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March 27, 2000

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

Mr. R. William Borchardt, Director, Office of Enforcement
U.S. Nuclear Regulatory Commission
One White Flint North, 11555 Rockville Pike
Rockville, MD 20852-2738

SUBJECT: Reply to Notice of Violation and Proposed Imposition of Civil Penalty-$88,000 (ref: NRC Inspection Report Nos. 50-247/99-08, 99-13, and 99-14)

Dear Mr. Borchardt:

Consolidated Edison Company of New York, Inc. (Con Edison) has received the Nuclear Regulatory Commission (NRC) letter (EA 99-319) dated February 25, 2000. Pursuant to the provisions of 10 CFR 2.201, Con Edison hereby provides our reply to the Notice of Violation and Proposed Imposition of Civil Penalty regarding the circumstances associated with the reactor trip event that occurred at Indian Point Unit 2 (IP2) on August 31, 1999. The enclosure to this letter provides a summary of our actions taken as a result of the event and the attachment 1 provides our reply to the specific Notice of Violation received. Attachment 2 summarizes Con Edison's commitments referenced in the enclosure and attachment 1.

In accordance with 10 CFR 2.201, Con Edison completed the payment (via electronic transfer) to the Treasurer of the United States in the amount of the proposed civil penalty of $ 88,000, on March 27, 2000.

The attached response does not include any personal privacy, proprietary or safeguards information.

If you have any further questions regarding this matter, please contact Mr. John McCann, Manager, Nuclear Licensing and Safety at (914) 734-5074 or me at (914) 788-3200.

Sincerely,

J. S. Baumstark
Vice President-Engineering

Enclosure
Attachments

Subscribed and sworn to
before me this 27th day
of March, 2000

Manuel Sanchez Jr.
MANUEL SANCHEZ, JR.
Notary Public, State of New York
No. 3443310
Qualified in Dutchess County
Commission Expires Nov. 30, 2002

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ENCLOSURE

Summary of Actions Taken as a Result of
August 31, 1999 Reactor Trip Event

As discussed in your letter dated February 25, 2000, the August 31, 1999 reactor trip event revealed three principal concerns, namely, (1) the failure to adequately control the configuration of certain plant equipment; (2) the failure to identify and correct several of these problems beforehand, despite prior opportunities to do so; and (3) weaknesses in management's initial response to the event and its oversight of the subsequent recovery of safety-related equipment. Con Edison concurs with the above principal concerns and the results of the NRC inspections that were conducted subsequent to the August 31, 1999 event.

On September 14, 1999, a public meeting between the Con Edison management and the NRC was held to discuss the above issues associated with the August 31, 1999 reactor trip event and subsequent response which involved several challenges in management, human performance, processes and equipment. As discussed at that meeting, Con Edison immediately mobilized the Significance Level 1 (SL1) review team to investigate and to collect facts from the event, to develop conclusions (root causes) and to determine corrective actions to prevent recurrence from this event. Additionally, a Utility Assistance Team consisting of utility peers, a member from Institute of Nuclear Power Operations, independent consultants and Con Edison personnel was formed to independently assess the performance of plant equipment and personnel.

Con Edison used the condition reporting system to document and track the issues that were identified from these reviews. The following condition reports document the results of the key investigations that were performed from this event: condition report CR 199906643 which documents the result of the investigation that was performed by the SL-1 Investigation Team, and condition report CR 199906868 which documents the result of the investigation performed by the Utility Assistance Team.

A formal recovery team was also organized, consisting of Con Edison managers and outside consultants, to develop a structured recovery plan and to provide management oversight of the event recovery efforts. The recovery plan provided a systematic approach for addressing those immediate actions needed for safe and efficient restart of the plant, as well as the process for managing longer-term corrective actions resulting from this event. On November 8, 1999, Con Edison submitted the IP2 Recovery Plan, Revision 3, which provided a summary of the results of the assessments performed, an overview of those actions taken to assure the safe and efficient restart of the plant, and a summary of several improvement initiatives that are being taken to address longer-term corrective actions from this event. In that letter, Con Edison also stated that those longer-term corrective actions would be carried forward into the year 2000 IP2 Business Plan.

On March 8, 2000, the NRC issued Inspection Report 05000247/1999011 that summarized a review that was conducted of IP2 Recovery Plan Revision 3 longer-term corrective actions and the corresponding implementing actions contained in our year 2000 IP2 Business Plan. Con Edison plans to provide a response to the above subject inspection report by March 30, 2000.

ATTACHMENT 1

REPLY TO NOTICE OF VIOLATION

INSPECTION REPORT NUMBERS 50-247/99-08, 99-13 AND 99-14

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
MARCH 27, 2000

<u>**ATTACHMENT**</u>

REPLY TO NOTICE OF VIOLATION
AND
PROPOSED IMPOSITION OF CIVIL PENALTY

Pursuant to the provisions of 10 CFR 2.201, Con Edison hereby provides the reply to the Notice of Violation and Proposed Imposition of Civil Penalty:

A. ALLEGED VIOLATION

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. Included in the design basis are the 480 Volt (V) vital bus degraded voltage relays described in Section 8.2.2.6 of the Updated Final Safety Analysis Report.

