NRC Region I Supplement for IP2 Performance Assessment during the May 2000 Senior Management Meeting

MEMORANDUM FOR: A. R. Blough, Director
Division of Reactor Projects

VIA: P. W. Eselgroth, Chief
Projects Branch 2

FROM: G. S. Barber, Senior Project Engineer 4/24/2000
Projects Branch 2

SUBJECT: **REVISED REACTOR OVERSIGHT PROGRAM PRELIMINARY EVALUATION OF INDIAN POINT UNIT 2**

This memo supplements the materials for the Spring 2000 Screening meetings by using Revised Reactor Oversight Program (RROP) tools to provide an additional, preliminary assessment of Indian Point 2 performance.

Indian Point 2 (IP2) is a facility with not only longstanding performance concerns but also a recent history of risk-significant events that illustrate significant performance issues. The February 2000 PPR and the Spring 2000 screening meetings reviewed licensee within the context of the oversight program as it existed during the time of the events and inspections. However, we also realized that the RROP provides an excellent set of tools that are very well-suited for assessing the type of performance seen at IP2 over the past year. Therefore, as a supplement to the screening meeting process, we also conducted an informal review of licensee performance using the RROP tools. This review is considered informal because it was not appropriate to perform all steps of the various RROP processes -- for example, we have not published the preliminary significance determinations in inspection reports and provided formal opportunities for the licensee to comment and to meet with us. However, there has been extensive involvement of various NRC offices in developing the enclosed materials and we therefore have good confidence in these assessments. Also, the assessment of the August 1999 event, a scram with a loss of a safety bus, was published as part of a "feasility review" in the 2/24/2000 Commission Paper on the RROP (Secy No. 00-0049, Attachment 7).

On May 10 & 11, 2000, the NRC senior managers will meet to assess performance of Indian Point Unit 2. This assessment will involve the participation by a number of technical offices from both headquarters and the region. Performance indicators (PIs) and inspection results over four quarters (from July 1, 1999 through June 30, 2000) will be considered. The purpose of this memo is to provide a preliminary assessment of IP2 safety performance using tools from the RROP during this time period. We consider this assessment preliminary until ConEd is given the opportunity to review the relevant Significance Determination Processes (SDP) and other details that support this assessment. I have attached copies of the Significance Determination Process (SDP) worksheets that were used to reach these conclusions. The relevant Performance Indicator (PI) data can be found on the external NRC web site (http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/IP2/ip2_chart.html).

adequately Protected

Overall, we have concluded that Indian Point Unit 2 operated in manner that preserved public health and safety. Indian Point Unit 2 met all cornerstone objectives with longstanding issues or significant reduction in safety margins. Thus, this evaluation indicates that applying the

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RROP to IP2 performance results in characterizing it at the Multiple/Repetitive Degraded Cornerstone Column level of the Action Matrix. (See Attachments 1 & 2)

The RROP evaluation was applied to two significant events and an emergency preparedness (EP) exercise that occurred within six months of each other. The first significant event was an August 31, 1999 reactor trip with electrical distribution system complications and the second significant event involved a February 15, 2000 steam generator tube failure. The EP exercise occurred on September 22, 1999. The risk insight derived from these two events and the exercise dominated the overall assessment with the RROP. Only non-green findings or PIs were considered during this evaluation.

Although we did not attempt to review all performance issues that occurred over the past year, we believe that the major issues that have been considered by this evaluation provide a sufficiently complete description of IP2 performance. A review of other inspections identified an ongoing pattern of weaknesses in management effectiveness, configuration management/control, engineering support, equipment reliability, work control, and corrective action program effectiveness that were similar to, but not as significant as those weaknesses that were identified during the two events and the exercise.

The **performance indicators** for the cornerstones were in the licensee response band with the following exceptions:

__August 1999 Event__

- An **Emergency Preparedness PI** crossed the **white** threshold for drill/exercise performance based on the fourth quarter 1999 PI data. A supplemental inspection is planned. (PI1)

__February 2000 Event__

- A **Barrier Integrity PI** crossed the **yellow** threshold based on exceeding the Technical Specification Leak Rate for Steam Generator Tube Integrity based on the first quarter 2000 PI data. A supplemental inspection is planned. This results in a degraded cornerstone. (PI2)

Additionally, NRC inspections identified and/or confirmed risk significant findings in three cornerstones: Initiating Events, Mitigating Systems, and Emergency Preparedness. These were based applying the SDP to findings that were the result of licensee performance problems or issues.

