50-382

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

June 6, 1996

Mr. Michael B. Sellman
Vice President Operations
Entergy Operations, Inc.
P. O. Box B
Killona, LA 70066

Dear Mr. Sellman:

SUBJECT: REVIEW OF PRELIMINARY ACCIDENT SEQUENCE PRECURSOR ANALYSIS OF 1995 OPERATIONAL EVENT AT WATERFORD STEAM ELECTRIC STATION, UNIT 3 (WATERFORD 3)

Enclosed for your review and comment is a copy of the preliminary Accident Sequence Precursor (ASP) analysis of an operational event which occurred at Waterford 3 on June 10, 1995 (Enclosure 1), and was reported in Licensee Event Report (LER) No. 95-002. This analysis was prepared by our contractor at the Oak Ridge National Laboratory (ORNL). The results of this preliminary analysis indicate that this event may be a precursor for 1995. In assessing operational events, an effort was made to make the ASP models as realistic as possible regarding the specific features and response of a given plant to various accident sequence initiators. We realize that licensees may have additional systems and emergency procedures, or other features at their plants that might affect the analysis. Therefore, we are providing you an opportunity to review and comment on the technical adequacy of the preliminary ASP analysis, including the depiction of plant equipment and equipment capabilities. Upon receipt and evaluation of your comments, we will revise the conditional core damage probability calculations where necessary to consider the specific information you have provided. The object of the review process is to provide as realistic an analysis of the significance of the 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. In previous years, licensees have had to wait until publication of the Annual Precursor Report (in some cases, up to 23 months after an event) for the final precursor analysis of an event and the resolution of their comments.

1/1
DF01

We have also enclosed several items to facilitate your review. Enclosure 2 contains specific guidance for performing the requested review, identifies the criteria which we will apply to determine whether any credit should be given

in the analysis for the use of licensee identified additional equipment or specific actions in recovering from the event, and describes the specific information that you should provide to support such a claim. Enclosure 3 is a copy of LER No. 95-002, which documented the event.

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

Sincerely,

Original signed by:
Chandu P. Patel, Project Manager
Project Directorate IV-1
Division of Reactor Projects III/IV
Office of Nuclear Reactor Regulation

Docket No. 50-382

Enclosure: As stated

cc w/encls: See next page

DISTRIBUTION:
Docket File
PUBLIC
PDIV-1 r/f
JRoe
EAdensam
CPatel
PNoonan
OGC
ACRS
JDyer, RIV

Document Name: WATASP95.LTR

OFC	LA/PD4-1	PM/PD4-1
NAME	PNoonan	CPatel:sp
DATE	6/6/96	6/6/96
COPY	YES/NO	YES/NO

OFFICIAL RECORD COPY

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. 95-002, which documented the event.

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

Sincerely,

Chandu P. Patel

Chandu P. Patel, Project Manager
Project Directorate IV-1
Division of Reactor Projects III/IV
Office of Nuclear Reactor Regulation

Docket No. 50-382

Enclosure: As stated

cc w/encls: See next page

Mr. Michael B. Sellman
Entergy Operations, Inc.

Waterford 3

cc:

Mr. William H. Spell, Administrator
Louisiana Radiation Protection Division
Post Office Box 82135
Baton Rouge, LA 70884-2135

Mr. Jerrold G. Dewease
Vice President, Operations
Support
Entergy Operations, Inc.
P. O. Box 31995
Jackson, MS 39286

Mr. James J. Fisicaro, Director
Nuclear Safety
Entergy Operations, Inc.
P. O. Box B
Killona, LA 70066

Mr. Robert B. McGehee
Wise, Carter, Child & Caraway
P.O. Box 651
Jackson, MS 39205

Mr. Dan R. Keuter
General Manager Plant Operations
Entergy Operations, Inc.
P.O. Box B
Killona, LA 70066

Mr. Donald H. Vinci, Licensing Manager
Entergy Operations, Inc.
P. O. Box B
Killona, LA 70066

Winston & Strawn
Attn: N. S. Reynolds
1400 L Street, N.W.
Washington, DC 20005-3502

Regional Administrator, Region IV
U.S. Nuclear Regulatory Commission
611 Ryan Plaza Drive, Suite 1000
Arlington, TX 76011

Resident Inspector/Waterford NPS
Post Office Box 822
Killona, LA 70066

Parish President Council
St. Charles Parish
P. O. Box 302
Hahnville, LA 70057

Mr. Jerry W. Yelverton, Executive Vice-
President and Chief Operating Officer
Entergy Operations, Inc.
P. O. Box 31995
Jackson, MS 39286-1995

Chairman
Louisiana Public Service Commission
One American Place, Suite 1630
Baton Rouge, LA 70825-1697

LER No. 382/95-002

Event Description: Reactor trip, breaker failure and fire, degraded offsite power, and degraded shutdown cooling

Date of Event: June 10, 1995

Plant: Waterford 3

Event Summary

A switchyard lightning arrestor failure caused a trip from 100% power at Waterford 3. Delayed opening of the 4.16 kV auxiliary transformer (UAT) feeder breaker resulted in excessive current flow which destroyed the breaker and started a fire that damaged cables and switchgear for nonvital train A. Power was initially lost to train A safety loads, but was recovered when emergency diesel generator (EDG) A started and loaded. Condenser vacuum was subsequently lost due to loss of power to balance of plant train A equipment and the unexpected bypass of circulating water flow around the condenser. Plant cooldown was delayed when low hydraulic fluid levels prevented proper operation of shutdown cooling (SDC) system isolation valves. The conditional core damage probability estimated for this combined event is 2.5×10^{-5}. The increase in conditional core damage probability over a one-year period due to the unavailablity of the SDC isolation valves is 1.9×10^{-5}.

Event Description

Waterford 3 was operating at 100% power on June 10, 1995. At 0858 hours a lightning arrestor failed at the Waterford Substation. The resulting grid disturbance caused the sudden pressure relay on Main Transformer A to actuate the main generator lockout relays. This actuation resulted in the trip of the generator output breakers, generator exciter field breaker, UAT secondary breakers, and trip of the main turbine.

The B 6.9 kV and 4.16 kV buses successfully transferred to Startup Transformer (SUT) B. However, during the transfer of 4.16 kV bus A2 to SUT A, the A2 SUT feeder breaker closed before the A2 UAT breaker opened. The UAT feeder breaker tripped on overcurrent, and power was lost to bus A2.

The reactor tripped on low Departure from Nucleate Boiling (DNBR) signals, caused by sensed low reactor coolant pump speed. Main feedwater (MFW) pump A also tripped, apparently from loss of power to the pump speed pickups.

Vital 4.16 kV bus A3 deenergized when power was lost to bus A2. EDG A started and reenergized safety-related loads. Emergency Feedwater (EFW) actuated and within 12 min, both MFW isolation valves had been closed due to high steam generator (SG) level.

One minute after the trip, all turbine generator building (TGB) switchgear room fire alarm annunciators actuated. Seven minutes later, the TGB operator reported heavy smoke coming from the switchgear room. Two auxiliary operators were directed to set up blowers to help dissipate the smoke, don protective clothing, and enter the switchgear room to investigate the cause of the smoke.

At 0929 hours (+31 min), 6.9 kV bus A1 deenergized, tripping two reactor coolant pumps, circulating water pumps, condensate pumps, and condenser air evacuation pumps. Six minutes later the TGB auxiliary operator reported a fire in the 2A switchgear and in the cables above the switchgear. The fire was caused by the delayed opening of the A2 UAT breaker, which resulted in an overcurrent condition well beyond the interrupting capacity of the breaker. The breaker failed internally and caused the fire (the breaker failure and fire are described in more detail in Additional Event-Related Information).

Upon notification of an actual fire in the switchgear room, the shift supervisor sounded the plant fire alarm (post event review indicated that the fire alarm should have been sounded when smoke was first detected), actuated the fire brigade, and directed the motor-operated disconnect for SUT A to be opened to ensure electrical isolation of the A2 bus. The control room supervisor left the control room to serve as fire brigade leader.

The fire brigade attempted to extinguish the fire using halon, carbon dioxide and dry-chemical fire extinguishers. When the fire brigade leader arrived at the fire scene, he immediately notified the control room to request offsite fire department assistance. The Hahnville Fire Department was contacted at 0940 hours (+42 min) via 911 for support.

The Hahnville Fire Department arrived on site 18 min later and recommended that water be used to extinguish the fire. The fire brigade leader was reluctant to use water on the fire (although experience gained from the 1976 Browns Ferry fire and other fires indicated that the use of water was necessary on large cable fires), and delayed its use for 20 min, while carbon dioxide and dry chemical extinguishers were unsuccessfully used on the fire. The fire was finally extinguished within 4 min, once water was used.

At 1112 hours (+2.2 h), condenser vacuum was broken after it had fallen to 20 in Hg. A condenser low vacuum alarm had actuated at 0940 hours, 11 min after 6.9 kV bus A1 deenergized and shortly after the fire was reported. The loss of vacuum was initially attributed to the unavailability of the two circulating water and condenser air evacuation pumps, resulting from the deenergization of bus A1, combined with several steam loads that were still discharging to the condenser, and the operators made a decision not to divert resources from fighting the fire to attempt to recover condenser vacuum. Subsequently it was determined that when the two circulating water pumps deenergized, their associated motor-operated discharge valves also deenergized and remained open, resulting in a bypass of circulating water flow.

