Template NRR-058

March 10, 2000

Mr. W. R. McCollum, Jr.
Vice President, Oconee Site
Duke Energy Corporation
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION, UNITS 1, 2 AND 3 RE: FINAL ACCIDENT SEQUENCE PRECURSOR ANALYSIS OF OPERATIONAL CONDITION

Dear Mr. McCollum:

Enclosed for your information is a copy of the final Accident Sequence Precursor analysis of the operational condition at Oconee Nuclear Station, Units 1, 2, and 3, reported in Licensee Event Report No. 269/98-004. We prepared this final analysis (Enclosure 1) based on our review and evaluation of your comments on the preliminary analysis and comments received from the NRC staff. Enclosure 2 contains our responses to your specific comments. Our review of your comments employed the criteria contained in the material that accompanied the preliminary analysis. The results of the final analysis indicate that this condition is a precursor for 1998.

We recognize and appreciate the effort expended by you and your staff in reviewing and providing comments on the preliminary analysis.

Sincerely,
/RA/
David E. LaBarge, Senior Project Manager, Section 1
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-269, 50-270, and 50-287

Enclosures: 1. Final Analysis
2. Responses to Comments

cc w/encl: See next page

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

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Oconee Nuclear Station

cc:
Ms. Lisa F. Vaughn
Legal Department (PBO5E)
Duke Energy Corporation
422 South Church Street
Charlotte, North Carolina 28201-1006

Anne W. Cottingham, Esquire
Winston and Strawn
1400 L Street, NW
Washington, DC 20005

Mr. Rick N. Edwards
Framatome Technologies
Suite 525
1700 Rockville Pike
Rockville, Maryland 20852-1631

Manager, LIS
NUS Corporation
2650 McCormick Drive, 3rd Floor
Clearwater, Florida 34619-1035

Senior Resident Inspector
U. S. Nuclear Regulatory Commission
7812B Rochester Highway
Seneca, South Carolina 29672

Virgil R. Autry, Director
Division of Radioactive Waste Management
Bureau of Land and Waste Management
Department of Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201-1708

Mr. L. E. Nicholson
Compliance Manager
Duke Energy Corporation
Oconee Nuclear Site
7800 Rochester Highway
Seneca, South Carolina 29672

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of Justice
P. O. Box 629
Raleigh, North Carolina 27602

Mr. Jeffrey Thomas
Manager - Nuclear Regulatory Licensing
Duke Energy Corporation
526 South Church Street
Charlotte, North Carolina 28201-1006

Mr. Richard M. Fry, Director
Division of Radiation Protection
North Carolina Department of Environment, Health, and Natural Resources
3825 Barrett Drive
Raleigh, North Carolina 27609-7721

Mr. Steven P. Shaver
Senior Sales Engineer
Westinghouse Electric Company
5929 Carnegie Blvd.
Suite 500
Charlotte, North Carolina 28209

LER No. 269/98-004

Event Description: Calibration and calculational errors compromise emergency core cooling system transfer to emergency sump

Date of Event: February 12, 1998

Plant: Oconee Nuclear Plant, Units 1, 2, and 3

Event Summary

At the Oconee Nuclear Plant, Units 1, 2, and 3 (Oconee 1, 2, and 3), incorrect calibration of the borated water storage tank (BWST) level instruments, failure to address potential errors in reactor building emergency sump (RBES) indicated level, and incorrect estimation of expected RBES level resulted in (1) the potential for emergency core cooling system (ECCS) pump loss of net positive suction pressure (NPSH) and vortexing, and (2) a situation where the emergency operating procedure (EOP) requirements for BWST-to-RBES transfer would never have been met. This would have required ad-hoc operator action to maintain post-loss-of-coolant accident (LOCA) core cooling. The estimated conditional core damage probability (CCDP) associated with these conditions is 2.0×10^{-5} at Oconee 1 and 2 and 1.9×10^{-5} at Oconee 3. This is an increase of 1.7×10^{-6} at Oconee 1 and 2 and 1.4×10^{-6} at Oconee 3 over the nominal core damage probability (CDP) in a 1-year period of 1.8×10^{-5}.

Event Description

On February 12, 1998, Oconee 1 was at 65% power and Oconee 2 and 3 were at 100% power. During an investigation of a Self-Initiated Technical Audit (SITA) issue, personnel at Duke Power determined that the BWST level instruments were miscalibrated by as much as 18 in. lower than assumed in the calculations supporting EOP actions. Because of the calibration error, the indicated water level in the BWST was higher than the actual water level. Consequently, during the drain-down of the BWST following a postulated LOCA, unacceptable ECCS and reactor building spray pump NPSH and vortex formation may occur before the operators, while complying with the EOPs, transfer pump suction from the BWST to the reactor building (RB) sump.[1]

The BWST level calibration errors occurred when three new level transmitters were installed in 1989, replacing two older pneumatic level instrument trains. The field installation drawings specified that the new transmitters be mounted at elevation "799-1 or below." As a result, the new calibration test tees for each instrument were typically located ~1 ft below the elevation of the impulse line tap into the system, but in the worst case the elevation difference was ~1.5 ft, as shown in Fig. 1 and Table 1. (Level transmitters LT 2A and LT 6 are the primary indicators of the water level in the BWST following a LOCA.) A review of the drawings for the original pneumatic instruments indicated an elevation difference of approximately 4 in. Although the calibration procedure was revised after the new transmitters were installed, the revision did not address the

Enclosure 1

elevation differences. (Current Oconee practice in other instrument calibration procedures is to include a "zero offset" on the calibration data sheet to account for the difference between the instrument test tee and impulse line tap elevations.)

A second potential source of calibration error, the relative height of the calibration test instrument compared to the calibration test tee, was also missing from the calibration procedure. Personnel determined that this error would substantially impact instrument calibration because the calibration test instrument elevation is adjusted to match the elevation of the test tee.

In 1986, a series of instrument error calculations, which addressed the BWST level instruments, were performed to determine the appropriate procedural set points for BWST-to-RBES transfer to satisfy ECCS pump NPSH requirements and to avoid vortexing in the pump suction lines. These calculations assumed that the zero reference elevation for the BWST level instruments was the elevation of the impulse line tap. In January 1988, these calculations were designated OSC-2820, *Emergency Procedure Guidelines Set Points*, to document the sources and derivation of numerical values used as EOP set points.

Although these calculations were updated on several occasions after the BWST level instruments were replaced in 1989, the assumed zero reference point was not changed. Therefore, because personnel calibrated the BWST level instruments to the test tee elevation rather than to the impulse line tap elevation, the error between the water level in the BWST assumed in the EOP calculations and the indicated water level differed by 1.0 to 1.5 ft in the nonconservative direction. This error is a significant fraction of the 6-ft and 2-ft BWST level set point action statements included in the EOPs. All BWST level transmitters were recalibrated to address the test tee elevation errors by 0431 on February 13, 1998, the day after the problem was discovered.

One week after the BWST level instrumentation miscalibration was found, personnel identified another problem related to the BWST-to-RBES transfer. The Oconee EOPs at the time of this event required the operators to begin the BWST-to-RBES transfer when the water level in the BWST was less than 6 ft and the water level in the RBES was greater than 4 ft (Ref. 2). The failure to consider instrument errors when the EOP minimum RBES level was specified, plus the incorrect calculation of the expected water level in the reactor building when the water level in the BWST dropped to 6 ft, resulted in the potential for the indicated water level in the RBES to never reach the 4-ft level required for transfer.

The original 1973 emergency procedure for transferring ECCS pump suction from the BWST to the RBES specified that the transfer should occur upon receipt of the low-low BWST level alarm, then set at 3 ft. No RBES level requirement was included in the original procedure.

In 1985, the ECCS pump suction transfer procedure was revised to require the water level in the BWST to be less than 6 ft and the water level in the RBES to be more than 2 ft. The 2-ft RBES level was included as a precaution to ensure an adequate water level in the sump following pipe breaks that occurred outside containment. The RBES level instruments in place at the time had a range of 0 to 3 ft. Between December 1984 and December 1986, as part of post-Three Mile Island accident upgrades, two wide-range RB water level transmitters were installed at each of the three Oconee units. These instruments provide RBES level indication of 0 to 15 ft.

When OSC-2820, *Emergency Procedure Guidelines Set Points* was issued in January 1988 (as described previously), the results of calculations performed 1-month earlier that addressed the potential error in the new RBES water level instruments were used as inputs in determining the minimum pump NPSH requirements during the recirculation mode. An RBES set point of 3.5 ft was established to ensure a minimum sump inventory for all accidents (the intent was to confirm that the inventory of water in the BWST had been transferred to the RB rather than to a location outside containment). The supporting analysis for the 3.5-ft set point included an allowance of +8.8 in. for instrument error to account for the possibility that the level transmitters might read high, but did not recognize the possibility that the RBES level indication might read low and never reach the EOP set point.

In February 1988, the RBES level instrumentation calculation was revised to address current leakage. This calculation estimated the "worst-case" instrument error to be +8.8/-21 in.[a] At the time the calculation was revised, personnel estimated that the water level in the RB would be 5.3 ft (64 in.) when the water level in the BWST reached 6 ft. Assuming a worst-case instrument error (-21 in.), the water level in the RBES (43 in.) would be greater than the 3.5 ft (42 in.) water level required for the BWST-to-RBES transfer, but only marginally. In April 1988, the EOP was revised to incorporate the 3.5-ft minimum RBES water level prior to transfer.

In July 1989, OSC-2820 was revised to require a minimum indicated RBES water level of 3.75 ft to ensure that minimum NPSH requirements would be met. Because the calculation did not evaluate the potential impact of the RBES level instruments reading low, the fact that the 3.75-ft level (45 in., or 2 in. greater than the 43 in. lowest indicated level considering maximum instrument error) might not be reached was not recognized. The EOPs were not revised to reflect the changes to OSC-2820 at that time.