__August 1999 Event__

- An SDP for the **Mitigating System Cornerstone** crossed the **yellow** threshold based on unavailability of certain auxiliary feedwater components and a degradation in feed and bleed capability. This was based on a review of an August 1999 event. (See Attachment 3) Some of the important licensee performance issues that led to these findings were the improper configuration of a Station Auxiliary Transformer Tap Changer and an improper setpoint for an Emergency Diesel Generator. This results in a degraded cornerstone. (IF1) (See Attachment 4)

September 1999 Exercise

- **An SDP for the Emergency Preparedness Cornerstone** crossed the **white** threshold based on a failure to identify an improper classification during a September exercise. (IF2) (See Attachment 7)

February 2000 Event

- **An SDP for the Initiating Event Cornerstone** crossed the **red** threshold based on a significant increase in the likelihood of a steam generator tube rupture with a corresponding increase in Core Damage Frequency (CDF) and large early release frequency (LERF). This was based on a review of a February 2000 event (See Attachment 5). The licensee performance issue that led to this finding was a steam generator tube inspection program that exhibited weaknesses in implementation and ownership. This results in a degraded cornerstone. (IF3) (See Attachment 6)

- **SDPs for the Emergency Preparedness Cornerstone** crossed the **white** threshold in four cases: (1) ERO Augmentation, (2) Accountability of Onsite Personnel, (3) Joint News Center Effectiveness, and (4) Corrective Actions during the February 2000 event. This results in a degraded cornerstone. (IF4, IF5, IF6, IF7) (See Attachment 7)

While the August and February events pre-date the implementation of the RROP, they were significant events that provide useful risk insights of Con Ed performance. Thus, for the purposes of this evaluation, these insights were evaluated against the RROP Action Matrix. Attachment 2 depicts the application of the enclosed PIs and SDPs within the cornerstone assessment matrix and shows that a maximum of four cornerstones were degraded. Applying the "double jeopardy" considerations to the February 2000 event would result in three cornerstones being degraded because the yellow Barrier Integrity PI and red Initiating Event SDP resulted from the same underlying cause, the February 15, 2000 steam generator tube failure. If the evaluation discounted the August event because it preceded RROP initiation, a minimum of two cornerstones would be degraded. Thus, considering all options, IP2 performance could be characterized as Multiple/Repetitive Degraded Cornerstones which would suggest that additional action per the RROP Action Matrix is necessary. (Attachments 1 & 2)

Attachment 1 - ACTION MATRIX

		Licensee Response Column	Regulatory Response Column	Degraded Cornerstone Column	Multiple/ Repetitive Degraded Cornerstone Column	Unacceptable Performance Column
RESULTS		All Assessment Inputs (Performance Indicators (PIs) and Inspection Findings) Green; Cornerstone Objectives Fully Met	One or Two White Inputs (in different cornerstones) in a Strategic Performance Area; Cornerstone Objectives Fully Met	One Degraded Cornerstone (2 White Inputs or 1 Yellow Input) or any 3 White Inputs in a Strategic Performance Area; Cornerstone Objectives Met with Minimal Reduction in Safety Margin	Repetitive Degraded Cornerstone, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or 1 Red Input[1]; Cornerstone Objectives Met with Longstanding Issues or Significant Reduction in Safety Margin	Overall Unacceptable Performance; Plants Not Permitted to Operate Within this Band, Unacceptable Margin to Safety
RESPONSE	Regulatory Performance Meeting	None	Branch Chief (BC) or Division Director (DD) Meet with Licensee	DD or Regional Administrator (RA) Meet with Licensee	RA (or EDO) Meet with Senior Licensee Management	Commission meeting with Senior Licensee Management
	Licensee Action	Licensee Corrective Action	Licensee Corrective Action with NRC Oversight	Licensee Self Assessment with NRC Oversight	Licensee Performance Improvement Plan with NRC Oversight	
	NRC Inspection	Risk-Informed Baseline Inspection Program	Baseline and supplemental inspection procedure 95001	Baseline and supplemental inspection procedure 95002	Baseline and supplemental inspection procedure 95003	
	Regulatory Actions	None	Supplemental inspection only	Supplemental inspection only	-10 CFR 2.204 DFI -10 CFR 50.54(f) Letter -CAL/Order	Order to Modify, Suspend, or Revoke Licensed Activities
COMMUNICATION	Assessment Reports	BC or DD review/sign assessment report (w/ inspection plan)	DD review/sign assessment report (w/ inspection plan)	RA review/sign assessment report (w/ inspection plan)	RA review/sign assessment report (w/ inspection plan) Commission Informed	
	Annual Public Meeting	SRI or BC Meet with Licensee	BC or DD Meet with Licensee	RA (or designee) Discuss Performance with Licensee	EDO (or Commission) Discuss Performance with Senior Licensee Management	Commission Meeting with Senior Licensee Management
	INCREASING SAFETY SIGNIFICANCE ---------->					

