

# Preliminary Precursor Analysis

Accident Sequence Precursor Program -- Office of Nuclear Regulatory Research

Indian Point, Unit 2	Manual reactor trip following steam generator tube failure	
Event Date 02/15/2000	LER 247/00-001-00	CCDP = $8.0 \times 10^{-5}$

## Event Summary

In early February 2000, primary-to-secondary tube leakage - ranging from one to four gallons per day (gpd) - was detected in steam generator (SG) No. 24. On February 15, 2000, while the unit was operating at 99% power, SG leakage rapidly increased from 4 gpd to greater than 75 gallons per minute (gpm). The reactor was manually tripped 13 minutes later, and the faulted steam generator was isolated one hour after the reactor trip. In addition to shutting down the reactor and isolating the affected steam generator, the plant operators also took appropriate action to cool down and depressurize the reactor coolant system to prevent leakage into the faulted steam generator. The highest leak rate which was observed during the event (about 146 gpm) occurred prior to the reactor trip. This maximum flow rate exceeded the capacity of two positive displacement charging pumps (98 gpm/pump).

Safety injection was manually initiated 1.5 hours after the trip in response to an excessive cooldown rate that caused a rapid reduction in the pressurizer level. Safety injection was reset and the reactor pressure was reduced to below main steam line safety valve setpoints within 30 minutes following safety injection initiation.

Plant cooldown was re-commenced about four hours after the reactor trip by using the intact steam generators and the main condenser. The residual heat removal (RHR) system was placed in-service and the primary-to-secondary tube leakage was terminated about 17 and 19 hours, respectively, following the reactor trip. The plant cooldown continued and the plant entered cold shutdown 24 hours following the tube failure. (Refs. 1 and 2)

*Complications.* A number of problems involving equipment and operator actions complicated the event response and delayed achieving the cold shutdown condition (Ref. 2).

- Rapid initial reactor coolant system (RCS) depressurization resulted in manual safety injection (SI) initiation.
- Main condenser vacuum was lost twice for durations of one and two hours, respectively, during cooldown.
- The isolation valve seal water system became inoperable during the event, which required operator response and an entry into a Technical Specification Limiting Condition for Operation statement.
- Prior to placing the overpressure protection system in service, it was necessary to enter the containment to install a temporary nitrogen supply for the pressurizer power-operated relief valve (PORV) to compensate for a design deficiency.

- Problems with the auxiliary spray valve lineup delayed final depressurization.
- Problems with the component cooling water (CCW) valve lineup to the RHR heat exchanger delayed the pre-operational RHR heatup.
- Some SG leak rate monitoring equipment was degraded for an extended period of time, which limited the amount of SG leak rate information available to the operators prior to the event.
- Conflicting requirements between an emergency operating procedure and the special operating procedure for the RHR system caused a one-hour delay in bringing the RHR system online.
- Leakage occurred past the main steam isolation valve (MSIV) on the faulted steam generator.

As the result of the last two conditions, the pressure in the faulted steam generator slowly decreased below RCS pressure due to ambient heat loss and normal post-trip steam losses through main steam isolation boundaries. The gradual pressure loss in the faulted steam generator caused a slow primary-to-secondary leakage that gradually overfilled the steam generator and almost caused filling of the main steam line at 19 hours following the reactor trip.

Additional information regarding the condition of the steam generator tubes and the internal stresses on the tubes is contained in References 3 and 4.

## Analysis Results

- **Total conditional core damage probability (CCDP):** The estimated total CCDP for the steam generator tube failure at Indian Point 2 is  $8.0 \times 10^{-5}$ . This estimate is based on the combined results from two analyses: one case involving a spontaneous tube rupture scenario and the other involving a tube failure with low leak rate scenario (see Modeling Assumptions–Assessment). The results show the following:
  - The total CCDP is dominated by the contribution from a spontaneous steam generator tube rupture ( $7.7 \times 10^{-5}$  - 96%) with a relatively high flow rate ( $> 225$  gpm).
  - The contribution from a steam generator tube failure with lower associated primary-to-secondary leak rates (75 - 225 gpm), as were observed during the Indian Point 2 event (maximum leak rate = 146 gpm), is a relatively small contributor ( $2.9 \times 10^{-6}$  - 4%) compared to the contribution from the large tube rupture scenario.
- **Dominant sequence.** Sequence 11 for the spontaneous steam generator tube rupture (SGTR) scenario accounts for 66% of the total contribution to the CCDP. The steam generator rupture failure event tree with the dominant sequence highlighted is provided in Fig. 1.

