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

Background

The staff's initial risk assessment to support the significance determination process for the Indian Point unit 2 steam generator inspection findings estimated the increase in the large early release frequency" (LERF) to be on the order of 10^{-3}/reactor-year. This supported an initial significance level of "red." In response," Consolidated Edison Company, the licensee for Indian Point unit 2, presented results and some supporting information for its own revised risk assessment at the regulatory conference held on September 26, 2000.

The licensee's analysis made several changes to the earlier assessments. The steam generator failure initiating event was split into two parts, according to break flow rates, a monte carlo analysis was performed to estimate the frequency of the two break sizes, human error probabilities were reduced for events with the smaller break size, and 87% of the resulting core damage frequency (CDF) was removed from the LERF category on the basis of considerations regarding the path the radioactive materials would travel from the damaged core to the atmosphere. The licensee's analysis did not address the potential for additional LERF due to tube failure during a core damage accident that might be caused by some event unrelated to tube condition, such as a station blackout. The licensee's final result is a CDF contribution of 6.7×10^{-6}/ry and a LERF contribution of 4.0×10^{-6}/ry. If accepted by the staff, this would change the significance level to "yellow" on the basis of the LERF contribution.

SLIDE 37.

TEMP INDEX
SG TTL
$2.5 \times 10^{-5} \times .01$
$= 4.6E-7$.

Staff Response to Licensee's Analysis

The staff has reviewed the licensee's revised risk analysis and supporting material. Staff conclusions regarding each of the licencee's analytical modifications is discussed below, by topic. In the following section, the staff presents its final risk analysis incorporating those factors that it finds to be appropriate.

1. Split Initiating Event Frequency into Two Break-Size Categories

This technique for grouping initiating events is an appropriate and often-used technique in probabilistic risk assessments. It allows events that have different steps for the mitigation processes or substantially different probabilities for success of similar steps to be treated separately. The split used by the licensee puts tube breaks that exceed the flow of one charging pump but not full charging capacity into a different initiating event than the breaks that exceed full charging capacity. The licensee then reevaluated the human error probabilities for the increased time available at the maximum break flow for the smaller break size category. The staff finds that this is appropriate and can facilitate improved analysis. However, because reactor coolant system pressure can be maintained with breaks of the smaller size, there is still a potential for the break size to be increased during the event. Therefore, the logic for the smaller break size should account for the potential for operator error to create conditions that might increase the break size.

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2. Tube Break Flow Rate for IP2 Event on February 15, 2000.

The licensee presented a mass-balance analysis which concluded that the flow through the tube break during the February 15, 2000 event was 109 gpm. Staff review of the licensee's analysis indicates that the flow rate was higher. (See memo from ?? to ?? dated ??.) The licensee used their flow rate estimate and information on the crack length for this and other steam generator tube failures to demonstrate that apex cracking in tubes will not result in break flow rates as high as occur for other types of tube cracks of the same length. Only six data points are used, so this provides little confidence regarding the maximum flow rates possible from apex cracking. The licensee presented metallurgical data to indicate that apex cracks should burst at higher pressures and open less at sub-burst pressures, compared to cracks in straight tube sections. Staff analysis concludes that burst is still possible for apex cracks, although it may be less likely. Because the licensee's revised analysis did not attempt to take credit for a reduced maximum break flow rate for its large tube break event category, this issue is not important to the risk assessment conclusion.