1. It is expected in a few limited situations that an inspection finding of this significance will be identified that is not indicative of overall licensee performance. The staff will consider treating these inspection findings as exceptions for the purpose of determining appropriate actions.

Regional focus!

Agency focus

Oversite Panel
0350 Process

TUBE FAILURE NEW PROGRAM WOULD COUNT ONCE?

ATTACHMENT 2
INDIAN POINT 2 (Worst Case)

	CY 1999		CY 2000				CY 2001
	Q3	Q4	Q1	Q2	Q3	Q4	Q1
IE				IF3[1] Red	IF3 Red	IF3 Red	IF3 Red
MS		IF1[2] Yellow	IF1 Yellow	IF1 Yellow	~~IF1~~ Yellow		
BI				PI2[3] Yellow	TUBE LEAK		
EP		PI1 White IF2 White		IF4 White IF5 White IF6 White IF7 White	IF4 White IF5 White IF6 White IF7 White	IF4 White IF5 White IF6 White IF7 White	IF4 White IF5 White IF6 White IF7 White
Worker RS							
Public RS							
PP							
Matrix Column		Degraded	Degraded	Multiple Degraded	Multiple Degraded	Multiple Degraded	Multiple Degraded

Aug 31 TIP

WHITE FOR EDG BREA

SOME DOUBLE JEOPARDY ALSO HERE

G:\BRANCH2\IP2\IP2_PERF_MATRIX.wpd

PI FOR EDGS + FINDINGS FROM AUG 31.

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[1]Classification based on event effects on CDF and LERF. NRC must conclude that the tube failure was caused by a licensee performance issue for red finding to be valid.

[2]This review of this event preceded the initiation of the Revised Reactor Oversight Program (RROP). Although it's use in this assessment could be challenged, it provides useful insights on ConEd performance.

[3]This finding could be voided based on the rules of "double jeopardy" if the red finding on Initiating Events remains.