At the end of May 1994, the EOPs were revised to reflect a higher minimum water level in the RBES before the BWST-to-RBES transfer was made. For instrument readability reasons, the minimum indicated water level in the RBES was established at 4 ft, which met the 3.75-ft level documented in OSC-2820. Again, this revision failed to consider the potential for the RBES level instruments reading low. Once the EOP change was made, the potential existed for the RBES level to indicate 5 in. below that which was procedurally specified when the operators were expected to begin actions required for transferring ECCS suction from the BWST to the RBES. This is based on an estimated water level in the RBES of 64 in. when the water level in the BWST was at 6 ft.

This problem was further impacted by another calculational error discovered in November 1997 (Ref. 3). The calculation of the inventory of water in the RBES (that had previously been used to estimate a water level depth of 64 in. in the RBES when the water level in BWST was at 6 ft) was found to incorrectly account for the following trapped water volumes that would reduce the expected water level in the RBES following a LOCA:

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[a]The worst-case negative instrument error was revised in 1996 to -18.1 in.

- water trapped in the reactor vessel cavity and in the deep end of the fuel transfer canal.
- water needed to make up for reactor coolant system shrinkage during cooldown.
- water needed to refill the pressurizer.
- water needed to fill the reactor building spray piping inside containment. and
- water needed to account for the vapor content maintaining containment pressure.

Reference 3 noted that the reactor vessel cavity and the fuel transfer canal could trap a large quantity of water and significantly reduce the inventory in the RBES—thereby reducing the RBES water level. The reactor vessel cavity is the volume between the reactor vessel and the primary shield (Fig. 2). Reactor coolant piping, core flood/decay heat removal piping, and in-core instrument tubing pass through the reactor vessel cavity. In addition, a drain line from the deep end of the fuel transfer canal empties into the cavity. The bottom of the reactor vessel cavity contains a 4-in. line that drains the cavity to the RB normal sump. However, the drain line was covered with a flange that contained a 3/4-in. pipe nipple that allowed very limited drainage (this flange was discovered to be missing at Unit 3).

The deep end of the fuel transfer canal could also trap a large quantity of water. Two lines are provided to drain the fuel transfer canal to the RB normal sump. Instead of perforated drain covers, the drain lines contained "basket strainers" that were believed to be much more likely to be blocked by debris, which would prevent the fuel transfer canal from draining. (An additional drain line, located 1 ft above the bottom of the fuel transfer canal, provides an alternate drain path to the reactor vessel cavity; however, drainage through the reactor vessel cavity was essentially blocked by the 3/4-in. restriction discussed previously.) The basket strainers had been installed for as low as reasonable achievable (ALARA) purposes during an outage about 10 years ago and had been allowed to remain during operation without a proper station modification evaluation.

An evaluation considering the effects of water being trapped in the reactor vessel cavity and in the fuel transfer canal concluded that the expected water level in the RBES was 3.07 ft instead of the 5.3 ft (64 in.) used in calculations for determining when the water level in the BWST reached 6 ft. This revised value would apply particularly to large- and medium-break LOCAs, when building spray would collect in the fuel transfer canal. Following the removal of the basket strainers and the flange on the reactor cavity drain in November 1997, the expected water level in the RBES was estimated to be ~4.5 ft.

In conclusion, three conditions that degraded the potential for BWST-to-RBES transfer were reported in Refs. 1 and 3. Incorrectly calibrated BWST level transmitters (1989–1998) could have resulted in ECCS pump loss of NPSH and vortexing when the operators performed the EOP steps required to place a unit on sump recirculation following a LOCA. Failure to consider potential RBES level instrument error when developing procedures for the BWST-to-RBES transfer, combined with the incorrect estimation of the expected water level in the RBES (1985–1998), could have resulted in a condition where EOP requirements for initiating BWST-to-RBES transfer would not have been met. This would have required ad-hoc operator action to maintain post-LOCA cooling.

Additional Event-Related Information

The Oconee ECCS (Fig. 3) consists of a high-pressure injection (HPI) and low-pressure injection (LPI) system, as well as a core flood system. The HPI system includes three 24-stage vertical centrifugal pumps that develop 3000-psi discharge pressure with a capacity of 500 gpm each. The HPI system provides both normal makeup and reactor coolant pump seal injection, as well as makeup to the reactor coolant system (RCS) for small- and medium-break LOCAs. HPI pump A or B is normally in operation; HPI pump C is for emergency use only. The HPI pumps will typically operate for 1–2 min without an adequate suction source before they are damaged.

The Oconee LPI system also includes three pumps. These high-capacity, low head pumps provide RCS makeup for removing decay heat during normal shutdown operations or following a large-break LOCA. When the RCS is not depressurized below the LPI pump shutoff head, the LPI pumps also provide the suction source for the HPI pumps during the recirculation phase following a small- or medium-break LOCA. Two of the LPI pumps are automatically started for LOCA mitigation; the third pump is manually started if required. The LPI pumps are more tolerant of reduced NPSH than the HPI pumps and can operate for greater periods of time with reduced NPSH. [While no information is available concerning the expected Oconee LPI pump performance at reduced NPSH, Ref. 4 provided this information for another low-pressure, high-capacity pump—the containment spray pump at Maine Yankee. The manufacturer of that pump indicated that the pump could operate indefinitely at 95% of required NPSH and for 15 min at 75% of required NPSH. The pump manufacturer also stated that similar pumps are routinely operated for 1–3 min at 50% of required NPSH without sustaining damage.]

The Oconee BWSTs provide 350,000 gal for injection when drawn down from the minimum Technical Specification (TS) level (46 ft) to 6 ft. Because the same BWST level channels are used to measure maximum and minimum water level, the BWST level calibration error did not impact the volume of water delivered to the RCS during the injection phase.

Modeling Assumptions

This analysis addressed the combined impact of (1) water trapped in the reactor vessel cavity and the fuel transfer canal, (2) the potential for RBES level instruments to indicate low due to instrument error, and (3) incorrectly calibrated BWST level transmitters that increase the probability that the operators would fail to transfer the ECCS pump suctions to the RBES once the inventory in the BWST is depleted. An event-specific model was developed to depict the potential combinations of instrument and operator errors that, following a LOCA or other condition requiring sump recirculation, could result in failure to transfer ECCS pump suction from the BWST to the RBES and result in the unavailability of long-term core cooling. This model, shown in Figs. 4 and 5, was used to estimate the importance of this event. Table 2 provides the definitions and probabilities for the event tree branches. The Oconee Standardized Plant Analysis Risk (SPAR) models developed for use in the Accident Sequence Precursor (ASP) Program were used to determine the nominal CDP in a 1-year period. The event tree model includes the following branches:

Initiating Event (IE-). The initiating events necessary to analyze this event consist of the set of sequences that require sump recirculation. Because of differences in timing, large-, medium- and small-break LOCAs and transients (including a loss of offsite power) that require feed-and-bleed cooling were addressed separately. Utilizing a 1-year time period (the longest interval analyzed in the ASP Program) and revising the initiating event frequencies to be consistent with historical values,[5] the probabilities of requiring sump recirculation for the different initiating events were estimated using the Oconee SPAR model. These probabilities are shown in Table 3.

Sump Recirculation Required (RECIRC). The initiating events of interest represent the set of sequences and their associated probability in a 1-year period that sump recirculation would be required. The probabilities are weighted by 0.1 or 0.9 to reflect the probability that the water level in the BWST will be 46 or 48.5 ft, respectively.

RBES Level ≥ 4 ft when BWST Level = 6 ft (RBES-OK). Success for this branch implies that the water level in the RBES is at least 4 ft when the water level in the BWST is drawn down to 6 ft. If the water level in the RB is at least 4 ft when the water level in the BWST reaches 6 ft, this analysis assumes the operators will begin to transfer the ECCS pump suctions to the RBES as specified in the EOP.[2] If the water level in the RB is less than the 4 ft required by the EOP, the potential exists for the operators to delay transfer until the ECCS pumps are damaged and can no longer be used for core cooling. The probability that the RBES level will not indicate 4 ft when the water level in the BWST reaches 6 ft (i.e., when the EOP requires the operators to transfer ECCS pump suction to the RBES) depends on the actual water level in the RB and the RB water level instrument error. These issues are discussed below.

a. *Impact of trapped water in reducing expected RBES level.* The primary contributors to the reduced RBES inventory reported in Refs. 1 and 3 were associated with the deep end of the fuel transfer canal and the reactor vessel cavity. At Units 1 and 2, the reactor vessel cavity drain line included a flange with a 3/4-in. pipe nipple that effectively prevented the reactor vessel cavity from draining to the RB sump (Fig. 2). At Unit 3, the pipe flange was found to be missing. This would have allowed water that entered the Unit 3 reactor vessel cavity to drain into the RB sump.

   The deep end of the fuel transfer canal drained to the RB sump through basket strainers at each of the units. The potential existed for these strainers to become clogged, thereby preventing the fuel transfer canal from draining. However, when the strainers were inspected, they were found to be clean at each unit[a] and would have allowed the fuel transfer canal to drain to the sump. The water drained from the fuel transfer canal would increase the calculated RB sump level an additional 0.75 to 3.8 ft, for Units 1 and 2. The missing reactor vessel cavity drain flange at Unit 3 would have allowed that unit's reactor vessel cavity to drain as well, resulting in a calculated RB sump level of 4.5 ft; this is the same as the calculated water level after the basket strainer and reactor vessel drain flange issues were resolved. These sump levels assume the BWST was initially at the TS-required level of 46 ft and was drained to 6 ft at the time the ECCS pump suctions were transferred to the RBES. In actuality, the BWST is maintained at a level of

[a]Personal communication, J. W. Minarick (SAIC) and R. L. Oakley (Duke Power), March 1, 1999.

