in fewer SV challenges and, therefore, a lower challenge rate. Unfortunately, because PORVs are usually available, operational data on SV challenges do 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 (e.g., 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 and excluded the names of the plants at which the events occurred. However, data were listed for Arkansas Nuclear One (ANO), Units 1 and 2. These data were 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 of Ref. 6, 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 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. Feed and bleed was unavailable because of 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 before 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. The lower decay heat level would substantially extend the time available to recover the AFW system if it failed and would eliminate the requirement to provide an alternate AFW suction source because the CST would not be expected to be emptied during the 22-h LPSI unavailability. (The decay heat load for this period is estimated to be less than 79% of the Technical Specification-required CST volume.) 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 condensate storage tank (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 during the LPSI relief valve repair. AFW-XHE-NOREC was changed 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

[1] One catastrophic seal failure was included in Table B-3 in Ref. 6 but was excluded from the set of seal degradations relevant to this event. That event occurred at ANO 1 and followed a loss of off-site power (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.*

[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, most likely, is conservative since at least some of the AFW components had recently operated and non-demand, standby failures, therefore, would 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, which has less than a 2% percent impact on these basic event probabilities.

longest nonrecovery duration addressed in that document. The 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 were not extrapolated.

The probability that AFW would have failed during the 22 h that the SDC system was removed from service is estimated to be 3.0×10^{-5}, using the St. Lucie ASP model modified as described previously. If the AFW system had failed, the condensate system could have been used for steam generator (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 CCDP estimated for the 5880-h PORV unavailability is 1.1×10^{-4}. This is an increase of 9.3×10^{-5} over the nominal CDP of 1.6×10^{-5} for the same period. The dominant core damage sequence, highlighted as sequence number 21 on the event tree in Fig. 1, contributes about 55% to the increase in the CCDP and involves

- a postulated reactor trip during the 5880 h the PORVs were unavailable,
- nonrecoverable failures of main feedwater (MFW) and AFW, and
- loss of feed and bleed ability because of the unavailability of the PORVs.

The second highest core damage sequence, which contributes about 33% of the increase in CCDP, is similar to sequence number 21 on Fig. 1 but involves a postulated LOOP instead of a transient and is highlighted on Fig. 2 . Sequence 16 involves

- a successful reactor trip given a LOOP with emergency power available,
- failure of the AFW system, and
- loss of feed and bleed ability because of the unavailability of the PORVs.[6]

Table 1 provides the definitions and probabilities for selected basic events for the assessment of the unavailable PORVs. The conditional probabilities associated with the highest probability sequences sorted by the increase in conditional probability for the condition assessment are shown in Table 2. Table 3 shows the sequence logic associated with the sequences in Table 2. Table 4 describes the system names associated with the dominant sequences for the condition assessment. Cut sets associated with the dominant sequences for the condition assessment are shown in Table 5.

[6] The LOOP event tree includes the successful recovery of offsite power within 6 h in the dominant sequence. This is an artifice of the top event ordering. Feed and bleed challenge would occur about 20 min after the trip, and core damage would begin shortly thereafter. Sequences 16 and 21 together represent the core damage sequence involving emergency power success and AFW and feed and bleed failure.

The CCDP estimated for the potential RCP seal LOCA is 5.6×10^{-6}. The dominant core damage sequence (the only sequence above the 1×10^{-6} ASP screening valve) involves

- a postulated RCP seal LOCA,
- AFW success, and
- failure of HPI.

Definitions and probabilities for selected basic events for the potential RCP seal failure are shown in Table 6. The conditional probabilities associated with the highest probability sequences sorted by the increase in CCDP are shown in Table 7. Table 8 shows the sequence logic associated with the sequences in Table 7. Table 9 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table 10.

Acronyms

ASP	accident sequence precursor
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
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.