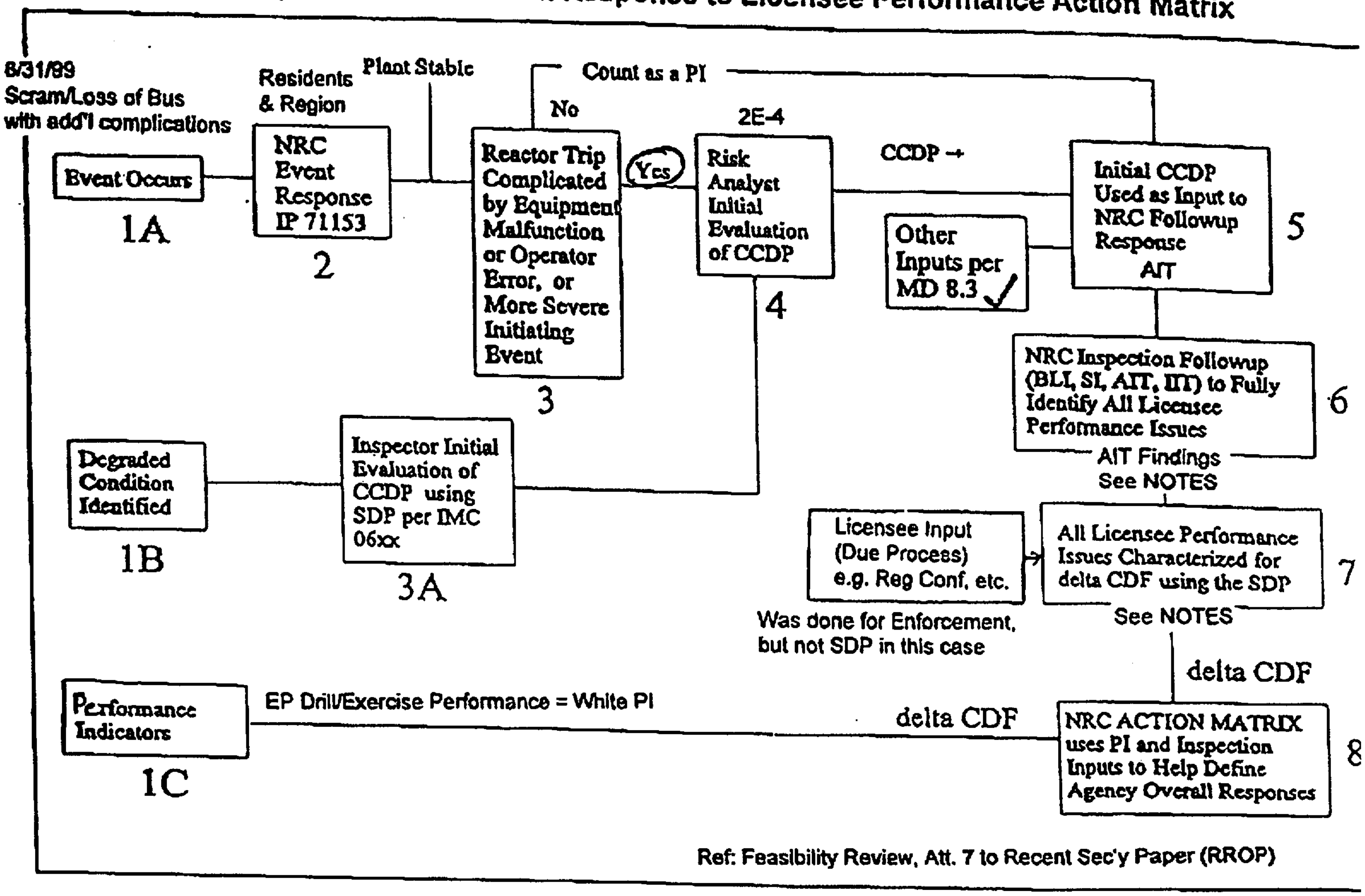
Attachment 3

IP2 Scram/Loss of Safety Bus (8/31/99)

4E 5
29140
36

DRAFT

Relationship of Event/Condition Response to Licensee Performance Action Matrix



NOTES:

AIT Findings and Significance

1. Configuration Control Failures: YELLOW finding in Mitigating Systems Cornerstone based on unavailability of certain AFW components and degradation in feed and bleed capability.

2. Poor management response and technical support: GREEN issues and cross-cutting issues

3. EP Issues:
   A. Failure to classify NOUE for 8/31/99 event: GREEN finding
   B. September 1999 NRC inspection of off-year exercise found repeat implementation problems which could be considered a WHITE finding. It is currently being classified as a WHITE PI because of double jeopardy considerations.
   C. Fourth Quarter 1999 WHITE PI for EP Drill/Exercise Performance, mostly same reasons as WHITE inspection finding - - - treat as one WHITE issue.

ATTACHMENT 4

NRC Region I SDP Review of August 31, 1999, Reactor Trip with Electrical Distribution System Complications

WORKSHEET FOR REACTOR AND PLANT SYSTEM DEGRADED CONDITIONS

Reference/Title (LER #, Inspection Report #, etc): LER 99-015, 50-247/99-09 & 99-13

Factual Description of Identified Condition (statement of facts known about the issue, without hypothetical failures included):

On August 31, 1999 Indian Point Unit 2 tripped and offsite power was lost to the 480 V emergency electrical busses. In addition, emergency diesel generator #23 output breaker failed to close and to energize bus 6A. The following equipment was rendered unavailable by the loss of bus 6A power, 23 safety injection pump, 1 PORV/ block valve (normally closed), 23 MD AFW pump, 23 CCW pump, 22 RHRP, 23 & 26 SWP. The gas turbine generators would not be available because the gas turbines power the 6.9kV busses and the problem was powering the 480V emergency buses. It would have taken a high stress operator action to reset a generator lockout before gas turbine or offsite power could be supplied to the 480 V. busses.

