INDIAN POINT 2 STEAM GENERATOR TUBE INSPECTION FINDINGS AND PRELIMINARY SIGNIFICANCE CHARACTERIZATION

COMMISSION TECHNICAL ASSISTANT BRIEFING

AUGUST 24, 2000

Indian Point 2 - February 15, 2000
SG Tube Failure
Commissioners' TA Briefing
August 24, 2000

- Introduction - Brian Holian, Deputy Division Director, DRS, Region I
- Special Steam Generator Team Inspection - Wayne Schmidt, Team Leader, DRS, Region I
- Risk Analysis - Steve Long, Senior Risk Analyst, DSSA, NRR
- Steam Generator Regulator Issue Summary - Ted Sullivan, Section Chief, DE, NRR

NRC Event Response and Special Inspection Team Findings

Wayne Schmidt, Team Leader, Region I

Introduction:

- Discussion of the February 15, 2000, event.
  - MD 8.3 - AIT focused on review of Con Edison's response.
    - Initial "Event Risk" Assessment (Conditional Core Damage Probability (CCDP))
    - Event cause not reviewed by AIT
- SG Special Inspection exited July 20, 2000.
    - Con Edison disagreed with the findings and provided some additional information.
  - Team's preliminary findings issued July 27, 2000.
  - Report in final Regional and NRR review (to be issued the week of 8/28).
    - Communication Plan
- SDP "Condition Risk" (Change in Core Damage Frequency (delta-CDF))
- Agency Focus Meeting 9/11 and SG Regulatory Conference 9/26.

Steam Generator Special Inspection:

- Reason for the Inspection
- Team Composition
- Inspection Phases
- General Background (SG specifics and history, technical specifications)
- Inspection Results
  - Performance Issues and Inspection Findings
- Con Edison Disagreements with Inspection Findings

Team Composition

Integrated NRC effort. Substantial coordination and cooperation between NRR and Region I in planning, conducting, and assessing findings.

- Inspection Support and Team Leader -Region I
- Engineering and Part Time Eddy Current Support -NRR
- Program Review Contractor Support -NRR
- Finding Characterization - Region I and NRR
- Significance Determination Process -NRR and Region I

Inspection Phases:

Broken up into several phases:

- Initial NRR engineering and contractor support to gather information and review the beginning of the 2000 outage.
- Assessment of 1997 Outage Performance
  - Steam Generator Visual and Eddy Current Inspection
  - Eddy Current Inspection Program
- Significance Determination Process - Assessing the potential risk of the findings.

Background:

IP 2 Steam Generators

- Model 44 SGs - no chemical cleaning done.
- 3,260 tubes - 92 in each of the low-rows (rows 1-4)
- Row 1 plugged prior to operation
- Mill-annealed Alloy 600 - 0.875-inch OD 0.05-inch wall thickness
- Six tube support plates provide horizontal stability
  - Each tube support plated has six flow slots flame cut across their diameter (between row 1 tube legs).

IP2 SG History

- Numerous degradation mechanisms prior to 1997
  - ODSCC
    - Crevice - between roll transition and the top of the tube sheet
    - Sludge pile
    - Dented areas
  - PWSCC
    - Tube roll transition
    - Dented tubes
    - None detected in U-bends
- 1997 Results
    - One PWSCC indication in the U-bend R2C67 in SG 24
    - Tube restrictions due to denting at the upper support plate
- February, 15, 2000 - tube failure
  - PWSCC at the apex of low-row U-bend (R2C5 in SG24).

Technical Specifications

- Eddy Current Testing
  - 40-percent TW defect plugging limit. (U-bend indications plugged on detection due to sizing problems.)
  - Report significant deformation of flow slots (hour-glassing).
    - Hour-glassing is the deformation of the flow slots, due to corrosion, to the point that the sides are forced towards the middle, making it look like an hour-glass.
    - Hour-glassing is significant because it moves the tube legs together putting stress at the tube apex.
    - Tube denting is a precursor to hour-glassing.
- Primary to Secondary Leakage Monitoring
  - Limited to 0.3 gpm

Inspection Results:

Initial Phase - 2000 Outage

- Observed use of the mid-range Plus Point probe and reviewed some 1997 data
  - Mid-range Plus Point U-bend technique not calibrated or setup in accordance with the EPRI qualification.
    - Technique changed to be correct
  - 2000 eddy current data was very noisy.
    - Con Edison did not have criteria for when the noise could be masking data.
    - Criteria developed - approximately 450 tubes exceeded the criteria. High frequency probe developed and used. Eight tubes with defects found out of the 450.

