April 28, 2000

Mr. A. Alan Blind
Vice President - Nuclear Power
Consolidated Edison Company of
New York, Inc.
Indian Point 2 Station
Broadway and Bleakley Avenues
Buchanan, NY 10511

SUBJECT: NRC AUGMENTED INSPECTION TEAM - STEAM GENERATOR TUBE FAILURE - REPORT NO. 05000247/2000-002

Dear Mr. Blind:

On March 3, 2000, the NRC completed an Augmented Inspection Team (Team) inspection at the Indian Point Unit 2 (IP2) Station. The enclosed report (Enclosure 1) presents the results of that inspection.

The Team was chartered (Enclosure 2) to review the causes, safety implications, and your staff's actions following the steam generator tube failure at IP2 on February 15, 2000. The Team reviewed the record of activities that occurred, interviewed personnel, and conducted plant walkdowns. The Team developed a sequence of events, determined the risk significance of the event, and assessed the quality of response by the plant staff and management. The cause of the tube failure was outside the scope of this inspection, and is being reviewed separately by the NRC. A summary of the Team's findings was presented at a public exit meeting on March 29, 2000. The NRC briefing slides from that meeting are provided in Enclosure 3.

The event had moderate risk significance. It involved a steam generator tube failure that resulted in an initial primary-to-secondary leak of reactor coolant of approximately 146 gallons per minute, and required an "Alert" declaration (the second level of emergency action in the NRC required emergency response plan). The event resulted in a minor radiological release to the environment that was well within regulatory limits. The Team noted that no radioactivity was measured off-site above normal background levels, and determined that the event did not impact the public health and safety.

Your staff acted to protect the health and safety of the public. Specifically, the operators promptly and appropriately took those actions in the emergency operating procedures to trip the reactor, isolate the affected steam generator, and depressurize the reactor coolant system. Additionally, the necessary event mitigation systems worked properly. Notwithstanding the above, the Team identified problems in several areas including operator performance, procedure quality, equipment performance, technical support, and emergency response. These problems challenged the operators, complicated the event response, and delayed the plant cooldown.

Several of the identified equipment problems such as a degraded steam jet air ejector steam supply valve, and an isolation valve seal water system design deficiency were long standing (Section 4.1). Some of the emergency plan implementation problems were similar to previously identified problems in this area; for example, technical support center personnel did not consistently anticipate plant problems and make timely recommendations to the operators (Section 4.3), which was also a finding during the September 1999 emergency preparedness exercise. The failure to correct these problems reflected weaknesses in engineering, corrective action processes, and operational support at the Station. The Team recognized that, prior to the event, your staff was in the process of implementing a station improvement program. This event demonstrated the need for continuous management attention to planned improvements to ensure they are timely and effective.

The Team reviewed the activities of your Event Investigation Team (EIT), and noted that while some of the preliminary assessments appeared similar to the Team findings, the EIT activities and proposed corrective actions were not finalized prior to the end of the inspection period. Therefore a final assessment of your planned corrective activities could not be reached. The NRC plans to review selected corrective actions prior to the plant re-start.

In accordance with NRC procedures, the AIT charter did not include the determination of compliance with NRC rules and regulations or the recommendation of enforcement actions. Those aspects will be addressed in subsequent inspections or reviews.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room (PDR).

Sincerely,

/RA/

Hubert J. Miller
Regional Administrator

Enclosures:
1. NRC Augmented Inspection Report No. 05000247/2000-002
2. NRC Augmented Inspection Team (AIT) Charter
3. NRC Briefing Slides - March 29, 2000, Exit Meeting

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REGION I

Docket No.:	50-247
License No.:	DPR-26
Report No.:	05000247/2000-002
Licensee:	Consolidated Edison Company of New York Broadway and Bleakley Avenues Buchanan, NY 10511
Facility:	Indian Point Station Unit 2
Location:	Broadway and Bleakley Avenues Buchanan, NY 10511
Dates:	February 18 - March 3, 2000
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Approved by:	Lawrence Doerflein, Chief Systems Branch Division of Reactor Safety Team Manager

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SUMMARY

Indian Point Unit 2 Station
NRC Inspection Report 50-247/00-02

An NRC Augmented Inspection Team (Team) reviewed the causes, safety implications, and associated licensee actions in response to a steam generator (SG) tube failure event that occurred on February 15, 2000.

Background

Indian Point Unit 2 has four steam generators, which are designated as the number 21, 22, 23 and 24 SGs. Each steam generator has 3260 U-shaped tubes. Reactor coolant (the “primary” side) passes through the tubes, heating the normally non-radioactive water in the steam generator (the “secondary” side) to produce steam which is used to operate the main turbine. After the steam passes through the main turbine, it is condensed and the water is pumped back to the steam generator to repeat the cycle. A cutaway view of a typical steam generator and a diagram depicting the primary and secondary flowpaths are included as Attachment 1 to this report.

On February 15, 2000, one of the tubes in the No. 24 steam generator failed, allowing reactor coolant into the steam generator. Until the affected steam generator was isolated, the contaminated water mixed with the steam and water in the secondary plant. Actions to mitigate a steam generator tube failure included shutting down the reactor, isolating the affected steam generator, and cooling down and depressurizing the reactor coolant system to prevent leakage into the steam generator.

Event Overview/Significance

The licensee performed the necessary actions to mitigate this event, including shutdown of the reactor, identification and isolation of the faulted SG, cooldown of the reactor coolant system (RCS), declaration of the Alert, and staffing of the emergency response organization (ERO). The Team noted that no radioactivity was measured off-site in excess of normal background levels and determined that the event did not impact the health and safety of the public. Necessary event mitigation systems worked properly. Although there was no impact on public health and safety, the event had moderate risk significance and required the declaration of an Alert.

The Team identified performance problems in several broad areas that challenged operators, complicated the event response, delayed achieving the cold shutdown condition, and impacted the radiological release. The problems summarized in Section 3.0, involved: operator performance, procedure quality, equipment performance, technical support, and emergency response.

Operator Performance

The operators performed the necessary activities to mitigate this event including (Section 4.2):

- The event was promptly recognized and properly classified.
- The reactor was promptly shutdown per procedure.
- The affected steam generator was identified and isolated.
- The plant was placed in cold shutdown to terminate the event.

Procedural adherence was generally good during the event. A few minor procedural adherence issues such as not shutting a condenser vacuum pump discharge valve were identified.

Some operator performance problems were noted during the plant cooldown phase involving:

- While attempting to cooldown the RCS, the reactor operator initiated an excessive cooldown rate that exceeded procedural and Technical Specification (TS) limits. The excessive cooldown led to several conditions that complicated the subsequent event response and delayed the RCS cooldown.

- Operators were slow to recognize configuration line-up problems that prevented successful operation of the auxiliary spray system to lower RCS pressure, and delayed heat-up of the residual heat removal system.

Procedure Quality

The procedures adequately guided the initial operator response; however, several procedure problems were identified that delayed the cooldown and depressurizing of the RCS.

Equipment Performance

The necessary event mitigation systems, including the reactor protection system, auxiliary feedwater system, and the safety injection system functioned properly. However, several long-standing equipment performance problems were identified that challenged operators during this event:

- Two losses of condenser vacuum resulted from problems with the operation of the automatic steam supply pressure control valve to the steam jet air ejectors (SJAEs), and the #22 condenser vacuum pump.

- The isolation valve seal water system (IVSWS) became inoperable during the event, and required operator action and an entry into a TS Limiting Condition for Operation Action Statement.

- A containment entry was required to install a temporary nitrogen supply to the pressurizer power operated relief valve to compensate for a design deficiency. This action was required prior to placing the over-pressure protection system in-service.
- The SG leak rate monitoring equipment had been degraded for an extended period of time, and limited the amount of SG leak rate information available to the operators prior to the event.

The Team determined that the number and duration of the equipment problems reflected weaknesses in engineering, corrective action processes, and operational support at the Station. The licensee's response to a number of the equipment problems identified during the event reflected an acceptance of "working around" rather than fixing the problem.

Emergency Response

The ERO took the necessary steps to ensure the protection of public health and safety. The operators properly classified the event, and the licensee implemented a thorough peer review of the emergency response to this event. The Team identified several emergency plan and implementing procedure problems similar to those identified by the licensee's peer review team including:

- The emergency response staff was slow to activate the emergency facilities.
- The licensee was slow to establish accountability (i.e., identify the location) of emergency response personnel.
- The emergency response data system (ERDS) was inoperable for the first several hours of the event due to a pre-existing equipment problem.
- Problems were noted in the implementation of the media response plan.
- Problems were identified involving the timeliness and quality of technical support provided to the operators.

The licensee developed and was in the process of implementing an emergency response improvement plan prior to the event.

Report Details

1.0 EVENT OVERVIEW

1.1 Synopsis of Event: Steam Generator Tube Failure

On February 15, 2000, at 7:17 p.m., the Indian Point Unit 2 (IP2) nuclear plant experienced a steam generator tube failure (SGTF) which required the declaration of an Alert at 7:29 p.m., and a manual reactor trip at 7:30 p.m. The operators identified that the #24 steam generator (SG) was the source of the leak and completed isolation of the #24 SG by 8:31 p.m. At 9:02 p.m., the operator opened the high pressure steam dump valves (HPSDVs) and established an excessive primary plant cooldown rate that caused a rapid reduction in the pressurizer level and required the operators to manually initiate safety injection (SI). The operators reset the SI (9:21 p.m.), reduced reactor coolant system (RCS) pressure to about 970 psig (9:32 p.m.), and re-commenced a plant cooldown at 11:35 p.m. The residual heat removal (RHR) system was placed in-service on February 16, 2000, at 12:38 p.m., and primary plant pressure was reduced below the #24 SG pressure to terminate the SG tube leakage at 2:20 p.m. The plant cooldown continued and the plant entered cold shutdown at 4:57 p.m. The licensee exited the Alert at 6:50 p.m.

Minor releases of radioactivity occurred during and following the event, as discussed in Section 4.4. The Augmented Inspection Team (Team) determined that the amount of radioactivity released was well below regulatory limits, and that the event did not impact the public health and safety.

The Team developed a detailed sequence of events based on interviews and review of plant logs, computer data, and recorded information. The sequence of events is provided as Attachment 2.

1.2 Summary of Augmented Inspection Team Activities

On February 18, 2000, the Team commenced the inspection. The Team was tasked to review the sequence of events, causal factors, safety significance, and licensee response to the event including the subsequent complications that were encountered during the plant cooldown. The NRC was concerned regarding several apparent operational and procedural deficiencies, unexpected equipment problems, and emergency response organization (ERO) problems that appeared to complicate the event response. The inspection was conducted in accordance with the Team Charter (Enclosure 2) and NRC Inspection Procedure 93800, “Augmented Inspection Team.”

The Team completed its onsite activities on March 3, 2000, and debriefed the licensee on the status of the inspection on March 8, 2000. The Team completed its activities and presented the preliminary findings on the inspection to licensee management, in a meeting open to public observation, on March 29, 2000.

2.0 EVENT SIGNIFICANCE

Following the initiation of the event, the operators manually tripped the reactor, correctly identified and isolated the affected SG (#24), and depressurized the RCS to reduce the leak rate through the failed SG tube. The RCS was initially cooled down using the intact SGs and the main condenser. The operators used the atmosphere steam dump valves (ASDVs) to continue the plant cooldown during two relatively short periods of time when the main condenser was unavailable for use as a heat sink. The auxiliary feedwater (AFW) system was used to maintain SG inventory levels during the cooldown.

In the unlikely event that the AFW system became unavailable, the operators could have removed decay heat by using a primary system cooling method referred to as “bleed and feed”. This method of cooling involves adding water to the RCS and removing steam through the pressurizer power-operated relief valves (PORVs). This method of cooling would have had a high probability of success since the redundant off-site and on-site power sources remained available throughout the event.

Several procedural and configuration problems were noted that delayed placing the RHR system in-service to complete the plant cooldown. This delay contributed to an increased inventory level in the leaking SG and led to a concern that the rising SG level would allow water to enter and challenge the integrity of the main steam (MS) lines. The licensee implemented a contingency plan to reinforce the MS line supports, and also developed a special procedure to use the SG blowdown system to prevent water from entering the MS lines. The RHR system was placed in-service and reactor pressure was reduced to lower the SG level through back leakage into the primary plant before the SG inventory actually entered the MS lines. The Team noted that the licensee had multiple methods available to protect the MS line integrity and concluded that the delay in placing RHR in-service complicated the event response, but did not result in any actual plant safety consequences.

The results of the licensee and independent NRC risk evaluation of this event were similar. The risk estimates appeared conservative in that the actual SG tube leak rate (maximum about 146 gallons per minute (gpm) at the initial reactor coolant system temperature and pressure) was less than the SG tube leak rate design analysis. This increased the amount of time operators had to complete the necessary event mitigation activities. The increased time to perform the necessary accident mitigation functions would lower the expected operator error rate, and reduce the plant risk below the calculated risk value. The licensee determined that the conditional core damage probability (CCDP) for this event was 7.7×10^{-5}. A preliminary NRC determination of CCDP for this event was 1.0×10^{-4}. The CCDP is used to estimate the risk significance of conditions or events.