Technical Specification (TS) 3.7, Auxiliary Electrical Systems, specifies, in part, that the reactor shall not be made critical without 6.9 kV buses 5 and 6 energized from the 138 kV sources at Buchanan Substation through the 138/6.9 kV Station Auxiliary Transformer. TS 3.7.6.3 allows that power operation may continue for 24 hours, if the entire 138 kV source of power is lost.

Contrary to the above:

Applicable regulatory requirements and the design basis were not correctly translated into specifications and procedures for a 1995 modification to the 480 V vital bus degraded voltage relays in that the correct reset values for the eight undervoltage relays were not established when the relays were replaced under modification EGP-91-06786E. Specifically, the information supporting License Amendment No. 165 dated September 22, 1993 associated with the degraded voltage relays specified a relay pickup (reset) setting of 429 Vac. However, the modification procedures did not specify pickup settings, and none were established in 1995 when the relays were calibrated and installed. Further, when the relays were calibrated in June 1997, the procedure did not include calibration of the relay reset points. As a result, the relays were unable to perform their design basis function and correctly reset, contributing to unnecessary transfer on August 31, 1999 of the 480 V vital busses from the normal offsite power supply to the emergency diesel generators (EDGs).

Applicable regulatory requirements and the design basis were not correctly translated into specifications and procedures for a 1995 modification to the 480 V vital bus degraded voltage relays in that the requirement for automatic operation of the station auxiliary transformer (SAT) load tap changer (LTC) was not translated into procedures. Specifically, calculation EGP-00110-00, "Summary of Degraded Voltage Study," which supported License Amendment No. 165 dated September 22, 1993, contains an analysis of 480 V bus performance that relied upon the SAT LTC to automatically adjust the voltage on the 480 V busses for the system to perform as designed. The licensee failed to translate the requirement for automatic operation of the LTC into station procedures. As a result, without procedural controls, the LTC was operated in manual from September 9, 1998 until August 31, 1999. With the LTC in manual, the 138 kV off site power system was unable to perform its intended function in that the LTC was unable to respond automatically to a decrease in transformer output. When the unit main generator tripped on August 31, 1999, the decrease in transformer output caused an extended voltage drop that actuated the 480 V bus degraded voltage relays which isolated the 480 V busses from the normal offsite power supply. With the LTC in manual operation from September 9, 1998 until August 31, 1999, the 138 kV offsite power system was inoperable (lost) for greater than 24 hours contrary to TS 3.7.B.3.

A.1 ADMISSION OR DENIAL OF THE ALLEGED VIOLATION:

Con Edison accepts the alleged violation.

A.2 REASONS FOR ALLEGED VIOLATIONS:

On August 31, 1999, at approximately thirty seconds after the reactor trip, the electric generator tripped as designed and four “inside” 6.9 KV station service busses, normally connected to the generator-supplied unit auxiliary transformer, "fast transferred" to the offsite source, through 138 kV to 6.9 kV Station Auxiliary Transformer. This fast transfer included all loads supplied from the 480V bus and affected 6.9 kV busses except for 22 condensate pump. 22 condensate pump is designed to be stripped from the bus during this transfer process and the system performed as designed. Throughout this event the transformer’s tap changer remained in manual, where operators had placed it approximately a year earlier because of a defective voltage control relay.

On a transfer of load to the offsite bus, the 480 volt bus voltage drops below the degraded voltage setpoint. This voltage level activates the degraded voltage relays set at 421 V (+/- 6V) in 180 sec (+/- 30 sec). The design of the station auxiliary transformer tap changer, when operating in automatic, is to automatically move to restore the voltage of the undervoltage (UV) condition.

With the tap changer not set in automatic, operator manual intervention would have been required to raise the voltage on the 480V buses to recover from the transient. Operators did not intervene, therefore normal voltage was not restored before the undervoltage relay settings (voltage level and duration) were satisfied.

As stated above, the station auxiliary transformer tap changer was in manual during the undervoltage condition. As a result, bus voltage remained below the undervoltage device reset value for more than 180 seconds, producing a station blackout signal. The review discovered that the tap changer was placed in manual on September 10, 1998, when it was determined that the voltage control relay would not maintain the required voltage in automatic. A condition report, CR 199807874 and work order, WO 98-03865 was initiated to correct this deficiency. However, the station had deferred the replacement of the defective voltage control relay for higher priority jobs on several occasions. Additionally, no compensatory action to offset the lack of automatic tap changer function was implemented.

Ineffective work prioritization by station management delayed the corrective maintenance on station auxiliary transformer tap changer (LTC). As a result, its automatic function remained unavailable for nearly one year and did not function on August 31, 1999.