The events in Sequence 11 involve:

- Spontaneous rupture of a steam generator tube (with an associated leak rate >225 gpm),
- Successful reactor trip,
- Successful response of the auxiliary feedwater system,
- Successful response of the high-pressure injection system,
- Failure of the operators to lower primary side pressure below the steam generator safety/relief valve setpoint, and
- Failure of the operators to depressurize the RCS, given that a steam generator atmospheric dump valve or safety/relief valve opened.

The three minimum cutsets in Sequence 11 (see Table 3) consist solely of human error-related failures involving the following key operator actions:

- Diagnose steam generator tube failure to start procedures.
- Throttle high-pressure injection to reduce pressure.
- Initiate RCS depressurization below steam generator relief valve setpoints (to stop primary-to-secondary leakage).
- Depressurize the RCS below steam generator relief valve setpoints following a relief valve lift.

● **Tables of results:**

- The conditional probabilities of the dominant sequences are shown in Table 1.
- The logic for the dominant sequences in the Indian Point 2 SGTR event tree is provided in Table 2a.
- Table 3 provides the conditional cut sets for the dominant sequences.

## Modeling Assumptions

- **Assessment:** The modeling approach used in analyzing this event is the same one used by the NRC staff in the Significance Determination Process (SDP) evaluation of the event reported in Reference 5.<sup>1</sup> Discussions with staff experts indicated that, considering the conditions associated with the flaw that existed in Indian Point 2 SG No. 24 at the time, either a partially opened tube failure with low leak rates or a spontaneous, fully open tube rupture with related high leak rates could have occurred when the degraded tube failed.

Basically, this approach split the conditional probability of steam generator tube rupture size given a steam generator tube failure into two parts, according to break flow rates. In this approach, tube failures whose associated flow rates exceed the flow of one charging pump, but are less than the full charging capacity are grouped into a different conditional probability category than the tube failures that result in leak rates that

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<sup>1</sup> Indian Point 2 had operated with the degraded steam generator tube in a degraded condition for some time prior to the February 15, 2000 failure. The risk associated with a potential tube failure induced by a steam generator depressurization transient event (e.g., a main steam line break) was considered in detail in Reference 5. This issue was also examined relative to the degraded steam generator tube at Indian Point 2 in the precursor analysis of the reactor trip, ESF actuation, and subsequent loss of 480 Volt bus 6A, which occurred at Indian Point 2 on August 31, 1999, as reported in LER No. 247-99-015.

exceed full charging capacity. This approach is appropriate when considering events that have different steps and/or event response times for the mitigation processes or substantially different probabilities for success of similar steps to be treated separately.

The model which was used in this analysis was the Indian Point 2, Revision 2QA SPAR Model, dated 04/14/1998 (Ref. 6). The CCDP associated with each of the two scenarios was quantified using the SGTR event tree from this model with appropriate input changes to the human error probabilities to reflect the time available for operator response to the specific scenario considered.

- **Initiating Event Frequency Changes.** As explained in the detailed discussion of the SDP evaluation of this event presented in Reference 5, the NRC staff used the existing base of operating experience to estimate the conditional probability that the steam generator tube failure would result in each of the two different leak rate ranges. Reference 7 contains a summary of the operating experience associated with steam generator tube failures. Considering the type of steam generator design, location of the tube flaw, the tube failure mechanism, and other relevant conditions, there are two previous steam generator tube ruptures which are pertinent to the one that occurred at Indian Point 2.

The two similar tube rupture events occurred at Surry 2 in 1976 and at the Doel Unit 2 reactor in Belgium in 1979. The Doel 2 tube failure resulted in a leak rate of 135 gpm; the tube failure at Surry 2 had an associated leak rate of 330 gpm. The operating experience data indicate that tube failures of the specific type that occurred at Indian Point 2 (resulting in leak rates in the range 75-225 gpm) occur approximately twice as often as tube failures with relatively higher leak rates (>225 gpm).