The Team reviewed the licensee’s environmental monitoring activities, and determined that they were adequate and met regulatory requirements. The Team noted that no radioactivity was detected off-site above normal background levels, and concluded that the event did not impact the public health and safety (Section 4.4.2).

3.0 EVENT CAUSAL FACTORS AND ROOT CAUSES

The primary cause for the event was the failure of a U-tube in the #24 SG. The SG inspection and maintenance history is described in Section 4.5. The SG tube failure mechanism will be reviewed separately by the NRC and was outside the scope of this inspection.

The Team sequentially analyzed the licensee's event response activities. Although this event did not result in any measurable off-site radiological consequences (Section 4.4), problems were noted in several areas which complicated the event response, delayed achieving a cold shutdown plant condition, and impacted the radiological release. The principle problems are listed below with a brief explanation.

Equipment Problems

Several longstanding equipment performance problems challenged the operator response to this event. The inability to correct these problems reflected weaknesses in engineering, corrective action processes, and operational support at the Station.

- Two losses of condenser vacuum resulted from problems with the operation of the automatic steam supply pressure control valve to the steam jet air ejectors (SJAEs), and the #22 mechanical vacuum pump (Section 4.1.3).

- The isolation valve seal water system (IVSWS) became inoperable during the event, and required operator response and an entry into a Technical Specification (TS) Limiting Condition for Operation Action Statement (Section 4.1.5).

- A containment entry was required to install a temporary nitrogen supply to the pressurizer PORV to compensate for a design deficiency. This action was required prior to placing the over-pressure protection system in-service (Attachment 3).

- The SG leak rate monitoring equipment had been degraded for an extended period of time, and limited the amount of SG leak rate information available to the operators prior to the event (Section 4.1.1).

Operator Performance

While attempting to cooldown the RCS, operators initiated an excessive cooldown rate that exceeded procedural and TS limits:

The rapid cooldown caused a pressurizer level reduction that required the operators to manually initiate SI. The SI actuation complicated the subsequent event response as discussed in Section 4.2.

Operators were slow to recognize a valve line-up problem that prevented successful operation of the auxiliary spray system to lower RCS pressure:

This contributed to a delay in stopping the leakage into the #24 SG as discussed in Section 4.2.

Operators did not effectively monitor the affect of RHR heat exchanger alignment changes:

This resulted in operators exceeding the maximum RCS hot leg to cold leg temperature differential permitted by station procedures (Section 4.2).

<u>Procedure Quality</u>

Several procedure problems were identified that delayed RCS cooldown, RCS depressurization, and emergency response organization (ERO) notifications (Sections 4.1.6, 4.2, and 4.3):

Procedure deficiencies affected Standard Operating Procedures, Emergency Operating Procedures, and Emergency Plan Implementing Procedures. Specific activities included initiation of residual heat removal (RHR) cooling, component cooling water alignment, use of auxiliary pressurizer spray, methods to monitor RCS temperature to maintain cold shutdown conditions, and ERO notifications. Station personnel were previously aware of the procedure issue involving initiation of RHR cooling, but had not corrected the problem prior to this event.

<u>Emergency Response</u>

Several problems were identified with the implementation of the emergency plan that reduced the effectiveness of the emergency response organization (ERO) (Section 4.3):

- Delayed activation of the emergency facilities, and delayed accountability of ERO personnel.
- The emergency response data system (ERDS) was inoperable for the first several hours of the event, and portions of the offsite radiation monitoring system did not function as designed. These repetitive equipment problems initially inhibited the Technical Support Center's (TSC's) and NRC's ability to monitor and assess the event.
- Problems were noted in the implementation of the media response plan.
- Problems were identified involving the timeliness and quality of technical support provided to the operators.

The Team determined that the problems listed above, as well as other items of lesser significance, revealed performance problems in several areas including: engineering, corrective action processes, and operational support at the Station.

4.0 PLANT RESPONSE: EQUIPMENT AND PERSONNEL

The operators performed the necessary activities to mitigate this event including (Section 4.2):

- The event was promptly recognized and properly classified.
- The reactor was promptly shutdown per procedure.
- The affected steam generator was identified and isolated.
- The plant was placed in cold shutdown to terminate the event.

However, the SG tube failure event was complicated by problems in several areas including: equipment performance, operator performance, procedure quality, technical support, ERO performance, and corrective actions. These problems resulted in a delay in stopping the primary-to-secondary water leakage and in achieving cold shutdown.

4.1 Equipment Performance

4.1.1 Main Steam Line and Main Condenser Air Ejector High Radiation Monitors

Non-condensable gasses are removed from the condensers during normal operation by the SJAEs and then released to the atmosphere through the plant vent. The release path is continuously monitored by a radiation detector (R-45). When the activity level reaches the high alarm setpoint, the condenser off-gas flow is automatically diverted to the containment. At about 7:17 p.m. on February 15, 2000, a high radiation alarm occurred on R-45, indicative of a SGTF. The plant equipment responded as designed to this signal and automatically re-aligned the SJAE exhaust to the primary containment structure at the initiation of the event.

In addition to the condenser off-gas radiation monitors, each of the four MS lines is monitored for activity by individual radiation monitors. The monitors are calibrated to detect a specific radioactive isotope (Nitrogen-16) most representative of the primary to secondary leak rate, and provide a reliable method for identifying and trending a SG tube leak during plant operation. The Team noted two previously identified and uncorrected, equipment deficiencies that reduced the effectiveness of the MS line radiation monitors for monitoring changes in the pre-event primary-to-secondary leak rate. The pre-event SG leak rate trend information is discussed further in Section 4.5.

- The strip chart recorder for the MS line radiation monitors had been out of service since April 1999. The strip chart recorder maintains a continuous recording of the primary to secondary leak rate from all four steam generators. Since April 1999, the licensee has relied on plant chemistry technicians to obtain periodic readings of the leak rate. This equipment problem reduced the pre-event SG leak rate information that would have been available to the operators. The licensee indicated that once the indicated leak rate exceeded 10 gallons per day (gpd), an operator would have been continuously stationed at the MS line radiation detector to monitor the SG tube leak rate.

- The potentiometer used to set the reactor power level input into the leak rate calculation circuit on the MS line radiation monitors has not functioned properly since December 1999. Power level inputs less than the actual reactor power provide a conservative estimate of the primary-to-secondary leak rate while power level inputs greater than actual would provide a non-conservative leak rate estimate. Three condition reports (CRs) have been issued since December 1999 documenting “as found” power level settings ranging from 16% to 108%. In each case, the power level setting was manually adjusted to match the actual reactor power of 100%.

  On January 8, 2000, the indicated primary-to-secondary leak rate on the #24 SG jumped to 15 gpd and then decreased to less than 1 gpd. Operators appropriately entered the steam generator tube leak abnormal operating procedure in response to this indication. Condenser off-gas samples indicated no change in the primary-to-secondary leak rate. The rapid change in leak rate indicated on the main steam line radiation monitor was attributed to the malfunctioning potentiometer.

The equipment problems discussed above (failed strip chart recorder and malfunctioning power level setpoint potentiometer) degraded the operators ability to monitor changes in the primary-to-secondary leak rate. The resolution of these equipment problems appeared non-timely considering that the licensee was aware of the degraded condition in the #24 SG prior to the event.

4.1.2 High Pressure Steam Dump Valves to the Main Condenser

The High Pressure Steam Dump Valves (HPSDVs) provide a method for effecting a plant cooldown by providing a flowpath for the transfer of steam to the condenser that bypasses the main turbine. The HPSDVs are operated in the automatic mode under temperature control during normal reactor operations and in pressure control during low steam flow conditions. The HPSDVs are aligned into four groups of valves; each group contains three valves. Each group operates as a unit and the first group goes to full open before the next group begins to open. The control room operator has indication (a light comes on at the control panel) when each valve group begins to open, but does not have an indication of the actual valve position.

The operators have experienced previous oscillations in automatic control during low steam flow conditions (CRs 199907799 and 200001215). During this event the operators observed erratic HPSDV operation following the reactor trip while operating the HPSDVs in the automatic mode under pressure control. The licensee reviewed the HPSDV performance and determined that the system was designed for a large load reduction and the valve performance could be unstable during automatic operation in low steam flow conditions. In response to the erratic HPSDV operation in automatic, the operator elected to operate the HPSDVs in manual for the plant cooldown.

In the manual mode, the operator can move the valve groups in either slow speed, by moving the ‘T’ switch a little, or in fast speed, by moving the ‘T’ switch all the way over to control the valve opening. The Team operated the HPSDVs in the plant simulator following the event and noted that when the valves were operated in fast speed the simulator cooldown rate matched the excessive plant cooldown rate observed during the initial plant cooldown. The cooldown rate was controllable when the high pressure steam dump valves were operated in slow speed.

The HPSDVs appeared to function properly in the manual mode during the event since the operators used the valves extensively during the plant cooldown. The Team determined that mis-operation of the HPSDV control ‘T’ switch, combined with a failure to effectively monitor plant conditions were the most likely causal factors for the excessive initial cooldown rate.

4.1.3 Main Condenser Steam Jet Air Ejector (SJAE) and Mechanical Vacuum Pumps

At 12:05 a.m. on February 16, vacuum became degraded to the point where the main condenser could not be used as a heat sink for the plant cooldown. This resulted in automatic closure of the HPSDVs. The operators then opened the ASDVs and discharged steam from the three intact steam generators to the atmosphere to continue the plant cooldown. This created an additional, albeit minor since the affected SG was already isolated, radiological release path to the environment as discussed in Section 4.4.

The loss of vacuum was caused by the failure to reposition the manual bypass valve that was controlling the SJAE steam supply pressure. The bypass valve had to be readjusted to maintain adequate steam pressure to the SJAE in response to the lowering main steam header pressure caused by the plant cooldown. The system was originally designed with two valves in series to control steam flow to the SJAE including a pressure control valve (PCV) and an automatic closure valve. The PCV was designed to control steam pressure to the SJAE automatically during normal plant operation, plant transients, and cooldown evolutions. The automatic closure valve provided two protective functions; isolation for over-pressure protection should the PCV fail, and also isolation on a loss of condensate flow through the SJAE condenser.

The PCV has been out of service for many years and controlling steam flow manually using the bypass valve had become a “normal” operator workaround. Several nuclear plant operators (NPOs) interviewed indicated that the PCV had never worked properly. The protective functions of the automatic closure valve are defeated when operating in the manual mode using the bypass valve. The licensee removed the SJAE steam supply PCV from service in December 1998 and decided not to pursue fixing this deficiency. This action entailed closing all open work orders, and removing the item from the operator work around list. However, the licensee failed to update the applicable system operating procedures and abnormal operating instructions to reflect this design change.

The licensee performed a safety screening and determined that it was acceptable to operate the system in manual bypass, based on the narrow conclusion that automatic operation was not described in the Updated Final Safety Analysis Report (UFSAR). The Team determined that this evaluation was poor since it did not consider the impact of the system deficiency on the operators, particularly during event response.

At 1:15 a.m., main condenser vacuum was reestablished using the #22 condenser vacuum pump. The ASDVs were closed and cooldown continued using the HPSDVs to the condenser. The condenser vacuum pump was started in accordance with plant operating procedures with both the six inch discharge line to the tunnel vent and three inch discharge line to the SJAE suction open. The six inch line is normally used to establish condenser vacuum, but is required to be isolated per plant operating procedures once condenser vacuum is established. The NPO failed to isolate the six inch line after condenser vacuum was re-established. Flow through the six inch discharge line bypassed the monitored and protected flow path past the R-45 detector. Since the six inch flow path was in parallel to the R-45 flow path, the licensee determined that the R-45 detector readings could be used to estimate the radioactive release through this pathway.

At 7:20 a.m. on February 16, condenser vacuum was lost for a second time and cooldown was shifted to the ASDVs. The #22 condenser vacuum pump thermal overload devices tripped after approximately six hours of operation. There was a 1997 deficiency tag issued on the #22 condenser vacuum pump which stated that the pump had a known deficiency of tripping on thermal overload. Condenser vacuum was restored in approximately 90 minutes using the #21 mechanical vacuum pump. The ASDVs were closed and the cooldown was continued by dumping steam to the main condenser.

The Team determined that in both cases the loss of condenser vacuum was due to long standing equipment deficiencies that were not resolved in a timely manner. In this event, the loss of vacuum resulted in manual operator action to reestablish cooldown using the ASDVs and established additional, albeit minor since the affected SG was already isolated, radiological release paths to the environment.

4.1.4 Atmospheric Steam Dump Valves (ASDV)

During periods when vacuum was lost to the main condenser the operators used the ASDVs associated with the three intact SGs to continue the cooldown, discharging steam to the environment.

There are four 6 inch power-operated relief valves, one for each SG, which are capable of releasing steam to the atmosphere. These valves were manually controlled from the main control board to control SG pressure in the #21, 22, and 23 SGs and the RCS cooldown rate. The ASDVs operated as designed.

