ENCLOSURE 4
ADDITIONAL INFORMATION PROVIDED BY CON EDISON FOLLOWING SEPTEMBER 26, 2000 REGULATORY CONFERENCE

Monte Carlo Analysis

Question:

Provide the distributions used in the Monte Carlo analysis and explain why they are considered to be conservative.

Answer:

In order to estimate the risk of Indian Point Unit 2 U-bend tube failures during Cycle 14, a probabilistic evaluation was performed by applying a Monte Carlo analysis to the individual events that progress to a tube failure with a particular leakage rate. The probability distributions for each event are attached and are based on the IP2 specific situation in 1997 as we now know it. The final distributions were compared with the actual year 2000 detected U-bend flaw distributions at IP2 in order to assure that conservative estimates were used in the analysis. The distributions used in the calculation represents the end of Cycle 14 conditions. Therefore the results are very conservative with respect to the condition of the steam generators during the last operating cycle.

One hundred tubes with undetected axial cracks in the U-bend region were assumed to exist at the completion of the 1997 Steam Generator inspection. A higher likelihood of shallow cracks caused by the lower probability of detecting shallow cracks is reflected in the estimation that 50% of the cracks are less than 30% through wall deep. It is presumed that there is a lower likelihood of deeper cracks due to the higher likelihood of them being detected. Because this analysis evaluates ligament tearing failures rather than low leakage rate penetrations through the tube wall, the crack depths are considered to be the average measured depth of a given crack.

Based on the year 2000 inspections, the maximum average crack depth in each cracked U-bend is compared to what was used in the Monte Carlo Analysis. This comparison is based on the depth detected in the 2000 inspection, after nearly a full cycle of crack growth. The crack depth in 1997 would clearly be smaller. The "70 – 90%" actual data includes R2C5.

Depth of Crack (% through wall)	Depth presumed in the Monte Carlo Analysis to represent the beginning of Cycle 14	IP2 Crack Depths in 2000 (based on 2000 800 KHz Data)
0-30%	50% (50 tubes)	0 tubes
30-50%	31% (31 tubes)	3 tubes
50-70%	15% (15 tubes)	3 tubes
70-90%	4% (4 tubes)	2 tubes

The cracks in each of the 100 tubes became deeper during Cycle 14. A crack growth rate was selected for each tube. The growth rate probabilities applied are shown below with a comparison

of the IP2 growth rates that were provided in the CMOA. These growth rates were derived from the U-bend cracks that had inspection data from both 1997 and 2000.

Crack Growth (% through wall per EFPY)	Crack Growth Rates presumed in the Monte Carlo Analysis during Cycle 14	IP2 Crack Growth Rates during Cycle 14 (based on comparison of 1997 and 2000 data)
0-4%	0%	20%
4-8%	58%	40%
8-12%	30%	40%
12-16%	10%	0%
16-20%	2%	0%

The crack depth at any time during Cycle 14 was calculated by adding the growth rate times the time duration to the initial flaw depth.

It was then determined whether the crack would have penetrated the wall. The likelihood that the crack would penetrate the tube wall was calculated based on the crack depth at a given time and the stress that would exist in the remaining ligament. The lowest CMTR reported tensile strength for any IP2 row 2 tube was used with a ΔP of 1,600 psig for the spontaneous rupture during normal operation condition. Using this tensile stress and ΔP, the calculated tube failure wall thickness based on pressure hoop stress results in a calculated ligament failure at 15% wall thickness, or an 85% crack depth. A 100% probability of through wall penetration is conservatively assumed for an 80% to 100% through wall crack and a 10 % probability of through wall penetration is assumed for crack depths between 70% and 80% through wall.

For each tube that is predicted to have a crack penetrate the wall, the total axial length of the final penetration was determined based on a crack length probability distribution. In the "IP2" data comparison provided below, all U-bend apex cracks detected in a given tube at IP2 were assumed to link together to form a single longer crack representing the length reported.

Length of Crack (inches)	Crack Length presumed in the Monte Carlo Analysis at the time that a crack penetrated the tube wall	IP2 Crack Lengths in 2000 (based on 2000 800 KHz Data)
0-0.5	4% (4 tubes)	4 tubes
0.5-1.0	7% (7 tubes)	0 tubes
1.0-1.5	12% (12 tubes)	1 tubes
1.5-2.0	18% (18 tubes)	0 tubes
2.0-2.5	22% (22 tubes)	3 tubes
2.5-3.0	18% (18 tubes)	0 tubes
3.0-3.5	10% (10 tubes)	0 tubes
3.5-4.0	6% (6 tubes)	0 tubes
4.0-4.5	3% (3 tubes)	0 tubes

Using the resulting crack lengths, a flow rate was determined from the flow rate to crack length trends reported for U-bend failures in NUREG 6365. The curve that was used was based on the NUREG data with the curve shifted from the mean of the IP2, Doel, and Surry 2 data to the upper bound (including the IP2 and Surry 2 data).

Figures representing these distributions are attached.

Question:

From the Monte Carlo analysis results, what is the time distribution of the "through-wall" spontaneous leakage events relative to the first and second year of Cycle 14.

Answer:

The Monte Carlo model predicted through wall penetration during the first year of Cycle 14 in 99% of the trials.

In order to prepare this answer, the Monte Carlo analysis was augmented to provide additional results data. The distributions for each "event" and the methods of analysis were not modified. The analysis was performed to track through tube wall events on a quarterly basis, i.e., every three months. The Monte Carlo analysis showed that approximately 90% of the through wall events occurred in the first quarter of operation. This means that of the 100 tubes in a trial that were presumed to have undetected cracks, that in 90% of the trials one of the tubes had a crack, that with crack growth, would satisfy the criteria for through-wall penetration during the first quarter of operation.

This high percentage occurred because very conservative crack depth and crack growth rate assumptions were used. The representation of the condition at the beginning of Cycle 14 was more conservative than the condition in the Steam Generators at the end of Cycle 14. Four percent of the tubes (out of 100 tubes) had beginning-of-cycle crack depths between 70 and 90%

of the wall thickness. The threshold for through wall penetration was conservatively set at 80%. As a result, many cracks went through wall right after or soon after the trial period began. This is considered unrealistic and very conservative. Due to the assumptions used in model, the calculations are not appropriate to be compared to industry events. Instead, the Monte Carlo calculations determine the upper range of the probability of a leakage event greater than a specified value.

Question:

What percentage of the Monte Carlo trials resulted in zero leakage?

Answer:

The through-wall leakage rates between 0 and 0.1 gpm were tracked in the analysis. Only a small percentage of the 10,000 trials resulted in leakage below 0.1 gpm. Specifically, in the case analyzed, only eighteen trials (<1%) had leakage in this range. The leakage was this low not because the crack length distribution allowed very short axial lengths to occur that were converted into leakage below 0.1 gpm.

Question:

What percentage of the Monte Carlo trials resulted in leakage between 0 and 75 gpm?

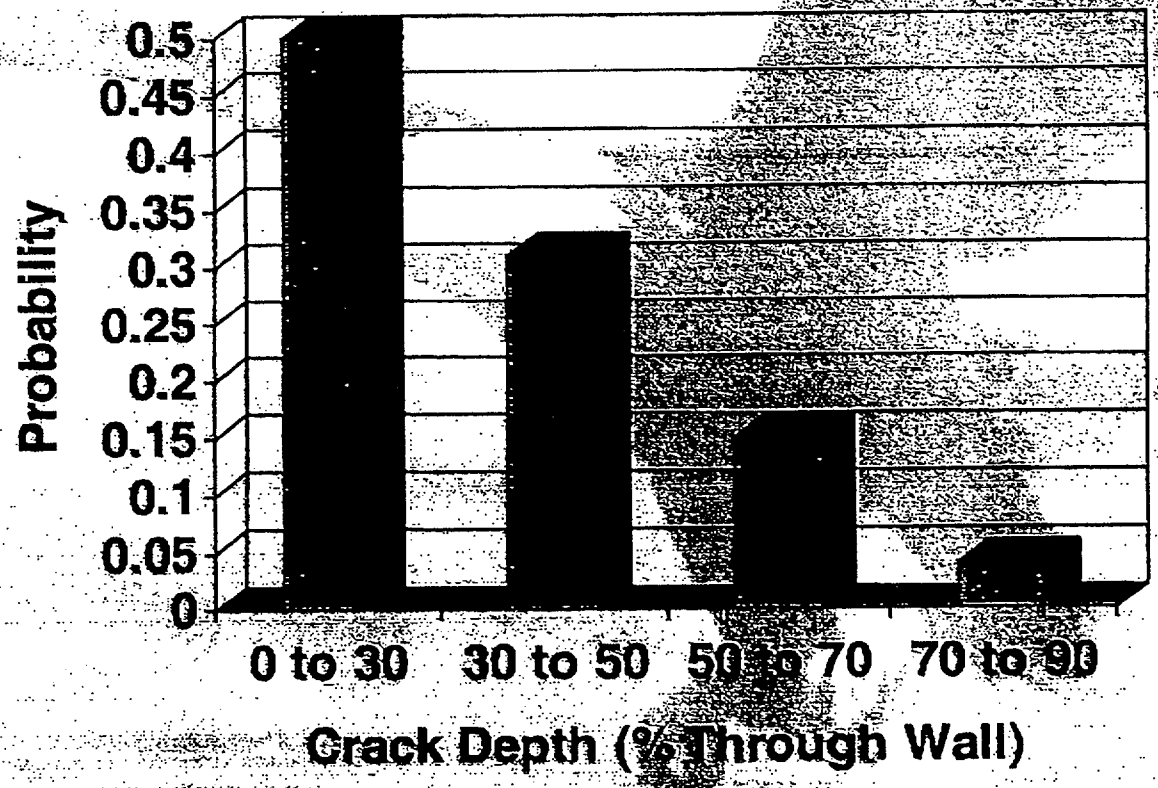
Answer:

Of the 10,000 trials, 37.2% resulted in leakage rates between 0.1 gpm and 75 gpm for Cycle 14. This correlates to a frequency of 0.186 per year.

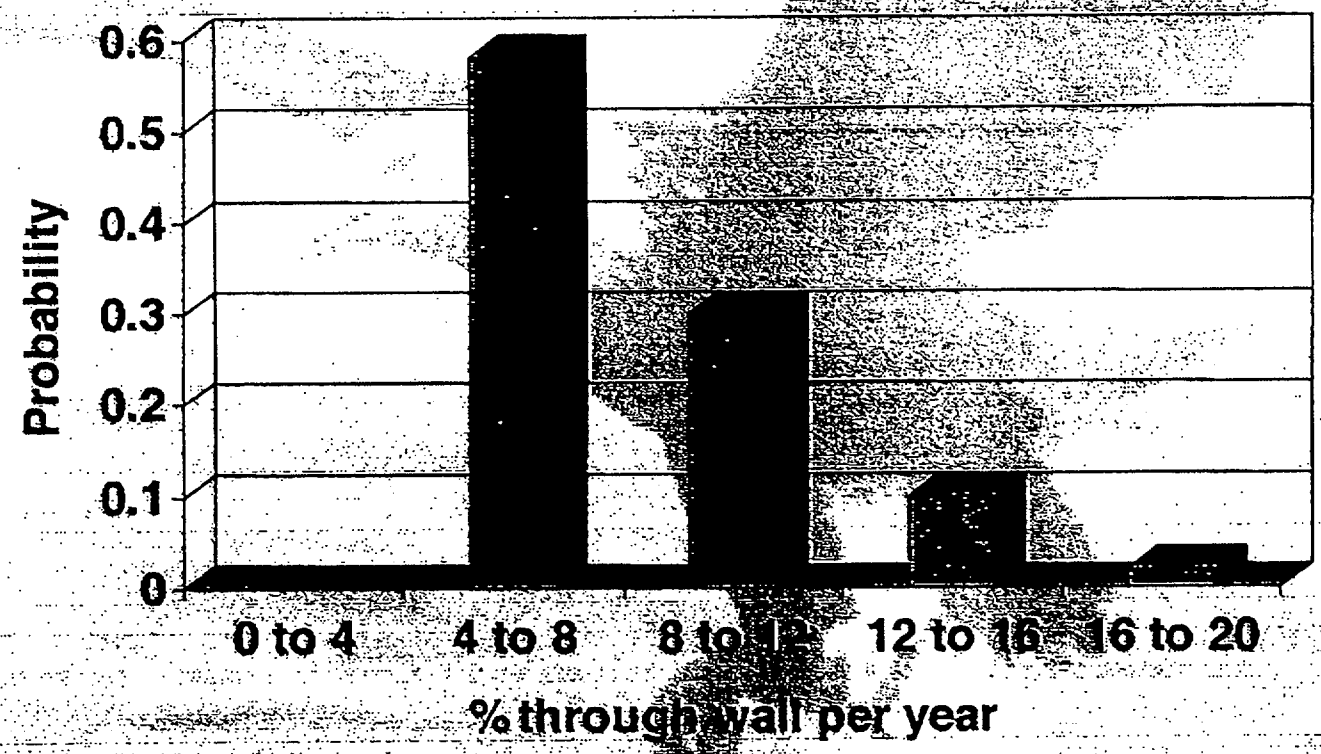
The frequency per cycle and per year for each of the leakage categories are provided below:

Leak Rate Range	Frequency per Reactor Year	Frequency per Cycle
<0.1 gpm	<0.1%	<0.1%
0.1 gpm – 75 gpm	18.6%	37.2%
75 gpm - 225 gpm	27.5%	55.0%
> 225 gpm	3.9%	7.8%

