10 CFR 50, Appendix B, Criteria XVI, 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 recurrence.

Contrary to the above:

1. During the 1997 refueling outage, the licensee identified primary water stress corrosion cracking (PWSCC) in a low-row tube in one of their steam generators. The PWSCC was located in the apex area of the U-bend of the tube. It was known at the time of this discovery, through generally available literature, that this area of the steam generator is vulnerable to this form of degradation. Although the licensee used an engineering study to evaluate this degradation and performed eddy current of the low row tubes in all the steam generators, the licensee did not take appropriate corrective action to assure the PWSCC was promptly identified and corrected in the steam generator. Specifically the licensee did not implement appropriate measures to determine the extent of the condition in the low row tubes. The licensee did not use available enhanced eddy current techniques to evaluate the condition of the other low row tubes to determine the degree to which they had PWSCC. In addition, the licensee did not inspect other vulnerable areas of the steam generator using eddy current techniques specifically devised to determine the over all extent of this condition.

2. During the 1997 eddy current testing of the low row tubes, including tube R2C5 in SG24 which failed on 2/15/00, the licensee encountered interference in the eddy current data in the form of base line noise. The eddy current data was used to evaluate the condition of the tubes and to detect flaws. The licensee did not identify the possibility the noise could mask signals representing flaws and did not take corrective actions to prevent the noise from masking the flaws that required evaluation. Specifically, the licensee did not adjust the data analysis techniques to compensate for the impact of the noise on the ability to evaluate the data, particularly in areas of the steam generator where there was an increased susceptibility to tube degradation.

10 CFR 50, Appendix B, Criteria IX, requires, in part, that measures be established to assure that special processes, including nondestructive testing, are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

1. At the time of the 1997 outage, the licensee had not established procedures to adequately determine the extent of steam generator flow slot deformation (hour glassing) in the uppermost support plate flow slots. This flow slot deformation is associated with steam generator tube denting and an increase in the stress on the low row tube apex. When the licensee encountered, during eddy current testing of several tubes, numerous eddy current probe restrictions (at the uppermost tube support plate locations) due to tube deformation caused by denting and hour glassing, the licensee did not adequately assess the existence of any flow slot deformation. This assessment would have provided an indication of increased stresses on the tubes and their enhanced vulnerability to PWSCC.

2. During the 1997 eddy current testing of several tubes, the licensee did not calibrate the eddy current plus point probe in conformance with the previously qualified technique.

S/1

This enhance eddy current technique is used to detect flaws in the U bend of the low row tubes. Specifically, the licensee did not use the proper calibration standard flaw size and phase rotation setting specified in the applicable Electric Power Research Institute (EPRI) qualification technique sheet which conforms with the special requirements contained in EPRI TR-106589-V1 "PWR Steam Generator Examination Guidelines: Revision 4" Volume 1.

As a result of these violations, at least four low row tubes had flaws (PWSCC) which were not identified and corrected in 1997, including Tube R2C5 in SG24 which failed on February 15, 2000.

SDP/ENFORCEMENT PANEL WORKSHEET
Indian Point 2 - February 15, 2000 - Steam Generator Tube Failure

EA:
Date of Panel: August 1, 2000

Licensee: Consolidated Edison Company of New York, Inc.
Facility/Location: Buchanan, New York

Docket No.: 50-247
License No.: DPR-26
Inspection/OI Report No(s): 2000-010
Date of Exit Meeting/OI Report Date: July 20, 2000

Panel Chairman (SES Sponsor): Brian Holian
Responsible Branch Chief/Lead Inspector: David Lew/Wayne Schmidt
Enforcement Representative: Dan Holody/Joe Nick
Other regional attendees: LATER
Headquarters attendees: LATER

ATTACHMENTS:
1. **SDP/enforcement Panel Disposition Record**
2. **Issues to Consider for Discretion**
3. **Special Inspection Summary**
4. **Risk Assessment and Input to Significance Determination Process**
5. **E-MAIL - Re: NRR Review of Con Ed Risk Analysis of IP-2 SGTR**
6. **Technical Information Provided by Con Ed on July 20, 2000, at a 11 Am Meeting**
7. **Con Ed Risk Assessment Calculation**
8. **Con Ed Vp Nuclear Engineering's Comments at the Close of the Exit Meeting**

1. Brief Summary of Issues/Potential Violations:

Con Edison management did not establish an effective 1997 steam generator inspection program that provided for adequate overall technical direction, as required by 10CFR50, Appendix B, Criterion IX Control of Special Process and Criterion XVI Corrective Actions. As a result, Con Edison did not recognize and take appropriate corrective actions for significant conditions adverse to quality relating to eddy current data collection/analysis and specific steam generator conditions. This lack of program quality contributed to the February 15, 2000, tube failure, in that detectable flaws in low radius U-bend tubes, including the tube that failed, were not identified,

It must be noted that Con Edison disagrees with the teams conclusions as discussed in Attachments 6 and 8. Con Edison provided some technical detail that will be reviewed by team members prior to the issuance of the report.

2. Purpose of Panel:

Discuss the Special Inspection Team's summary of findings and conclusions documented in Attachment 1, Section I.

Discuss and decide on the proper SDP assumptions for this event, see Reference 1, Section IV - Risk and Significance Assessment.

3. Regional Recommended Strategy:

Send choice letter for potential red finding as part of the IR cover letter.

A regulatory conference is recommended to discuss the performance issues and the CDF/LERF assumptions..