The pressure relief setpoint for automatic opening of the SG ASDVs is normally 1020 pounds per square inch (psig). The automatic opening of the ASDVs is determined by a controller such that the rate at which the valve opens is directly related to the magnitude of the difference between the setpoint and the SG pressure. During the event the control room operators raised, per procedure AOI-1.2, “Steam Generator Tube Leak,” the pressure relief setpoint on the #24 SG ASDV to 1030 psig to reduce the likelihood of a radiological release to atmosphere. The pressure indication used by the controller for the #24 SG ASDV reached, but did not exceed, 1030 psig for a short time. The Team concluded, based on a review of additional plant data, that the #24 ASDV did not open during the event.

4.1.5 <u>Isolation Valve Seal Water (IVSW) System</u>

At 2:10 a.m. on February 16, the operators declared the isolation valve seal water (IVSW) system inoperable and entered TS 3.0.1. Technical Specification 3.3.C requires the IVSW tank to be maintained at a minimum pressure of 52 psig and a minimum volume of 144 gallons of water. The IVSW system was declared inoperable due to the operators not being able to refill the tank above its TS required minimum level. The licensee stated that it appeared the IVSW system was draining into the component cooling water (CCW) system. A similar drain down of the IVSW tank occurred following a SI actuation in 1997. Following the 1997 event, the licensee revised the emergency operating procedures to dispatch a NPO to monitor the tank level following receipt of a SI actuation signal, and to refill the tank as necessary. The revision of the emergency operating procedure, in lieu of correcting the system design problem reflected an acceptance to “work around” rather than correct the system problem.

The IVSW system provides a water seal at a pressure greater than the containment design pressure in piping lines that could be a source of leakage. The system is actuated on a containment isolation signal within one minute to terminate containment leakage. The containment isolation system is designed to leak at a ratio of less than 0.1% per day at design pressure without the benefit of the IVSW system.

A Phase A containment isolation signal is generated upon a SI actuation. The Phase A containment isolation signal closes the containment isolation valves that require early closure in addition to actuating the IVSW system. The CCW valves supplying cooling water to the reactor coolant thermal barrier heat exchanger do not close, by design, on a Phase A containment isolation. However, seal water flow from the IVSW system is initiated to these valves. It appeared that a IVSW actuation during a Phase A containment isolation would initiate a flow path from the higher pressure IVSW system into the lower pressure CCW return line from the reactor coolant pump heat exchangers. On receipt of a subsequent Phase B containment isolation signal, the CCW valves close and the open flowpath would no longer exist.

Technical Specification 3.3.C requires the IVSW system to be operable prior to taking the reactor above cold shutdown conditions. Additionally, TS 3.3.C requires that the IVSW tank be maintained at a minimum pressure of 52 psig and contain a minimum of 144 gallons of water. Following receipt of a Phase A containment isolation signal, the system is required to be operable by TS until the reactor is placed into a cold shutdown condition. The tank became inoperable in less than five hours following initiation of the SI signal during this event. The NPO was initially not able to refill and maintain level in the tank due to the apparent leakage into the CCW system. The IVSW system had to be reset and the automatic initiation valves shut, before the tank could be refilled and the system declared operable.

The Team noted several long-standing design deficiencies with the IVSW system. Since 1984 there have been six licensee event reports (LERs) involving leakage in valves sealed by the IVSW system exceeding the TS limit. An LER was submitted following the 1997 event regarding the IVSW system not performing per the design as stated in the UFSAR. In 1998, the licensee's review of the design basis documentation for the system identified discrepancies that were documented in CR 1998-10169. A preliminary calculation completed by the licensee in January 2000, in response to the 1998 design basis review, raised potential concerns regarding the capability of the system to meet its design requirements.

Based on the observed performance of the IVSW system during the event, and the long standing design deficiencies identified with the system, the Team questioned the ability of the IVSW system to meet its TS operability requirements and UFSAR design requirements, even with compensatory operator action. At the end of the inspection period, this issue remained open pending NRC review of the licensee's evaluation and satisfactory resolution of this issue.

4.1.6 Residual Heat Removal (RHR) System

Shortly after 12:00 p.m. on February 16, the RHR system was placed in service to continue the plant cooldown. The Team identified several operating and procedural problems which delayed placing the RHR system in-service. Collectively, the problems contributed to the relatively long period of time (about 20 hours) required to place the plant in cold shutdown.

Emergency Operating Procedure (EOP) ES-3.1, "Post-SGTR Cooldown Using Backfill," Step 9, directed the operators to place the RHR system in service when RCS pressure was less than 300 pounds per square inch (psig). Control room personnel questioned the 300 psig limit since this was below the minimum pressure of 350 psig for operating the reactor coolant pumps (RCPs); the #24 RCP was running at this time. The Shift Manager, based on a vendor recommendation through the Technical Support Center, invoked 10 CFR 50.54(x) and changed the ES-3.1 procedure to allow the RHR system to be placed in-service at 450 psig.

The technical basis for the change was considered appropriate. However, the setpoint had previously been 450 psig and was changed to 300 psig in 1998, per a vendor recommendation developed to address an instrumentation accuracy issue. The EOP Coordinator indicated that a verification and validation (V&V) of Revision 30 (which changed the setpoint from 450 psig to 300 psig) was not performed since the change was considered to be administrative. The Team determined that Revision 30 to ES-3.1 was not administrative, and therefore a V&V should have been performed. This indicated a lack of rigor in the evaluation of an EOP change, and the Team determined that a proper V&V would have identified the discrepancy between the EOP and the RCP trip criteria.

The procedure for heating up and placing the RHR system in-service, Standard Operating Procedure (SOP- 4.4.2), assumed that both CCW isolation valves to the RHR heat exchanger were closed. Procedure SOP 4.4.2 directed the operators to open one of the valves; however, both of these isolation valves were already open due to the previous SI actuation. The Team determined that the plant procedures did not provide sufficient guidance to the operators for placing the RHR system in-service following a SI actuation.

While preparing to place the RHR system in-service, the reactor operator (RO) noted that the CCW valves for the RHR heat exchangers were not in the normally closed position, and questioned the control room supervisor (CRS) for guidance. The RO apparently did not receive an answer to this question, left the valves open, and continued to implement procedure SOP 4.4.2. The RHR system temperature was lowered due to operation with both CCW valves open, which led to a further delay in the heatup and initiation of the RHR system. Subsequently, about an hour and a half later, the operators recognized the impact of the open CCW valves, and resolved this discrepancy by closing both of the CCW isolation valves and then performing the procedure as written.

The operators initiated a RHR SOP procedure change to isolate the idle RHR heat exchanger using the outlet motor-operated valve in lieu of the heat exchanger outlet butterfly valve. The butterfly valve was apparently not designed to be leak tight and the Team determined that its use in the RHR SOP as an isolation boundary reflected a poor consideration for the operational characteristics of the valve. The time associated with implementing the RHR SOP change further delayed the plant cooldown.

4.1.7 <u>Elevated Auxiliary Feedwater Pump (AFWP) Room Temperatures</u>

During the event, the operators noted that the temperature in the auxiliary feedwater pump (AFWP) room was higher than normal. The operators investigated this condition and determined that plywood had been improperly installed over the louvers for the AFWP room suction vent. Procedure SOP-11.5, "Space Heating and Winterization," required plywood to be installed over the louvers for the room adjacent to the AFWP room, but not for the AFWP room. The licensee determined that the plywood did not adversely affect the AFW system operability. The Team reviewed this evaluation and agreed with the licensee's conclusion.

4.1.8 Miscellaneous Equipment Issues

Based on associated risk, the Team did not review, in detail, all of the equipment problems identified during the event. Individually many of the equipment problems appeared minor in nature, or did not affect safety related equipment. However, many of the problems required immediate operator attention, and collectively they appeared to increase the burden on operators, and ERO personnel. Attachment 3 contains a listing and brief description of selected equipment problems.

4.2 Operational Performance

The operators' response to this event was adequate. The key operator actions to mitigate a SGTF event were performed as discussed in Section 2.0. However, the Team noted several operator performance, and procedural deficiencies that unnecessarily complicated the event response. These complications extended the duration of the event, increased the radiological release to the environment, and challenged TS and procedural requirements.

Pre-Event Activities

The team determined that the licensee was aware of the increasing SG leak rate trend since early in the operating cycle (Section 4.5), and had implemented some actions prior to the event to improve the operator performance to a steam generator tube leak event. Specifically, the licensee monitored the SG leak rate once per shift, an increase from once per day, to detect any measurable change in the SG leak rate, and also directed operators to review abnormal operating procedure, AOI-1.2, "Steam Generator Tube Leak".

The Team noted that while the actions described above were appropriate, some additional actions could have been implemented to enhance the licensee's preparations for this event. Specifically, the MS line radiation monitoring system deficiencies should have been corrected to provide additional information that could have been used to trend the pre-event leak rate (Section 4.1.1). Additionally, the licensee's pre-event activities were significant and should have been reported to and reviewed by the Nuclear Facility Safety Committee (NFSC) (the off-site review committee). Technical Specification 6.5.2.7 requires the NFSC to review indications of an unanticipated deficiency in some aspect of design or operation of safety-related structures, systems, or components. The Team determined, based on the licensee's review of NFSC meeting minutes, that the NFSC had not performed a review of the degraded SG condition, and the pre-event activities.

Initial Event Response

The operators identified the SG tube leak, and entered abnormal operating procedure AOI 1.2. The operators manually tripped the reactor and entered emergency operating procedure (EOP) E-0, "Reactor Trip or Safety Injection" after determining that two charging pumps in maximum speed were unable to maintain pressurizer level. The operators exited E-0, and entered ES-0.1, "Reactor Trip Response," after determining that manually initiating safety injection (SI) was not required at the time. The operators then entered abnormal operating instruction AOI 1.2, isolated the #24 SG, and commenced a normal plant cooldown per operating procedure POP 3.3, “Plant Cooldown”. The Team determined that the initial operator response to this event was prompt and appropriate, and consistent with the operating procedures.

Initial Plant Cooldown Per POP 3.3

The CRS directed the reactor operator at the controls (OTC) to maintain the cooldown rate less than 50°F per hour using the HPSDVs. The OTC operated the HPSDVs in the manual control mode during the plant cooldown. During the post event review, the Team determined that the OTC established an excessive RCS cooldown rate that exceeded the POP 3.3 limit as well as the limits imposed by TS 3.1.B.1 (limits the RCS cooldown rate to a maximum of 100°F/hour), and TS 3.1.B-5 (limits the differential temperature between the spray flow, and the pressurizer to 320°F). The licensee initiated an engineering evaluation, as required by TSs, to evaluate the impact of the cooldown on plant components.

The Team noted that the HPSDVs appeared to work properly in the manual mode during the event and determined that the most likely cause for the excessive cooldown was operator error (i.e mis-operation of the HPSDV control switch, and/or poor monitoring of the plant process parameters) as discussed in Section 4.1.2. The excessive cooldown caused a rapid decrease in the pressurizer level, and within about two minutes the level decrease required the operators to manually initiate SI. The failure of the OTC to maintain the plant cooldown within the POP 3.3 limits, initiated the sequence of events that led to the SI. This had several adverse effects that complicated the subsequent event response including:

- The CCW isolation valves to the RHR heat exchangers opened which subsequently delayed placing the RHR system in-service (Section 4.1.6);

- The SJAE exhaust was re-directed from the containment back to the plant vent and caused an additional, albeit small, radiological release (Section 4.4). The plant procedures did not address redirecting the SJAE exhaust back to the containment to minimize the radioactive release to the environment;

- The IVSWS actuated and then failed during the event requiring further operator attention (Section 4.1.5).

Plant Pressure Reduction Using Auxiliary Spray

The operators placed the auxiliary spray system in-service per ES-3.1, “Post-SGTR Cooldown Using Backfill,” on February 16, at 12:56 p.m., and attempted to reduce the RCS pressure below the SG pressure to terminate the leakage into the #24 SG. The operators lined up the auxiliary spray system as described in ES-3.1, but noted that the RCS pressure did not decrease as expected. Approximately one hour later the operators identified that the problem was caused by the normal pressurizer spray valve being left in the open position. The ES-3.1 procedure was deficient in that it did not provide adequate guidance to the operators for securing the normal spray system prior to lining up the auxiliary spray system. A detailed V&V of the procedure should have identified this discrepancy.

Notwithstanding the procedure problem discussed above, the Team noted that the necessary information to diagnose the normal spray line-up problem was readily available to control room personnel and concluded that the operators were slow to identify this configuration deficiency. The delay in reducing RCS pressure allowed the leakage into the #24 SG leakage to continue and contributed to the concern that the rising SG inventory would overflow into the main steam lines.

Loss of Condenser Vacuum Events

The NPO responses to the two loss of condenser vacuum events are described in Section 4.1.3. The Team noted that during the first event the NPO failed to isolate the six inch discharge line from the mechanical vacuum pump as required by the plant operating procedures. This operator error allowed the condenser vacuum pump discharge to bypass the plant protective system that would have redirected the condenser off-gas back to the containment upon receipt of a high radiation condition.

