April 10, 2001

EA No. 01-055

Mr. John Groth
Senior Vice President - Nuclear Operations
Consolidated Edison Company of
New York, Inc.
Indian Point 2 Station
Broadway and Bleakley Avenue
Buchanan, NY 10511

SUBJECT: INDIAN POINT UNIT 2 - NRC SUPPLEMENTAL INSPECTION 05000247/2001-002

Dear Mr. Groth:

The Nuclear Regulatory Commission conducted a supplemental inspection from January 16th through February 9th, 2001, at your Indian Point 2 (IP2) facility. This inspection was conducted in accordance with the guidance contained in NRC Manual Chapter 0305 and inspection procedure 95003 and was performed in response to your facility's designation as having multiple degraded cornerstones, as defined by the NRC's reactor oversight process.

The results of our inspection indicate that your facility is being operated safely. However, the team identified problems similar to those that have been previously identified at the IP2 facility, particularly in the areas of design control, human and equipment performance, problem identification and resolution, and emergency preparedness. Senior management has raised performance expectations, increased accountability and emphasis on training, and taken steps to establish improvement programs that are aligned with the station's business planning process. While some performance improvements were noted, as a result, progress has been slow overall and limited in some areas, indicating the need for you to maintain, and in some areas consider accelerating, the ongoing performance improvement program which has been in place. One such area is that of design control where recurrent problems were found in the translation of important design assumptions into plant operating procedures, drawings, calculations, and testing programs.

The inspection team assessed its findings together with the results of similar, previous inspections in order to provide insight into the overall root and contributing causes of performance issues at the site. The NRC's effort at summarizing potential causes is not intended to be a substitute for a more focused root cause study or self-assessment on your part. We found that most performance issues could be attributed to one or more of the following:

- Weaknesses in the ability to retrieve, verify, and assure the quality of engineering products, particularly design basis information.

- Inconsistent reinforcement of existing management standards with respect to staff performance, particularly in the areas of procedural quality and adherence and in implementation of the corrective action program;

- A tendency, in some instances, for the plant staff to accept degraded conditions;

- Some limitations in the application of resources leading to, for example, staffing issues and training weaknesses.

We observed that your current performance improvement plan, developed within the framework of your business plan, appears to envelope the areas needing improvement. The team determined that an alignment existed between the business plan and actions necessary to address performance issues. However, the plan is general in nature and relies heavily on department level implementation strategies that vary in quality and depth. We note previous improvement plans similarly covered the issues broadly, but were not fully effective. In that regard, you are requested to respond to this inspection report by May 7, 2001, highlighting both changes made to your business plan, based on the issues raised during this inspection, and measures you will use to monitor the effectiveness of your performance improvement efforts.

We will continue heightened oversight of Indian Point 2 until we gain confidence that your performance improvement program has substantially addressed the performance weaknesses identified in this and previous NRC inspections. This will include inspection of targeted areas of weakness, periodic site visits and public management meetings, and quarterly assessments by senior regional management. A more detailed oversight plan will be published in late May 2001, following receipt and assessment of your response.

We are planning two public meetings to discuss your performance improvement efforts. The first meeting, tentatively scheduled for April 30, 2001, will cover your response to this inspection focusing principally upon design control activities to provide confidence that appropriate actions are being taken and planned in this important area. Secondly, we are finalizing plans for an annual review meeting (as prescribed in the Agency Action Matrix), which will occur in the local area of the plant in June 2001; this will provide opportunity for broader discussion on your improvement program.

The details of our inspection findings are provided in the enclosed inspection report and were discussed with you and members of your staff throughout the inspection and at a public meeting held on March 2nd, 2001. The issues identified in the enclosed inspection report have, individually, been evaluated under the risk significance determination process as being minor in nature or having very low safety significance (Green). However, the issues provide evidence of some program and process weaknesses similar to those which contributed to previous plant events. We have determined that violations of regulatory requirements are associated with several of these issues. These violations are being treated as Non-Cited Violations, consistent with Section VI.A.1 of the NRC's Enforcement Policy. If you deny the non-cited violations, you should provide a response with the basis of your denial, within 30 days of the date of this inspection report to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region I, 475 Allendale Road, King of Prussia, PA 19406-1415; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Indian Point 2 facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room). Should you have any questions regarding this report, please contact Mr. Brian Holian at 610-337-5128.

Sincerely,

/RA/

Hubert J. Miller
Regional Administrator

Docket No. 05000247
License No. DPR-26

Enclosure: Inspection Report 05000247/2001-002

cc w/encl:
A. Blind, Vice President - Nuclear Power
J. Baumstark, Vice President, Nuclear Power Engineering
J. McCann, Manager, Nuclear Safety and Licensing
B. Brandenburg, Assistant General Counsel
C. Faison, Licensing, Entergy Nuclear Operations, Inc.
W. Smith, Operations Manager
C. Donaldson, Esquire, Assistant Attorney General, New York Department of Law
P. Eddy, Electric Division, Department of Public Service, State of New York
T. Rose, NFSC Secretary
W. Flynn, President, New York State Energy Research
and Development Authority
J. Spath, Program Director, New York State Energy Research
and Development Authority
The Honorable Sandra Galef, NYS Assembly
County Clerk, West Chester County Legislature
A. Spano, Westchester County Executive
R. Bondi, Putnam County Executive
C. Vanderhoef, Rockland County Executive
J. Rampe, Orange County Executive
T. Judson, Central NY Citizens Awareness Network
M. Elie, Citizens Awareness Network
D. Lochbaum, Nuclear Safety Engineer, Union of Concerned Scientists
J. Riccio, Public Citizen's Critical Mass Energy Project
M. Mariotte, Nuclear Information & Resources Service
E. Smeloff, Pace University School of Law
F. Kich, Manager, Training

Distribution w/encl: **(VIA E-MAIL)**
H. Miller, RA
J. Wiggins, DRA
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R. Urban, ORA, (EA Packages Only)
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P. Eselgroth, DRP
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OFFICE	RI/DRS	RI/DRS *	RI/DNMS *	RI/DRS	RI/DRS *
NAME	WSchmidt **/LLS for/**	JYerokun	JKottan	LScholl **/LLS/**	GMorris
DATE	04/09/01	03/26/01	03/22/01	04/09/01	03/23/01

OFFICE	RI/DRS *	RI/DRS *	RI/DNMS *	RI/DRS *	RI/DRP *
NAME	SPindale	GCranston	LPeluso	NMcNamara	GWertz
DATE	03/29/01	03/23/01	03/27/01	03/22/01	03/26/01

OFFICE	HQ/NRR *	RII/DRP *	RII/DRP *	CONTRACTOR *	CONTRACTOR*
NAME	RPelton	RGibbs	GMcCoy	DPrevatte	OMazzoni
DATE	03/27/01	03/23/01	03/23/01	03/28/01	03/27/01

OFFICE	RIV/DRS	RI/ORA	RI/ORA		
NAME	JShackelford **/BEH for/**	BHolian **/BEH/**	HMiller **/HJM/**		
DATE	04/09/01	04/09/01	04/10/01		

