November 20, 2000

EA-00-179

Mr. John Groth
Senior Vice President - Nuclear Operations
Consolidated Edison Company of
New York, Inc.
Indian Point 2 Station
Broadway and Bleakley Avenue
Buchanan, NY 10511

SUBJECT: FINAL SIGNIFICANCE DETERMINATION FOR A RED FINDING AND NOTICE OF VIOLATION AT INDIAN POINT 2
(NRC Inspection Report 05000247/2000-010)

Dear Mr. Groth:

The purpose of this letter is to provide you with the final results of our significance determination of the preliminary Red finding identified in the subject inspection conducted between March 7, 2000 and July 20, 2000. The inspection report was sent to you in a letter dated August 31, 2000. This inspection finding was assessed using the significance determination process and was preliminarily characterized as Red, an issue of high safety significance.

This finding involved deficiencies in the overall direction and execution of the 1997 steam generator (SG) inservice examinations at Indian Point 2. Specifically, Consolidated Edison did not identify and correct a significant condition adverse to quality, namely, the presence of primary water stress corrosion cracking (PWSCC) flaws in steam generator tubes, despite opportunities to do so. As a result, tubes with PWSCC were left in service following your 1997 SG inspection until one of these tubes failed on February 15, 2000, when the reactor was at 100% power. As noted in the subject inspection report, the specific opportunities to recognize degraded tubes included the identification of a PWSCC defect, indications of tube denting, and significant eddy current test signal interference. While there were no public health and safety consequences from the tube failure event itself, leaving the degraded tube in service following your 1997 SG inspections resulted in a significant reduction in safety margin during Operating Cycle 14 based on the increased probability of a steam generator tube rupture event.

Our August 31, 2000, letter also provided you an opportunity to attend a Regulatory Conference. The conference, which was open for public observation and transcribed, was held on September 26, 2000, to further discuss your views on this issue. During the conference, your staff discussed an analysis of the probability of a tube rupture, your assessment of the significance of the issue, and measures to prevent recurrence. Also, you indicated that your risk analysis characterized this issue as a Yellow finding, based on your plant-specific analysis of the degraded condition following the 1997 inspection. As a result of your presentation, the NRC requested additional information to support your contention. That additional information, as well as the transcript of the conference and your presentation, were issued by the NRC on October 24, 2000.

The NRC has evaluated the information developed during the inspection, as well as the information you presented during and subsequent to the conference. Based on that evaluation, although the NRC has lowered its calculation of the risk estimate in this case, the NRC revised risk estimate (Enclosure 2) remained above the threshold for classifying this finding as Red, an issue of high safety significance. The NRC recognizes that there is a wide band of uncertainty involved in such risk calculations and additional extensive review could possibly remove some of those uncertainties. Our risk estimate, which classifies the finding as Red, does include a sensitivity analysis that for certain assumptions shows a range of results at the Yellow/Red threshold. However, as noted in our October 10, 2000 letter, the Indian Point 2 facility has been found to have multiple degraded cornerstones. In response to deficiencies at the Indian Point 2 facility, the staff is following guidance in the NRC Action Matrix, which includes oversight of your performance improvement plan and conduct of a significant team inspection.

You have 10 business days from the date of this letter to appeal the staff's determination of significance for the identified Red finding. Such appeals will be considered to have merit only if they meet the criteria given in NRC Inspection Manual Chapter 0609, Attachment 3.

The NRC has determined that your failure to identify and adjust or modify the inspection methods and analysis to account for significant conditions that affected the quality of the 1997 steam generator inspection is a violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, as cited in the enclosed Notice of Violation (Notice). The circumstances surrounding the violation were also described in detail in the subject inspection report. In accordance with the NRC Enforcement Policy, NUREG-1600, the Notice of Violation is considered escalated enforcement action because it is associated with a Red finding.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS).

ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Hubert J. Miller
Regional Administrator
Region I

Docket No. 05000247
License No. DPR-26

Enclosures:
1. Notice of Violation
2. NRC Significance Determination Analysis

cc w/encls:
A. Alan Blind, Vice President - Nuclear Power
J. Baumstark, Vice President, Nuclear Power Engineering
J. McCann, Manager, Nuclear Safety and Licensing
B. Brandenburg, Assistant General Counsel
C. Faison, Director, Nuclear Licensing, NYPA
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C. Donaldson, Esquire, Assistant Attorney General, New York Department of Law
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and Development Authority
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NOTICE OF VIOLATION

Consolidated Edison Company of New York
Indian Point 2 Station

Docket No. 05000247
License No. DPR-26
EA-00-179

During an NRC inspection conducted from March 7 through July 20, 2000, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violation is listed below:

> 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions,” requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.
>
> Contrary to the above, despite opportunities during the 1997 Indian Point 2 refueling outage, Con Edison did not fully identify and correct a significant condition adverse to quality involving the presence of primary water stress corrosion cracking (PWSCC) flaws in four Row 2 steam generator tubes, in the small-radius low-row U-bend apex area. In conducting the 1997 steam generator inservice inspection, Con Edison did not adequately account for conditions that adversely affected the detectability of, and increased the susceptibility to, tube flaws. Specifically, while performing steam generator eddy current test (ECT) examination, during the 1997 outage:
>
> - a PWSCC defect was identified for the first time, at the apex of one row 2 tube, signifying the potential for other similar cracks in the low-row tubes. However, Con Edison did not adequately evaluate the susceptibility of low-row tubes to PWSCC and the extent to which this degradation existed.
>
> - indications of tube denting were identified for the first time in low-row tubes at the upper tube support plate (TSP) when restrictions were encountered as ECT probes were inserted into those tubes. Restrictions in 19 low-row tubes signified increased probability of deformed flow slots (hour-glassing) at the upper TSP. Hour-glassing of the upper TSP increases the stresses at the U-bend apex of tubes. These stresses are a prime precursor for PWSCC. However, Con Edison did not adequately evaluate the potential for hour-glassing based on the indications of the low-row tube denting.
>
> - significant ECT signal interference (noise) was encountered in the data obtained during the actual ECT of several low-row U-bend tubes. This significant noise level reduced the probability of identifying an existing PWSCC tube defect. However, the 1997 SG inspection program was not adjusted to compensate for the adverse effects of the noise in detecting flaws, particularly when conditions that increased susceptibility to PWSCC existed.

As a result, a minimum of four tubes (with PWSCC flaws in their small radius U-bends) were left in service following the 1997 inspection, until the failure of one of these tubes occurred on February 15, 2000 while the reactor was at 100% power.

This violation is associated with a Red SDP finding.

Pursuant to the provisions of 10 CFR 2.201, Con Edison is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555 with a copy to the Regional Administrator, Region I, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room). If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.790(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days.

Dated this 20th day of November 2000

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

Result

The staff has reviewed the licensee's risk assessment and its supporting analyses, and has produced this final risk assessment. For the purpose of significance determination, the numerical result of the staff's assessment is in the "red" range on the basis of a LERF contribution that is greater than 1×10^{-5}/reactor-year. The bases for this result are documented, herein.

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^{-4}/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 6.6×10^{-6}/ry and a LERF contribution of 3.6×10^{-6}/ry. If accepted by the staff, this would change the significance level to "yellow" on the basis of the LERF contribution.

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 licensee's analytical modifications are 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.

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 the Augmented Inspection Team report 05000247/2000-002 dated April 28, 2000.) The licensee used its 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 result in lower break flow rates than those that 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 take credit for a reduced maximum break flow rate for its large tube break event category, the difference in leak flow assumptions does not significantly impact the staff's analysis.

