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January 19, 2001

Re: Indian Point Unit No. 2
Docket No. 50-247
NL-01-005

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop P1-137
Washington, DC 20555-0001

References: 1) NRC Inspection Report 05000247/2000-010 and NRC Letter to Mr. J. Groth from Mr. H. J. Miller, Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2 dated November 20, 2000

2) NRC Inspection Report 05000247/2000-012 and NRC Letter to Mr. A. Blind from Mr. W. Lanning dated December 4, 2000

3) NRC Letter to Mr. J. Groth from Mr. H. J. Miller dated December 20, 2000

Subject: Reply to a Notice of Violation – NRC Inspection Report 05000247/2000-010

Dear Sirs:

The purpose of this letter is to respond to the Notice of Violation enclosed with the NRC's letter of November 20, 2000. This violation is associated with the steam generator in-service inspections performed during the 1997 refueling outage at Indian Point Unit No. 2. We are also providing supplemental information regarding improvement initiatives in our Corrective Action Programs in response to continuing NRC interest in this important area as described in the NRC letter to Mr. J. Groth from Mr. H. J. Miller dated December 18, 2000 and NRC Inspection Report 05000247/2000-012. Following the February 15, 2000 steam generator event, we have made multiple significant steam generator program improvements within the site-wide corrective action program. While the details of certain

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of our steam generator program activities have previously been reported to the NRC, several of them have been implemented quite recently and are summarized here. Specific actions have been entered into our corrective action system.

Steam Generator Program Improvements

On March 22, 2000 a new Station Administrative Order (SAO)-180, "Administrative Steam Generator Program," was approved. This SAO implements Con Edison's commitment to the requirements of the nuclear industry initiative described in the Nuclear Energy Institute (NEI) "Steam Generator Program Guidelines 97-06." Major elements of this program include:

a) The establishment of a Steam Generator Management Committee (SGMC) chaired by the Vice President, Nuclear Engineering. The SGMC is a multi-discipline committee that provides recommendations and guidance to the Chief Nuclear Officer for improving steam generator reliability.

b) The appointment of a Steam Generator Program Manager who oversees the implementation of the program.

c) Criteria specified to ensure greater steam generator integrity relative to potential degradation mechanisms, inspection, tube integrity assessments, primary to secondary leakage monitoring, maintenance of secondary integrity, and reporting requirements.

d) Enhanced program requirements in the areas of Primary and Secondary Water Chemistry, Foreign Material Exclusion, and Self-Assessment of program health.

Primary to Secondary Leakage Limits

New primary to secondary leakage limits identified in the February 2000 revision of EPRI TR-104788, "PWR Primary to Secondary Leakage Guidelines" have been implemented. Applicable station procedures have been revised to identify reduced primary to secondary leakage administrative limits and actions. The administrative limit was reduced from 150 gpd to 75 gpd. Although this change could not have precluded the February 15, 2000, event, the new limit reduces the probability of occurrence of another steam generator tube rupture.

Steam Generator Replacement Project

During the Third and Fourth Quarter, 2000, a project to replace the original Westinghouse Model 44 steam generators with newer Westinghouse Model 44F steam generators was completed. The replacement steam generators incorporate several improved design features, including thermally treated Alloy 600 tubes, and 405 stainless steel tube support plates with broached quatrefoil tube holes in a square pitch array. These material improvements significantly minimize denting because of the higher corrosion resistance of 405 stainless steel as compared to the original steam generator carbon steel tube support plates. The quatrefoil tube hole arrangement design is an enhancement of the flow slots in the upper support plate. This design eliminates the probability of flow slot hourglassing.

Further, the low-row steam generator tubes (ROWS 1-7) were stress relieved during manufacturing to reduce residual stresses from the bending process. This further reduces the potential of PWSCC in the U-bend area. The replacement steam generators have full depth hydraulically expanded tube to tube sheet joints. Although this would not reduce the probability of a tube leak in the U-bend area, it will reduce that potential within the tube sheet area.

Replacement Steam Generator Examinations

Pre-service inspections were performed on the primary and secondary sides of the replacement steam generators. The primary side inspection consisted of 100% full length Bobbin probe, 100% hot leg top of tube sheet inspection with Rotating Pancake Coil (RPC) probe, 100% Row 1 and 2 U-bend inspection with RPC probe, and inspection of 80 of the row 1, 2 and 3 U-bend tubes with the 800 kHz +Point Probe. No tubes were plugged based upon the results of these inspections.

Secondary side inspection and Foreign Object Search and Retrieval (FOSAR) activities were performed both when the generators were in storage horizontally and when installed vertically.

Secondary Side Copper Reduction

One of the major areas of concern identified in connection with prior steam generator eddy current inspections was the effect of interference or noise on the eddy current test signals obtained during the actual testing of several low-row U-bend tubes. One cause of noise is the presence of ferro-magnetic materials such as iron oxide and copper in the secondary side of the steam generators. During the 2000 outage a number of steps were taken to reduce the amount of ferro-magnetic materials that could accumulate on the secondary side of the generators.

The last remaining six low-pressure feedwater heat exchangers and the gland seal steam condenser, which had contained copper bearing tubes, were replaced. This minimizes the amount of copper that could eventually enter the steam generators. The copper removal program activities have been in progress since 1982, with the replacement of moisture separator reheaters and high-pressure feedwater heaters with stainless steel components. Nine other low-pressure feedwater heaters were replaced in 1987. Over three successive refueling outages (1991, 1993 and 1995) the three, admiralty brass condensers were replaced with titanium tube modular units. This completed the removal of copper bearing alloys in the principal components of the secondary side of the plant.

Long Loop Recirculation System

The Long Loop Recirculation System provides a flow path for the recirculation of water from the condensate and feedwater systems, to enable cleanup of impurities prior to plant startup. Using the existing condensate pumps to provide a motive force, impurities within the hotwell, condensate and feedwater system piping and equipment will be flushed to the hotwells through the condensate and feedwater systems, and then filtered by new particulate filters. A portion of the effluent of the filter can be polished using vendor supplied, trailer mounted demineralizers. All of the water is returned to the condenser. The system has been installed and has been used during the present start up. Use of this system will minimize the amount of copper and iron oxide material that is available for deposit on the secondary side of the replacement steam generators.

Removal of Residual Copper in the Feedwater System

To maximize the operational life of the steam generators, a flush to remove copper was performed on the feedwater system. This was accomplished concurrently with the Steam Generator replacement project by increasing the pH on the secondary side to greater than 10.0 with the addition of chemicals such as Hydrazine and Ammonia.

