50-270

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

January 26, 1998

Mr. William R. McCollum
Vice President, Oconee Site
Duke Energy Corporation
P.O. Box 1439
Seneca, SC 29679

SUBJECT: REVIEW OF PRELIMINARY ACCIDENT SEQUENCE PRECURSOR ANALYSIS OF OPERATIONAL EVENT AT OCONEE NUCLEAR STATION, UNIT 2

Dear Mr. McCollum:

Enclosed for your review and comment is a copy of the preliminary Accident Sequence Precursor (ASP) analysis of an operational event that occurred at the Oconee Nuclear Station, Unit 2, on April 21, 1997 (Enclosure 1), and was reported in Licensee Event Report (LER) No. 270/97-001. This analysis was prepared by our contractor at the Oak Ridge National Laboratory (ORNL). The results of this preliminary analysis indicate that this condition may be a precursor for 1997. In assessing operational events, an effort was made to make the ASP models as realistic as possible regarding the specific features and response of a given plant to various accident sequence initiators. We realize that licensees may have additional systems and emergency procedures, or other features at their plants that might affect the analysis. Therefore, we are providing you an opportunity to review and comment on the technical adequacy of the preliminary ASP analysis, including the depiction of plant equipment and equipment capabilities. Upon receipt and evaluation of your comments, we will revise the conditional core damage probability calculations where necessary to consider the specific information you have provided. The objective of the review process is to provide as realistic an analysis of the significance of the event as possible.

In order for us to incorporate your comments, perform any required reanalysis, and prepare the final report of our analysis of this event in a timely manner, you are requested to complete your review and to provide any comments within 30 days of receipt of this letter. We have streamlined the ASP Program with the objective of significantly improving the time after an event in which the final precursor analysis of the event is made publicly available. As soon as our final analysis of the event has been completed, we will provide for your information the final precursor analysis of the event and the resolution of your comments.

We have also enclosed several items to facilitate your review. Enclosure 2 contains specific guidance for performing the requested review, identifies the criteria that we will apply to determine whether any credit should be given in the analysis for the use of licensee-identified additional equipment or specific actions in recovering from the event, and describes the specific information that you should provide to support such a claim. Enclosure 3 is a copy of LER No. 270/97-001, which documented the event.

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This request is covered by the existing OMB clearance number (3150-0104) for NRC staff followup review of events documented in LERs. Your response to this request is voluntary and does not constitute a licensing requirement.

Sincerely,

David E. LaBarge, Senior Project Manager
Project Directorate II-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-270

Enclosures: As stated

cc w/encl: See next page

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ORIGINAL SIGNED BY:

David E. LaBarge, Senior Project Manager
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Oconee Nuclear Station

cc:
Mr. Paul R. Newton
Legal Department (PBO5E)
Duke Energy Corporation
422 South Church Street
Charlotte, North Carolina 28242

J. Michael McGarry, III, Esquire
Winston and Strawn
1400 L Street, NW.
Washington, DC 20005

Mr. Robert B. Borsum
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

Regional Administrator, Region II
U. S. Nuclear Regulatory Commission
Atlanta Federal Center
61 Forsyth Street, S.W., Suite 23T85
Atlanta, Georgia 30303

Max Batavia, Chief
Bureau of Radiological Health
South Carolina Department of Health and Environmental Control
2600 Bull Street
Columbia, South Carolina 29201

County Supervisor of Oconee County
Walhalla, South Carolina 29621

Mr. J. E. Burchfield
Compliance Manager
Duke Energy Corporation
Oconee Nuclear Site
P. O. Box 1439
Seneca, South Carolina 29679

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

L. A. Keller
Manager - Nuclear Regulatory Licensing
Duke Energy Corporation
526 South Church Street
Charlotte, North Carolina 28242-0001

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

LER No. 270/97-001

Event Description: Unisolable reactor coolant system leak

Date of Event: April 21, 1997

Plant: Oconee 2

Event Summary

An unisolable 12 gpm leak developed in the reactor coolant system (RCS) high pressure injection (HPI) nozzle safe end-to-piping weld downstream of reactor coolant pump (RCP) 2A1 (Ref. 1). Unit 2 was shut down and personnel removed and inspected the leaking pipe section. The leak was caused by a circumferential crack, with through-wall penetration along 77° of the outer pipe surface. In addition, the nozzle thermal sleeve was loose and cracked, with portions missing from the end that extends into the RCS flow path. The piping failures were caused by high-cycle thermal fatigue that was caused by the mixing of makeup, warming, and RCS flows. The estimated conditional core damage probability (CCDP) associated with this event is 1.0×10^{-5}.

Event Description

At approximately 2245 on April 21, 1997, with Unit 2 at 100% power, changes were noted in the rate at which the water level in the letdown storage tank (LDST) was decreasing and Reactor Building (RB) sump level was increasing. RB radiation monitor alarms followed. At 2300 the RCS leak rate was estimated to be 2.36 gpm. Personnel entered the RB at 0215, determined that a leak did exist, but could not identify the source.

The shutdown of Unit 2 began at 0352, with the intention to reduce power to 15%. Because reducing the power level reduces the radiation levels in the RB, personnel could then perform a more detailed inspection of the leak area with the main turbine remaining on line. At 0900, a more accurate leak rate calculation was performed with power stabilized at 20%. This calculation indicated that the leak rate had increased from 2.36 gpm at 2300 to 6.25 gpm at 0940. By 1048 it had increased above 8 gpm.

At 1217, during another RB entry, the leak location was identified as being in the vicinity of 2HP-127, the block valve closest to the HPI injection nozzle on the 2A1 RCP cold leg (Fig. 1). The decision was made to proceed to cold shutdown. The turbine-generator was taken off-line at 1250 and the reactor was tripped at 1448 on April 22, 1997. The leak rate peaked at approximately 12 gpm at 1750 and then began to decrease as RCS pressure was reduced as the shutdown continued.

The leak was found to be in an unisolable section of piping, at the weld between the HPI piping and injection nozzle safe end. The unit was placed in a reduced inventory condition and the pipe from the safe end to the block valve was cut out for examination (a temporary cap was then welded to the safe end and RCS water level was raised). This examination determined that the leaking weld was caused by a 360° inside circumferential crack that penetrated, at a minimum, 24% of the pipe wall. The flaw depth increased and became through-wall over 77° of the outer circumference, as shown in Fig. 2. The nozzle thermal sleeve was also found to be loose and cracked, with portions missing from the end that extends into the RCS flow. Cracking (~20% through-wall) was also found in the pipe in the vicinity of the warming line nozzle. Video examination, ultrasonic testing (UT), and radiographic testing (RT) of the welds and thermal sleeves in the other HPI nozzles showed no indications of cracking or loosening or other signs of degradation.

The licensee concluded that the piping failures were caused by high-cycle thermal fatigue, resulting from thermal mixing of the warming line, makeup flow, and RCS flow. Thermal mixing occurred in the thermal sleeve, safe end and piping because of varying operational conditions, including low makeup flow through the thermal sleeve. This caused cracking in the pipe, pipe-to-safe end weld, and safe end and contributed to the thermal sleeve failure. Vibration may have also contributed to the final failure, once the crack was essentially through the pipe wall.

Following several earlier industry events involving cracked thermal sleeves and nozzle safe ends (described in the following section), Oconee adopted an augmented inspection plan to periodically check piping near the pipe-to-safe end welds (on Units 2 and 3) and the thermal sleeves (on all units). A review of the inspection schedules indicated that these inspections had been performed on Unit 2 in May 1996. However, the licensee determined that the inspection program failed to include UT of the piping near the pipe-to-safe end weld. Because of this, the weld that was cracked and leaking had not been inspected since 1982. The criteria for reviewing safe end radiographs were also poorly defined.

A reassessment of all radiographs of the thermal sleeves performed since 1983 determined that there had been no RT on the thermal sleeves at Unit 1 since 1989. However, a review of radiographs taken between 1983 and 1989 indicated no degradation of any of the thermal sleeves at Unit 1. Unit 1 was shut down on June 14, 1997 and its HPI nozzles and thermal sleeves were examined. The Oconee 1 thermal sleeves are of a different design, utilizing two concentric sleeves instead of the single sleeves used in the nozzles at Units 2 and 3. No unacceptable indications were found in the Unit 1 nozzles and sleeves.[1]

Because the reassessment of Unit 3 radiographs indicated that the 3A1 thermal sleeve was potentially degraded, Unit 3 was shut down for inspection on May 1, 1997. Cladding cracks were found in the 3A1 thermal sleeve. UT of the other Unit 3 nozzles found no rejectable indications. Both the 2A1 and 3A1 nozzles were restored by installation of new safe ends, thermal sleeves and associated piping.