At 1147 hours (+2.75 h), the main steam isolation valves were closed and the atmospheric dump valves used for decay heat removal. At 2348 hours (14.8 h after the event began), the emergency feedwater system was secured and Condensate Pump B (the operable condensate pump) was used to supply water to Steam Generator B.

By 1257 hours on June 11, 1996, the plant had been cooled down and depressurized to shutdown cooling entry conditions. At 1311 hours, shutdown cooling suction header isolation valve SI-405B was commanded open while placing the shutdown cooling system in service. It closed after only partially opening and was declared inoperable. The equivalent valve in train A, SI-405A was then opened. Several hours later, this valve's hydraulic pump was observed to be continually running instead of cycling as designed. Valve SI-405A was also closed and declared inoperable.

A containment entry was made to inspect the two valves, and low hydraulic fluid levels were found in both valve actuator reservoirs. Approximately 200 in^3 of hydraulic fluid were added to the reservoir for SI-406B,

and the valve operated satisfactorily. Shutdown cooling loop B was placed in service between 1800-2400 hours on June 12, 1996.

When valve SI-406A was tested after fluid had been added to its reservoir, the valve opened slowly. Additional troubleshooting indicated that the valve's hydraulic pump had been damaged by the continuous operation caused by the low hydraulic fluid level. The pump was replaced and the valve was returned to service shortly after midnight on June 13, 1996. Cooldown to Mode 5 began, with A train components still powered by EDG A.

Additional Event-Related Information

The Waterford 3 fast bus transfer scheme consists of automatic or manual transfer of in-house loads from the UATs to the SUTs. During a fast bus transfer, the UAT feeder breakers to the A1 and B1 6.9 kV and the A2 and B2 4.16 kV buses are required to open in five cycles and the SUT feeder breakers are required to close in seven cycles, resulting in a two-cycle deadband on the respective buses.

This scheme is a "simultaneous" bus transfer scheme (zero to two-cycle deadband) instead of the "sequential" bus transfer scheme (greater than six-cycle deadband) commonly used in the United States. The simultaneous bus transfer scheme is used in all Swedish nuclear power plants. To prevent exceeding the fault duty of associated equipment and buses when two sources are in parallel, the Swedish design includes an interlock which limits the time period during which both breakers are permitted to remain closed to less than 0.1 sec. The Waterford 3 design did not include the interlock, and both breakers appeared to have remained closed for about 0.3 sec during the event.

During the time that the two breakers were simultaneously closed, the A2 bus connected SUT A to the main generator, which then provided power to the grid via the UAT and Bus A2. During this time the main generator was rotating faster than the system frequency. When the UAT breaker attempted to open, the generator was approaching 180 degrees out of phase, and the interrupting current was extremely high. This high current resulted in internal breaker failure and the creation of ionizing gases which caused the fire in the

A2 switchgear. A preliminary investigation indicated that the most probable cause for the slow opening time of the UAT breaker was restricted movement of the trip latch roller bearing.

The amount of damage to the breaker and surrounding equipment indicates that the fault current through the breaker was extremely high and significant arcing occurred for some period of time. The arc chutes and main contacts on all phases were destroyed and the contact structures, breaker frame, and cubicle were also significantly damaged. The main bus and bus enclosure also appeared to have experienced severe arcing damage.

The fire that resulted from the breaker failure damaged the bus and surrounding cables and components. Two cubicles were heavily damaged and approximately ten feet of the feeder cables were destroyed. Cables in approximately a 5-foot diameter column above the breaker had visible fire damage over their entire 10-foot vertical run. Fire stops installed in the vertical portion of the cable tray were not effective in limiting fire damage. At the top of the vertical run, the cables were routed through a horizontal cable tray. Approximately eight feet of cable in the horizontal tray had visible fire damage. Fire damage ended at a fire stop installed inside the horizontal tray. There was general smoke and slight heat damage to the exterior of the remaining cubicles in the A2 bus. In addition, there was external heat damage to the jackets of four of the 15 feeder cables from the SUT to the A2 bus, and burn marks on the conduit of the cables which supply 6.9 kV power to the reactor coolant pump 1A and 2A motors.

The TGB switchgear room contains both the A and B trains of nonvital switchgear. The ceiling of the room is approximately 25 ft above the floor; the top of the switchgear cubicles are approximately 7 ft high. A 10-ft high concrete block radiant heat shield, located 6 ft from the front of each set of cubicles, separates the two trains. The fire did not affect the B train switchgear or cables.

The TGB switchgear room had an ionization-type fire detection system, with detectors mounted on the ceiling, but no fire suppression system. The fire detection computer recorded the first fire alarm 55 sec after the reactor trip. Within 7 sec, all 36 fire detectors in the room had alarmed. Twenty-five minutes after the trip the first detector went into "device communication error," it apparently failed at that time and melted. By 0942 hours (+43 min), all detectors in the room had failed.

Subsequent to the fire, the licensee found tape over the fire alarm annunciator buzzer located on the fire detection computer in the control room. Because of the tape, the alarm volume was low and nonintrusive. Due to the alarm panel's placement in the control room, alarm lights were also not readily visible. These factors, combined with the fact that the fire was not declared until after the auxiliary operators entered the switchgear room and observed it (36 min after smoke was reported) contributed to the delay in responding to the fire.

Unlike many PWRs, the Waterford primary pressure relief system includes only code safety valves; no power operated relief valves (PORVs) are incorporated in the design. The lack of PORVs prevents the use of feed and bleed for core cooling in the event both main and emergency feedwater systems are unavailable. If both of these systems were to fail at Waterford, safety-related secondary-side atmospheric dump valves could be used to depressurize the steam generators to below the shutoff head of the condensate pumps. These pumps could then be used for decay heat removal.

Modeling Assumptions

The event was modeled both as (1) a reactor trip, loss of feedwater (due to the loss of condenser vacuum 2.2 h after the trip), loss of offsite power to train A safety-related components, and unavailability of SDC isolation valves SI-405A and SI-405B during the cooldown (initiating event assessment) and (2) a long-term unavailability of the SDC isolation valves (condition assessment).

Reactor trip, loss of feedwater, and unavailable SDC isolation valves (initiating event assessment).

The ASP model for Waterford 3 was revised to address the potential failure of the main feedwater isolation valves (MFIVs) to open. These valves were closed due to high SG levels shortly into the event. Failure of these valves to open would prevent use of the AFW system and the condensate system for SG makeup. Because significant crew resources were being used to fight the fire, short-term ex-control room recovery of EFW (beyond the use of the AFW pump) and HPI, had these systems failed, was not considered feasible.

Redundant shutdown cooling isolation valves SI-405A and SI-405B were both assumed to be failed. This assumption may be conservative for SI-405A, since it initially operated. However, the licensee determined that the valve's hydraulic motor was sufficiently damaged to require replacement before the plant cooldown continued.

The ASP models for a transient do not currently address the potential unavailability of offsite power to an individual train, as was observed in this event. During the event, power to safety-related train A loads was provided by EDG A. The potential failure of the EDG to power train A was modeled using two calculations, one in which components powered by the EDG were assumed to be unavailable because the EDG was failed (calculation 1a) and one in which the EDG was assumed to be operable (calculation 1b). The impact of the EDG failure postulated in calculation 1a was approximated by setting basic events for pumps powered by the EDG to TRUE. These two calculations were weighted using the probability of EDG failure to estimate the overall conditional core damage probability for the initiating event:

$$p(cd) = p(\text{EDG A fails}) \times p(cd \mid \text{EDG A fails}) + [1 - p(\text{EDG A fails})] \times p(cd \mid \text{EDG A succeeds}).$$

The mission time for the initiating event assessment was assumed to be the time from the reactor trip until shutdown cooling was established, ~60 h. EDG A continued to supply train A loads beyond this time. However, the added risk is considered to be small compared to the risk before shutdown cooling was established. [The ASP program addresses shutdown-related events that are considered unusual and significant. Events such as this one, where one train is powered from its EDG, are not typically selected for analysis.]

The following changes were made to basic events to reflect conditions observed during the event:

Basic event	Revised probability	Description (reason for change)
AFW-TRAIN-FC-ALL	9.8×10^{-3}	Nonsafety auxiliary feedwater system fails to provide flow to SGs (revised to reflect extended mission time).
COND-PFS-FC-SYS	7.8×10^{-3}	Secondary heat removal using condensate system fails (revised to reflect extended mission time)

EFW-MDP-FC-A, B	5.0×10^{-3}	EFW MDP failures (revised to reflect extended mission time)
EFW-PMP-CF-ALL	2.0×10^{-4}	Common cause failure of EFW pumps (revised to reflect extended mission time)
EFW-TDP-FC-TDP	4.1×10^{-2}	EFW TDP train failures (revised to reflect extended mission time)
EFW-XHE-NOREC	TRUE	Ex-control room resources required for recovery utilized to fight fire
EPS-DGN-FC-3A	1.4×10^{-1}	EDG A fails to start and run (revised to reflect extended mission time)
HPI-XHE-NOREC	TRUE	Ex-control room resources required for recovery utilized to fight fire
MFW-SYS-TRIP	TRUE	Main feedwater system trips (main feedwater unavailable due to loss of condenser vacuum)
MFW-VLV-CF-MFIV	1.8×10^{-4}	Common cause failure of the MFIVs to open (basic event added to model)
MFW-XHE-NOREC	TRUE	Operator fails to recover main feedwater (main feedwater not recoverable due to loss of vacuum)
RHR-MOV-CF-SUCT	TRUE	Common cause failure of RHR suction valves (set to TRUE to reflect the failure of SI-405A and SI-405B)
EFW-MDP-FC-A HPI-MDP-FC-A RHR-MDP-FC-A	TRUE	Motor-driven pumps fail to start and run (set to TRUE for calc 1a to address potential unavailability of EDG A)

The mission time for the high-pressure injection pumps was not revised to reflect the 60 h mission time. If a transient-induced loss of coolant accident (LOCA) had occurred, the modeled plant response would have been accomplished in less than 24 h. With the SDC isolation valves unavailable following a transient-induced (small-break) LOCA, the operators would have transferred to high-pressure recirculation once the refueling water storage pool was depleted. This would have occurred ~6 h following the LOCA.