In June 1995, modification EGP-91-06786-E was implemented to replace the original Westinghouse undervoltage relays for the 480v vital buses with a higher accuracy Asea Brown Boveri type electronic relays and raised the undervoltage trip settings from 403 Vac to 421 Vac. In September 1992, Con Edison submitted Technical Specifications (TS) Amendment 165 to change these undervoltage trip settings. This change is to assist in voltage recovery if a plant trip occurred. In addition, an engineering calculation EGP-00110-00, Summary of Degraded Voltage Study, was performed to demonstrate that adequate voltage can be maintained during a fast transfer of loads. This calculation was based on the tap changer in automatic mode and not in a manual mode of operation. On September 22, 1993, NRC Safety Evaluation Report (SER) 165 was issued supporting the above change. The above modification was implemented in February 1995, however the system operating procedures were not revised at that time to assure the LTC was operated in the automatic mode and compensatory measures taken were ineffective to assure the operability of the 138 KV offsite power system with the LTC in manual. Station personnel failed to recognize the importance of the design and licensing basis requirements for the auxiliary transformer tap changer.

When modification EGP-91-06786-E was implemented in 1995, appropriate undervoltage relay reset values were not established because the original undervoltage relays did not have separately adjustable pickup and dropout settings. Subsequent calibration performed in June 1997 using procedure PT-R61, 480 Volt Breaker Undervoltage Relays, likewise did not include calibration of the dropout and pickup points.

A.3 CORRECTIVE STEPS THAT HAVE BEEN TAKEN AND THE RESULTS ACHIEVED:

Subsequent to the August 31 event, an engineering calculation FEX-00119-00, 480V Bus Blackout Analysis, was performed to determine the transient and final (recovered) voltages on the buses. Also, undervoltage relay testing was conducted to identify the actual reset value. The calculation and tests confirmed that the final bus voltages were not set high enough to have reset the undervoltage relays with the auxiliary transformer load tap changer (LTC) in the manual mode. Subsequently, modification EGP-91-06786-E was revised to establish a relay reset value above the dropout setting. The periodic calibration test procedure PT-R61, 480 Volt Breaker Undervoltage Relays, was also revised to include the specific calibration reset value.

The defective voltage control relay was repaired and LTC was restored back to automatic function. Station procedures, System Operating Procedure (SOP) 27.1.1, Operation of 345KV and 138KV Components, SOP 1.3, Reactor Coolant Pump Startup and Shutdown, SOP 20.2, Condensate System Operations, and SOP 27.1.4, 6900V System, were revised to require maintaining the LTC in automatic rather than in manual. Additionally, the current engineering procedure SE.SQ 12.207, Modification Tracking, adequately tracks identified procedure changes for implementation as part of the modification process.

The Operations Alarm Response Procedure for Window 4-5 was revised to establish a requirement that with LTC in manual, the 138KV offsite power system will be considered inoperable and a 24 hour Limited Condition of Operation (LCO) action statement will be entered in accordance with TS 3.7.B.3.

Additionally, as part of the CR 199906643, several extent-of-condition (EoC) team reviews were conducted to identify similar vulnerabilities in other areas. These extent-of-condition team reviews are summarized as follows:

1. Operation of Equipment in Manual. The Corrective Action Group (CAG) extent-of-condition team assessed if there were any plant equipment issues that require the operation of equipment in manual when an automatic capability exists. A sample population of active Temporary Facility Changes (TFC), active Caution Tags, active Operator Work Arounds (OWA), and Active Temporary Procedure Changes (TPC) was performed. The team identified a total of sixty (60) potential issues, of which nineteen (19) issues were dispositioned prior to restart. The remainder were evaluated and determined not to be restart holds by the Outage Scope Committee Group and were recommended for resolution post restart. These post-restart issues were appropriately prioritized and scheduled for disposition.

2. Impacts of Modifications and Licensing Amendments on Plant Procedures. The Corrective Action Group extent-of-condition team assessed whether the existing plant processes ensure that the requirements of modifications and license amendments are being implemented in plant operations procedures. A sample population was chosen and review performed of select License Amendments, NRC Safety Evaluation Reports and plant modifications to verify that the requirements contained within these change documents are correctly reflected in Operations procedures. The review of licensing amendments issued since January 1997 verified that the requirements of the licensing amendments were met by operations procedures. The review of thirteen (13) electrical and five (5) mechanical modifications identified three (3) instances where the recommended changes had not been incorporated in operations procedures when the modifications were implemented. In all three (3) cases, the operation's procedure database indicated the required procedure change. Although these procedure changes had already been identified for implementation, Condition Reports CR 199907148, 199907154 and 199907155 were initiated to document the discrepancies. These condition reports were reviewed by Operations and Outage Scope Control Committee prior to restart and no procedure changes were deemed necessary prior to restart since the changes were administrative and did not impact the safe operation of the plant. Two of condition reports (CR 199907148 and CR 199907154) were subsequently dispositioned and the remaining CR 199907155 is scheduled for disposition by March 31, 2000.

3. Maintenance of Licensing Basis. The Corrective Action Group extent-of-condition team assessed whether the temporary change processes are maintaining the licensing basis of the plant as expressed in the Updated Final Safety Analysis Report (UFSAR). A sample population for review consisted of twenty-four (24) TFC, TPC and caution tags. The review identified one (1) potential conflict where the Primary Sample System Booster Pump has been out of service. This condition was

previously identified in condition report CR 199904455 and appropriate actions are being taken to address this issue.