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	Fraction 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 $\geq$134 gpm, it would have aided the consistency 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. Similarly, a rough comparison can be made for events with flow rates above and below about 130 gpm by assuming that about half of the licensee's results for the 75 to 225 gpm range fall below 130 gpm. If so, then the Monte Carlo calculation predicts a 1:2 ratio of events with flows above 130 gpm to events with flows below 130 gpm. Because we have experienced 3 events with flows above 130 gpm, this would predict an additional 5 or 6 actual events with flows below 130 gpm. Therefore, the staff concludes that the licensee's Monte Carlo analysis does not provide an appropriate basis for estimating the ratio between the initiating event frequencies for the two tube break sizes. Accordingly, the staff evaluation used 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 two 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 appropriate for quantifying initiating events. 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 based its 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 teleconference 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)
		1.0×10^{-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}	$\underline{2.09 \times 10^{-6}\text{/ry}}$ (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 be very small (for an HEP) in the case of the spontaneous SGTR case with break flow below 225 gpm, the staff will use the licensee's HEP in the risk analysis[1].

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[1]Also, it should be noted for clarity that the factor of 0.13 between CDF and LERF noted in the licensee's presentation on September 26th actually was applied by them only to the spontaneous ruptures with break flows >225 gpm. They applied a factor of 0.55 for spontaneous ruptures between 75 and 225 gpm, and credited no reductions for ruptures

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 were also the conditional probability of inducing those sizes of breaks by increasing the pressure differential with a main steam line break event. This raises two issues.

The first is that the staff does not agree it is proper to use initiating event frequencies as conditional probabilities. The staff estimates that, during the last year of operation, 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.

The second issue is the numerical split of the conditional failure probabilities between the break size categories. 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 the plant's safety injection pumps. However, without a break in a tube, RCS pressure can exceed the shut-off head of the safety injection pumps once the cooling effect of the steam line break is terminated, because the charging pumps are still running. Operator action is necessary to limit the pressure differential across the tubes. The emergency operating procedure guidelines (EPGs) for Westinghouse plants call for limiting the pressure difference to 1600 psid to minimize the potential for inducing tube ruptures. But, the EPGs also state that the tubes will be able to withstand full RCS pressure so long as the tube integrity has been maintained according to the licensing basis requirements. The problem is that the operators will always expect that the tubes are being maintained in accordance with the licensing basis. Consequently, a pressure differential approaching the normal RCS pressure level may occur. Compared to its behavior in a spontaneous rupture, a crack that fails at a higher pressure difference would be expected to open more, which would increase flow rate. However, operating experience data is not readily available to derive the frequency of steam line breaks with each maximum pressure differential nor is the flaw population size data available to estimate the probability distribution of final flow rates after a crack fails.

As a result, the staff estimated that the conditional probability of a tube break was about 1.0 if a steam line break event had occurred during the final year of operation. Although somewhat non-conservative (induced tube failures would be expected to result in a larger fraction being at higher leak rates), the staff did set the probability for resulting flow rates in the 75 to 225 gpm range at 0.67 and the probability for flow rates above 225 gpm at 0.33. These estimates were based on experience with spontaneous rupture events not for induced tube ruptures.

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,

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induced by steam side depressurization events.

because most depressurizations affect only one generator. The licensee did not take credit for this reduction in its risk assessment. It is most likely that 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 the worst. Hydro-testing of steam generator tubes in all four steam generators, following the tube failure, validated the “lead” generator assumption. Therefore, the staff has continued to apply the factor of 0.25 to the tube ruptures that are induced by steam side depressurizations.

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 its 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 stated by the licensee. However, the licensee also stated 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 a break in the RCS boundary, 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 computer code version 3.0B rev16, which the NRC staff has previously 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 does not credit this factor for LERF reduction (LERF reduction factor assumed in ConEd’s analysis ~ 0.13), but does consider it as an element in its sensitivity study.

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 generator 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 licensee's 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 1.0 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, with depressurized secondary. 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 experience the highest temperature 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° Kelvin (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 particular transient test. 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 led to failure of that tube. Analyses with the steam generator still pressurized result in lower tube temperatures. Therefore, the staff agrees with the licensee that the potential for thermally-induced rupture is not a substantial consideration for this risk assessment.