The licensee addressed the switchgear room fire in the Waterford Individual Plant Examination for External Events (IPEEE), Ref. 3. In that document the licensee concluded that the fire, while extensive and not

suppressed until the cables from the UAT to the switchgear were fully involved, did not cause significant damage outside the plume/ceiling jet. Fire modeling also confirmed that a large TBG switchgear fire would not generate a hot gas layer that could fail cables outside the plume. Because of this, the IPEEE assumed that TGB switchgear fires would only cause damage to one train of offsite power. This assumption was utilized in this analysis as well. A sensitivity analysis addressed the potential impact if the fire, or common cause breaker problems, had also resulted in a nonrecoverable loss of offsite power to train B. The results of the sensitivity analysis are described in Analysis Results.

Long-term unavailability of the SDC isolation valves (condition assessment).

The SDC isolation valves were assumed to have been unavailable since the last refueling outage, in the spring of 1994. The longest time period utilized to assess a condition (unavailability) in the ASP program is one year, during which the plant is typically assumed to have been at power 70% of the time. In this event however, Waterford was at power for the full one-year period, resulting in an unavailability of 8760 h. This assumption presumes the loss of hydraulic fluid from the valve actuators occurs during valve operation, and not when the valves are inoperative, and that the fluid level during the previous use of the valves was barely acceptable. If the hydraulic fluid was lost when the valves were in standby, then the analysis duration is overestimated (the valves would then become unavailable at one-half of the duration since last use).

Consistent with the previous assessment, shutdown cooling isolation valves SI-405A and SI-405B were both assumed to be failed. This was reflected by setting basic event RHR-MOV-CF-SUCT to TRUE. Plant response to all initiators addressed in the ASP model was considered impacted by the unavailability of the SDC isolation valves.

Analysis Results

The conditional core damage probability estimated for trip, fire and resulting loss of offsite power to train A, loss of feedwater, and unavailability of the SDC isolation valves is 2.5×10^{-5}. The dominant sequence, highlighted on the event tree in Fig. 1, contributes about 83% to the conditional probability estimate for the initiating event and involves failure of EFW (including the AFW pump) to provide secondary-side cooling,

and failure of the condensate system as an alternate source of cooling water. The dominant cut sets involve failure to provide an alternate source of water to the EFW pumps following depletion of the condensate storage pool, and failure of the condensate system to provide flow to the steam generators (failure to initiate and equipment failure both contribute).

Table 1 provides the definitions and probabilities for selected basic events for the initiating event assessment. The conditional probabilities associated with the highest probability sequences are shown in Table 2, while 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. The minimal cut sets associated with each sequence are shown in Table 5. These tables provide analysis results for calculation 1a (EDG A failed) and calculation 1b (EDG A operable). The calculations for 1a and 1b were combined as described in the Modeling Assumptions. However, the assumptions concerning the status of the EDG in calculations 1a and 1b had little impact on the analysis results (2.52×10^{-5} for calculation 1a verses 2.48×10^{-5} for calculation 1b). Therefore, the results for calculation 1a can be considered to reasonably represent the significance of the initiating event.

The calculation for the reactor trip and fire is sensitive to the assumption that the fire or potential common cause breaker failures would not impact the availability of offsite power to train B. If the fire could have impacted train B, or if slow breaker opening also resulted in the loss of train B switchgear (this is believed to be unlikely), the event could have been more significant. For example, an assumption of a 0.03 probability of nonrecoverable loss of offsite power to train B (similar to train A) results in an estimated conditional core damage probability of 1.4×10^{-4} (such an event would be considered significant from an ASP standpoint).

The unavailable SDC isolation valves (the condition assessment) result in an overall increase in core damage probability for the assumed 1 year period of 1.9×10^{-5}. The dominant core damage sequence involves a small-break LOCA with depressurization success and failure to initiate SDC (which would avoid the use of high-pressure sump recirculation) and failure of high-pressure recirculation.

For most ASP analyses of conditions (equipment failures over a period of time during which postulated initiating events could have occurred), sequences and cut sets associated with the observed failures dominate the conditional core damage probability (the probability of core damage over the unavailability period, given

the observed failures). The increase in core damage probability because of the failures is therefore essentially the same as the conditional core damage probability, and the conditional core damage probability can be considered a reasonable measure of the significance of the observed failures.

For this event, however, sequences unrelated to the SDC isolation valves dominate the conditional core damage probability estimate. The increase in core damage probability given the failed SDC isolation valves, 1.9×10^{-5}, is, therefore, a better measure of the significance of the SDC valve problems.

Definitions and probabilities for selected basic events for the condition assessment are shown in Table 6. The conditional probabilities associated with the highest probability sequences are shown in Table 7. Table 8 lists the sequence logic associated with the sequences listed in Table 7. Table 9 describes the system names associated with the dominant sequences. Cut sets associated with each sequence are shown in Table 10.

Acronyms

AFW	Auxiliary Feedwater
ASP	Accident Sequence Precursor
ATWS	Anticipated Transient Without Scram
CCDP	Conditional Core Damage Probability
cd	Core Damage
DNBR	Departure from Nucleate Boiling
EDG	Emergency Diesel Generator
EFW	Emergency Feedwater
HPI	High Pressure Injection
HPR	High Pressure Recirculation
IPEEE	Individual Plant Examination for External Events
kV	Kilo-Volts
LOCA	Loss-of-Coolant Accident
LOOP	Loss of Offsite Power
MFIV	Main Feedwater Isolation Valves

MFW	Main Feedwater
PORV	Power Operated Relief Valve
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RWSP	Refueling Water Storage Pool
RWST	Refueling Water Storage Tank
SDC	Shutdown Cooling
SG	Steam Generator
SRV	Safety Relief Valve
SUT	Startup Transformer
TGB	Turbine Generator Building
UAT	Unit Auxiliary Transformer

References

1. LER 382/95-002, Rev. 0, "Reactor Trip and Non-Safety Related Switchgear Fire," July 7, 1995.
2. NRC Augmented Inspection Team Report 50-382/95-15, July 5, 1995
3. Waterford 3 Individual Plant Examination for External Events, July 1995.