48.5 ft about 90% of the time, which would increase the water level in the sump at the time operators transfer to the sump.[a]

b. *Potential RBES level instrument error.* The estimated error for the RBES level channels is +8.8/−18.1 in., including current leakage. Based on information provided by personnel at Duke Power following the January 28, 1999, telephone conversation with Nuclear Regulatory Commission (NRC) and ASP program staff, this error is assumed to represent the $\pm 2\sigma$ values of an approximately normal distribution. Using this assumption and the expected water levels in the RB described above, the probability that both RBES level channels will read less than 4 ft can be estimated.[b] Using the +8.8-in. and −18.-in. values, the mean error (due to current leakage) is calculated to be −4.7 in. and the standard deviation (σ) is calculated to be 6.7 in. For Oconee 1 and 2, with a calculated water level in the RB sump of 3.8 ft (45.6 in.), the probability that an RB level channel will not read 4 ft (48 in.) is estimated to be

$$\Phi[(48 \text{ in} - \text{mean level})/\sigma] = \Phi[(48 - (45.6 - 4.7)) / 6.7] = 0.86 ,$$

where $\Phi[\ ]$ is the cumulative normal probability distribution. The probability of not exceeding 4 ft on either channel can be estimated using the independent failure probability (0.86) and the correlation in the errors in the two channels. Unfortunately, essentially no information exists concerning the expected correlation between the two channels. As a surrogate for this information, data developed in conjunction with an NRC reactor protection system reliability study[6] was used to estimate a β-factor for the common-cause failure of the two level channels.[a] The resulting estimate (β = 0.024) implies a very limited correlation between the two channels. Using this estimate for β, the probability that the RB water level indicators will not indicate that the level is at least 4 ft on either channel is estimated to be 0.735. Because of the limited correlation between channels, this compares to a probability of 0.732 if the channels were independent.

The probability (to two significant figures) of not indicating 4 ft on either RB level channel for initial BWST levels of 46 ft and 48.5 ft at a BWST drain-down to 6 ft (the EOP-specified level to begin transferring ECCS pump suctions to the RBES) is shown in Table 4.

Cold-Leg Break (CLBREAK). Success for this branch implies that the LOCA occurred in one of the cold legs. Based on information provided in Ref. 1, operator action to open the sump isolation valves will transfer ECCS pump suction to the RBES following a cold-leg break. This is because containment pressure is high enough to overcome the elevation head of the BWST. For a hot-leg break, however, the lower expected containment pressure requires the operators to also isolate the BWST before the ECCS pumps take suction from the RBES. Closure of the BWST isolation valves occurs later in the transfer sequence and requires additional time. The

[b]During the January 28, 1999, telephone conversation, personnel at Duke Power stated that the Oconee operators would take action when the first RBES level channel indicated that the water level in the RB was 4 ft. Failure to take action would therefore require failure of both channels to indicate a 4-ft level.

[a]Personal communication, J. W. Minarick (SAIC) and D. M. Rasmuson (NRC), March 15, 1999.

difference in timing is important, primarily for large- and medium-break LOCAs, and therefore cold- and hot-leg breaks must be distinguished in the model. To recognize the greater likelihood of a break in a cold leg because of the greater number of cold leg pipe segments and welds,[b] this analysis assumes a probability of 0.6 that a LOCA will occur in a cold leg.

RBES = 4 ft at BWST Minimum Level (RBES-MIN). If transfer to the RBES is delayed, the water level in the BWST will ultimately decrease to the point where the ECCS pumps are damaged by vortexing or unacceptable NPSH. Success for this branch implies that the water level in the RB reaches 4 ft, satisfying the EOP BWST-to-RBES transfer requirement, in time for the operators to effect RBES transfer before ECCS pump damage occurs. The incorrectly calibrated BWST level transmitters at the three units effectively raised the indicated level at which vortexing would begin. The level at which vortexing is expected to begin was chosen as the BWST level associated with unacceptable LPI pump operation because the impact of vortexing on pump performance is expected to dominate. Based on the information included in **Additional Event-Related Information**, the impact of the slight reduction in NPSH caused by a 1-ft reduction in BWST level is expected to be relatively minor. However, once vortexing begins it is expected to completely develop with only a slight additional reduction in the water level in the BWST (see, for example, the description of the loss of residual heat removal capabilities at Diablo Canyon on April 10, 1987, in Ref. 8).

Attachment A to Ref. 1 indicates that vortexing is expected to begin at a BWST water level of 0.85 ft (refer to Fig. 1). Considering the calibration errors described in Table 1, vortexing is expected to begin, unknown to the operators, at an indicated BWST level of approximately 1.8 ft for Units 1 and 2, and 2.3 ft for Unit 3. To complete the transfer from the BWST to the RBES before vortexing impacts the LPI pumps, the operators must begin the transfer process at an indicated BWST level greater than 2 ft (the level specified in the EOP at which the BWST must be isolated).

Based on ECCS flow rates and valve cycle times,[a] plus additional assumptions concerning initiator-specific flow rates, the time to perform an intermediate EOP step, and unit-specific average BWST calibration errors,[b]

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[b]Reference 7 provides a discussion of the factors that influence the likelihood of pipe break.

[a]Personal communication, J. W. Minarick (SAIC) and B. Abellana (Duke Power), March 10, 1999. For a large-break LOCA, an LPI flow rate of 6000 gpm (two trains), a building spray flow rate of 3000 gpm (two trains), and an HPI flow rate prior to operator termination of 1400 gpm are estimated. Cycle times for the RBES and BWST isolation valves are 70 and ~30 s, respectively.

[b]The following flow rates were assumed in the analysis at the time of switchover: 9000 gpm [large-break LOCA (LPI plus building spray)], 4400 gpm [medium-break LOCA (HPI plus building spray)], and 1400 gpm [small-break LOCA and feed-and-bleed cooling (HPI)]. For cold leg breaks, the analysis assumed the RBES valves must be opened 50% for the RBES to become the pump suction source. For hot leg breaks, the analysis assumed the BWST isolation valves had to completely close before the sump provided suction flow. In addition, an intermediate step in the EOP requiring building spray throttling was assumed to require 1 min. The average BWST calibration error was assumed to be –1.0 ft for Units 1 and 2 and –1.4 ft for Unit 3.

the estimated BWST indicated levels at which the RBES transfer must begin to prevent vortexing are shown in Table 5.

The conditional probabilities that RB water level on both level transmitters is still less than 4 ft when the BWST reaches the minimum acceptable levels listed in Table 5, given the RBES level indication was less than 4 ft when the water level in the BWST was 6 ft, were estimated using the same approach as for branch RBES-OK. These conditional probabilities are also included in Table 5.

Operators Switch to RBES at BWST Minimum Level (OPS-MIN). Success for this branch implies a decision on the part of the operators to transfer the ECCS pumps to the RBES before pump damage occurs, even though the water level in the RB was less than 4 ft. If the water level in the RB is less than 4 ft when the water level in the BWST is drawn down to 6 ft, the operators will find themselves outside their procedural bases—action to effect transfer to the RBES would technically be a violation of the EOP (Ref. 2) as written at the time the condition was discovered. However, the operators would be aware conceptually of the need to transfer to the sump before the BWST depletes and would know that the procedure required the transfer to be completed by the time the BWST level indicated 2 ft. This knowledge is expected to result in an increasing urgency (initially tempered by the understanding that some minimum RB water level was required for the pumps to operate in the recirculation mode) to transfer the ECCS pumps to the RBES as the water level in the BWST drops, ultimately resulting in such a decision. Degraded ECCS pump performance, if observed, would serve to reinforce the decision to transfer (operator burden, the need for rapid response, plus annunciator noise, particularly following a large- or medium-break LOCA, would be expected to compromise such an observation). The Technical Support Center (TSC) would be fully operational at the time for small-break LOCAs and would also be expected to reinforce the decision to transfer suction to the RBES.

The probability of not transferring the ECCS pumps cannot be rigorously estimated using contemporary Human Reliability Analysis (HRA) methods because the action is outside the procedure basis and is, in part, ad-hoc. For the purposes of this analysis it was assumed that, without TSC assistance, the operators would not begin to transfer the ECCS pumps to the RBES at an indicated BWST level of 6 ft. However, around an indicated BWST water level of 4 ft, it was assumed that there was an even chance that the operators would begin transferring the ECCS pumps to the RBES rather than waiting further for indication that the water level in the RB had risen to 4 ft, and that at an indicated level of 2 ft the operators would likely transfer the pumps to the sump. A value of 0.5 was therefore assigned to the probability that the operators would begin to transfer suction to the RBES at an indicated BWST water level of 4 ft, and a value of 0.1 was assigned to the probability that the operators would begin to transfer at an indicated level of 2 ft. At an indicated water level of 6 ft, a value of 1.0 was assigned to the probability that the operators would begin to transfer to the sump. For small-break LOCAs, the TSC would also be available to aid the operators. A moderate dependency is assumed between the operators and the TSC for a decision at 4 ft and greater, and a low dependency is assumed for the decision at 2 ft, resulting in probability estimates of 0.9, 0.3, and 0.01, at 6, 4, and 2 ft, respectively.[a]

[a]Small-break LOCAs do not measurably contribute to the significance of this event. Assumptions concerning the probability of operator error following a small-break LOCA have little impact on the analysis results.

The probabilities that the operators, with and without support from the TSC, would fail to begin transferring the suction for the ECCS pumps to the RBES by the time the water levels in the BWST were estimated by linearly interpolating between the probabilities estimated for water levels of 2, 4, and 6 ft. Representative operator error probabilities are shown in Table 6.