Further, the removal of residual copper from an additional portion of the feedwater system was accomplished with the recently installed Long Loop Recirculation System. The replacement steam generators were isolated from the feedwater system during this operation. The pH in the feedwater system was increased by the addition of Ammonium and Hydrazine to a maximum pH of 10.5. The Long Loop Recirculation System was then utilized to circulate the fluid with the purpose of putting the residual copper in the secondary side of the plant into a soluble state. This process was initiated on November 23 and completed on November 28. This copper was removed primarily through the draining and filling of the system. It is estimated that this process removed approximately 2,200 grams of copper.

Corrective Action Program Initiatives

At Indian Point 2 we are doing our utmost to improve issues identification and our Corrective Action Program (CAP). The initiatives described above pertaining to our steam generator program are but a part of a much broader station commitment to CAP improvements. Our attention to improving issue identification and corrective action programs at Indian Point 2 is continuing, and additional focus on these programs will occur in 2001, specifically addressing program performance and the issues noted in the referenced December 4, 2000 Inspection Report.

As a result of recent CAP improvements, responses to identified problems have become more comprehensive, effective, and timely. By the end of year 2000, the total number of outstanding CR evaluations and corrective actions have been reduced by over one-third to a much more manageable level of approximately 2800 CR's. The average age of open evaluations dropped from 150 days at the beginning of the year to less than 30 days by year's end. CAP metrics demonstrate significant site-wide improvements in overall program quality during 2000. There are no IP2 departments that are currently below standard in any of the key quality measures, such as the quality of root/apparent cause evaluations, schedule adherence, and timeliness for completing evaluations and corrective actions.

Seven (7) structured human performance stand-downs were held in 2000 to provide reinforcement to our employees of the importance of recognizing and correcting human performance issues. Recent station and industry events were reviewed as part of the lessons-learned function at these stand-downs. This effort will continue into 2001. In January 2001, Human Performance Fundamentals Training was provided to site managers and supervisors. This training focused on providing human performance awareness to management and recognition of tools that are available to address human performance issues.

Our current multiple initiatives in the various areas of our corrective action program are discussed in Attachment A to this letter. The station's corrective action program, having previously been identified as a specific area of interest and focus, will continue to receive our sustained attention following the unit's return to full power operation.

NOV Pertaining to 10 CFR 50, Appendix B, Criterion XVI

Con Edison is committed to significant improvements in all aspects of Indian Point 2 operations. We firmly believe that this commitment will result in improved plant performance. As previously noted in the NRC's Inspection Report 05000247/2000-010, Con Edison believes that the Company's 1997 steam generator inspections were consistent with then-applicable NRC requirements, including 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions." Accordingly, pursuant to the provisions of 10 CFR 2.201, we deny the violation set forth in the referenced Inspection Report. We hope that this letter and its attachments and exhibits adequately explain the basis for this difference, but irrespective of this, we believe that Con Edison and the NRC share a common view of the steps that should be taken to improve plant performance and public confidence in plant operations.

Following receipt of the NRC's November 20, 2000 letter, Con Edison requested third-party experts to review the NRC's Inspection Report 05000247/2000-010, as well as related materials, including specifications, processes, practices, and eddy current data from the 1997 inspections, and to address the conclusions reached in the Inspection Report related to the adequacy and sufficiency of the 1997 steam generator inspections. The conclusions of these experts are set forth in affidavits which are included as exhibits to Attachment B. Attachment B and its exhibits accordingly form the basis for denial of the violation.

Commitments made by Con Edison contained in this letter are listed in Attachment C.

Should you or your staff have any questions regarding this submittal, please contact either the undersigned or Mr. John F. McCann, Manager, Nuclear Safety and Licensing.

Sincerely,

Attachments

ERRILIA A. AMANNA
Notary Public, State of New York
No. 01AM[illegible]
Qualified in Westchester County
Commission Expires March 20, 2002

cc: Director, Office of Enforcement
US Nuclear Regulatory Commission
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ATTACHMENT A TO NL 01-005

CORRECTIVE ACTION PROGRAM SUMMARY

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
JANUARY 2001

INDIAN POINT 2 CORRECTIVE ACTION PROGRAM

NRC Inspection – Problem Identification and Resolution

On December 4, 2000, the NRC issued Inspection Report (IR) No. 50-247/00-012, documenting the results of the annual baseline inspection for the problem identification and resolution (PI &R) process at Indian Point 2 (IP2). The inspection examined activities conducted at Indian Point 2 as they relate to the identification and resolution of problems, and compliance with the Commission's rules and regulations and the conditions of the operating license. In the report, the NRC Staff recognized the progress made in reducing the backlog of open evaluations and corrective actions within the overall corrective action program (CAP). However, based on the sample selected for review, the NRC team identified CAP performance issues and findings that revealed some continuing weaknesses in the initiation of condition reports for identified issues, in the significance classification and prioritization of problem evaluations, and in the prioritization of corrective action tasks. The examples cited for the above weaknesses were identified as Green (very low risk significant) inspection findings, in accordance with the NRC's reactor oversight program significance determination process. Con Edison recognizes our current challenge to continue our improvement efforts, both in the corrective action program and addressing the recurring equipment challenges.

During 2000, the Corrective Action Group (CAG) commenced several initiatives to address issues similar to those raised in IR 00-012 that had been identified as part of our own internal self-assessments. Specific actions being taken to address the crosscutting issues described in the report are as follows:

- Effectiveness of Problem Identification

  The inspection report states that Con Edison has not identified some lower level issues and in some instances, personnel did not initiate condition reports for identified problems. As a result, the information was not captured in the corrective action program for tracking and trending purposes or to determine the need for additional evaluation to ensure effective resolution.

  Con Edison recognizes that documenting all levels of issues found in our condition reporting system is essential so that we can immediately address those issues and learn from them. As discussed in the inspection report, those specific issues should have had condition reports generated when they were first discovered. To address this challenge, we are continuing to reinforce the importance of initiating a condition report when a condition adverse to quality is discovered or introduced during their work activities. Also, in February 2000, CAG initiated refresher/new training for site personnel in the use of the electronic Condition Reporting System (CRS). This training emphasizes the importance of identifying and documenting any and all condition adverse to quality. The training also stresses that if we don't recognize and understand the problem, we cannot fix it. This training effort, which is continuing, is producing the desired focus on CRs. During 2000 approximately 11,000 condition reports were initiated.

- Prioritization and Evaluation of Issues

The inspection report indicates that although most issues were appropriately classified, some weaknesses in the screening and escalation processes exist. Some examples of weaknesses in the quality of evaluations and use of cause codes for trending were identified. Although progress in reducing the backlog of open and overdue evaluations was recognized, the report confirmed our assessments that the number of overdue evaluations remains higher than desired.