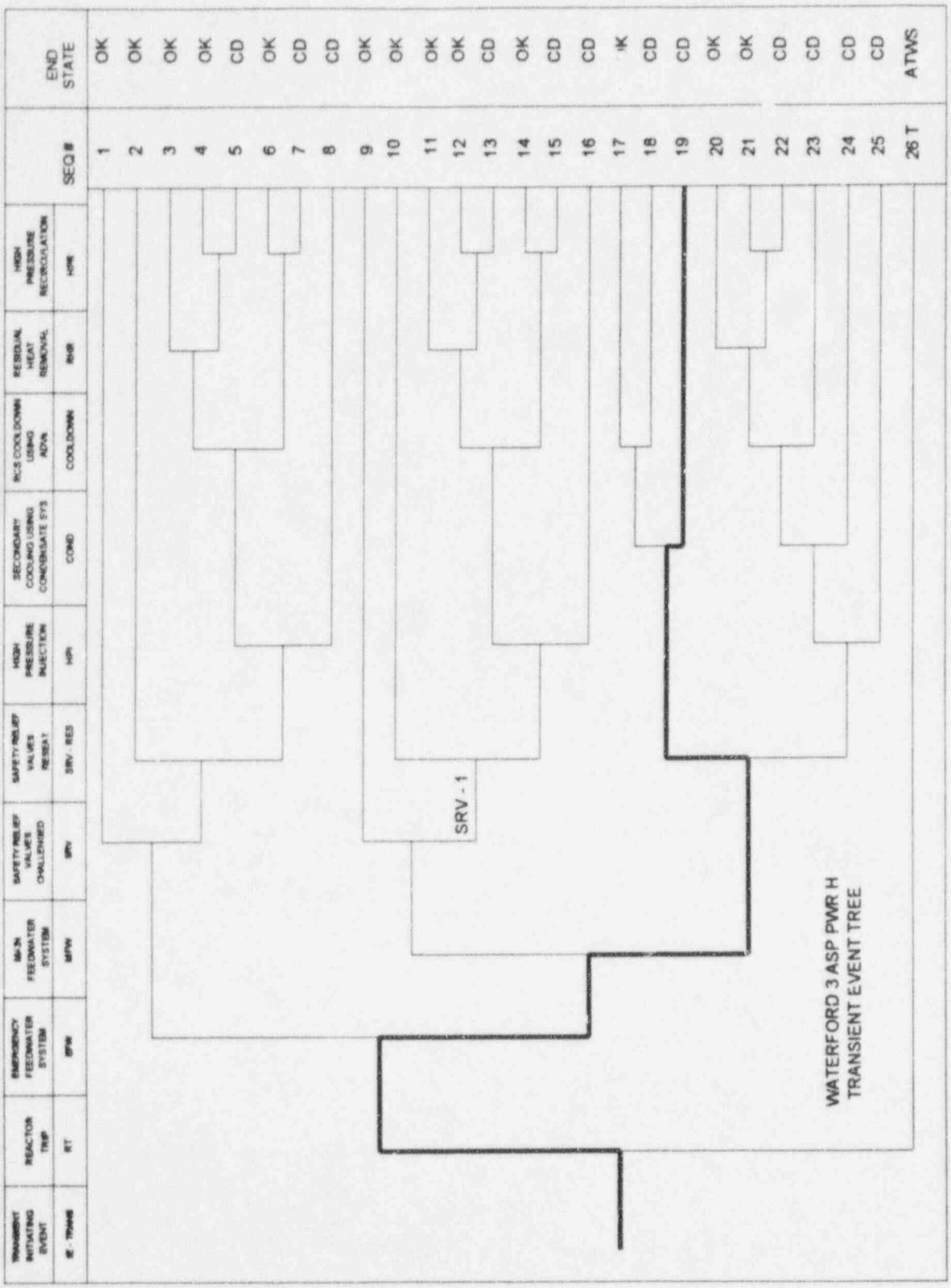

Fig. 1 Dominant core damage sequences for LER No. 382/95-002.

Table 1. Definitions and probabilities for selected basic events for the initiating event assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Loss of Offsite Power Initiating Event	8.5 E-006	0.0 E+000	IGNORE	No
IE-SGTR	Steam Generator Tube Rupture Initiating Event	1.6 E-006	0.0 E+000	IGNORE	No
IE-SLOCA	Small Loss of Coolant Accident Initiating Event	1.0 E-006	0.0 E+000	IGNORE	No
IE-TRANS	Transient Initiating Event	6.8 E-004	1.0 E+000		Yes
AFW-TRAIN-FC-ALL	AFW pump train fails to provide flow	8.7 E-003	9.8 E-003		Yes
COND-PFS-FC-SYS	Secondary Heat Removal Using Condensate System Fails	1.5 E-002	7.8 E-003		Yes
COND-XHE-XM	Operator Fails to Initiate Secondary Cooling	1.0 E-002	1.0 E-002		No
EFW-MDP-FC-A	EFW Motor-Driven Pump A Failures	3.9 E-003	1.0 E+000	TRUE*	Yes
EFW-MDP-FC-B	EFW Motor-Driven Pump B Failures	3.9 E-003	5.0 E-003		Yes
EFW-PMP-CF-ALL	Common Cause Failure of EFW Pumps	1.4 E-004	1.4 E-004		No
EFW-TDP-FC-TDP	EFW Turbine-Driven Pump Train Failures	3.8 E-002	4.1 E-002		Yes
EFW-XHE-NOREC	Operator Fails to Recover EFW System	2.6 E-001	1.0 E+000	TRUE	Yes
EFW-XHE-NREC-ATW	Operator Fails to Recover EFW During ATWS	1.0 E+000	1.0 E+000		No
EFW-XHE-XA-CCW	Operator Fails to Initiate Backup Water Source	1.0 E-003	1.0 E-003		No
EFW-XHE-XA-CCWA	Operator Fails to Initiate Backup Water Source During an ATWS	1.0 E-003	1.0 E-003		No
HPI-MDP-FC-A	HPI Motor-Driven Pump A Train Failures	3.9 E-003	1.0 E+000	TRUE*	Yes

Table 1. Definitions and probabilities for selected basic events for the initiating event assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPI-XHE-NOREC	Operator Fails to Recover the HPI System	8.4 E-001	1.0 E+000	TRUE	Yes
HPR-AOV-CF-SMP	Common Cause Failure of Sump Air-Operated Valves	1.0 E-004	1.0 E-004		No
HPR-HDV-CF-RWSP	Common Cause Failure of RWSP Isolation Hydraulic Discharge Valves	2.0 E-004	2.0 E-004		No
HPR-MOV-CF-HLEG	Common Cause Failure of Hot Leg Motor-Operated Valves	1.1 E-003	1.1 E-003		No
HPR-XHE-NOREC	Operator Fails to Recover the HPR System	1.0 E+000	1.0 E+000		No
HPR-XHE-XM	Operator Fails to Initiate Hot Leg Recirculation	1.0 E-003	1.0 E-003		No
MFW-SYS-TRIP	Main Feedwater System Trips	2.9 E-001	1.0 E+000	TRUE	Yes
MFW-VLV-CF-MFIV	Common Cause Failure of MFIVs to Open	0.0 E+000	2.6 E-004	NEW	Yes
MFW-XHE-NOREC	Operator Fails to Recover Main Feedwater	3.4 E-001	1.0 E+000	TRUE	Yes
PCS-VCF-HW	Turbine Bypass Valves / Condensate / Circulation Failures	1.0 E-003	1.0 E-003		No
PCS-XHE-XM-CDOWN	Operator Fails to Initiate Cooldown	1.0 E-003	1.0 E-003		No
PPR-SRV-CO-TRAN	SRVs Open During Transient	2.0 E-002	2.0 E-002		No
PPR-SRV-OO-1	SRV 1 Fails to Reseat	1.6 E-002	1.6 E-002		No
PPR-SRV-OO-2	SRV 2 Fails to Reseat	1.6 E-002	1.6 E-002		No
RHR-MDP-FC-A	RHR Motor-Driven Pump A Failures	3.8 E-003	1.0 E+000	TRUE*	Yes
RHR-MOV-CF-SUCT	Common Cause Failure of RHR Suction Valves	1.2 E-003	1.0 E+000	TRUE	Yes
RHR-XHE-NOREC	Operator Fails to Recover the RHR System	3.4 E-001	3.4 E-001		No

Table 1. Definitions and probabilities for selected basic events for the initiating event assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
RPS-VCF-FO	Reactor Trip System Fails	6.0 E-005	6.0 E-005		No
RPS-XHE-XM-SCRAM	Operator Fails to Manually Trip the Reactor	1.7 E-001	1.7 E-001		No

[a] These basic events were set to TRUE for calculation 1a only (i.e., EDG A failed).

Table 2. Sequence conditional probabilities for the initiating event assessment for LER 382/95-002

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent Contribution
TRANS	19	2.0 E-005	82.5
TRANS	18	2.2 E-006	9.1
TRANS	24	6.6 E-007	2.6
TRANS	05	5.7 E-007	2.2
TRANS	26-8	4.4 E-007	1.7
Total (all sequences)		**2.5 E-005**	

Table 3. Sequence logic for dominant sequences for the initiating event assessment for LER 382/95-002

Event tree name	Sequence name	Logic
TRANS	19	/RT, EFW, MFW, /SRV-RES, COND
TRANS	18	/RT, EFW, MFW, /SRV-RES, /COND, COOLDOWN
TRANS	24	/RT, EFW, MFW, SRV-RES, /HPI, COND
TRANS	05	/RT, /EFW, SRV, SRV-RES, /HPI, /COOLDOWN, RHR, HPR
TRANS	26-8	RT, /RCSPRESS, EFW-ATWS

Table 4. System names for the initiating event assessment for LER 382/95-002

System name	Logic
COND	Secondary Heat Removal Using Condensate System Fails
COOLDOWN	RCS Cooldown to RHR Pressure Using Turbine-Bypass Valves, etc.
EFW	No or Insufficient EFW Flow
EFW-ATWS	No or Insufficient EFW Flow During an ATWS
HPI	No or Insufficient HPI System Flow
HPR	No or Insufficient HPR Flow
MFW	Failure of the Main Feedwater System
RCSPRESS	Failure to Limit RCS Pressure to < 2300 psi
RHR	No or Insufficient RHR System Flow
RT	Reactor Fails to Trip During Transient
SRV	SRVs Open During Transient
SRV-RES	SRVs Fail to Reseat

Table 5. Conditional cut sets for higher probability sequences for the initiating event assessment for LER 382/95-002