Steam Generator Inspection Results

- Overall the team found that technical direction for the 1997 SG inspection program (eddy current and visual) was deficient in several respects. Con Ed did not address conditions that adversely affected the detection of, and increased the susceptibility to, PWSCC flaws in the low-row, small radius U-bend tubes.

- 1997 - First instance of U-bend PWSCC defect (R2C67 in SG 24).
  - Significance not understood by Con Ed.
  - Apex flaws have been associated with through wall leakage and burst.
  - There have been tube ruptures due to PWSCC at U-Bend apex (Surry -2 1976)
  - No review for the possibility of hour-glassing.
  - No entry into the corrective action program.
  - Tube plugged on detection.

- 1997 - First instance of low-row (row 2) tube denting at the upper support plate.
  - Indicated a significant potential for hour-glassing.
  - 19 tubes identified, as U-bend restrictions. The team found that these were upper support plate restrictions due to denting. The tubes were plugged in accordance with TS.
  - No procedure or specific examination criteria for significant hour-glassing.
  - No corrective action program review.

- 1997 - Significant signal "noise" interfered with the data analysis in the U-bend areas.
  - This problem was not evaluated.
  - Detailed careful review of 1997 data could have identified four defects Included the one tube that failed (R2C5 in SG 24).
  - Con Ed did not investigate and evaluate noise in the other low-row tubes after finding the defect R2C67 in SG 24.
  - No corrective action program review.

1997 Steam Generator Program Issues

- Compared to Rev 4 of the EPRI Guidelines, technique qualification, data analysis guidelines, and analyst training reviewed.
- Con Ed did not ensure that the mid-range Plus Point used in the U-bend area was calibrated and setup in accordance with the EPRI technique -had a marginal effect on the detection of small flaws.
- Data analysis guidelines did not have any specifics on how to use the mid-range Plus Point in the U-bends.
- Training documentation was incomplete.

Inspection Findings:

- **Potential Red** - Inadequate Corrective Actions taken during 1997 outage inspection. Three significant conditions not identified and evaluated. Collectively, they decreased probability of detection of U-bend flaws and increased the probability that a defect would remain in-service.
  - First PWSCC U-bend indication not recognized for its significance. Not entered in Corrective Action System.
  - First upper TSP denting not recognized for its potential for hour-glassing and Con Edison did not have a method of ensuring that significant hour-glassing was not taking place. Not entered into Corrective Action System.
  - Eddy Current noise not evaluated and not corrected for. Not entered into Corrective Action System.

- **Green - NCV** - Mid-range Plus Point probe not properly calibrated and setup for U-bend inspections - based on EPRI guidance.
  - Would not have a significant affect on the ability to detect flaws. Con Ed corrected the issue during the 2000 exam.

- No color - Con Edison's root cause analysis did not address the performance issues identified by the team and was inadequate.

Con Edison Disagreements with Findings:

- The PWSCC indication was expected and no additional assessment was warranted after this discovery.
  - NRC Response
    - Based on SG Life Prediction PWSCC was a possibility and needed to be inspected for, but it was not clearly expected. The team believes this was a significant unrealized opportunity.
- There were no specific noise criteria relative to the probability of detection of flaws using eddy current examination in the EPRI Guidelines.
  - NRC Response
    - This is a true statement; however, the issue of noise masking signals is not new to eddy current inspection.
    - Several NRC documents discuss noise NUREG 1477 and IN 94-88.

