March 20, 2000

MEMORANDUM TO: Frank J. Miraglia, Jr.
Deputy Executive Director for Reactor Programs

FROM: Samuel J. Collins, Director ***/ra/***
Office of Nuclear Reactor Regulation

SUBJECT: LESSONS-LEARNED EVALUATION FROM INDIAN POINT STATION UNIT 2 FAILURE EVENT

In a February 28, 2000, memorandum (Attachment 1), the Office of Nuclear Reactor Regulation (NRR) requested that the Office of Nuclear Regulatory Research (RES) perform an independent technical review of two NRR safety evaluations (SE) regarding Indian Point 2 (IP2) steam generators (SGs). One of these involved approval of an alternate repair criteria and the other an extension of the tube inspection interval beyond that required by the plant technical specifications (TS). RES responded to NRR's request in a memorandum dated March 16, 2000, (Attachment 2).

The review did not identify any issues with the staff's SE regarding the use of the F* repair criteria, but did conclude that RES could not reconcile several statements and conclusions in the staff's SE regarding the inspection interval with the information the staff received from the licensee. Specifically, the RES letter indicates that the licensee's assessment of two forms of degradation found in their generators was inadequate: (1) outside diameter stress corrosion cracking (ODSCC) above the top of the tube sheet locations (sludge pile), and (2) primary water stress corrosion cracking (PWSCC) at a row 2 U-bend. RES considered this contrary to the SE prepared by NRR, which concluded that the tubes would meet structural and leakage integrity through the end of the operating cycle.

As follow-up to the IP2 event, the NRC staff will review results of the licensee's current SG inspections, results from previous inspections, the licensee's root cause evaluation, and the licensee's corrective actions as part of its determination as to whether the IP2 SGs are safe to be put back into operation.

As part of its evaluation of the February 15, 2000, IP2 SG tube failure event, the NRC staff will be performing an evaluation of lessons learned from both technical and regulatory process perspectives. NRR's February 28, 2000, memorandum only requested RES review of the technical issues, and did not request that they address the associated regulatory process issues. These process issues do play a role in regulatory decisions, especially when plant TSs are involved. It should be noted that all of this information needs to be evaluated in an integrated fashion in order to accurately assess the lessons learned. The results of this

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lessons-learned assessment will be used to identify any generic technical or process elements that could be improved in the NRC's review of SG issues. It is expected that this assessment will be completed within two months of receiving the licensee's inspection results and root cause failure analysis, currently scheduled to be submitted by early April.

Docket No.: 50-247

Attachments: As stated

lessons-learned assessment will be used to identify any generic technical or process elements that could be improved in the NRC's review of SG issues. It is expected that this assessment will be completed within two months of receiving the licensee's inspection results and root cause failure analysis, currently scheduled to be submitted by early April.

Docket No.: 50-247

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February 28, 2000

MEMORANDUM TO: Ashok Thadani, Director
Office of Nuclear Regulatory Research

FROM: Samuel J. Collins, Director ***/ra by RPZimmerman for/***
Office of Nuclear Reactor Regulation

SUBJECT: REQUEST FOR INDEPENDENT REVIEWS OF MAY 26, 1999, SAFETY EVALUATION REGARDING STEAM GENERATOR TUBE INSPECTION INTERVAL AND FEBRUARY 13, 1995, SAFETY EVALUATION REGARDING F* REPAIR CRITERIA FOR INDIAN POINT STATION UNIT 2

In follow up to discussions with your staff on February 18, 2000, concerning the recent steam generator tube failure event at Indian Point Station Unit 2 (IP-2), this memorandum documents the Office of Nuclear Reactor Regulation's request that the Office of Nuclear Regulatory Research (RES) perform an independent review of the attached safety evaluation (SE) regarding the steam generator (SG) tube inspection interval for this Unit. In addition, this memorandum requests that RES perform an independent review of the attached safety evaluation allowing the F* repair criteria to be used at IP-2.

As you are aware, IP-2 shut down February 15, 2000, because of a sudden increase in primary to secondary leakage in SG 24. In 1999 the staff approved a license request to extend the SG tube inspection interval beyond the 24 calendar months required by the plant technical specifications. In particular, by letter dated December 7, 1998, as supplemented by letter dated May 12, 1999, Consolidated Edison Company of New York, Inc. (the licensee), proposed to amend the technical specifications for the Indian Point Station Unit 2. These letters are also attached. This was to allow a one-time extension of the SG inspection interval and remove the requirement of receiving NRC concurrence on the licensee's proposed SG examination program. By letter dated June 9, 1999, the staff issued the requested amendment and forwarded the SE of the licensee's proposed amendment request to the licensee (TAC No. MA4526).