Post-Event Operation of the RHR System

The Team reviewed the operation of the RHR system to ensure that the system was operated properly to maintain the RCS in a cold, shutdown condition. Following the event, the RHR system was used to remove the reactor decay heat while all reactor coolant pumps (RCPs) were secured. Operating procedure SOP, 4.2.1, “Residual Heat Removal System Operation,” states that the RHR heat exchanger inlet temperature shall be used for monitoring the RCS temperature when all RCPs are secured. The Team identified that this temperature indication could provide a non-conservative indication of the RCS temperature since a portion of the relatively cool RHR heat exchanger outlet flow is typically returned to mix with the inlet flow to the RHR heat exchanger upstream of the temperature sensor. This would lower the fluid temperature monitored by the RHR heat exchanger inlet temperature sensor below the existing RCS temperature.

The operators permitted the RHR heat exchanger inlet temperature to approach 190°F on two occasions following the event (at 6:00 p.m. on February 16, and at 2:40 a.m. on February 17). Although permitted by procedure, the Team was concerned that operation of the RHR system in this manner combined with the non-conservative temperature monitoring error discussed above could have resulted in the actual RCS temperature inadvertently exceeding 200°F. The Team determined, based on nominal system values, that the RHR heat exchanger inlet temperature indicated approximately 7-16°F below the actual RCS temperature during the two events described above. The licensee initiated condition report (CR) 200001286 to review the method for monitoring RCS temperature during RHR system operation.

On February 17, at 2:40 a.m., the operators removed one of the RHR heat exchangers from service. The Team identified that following this planned evolution the differential temperature between the RCS hot and cold legs reached about 90°F. This exceeded the 72°F limit specified in SOP 4.2.1. The licensee initiated CR 200001681 to review this issue.

Operator Logkeeping

The Team noted that the operator logs were not maintained throughout the event as required by the licensee's administrative procedures. Specifically, the operators did not consistently log significant plant items such as the event declaration, implementation of the emergency plan, abnormal indications, major plant evolutions, and equipment alignment changes.

Licensee Requirements for Procedural Adherence and Use

The Team reviewed OAD-33, "Procedure Adherence and Use," and noted inconsistent guidance pertaining to the requirements for allowing an operator to deviate from a written procedure. Specifically:

Section 4.4.1 was based on an American National Standard Institute Standard (ANSI N18.7-1976) and allowed operators (on their initiative) to not follow a procedure provided that the action was necessary to protect the health and safety of the public, plant personnel, or to prevent damage to plant equipment. The section also required the operator to inform the shift manager (SM), after the fact, regarding the procedural deviation.

Section 4.4.2 required the operator to obtain permission from a Senior Reactor Operator (i.e. the SM) before deviating from a procedure. This section also required that the action be taken when immediately needed to protect public health and safety. This was consistent with 10 CFR 50.54 (x) which limits departures from a license condition to emergency situations to protect public health and safety.

The Team discussed a concern with station and operations management that the guidance contained in Section 4.4.1 of administrative procedure OAD 33 could result in an improper deviation from an approved operating procedure. The licensee planned to review and revise, as necessary, all affected administrative procedures prior to restart.

4.3 Emergency Response Organization Performance

The SM correctly classified the event as an Alert using Emergency Action Level (EAL) 3.1.2 for reactor coolant leakage exceeding the capacity of one charging pump (>75 gpm). Notifications to the State of New York, the Counties of Rockland, Westchester, Putnam and Orange and the Town of Peekskill met the 15-minute time requirement as described in the licensee's Emergency Plan (E-Plan) Implementing Procedure, IP-1002.

Immediately following the event, the licensee conducted emergency facility critiques and appointed an independent review team consisting of emergency response specialists from other utilities to assess the adequacy of the ERO's performance. The post-critique report was self-critical and thorough. The identified problems, which included the independent review team findings, encompassed the broad areas of ERO mobilization, facility activation, accountability and communications and are discussed below in more detail.

The licensee's emergency facilities were not activated for approximately one hour and 40 minutes after the event declaration. Emergency Plan Figure 5.2-1 requires the minimum facility staffing to be completed within 60 minutes. Contributing factors to the failure to activate the ERO facilities within the required time included: (1) emergency response pagers were not activated by the corporate information group (CIG) for about 20 minutes after the event declaration; (2) the automated telephone notification system was not activated until 50 minutes after the event declaration because the recorded event message was incorrect and had to be re-recorded; (3) there was confusion at the security guard house as to where to send responders for accountability and facility assignments; and (4) activation of the operations support center (OSC) was delayed due to the licensee's decision to move the facility to another location for better coordination with the technical support center (TSC). The OSC was originally scheduled to be moved next to the TSC in March 2000, as part of the on-going corrective action plan to improve ERO performance.

The Team determined that the procedure and process used to activate the pagers were complex and required an excessive period of time (approximately 20 minutes) to activate the pagers. This resulted in licensee personnel having about 40 minutes to travel to the site, and activate the ERO facilities. The slow pager activation process appeared to be a significant factor in the licensee's failure to meet the facility activation requirements. The Team reviewed the monthly communication tests and found that there was no formal process for documenting pager activation problems and for ensuring that all ERO staff received the proper signal. Prior to the event, the licensee had not fully implemented the activation procedures during scheduled daytime emergency drills or exercises. The Team determined that the licensee was not aware of the pre-existing activation problems.

Accountability of onsite personnel was not completed within 30 minutes as specified in Section 6.4.1(d) of the E-Plan. The delay in completing accountability appeared to be related to an inconsistent understanding between ERO managers of the requirements for declaring that accountability was complete. Specifically, the SM completed an initial accountability check; however, the OSC Manager requested that the accountability check be re-performed since several people were identified as missing following the first check. Accountability was subsequently declared complete at about one hour and 15 minutes after the start of the event. Section 8.1.3, "Drills and Exercises," of the E-Plan, committed the licensee to conduct an "off-hours" exercise once every six years. The

Team noted that the last “off hours” exercise was conducted in 1993 and did not meet this requirement. The Team determined that the failure to exercise the ERO during an “off hours” condition, as required, contributed to the accountability problem remaining undetected.

During the Alert declaration, security personnel secured the owner controlled and protected areas for establishing accountability. This included closing the main entrance gate and only granting access to oncoming ERO members. The security manager determined, however, that the Indian Point Unit 3 access gate, which is an egress to the IP2 owner control area, was not guarded until midnight and not locked until 3:00 a.m. Although this was not a procedural requirement, security personnel were expected to immediately ensure that the gate was closed. As a result, some ERO responders were not accounted for because they bypassed the main gate for the owner controlled area. The potential consequences of not securing all access points included inaccurate accountability of ERO responders and the potential for open access of the general public into the EOF. Security immediately implemented a change to Post Guidelines 5, 6 and 12 to require that the Unit 3 gate be immediately closed during an Alert and above.

At the time of the event, the licensee was in the process of implementing a transition to upgrade the TSC and OSC facilities. This transition included the development and staging of new operating procedures. Facility training was scheduled to be conducted during the months of February and March 2000. As a result, ERO personnel in the TSC and OSC were confused as to which procedures were applicable so they elected to use the current procedures along with the new (unapproved) procedures. The licensee stated that the requirements in the new procedures were similar to the existing procedures but contained improved guidance for ERO personnel. Based on this information, the Team determined that use of the new procedures should not have adversely affected the performance of ERO personnel.

Several equipment problems were found in the TSC including:

- The removal of two computer information displays from the TSC apparently caused initial confusion among technical staff personnel who reported having a difficult time accessing real-time plant operating data. Technical support personnel reported that the information display problems contributed to a delay in making an initial estimate of the 24 steam generator tube leak rate, and an incorrect determination that the SG tube leak rate significantly increased prior to the SI initiation.

- The emergency response data system (ERDS), located in the TSC, is a real-time electronic data link between the licensee’s onsite computer system and the NRC Operations Center. It provides for the automated transmission of plant parameters. During the night of the event, ERDS was not operable until 3:00 a.m. The licensee is required by 10 CFR Part 50, Appendix E.IV to test the system quarterly to verify that it is available. The records for the first quarter of 2000 indicated that initial test attempts were unsuccessful due to noise on the telephone lines. The test was subsequently completed successfully using an alternate telephone line; however, the ERDS was then placed back onto the original telephone line without additional testing to ensure that it would work in this configuration. The Team concluded that the licensee failed to properly correct the identified ERDS problem prior to the event.

- 10 CFR 50.72(B)(c)3 requires that licensees maintain an open, continuous communication channel with the NRC Operations Center upon request by the NRC. At 7:00 a.m., on February 16, the NRC formally requested, via the resident inspector, that a communication link be established and continuously manned. The licensee did not establish this line in a timely manner (i.e., approximately two hours elapsed between the time of the initial request, and the establishment of a line). The delay in manning this line appeared related to a difficulty in locating the proper communications equipment.

The ERO technical staff performed well in developing a contingency plan to lower SG level through the steam generator blowdown purification system. However, the Team noted several other examples where the ERO technical staff was narrowly focused or failed to implement timely and effective corrective actions to resolve the problems that complicated the event response. Some of the specific examples included:

- The ERO technical staff in the TSC did not anticipate and help resolve the procedural, and plant configuration problems (discussed in Sections 4.1.6, and 4.2) without delaying the plant cooldown and depressurization.

- ERO technical support personnel in the TSC and OSC should have been aware of the longstanding use of the manual bypass valve to control the steam supply pressure to the main condenser SJAE. These personnel did not anticipate and recommend that the bypass valve be re-positioned to prevent the degradation in condenser vacuum (Section 4.1.3).

- ERO technical support staff in the EOF did not properly resolve two discrepant radiological survey readings that were reportedly taken external to the #24 ASDV tailpipe until the basis for not taking an additional confirmatory sample was challenged by the NRC (i.e., one survey indicated that a release had occurred, and one showed background levels).

- When the control room operators initiated SI, the condenser off-gas was re-directed from the containment to the plant vent (discussed in Section 4.2). The ERO technical support staff in the TSC did not make any recommendations to secure this release path.

- Primary boron concentration sample results did not appear to be consistently communicated well between the control room and technical support center personnel.

- The ERO technical support staff in the OSC were slow to complete the pinning of the main steam lines to protect against a possible challenge to the lines from overfilling of the #24 SG. This activity was not completed until just prior (about 5 minutes) to the approximate time when the SG was projected to overfill (discussed in Event Timeline - Attachment 1).

Section 5.2.3 of the E-Plan defined the purpose of the emergency news center (ENC). The associated implementing procedure and the Emergency News Center Response Plan defined the overall operation of the ENC, onsite responsibilities, and the process for disseminating accurate information to state, county, and local agencies and the general public. The Team determined that the Media Relations Emergency Response Plan poorly described the delegation of assignments, position responsibilities, time requirements for contacting off-site officials, and training requirements.

Based on the licensee's findings and inspector interviews, the Team determined that the oversight of the ENC was weak relative to ensuring that the E-Plan commitments would be met. Despite the fact that the ENC was successful in issuing two press releases during the event, several performance problems were identified that adversely impacted the ENC performance. These problems included:

- Facility activation was delayed since the individual with the key to the facility was filling an ERO position located in the EOF, personnel unexpectedly actuated the building security alarm during initial entry, and the available media managers had not been formally qualified.

- Technical and support personnel did not appear to have a good knowledge of their positions, and responders lacked familiarity with the specifics of the job.

- A discrepancy was noted between the information documented on an offsite notification form, and the information provided by the licensee corporate spokesperson and a press release regarding whether a radiological release had occurred.

- Proper controls had not been established to prevent unrestricted public access to the center.

- The responsibilities of the ENC Duty Officer prior to activation were not clearly defined.

- Although attempts were made, one town official was not contacted per Appendix 5 of the Media Emergency Plan due, in part, to an outdated phone list.

In September 1999, the NRC evaluated the licensee's performance during an emergency exercise (as described in NRC Inspection Report 99-12) and identified several ERO performance weaknesses. The licensee subsequently developed a corrective action plan to improve ERO performance. While some of the problems identified during this event such as facility activation and accountability were new, other problems, such as the quality of ERO technical support were similar to the previously identified problems.

4.4 Radiological Release Assessment

4.4.1 General Description

The #24 SG tube leak initially resulted in a radioactive gaseous (principally noble gases) release to the turbine and condenser. During normal operation, the condenser is continually evacuated through the SJAE to the atmosphere. This normally non-radioactive exhaust pathway is monitored by a radiation monitor (R-45) prior to release to the atmosphere. The radioactive gas set off the high radiation alarm on the SJAE monitor (R-45) within one minute following the tube failure and automatically diverted the SJAE flow from the atmosphere to the reactor containment. As a result, any initial radioactive gaseous release from the SJAE to atmosphere was limited to the time it took for the valve to automatically divert flow to containment (i.e., about 45 seconds). The No. 24 SG was then isolated to limit any subsequent releases. Following the SI (Section 4.2), the condenser off-gasses were redirected from the containment back to the plant vent for the duration of this event. This created an additional minor release path as noted in Attachment 5. Attachment 5, using a simplified plant diagram, depicts the principal release paths.