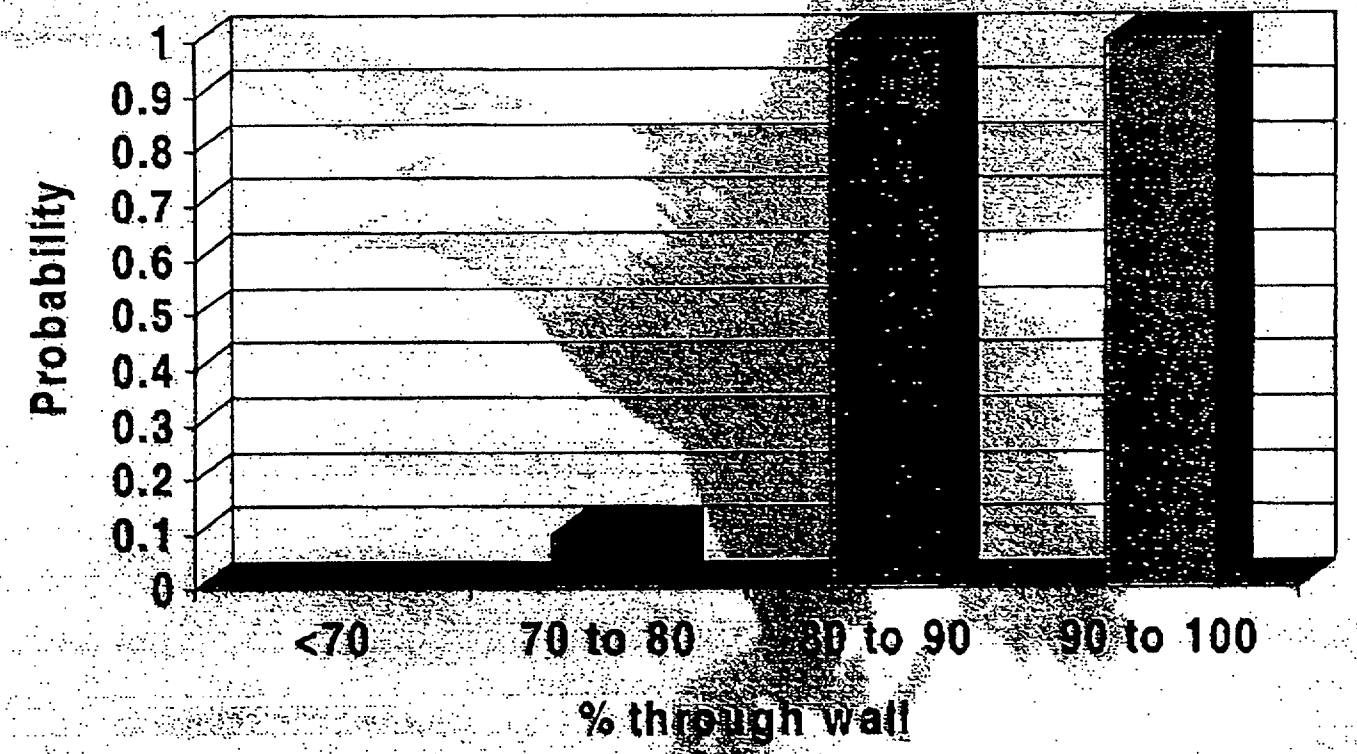
Depth of Cracks



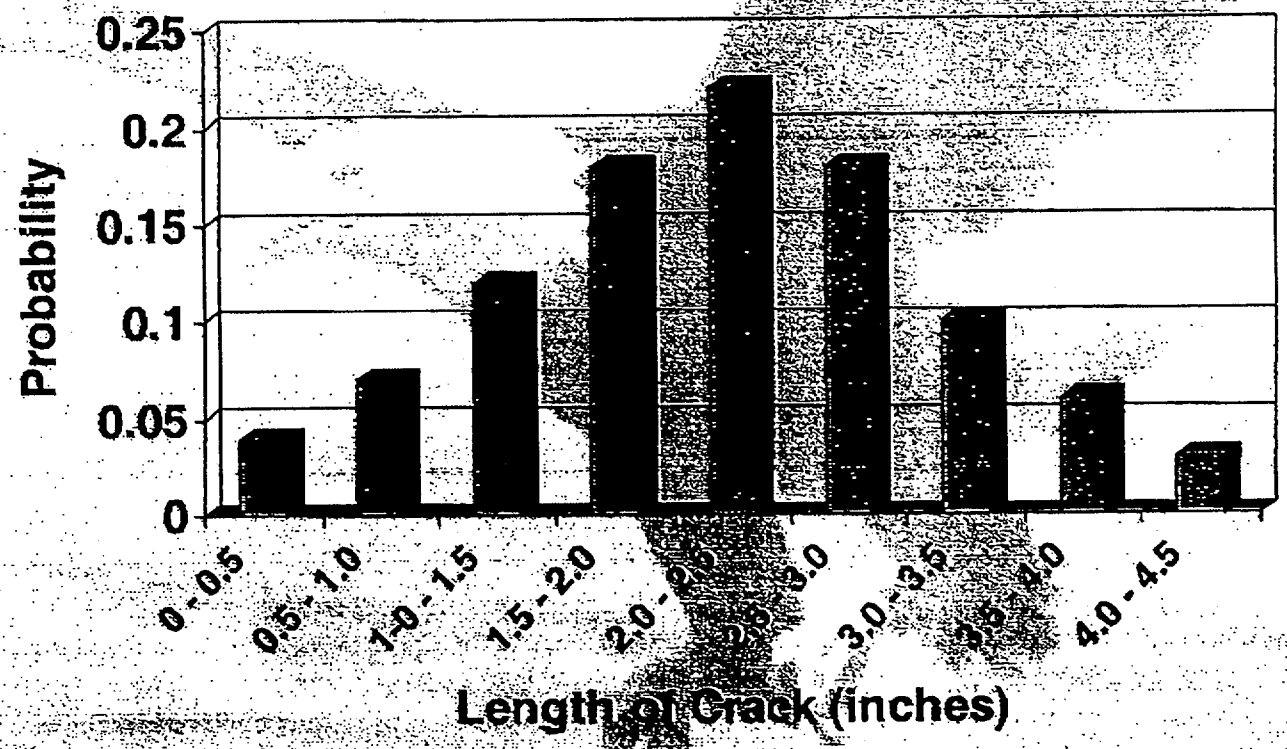
Crack Growth Rate



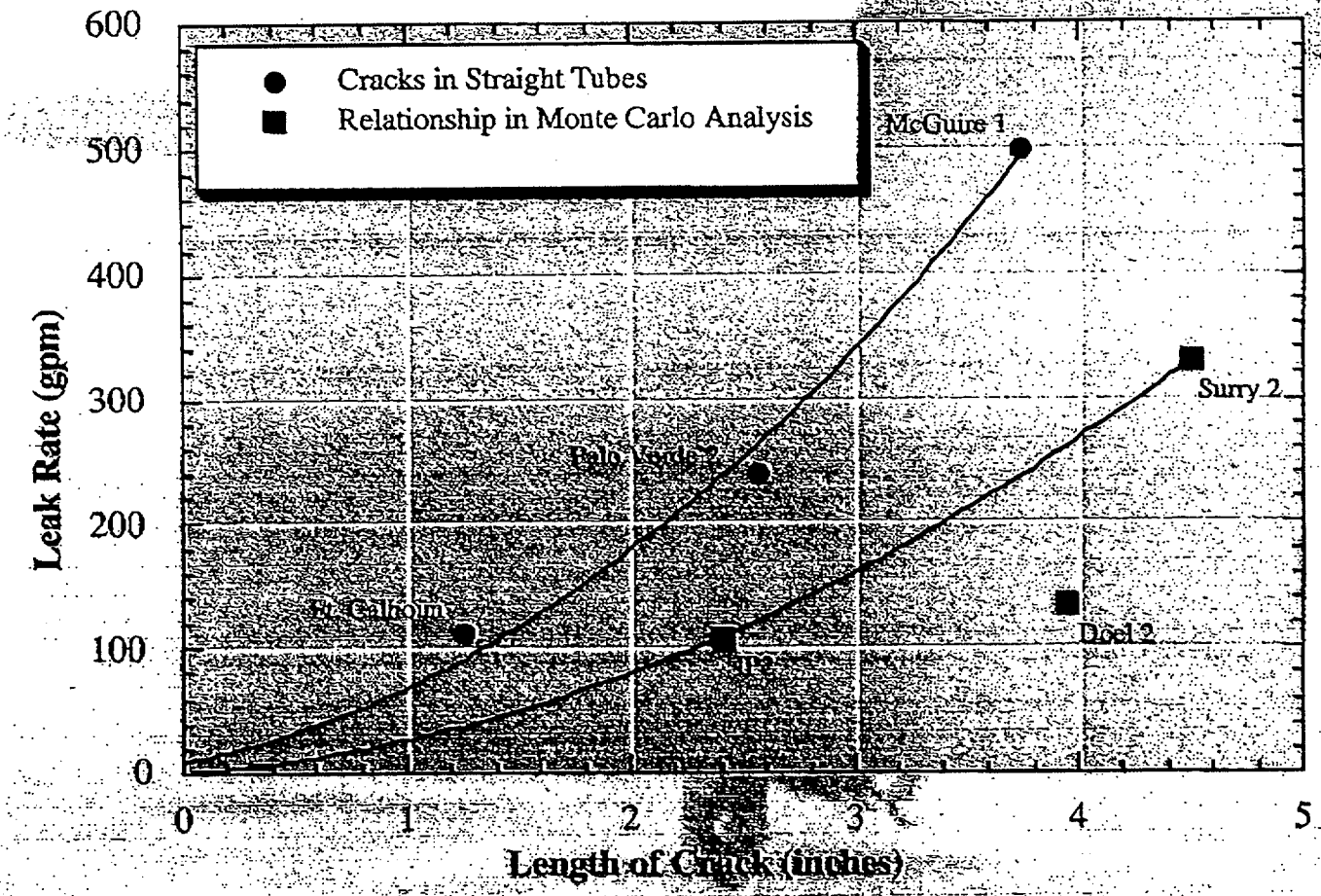
Crack Penetrating Wall



Axial Length of Crack



Flow Rate through Crack



Indian Point 2 Model – Steam Generator Tube Rupture Sequences

Table 1 shows the top 100 SGTR sequences with the failed split fractions for each sequence.

Each sequence includes an SISF split fraction that simply indicates that the sequence involves a loss of coolant from the primary system. This split fraction is a flag and has no quantitative value. It should also be noted that the sequences are shown in groups of two with the only difference being the inclusion of a SWS1 split fraction in one sequence of each pair. This SWS1 split fraction is required to properly reflect the fact that Indian Point 2 has two separate service water headers, either of which could be aligned to the essential or non-essential header at a given time. The two sequences therefore represent identical scenarios except that in one sequence, service water pumps 21, 22 and 23 are aligned to the essential header and in the other sequence, service water pumps 24, 25 and 26 are aligned to the essential header. Since either plant configuration is equally likely, the value of SWS1 is 0.5 and the sum of the two sequences represents the complete scenario.

Those sequences which are assigned to Plant Damage State 48A represent core damage sequences with an un-isolated secondary side while those sequences assigned to Plant Damage State 48B represent core damage sequences with the release through a modulating relief valve allowing radionuclide deposition and partitioning. Based on the expected core inventory release fractions associated with the two plant damage states, Plant Damage State 48A can be considered a large early release, while Plant Damage State 48B involves sufficient deposition and partitioning to preclude it from being a large early release. The Plant Damage State totals in the baseline model are 1.35E-7 for PDS 48A and 8.7E-7 for PDS 48B.