Offsite power remained available to the 6.9 kV busses. Therefore, the feedwater and condensate pumps and condenser would have remained available. The operating EDGs powered the MFW pump lube oil system

The loss of offsite power would occur on any plant trip. The cause of this was the setting of the degraded undervoltage relay reset and that the station auxiliary transformer tap changer was in manual and was unable to recover 480 V. bus voltage. The tap changer was placed in manual In September of 1998 and this condition would have existed since that time (no other plant trips occurred during this period).

The PORV block valves are normally closed and ½ would not be capable of being opened. The success criteria in the IPE requires 2/2 PORVs open for success of feed and bleed (F&B). Therefore, F&B would not be available.

The #23 EDG breaker which had the mis-calibrated overcurrent setting was placed inservice on July 2, 1999. The breaker would have tripped any time the EDG attempted to energize this bus after this date. These conditions existed from July 2, 1999 to August 31, 1999 or > 30 days.

Since every time a plant transient occurs offsite power would be lost, it's appropriate to use Row 1 from Table 1 to estimate the frequency of a LOOP. This condition existed for greater than 30 days so the Initiating Event Likelihood is A.

System(s) and Train(s) with degraded condition: Offsite Power and #23 EDG

Licensing Basis Function (if applicable): Provide Normal and Emergency Power to Safety-related equipment.

Maintenance Rule category (check one): __X__ risk-significant _____ non-risk-significant

Time degraded condition existed or assumed to exist: Tap Changer Place in Manual 9/98 and #23 EDG breaker mis-calibrated July 1999.

Functions and Cornerstones degraded as a result of this condition (check ✓)

INITIATING EVENT CORNERSTONE

__√__ Transient initiator contributor (e.g., reactor/turbine trip, loss offsite power)

_____ Primary or Secondary system LOCA initiator contributor (e.g., RCS or main steam/feedwater pipe degradations and leaks)

MITIGATION CORNERSTONE

__√__ Core Decay Heat Removal

__√__ Initial injection heat removal paths

_____ Primary (e.g., Safety Inj)

_____ Low Pressure

_____ High Pressure

__√__ Secondary - PWR only (e.g., AFW)

__√__ Long term heat removal paths (e.g., contmt sump recirculation, suppression pool cooling)

_____ Reactivity control

BARRIER CORNERSTONE

_____ RCS LOCA mitigation boundary degraded (e.g., PORV block valve, PTS issue)

_____ Containment integrity

_____ Breach or bypass

__√__ Heat removal, hydrogen or pressure control

_____ Fuel cladding degraded

PHASE 1 SCREENING PROCESS
Check the appropriate boxes ✔

Cornerstone(s) assumed degraded:

☒Initiating Event ☒Mitigation Systems ☐RCS Barrier ☐Fuel Barrier ☒Containment Barrier

If more than one Cornerstone is degraded, then go to Phase 2. If NO Cornerstone is degraded, then the condition screens OUT as "Green" and is not assessed further by this process.

If only one Cornerstone is degraded, continue in the appropriate column below.

Initiating Event	Mitigation Systems	RCS Barrier	Fuel Barrier	Containment Barrier
1. Does the issue contribute to the likelihood of a Primary or Secondary system LOCA initiator? ☐ **If YES → Go to Phase 2** If NO, continue 2. Does the issue contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment will not be available? ☐ **If YES → Go to Phase 2** ☐ If NO, screen OUT	1. Is the issue a design or qualification deficiency that does NOT affect operability per GL 91-18 (rev 1)? ☐ **If YES → Screen OUT** If NO, continue 2. Does the issue represent an actual Loss of Safety Function of a System? ☐ **If YES → Go to Phase 2** If NO, continue 3. Does the issue represent an actual Loss of Safety Function of a Single Train, for > TS AOT? ☒ **If YES → Go To Phase 2** If NO, continue 4. Does the issue represent an actual Loss of Safety Function of a Single Train of non-TS equipment designated as risk-significant under 10CFR50.65, for > 24 hrs? ☐ **If YES → Go To Phase 2** ☐ If NO, screen OUT	☐ **1. Go to Phase 2**	☐ **1.Screen OUT**	**1. TBD**

Result of the Phase 1 screening process: _____ screen OUT as "Green" ___X__ go to Phase 2

Important Assumptions (as applicable):