As a result of the steam generator tube failure, any radioactivity that passed into the condenser affected the condensate water that was circulated back to the remaining steam generators until 7:35 p.m., when the main feedwater pumps were secured. The AFW pumps were subsequently operated to provide an unaffected feedwater source to the steam generators. Five minutes after the R-45 high radiation monitor alarmed, a control room operator manually isolated all four SG water discharge paths (steam generator blowdown) which limited the amount of radioactive release to the environment through that pathway.

On February 16, 2000, at 12:05 a.m., condenser vacuum was lost which affected the ability to reduce reactor plant pressure and temperature through the condenser. Consequently, operators opened the atmospheric steam dump valves (ASDVs) on steam generators #21, #22, and #23 in order to continue reactor plant cooldown. Opening of the ASDVs provided another potential, albeit minor since the affected SG was already isolated, unmonitored release pathway to the environment.

Condenser vacuum was restored at about 1:15 a.m., by use of the #22 condenser vacuum pump, which established another potential release pathway to atmosphere. At that time, the ASDVs were closed and steam flow to the condenser was reestablished. At 7:20 a.m., condenser vacuum was lost again and reactor plant cooldown was again effected by opening the #21, #22, and #23 ASDVs. Vacuum was restored after 92 minutes and the ASDVs were closed.

Given the potential for radioactive gaseous release from the secondary steam plant, the licensee initiated action following the event to account for all known and possible release pathways. The calculation assumed that the #24 ASDV leaked at the Class IV valve leak rate for the ten hour duration that the #24 SG pressure was elevated. The Team determined that this assumption was conservative and bounding for any actual leakage through this path.

Based on sampling and analysis, the radioactive gases released from the condenser were identified as radioactive noble gases (argon, krypton, and xenon). Releases from the ASDVs were assumed to contain the same noble gases as well as some limited radioiodine that may have carried over in the steam. The licensee calculated that a total of about 1.7 curies (Ci) of radioactive gases may have been released, resulting in a dose at the site boundary of about 0.01 mrem to the whole body and 0.04 mrem to the thyroid. Most of this activity, approximately 1.5 curies, was attributed to the planned containment venting operation on February 17, 2000, that was necessary in order to open the containment for examination of the steam generators. This venting activity was performed in accordance with the licensee’s procedures, and constituted a planned, controlled, and monitored radiological effluent release.

Radioactive liquids generated from this occurrence were drained into the liquid radioactive waste processing system to be treated, (i.e. filtered, demineralized, and sampled prior to release) in accordance with the licensee’s Radiological Effluent Technical Specifications. On February 21, and 22, a small amount of liquid activity that had been introduced into the SG blowdown system piping during the event was unexpectedly released to the discharge canal during a planned discharge of the contents of a groundwater collection tank. The release was diluted in the discharge canal prior to release into the Hudson River. The total radioactive liquid released was estimated to be .0138 curies, resulting in an estimated whole body exposure to the public of 0.001 mrem.

All of the gaseous and liquid releases that are known, or assumed, to have occurred (based on the licensee’s evaluation and assessment) from the #24 steam generator tube failure event, including the resultant exposure at the site boundary, are listed in Attachment 5.

4.4.2 Environmental Radiation Measurements

Evidence of significant noble gas releases may be detectable but are dependent on several factors including, the amount of radioactivity involved, the radiation and decay characteristics of the isotopes, the duration of the release, and meteorological conditions. Meteorological data during the first four hours of the event indicated that winds were light and variable (2-4 mph). A non-specific wind direction prompted the licensee to review all direct radiation measurement locations in the vicinity of Indian Point Station. To support the Radiological Environmental Monitoring Program, the licensee maintained several fixed radiation monitoring stations established in the environment surrounding the Indian Point plants. There are 32 thermoluminescent dosimeters (TLDs) surrounding the plant close to the site boundary and another 32 TLDs surrounding the plant at approximately 5 miles. There are about 20 additional TLDs at various other locations. In addition, there are 16 pressurized ion chambers (PICs) surrounding the plant at between 0.2 and 2 miles that are designed to provide continuous radiation readings at 15 minute intervals.

After the event, the environmental TLDs were changed and read with the following results:

	Range	Average
Inner ring TLDs	.0051-.010 mrem/hr	.0064 mrem/hr
Outer ring TLDs	.0051-.0083 mrem/hr	.0065 mrem/hr

Background comparison from 1998 Radiological Environmental Operating Report:

1998	Inner ring TLDs	.0056-.011 mrem/hr	.0066 mrem/hr
1998	Outer ring TLDs	.0060-.010 mrem/hr	.0068 mrem/hr

Based on the above comparison, the environmental TLDs read after the event did not show any radiation exposure distinguishable from naturally occurring background.

The licensee maintains a network of pressurized ion chamber (PIC) instruments (Reuter-Stokes) surrounding the facility. While not a regulatory requirement, these devices provided additional information relative to radiological dose impact. These electronic instruments are designed to continuously monitor and record the level of radiation in the vicinity. Ten out of the sixteen PICs responded with data during the event. All ten PICs indicated steady indication of background radiation throughout the duration of the steam generator tube failure event. However, one of the PIC units (sector 9) was noticed to perform erratically, well after any postulated or actual release. Review and evaluation of maintenance records associated with this particular unit revealed indications of deteriorating instrument performance as early as January 2000. While unexplained, the erratic performance could not be associated with any actual radiological cause. Accordingly, the sector 9 PIC data has been discounted as unreliable. All remaining PIC instruments provided supporting data that any release that occurred was not distinguishable from naturally occurring background.

Three soil samples were taken by the licensee between 0.25 and 2 miles North of Indian Point and 3 soil samples 1 mile South of the plant. The NRC and the State of New York also took 8 soil samples at various locations around the plant. No radioactivity except for naturally occurring radionuclides were detected in any of the soil samples. Air samples were obtained by the licensee from 9 continuously operating environmental air sampling stations that circle the plant between 0.4 - 6.4 miles. Analysis of these particulate and iodine air samples did not show any measurable radioactivity.

The Team conducted independent onsite and offsite surveys, collected independent offsite soil samples, and reviewed licensee data from offsite TLDs, offsite radiation monitors, and air and soil measurements. The team reviewed the licensee's radiological response to the event (Included as Attachment 4, Radiological Response Event Time Line) and determined that the licensee's radiological response and environmental monitoring of the event were adequate and met regulatory expectations and requirements. Based on the environmental monitoring data reviewed (including the results of radiation surveys conducted by licensee and Westchester County survey teams during the occurrence on February 15-16), the Team concluded that any radiological release that occurred was not measurable from naturally occurring background radiation; and confirmed that the licensee's radiological release and dose assessment was reasonable.

4.4.3 Indian Point Steam Generator Tube Failure Event Calculated Releases

A detailed summary of the calculated releases attributed to this event is contained in Attachment 5.

NRC Assessment

The Team reviewed the licensee's chemistry sample analyses, radiation monitoring data, and meteorological information that were pertinent to radiological release and public dose assessment associated with the steam generator tube failure event. Additionally, the Team performed independent radiological surveys on- and offsite, and collected soil samples offsite to confirm the absence of any trace or residual activity. The team reviewed the assumptions that were used by the licensee, and performed an independent computation to verify and validate the reasonableness of the licensee's dose assessment. This effort confirmed that the licensee's assumptions were conservative and that the dose assessment was an upper bound of the release due to this event.

Public Dose Assessment

In 40 CFR Part 190, the Environmental Protection Agency (EPA) established public dose limits resulting from the uranium fuel cycle as: 25 mrem per year to the whole body, 75 mrem per year to the thyroid, and 25 mrem to any other organ. In the Indian Point Unit 2 Radiological Effluent Technical Specifications, more stringent criteria are specified for gaseous and liquid effluents: 3 mrem to the whole body, and 10 mrem to any organ from radioactive liquid effluents in a year; and 10 mrem to the whole body, and 15 mrem to any organ from radioactive gaseous effluents in a year.

The exposure calculations resulting from the event were compared to the EPA and operating license limits as tabulated below.

	Whole Body	Thyroid	% of Tech Specs
Gaseous	0.0104 mrem	0.0425 mrem	0.104% WB; 0.28% Organ
Liquids	0.00092 mrem	0.0015 mrem	0.031% WB; 0.015% Organ
Total	0.0113 mrem	0.0440 mrem	
% of EPA	0.045 %	0.059 %	

Based on the above comparison, the conservatively calculated public exposures due to the event were a very small fraction of regulatory limits, and would be generally indistinguishable from naturally occurring background radiation. (Note: National Council on Radiation Protection and Measurements and the Environment Protection Agency report naturally occurring background to be between 300 and 400 millirem per year, depending on location.)

NRC Regulatory Guides[1] describe the computational method that NRC regards as an acceptable approach to estimate or project radiation dose to the public due to radiological releases to the atmosphere. The approach is dependent on several variables, including atmospheric conditions, radiological characteristics of the gases, applicable atmospheric dispersion and radiological dose factors, wind speed and direction, atmospheric stability; and release elevation, concentration, rate, and duration. Consequently, estimates of radioactivity released versus dose consequence are highly dependent on the data and assumptions used, and vary accordingly. Notwithstanding, independent analysis using a NRC computer code based on these Regulatory Guides (PC-DOSE), conservative assumptions, and actual radiological measurements confirmed that the total quantity of radioactive gases released as a result of the steam generator tube leak event did not result in any dose consequence distinguishable from naturally occurring background.

4.5 Steam Generator Maintenance and Inspection History

The Team reviewed the licensee's programs for inspecting and maintaining the steam generators, including a review of the results of the latest steam generator tube inspection and secondary chemistry performance. Although determination of the cause for the SG tube failure was outside the Team Charter, the information discussed below was collected to assist in review of the licensee's pre-event SG tube condition monitoring activities. All findings discussed below were forwarded to the NRC specialists responsible for reviewing the cause of the tube failure.

The last steam generator inspection was completed in June 1997 during the scheduled Cycle 13 refueling outage. The scope of inspection included 100% inspection of all in-

[1] 1.109, Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR 50, Appendix I, and 1.111, Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors

service tubes. The eddy current inspection was conducted using a combination Cecco-5 /bobbin probe. The baseline inspection was supplemented with a Plus Point rotating probe inspection at areas where the Cecco-5 probe could not access a specific tube location, including all of the row 2 and 3 tight radius U-bends.

The Team reviewed the qualification of the Cecco-5 probe and found it was qualified in accordance with industry standards. The inspector noted a minor discrepancy between the minimum required digitizing rate used for probe qualification and the allowed minimum digitizing rate during the 1997 inspections. The probe was qualified using a minimum digitizing rate of 33 samples per inch; however, the licensee's acquisition technique sheet used during the 1997 inspections allowed digitizing rates as low as 30 samples per inch. The digitizing rate is a measure of the number of data samples taken as the probe is pulled through the tube. The Team determined this was a documentation issue and that actual data was obtained above the minimum required digitizing rate.

As a result of the 1997 inspections and analysis, a total of 173 tubes were removed from service by plugging. Identified degradation mechanisms included outside diameter stress corrosion cracking (ODSCC) and primary water stress corrosion cracking (PWSCC) at dented tube support plate intersections, pitting and ODSCC in the tube sheet sludge pile region, and PWSCC in the tube sheet roll transition. In addition, one tube was plugged in the #24 SG for a PWSCC indication in a tight radius (row 2) U-bend. This was the first evidence of this degradation mechanism in the Indian Point 2 SGs. The licensee repaired 131 tubes with eddy current indications in the tube sheet roll transition. At the time of the event, 10.2% of the tubes in all four steam generators, or 1325 tubes, had been removed from service.

In-situ pressure tests were conducted on 6 tubes in the 1997 refueling outage. The licensee tested tubes containing eddy current indications assessed as having the most limiting structural characteristics. No leakage was identified. Based on the results of the in-situ pressure tests, and an assessment of the eddy current inspection results for the previous cycle of operation, the licensee completed an operational assessment that concluded that steam generator structural and leakage integrity was provided for the full cycle of operation.

In December 1998 the licensee requested a TS amendment for a one-time only extension of the SG inspection interval for the current operating cycle from June 13, 1999 to June 3, 2000. In a safety evaluation dated June 9, 1999, the NRC granted the licensee's request. The request was granted based on the 100% inspection conducted in June 1997 and the 304 days spent in cold shutdown during the operating cycle. The staff concluded that, based on the inspections conducted, the licensee's leakage monitoring and operational assessment, there was reasonable assurance that the SG tubes would maintain structural and leakage integrity for the extended period of operation.