- The root cause submitted was complete and accurate .
  - NRC Response
    - The finding stands based on the inspection results.
- The 2000 NRC Team's findings are not in agreement with NRC Team Inspection Report 50-247/97007, dated July 16, 1997.
  - NRC Response
    - The1997 inspection was not a team, it was an integrated report with the SG inspection done by one inspector. Con Edison's SG inspection was deemed adequate.
    - It was a sampling process and not to the depth of the team inspection.
    - There was no specific review of the quality of the eddy current data or the analysis of the specific results.

- All 1997 steam generator inspection requirements were met and the team had not identified any specific requirements, standards or guidelines that were not met.
  - NRC Response
    - The team identified 10 CFR 50, Appendix B, Criterion XVI Corrective Actions as a requirement that was not met.

Eddy Current Testing

- Principle
  - A coil in an alternating current circuit produces a magnetic field.
  - If a conductor is placed into this magnetic field a secondary current (eddy current) is induced in the conductor and it too generates its own magnetic field
  - The secondary current and magnetic field oppose the primary current and field
- The probe establishes the eddy current in the SG tube and the analyst detects defects in the SG tube by observing changes in the coil voltage and the phase angle between the coil voltage and current.

NRC Risk Assessment for Significance Characterization of Degraded SG Tubes

Steve Long, SPSB/DSSA/NRR

Risk Assessment for IP2 SG Tube Degradation

For the SDP, ΔCDF and ΔLERF are assessed for the *condition* of the tubes over the time that degradation exceeded allowable levels.

This is *different* from the licensee's assessment of the conditional core damage probability for the very specific features of the event that actually occurred on Febrauary 15, 2000.

The degraded condition of the tube made it vulnerable to several potential causes for failure:

spontaneous failure (with potential flows ranging from tenths to hundreds of gpm)

steam system depressurization transients

reactor coolant system over-pressurization transients

core damage accidents (with steam system dry and depressurized but RCS not fully depressurized)

Each of these sequences would add to the frequency of core damage accidents with containment bypass (treated as LERF).

The risk assessment process considers the frequency of each of these challenges, the probability that the tube would fail given each, and the probability that the challenge with tube failure would lead to core damage.

Of these, the spontaneous rupture dominates the risk estimate at about 1×10^{-4}/RY averaged over the last year.

The steam system depressurization transients and the core damage accidents could add about 1×10^{-5}/RY each if the tubes were susceptible for a whole year, but it is not clear whether they were.

Although the frequency of each of these accident sequences could be subjected to more detailed analysis, it is not expected that the result would be to reduce the total core damage frequency increment to a value below 1×10^{-5}/RY.

Because the numerical threshold between "red" and "yellow" is 1×10^{-5}/RY for core damage accidents that would create large releases, it does not appear that more detailed analysis would change the "color" assignment.

Question: What is the difference between the NRC's risk assessment and the one produced by the Con Ed?

Answer: The NRC's analysis evaluates the risk increase caused by the degraded ***condition*** of the steam generator tubes. The most severely degraded tube could have ruptured for a variety of reasons under a variety of circumstances. The NRC's analysis considers all of the circumstances in which the tube might have been induced to fail or might have failed spontaneously. For each circumstance, the NRC evaluated the frequency of the circumstance, the probability that the tube would fail under that circumstance, and the probability that the circumstance, when complicated by tube failure, would lead to core damage. The NRC used the sum of the results for all circumstances as the measure of the risk created by the tube degradation.

The licensee's analysis considered only the specific features of the spontaneous tube failure ***event*** as it occurred on February 15, 2000. Credit was taken for the specific leak rate that occurred being less than the leak rate assumed in most Probabilistic Risk Assessments. For the lower leak rate, there is more time for the plant personnel to take the actions that are necessary to prevent core damage. This makes the probability of human error lower. Because the probability of core damage following a steam generator tube rupture is dominated by the probability of human errors (which is higher than the probability of equipment failures), the licensee's re-evaluation of the human error probabilities led to substantially lower results. However, it neglects the potential for the tube failure to have a much higher flow rate. It also neglects the potential for the tube failure to have been induced by other circumstances that would have complicated the recovery process that the plant personnel needed to accomplish to prevent core damage. Therefore, the NRC does not consider the licensee's approach to be appropriate for establishing the risk significance of the tube degradation that occurred.