Table 2 provides a more detailed description of the failures and successes included in the dominant SGTR sequences. Figure 3.1-5 of the Indian Point 2 IPE provides the SGTR event tree and the top events included in that tree. Those events are:

RW	Refueling Water Storage Tank availability
HP	High Pressure Injection
L1	Auxiliary Feedwater
O3	Operator cools down and depressurizes without AFW
OS	Operator stops AFW to ruptured SG and isolates generator
O4	Operator cools down and depressurizes with AFW before overfill
O5	Operator cools down and depressurizes following overfill
SO	Isolation of the steam generator after overfill
MU	RWST makeup following successful depressurization
AS	Accumulator availability
LP	Low Pressure Injection
LR	Low Pressure Recirculation (Shut Down Cooling)
RH	Recirculation Heat Removal

Table 1

Rank	Baseline SGTR CDF	Conditional SGTR CDF	Failed Split Fractions	Plant Damage State
1	2.54E-07	2E-05	//SISF/O41*O5A	PDS48B
2	2.54E-07	2E-05	//SWS1*SISF/O41*O5A	PDS48B
3	8.59E-08	6.6E-06	//SWS1*SISF/OS1*O5E	PDS48B
4	8.59E-08	6.6E-06	//SISF/OS1*O5E	PDS48B
5	5.06E-08	3.9E-06	//SISF/HP3*O41*O5G	PDS48B
6	5.06E-08	3.9E-06	//SWS1*SISF/HP3*O41*O5G	PDS48B
7	3.03E-08	2.3E-06	//SISF/OS1*SO1*LR2	PDS48A
8	3.03E-08	2.3E-06	//SWS1*SISF/OS1*SO1*LR2	PDS48A
9	2.18E-08	1.7E-06	//SWS1*SISF/HP3*L14	PDS48B
10	2.18E-08	1.7E-06	//SISF/HP3*L14	PDS48B
11	7.23E-09	5.6E-07	//SISF/OS1*O5E*SO3	PDS48A
12	7.23E-09	5.6E-07	//SWS1*SISF/OS1*O5E*SO3	PDS48A
13	6.48E-09	5E-07	//SWS1*SISF/RW2*OS1	PDS48A
14	6.48E-09	5E-07	//SISF/RW2*OS1	PDS48A
15	6.31E-09	4.9E-07	//SISF/OS1*SO1*MU1	PDS48A
16	6.31E-09	4.9E-07	//SWS1*SISF/OS1*SO1*MU1	PDS48A
17	4.89E-09	3.8E-07	//SWS1*SISF/RW2*O41	PDS48B
18	4.89E-09	3.8E-07	//SISF/RW2*O41	PDS48B
19	4.85E-09	3.7E-07	//SISF/L11*O31	PDS48A
20	4.85E-09	3.7E-07	//SWS1*SISF/L11*O31	PDS48A
21	3.18E-09	2.4E-07	//SISF/HP3*OS1*SO1	PDS48A
22	3.18E-09	2.4E-07	//SWS1*SISF/HP3*OS1*SO1	PDS48A
23	2.27E-09	1.7E-07	//SISF/O41*SO2*LR2	PDS48A
24	2.27E-09	1.7E-07	//SWS1*SISF/O41*SO2*LR2	PDS48A
25	2.23E-09	1.7E-07	//EA1B*SISF/O41*O5A	PDS48B
26	2.23E-09	1.7E-07	//EA1B*SWS1*SISF/O41*O5A	PDS48B
27	2.23E-09	1.7E-07	//EB1B*SISF/O41*O5A	PDS48B
28	2.23E-09	1.7E-07	//EB1B*SWS1*SISF/O41*O5A	PDS48B
29	2.00E-09	1.5E-07	//EA1B*EBCB*SISF/HP6*O41*O5G	PDS48B
30	2.00E-09	1.5E-07	//EA1B*EBCB*SWS1*SISF/HP6*O41*O5G	PDS48B
31	1.30E-09	1E-07	//SISF/L11*SO4	PDS48A
32	1.30E-09	1E-07	//SWS1*SISF/L11*SO4	PDS48A
33	1.30E-09	1E-07	/MC26C1/SISF/O41*O5A	PDS48B
34	1.30E-09	1E-07	/MC26C1/SWS1*SISF/O41*O5A	PDS48B
35	9.89E-10	7.6E-08	//SISF/L11*LR4L	PDS48B
36	9.89E-10	7.6E-08	//SWS1*SISF/L11*LR4L	PDS48B
37	9.21E-10	7.1E-08	//SWS1*SISF/HP3*OS1*O53	PDS48B
38	9.21E-10	7.1E-08	//SISF/HP3*OS1*O53	PDS48B
39	9.03E-10	6.9E-08	//SISF/O41*O5A*SO2	PDS48A
40	9.03E-10	6.9E-08	//SWS1*SISF/O41*O5A*SO2	PDS48A
41	8.65E-10	6.7E-08	//EA1B*EBCB*SISF/HP6*L14	PDS48B
42	8.65E-10	6.7E-08	//EA1B*EBCB*SWS1*SISF/HP6*L14	PDS48B
43	7.55E-10	5.8E-08	//EA1B*SISF/OS1*O5E	PDS48B
44	7.55E-10	5.8E-08	//EA1B*SWS1*SISF/OS1*O5E	PDS48B
45	7.55E-10	5.8E-08	//EB1B*SISF/OS1*O5E	PDS48B
46	7.55E-10	5.8E-08	//EB1B*SWS1*SISF/OS1*O5E	PDS48B
47	6.08E-10	4.7E-08	//SWS1*SISF/HP3*OS1*LR2	PDS48B
48	6.08E-10	4.7E-08	//SISF/HP3*OS1*LR2	PDS48B
49	4.73E-10	3.6E-08	//SISF/O41*SO2*MU1	PDS48A
50	4.73E-10	3.6E-08	//SWS1*SISF/O41*SO2*MU1	PDS48A
51	4.56E-10	3.5E-08	/MC26A1/SISF/OS1*SO1*LRF	PDS48A
52	4.56E-10	3.5E-08	/MC26A1/SWS1*SISF/OS1*SO1*LRF	PDS48A
53	4.56E-10	3.5E-08	/MC26B1/SISF/OS1*SO1*LRF	PDS48A
54	4.56E-10	3.5E-08	/MC26B1/SWS1*SISF/OS1*SO1*LRF	PDS48A

55	4.45E-10	3.4E-08	//EA1B*SISF/HP3*O41*O5G	PDS48B
56	4.45E-10	3.4E-08	//EA1B*SWS1*SISF/HP3*O41*O5G	PDS48B
57	4.45E-10	3.4E-08	//EB1B*SISF/HP3*O41*O5G	PDS48B
58	4.45E-10	3.4E-08	//EB1B*SWS1*SISF/HP3*O41*O5G	PDS48B
59	4.39E-10	3.4E-08	/MC26C1/SISF/OS1*O5E	PDS48B
60	4.39E-10	3.4E-08	/MC26C1/SWS1*SISF/OS1*O5E	PDS48B
61	4.28E-10	3.3E-08	//SWS1*SISF*CC1/OS1*SO1*RHF	PDS48A
62	4.28E-10	3.3E-08	//SISF*CC1/OS1*SO1*RHF	PDS48A
63	3.48E-10	2.7E-08	//EA1B*EBCB*SISF/HP6*OS1*LP10	PDS48B
64	3.48E-10	2.7E-08	//EA1B*EBCB*SWS1*SISF/HP6*OS1*LP10	PDS48B
65	3.38E-10	2.6E-08	/X31*G2F/SISF/O41*O5A	PDS48B
66	3.38E-10	2.6E-08	/X31*G2F/SWS1*SISF/O41*O5A	PDS48B
67	3.14E-10	2.4E-08	/W21*G2F/SISF/O41*O5A	PDS48B
68	3.14E-10	2.4E-08	/W21*G2F/SWS1*SISF/O41*O5A	PDS48B
69	2.66E-10	2E-08	//EA1B*SISF/OS1*SO1*LR2	PDS48A
70	2.66E-10	2E-08	//EA1B*SWS1*SISF/OS1*SO1*LR2	PDS48A
71	2.66E-10	2E-08	//EB1B*SISF/OS1*SO1*LR2	PDS48A
72	2.66E-10	2E-08	//EB1B*SWS1*SISF/OS1*SO1*LR2	PDS48A
73	2.59E-10	2E-08	/MC26C1/SISF/HP3*O41*O5G	PDS48B
74	2.59E-10	2E-08	/MC26C1/SWS1*SISF/HP3*O41*O5G	PDS48B
75	1.92E-10	1.5E-08	//EA1B*SISF/HP3*L14	PDS48B
76	1.92E-10	1.5E-08	//EA1B*SWS1*SISF/HP3*L14	PDS48B
77	1.92E-10	1.5E-08	//EB1B*SISF/HP3*L14	PDS48B
78	1.92E-10	1.5E-08	//EB1B*SWS1*SISF/HP3*L14	PDS48B
79	1.80E-10	1.4E-08	//SISF/HP3*O41*O5G*SO2	PDS48A
80	1.80E-10	1.4E-08	//SWS1*SISF/HP3*O41*O5G*SO2	PDS48A
81	1.72E-10	1.3E-08	//SWS1*SISF/HP3*L14*SO5	PDS48A
82	1.72E-10	1.3E-08	//SISF/HP3*L14*SO5	PDS48A
83	1.55E-10	1.2E-08	/MC26C1/SISF/OS1*SO1*LR2	PDS48A
84	1.55E-10	1.2E-08	/MC26C1/SWS1*SISF/OS1*SO1*LR2	PDS48A
85	1.28E-10	9.8E-09	/Z61*X3F*G2F*G3E*A6F*A3F*MC26BF*MC26CF*MC27F/SWS1*SISF/L13*LRF	PDS48B
86	1.27E-10	9.8E-09	/Z61*X3F*G2F*G3E*A6F*A3F*MC26BF*MC26CF*MC27F/SISF*SAF/L13*LRF	PDS48B
87	1.27E-10	9.8E-09	//SWS1*SISF/HP3*OS1*AS1	PDS48B
88	1.27E-10	9.8E-09	//SISF/HP3*OS1*AS1	PDS48B
89	1.25E-10	9.6E-09	//SISF/HP3*O41*LR2	PDS48B
90	1.25E-10	9.6E-09	//SWS1*SISF/HP3*O41*LR2	PDS48B
91	1.24E-10	9.5E-09	//SISF/OS1*SO1*RH1	PDS48A
92	1.24E-10	9.5E-09	//SWS1*SISF/OS1*SO1*RH1	PDS48A
93	1.15E-10	8.8E-09	/X31*G2F/SISF/OS1*O5E	PDS48B
94	1.15E-10	8.8E-09	/X31*G2F/SWS1*SISF/OS1*O5E	PDS48B
95	1.13E-10	8.7E-09	//EA1B*EBCB*SISF/HP6*OS1*SO1	PDS48A
96	1.13E-10	8.7E-09	//EA1B*EBCB*SWS1*SISF/HP6*OS1*SO1	PDS48A
97	1.12E-10	8.6E-09	/MC26C1/SISF/HP3*L14	PDS48B
98	1.12E-10	8.6E-09	/MC26C1/SWS1*SISF/HP3*L14	PDS48B
99	1.06E-10	8.2E-09	/W21*G2F/SISF/OS1*O5E	PDS48B
100	1.06E-10	8.2E-09	/W21*G2F/SWS1*SISF/OS1*O5E	PDS48B