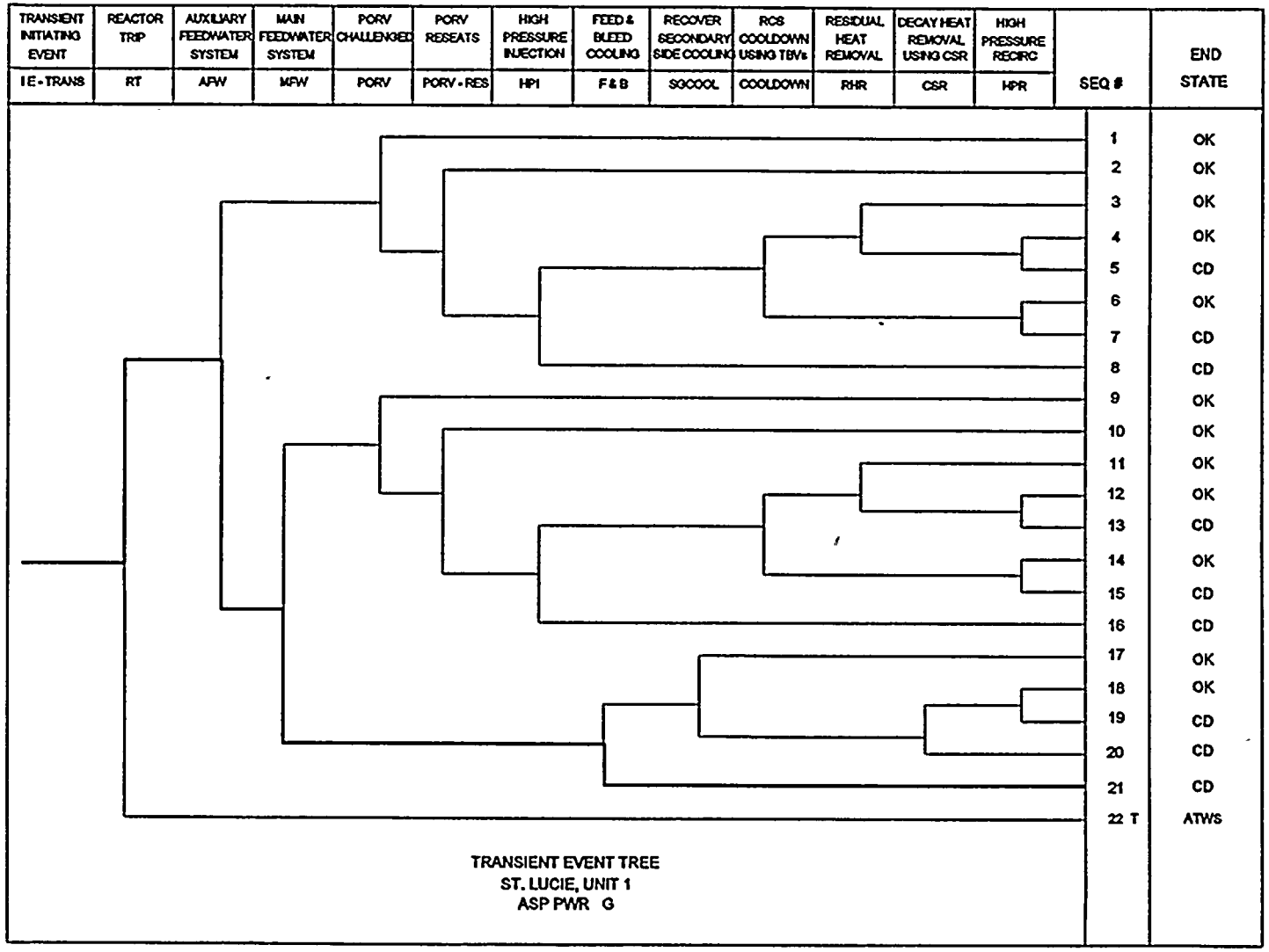

Fig. 1 Dominant core damage sequence given a transient for LER Nos. 335/95-004, -005, -006.