In October 2000, CAG initiated a formal review of closed condition reports to independently assess the adequacy of the closure for condition reports that were closed between December 1, 1998 and June 30, 2000. This effort focused on determining whether: (1) proper classification was identified for the condition report (i.e., significance level), (2) description of condition reports provided a proper problem statement, (3) corrective action(s) identified for addressing problems were effective and, (4) implementation of the corrective action(s) and closure of the condition report was effective. The results of this assessment indicated reasonable confidence exists that appropriate corrective actions are being identified and completed for those conditions reported. However, several process and quality related issues were identified during the review. These issues related to closure of condition reports to another IP2 process (thus making the tracking of closure status difficult), overlooking assignment of corrective actions to address human performance errors, inconsistent quality of condition report responses, lack of documenting the problem resolution processes, lack of clarity for problem statements, lack of adequate focus on larger programmatic issues that could provide barriers for repetitive failures, and the correlation of repetitive equipment with CRs. Based on these results, condition reports were generated to document these issues, and interim actions were implemented to address process improvements.

Corrective Action Program (CAP) reports have been significantly enhanced during 2000 by the development of Accountability Based CAP metrics. These reports have been successful in improving CAP performance as the trends of all key CAP indicators are positive. Reductions in the backlog of long-standing and overdue evaluations have been made during 2000. For example, significant reductions in the average age of open CR evaluations and the number of overdue CR evaluations occurred. An especially powerful aspect of these metrics has been their influence in improving the quality of CR closures. These quality metrics have improved the ability to close out CR's and have resulted in improving the ability to fix the problem right the first time.

- Effectiveness of Corrective Actions

The report recognizes the progress made in reducing the backlog of open and overdue corrective actions, but identifies weaknesses in the process used to prioritize completion commensurate with the condition's risk.

Actions being taken in response to the formal review of closed Condition Reports discussed above will result in increased effectiveness of corrective actions. Additional program changes are in the process of being implemented to clarify condition report significance levels to ensure appropriate attention is placed on completion of corrective actions commensurate with the condition's potential risk significance. Improved metrics, management involvement, and increased oversight by the Corrective Action Review Board (CARB) will continue the progress in reducing the backlog of open and overdue corrective actions.

- Effectiveness of Licensee Audits and Assessments

The inspection report states that Con Edison QA department audits and line organization self-assessments indicated the ability to self-identify issues, many of which were similar to the NRC team's findings. However, a QA effectiveness review focused on verification of action completion, not on the effectiveness of actions taken.

In November 2000, the CAG initiated a corrective action effectiveness review of the August 1999 event to compliment the QA review. The objective of this review is to: (1) determine whether the Station documents, evaluates, understands, and allocates resources to resolve equipment problems on a consistent, risk informed basis and, (2) whether risk significant events do not evolve or escalate from lack of appropriate and adequate response to degrading plant conditions. The scope of this review is primary focused in the following areas:

- Equipment condition and performance causes that precipitated or aggravated the event and the associated plant response.

- Subsequent significant events that challenged the operators and the effectiveness of management support provided.

Some additional details of the Indian Point 2 Corrective Action Program and program improvements are provided below.

Program Overview

Problem identification and resolution at Indian Point 2 is performed in accordance with Station Administrative Order (SAO) – 112, "Corrective Action Program". This process is designed to identify and analyze nonconforming or anomalous conditions, and to initiate timely and effective corrective actions to resolve identified conditions and preclude recurrence. A computer based Condition Reporting System (CRS) provides the mechanism to initiate conditions, track assignments and corrective action closure, and is widely available for use. Management ensures that employees are trained on using CRS, encourages employees at all levels to identify and report a broad range of problems, and reinforces their expectations that problem identification, reporting, and corrective action is a part of each employee's daily work activities. Identified problems are screened promptly for their effect on safety, reliability, operability, and reportability. The corrective action process applies Significance Levels (SL) to conditions based on the probability of an occurrence and the consequences of an event. Four levels of significance are defined with level 1 (SL-1) being the most significant and level 4 (SL-4) being the least significant. The Corrective Action Program requires a formal root cause analysis for SL-1 and SL-2 Condition Reports (CR). Individuals or teams trained in root cause analysis techniques evaluate significant problems using structured root cause methodology to identify root and contributing causes and corrective actions to prevent recurrence. SL-3 CR's require an apparent cause evaluation, focusing on correcting the immediate cause, and SL-4 CR's may have but do not require a response. The overall corrective action program is periodically monitored and assessed for effectiveness.

Employees are directed to originate a CR for any nonconforming or anomalous conditions that are discovered as soon as possible. This is usually no later than the end of the shift for shift personnel and within the next working day for non-shift personnel. The Originator of a CR determines, if possible, if the identified condition is potentially an Operability, Reportability, and/or Environmental concern, and, if so, is required to immediately report the condition to Operations shift management. All CR's are reviewed by shift management within 24 hours to ensure appropriate immediate actions have been taken. A Corrective Action Screening Committee meets daily to determine the significance level and assign a manager (Owner) to analyze the cause(s) and develop corrective actions. The process requires that every CR be evaluated by the responsible manager within 30 days. Corrective actions are discussed with the appropriate group/individual, due dates agreed on, and assignments made. It is expected that managers outside a particular organization support each other's priority for problem resolution. The CRS is used to track CR evaluations, assignments and corrective action closure. On-line reports and periodic status summaries developed by the Corrective Action Group are provided to assist managers in monitoring progress is evaluating and closing CR's.

A Corrective Action Review Board (CARB), chaired by the Plant Manager and the Corrective Action Program Manager, assist in managing the corrective action program. CARB includes the line managers from all major Indian Point 2 departments and meets at a regular basis to monitor the effectiveness of the corrective action program. The focus of CARB over the past year has been on obtaining line management ownership of the corrective action program and ensuring that improvements in the program continue. CARB is also chartered with the following:

- Reviewing, approving, and scoring for quality, all SL-1 and selected SL-2 Condition Reports.

- Reviewing and approving all effectiveness reviews performed for all SL-1 CR's.
- Reviewing Corrective Action Trend Reports and, when necessary, investigates adverse trends in station performance.
- Assessing department/section corrective action program implementation by reviewing quarterly assessments of program health.
- Approving all Corrective Action Program changes and, as necessary, recommends changes.
- Reviewing all requests for schedule extensions of investigations and corrective actions associated with SL-1 and SL-2 CR's.

Program Improvements

Indian Point 2 has made significant improvements to the corrective action program since the 1997 Steam Generator eddy current inspections. An electronic Commitment Identification Reporting System (CITRS) was developed in 1996. Prior to CITRS condition reporting was a "paper" system, with little capability to manage the process. Although some improvements were evident, an Independent Safety Assessment (ISA) Team in early 1998 concluded that the process was cumbersome and inefficient. While CITRS allowed problems to be identified in one central place, there were separate and distinct databases for tracking and resolving problems that inhibited effective integration for work management and cause trending purposes. Additionally, corrective action was seen to be partially owned by several organizations and there was little ownership for problem resolution. Actions could be assigned to almost anyone and then transferred to others indiscriminately. Searches of the database were difficult to conduct and meaningful reports and trending were not easily developed. Management standards and expectations for a corrective action program were not clearly established, communicated, nor reinforced.