Additional Event-Related Information

At Oconee, the HPI system provides both normal RCS makeup and RCP seal injection, as well as HPI for small-break loss-of-coolant accident (LOCA) mitigation. During normal operation, the HPI system A header supplies makeup (typically 15–20 gpm) from the LDST through each of two lines to the RCS. These lines are equipped with "warming" lines that provide a minimum flow of 3 gpm. The B HPI header is for emergency injection only, and has no warming lines.

The HPI injection lines terminate at injection nozzle assemblies located on each of the cold legs downstream of the RCPs. Each nozzle assembly (Fig. 3) consists of an Inconel-clad carbon steel nozzle to which a stainless steel safe end is welded. The HPI piping is welded to the other end of the safe end. Inside the safe end is a stainless steel thermal sleeve, which extends into the RCS flow path. The function of the thermal sleeve is to minimize thermal shock and stresses on the nozzle by transporting the relatively cold HPI water (~100–120°F) into the main flow path. There it mixes with the 555°F RCS cold leg water. Without the thermal sleeve, the HPI water would directly contact the nozzle, resulting in unacceptable stresses in the nozzle material.

Additional information concerning this event is provided in NRC Information Notice 97-46 (Ref. 2). Problems similar to this event occurred in 1982 at Crystal River 3 and Oconee, and in 1988 at Farley and Davis-Besse. These events are described in NRC Information Notice 82-09 (Ref. 3), Generic Letter 85-20 (Ref. 4) and NRC Bulletin 88-08 (Ref. 5). Generic Letter 85-20 adopted recommended corrective actions developed by the B&W Owner's Group following the 1982 problems at Crystal River 3 and Oconee.

Modeling Assumptions

This event was modeled as a potential small-break LOCA at the 2A1 cold leg HPI nozzle. In the actual event the pipe crack developed slowly and began to leak. This leakage was detected and the plant was shut down while the injection line remained substantially intact. It is possible, however, that the crack could have developed differently, resulting in catastrophic failure of the injection line before detection.

The probability of such a "rupture before leak", which would result in a small-break LOCA, was assumed to be 5.3×10^{-2}. This value was estimated based on data related to thermal fatigue-induced piping failures included in the recently developed Swedish Nuclear Power Inspectorate (SKI) piping failure data base.[6] The data base currently includes over 2300 pipe failure records that represent about 4300 reactor-years of operating experience. For failures due to thermal fatigue, 13 leaks and no ruptures were observed in stainless steel piping 1–4 in. in diameter. Using a Chi-square approach with zero observed failures in these 13 demands, the 5.3×10^{-2} conditional probability is estimated. [a]This value is consistent with the average number of piping failures

[a]The use of a Chi-square distribution, a standard approach to estimate failure probabilities for small numbers of events, is described in section 5.5 of the *PRA Procedures Guide*, NUREG/CR-2300, January 1983. A number of alternate estimators have been proposed for the case where no failures have been observed. See, for example, Section 5.5 of NUREG/CR-2300 and "Estimation from Zero-Failure Data," R. T. Bailey, *Risk Analysis*, Vol. 17, No. 3, June 1997. Almost all estimators, both "classical" and Bayesian, produce failure probabilities within a factor of 2 of 5.3×10^{-2}.

that are ruptures estimated in 1981 by Thomas (Ref. 7)[b] and is about a factor of 2 smaller than the leak-before-break probability developed by the Electric Power Research Institute (EPRI) in 1992 (Ref. 8).[a]

Flow lost from an HPI injection line break is unavailable for RCS makeup. Orifices in each injection line provide for flow indication to allow the operators to redirect HPI flow between the two sets of injection lines so that a majority of the flow goes through the intact header into the RCS. The HPI system design also includes cross-connects to allow flow from the center HPI pump to be directed to the intact injection lines if the pump that normally supplies these lines (pump A in the case of a break in the 2A1 injection line) is unavailable. To address a potential HPI line break, the HPI and piggy-back cooling (high-pressure recirculation) fault trees were revised to require flow through the intact header in the event of such a break (a break in header A was modeled). In addition, the potential for the operators to realign pump B to inject through the B header was also added to the model.

The model was also revised to address use of rapid RCS depressurization and low pressure injection (LPI) in the event that HPI were to fail. The Oconee Individual Plant Examination (Ref. 9) states that the emergency operating procedures direct the operators to use secondary heat removal to depressurize the RCS until LPI flow is greater than 100 gpm per header. The probability of the operators failing to depressurize the RCS and initiating LPI was assumed to be 0.1, consistent with Ref. 9.

Analysis Results

The CCDP for a postulated small-break LOCA associated with the leaking 2A1 HPI nozzle weld is estimated to be 1.0×10^{-5}. The dominant sequence, sequence 10 in Fig. 4, involves

- a postulated HPI line break (small-break LOCA) given the weld leak,
- successful reactor trip and secondary side cooling,
- failure of HPI, and
- failure to depressurize the RCS to allow use of the LPI system for makeup.

The dominant cut sets involve common-cause failures of the nonrunning HPI pumps to start and of the HPI suction valves to open following the postulated HPI line break, combined with failure to depressurize the RCS to allow use of LPI.

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[b]Ref. 7 estimated that between 2% and 45% of piping failures were catastrophic, depending on the failure cause. On average, approximately 6% of all failures were estimated to be catastrophic. Unfortunately, piping failures caused by high-cycle fatigue were not separately enumerated. Three percent of low-cycle fatigue failures were estimated to be catastrophic, compared to 20% of vibration-related fatigue failures and 20% of failures associated with "thermal shock."

[a]Ref. 8 estimated that the probability of break before leak varied from 0.09 to 0.11, depending on pipe size.

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

During the Unit 3 shutdown to inspect its HPI nozzles and thermal sleeves, two of its three HPI pumps were damaged when they were operated with inadequate net positive suction head (NPSH). This resulted from a drained reference leg in the LDST instrumentation. The impact of the HPI pump failures as well as the potential for a combined RCS leak and HPI pump failure is addressed in the analysis of LER 287/97-003.

Acronyms

B&W	Babcock and Wilcox
CCDP	conditional core damage probability
CCF	common-cause failure
DHR	decay heat removal
EPRI	Electric Power Research Institute
HPI	high pressure injection
LDST	letdown storage tank
LOCA	loss-of-coolant accident
LPI	low pressure injection
MOV	motor-operated valve
NPSH	net positive suction head
RB	reactor building
RCS	reactor coolant system
RCP	reactor coolant pump
RT	radiographic testing
TW	through-wall
UT	ultrasonic testing

References

1. Licensee Event Report 270/97-001, "Unisolable Reactor Coolant Leak due to Inadequate Surveillance Program," May 21, 1997.

2. NRC Information Notice 97-46, "Unisolable Crack in High-Pressure Injection Piping," July 9, 1997.

3. NRC Information Notice 82-09, "Cracking in Piping to Makeup Coolant Lines at B&W Plants," March 31, 1982.

4. NRC Generic Letter 85-20, "Resolution of Generic Issue 69: High Pressure Injection/Makeup Nozzle Cracking in Babcock and Wilcox Plants," November 11, 1985.

5. NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," June 22, 1988 (and supplements 1 - 3 dated June 24, 1988, August 4, 1988, and April 11, 1989, respectively).

6. Personal communication, B. Lydall (RSA Technologies) and J. Minarick (SAIC), September 25, 1997. The development of the SKI piping failure data base is described in "PSA Applications and the Estimation of Piping System Component Reliability Parameters," B. Tomic, R. Nyman, and B. Lydall, presented at COPSA '97, International Conference on the Commercial and Operational Benefits of Probabilistic Safety Assessment, Edinburgh, October 6-9, 1997.

7. H.M. Thomas, "Pipe and Vessel Failure Probability," *Reliability Engineering*, Vol 2, 1981, p. 83.

8. *Pipe Failures in U.S. Commercial Nuclear Power Plants*, EPRI TR-100380, July 1992.