Substantial uncertainty is associated with the probabilities estimated for this branch. As noted earlier, the operator action being modeled is outside the domain of contemporary HRA methods. This, plus the fact that the impact of errors in procedures have not been considered in simulator exercises, results in very little information being available to accurately estimate such probabilities. The estimated probabilities are considered reasonable, considering the state of the art.

Operators Proceed Without Delay through Procedure (NO-DELAY). If RB water level indicates 4 ft when the BWST level is 6 ft, the operators are expected to begin transferring the suction for the ECCS pumps to the RBES as required by the EOP. Following a hot leg break, if the operators prolong the transfer and delay isolating the BWST until its indicated level approaches 2 ft (as allowed by the procedure), the ECCS pumps can also fail from vortexing. Success for this branch implies that the operators proceed expeditiously in transferring the pump suctions to the RBES. A failure probability of 0.1 was utilized for large- and medium-break LOCAs, where a delay of a few of minutes is sufficient to initiate vortexing, considering the miscalibrated BWST level transmitters. For small-break LOCAs and feed-and-bleed cooling, because of the slow BWST drain down, only a deliberate decision to delay BWST isolation until a BWST level of ~2 ft is indicated will result in pump damage; a failure probability of 0.01 is assumed in these cases.

Depressurization to Allow Low-Pressure Recirculation (LPR) (DEPRESS). Medium- and small-break LOCAs and feed-and-bleed cooling require HPI for injection success. When the inventory of water in the BWST is depleted, the LPI pumps are used to take suction from the RBES and provide flow, at adequate NPSH, to the HPI pumps. Oconee procedures require the HPI pumps to be lined up in series with the LPI pumps when the water level in the BWST is at 10 ft. The loss of LPI pump flow at the onset of vortexing is expected to cause the HPI pumps to fail, resulting in the need to rapidly depressurize the RCS to allow use of the LPI pumps for injection. Depressurization is possible following a LOCA, provided secondary-side cooling is available (depressurization cannot be used during feed-and-bleed cooling because secondary-side cooling is unavailable). Consistent with previous precursor analyses of events at Oconee (Ref. 9), the probability of failing to depressurize the RCS to allow use of the LPI pumps for injection was assumed to be 0.1. The probabilities of failing to depressurize to allow LPR for the initiating events of interest are given in Table 7.

LPR Recovered (LPR-REC). Success for this branch implies that LPR is recovered following an initial failure to transfer, for example, through use of the third LPI pump once transfer is complete. Failure to recover LPR would be highly dependent on the initially faulty assessment that resulted in the failure of the running LPI pumps. For a large-break LOCA, operator burden (associated with the unusual nature of the instrumentation anomalies in addition to the existence of the large-break LOCA) plus annunciator noise would be expected to delay the operating crew's realization that the LPI pumps had failed and delay diagnosis of the failure and implementation of any recovery strategy until well beyond the time that core uncovery occurs [7 min after loss of LPI (Ref. 1)]. A nonrecovery probability of 1.0 was therefore assumed for LPR-REC following a large-break LOCA.

For a medium-break LOCA, a failure probability of 0.5 was estimated for LPR-REC (this is conditional on the failure of OPS-MIN). This estimate considers the limited time available to recover recirculation cooling [15 min based on the Oconee probabilistic risk assessment (PRA) (Ref. 9) description of recovery event LLP0P3CREC], the burden imposed by the unusual nature of the failure, and the expected difficulty in analyzing the nature of the failure[a]. The potential for TSC support during some medium-break LOCAs was considered as a sensitivity analysis. The additional time and TSC support that would be available following a small-break LOCA would improve the likelihood of recovery; a failure probability of 0.1 was used with this initiator. The non-recovery probabilities for LPR for the initiating events of interest are given in Table 8.

Analysis Results

The combined CCDP associated with the BWST level transmitter miscalibration and RB water level error over a 1-year period for recirculation-related sequences is 1.7×10^{-6} for Units 1 and 2, and 1.4×10^{-6} for Unit 3 (Table 9). Because design and installation errors such as those that comprise this event are not typically addressed in PRAs (their contribution to nominal cut sets is zero), this CCDP is also the increase in the nominal CDP, or importance, for the event. The overall CCDP, considering all sequences, is therefore the estimated CDP for Oconee in a 1-year period (1.8×10^{-5}, based on the ASP models) plus the above increases, or 2.0×10^{-5} for Units 1 and 2, and 1.9×10^{-5} for Unit 3.

Although the significance of the event at Units 1 and 2 is slightly greater than at Unit 3 (a result of the higher calculated RB water level at Unit 3), the dominant sequence (6.1×10^{-7}) within the subset of recirculation-related sequences involves a medium hot leg break at Unit 3 (sequence 2-4 on Fig. 5). In this sequence, when the water level in the BWST is drawn down to an indicated level of 6 ft following a postulated medium-break LOCA, the indicated water level in the RB is 4 ft, and the operators would begin transferring the suction for the ECCS pumps to the RBES. However, if the operators delay isolation of the BWST until the water level in the BWST approaches 2 ft, the ECCS pumps would fail as a result of air binding. Depressurization to allow use of the LPI pumps is successful, but the operators fail to recover LPR, resulting in core damage. This sequence is highlighted on the medium-break LOCA event tree shown in Figs. 4 and 5 [which represents the recirculation (PB-COOL) branch in Fig. 4]. The medium-break LOCA model is similar to that developed to support the analysis of LER No. 287/97-003 in Ref. 10 and is described in that analysis. (Sequences associated with the late failure of HPI, which was important in the analysis of LER No. 287/97-003, have been excluded.)

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[a]See, for example, the analysis of LER 287/97-003 in the 1997 annual precursor report [*Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report*, NUREG/CR-4674, Vol. 26, November 1998 (Ref. 10)]. In this event, two Oconee 3 HPI pumps were damaged during a reactor shutdown as a result of a low water level in the letdown storage tank. After the low HPI pump discharge pressure was observed, over a 15-min period the operators started and stopped the two pumps and operated associated valves in an attempt to recover HPI pump discharge pressure before recognizing the potential cause of the problem and securing the pumps.

The second most dominant sequence (with a CCDP of 2.9×10^{-7}) is similar to the dominant sequence but occurs at Units 1 and 2. In addition to medium-break LOCA sequences, large-break LOCA and feed-and-bleed cooling sequences with CCDPs greater than 1.0×10^{-7} occur at all three units. As can be seen in the Table 9, small-break LOCA sequences contribute to a minor extent. All small-break LOCA sequences have CCDPs below 1.0×10^{-7}.

The medium-break LOCA sequences were analyzed with the assumption that the TSC would not be available at the time when transfer to sump recirculation was required. The resulting medium-break LOCA CCDPs, accounting for the unavailability of the TSC, are 9.8×10^{-7} for Units 1 and 2 and 8.5×10^{-7} for Unit 3; the overall CCDP for the event is 1.7×10^{-6} at Units 1 and 2 and 1.4×10^{-6} for Unit 3 (Table 9). The estimated time for BWST drawdown following a medium-break LOCA is 90 min at Oconee, and it is possible, at least for some medium-break LOCAs, that the TSC would be operational at the time of sump switchover. This potential was addressed in a sensitivity analysis that assumed the TSC was available when calculating OPS-MIN (Table 6). The resulting medium-break LOCA CCDPs, accounting for the availability of the TSC, are 6.5×10^{-7} for Units 1 and 2 and 8.2×10^{-7} for Unit 3; the overall CCDP for the event reduces to 1.3×10^{-6} at each unit.

To illustrate the calculational process, definitions and probabilities for the event tree branches associated with the potential loss of sump recirculation at Unit 1 or 2 following a medium-break LOCA with an initial water level in the BWST of 46 and 48.5 ft are shown in Table 10. Table 11 lists the sequence logic associated with the core damage sequences. The conditional probabilities for the six recirculation-related core damage sequences are shown in Tables 12 and 13.

Acronyms

ALARA	as low as reasonably achievable (radiation exposure)
ASP	accident sequence precursor
BWST	borated water storage tank
CCDP	conditional core damage probability
CDP	core damage probability
C/L	center line
ECCS	emergency core cooling system
EOP	emergency operating procedure
HPI	high-pressure injection
HRA	human reliability analysis
LDST	letdown storage tank
LOCA	loss-of-coolant accident
LPI	low-pressure injection
LPR	low-pressure recirculation
LT	level transmitter
NPSH	net positive suction head (pressure)
NRC	Nuclear Regulatory Commission
RB	reactor building

RBES	reactor building emergency sump
RCS	reactor coolant system
SITA	Self-Initiated Technical Audit
SLOCA	small-break LOCA
SPAR	standardized plant analysis risk
TS	technical specifications
TSC	Technical Support Center

References

1. LER 269/98-004, Rev. 1, "ECCS Outside Design Basis Due to Instrument Errors/Deficient Procedures," April 7, 1998.

2. Oconee Emergency Operating Procedure EP/1/A/1800/01, "Cooldown Following Large LOCA," CP-601, Revision 18, p 13.

3. LER 269/97-010, Rev. 0, "Inadequate Analysis of ECCS Sump Inventory due to Inadequate Design Analysis," January 8, 1998.

4. NRC Information Notice 96-55, *Inadequate Net Positive Suction Head of Emergency Core Cooling and Containment Heat Removal Pumps under Design Basis Accident Conditions*, October 22, 1996.

5. *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 - 1995*, NUREG/CR-5750, February 1999.

6. *Westinghouse Reactor Protection System Unavailability, 1984 - 1995*, NUREG/CR-5500, Vol. 2, *in press*.

7. H. M. Thomas, "Pipe and Vessel Failure Probability," *Reliability Engineering*, 2: p 83–124 (1981).

8. *Loss of Residual Heat Removal System*, NUREG-1269, June 1987, Appendix C, p. 4.