Table 2.6 SDP Worksheet for Indian Point Unit 2 Nuclear Plant —— LOOP

Estimated Frequency (Table 1 Row) 1 Exposure Time >30days Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	*Full* Creditable Mitigation Capability for each Safety Function:
Emergency AC Power (EAC)	1 / 3 Emergency Diesel Generators (1 multi-train system) or 2 /2 Gas Turbines (Operator action)
Recovery of AC power in < 5 hrs (REC5)[1,3]	Recovery of AC power (Operator action)
Recovery of AC Power in < 2 hrs (REC2)[2]	Recovery of AC power (Operator action under high stress)
Early Inventory, HP Injection (EIHP)	1 / 3 HPI pumps (1 multi-train system)
Secondary Heat Removal (TDAFW)	1 / 1 TDAFW pump (1 train)
Secondary Heat Removal (AFW)	1 / 2 MDAFW trains (1 multi-train system) or 1 / 1 TDAFW train (1 ASD train)
Primary Heat Removal, Feed/Bleed (FB)	2 / 2 PORVs open for Feed/Bleed (operator action)
High Pressure Recirculation (HPR)	1 / 3 HPI pumps with (1 / 2 LPIS pumps or 1 / 2 RSS pumps) with switchover to recirculation (operator action)

Circle Affected Functions	Recovery of Failed Train	*Remaining Mitigation Capability Rating for Each Affected Sequence*	Sequence Color
1 LOOP - AFW - HPR (3)	1 (MFW)	2 (1-MDAFWP) +1 (TDAFWP) +2 (HPR)=6	Green
2 LOOP - AFW - FB (4)	1 (MFW)	2 (1-MDAFWP) + 1 (TDAFWP) + 0 (FB)=4	Yellow
3 LOOP - AFW - EIHP (5)	1 (MFW)	2 (1- MDAFWP) + 3 (2-SIP)=6	Green
4 LOOP - EAC - HPR (7, 11)		Do not believe sequence would lead to CD	
5 LOOP - EAC - EIHP (8, 13)		3 (2-EDGs) + 3 (2 HPI) + 3 (Charging Pumps) = 9	Green
6 LOOP - EAC - REC5 (9)	1 (MFW)	3 (2-EDGs) + 2 (REC5)= 6	Green
7 LOOP - EAC - TDAFW - FB (12)	1(MFW)	3 (2-EDGs) + 1 (TDAFW) + 0 (0 PORVs)=5	White
8 LOOP - EAC - TDAFW - REC2 (14)	1 (MFW)	3 (2-EDGs) + 1 (TDAFW) + 1 (REC2) = 6	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event: Since offsite power was not lost to the 6.9kV buses the operators could have manually recovered feedwater. If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met: 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use.

Notes:

(1) In an SBO situation, an RCP seal LOCA may occur, with subsequent core damage at about 5 hours.

