## Risk Assessment for Indian Point Unit 2
## A Hypothetical Case
## Loss of Safeguards Electrical Bus 6A
## Coincident with a Steam Generator Tube Rupture

### Background:

**February 15 Steam Generator Tube Rupture**

The Indian Point Unit 2 facility experienced a steam generator tube rupture (SGTR) on February 14, 2000 when a flaw in the U-bend of tube R2C5 in steam generator 24 failed. This flaw had not been detected during the last nondestructive examination of steam generator tubes. During the recovery process there were no failures in equipment or operator actions that were needed to mitigate the consequences of this SGTR.

The conditional core damage probability (CCDP) associated with this event was calculated by ConEd using their risk model as 7.7E-05. This is comparable to the CCDP of 3.3E-04 calculated using the NRC's Rev. 2-QA Standardized Plant Analysis Risk Model (SPAR) for Indian Point Unit 2. Additional analysis was performed by NRR to quantify the increase in core damage frequency (CDF) and large early release frequency (LERF) that resulted from operation with the flawed steam generator tubes[1]. An incremental increase in CDF was calculated as 1.0E-04 per reactor year for the second year of operation. In accordance with the guidance from MC0609, Appendix H, the LERF frequency equals the CDF for a SGTR, therefor the LERF frequency for this condition is also 1.0E-04. (Reference: memorandum Barrett to Blough, dated May 4, 2000). Risk was dominated by the probability of human error in identifying and isolating the faulted steam generator and depressurizing the reactor coolant system to below the steam generator safety valve pressure.

**August 31, 1999 Reactor Trip and Loss of Safeguards Electrical Power**

The Indian Point Unit 2 facility ~~also~~ experienced a reactor trip on August 31, 1999, pri~~or to the SGTR~~. This trip was complicated by the loss of the 6A 480 volt ac safeguards electrical bus and the subsequent loss of the 24 battery. The loss of the 6A bus resulted in the loss of some emergency core cooling equipment including: one of the two motor driven auxiliary feedwater (AFW) trains, one of three high pressure injection trains, one of two high pressure recirculation trains, one of two residual heat removal trains and loss of power to one of the two normally closed PORV block valves. & Con Ed

The CCDP associated with this event was calculated as 2.0E-04 by the NRR Operations support team (OST). Risk was dominated by the failure probabilities of the one remaining motor driven AFW pump, the turbine driven AFW pump and the probability for non-recovery of main feedwater. Had All ~~auxiliary~~ feedwater failed, core damage could not be prevented through primary bleed and feed ~~The success for reactor coolant system bleed and feed requires flow through~~ Since both power operated relief valves (PORVs)~~, which was prevented because of the closed block valve powered by bus 6A~~. one need for successful B&F The CDF calculated using the NRC's Rev. 2-QA Standardized Plant Analysis Risk Model (SPAR) for Indian Point Unit 2 is somewhat less than that calculated by the

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[1] Subsequent examination determined that other tubes had not been detected during the examination preformed prior to the SGTR event.

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OST. The Rev 2-QA SPAR[2] model calculated a CCDP for this event of 4.9E-05. The difference being that the SPAR model uses industry average basic event equipment failure data where the OST used data from the IP-2 individual plant evaluation (IPE) without including credit for equipment recovery.

## Risk Analysis of Concurrent Events

The August 31st event was initiated following a normal reactor trip by safeguards bus undervoltage protective devices. A switchyard transformer automatic tap changer was positioned in its manual mode for an extended period. 480 volt ac bus voltage sagged following the trip because of plant distribution system impedance. All three emergency diesel generators (EDGs) started and their output breakers closed onto the three safeguards electrical buses, however, the generator output breaker to bus 6A tripped open on overload. Subsequent investigation found issues with the overcurrent trip device calibration process including the type of equipment used for this activity. Although the process deficiencies may have caused a common cause failure of all three EDG output breakers, only one of the breakers overcurrent trip point was mistakenly set low enough to cause an overcurrent trip. The above referenced risk analysis for this event did not include recovery of power from the EDG or offsite power. This was partially due to the fact that the licensee's organization performed poorly during follow-up to the event as evidenced by their allowing the associated station battery to discharge to the point of cell reversal.

In reviewing the circumstances of these two events, it is clear that the causes for the August 31st event may not have revealed themselves until the SGTR event. If that were the case the SGTR recovery would have become complicated by the loss of power to important emergency safeguards equipment. A SGTR is a significant challenge to operators who would have to cope with additional degraded plant equipment.

A risk assessment was performed of this hypothetical event, which imposed the bus 6A electrical failures on to a SGTR event analysis. The CCDP of 3.8E-04 was calculated using the NRC's Rev. 2-QA Standardized Plant Analysis Risk Model (SPAR) for Indian Point Unit 2. The probability for core damage was dominated by the failure to identify and isolate the faulted steam generator and the failure to depressurize the RCS.

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[2] The IP-2 Rev 2-QA SPAR model was corrected to reflect the normally CLOSED position of the PORV block valves and was revised to credit operator recovery of the RHR suction path MOVs for shutdown cooling. The SPAR model human error recovery process was used to calculate the HRA for this recovery action as 2.0E-03 after consultation with RI operator licensing personnel.