Cut set No.	Percent Contribution	Conditional Probability*	Cut sets
TRANS Sequence 19		2.1 E-005	
1	48.1	1.0 E-005	EFW-XHE-XA-CCW, COND-XHE-XM
2	37.5	7.8 E-006	EFW-XHE-XA-CCW, COND-PFS-FC-SYS
3	6.8	1.4 E-006	EFW-PMP-CF-ALL, COND-XHE-XM
4	5.3	1.1 E-006	EFW-PMP-CF-ALL, COND-PFS-FC-SYS
5	1.2	2.6 E-007	EFW-XHE-XA-CCW, MFW-VLV-CF-MFIV
TRANS Sequence 18		2.3 E-006	
1	43.6	1.0 E-006	EFW-XHE-XA-CCW, PCS-XHE-XM-CDOWN
2	43.6	1.0 E-006	EFW-XHE-XA-CCW, PCS-VCF-HW
3	6.1	1.4 E-007	EFW-PMP-CF-ALL, PCS-XHE-XM-CDOWN
4	6.1	1.4 E-007	EFW-PMP-CF-ALL, PCS-VCF-HW
TRANS Sequence 24		6.7 E-007	
1	24.0	1.6 E-007	EFW-XHE-XA-CCW, PPR-SRV-OO-1, COND-XHE-XM
2	24.0	1.6 E-007	EFW-XHE-XA-CCW, PPR-SRV-OO-2, COND-XHE-XM
3	18.7	1.2 E-007	EFW-XHE-XA-CCW, PPR-SRV-OO-1, COND-PFS-FC-SYS
4	18.7	1.2 E-007	EFW-XHE-XA-CCW, PPR-SRV-OO-2, COND-PFS-FC-SYS
5	3.4	2.3 E-008	EFW-PMP-CF-ALL, PPR-SRV-OO-1, COND-XHE-XM
6	3.4	2.3 E-008	EFW-PMP-CF-ALL, PPR-SRV-OO-2, COND-XHE-XM
7	2.6	1.8 E-008	EFW-PMP-CF-ALL, PPR-SRV-OO-1, COND-PFS-FC-SYS
8	2.6	1.8 E-008	EFW-PMP-CF-ALL, PPR-SRV-OO-2, COND-PFS-FC-SYS
TRANS Sequence 05		5.7 E-007	
1	21.0	1.2 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-MOV-CF-HLEG, HPR-XHE-NOREC

Table 5. Conditional cut sets for higher probability sequences for the initiating event assessment for LER 382/95-002

Cut set No.	Percent Contribution	Conditional Probability[a]	Cut sets
2	21.0	1.2 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-MOV-CF-HLEG, HPR-XHE-NOREC
3	19.1	1.1 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-XHE-XM
4	19.1	1.1 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-XHE-XM
5	3.8	2.2 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
6	3.8	2.2 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
7	1.9	1.1 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
8	1.9	1.1 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
TRANS Sequence 26-8		4.4 E-007	
1	94.8	4.2 E-007	RPS-XHE-XM-SCRAM, RPS-VCF-FO, EFW-TDP-FC-TDP, EFW-XHE-NREC-ATW
2	2.3	1.0 E-008	RPS-XHE-XM-SCRAM, RPS-VCF-FO, EFW-XHE-XA-CCWA, EFW-XHE-NREC-ATW
Total (all sequences)		**2.5 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 are also given in Table 1.

Table 6. Definitions and probabilities for selected basic events for the condition assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
EPS-DGN-FC-3A	Diesel Generator 3A Fails	4.2 E-002	4.2 E-002		No
EPS-DGN-FC-3B	Diesel Generator 3B Fails	4.2 E-002	4.2 E-002		No
HPI-MDP-CF-ALL	Common Cause Failure of HPI Motor-Driven Pumps	1.0 E-004	1.0 E-004		No
HPI-MDP-FC-B	HPI Motor-Driven Pump-B Train Failures	3.9 E-003	3.9 E-003		No
HPI-MOV-CF-ALL	Common Cause Failure of Injection Motor-Operated Valves	5.5 E-005	5.5 E-005		No
HPR-AOV-CF-SMP	Common Cause Failure of Sump Air-Operated Valves	1.0 E-004	1.0 E-004		No
HPR-HDV-CF-RWSP	Common Cause Failure of RWSP Isolation Hydraulic Discharge Valves	2.0 E-004	2.0 E-004		No
HPR-HDV-OO-RWSPA	RWSP Train A Isolation Hydraulic Discharge Valve Failures	2.0 E-003	2.0 E-003		No
HPR-HDV-OO-RWSPB	RWSP Train B Isolation Hydraulic Discharge Valve Failures	2.0 E-003	2.0 E-003		No
HPR-MOV-CC-INJ1	Loop 1 Hot Leg Isolation Motor-Operated Valve Fails	6.2 E-003	6.2 E-003		No
HPR-MOV-CC-INJ2	Loop 2 Hot Leg Isolation Motor-Operated Valve Fails	6.2 E-003	6.2 E-003		No
HPR-MOV-CF-HLEG	Common Cause Failure of Hot Leg Motor-Operated Valves	1.1 E-003	1.1 E-003		No
HPR-SMP-FC-SUMP	Containment Recirculation Sump Failures	5.0 E-005	5.0 E-005		No
HPR-XHE-NOREC	Operator Fails to Recover the HPR System	1.0 E+000	1.0 E+000		No
HPR-XHE-NOREC-L	Operator Fails to Recover the HPR System During LOOP	1.0 E+000	1.0 E+000		No
HPR-XHE-XM	Operator Fails to Initiate Hot Leg Recirculation	1.0 E-003	1.0 E-003		No

Table 6. Definitions and probabilities for selected basic events for the condition assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPR-XHE-XM-L	Operator Fails to Initiate Hot Leg Recirculation During LOOP	1.0 E-003	1.0 E-003		No
MSS-VCF-HW-ISOL	Ruptured Steam Generator Isolation Failures	1.0 E-002	1.0 E-002		No
MSS-XHE-NOREC	Operator Recovery Action for Steam Generator Isolation	1.0 E-001	1.0 E-001		No
PPR-SRV-CO-TRAN	SRVs Open During Transient	2.0 E-002	2.0 E-002		No
PPR-SRV-OO-1	SRV 1 Fails to Reseat	1.6 E-002	1.6 E-002		No
PPR-SRV-OO-2	SRV 2 Fails to Reseat	1.6 E-002	1.6 E-002		No
RHR-MOV-CF-SUCT	Common Cause Failure of RHR Suction Valves	1.2 E-003	1.0 E+000	TRUE	Yes
RHR-XHE-NOREC	Operator Fails to Recover the RHR System	3.4 E-001	3.4 E-001		No
RHR-XHE-NOREC-L	Operator Fails to Recover the RHR System During a LOOP	3.4 E-001	3.4 E-001		No

Table 7. Sequence conditional probabilities for the condition assessment for LER 382/95-002

Event tree name	Sequence name	Change to CCDP (Importance)	Percent Contribution
SLOCA	03	8.1 E-006	43.5
SGTR	03	4.8 E-006	25.9
TRANS	05	3.5 E-006	19.1
LOOP	05	2.0 E-006	10.9
Total (all sequences)		1.9 E-005	

Table 8. Sequence logic for dominant sequences for the condition assessment for LER 382/95-002

Event tree name	Sequence name	Logic
SLOCA	03	/RT, /EFW, /HPI, /COOLDOWN, RHR, HPR
SGTR	03	/RT, /EFW-SGTR, /HPI, /RCS-SG, SGISOL, /RCSCOOL, RHR
TRANS	05	/RT, /EFW, SRV, SRV-RES, /HPI, /COOLDOWN, RHR, HPR
LOOP	05	/RT-L, /EP, /EFW-L, SRV-L, SRV-RES, /HPI-L, /COOLDOWN, RHR-L, HPR-L

Table 9. System names for the condition assessment for LER 382/95-002

System name	Logic
COOLDOWN	RCS Cooldown to RHR Pressure Using Turbine-Bypass Valves, etc.
EFW	No or Insufficient EFW Flow
EFW-L	No or Insufficient EFW Flow During a LOOP
EFW-SGTR	No or Insufficient EFW Flow During a Steam Generator Tube Rupture event
EP	Failure of Both Trains of Emergency Power
HPI	No or Insufficient HPI System Flow
HPI-L	No or Insufficient HPI System Flow During a LOOP
HPR	No or Insufficient HPR Flow
HPR-L	No or Insufficient HPR Flow During a LOOP
RCS-SG	Failure to Lower RCS Pressure to Less Than Steam Generator Relief-Valve Set Point
RCSCOOL	Failure to Cooldown RCS to Less Than RCS Pressure
RHR	No or Insufficient RHR System Flow
RHR-L	No or Insufficient RHR System Flow During a LOOP
RT	Reactor Fails to Trip During a Transient
RT-L	Reactor Fails to Trip During a LOOP
SGISOL	Failure to Isolate Ruptured Steam Generator Before RWST Depletion
SRV	SRVs Open During a Transient
SRV-L	SRVs Open During a LOOP
SRV-RES	SRVs Fail to Reseat

Table 10. Conditional cut sets for higher probability sequences for the condition assessment for LER 382/95-002

Cut set No.	Percent Contribution	CCDP (Importance)*	Cut sets
SLOCA Sequence 03		8.1 E-006	
1	40.2	3.3 E-006	RHR-XHE-NOREC, HPR-MOV-CF-HLEG, HPR-XHE-NOREC
2	36.5	3.0 E-006	RHR-XHE-NOREC, HPR-XHE-XM
3	7.3	5.9 E-007	RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
4	3.7	3.0 E-007	RHR-XHE-NOREC, HPI-MDP-CF-ALL, HPR-XHE-NOREC
5	3.7	3.0 E-007	RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
6	2.0	1.6 E-007	RHR-XHE-NOREC, HPI-MOV-CF-ALL, HPR-XHE-NOREC
7	1.8	1.5 E-007	RHR-XHE-NOREC, HPR-SMP-FC-SUMP, HPR-XHE-NOREC
8	1.4	1.1 E-007	RHR-XHE-NOREC, HPR-MOV-CC-INJ1, HPR-MOV-CC-INJ2, HPR-XHE-NOREC
SGTR Sequence 03		4.8 E-006	
1	99.7	4.8 E-006	MSS-VCF-HW-ISOL, MSS-XHE-NOREC, RHR-XHE-NOREC
TRANS Sequence 05		3.5 E-006	
1	20.1	7.0 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-MOV-CF-HLEG, HPR-XHE-NOREC
2	20.1	7.0 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-MOV-CF-HLEG, HPR-XHE-NOREC
3	18.2	6.4 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-XHE-XM
4	18.2	6.4 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-XHE-XM
5	3.6	1.3 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
6	3.6	1.3 E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
7	1.8	6.3 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPI-MDP-CF-ALL, HPR-XHE-NOREC
8	1.8	6.3 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPI-MDP-CF-ALL, HPR-XHE-NOREC