4. Review of Significant Open Condition Report Issues. The Corrective Action Group extent-of-condition team assessed whether any open corrective actions contained in SL1 and SL2 Condition Reports should be resolved prior to restart. The team identified sixty-one (61) SL1 and SL2 Implementing Condition Actions (ICAs) and eight (8) SL2 reports as potential restart items. The Outage Scope Control Committee reviewed those issues and those that were deemed necessary for resolution prior to restart were appropriately addressed. The remainder were considered post restart and those issues were appropriately prioritized and scheduled for disposition.

5. Proper Knowledge of Plant Design and Licensing Bases. The Engineering extent-of-condition team assessed whether appropriate site personnel have an adequate understanding of the design and licensing basis (i.e., when performing 10 CFR 50.59 screening and evaluations) for those event-related plant modifications. The review concluded that the recent revision (Revision 8) to SAO-460, 10 CFR 50.59 Safety Evaluations, provides adequate guidance when performing 10 CFR 50.59 reviews. Additionally, a review of selected active work orders was performed to determine whether a written operability determination or safety evaluation should be prepared for these work orders and, whether the written operability evaluations were still appropriate as written. This review was conducted prior to the unit restart. Approximately 347 outstanding work orders were reviewed and the review concluded that although some work orders needed the documentation of their operability determination recreated, no operability concerns existed.

6. Modification Review. The Engineering extent-of-condition team performed a sample review of electrical modifications to determine whether the relay reset setpoints were properly addressed in modifications. A list of modifications developed between 1990 and the present was reviewed to identify those modifications with the potential to involve the need to specify a setpoint and a reset point for protective relays and other instrumentation. Based on the review of protective relay modifications from 1990 through 1998, no other modifications, calculations or safety evaluations were found which failed to specify the appropriate pickup and drop out parameters, where required. Additionally, the process for controlling and developing setpoints was changed in October 1999 by the issuance of procedure change was issued to procedure SAO-452, IP2 Setpoint Control Program, (supplemented by administrative directives.) These new procedures upgraded the process and specified the requirements of reset values for device setpoints.

A.4 CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FUTHER VIOLATIONS:

Con Edison has addressed the specific issues that were deemed necessary for restart and documented results in condition report CR 199906643. The specific post-restart corrective actions that are related to this violation issue are also addressed in CR 199906643 (Direct Cause No.2, Root Cause No.2, and Additional Contributing Cause No. 3).

In addition to those corrective actions resulting directly from the reviews and assessments described above, longer-term corrective actions (i.e., post restart) were developed to address the human performance and programmatic challenges identified from this event. The Recovery Plan, Revision 3, submitted on November 8, 1999, provided the necessary structure and guidance to address those specific challenges required for safe and efficient restart of the plant, as well as, a process for managing longer-term improvement actions resulting from lessons-learned following this event. These longer-term corrective actions have been incorporated into our year 2000 IP2 Business Plan.

The specific longer-term corrective actions related to this violation are:

Configuration Management Control Improvements. The event identified several weaknesses in the control of plant configuration. For example, the load tap changer was not in the automatic position, contrary to the plant licensing improvements to enhance the plant configuration control process; completion of FSAR verification effort within the current schedule; update and/or develop design basis documents to include current design and licensing bases information; and validate and upgrade critical setpoint values, calculations, and bases documents (e.g., Emergency Operating Procedures, Instrument Drift) are in progress.

Increasing the Knowledge of Plant Design and Licensing Bases. Knowledge of the design and licensing bases for plant systems, structures, and components is needed. The current FSAR update project will enhance the accuracy and availability of the design and licensing bases, and additional training will be conducted to more effectively utilize this updated information. Procedures will be reviewed and revised, as appropriate, to more effectively implement operability reviews in accordance with NRC Generic Letter 91-18, Revision 1, "Resolution of Degraded and Nonconforming Conditions". Additionally, training will be provided to appropriate personnel on this review process.

The above longer-term corrective actions are scheduled for completion by December 31, 2000.

A.5 DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

Con Edison will complete the longer-term corrective actions related to this issue by December 31, 2000.

B. ALLEGED VIOLATION

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions and procedures of a type appropriate to the circumstances. Instructions and procedures shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Technical Specification (TS) 3.7, Auxiliary Electrical Systems, specifies, in part, that the reactor shall not be made critical without three emergency diesel generators (EDGS) operable. TS 3.7.B.1 allows power operation to continue for seven days if one EDG is unavailable.

Contrary to the above, on May 27, 1999, the licensee's procedure used to calibrate the Westinghouse Model DB-75 breaker trip units (Amptectors) for the EDGS, an activity affecting quality, was not adequate to ensure that the calibration was satisfactorily accomplished. Specifically, when the Amptector for the 23 EDG output breaker was calibrated on May 27, 1999, the method for adjusting the short time overcurrent trip setpoint did not ensure that the short time overcurrent trip setting was within specifications. The required setting for the 23 EDG output breaker short time overcurrent trip was 6000 Amperes (A) ± 2%. However, on August 31, 1999, the 23 EDG output breaker tripped on a short time overcurrent condition at approximately 3200A resulting in the EDG failing to perform its intended function of supplying power to one of the vital busses. As a result of the miscalibration, the EDG was inoperable during power operation from May 27, 1999 to August 31, 1999, contrary to TS 3.7.B.1.