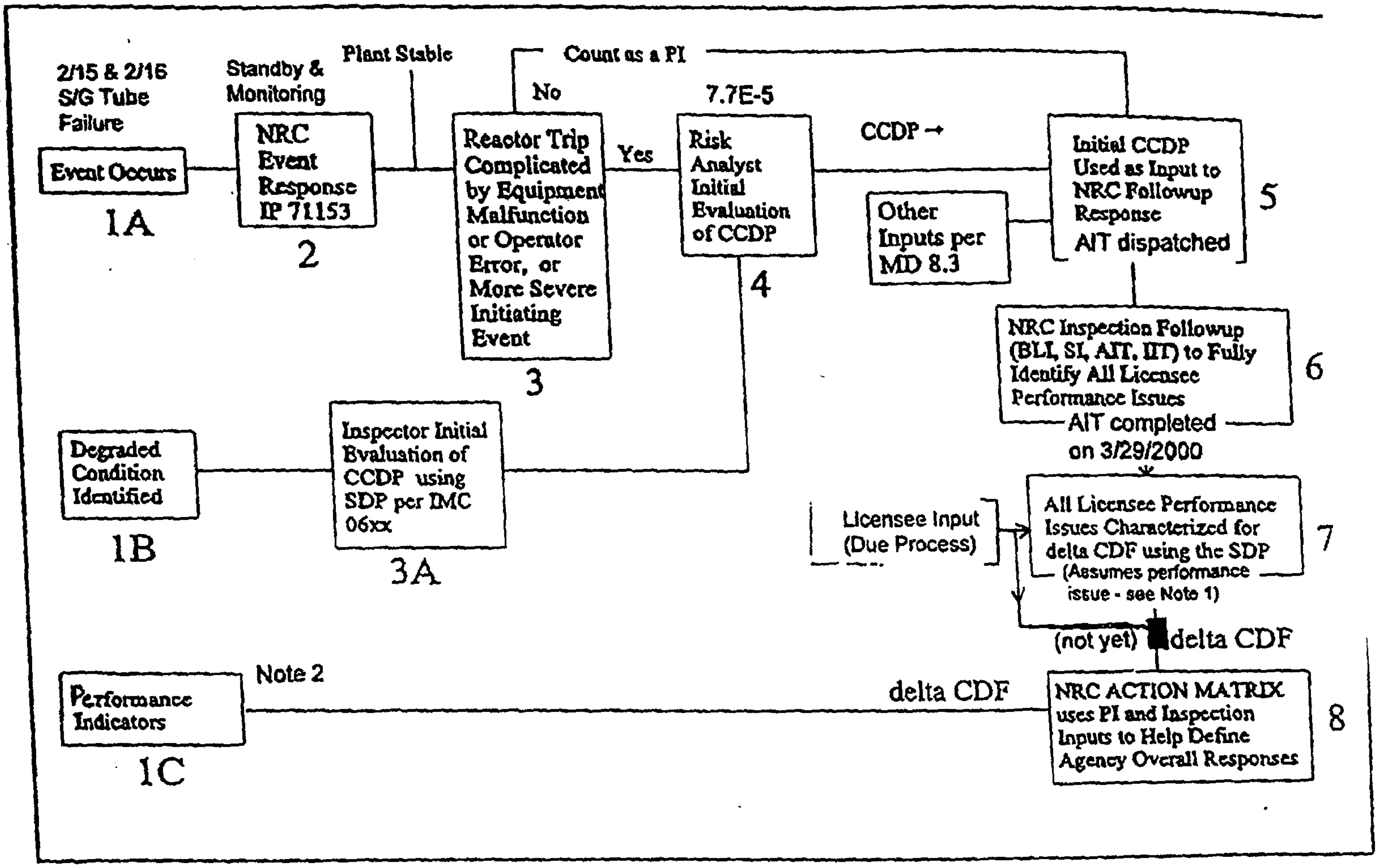
(2) For the functions "Recovery of AC Power in < 2 hrs (REC2)" and "Recovery of AC Power in < 5 hrs (REC5)" no similar human action was found in the IPE (Table 3.3-7, pages 3-370 to 3-374).

Attachment 5

IP2 Steam Generator Tube Leak (2/15/00)

DRAFT

Relationship of Event/Condition Response to Licensee Performance Action Matrix



NOTES:

1. Risk Insight:
If the failed tube is attributed to either a human performance error or an inadequate SG inspection program, this would constitute a performance issue. NRR is evaluating these possibilities. Per OST, if a performance issue existed, this event would have a significant impact on the Initiating Events cornerstone. The delta CDF would be on the order of E-04 which is a RED finding.

2. The Barrier Integrity PI crossed YELLOW threshold based on exceeding maximum allowable T.S. leak rate for SG tube leakage.

3. Operational, communications, procedural, equipment, and technical support issues challenged operators and delayed attainment of Cold Shutdown. Likely result: GREEN findings and cross-cutting issues.

4. Emergency Response Organization failed to meet the intent of two emergency planning standards, emergency facilities were not activated and accountability was not performed in a timely manner. Result: TWO WHITE findings.

ATTACHMENT 6

Memorandum to: Richard J. Barrett, Chief
Risk Assessment Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

From: Steven M. Long,
Sr. Reliability and Risk Analyst
Risk Assessment Branch
Division of Systems safety And Analysis
Office of Nuclear Reactor Reguation

Subject: **Risk Assessment for Condition of Indian Point Unit 2 Steam Generator Tubes During Operational Cycle 14**

During operation cycle 14, Indian Point unit 2 experienced degradation of steam generator tubes on February 15, 2000, that culminated in failure of a flaw in the U-bend of tube R2C5 in steam generator 24. In addition, inspection following the tube failure event revealed 3 additional tubes with defects in the same region.