Table 10. Conditional cut sets for higher probability sequences for the condition assessment for LER 382/95-002

Cut set No.	Percent Contribution	CCDP (Importance)*	Cut sets
9	1.8	6.3 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
10	1.8	6.3 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
11	1.0	3.5 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, HPI-MOV-CF-ALL, HPR-XHE-NOREC
12	1.0	3.5 E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, HPI-MOV-CF-ALL, HPR-XHE-NOREC
LOOP Sequence 05		2.0 E-006	
1	15.0	3.0 E-007	PPR-SRV-OO-1, RHR-XHE-NOREC-L, HPR-MOV-CF-HLEG, HPR-XHE-NOREC-L
2	15.0	3.0 E-007	PPR-SRV-OO-2, RHR-XHE-NOREC-L, HPR-MOV-CF-HLEG, HPR-XHE-NOREC-L
3	13.6	2.7 E-007	PPR-SRV-OO-1, RHR-XHE-NOREC-L, HPR-XHE-XM-L
4	13.6	2.7 E-007	PPR-SRV-OO-2, RHR-XHE-NOREC-L, HPR-XHE-XM-L
5	3.4	6.8 E-008	EPS-DGN-FC-3A, /EPS-DGN-FC-3B, PPR-SRV-OO-1, RHR-XHE-NOREC-L, HPR-MOV-CC-INJ1, HPR-XHE-NOREC-L
6	3.4	6.8 E-008	EPS-DGN-FC-3A, /EPS-DGN-FC-3B, PPR-SRV-OO-2, RHR-XHE-NOREC-L, HPR-MOV-CC-INJ1, HPR-XHE-NOREC-L
7	3.4	6.8 E-008	/EPS-DGN-FC-3A, EPS-DGN-FC-3B, PPR-SRV-OO-1, RHR-XHE-NOREC-L, HPR-MOV-CC-INJ1, HPR-XHE-NOREC-L
8	3.4	6.8 E-008	/EPS-DGN-FC-3A, EPS-DGN-FC-3B, PPR-SRV-OO-2, RHR-XHE-NOREC-L, HPR-MOV-CC-INJ1, HPR-XHE-NOREC-L
9	2.7	5.4 E-008	PPR-SRV-OO-1, RHR-XHE-NOREC-L, HPR-HDV-CF-RWSP, HPR-XHE-NOREC-L
10	2.7	5.4 E-008	PPR-SRV-OO-2, RHR-XHE-NOREC-L, HPR-HDV-CF-RWSP, HPR-XHE-NOREC-L
11	2.1	4.2 E-008	EPS-DGN-FC-3A, /EPS-DGN-FC-3B, PPR-SRV-OO-1, HPI-MDP-FC-B, RHR-XHE-NOREC-L, HPR-XHE-NOREC-L

Table 10. Conditional cut sets for higher probability sequences for the condition assessment for LER 382/95-002

Cut set No.	Percent Contribution	CCDP (Importance)[a]	Cut sets
12	2.1	4.2 E-008	EPS-DGN-FC-3A, /EPS-DGN-FC-3B, PPR-SRV-OO-2, HPI-MDP-FC-B, RHR-XHE-NOREC-L, HPR-XHE-NOREC-L
13	1.4	2.8 E-008	PPR-SRV-OO-1, HPI-MDP-CF-ALL, RHR-XHE-NOREC-L, HPR-XHE-NOREC-L
14	1.4	2.8 E-008	PPR-SRV-OO-2, HPI-MDP-CF-ALL, RHR-XHE-NOREC-L, HPR-XHE-NOREC-L
15	1.4	2.8 E-008	PPR-SRV-OO-1, HPI-AOV-CF-ALL, RHR-XHE-NOREC-L, HPR-XHE-NOREC-L
16	1.4	2.8 E-008	PPR-SRV-OO-2, HPI-AOV-CF-ALL, RHR-XHE-NOREC-L, HPR-XHE-NOREC-L
17	1.1	2.2 E-008	/EPS-DGN-FC-3A, EPS-DGN-FC-3B, PPR-SRV-OO-1, RHR-XHE-NOREC-L, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC-L
18	1.1	2.2 E-008	/EPS-DGN-FC-3A, EPS-DGN-FC-3B, PPR-SRV-OO-2, RHR-XHE-NOREC-L, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC-L
19	1.1	2.2 E-008	EPS-DGN-FC-3A, /EPS-DGN-FC-3B, PPR-SRV-OO-1, RHR-XHE-NOREC-L, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC-L
20	1.1	2.2 E-008	EPS-DGN-FC-3A, /EPS-DGN-FC-3B, PPR-SRV-OO-2, RHR-XHE-NOREC-L, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC-L
Total (all sequences)		**1.9 E-005**	

[a] The change in conditional probability (importance) is determined by calculating the conditional probability for the period in which the condition existed and given the condition, and subtracting the conditional probability for the same period but with plant equipment assumed to be operating nominally. The conditional probability for each cut set within a sequence is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per hour basis), and t is the duration time of the event (in this case, 8760 h). This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are: $\lambda_{TRANS} = 6.8 \times 10^{-4}$/h, $\lambda_{LOOP} = 8.5 \times 10^{-6}$/h, $\lambda_{SLOCA} = 1.0 \times 10^{-6}$/h, and $\lambda_{SGTR} = 1.6 \times 10^{-6}$/h.

GUIDANCE FOR LICENSEE REVIEW OF PRELIMINARY ASP ANALYSIS

Background

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

Modeling Techniques

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

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

Guidance for Peer Review

Comments regarding the analysis should address:

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

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

Criteria for Evaluating Comments

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

Criteria for Evaluating Additional Recovery Measures

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

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

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

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

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

---

* 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.

Entergy Operations

Entergy Operations, Inc.
P.O. Box B
Killona, LA 70066
Tel 504-464-3120

D. R. Keuter
General Manager
Plant Operations
Waterford 3

W3F1-95-0099
A4.05
PR

July 7, 1995

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

Subject: Waterford 3 SES
Docket No. 50-382
License No. NPF-38
Reporting of Licensee Event Report

Gentlemen:

Attached is Licensee Event Report Number LER-95-002-00 for Waterford Steam Electric Station Unit 3. This Licensee Event Report is submitted in accordance with 10CFR50.73(a)(2)(iv) and 10CFR50.73(a)(2)(x).

Very truly yours,

D.R. Keuter
General Manager
Plant Operations

DRK/RTK/tjs
Attachment

cc: L.J. Callan, NRC Region IV
C.P. Patel, NRC-NRR
G.L. Florreich
J.T. Wheelock - INPO Records Center
R.B. McGehee
N.S. Reynolds
NRC Resident Inspectors Office
Administrator - LRPD

ENCLOSURE 3

NRC FORM 366 (5-92)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Waterford Steam Electric Station Unit 3	05000 382	1 OF 18

TITLE (4)
Reactor Trip and Non-Safety Related Switchgear Fire

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									N/A	05000
06	10	95	95	-- 002 --	00	07	07	95	N/A	05000

OPERATING MODE (9)	1
POWER LEVEL (10)	100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
D.W. Vinci, Licensing Manager	(504) 739-6370

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
X	EA	BKR	G080	Y						

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE)		NO		04	30	96

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On June 10, 1995, a fault recorder at the Waterford Switchyard recorded a single phase fault. Subsequent inspection identified a failed C phase lightning arrestor on a Substation Transformer. At approximately the same time, with the plant in mode 1 at 100% power, a reactor trip occurred, and one of the two independent offsite power sources was lost. Shortly thereafter a report was received from the Turbine Generator Building (TGB) operator of smoke in the TGB switchgear. The A2 bus in the TGB switchgear caught fire causing damage to the bus and surrounding cables and components. The fire damage was limited mainly to the Unit Auxiliary Transformer Feeder Breaker supplying the 4.16 KV A2 non-safety related bus and the adjoining meter cabinet. The root cause of the fire in the A2 switchgear was the improper automatic bus transfer from the Unit Auxiliary Transformer to the Startup Transformer and the root cause of the reactor trip was low Departure from Nucleate Boiling Ratio. The plant will operate on both Startup Transformers until repairs are made to the affected A2 switchgear during the refuel 7 outage. This event did not compromise the health and safety of the public.

REPORTABLE OCCURRENCE

This event resulted in an automatic reactor shutdown and involved a fire which required the declaration of an Unusual Event. Therefore, this event is reportable pursuant to 10CFR50.73(a)(2)(iv) and 10CFR50.73(a)(2)(x).