B.1 ADMISSION OR DENIAL OF THE ALLEGED VIOLATION:

Con Edison accepts the alleged violation.

B.2 REASONS FOR ALLEGED VIOLATION:

On August 31, 1999, the reactor automatically tripped from 99% power on a reactor protection system OTDT. About three minutes later, normal offsite power to all four of the 480 Vac vital buses was lost and all three emergency diesel generators (EDGs) started and re-energized the buses. A few seconds thereafter, the 23 EDG output breaker tripped open, de-energized 480 Vac bus 6A. The remaining two EDG's continued to run and supplied their loads.

Upon receiving this fault indication in the Central Control Room (CCR), operation and maintenance personnel were dispatched to inspect the 23 EDG output breaker which is a Westinghouse model DB-75 breaker that uses a solid state overcurrent protective device called an Amptector. The personnel reported that the overcurrent protection device on the output breaker for 23 EDG had tripped. Since the breaker tripped after approximately 14 seconds after closing on a short time overcurrent, a process to validate the amptector settings commenced. The settings for 23 EDG output breaker amptector was checked using existing station test procedure (PT-3Y5) and the test results found the breaker setting to be within specifications. Since the test involves the use of secondary injection current (using the manufacture-supplied Amptector test set), a decision was made to repeat the test using primary current injection. Using this primary injection method, the breaker tripped at a value of approximately 3200 amps. The required short time overcurrent trip setting for this breaker was 6000 Amperes (A) ±8% of setting (rather than as discussed in NRC Inspection Report 05000247/99014, paragraph E8.2).

The Amptector was calibrated using an Amptector test kit and a secondary current injection method. With a current transformer (sensor) ratio of 3000/5 and a desired trip setting of 6000A, the specified short time pickup setting was approximately 10A. The specification required using a relatively coarse adjustment at the bottom of the high range (10-60A) tester. At 10A the adjustment was not precise enough to ensure that the breaker would trip within the acceptance band.

The cause for the incorrect Amptector setting was difficulty in performing calibration of the Amptector. First, the equipment used to set the breakers has a low scale from 0-10 amps (secondary coil setting, not primary overcurrent setting) and a high scale. The setting equivalent to 6000 amps primary overcurrent protection is very close to the 10 amp setting for the coil. Unless extreme care is used in setting this number, it is possible to set it incorrectly, and a slight shift in this value can result in a sizeable shift in the over current trip setting. After the event, breaker settings were checked on the other DB-75 and DB-50 breakers with settings near the low/high switchover value.

B.3 CORRECTIVE STEPS THAT HAVE BEEN TAKEN AND THE RESULTS ACHIEVED:

A review was conducted of all circuit breakers installed at IP2 that use the amptector overcurrent trip device. There are eight-two (82) circuit breakers of which sixty-nine (69) are DB-50 and thirteen (13) are DB-75 (this includes spare breakers). Fifty (50) of the sixty-nine (69) DB-50 circuit breakers were found to be outside our target range of concern. Therefore, these breakers were omitted from further review since they were satisfactorily tested at their trip settings in the past. One (1) breaker was found to be a spare and not in use, it was opted to calibrate this breaker prior to use. Of the thirty-one (31) remaining breakers, fifteen (15) breakers have settings under 20A and sixteen (16) breakers have settings greater than 20A. All thirty-one (31) breakers were tested using the primary current test method and re-calibrated as necessary, to assure satisfactory trip settings.

The secondary injection calibration procedures (PT-3Y5 and PC-3Y5) were revised to verify the setting of the breakers. Testing was performed, first by injecting a slightly lower current value than the trip setpoint to verify that the breakers will not trip at a lower setting. Then, the breakers were injected with a current value equivalent to the trip setting to verify that the breaker trips at the proper setpoint value. The calibration process was then verified by performing primary current injection. Once the calibration procedure was changed, primary injection verification has found all subsequent calibration settings to be correct. This process validates the revisions made to the Amptector calibration test procedures.

Additionally, as part of the CR 199906643, an extent-of-condition (EoC) team review was conducted to identify similar vulnerabilities in other areas. The following summarizes the scope and the results of the review applicable to this violation: The review team assessed if any other potential 480v bus loading issues exist and whether they should be resolved prior to restart. Based on this review, two (2) outstanding issues were found and resolved prior to restart. They were associated with Caution Tag 99-325 (Pressurizer Backup Heater) and CR 199807042 (MCC 25-2H contactor).

B.4 CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FUTHER VIOLATIONS:

Con Edison has addressed the specific issues that were deemed necessary for restart and documented results in condition report CR 199906643. The specific post-restart corrective actions that are related to this violation issue are also addressed in CR 199906643 (Direct Cause No. 3, Root Cause No. 3, and Contributing Cause No. 3).