Primary-to-secondary leakage was first identified by condenser off-gas sampling in September 1998. The leak rate was quantified at 0.5 gallons per day (gpd). The leak rate slowly increased during the next 12 months and reached 2 gpd when a plant trip resulted in the unit being shutdown to hot standby for 2 months starting in August 1999. During the shutdown the licensee performed tritium surveys that indicated that the #24 SG was the primary source of the leakage. Following startup in October 1999, the leakrate appeared to vary from 2 to 4 gpd but returned to the pre-shutdown levels of 1.5 to 2.0 gpd through December 1999. Starting in January 2000 the leak rate slowly increased to about 3-4 gpd just prior to the tube failure on February 15, 2000. The MS line radiation monitors first showed indication of leakage from the #24 SG on February 3, 2000. The team determined that this leak rate was significantly below the TS 3.1.F.2.a.1 limit of 432 gpd.

The failed tube was identified in the #24 SG as tube row 2 column 5, a tight radius U-bend tube. A visual inspection of the rupture area characterized the flaw as approximately 2 to 3 inches in length. Preliminary eddy current analysis characterized the flaw as PWSCC with an approximate length of 1.8 inches located at the apex of the U-bend. The licensee reviewed the Plus Point eddy current data taken at the flaw location during the 1997 refueling outage inspection and questioned the quality of the eddy current data collected at this location. Specifically, geometric variations in the tube circumference caused an uneven rotation of the eddy current probe as it was pulled through the tight radius U-bend tubes. The uneven probe rotation resulted in anomalous eddy current signals and reduced the probability of detection for indications in the tight radius U-bends. NRC specialists will perform an independent review of this data.

During the current forced outage the licensee initially planned a 100% inspection of all four steam generators, similar to the inspections conducted in the 1997 refueling outage. The inspection scope was subsequently expanded based on inspection results. The results of the current inspection will be reviewed by the NRC Office of Nuclear Reactor Regulation to determine any necessary SG corrective actions prior to the plant start-up.

The Team reviewed the licensee’s methodology for determining the primary-to-secondary leakrate that resulted from the tube failure event. The leak rate was determined by comparing the charging pump flow, letdown flow, and pressurizer level response during the event. Additionally, a second leakrate calculation was performed based on the rate of change in steam generator water level during the event. The two methods yield comparable results. Both calculations are considered a "nominal" calculation, and do not account for potential sources of inaccuracy such as instrumentation error. The licensee’s preliminary results concluded the leakrate at the initiation of the event was 146 gallons per minute (gpm), and was reduced to 0 gpm at the conclusion of the event. Operator action to rapidly lower primary system pressure, in accordance with the EOPs, was successful at decreasing the overall primary-to-secondary leakrate. The team evaluated that the licensee’s methodology for calculating the primary-to-secondary leakrate was valid and provided reasonable results.

The Team reviewed the licensee's secondary chemistry performance during the last and previous cycles of operation. Measured chemistry parameters during the last cycle of operation followed industry recommended guidelines and practices. Although the licensee has complied with industry standards, the inspector noted some areas where the licensee did not take a proactive approach in managing secondary water chemistry performance: the plant was designed and built without a condensate polishing system to reduce impurities transported to the steam generators in the event of a main condenser tube leak, however, the main condensers were not completely upgraded to a leak tight design until 1995; the water treatment plant, used to provide secondary system make-up water, was not upgraded to a state-of-the-art system until December 1999; and the licensee initiated a secondary side copper reduction program in 1982, however, six low pressure feedwater heaters and the gland steam condenser still contain tubes manufactured of copper containing alloys.

There was one secondary chemistry upset during the last operating cycle. In October 1999, a tube leak in a feedwater sample cooler during a plant shutdown resulted in approximately 1500 gallons of river water being introduced into the steam generators during the reactor startup. The chemistry upset was cleaned up through extensive steam generator blowdowns prior to reactor startup. The Team determined that none of the secondary chemistry issues discussed above had a direct causal effect on the February 2000 SGTF (i.e., the failure was initiated from the primary not secondary side of the tube).

4.6 Immediate and Interim Corrective Actions

The Team determined that the licensee's immediate actions for this event were directed towards protecting the health and safety of the public. These actions included: the initial operator actions, the event declaration, and the staffing of the emergency response organization.

The Team concluded that station management initiated adequate interim corrective actions to review and address both the equipment and personnel performance issues identified during the event. Specifically, station management formed a team consisting of industry peers to review the implementation of the emergency plan, and also formed a Significance Level One (SL1) condition report Event Investigation Team (EIT) to review the event. Station management also mobilized the Command and Control Organization (CCO) to oversee the activities of these teams as well as to oversee safe plant operation during the recovery process. A station Recovery Plan was developed to focus the activities of the CCO.

The Team reviewed the SL1 EIT charter and the Recovery Plan. Both documents established a reasonable scope of activities, expectations, and assigned tasks. The CCO met twice per week and the SL1 EIT met daily. The Team observed a CCO meeting and determined that the status of issues pertinent to plant safety and recovery were reasonably communicated. The SL1 EIT was sufficiently staffed with 15 members and continued progress towards understanding the event was evident at the daily meetings. Recovery Plan implementation and the SL1 EIT review had not been completed by the end of the inspection. Therefore a full conclusion regarding the effectiveness of the licensee's planned corrective actions could not be reached. The NRC plans to review selected corrective actions prior to the plant restart.

5.0 CONCLUSIONS

The licensee took the necessary steps to mitigate this event, including shutdown of the reactor, identification and isolation of the faulted SG, cooldown of the RCS, declaration of the Alert, and staffing of the ERO. The Team noted that no radioactivity was measured off-site in excess of normal background levels and determined that the event did not impact the health and safety of the public. Necessary event mitigation systems worked properly.

The Team determined, however, that this event indicated significant performance problems in several broad areas that complicated the event response, delayed achieving a cold shutdown plant condition, and impacted the radiological release. Specific problem areas were discussed in Section 3.0, and included: equipment performance, operator performance, procedure quality, technical support, and performance of the ERO.

Several of equipment problems that challenged operators during this event, such as the degraded steam jet air ejector steam supply valve and an isolation valve seal water system design deficiency, were longstanding. In addition, some of the emergency plan implementation problems were similar to previously identified problems in this area; for example, the technical support center personnel did not consistently anticipate plant problems and make timely recommendations to the operators which was also a finding during the September 1999 emergency preparedness exercise. The Team concluded that the number and duration of the identified problems reflected weaknesses in engineering, corrective action processes, and operational support at the Station. The Team recognized that, prior to the event, the licensee was in the process of implementing a station improvement program. This event demonstrated the need for continuous management attention to planned improvements to ensure they are timely and effective.

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*Attended the AIT Entrance Meeting on February 18, 2000.

LIST OF ACRONYMS USED

AIT	Augmented Inspection Team (Team)
ASDV	Atmospheric Steam Dump Valves
AFW	Auxiliary Feedwater
AFWP	Auxiliary Feedwater Pump
CCDP	Conditional Core Damage Probability
CCO	Command Control Organization
CCW	Component Cooling Water
Ci	Curie
CR	Condition Report
CRS	Control Room Supervisor
EAL	Emergency Action Level
ED	Emergency Director
EIT	Event Investigation Team
ENC	Emergency News Center
EOF	Emergency Operations Facility
EOP	Emergency Operating Procedure
EP	Emergency Plan (also referred to as E-Plan)
EPA	Environment Protection Agency
ERDS	Emergency Response Data System
ERO	Emergency Response Organization
gpd	gallon per day
gpm	gallon per minute
HPSDV	High Pressure Steam Dump Valve
IP2	Indian Point Unit 2
IVSW	Isolation Valve Seal Water
IVSWS	Isolation Valve Seal Water System
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MS	Main Steam
NFSC	Nuclear Facility Safety Committee
NPO	Nuclear Plant Operator
NRC	Nuclear Regulatory Commission
ODSCC	Outside Diameter Stress Corrosion Cracking
OSC	Operations Support Center
OTC	Operator at the Controls
PCV	Pressure Control Valve
PDR	Public Document Room
PIC	Pressurized Ion Chamber
POM	Plant Operations Manager
PORV	Pressure Operated Relief Valve
psig	Pounds per square inch gauge
PWSCC	Primary Water Stress Corrosion Cracking
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RO	Reactor Operator

SBBPS	Secondary Boiler Blowdown Purification System
SG	Steam Generator
SGTL	Steam Generator Tube Leak
SGTF	Steam Generator Tube Failure
SI	Safety Injection
SJAE	Steam Jet Air Ejectors
SL1	Significance Level One Root Cause Investigation Team
SM	Shift Manager
SOP	System Operating Procedure
Team	Augmented Inspection Team
TLDs	Thermoluminescent dosimeters
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
V&V	Validation and Verification

ATTACHMENT 1

STEAM GENERATOR CUTAWAY AND PLANT SYSTEM DIAGRAMS

ATTACHMENT 2
IP2 STEAM GENERATOR TUBE LEAK (2/15/00)
SEQUENCE OF EVENTS and
ORGANIZATION RESPONSE TIME LINE

The AIT established a sequence of events for the plant response; those times are shown in **bold face**. The plant support responses are also shown to describe the organizations' actions to support the operators. Organization response times and many plant response times were constructed from interviews and should be considered approximate. Information notes and time line relevant Team assessments are shown in *italics.*

Event: Radioactive chemistry monitoring of condensate since early in the operating cycle indicated minor primary-to-secondary leakage. In early February 2000, main steam (MS) line radiation monitors indicated detectable (1-4 gallons per day (gpd)) primary-to-secondary leakage through the #24 steam generator (SG). Chemistry technicians trended the MS line radiation monitor readings for indications of further tube degradation. Industry guidance indicated that degradation of the SG tube leak would be gradual, permitting operators time to respond in a controlled manner. On February 15, the #24 SG U-tube leakage rapidly increased from 4 gpd to > 75 gallons per minute (gpm), requiring operators to manually trip the reactor and implement emergency operating procedures (EOPs).

Date	Time	Event
7/97		*#24 SG tube inspections (24 month interval) were performed. 100% of tubes were inspected full length and all identified defects were repaired or the tubes containing the defects were removed from service.*
7/09/99		*NRC granted relief to extend the SG tube inspection interval to 6/03/00 (Technical Specification (TS) Amendment 201).*
12/99		*Total reactor coolant system (RCS) to SG leakage was stable at 2 gpd. SG blowdown sample chemistry analysis and MS line radiation monitors did not indicate which SG(s) was leaking.*
2/03/00		**MS line radiation monitors indicated 1.2 gpd leakage from #24 SG. Total RCS to SG combined leakrate was 2.1 gpd, based on condenser off-gas sampling.**
2/04-2/15/00		**MS line radiation monitors indicated leakage from only the #24 SG and showed instantaneous leakrates ranging from 1 gpd to 5 gpd with a generally increasing trend. The #24 SG daily average leakrate increased to 3.1 gpd by 2/15/00.**
2/15/00		**Reactor at 99% power.**
	1917	**#24 SG main steam line high radiation alarm, R-45 condenser steam jet air ejector (SJAE) high radiation alarm. The R-45 detector response caused the SJAE discharge to divert to containment. Operators entered AOI-1.2, "SG Tube Leak" and started a second charging pump.**
	1922	**Operators closed all SG blowdown valves.**

1929 **ALERT event classification was declared based on an RCS leak > capacity of one charging pump, Emergency Action Level (EAL) 3.1.2.**

1930 **SG tube leak exceeded the capacity of 2 charging pumps. Operators manually tripped the reactor (entered E-0, “Reactor Trip/Safety Injection”). Entered TS 3.1.F.2.a(1) for primary-to-secondary leakage > 0.3 gpm, which required the reactor to be in cold shutdown within 24 hours.**
The licensee’s post event analysis determined that the SG tube leak rate was approximately 146 gpm at this time.

1935 **Received high SG feedwater flow alarms. Manually tripped both main feed pumps per ES-0.1, “Reactor Trip Response”.**

1941 **#24 SG level continued increasing due to the SG tube leak and auxiliary feedwater (AFW) injection. Secured feeding #24 SG. Began notifying state and local officials of ALERT (Form 30a).**

2007 Notified NRC operations center of SG tube leak event, reactor trip, and ALERT per 10 CFR 50.72.

2012 **#24 SG narrow range level = 12% and lowering slowly. Resumed AFW flow. #24 SG level and pressure began rising.**

2018 **Began #24 SG isolation per AOI-1.2.**

2019 **Operators manually raised the #24 SG atmospheric steam dump valve (ASDV) lift setpoint to 1030 psig per AOI-1.2. This reduced the likelihood of a radiological release via the #24 SG ASDV.**

2024 **Secured AFW to #24 SG.**

2031 **Operators completed isolating #24 SG. The #24 SG pressure continued rising.**

2036 **Operators briefed for RCS cooldown per POP-3.3, “Plant Cooldown”.**

2059 Technical Support Center (TSC) Activated.

2101 **#24 SG pressure peaked at approximately 1030 psig and began to decrease.**

2102 **RCS pressure, temperature, and level were all slowly decreasing. Operators initiated RCS cooldown from the intact SGs (#21-23 SGs), using the high pressure steam dumps (turbine bypass valves) to the condenser per POP-3.3. An excessive RCS cooldown rate was established.**
Manual steam dump control required close operator attention to manage the RCS cooldown rate. Operators consequently initiated a much larger steam flowrate than intended and did not effectively control the cooldown rate.