Based on this result, in Reference 5, the staff used a conditional probability split of 0.67 for steam generator tube ruptures with associated leak rates between 75-225 gpm and 0.33 for tube ruptures with associated leak rates > 225 gpm. These probabilities were used in the subject analysis (i.e., in each case, the initiating event probability IE-SGTR was set to 1.0 in the event assessment and the CCDP calculated was multiplied by 0.67 for the low leak rate case and by 0.33 for the high leak rate case).

- **Basic Event Probability Changes.** Changes to basic events were made for both cases—spontaneous tube rupture scenario and the tube failure with low leak rate scenario—to reflect the event condition analyzed. Table 4 provides the basic events which were modified to reflect the spontaneous tube rupture scenario.

Since the CCDP contribution from the SG tube failure scenario with an associated low leak rate was relatively insignificant compared with the contribution from the spontaneous tube rupture scenario, only a brief discussion of the analysis of this scenario is presented here for completeness. The bases for the changes for both cases are as follows:

- o *Operator fails to diagnose SGTR and start procedures (spontaneous tube rupture scenario)* - In contrast to the SG tube failure with relatively low leak rate case, the human error probabilities associated with the key operator actions for a spontaneous SGTR with associated leak rate > 225 gpm are higher than the generic nominal human error probabilities to reflect the shorter times available for the operators to respond to the initiating event. Since the default human error values for an SGTR in

the Revision 3i SPAR model are those associated with a spontaneous, fully open tube rupture, only one human error-related basic event was modified to reflect actual event conditions—RCS-XHE-DIAG, *Operator fails to diagnose SGTR and start procedures*. This failure probability was estimated using the human reliability analysis methodology contained in the Revision 3i SPAR models (Ref. 8)

The tube leakage in the faulted steam generator was being monitored for some time prior to the event (since September 1998). Given that the operators had previous knowledge of a faulted tube, the performance shaping factor (PSF) multiplier associated with the “complexity” PSF was changed from 2 (moderately complex) to 1 (nominal). Considering the operational and procedural problems that were encountered during the actual event and recovery at Indian Point 2 (see the Event Summary section, above) PSF level for “work processes” was changed from “good” (0.8--the generic value used in the SPAR-3i models) to “nominal” (1.0). This adjustment was based on the operating and procedural problems that were encountered during the operators’ response to the event and the attempt to bring the unit to a safe shutdown condition, which delayed the plant cooldown and depressurization to the RHR initiation setpoint. Given these adjustments, The probability that the operators fail to diagnose the tube rupture and start SGTR procedures was changed from  $8.0 \times 10^{-3}$  to  $5.0 \times 10^{-3}$ .

- o *Human error probabilities (steam generator tube failure with low leak rate scenario)* - If not properly mitigated, the effects of a steam generator tube failure with a leak rate in the range 75-225 gpm with respect to core damage are the same as a spontaneous SGTR with an associated leak rate >225 gpm. However, the smaller leak rates from the tube failure case result in longer response times available for operators to take mitigating actions than would be available in the case of a spontaneous, fully open tube rupture. Consequently, for the low leak rate scenario, the failure probabilities of key operator actions were decreased from nominal values to account for the longer operator response times that were available during the actual event.

Several operating and procedural problems were encountered that delayed RCS cooldown and RHR initiation. These were considered by adjusting the amount of time which is available prior to refueling water storage tank (RWST) depletion. However, with the capability to provide makeup to the RWST, the available time can be extended even further. Hence, no changes were made to the model for the low leak rate scenario to consider these delays.

- o *Other equipment problems.* Other miscellaneous equipment problems were identified during the event (see Event Summary section). These problems did not affect safety-related equipment needed for plant recovery. Condenser vacuum was lost two times during plant cooldown due to problems with the operation of the automatic steam supply pressure control valve to the steam jet air ejectors, and a condensate vacuum pump. The analysis conservatively assumed that secondary cooling via the main condenser and main feedwater system (since the condenser is needed to supply condensate) was failed during the entire duration of the event (PCS-CNDSR-HW, MFW-SYS-TRIP, and MFW-SYS-UNAVAIL were set to TRUE). However, these assumptions did not change the overall risk result.
- o *Non-recovery probabilities for individual sequences* - Table 4 shows the non-recovery probabilities of selected sequences for the spontaneous tube rupture

scenario. For the scenario involving the tube failure with low leak rate, the non-recovery probabilities for select sequences were modified to account for the refill capability of the RWST. Indian Point 2 has makeup capability to the RWST via two primary water pumps, each pump with a 120 gpm capacity (Ref. 10). From the Indian Point 2 individual plant examination (Table 3.3-7, Ref.9), the failure probability for RWST refill is  $1.2 \times 10^{-3}$ . Since RWST refilling operation is a procedurized normal plant evolution,<sup>2</sup> this non-recovery probability is reasonable. Further, more than 25 hours (= 345,000 gallons/225 gpm) is available to establish makeup prior to RWST depletion during a tube failure with leak rates less than 225 gpm.