In addition to those corrective actions resulting directly from the reviews and assessments described above, longer-term corrective actions (i.e., post restart) were developed to address the human performance and programmatic challenges identified from this event. The Recovery Plan, Revision 3, submitted on November 8, 1999, provided the necessary structure and guidance to address those specific challenges required for safe and efficient restart of the plant, as well as a process for managing longer-term improvement actions resulting from lessons-learned following this event. These longer-term corrective actions have been incorporated into our year 2000 IP2 Business Plan.

The specific longer-term corrective actions related to this issue are:

Maintenance Improvements. Observations of Maintenance department performance during the recovery reinforced the need for improvements in the areas of organization and management, work planning, work performance, training and qualification. Specific needs include: establishment of an Instrument and Controls Planning Group; development of a planning standard for the Instrument and Controls organization; implementation of a procedure upgrade program; and incorporation of Post Maintenance Tests into work packages.

Human Performance Improvements. Several human performance issues were identified during the assessments conducted after this event. A systematic approach to improve IP2 human performance will be taken. Human performance improvements will include the following specific attributes:

- Periodic, structured, human performance stand downs.
- Institute of Nuclear Power Operations assistance with initial program development.
- Periodic self-assessments of station human performance.
- Assessment of knowledge weaknesses associated with administrative procedure requirements and plant design and licensing basis.
- Formal training in human performance evaluation techniques.
- Effectiveness reviews.

The above longer-term corrective actions are scheduled for completion by December 31, 2000.

B.5 DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

Con Edison will complete the longer-term corrective actions related to this issue by December 31, 2000.

C. ALLEGED VIOLATION

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude recurrence.

Contrary to the above, between January 1999 and August 31, 1999, a significant condition adverse to quality existed involving repetitive problems with channel 4 of the reactor protection system (RPS) over-temperature/delta-temperature (OTDT) circuitry, and during that time, the condition was not promptly identified, the cause of the condition was not determined, and corrective actions were not taken to preclude recurrence, as evidenced by the following:

- In January 1999, the channel 4 OTDT instrument setpoint was found to be lower than normal.
- In July 1999, a loop 4 OTDT bistable failed when a 118 Volt ac vital inverter transferred to its alternate source.
- On August 26, 1999, a spurious trip of channel 4 of the OTDT instrument occurred.

The cause of these repetitive problems was not determined and thus, the adverse condition was not corrected. As a result, on August 31, 1999, during maintenance on the channel 3 OTDT instrument, the plant tripped due to a spurious trip of channel 4.

C.1 ADMISSION OR DENIAL OF THE ALLEGED VIOLATION:

Con Edison accepts the alleged violation.

C.2 REASONS FOR ALLEGED VIOLATIONS:

On August 30, 1999, Instrument and Control (I&C) technicians were performing a scheduled periodic surveillance test for Pressurizer Pressure, PT-Q55 and had completed testing of OTDT Channels 1 and 2. While performing the test for Channel 3, the I&C technicians found that the bistable would trip and reset at non reproducible setpoint values (the values were within the acceptance criteria but a bistable should have distinct trip and reset points). The technicians stopped the test and restored the channel. The I&C technicians and the supervisor recommended replacing the bistable prior to continuing the test and subsequently, operators placed the OTDT Channel 3 in the trip position for maintenance work. This action placed the OTDT trip logic in a condition such that any additional trip signal (in normal configuration it takes "two out of four" reactor trip signal) generated on one of the remaining three channels, would cause an OTDT reactor trip.

At 14:31:57 hours on August 31, 1999, while the OTDT trip logic was still in a degraded condition, a spurious electrical signal spike occurred on OTDT Channel 4. This completed the "two out of four" reactor trip logic, causing an OTDT reactor trip.

Voltage signals are more susceptible to extraneous electrical noise than current signals. Channel 4 OTDT is powered from 24 Instrument Bus, which in turn is powered from 24 DC Bus through 24 Static Inverter. Interviews with Reactor Operators (ROs) revealed that the 24 DC Bus ground alarm is frequently activated when the annunciator alarm test button is pushed. Annuciator alarm tests are performed each shift. The ground alarm on annunciator alarm check, which frequently occurs implies that a potential grounding condition on this bus might exist when the annunciator alarm check function is actuated. A review of past occurrences support that the most probable cause was due to a ground on 24 DC bus which caused a high channel noise level on the OTDT circuit. Based on the above, the noise generated by an intermittent ground on 24 DC bus produced a false reactor trip signal, resulting in a plant trip.

Subsequent review of signal to noise history revealed that a similar spike occurred on OTDT Channel 4, four days earlier. The duration of that signal was 73 milliseconds, and it was sufficient to cause an OTDT channel trip alarm in the central control room (CCR). A condition report 199906545 was initiated by Operations on August 26, 1999 describing this anomaly (channel spike). A copy of the condition report was submitted to the system engineer on August 30, 1999, for review but was not reviewed until the morning of August 31, 1999.