4. Analysis of Significance/Root Cause:

a. Actual Consequence(s):

The event had moderate risk significance. It involved a steam generator tube failure that resulted in an initial primary-to-secondary leak of reactor coolant of approximately 146 gallons per minute, and required an "Alert" declaration (the second level of emergency action in the NRC required emergency response plan). The event resulted in a minor radiological release to the environment that was well within regulatory limits. No radioactivity was measured off-site above normal background levels and, consequently, the event did not impact the public health and safety. The licensee's staff acted to protect the health and safety of the public. Specifically, the operators appropriately took those actions in the emergency operating procedures to trip the reactor, isolate the affected steam generator, and depressurize the reactor coolant system. Additionally, the necessary event mitigation systems worked properly. Notwithstanding the above, the NRC identified problems in several areas including operator performance, procedure quality, equipment performance, technical support, and emergency response. These problems challenged the operators, complicated the event response, and delayed the plant cooldown.

b. Potential Consequence(s):

See Attachment 3, section IV - Risk and Significance Assessment. Attachments 4 and 7 provides the more detailed initial NRC and Con Edison reviews, respectively, and Attachment 5 is the initial NRR review of the Con Edison assessment.

c. Potential for Impacting Regulatory Process:

d. Willful Aspects: None

e. Root Causes:

See Reference 1 - Section II - Conclusion/Root Cause

5. Apparent Severity Level(s)/Color and Basis:

An SDP Red finding is proposed. See Reference 1, Section V -Draft Notice of Violations.

Based on an initial review of EGM 96-003 Steam Generator Tube Inspections, updated June 1, 2000, Case #6 appears to apply.

The initial NRC SDP Red characterization is preliminary and based on a initial assumption of a SGTR with core damage and a large early release (LER) from a stuck open safety valve.

Con Edison's prepared a differing position based on assumptions for the day of the event to determine a CDF with a time profile greater than 50 hours; their assumption is that this does not result in an LER, but a release after the emergency plan has had time to act to protect the public, and would be a White finding.

6. Application of Enforcement Policy

A potential Red Finding and NOV with no Severity level is proposed IAW with the enforcement policy for SDP findings.

a. Enforcement/Performance History:

Indian Point 2 is an Agency Focus plant. Also a civil penalty was issued on February 25, 2000, for three violations related to a loss of offsite power event in August 1999. Those violations, issued prior to the new ROP implementation, were characterized as a Severity Level II problem.

b. Is Credit Warranted for Identification? Explain:

Credit is not warranted for identification. The problem was revealed through the steam generator tube failure event of February 15, 2000.

c. Is Credit Warranted for Corrective Actions? Explain:

Credit is not warranted for corrective actions. Although the actions to correct the problem of stopping the primary to secondary leakage were appropriate and the release of radioactivity to the environment was not measurable, the corrective actions were not comprehensive and are still being reviewed by NRR. Additional corrective actions, such as plugging all row 3 steam generator tubes, is under review. Issues related to Con Edison's Condition Monitoring and Operational Assessment of the event are not resolved.

The root cause provided by the licensee did not identify, not address, deficiencies in the processes and practices that were implemented for the licensee's 1997 steam generator inspection, as was inadequate as described in Reference 1, Section III - Performance Issues

d. Should Discretion Be Exercised to Mitigate or Escalate Sanction?

There are three issues on the 'List of Issues That May Warrant Discretion' for consideration. See Attachment 2 for discussion.

7. **Is action being considered against individuals?**

No.

8. Non-Routine Issues/Additional Information/Relevant Precedent/Lessons Learned:

Generic communication may be needed for this issue regarding NRC expectations and observations related to the use of the EPRI Guidelines on steam generator eddy current testing, poor signal to noise ratios (high noise levels), the significance of top tube support plant hourglassing and U-bend/top support plate restrictions, and oversight of the contractor. NRR would provide any programmatic guidance deemed necessary.

Attachment 1

SDP/Enforcement Panel Disposition Record

Licensee : Con Edison - Indian Point 2
EA No. ____________
Panel Date: ________
Issue: February 15, 2000 steam generator tube failure

Attendees

Chair - Holian Branch Chief - Lew Enf Reps Holody, NIck
OI Rep. - ________ RI Counsel - ______ Others - ____________
HQ Reps ____________

Required Actions (Preliminary Proposed Actions - See OE Strategy Form for official record of panel decision.)

1) **Apparent Red + Choice letter**

Responsible Person: ____________ ECD: ______

2)

Responsible Person: ____________ ECD: ______

3)

Responsible Person: ____________ ECD: ______

4)

Responsible Person: ____________ ECD: ______

Examples of Specific Actions To Be Documented

- Call Licensee and Schedule Conf or give heads up on choice letter
- Prepare summary of OI findings as attachments to choice letter or conf letter
- Issue letters scheduling conference or providing choice
- Gather additional information and repanel
- Prepare the draft enforcement action
- Finalize the enforcement action
- Forward Package to OE

Attachment 2

ISSUES TO CONSIDER FOR DISCRETION

- ☐ Case involves particularly poor licensee performance. Yes

- ☐ Excessive duration of the problem resulted in a substantial increase in risk. Yes

- ☐ Discretion should be exercised by escalating or mitigating to ensure that any proposed civil penalty reflects the NRC's concern regarding the violation at issue and that it conveys the appropriate message to the licensee. Yes escalate

ATTACHMENT 3

Indian Point 2 Steam Generator Special Inspection Summary

Prepared by: Wayne Schmidt - Team Leader - Region I - 610-337-5315

I. Inspection Scope:

The NRC conducted a special team inspection to review the causes of the failure of a steam generator tube on February 15, 2000. The NRC team members included personnel from the Office of Nuclear Reactor Regulation and Region I, and NRC-contracted specialists in steam generator eddy current testing. The purposes of the special inspection were to determine the adequacy of Con Edison's performance during the 1997 steam generator inspections and to assess Con Edison's root cause evaluation, date April 14, 2000. The team also reviewed portions of the June 2, 2000, Con Edison steam generator condition monitoring and operational assessment report (CMOA) for possible regulatory issues.

II Conclusion/Root Cause:

Con Edison returned Indian Point, Unit 2, to service in 1997 in a condition that deteriorated with time to the point that a steam generator tube failure occurred in February 2000. During this 31 month period the unit operated for approximately 19 months and was shutdown October 1997 - August 1998 (10 months), due initially to DB-50 circuit breaker problems and again August - October 1999 (2 months), following a loss of offsite power event.