9. Oconee Nuclear Station Units 1, 2, and 3, IPE Submittal Report, December 1990, p. 5.7-22, Rev. 1.

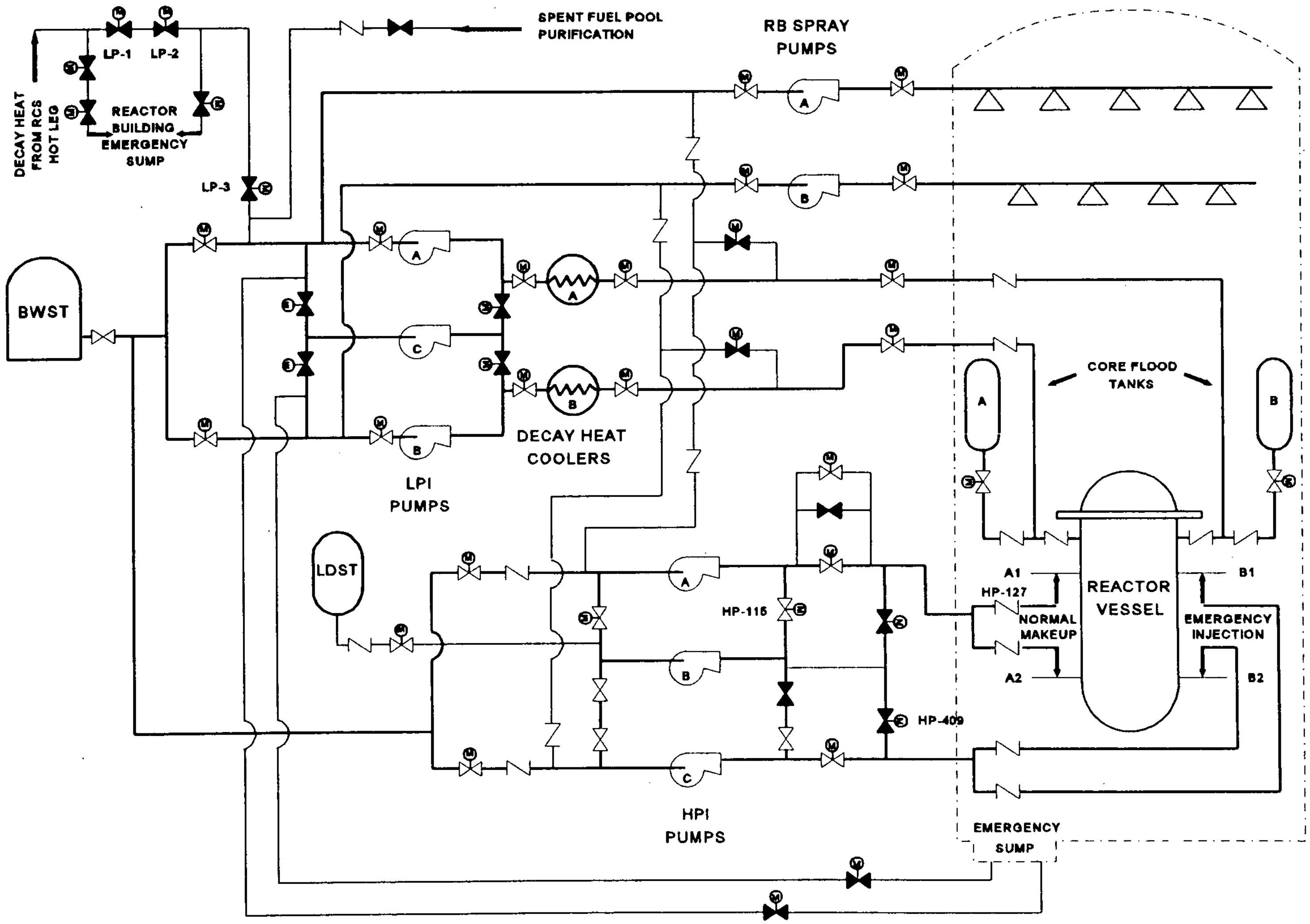

Fig. 1 Flow diagram of the emergency core cooling system at Oconee 2.

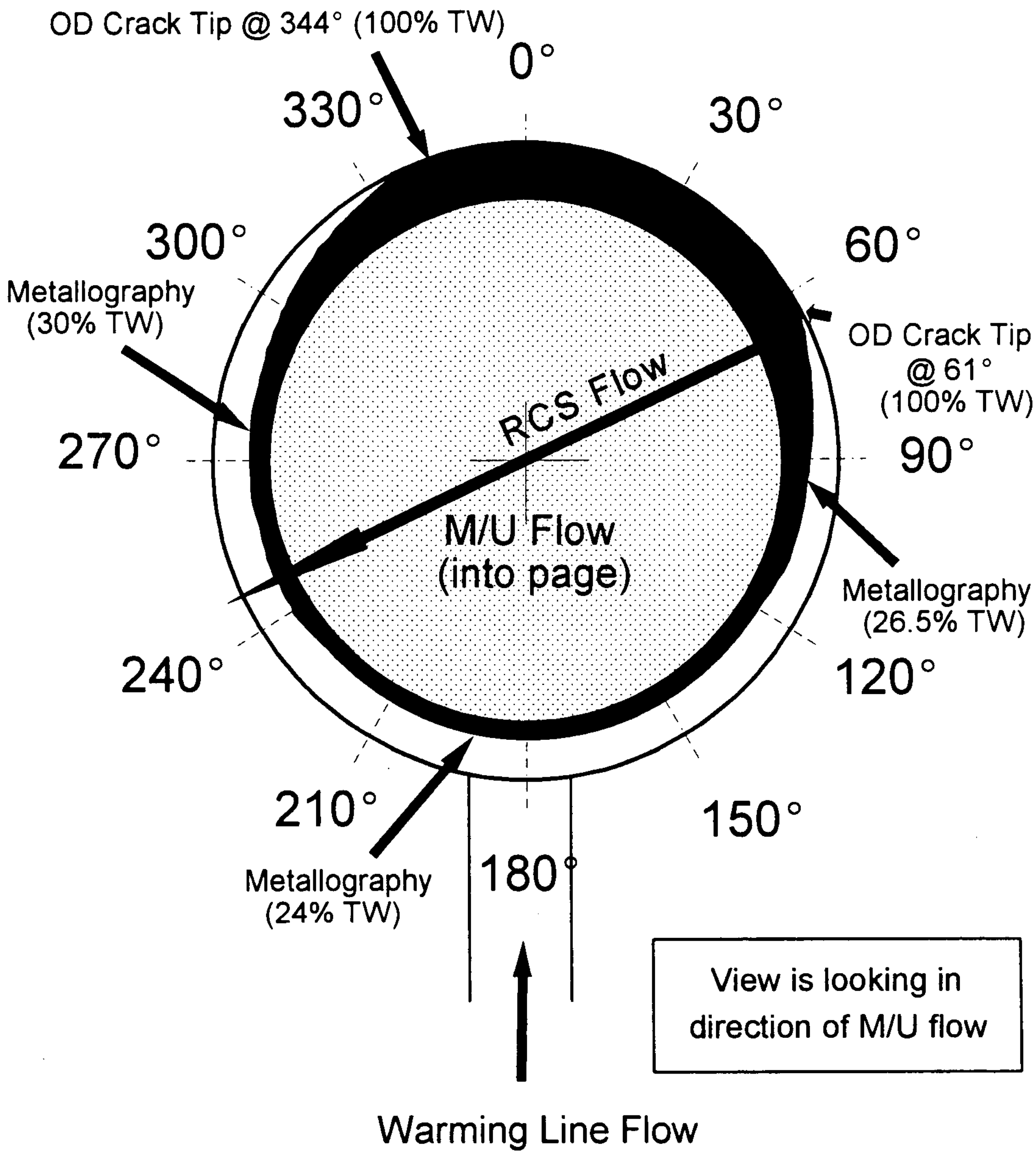

Fig. 2. Through-wall flaw depth in pipe at Oconee 2 (source: NRC Information Notice 97-46, "Unisolable Crack in High-Pressure Injection Piping," July 9, 1997). (TW is through-wall, OD is outside diameter, M/U flow is makeup flow, and RCS is reactor coolant system.)