*** Individuals concurred via e-mail**

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.:	05000247
License No.:	DPR-26
Report No.:	2001-002
Licensee:	Consolidation Edison Company of New York, Inc.
Facility:	Indian Point 2 Nuclear Power Plant
Location:	Buchanan, New York 10511
Dates:	January 16, 2001 to February 9, 2001
Inspectors:	J. Shackelford, Team Leader, Region IV L. Scholl, Senior Reactor Inspector, Region I W. Schmidt, Senior Reactor Inspector, Region I J. Yerokun, Senior Reactor Inspector, Region I R. Gibbs, Senior Resident Inspector, Region II R. Pelton, Human Performance Specialist, NRR G. Morris, Reactor Inspector, Region I S. Pindale, Reactor Inspector, Region I G. Cranston, Reactor Inspector, Region I N. McNamara, Reactor Inspector, Region I G. Wertz, Resident Inspector, Region I G. McCoy, Resident Inspector, Region II D. Prevatte, Contractor O. Mazzoni, Contractor J. Kottan, Radiological Safety Program Manager, Region I (3rd on-site week) L. Peluso, Health Physicist, Region I (3rd on-site week)
Approved By:	Brian Holian, Deputy Director Division of Reactor Safety

Executive Summary

The NRC designated Indian Point 2 (IP2), owned and operated by Consolidated Edison Company of New York, Inc. (the licensee), a “multiple degraded cornerstone” facility in October 2000. As a result, a supplemental inspection was performed in accordance with the guidance in NRC manual chapter 0305 and inspection procedure 95003. A multi-disciplinary team of 14 NRC inspectors conducted the inspection over the course of approximately two months, with a total of three weeks of onsite effort. This report contains the results of that inspection. The objectives of the inspection included the following:

1) To provide the NRC additional information to be used in deciding whether the continued operation of the facility is acceptable and whether additional regulatory actions are necessary to arrest declining plant performance;
2) To provide an independent assessment of the extent of risk significant issues to aid in the determination of whether an unacceptable margin of safety exists;
3) To independently assess the adequacy of the programs and processes used by the licensee to identify, evaluate, and correct performance issues;
4) To independently evaluate the adequacy of programs and processes in the affected strategic performance areas; and,
5) To provide insight into the overall root and contributing causes of identified performance deficiencies.

The results of this inspection indicated that the licensee was operating IP2 safely, with an acceptable margin of safety, and that continued operation was acceptable. However, the team identified problems similar to those that have been previously identified at the IP2 facility, particularly in the areas of design control, human and equipment performance, problem identification and resolution, and emergency preparedness. In general, some progress has been observed in improving previously identified performance problems at the facility; however, progress has been slow overall, and limited in some areas. The team identified a number of performance weaknesses in programs and processes at the facility which indicate the need to maintain, and in some areas consider accelerating, the ongoing performance improvement program which has been in place.

The team determined that the overall program for problem identification and resolution was adequate. It was noted that some improvements had been made, in particular, an improved emphasis on problem identification and a metrics and tracking system for corrective action program issues. However, the team identified several continuing challenges to the program. It was observed that the effectiveness of some of the corrective actions for previously identified deficiencies was mixed. Additionally, the overall timeliness of corrective actions continued to be a significant challenge, and longstanding issues persisted with respect to prioritizing issues for resolution and trending causal factors. Additionally, the corrective action backlog presents an ongoing challenge to the station. Finally, as noted in previous assessments, weaknesses continue to exist in the operating experience review program, although some improvements have been made in this area. While performance difficulties continue to exist with respect to the review and disposition of technical issues, the site has made progress in areas related to industry outreach and bench-marking efforts.

Executive Summary

In the assessment of the reactor safety strategic performance area, the team selected the service water system and the 480 Vac system (including the emergency diesel generators) for in-depth reviews. These systems were selected primarily based on their overall importance to plant risk (the service water system is an important cooling water system and the 480 Vac/emergency diesel generators provide the emergency power source for the facility). Additionally, neither of these systems had received recent in-depth reviews from either the NRC or the licensee. With respect to these systems, the inspection focused heavily on the important design aspects, the quality of procedures, configuration control, and equipment performance. Additionally, the team reviewed the licensee's programs and processes associated with human performance and emergency preparedness.

It was determined that the licensee's overall performance was acceptable in the reactor safety strategic performance area. However, the team identified a number of issues in the areas of design control, equipment and human performance, and emergency preparedness which indicated weaknesses in these areas as well as the need for continued improvement.

Specifically, in the design control area, a number of performance issues were identified with respect to weaknesses in translating important design assumptions into plant operating procedures, drawings, calculations, and testing programs, including acceptance criteria. In some cases these deficiencies called into question the operability of the affected equipment. However, subsequent analyses demonstrated that the equipment would have been able to perform its safety function. The team also determined that difficulties existed in retrieving the design basis information necessary to support design control, system testing, and plant modification efforts. This particular issue had been previously identified, during NRC inspections as well as by the licensee in self-assessment efforts, and slow progress has been made to improve in this area. Additionally, this deficiency appears to have had additional impact in that some inconsistencies in the review of certain technical issues by the plant staff were observed.

In the area of equipment performance, the team determined that the reliability, material condition, and overall performance was acceptable for the reviewed systems. However, a number of other equipment issues presented challenges to both the plant and the operators. For example, emergent equipment failures in secondary plant systems continue to challenge the plant operators and have required numerous plant power changes. Examples included the feedwater pump oscillations during the recent plant startup, the heater drain pump flow element leak, and the feedwater system leak. In addition, the team noted that there had been some history of failures associated with the service water system strainers and boundary valves. The team also noted that a decrease in reliability and a concurrent increase in unavailability of the gas turbine generators occurred in the final quarter of 2000. This appears to be partly attributable to a decrease in the emphasis on maintenance for this equipment. Finally, the team concluded that the station work backlog continued to pose a significant challenge to the plant. It was also determined that due to oversights, a number of important work items had not been accurately captured in the accounting for the backlog, indicating that it may have been even somewhat larger than stated. Examples of this included the procedure changes required by the "communications to staff" program and the issues associated with verifying the comprehensiveness of the testing of various instrumentation and control components.

In the area of human performance, the team noted an increased emphasis on overall improvement and a recognition of the need for an improved training program. However, a number of program and process issues were identified. In particular, a challenge existed with respect to the number of licensed operators. This issue presented difficulties with respect to overall scheduling as well as overtime considerations. During the course of the inspection, the team witnessed a number of both planned and unplanned deviations from the overtime policy. However, the team also noted that licensee management recognized this problem and took steps to increase the number of licensed operators at the site.

The team also observed that operator performance issues have contributed to previous events and that some performance problems continue to occur. Performance errors were observed in the August 1999 reactor trip, the February 2000 steam generator tube failure, and again recently in the January 2001 turbine trip. Additionally, inconsistencies continued to exist with respect to procedural quality and adherence. Examples were also observed whereby the control room staff was unnecessarily challenged with maintenance planning efforts (in the control room) rather than having these same planning activities conducted by the work control organization outside the control room. However, the team did observe that overall crew performance was acceptable, and in particular, crew communications were good, indicating that some improvements had been made in this area.

In the area of emergency preparedness, the team determined that the overall program was adequate and provided reasonable assurance that the emergency response organization could respond effectively to an emergency. Additionally, while issues were identified that indicated the need for continued improvement, improvements were noted in a number of areas where performance issues had been previously identified. Notwithstanding, the team observed that the remediation for some of the previously identified performance issues in the technical support center, emergency operations facility, and joint news center had not been fully effective. Examples included weaknesses in technical support center assessment activities and communication, and information dissemination and coordination activities in the emergency operations facility and the joint news center. The team acknowledged that while some corrective actions had been taken in these areas, the training program had not been fully effective in preventing the recurrence of these issues. The team also found minor examples of performance issues associated with implementation of the emergency plan and the associated implementing procedures.