9. Oconee Nuclear Station Units 1, 2 and 3, *IPE Submittal Report*, Rev. 1, December 1990.

10. *Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report*, NUREG/CR-4674, Vol. 26, November 1998.

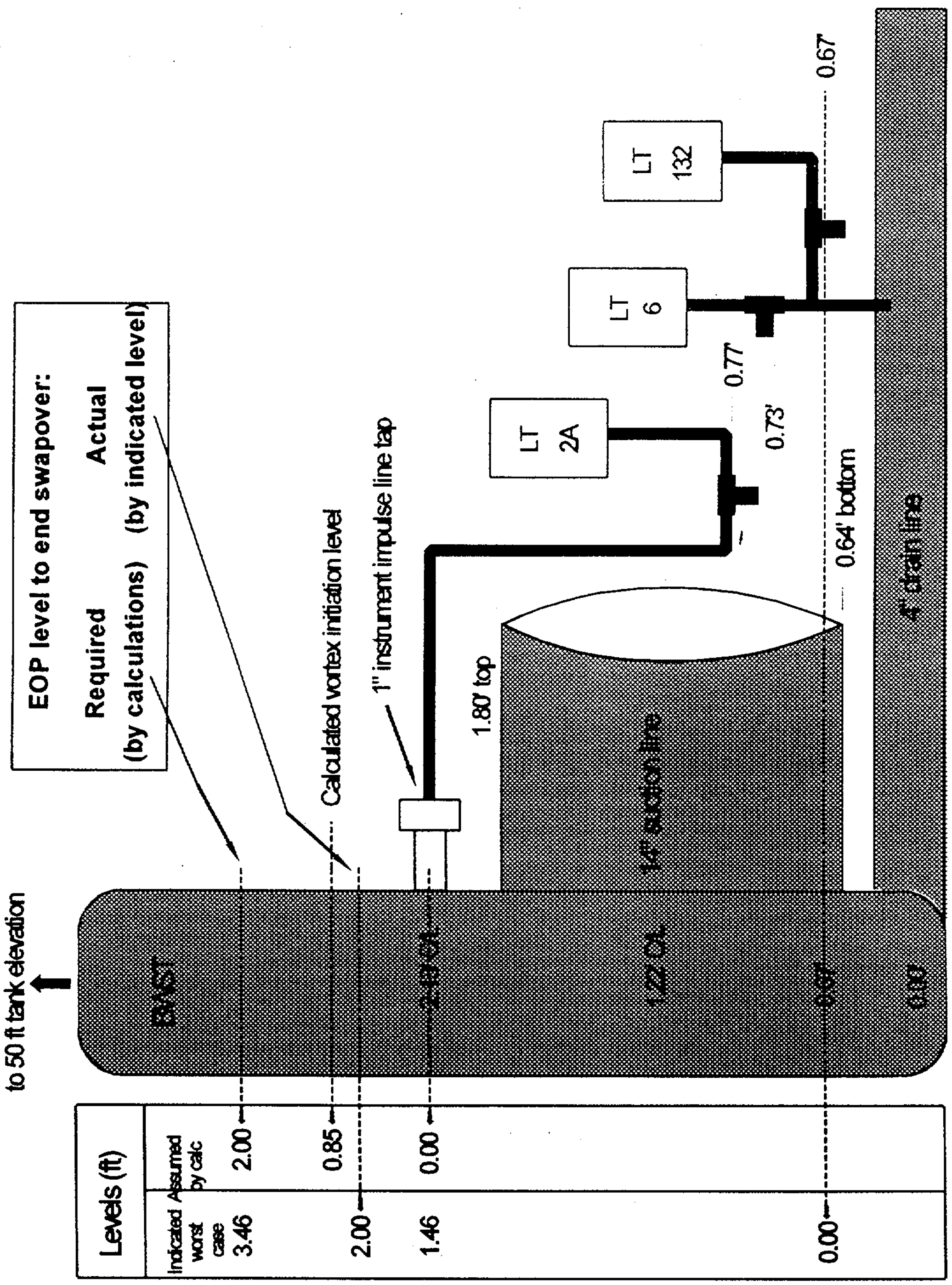

Fig. 1 Borated water storage tank level instrument arrangement (*Source:* LER 269/98-004, Rev. 1). Indicated worst case is for Unit 3. BWST is borated water storage tank, C/L is center line, EOP is emergency operating procedure, and LT is level transmitter.

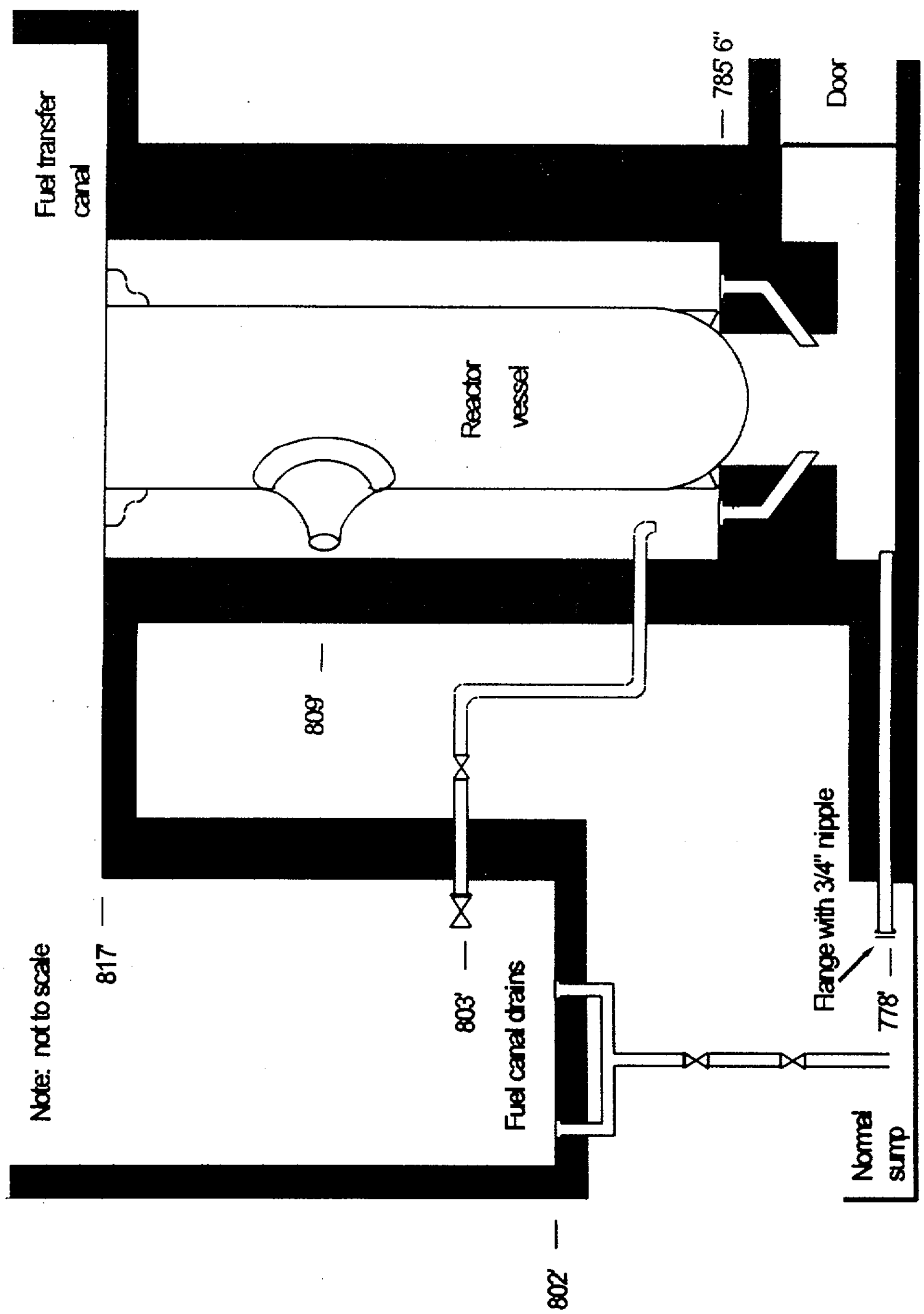

Fig. 2 Interior structures in the reactor building (*Source:* LER 269/98-010, Rev. 0).