- **Model Update:** The Revision 2QA SPAR model for Indian Point 2 was updated to incorporate updated system/component failure data obtained from reviews of recent operating experience, to modify fault trees associated with secondary heat removal, and to modify the non-recovery probability of the inboard isolation valve to the RHR suction line during a SGTR. These updates are independent of the actual event analyzed. The bases for these updates are described in the footnotes to Tables 2b and 4.

## References

1. LER 247/00-001-00, "Manual Reactor Trip Following Steam Generator Tube Rupture," dated March 17, 2000.
2. NRC Augmented Inspection Team Report No. 05000247/2000-002, April 28, 2000.
3. LER 247/00-003-00, "Steam Generators 21 and 24 Classified as Category C-3 per Technical Specification Table 4.13-1," dated April 24, 2000.
4. LER 247/00-005-00, "Steam Generator Primary to Secondary Side Design Pressure Differential Exceeded," dated May 22, 2000.
5. "Significance Determination Risk Assessment for Indian Point Unit 2 Steam Generator Inspection Findings - Review of Licensee Response to Initial Significance Determination and Final Staff Analysis," Enclosure No. 2 to letter dated November 20, 2000, from Hubert J. Miller, USNRC, to John Groth, Consolidated Edison.
6. Idaho National Engineering and Environmental Laboratory, "Simplified Plant Analysis Risk (SPAR) Model for Indian Point Unit 2," Revision 2QA, April 1998.
7. P. E. MacDonald, et al., "Steam Generator Tube Failures," NUREG/CR-6365, April 1996.
8. J. C. Byers, et al., "Revision of the 1994 ASP HRA Methodology (Draft)," INEEL/EXT-99-00041, January 1999.
9. Indian Point Station, Unit 2, Individual Plant Examination, dated August 12, 1992.
10. Indian Point Station, Unit 2, Updated Final Safety Analysis Report.

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<sup>2</sup> D. Marksberry (U.S. NRC), Private communications with J. Trapp (U.S. NRC, Region I), July 24, 2000.

11. F. Marshall, A. Azarm, and D. Rasmuson, "Common-Cause Failure Database and Analysis System," NUREG/CR-6286, Volumes 1-4, June 1998.
12. S. A. Eide, et. al., "Reliability Study: Westinghouse Reactor Protection System, 1984-1995," NUREG/CR-5500, Vol. 2, April 1999.
13. R. J. Belles, et al., "Precursors to Potential Severe Core Damage Accidents: 1996," NUREG/CR-4674, Vol. 25, December 1997.