The team integrated these supplemental inspection findings and the results of previous similar efforts to develop the overall root and contributing causes to performance issues at the site. However, this effort was not intended to be a substitute for a more focused root cause study or self-assessment on your part.

The team determined that weaknesses existed with:

- The ability to retrieve, verify, and assure the quality of engineering products, particularly design basis information. These weaknesses contributed to problems in developing and validating calculations, testing methodologies, and acceptance criteria.

- An inconsistent reinforcement of existing management standards with respect to staff performance, particularly in the areas of procedural quality and adherence and in implementation of the corrective action programs. The team concluded that although adequate standards existed, inconsistent application of these standards appeared to cause performance issues to continue in those areas.

- A tendency, in some instances, for the plant staff to accept degraded conditions. This was true for both equipment issues and the quality of technical information. However, the team concluded that improvement has been made in this area.

- Some limitations in the application of resources which led to, for example, staffing issues and training weaknesses.

The team noted that station management identified similar root causes. Further, the team determined that, while a number of program and process issues existed at Indian Point 2 (some of a longstanding nature), some improvements have been made. While progress has been somewhat slow overall and limited in some areas, the business plan appeared to envelope the major performance issues which have been identified, and if executed properly, should result in continued station performance improvements. Previous site improvement plans had shown similar promise, but were not fully effective in improving overall plant performance. The NRC will continue heightened oversight of Indian Point 2 until we gain confidence that the performance improvement program has substantially addressed the performance weaknesses identified in this and previous NRC inspections.

SUMMARY OF FINDINGS

IR 05000247-01-02, on 01/16 - 02/09/2001; Consolidated Edison; Indian Point 2 Nuclear Power Plant. Supplemental Inspection, Multiple Degraded Cornerstones - 95003, Problem Identification and Resolution, Human Performance, Safety Systems, Chemistry, Emergency Preparedness.

The inspection was conducted by Region I, Region II, Region IV regional and resident inspectors and NRC Headquarters and contract personnel. The significance of issues is indicated by their color (green, white, yellow and red) and was determined by the Significance Determination Process (SDP). This inspection identified all green issues.

Cornerstone: Mitigating Systems

The team identified the following issues concerning design control. The four individual findings are being treated as a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." (NCV 2001-002-002)

> **Green.** The design temperature ratings of electrical components in the emergency diesel generator (EDG) building, including ventilation fan thermal overloads, cabling, and control power transfer switches had not been verified. These issues were of very low significance because the as-found thermal overload settings would not have resulted in the loss of ventilation at the maximum building temperatures, the effects of elevated temperature on the cabling voltage drop calculation would have been negligible, and information obtained from the vendor indicated that the control power transfer switch circuitry would have remained functional at the elevated temperature. (Section 2.A.1.b.1)

> **Green.** The results of the EDG loading calculation had not been transmitted to the operations department for inclusion into appropriate operating and test procedures. These issues were of very low safety significance since the ability of the EDGs to provide emergency power was not affected and the procedure issues would not have impacted safe operation of the affected systems. (Section 2.A.1.b.1)

> **Green.** The ability of the service water system to supply adequate flow to all safety-related components based on existing service water low header pressure alarm setpoint and the control room log limits was not supported by engineering calculations. The licensee performed a preliminary analysis and determined that the alarm setpoint of 53 psig was adequate to ensure adequate flows. However, if pressure decreased to the control room log limit of 48 psig the system would not have had sufficient capacity to supply adequate flow to all components. The licensee increased the control room log limit to 58 psig, giving a 5 psig margin to the 53 psig low pressure alarm design limit. This issue was of very low safety significance because there was no indication that the service water system had been operated below a header pressure of 53 psig. (Section 2.A.2.b.3)

Green. Controls were not in place to prevent damage to components in the service water strainer room given an external flood caused by high river water level and a concurrent internal flood due to a potential single failure of a service water pump vacuum breaker valve. The licensee implemented a temporary procedure change to address this issue. This issue was of very low safety significance because it involved the relatively low probability of an internal flooding event coupled with the low probability of an external flooding event. (Section 2.A.2.b.3)

The team identified the following issues concerning the quality and use of procedures. The four individual findings are being treated as a non-cited violation of procedures required by Technical Specification 6.8.1 (NCV 2001-002-003).

Green. Abnormal Operating Instruction (AOI) 27.3.1, “Emergency Fuel Oil Transfer Using the Trailer,” Rev. 0, did not provide adequate instructions for filling the trailer. This issue was of very low safety significance because the use of this procedure has never been required and would require minor changes to resolve the discrepancies. (Section 2.A.2.b.1)

Green. Addendum VI to SAO 100, “Indian Point Station Procedure Policy,” Rev. 3, which describes the process for implementing temporary procedure changes (TPCs), was not followed when alarm response procedure ARP AS-1 (Accident Assessment Panel 1; windows 5-4 and 6-4) was changed with TPC 00-0853. This TPC was implemented because a temporary modification disabled the associated alarm inputs; however, the alarm inputs had already been disabled and the change was not required for immediate operation of the plant. This issue was of very low safety significance because the use of a TPC did not have any actual detrimental affect on plant operations. (Section 2.A.2.b.1)

Green. The reactor coolant loop Delta-Temperature alarm was received during power ascension as a result of having an incorrect setpoint value in calibration procedure. This issue was determined to be of very low safety significance since the instrument does not have any automatic protective function, only an alarm function. (Section 2.A.4.b.1)

Green. Leaving two oil absorbent pads inside the EDG 21 instrumentation cabinet following repairs to a leak did not comply with SAO-701, “Control of Combustibles and Transient Fire Load,” Rev. 8. This issue was of very low safety significance because it did not represent a fire impairment nor a degradation of a fire protection feature or defense in depth issue. (Section 2.A.4.b.1)

The team identified the following other findings concerning design, testing, and maintenance rule issues.

Green. Design bases information was not translated into electrical systems testing and operating procedures acceptance criteria or operating limits. This issue was of very low safety significance because none of the test results or operating data reviews identified instances where equipment was operating outside of its design limits. This failure to include appropriate acceptance in the procedures and drawings to ensure activities have been satisfactorily accomplished is being treated as a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." (NCV 2001-002-004) (Section 2.A.2.b.2)

Green. The plant testing program did not include a verification that the safety-related service water strainer room drain line check valve, MD-500, could open to prevent internal strainer pit flooding. The licensee demonstrated operability by manually cycling the valve from the full open to full closed position and observing that the valve opened with minimal effort and that there was no restriction in movement. . This failure to test a valve by periodically exercising it to its safety function position is being treated as a non-cited violation of 10 CFR 50.55a, "Codes and Standards," paragraph (f), "Inservice Testing Requirements." (Section 2.A.2.b.3) (NCV 2001-002-005)

Green. Corrective actions were not taken to resolve reliability and availability performance issues with the alternate AC power sources, gas turbines (GTs) -1, -2 and -3. The GTs had not been meeting the licensee developed maintenance rule reliability and availability performance goals since 1995. The team did an independent calculation of the change in core damage probability associated with the unavailability of GT-2 for an estimated repair length of 60 days and determined that the risk increase to be within the very low safety significance band (<1E-6). This issue was of very low safety significance because the Technical Specifications relative to GT availability were met. This failure to effectively implement corrective actions to ensure that the established maintenance rule goals would be met is being treated as a non-cited violation of 10 CFR 50.65 (a)(1). (Section 2.A.3.b.1) (NCV 2001-002-006)