3. Initiating Event Frequencies for Spontaneous tube Ruptures

The licensee used a Monte Carlo analysis to estimate the frequency of occurrence for tube breaks of each size. While the staff agrees that Monte Carlo techniques are appropriate tools for combining widely varying parameters with complex interrelationships, it notes that the results must be checked for consistency with known information before the results are credited. The licensee's results and the actual occurrences are:

Leak Rate Range	Faction of Results	Actual Events	
< 0.1 gpm	< 0.1%	0	(0%)
0.1 gpm to 75 gpm	37.2%	0	(0%)
75 gpm to 225 gpm	55.0 %	2	(67%)
> 225 gpm	7.8%	1	(33%)

Because all of the real events had flow rates ≥135 gpm, it would have aided the reality check if the licensee's results had a break point at that value. Even so, it is apparent that the ratio of the licensee's initiating event frequencies is substantially shifted from the actual experience. Given the one actual event with break flow above 225 gpm, the licensee's Monte Carlo analysis indicates that there should have been about 12 events with lesser flow rates, but only 2 have occurred. If it is assumed that the licensee's results have at least half of their 55% occurrence in the 75-to-225 gpm range occur below the 135 gpm value, then the comparison with experience indicates that there should have been 5 or 6 events with flow rates below 135 gpm, but none have occurred. On this basis, the staff concludes that the licensee's Monte Carlo analysis is not an appropriate basis for estimating the ratio between the initiating event frequencies for the two tube break sizes. The staff evaluation will use the 2:1 ratio from the actual experience.

A second issue with respect to the initiating event frequencies is that the licensee's risk assessment averaged the occurrence fractions given above over the entire 2 year operating period, effectively halving the initiating event frequencies. First, the staff notes that averaging is

inconsistent with the licensee's Monte Carlo analysis, which placed approximately 90% of the failures in the first 90 days of the two year period that was modeled. This provides another indication that the licensee's Monte Carlo analysis is not accurate for initiating event quantification. More importantly, the staff notes that the continuing deterioration of the tubes over time makes the last part of the cycle contribute the most risk, especially when operation is terminated by a tube failure. Therefore, the staff will base it's significance determination on the increase in core damage and large early release frequencies calculated as the average over the last year of operation for this case.

4. Human Error Probabilities

In a tele-conference on October 20, 2000, the licensee supplemented (and corrected some) of the information provided in the regulatory conference. Specifically, the conditional probabilities for core damage and large early release were provided for spontaneous and induced tube rupture sequences in each of the two tube break size ranges. These and their corresponding results are:

Sequence	Initiating Event Freq.	Conditional Probability	Result
SGTR >225	0.0385/yr	7.75×10^{-5}	2.98×10^{-6}/ry (CDF)
		$0.13 \times 7.75 \times 10^{-5}$	3.87×10^{-7}/ry (LERF)
SGTR 75-225	0.275/yr	2.90×10^{-6}	7.97×10^{-7}/ry (CDF)
		1.60×10^{-6}	4.4×10^{-7}/ry (LERF)
MSLB/SGTR >225	0.0076/yr x 0.0385	2.5×10^{-3}	7.31×10^{-7}/ry (both)
MSLB/SGTR 75-225	0.0076/yr x 0.275	1.0×10^{-3}	2.09×10^{-6}/ry (both)
			6.6×10^{-6}/ry (CDF)
			3.6×10^{-6}/ry (LERF)

This information provides some insight into the degree of mitigation credit taken in the licensee's analysis for the smaller break size. For spontaneous tube ruptures, it is about a factor of 27 reduction for CDF and about a factor of 6 for LERF. For the sequences with tube rupture induced by steam line break, the factors are only 2.5 for CDF and LERF. Although the overall human error probability appears to quite small (for an HEP) in the case of the spontaneous SGTR case with break flow below 225 gpm, the staff has not performed its own analysis to check the licensee's value.