Other related operating experience included the following:

- On January 21, 1999, a Condition Report 199900467 was initiated by Operations to document a condition where during routine control board walkdown, the operator observed Loop 4 OTDT setpoint lower than normal. Immediately, the Central Control Room (CCR) Protection Rack was checked for an anomaly and the operators observed that the output from OTDT flux tilt controller unit (QM-441A) was reading normal. Subsequently, further trouble shooting and calibration was performed per Action Request (AR) 99-06223. As part of the trouble shooting effort, the flux tilt controller unit, capacitors, and 480V relay were replaced prior to restoring the channel back to service. Additionally, a copy of the condition report was sent to the system engineer for information.

- On July 2, 1999, Condition Report 199905224 was initiated when the 24 static inverter inadvertently swapped the 24 Instrument Bus to the alternate power supply. When this occurred, an alarm was received in the CCR indicating that Loop 4 OTDT Channel had tripped. Subsequent investigation revealed that a failure of the output bistable for OTDT Channel 4 had occurred causing the 24 Instrument Bus to swap to the alternate power. The bistable was subsequently replaced per AR 99-09797. The failed bistable was also sent to an offsite vendor for failure analysis (Note: The result of the analysis was not available prior to the August 31, 1999 reactor trip event.) The failure analysis subsequently indicated that the bistable failed due to a higher than expected DC voltage being injected into the component.

Although investigation was underway to further review the cause of the July 2. 1999 occurrence, the result of the vendor failure analysis for the August 26, 1999 bistable failure was not available prior to the August 31, 1999 reactor trip event. The review of this data prior to the August 31, 1999 reactor trip event may have triggered a more indepth review, a closer monitoring program for detecting the intermittent pikes on OTDT channels and additional precautions during performance of surveillance tests. However, none of these actions was taken prior to the August 31, 1999 event and the previous condition reports were being monitored by the system engineer as a track and trend status.

C.3 CORRECTIVE STEPS THAT HAVE BEEN TAKEN AND THE RESULTS ACHIEVED:

Significance Level 1 (SL1) Condition Report 199906643 and Significance Level 2 (SL2) Report 199906868 were written to document the results of the August 31, 1999 reactor trip post-trip assessment, to document the root cause evaluations performed, to document the extent of condition reviews and to track Implementing Corrective Actions (ICA) for the above condition reports.

A SL1 Condition Report Investigation Team was chartered in accordance with the Corrective Action Program to develop conclusions (root causes) and determine corrective actions to prevent recurrence of this event. This Investigation Team included experienced IP2 and consultant members who reviewed the following:

- The plant response to the reactor trip including operator actions.
- The cause of the plant anomalies identified after the trip.
- The cause of the OTDT spurious signal on Channel 4.
- Any potential precursor events related to the trip circuit.
- Industry operating experience.

Based on the investigation, the SL1 Team concluded the following:

- Direct Cause No. 1- A spike on Channel 4 OTDT, most likely caused by extraneous electrical noise, completed the reactor trip logic.
- Root Cause No. 1 – The station did not appreciate the risk significance of signal spikes and intermittent grounds on DC logic circuits which were prevalent in the early 1990s, and noted again in 1999.

SL2 Condition Report 199906868 documented the corrective actions to address the Utility Assistance Team's observations. The team was formed by the Plant Manager to independently assess the performance of plant equipment and personnel during and subsequent to the event. The team concluded that the prior OTDT spurious alarms were not well communicated. An extent of condition (EoC) review was performed to address this issue and results documented in Condition Report 199906643. The extent-of-condition addressed whether spurious control room alarms have become a distraction to the control room operators. The objective of the review was to: determine those existing or recurring control room alarm conditions that can potentially affect the Reactor Protection System; perform a broad review of condition reports and work orders to evaluate whether any outstanding conditions could individually or collectively affect operator's response; and, capture and sort these collected data in a relational database to assist engineers and technicians in resolving the appropriate deficiencies. The above review and identified issues were corrected or were appropriately addressed and prioritized for repair prior to unit restart.

To address extraneous electrical noise, engineering and maintenance established a troubleshooting plan to identify the cause of extraneous electrical noise. The plan included simulating the condition at the time of the event and looking for a potential DC ground fault condition. The DC ground fault condition was suspected as the most plausible cause. However, the condition could not be duplicated and no anomalies were found that could have caused the signal spike on Channel 4 OTDT. On October 9, 1999, the plant manager issued a Station Ground Policy. The policy reiterated the requirements of station procedure SAO-204, Work Control, where high priority should be established on work orders for addressing unplanned control room alarms that are either safety-related or directly affect power production. Since DC bus grounds can actuate control room alarms, the expectation is to aggressively pursue the reason for the unexpected alarm and make every reasonable attempt to isolate and fix the condition.

Additionally, a clear expectation was established for Operations, Maintenance and Engineering to more effectively communicate any potential plant issues that could affect the safe operation of the plant. Existing operator work arounds such as, TFCs, TPCs, and caution tags were reviewed for potential resolution prior to restart. The review also consisted of open SL1 and SL2 condition reports and ICAs that may potentially impact the operator performance, if not resolved. Based on those review, appropriate issues were dispositioned prior to restart and the remainder tracked for expeditious resolution.