Cornerstone: Emergency Preparedness

Green. The team found that the Emergency Response Data System (ERDS) was found inoperable during an exercise in November 2000 and again during a test conducted in the 1st quarter 2001. The NRC conducted an ERDS test during this inspection and found both the system and it's backup to be operable. This issue was determined to be of very low safety significance because the licensee retained capability to communicate via the telephone system. The failure to correct a deficiency identified during a drill/exercise is being treated as a non-cited violation of 10 CFR 50.47(b)(14). (Section 2.D.1.b) (NCV 2001-002-007)

Green. The licensee could not locate Emergency Operations Facility inventory records for the third quarter 2000 nor verify those inventories were actually conducted and a review of available quarterly inventory records identified cases where the records were not properly filled out. This issue was determined to be of very low safety significance because notwithstanding the discrepancies which were identified, the licensee had sufficient resources in the facilities to properly respond to an event. The failure to properly maintain emergency facilities and equipment is being treated as a non-cited violation of 10 CFR 50.47(b)(8) and the licensee's E-Plan, Section 8.3 which states quarterly inventories will be conducted. (Section 2.D.4.b) (NCV 2001-002-008)

Green. The licensee was not able to produce the 3rd quarter records for the operational check of the emergency communications links between facilities and could not verify that the tests had been conducted. This issue was determined to be of very low safety significance because the licensee had installed spare operable telephone lines. The failure to conduct and/or document the performance of quarterly communications tests is being treated as a non-cited violation of 10 CFR 50.54(q) and Section 8.1.3 of the licensee's E-Plan. (Section 2.D.4.b) (NCV 2001-002-009)

Green. The team found that ten individuals assigned to the offsite and onsite monitoring teams had let their respirator qualifications lapse. This issue was determined to be of very low safety significance because there were sufficient responders with respiratory qualifications to fill the positions. The failure to maintain qualifications necessary to maintain proficiency as an emergency responder is being treated as a non-cited violation of 10 CFR 50.54(q) and Section 8.1.2 of the licensee's E-Plan. (Section 2.D.5.b) (NCV 2001-002-010)

Green. The licensee continued to identify exercise deficiencies that are repetitive performance issues and are reflective of past performances, particularly in the area of plant assessment and the dissemination of the information to the general public. The team determined that the training program was not fully effective in preventing recurrence of repetitive exercise issues to ensure consistent emergency response organization performance. This issue was determined to be of very low safety significance because these performance issues did not deal with the risk significant planning standards (classifications, notifications, PARs). The failure to establish an effective training program to train employees and exercising, by periodic drills to ensure that employees maintain the proficiency of their specific emergency response duties, is being treated as a non-cited violation of 10 CFR Part 50.54(q) and Appendix E.IV.F.2.g. (Section 2.D.5.b) (NCV 2001-002-011)

Summary Of Findings

Cross-Cutting Issues: Problem Identification and Resolution

The team identified the following findings which are being treated as a non-cited violation of 10 CFR 50, Appendix B, Criteria XVI, “Corrective Action.” (NCV 2001-002-001)

Green. The licensee failed to identify and correct the cause of repetitive failures of the service water strainers and motor operated service water isolation valve SWN-7. These items were determined to be of very low safety significance because the strainer failures did not have more than a minimal impact on system operability and the valve failures were identified when the valve was out of service for maintenance. (Section 1.A.b)

Green. The licensee failed to initiate condition reports for three failures to meet the acceptance criteria for service water strainer blowdown flow rates during the performance of procedure PT-93 on July 13, 2000. This issue was determined to be of very low safety significance because the operability of the system was not affected. (Section 1.A.b)

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<u>Report Details</u>

1. Review of Licensee Control Systems for Identifying, Assessing, and Correcting Performance Deficiencies

The team evaluated the ability of Consolidated Edison of New York (the licensee) to identify, assess, and correct performance problems within the corrective actions program. The evaluation focused on the programmatic performance of the condition reporting system and on the identification and resolution of plant performance issues.

A. Significant Deficiencies Review

a. Inspection Scope

The team conducted a review of the licensee's condition reporting system and related programs focusing on evaluating the ability to identify, assess, and effectively correct performance deficiencies. The review focused primarily on evaluations and assessments associated with program performance issues and organizational deficiencies. Additionally, the team reviewed licensee actions taken to address identified program performance issues (e.g., the effectiveness reviews conducted for the August 1999 loss of offsite power and reactor trip event). The team reviewed performance aspects associated with the January 2, 2001, turbine trip and other important issues associated with the plant systems and processes described in section 2 of this report.

b. Findings

Program Issues

In most cases, the team found that the licensee's condition reporting system was effective in identifying program performance issues and organizational deficiencies and that the individual site department business plans included the long term corrective actions for the identified performance issues within their respective organizations.

The overall ability to easily access and use the condition reporting system had been previously identified as a performance issue, and the team observed that this problem continued to challenge the plant staff. The quality assurance (QA) organization had attributed the usage problems to inadequate training and an overall lack of familiarity.[1] To address this issue, approximately one-half of the plant employees received training on the system during 2000. However, the team concluded that implementation of this corrective action was slow, because a previous condition report (CR) [2] had been initiated to document this same knowledge weakness in November 1999.

[1] These conclusions were documented in condition report (CR) 200000994.

[2] CR 199908802

Additionally, the team observed that the condition reporting system exhibited several computer based weaknesses. As examples, on several occasions during the inspection, the system was unavailable due to plant computer problems and the program made it difficult to track the status of corrective actions. The licensee had recognized these deficiencies and included an initiative in the 2001 business plan to purchase new condition reporting system software.

Line management ownership of the corrective action program had also been previously identified as an important performance issue and the team found that challenges continued to exist in this area. The team noted that the licensee had implemented measures to improve accountability (i.e., an improved metrics report, condition report quality reviews, and quarterly departmental reviews) but more improvement was needed to assist in managing and reducing the backlog and provide more effective condition report responses. Line management ownership of the program was expected to become even more important because the proposed revision 4 (Rev. 4) to the corrective action program procedure[3] would result in a significant increase in the backlog since individual items would not be closed until their associated work orders were completed. The team noted that the 2001 business plan addressed insufficient line management ownership as one of the most significant contributing causes for corrective action program problems.

The licensee's ability to trend condition reporting causal factors continued to be a challenge. This item had been identified by the NRC as an issue in 1998, and more recently in the 2000 problem identification and resolution inspection. To address this longstanding issue, the corrective action group had recently begun assigning causal factors to condition reports because prior efforts by the line organizations to perform this function had not been successful. The licensee indicated that the complicated nature of the condition reporting system software and unfamiliarity of the program by the plant staff were the primary reasons for this continuing deficiency. The licensee had initiated measures to address this issue by evaluating a less complicated software and assigning a specific individual for assigning causal factors. Additionally, plans to improve this deficiency were included in the licensee's 2001 business plan. The team determined that the inability to trend causal factors was a weakness of a longstanding nature and one for which there had been little measurable progress.