The team concluded that the overall technical direction and execution of the 1997 steam generator inspection program were deficient in several respects. Con Edison did not recognize and take appropriate corrective actions for significant conditions adverse to quality that affected eddy current data collection/analysis. This increased the likelihood that detectable flaws in low row U-bend tubes were not identified.

III Performance Issues;

1. Based on a independent NRC review of eight U-bend PWSCC indications detected during the 2000 inspection, the NRC determined that at least four should have been identified in 1997. This included SG 24, R2C5, the tube that leaked on February 15, 2000. During the 1997 steam generator inspection Con Edison did not adequately respond to issues that decreased the probability of detection of small radius U-bend tube indications and increased the likelihood of apex flaws in the small radius U-bend steam generator tubes.

   More specifically, Con Edison did not:

   1. take appropriate corrective actions following identification of a new and significant tube degradation mechanism, i.e., inside diameter (ID) primary water stress corrosion cracking (PWSCC) at the apex of a low row U-bend tube. Operating experience indicates that apex cracking is more likely to result in tube failure than other U-bend cracks. The 1997 steam generator inspection program did not fully assess the implications of this new degradation mechanism and adjust, as appropriate, the inspection methods and analyses.

   2. recognize the significance of, and fully evaluate, the flaw masking effects of the high noise encountered in the eddy current signal. In the case of the steam generator tube that failed, the magnitude of the noise was a problem that negatively impacted the probability of detection. The data analysis techniques were not adjusted to compensate for the noise to improve the identification of a flaw signal and ensure the appropriate probability of detection, particularly when conditions which increased susceptibility to tube degradation existed.

   3. appropriately establish procedures and implement practices to address the potential for hour-glassing in the upper support plate flow slots. Hour-glassing in this location is indicative of increased stresses on the steam generator tubes, which increase the likelihood of tube cracks. Further, the potential existence and impact of upper support plate hour-glassing were not assessed following the identification in 1997 of eddy current probe restrictions at the upper support plate and the identification of a PWSCC indication at the apex of a steam generator tube.

   4. ensure the use of properly qualified eddy current techniques. The U-bend plus-point eddy current probe was not set-up properly for use. Specifically, you did not use the proper calibration standard and phase rotation specified by the EPRI technique qualification standard. While this issue had a small effect on the probability of detection of low row U-bend indications, it was another example that reflected the deficiencies in the overall technical direction and execution of the 1997 steam generator program.

   The team also concluded that Con Edison's root cause analysis for the tube failure, dated April 14, 2000, did not sufficiently address the above described deficiencies. While the root cause analysis attributed the tube failure to a flaw that was obscured by eddy current signal noise, it did not identify, nor address, deficiencies in the processes and practices that were implemented for the 1997 steam generator inspection.

IV Risk and Significance Assessment:

NRC Assessment:

During the February 15, 2000, event, the leakage from the apex crack in SG 24 tube R2C5 did not reach the full steam generator tube rupture (SGTR) flowrate, due to remaining crack ligaments in the flaw area. However, if additional stress had been placed on the flaw by any larger than normal differential pressure the SGTR leakrate could have been reached. Therefore the risk analysis was done assuming an SGTR. The risk associated with the condition of the tubes during Cycle 14 comes from several potential accident sequences:

1. Spontaneous rupture of a tube, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.

2. Rupture of one or more tubes induced by a steam system depressurization event, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.

3. Rupture of one or more tubes induced by a reactor system over-pressurization event, causing core damage and bypass of the containment by large radioactive releases.

4 A core damage event that occurs with the reactor system at normal operating pressure, inducing tube rupture by increasing tube temperature and/or tube differential pressure, causing bypass of the containment by large radioactive releases.

Of these, the first two increase both the core damage frequency (CDF) and the frequency of large radioactive releases bypassing the containment and reaching the environment (hereafter assumed to be a "large early release"). The latter two sequences are already included in the plant's core damage frequency estimate, but would not normally be included in its large early release frequency (LERF). The induced tube ruptures cause them to make contributions to LERF.

The NRC staff estimated the sum of these tube degradation related risk contributions to get a yearly incremental CDF/LERF for an SGTR of approximately 1E-4/reactor year (RY). Using the single SGTR over a 23 month period established a low bound event frequency of approximately 0.5 SGTR/RY. Because the condition deteriorated with time, it can be argued that the initiating event frequency had not increased over the first year but only during the last year of operation. This would establish a high bound of 1 SGTR/RY. Multiplying these two estimates of the initiating event frequency by the SGTR CDF/LERF probability results in estimates for the incremental CDF of between 5E-5/RY and 1E-4/RY.

Con Edison Assessment:

The preliminary Con Edison assessment states that the probability of CDF resulting from a SGTR is 1E-6/RY the initially assumed frequency of a SGTR as 1.3E-2/RY, so the yearly incremental CDF conditional core dame probability is 0.77E-4/RY (1E-6/1.3E-2)

Con Edison completed a more detailed calculation of CDF for the actual conditions present at the time of the tube failure and for the actual leakrate observed. This calculation assumes that the flow rate from the leak remains at below the design basis rate, which reduces the time to core damage and postpones the release time to the point that Con Edison believes it would not be considered an early release.

Significance Determination Process:

The magnitudes of the yearly incremental CDF for an SGTR in the initial NRC (1E-4/RY) and the preliminary Con Edison estimate (O.77E-4/RY) are relatively the same.

The new Con Edison calculation indicates a specific conditional CDF of 2.2 E-6, with no LERF

The current guidance for assigning risk significance is contained in a draft NUREG/CR titled "Basis Document for Large Early Release Frequency (LERF) Significance Determination Process (SDP) - Inspection Findings That May Affect LERF." The Office of Research is sponsoring the project at Brookhaven National Laboratory that is developing this guidance. The guidance is summarized in Table 1 of that document as shown here.