In October 1998, a new station wide Corrective Action Program was implemented. This new program clearly defined reporting thresholds, emphasized strong individual and department accountability for closure of items, and established an appropriate process for determining CR priority and significance levels. Additional program enhancements included the following:

- Established and staffed a full-time, centralized Corrective Action Group.
- Identified and published appropriate performance indicators and trending methods to measure program effectiveness.
- Upgraded the process for conducting root cause and apparent cause analysis to include human error and equipment failure cause codes.
- Developed training requirements and provided baseline training for the revised process.
- Established a process to conduct periodic effectiveness reviews of completed corrective actions.
- Implemented the Corrective Action Review Board (CARB).

- Established an "Owner" concept and designated managers to take ownership of corrective action program actions. These individuals are responsible for successful close out of activities and can only assign actions to other owners.

In support of this new program, a more user friendly, reliable, and unified Condition Reporting System (CRS) was developed. CRS provides extensive CR reporting and monitoring capabilities. Stand alone web-based reports were developed to enable users to quickly locate and use data.

These program and system improvements, coupled with management's reinforcement of standards and expectations, have resulted in reporting material, process and program deficiencies at a low threshold. Since 1998 over 30,000 Condition Reports have been entered into CRS. The number of CR's being written each year continues to trend up. For example in 2000, approximately 13.5% more CRs were written than in the previous year. This increase in the identification of deficiencies is attributed to management's frequent reinforcement of their expectation to find problems through self-assessments of programs, processes and procedures, and to report these problems for evaluation in a timely manner.

Corrective Action Program (CAP) metrics have been significantly enhanced during 2000 by the development of Accountability Based CAP metrics. These metrics provide the management team a "report card" on each CAP owner's program health. Specifically, an owner's ability to close assignments in a timely manner, to be accountable to a schedule, and to provide high quality CR closures are measured.

These reports have been successful in improving CAP performance as the trends of all key CAP indicators are positive. For example, the average age of open CR evaluations has decreased from well over 100 days to approximately 30 days and the number of overdue CR evaluations has decreased from over 1,000 to less than 200 recently. An especially powerful aspect of these metrics has been their influence in improving the quality of CR closures.

In addition to increases in the number of CR's closed, the quality of both SL-2 (root cause) and SL-3 (apparent cause) have significantly increased over the past year. A score sheet rates an owner in the following areas:

- Identifying the root (or apparent) cause.
- Identification of appropriate corrective actions.
- Focus of the corrective actions.
- Identification of interim or compensatory actions, as appropriate.
- Assessment of the safety significance of the event/problem.

These quality metrics have improved the ability to close out CR's and have resulted in improving the ability to fix the problem right the first time.

Another successful new metric is the development of a site-wide "self-identification" rate. This metric determines the percent of a department's problems that are being identified internally, as opposed to other internal and external groups. The self-identification rate for the station was initially 22% and has increased to 40% over the past year, with several departments consistently self-identifying over 65% of their problems. This success supports management's expectation for rigorous self-assessment.

Additional corrective action program improvements accomplished during 2000 include the following:

- Revision to SAO-112, "Corrective Action Program", to remove several of the error traps that were associated with earlier revisions of this procedure.
- Developed over ten "conduct of business" procedures, including guidelines on how to perform effectiveness reviews.
- Initiated hands-on training for using the Condition Reporting System (CRS).
- Initiated a weekly Corrective Action Newsletter that provides information to site personnel on corrective action program performance.
- Provided root cause initial and refresher training.
- Developed a station "event-free clock" metric that measures the time between major human performance events, and provides trends in this area.
- Eight Corrective Action Group employees visited other nuclear stations to benchmark best practices.
- Received CAP assistance from the Institute of Nuclear Power Operations (INPO), Millstone, D. C. Cook, Beaver Valley, South Texas Project, Indian Point 3, and Calloway.
- Facilitated periodic site-wide human performance stand downs to discuss the meaning of "error-free" performance, how to achieve it, and most importantly how to recognize error rich environments.
- Expanded the Corrective Action Group's staffing from 8 to 12 individuals. Experienced managers from South Texas and Connecticut Yankee have been hired, with additional experienced professionals expected to join the group in early 2001.
- Initiated a Human Performance Daily Newsletter that identifies potential challenges to human performance successes. This newsletter also provides daily tips and information on the "event free clock".

As a result of recent CAP improvements, responses to identified problems have become more comprehensive, effective, and timely. By the end of year 2000, the total number of outstanding CR evaluations and corrective actions have been reduced by over one-third to a much more manageable level of approximately 2800 CR's. The average age of open evaluations dropped from 150 days at the beginning of the year to less than 30 days by year's end. CAP metrics demonstrate significant site-wide improvements in overall program quality during 2000. There are no IP2 departments that are currently below standard in any of the key quality measures, such as the quality of root/apparent cause evaluations, schedule adherence, and timeliness for completing evaluations and corrective actions.

Management recognizes that additional improvements in the corrective action program are required. Corrective Action Group plans for 2001 describe specific areas where the program is not fully effective, provide goals and expected results, and identify specific additional actions for program improvements. Objectives include, affirming and continuously reinforcing the ownership of the corrective action program by all employees and contractors through frequent communications, management interaction, and strong oversight by the Corrective Action Review Board, Station Nuclear Safety Committee, Quality Assurance and the Nuclear Facilities Safety Committee. Also, familiarizing the personnel with the corrective actions process changes, management expectations for condition reporting, and management support for effective problem resolution. We also recognize the need for continuing training of our people in the area of problem investigation (i.e., apparent cause/root cause investigation) and to establish a standard for quality and effectiveness reviews. We continue to use the performance indicators to monitor, measure and adjust our performance.

ATTACHMENT B TO NL 01-005
REPLY TO A NOTICE OF VIOLATION
INSPECTION REPORT NO. 05000247/2000-010

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
JANUARY 2001

I. RESTATEMENT OF THE NOTICE OF VIOLATION

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 (hourglassing) at the upper TSP. Hourglassing of the upper TSP increases the stress 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 hourglassing 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 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.