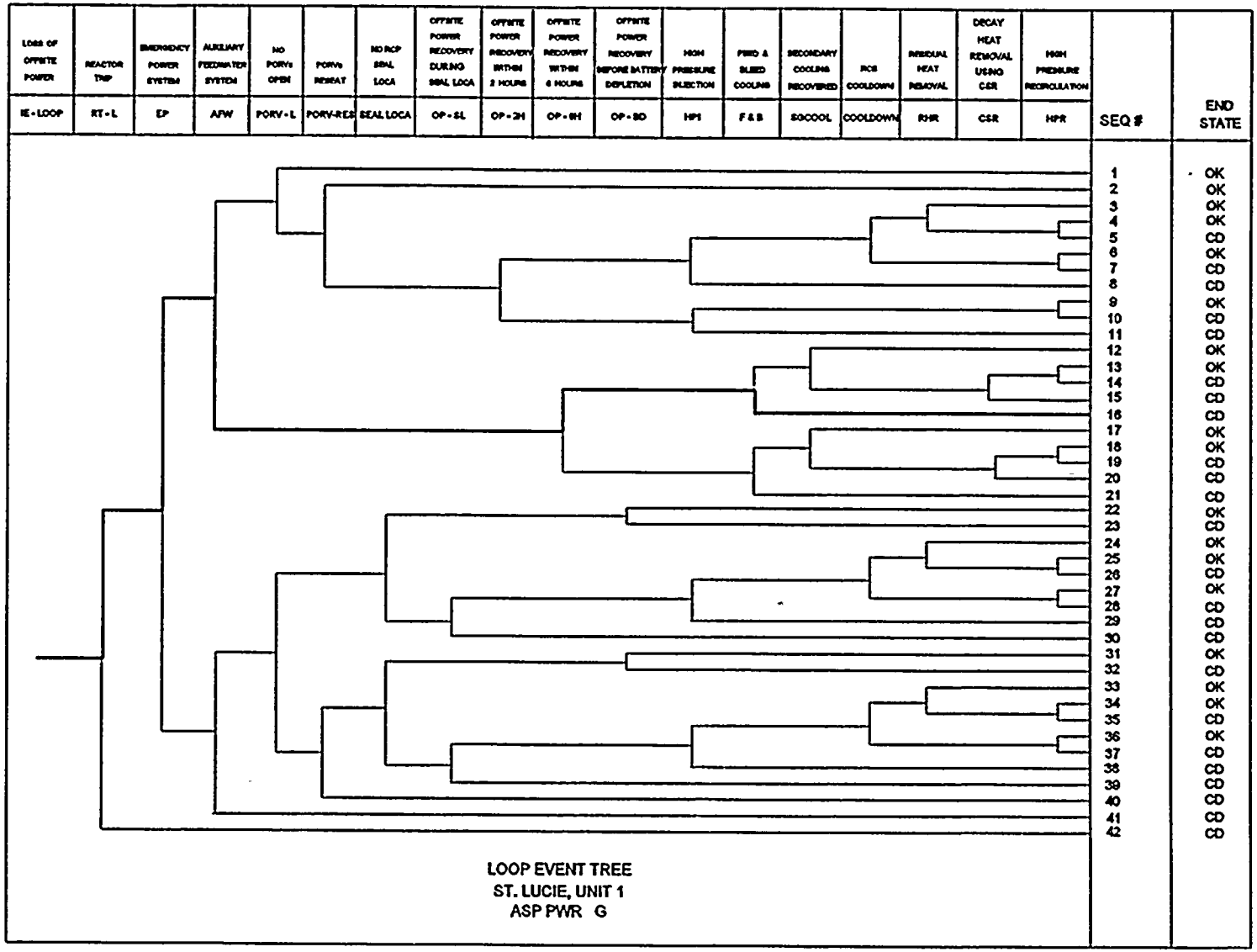

Fig. 2 Dominant core damage sequence given a LOOP for LER Nos. 335/95-004, -005, -006.