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

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

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

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

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

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

The sum of these tube degradation related risk contributions for Indian Point unit 2 during cycle 14 is estimated to be a probability of core damage accident with a large release at approximately 10^{-4}. This risk occurred mostly during the latter year of the operational cycle.

The basis for this estimate is discussed below for each potential accident sequence, individually.

IE P 1/YR

Spontaneous Tube Rupture:

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

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

Ruptures Induced by Steam System Depressurization:

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

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

However, in order to estimate the increase in probability of core damage and large release, it is necessary to consider the length of time that this increase in frequency is applicable. Based on the currently available information, the period of time the tube was susceptible to this accident sequence is estimated in Appendix B as approximately six months or 0.5 year. Thus, the number of ruptures that would be mathematically "expected" for this frequency over this period is 9.5 xs 10^{-6}. For such small expectation values, the probability of occurrence of a single event is numerically indistinguishable, so the increase in the probability of core damage and large release from this sequence for this condition is estimated to be about 1×10^{-5}.

Ruptures Induced by Reactor System Over-Pressurization Events:

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

The PRA for Indian Point unit 2 estimates a core damage frequency contribution of 1.81×10^{-6} / RY due to ATWS events. Based on the rate of degradation estimated in Appendix B, we estimate that an ATWS event would have induced tube R2C5 to rupture for a period of about 6 months. In the same manner described above for steam system depressurization sequences, this results in an estimated increase in the large early release probability of 9×10^{-7}. There is no increase in the core damage probability because the ATWS sequences that would induce the tube rupture are already part of the core damage frequency estimate, and the addition of the tube rupture potential is not assumed to change the frequency with which ATWS would cause core damage.

Tube Ruptures Induced by Other Core Damage Sequences:

Other core damage sequences that are included in licensees' and NRC's PRAs may also cause large releases by inducing steam generator tube ruptures, but this effect is rarely included in the results of current PRAs. The studies documented in NUREG-1150 and particularly NUREG-1570 do address this potential for large releases to bypass containment due to tube failures.

For accident sequences in which the reactor coolant system (RCS) remains at high pressure, the failures of flawed tubes may be caused by steam system depressurization that sometimes occurs as an essential or incidental part of the event sequence that leads to core damage. Also, for sequences with high RCS pressure and dry steam generators (hi/dry sequences), tube failure may be induced when the overheating reactor core causes the tube temperatures to rise so high that their metal weakens. Tubes with flaws that would not fail upon steam system depressurization may still fail when the tube temperatures increase, later in the accident sequence. This is clearly the case for the Indian Point tube for some period during the last cycle, before it was susceptible to failure by steam system depressurization, alone. It also is clear that, for some shorter period of time, tube R2C5 would have failed if dry and overheated by a high pressure core damage accident, even if the steam system remained pressurized.

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

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

Summarization of Overall Risk Increase:

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

A Significance Determination in accordance with the new Reactor Oversight Process is included Appendix B.

Flawed Tube Strength as A Function of Time

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

Based on these measurements, the tube's burst pressure at the beginning of the cycle is estimated by NRC staff in the Division of Engineering to be approximately 4500 psid. When the tube burst during operation, it's burst pressure had decreased to the plant's normal operating pressure differential, 1600 psid, the tube burst. The period of power operation that elapsed between these times was 22.5 months.

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

Initial strength	4,500 psid	23 months
TI-SGTR threshold	2800 psid*	10 months
PI-SGTR threshold	2350 psid	6 months
Spontaneous rupture	1,600 psid	(instantaneous)

* The pressure assumed here for the threshold for thermally-induced steam generator tube rupture during a severe accident was estimated based on the calculations performed by the NRC's Risk Assessment Staff for the Farley unit 1 reactor. It is based on the stress magnification factor for which there was a 50% probability of rupture for the conditions studied at the Farley unit. Those conditions differ significantly from the conditions at the Indian Point unit 2, but are used because they are the most similar conditions for which results are currently available.

Significance Determination

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

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

Table 1 Risk Significance Based on LERF and CDF

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

The conceptual question is how to assign a frequency to an accident initiating event that has happened once as the consequence of a condition that has developed over a period of time. The following discussion is considered sufficient to establish the "color" of the situation that occurred at Indian Point unit 2.

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

10^{-5}/ RY. Therefore, the CDF increment associated this event is considered to be clearly above the 10^{-5}/ RY criterion for a "red" significance assessment.