Table 2

ık	Sequence	Sequence CDF	Discussion of Split Fractions

	//SISF/O41*O5A
	
	//SWS1*SISF/O41*O5A
		2.54E-07
		
		2.54E-07
			In this sequence, the operator has successfully isolated the SG and terminated auxiliary feedwater flow to the ruptured steam generator (Top Event OS).
			
			Following successful isolation, the operator must still depressurize and cool down the RCS (Split Fraction O41). In this sequence, he fails to do so prior to overfill.
			
			Split Fraction O5A represents the continued attempt to depressurize and cool down the RCS after the initial failure in O41 and prior to RWST depletion. The relief and safety valves are again challenged (Top Event SO) during this time with the condition of two phase flow increasing the likelihood of the safety valve failing to re-close.
			
			In this sequence, depressurization (O5) is not successful but isolation prior to RWST depletic (SO) is successful. As a result, primary to secondary leakage is assumed to continue through modulating relief valve and eventually the RWST is depleted. Since makeup flow to the RW is insufficient for this tube rupture flow rate and the RCS remains at high pressure and cannot transitioned to shutdown cooling, core damage occurs.
			
			Since the releases are through a modulating valve, this sequence allows enough source term reduction through deposition and partitioning to keep releases below the LERF level and is assigned to Plant Damage State 48B.

	//SWS1*SISF/OS1*O5E
	
	//SISF/OS1*O5E
		8.59E-08
		
		8.59E-08
			In this sequence, split fraction OS1 fails, which represents failure of the operator to isolate ar terminate feedwater flow to the ruptured SG prior to overfill.
			
			Split Fraction O5E represents late depressurization (following overfill and prior to RWST depletion). This split fraction differs from O5A, however, since there are no previously successful top events involving operator action and cognitive errors must therefore be includ
			
			As in the previous sequence, depressurization is not successful but isolation prior to RWST depletion is successful, core damage occurs, releases are through a modulating relief valve ar the sequence is assigned to Plant Damage State 48B.

	//SISF/HP3*O41*O5G
	
	//SWS1*SISF/HP3*O41*O5G
		5.06E-08
		
		5.06E-08
			Split Fraction HP3 represents initial failure of high pressure injection.
			
			Split Fraction O41 is the same action described above.
			
			The operators will continue cool down and depressurization actions under top event O5 and since high pressure injection is not available, they will at a certain point be directed to initiat rapid cool down of the RCS to achieve core cooling recovery using the low pressure injectio system. Split fraction O5G models this action including the additional equipment needed to accomplish the more rapid cool down.
			
			In this sequence, depressurization to allow low pressure injection is not successful, but isolat prior to core damage is successful. As a result, releases following core damage are through a modulating relief valve and this sequence is assigned to Plant Damage State 48B.

	//SISF/OS1*SO1*LR2
	
	//SWS1*SISF/OS1*SO1*LR2
		3.03E-08
		
		3.03E-08
			In this sequence, split fraction OS1 fails, which represents failure of the operator to isolate th various leakage paths to and from the ruptured steam generator and terminate feed water flow the ruptured SG prior to overfill.
			
			Split fraction SO1, which represents inability to isolate following overfill, also fails.
			
			Top event O5, depressurization and cool down the RCS to the point where shutdown cooling can be implemented, prior to RWST depletion, is successful. However, split fraction LR2 fai which represents the inability to actually implement shutdown cooling following depressurization. It should be noted that the current model assumes that both RWST makeup (MU) and shut down cooling (LR) are required to prevent core damage following successful depressurization. This is a substantial conservatism since with successful makeup, the extend time available would make any failure of shutdown cooling highly likely to be recoverable ar with successful implementation of shutdown cooling, little or no additional makeup is require
			
			Given the current modeling, this sequence represents core damage with a continuously open p to the environment and is assigned to Plant Damage State 48.

	//SWS1*SISF/HP3*L14
	
	//SISF/HP3*L14
		2.18E-08
		
		2.18E-08
			Split Fraction HP3 represents initial failure of high pressure injection.
			
			Similar to sequences 5 and 6 above, this sequence represents failure to depressurize to recove core injection following a failure of the high pressure injection system. In this case, however the failure to depressurize is a result of failure of the Auxiliary Feedwater System (Split Fract L14) under the more demanding success criteria for this action (both motor driven AFW pum required).
			
			Although depressurization to allow low pressure injection is not successful resulting in core damage, isolation prior to core damage is successful. As a result, releases following core damage are through a modulating relief valve and this sequence is assigned to Plant Damage State 48B.

	//SISF/OS1*O5E*SO3
	
	//SWS1*SISF/OS1*O5E*SO3
		7.23E-09
		
		7.23E-09
			In this sequence, split fraction OS1 fails, which represents failure of the operator to isolate ar terminate feed water flow to the ruptured SG prior to overfill.
			
			Split Fraction O5E represents late depressurization (following overfill and prior to RWST depletion). Split fraction SO3, which represents inability to isolate following overfill, accounting for dependencies with O5E, also fails.
			
			Since both depressurization and isolation prior to RWST depletion are failed, core damage occurs with a continuously open path to the environment and is assigned to Plant Damage St 48A.