2104 **Received the pressurizer low level alarm. Operators manually initiated safety injection (SI) due to pressurizer level < 9%, and entered E-0.**
Operators were not certain what had caused pressurizer level to decrease so rapidly. The SI actuation caused several automatic plant responses which complicated the subsequent plant response as discussed below:

- *SJAE discharge realigned from containment back to the atmosphere, thus opening a radiological release path;*
- *Component cooling water (CCW) valves to the residual heat removal (RHR) heat exchangers opened. This delayed the RHR system heatup and subsequent RCS cooldown;*
- *The Isolation valve seal water system (IVSWS) functioned in response to the Containment Isolation “Phase A” signal. The IVSWS tank then drained into the CCW system, making IVSWS inoperable.*

2102-2113 RCS pressure dropped from 2230 to 1300 psig, RCS temperature dropped 90°F, pressurizer level dropped from 27% to below the indicating range, #21-23 SG levels dropped rapidly.
The large steam flowrate to the condenser created a rapid and excessive RCS cooldown. The RCS pressure, temperature, and pressurizer level rapidly decreased. Several TSC personnel thought the steam generator tube failure (SGTF) had gotten much worse. During its review, the Team determined that the SG tube leakrate had not increased. The licensee's event review team subsequently reported that this significant thermal transient exceeded RCS cooldown rate and pressurizer to pressurizer spray line temperature differential limitations. The licensee intends to report these TS violations as required by 10 CFR 50.73.

2113 Operators terminated the RCS cooldown (closed the steam dumps to the condenser) and transitioned from E-0 to E-3 "SG Tube Rupture".

2115 Activated the Emergency Operations Facility (EOF) and the Operations Support Center (OSC).
Neither the TSC, OSC, or EOF were activated within 1 hour after the ALERT declaration as required by the station's Emergency Plan.

2121 Operators reset the SI signal.

2127 Initiated maximum RCS depressurization (RCS pressure 1530 psig) per E-3.

2132 Completed RCS depressurization (RCS pressure 970 psig, pressurizer level > 50%). Secured from maximum pressurizer spray per E-3.

2135 Secured all three SI pumps as required by procedure. RCS began heating up at 20°F per hour.

2230 Plant status: RCS = 465°F, 1060 psig; #24 SG = 985 psig, wide range level 72%. Secured #21 RCP.

2235 Secured #22 RCP.

2240 Secured #23 RCP.

2252 Transitioned to ES-3.1, "Post SGTR Cooldown Using Backfill."

2335 Began RCS cooldown.
RCS boron concentration sample results taken at 2230 were apparently reported to the TSC, but not communicated to the control room in a timely manner. This contributed to a delay in initiation of the RCS cooldown.

2338 As intended, operator actions had reduced RCS pressure below #24 SG pressure. The RCS leakage through the ruptured U-tube into the #24 SG stopped.

2/16

0000 Plant status: Pressurizer level 47%; RCS = 466°F, 890 psig; #24 SG = 915 psig, wide range level 75%. Intact SGs = 445 psig.

0005 Operators lost condenser vacuum and continued RCS cooldown using SG ASDVs from the three intact SGs (#21-23 SG). This opened an unmonitored release path to the environment.
The Team later determined that the loss of condenser vacuum was due to a longstanding material deficiency. Operators reported that the SJAE steam supply pressure regulator had never worked properly. Following the previous reactor startup, operators had manually positioned the regulator bypass valve locally to support full power operation. Failure to reposition this valve as the

steam supply pressure lowered during the plant cooldown caused the loss of condenser vacuum.

0115 Re-established condenser vacuum using the #22 condenser vacuum pump. Continued RCS cooldown using the high pressure steam dumps to the condenser. Secured using SG ASDVs. RCS = 788 psig.

0135 #21-23 SG chemistry analysis indicated elevated activity levels (6 E-6 micro curies per cubic centimeter).

0210 Operators attempted to refill the IVSWS tank. The tank inventory unexpectedly drained into the CCW system and operators could not maintain IVSWS tank level. IVSWS was declared inoperable (TS 3.0.1).
The IVSWS leakage into the CCW system appeared similar to a 1997 problem. The initial assessment was that either a material deficiency or a long-standing system design problem caused the IVSWS tank to drain rapidly.

0442 #24 SG narrow range level = 9%, wide range level = 65%. Began refilling #24 SG per ES-3.1.

0450 #24 SG pressure decreased below RCS pressure which reestablished RCS leakage into the #24 SG.
The Team determined that during two time intervals totaling approximately 9 hours (0450-0520 and 0550-1420 on 2/16) RCS pressure exceeded the #24 SG pressure, which reinitiated the RCS leak into the #24 SG. The RCS to SG pressure difference was attributed to several factors including: multiple delays in placing RHR in-service to cooldown the primary plant, and lowering of the #24 SG pressure due to cooldown, and steam losses through isolation boundaries.

0510 Plant Status: RCS = 330°F, 488 psig; #24 SG = 478 psig, wide range level = 67%.

0535 In-field radiation monitoring detected no elevated activity at a two mile radius from the site. The initial off-site radiological dose consequence estimate was ≤ 1 millirem at the site boundary.

0720 The #22 condenser vacuum pump tripped due to thermal overload and condenser vacuum was lost. Operators started the #21 condenser vacuum pump and continued RCS cooldown using #21-23 SG ASDVs.
The #22 condenser vacuum pump was degraded prior to the event, due to thermal overload problems which had not been repaired since being identified in 1997. This degraded equipment condition reduced reliability of the condenser as a heat sink to cooldown the RCS. Operation with this longstanding degraded equipment condition resulted in an additional radioactive release when operators consequently used the #21-23 SG ASDVs for RCS cooldown.

0737 The Operations shift briefing stated the top priority was to place RHR in service. RCS = 307°F, 400 psig. #24 SG wide range level = 81%.

0852 Restored condenser vacuum using the #21 condenser vacuum pump. Secured using #21-23 SG ASDVs for RCS cooldown.

0900 The Emergency Director (ED), TSC Manager, and Plant Operations Manager (POM) expressed concern that RHR was not in service and the #24 SG level continued to rise. They were concerned that if water from the SG overflowed into the hot main steam header piping, either the weight of the water or a pressure event from water flashing to steam could rupture the steam header and create an unisolable radioactive release path. They discussed contingencies and selected their preferred option. This option was to establish a lineup to transfer water from the #24 SG to the secondary boiler blowdown purification system (SBBPS). TSC personnel developed a procedure change to address

using the desired SBBPS lineup. Radiological engineers informed the TSC manager that this plan would result in a radioactive release within regulatory limits, but would be the largest release of this event.
The Team determined that the emergency response organization was proactive in identifying a contingency plan to protect the main steam line piping boundary. However, efforts to pin the #24 main steam line header to provide additional mechanical support were slow.

0905 IVSWS tank was restored to normal pressure and level. Exit TS 3.0.1.

0919 Operators implemented an emergency procedure change to ES-3.1 (step 9), revising the maximum RCS pressure at which RHR could be placed in service.
Operators experienced several problems (procedure and/or knowledge related) which delayed placing RHR in service.

1000 RCS boron concentration = 1410 ppm.
RCS boron samples at 30 minute intervals were required by ES-3.1. Chemists performed the required samples. However, the TSC had not been able to obtain RCS boron concentration sample results from chemists for several hours. This represented a communication problem which hindered core physics safety assessment in the TSC.

1032 Started the #21 RHR pump on recirculation for RHR system heatup.
RHR warmup took longer than expected due to operators implementing SOP-4.2.1 "RHR System Operation" without realizing the CCW valves to the RHR heat exchangers had opened as designed when operators manually initiated SI the previous evening. (approximate 1.5 hour delay)

1118 Personnel were dispatched to the auxiliary feedwater pump building to pin the #24 main steam line.

1143 The SBBPS procedure was revised to support implementing the contingency plan to transfer water from the #24 SG to the SBBPS collection tank prior to #24 SG water level reaching the main steam header. OSC personnel were directed to perform the system lineup with the exception of four isolation valves. The shift manager maintained control of isolation valves required to initiate flow through this path.

1145 Personnel were dispatched to the containment to pin the #24 main steam line.

1200 Plant Status: RCS = 317°F, 379 psig; #24 SG = 247 psig, level 90% and increasing.
The ED, TSC Manager, and POM maintained close contact regarding the contingency for performing a planned radiological release via the SBBPS in the event RHR was not established soon to cooldown the RCS and halt the #24 SG level rise. Management did not intend to implement this contingency unless absolutely necessary. Engineers estimated that SG water would begin filling the main steam lines at approximately 1330-1400 on 2/16.

1238 RHR was placed in service, with one pump and two heat exchangers, cooling the RCS. RCS = 310°F, 380 psig.

1245 OSC personnel completed lining up the SBBPS system for transfer of #24 SG water with the exception of four isolation valves.

1247 Secured #24 RCP (all RCPs were now secured).

1256 Auxiliary spray was placed in service per ES-3.1 to reduce RCS pressure. No RCS pressure response was observed.
Procedure ES-3.1 was deficient in that it did not instruct operators to close the normal spray valve to prevent bypassing the spray nozzle (1+ hour delay).

1258 The Shift Manager observed a small reduction on the reactor vessel level recorder after securing the last RCP. Combined with absence of RCS pressure control, this led the Shift Manager to question whether a small gas bubble had developed in the reactor vessel head. Approximately 20 minutes later, operators determined there was no gas bubble in the reactor vessel.

1315 Plant Status: RCS = 328°F, 360 psig; #24 SG = 229 psig, wide range level = 91%.

The Team later determined that, at existing plant conditions, 91% indicated SG level actually represented the top of the indicating range (100% level). Numerous personnel within the emergency response organization (in addition to some control room operators) didn't realize the #24 SG level indication was no longer valid at 91% and that the SG was continuing to fill.

1345 Operators continued questioning why auxiliary pressurizer spray was ineffective at reducing RCS pressure.

Neither operators, nor the TSC recognized that ES-3.1 had established an incorrect pressurizer spray valve lineup. This configuration problem existed for over an hour before the acting Operations Manager recognized the problem.

1355 OSC personnel completed pinning the #24 main steam line to provide additional mechanical support in the event that SG water entered the line.

The Team determined that TSC/OSC support for pinning the steam line was slow and not completed until the approximate time at which water was expected to begin filling the #24 SG main steam line.

1400 Plant Status: RCS = 298°F, 278 psig; #24 SG = 220 psig, level 91%. Operators corrected the pressurizer spray lineup and established RCS pressure control.

1420 RCS pressure < #24 SG pressure. Reactor coolant leakage through the ruptured U-tube again stopped and #24 SG water level began to slowly decrease.

Establishment of RCS cooldown using RHR and control of RCS pressure using alternate pressurizer spray enabled operators to reduce RCS pressure below #24 SG pressure.

1638 Shutdown risk assessment was performed. RCS Integrity function was YELLOW due to the SGTR. All other shutdown safety functions were green.

1645 Plant Status: RCS = 217°F, 141 psig; #24 SG = 145 psig, wide range level = 91%.

1657 Achieved COLD SHUTDOWN (RCS < 200°F), exited TS 3.1.F.2.a(1).

1720 #24 SG level returned on-scale at 90% and continued slowly decreasing.

1850 Exited ALERT emergency event classification.

Supplementary Notes:

1. Total radioactivity release (1.7 curies of primarily Xe-133, Xe-135) and dose consequence at the site boundary (0.01 millirem whole body and 0.04 millirem to the thyroid) were relatively small and within regulatory limits.

2. Operator logs were incomplete. The majority of the items listed in the time sequence above, including procedure and equipment problems were not identified in operator logs. Statements of event classification, local/state/federal EP notifications, emergency response facility activation, initiation of RCS cooldown, problems establishing RCS

pressure control, and transferring RHR to single heat exchanger operation (almost inadvertently exceeding the 200°F cold shutdown temperature limit) were not included in the logs as required by station procedure OAD3, “Plant Surveillance and Log Keeping”, Rev. 30.

3. NRC established event Monitoring Mode activities @ 2045 on 2/15, transitioned to Standby Mode @ 2049, transitioned to Monitoring Mode @ 2335, and secured from Monitoring Mode @ 1915 on 2/16.

ATTACHMENT 3
IP2 STEAM GENERATOR TUBE LEAK EVENT (2/15/00)
SUMMARY OF SELECTED EQUIPMENT PROBLEMS

1. The pressurizer pressure master controller did not control (close) in automatic. This required operators to take manual control. (Condition Report (CR) 2000-1137).