Table 1 Risk Significance Based on LERF and CDF

incremental CDF Range/RY	SDP Based on CDF	SDP Based on LERF
$\geq 10^{-4}$	Red	Red
$< 10^{-4} - 10^{-5}$	Yellow	Red
$<10^{-5} - 10^{-6}$	White	Yellow
$<10^{-6} - 10^{-7}$	Green	White
$<10^{-7}$	Green	Green

Therefore, the CDF/LERF increment associated for a SGTR event is considered to be clearly above the 10^{-5}/RY criterion for a "red" significance determination. However the Con Edison assumption for lower than design SGTR leakage drops the CDF to 2.2 e-6 with no LERF - so this would be a white CDF finding with no LERF.

V. Potential Notice of Violation

TO BE PROVIDED IN SEPARATE FILE

ATTACHMENT 4

May 4, 2000

MEMORANDUM TO: A. Randolph Blough, Director
Division of Reactor Projects
Region I

FROM: Richard J. Barrett, Chief ***/RA/***
Probabilistic Risk Assessment Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

SUBJECT: RISK ASSESSMENT AND INPUT TO SIGNIFICANCE DETERMINATION PROCESS FOR CONDITION OF INDIAN POINT, UNIT 2, STEAM GENERATOR TUBES DURING OPERATIONAL CYCLE 14 (TAC NO. MA8219)

As you requested, the Probabilistic Safety Assessment Branch has reviewed the information available and performed a risk assessment for the recent findings at Indian Point, Unit 2.

During operation Cycle 14, Indian Point, Unit 2, experienced degradation of steam generator tubes that culminated in failure of a flaw in the U-bend of tube R2C5 in steam generator 24. In addition, inspection following the tube failure event revealed five additional tubes with defects in the same region of steam generator 24, plus other defects in other regions and other generators. However, none of these other defects appears to have become susceptible to induced rupture by the time tube R2C5 ruptured spontaneously.

The risk associated with the condition of the tubes during Cycle 14 comes from several potential accident sequences:

1. Spontaneous rupture of a tube, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.

2. Rupture of one or more tubes induced by a steam system depressurization event, not successfully mitigated by plant operators, causing core damage and bypass of the containment by large radioactive releases.

3. Rupture of one or more tubes induced by a reactor system over-pressurization event, causing core damage and bypass of the containment by large radioactive releases.

CONTACT: Steve Long, SPSB/DSSA
415-1077

4. A core damage event that occurs with the reactor system at normal operating pressure, inducing tube rupture by increasing tube temperature and/or tube differential pressure, causing bypass of the containment by large radioactive releases.

Of these, the first two increase both the core damage frequency (CDF) and the frequency of large radioactive releases bypassing the containment and reaching the environment (hereafter assumed to be a "large early release"). The latter two sequences are already included in the plant's core damage frequency estimate, but would not normally be included in its large early release frequency (LERF). The induced tube ruptures cause them to make contributions to LERF.

The sum of these tube degradation related risk contributions for Indian Point Unit 2 during Cycle 14 is estimated to be a probability of core damage accident with a large release at approximately 10^{-4}. This risk occurred mostly during the latter year of the operational cycle.
The basis for this estimate is discussed below for each potential accident sequence, individually.

Spontaneous Tube Rupture:

The Indian Point, Unit 2, probabilistic risk assessment (PRA) includes this sequence. The probability of the initiating event, spontaneous tube rupture, was assumed to be 1.3×10^{-2} per reactor-year of operation (RY) and the resulting CDF was estimated as 1.0×10^{-6}/RY. From this, the conditional probability for failing to mitigate a rupture after it occurs is inferred to be 7.7×10^{-5}. This number is comparable to the conditional probability values obtained from the NUREG-1150 model for Surry, 1.4×10^{-4}, and from the NRC's Rev. 2 QA SPAR model for Indian Point, Unit 2, 3.3×10^{-4}. So, given that the spontaneous rupture initiating event did occur at Indian Point, Unit 2, the conditional probability of core damage is estimated to be about 1×10^{-4}. Because most of the core damage sequences resulting from spontaneous tube rupture involve loss of steam system integrity, approximately the same conditional probability applies to the occurrence of a large early release of radioactive material to the environment.

The most probable reasons for a spontaneous rupture event to cause core damage involve human errors while attempting to cool down the unit. The probability of the operators making (and not correcting) these errors depends on the amount of time available to them, which depends on the leak rate through the ruptured tube. The PRAs assume that the rupture is as large as can occur with one tube, which creates a leak flow of several hundred gallons per minute (gpm). The rupture that actually occurred at Indian Point, Unit 2, resulted in only about 150 gpm of leakage. So, the operators had much more time to correct the situation than is assumed in the PRA models that were used above to estimate the conditional probability of core damage. Thus, it can be argued that the probability of the Indian Point operators failing to mitigate this particular rupture was much lower than 10^{-4}. However, the flaw that failed in the Indian Point tube was about 2 inches long, and a flaw this long is capable of bursting to the extent assumed in the PRAs. The fact that the tube flaw was held partially closed by several ligaments across the flaw is the reason that it did not open completely and leak much more. Experience has shown that the probability is about 0.5 that tubes with large flaws will leak substantially or only partially break open before they fail completely, allowing operators an

Attachment 4

opportunity to intercede before complete failure occurs. Thus, the fact that the type of degradation that occurred can result in large flaws and that the flaw that failed was indeed large indicates that the risk associated with the degradation at Indian Point, Unit 2, is best estimated as having about 10^{-4} conditional probability of core damage and large release from the spontaneous rupture sequence.

Ruptures Induced by Steam System Depressurization:

Core damage sequences of this type are not generally included in licensees' PRAs, but have been evaluated by the NRC in NUREGs-0844, -1477 and -1570. They are similar to the spontaneous rupture sequences in licensees' PRAs except that the loss of steam system integrity comes first and causes the tube rupture instead of *vice versa*. As in the spontaneous rupture sequences, the most probable path to core damage involves errors in the operators' response to the conditions that occur. For a tube rupture induced by a steam system depressurization, the errors are estimated to be more probable because the events are more complicated and the operators do not normally drill on this type of sequence.