The licensee continued to face challenges in the area of condition report response effectiveness. The licensee had initiated a number of condition reports (as a result of audits and self-assessments in this area) which pointed out various problems related to this issue. For example, CR 200003865 identified that the extent-of-condition assessments were better developed for significance level (SL) 3 CRs when compared to the more significant SL1 and SL2 CRs.[4] Additionally, with respect to the quality and effectiveness of corrective actions, several deficiencies were identified. For example, CR 200004854 identified that several SL2 CRs did not meet management expectations for quality, primarily due to insufficient line management ownership for corrective action

[3] Station Administrative Order (SAO)-112 Corrective Action Program, Rev. 4

[4] The licensee's system assigned a significance level to each CR, with SL3 having the lowest significance and SL1 having the highest.

evaluations. As a result, the licensee required that all SL2 CRs receive a quality review by the Corrective Action Review Board (CARB). However, the team observed that the CARB's review of at least one SL1 CR was of mixed quality. Specifically, one CARB member was not fully aware of all the key elements to be considered during the review. Another member expressed concern that if the board assigned lower quality scores, then that would require the SL1 report to be revised. The team was concerned that this attitude indicated a potential hesitancy to score CR quality responses low to avoid required revisions. Additionally, the quality review process observed by the team was informal and lacked critical assessment on some issues.

The team noted that the licensee's effectiveness reviews continued to indicate difficulties with the corrective actions taken to address problems identified following the August 1999 loss of offsite power and reactor trip event. The licensee used outside contractors to conduct several independent assessments such as a review of common cause trends in the condition reporting system, a review of the closure of condition reports, and a review of corrective action effectiveness for actions taken following the event. These reviews were self-critical and provided valuable information with respect to improving plant performance. However, these reviews also identified areas where previous corrective actions have not been fully effective.

<u>Implementation Issues</u>

In the review of the implementation of the corrective action program, the team identified a number of issues related to weaknesses in implementing effective corrective actions and in identifying repetitive failures of certain plant components. Additionally, several examples were identified where condition reports were not promptly initiated for plant and equipment deficiencies.

For example, the team discovered instances of repeated equipment failures that were not identified in the condition reporting system. While the issues were individually raised in separate condition reports that were subsequently closed to work orders, the repetitive nature of the failures were not questioned relative to the adequacy of previous corrective actions. Examples included:

- Repetitive service water strainer failures were identified through the review of maintenance activities performed since early 1998. The strainers had failures caused by issues such as: tripping overloads, binding, and a damaged arm shaft.[5] As part of an effort to address the unavailability caused by the failures in December 1998, the licensee added a preventive maintenance work scope that involved a periodic overhaul or replacement of a strainer with a rebuilt internals package every six months. However, additional failures subsequently occurred, caused by issues such as binding, tripping, and high differential pressure. There was no indication that the problems were being pursued as repetitive failures to

[5] CRs 199905026, 199902815 and 199902586, respectively

ascertain their root causes or to perform broader corrective actions to preclude repetition. This issue was determined to be of very low significance (Green) because each failure had a minimal impact on system operability.

- Repeated failures of service water valve 7 (SWN-7) were identified during a review of condition reports. SWN-7 is the isolation valve for the service water supply to turbine building loads and provides a barrier between the essential and non-essential loads. CR 200002700, written in April 2000, identified that the sector gear on the operator for SWN-7 required replacement and was closed out to a work order to complete the repair. On May 1, 2000, CR 200003085 was written to clarify that this was the second failure of this valve due to a damaged sector gear. This CR also noted that the worm gear on the valve operator was damaged, and had not been repaired even though the licensee attempted to return the valve to service. Although this worm gear had been determined to be damaged, the condition report identified that a new worm gear was on order and as of May 2000 had not been received. The team questioned why post maintenance testing had been attempted on the valve while it still contained damaged components and why this issue had not been raised by any of the condition reports in the system. After reviewing the condition reports and work orders involved with this issue, the licensee agreed that the condition reports had been inappropriately closed without an engineering evaluation to address the repetitive failure. This issue was determined to be of very low significance (Green) because the deficiency had been discovered when the valve was out of service for preventive maintenance and had not been returned to service.

Contrary to 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” the licensee failed to take adequate measures to properly identify and correct several instances of repeated failures and degradation of the service water strainers and valve SWN-7. As a result the licensee failed to determine the root causes and to take appropriate corrective action to preclude repetition of these issues. This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). The two specific issues were entered into the corrective action program as CRs 200101388 and 200101125 **(NCV 05000247/2001-002-001)**.

The team also identified several examples where the licensee failed to promptly issue a CR upon the discovery of an adverse condition or deficiency. For example, during the performance of PT-R93, “Essential Service Water Header Flow Balance,” in July 2000, the team identified three cases where the as-found service water strainer blowdown flows exceeded the 215-235 gpm acceptance criterion, and no condition report had been generated as required by the corrective action program.[6] The affected strainers were: pump 21 strainer (277 gpm as-found flow), pump 23 strainer (305 gpm as-found flow), and pump 26 strainer (254 gpm as-found flow). It was also noted that the procedure required blowdown flows to be adjusted to within the acceptable range prior to obtaining

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[6] SAO-112, Rev. 3

the as-found flows for the remaining components. Even though the remaining components' as-found flows might be acceptable, this premature adjustment of blowdown flows had the potential to mask unacceptable flows to the other loads.

It was estimated that, before the adjustments, flow to the other loads were approximately 1.15% lower than recorded. This would have resulted in only one of the other components, a containment fan cooler unit, to have flows less than its acceptance criterion. The fan cooler's flow would have been 10 gpm below the 1,740 gpm acceptance criterion. However, since the actual required flow for operability was 1,600 gpm, it would have still been able to perform its safety function.

The licensee failed to generate CRs for three failures to meet the acceptance criteria for service water strainer blowdown rates in procedure PT-R93 on July 13, 2000. This issue was determined to be of very low significance (Green) because the operability of the system was not affected. This issue is considered an additional example of the non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions." This issue was entered into the corrective action program as CR 200100568 **(NCV 05000247/2001-002-001)**.

The team identified other examples, of a more minor nature, of the failure to initiate required CRs. Although, each of these issues warranted correction, none presented an operability concern and were therefore considered to be minor violations of regulatory requirements, not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. Representative examples included:

- The licensee failed to initiate condition reports for instrumentation and control preventive maintenance procedures 1775-1 and 1778-1 when the alarms could not be verified (as required by the procedure) due to tagout 98-10993 which removed dc control power. Also, the licensee was slow to initiate condition reports after the team identified this on January 18, 2001. CRs 200101467 and 200101468 were written, but not until February 8, 2001.

- During the walkdown of the service water pump intake bay, the team identified several issues that did not meet foreign material exclusion requirements. The conditions involved: (1) the presence of spalling concrete, (2) peeling epoxy coating on SW piping, (3) a 3/4 inch carbon steel nut in the service water strainer pit drain valve MD-501, and (4) degraded valve assembly nuts on the drain valve. The spalling condition had been previously identified in CR 199808290, but there was little evidence of any meaningful corrective action beyond installing a tarp in the area. Following the team's identification of these issues, the licensee generated CRs 200101433, 200101464, and 200101431 to address these conditions.

- During a walkdown of the service water system, the team noted several conditions that demonstrated a lack of attention to detail by maintenance personnel. Specifically, instances of the use of fasteners fabricated from dissimilar materials, inconsistent use of washers in bolted arrangements, improper nut thread engagement, and physical differences between the fasteners used on similar equipment. The licensee issued CRs 200100565, 200100560, and 200100510 to address these issues.