3 4	//SWS1*SISF/RW2*OS1 //SISF/RW2*OS1	6.48E-09 6.48E-09	In this sequence, split fraction RW2, the Refueling Water Storage Tank supply to the core injection systems, fails. This fails high pressure injection and eliminates the ability to recove core cooling by depressurizing and using low pressure injection. Split fraction OS1 also fails, representing operator failure to isolate and terminate feed water flow to the ruptured SG, allowing continued loss of primary coolant. Given failure of all injection, early core damage is assumed and later actions to depressurize (O5) and isolate (S(are bypassed. Since core damage occurs with a continuously open path to the environment, this sequence is assigned to Plant Damage State 48A.
5 6	//SISF/OS1*SO1*MU1 //SWS1*SISF/OS1*SO1*MU1	6.31E-09 6.31E-09	In this sequence, split fraction OS1 fails, which represents failure of the operator to isolate th various leakage paths to and from the ruptured steam generator and terminate feed water flov the ruptured SG prior to overfill. Split fraction SO1, which represents inability to isolate following overfill, also fails. Top event O5, depressurization and cool down the RCS to the point where shutdown cooling can be implemented, prior to RWST depletion, is successful. Switchover to shutdown coolin has not yet been challenged and the model assumes some make up to the RWST is required. Split fraction MU1 represents the inability to provide that make up and this sequence therefo leads to core damage. Since this sequence represents core damage with a continuously open path to the environmen is assigned to Plant Damage State 48A.
7 8	//SWS1*SISF/RW2*O41 //SISF/RW2*O41	4.89E-09 4.89E-09	In this sequence, split fraction RW2, the Refueling Water Storage Tank supply to the core injection systems, fails. This fails high pressure injection and eliminates the ability to recove core cooling by depressurizing and using low pressure injection. Steam generator isolation (Split fraction OS1) succeeds but split fraction O41, depressurizati and cool down, fails, allowing continued loss of primary coolant. Given failure of all injecti early core damage is assumed. Since core damage occurs with releases through a modulating relief valve, this sequence is assigned to Plant Damage State 48B.
9 0	//SISF/L11*O31 //SWS1*SISF/L11*O31	4.85E-09 4.85E-09	In this sequence, auxiliary feed water (split fraction L11) fails along with the operator action depressurize and cool down in the absence of auxiliary feed water (split fraction O31). This is assumed to lead directly to core damage and this sequence is assigned to Plant Dama State 48A.
1 2	//SISF/HP3*OS1*SO1 //SWS1*SISF/HP3*OS1*SO1	3.18E-09 3.18E-09	In this sequence, high pressure injection (HP3) has failed as well as steam generator isolatio (split fractions OS1 and SO1). This is assumed to lead directly to core damage with a continuously open path to the environment and this sequence is assigned to Plant Damage State 48A.

3	//SISF/O41*SO2*LR2	2.27E-09	In this sequence, the operator has successfully isolated the SG and terminated auxiliary feed water flow to the ruptured steam generator (Top Event OS). Early depressurization and cool down of the RCS (Split Fraction O41) fails, however. Split fraction SO2, which represents inability to isolate following overfill, also fails. Top event O5, depressurization and cool down the RCS to the point where shutdown cooling can be implemented, prior to RWST depletion, is successful. However, split fraction LR2 fa which represents the inability to actually implement shutdown cooling following depressurization. This sequence represents core damage with a continuously open path to the environment and assigned to Plant Damage State 48A.
4	//SWS1*SISF/O41*SO2*LR2	2.27E-09	
5	//EA1B*SISF/O41*O5A	2.23E-09	These sequences are identical to sequences 1 and 2 except that they include failure of automa SI actuation signals. Since there is no dependence on automatic SI for the O41 and O5A functions, these sequence simply represent the complement of the above sequences, since RISKMAN modeling accoun for the success probability of the SI actuation in those sequences Consistent with sequences 1 and 2, these sequences are assigned to Plant Damage State 48B
6	//EA1B*SWS1*SISF/O41*O5A	2.23E-09	
7	//EB1B*SISF/O41*O5A	2.23E-09	
8	//EB1B*SWS1*SISF/O41*O5A	2.23E-09	
9	//EA1B*EBCB*SISF/HP6*O41 *O5G	2.00E-09	These sequences are identical to sequences 5 and 6 except that they include failure of both tr of automatic SI actuation signals. Since top event HP represents high pressure injection, whi has a dependency on the automatic actuation signal, the split fraction used (HP6) reflects the failure probability of high pressure injection in the absence of the automatic actuation signal. Consistent with sequences 5 and 6, these sequences are assigned to Plant Damage State 48B
10	//EA1B*EBCB*SWS1*SISF/H P6*O41*O5G	2.00E-09	
11	//SISF/L11*SO4	1.30E-09	In these sequences, AFW fails (L11) but the operator successfully depressurizes and cools do (O31) using the ruptured steam generator and a Pressurizer PORV, avoiding steam generator overfill. Early operator action to stop AFW is not required given failure of L11 and top event OS is bypassed. Isolation is challenged in SO and fails in this sequence. Although RWST makeup and shutdown cooling are possible since depressurization and cool down is successful, they a not credited in these sequences. This is conservatively modeled as a core damage sequence and, given failure of SO, this sequence is assigned to Plant Damage State 48A.
12	//SWS1*SISF/L11*SO4	1.30E-09	
13	//SISF/O41*O5A	1.30E-09	These sequences are identical to sequences 1 and 2 except that they include failure of autom SI actuation signals. Since there is no dependence on automatic SI for the O41 and O5A functions, these sequenc simply represent the complement of the above sequences, since RISKMAN modeling accour for the success probability of the SI actuation in those sequences Consistent with sequences 1 and 2, these sequences are assigned to Plant Damage State 48B
14	//SWS1*SISF/O41*O5A	1.30E-09	

Question:

Describe industry experience of small primary to secondary leaks caused by PWSCC in the u-bend area.

The following documents were identified that contained industry information.

The EPRI "Primary to Secondary Leak" Guidelines, Rev 2. February 2000
NUREG-6365, "Steam Generator Tube Failures" published in 1996.
'Model 44 and 51 Steam Generator Tube Corrosion Performance Comparison to Indian Point Unit 2", submitted as part of the Condition Monitoring Operational Assessment Report on June 2, 2000

Twenty-three examples of Steam Generator Leakage were identified.

Date	Plant	Leak Rate	Degradation	Source
2/26/75	Point Beach	125 gpm	Wastage-Sludge Pile	Ref 2,3
9/15/76	Surry 2	330	PWSCC U-Bend	Ref 2,3
6/25/79	Doel 2	135	PWSCC U-Bend	Ref 2,3
10/2/79	Prairie Island	336	Loose Part Wear	Ref 2,3
1/25/82	Ginna	760	Loose Part Wear	Ref 2,3
5/16/84	Ft. Calhoun	112	IGSCC/Tube Support	Ref 2
7/15/87	North Anna 1	637	High Cycle Fatigue	Ref 1,2,3
10/19/88	Indian Point 3	2	High Cycle Fatigue	Ref 3
3/7/89	McGuire 1	500	IGSCC - Defect	Ref 2
6/21/89	Beaver Valley	0.35	Loose Parts	Ref 3
12/17/90	Main Yankee	1.4	ODSCC, Top U-bend	Ref 2
3/6/90	TMI 1	0.5	High Cycle Fatigue	Ref 2
2/9/91	Mihama 2	700	High Cycle Fatigue	Ref 2,3
1/16/92	McGuire 1	0.17	ODSCC, CL R47C46	Ref 2
3/9/92	ANO-2	0.25	ODSCC, HL, TS	Ref 2
3/14/93	Palo Verde 2	240	ODSCC, Axial	Ref 2
10/23/93	Braidwood 1	0.21	ODSCC, near AVB	Ref 2
3/19/94	Oconee 3	0.23	Fatigue, Circ Crack	Ref 1
7/27/94	Oconee 2	0.17	Fatigue, Circ Crack	Ref 1
11/16/96	ANO-2	0.06	ODSCC – Eggcrate	Ref 1
6/13/97	McGuire 2	0.04	ODSCC – freespan	Ref 1
8/16/98	Farley 1	0.06	ODSCC – Freespan	Ref 1
2/15/00	Indian Point 2	109	PWSCC – U-Bend	Ref 3

Of these events, the only ones that were identified as being caused by PWSCC in the U-Bend were Surry 2, Dole 2, and Indian Point 2. However, Surry 2 and Doel 2 were larger leak events and were discussed in our presentation on 9/26/00.

September 29, 2000

STAFF RESPONSE TO TASKING MEMORANDUM AND STAKEHOLDER CONCERNS

as of September 29, 2000

September 29, 2000

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I. Topic Area: Risk-Informed and Performance-Based Regulation

A. Plant-Specific Licensing Reviews *(see note)

SES Manager: Gary Holahan, Director, DSSA, NRR

Objective: The use of probabilistic risk assessment in risk-informed decision making for changes to plant-specific licensing basis is intended to enhance safety decisions, efficiently utilize NRC resources and reduce unnecessary conservatism. The goal is to complete first of a kind risk-informed licensing reviews such that lessons learned may be utilized for future staff reviews.