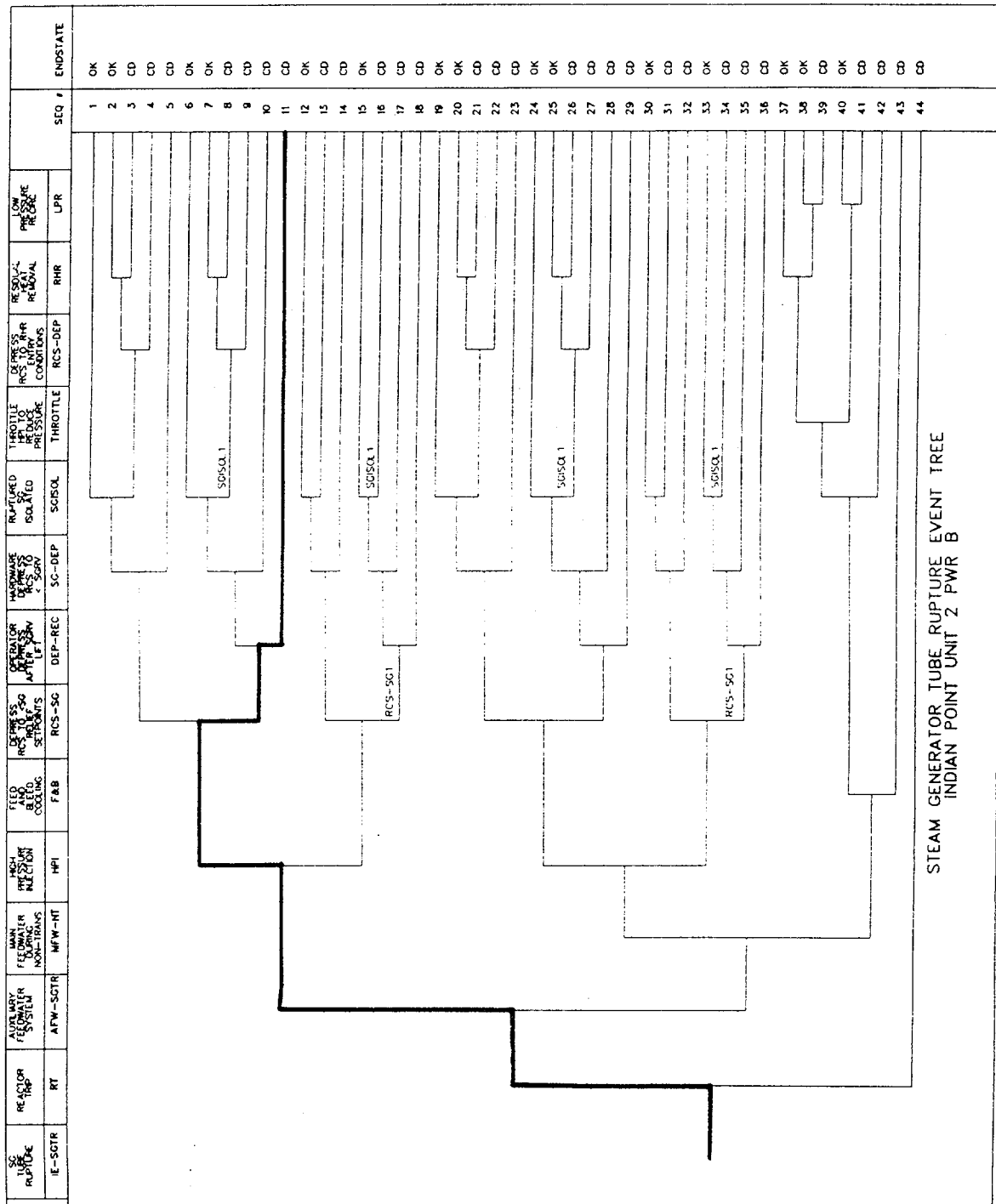


Figure 1. Steam Generator Tube Rupture Event Tree



**Table 1.** Conditional probabilities associated with the highest probability sequences.

Event tree name	Sequence no.	Conditional core damage probability (CCDP)	Percent contribution
SGTR	11	5.3E-005	66.3
SGTR	03	1.7E-005	21.3
<b>Total (all sequences)<sup>(1)</sup></b>		<b>8.0E-005</b>	<b>100</b>

1. Total CCDP includes all sequences (including those not shown in this table).

**Table 2a.** Event tree sequence logic for dominant sequences.

Event tree name	Sequence no.	Logic ("P" denotes success; see Table 2b for top event names)
SGTR	11	/RT /AFW-SGTR /HPI RCS-SG DEP-REC
SGTR	03	/RT /AFW-SGTR /HPI /RCS-SG /SG-DEP SGISOL /RCS-DEP RHR

**Table 2b.** Definitions of top events listed in Table 2a.

AFW-SGTR	No or insufficient auxiliary feedwater flow during steam generator tube rupture (SGTR)
DEP-REC	Operator fails to depressurize reactor coolant system (RCS) given steam generator (SG) atmospheric dump valve (ADS) or safety relief valve opened
HPI	No or insufficient flow from the high-pressure injection system
RCS-DEP <sup>(1)</sup>	Failure to cooldown RCS to < residual heat removal (RHR) operating pressure
RCS-SG	Operator fails to lower RCS pressure to < SG relief valve setpoint
RHR	No or insufficient flow from the RHR system
RT	Reactor fails to trip during transient
SG-DEP	Hardware fails to lower RCS pressure to < SG relief valve setpoint
SGISOL	Failure to isolate ruptured SG before refueling water storage tank depletion