2. Condenser vacuum was lost two times which required operators to use the #21-23 steam generator atmospheric steam dump valves for the plant cooldown. Each loss of condenser vacuum was attributed to longstanding equipment problems. The equipment problems included: the steam jet air ejector (SJAE) steam supply pressure regulator was inoperable and required operators to manually throttle steam flow using a bypass valve, and the #22 condenser vacuum pump tripped on a thermal overload condition. (CR 2000-0984)

3. The reactor coolant system (RCS) overpressure protection system (OPS) was inoperable due to an inadequate nitrogen supply to the pressure operated relief valve (PORV) accumulators. This delayed OPS operability during the RCS cooldown until a temporary modification could be implemented. A permanent design change is scheduled to correct this design deficiency during the next refueling outage. (CR 2000-1025)

4. The isolation valve seal water system (IVSWS) tank level was lost during the event. Operators refilled the tank, however, it unexpectedly emptied again soon after operators refilled it. Plant engineers believed that the IVSWS system water transferred into a low pressure portion of the component cooling water (CCW) system. This appeared to be a repeat problem from 1997 and a potential longstanding design deficiency. The inoperable IVSWS system required operator attention during the event. (CR 2000-1026/1033)

5. Ten safeguards and containment isolation valve position indication lights, located in control room, failed to illuminate. (CR 2000-0997 through 1007)

6. The SJAE discharge isolation valve was reported to be slow to close following the containment isolation phase “A” signal. (CR 2000-1008)

7. The excess letdown CCW isolation valve 793 position indication light repeatedly blew fuses. No valve position indication for this valve was available. (CR 2000-1023)

8. The auxiliary feedwater (AFW) pump room heated up (to approximately 80°F) with motor driven pumps running in response to the event. Station personnel had inadvertently placed wooden planks over the AFW pump room fresh air inlet ventilation dampers when implementing the station Winterization Plan. The AFW pumps did not overheat, however, this unexpected room heatup diverted operator response to correct this condition. (CR 2000-1051)

9. The Emergency Data Display System (EDDS) and the Emergency Response Data System (ERDS) were inoperable for several hours at the beginning of the event. The problem appeared to be related to the failure to perform a post-maintenance test following corrective maintenance to the ERDS telephone lines. The delay initially inhibited the NRC’s ability to remotely monitor and assess the event. (CR 2000-1094)

10. Reuter-Stokes off-site telemeter radiation monitor system didn’t provide normal display output during the event. This appeared to be repeat, longstanding degraded material condition which reduced the off-site dose assessment capabilities. (CR 2000-1095/1218)

11. Anomalies were identified with the recorded residual heat removal system heat exchanger inlet temperature readings. The deficiency would have adversely affected the operators ability to monitor plant temperature changes during shutdown cooling. (CR 2000-1508)

ATTACHMENT 4
IP2 STEAM GENERATOR TUBE LEAK (2/15/00)
RADIOLOGICAL RESPONSE TIME LINE

The AIT established a sequence of events for the radiological response. Some response times were constructed from logs and interviews and should be considered approximate. Information notes and time line relevant Team assessments are shown in *italics.*

February 15, 2000

8:00 p.m. - various onsite plant locations, radiation and contamination surveys were performed and two offsite monitoring teams were sent North and South of the plant to obtain air samples. No evidence of a release was detected.

Between 9:45 p.m. and 10:00 p.m. - the emergency response computer system, MIDAS, was queried for pressurized ion chamber (PIC) direct radiation reading data from all 16 sectors around the plant - only 6 sectors responded with no readings above background reported.

10:00 p.m. - radiation surveys were conducted due North of the plant at the Hudson River shoreline (1.8 miles NNW), also at 1.3 miles NE and 1 mile SW of the plant. No evidence of a release was detected.

Midnight - an offsite team was sent to collect air samples from nine fixed environmental air sampler locations.

February 16, 2000

12:50 a.m. - miscellaneous in-plant auxiliary building and support buildings were surveyed. No elevated readings were noted.

2:30 a.m. - offsite teams were sent out to measure radiation levels and air samples North and South of the plant. No elevated readings were detected.

3:15 a.m. - a survey of the plant roof indicated #24 steam generator atmospheric steam dump (ASD) had elevated readings (500 corrected counts per minute, direct radiation). There was no radiological contamination found on the roof.

A survey taken at the same location at 10:00 a.m. did not indicate any radioactivity associated with the #24 ASD. The licensee tended to regard this survey, as supported by the collected environmental survey and measurement data, as a basis for considering that there may have been no actual release from this pathway. On February 17th, the team questioned this basis in view of the conflicting survey information reported for the #24 ASD. Subsequently, the licensee performed additional surveys of #24 ASD and confirmed that the first survey (3:15 a.m., February 16) was correct since the presence of residual radioactivity was indicated. Subsequently, the licensee performed a gamma scan on the atmospheric side of the #24 ASD and confirmed the presence of Xenon 133 and Xenon 135 (5 day and 9 hour half-lives, respectively) indicating a release of noble gas likely occurred from this pathway. Accordingly, the licensee initiated a comprehensive review and evaluation of all possible pathways that could have occurred as a result of this steam *generator tube leak event. Several weeks after the event, the NRC determined that the drain valves to certain of the atmospheric steam dumps were mislabeled. The licensee initiated action to correct the mislabeling and determine the effect on the accuracy of any radiological surveys that used these drain valves as reference points.*

5:35 a.m. - radiation monitoring was conducted at a 2 mile radius from the site. No elevated radiation readings were detected.

9:00 a.m. - two offsite teams collected soil and air samples, north and south of the plant.

9:00 a.m. - 2:30 p.m. - direct radiation readings and air samples (particulate and iodine) were taken at 8 offsite locations between 0.9 to 1.8 miles from the plant. No readings above background were detected.

10:00 a.m. - the North and South plant fence line was surveyed. All areas were <0.1 mrem/hr and no detectable contamination was found.

1:00 p.m. - an offsite team was sent out to get soil samples in sector 2 (NNE) and 16 (NNW) to ensure all surrounding county soils had been sampled.

Indian Point Unit 3 roof and onsite plant areas were surveyed for contamination. None was detected. Nine fixed environmental air samplers were changed and counted. No readings above background were detected.

<u>February 17, 2000</u>

3:00 a.m. to 5:00 a.m. - various in-plant areas were surveyed indicating some elevated readings in the secondary plant areas (up to 2 mrem/hr).

<u>February 18, 2000</u>

Four additional PIC sector data readings were obtained to provide a more complete picture of the North and South sector radiation readings during the event. No elevated readings were found.

<u>February 19, 2000</u>

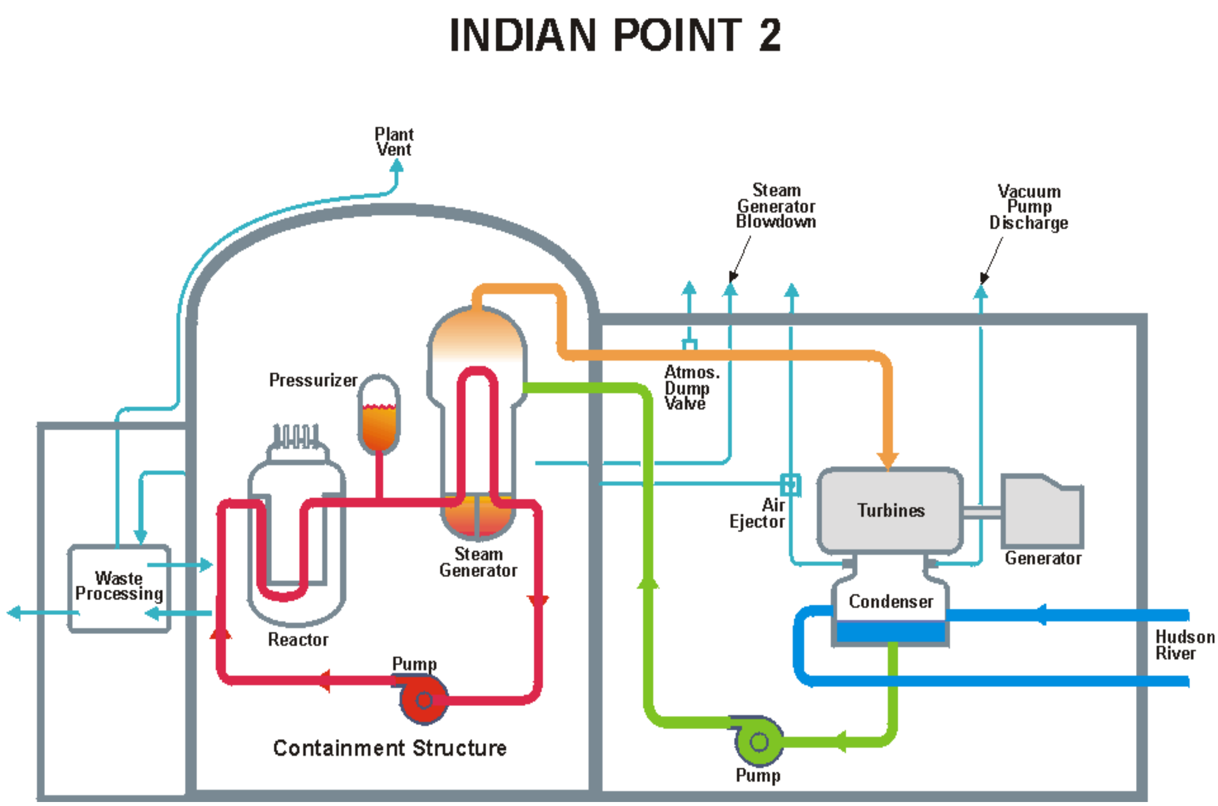
Eighty-two off-site and 20 onsite TLDs were exchanged and processed. None of the TLDs indicated any readings above background.

Comprehensive plant area surveys were conducted. The steam generator blowdown flash tank and the secondary boiler blowdown indicated elevated readings. On February 20th, additional plant area surveys revealed elevated readings on the secondary boiler blowdown heat exchanger and flash tank.

On February 25th, the licensee formed a multi-disciplined group to address all possible release paths and the radiological dose consequences of the event. Final revised release calculations were completed by March 14, 2000.

IP2 STEAM GENERATOR TUBE LEAK (2/15/00)
RADIOLOGICAL RELEASE PATHS

Illustration of the Release Paths:



Calculated Release Paths:

Gaseous Releases (Noble Gas: Xenon 133, 135; Argon 41; Krypton 85, 88, 87)

Source of Release	Duration	Amount	Projected Exposure
A. Containment vent	24 hrs	1.50 Ci	4.04E-5 mrem
B. Evacuate condenser (Vacuum Pump)	3 hrs	9.60E-2 Ci	4.50E-3 mrem
C. #24 ASDV (Incl. Iodine fraction, 1E-2)	10 hrs	3.64E-2 Ci	2.19E-3 mrem 3.44E-2 mrem, organ
D. Gland Seal Exhaust	70 mins	5.77E-2 Ci	3.21E-3 mrem 2.20E-3 mrem, organ
E. Secondary steam leaks	10 hrs	2.53E-3 Ci	4.20E-4 mrem 4.40E-3 mrem, organ
F. Initial SJAE	45 sec	7.1E-5 Ci	1.59E-6 mrem
G. #21, #22, #23 ASD	2.7 hrs	2.60E-5 Ci	1.45E-3 mrem, organ

Gaseous Releases (Noble Gas: Xenon 133, 135; Argon 41; Krypton 85, 88, 87)

H. S/G #24 Blowdown (Also includes I - 131, 132, 133)	5 mins	3.25E-5 Ci	1.80E-5 mrem, organ
I. S/G #21, #22, #23 Blowdown (Also includes I - 131, 132, 133)	10 mins	3.88E-7 Ci	2.07E-5 mrem, organ
TOTAL:		1.693 Ci	1.04E-2 mremWB 4.25E-2 mrem organ thyroid

Gaseous Release Comparisons

Total gaseous releases represent: 0.1% of TS limit (10 mrem/yr) Total Body
0.28% of TS limit (15 mrem/yr) Organ

Liquid Releases

Source of Release	Amount	Exposure
A. Miscellaneous Liquids: hotwell, condensate, feedwater	7.06E-3 Ci	8.42E-4 mrem 1.35E-3 mrem, organ
B. Groundwater inleakage released through contaminated piping from the event		
2/21/00	2.78E-3 Ci	2.01E-5 mrem 6.61E-5 mrem, organ
2/22/00	2.56E-3 Ci	5.77E-5 mrem 8.38E-5 mrem, organ

C. Gland Seal Exhaust	5.71E-4 Ci	2.10E-6 mrem, organ
D. S/G #24 Blowdown	5.59E-4 Ci	2.30E-6 mrem, organ
E. S/G #21, #22, #23 Blowdown	2.82E-4 Ci	3.00E-6 mrem, organ
F. Secondary side leaks	5.80E-6 Ci	1.30E-6 mrem, organ
TOTAL:	1.38E-2 Ci	9.20E-4 WB, 1.51E-3 mrem, organ

Liquid Release Comparison

Total liquid releases represent: 0.031% of TS limit (3 mrem/yr) Total Body
0.015% of TS limit (10 mrem/yr) Organ