Prior to February 28, 2001		
Milestones	Date	Lead
1. SER to be issued on St. Lucie 1/2 application for LPSI system AOT relaxation.	2/15/00C	M. Wohl, SPSB
2. SER to be issued on Waterford 3 application for CSS AOT relaxation.	5/15/00C	M. Wohl, SPSB
3. SER to be issued on Waterford 3 application for LPSI system AOT relaxation.	5/25/00C	M. Wohl, SPSB
4. SER to be issued on CE Owners Group Joint Applications Report for Containment Isolation Valve AOT Relaxation for 8 sites.	6/26/00C	M. Wohl, SPSB
5. SER to be issued on Waterford 3 application for EDG AOT extension.	7/21/00C	I. Jung, SPSB
6. SER to be issued on Oconee application for HPSI system AOT extensions.	~~12/01/00 (see comments)~~ 9/6/00C	D. O'Neal, SPSB

Through September 30, 2001		
Milestone	Date	Lead
None		

Beyond September 30, 2001		
Milestone	Date	Lead
None		

Comments:

* The objective of this specific issue has been realized. NRC has completed numerous first of a kind risk-informed licensing reviews and has learned lessons that are and will

CON EDISON CALCULATION / ANALYSIS COVER SHEET

3/16/00

Calculation Number: PGI-00443-00
Entry Date: 03/09/2000

Type: CA34
PIPE FLOW

Project Number: NONE
Document Page : 20
Old_Calculation:

Modification: NONE
Scanned: N
Revision: NO

Title ESTIMATED PRIMARY TO SECONDARY LEAKAGE DURING TUBE RUPTURE EVENT

Tag Number
24SG

Component Type	Component Description
PIPE	PIPE

Component Style	Style Description
TUBE	TUBE OR TUBING

System	Description
RCS	REACTOR COOLANT SYSTEM

Structure	Description
VC	VAPOR CONTAINMENT BUILDING VCI

Preparer: R. WATERS
Signature: 3/16/00
Update Date 03/16/2000
Reviewer: D. C. INGRAM
Signature/Date: D Curt Ingram / 3/16/00

Approval/Date 3/16/00

Confirm. Required?

Concurrence (If Required)

CON EDISON CALCULATION/ANALYSIS
Description of Change Sheet

Calculation No: PGI-00443-00

Revision No.	Description of Change	Reason for Change
0	Initial Release	

FORM36a

CON EDISON
CALCULATION/ANALYSIS
SUMMARY SHEET

	CALCULATION NO. PGI-00443-00 / REVISION 0	PAGE 3 OF 20
PREPARER/DATE Roger M. Waters Charles Hayes 3/16/00	REVIEWER/DATE D.C. Ingram 3/16/00	CLASS NONE
SUBJECT/TITLE Estimated Primary to Secondary Leakage Rate During Tube Rupture Event 2/15/00.		PROJECT NO. NONE
		MOD NO. NONE REV.

OBJECT OF CALCULATION:

The intent of this calculation is to provide estimates for primary to secondary leakage rates at various time periods throughout the tube rupture event. These estimates will aid in the SLI team in understanding of the event dynamics.

The total volume of water transferred from the primary side to the secondary side was also estimated.

CALCULATION METHOD/ASSUMPTIONS:

The development of the estimated leakage into 24 Steam Generator (SG) used, where possible, measured plant parameters. The key input parameters were the charging flowrate, letdown flowrate, pressurizer level and the water level in SG 24. The particular parameters used at a given time during the event were those that were determined to be less influenced by the plant transient. These parameters were not adjusted for measurement uncertainties or uncertainties introduced by the transient. As such the tube rupture flowrates determined must be regarded as nominal values.

DESIGN BASIS AND REFERENCES:

1. SAS or Proteus data via the Plant Information interface.
2. Properties of Saturated and Superheated Steam, Combustion Engineering
3. Westinghouse Pressurizer Vendor Manual #1890.
4. Graph SP-19, IP2 Steam Generator Volume versus Level.

CONCLUSIONS:

The flowrate through the ruptured tube varied throughout the event. The highest flowrate was encountered prior to the reactor trip and was estimated to be 109 gpm. After the reactor trip and prior to the manual SI the primary to secondary side pressure drop decreased and the flowrate decreased to an estimated 91 gpm. After the manual SI the primary to secondary side pressure drop decreased rapidly and consequently so did the flowrate. At times between the SI and Cold Shutdown this pressure drop was positive, zero or negative. When the pressure drop was negative there was back flow between SG 24 and the RCS. Between SI and Cold Shutdown the estimated flowrate varied between 70 gpm and 0 gpm.

The volume of water transferred from the primary side to the secondary side were estimated as follows:

Tube Rupture to Reactor Trip	1313 gallons
Reactor Trip to Manual SI	8685 gallons
Manual SI to Cold Shutdown	9199 gallons

The total volume of primary side water transferred to the secondary side is therefore estimated at 19200 gallons.

Estimated Primary to Secondary Leakage During Tube Rupture Event Calculation PGI-00443-00

Summary

Event Period	Time	Average Primary to Secondary Leakage (gpm)*	Volume (gallons)**
Tube Rupture to Reactor Trip	19:17 to 19:29	109	1313
Reactor Trip to Manual SI	19:29 to 21:04	91	8685
Post SI	21:04 to 21:30	70	1824
Post SI	21:30 to 22:00	37	1120
Post SI	22:00 to 22:30	7	200
Post SI	22:30 to 23:00	3	80
Post SI	23:00 to 23:30	4	120
Post SI	23:30 to 06:00	0	0
Post SI	06:00 to 07:00	11	655
Post SI	07:00 to 12:30	11	3600
Post SI	12:30 to 14:00	18	1600
Post SI	14:00 to Cold Shutdown	0	0

The total volume of primary to secondary leakage = 19197 gallons**

*The leak rates calculated are in given in gpm of "cold" water (100 F and atmospheric pressure).
**The water volumes calculated are given in gallons of "cold" water (100 F and atmospheric pressure).

Introduction

The primary to secondary leakage rates during the tube rupture event are calculated. Inputs to the calculation are from measured plant parameters. The origin of each calculation input is identified in the body of the calculation. Figures 1 through 7 show some of the measured plant parameters that are used or refered to in this calculation. These Figures originate from SAS or Proteus (Ref. 1).

The tube rupture flowrate was estimated for four periods:

1. Just Prior to Tube Rupture
2. From Tube Rupture to Reactor Trip
3. From Reactor Trip to Manual SI
4. From Manual SI to Cold Shutdown

The calculations for each of these time periods are now presented.

Estimated Primary to Secondary Leakage During Tube Rupture Event Calculation PGI-00443-00

Time Period **Just Prior to Tube Rupture**

One Charging Pump Operating
Pressurizer Level Steady

Charging Flow	59 gpm	(From computer point F0128 - see Figure 2)
Letdown Flow	87 gpm	(From computer point F0134 - see Figure 2)

During steady state at power operation the total inflow to the RCS is matched by the total outflow.

The total inflow is given by the charging flow as measured on F0128 plus the seal injection flow returned to the RCS via the pump shaft. The seal injection flow returned to the RCS is given by the difference between the as measured charging and letdown flowrates.

Therefore, seal injection returned to RCS = 28 gpm

Time Period **From Tube Rupture to Reactor Trip (19:17 to 19:29)**

Determine average charging flow (19:17 to 19:29)

Charging Flow from SAS computer point F0128 (See Figure 2).

Charging flow increased abruptly when the second charging pump was started.

19:17 to 19:19	61 gpm for	2 minutes
19:19 to 19:20	80 gpm for	1 minutes
19:19 to 19:21	118 gpm for	1 minutes
19:21 to 19:25	101 gpm for	4 minutes
19:25 to 19:29	119 gpm for	4 minutes

Therefore, average charging flow = 100 gpm for 12 minutes

Determine average seal injection flow returned to RCS (19:17 to 19:29)

The seal injection flow returned to the RCS increases (scales) as the charging flow increases

Therefore the seal inj. returned flow scaling factor is 100 divided by 60 = 1.67

Therefore the seal inj. return flow during this period is 28 times 1.67 = 47 gpm

Determination of total inflow to RCS from charging system (19:17 to 19:29)

The total inflow is the sum of the charging flow and the seal inj. returned flow

Therefore, total inflow = 100 plus 47 = 147 gpm

Letdown Flow (19:17 to 19:29)

Letdown Flow from SAS computer point F0134 (See Figure 2).

Letdown Flow remained constant during this period = 87 gpm

Pressurizer Level (19:17 to 19:29)

Pressurizer Level from SAS computer point L0480 (See Figure 3).

The pressurizer level decreased significantly during the period.

19:17 to 19:29 Level decreased from 43.4 % to 35.5 %

Assuming that 1% level is equivalent to 126 gallons of "hot" water (650 F and 2235 psig).
[Based on distance between taps and inside diameter from Ref. 3.]

Then, equivalent volume of "cold" water is 75.6 gallons (Conversion "hot" to "cold" from Ref. 2).