II. CON EDISON'S RESPONSE

A. Basis for Denial of the Violation

Con Edison respectfully denies the alleged violation based upon the fact that the 1997 steam generator tube inservice examination at Indian Point 2 was conducted in accordance with industry guidelines and requirements applicable at the time. Comprehensive reviews of the 1997 eddy current inspection program conducted by Con Edison and independent third-party experts confirm that the 1997 inspections used conservative approaches in both the selection of the inspection sample, and in the analysis guidelines and reporting requirements. All eddy current data were analyzed by experienced and qualified personnel who received site-specific training in accordance with Revision 4 of the EPRI PWR Steam Generator NDE Guidelines, which were in effect at the time of the inspection. Probes, techniques and procedures applied were the most advanced qualified technology available at that time. NRC Inspection Report No. 05000247/2000-010 does not reference any requirement, industry standard, benchmark or guidance that was not met in 1997 which could have lead to a failure to detect primary water stress corrosion cracking (PWSCC) tube defects.

In several significant respects, the planning and execution of the 1997 steam generator inspection exceeded then-current standards. Although not required by any standard at the time, licensee hired an independent eddy current expert to provide oversight of the principal contractor's eddy current work. The independent expert's activities included review and approval of the contractor's plans and procedures, including site-specific analyst training, and confirming that they met all requirements and industry guidelines.

During the course of the 1997 steam generator tube inspections, and in subsequent data analysis, reasonable and appropriate measures were taken to identify and address significant conditions adverse to quality involving the presence of PWSCC in steam generator tubing. The failure to detect instances of PWSCC in 1997 was associated with the inherent subjectively-based limitations of eddy current testing methodology at that time. Such limitations were contemporaneously acknowledged, including by the NRC with issuance of Information Notice 97-26 (May 19, 1997). 10 CFR 50 Appendix B, Criterion XVI necessarily presumes that candidate conditions adverse to quality are identifiable, utilizing examination techniques reasonably available and in use at the time of inquiry. For the reasons set forth herein and in the enclosed exhibits, with respect to Indian Point 2 steam generator tube low-row U-bends, this was not in all instances the case in 1997.

Guidance as to the appropriate mechanisms for interpreting and applying 10 CFR 50 Appendix B, Criterion XVI can be found in NRC Inspection Procedure 71152, "Identification and Resolution of Problems." IP 71152 provides assessment guidance relative to problem identification and resolution, and in pertinent part notes that licensee problem identification should be assessed "commensurate with its significance and ease of discovery." (Ref. NRC IP 71152-03.01.c). It is clear from this that ease of discovery should be fully considered in evaluating licensee problem identification and resolution. In this instance, and as more fully described below, extensive efforts were made in 1997 with the intent to identify any steam generator tube indications that were potentially susceptible to significant leaks or rupture. In the case of tube R2C5 of steam generator 24, it is clear that the indication was not identified. It is noteworthy, however, that the ease of detection regarding the subject indication was questionable. This is supported by the fact that various experts consulted by the NRC have evidently reached different decisions on this matter, based on the same baseline information. (See NRC Indian Point 2 Steam Generator Tube Failure Lessons-Learned Report (TAC No. MA9163; October 23, 2000) at page 9.) Their differing viewpoints regarding the ease of discovery of this indication supports licensee's position. Based on the significant difficulty of discovery regarding the subject indication, Con Edison believes that a violation of 10 CFR 50, Appendix B, Criterion XVI cannot be sustained consistent with the actual facts and circumstances.

IP2 could [illegible] detected that its inspection process was [illegible]

Con Edison presently submits that application of evolving steam generator inspection capabilities and standards of today retrospectively to circumstances at Indian Point 2 that existed in 1997 should not be a basis for NRC enforcement action. Compare the requirements of 10 CFR 50.109. The occurrence of a steam generator tube failure following an inspection does not mean in or of itself that the inspection was inadequate. When a licensee followed regulatory requirements, and particularly when the licensee also followed then-existing industry practices, and an event nonetheless occurred, then from a regulatory perspective the licensee should not be held liable for the event. Rather, the licensee and the NRC should work in unison to help ensure that similar events do not again recur.

Didn't [illegible]

Con Edison's positions are supported by seven affidavits which were prepared by several steam generator inspection and eddy current experts. These individuals have been immersed in steam generator inspections and eddy current testing for a significant number of years. They are well qualified to render an opinion of Con Edison performance and the state of steam generator NDE in 1997. While some of the experts differed with the way Con Edison may have implemented some of its inspection processes, there was agreement that Con Edison's performance was in accordance with all requirements and industry standards, and that its findings were within the range of acceptable performance.

Specific responses to each of the bulleted items cited within the Notice of Violation are as follows:

Statement 1

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.

Response

During the 1997 steam generator inspections, reasonable and appropriate measures that were then available were taken to identify and correct primary water stress corrosion cracking (PWSCC) in low-row U-bends. During the 1997 inspection, a single U-bend PWSCC indication was detected at the U-bend apex of tube R2C67 in steam generator 24. The indication did not leak at the EOC-13. The response to detection of PWSCC in a low-row U-bend was appropriate and consistent with industry practice. R2C67 was removed from service by plugging.

The EPRI PWR Steam Generation Examination Guidelines: Revision 4, Volume 1, provide the recommended steam generator tube inspection frequency and inspection sample size. Figure 3-1 sets forth the specific recommendations for sample size. In 1997 the recommendation was to inspect a 20% sample of all tubes in all steam generators at each inspection. The plan at the outset to inspect 100% of the Row 2 &3 tubes in the course of the 1997 Indian Point 2 steam generator examinations therefore exceeded this provision of the EPRI guidelines.

Table 3-2 of the Guidelines at Section 3.4.3 sets forth the critical area sampling for Westinghouse Steam Generators. Table 3-2 identifies both inspection scope and the examination techniques for steam generators with active damage mechanisms. The Table 3-2 requirement for U-Bend IGA/ODSCC/PWSCC is a 100% inspection of the Row 1 & 2 U-Bends with a qualified RPC (rotating pancake coil) examination technique or equivalent. The 100% inspection of Row 2 & 3 U-bends with a qualified, rotating + Point coil met this requirement in the 1997 examinations.

The indication found in 1997 was based on the first +Point inspection of the Indian Point Unit 2 low-row U-bends following years of prior inspections with a bobbin coil only. Discovery of a single U-bend indication in the +Point inspection after prior bobbin coil inspections was not an unusual event after close to 16 EPFY of operation. It was more reasonable to conclude that the detection of U-bend PWSCC in R2C67 was attributable to the enhanced detection capabilities of the +Point probe than to accelerated tube deterioration during Cycle 13. 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, and flow slot closure due to hourglassing in the upper support plate far exceeded that at the top tube support plate at Indian Point 2.