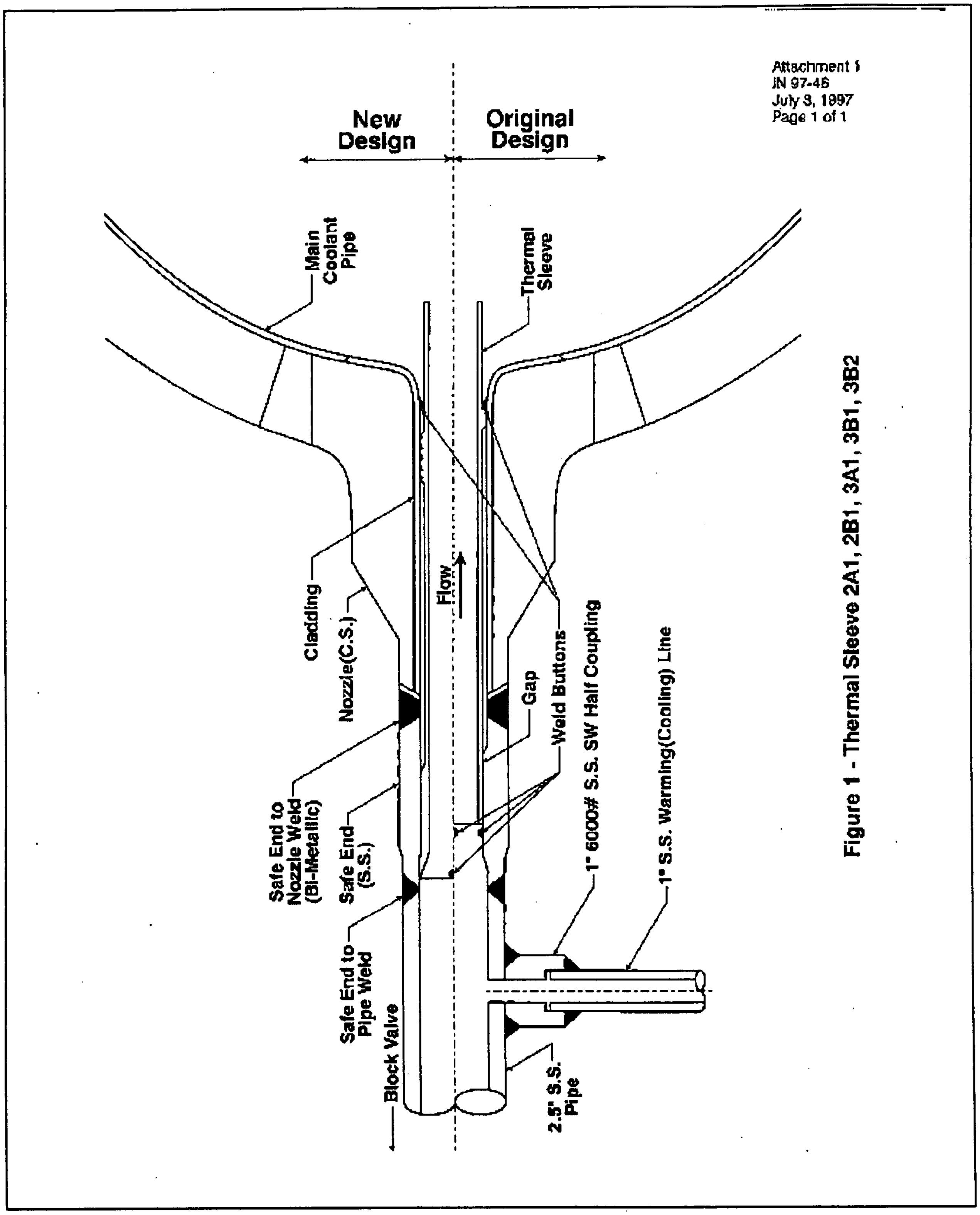

Fig. 3. Thermal Sleeve 2A1, 2B1, 3A1, 3B1, and 3B2 (source: NRC Information Notice 97-46, "Unisolable Crack in High-Pressure Injection Piping," July 9, 1997). (S.S. is stainless steel, C.S. is carbon steel, and SW is socket weld.)

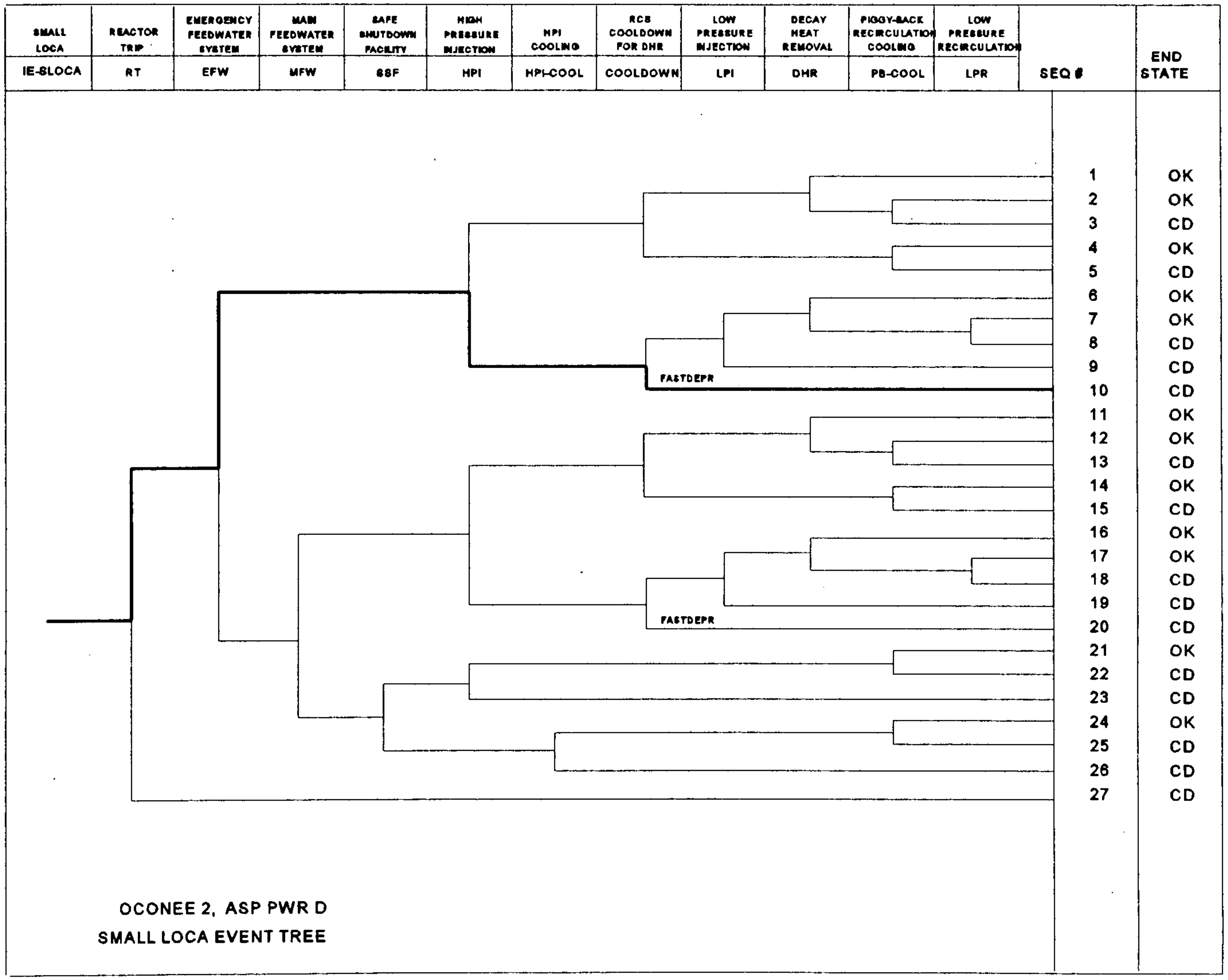

Fig. 4. Dominant core damage sequence for LER 270/97-001.

Table 1. Definitions and Probabilities for Selected Basic Events for LER No. 270/97-001

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event–Loss of Offsite Power	2.7 E-006	0.0 E+000		Yes
IE-SGTR	Initiating Event–Steam Generator Tube Rupture	1.3 E-006	0.0 E+000		Yes
IE-SLOCA	Initiating Event–Small Loss-of-Coolant	6.5 E-007	5.3 E-002		Yes
IE-TRANS	Initiating Event–Transient (TRANS)	7.7 E-004	0.0 E+000		Yes
DHR-HTX-CF-ALL	Common-Cause Failure (CCF) of the Decay Heat Removal (DHR) Heat Exchangers	1.3 E-005	1.3 E-005		No
DHR-MDP-CF-ALL	CCF of all Motor-Driven DHR Pumps	2.5 E-005	2.5 E-005		No
DHR-MOV-CC-SUCA	DHR Suction Motor-Operated Valves (MOVs) LP-1 or LP-2 Fail	6.0 E-003	6.0 E-003		No
DHR-MOV-CC-SUCB	DHR MOV LP-3 Fails	3.0 E-003	3.0 E-003		No
DHR-MOV-CF-DISCH	CCF of the DHR Discharge Valves	2.7 E-004	2.7 E-004		No
DHR-XHE-XM	Operator Fails to Initiate the DHR System	1.0 E-003	1.0 E-003		No
HPI-LINE-BREAK	Line Break in HPI Loop A	0.0 E+000	1.0 E+000	TRUE	Yes
HPI-MDP-CF-ABC	CCF (to Run) of the Motor-Driven HPI Pumps	1.9 E-005	1.9 E-005		No
HPI-MDP-CF-START	CCF (to Start) of the Motor-Driven HPI Pumps B and C	6.3 E-004	6.3 E-004		No
HPI-MDP-FC-B	HPI Train B Fails	3.9 E-003	3.9 E-003		No
HPI-MDP-FC-C	HPI Train C Fails	3.9 E-003	3.9 E-003		No
HPI-MOV-CC-409	HPI MOV HP409 Fails to Open	3.0 E-003	3.0 E-003		No
HPI-MOV-CC-SUCA	Isolation Valve in HPI Water Supply Path A Fails	4.2 E-003	4.2 E-003		No