Note:

1. Fault tree modified to reflect the use of atmospheric dump valves as an alternate success path for secondary heat removal. The Revision 2QA SPAR model for Indian Point 2 considers the main condenser as the only means for secondary heat removal for cooldown to residual heat removal (RHR) operating conditions. The success criteria assume 2-out-of-3 atmospheric dump valves (ADVs) are required to remove decay heat for depressurization, given that the fourth valve associated with the faulted steam generator is not available (Ref. 9). Each ADV can pass 2.5% of rated steam flow (Ref. 10). Fault Tree RCS-DEP was modified as follows:  
RCS-DEP = [PCS-XHE-XM-RCOOL AND {(PCS-ADV-HW OR PCS-ADV-CCF) AND PCS-CNDSR-HW}]  
The basic events are defined in Table 4.

**Table 3.** Conditional cut sets for the dominant sequence. (See Table 4 for definitions and probabilities for the basic events.)

CCDP	Percent Contribution	Minimum cut sets (of basic events)		
Event Tree: SGTR, Sequence 11				
3.3E-005	62.5	RCS-XHE-RECOVER	RCS-XHE-DIAG	SGTR-11-NREC
1.3E-005	25.0	RCS-XHE-RECOVER	RCS-XHE-XM-SG	SGTR-11-NREC
6.7E-006	12.5	RCS-XHE-RECOVER	HPI-XHE-XM-THRTL	SGTR-11-NREC
5.3E-005	Total			
Event Tree: SGTR, Sequence 03				
3.4E-006	20.5	RHR-MOV-CC-SUCA	MSS-VCF-HW-ISOL	SGTR-03-NREC
3.4E-006	20.5	RHR-MOV-CC-SUCB	MSS-VCF-HW-ISOL	SGTR-03-NREC
3.4E-006	20.5	RHR-MOV-OO-RWST	MSS-VCF-HW-ISOL	SGTR-03-NREC
2.3E-006	13.7	RHR-XHE-XM	MSS-VCF-HW-ISOL	SGTR-03-NREC
6.8E-007	4.1	RHR-MOV-CC-SUCA	MSS-XHE-XM-ERROR	SGTR-03-NREC
6.8E-007	4.1	RHR-MOV-OO-RWST	MSS-XHE-XM-ERROR	SGTR-03-NREC
6.8E-007	4.1	RHR-MOV-CC-SUCB	MSS-XHE-XM-ERROR	SGTR-03-NREC
6.4E-007	3.8	RHR-MDP-CF-ALL	MSS-VCF-HW-ISOL	SGTR-03-NREC
4.5E-007	2.7	RHR-XHE-XM	MSS-XHE-XM-ERROR	SGTR-03-NREC
3.0E-007	1.8	RHR-MOV-CF-DIS	MSS-VCF-HW-ISOL	SGTR-03-NREC
1.7E-005	Total <sup>1</sup>			