In addition, by letter dated March 13, 1995, the staff issued an amendment allowing the repair of SG tubes via the implementation of an F* criteria, and forwarded the related February 13, 1995, SE (TAC No. M89373). The SE is attached. The F* criteria allowed tubes that are degraded in a location not affecting structural integrity of the tube to remain in service as an alternative to removal from service through the use of tube plugs. The amendment was issued in response to an application from the licensee transmitted by letter dated April 13, 1994, and supplemented by letters dated December 20, 1994, January 12, 1995, and January 31, 1995.

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ATTACHMENT 1

We request that you perform an independent review of that part of the SE regarding the extension of the inspection interval, transmitted to the licensee on June 9, 1999. A written response is requested by March 8, 2000.

We also request that you perform an independent review of the SE regarding the implementation of the F* repair criteria, transmitted to the licensee on March 13, 1995. A written response is also requested by March 8, 2000.

The purpose of these independent reviews is to determine if the staff's conclusions are technically sound and that the data presented by the licensee provided reasonable assurance that the delayed inspection and the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next scheduled inspection. Your support for this quick response is greatly appreciated.

Docket No.: 50-247

Attachments: As stated

March 16, 2000

MEMORANDUM TO: Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

FROM: Ashok C. Thadani, Director /RA/
Office of Nuclear Regulatory Research

SUBJECT: REQUEST FOR INDEPENDENT REVIEWS OF MAY 26, 1999, SAFETY EVALUATION REGARDING STEAM GENERATOR TUBE INSPECTION INTERVAL AND FEBRUARY 13, 1995, SAFETY EVALUATION REGARDING F* REPAIR CRITERIA FOR INDIAN POINT STATION UNIT 2

This memorandum is in response to your memorandum of February 28, 2000, requesting an independent review of safety evaluations regarding steam generator tube inspection and repair issues for the Indian Point Station, Unit 2. Staff in the Division of Engineering Technology, RES, had initiated a review of these issues based on a verbal request from your staff on February 18, 2000. We expanded our review to include the F* criteria based on your memorandum.

You stated that the purpose of the independent reviews was to "determine if the staff's conclusions are technically sound and that the data presented by the licensee provided reasonable assurance that the delayed inspection and the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next scheduled inspection." Consequently, our review has not addressed regulatory process issues.

We based our review on the staff's Safety Evaluation of May 26, 1999, and other written documentation pertinent to that evaluation. In performing our review, we addressed the specific question of granting the extended inspection interval with the assumption that the original inspection interval was justified, and then evaluated the technical basis for the original interval. Details of our assessment are provided in the attachment to this memorandum.

With regard to the use of the F* repair criteria, we did not identify any issues related to the staff's evaluation or the information submitted by the licensee. The evaluation and the information submitted by the licensee do provide reasonable assurance that the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next inspection interval.

With regard to the extended inspection interval, working from the assumption that the original inspection interval was justified, we concur that the licensee's lay-up procedures for the steam generators were appropriate, and granting the requested 48 day extension of the inspection interval would not have appreciably increased the probability of tube failure.

Attachment 2

However, In our review of the original inspection interval for cycle 14, we cannot reconcile several statements and conclusions in the safety evaluation (SE) with the request for additional information (RAI) and the information we reviewed, particularly with respect to the operational assessments conducted for stress corrosion cracking in the second row U-bend region and at the top of the tubesheet under the sludge. In its review of the licensee request, the NRR staff recognized the importance for maintaining required tube structural and leakage integrity for the entire cycle 14, and in a request for additional information, posed the following question (question 1): "[F]or each degradation mechanism, please provide a general description of the operational assessment methodology used to ensure that SG tube integrity will be maintained for the entire fuel cycle (cycle 14). The description should include an explanation of the predictive methodology, flaw growth rates, and NDE uncertainty used to determine structural and accident leakage integrity."

We find the licensee's response to the staff's question weak and incomplete. For example the licensee provided only a very short discussion regarding their operational assessment for stress corrosion cracking at the row 2 U-bend. No predictive methodology was discussed nor were growth rates or NDE uncertainty applied in their evaluation. The licensee simply stated that the indication was below the in-situ screening threshold (i.e., small) and "[A]s this represented the first detected U-bend indication after approximately 23 years of operation, any growth rates associated with this indication would be considered minimal." While more detailed discussions regarding the weakness of the analyses conducted by the licensee are included in the attachment, we disagree with the licensee's contention because it is inconsistent with the evolution of stress corrosion cracking and with other industry experience.