Although low-row cracking had been reported by the industry in operating SGs for many years, the incidence of PWSCC was relatively low, occurred predominantly in row 1 U-bends, and to a much lesser extent in the row 2 U-bends. Very few cracks had been reported in the row 2 U-bends, and no large leakage events due to row 2 cracking had been reported until the February 2000 Indian Point-2 leakage event. The following table presents a summary of row 2 U-bend indications in Westinghouse-supplied Model 44 and 51 steam generators. These data clearly show the historical trend, and confirm that discovery of a single instance of PWSCC in a row 2 U-bend at Indian Point 2 in 1997 was consistent with industry experience.

Summary of Row 2 U-Bend Indications
Westinghouse Originally Supplied Model 44 and Model 51 Steam Generators

Plant	Year Ind. Found	Heat Treat	Probe	Crack Type		ID or OD Crack		U-Bend Location	
				Axial	Circ.	PWSCC	ODSCC	Near Apex	Near Tangent
Row 2 Indications									
Farley-1	1991	Yes	Pancake	1 tube 2 ind.		1 tube 2 ind.			1 tube 2 ind.
	1994	Yes	Pancake	2			2		2
Farley-2	None	Yes							
Diablo Canyon-1	1992	Yes	Pancake	1		1			1
	1994		Pancake	1		1			1
	1997		+Point	1		1			1
Diablo Canyon-2	1996	Yes	+Point	1		1			1
	1998		+Point	1		1		1	
Kewaunee	1990	No	Bobbin/ Pancake		1				1
	2000	No	+Point	1 tube 2 ind.		1 tube 2 ind.(1)			1 tube 2 ind.
Prairie Island-1	None	No					1 MBM '81		1
Prairie Island-2	None	No							
Indian Point-2	1997	No	+Point	1		1		1	
	2000	No	+Point	8 tubes 15 ind.		8 tubes 15 ind.		8 tubes 15 ind.	

Note:
1. New inspection results under review as potential MBMs. Indications were plugged.

Based on the information available in 1997, reviewed from the perspective of the 1997 inspection without the benefit of either subsequently-improved inspection techniques, the passage of time or 2000 inspection results, no additional corrective actions beyond plugging the affected tube would have been appropriate in response to the indication identified in R2C67. The appearance of a single row 2 U-bend PWSCC indication was not an unusual event, and the characteristics of the indication were consistent with the data included in the SSPD training and testing materials. If anything, the detection of a PWSCC indication in 1997 tended to corroborate the effectiveness of the new NDE technique (viz., +Point probe) being utilized.

The detection of an indication in R2C67 of steam generator 24 was also not an unusual or unexpected event in the context of the extensive steam generator degradation tracking work that Con Edison had commissioned prior to the 1997 inspections, a meticulous and comprehensive level of effort that comprehended international industry experience. Following the 1995 SG inspection outage Con Edison retained Dominion Engineering to independently develop projections of degradation for all degradation

Then signal-to-noise issues should have been recognized, mechanisms that had been observed in the IP2 SGs to date or were expected to occur based on industry experience with similar SGs. Notably, low-row U-bend PWSCC was recognized and included in the projection analysis. The projections were developed using Monte Carlo analysis and were based on a Weibull distribution for each degradation mechanism.

The result of this analysis identified that U-bend PWSCC was expected to occur at IP2 following 20 cycles of operation, and that this occurrence would initially be marked by the detection of one or two such degraded tubes. That PWSCC was initially observed several cycles before the estimate of Dominion Engineering is within the expected margin of error for such statistical studies. The important issue, however, is that Con Edison was fully aware of the potential for PWSCC to occur. In response to this prior in-depth and plant-specific assessment of SG tube degradation mechanisms, the 1997 inspection effort at Indian Point 2 was specifically qualified to detect U-bend PWSCC. The scope of inspection included 100% of the tubes, and all low-row U-bends were inspected using the best probe available for PWSCC detection.

The initial detection of U-bend PWSCC during the 1997 SG inspection outage was therefore no surprise, and in fact tended to corroborate prior degradation mechanism tracking efforts. The response taken by Con Edison following the 1997 SG inspections was to recommission a further analysis by Dominion Engineering to reflect the latest ECT results for all degradation mechanisms. This new analysis predicted that the next occurrence of PWSCC would be as early as RFO 14, again with an incident of one or two tubes. Thus, Con Edison was fully aware of the potential for PWSCC in low-row U-bends at Indian Point 2, but with very limited instances of initial onset which would progress at a slow rate.

Moreover, following the detection of low-row U-bend PWSCC in the R2C67 tube during the 1997 inspection, every available opportunity for evaluating the susceptibility of other low-row tubes to PWSCC was pursued, and the potential for degradation in other tubes assessed to the full extent of then-current diagnostic capabilities. In particular, the 1997 Indian Point Unit 2 inspection program specified a 100% inspection of all row 2 and 3 U-bends in each steam generator using a mid-range +Point rotating probe, the best qualified technique available at the time. The +Point probe was qualified by EPRI and added to the EPRI performance demonstration database in May 1996.

This technique was identified in NRC Information Notice 97-26, "Degradation in Small-Radius U-Bend Regions of Steam Generator Tubes", as qualified for detecting indications in small radius U-bends "in accordance with enhanced qualification criteria developed by EPRI."

From a programmatic point of view, during the 1997 inspection additional analyst training was provided in those instances when the inspection findings were unexpected or not consistent with materials used to train analysts. For example, discovery of ODSCC/IGA in the hot leg tubesheet crevice region during the course of the Indian Point 2

1997 inspection resulted in additional analyst training and complete re-evaluation of data in the hot leg 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. For the reasons set forth above, the identification of PWSCC in the R2C67 tube was not such an instance of an unexpected finding, and thus did not elicit modifications to the inspection program. Nor were any such modifications available or availing. Since the U-bend eddy current inspection program already comprehended a 100% inspection using the most sophisticated qualified probe then available, there were no further opportunities for evaluating low-row tube PWSCC that were not already being utilized to the fullest extent possible.

signal-to-noise available   mid-cycle inspections available

Statement 2

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 (hourglassing) at the upper TSP. Hourglassing of the upper TSP increases the stress 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 hourglassing based on the indications of the low-row tube denting.

Response

Denting of steam generator tubes and flow slot hourglassing were recognized as active degradation mechanisms at Indian Point 2 since at least 1978, by which time Con Edison was conducting inspections and actively applying corrective actions to address the problem.

These corrective actions, which were routinely communicated to the NRC at the time of development and application, included steam generator water chemistry improvements, visual inspection of the SG secondary side, removal and evaluation of a section of tube support plate, and metallurgical and mechanical characterization of dented tubes that had been removed from the bundle at the first support plate. The first incidence of ECT probe restriction in the U-bend occurred in 1984 in two Row 3 tubes of steam generator 22 that were restricted at 6H (the hot leg of the 6th support plate). An additional restriction was detected in 1986 and two more in 1989, when the first row 2 tube in SG 21 was determined to be restricted at 6C.