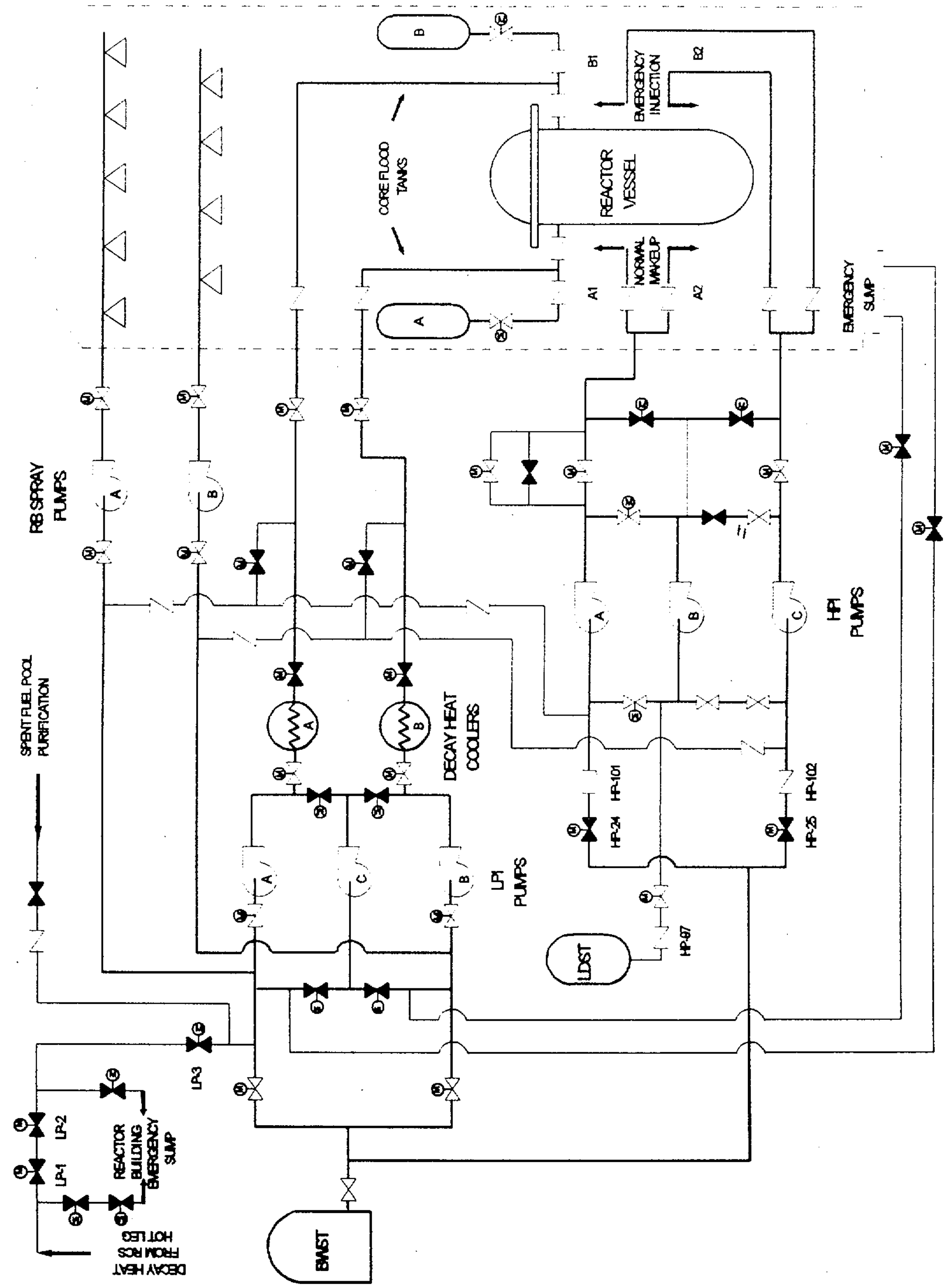

Fig. 3 Flow diagram of the emergency core cooling system at Oconee (*Source: Oconee 2 Final Safety Analysis Report*). BWST is borated water storage tank, HPI is high-pressure injection, LDST is letdown storage tank, LPI is low-pressure injection, and RB is reactor building.

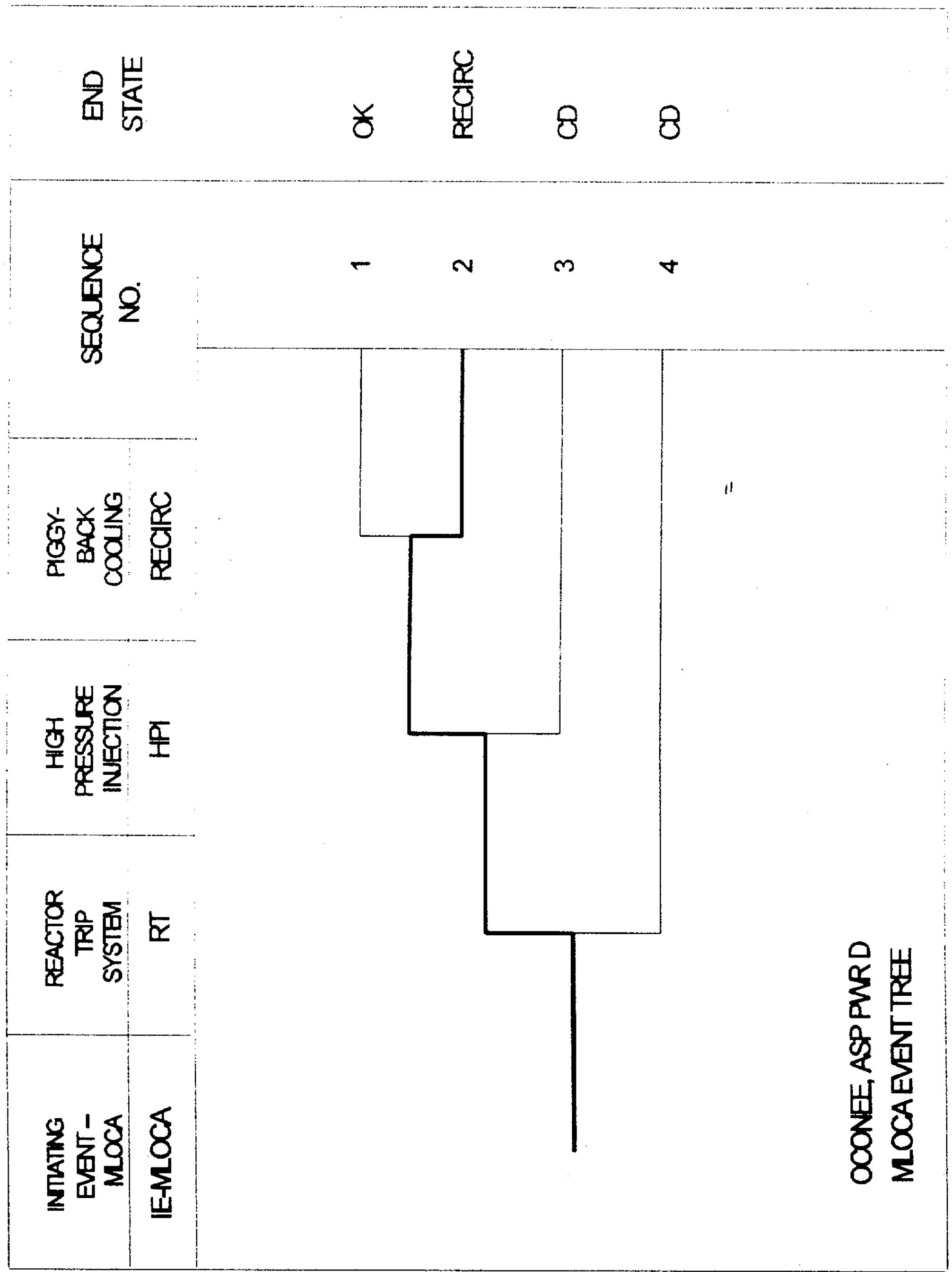

Fig. 4 Event tree for medium-break LOCAs at Oconee.

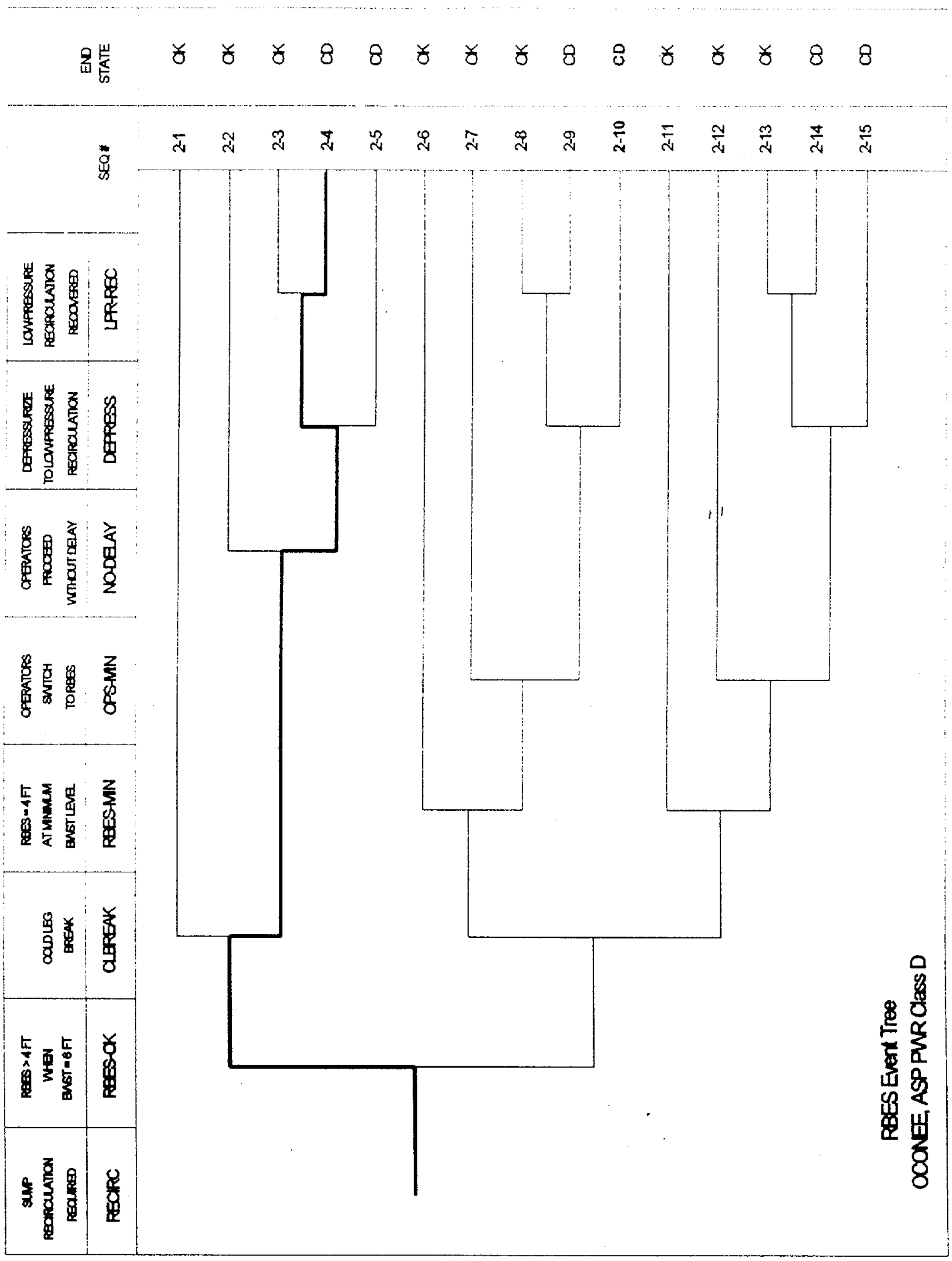

Fig. 5 Event tree for failure to transfer the emergency core cooling system pumps to the reactor building emergency sump (RBES). BWST is borated water storage tank.