Table 1. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

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 Auxiliary Feedwater (AFW) Pumps	1.7 E-004	1.7 E-004		No
AFW-XHE-NOREC	Operator Fails to Recover AFW System	2.6 E-001	2.6 E-001		No
AFW-XHE-NOREC-L	Operator Fails to Recover AFW During a Loss-of-Offsite Power (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-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[a]	Operator Fails to Recover Emergency Power	8.0 E-001	8.0 E-001		No
HPI-MDP-CF-ALL	Common Cause Failure of High Pressure Injection (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
HPI-TNK-FC-RWST	Refueling Water Storage Tank 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

[a] The potential recovery of ac power through recovery of offsite power or use of the unit 1/unit 2 cross-tie is addressed in basic events OEP-XHE-NOREC-BD (operator fails to recover offsite power before batteries are depleted) and OEP-XHE-NOREC-SL [operator fails to recover offsite power (seal LOCA)]. Because these basic events are in sequences that contribute to less than 1% of the total CCDP, they do not appear in Table 1 which provides definitions and probabilities for basic events that appear in the dominant sequences, or Table 5 which lists the dominant sequences and their cut sets.

Table 1. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Event name	Description	Base probability	Current probability	Type	Modified for this event
MFW-XHE-NOREC	Operator Fails to Recover Main Feedwater	3.4 E-001	3.4 E-001		No
PPR-SRV-CC-1	Power-Operated Relief Valve (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 a Station Blackout	3.7 E-001	3.7 E-001		No
PPR-SRV-CO-TRAN	PORVs Open During Transient	4.0 E-002	4.0 E-002		No
PPR-SRV-OO-1	PORV 1 Fails to Reclose After Opening	2.0 E-003	0.0 E+000	FALSE	Yes
PPR-SRV-OO-2	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

Table 2. Sequence Conditional Probabilities for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Core damage probability (CDP)	Importance (CCDP - CDP)	Percent contribution[a]
TRANS	21	5.1 E-005	7.2 E-007	5.0 E-005	54.9
LOOP	16	3.1 E-005	4.5 E-007	3.0 E-005	33.3
LOOP	40	8.5 E-006	1.2 E-008	8.5 E-006	9.2
TRANS	08	1.3 E-006	8.1 E-010	1.3 E-006	1.4
Total (all sequences)		1.1 E-004	1.6 E-005	9.3 E-005	

[a] Percent contribution to the total importance.

Table 3. Sequence Logic for Dominant Sequences for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

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
TRANS	08	/RT, /AFW, PORV, PORV-RES, HPI

Table 4. System Names for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

System name	Logic
AFW	No or insufficient AFW flow
AFW-L	No or insufficient AFW flow during LOOP
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 off-site power within 6 h
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]
RT	Reactor fails to trip during transient
RT-L	Reactor fails to trip during LOOP

Table 5. Conditional Cut Sets for Higher Probability Sequences for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets[b]
TRANS Sequence 21		5.1 E-005	
1	80.2	4.1 E-005	AFW-XHE-XA-CST2, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
2	14.2	7.0 E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
3	4.4	2.2 E-006	AFW-MOV-CF-SGALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
LOOP Sequence 16		3.1 E-005	
1	79.0	2.4 E-005	AFW-XHE-XA-CST2L, AFW-XHE-NOREC-L, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
2	13.9	4.4 E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
3	4.3	1.3 E-006	AFW-MOV-CF-SGALL, AFW-XHE-NOREC-L, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
LOOP Sequence 40		8.5 E-006	
1	52.4	4.5 E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-SRVS
2	47.5	4.0 E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-SRVS
TRANS Sequence 08		1.3 E-006	
1	62.6	8.2 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-SRVS, HPI-MDP-CF-ALL
2	34.7	4.5 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-SRVS, HPI-MOV-CF-DISAL
3	1.6	2.2 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-SRVS, HPI-TNK-FC-RWST
Total (all sequences)		1.1 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 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, 5880 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 and $\lambda_{LOOP} = 1.6 \times 10^{-5}$/h.