1. Total CCDP includes all cutsets (including those not shown in this table).

**Table 4.** Definitions and probabilities for selected basic events.

Event Name	Description	Probability/ Frequency (per hour)	Modified
HPI-XHE-XM-THRTL	Operator Fails to Throttle High-Pressure Injection to Reduce Pressure	$1.0 \times 10^{-3}$	Yes <sup>1</sup>
IE-LOOP	Initiating Event—Loss of Offsite Power	0.0	Yes <sup>2</sup>
IE-SGTR	Initiating Event—Steam Generator Tube Rupture (SGTR)	1.0	Yes <sup>2</sup>
IE-LOCA	Initiating Event—Loss-of-Coolant Accident	0.0	Yes <sup>2</sup>
IE-TRANS	Initiating Event—Transient (Other than Above)	0.0	Yes <sup>2</sup>
MSS-VCF-HW-ISOL	Faulted Steam Generator Isolation Hardware Failures	$1.0 \times 10^{-2}$	No
MSS-XHE-XM-ERROR	Operator Fails to Isolate Faulted Steam Generator	$2.0 \times 10^{-3}$	Yes <sup>1</sup>
PCS-ADV-CCF	Common-Cause Failure of 2-out-of-3 Atmospheric Dump Valves to Open	$2.6 \times 10^{-6}$	New <sup>3</sup>
PCS-ADV-HW	Atmospheric Dump Valve Hardware Failures (2 of 3 valves)	$3.0 \times 10^{-10}$	New <sup>3</sup>
PCS-CNDSR-HW	Main Condenser Hardware Failures	True	New <sup>3</sup>
PCS-XHE-XM-RCOOL	Operator Fails to Initiate Reactor Coolant System (RCS) cooldown to Residual Heat Removal (RHR)	$1.0 \times 10^{-3}$	No
RCS-XHE-DIAG	Operator Fails to Diagnose SGTR to Start Procedures	$5.0 \times 10^{-3}$	Yes <sup>4</sup>
RCS-XHE-RECOVER	Operator Fails to Depressurize RCS below Steam Gen. Relief Setpoints Following a Relief Valve Lift	$2.0 \times 10^{-2}$	Yes <sup>1</sup>
RCS-XHE-XM-SG	Operator Fails to Initiate RCS Depressurization	$2.0 \times 10^{-3}$	Yes <sup>1</sup>
RHR-MDP-CF-ALL	RHR Pump Common Cause Failures	$5.6 \times 10^{-4}$	No
RHR-MOV-CC-SUCA	Failure of RHR Suction Motor-Operated Valve "A"	$3.0 \times 10^{-3}$	No
RHR-MOV-CC-SUCB	Failure of RHR Suction Motor-Operated Valve "B"	$3.0 \times 10^{-3}$	No
RHR-MOV-CF-DIS	Common-Cause Failure of RHR Discharge Motor-Operated Valves	$2.6 \times 10^{-4}$	No
RHR-MOV-OC-VLV	RHR Discharge Valve Fails	$1.4 \times 10^{-4}$	No
RHR-MOV-OO-RWST	Residual Heat Removal/Refueling Water Storage Tank Isolation Motor-Operated Valve Fails	$3.0 \times 10^{-3}$	No
RHR-XHE-XM	Operator Fails to Initiate RHR System	$2.0 \times 10^{-3}$	Yes <sup>1</sup>
RPS-BKR-FC-FTO	Reactor Protection System Breakers Fail to Open	$1.6 \times 10^{-6}$	Yes <sup>5</sup>
RPS-VCF-FO-ELEC	Control Rod Drives Remain Energized	$1.4 \times 10^{-5}$	Yes <sup>5</sup>
RPS-VCF-FO-MECH	Control Rod Assemblies Fail to Insert	$1.2 \times 10^{-3}$	Yes <sup>5</sup>
RPS-XHE-ERROR	Operator Fails to De-Energize RPS Motor-Generator Sets	$1.0 \times 10^{-3}$	Yes <sup>5</sup>
RPS-XHE-XM-SCRAM	Operator Fails to Manually Trip the Reactor	$2.5 \times 10^{-3}$	Yes <sup>5</sup>
SGTR-03-NREC	SGTR Sequence 3 Nonrecovery Probability	$3.4 \times 10^{-1}$	Yes <sup>6</sup>
SGTR-08-NREC	SGTR Sequence 8 Nonrecovery Probability	$3.4 \times 10^{-1}$	Yes <sup>6</sup>
SGTR-11-NREC	SGTR Sequence 11 Nonrecovery Probability	1.0	No
SGTR-13-NREC	SGTR Sequence 13 Nonrecovery Probability	$3.4 \times 10^{-1}$	Yes <sup>6</sup>
SGTR-18-NREC	SGTR Sequence 18 Nonrecovery Probability	$3.4 \times 10^{-1}$	Yes <sup>6</sup>