Table 1. Definitions and Probabilities for Selected Basic Events for LER No. 270/97-001 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPI-MOV-CC-SUCB	Isolation Valve in HPI Water Supply Path B Fails	4.2 E-003	4.2 E-003		No
HPI-MOV-CF-SUCT	CCF of HPI Suction Isolation MOVs	2.7 E-004	2.7 E-004		No
HPI-MOV-OO-115	MOV HP115 Fails to Close	3.0 E-003	3.0 E-003		No
HPI-TNK-VF-BWST	BWST Failures	2.4 E-006	2.4 E-006		No
HPI-XHE-XM-PMPB	Operators Fail to Align HPI Pump B to Loop B	1.0 E-002	1.0 E-002		No
HPR-MOV-CF-BWST	CCF of BWST Isolation MOVs	2.7 E-004	2.7 E-004		No
LPR-MOV-CF-BWST	CCF of BWST Isolation MOVs	2.7 E-004	2.7 E-004		No
LPR-MOV-CF-SUMP	CCF of Sump Isolation MOVs	2.7 E-004	2.7 E-004		No
LPR-SMP-FC-SUMP	Failures in the Reactor Building Sump	5.0 E-005	5.0 E-005		No
PBC-MOV-CF-DHR	CCF of DHR to HPI Supply MOVs	2.7 E-004	2.7 E-004		No
PBC-XHE-XM	Operator Fails to Initiate Piggy-Back Cooling	1.0 E-003	1.0 E-003		No
PCS-VCF-HW	Hardware Failures in the Secondary Systems	3.0 E-003	3.0 E-003		No
PCS-XHE-XM-CDOWN	Operator Fails to Initiate Cooldown	1.0 E-003	1.0 E-003		No
PCS-XHE-XM-FDEPR	Operator Fails to Initiate a Fast Depressurization for LPI	1.0 E-001	1.0 E-001		No
RPS-SYS-FC-ELECT	Control Rod Drives Remain Energized	4.3 E-004	4.3 E-004		No
RPS-SYS-FC-MECH	Nonrecoverable Failures in the RPS	1.2 E-006	1.2 E-006		No
RPS-XHE-XM-SCRAM	Operator Fails to Manually Trip the Reactor	1.0 E-002	1.0 E-002		No

Table 2. Sequence Conditional Probabilities for LER 270/97-001

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution
SLOCA	10	5.6 E-006	55.6
SLOCA	03	3.3 E-006	33.5
SLOCA	05	5.2 E-007	5.1
SLOCA	27	2.9 E-007	2.8
SLOCA	09	1.2 E-007	1.2
Total (all sequences)		**1.0 E-005**	

Table 3. Sequence Logic for Dominant Sequences for LER 270/97-001

Event tree name	Sequence number	Logic
SLOCA	10	/RT, /EFW, HPI, FASTDEPR
SLOCA	03	/RT, /EFW, /HPI, /COOLDOWN, DHR, PB-COOL
SLOCA	05	/RT, /EFW, /HPI, COOLDOWN, PB-COOL
SLOCA	27	RT
SLOCA	09	/RT, /EFW, HPI, /FASTDEPR, LPI

Table 4. System names for LER 270/97-001

System name	Logic
COOLDOWN	RCS Cooldown to DHR Pressure Using Turbine Bypass Valves, etc.
DHR	No or Insufficient Flow from the DHR System
EFW	No or Insufficient Flow from the EFW System
FASTDEPR	RCS Rapid Cooldown/Depressurization to LPI Pressure Using Turbine Bypass Valves, etc. (HPI Failed)
HPI	No or Insufficient Flow from the HPI System
LPI	No or Insufficient flow from the LPI System
PB-COOL	No or Insufficient Flow from Piggy-Back Cooling
RT	Reactor Fails to Trip During a Transient

Table 5. Conditional Cut Sets for Higher Probability Sequences for LER No. 270/97-001

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
SLOCA Sequence 10		5.6 E-006	
1	59.4	3.3 E-006	HPI-LINE-BREAK, HPI-MDP-CF-START[c], PCS-XHE-XM-FDEPR
2	25.4	1.4 E-006	HPI-MOV-CF-SUCT, PCS-XHE-XM-FDEPR
3	3.7	2.0 E-007	HPI-LINE-BREAK, HPI-XHE-XM-PMPB, HPI-MDP-FC-C, PCS-XHE-XM-FDEPR
4	1.7	1.0 E-007	HPI-MDP-CF-ABC, PCS-XHE-XM-FDEPR
5	1.7	1.0 E-007	HPI-LINE-BREAK, HPI-MDP-CF-START[c], PCS-VCF-HW
6	1.6	9.3 E-008	HPI-MOV-CC-SUCA, HPI-MOV-CC-SUCB, PCS-XHE-XM-FDEPR
7	1.4	8.0 E-008	HPI-LINE-BREAK, HPI-MDP-FC-B, HPI-MDP-FC-C, PCS-XHE-XM-FDEPR
8	1.1	6.2 E-008	HPI-LINE-BREAK, HPI-MDP-FC-C, HPI-MOV-CC-409, PCS-XHE-XM-FDEPR
9	1.1	6.2 E-008	HPI-LINE-BREAK, HPI-MDP-FC-C, HPI-MOV-OO-115, PCS-XHE-XM-FDEPR
SLOCA Sequence 03		3.3 E-006	
1	39.1	1.3 E-006	DHR-MDP-CF-ALL[d]
2	21.2	7.2 E-007	DHR-HTX-CF-ALL
3	9.3	3.1 E-007	DHR-MOV-CC-SUCA, PBC-XHE-XM
4	4.7	1.5 E-007	DHR-MOV-CC-SUCB, PBC-XHE-XM
5	2.5	8.6 E-008	DHR-MOV-CC-SUCA, HPR-MOV-CF-BWST
6	2.5	8.6 E-008	DHR-MOV-CC-SUCA, LPR-MOV-CF-BWST
7	2.5	8.6 E-008	DHR-MOV-CC-SUCA, LPR-MOV-CF-SUMP
8	2.5	8.5 E-008	DHR-MOV-CC-SUCA, PBC-MOV-CF-DHR
9	1.5	5.3 E-008	DHR-XHE-XM, PBC-XHE-XM

Table 5. Conditional Cut Sets for Higher Probability Sequences for LER No. 270/97-001 (Continued)

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
10	1.2	4.3 E-008	DHR-MOV-CC-SUCB, HPR-MOV-CF-BWST
11	1.2	4.3 E-008	DHR-MOV-CC-SUCB, LPR-MOV-CF-BWST
12	1.2	4.3 E-008	DHR-MOV-CC-SUCB, LPR-MOV-CF-SUMP
13	1.2	4.2 E-008	DHR-MOV-CC-SUCB, PBC-MOV-CF-DHR
SLOCA Sequence 05		5.2 E-007	
1	30.5	1.5 E-007	PCS-VCF-HW, PBC-XHE-XM
2	10.1	5.3 E-008	PCS-XHE-XM-CDOWN, PBC-XHE-XM
3	8.3	4.3 E-008	PCS-VCF-HW, LPR-MOV-CF-BWST
4	8.3	4.3 E-008	PCS-VCF-HW, HPR-MOV-CF-BWST
5	8.3	4.3 E-008	PCS-VCF-HW, LPR-MOV-CF-SUMP
6	8.2	4.2 E-008	PCS-VCF-HW, PBC-MOV-CF-DHR
7	2.7	1.4 E-008	PCS-XHE-XM-CDOWN, HPR-MOV-CF-BWST
8	2.7	1.4 E-008	PCS-XHE-XM-CDOWN, LPR-MOV-CF-BWST
9	2.7	1.4 E-008	PCS-XHE-XM-CDOWN, LPR-MOV-CF-SUMP
10	2.7	1.4 E-008	PCS-XHE-XM-CDOWN, PBC-MOV-CF-DHR
11	1.5	7.9 E-009	PCS-VCF-HW, LPR-SMP-FC-SUMP
SLOCA Sequence 27		2.9 E-007	
1	78.1	2.2 E-007	RPS-SYS-FC-ELECT, RPS-XHE-XM-SCRAM
2	21.8	6.3 E-008	RPS-SYS-FC-MECH
SLOCA Sequence 09		1.2 E-007	
1	88.1	1.1 E-007	/PCS-VCF-HW, /PCS-XHE-XM-FDEPR, HPI-TNK-VF-BWST

Table 5. Conditional Cut Sets for Higher Probability Sequences for LER No. 270/97-001 (Continued)

Cut set number	Percent contribution	CCDP[a]	Cut sets[b]
2	6.2	8.1 E-009	HPI-LINE-BREAK, /PCS-VDF-HW, /PCS-XHE-XM-FDEPR, HPI-MDP-CF-START, DHR-MOV-CF-DISCH
3	2.7	3.4 E-009	/PCS-VCF-HW, /PCS-XHE-XM-FDEPR, HPI-MOV-CF-SUCT, DHR-MOV-CF-DISCH
Total (all sequences)		**1.0 E-005**	

[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 1 and begin with the designator "IE." The probabilities for the basic events also are given in Table 1.