In the case of Indian Point, Unit 2, it is clear that a secondary depressurization event would have caused tube R2C5 to rupture when it was in the weakened condition that just preceded its spontaneous rupture. During that period, the CDF (and large release frequency) is estimated using a steam system depressurization frequency of 7.6×10^{-3}/RY, the assumption that only one of four steam generators was susceptible, a conditional rupture probability of 1.0, and a human error probability of 10^{-2}. The result is an increase in both the CDF and the large release frequency of about 1.9×10^{-5}/RY.

However, in order to estimate the increase in probability of core damage and large release, it is necessary to consider the length of time that this increase in frequency is applicable. Based on the currently available information, the period of time the tube was susceptible to this accident sequence is estimated in Appendix A as approximately 4 to 11 months or 0.3 to 0.9 year. Thus, the number of ruptures that would be mathematically "expected" for this frequency over this period is 6×10^{-6} to 1.7×10^{-5}. For such small expectation values, the probability of occurrence of a single event is numerically indistinguishable, so the increase in the probability of core damage and large release from this sequence for this condition is estimated to be about 1×10^{-5}.

Ruptures Induced by Reactor System Over-Pressurization Events:

Tube ruptures that are induced by the normal operational occurrences that involve slight elevations in reactor system pressure are considered to be captured by the value used for the frequency of spontaneous ruptures. The additional sequences considered here are those involving gross over-pressure events that, by themselves, would produce core damage. These result from failure of the reactor control system to shut down the nuclear chain reaction when required by a design-basis transient, such as loss of feed water to the steam generators. These events are called anticipated transients without scram (ATWS) events. Most licensees' PRAs include core damage sequences due to ATWS events, but do not consider the probability that such an event could also rupture a steam generator tube, causing containment bypass by the radioactive material it would release from the damaged reactor core.

The PRA for Indian Point, Unit 2, estimates a CDF contribution of 1.81×10^{-6}/RY due to ATWS events. ATWS events that create a reactor coolant system pressure above 3,200 psi are assumed to lead to core damage. During the period of extreme reactor system pressure, the steam system pressure is expected to be at the steam system safety valve setpoint, producing a pressure differential across the steam generator tube walls of at least 2,100 psid. Based on the rate of degradation estimated in Appendix A, we estimate that an ATWS event would have induced tube R2C5 to rupture for a period greater than 3 months. In the same manner described above for steam system depressurization sequences, this results in an estimated increase in the large early release probability that is $> 4 \times 10^{-7}$, perhaps by a factor > 3. There is no increase in the core damage probability because the ATWS sequences that would induce the tube rupture are already part of the CDF estimate, and the addition of the tube rupture potential is not assumed to change the frequency with which ATWS would cause core damage.

Tube Ruptures Induced by Other Core Damage Sequences:

Other core damage sequences that are included in licensees' and NRC's PRAs may also cause large releases by inducing steam generator tube ruptures, but this effect is rarely included in the results of current PRAs. The studies documented in NUREG-1150 and particularly NUREG-1570 do address this potential for large releases to bypass containment due to tube failures. For accident sequences in which the reactor coolant system (RCS) remains at high pressure, the failures of flawed tubes may be caused by steam system depressurization that sometimes occurs as an essential or incidental part of the event sequence that leads to core damage. Also, for sequences with high-RCS pressure and dry steam generators (hi/dry sequences), tube failure may be induced when the overheating reactor core causes the tube temperatures to rise so high that their metal weakens. Tubes with flaws that would not fail upon steam system depressurization may still fail when the tube temperatures increase, later in the accident sequence. This is clearly the case for the Indian Point tube for some period during the last cycle, before it was susceptible to failure by steam system depressurization, alone. It also is clear that, for some shorter period of time, tube R2C5 would have failed if dry and overheated by a high-pressure core damage accident, even if the steam system remained pressurized.

To accurately estimate the additional probability of a large release due to a core damage accident during the last cycle, it is necessary to separately identify the hi/dry core damage sequence frequency and subdivide it into cases with and without steam system depressurization. It also is necessary to estimate the time periods during which tube R2C5 was susceptible to rupture 1) from steam system depressurization, alone, 2) from high temperature without steam system depressurization, and 3) from the combination of high temperatures and steam system depressurization.

However, without expending the effort to perform this detailed analysis, it can be seen that the result would not substantially change the overall risk estimate for the situation at Indian Point Unit 2, during Cycle 14. This is based on the fact that the total CDF is estimated to be 2.6×10^{-5}/RY. Although the majority of this frequency is expected to be hi/dry sequences, and about half of those sequences may involve steam system depressurization, the contribution to the total increase in the large release probability would still be about an order of magnitude less than the dominant contribution from spontaneous tube rupture, even if tube R2C5 was susceptible for about a year.

Summarization of Overall Risk Increase:

On the basis of the foregoing discussions, it is estimated that the risk increase caused by the degradation of the tubes at Indian Point, Unit 2, during operational Cycle 14 is approximately 10^{-4} increase in core damage probability and a similar magnitude increase in large release probability. The risk from spontaneous rupture is the dominant contributor to the increases in both the core damage and the large release probabilities. The risk contribution from ruptures induced by steam system depressurizations adds about 10 percent of these totals, and the risk contribution from other core damage sequences that induce tube failure adds perhaps another 10 percent to the probability of large release, without increasing the core damage probability. More detailed analysis is not expected to change the magnitude of this estimate.

The risk input for use in a Significance Determination in accordance with the new Reactor Oversight Process is provided in Appendix B.