**Notes:**

- Model update--Risk-important human error probabilities were updated with generic human error probabilities from the human reliability analysis methodology used in the Revision 3i Standardized Plant Analysis Risk (SPAR) models.
- Although the initiating event frequency for a steam generator tube failure was set to 1.0, the conditional probability that the tube failure would result in a leak rate >225 gpm was assumed to be 0.33, and the conditional probability that the tube failure would result in a leak rate in the range 75 gpm to 225 gpm was assumed to be 0.67, based on operating experience data. For bases for these values, see text (Modeling Assumptions-Initiating Event Frequency Changes). All other initiating event frequencies were set to 0.0.
- Model update--New basic event for modified Fault Tree RCS-DEP (see footnote to Table 2a). The success criteria assume 2-out-of-3 atmospheric dump valves (ADVs) are required to remove decay heat for depressurization, given that the fourth valve associated with the faulted steam generator is not available (Ref. 9). Each ADV can pass 2.5% of rated steam flow (Ref. 10). Basic event failure probabilities are estimated as follows:
  - PCS-ADV-HW - The failure probability of 2-out-of-3 ADVs is  $3 \times 10^{-10}$  or  $3(p)^2$ , where (p) is the failure probability of a single ADV. From the SPAR model (Ref. 6), the probability of a single ADV to fail to open/remain open is  $1.0 \times 10^{-5}$ .
  - PCS-ADV-CCF - The common-cause failure probability of 2-out-of-3 ADVs to open (3 combinations of 2 valves) is  $2.6 \times 10^{-6}$  (Ref. 11).

- PCS-CNDSR-HW - Set to TRUE to reflect the fact that main condenser vacuum was lost two times during the February 15, 2000 event. This is a conservative assumption; however, this basic event has no impact on the overall risk result.

**Table 7. Footnotes (Continued)**

4. See text (Modeling Assumptions-Basic Event Probability Changes) for basis.
5. Model update—Probabilities for RPS hardware failures and human errors were updated to reflect those used in the Revision 3i SPAR model. These updated values are based on the values contained in the Westinghouse RPS Reliability Study, NUREG/CR-5500, Vol. 2 (Ref.12). In addition, the basic event RPS-XHE-ERROR was redefined to reflect manual rod insertion as an alternative to the RPS. This alternative is proceduralized in the EPGs (Reference - Westinghouse EGP, E-0/FR-s.1, Step 1). Therefore, a nominal human error probability of  $1.0 \times 10^{-3}$  was used in the analysis.
6. An SGTR will not affect the containment environment as long as the pressurizer relief valves are not challenged or used to depressurize the RCS (as an alternative to main and auxiliary sprays). Therefore, valve failures inside containment (e.g., RHR drop line) are accessible for purposes of recovery. The non-recovery probabilities of the minimal cut sets of dominant sequences involving recoverable valves were modified to reflect this recovery potential. The value used (0.34 - NUREG/CR-4674, Vol. 5, Table 3.1) is the generic non-recovery probability used in the ASP Program for recovering valve failures.

# **GUIDANCE FOR LICENSEE REVIEW OF PRELIMINARY ASP ANALYSIS**

## **Background**

The preliminary precursor analysis of an event or condition 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 (LOSP) 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 other pertinent reports, such as the licensee event report (LER) and/or NRC inspection reports.

## **Modeling Techniques**

The models used for the analysis of events were developed by the Idaho National Engineering and Environmental Laboratory (INEEL). The models were developed using the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) software. The developed models are called Standardized Plant Analysis Risk (SPAR) models. The SPAR models are based on linked fault trees. Fault trees were developed for each top event on the event trees to a super component level of detail.

SPAR Version 2 models have four types of initiating events: (1) transients, (2) small loss-of-coolant accidents (LOCAs), (3) steam generator tube rupture (PWR only), and (4) loss of offsite power (LOSP). The only support system modeled in Version 2 is the electric power system. The SPAR models have transfer events trees for station blackout and anticipated transient without scram.

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 Summary" section:
  - accurately describe the event as it occurred; and
  - 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;
  - accurately describe the modeling of the event appropriate for the events that occurred or that had the potential to occur under the event conditions; and
  - includes assumptions regarding the likelihood of equipment recovery?

Appendix G 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 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 simulation).

This documentation must be the revision or cover the practices at the time of the event occurrence. 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).

## **An Example of a Recovery Measure Evaluation**

A pressurized-water reactor plant experiences a reactor trip. During the subsequent recovery, it is discovered that one train of the auxiliary feedwater (AFW) system is unavailable. Absent any further information regarding 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 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, and
- 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 event or condition:

- Preliminary ASP analysis.
- Specific LER, NRC inspection report, or other pertinent reports for each preliminary ASP analysis.

## **Schedule**

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

## Reference

1. R. J. Belles et al., "Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report," USNRC Report NUREG/CR-4674 (ORNL/NOAC-232) Volume 26, Lockheed Martin Energy Research Corp., Oak Ridge National Laboratory, and Science Applications International Corp., Oak Ridge, Tennessee, November 1998.

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