Over the course of discovery of flow slot hourglassing and tube denting phenomena, various remedial actions were taken to assess and address these issues. Extensive efforts were taken to characterize dents and justify the application of a suitable plugging criteria. Since 1976 Con Edison was actively engaged in SG secondary side inspection activities related to flow slot hourglassing and secondary side support plate integrity issues. By 1979, Con Edison had observed incidents of ligament cracking at lower support plate flow slots. To assess the efficacy of the various corrective actions that were being implemented, Con Edison was by 1978 monitoring the extent and progression of flow slot hourglassing. To facilitate visual inspection of the uppermost support plate, additional inspection ports (so-called "hillside ports") were installed in SG 22 and SG 23, which were perceived to be leading SGs in this degradation mechanism. The results of these inspections were regularly reported to the NRC. In response to the Surry incident, in 1982 Con Edison incorporated a requirement to inspect for and report "significant" hourglassing to the NRC in the plant Technical Specifications. That there were no explicit numerical criteria for "significant" hourglassing is a measure of industry consensus and understanding of the effect of hourglassing on tube integrity and the belief that visual inspections would reveal Surry-type degradation. Moreover, since the objective of monitoring support plate integrity was to prevent tube leaks, it was also believed that dent gauging and periodic ECT inspection of the tubes themselves would be sufficient and adequate to assure that tube integrity would be maintained. The efficacy of Con Edison's corrective actions at Indian Point 2 was evidenced by 1989, by which time the progression of hourglassing had slowed to the extent that changes in subsequent outage-to-outage visual observations were virtually imperceptible. Additionally, the incidence of tube denting had declined to a very low rate. This response was associated with significant improvements that had been implemented in the steam generator water chemistry program.

The 1997 low-row U-bend probe restrictions need to be evaluated in light of this historical experience. In 1997, 19 tubes had restrictions that prevented a 0.610-inch +Point probe from passing through the tube. The distribution was specifically discussed in our RAI response to Question 11 in Reference 3. An excerpt from that RAI response provides as follows:

> "Nineteen of the twenty tubes were identified as being restricted to a 610 mil bobbin probe at the hot and/or cold leg of the sixth tube support plate (TSP). The nineteen tubes were comprised of fifteen tubes in row 2, three tubes in row 3, and one tube in row 4. Three tubes of the nineteen, row 2 column 62 and row 2 column 63 in SG 22, and row 3 column 31 in SG 23, were at hard spot locations, which are not subject to hourglassing and possible U-bend ovalization. The twentieth tube, which was row 29 column 15 in SG 24, is not a low radius U-bend tube.... Details of the examination data showed restrictions to the 610 mil bobbin probes at the sixth TSP; that is, the probes were not able to get to the bends. The terminology used in 1997 that stated U-bend restrictions was used in a generic sense to describe that the restrictions to the probes were at the uppermost region of the steam generators."

The most significant factor in evaluating the occurrence of probe restrictions in 1997 was the differing physical geometry of the +Point probe. All previous U-bend examinations had been conducted with very flexible ball joint bobbin coil probes of a much different mechanical design. In the 1997 inspection itself, 14 of the 19 instances of restrictions with 0.610-inch +Point probes did not exhibit restrictions to passage when an identically-sized 0.610-inch RPC coil was used to examine both legs. The remaining five (5) tubes exhibited restrictions on only one tube leg.

This demonstrates that the source of probe restrictions was principally if not entirely associated with the different physical dimensions of the +Point probe, rather than increased denting at upper TSPs. Since there were in fact no discernable indications of low-row tube denting, as distinguished from the observable consequences of utilizing a differently-shaped probe, there were no inferences to draw from the restrictions actually encountered.

For reasons of different probe geometry and the actual passage of 0.610-inch probes in straight-leg examinations in 1997, Con Edison concluded that most if not all of the probe restrictions encountered in 1997 were associated with conditions that had existed since prior to approximately 1989, and did not conclude that the restrictions signaled a resumption of a previously-arrested degradation mechanism. This belief was consistent with the following factors:

1) Increases in frequency were to a considerable extent attributable to an expansion of the scope of the inspection to 100% of all four steam generators.

2) Of the 19 restrictions, five (5) of the restrictions were in areas where the flow slots were visually inspected and no hourglassing was observed.

3) Three (3) of the 19 restrictions were at locations that did not line up with flow slots.

4) Thus for eight (8) of the 19 restrictions that occurred in 1997, there was no positive correlation to the symptom of denting and hourglassing.

Visual inspection of tube/support plate intersections was the accepted and customary practice throughout the industry in 1997 for assessing support plate flow slot deformation. Such inspections were thoroughly conducted at Indian Point 2 in 1997, and reported as visual inspections in Con Edison's subsequent written report to the NRC. Only three years later, in 2000, was additional knowledge gained through analysis that hourglassing resulting in leg displacement of as little as 0.1 inch could be sufficient to increase U-bend extrados stress to an extent that susceptibility to PWSCC was increased. This information was not known anywhere in the industry in 1997, and accordingly could not form the basis for a 1997 inspection performance standard.

The 1997 inspection experience thus reveals the consequences of the first-time utilization of a probe with a much different physical geometry, rather than evidence of increased tube denting. Flow slot deformation was examined visually, in accordance with then-prevailing industry custom and practice. However, even if conditions for denting- or hourglassing-related PWSCC precursors are presumed to have existed in 1997, and it is also presumed that they should have been detected, then the potential for those conditions to have contributed to low-row U-bend PWSCC were examined to the fullest extent possible by the examination of 100% of the potentially susceptible row 2 and row 3 tubes utilizing the most advanced qualified +Point probe then available.

Statement 3

Significant ECT signal interference (noise) was encount. red 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.

Response

During the 1997 inspection, a single U-bend flaw was detected in tube R2C67 of steam generator 24. At the time, a depth of 50% through-wall was estimated. A review of this data indicates that the flaw had an amplitude of 3.11 volts, whereas the background noise level was 1.04 volts peak-to- peak and 0.44 volts vertical maximum. The indication thus had a signal-to-noise ratio of approximately 3 to 1. This response was consistent with the U-bend data in the site-specific performance demonstration training and testing materials utilized for analyst training in connection with the 1997 Indian Point inspection. Moreover, the noise levels experienced at Indian Point in 1997 did not appear to differ appreciably from row 1 and 2 U-bend data from other plants. Thus at that time, it appeared that the eddy current technique was performing as expected.