5. Tube Ruptures Induced by Steam Line Break

As indicated in the table above, the licensee used the same numerical values it had derived for the initiating event frequencies of the two break size categories as if they are also the conditional probability of inducing those sizes of breaks by increasing the pressure differential with a main steam line break event. The staff does not agree that this is mathematically proper nor physically logical. The staff estimates that the largest flaw left in service in 1997 had a conditional probability of 1 that it would rupture if exposed to the higher pressure differential resulting from depressurization of the secondary side of the steam generator during the last year of operation. At the regulatory conference, the licensee stated that it had considered the pressure differential across the tube wall to be limited to 1800 psi during a main steam line break accident, due to the characteristics of its safety injection pumps. However, actual steam side depressurization events have resulted in higher pressure differentials because they were slower

depressurizations that did not require safety injection to maintain reactor pressure. — ALSO HYDO-TESTED TUBES & NO FAILURES

As a result the staff estimates that the conditional probability of a break in the 75 to 225 gpm range is about 0.67 and above 225 gpm is 0.33, based on experience with spontaneous rupture events. This is somewhat non-conservative, because the higher pressure differential would be expected to increase the crack opening, which would increase the flow rate.

6. Number of Steam Generators Affected by Steam Line Break

In the staff's initial risk assessment, only one steam generator was assumed to be degraded to the extent that a tube would rupture in the event of a steam side depressurization event. This provided a reduction in the risk associated with those depressurizations by a factor of 0.25, because most depressurizations affect only one generator. The licensee did not take credit for this reduction in its risk assessment. The staff believes that most tube U-bend apex cracking situations that result in the in-service rupture of a tube will show a "lead" generator in which the degradation is worst. As at Indian Point unit 2, the other generators probably will not have degraded yet to the extent that they are susceptible to steam side depressurization. Therefore, the staff has continued to apply the factor of 0.25 to the tube ruptures that are induced by steam side depressruizations.

7. Reduction of LERF from CDF

The licensee sorted its IPE core damage sequences due to spontaneous tube rupture according to whether the main steam line safety valve through which radioactivity is discharged to the atmosphere was modulating properly or was stuck open. If the valve was stuck open, the sequence was put in the LERF category; if it was modulating properly, the sequence was put in the category for successful containment. In it's previous risk analyses, the staff has put high pressure core damage sequences with ruptured steam generator tubes in the large release category so long as the pressure was sufficient to open the steam line safety valves. The staff does not believe that the effects on radionuclide deposition in the secondary side of the steam generator due to the modulating valve would reduce the amount of radioactivity ultimately released sufficiently to make the event appear to be more like a contained core damage accident than an accident with a large early release. This is the major effect claimed by the licensee. However, the licensee also claimed that the thermal-hydraulic calculations of core damage accidents performed to support its IPE showed that proper operation of the steam safety valves caused reactor coolant system (RCS) pressure to remain high enough that the RCS eventually burst by creep failure inside the containment. The staff believes that effect, if it occurs, could reduce the amount of radioactivity released to the atmosphere sufficiently to move an accident sequence out of the LERF category. However, the thermal-hydraulic calculations were performed some time ago with the MAAP 3.0B rev16 code, which the NRC staff has found to produce results that differ substantially from the results of current NRC codes for this type of analysis. It is also unclear that a steam safety valve that was modulating properly would continue to do so when the gas passing through it became very much hotter than its design temperature. Therefore, the staff analysis that follows for this significance determination does not credit this factor for LERF reduction, but does consider it as a sensitivity study.

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8. Tube Ruptures During Core Damage Sequences with Causes Other Than Tube Degradation

As discussed in NUREG-1570, core damage sequences caused by events such as station blackout can be changed from the non-LERF to the LERF category by failure of degraded steam generator tubes during the accident sequence. There are two potential causes for tube failure. One is the potential for increased differential pressure to cause tube rupture if the steam side of a steam generator becomes depressurized while the reactor is still pressurized. Previous risk assessments have applied probabilities that a steam generators would depressurize due to a stuck-open safety valve on the steam line. In addition, because steam side leak tightness is not normally tested in pressurized water reactors, there is little assurance that a steam generator would remain pressurized, once it has evaporated all of its water inventory, even if all valves were nominally "closed." This also means that there is only anecdotal experience to provide data on the probability that a steam generator will depressurize when empty. Indian point unit 2 has provided some of the previous anecdotal experience. It also had some indication of leakage into the steam line during the February 15th event. And, after some valve work induced more leakage, IP2 was unable to pressurize the secondary side of the steam generator for a test during the outage. However, the licensees risk assessment declined to add to the LERF category for these sequences, citing the probability of 0.018 used in NUREG-1150 for conditional tube failure probability during SBO core damage sequences. Considering the staff's estimate of 1 for the conditional probability of tube rupture in the event of an elevated pressure differential, the staff believes that this is a significant omission from the licensee's analysis.