If you or your staff would like to discuss this assessment in further detail, please feel free to contact me or Steve Long.

cc: William M. Dean

Attachment 4

Flawed Tube Strength as A Function of Time

Based on the license's reanalysis of their eddy current results from 1997, it appears that an inside diameter flaw approximately 2.4 inches long and averaging approximately 72 percent through wall was present in steam generator 24 tube R2C5 when the plant was returned to service.

Based on these flaw size measurements, NRC staff in the Division of Engineering performed burst pressure estimates for the subject tube at the time it was returned to service. Available burst pressure prediction models apply specifically to straight tubes rather than to u-bend geometries. These straight tube models indicate a burst pressure in the range of 3200 to 3620 psi. Westinghouse work in the early 1980's indicates that tubes exhibit higher burst strengths in the u-bends for a given size flaw than in the straight length portions due to the cold-worked state of the material in the u-bends. This Westinghouse work is not well documented nor is there much corroborating evidence for this work. The best that can be drawn from this information at this time is that burst pressures are somewhere between zero and 58 percent higher in the u-bend than the straight length regions for given size flaws. Thus, the staff concludes that the subject tube had a burst capability in the range of 3200 to 5700 psi at the time the plant was returned to service in 1997.

When the tube burst during operation, it's burst pressure had decreased to the plant's normal operating pressure differential, 1600 psid. The period of power operation that elapsed between these times was 22.5 months.

Assuming that the growth in the flaw created a decrease in strength that was linear with time, the following table was constructed for the duration of the periods that the flawed tube was susceptible to rupture at various pressure levels that are important thresholds for the risk assessment process.

Initial strength	= 3,200 - 5,700 psid	at	23 months
TI-SGTR threshold	< 2,800 psid*	for	7 - 17 months
PI-SGTR threshold	< 2,350 psid	for	4 - 11 months
Spontaneous rupture	= 1,600 psid		(instantaneous)

* This value is an approximation, based on the stress magnification factor that resulted in a 50 percent failure probability in the analysis previously performed for the Farley, Unit 1, license amendment application review. Of the analyses currently available to the staff, that one is the most similar to the Indian Point, Unit 2, reactor. However, that analysis contained many assumptions about the location of the flaw and the spatial distribution of tube temperatures that are not identical to the situation at Indian Point, Unit 2. In addition, these two reactors have not been verified to produce the same thermal-hydraulic conditions for severe accident sequences. However, because the value is not crucial to the conclusion, it is considered sufficient and useful to indicate the nature of the situation.

Significance Determination Input

The draft significance determination process (SDP) for the New Reactor Oversight Process is based on changes to core damage frequency associated with a condition at a power reactor unit. For conditions that increase the frequency of a large early release (LERF) the threshold significance determination criteria are reduced by a factor of 10, compared to the criteria used for core damage sequences that do not produce a large, early release. The guidance for core damage sequences involving steam generator tube rupture is to consider them as LERF sequences .

The current guidance for assigning risk significance is contained in a draft NUREG/CR titled "Basis Document for Large Early Release Frequency (LERF) Significance Determination Process (SDP) - Inspection Findings That May Affect LERF." The Office of Research is sponsoring the project at Brookhaven National Laboratory that is developing this guidance. The guidance is summarized in Table 1 of that document as shown here.

Table 1 Risk Significance Based on LERF and CDF

Frequency Range/ry	SDP Based on CDF	SDP Based on LERF
$\geq 10^{-4}$	Red	Red
$< 10^{-4} - 10^{-5}$	Yellow	Red
$<10^{-5} - 10^{-6}$	White	Yellow
$<10^{-6} - 10^{-7}$	Green	White
$<10^{-7}$	Green	Green

The conceptual question is how to assign a frequency to an accident initiating event that has happened once as the consequence of a condition that has developed over a period of time. The following discussion is considered sufficiently quantitative to establish the risk input for determining the "color" of the situation that occurred at Indian Point, Unit 2.

Indian Point, Unit 2, was returned to service in 1997 in a condition that deteriorated with time to the point that a steam generator tube rupture occurred within approximately 23 months of operation. The risk assessment indicates that the reactor was susceptible to the various accident sequences primarily during the last year of this period. If the licensee's tube inspection and operational assessment processes that led to this event were repeated without improvement, it is expected that a similar result would occur. This is used to establish an average frequency for the steam generator tube rupture initiating event of about 0.5/RY. Because the condition deteriorated with time, it can also be argued the initiating event frequency had zero increase over the first year and was increased about 1.0/RY during the second year. Multiplying these two estimates of the initiating event frequency by the probability that core damage would not be averted (about 1×10^{-4}) results in estimates for the incremental CDF of 5×10^{-5}/RY and 1×10^{-4}/RY, respectively. Consideration of the other pertinent sequences

(where tube rupture is induced instead of initiating the sequence) is expected to add an additional increase on the order of 10^{-5}/RY. Therefore, the CDF/LERF increment associated this event is considered to be clearly above the 10^{-5}/RY criterion for a "red" significance determination.

Attachment 4

It should be noted that , if this risk analysis had been formally utilized as part of the revised reactor oversight program, it would have been subjected to additional review and discussion with the licensee and with the SDP and Enforcement Review Panel during the process for finalizing a significance determination. In addition, the assignment of a color in the significance determination process would depend upon a determination that the action or inaction that created the risk increment constituted inadequate performance by the licensee. Because, the agency has decided not to apply the revised program to this event at Indian Point, these steps were not taken. Therefore, this analysis should not be construed as the NRC's significance determination or the final establishment of a "color" for this event.

Attachment 4

ATTACHMENT 5

From: Steven Long
To: Richard Barrett, Thomas Shedlosky
Date: Thu, Jul 20, 2000 11:22 AM
Subject: Re: ConEd Risk Analysis of IP-2 SGTR

Tom,

I read the licensee's risk assessment and have some observations:

1. I basically agree with their results for what they did, but note that it is a calculation of the conditional core damage probability (CCDP) for an SGTR event with low break flow rate, not an assessment of the level of risk increase (deltaCDF and deltaLERF) that the plant had due to the degraded condition of the tubes. There are two important differences discussed below.