The SE states that "[T]he licensee assessed the SG tube integrity for the remainder of the present operating cycle (cycle 14) on the basis of the end of cycle 13 inspection and testing results. The severity of degradation at the end of cycle 14 was projected considering BOC degradation status, degradation growth rates, and EOC allowable degradation. The severity of degradation at the EOC 14 was projected to determine if required structural and leakage integrity margins would be maintained." Contrary to our findings, the SE indicates that the licensee conducted more thorough operational assessments than were described in the licensee's response to the RAI, and concludes that the tubes would meet structural and leakage integrity through the end of operating cycle 14.

Based on the information we have reviewed, we believe the licensee's assessment of two forms of degradation found in their generators was inadequate: (1) ODSCC above the top of the tubesheet location (sludge pile); and (2) PWSCC at a row 2 U-bend. We believe that a more thorough operational assessment for these forms of degradation would have predicted an increased probability of tube leakage or rupture by the end of cycle 14.

If you or your staff would like to further discuss our findings please let us know. For additional technical information regarding this review, please contact Dr. Joseph Muscara, (JXM8) of my staff on 415-5844.

Attachment: As stated
cc: C.J. Paperiello
F.J. Miraglia

REVIEW OF SAFETY EVALUATIONS REGARDING STEAM GENERATOR TUBE INSPECTION INTERVAL AND F* CRITERIA FOR INDIAN POINT STATION 2

INSPECTION INTERVAL EVALUATION

The RES evaluation is based on review of the following documentation:

(1) The May 26, 1999 Safety Evaluation;
(2) The original licensee submittal dated December 7, 1998;
(3) The licensee response dated May 12, 1999 to the NRR request for additional information (RAI);
(4) The licensee report dated July 29, 1997, of the steam generator tube inservice examination conducted during the 1997 refueling outage.

The licensee was effectively requesting a one time extension of the steam generator inspection interval from June 1999 to June 2000. Upon return to service following the 1997 refueling outage, Indian Point 2 (IP2) was shut down on October 25, 1997 for an unscheduled maintenance outage that lasted 304 days. In effect, because of the period the plant was shut down, the licensee was requesting an extension of the inspection interval of 48 days. Because the licensee followed industry guidelines for maintaining the wet lay-up chemistry to minimize corrosion of the generators during the outage, any degradation that would have occurred during this period would have been negligible. Further, the licensee had conducted an extensive inspection program during the 1997 refueling outage. Therefore, if the issue is reduced to an assessment of whether the additional 48 days of operation would significantly adversely affect the integrity of the steam generators, given that the required integrity is maintained during the 24-month cycle of operation, RES would conclude that no appreciable increase in the probability of tube failure would result.

In its review of the licensee request, the NRR staff recognized the importance for maintaining required tube structural and leakage integrity for the entire fuel cycle 14. In this context, a request for additional information was issued with two of four questions relating to tube structural integrity. Question 1 stated "[F]or each degradation mechanism, please provide a general description of the operational assessment methodology used to ensure that SG tube integrity will be maintained for the entire fuel cycle (cycle 14). The description should include an explanation of the predictive methodology, flaw growth rates, and NDE uncertainty used to determine structural and accident leakage integrity." In discussing the licensee's steam generator tube integrity assessment for the eight forms of degradation that were detected at the end of fuel cycle 13, the SE states that "[T]he licensee assessed the SG tube integrity for the remainder of the present operating cycle (cycle 14) on the basis of the end of cycle 13 inspection and testing results. The severity of degradation at the end of cycle 14 was projected considering BOC degradation status, degradation growth rates, and EOC allowable degradation. The severity of degradation at the EOC 14 was projected to determine if required structural and leakage integrity margins would be maintained.", and "[T]he licensee's evaluation determined that the forms of degradation listed above did not present a challenge to the 3ΔP structural margin criteria for the expected operating cycle length of 21.4 effective full power months (EFPM). Based on a review of this portion of the licensee's assessment the staff expects the steam generator tubes will continue to satisfy structural and leakage integrity requirements under normal and accident conditions through the end of the current operating cycle (cycle14)."