So, the staff concludes that it is appropriate to disregard the potential for thermally-induced tube failures for sequences in the base CDF. But, it is necessary to consider the potential for pressure-induced failures to change some of the non-LERF base CDF sequences to LERF sequences, increasing the total LERF contribution associated with the tube degradation.

Final Staff Risk Assessment

<u>Initiating Event Frequencies</u>

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 provides this information. The staff used the existing experience base to assign probabilities for the two different steam generator tube rupture leak rates. 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 utilized by the staff in its analysis are 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.

For the frequency of generator steam-side depressurization events that might induce a tube rupture, the licensee did not dispute the frequency the staff used in its initial risk assessment. However, the licensee did state that its analysis assumed the differential pressure in those events would not exceed 1800 psid. That would affect both the frequency of the higher pressure differential condition and the estimation of the period of operation during which a degrading tube would be susceptible to rupture. The staff has reviewed the issue and agrees that the combination of frequency and period of susceptibility used in our initial assessment is probably too conservative. Ideally, the probability distribution of events as a function of pressure differential should be combined with the rate of declining tube strength over time to arrive at a net frequency for burst due to those events. However, the currently available data base is not designed to facilitate that analysis. So, for this final analysis, the staff has chosen a simplified approximation using the frequency of high differential pressure events from NUREG-0844 and the period of susceptibility to that pressure.

Conditional Probabilities for Tube Rupture Induced by Steam Generator Depressurization

As discussed in the preceding section, the staff's final analysis will consider only the depressurization events that are expected to create 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 assuming average values for the crack length and depth growth rates documented in the Condition Monitoring Operational Assessment (CMOA) report. Therefore, the staff sets the conditional rupture probability to unity for the last year of operation. Therefore, the probabilities utilized by the staff in its analysis are 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, 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 the large break case. For the smaller break case, the staff will adopt the licensee's value of 1×10^{-3}.

<u>Staff Results</u>

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

for SGTR >225 gpm:

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

for SGTR between 75 and 225 gpm:

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

for MSLB with SGTR >225 gpm:

$$0.001/\text{yr} \times 0.33 \times 0.25 \times 1 \times 10^{-2} \quad = 8.25 \times 10^{-7}/\text{ry}$$

for MSLB with SGTR between 75 and 225 gpm:

$$0.001/\text{ry} \times 0.67 \times 0.25 \times 1.0 \times 10^{-3} \quad = \underline{1.67 \times 10^{-7}/\text{ry}}$$

$$2.85 \times 10^{-5}/\text{ry total CDF}$$

As in previous analyses, the staff estimates that the LERF contribution from these sequences is equal to this CDF contribution as described in item 7 above.

In addition, it is necessary to estimate the LERF that would result from steam generator depressurization-induced tube ruptures during other core damage accidents, such as those caused by station blackout 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 total core damage frequency estimated in the Indian Point unit 2 IPE was 3.13×10^{-5}/ry, but the licensee has not tabulated the "high/dry" portion of their core damage frequency. Based on its experience with other pressurized water reactors, the staff expects the Indian Point unit 2 "high/dry" frequency to be in the range between 1×10^{-5}/ry and 2×10^{-5}/ry.

Estimation of the fraction of these events with a depressurized generator is highly speculative. NUREG-1150 estimated probabilities that one or more generators would depressurize as 0.74 and 0.05 for Surry and Sequoyah, respectively, based on procedural differences. NUREG-1570 added the concern about depressurization of dry generators by leakage through nominally “closed” valves. But, because no leak rate tests are required for main steam isolation in pressurized water reactors, only anecdotal data is available from events where leakage was large enough to affect normal plant operations. As a sensitivity study, NUREG-1570 added 0.50 as the probability for one or more of the isolated generators depressurizing by leakage.