2. The licensee had no way of knowing before the tube failure that it would have such a low flow rate. The average SGTR has had about 350 gpm and the maximum has been around 700 gpm. So, part of the difference between their CCDP for the event that they actually experienced and the deltaLERF that the NRC uses for our significance determination process (SDP) is their luck in having the degradation revealed by a small failure instead of a large one. From our review of the size of the flaw that failed, it is obvious that much larger flow rates could have occurred if that long flaw had not been held mostly closed by multiple remaining ligaments. There is no guarantee that such ligaments will always be present in flaws or even that those that were present in this flaw would hold for the 52 hour duration assumed to be available in the licensee's human error probability calculations. (Some of the human errors involve leaving the flaw under stress for extended periods.)

3. There are other types of accidents, besides spontaneous tube rupture, that contribute to deltaLERF. These are steam-side depressurization events and core damage events that would have induced the tube to rupture if they had occurred before the spontaneous rupture occurred These types of events are included the PRAs (and some in the design basis), but without the potential for complication by induced SGTR. My risk assessment input to our SDP does consider these other types of accident sequences in addition to the spontaneous rupture sequence. They come in at the low E-5/RY range, so they don't dominate my result. However, they would have to be considered in detail before one could conclude that the deltaLERF for the IP2 SG condition was less than 1E-5, and therefore not "red".

So, in summary, I don't dispute IP2's CCDP analysis, but I do not agree that it is the proper basis for assessing the risk of the situation that was created by your finding that their inspection of their tubes was inadequate to justify the run time that they attempted.

Steve Long

>>> Thomas Shedlosky 07/20 8:55 AM >>>
I've attached a copy of the ConEd risk assessment of the February 15th SGTR, please note that ConEd has evaluated the condition at the actual maximum primary to secondary flow rate of 109 g.p.m. This allowed them to update the HRAs and also to take credit for charging.

Mr. A. Alan Blind
The issue will be moving into enforcement space shortly because the inspection that reviewed the steam generator tube inspection program concludes today with its exit meeting. We'll continue to need your support.

Tom Shedlosky
610-337-5171

Attached: MSWord Document psa-000717-1rev0.doc

CC: Brian Holian, Wayne Lanning

TECHNICAL INFORMATION PROVIDED BY CON ED ON JULY 20, 2000, AT A 11 AM MEETING MARKED DRAFT.

During the course of the NRC Special Inspection Team assessment of the Indian Point Unit 2 1997 steam generator inspection, the team raised a number of questions relating to the program. Additional clarification on five of the items is provided below.

Item Number 1

Con Ed did not recognize nor evaluate potential noise in the eddy current test (ECT) data. This is important as the noise could mask a 70% to 100% through-wall indication.

Discussion

In 1997 a single U-bend indication was detected in SG 24 Row 2 Column 67. At the time, a depth of 50% through-wall was estimated using a +Point probe and the tube was repaired by plugging. The indication had a signal to noise ratio of approximately 3 to 1 and the noise levels did not appear to differ appreciably from row 1 and 2 U-bend data from other plants. The inspection method used was the most advanced technique available in the industry and it appeared to us that the technique was performing as expected. Based on the information available in 1997, there was no indication that flaws between 70% and 100% through-wall would be missed due to noise. Also, there was no data available which would establish a correlation between signal amplitude and depth. It also should be noted that in 1997 there were no industry criteria to evaluate noise in a quantitative manner.

In response to the NRC's question, a current review of the 1997 data was conducted. The review of this data shows that the indication in R2 C67 had an amplitude of 3.11 volts while the background noise level was 1.04 volts peak to peak and 0.44 volts vertical maximum. This data was compared to the EPRI data for technique 96511 and the response from the calibration standards. It should be noted that the EPRI qualification data set consisted primarily of EDM notches placed in row 1 U-bend samples. It is recognized that EDM notches yield larger signal amplitudes for a given depth than PWSCC. In the absence of data from partial through-wall PWSCC specimens, the response of the calibration notches was benchmarked along with the noise levels present in the EPRI samples. The peak to peak and vertical maximum voltages are listed in the table below. All measurements were made from the 300 kHz component.

CALIBRATION STANDARD USED IN ETSS 96511

AXIAL EDM SLOTS	VOLTS PEAK to PEAK	VOLTS VERTICAL MAX
100 %	20.00	9.39
80 ID	5.40	1.96
60 ID	3.84	1.11
40 ID	2.17	0.44
20 ID	0.66	0.12

This data suggests that, given the noise levels in R 2 C 67, flaws $\geq$ 40% would be detectable (i.e. signal to noise for a $\geq$ 40% flaw is $\geq$ 1 to 1).

The 1997 noise level in SG 24 Row 2 Column 5 was also evaluated. This data shows a peak to peak amplitude of 1.63 volts and a vertical maximum amplitude of 0.98 volts. The result from this assessment suggests that flaw depths of approximately 50% TW and less may not be detected (signal

to noise < 1 to 1). This observation is consistent with NRC IN 97-26, "Degradation in Small Radius U-Bend Regions of Steam Generator Tubes" issued May 19, 1997 which states:

> *"There continues to be an absence of pulled tube information to confirm that the detection threshold for these cracks is better than 40 or 50-percent through wall. In addition, available inspection techniques are not capable of reliably sizing crack depths and, for this reason, it has been industry's practice to "plug on detection" U-bend indications that are found."*

The table below lists the EPRI samples, their noise levels, and the depth of the flaws in the u-bend.