[b]Basic event HPI-LINE-BREAK is a type TRUE event. This type of event is not normally included in the output of the fault tree reduction process, but has been added to aid in understanding the sequences to potential core damage associated with the event. Hence, because HPI-LINE-BREAK only affects HPI loop A, this basic event was added to those cut sets that involved failures in HPI loops B and C. If a cut set already involved the common-cause failure of all three HPI loops, the addition of HPI-LINE-BREAK would be superfluous and the cut set would no longer be a minimal cut set.

[c]This basic event represents the common-cause failure of HPI pumps B and C failing to start. At Oconee, one of the HPI pumps (pump A in this analysis) is always running to provide normal RCS makeup and seal injection; however, its flow is lost due to the HPI line break.

[d]Components in the DHR system are shared with the LPI system. For example, the DHR motor-driven pumps are also the LPI pumps when providing low-pressure injection, or piggy-back cooling. Failure of the DHR pumps therefore results in the failure of both DHR and PB-COOL in this sequence.

GUIDANCE FOR LICENSEE REVIEW OF PRELIMINARY ASP ANALYSIS

Background

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

Modeling Techniques

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

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

Guidance for Peer Review

Comments regarding the analysis should address:

- Does the "Event Description" section accurately describe the event as it occurred?

- Does the "Additional Event-Related Information" section provide accurate additional information concerning the configuration of the plant and the operation of and procedures associated with relevant systems?

- Does the "Modeling Assumptions" section accurately describe the modeling done for the event? Is the modeling of the event appropriate for the events that occurred or that had the potential to occur under the event conditions? This also includes assumptions regarding the likelihood of equipment recovery.

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

Criteria for Evaluating Comments

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

Criteria for Evaluating Additional Recovery Measures

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

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

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

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

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

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* Revision or practices at the time the event occurred.

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

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

Materials Provided for Review

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

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

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

Schedule

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

References

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

DUKE POWER

May 21, 1997

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Subject: Oconee Nuclear Station Unit
Docket Nos. 50-270, -287
Licensee Event Report 270/97-01, Revision 0
Problem Investigation Process No.: 2-097-1324

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a) (1) and (d), attached is Licensee Event Report 270/97-01, concerning the completion of a plant shutdown required by the plant's Technical Specifications. This shutdown was due to an unisolable leak in the Reactor Coolant System, which was a condition resulting in a principal safety barrier being degraded.

This report is being submitted in accordance with 10 CFR 50.73(a)(2)(i)(A) and 50.73(a)(2)(ii). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

J. W. Hampton

J. W. Hampton

/fts

Attachment

IE22

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PDR ADOCK 05000270
S PDR

15pp

Enclosure 3

Document Control Desk
Date: May 21, 1997

cc: Mr. Luis A. Reyes
Administrator, Region II
U.S. Nuclear Regulatory Commission
61 Forsyth Street, S. W., Suite 23T85
Atlanta, GA 30303

Mr. D. E. LaBarge
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

INPO Records Center
700 Galleria Parkway
Atlanta, GA 30339-5957

Mr. M. A. Scott
NRC Resident Inspector
Oconee Nuclear Station

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION
(4-95)

APPROVED OMD NO. 3150-0104
EXPIRES: 04/30/98
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit Two	05000 270	1 of 13

TITLE (4)
Unisolable Reactor Coolant Leak Due to Inadequate Surveillance Program

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER(S)
									Unit Three	05000 287
04	21	97	97	- 001 -	00	05	21	97		05000

OPERATING MODE (9): N
POWER LEVEL (10): 100%

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR (*Check one or more of the following*) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (*Specify in Abstract below and in Text, NRC Form 366A*)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)A	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
Rick Bond, Safety Review Manager	(864)	885-3043

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E	AB	PSP	X000	NO					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (*if yes, complete EXPECTED SUBMISSION DATE*)	X NO				

ABSTRACT (*Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines*) (16)

On April 21, 1997, Unit 2 was at 100% Full Power(FP). At 2245 hours, Operators noted indications of a 2.5 gpm Reactor Coolant System (RCS) leak. The source could not be determined, so at 0352 hours on April 22, power reduction began. At 20%FP Operators could not identify the leak as isolable, so the decision was made to go to cold shutdown. At 1448 hours, the reactor was tripped by a planned test. At 1500 hours, a NOUE was declared when the leak exceeded 10 gpm. The NOUE was terminated at 2032 hours after the leak reduced below 10 gpm. The leak was found to be a crack at the safe end to pipe weld on the High Pressure Injection to RCS cold leg nozzle near Reactor Coolant Pump 2A1. The safe end and pipe were found to be cracked internally and the thermal sleeve was found to be loose and damaged. The failures were caused by thermal cycling fatigue. The root causes were determined to be failure to implement an effective HPI nozzle inspection program based on available industry recommendations and failure to effectively evaluate known problems and implement appropriate corrective actions. Corrective actions include repair of the nozzle components and establishing an effective program to inspect and support nozzles. Evaluation shows that the HPI line still had a factor of safety greater than 2 under design basis event loads. Prompt shutdown prevented the development of an unsafe condition.

Background

The High Pressure Injection (HPI) System [EIIS:BQ] controls the Reactor Coolant System (RCS) [EIIS:AB] inventory, provides the seal water for the Reactor Coolant Pumps [EIIS:P], and recirculates RCS letdown for water quality maintenance and reactor coolant boric acid concentration control.

The HPI System is also a part of the Emergency Core Cooling System (ECCS) which mitigates the consequences of loss of coolant accidents (LOCA). The HPI System prevents uncovering of the core for smaller break sizes, where high RCS pressure is maintained, and delays the uncovering of the core for intermediate break sizes. The HPI System, during emergency operation, supplies borated water to the RCS from the Borated Water Storage Tank (BWST). The HPI System has three parallel HPI pumps that have the capability to take suction from the BWST. The HPI pumps have the capability to discharge through two redundant flow headers into the RCS, utilizing four injection lines (two per header). The HPI headers are cross-connected by piping and associated valves to provide for remote manual alignment to ensure flow to the core through both HPI trains should a single failure of an HPI pump or HPI injection valve prevent automatic injection through one train.

The HPI System, during normal makeup operation, supplies borated water to the RCS from the Letdown Storage Tank (LDST). The "A" HPI header supplies normal RCS makeup flow, typically 15 to 20 gpm through each of the two lines. These lines are each equipped with a "bypass" or "warming" line that provides a minimum flow preset by procedure to 3 gpm. The "B" HPI header is for emergency use only, and has no bypass lines.

The HPI injection lines terminate at injection nozzle [EIIS:NZL] assemblies located on each of the reactor inlet pipes downstream of the Reactor Coolant Pumps. Each nozzle assembly consists of a carbon steel nozzle (inconel clad on inside), to which a stainless steel safe end is welded. The HPI piping is welded to the other end of the safe end. Inside the safe end is a stainless steel thermal sleeve, which extends into the main RCS flow path. The function of the thermal sleeve is to minimize thermal shock and stresses on the nozzle by transporting the relatively cold HPI water (approximately 100 to 120F) into the main flow path. There it will mix with the 555F RCS cold leg water. Without the sleeve, the HPI water would have a direct impact on the nozzle itself, producing unacceptable thermal stress on the nozzle material.

Technical Specification 3.1.6.1 states: "If the total reactor coolant leakage rate exceeds 10 gpm, the reactor shall be shut down within 24 hours of detection."