Regarding the licensee's operational assessment in general, RES found it to be incomplete and the arguments presented to be weak. For most of the degradation mechanisms addressed, the operational assessment was more of a condition monitoring evaluation. The condition at the end of cycle 14 was assumed to be similar to the condition at the end of cylcle13. Since the structural and leak integrity were met at the end of cycle 13, the licensee concluded they would also be met at the end of cycle 14.

However, the behavior of stress corrosion cracks is expected to differ from one operating cycle to the next especially when the cracks first initiate or are detected. The appearance of a 'first' stress corrosion crack typically indicates that an incubation phase has passed and that more cracks are likely.   Studies from service experience indicate that once stress corrosion cracks initiate, the number of future indications will initially increase exponentially with time. Further, in the relatively early stages of crack growth, the growth rate is dependent on crack size and loading. For the relatively constant loading for steam generator tubes, this means that as the crack size increases, the growth rate will increase. There will be a transition from this increasing growth rate to a more constant growth rate as the cracks get larger. However, given the first indication of stress corrosion cracking in steam generator tubes, the physics of the process and service experience suggest that both the number of cracks and their rate of growth will increase. Thus it cannot be expected that the number and sizes of cracks, for the degradation mechanisms first identified during cycle 13, would be the same at the end of cycle 14.

RES considers the licensee's May 12, 1999 response to the RAI related to the operational assessment for two important forms of degradation found in their generators to be particularly inadequate. These forms of degradation are stress corrosion cracks above the top of tubesheet under the sludge pile, and primary water stress corrosion cracks at the row 2 U-bend.

<u>ODSCC Above Top of Tubesheet (Sludge Pile)</u>

The licensee reported that ODSCC in the sludge pile was detected for the first time in the 1997 inspection, and that 22 indications of this type were detected. The licensee contended that the bounding growth rate for these cracks was such that 40% to 50% throughwall cracks that might not have been detected during the inspection would still meet the integrity requirements at the end of cycle 14. Based on the following discussion, RES concludes that this contention is not credible.

The limiting indication of this type was identified as having a maximum depth of 69%, average depth of 48%, and a length of 0.55 inch. The tube with this indication was inspected in 1995 with the Cecco-5 probe and no indication was detected at that time. The licensee reports that the growth in average depth for cycle 13 is bounded by about 18% to 28% for sludge pile ODSCC indications. This was determined by assuming that the indication was 20% to 30% throughwall at the beginning of cycle 13. But the tube with this indication was inspected at the end of cycle 12 and no indications were detected. Therefore, another plausible assumption is that the crack started to grow in cycle 13, either at the beginning of the cycle or even later in the cycle. In addition, the licensee assumed that the +Point depth profile was accurate, i.e., no

NDE sizing uncertainty was applied to the detected crack size even after the licensee has stated that "[R]ecent +Point depth sizing evaluations performed by Westinghouse for axial ODSCC indicate that flaw average depth standard deviation measurement error is about 10% through-wall."

Certainly, assuming that the crack was 20% or 30% throughwall at the beginning of the cycle and not allowing for inspection sizing error, did not provide a bounding estimate, as claimed by the licensee, of the crack growth rate. If the crack had started to grow at the beginning of cycle 13 and a one standard deviation sizing error had been applied to the detected crack, then the growth in average depth would have been 58% for the cycle. The licensee did not discuss the growth for the maximum depth of the crack which was 69% at the end of the cycle. The licensee stated that "[T]he modest growth would lead to acceptable end-of-cycle (EOC) structural integrity even if 40% to 50% average depth indications were not detected." However, if one applies the higher growth rate (58% for one cycle) that is obtained assuming that the crack had initiated at the beginning of cycle 13 and makes some adjustment for sizing error, then the undetected cracks with average depth indications of 40% to 50% would penetrate throughwall during one operating cycle, and potentially not meet the structural integrity requirements at the end of cycle. Furthermore, if these cracks with average depths of 40% to 50% have similar morphology to the crack found during the inspection, i.e., the maximum depth is 21% greater than the average depth, and the growth during the cycle is added to the maximum depth, then the cracks would grow throughwall during the cycle and the tubes would leak even if the growth rate of 28% is applied as estimated by the licensee.