ETSS 96511 FLAW MATRIX

SAMPLE	NOISE VPP	NOISE VM	DEPTH	DEPTH	DEPTH
Z5324	0.72	0.21	41	27	32
TVA-1	0.78	0.27	45	44	44
TVA-13	0.75	0.20	55	55	55
TVA-23	0.70	0.16	55	58	54
1019-I	1.26	0.29	40		
1019-III	1.39	0.61	50		
1019-IV	1.60	0.56	60		
1019-UB-I	1.22	0.41	60		
Z-5300	1.71	0.52	44	100	
TSL-126	1.19	0.19	>40		
TSL-15	1.33	0.16	>40		
TSL-2	1.03	0.20	100		
TSL-10	0.66	0.17	>40		
TSL-113	1.04	0.15	42	42	
TSL-115	1.27	0.16	62	62	
AVERAGE	1.11	0.28	N/A	N/A	N/A

The data shows that some samples had a noise level greater than that observed in R 2 C 67, while other samples were less. Specifically, 9 of 15 samples were ≥ 1.04 volts peak to peak and 3 of 15 Samples were ≥ 0.44 volts vertical maximum.

We would conclude that, based on the information available in 1997 reviewed at the time of the 1997 inspection without the benefit of the passage of time or 2000 inspection results, there was no indication that flaws between 70% and 100% through-wall would be missed due to noise.

Data quality criteria were not in place in 1997 across the industry, and guidance was only developed following the current evaluation of R2C5. There were no criteria and no database to form a postulate that the noise effects could mask a flaw such as that present in R2C5 in 1997. It is very doubtful that any review in 1997 of the finding of a single apex flaw in row 2 at Indian Point-2 would have rationally led to consideration of a potential imminent flaw. Hindsight is very enlightening, but any review of 1997 evaluations must be put into the knowledge basis of 1997 rather than after the knowledge gained from the R2C5 evaluation.

Item Number 2

There was no specific corrective action in response to a new and significant defect

at the apex of R 2 C 67. The flaw had been sized at 50% through-wall. ConEd should have recognized that corrective action was required in accordance with 10CFR Part 50 Appendix B.

Discussion

The corrective action taken in response to the detection of the R2C67 PWSCC indication was appropriate.

In 1997 Revision 4 of the EPRI Guidelines required the use of a qualified technique. We used such a qualified technique during the 1997 inspection – ETSS 96511. Moreover, the ECT response to R2 C67 was typical of those in the training materials, indicating to us that this technique was performing as was expected. A review of the EPRI ETSS shows that the noise levels in R2 C67 were bounded by the response of the samples used in the EPRI study.

The indication found in 1997 was based on the first +Point inspection of the IP2 low row U-bends following prior inspections with the bobbin coil. The first +Point inspections typically lead to an inspection transient (step increase in numbers of indications). The finding of a single U-bend indication in the +Point inspection after prior bobbin coil inspections was not considered an unusual event after about 16 EPFY of operation. In contrast, the Surry-2 tube rupture occurred in a row 1 tube after about 2 EFPY of operation when denting progression was very active with hourglassing progressing to flow slot closure, which exceeds that at the top TSP at Indian Point-2.

Based on the information available to us in 1997, reviewed at the time of the 1997 inspection without the benefit of the passage of time or 2000 inspection results, no additional corrective actions would have been required in response to the indication identified in R2 C67.

From a programmatic point of view, during the 1997 inspection, additional analyst training was provided whenever the inspection findings were unexpected. Discovery of ODSCC/IGA in the tubesheet crevice region during the course of the Indian Point 2 1997 inspection resulted in additional analyst training and re-evaluation of data in the tubesheet crevice region. This was done as these indications were not considered "typical flaw responses" and differed, somewhat, from the materials the analysts had been trained on. This was not the case, however, with the discovery of the R2 C67 indication.

All elements of the licensee and vendor quality assurance programs were complied with in 1997, and hence the requirements of 10CFR Part 50, Appendix B were satisfied.

Item Number 3

Given that some of the samples used in the EPRI study had noise levels *above,* while others had noise levels *below* those observed in R2 C67, we should not have used the POD listed in the technique.

Response

As discussed previously, the noise level in R2 C67 was bounded by the EPRI study. In addition, the analyst experience was that similar noise levels existed at other plants that were using the same ECT technique. In 1997 there was no Industry guidance which would have directed us, or suggested that we

use a POD other than that listed in the ETSS. Moreover, there are no NRC regulations, requirements or technical advisories that contain such direction or guidance.

Item Number 4

The correct calibration standards were not used.

Discussion

The calibration standards which were used in 1997 met industry standards and followed the then current EPRI guidance – EPRI PWR Steam Generator Examination Guidelines, Rev. 4.

EPRI PWR Steam Generator Examination Guideline – Revision 4 requirements for rotating probes were as follows:

Electro-discharge machining (EDM) and laser-machined notch standards are typically used to establish setup conditions for rotating probe technology. The notches should be of:

- *both axial and circumferential orientation, and*
- *standard lengths and depths on the OD and ID.*

There is no further guidance provided for specific depths of the notches. Although the 1997 IP-2 calibration standards did not include a 40% ID notch, they met the requirements at that time.

Item Number 5

The probe setup was incorrect. Probe motion was set to horizontal.

Discussion

The setup used in 1997 met the then applicable ETSS probe setup guidelines/requirements.

ETSS 96511 establishes phase (10 Degrees) on the 40% ID notch. The plus point technique, as applied at IP-2 in 1997, set phase such that residual probe motion was horizontal with the 20% ID notch at 0 to 5 degrees. The calibration standard used in the EPRI ETSS 96511 qualification did include a 40% ID notch. A review of this data shows that when the 40% ID notch is set at 10 degrees the resultant phase for the 20% notch is approximately 1 degree with residual from probe motion horizontal.

The EPRI Revision 5 standard used at Indian Point 2 during the 2000 inspections does have a 40% ID flaw, and this signal was used to calibrate the analysis software as specified in ETSS-96511. The site specific technique sheet, ANTS IP2-00-E, specifies 15 degrees for the 40% notch, which is more conservative than the 10 degree EPRI ETSS requirement. Review of the 1997 data for R2C5 using the mid-range probe and the 2000 setup with the phase rotation set at 15 degrees, also did not show a flaw.