- During a review of the Temporary Facility Change (TFC) process, the team noted that the licensee failed to conduct the quarterly review of TFCs for the fourth quarter of 2000 as required by station procedures.[7] The purpose of this review is for the Generation Support Manager to determine the compliance of each individual change with respect to the procedure requirements and to determine whether individual open TFCs should remain in effect. The team considered this to be a minor violation of administrative controls. The licensee initiated CR 200101456 to address this issue.

- During the review of the 480 Vac Design Basis Document (DBD), the team found that only 2 of 101 open items had been entered into the corrective action program for resolution. The remaining 99 open items contained conditions such as missing or unapproved calculations and specifications. In response, the licensee grouped the 99 items into 13 general categories and generated a separate condition report for each category.

Additionally, the team identified a weakness in documentation and in initial efforts to establish root and contributing causes of the January 2, 2001, turbine trip. In CR 200100048 the licensee indicated that a contributing cause for the event was an off-normal system line-up leading to the operator having to start a second condensate pump to address a lower that normal feed pump suction pressure. Additionally, the report described untimely actions by a reactor operator which caused overfeeding of the steam generators and an associated steam generator high level turbine trip. However, in the resolution of the CR, there were no specific corrective actions to address the root and the contributing causes. The licensee noted in the interim action section of the report, that the operations manager was completing crew briefings on the event and that procedures were to be changed. However, the CR did not address any potential operator knowledge deficiencies in the operation of the condensate and feed system. After significant interaction with NRC staff, ConEd ultimately developed a reasonably comprehensive assessment of the event and took additional corrective actions.

B. Quality Assurance, External Audits, and Self-Assessments Review

a. Inspection Scope

The team reviewed selected audits and assessments performed by the line organizations, the quality assurance group, and external sources to determine whether the licensee had demonstrated the capability to identify performance issues before they resulted in undesired consequences. The team evaluated management support of these assessments and also evaluated the effectiveness of management systems to process and act upon identified performance issues.

[7] SAO-206, "Temporary Facility Changes," Rev. 20, section 6.1

b. Findings

In general, the audits and self-assessments reviewed by the team were well conducted and provided sufficient detail and recommendations for improvement. Also, the corrective actions taken were generally effective. The condition reporting system was used to identify and track the closure of issues from the audits and self-assessments. Some examples of effective self-assessment activities included the following:

- Audit 00-09-C, “Corrective Action - 1st Half 2000," dated September 28, 2000, was thorough and self-critical in identifying areas of needed corrective action program improvements. These improvements included a revision to the program procedure, enhanced metrics for timeliness and quality of condition report responses, and improved training for new employees. The team reviewed the condition reports for the significant audit findings and determined that the licensee’s response to the performance deficiencies was acceptable. The team noted that continued efforts for further improvements in these areas was also included in the corrective action program 2001 business plan.

- The team reviewed several audits and condition reports associated with plant procedures. In particular, Quality Assurance Audits 98-08-L (January 5, 1999) and 00-08-A, (February 2001) assessed station instructions, procedures and drawing control. The team determined that the audits and associated condition reports were of good quality and provided the proper emphasis on station improvement.

- The system engineering self-assessment on engineering work control interface completed in February 1999 identified weaknesses.[8] The team reviewed the completed corrective actions for these condition reports and interviewed several system engineers and work week managers with respect to the findings. The team determined that the corrective actions were adequate.

Notwithstanding these positive observations, the team identified a number of performance weaknesses in the self-assessment program. The following examples are representative:

- The quality assurance (QA) department self-assessment of the audit program dated March 6, 1999, contained no substantive assessment of QA’s ability to evaluate plant problems and effectively communicate those problems to plant management. The purpose of the assessment was to evaluate the audit program against industry practices and identify areas for improvement. However, the assessment primarily focused on elements such as training, staffing, audit report detail, procedures, and office space.

[8] CR 199902791 and CR 199902792

- QA's 2000 self-assessment dated September 14, 2000, concluded that the organization's program elements were not adequate for effectively promoting performance-based continuous improvement. The assessment identified that plant risk assessment data needed to be more effectively used in the audit process. The assessment also identified that individual auditor training plans needed to be developed to provide better technical skills. These were good findings. However, the training matrix developed to address the assessment's findings did not include plant risk training. The team considered that not including risk training in the matrix was a weakness with respect to the ability to integrate priority assessment results into effective corrective actions. The team noted that continued efforts for further improvements were included in the 2001 business plan.

- The primary purpose of the engineering third party self-assessment issued on August 14, 2000, was to review the quality of engineering output documents. However, the assessment did not document any reviews of actual engineering calculations or other output documents. The team also reviewed another assessment,[9] and found it had covered numerous engineering work product areas. The discussions provided appeared to be self-critical and constructive and represented meaningful assessments.

- It was recognized in the February 2001 audit of "Plant Operations and Operations Performance, Training, and Qualification," that the corrective actions associated with a similar audit in January 1999 had not been fully effective. Specifically, several issues associated with procedure quality and adherence were identified, but the subsequent effectiveness review concluded that the station still had problems with procedural compliance and accountability. As a result of this issue, the licensee issued CR 200005446.

C. <u>Work Authorization and Allocation of Resources Process</u>

a. <u>Inspection Scope</u>

The team reviewed the corrective action and maintenance backlogs for the systems selected for detailed review to assess the extent of the backlog and determine if there was open work which would prevent the systems from performing their safety functions and reviewed the prioritization and timeliness of corrective action program items. For the systems selected for review by the team, there were a total of approximately 40 open requests for engineering services and modifications.

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[9] IP2 Engineering Document Quality Review, January 5, 2001

b. Findings

Backlog Review

The team found that the overall backlog of open CRs and work orders had increased, however there had been some improvement in the timeliness of completing condition report evaluations.

The total number of open corrective maintenance work orders for all plant systems was reported by the licensee to be approximately 875 at the end of the inspection and had gradually increased over the past several months. The number of temporary facility changes and control room deficiencies had trended upward and continued to exceed the plant goals. A recent reduction in the number of operator work-arounds had been achieved but the number had also continued to exceed the plant goal.

With respect to the maintenance backlog in the service water, 480 Vac, and emergency diesel generator (EDG) systems the team did not identify any open issues that appeared to challenge the functionality of the system. There were no overdue preventive maintenance work orders for the service water system. However, six were overdue for the 480 Vac and emergency diesel generator systems; none appeared to have a potential effect on equipment operability.

The team also noted that some open work items had not been accurately captured in the accounting for the backlog. Examples of this included approximately 99 open items from the recently completed design basis review of the 480 Vac system, a significant number of issues related to the instrumentation and control preventive maintenance program, and a large number of procedure changes associated with the "communications to staff" program. These observations indicated that the actual plant work backlog was somewhat larger than previously believed.

The team observed that the licensee continued to face challenges with respect to the use of plant risk information for condition report and corrective action prioritization. This had been identified in the recent NRC problem identification and resolution inspection, as well as in other previous NRC inspections and licensee self-assessments. The team concluded that this was another example of a longstanding weakness in the corrective action program and one for which limited progress had been achieved.

Finally, the team observed that the licensee's average time to close corrective actions was significantly outside station goals. The average as of the January 2001 data was approximately 256 days (i.e., time from identification to problem correction). The station goal for this metric, which was based on industry bench marking data, was in the 90 - 180 day range. It was noted that the configuration management and controls backlog appeared to the leading contributor to driving the average in the upward direction with a 560 day closure time as of the January 2001 data.