INITIAL CONDITIONS

At the start of this event on June 10, 1995, Waterford 3 was in mode 1 at 100 percent power. No procedures specific to this event were being performed at the time of this event. There were no Technical Specification (TS) Limiting Conditions for Operation (LCOs) in effect specific to this event at the time of this event. Also, there was no major equipment out of service associated with this event at the time of this event.

EVENT DESCRIPTION

This report is being submitted as a preliminary report because the investigation into the event described in this report is still ongoing. A revision to this Licensee Event Report will be submitted when the investigation is complete.

On June 10, 1995, at 0858 hours, Waterford 3 was operating at approximately 100% power in mode 1 (Power Operation). The following sequence of events describe the major occurrences associated with this event.

08:58:05 The event was initiated by a failed phase C lightning arrestor (EIIS Identifier LAR) on the Waterford Substation #2 Transformer (230 KV/34.5 KV)(EIIS Identifier FK-XFMR). The resulting grid disturbance caused the Sudden Pressure Relay (EIIS Identifier EA-RLY) on the Main Transformer A (EIIS Identifier EA-XFMR) to actuate the Main Generator lockout relays (EIIS Identifier TB-RLY). These relays perform the major protective functions of tripping the generator output breakers (EIIS Identifier EL-BKR), tripping the generator exciter field breaker (EIIS Identifier TL-BKR), tripping the main turbine (EIIS Identifier TA), tripping the Unit Auxiliary Transformer (UAT) secondary breakers (EIIS Identifier EA-BKR), closing the Startup Transformer (SUT) secondary breakers (EIIS Identifier EA-BKR), and tripping the heater drain pumps (EIIS Identifier SJ-P).

The B1 7 KV bus (EIIS Identifier EA-BU) successfully transfers to the SUT. The A1 7KV bus (EIIS Identifier EA-BU) appeared to successfully transfer to the SUT. The A2 and B2 4.16 KV buses (EIIS Identifier EA-BU) attempt to transfer to the SUTs. The B2 bus successfully transfers.

The reactor trips on low Departure from Nucleate Boiling Ratio (DNBR) when Reactor Coolant Pump (RCP)(EIIS Identifier AB-P)

speed of less than 96.5% of rated RCP speed is detected. All Control Element Assemblies (CEAs)(EIIS Identifier AA) insert into the core.

The A2 SUT feeder breaker (EIIS Identifier EA-BKR) tripped on overcurrent. An undervoltage lockout relay (EIIS Identifier EA-27) tripped. The A3 4.16 KV safety bus is deenergized. Emergency Diesel Generator (EDG) A (EIIS Identifier EK-DG) starts and picks up the loads on the safety related bus.

Operators enter OP-902-000 Emergency Entry Procedure.

Feed Water Pump Turbine (FWPT) A (EIIS Identifier SJ-P) overspeed trip is indicated on the sequence of events (SOE) log. The FWPT is believed to have actually tripped when the feedwater pump speed pickups lost power and sent a signal to close the feed water pump governor valve.

08:58:15 Emergency Feedwater Actuation Signal-1 (EFAS-1) Actuated.

08:58:16 EFAS-2 Actuated.

09:05 Main Feedwater Isolation Valve (MFIV) #2 (EIIS Identifier SJ-V) closes on high Steam Generator level (96% Wide Range with 800 psia).

09:06 TGB Operator reports smoke coming from the TGB switchgear (EIIS Identifier EA-SWGR) room. Simultaneously, a report was received by telephone in the control room of smoke coming from the east side of the TGB. This report was initiated by employees working in the Generation Support Building (GSB). The Shift Supervisor (SS) orders two Nuclear Auxiliary Operators (NAOs) to don bunker gear to enter the room and investigate. The Operations Superintendent noticed light white smoke exiting the TGB while reporting to the control room.

09:11 MFIV #1 closes on high Steam Generator level.

09:21 Operations enters OP-902-005 "Loss of Off-Site Power/Station Blackout Recovery Procedure".

09:35 Fire is reported above the A2 switchgear. The SUT A motor operated disconnect (EIIS Identifier EA-MOD) is manually opened by the control room to aid in extinguishing the fire. An NAO and additional fire brigade members attempted to extinguish the fire using Halon, CO2, and dry chemical extinguishers.

09:41 The Hahnville Fire Department is contacted via 911 for support.

09:45 An Unusual Event was declared due to the fire in the protected area lasting longer than 10 minutes.

09:58 Hahnville Fire Department arrives on site.

10:18 Hahnville Fire Department applies water to the insulation above the A2 bus.

10:22 Fire Team Leader reports the fire appears to be extinguished.

11:13 The fire is declared out and reflash watch is set.

11:59 Atmospheric Dump Valves (EIIS Identifier SB-V) are automatically cycling to control Reactor Coolant System (RCS) (EIIS Identifier AB) temperature.

13:52 Waterford 3 exited from the Unusual Event.

14:15 Commenced plant cooldown.

CAUSAL FACTORS

The failed phase 'C' lightning arrestor on the Waterford Substation #2 Transformer (230 KV/34.5 KV) led to three major events: (1) inadvertent

Main Transformer sudden pressure relay 'A' trip, (2) fire in the A2 switchgear, and (3) reactor trip.

LP&L Southern Region Report SY-95-14, which documents the special diagnostic test results on the sudden pressure relays for both 'A' and 'B' main transformers, indicates that the root cause of the inadvertent main transformer sudden pressure relay 'A' trip is that the 'A' main transformer sudden pressure relay time limits were slightly below band.

The root cause of the fire in the A2 switchgear was the improper automatic bus transfer from the UAT to the SUT. This condition caused the A2 bus to temporarily connect the SUT 'A' to the main generator (EIIS Identifier TB-GEN) which then provided power to the grid via the UAT and A2 bus at that time. This is confirmed by the fault tracing from the Waterford switchyard fault recorder. When the UAT breaker attempted to open, it tried unsuccessfully to interrupt the current. During this time, the main generator is rotating faster than the system frequency. Just prior to the time the breaker attempted to open, the Waterford switchyard fault recorder indicated the current flow on the 4 KV bus to be excessive and approaching 180 degrees out of phase. This condition apparently caused the breaker's interruptable rating to be exceeded. When the UAT breaker tried to open, it failed internally creating ionizing gases. The ionizing gases probably created the fire in the A2 switchgear. A preliminary internal investigation, with assistance from General Electric (GE) Engineers, concluded that the most probable cause for the slow opening time of the UAT

breaker was restricted movement of the trip latch roller bearing. The purpose of the trip latch roller bearing is that it provides for a low friction rolling surface for free movement of the trip latch, which collapses the four bar linkage, thereby opening the main contacts. The bearing appeared to be sluggish in movement between the inner and outer bearing races and the bearing surface was found to be covered with hardened grease. This could be attributed to the heat of the fire which would burn the grease on the bearing surface. Inspection of other similar breakers in the plant has determined that they are not covered with the hardened grease. Additionally, the inspection identified that the trip latch roller bearing on the feeder breaker to the 221A bus was difficult to operate. The trip latch roller bearing was subsequently replaced.

The degree of damage to the breaker and surrounding equipment indicates that the fault energy of the breaker was extremely high. With the extent of the damage that occurred during this failure, evidence that would normally be utilized to evaluate the conditions of the circuit breaker is not available. The arc chutes were destroyed, the contact structures were damaged extensively, and the breaker frame and cubicle were also damaged. The main bus and bus compartment experienced severe arcing damage. The center phase (A phase) of the breaker sustained the worst damage. The right phase (B phase, looking at the front of the breaker) arcing contact was hardly damaged, the middle phase arcing contact was totally destroyed, and the left one (C phase) was partially destroyed. The main contacts on all the phases were destroyed.

The root cause of the reactor trip was low DNBR. RCPs 1A and 2A, powered from the A1 bus, slowed down as a result of the decreased voltage. The cause of the decreased voltage is still under investigation. At 96.5% of rated speed, the Core Protection Calculators (CPCs) (EIIS Identifier JC) inserted a 0.1 multiplier to the DNBR calculation. This caused the reactor to trip on low DNBR.

IMMEDIATE CORRECTIVE MEASURES

The immediate corrective measures consisted of extinguishing the fire and placing the plant in a safe condition. The following seven actions were also taken.

1.) Damage Assessment

On June 10, 1995, the A2 bus in the Turbine Generator Building Switchgear caught fire causing damage to the bus and surrounding cables and components. The initial assessment of the fire determined that it originated in the A2 bus #1 cubicle. The fire caused major damage to the #1 & #2 cubicles and destroyed approximately 10 feet of the feeder cables. Cubicle #1 contained the 4160 volt feeder from the Unit Auxiliary Transformer (UAT) and Cubicle #2 contained the Potential Transformer and associated relays and components. There was general smoke and slight heat damage to the exterior of the remaining cubicles in the A2 bus. In

addition, there was external heat damage to the jackets of four (4) of the fifteen (15) feeder cables from the Start Up Transformer (SUT) to the A2 bus. There were also burn marks on the conduit of the cables which supply 6.9 KV to the Reactor Coolant Pump (RCP) 1A and 2A motors.