The licensee stated that "[W]hile ODSCC in the sludge pile region is a new mechanism at Indian Point 2, the 22 indications detected represent 0.17% of the total tube population. Therefore, based upon the observed sludge pile flaw eddy current characteristics at IP-2 and in-situ testing results, from more limiting flaws at similar plants, it can be concluded that this corrosion mechanism would not represent either a burst or steam line break leakage potential at EOC 14." This implies that the condition of the generator with respect to this cracking phenomenon will be similar at the end of cycle 14 to that at the end of cycle 13. The fact that the licensee detected 22 ODSCCs in the sludge pile indicated that the incubation period for this phenomenon had been reached and that increasing numbers of cracks could now initiate and grow during subsequent plant operation. The licensee did not conduct a thorough operational assessment with respect to estimating the crack distribution at the beginning of cycle 14, i.e., the cracks left in the generator because they were not detected by NDE. They did not determine the number of new cracks that would initiate during the cycle; this number would likely be greater than was experienced during the previous cycle since the phenomenon was still relatively new at IP-2. They did not apply crack growth rates to the undetected cracks and the newly initiated cracks so that they could estimate the crack distribution at the end of cycle 14. Therefore, there was not a good basis for estimating the structural and leak integrity at the end of cycle 14.

PWSCC at Row 2 U-Bend

The stress corrosion cracking process involves two separate steps, an initiation or incubation period, and a growth period. Once cracks initiate, the growth rates are similar for cracks in tubes that take either a short time or long time to initiate. The crack growth rates can be quite high for U-bend regions because of the high residual stresses induced by fabrication and/or strain induced by the tube denting process during operation.

The licensee cites that PWSCC at the row two U-bend was detected for the first time in the June 1997 inspection. The licensee further states that "[A]s this represents the first detected U-bend indication after 23 years of operation, any growth rates associated with this indication would be considered minimal." Based on the stress corrosion cracking process, this conclusion is not credible.

The detection of the first row 2 U-bend crack at IP2 was an important finding in that it indicated the incubation period for crack initiation had been reached, and now the cracks could begin to appear and grow. Further, in addition to the residual stresses present from the fabrication of the tube, inspection results for IP2 have shown the tubes to be locked in the support plates by the denting that has occurred at this plant. The 1997 inspection showed that several tubes at the upper support plate, including row 2 tubes, were locked in the support plate as evidenced by the 610 mil or 640 mil diameter probe not being able to pass through the tube from either, or both, the cold leg side or the hot leg side at the upper support plate elevation. When the tight U-bend tubes are locked in the upper support plate, the legs of the tube begin to move closer together as the denting process continues, the support plate deforms and cracks, and the flow slots begin to deform and close, commonly known as hourglassing. The motion of the U-bend tube legs causes ovalization and operation-induced straining of the upper portion of the tube at the U-bend. This straining leaves the tube region highly susceptible to stress corrosion cracking.

The 1997 inspection also found evidence that the tube U-bend was being deformed by the denting process due to the inability of the 610 mil probe to pass through 20 row 2 U-bends. Secondary side inspection (as reported in the licensee's inspection report) of the upper support plate in 1997 also found some small cracks in the support plate not previously observed. Leakage from stress corrosion cracking at tight U-bend locations has occurred in operating plants, including two cases of tube rupture in row 1 U-bends. Some licensees have preventively plugged rows of tight-radius U-bend tubes in their steam generators before placing the generators in service, during service, or upon detection of the first crack(s) to avoid stress corrosion cracking incidences during service at these locations.

The results and observations discussed above appear to be in conflict with the licensee's assessment and the staff's safety evaluation.

<u>F* EVALUATION</u>

In evaluating the F* criterion approved for IP-2 in 1995, RES reviewed the 1995 SE and the December 24, 1994 licensee response to an NRR RAI. F* is a repair criterion that allows defects to remain a specified distance (the F* distance) below the end of the roll transition region in the tubesheet of the SG. For proper implementation, the F* distance must be shown to be sufficient to resist operational and transient pull-out forces on the tube, and primary to secondary leakage should be maintained in accordance with the plant technical specifications. The minimum F* distance is calculated based on consideration of the shear stress developed at the tube-tubesheet interface, the area of contact, and the coefficient of friction between the tube and tubesheet. The licensee provided calculations, and results of tests on mock-up tube-tubesheet assemblies to validate the calculations. The mock-up test conditions reasonably simulated the conditions that would be expected in the SGs (e.g., variations in tube yield strengths, variations in tubesheet bore surface roughness and diameter). The minimum calculated F* distance was increased to account for the limited sample size in the testing, statistical scatter in the data, and for NDE uncertainty. The evaluation and the information submitted by the licensee do provide reasonable assurance that the use of the F* repair criteria would not result in an appreciably increased probability of tube failure prior to the next inspection interval.