Severe accident management guidelines have been implemented to refill dry steam generators when core damage seems imminent. For the “high/dry” core damage sequences, feedwater is usually not available, so procedures require depressurizing the generators one-by-one and filing them with water from low pressure sources. This alone could bring the conditional probability of depressurization to near 1.0 for the high/dry sequences[2]. For this analysis, the staff assumed that only one generator is sufficiently degraded to burst if depressurized. The staff has not yet calculated the thermal-hydraulic response of the reactor coolant system caused by adding cold water to a dry steam generator during a core damage accident. Phenomena such as condensing steam to depressurize the RCS, voiding the RCS loop seals by evaporation when the RCS depressurizes and allowing full-loop circulation of hot steam through the unfilled generators, and the repressurization effects when the accumulators discharge water onto hot RCS and core surfaces are too difficult to predict without detailed analysis. Therefore, it is not currently possible to predict what the effects would be on a still-pressurized generator with a severely degraded tube if one or more of the other generators was depressurized and successfully filled. But, there is a probability of 0.25 that the degraded generator would be the first to be depressurized, in which case the tube would fail. Therefore, the staff assumes that the conditional probability of the degraded generator becoming depressurized during “high/dry” core damage sequences is in the range 0.25 to 1.0.

When the conditional probability of depressurization for the degraded generator is applied to the expected “high/dry” frequency of 1×10^{-5}/ry to 2×10^{-5}/ry, the results are in the range 2.5×10^{-6}/ry to 2.0×10^{-5}/ry. This gives a total LERF estimate for the staffs analysis as:

LERF from additional CDF	=	2.85×10^{-5}/ry
LERF from “high/dry” base CDF	=	2.5×10^{-6}/ry to 2.0×10^{-5}/ry
total LERF	=	3.10×10^{-5}/ry to 4.85×10^{-5}/ry

[2]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 eliminate LERF from many of those sequences. This is because high pressure feedwater is available for many 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 1×10^{-5}/ry.

This result is well above the “Red/Yellow” threshold value of 1×10^{-5}/ry threshold used in the significance determination process.

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:

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

for SGTR between 75 and 225 gpm:

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

for MSLB with SGTR >225 gpm:

$$0.001/\text{yr} \times 0.33 \times 0.25 \times 1 \times 10^{-2} = 8.25 \times 10^{-7}/\text{ry}$$

for MSLB with SGTR between 75 and 225 gpm:

$$0.001/\text{ry} \times 0.67 \times 0.25 \times 1.0 \times 10^{-3} = \underline{1.67 \times 10^{-7}/\text{ry}}$$

5.38×10^{-6}/ry LERF from CDF crediting licensee’s reduction factors

So, if the staff also credits the licensee’s basis for considering 83% of the CDF from spontaneous ruptures to create releases too low to be in the LERF category, then the sum of the LERF contributions for all sequences considered by the licensee would be below 1×10^{-5}/ry. However, as discussed above, the licensee did not 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. In the staff’s base case analysis, above, that contribution was estimated in the range of 2.5×10^{-6}/ry to 2×10^{-5}/ry. Including that contribution, the corresponding sensitivity case LERF results is:

LERF from additional CDF	=	5.38×10^{-6}/ry
LERF from “high/dry” base CDF	=	2.5×10^{-6}/ry to 2.0×10^{-5}/ry
low sensitivity study total LERF	=	7.88×10^{-6}/ry to 2.54×10^{-5}/ry

Thus, the range of results for the sensitivity case include the numerical threshold for the “Red/Yellow” determination, with the larger portion of the range on the “Red” side. From this sensitivity case, the staff concludes that the question about the reduction in radiological releases created by a functioning steam line safety valve could be important when a plant is known to have a low “high/dry” component of its base CDF plus a high probability of maintaining the degraded steam generator secondary in a pressurized condition until the RCS fails inside the containment. However, the licensee did not address those factors in its response to the staff's initial risk assessment. Therefore, on the basis of the information available, the staff concludes that it is most probable that a LERF contribution above 1×10^{-5}/ry will occur for a year during which a steam generator is degrading severely enough to allow a tube to rupture during normal operation.

Staff Conclusion

The foregoing staff review and analysis has estimated 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 1×10^{-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 spontaneous rupture CDF contribution out of the LERF category. On this basis, the staff concludes that the result of its final risk evaluation is best quantified as a "Red" result.

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