2.) Bus Repairs and Testing

The cables from the UAT A were damaged to such an extent that they could not be repaired in a short period of time. Efforts were thus concentrated on restoring the SUT A feeder to the A2 bus. The cleanup started as soon as Operations tagged out the electrical power to the A2 bus. The breakers and relays were removed from the cubicles in the A2 bus to clean and calibrate the components and perform Preventive Maintenance (PM) tasks. In addition, the copper buses in cubicles #1 & #2 were removed from the A2 bus. Cubicles #1 & #2 and associated components of the A2 bus were removed and TAR 95-006 was initiated to isolate the cubicles from the rest of the bus. The breakers and relays were also removed from the cubicles in the A1 bus to clean and calibrate the components and perform PM tasks. After completion of the above mentioned work the A1 and A2 buses were ready for reenergization.

3.) Cable Repairs and Testing

The cables from the SUT A to the A2 bus were meggered, power factor tested and vendor (CM Technologies Corporation) ECAD tested with acceptable

results. The ECAD testing performs a series of tests to verify continuity, insulation integrity and identify any fault locations in the cables. The damaged sections of the outer jackets were removed and after discussions with the cable vendor (Okonite), a Raychem kit (heat shrink) was recommended and installed to wrap the cables. The same series of tests were once again performed on the cables to verify acceptable results. The cables from the A1 bus to the RCP 1A & 2A and Condensate Pump A & C motors (EIIS Identifier SD-P-MO) were meggered and ECAD tested with acceptable results. The above cables were tested because they either had fire damage or were suspected of having fire damage due to their close proximity to the fire. The test results for the cables that were suspect were evaluated by Waterford Engineering, ECAD Field Engineers, and Okonite Service Representatives. Based on these evaluations the cables were determined to be acceptable.

4.) Transformer Repairs and Testing

Main Transformer (MT) A, UAT A, and SUT A were power factor and megger tested with acceptable results. The Sudden Pressure (SP) relays for MT A & B were also tested with acceptable results. However, the SP relay for MT A, which caused the Main Turbine Trip, was found to be slightly more sensitive. The SP relays on the Main Transformers have been disconnected. These transformers are still protected by two differential relaying schemes. In addition, oil samples were analyzed for the six (6) transformers (2 MTs, 2 UATs, and 2 SUTs) with acceptable results.

5.) Main Generator Testing

Potential damage to the Main Generator due to the event was discussed with Westinghouse to determine what testing, if any, would be required. Based on these discussions, Waterford Engineering determined that Main Generator testing was not required. However, the Main Generator Exciter was tested by Westinghouse to ensure proper operation of the Exciter. At the conclusion of the testing it was determined that the parameters were within limits. Five fuses were found blown on the exciter wheel. However, the diodes associated with the blown fuses were found to be functional.

6.) Review of Maintenance Practices

An initial review by General Electric of the Waterford 3 "4.16 KV GE Magna-Blast Breaker" maintenance procedure (ME-04-131) used for the UAT-A2 feeder breaker concluded that our maintenance practices were adequate. Preventive Maintenance (PM) is performed on a three year interval and was performed on the following dates: 03-26-84, 04-27-84, 02-08-87, and 10-26-92.

A PM task was scheduled for 11-16-89. However, since the PM could not be performed at that time, the PM was postponed until refuel in 1992. In addition, the only Corrective Maintenance that was performed on the breaker dealt with the replacement of a light socket.

7.) Event Review Team

On June 11, 1995, an Event Review Team was assembled to investigate the events surrounding the reactor trip, fire, and partial loss of offsite power that occurred on June 10, 1995, at Waterford 3. As a result of this team's efforts, an Event Review Team Root Cause Analysis Report was prepared.

ACTIONS TO PREVENT RECURRENCE

Four corrective actions to prevent recurrence have been identified:

1. Additional evaluations on the design of the Electrical Distribution System will be performed to determine the adequacy of the design.

2. An in-depth review will be conducted on the current maintenance practices associated with Waterford 3 Maintenance Procedure ME-04-131 "4.16 KV GE Magna-Blast Breaker" used for the Unit Auxiliary Transformer A2 bus feeder breaker.

3. Guidance was provided to the Fire Brigade on the identification of a fire in the absence of a visible flame. Waterford 3 placed a Standing Instruction in the control room subsequent to the June 10, 1995, fire in the protected area. The Standing Instruction states that a fire should be declared even without the actual observance of flames should

the smoke and/or heat be of such degree that the use of protective gear and/or Self Contained Breathing Apparatus (SCBA) equipment is considered.

4. The reason for the loss of the A1 bus will continue to be investigated.

Also, Waterford 3 will operate on both Startup Transformers until the next refuel outage. Design Engineering-Electrical/I&C has determined that operating from the Startup Transformers will have no adverse impact on normal plant operations. This determination is based on calculation EC-E91-050 "Degraded Voltage Relay Setpoint & Plant Load Study". In addition, several Condition Reports were initiated to implement the Waterford 3 Corrective Action Program for minor problems associated with this event that were identified by the Event Review Team.

SAFETY SIGNIFICANCE

Loss of offsite power (LOOP) is assumed in the limiting safety analysis (FSAR Chapter 15 transients and accidents), if the LOOP makes the consequences of the event worse. The Loss of Normal AC Power analysis (FSAR Sub-section 15.2.1.4), which assumes loss of all offsite power (and thus simultaneous losses of load, feedwater, reactor coolant pumps, circulating water pumps (EIIS Identifier MN-P), and condensate pumps) bounds the loss of the A2 bus. This is, therefore, an analyzed event. All safety systems operated as designed throughout this event. The

consequences of this event are less severe than the previously analyzed Loss of Normal AC Power event.

The impact of this event is on the probability of core damage, an area addressed by the Probabilistic Safety Assessment (PSA). In Supplement 4 to Generic Letter 88-20, the NRC requested each licensee to perform an Individual Plant Examination of External Events (IPEEE) to address the severe accident (core damage) risk posed by external events (which include fires). The risk posed by a fire in the TGB switchgear room was identified and addressed in the Waterford 3 Fire IPEEE, currently being completed. The fire that occurred in the UAT to A2 bus breaker is one of the most severe TGB switchgear fires that can reasonably be expected, since it involved a very high fault current in a large breaker, producing a fully-involved switchgear fire with major insulation combustion.

Although the heat release rate was undoubtedly large (estimated to be much larger than in most switchgear fires), severe damage was limited to two cubicles on the A2 bus and the cables in the UAT A to A2 bus duct. Minor damage occurred to the SUT A to A2 bus duct and to adjacent A2 and A1 switchgear cubicles. The B train of offsite power (SUT B to B2 and its bus duct tie to B3) was not affected. The two trains of offsite power are well separated: the bus ducts are physically separated by about 20 feet and the switchgear cubicles themselves are separated by a concrete block radiant shield. The degree of separation and the fact that this fire had no effect

on the B train of offsite power make the possibility of a TGB switchgear fire that could fail both trains of offsite power remote.

The risk of core damage immediately after the fire or during the time when the plant is in a degraded condition (loss of the A train of offsite power, with the A3 bus powered by EDG A) was on the order of the average yearly core damage risk for all causes. When the plant tripped, continued feedwater flow was necessary for decay heat removal. The trip put a demand on the plant to respond to the ensuing transient. If the main feedwater pumps were lost (as eventually occurred), Emergency Feedwater (EFW; EIIS Identifier BA) would be needed to maintain decay heat removal. There was a small probability that EFW would have failed to start, and that the Startup Feedwater (EIIS Identifier SJ) pump would also have failed. Once EFW started, it was unlikely that all three pumps would fail to run (including pump A failure as a result of EDG A failure).

The average annual frequency of a severe fire in the TGB switchgear room can be estimated as 0.125 per year (1 event in about 8 years on-line). This conservatively assumes that a fire such as this 6/10/95 event will happen on average every 8 years, which is about an order of magnitude higher than the frequency expected from generic data. If this conservatively high fire frequency is used in the Fire IPEEE analysis, with the realistic assumption (based on the damage observed in this event) that a TGB switchgear fire cannot fail both offsite power trains, the TGB switchgear fire scenario is of relatively low average risk (the average

probability of core damage is estimated to be about 2E-6 per year, or about 10 times lower than the overall average yearly core damage probability). The primary reason for the low risk is the availability of multiple, diverse feedwater sources and the availability of offsite power B and both EDGs. This low core damage risk indicates that the plant is not vulnerable to core damage as a result of an event such as this.

This core damage probability estimate used a model applicable to post-trip, Mode 3 conditions, when feedwater to a steam generator is required for decay heat removal. Once the plant was on Shutdown Cooling (EIIS Identifier BP), the risk was lower than estimated because the lower decay heat level, pressure, and temperature would give operators much more time to respond to possible Shutdown Cooling failures before core damage would occur.

Since loss of offsite power is an analyzed event, the fire on the A2 bus does not affect the conclusions of the safety analysis. All safety systems operated as designed throughout this event. This event is addressed in the Waterford 3 Fire IPEEE analysis, currently being completed. The average annual core damage risk for a TGB switchgear fire (including this event) is very low, indicating that Waterford 3 is not vulnerable to core damage from an event such as this. Based on the above, the health and safety of the public was not compromised.

SIMILAR EVENTS

Waterford 3 received an operating license authorizing full power operation in 1985. A review of Licensee Event Reports (LERs) dating back to that time revealed no pattern of similar recurring events. However, four LERs documenting grid disturbances that affected the operation of Waterford 3 were identified. These four LERs are LER-85-054-00, LER-90-003-01, LER-90-012-00, and LER-91-013-01.