Spontaneous Rupture

ΔLERF Contribution = [Tube Rupture Frequency] x [Probability of Not Preventing Core Damage]

Tube Rupture Frequency:

The condition of the tubes was allowed to deteriorate to the point that a substantial failure occurred before the end of the planned period of operation.

The flaw that failed was long enough to cause a full SGTR flow rate if remaining ligaments had failed.

Experience indicates that about half of the in-service tube failures are gross failures and half are leaks that result in shutdown before gross failure occurs.

So, probability of rupture is about 0.5.

The period of time to be used to make this a "frequency" is not determinate, because the failure occurs as soon as the tube is unable to withstand normal operating conditions. The practice is to average core damage frequency increments over a 1 year period.

So, frequency is estimated as about 0.5/RY.

Probability of Not Preventing Core Damage:

The net probability can be derived from a PRA by dividing the core damage frequency contribution from tube ruptures by the tube rupture frequency used in the PRA.

Results vary with the PRA used:

The IP2 IPE gives 7.7×10^{-5}
The NRC's SPAR model for IP2 gives 3.3×10^{-4}
The NUREG-1150 model for Surry gives 1.8×10^{-4}

Review of cutsets indicates that the dominant contributions are human errors, which are very uncertain.

Conclusion is that the non-mitigation probability is about 10^{-4}

Contribution to SDP ΔCDF and ΔLERF:

Products of the above estimates range from 1.7×10^{-4}/RY to 3.9×10^{-5}/RY

Geometric mean is about 8×10^{-5}/RY

Tube Ruptures Induced by Steam System Depressurization Events

ΔLERF Contribution = [Frequency of Steam System Depressurization]
x [Conditional Probability of Tube Rupture]
x [Probability of Not Preventing Core Damage]

Frequency of Steam System Depressurization:

This frequency is estimated from experience to be in the mid-10^{-3}/RY for Westinghouse plants.

Estimates have ranged from 7 x 10^{-3}/RY to 1 x 10^{-3}/RY.

Assume value is 5 x 10^{-3}/RY for IP2

Conditional Probability of Tube Rupture:

It is clear that the tube at R2C5 in SG 24 would have failed earlier if theΔP increased.

It is not clear for what period of time the tube was susceptible to rupture at the increased ΔP that would result from a steam system depressurization event.

Most steam system depressurization events affect only one SG, so divide probability by 4 to account for number of SGs at IP2. (Assumes frequency per plant is independent of the number of SGs in the plant.)

Applying the increased probability to a default period of one year would give a conditional rupture probability of 0.25.

Probability of Not Preventing Core Damage:

The probability of not preventing core damage for this sequence was estimated in NUREG-1570 at 10^{-2}, based on extensive modeling of the thermal-hydraulic conditions and human error probabilities.

Contribution to SDP ΔCDF and ΔLERF :

The product of these factors is about 1 x 10^{-5}/RY.

Increased LERF Due to Tube Ruptures Induced by Core Damage

ΔLERF Contribution = ["Hi/Dry" Part of the Core Damage Frequency]
x [Probability that Tube Rupture Will Be Induced by Physical Phenomena]

"High/Dry" Part of Core Damage Frequency:

Some core damage accident sequences involve increased ΔPs across some or all SGs, which can induce rupture of flawed tubes, as discussed in the previous slide.

In addition, studies documented in NUREGs 1150 and 1570 demonstrated that, if the SGs were dry, core damage accidents could increase temperatures in SG tubes to the point that flawed tubes would fail by creep before other parts of the RCS pressure boundary, creating a large early release of radioactive materials for what would otherwise be a "contained" accident.

This part of the CDF is estimated to be between 1 and 2 x 10^{-5}/RY from other PRAs for Westinghouse plants

Probability that Tube Rupture Will Be Induced by Physical Phenomena:

Challenges to the tubes during core damage accident conditions can arise from increased pressure differentials across the tubes caused by steam side depressurization, from increased tube temperatures that weaken the Inconel tube material, and from combinations of these effects.

There are a number of core damage sequences that present different levels of challenge to the tubes.