The other potential cause for steam generator tubes to rupture during core damage sequences is that the tubes may be subjected to very high temperatures as the core melts. This would weaken the tube material and may lead to a rupture if the tube is sufficiently degraded. The conditions found by previous analyses to be necessary for this to occur are high reactor pressure and a dry, depressurized steam generator. These are called the "high/dry" core damage sequences. This was discussed at the regulatory conference. The licensee's consultant stated that the short radius U-bend tubes are located in a region of the tube bundle that is not expected to be heated the most during these accidents. The staff pointed out that, in one of 4 transient tests conducted in a 1/7th scale model, tubes in the region of the tube bundle that contains the tube that failed at IP2 on February 15th were in the portion of the tube bundle that received the hot flow. The licensee responded that, although they were in the hot gas flow path, they were substantially cooler than the hottest tubes and would not be expected to exceed 800 Kelvins (K) at the U-bend region where the crack was located. On that basis, the licensee concluded that the material would not weaken enough to result in tube failure. The staff has checked this assertion and estimates that the tube apex temperature could reach about 850 K, provided that the steam generator is depressurized and the flow pattern is as depicted in that one of the 4 transient tests. This temperature would reduce the material strength by about 20%. Although the tube that failed on February 15th would be expected to fail if material strength was reduced by 20%, the depressurized condition of the steam generator that would allow that temperature increase by itself would have lead to failure of that tube. Therefore, the staff agrees with the licensee that the potential for thermally-induced rupture is not a substantial consideration for this risk assessment.

Final Staff Risk Assessment

Initiating Event Frequencies

The staff analysis is based on the position that the licensee's failure to identify the inadequacy of its tube inspection process for control of degradation by apex cracking would eventually lead to a tube failure event while in operation. For cases where an apex crack was found by inspection before one had failed in service, it is assumed that another cycle would begin without adequate inspection. Indeed, that was what occurred in 1997. Therefore, the probability that an in-service event would eventually occur is taken to be approximately one.
Thus, the issue becomes what the probabilities are for each type of potential in-service failure. As described in the previous section, the staff does not find the licensee's Monte Carlo analysis sufficiently realistic to provide this information. So, the staff has used the meager experience base to assign probabilities. None of the in-service failures of apex cracks to date has been a leakage event that could be considered to "leak before break" in a manner that would allow the reactor operators to avoid the imminent break. One break has produced a flow rate above 225 gpm, and the other two have produced flow rates approximately in the middle of the 75 to 225 gpm range. Therefore, the probabilities are split as 0.33 for breaks above 225 gpm and 0.67 for breaks between 75 and 225 gpm.

The frequency that the staff considers in the significance determination process is the worst annualized frequency attained if the event is protracted and worsens over multiple years. Therefore, the staff has assumed a total frequency of one in-service failure event in the last year of operation before that event occurs to terminate the condition.

Conditional Probabilities for Tube Rupture Induced by Steam Generator Depressurization

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As discussed in the preceding response to the licensee's analysis, the staff believes that the most frequent types of steam generator depressurization events are those that occur from stuck safety valves and other holes smaller than the full rupture of the main steam line. These events have most often allowed the RCS to remain at or return to high pressures, creating differential pressure across the stream generator tubes near 2200 psid. Under those conditions, an apex flaw that would eventually fail within a year at normal service conditions is expected to be weak enough already to fail under the depressurization transient conditions. Therefore, the staff sets the conditional rupture probability to unity for the last year of operation. This is split to 0.33 for breaks above 225 gpm and 0.67 for breaks between 75 and 25 gpm.