D. Review of Station Performance Goals and Strategic Plans

a. Inspection Scope

The team evaluated the licensee's performance goals to assess whether these goals and associated strategic plans were aligned with the actions needed to correct the known performance issues at Indian Point 2. The team conducted numerous management and plant staff interviews and specifically reviewed the departmental business plans for the following organizations: corrective action program, configuration management, work management, emergency planning, operator training, engineering, operations, and maintenance.

b. Findings

Performance Goals

The team reviewed the 2001 business plan for the site organizations as noted above. It was determined that the business planning process had adequately provided for the integration of efforts and provided an appropriate allowance for resources and associated funding. However, it was also noted that the details provided in the individual department plans varied significantly. Several of the plans lacked proposed completion dates for certain items and others were somewhat general in the description of areas of needed improvement. Some representative examples of individual department business plan observations are listed below.

- Several weakness in the documentation associated with the configuration management and control business plan were noted. For example, several business plan items associated with Technical Specification setpoint calculation issues contained question marks as place holders. Additionally, items related to staff training in the updated final safety analysis report, licensing basis and design basis documents contained provisions for funding, yet did not contain justification or support for station organizational goals. A similar example existed with a business plan goal associated with "Operating Equipment Staff Augmentation." The business plan listed the next seven design basis documents to be updated in the continuing design basis document upgrade project. The team noted that two of the systems, main steam and the emergency diesel generators were scheduled to have been started on October 1, 2000, but no current status appeared in the plan. Interviews with plant staff indicated that the projects had not yet been started.

- The maintenance department business plan was detailed and comprehensive. Major improvement areas were identified and included the maintenance backlog reduction plan, the work control process improvement plan, and instrumentation and control preventive maintenance program upgrade plan. The team noted that, with a few minor exceptions, the plan identified managers responsible for required actions, along with expected completion dates.

- The corrective actions program business plan was not fully developed and none of the plan's initiatives had schedule dates for completion. Additionally, the plan did not specifically address the resources required to complete the planned initiatives. The team also noted instances whereby items were closed prematurely. However, the team noted that even though the approved plan was not fully developed, the plan's major elements appeared to address needed improvement areas such as human error reduction, operating experience, trending, and line management ownership for corrective actions.

- The operations training business plan contained proposed budgets, staffing, and schedules for completing major department initiatives. Additionally, it was noted that effectiveness reviews of major actions taken were scheduled for later in 2001. The plan contained initiatives associated with major areas of operator knowledge weaknesses and referenced performance improvement programs established to improve the skills, knowledge, and abilities of licensed operators.

- The design and site engineering business plans included appropriate areas for improving engineering processes, design bases documentation, and equipment reliability. Backlog reduction efforts were also included in the plans. However, specific project details and schedules were not included within the business plans.

Management Interviews

The team conducted extensive interviews of licensee managers throughout the organization including the chief nuclear officer, site vice presidents, and many department managers. The management consensus was that the current plant performance problems started as experienced staff began to leave site in the early 1990s. This, combined with a lack of infrastructure improvements, and a successful extended plant run in 1996 led to an organization that lost a significant portion of its knowledge base, did not seek out external perspectives, and did not recognize the need for continued improvement due to demonstrated high capacity generation.

The team concluded that the station management was in general agreement with respect to the performance problems which existed at the site and in the areas requiring improvement. Additionally, the station management was in almost unanimous agreement in the belief that the 2000 business plan was a success and had allowed for focus on areas for improvement and in planning for and obtaining needed resources to complete the required tasks. The managers also believed that the 2001 business plan provided an adequate scope and method of documenting needed areas of future improvement along with the resources to accomplish the activities. Several managers indicated that the use of an approved, resource-loaded business plan was the first time that the organization had such a detailed plan for which they had been held accountable.

E. Employee Concerns Program Review

a. Inspection Scope

The team performed a review of the licensee's employee concerns program (ECP), also known as the Ombudsman Program. This review focused on the adequacy and responsiveness to employee concerns and included an assessment as to whether a safety conscious work environment existed at the facility. The team interviewed numerous personnel at various levels of the organization and reviewed the program files and documentation associated with the program. The team also reviewed a self-assessment of the Ombudsman Program to evaluate whether appropriate action was taken for deficiencies which had been identified.

b. Findings

The team noted that the ECP appeared to provide an acceptable means for employees to raise safety concerns to management without fear of retaliation. In addition, the licensee's condition reporting system allowed employees to raise safety issues anonymously and was viewed as an alternate process to the ECP. The team did note that the number of anonymous CRs initiated could be an indication that some employees were reluctant to identify themselves with concerns raised. In most cases, the team found the licensee's response to employee concerns was acceptable and interviews with site employees indicated that a safety conscious work environment existed at the facility.

Notwithstanding the overall adequacy of the program, the team identified several minor deficiencies. It was determined that the ECP procedure, SAO-123, "Employee Concerns Program," Rev. 10, lacked specificity with respect to several important program elements. These elements included (1) how employees access the ECP, (2) methods for employees to report safety concerns, (3) program assurance of maintaining employee confidentiality, and (4) measures to protect employees against retaliation. The team reviewed other aspects of the program such as general employee training information, bulletin board information about the program, and posted information at drop boxes where employees submit concerns. As a result of this finding, the responsible manager, otherwise known as the Ombudsman, initiated CR 200100619 to correct the deficiency. The team determined that, even though the governing procedure lacked the desired specificity, sufficient information regarding these program elements were included in the program.

The team reviewed the 2001 business plan for the ECP and found that it provided the expected degree of specificity for program improvements. In particular, the team noted that more detailed training for managers and other plant personnel was scheduled for 2001. Also, the plan included initiatives for updating the program procedure, preparations for the annual self-assessment, documentation improvements, and program improvements for the classification and tracking of concerns.

F. Operating Experience Review Program

a. Inspection Scope

The team conducted a review of the operating experience review program to determine if appropriate actions were taken to address potential plant problems identified as a result of industry operating experience. The team reviewed the licensee's governing operating experience review procedure, program assessments, and backlog of open items. Interviews were conducted with program personnel as well as the line organizations. The team also reviewed selected 10 CFR Part 21 reports and NRC Information Notices from 1998 thru 2000 to determine if the program had adequately assessed the issues for applicability at the site.

b. Findings

Previous NRC inspection efforts as well as licensee assessments had identified weaknesses in the licensee's operating experience review program. The team determined that while some limited progress had been made, primarily in the area of industry bench marking and outreach efforts, that weaknesses continued to exist in the program. The team observed that some progress had been made by the advent of enhanced electronic access and by increased resource allocation. However, the overall implementation of the program, particularly by the line organizations, continued to be a problem. Additionally, the team determined that while there had been progress in the reduction of the backlog associated with operating experience items, continued emphasis was needed. The following observations are representative of the team's findings with respect to the program:

- Surveillance Report 99-SR-040, "Operating Experience Review," dated November 11-18, 1999, was performed by the site quality assurance organization. The team determined that the audit was self-critical and identified several needed program improvements. The audit concluded that plant personnel did not effectively use operating experience. The team reviewed the results and found that no action had been taken on the audit findings until June 2000. The team concluded that based on the significant programmatic nature of the findings that the licensee's response was untimely. However, the team verified that the corrective actions were eventually included in the corrective action program 2000 business plan and were completed by the end of the year.