[b] Basic events PPR-SRV-CC-1 and PPR-SRV-CC-2 are type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

Table 6. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event - Loss-of-Offsite Power	1.6 E-005	0.0 E+000		Yes
IE-SGTR	Initiating Event - Steam Generator Tube Rupture	1.6 E-006	0.0 E+000		Yes
IE-SLOCA	Initiating Event - Small Break Loss-of-Coolant Accident	1.0 E-006	2.8 E-002		Yes
IE-TRANS	Initiating Event - Transients	4.0 E-004	0.0 E+000		Yes
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 Auxiliary Feedwater (AFW) Pumps	1.7 E-004	1.7 E-004		No
AFW-XHE-NOREC	Operator Fails to Recover AFW System	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
HPI-MDP-CF-ALL	Common Cause Failure of High Pressure Injection (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
HPI-TNK-FC-RWST	Refueling Water Storage Tank 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
PPR-SRV-CC-1	Power-Operated Relief Valve (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-OO-1	PORV 1 Fails to Reclose After Opening	2.0 E-003	0.0 E+000	FALSE	Yes

Table 6. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event name	Description	Base probability	Current probability	Type	Modified for this event
PPR-SRV-OO-2	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 Relief Valve Fails to Reclose After Opening	0.0 E+000	9.0 E-002		Yes
RPS-NONREC	Nonrecoverable Reactor Protection System Trip Failures	2.0 E-005	2.0 E-005		No

Table 7. Sequence Conditional Probabilities for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent contribution
SLOCA	06	4.4 E-006	78.6
SLOCA	23	6.1 E-007	10.9
SLOCA	24	5.6 E-007	10.0
Total (all sequences)		5.6 E-006	

Table 8. Sequence Logic for Dominant Sequences for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event tree name	Sequence name	Logic
SLOCA	06	/RT, /AFW, HPI
SLOCA	23	/RT, AFW, MFW, F&B
SLOCA	24	RT

Table 9. System Names for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

System name	Logic
AFW	No or insufficient AFW flow
F&B	Failure to provide feed-and-bleed cooling
HPI	No or insufficient flow from HPI system
MFW	Failure of the main feedwater system
RT	Reactor fails to trip during transient

Table 10. Conditional Cut Sets for Higher Probability Sequences for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets[b]
SLOCA Sequence 06		4.4 E-006	
1	62.6	2.8 E-006	HPI-MDP-CF-ALL
2	34.7	1.5 E-006	HPI-MOV-CF-DISAL
3	1.6	7.5 E-008	HPI-TNK-FC-RWST
SLOCA Sequence 23		6.1 E-007	
1	80.2	4.9 E-007	AFW-XHE-XA-CST2, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
2	14.2	8.7 E-008	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
3	4.4	2.7 E-008	AFW-MOV-CF-SGALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
SLOCA Sequence 24		5.6 E-007	
1	100.0	5.6 E-007	RPS-NOREC
Total (all sequences)		5.6 E-006	

[a] The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probability of the initiating events are given in Table 6 and begin with the designator "IE". The probabilities for the basic events are also given in Table 6.

[b] Basic events PPR-SRV-CC-1 and PPR-SRV-CC-2 are type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

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

Event Description: Failed Power Operated Relief Valves (PORVs), Reactor Coolant Pump (RCP) seal failure, relief valve failure and subsequent Shutdown Cooling (SDC) unavailability, plus other problems

Date of Event: August 2, 1995

Plant: St. Lucie 1

Licensee Comments

Reference: J. A. Stall (Florida Power &Light Company) letter to the U.S. Nuclear Regulatory Commission, "Comments on the Preliminary Accident Sequence Precursor Analysis," L-96-155, June 20, 1996.

Comment 1: (Summary) The conditional core damage probability (CCDP), as calculated in the NRC evaluation, represents the total core damage probability (CDP) given the PORVs are unavailable. Presenting the results in this manner can make it difficult to compare the precursor evaluation results to the screening value of 1E-6 since the baseline CDP for many of the dominant sequences identified are not impacted by the PORV unavailability and have baseline values above 1E-6.... It is recommended that both the CCDP and the change in CDP be described, as discussed in the 1994 precursor report for condition assessments....