It is clear that, just before the tube failure on February 15th, any slight combination of these effects would have induced tube failure.

But it is not clear how long the periods of susceptibility lasted for each of the various challenging sequences.

Contribution to SDP ΔLERF:

It is not possible without further detailed analysis to realistically estimate the contribution from this type of sequence.

If temperature effects alone would have induced tube failure during the last year, then the ΔLERF would be in the range of the "high/dry" frequency, about 10^{-5}/RY.

If a depressurized SG was necessary to induce the flawed tube to rupture during most of the year, then the ΔLERF would depend on the probability of SG depressurization. (IP2 has some history of SG leakage while "isolated.")

It would be necessary to perform extensive analyses before concluding whether this contribution to ΔLERF is sufficient to make the total ΔLERF for the condition exceed 1 x 10^{-5}/RY.

Staff Knowledge of Licensee's Risk Analysis

The staff has reviewed an analysis by the licensee that calculates a *conditional core damage probability* given the specifics of the event that actually occurred on February 15, 2000.

That analysis used the less-than-maximum potential flow rate to re-estimate the time available for operators to take mitigative actions and the human error probabilities associated with those actions.

This greatly reduced the estimated probability that core damage would occur, because the dominant cutsets in the risk analysis are those containing human errors.

The staff has three criticisms of the licensee's analysis:

> Some of the human errors considered would result in the flawed tube experiencing high stress for an extended period or even experiencing higher stresses than actually encountered during the event. The staff does not believe that the flow rate can be assumed not to increase over extended exposures to such conditions, given the size of the flaw and the incomplete state of its failure.
>
> The analysis does not take into account the potential for the flaw to have been initially revealed by a different degree of failure with a different flow rate.
>
> The analysis does not take into account the risk associated with the exposure to other potential events that would have been complicated by induced tube rupture.

NRC SE/RIS and Related Initiatives Regarding SG Tube Technical Issues

Ted Sullivan, EMCB/DE/NRR

SAFETY EVALUATION PROCESS

- IP-2 TECH SPECS REQUIRED NRC APPROVAL TO RESTART
- INFORMATION REVIEWED BY NRC STAFF DEALT WITH
  - 2000 INSPECTION PROCESS
  - CONDITION MONITORING ASSESSMENT (WERE TUBE INTEGRITY CRITERIA MET, EXCEPT FOR R2C5)
  - OPERATIONAL ASSESSMENT (WOULD TUBE INTEGRITY CRITERIA BE SATISFIED UNTIL THE NEXT INSPECTION)
- SINCE CON ED REPLACING SGs, TS CONDITION REQUIRING RESTART APPROVAL NO LONGER APPLIES
- SE ESSENTIALLY COMPLETE BUT WILL NOT BE ISSUED
- INSTEAD, STAFF WILL DEVELOP RIS DISCUSSING MAJOR FINDINGS FROM THE IP-2 SE AND FINDINGS FROM RECENT ANO-2 EXPERIENCE

ISSUES - DRAFT SE

STAFF WAS UNABLE TO CONCLUDE THAT TUBE INTEGRITY CRITERIA COULD BE MET UPON PLANT RESTART AT TIME LICENSEE ELECTED TO PROCEED WITH SG REPLACEMENT.

UNRESOLVED ISSUES RELATING TO LICENSEE'S OPERATIONAL ASSESSMENT, INCLUDING:

- PROBABILITY OF DETECTION (POD) OF U-BEND CRACKS
- CRACK SIZE MEASUREMENT ERROR IN U-BENDS
- CRACK GROWTH RATES

  COMMON DENOMINATOR: ASSUMED POD AND SIZING PERFORMANCE NOT VALIDATED BY DESTRUCTIVE EXAMINATION OF CRACKED TUBE SPECIMENS

- PREDICTIVE MODELS
- RELATIVE SUSCEPTIBILITY OF ROW 3 U-BENDS TO CRACKING COMPARED TO ROW 2

Planned Agency Actions and Approach for IP2

Brian Holian, Director, DRS, Region I

Planned Agency Actions and Approach for IP2

Brian Holian, Director, DRS, Region I