Technical Specification 3.1.6.2 states: "If unidentified reactor coolant leakage (excluding normal evaporative losses) exceeds 1 gpm or if any reactor coolant leakage is evaluated as unsafe, the reactor shall be shut down within 24 hours of detection."

Technical Specification 3.1.6.3 states: "If any reactor coolant leakage exists through a non-isolable fault in a RCS strength boundary (such as the reactor vessel, piping, valve body, etc., except the steam generator tubes), the reactor shall be shut down, and cooldown to the cold shut down condition shall be initiated within 24 hours of detection."

Technical Specification 3.3.1 requires three HPI pumps and two HPI flow paths to be operable when RCS temperature is greater than 350 degrees with fuel in the core. Additionally, valves HP-409 and HP-410 in the cross-connect must be operable. This is based on considerations of potential small breaks at the Reactor Coolant Pump discharge piping for which two HPI trains (two pumps and two flow paths) are required to assure adequate core cooling. Included in the Technical Specification definition of operable is the requirement that essential auxiliary equipment, such as instrumentation and controls, be capable of performing its related support function.

Event Description

On April 21, 1997, at approximately 2245 hours, while Oconee Unit 2 was operating at 100% Full Power (FP), the Reactor Operator noticed a change in the rate of decrease of the Letdown Storage Tank (LDST) and an increase in the Reactor Building (RB) Normal Sump (RBNS) rate, followed by Reactor Building radiation monitor system alarms. At 2300, Operations entered the Abnormal Procedure (AP) on excessive Reactor Coolant System (RCS) leakage. RCS leakage indicated 2.36 gpm leak. At 2337 hours, it was determined that the RCS leak was greater than the Technical Specification (TS) 3.1.6.2 limits on unidentified leakage.

At 0215 hours on April 22, a RB entry was made which determined that a leak existed at the second grating level in the "A" Steam Generator Cavity, near Reactor Coolant Pump 2A1. However, a positive identification of the leak could not be made.

Unit shutdown was commenced at 0352 hours after a meeting with Operations shift personnel, Radiation Protection, the Shift Work Manager, and the Station Manager. The original intent was to reduce power to 15%FP, where radiation levels would be reduced to the point that personnel could enter the area to better identify (and, if possible, isolate) the leak, while still keeping the main turbine on line.

At 0426 hours, an Emergency Notification System call was made to the NRC to report a shutdown due to RCS leakage in excess of TS limits.

The power reduction was stopped at 20%FP, at approximately 0900 hours. With power stable, a more accurate leak rate calculation could be performed. A calculation completed at 0940 hours indicated that the leak rate had increased to 6.25 gpm. By 1048 hours it had increased slightly above 8 gpm.

Another RB entry was made to better determine the exact location of the leak. At 1217 hours, personnel in the RB informed the control room that it appeared to be on 2HP-127, the High Pressure Injection (HPI) block valve closest to the HPI injection nozzle on the 2A1 Reactor Coolant Pump cold leg. The decision was made to continue to cold shutdown.

At 1250 hours, Unit 2 turbine-generator was taken off line. At 1448 hours, the reactor was tripped, by a planned test, to meet commitments on control rod trip time testing.

At 1600 hours, a Notice of Unusual Event (NOUE) was declared when the leak increased above 10 gpm. The leak rate peaked at about 12 gpm at 1750 hours, then began decreasing as RCS system pressure was reduced while shutting down. The NOUE was terminated at 2032 hours after two consecutive leak measurements showed the leak had reduced below 10gpm. The RCS cooldown continued until the unit was at cold shut down. Subsequent entries into the RB, on the morning of April 23, identified the leak as being at the safe end to pipe weld at the 2 ½ inch OD, schedule 160 Stainless Steel HPI pipe to RCS cold leg nozzle near Reactor Coolant Pump 2A1.

A Failure Investigation Process (FIP) Team was created to investigate the root cause and a Recovery Team was created to address the necessary repair activities.

Over the night of April 27-28, the pipe was cut from the cracked portion of the safe end out to valve 2HP-127, including the tie to the minimum flow line connection. This section of pipe was sent to the Babcock and Wilcox (B&W) Lynchburg Research Center for failure analysis. Radiographic Tests (RT) and visual inspection of the 2A1 HPI nozzle thermal sleeve determined that the thermal sleeve was loose. Also, the nozzle safe end had multiple internal cracks discovered during Dye Penetrant Test (PT). A contingency plan was implemented to weld a temporary cap on the safe end and refill the RCS above reduced inventory conditions, while developing plans and an implementation package for the thermal sleeve an safe end repairs.

Duke Power reviewed the potential impact of this problem on Units 1 and 3 and generated a Justification for Continued Operation, which indicated that it was appropriate, based on knowledge available at the time, to continue to operate both units.

Ultrasonic Tests (UT) on the 2A1 safe end also showed the internal cracking revealed by PT. UTs were performed on the safe ends of the other three nozzles (2A2, 2B1, 2B2). UT was also performed on the pipe to safe end welds and pipe back to the first isolation valve. No other lines on Unit 2 showed any rejectable indications.

On April 29, an internal video inspection was performed on the 2A1 thermal sleeve. It was found to be axially cracked through wall and to have holes where two pieces were missing. The 2A2, 2B1 and 2B2 HPI thermal sleeves were inspected by inserting video equipment through disassembled HPI check valves. No problems were found.

On May 1, the 2A1 thermal sleeve and safe end were removed and sent to the B&W laboratory for analysis. PT was performed on the nozzle inner radius (knuckle area) for indication of cracks on the cladding. None were found. Then the safe end and thermal sleeve were replaced.

One portion of the FIP activity was to review the maintenance and operational history of the HPI nozzles. This led to the review of documentation associated with similar problems with thermal sleeves and safe ends in 1982 at Crystal River 3 and Oconee, and in 1988 at Farley 2 and Davis Besse. These events were described in a series of NRC documents such as IE Information Notice 82-09, "Cracking in Piping of Makeup Coolant Lines at B&W Plants", Generic Letter 85-20, "High Pressure Injection/Make-up Nozzle Cracking in B&W plants", and NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," and an associated set of reports by the Babcock and Wilcox (B&W) Owners' Group (BWOG). Reports related to Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification," were also reviewed relative to this event.

Generic Letter 85-20 adopted recommended corrective actions listed in a BWOG report on the Crystal River and Oconee problems in 1982. An Augmented Inservice Inspection Plan was to RT the safe ends periodically to check for loosening of the thermal sleeves, as indicated by the existence (or lack) of a gap or separation in the rolled fit joint between the thermal sleeve and the safe end. Also, "adjacent piping" (i.e. pipe at/near the pipe to safe end weld) was to be UT inspected on the normal makeup lines (for Units 2 and 3). By Bulletin 88-08, the pipe to safe end weld (plus others) on the emergency HPI lines were to be periodically UT inspected.

A review of inspection schedules indicated that these inspections had been performed on Unit 2 in May of 1996. It was learned that the actual scope of the UT exams was not as extensive as described in the BWOG recommendations from the 1982 event. Specifically, the requirement to UT adjacent piping on the normal makeup lines was not included in the program. Therefore, the weld which was cracked and leaking had not been inspected since 1982.

Also, the criteria for reviewing the RTs of the safe ends were not well defined and the personnel currently performing the reviews did not observe indications that the condition of the 2A1 thermal sleeve was degraded in 1996.

A Level III RT inspector performed a reassessment of all the RTs of thermal sleeves performed since 1983 in order to evaluate the impact on Units 1 and 3. The reassessment found there had been no RT taken on Unit 1 since 1989 but the RTs taken between 1983 and 1989 indicated no degradation of any Unit 1 thermal sleeves. The reassessment of Unit 3 RT results indicated that the 3A1 thermal sleeve was potentially degraded. On May 1, at 1430 hours, Management made the decision to shut down Unit 3 for inspection.

The 3A1 thermal sleeve was found to be damaged. Indications on the inside of the 3A1 nozzle were found by PT. Additional UTs with increased scope were performed on the nozzle and indicated that the observed cracks were limited to the cladding and did not penetrate to the carbon steel base metal. Framatome Technology Inc. (formerly B&W Nuclear Technology) performed an evaluation of the indications and determined them to be acceptable with no repairs necessary. The UTs of the other Unit 3 nozzles found no rejectable indications.

Both the 2A1 and 3A1 nozzles were restored by installation of new safe ends, thermal sleeves, and associated piping.

Throughout this period, communications continued between Duke Power and the NRC relative to the Justification for Continued Operation for Unit 1. Duke concluded that continued operation was justified, but has agreed to shut down Unit 1, on or before June 14, 1997, for inspection of the HPI nozzle components.