Human Error Probabilities and Conditional Probabilities for Core Damage

The licensee's conditional probability for core damage given spontaneous tube rupture >225 gpm is in close agreement with the staff's value for 600 - 800 gpm events. In the staff's analysis, this value is dominated by human error probabilities. Therefore, the staff believes it is reasonable to expect a substantial reduction for SGTR events below 225 gpm. However, the staff has no independent analysis to provide a value to quantify the risk. So, the licensee's value is used, with caution in interpreting the results.

For tube ruptures induced by steam line breaks, the conditional core damage frequency the staff used in its initial analysis was 1×10^{-2}, based on analyses described in INEL-95/0641 for MSLB events with 1 failed tube. The range of human error probabilities in that document is broad, and it does cover the licensee's values of 1 and 2.5×10^{-3}. That makes this part of the quantification very uncertain and subject to debate. However, the staff will continue to use its initial value for

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Staff Results

For spontaneous and MSLB-induced ruptures, the staff CDF contributions are:

for SGTR >225 gpm:

$$0.33/\text{yr} \times 7.75 \times 10^{-5} = 2.56 \times 10^{-5}/\text{ry}$$

for SGTR between 75 and 225 gpm:

$$0.67/\text{yr} \times 2.90 \times 10^{-6} = 1.94 \times 10^{-6}/\text{ry}$$

for MSLB with SGTR >225 gpm:

$$0.005/\text{yr} \times 0.33 \times 0.25 \times 1 \times 10^{-2} = 4.13 \times 10^{-6}/\text{ry}$$

for MSLB with SGTR between 75 and 225 gpm:

$$0.005/\text{ry} \times 0.67 \times 0.25 \times 1.0 \times 10^{-3} = \underline{8.37 \times 10^{-7}/\text{ry}}$$

3.25×10^{-5}/ry total CDF and LERF

As in previous analyses, the staff estimates that the LERF contribution from these sequences is equal to this CDF contribution. Thus, the staff's analysis produces a result that is clearly in the " red" numerical range for LERF, without consideration of the LERF contributions due to pressure-induced tube failures in other core damage sequences. (As previously described, some accident sequences already in the licensee's base CDF but not in the base LERF would be changed to the LERF category by inclusion of the effects of tube ruptures that could be induced by changes in the differential pressure across the tubes in those sequences. Thus, those sequences also contribute to the total LERF associated with the tube degradation.)

Sensitivity Study

As a sensitivity study, the staff also analyzed a case crediting the licensee's distinction between LERF and non-LERF sequences. Using the licensees conditional LERF probabilities, these results become:
for SGTR >225 gpm:

$$0.33/\text{yr} \times 7.75 \times 10^{-5} \times 0.13 \quad = 3.32 \times 10^{-6}/\text{ry}$$

for SGTR between 75 and 225 gpm:

$$0.67/\text{yr} \times 1.60 \times 10^{-6} \quad = 1.07 \times 10^{-6}/\text{ry}$$

for MSLB with SGTR >225 gpm:

$$0.005/\text{yr} \times 0.33 \times 0.25 \times 1 \times 10^{-2} \quad = \cancel{4.13 \times 10^{-6}}/\text{ry}$$

for MSLB with SGTR between 75 and 225 gpm:

$$0.005/\text{ry} \times 0.67 \times 0.25 \times 1.0 \times 10^{-3} \quad = \underline{8.37 \times 10^{-7}/\text{ry}}$$

9.36×10^{-6}/ry LERF (partial - crediting licensee's reduction factors)

