Indian Point Unit 2
SGT Failure Risk Perspective

The licensee presented a risk analysis at the NRC Regulatory Conference. The licensee analysis determined that Yellow, not Red was the appropriate risk level for the steam generator findings. The key assumptions made in the licensee's analysis was that based on the 2000 SG inspection results, the likelihood of a tube leak (<225gpm) was much higher than a full tube rupture. A sophisticated method was employed to determine the frequency of tube failures which leak versus rupture. The licensee used this input to split SGTR calculations into 2 categories based on leak rate. The lower leak rate (higher probability) SGTFs were modelled with relaxed success criteria because of the additional time available for operator actions and the ability to use the charging pump if the SI pumps were to fail. These assumptions resulted in a lower delta-CDF value (delta CDF ~ 6.7E-6 (White)). The licensee also provided a site specific delta-CDF to delta-LERF correlation. The NRC's analysis used a conservative assumption provided in appendix H of the SDP guidance. The site specific LERF/CDF correlation reduced the fraction of SGTF sequences which result in core damage by nearly an order of magnitude. Using this assumption the licensee determined the delta-LERF was ~ 4.5E-6 (Yellow).

Key Assumptions

- Delta-CDF to Delta-LERF Conversion - NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Vol. 1 & 2, Figure 12.23, provides the conditional containment failure probability (CCDP) for large dry plus subatmospheric PWR containments. The CCDP is the probability that containment will be bypassed if a core damage event occurs. The CCDP for containment bypass is dominated by SGTR. From Figure 12.23 it can be determined that the worse case CCDP for SGTR containment bypass events is 0.45 (Prairie Island) followed by Ginna at 0.4 with the majority of other plants at ~ 0.1. Therefore, ConEdison's estimate of 0.13 for the delta-cdf to delta-LERF is reasonable.

- Initiating Event Frequency - ConEdison's risk analysis of this event used a complex monte carlo estimate to establish an initiating event frequency for the actual conditions in the steam generator. The analysis was very in-depth and resulted in a conditional SG tube failure probability of .28 for leaks between 75 gpm and 225 gpm and a conditional probability of .039 for ruptures of greater than 225 gpm. This analysis used the 2000 eddy current testing results to determine the magnitude and quanity of existing flaws, crack growth rate estimates, and material properties and tube stress levels to estimate the size and frequency of tube ruptures. These results are not consistent with the sparse industry experience of actual failures in NUREG/CR-6365 which describes 2 PWSCC failures [one at Surry (~330gpm) and one at Doel (~135 gpm)]. Since the licensee's analysis results are not consistent with actual industry experience, the NRC's estimate of 0.5 tube ruptures should continue to be used.

Analysis

- Spontaneous Ruptures - From the IPE the contribution of CDF from SGTR's is 1E-6. Dividing this by the revised initiating event frequency due to the performance issue (change IE frequency from nominal 1.3E-2/yr to .5/yr) will result in the spontaneous rupture delta-cdf for these findings. Delta CDF ~ 1E-6/.5=2E-6, Delta LERF=2E-6*.13=2.6E-7

Delta-CDF ~ 2E-6 Delta-LERF ~ 2.6E-7

- Induced Ruptures (Secondary Depressurizations) - using a initiating event frequency for a stuck open safety valve plus a steam line break inside containment from NUREG\CR-5750, Table 3-1 (5E-3+1E-3=6E-3) (less than the NRC's estimate for depressurization events 7.6E-3/year stated in IR 2000-10). Other assumptions 1/4 Sgs suspectible (all other defects passed burst test - negligible leakage at SLB conditions), probability depressurization will result in a rupture .5 (less than 1 used in IR 2000-10 due to insights from Regulatory Conference i.e all tubes with flaws met 3 times delta P burst margin criteria), human error probability 1E-2. The delta-CDF contribution is [(6E-3/4)*.5)]*.01= 7.5E-6. Since containment bypass is assumed delta-LERF ~7.5E-6

Delta-CDF ~ 7.5E-6 Delta-LERF ~ 7.5E-6

- ATWS induced SG Tube Ruptures - based on the licensee's PRA the ATWS contribution to delta-CDF is 5E-7. A conservative assumptions is that all ATWS CD sequences lead to a SGTR . Delta LERF ~ 6.5E-8.

Delta CDF ~ 5E-7 Delta LERF ~ 6.5E-8

Final Results

- **Total delta CDF ~ 1E-5 (Yellow) Total Delta LERF ~ 7.83E-6 (Yellow)**

Conclusion

The NRC's analysis for determining risk of this condition documented in IR 2000-10 determined a Red significance finding for both Delta-CDF and Delta-LERF. The licensee provided additional information at the Regulatory Conference that was used to modify the previous analysis. The risk estimates, while in excess of those determined by ConEdison show that Yellow would be the proper significance color for these findings. This assessment also shows that an extensive analysis of the licensee's monte carlo initiating event frequency is not needed and would not be an effective use of NRC resources.

Powering Bus 6A from EDG 23 if other EDGs failed during this event

1. Would the interlock have prevented the EDG 23 output breaker closure onto Bus 6A?

   No - SBO interlock would not prevent closure.

2. Given that there was a significant difference between the as-found condition and the set points of the over-current setting, why wouldn't the EDG output breaker trip again?

   EDG #23 would be available - amptector setting 3200 versus 6000 amps. Sequences of closure CCW/SWP/AFW pump AFW pump closed in between CCW and SWP which gave the AMPs > 3200 amps. Couldn't close in all 3 pumps.

   Close the breaker at control room. Could take some time to clear tagout ~ 1 hour. No tagout if failure to start - would be tagout if failure to run.

Powering emergency buses using Appendix R method in the event of failure of other EDGs

1. Which bus can be powered from this method?

   RHR, CCW, AFW, Charging, SI, SWP can all be supplied power.

2. What is the procedure used?

   AOP 27.1.9, Last ditch effort.

3. Approximately how long does it take to implement the procedure?

Powering buses 2A, 3A, 5A, and 6A from 6.9 kV buses en the event of failure of all EDGs

1. During the event, how did the operators recognize that the interlock signal prevented closing the breakers from the 6.9kV buses onto the 490V buses?

   Training 5A or 6A de-energized so blackout logic in effect!

2. During the event, if all three EDGs were failed, how would the operators recognize the method of bypassing the interlock?

   Bypassed SBO relays done before - ½ hour after having a TFC in hand jumpering out contacts.

3. Assuming that the operators recognized that the breakers are not closing due to the lockout, how will they figure out what needs to be done to override the interlock? How long will it take them to recognize the need to override the interlock? How long will take them to override the interlock?