Table 1. BWST Level Transmitter Test Tee – Impulse Line Elevation Errors

Unit	Elevation error in BWST level transmitters (ft)		
	LT 2A	LT 6	LT 132
Unit 1	-0.77[a]	-1.01[a]	-0.94[a]
Unit 2	-0.97[a]	-1.10[a]	-1.08[a]
Unit 3	-1.36	-1.40	-1.46

[a] NRC staff, ASP program staff, and personnel from Duke Power, teleconference, January 28, 1999.

Table 2. Definitions and Probabilities for Event Tree Branches for LER No. 269/98-004

Branch name	Description	Failure probability
IE-	Initiating Event	Table 3
RT	Reactor Trip	5.5 E-006[a]
HPI	High Pressure Injection	2.4 E-004[a]
RECIRC	Sump Recirculation Required — BWST water level at 46.0 ft BWST water level at 48.5 ft	1.0 E-001 9.0 E-001
RBES-OK	RBES Level ≥ 4 ft when BWST Level = 6 ft	Table 4
CLBREAK	Cold Leg Break	4.0 E-001
RBES-MIN	RBES = 4 ft at BWST Minimum Water Level	Table 5
OPS-MIN	Operators Switch to RBES at BWST Minimum Water Level	Table 6
NO-DELAY	Operators Proceed Without Delay through Procedure	1.0 E-001
DEPRESS	Depressurization to Allow LPR	Table 7
LPR-REC	LPR Recovered	Table 8

[a]System failure probability estimated using Oconee ASP model fault trees.

Table 3. Probability of Requiring Sump Recirculation for the Different Initiating Events During a 1-year Period (IE–)

Initiating event	Description	Probability of requiring sump recirculation
IE-LLOCA	Large-break LOCA	5.0 E-006
IE-MLOCA	Medium-break LOCA	4.0 E-005
IE-SLOCA	Small-break LOCA	9.2 E-005
IE-F/B	Feed-and-bleed (transients)	2.4 E-005

Table 4. Probability that Neither RB Water Level Channel will Indicate 4 ft (RBES-OK)

Unit	Initial BWST level	Probability that neither RB water level channel indicates 4 ft
Oconee 1 and 2	46 ft (10% of the time)	0.74
	48.5 ft (90% of the time)	0.55
Oconee 3	46 ft (10% of the time)	0.18
	48.5 ft (90% of the time)	0.064

Table 5. Minimum Acceptable BWST Levels to Initiate RBES Transfer and Conditional Probability that RB Level Will Not Indicate 4 ft (RBES-MIN)

Initiating event	Unit	Minimum acceptable BWST level to initiate RBES transfer (ft)	Conditional probability that RB level will not indicate 4 ft (initial BWST level = 48.5 ft)	Conditional probability that RB level will not indicate 4 ft (initial BWST level = 46.0 ft)
Large-break LOCA (cold leg)	1, 2	2.37	0.19	0.62
	3	2.77	0.022	0.24
Large-break LOCA (hot leg)	1, 2	4.43	0.39	0.85
	3	4.83	0.10	0.63
Medium-break LOCA (cold leg)	1, 2	2.10	0.17	0.59
	3	2.50	0.018	0.20
Medium-break LOCA (hot leg)	1, 2	3.10	0.25	0.70
	3	3.50	0.038	0.34
Small-break LOCA (cold leg)	1, 2	2.0[a]	0.17	0.58
	3	2.33	0.016	0.18
Small-break LOCA (hot leg)	1, 2	2.25	0.18	0.61
	3	2.65	0.020	0.22
Feed-and-bleed cooling	1, 2	2.25	0.18	0.61
	3	2.65	0.020	0.22

[a]Based on procedure.

Table 6. Probability of Operator Failure to Transfer ECCS Pumps (OPS-MIN)

Initiating event	Unit	Minimum acceptable BWST level to initiate RBES transfer (ft)	Probability of operator error without TSC support	Probability of operator error with TSC support
Large-break LOCA (cold leg)	1, 2	2.37	0.14	0.14
	3	2.77	0.20	0.20
Large-break LOCA (hot leg)	1, 2	4.43	0.63	0.63
	3	4.83	0.76	0.76
Medium-break LOCA (cold leg)	1, 2	2.10	0.11	0.01
	3	2.50	0.16	0.09
Medium-break LOCA (hot leg)	1, 2	3.10	0.27	0.17
	3	3.50	0.36	0.22
Small-break LOCA (cold leg)	1, 2	2.0[a]	0.01	0.01
	3	2.33	0.023	0.023
Small-break LOCA (hot leg)	1, 2	2.25	0.02	0.02
	3	2.65	0.044	0.044
Feed-and-bleed cooling (cold leg)	1, 2	2.25	0.01	0.01
	3	2.65	0.23	0.23
Feed-and-bleed cooling (hot leg)	1, 2	2.25	0.02	0.02
	3	2.65	0.044	0.044

[a]Based on procedure.

Table 7. Probability of failing to depressurize to allow LPR (DEPRESS)

Initiating event	Probability of failing to depressurize to allow LPR
IE-LLOCA	0.0 E+000
IE-MLOCA	1.0 E-001
IE-SLOCA	1.0 E-001
IE-F/B	1.0 E+000

Table 8. Probability of Failure to Recover LPR (LPR-REC)

Initiating event	Probability of failure to recover LPR
IE-LLOCA	1.0 E+000
IE-MLOCA	5.0 E-001
IE-SLOCA	1.0 E-001
IE-F/B	1.0 E-001

Table 9. Estimated CCDPs from Sequences that Require Recirculation for LER No. 361/98-003

Initiating Event	Estimated CCDPs from Sequences that Require Recirculation	
	Unit 1 and Unit 2	**Unit 3**
Large-break LOCA	4.6 E-007	2.2 E-007
Medium-break LOCA	9.8 E-007	8.5 E-007
Small-break LOCA	6.2 E-008	6.7 E-008
Feed-and-bleed cooling	1.8 E-007	2.4 E-007
Total	**1.7 E-006**	**1.4 E-006**

Table 10. Definitions and Probabilities for Event Tree Branches given a Medium-Break LOCA at Unit 1 or 2 for LER No. 269/98-004

Branch name	Description	Failure Probability	
		46.0 ft BWST level	48.5 ft BWST level
MLOCA	Initiating Event – Medium-Break Loss of Coolant Accident	4.0 E-005	4.0 E-005
RT	Reactor Trip	5.5 E-006	5.5 E-006
HPI	High Pressure Injection	2.4 E-004	2.4 E-004
RECIRC	Sump Recirculation Required	1.0 E-001	9.0 E-001
RBES-OK	RBES Level ≥ 4 ft when BWST Level = 6 ft	7.4 E-001	5.5 E-001
CLBREAK	Cold Leg Break	4.0 E-001	4.0 E-001
RBES-MIN	RBES = 4 ft at BWST Minimum Water Level (Cold-Leg Break)	5.9 E-001	1.7 E-001
	RBES = 4 ft at BWST Minimum Water Level (Hot-Leg Break)	7.0 E-001	2.5 E-001
OPS-MIN	Operators Switch to RBES at BWST Minimum Water Level (Cold-Leg Break)	1.1 E-001	1.1 E-001
	Operators Switch to RBES at BWST Minimum Water Level (Hot-Leg Break)	2.7 E-001	2.7 E-001
NO-DELAY	Operators Proceed Without Delay through Procedure	1.0 E-001	1.0 E-001
DEPRESS	Depressurization to Allow LPR	1.0 E-001	1.0 E-001
LPR-REC	LPR Recovered	5.0 E-001	5.0 E-001

Table 11. Sequence Logic for MLOCA Sequences for LER No. 361/98-003

Event tree name	Sequence number	Logic
MLOCA + RECIRC	2-4	/RT, /HPI, /RBES-OK, CLBREAK, NO-DELAY, /DEPRESS, LPR-REC
MLOCA + RECIRC	2-5	/RT, /HPI, /RBES-OK, CLBREAK, NO-DELAY, DEPRESS
MLOCA + RECIRC	2-9	/RT, /HPI, RBES-OK, /CLBREAK, RBES-MIN, OPS-MIN, /DEPRESS, LPR-REC
MLOCA + RECIRC	2-10	/RT, /HPI, RBES-OK, /CLBREAK, RBES-MIN, OPS-MIN, DEPRESS
MLOCA + RECIRC	2-14	/RT, /HPI, RBES-OK, CLBREAK, RBES-MIN, OPS-MIN, /DEPRESS, LPR-REC
MLOCA + RECIRC	2-15	/RT, /HPI, RBES-OK, CLBREAK, RBES-MIN, OPS-MIN, DEPRESS

Table 12. Sequence Conditional Probabilities for MLOCA for LER No. 361/98-003 (Unit 1 or 2 with Initial BWST Level of 48.5 ft Only)

Event tree name	Sequence number	Conditional core damage probability (CCDP)[a]	Core damage probability (CDP)[b]	Importance (CCDP-CDP)	Percent contribution
RECIRC	2-4	2.9 E-007	0.0	2.9 E-007	37.7
RECIRC	2-5	6.5 E-008	0.0	6.5 E-008	8.4
RECIRC	2-9	1.0 E-007	0.0	1.0 E-007	13.0
RECIRC	2-10	2.2 E-008	0.0	2.2 E-008	2.9
RECIRC	2-14	2.4 E-007	0.0	2.4 E-007	31.2
RECIRC	2-15	5.3 E-008	0.0	5.3 E-008	6.9
Total (all sequences)		**7. 7 E-007**	**0.0**	**7.7 E-007**	

[a]Sequences shown only.
[b]Because design and installation errors such as those that comprise this event are not typically addressed in PRA, their contribution to nominal sequences is zero.