This estimate of the LERF contribution from these sequences is just below the red/yellow threshold. However, it does not yet include any consideration of the additional LERF that would result from steam generator depressurization-induced tube ruptures during other core damage accidents, such as those caused by SBO events. Those events are estimated as the "high/dry" portion of the core damage frequency times the probability that the steam generator is depressurized. The licensee has not tabulated the "high/dry" portion of their core damage frequency for Indian Point unit 2, so values from similar plants are used by the staff to complete the sensitivity case. Staff analyses for similar plants have found "high/dry" core damage frequencies in the range of 1-to-2 x 10^{-5}/ry. Estimation of the fraction of these events with a depressurized generator is highly speculative. However, if only one generator is degraded and its probability of it becoming depressurized is only 0.03 to 0.06, that would bring the total LERF to the red/yellow threshold. That probability is somewhat less than the values used previously

by the staff in NUREG-1150 and NUREG-1570, so their inclusion is expected to increase the total LERF above the 1 x 10^{-5} threshold.

More importantly, the severe accident management guidelines now call for operators to depressurize the steam generators and use low pressure pumps (such as the diesel-driven fire pump) when core damage appears imminent during high pressure core damage scenarios that do not have high-pressure feedwater available (e.g., station blackout scenarios). This could bring the probability of depressurizing the weak steam generator to a value near 1.0 for the " high/dry" accidents. *That alone would put the LERF contribution from the most degraded generator above the red/yellow threshold.* (It is of interest to note that the same procedure, if reliably applied to the sequences that reach core damage because of tube failure, might essentially eliminate LERF from those sequences. This is because high pressure feedwater is available for most of those sequences, it only has been isolated from the ruptured generator in accordance with the emergency operating procedures.) Consequently, consideration of the severe accident guidelines that were implemented after and not credited by the licensee's IPE, could change the situation with respect to which sequences would contribute the most to LERF, but still would be expected to produce a LERF contribution above 1 x10^{-5}/ry.

Consequently, the staff concludes that an analysis that accounts for all LERF contributions will have results above 1 x 10^{-5}/ry for a year during which a steam generator is degrading severely enough to allow a tube to rupture during normal operation.

Staff Conclusion

The forgoing staff review and analysis has demonstrated that, when all contributions to LERF are considered, the condition being assessed is most likely to remain in the "red" category, with its LERF increment above the 1 x 10^{-5} threshold. This is true even when considerable credit is given for reduced human error probabilities for the smaller break size events and the licensee's rational is credited for taking much of the CDF contribution out of the LERF category. It is expected to remain above the threshold if the recent severe accident guideline for refilling steam generators is taken into account. On this basis, the staff concludes that the result of its risk evaluation is best quantified as a "red" result.

The staff acknowledges that it is the nature of risk analyses that their numerical results are very uncertain. Although not expected, it is possible that knowledge gained in the future would alter this analysis sufficiently to change the conclusion regarding the "color" determination for a similar future inspection finding. However, for the purpose of assigning a color to past licensee performance, the staff believes that the performance should be judged on the basis of the risk perceptions at the time of the performance and finding. In that regard, the staff notes that current PRAs show steam generator tube ruptures to be a dominant contributor to public heath consequences from nuclear accidents. The IPE for Indian Point unit 2 has a conditional core damage probability of 7.75 x 10^{-5} and a conditional large release probability of 1 x 10^{-5} for a steam generator tube rupture. Additionally, though the IPE does not treat the induced tube rupture probabilities, these issues were been known from treatments in NUREGs 0844, 1150, 1477 and 1570. Also, tube support plate flow-slot hour-glassing and the associated tube U-bend apex cracking have been known phenomena that the Indian Point unit 2 technical specifications specifically addressed. Tube ruptures due to these phenomena had occurred

prior to 1997. Therefore, it is the staff's position that these risk perspectives at the time of the licensee's actions would warrant a "red" determination, and that mitigating knowledge developed after the fact is not relevant to judging the adequacy of the licensee's performance at a time when that additional knowledge did not serve as a basis for their actions.

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