Then this level reduction is equivalent to an inventory change of -597 gallons of "cold" water

At an average rate of -50 gpm for 12 minutes

Estimated Primary to Secondary Leakage During Tube Rupture Event Calculation PGI-00443-00

Estimation of primary to secondary flow rate during this period (19:17 to 19:29)

Total Inflow to RCS = Letdown Flow + Tube Rupture Flow + Pressurizer Inventory Change

Therefore, Tube Rupture Flow = Total Inflow to RCS - Letdown Flow - Pressurizer Inventory Change

Tube Rupture Flow =	147 minus	87	minus	-50	=	109 gpm
Total primary to secondary leakage volume during this period					=	1313 gallons

Time Period **From Reactor Trip to Manual SI (19:29 to 21:04)**

Determine average charging flow (19:29 to 21:04)

Charging Flow from SAS computer point F0128 (See Figure 2).

Charging flow varies between 120 gpm and 75 gpm.

19:29 to 19:38	119 gpm for	9 minutes
19:38 to 19:52	94 gpm for	14 minutes
19:52 to 20:08	82 gpm for	16 minutes
20:08 to 20:31	104 gpm for	23 minutes
20:31 to 21:00	85 gpm for	29 minutes
21:00 to 21:04	115 gpm for	4 minutes

Therefore, average charging flow = 95 gpm for 95 minutes

Determine average seal injection flow returned to RCS (19:29 to 21:04)

The seal injection flow returned to the RCS increases (scales) as the charging flow increases

Therefore the seal inj. returned flow scaling factor is	95 divided by	60	=	1.58	
Therefore the seal inj. return flow during this period is	28 times	1.58	=	44	gpm

OCT-02-2000 21:24 USNRC INDIAN POINT TWO 914 739 9359 P.09

Determination of total inflow to RCS from charging system (19:29 to 21:04)

The total inflow is the sum of the charging flow and the seal inj. returned flow

Therefore, total inflow = 95 plus 44 = 139 gpm

Letdown Flow (19:29 to 21:04)

Letdown Flow from SAS computer point F0134 (See Figure 2).

Letdown flow dropped to zero and reestablished at 41 gpm.

19:29 to 19:32	34 gpm for	3 minutes
19:32 to 19:41	14 gpm for	9 minutes
19:41 to 21:04	41 gpm for	83 minutes

Therefore, average letdown flow = 38 gpm for 95 minutes

Pressurizer Level (19:29 to 21:04)

Pressurizer Level from SAS computer point L0480 (See Figure 3).

After the trip the pressurizer level recovered from 14 % to 35% and then decreased to 26% at SI

19:29 to 21:04 Level increased from 14 % to 26 %

Assuming that 1% level is equivalent to 126 gallons of "hot" water
[see above.]

Then, equivalent volume of "cold" water is 75.6 gallons

Then this level increase is equivalent to an inventory change of 907 gallons of "cold" water

At an average rate of 10 gpm for 95 minutes

Estimation of primary to secondary flow rate during this period (19:29 to 21:04)

Total Inflow to RCS = Letdown Flow + Tube Rupture Flow + Pressurizer Inventory Change

Therefore, Tube Rupture Flow = Total Inflow to RCS - Letdown Flow - Pressurizer Inventory Change

Tube Rupture Flow =	139 minus	38	minus	10	=	91 gpm
Total primary to secondary leakage volume during this period					=	8685 gallons

The above methodology is appropriate for time periods prior to SI. For times after SI it is concluded that the pressurizer level measurements are inaccurate due to the emptying of the pressurizer and possible steam intrusion into the instrument's reference leg. Consequently, a secondary side balance is used to determine leak rate for the periods after SI. This gives more accurate result as the steam generator was isolated by closing the MSIV and the steam generator blowdown prior to this time period.

If the steam generator is isolated then the level increase in the generator can be attributed to primary to secondary side leakage and the leakage rate can be determined from the SG 24 level increase. (SP-19 (Ref. 4) gives the relationship between SG WR level and gallons).

Time Period **Post Manual SI (21:04 to 21:30)**

Steam Generator 24 Level from SAS computer point L0463 (See Figure 6).

21:04 to 21:30	Steam generator level increased from approximately	62.5 to	68.2 %	

Assuming 1% wide range level is equivalent to 320 gallons then the volume increase over [Based on Graph SP-19].

this	26 minute	period	was	1824 gallons
			or	70 gpm

Time Period **Post Manual SI (21:30 to 22:00)**

Steam Generator 24 Level from SAS computer point L0463 (See Figure 6).

21:30 to 22:00 Steam generator level increased from approximately 68.2 to 71.0 %

Assuming 1% wide range level is equivalent to 400 gallons then the volume increase over [Based on Graph SP-19].

this	30 minute	period	was	1120 gallons
			or	37 gpm

Time Period **Post Manual SI (22:00 to 22:30)**

Steam Generator 24 Level from SAS computer point L0463 (See Figure 6).

21:30 to 22:00 Steam generator level increased from approximately 71.0 to 71.5 %

Assuming 1% wide range level is equivalent to 400 gallons then the volume increase over [Based on Graph SP-19].

this	30 minute	period	was	200 gallons
			or	7 gpm

Time Period **Post Manual SI (22:30 to 23:00)**

Steam Generator 24 Level from SAS computer point L0463 (See Figure 6).

22:30 to 23:00 Steam generator level increased from approximately 71.5 to 71.7 %

Assuming 1% wide range level is equivalent to 400 gallons then the volume increase over [Based on Graph SP-19].

this	30 minute	period	was	80 gallons
			or	3 gpm

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Time Period **Post Manual SI (23:00 to 23:30)**

Steam Generator 24 Level from SAS computer point L0463 (See Figure 6).

23:00 to 23:30 Steam generator level increased from approximately 71.7 to 72.0 %

Assuming 1% wide range level is equivalent to 400 gallons then the volume increase over [Based on Graph SP-19].

this	30 minute	period	was	120 gallons
			or	4 gpm

Time Period **Post Manual SI (23:30 to 06:00)**

23:30 to 06:00 Steam generator and RCS pressure were approximately equal throughout this time period. Steam generator level changes are therefore not due to leakage and cannot be used. RCS backfill from SG 24 and addition of auxiliary feedwater contribute to the level changes. (See Figures 1 and 7).

For this time period of	390 minutes	there was	0 gallons transferred.
		or	0 gpm.

Time Period **Post Manual SI (06:00 to 07:00)**

06:00 to 07:00 Steam generator level is increasing due to the addition of auxiliary feedwater and the primary to secondary leakage. Assume leak rate equal to that between 07:00 and 12:30. (See Figure 1).

For this time period of	60 minutes	there was	655 gallons transferred.
		or	11 gpm.

Estimated Primary to Secondary Leakage During Tube Rupture Event Calculation PGI-00443-00

Time Period **Post Manual SI (07:00 to 12:30)**

Steam Generator 24 Level from SAS computer point L0463 (See Figure 1).

07:00 to 12:30 Steam generator level increased from approximately 81.0 to 90.0 %

Assuming 1% wide range level is equivalent to 400 gallons then the volume increase over
[Based on Graph SP-19].

this	330 minute	period	was	3600 gallons
			or	11 gpm

Time Period **Post Manual SI (12:30 to 14:00)**

Steam Generator 24 Level from SAS computer point L0463 (See Figure 1).

During this period the indicated SG 24 water level held constant at approx. 90%. However, there was also a substantial primary to secondary side pressure drop which would suggested continued leakage. It is conservative to assume that leakage continued at the same rate as in the previous time period. An "artificial" level is therefore used in this calculation.

12:30 to 14:00 Steam generator level increased from approximately 90.0 to 94.0 %

Assuming 1% wide range level is equivalent to 400 gallons then the volume increase over

this	90 minute	period	was	1600 gallons
			or	18 gpm

Time Period **Post Manual SI (14:00 to Cold Shutdown)**

14:00 to Shutdown Steam generator and RCS pressure were approximately equal throughout this time period. Therefore, there was no primary to secondary leakage during this period. (See Figure 1).

For this time period there were		0 gallons transferred.
	or	0 gpm.

Figures

Figure 1 RCS Wide Range Pressure, Steam Generator 24 Outlet Pressure, Loop 1 Cold Leg Temperature (WR), RHR Hx Header Temperature and Steam Generator 24 Wide Range Level. 18:00 2/15/00 to 18:00 2/16/00.

Figure 2 Charging and Letdown Flow 19:00 to 24:00 2/15/00.

Figure 3 Pressurizer Level 19:00 to 24:00 2/15/00.

Figure 4 Steam Generator 24 Pressure 19:00 to 24:00 2/15/00.

Figure 5 RCS Pressure 19:00 to 24:00 2/15/00.

Figure 6 Steam Generator 24 Wide Range Level 19:00 to 24:00 2/15/00.

Figure 7 Steam Generator 24 Wide and Narrow Range Level, Pressure and AFW Flow 19:00 to 21:00 2/15/00.