Conclusion

There were no radiological overexposures, radioactive releases, or personnel injuries associated with this event. This event did involve a weld leak, however the weld leak does not meet criteria to be NPRDS reportable as an equipment failure.

Laboratory results indicate that the leaking weld crack was circumferential with a 360 degree inside diameter crack, of which approximately 77 degrees was through-wall to the outside diameter. The face of the crack was a brown color, indicating that the crack had propagated over a long period of time, believed to be longer than two years. The primary initiator of the crack was high cycle/low amplitude stresses consistent with thermal cycling in the weld region. Any contributory role of vibration was limited to final failure after the crack was virtually through wall.

The pipe from the weld to the warming line connection was found to have cracks, averaging 20% through wall, consistent with thermal cycling.

The 2A1 and 3A1 thermal sleeves' damage may have been initiated and propagated by localized thermal fatigue, with some contribution from flow induced vibration after the sleeves was loosened.

The FIP team concluded that the failure scenario was:

- High cycle thermal fatigue, resulting from thermal mixing of the warming line, makeup and Reactor Coolant System (RCS) flow, caused cracking in the pipe, pipe to safe end weld, and safe end and contributed to the thermal sleeve failure.

- Thermal mixing occurred in the thermal sleeve, safe end and piping due to varying operational conditions, including low makeup flow through the thermal sleeve.

- Thermal hot shocking (sudden significant increase in temperature) initiated thermal sleeve loosening.

- RCS flow induced vibration contributed to thermal sleeve failure after loosening.

- It is improbable that the weld, piping, or safe end damage would have occurred without concurrent damage to the thermal sleeve.

- The through wall crack propagated over a long period of time.

The root causes of the event were:

1. Failure to implement an effective HPI nozzle inspection program based on available industry recommendations.

   This event is similar to events (in 1982) which involved cracking of welds, pipe, and thermal sleeves at Oconee and Crystal River. The 1982 Oconee event did not result in through-wall leakage of RCS. However, the corrective actions from that event were intended to detect a similar crack prior to degradation to the point of leakage. Therefore, this event is considered recurring. The corrective actions from the 1982 event did not prevent this event because the actual corrective actions taken did not meet the letter or the intent of the recommended corrective actions.

   The Augmented Inservice Inspection (ISI) program set up after the 1982 event:

a) added periodic UT of the safe end of all normal make up nozzles, but did not define this to cover the base metal in addition to the safe end to nozzle weld.

b) did not include periodic UT of "some associated piping" for normal make up nozzles, which should have included the pipe to safe end weld.

c) did not include periodic UT of the "cold leg ID nozzle knuckle transition" for the three nozzles where thermal sleeves had been replaced in 1982.

d) added periodic Non-Code RT of the safe end and thermal sleeves but did not provide adequate procedural guidance or acceptance criteria.

e) designated the refueling outage numbers when the inspections were to be performed but did not adequately document that these inspections had a fixed frequency and did NOT have the flexibility contained in the ASME Code.

Additions to the Augmented Inservice Inspection (ISI) program, required by Bulletin 88-08 after the Farley 2 event, were properly implemented but addressed the HPI emergency header nozzle lines only.

2. Failure to effectively evaluate known problems (industry and in-house experience) and implement appropriate corrective actions (during a period of 1982 through the present).

   Operating experience from Davis Besse, and Oconee data from 1990 collected for Bulletin 88-08, indicated that the normal makeup lines were subject to periods of thermal cycling due to unexpected phenomena. These problems were documented in B&W reports issued in 1990 and 1992. Recommendations in these reports were not acted upon. These recommendations, if acted upon, could have reduced the thermal cycling experienced by the HPI makeup lines.

NOTE: The Failure Investigation Process Team will issue a final written report which will provide more technical detail of the failure and the investigation. The above conclusions are based on data received to date.

Corrective Action:

Immediate:

1. Unit 2 was brought to cold shutdown to reduce the leak.

2. A Failure Investigation Process (FIP) team was initiated to investigate the cause of the leak.

Subsequent:

1. The 2A1 thermal sleeve, safe end, and cracked piping between 2HP-127 and the safe end were replaced.

2. The potential impacts on Units 1 and 3 were evaluated and a Justification for Continued Operation (JCO) was developed. Compensatory actions supporting the JCO were implemented under procedural controls, including increased testing and surveillance of potential Reactor Coolant System (RCS) leakage.

3. The need to closely monitor indicators of potential RCS leakage was stressed to the Operators on Units 1 and 3. They were also instructed to treat all leaks inside the Reactor Building as unisolable for immediate response.

4. Operators on Units 1 and 3 were instructed to be more aware of the need to maintain stable High Pressure Injection (HPI) make-up flow. Maintenance and testing that could upset HPI make-up flow was minimized.

5. Upon re-examination of the Radiographic Test (RT) indication on 3A1 thermal sleeve, Unit 3 was shut down and the sleeve and safe end replaced.

6. The JCO for Unit 1 was revised following discovery of the indication on Unit 3.

7. Additional inspections were performed on the other three nozzles on both Unit 2 and Unit 3.

8. Other B&W Owners' Group members were notified. A list of questions and answers related to HPI operation and thermal sleeve experience was shared among the members.

9. The current Inservice Inspection (ISI) program and associated commitments were evaluated. All other Augmented ISI commitments were found to be fully implemented.

Planned:

1. Complete the laboratory analysis on the sleeves, safe ends, and associated piping removed from Units 2 and 3 and issue a formal report on the findings.

2. Complete a comparison of the field ultrasonic test (UT) results with the metallurgical lab results of the 3A1 nozzle components. The intent of this comparison will be to make a judgment of the capability of UT examinations to locate safe end to piping, safe end, and safe end to nozzle flaws.

3. Unit 1 will commence shutdown on or before June 14, 1997 to perform RT and UT examinations on the HPI nozzle components.

4. Duke will submit a new HPI System nozzle component augmented inspection plan for all three units to the NRC no later than
   a) 30 days prior to the scheduled start of the next Unit 1 refueling outage, currently scheduled in September, 1997, or
   b) September 1,1997, whichever comes first.

5. Establish a more effective Engineering Support Program for nozzle and thermal sleeve inspection and assessment. This program should ensure the inclusion of up to date industry experience, operating conditions and component reliability.
6. During implementation of NSM-12975 on Unit 1, replace all the piping from the safe ends to valves 1HP-126, -127, -152, and -153 and perform concurrent video inspections of all safe ends and thermal sleeves.

7. Install temporary temperature instrumentation to monitor the makeup lines. Periodically evaluate the data.

Planned corrective actions 1 through 7 are considered to be NRC Commitment Items. These are the only NRC Commitment items contained in this report.

Safety Analysis:

This leak started small and the growth rate was slow enough that an orderly shut down could be performed without exceeding the capability of the normal make-up system. However, the leak was a non-isolable fault in a Reactor Coolant System (RCS) strength boundary and the leak rate did exceed Technical Specification limits. The leak rate also met the criteria of the Emergency Plan to be declared a NOUE. The leak was entirely within the reactor building containment and no radioactive releases were made.

Analysis performed by Structural Integrity Associates, a consultant to the Failure Investigation Process team, concluded that, even with the existing crack, the 2A1 High Pressure Injection (HPI) line had enough remaining strength to provide a factor of safety greater than 2 under design basis event loads. This provides reasonable assurance that the line would not have catastrophically broken, even during a design basis event. It can therefore be concluded that the HPI system, and this line specifically, was still capable of performing its Emergency Core Cooling System function.

If the leak had not been discovered or actions taken to reduce pressure in the system by shutting down the unit, this leak potentially could have grown to a 2 ½ inch pipe break (approximately 0.025 square feet), which would have constituted a small break Loss Of Coolant Accident. Breaks at this location are bounded by analyses in the Oconee UFSAR and are addressed in Emergency Procedures, which give detailed guidance to the Operators for responding to this break. This guidance is to trip the reactor coolant pumps, if not already tripped, and redirect HPI flow so that the majority of the flow goes through the unbroken header into the RCS. This limits the amount of injection flow and RCS inventory that would be pumped out the broken line. The UFSAR analysis concludes that this break can be handled without core damage.

This event does not fit the normal precursor analysis method because the leak was not large enough to be considered an initiating event and the event did not cause failure of a mitigation system.

In summary, even though this was a significant event, there was no actual radiological impact. Appropriate analysis, systems, and guidance existed to adequately mitigate this event and the equivalent worst case UFSAR scenario. Therefore, the health and safety of the public was not affected by this event.