Response 1: The PORV unavailability analysis has been revised to provide the CCDP and change in CDP (importance) for the event.

Comment 2: (Summary) The Event Summary discusses three primary events that are addressed in the draft precursor analysis (reactor coolant pump seal stage failures, PORV unavailability, and removal of the shutdown cooling system from service for 22 h). This section states that "The conditional core damage probability estimated for this event is 1.3E-4." The CCDP is actually the total CCDP for three different events .... It is recommended that the Event Summary should (1) identify that the total CCDP represents a combination of multiple events, and (2) provide the contribution from each event so that it is clear what is the dominant contributor to the total CCDP.

Response 2: The Event Summary has been revised to describe the contribution from the individual failures by adding the following:

The conditional core damage probability estimated for the PORV unavailability is 1.1×10^{-4}. This is an increase of 9.3×10^{-5} over the nominal core damage probability for the same period. The

conditional core damage probability associated with the potential RCP seal LOCA is 5.3 x 10^{-6}. The increase in core damage probability associated with the removal of the SDC system from service to replace the thermal relief valve is less than the ASP screening value of 1.0 x 10^{-6}.

Comment 3a: (Summary) LOOP sequences 16 and 21 are essentially the same except for whether offsite power is recovered within 6 h. The representation of these sequences in the event tree is confusing. It appears that the sequence for feed and bleed failure is not correct in that it occurs after the attempted recovery of offsite power at 6 h is either successful or fails. Feed and bleed is a short term action (less than 30 min) after a complete loss of feedwater.... It is recommended that since LOOP 16 is a dominant contributor to the total CCDP, that the actual sequence of events represented by sequences LOOP 16 and LOOP 21 be more clearly explained, and that the potential for recovery of MFW and/or condensate pumps be evaluated.

Response 3a: The representation of offsite power recovery in the LOOP event tree is not necessarily chronological. In the blackout sequences, the probability of an RCP seal LOCA and the probability of failing to recover AC power are calculated using a convolution approach that recognizes that both probabilities are a function of time. The model recognizes that offsite power will likely be recovered after feed and bleed is demanded, and requires EDG success for feed and bleed success. The intent of the 6 h recovery of offsite power branch is to address the potential for recovery of an initially failed AFW system before transfer to sump recirculation. Since feed and bleed has been demanded and has failed in this sequence before this time because of the unavailable PORVs, the potential recovery of offsite power by 6 h has no effect on the overall analysis results (LOOP 16 and LOOP 21 together represent the dominant sequence for the event). The description of the LOOP 16 sequence in Analysis Results has been clarified to address this by adding the following footnote

[6] The LOOP event tree includes the successful recovery of offsite power within 6 h in the dominant sequence. This is an artifice of the top event ordering. Feed and bleed challenge would occur about 20 min after the trip, and core damage would begin shortly thereafter. Sequences 16 and 21 together represent the core damage sequence involving emergency power success and AFW and feed and bleed failure.

Comment 3b: (Summary) In LOOP sequences 40, 30, 39, 41, 23, and 32, the basic event for failure to recover emergency power (EPS-XHE-NOREC) does not give proper credit for the capability to tie a diesel generator from Unit 2 to Unit 1 via the blackout crosstie. . . .

Response 3b: The potential use of the blackout crosstie has been added to the ASP model for the event for plant-centered LOOPs, consistent with the treatment of dual-unit crossties in other 1995 precursor analyses. The potential recovery of ac power through recovery of offsite power or use of the unit 1/unit 2 cross-tie is addressed in basic events OEP-XHE-NOREC-BD (operator fails to recover offsite power before batteries are depleted) and OEP-XHE-NOREC-SL [operator fails to recover offsite power (seal LOCA)]. Consideration of the cross-tie had little effect on the analysis results; the cross-tie-related basic events are in sequences that contribute to less than 1% of the total CCDP and do not appear in

Table 1, which provides definitions and probabilities for basic events that appear in the dominant sequences, or Table 5, which lists the dominant sequences and their cut sets.