In 1997 no formal industry criteria existed to evaluate noise in a quantitative manner. Furthermore, no data were available to establish a correlation between signal amplitude and depth. The only information then available consisted of the response data from R2C67, the EPRI data for technique 96511, and the response from the calibration standards. The EPRI qualification data set consists primarily of EDM notches placed in row 1 U-bend samples. It should be noted that EDM notches typically yield larger signal amplitudes for a given depth than PWSCC. In the absence of data from partial through-wall PWSCC specimens, the responses of the calibration notches were benchmarked along with the noise levels present in the EPRI samples. This benchmarking took place after the 2000 inspection program. 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 R2C67, flaws ≥ 40% would be detectable (i.e. signal to noise for a ≥ 40% flaw is ≥ 1 to 1.)

The 1997 noise level in tube R2C5 from steam generator 24 was also evaluated. This data shows a peak to peak amplitude of 1.63 volts, and a maximum vertical amplitude of 0.98 volts. The results from this assessment suggest that flaw depths of approximately 50% through-wall and less may not be detected (signal to noise < 1 to 1). This observation is consistent with NRC IN 97-26.

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 R2C67, while other samples were less. Specifically, 9 of 15 samples were $\geq$ 1.04 volts peak to peak and 3 of 15 samples were $\geq$ 0.44 volts vertical maximum.

Attempting to posit ECT failures to detect indications based upon the quality of eddy current data obtained in 1997 would be unreasonable, since data quality criteria was not available in 1997. An industry effort to develop tube noise and data quality guidance was only initiated following the recent evaluations of R2C5. Not only were there no noise criteria in 1997, but there was also no database from which it could be postulated that noise effects could mask a flaw under circumstances such as those present in R2C5.

It is also not clear what 1997 SG inspection program adjustments could have been made to compensate for the effects of particular noise levels in diminishing the detectability of flaws even if those confounding influences had been appreciated. As indicated in response to Statements 1 and 2, there were no conditions revealed in the 1997 inspections from which an increased EOC 13 susceptibility to PWSCC could be inferred. However, even if there had been, the most sensitive qualified probe then available was already being utilized in a 100% inspection of susceptible low-row U-bend tubes, hence there were no compensatory programmatic adjustments that could have been made beyond those already being utilized.

Statement 4

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.

Response

The NRC's review of the 2000 eddy current inspection data states that during operating Cycle 14 there were three tubes in addition to tube R2C5 from steam generator 24 which had indications in their U-bend areas. These tubes were tubes R2C69 and R2C72 from steam generator 24, and tube R2C87 from steam generator 21. This is not an unusual event, and does not by itself support a conclusion of non-compliance with Appendix B, Criterion XVI. There have been many instances where indications detected during a current inspection program are found in prior outage inspection data when the review of historical data is conducted with the knowledge of subsequent inspection results. Furthermore, it is not clear that these three particular tubes exceeded servicability criteria in 1997. When the three tubes were identified during the 2000 inspection and subsequently in-situ pressure tested, acceptance requirements were met. This is further discussed in the 2000 CMOA, Table 3.2 contained in the U-Bend Section (Reference 1).

B. Corrective Steps That Will Be Taken to Avoid Further Violations

Notwithstanding Con Edison's denial of the alleged violations, it is appropriate to take further actions to ensure we protect the integrity of the newly-installed steam generators in addition to those steam generator program improvements that have already been implemented. Key actions in this regard are summarized below:

1. Secondary Side Chemistry Program Revisions

With the removal of the last copper containing Feedwater heater, the Secondary Side Chemistry Program will be altered slightly to minimize the transport of iron through the secondary system and potentially into the steam generators. This will reduce the rate at which iron oxides will accumulate in the steam generators, thereby reducing the potential for oxide generated noise during future eddy current testing. The addition of hydrazine serves to control pH in the secondary side of the plant. Prior to the 2000 outage the acceptable pH range was 9.2 to 9.6. To reduce the transport of iron, this pH range has been increased to 9.6 to 10.0. However, this will have a short-term effect of increasing copper concentrations slightly during the initial stages of operation. Residual copper will be placed into solution and purged by the Long Loop Recirculation System during start up (below 200 F) and by the steam generator blowdown system during operation.

2. Steam Generator Outage Support Engineering Specification Updates

Subsequent to the completion of the Steam Generator Replacement Project and the programmatic improvements mandated by SAO-180, specific engineering specifications will need to be updated. This will be completed prior to the next outage. Engineering specifications for conducting steam generator inspection and repair activities are as follows:

MP 72211 - Search & Recovery of Foreign Objects in SG
MP 72214 - Visual Inspections of SG Secondary Side
MP 72217 - Eddy Current Exams of SG Tubes
MP 72224 - Identification and Repair of Leaking Tubes in SG
MP 72238 - Inspection, Plugging or Replacement of SG Tube Plugs

3. Steam Generator Tube Failure Lessons Learned Report, dated October 23, 2000

The referenced report contains a list of recommendations from the task group on actions to prevent a similar type of event from occurring. Indian Point is actively participating is this effort with NEI and with EPRI. On December 20, 2000 NEI and industry representatives meet with regulatory representatives to present the results of our initial review of the recommendations. The Indian Point Steam Generator Project Manager participated in the meeting to develop the presentation on December 20th. Indian Point will continue to participate in these types of industry actions to address the recommendations outlined in the report.

Date When Full Compliance Will be Achieved

Based upon the implementation of Station Administrative Order-180, "Administrative Steam Generator Program," and the completion of the Steam Generator Replacement Project, as discussed in the cover letter to this Attachment, full compliance has been achieved at the present time. Consequently, the elements of the violation that are being contested are in fact now remediated, and further violations will be avoided. We have concluded that the steam generator in-service inspection program at Indian Point 2 is currently in full compliance with 10 CFR 50, Appendix B, Criterion XVI. The basis for this conclusion is the various steps we have taken, including but not limited to steam generator replacement, as set forth more fully in the December 18, 2000 letter of Mr. J. Baumstark to the NRC (Reference 4).

References

1) 2000 Refueling Outage Steam Generator Inspection Condition Monitoring and Operational Assessment Reports, May 31, 2000, transmitted by Con Edison Letter dated June 2, 2000

2) Indian Point 2 Technical Evaluation Report of Steam Generator Tube Failure, Category C-3 Steam Generator Inspection Results, and Steam Generator Operational Assessment, transmitted by NRC Letter dated October 11, 2000

3) Con Edison Letter to NRC dated June 16, 2000

4) Con Edison Letter from Mr. J. Baumstark to Mr. H. J. Miller dated December 18, 2000

ATTACHMENT C TO NL-01-005

NEW REGULATORY COMMITMENTS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
JANUARY 2001

The following list identifies those actions committed to by Con Edison in this document. No further regulatory commitments are contained herein.

Commitment	Due Date
Subsequent to the completion of the Steam Generator Replacement Project and the programmatic improvements mandated by SAO-180, specific engineering specifications will be updated.	This will be completed prior to the next outage.