C.4 CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FUTHER VIOLATIONS:

Con Edison has addressed the specific issues that were deemed necessary for restart and documented results in condition report CR 199906643. The specific post-restart corrective actions that are related to this violation issue are also addressed in CR 199906643 (Direct Cause 1 and Root Cause 1).

In addition to those corrective actions resulting directly from the reviews and assessments described above, longer-term corrective actions (i.e., post restart) were developed to address the human performance and programmatic challenges identified during this event. The Recovery Plan, Revision 3, submitted on November 8, 1999, provided the necessary structure and guidance to address those specific actions required for safe and efficient restart of the plant, as well as a process for managing longer-term improvement actions resulting from lessons-learned. These longer-term corrective actions have been incorporated into our year 2000 IP2 Business Plan.

The specific longer-term corrective actions related to this issue are:

<u>Human Performance Improvements.</u> Several human performance issues were identified during the assessments conducted after this event. A systematic approach to improve IP2 human performance will be taken. Human performance improvements will include the following specific attributes:

- Periodic, structured, human performance stand downs.
- Institute of Nuclear Power Operations assistance with initial program development.
- Periodic self-assessments of station human performance.
- Assessment of knowledge weaknesses associated with administrative procedure requirements and plant design and licensing basis.
- Formal training in human performance evaluation techniques.
- Effectiveness reviews.

Work Control Optimization. Weaknesses in the work control program were identified during the recovery from the event. Although significant work was completed during the recovery, backlogs of work items remain relatively high, and are not being reduced at a rate that meets management expectation. Further backlog reduction and improved work management will be achieved through the development and management of a single daily integrated schedule that identifies and coordinates all plant work items, and that provides for clear responsibilities and accountabilities for all groups that develop and implement the schedule.

The above longer-term corrective actions are scheduled for completion by December 31, 2000.

C.5 DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

Con Edison will complete the longer-term corrective actions related to this issue by December 31, 2000.

ATTACHMENT 2

REPLY TO NOTICE OF VIOLATION

INSPECTION REPORT NUMBERS 50-247/99-08, 99-13 AND 99-14

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
MARCH 27, 2000

Con Edison – Indian Point Unit 2
Commitments

The following list identifies those actions committed to by Con Edison in this document. Any other actions discussed in the submittal represent intended or planned actions by Con Edison. These actions are described to the NRC for the NRC's information and are not regulatory commitments.

Commitment	Due Date
1. Con Edison plans to provide our response to inspection report 05000247/1999011 by March 30, 2000. (Reference Enclosure)	March 30, 2000
2. The event identified several weaknesses in the control of plant configuration. For example, the load tap changer was not in the automatic position, contrary to the plant licensing improvements to enhance the plant configuration control process; completion of the FSAR verification effort within the current schedule; update and/or develop design basis documents to include current design and licensing bases information; and validate and upgrade critical setpoint values, calculations, and bases documents (e.g., Emergency Operating Procedures, Instrument Drift) are in progress. (Reference Attachment 1, paragraph A.4)	December 31, 2000
3. Knowledge of the design and licensing bases for plant systems, structures, and components is needed. The current FSAR update project will enhance the accuracy and availability of the design and licensing bases, and additional training will be conducted to more effectively utilize this updated information. Procedures will be reviewed and revised, as appropriate, to more effectively implement operability reviews in accordance with NRC Generic Letter 91-18, Revision 1, "Resolution of Degraded and Nonconforming Conditions". Additionally, training will be provided to appropriate personnel on this review process. (Reference Attachment 1, paragraph A.4)	December 31, 2000

Commitment	Due Date
4. Observations of Maintenance department performance during the recovery reinforced the need for improvements in the areas of organization and management, work planning, work performance, training and qualification. Specific needs include: establishment of an Instrument and Controls Planning Group; development of a planning standard for the Instrument and Controls organization; implementation of a procedure upgrade program; and incorporation of Post Maintenance Tests into work packages. (Reference Attachment 1, paragraphs B.4)	December 31, 2000
6. Several human performance issues were identified during the assessments conducted after this event. A systematic approach to improve IP2 human performance will be taken. Human performance improvements will include the following specific attributes: • Periodic, structured, human performance stand downs. • Institute of Nuclear Power Operations assistance with initial program development. • Periodic self-assessments of station human performance. • Assessment of knowledge weaknesses associated with administrative procedure requirements and plant design and licensing basis. • Formal training in human performance evaluation techniques. • Effectiveness reviews. (Reference Attachment 1, paragraphs B.4 and C.4)	December 31, 2000
7. Weaknesses in the work control program were identified during the recovery from the event. Although significant work was completed during the recovery, backlogs of work items remain relatively high, and are not being reduced at a rate that meets management expectation. Further backlog reduction and improved work management will be achieved through the development and management of a single daily integrated schedule that identifies and coordinates all plant work items, and that provides for clear responsibilities and accountabilities for all groups that develop and implement the schedule. (Reference Attachment 1, paragraphs C.4)	December 31, 2000