Table 13. Sequence Conditional Probabilities for MLOCA for LER No. 361/98-003 (Unit 1 or 2 with Initial BWST Level of 46 ft Only)

Event tree name	Sequence number	Conditional core damage probability (CCDP)[a]	Core damage probability (CDP)[b]	Importance (CCDP-CDP)	Percent contribution
RECIRC	2-4	1.9 E-008	0.0	1.9 E-008	9.2
RECIRC	2-5	4.3 E-009	0.0	4.3 E-009	2.1
RECIRC	2-9	5.1 E-008	0.0	5.1 E-008	24.7
RECIRC	2-10	1.1 E-008	0.0	1.1 E-008	5.3
RECIRC	2-14	9.9 E-008	0.0	9.9 E-008	48.0
RECIRC	2-15	2.2 E-008	0.0	2.2 E-008	10.7
Total (all sequences)		**2.1 E-007**	**0.0**	**2.1 E-007**	

[a]Sequences shown only
[b]Because design and installation errors such as those that comprise this event are not typically addressed in PRA, their contribution to nominal sequences is zero.

LER No. 269/98-004

Event Description: Calibration and calculational errors compromise emergency core cooling system transfer to emergency sump

Date of Event: February 12, 1998

Plant: Oconee Nuclear Plant, Units 1, 2, and 3

Licensee Comments

Reference: Letter from W. R. McCollum, Site Vice President, Oconee Nuclear Site, to U. S. Nuclear Regulatory Commission, "Review of Preliminary Accident Sequence Precursor Analysis," July 15, 1999.

Comment: The ORNL precursor evaluation is thorough and well thought out. Overall, the values selected for the various parameters are reasonable. There is, however, one modeling assumption that Duke finds to be too pessimistic. Duke believes the nonrecovery probabilities assigned to LPR-REC (low-pressure recirculation recovered) are too high. It is recognized that insufficient information is available on the recovery being considered for quantification by any generally accepted technique. As a result, there is a natural tendency to assign conservative nonrecovery probabilities. The considerations that Duke believes provide a basis for less pessimistic assumptions regarding the potential for recovery are identified below. The timing estimates provided are based on RELAP and MAAP analyses of a large hot leg break with all engineered safeguards available.

Comment 1a: The ORNL precursor evaluation assumed a nonrecovery probability of 1.0 for the large-break LOCA cases. Such an assumption implies complete certainty that the action will fail. A failure probability of 1.0 seems pessimistic for the following reasons.

1. Based on the RELAP and MAAP simulations, it is estimated that at least 30 min are available following the loss of coolant injection before core damage would begin. While there would certainly be some concern over the cause of failure of the previously operating low-pressure injection (LPI) pumps, it is also clear that inaction will lead to core damage [the inadequate core cooling section of the emergency procedure (EP) will be entered following core uncovery]. Given that aligning the C LPI pump requires only a few minutes, at least 30 min are expected to be available for evaluation on the situation.

2. Significant core damage is not expected for more than 1 h following the initiation of the LOCA. The technical support center (TSC), or at least some of the TSC staff, should be available to assist in the evaluation.

Enclosure 2

3. These timing estimates assume a very large break of the horizontal portion of the hot leg. Breaks at locations higher than the horizontal run of the hot leg will provide significantly more liquid inventory in the reactor coolant system (RCS) at the time that coolant injection is lost and extend the time to significant core heatup. Breaks at the small end of the large-break LOCA range may also afford additional time.

For these reasons, we feel that a value of 1.0 for the nonrecovery probability reflects a degree of certainty that is not appropriate. A value of 0.5 for the nonrecovery probability would be indicative of complete uncertainty in the recovery potential, reflecting neither a pessimistic nor optimistic bias in the assumed recovery potential. A value of 0.5 is a more appropriate (but possibly conservative) selection for the nonrecovery probability.

Response 1a: A nonrecovery probability of 1.0 was used for LPR-REC following a large-break LOCA because once the LPI pumps had failed, the short amount of time available would not support diagnosis and alignment of the third LPI pump. The models used for ASP analyses assume an undesirable end state when core uncovery occurs (see Appendix B to *Precursors to Potential Severe Core Damage, 1994, A Status Report*, NUREG/CR-4674, Vol. 21, December 1995). The LER reporting this event estimates core uncovery to occur about 7 min after the loss of low-pressure injection. The Oconee 3 Probabilistic Risk Assessment (PRA), Rev. 1, includes a 10-min time period to diagnose a loss of LPI and start and align LPI pump C (basic event LLP0P3CREC in the Oconee PRA) following the typical pump and valve failures addressed in the PRA.

In the modeling of this event, LPR-REC is applied only after the operators have failed to recognize the need to swap suction to the sump as the water level in the BWST continues to decrease, resulting in the failure of the LPI pump. As noted in **Modeling Assumptions**, operator burden (associated with the unusual nature of the instrumentation anomalies in addition to the existence of the large-break LOCA) plus annunciator noise would be expected to delay the operating crew's realization that the LPI pumps had failed and delay diagnosis of the failure and implementation of any recovery strategy until well beyond the time that core uncovery occurs, even if the large-break LOCA is somewhat smaller than double-ended or occurs at a more advantageous location in the hot leg. For this reason, a nonrecovery probability of 1.0 is considered appropriate for LPR-REC for a large-break LOCA and has been retained in the analysis. **Modeling Assumptions** has been expanded to provide additional detail concerning the assumption of 1.0 for the nonrecovery probability of LPR-REC.

Comment 1b: The ORNL precursor evaluation assumed a nonrecovery probability of 0.5 for the medium LOCA cases. Such an assumption implies complete uncertainty in the success potential. A more optimistic view for the recovery potential is appropriate for the following reasons.

1. For the medium-break LOCAs, ~90 min is required to deplete the BWST inventory. The time to significant core heatup following the loss of injection should be longer than for the large LOCA case discussed previously. The time available for evaluation is sufficient to establish a reasonable understanding of the nature of the events.

2. The TSC is expected to be available prior the loss of injection. Because the TSC will be in place during the important stages of the event, their evaluation is more likely to be rapid and correct. The availability of the TSC is expected to aid the control room in determining the appropriate action.

3. Considerations of break size and location that are not the most limiting would also contribute to a higher likelihood of success.

The availability of the TSC to monitor the accident and assist in the diagnosis and decision making is expected to provide reasonable reliability in arriving at an appropriate course of action. Success under these conditions is likely, and a nonrecovery probability of 0.1 is judged to be a more appropriate value. The medium-break LOCA situation is judged to be similar to the small-break LOCA situation because of the TSC availability.

Response 1b: The availability of the TSC by the time that sump switchover is required following a medium-break LOCA is acknowledged, at least for day-time working hours. This availability would impact branch OPS-MIN as well as LPR-REC. Since LPR-REC is only demanded if the operators fail to effect transfer to the sump before the ECCS pumps fail, the TSC, if available, will have also failed to understand the event before pump failure. Considering the limited time available to recover recirculation (15 min based on the Oconee PRA description of LLP0P3CREC), the burden imposed by the unusual nature of the failure, and the expected difficulty in analyzing the nature of the failure,[a] a nonrecovery probability of 0.5 for LPR-REC (conditional on the failure of OPS-MIN) is considered appropriate and has been retained in the analysis. The intent was not to use 0.5 because there was complete uncertainty as to the recovery potential in a Bayesian sense, but to instead use the value because it was a reasonable estimate of the conditional probability that LPR would not be recovered, given that OPS-MIN had already failed.

The medium-break LOCA CCDPs, accounting for the unavailability of the TSC, are 9.8×10^{-7} for Units 1 and 2 and 8.5×10^{-7} for Unit 3; the overall CCDP for the event is 1.7×10^{-6}

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[a]See, for example, the analysis of LER No. 287/97-003 in the 1997 annual precursor report (*Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report*, NUREG/CR-4674, Vol. 26, November 1998). In this event, two Oconee 3 HPI pumps were damaged during a reactor shutdown as a result of a low water level in the letdown storage tank. Over a 15-min time period following observation of low HPI pump discharge pressure, the operators started and stopped the two pumps and operated associated valves in an attempt to recover HPI pump discharge pressure before recognizing the potential cause of the problem and securing the pumps.

at Units 1 and 2 and 1.4×10^{-6} for Unit 3. To address the impact of the potential availability of the TSC by the time that sump switchover is required, the conditional core damage probability (CCDP) for a medium-break LOCA was recalculated assuming the TSC would be available for all medium-break LOCAs at the time sump switchover was required. The resulting medium-break LOCA CCDPs are 6.5×10^{-7} for Units 1 and 2 and 8.2×10^{-7} for Unit 3; the overall CCDP for the event reduces to 1.3×10^{-6} at each unit. The **Analysis Results** has been revised to describe this result as a sensitivity analysis.

Comment 1c: The discussion presented above provides suggested revisions to the nonrecovery probabilities assumed for LPR-REC. While even lower values than suggested might be appropriate, it is judged that the suggested values do not contain a significant bias in either a pessimistic or optimistic direction.

Response 1c: See the above responses to comments.