- The team reviewed the licensee's self-assessment, "Operating Experience Peer Evaluation," dated September 5-7, 2000. The assessment concluded that the program needed improvement in that the "observed performance did not indicate an active program or that individuals were sufficiently engaged with respect to the usage of operating experience." The team reviewed a number of condition reports that were initiated as a result of the assessment. For example, CR 200006619 was initiated to address operating experience training because as the assessment stated "station personnel are passive with respect to obtaining operating experience information in support of their day-to-day activities." However, the corrective actions did not address the need to train personnel on the value of operating experience as it relates to their daily work, but established a focus group with departmental points of contact. The team determined that no site wide training had been provided on operating experience and none had been provided for specific target audiences such as engineering, operations and maintenance personnel.

- The team reviewed nine selected operating experience review evaluations. Of the nine which were reviewed, the team found thoroughness issues with four of the evaluations. For example, CR 200009927 evaluated a 10 CFR Part 21 notification of a defective Foxboro relay module. The licensee verified that the defective relay was not installed in the plant but failed to place an in-stock spare on administrative hold until verification that the spare relay was not defective. The reviewer had intended to place the spare relay on hold and communicated this intent by e-mail versus using the condition reporting system for tracking the action. Subsequently, the individual did not follow through with his intentions and the verification was not performed until the inspection team discovered the problem. The spare relay was later checked and found to be satisfactory. The licensee initiated CR 200100904 to address this problem. An additional example of an inadequate response to an operating experience review item involved the failure to evaluate a residual heat removal system operating procedure. Specifically, CR 200004907 evaluated an industry notification which addressed the need to evaluate the system fill and vent procedure for certain specific problems described in the notification. The individual who performed the review misunderstood the process and failed to initiate a corrective action item or communication to staff item, consequently no procedure review was performed. The licensee initiated CR 200100894 for this problem.

- The team noted problems in the timeliness associated with completing operating experience reviews and corrective actions. For example, the evaluation for CR 199802561 took two years to complete. This item concerned NRC Information Notice 95-52 Supplement 1 which was related to fire protective systems. Interviews indicated that the delays in addressing this issue were related to resource limitations. Another example involved CR 199810884 which took 17 months in order to complete the needed corrective actions. This item was related to pipe weld failures in the chemical volume and control system that had occurred in the industry. The corrective action involved a radiograph of the suspect flow orifice in the piping to determine if cavitation damage had occurred.

- The team attended a CARB meeting on February 8, 2001. The meeting focus was to approve a SL1 condition report regarding the failure to maintain containment integrity calculations provided by a vendor. The presenter failed to address operating experience in the report, however, this shortcoming was identified by the board co-chair.

- The team reviewed the backlog of operating experience review items. In January 2001 the total backlog of open items was 133 with 38 items being overdue. The team noted that the backlog had gradually decreased from 366 in October 1999. A significant reduction in the backlog had occurred in June 2000 when the backlog decreased from 205 to 118. The licensee attributed this reduction to an increase in resources in the this area. The team concluded that progress had been made in the operating experience review backlog but continued emphasis was warranted in this area.

G. Supplemental Inspection - Emergency AC Power Unavailability, >2EDG Performance Indicator

a. Inspection Scope

The Indian Point 2 performance indicator (PI) for “Emergency AC Power Unavailability, >2EDG” exceeded 2.5% (white band) starting in the 2nd quarter of 1999. The AC power system availability declined due to the failure of the 23 emergency diesel generator (EDG) to operate on demand during the reactor trip event with complications on August 31, 1999. EDG 23 failed because the overcurrent trip device (amptector) on its supply breaker to emergency bus 6A had been improperly calibrated. The improperly calibrated amptector added 1444 hours of unavailability and increased the fault exposure hours in the calculated PI for EDG 23.

The NRC review of the performance of the emergency AC power supplies during the August 31, 1999, event was previously described in NRC Augmented Inspection Report 05000247/1999-08, Followup to the Augmented Inspection Team Report 05000247/1999-013, and the Enforcement Followup Inspection to the Augmented Inspection Team Report 05000247/1999-014. The corrective actions related to testing of the safety related breakers and other issues were described in a licensee letter to the NRC dated June 5, 2000.

b. Findings

During these reviews, the NRC verified that the licensee’s evaluations provided assurance that the root and contributing causes for the EDG failure were understood, that the extent of condition on other safety-related breakers was identified, and that corrective actions to correct weaknesses in the calibration of overcurrent devices were sufficient to address the causes for the event and to preclude recurrence. As such, the NRC removed this issue from consideration in future Agency actions, per the Action Matrix, in accordance with the guidance in Inspection Manual Chapter 0305, “Operating Reactor Assessment Program.”

H. Conclusions Associated with Licensee Control Systems for Identifying, Assessing, and Correcting Performance Deficiencies

The team determined that the overall program for problem identification and resolution was adequate. It was noted that some improvements had been made, in particular, an increased emphasis on problem identification and an improved metrics and tracking system for corrective actions program issues. However, the team identified several continuing challenges to the program. In particular, it was observed that the effectiveness of some of the corrective actions for previously identified deficiencies was of somewhat mixed quality. Additionally, significant challenges existed with respect to the timeliness of corrective actions and longstanding issues remained with respect to prioritizing issues for resolution and in trending causal factors. Further, the backlog associated with open corrective actions presented an ongoing challenge to the station. Finally, as noted in previous assessments, weaknesses continued to exist in the operating experience review program, although some improvements had been made in this area. While performance difficulties continued to exist with respect to the review and disposition of technical issues, the site has made considerable progress in areas related to industry outreach and bench-marking efforts.

2. Assessment of Performance in the Reactor Safety Strategic Performance Area

A. Emergency Diesel Generator, 480 Vac and Service Water Systems

1. System Design

a. Inspection Scope

The team selected the emergency diesel generator (EDG), 480 Vac and service water systems for detailed reviews. The selection was based on these systems' importance to overall plant risk and also due to the fact that these systems had not received recent, in-depth reviews by either the NRC or the licensee. The team reviewed licensing and design basis documents for these systems, including the Updated Final Safety Analysis Report (UFSAR), calculations, engineering analyses, and system descriptions (when available) to determine the functional requirements of the systems for normal, abnormal and accident operating conditions. The team reviewed a sample of risk significant plant modifications for the selected systems, including those that involved vendor supplied products and services to verify that the design changes did not negatively impact the ability of the systems to perform their design bases functions and that the changes would not cause initiating events. During this review, the team evaluated the effectiveness of the licensee in controlling design and licensing information, in providing necessary calculations to support plant changes and in developing and implementing thorough post-modification testing. The team assessed the adequacy of the licensee in evaluating applicable system and support system design attributes and regulatory requirements. The team also reviewed system modifications to ensure that original design and accident analyses assumptions were not invalidated by the changes. Additionally, the team reviewed the modifications to confirm that the licensee had properly evaluated any required changes or additions to plant procedures.

The team conducted general walkdowns of the systems. Also, recent changes to plant maintenance and operating procedures were also reviewed to ensure that they did not result in inadvertent design changes to the systems. For procedures that involved design changes, the team verified that the change was subjected to the appropriate design change processes, including review in accordance with 10 CFR 50.59, "Changes, Tests, and Experiments."

The team assessed the adequacy of communications between the site departments during the performance of design related activities such as the updating of training programs, updates of design related materials and the performance of operability evaluations. The team verified that the appropriate departments were involved in the evaluation and concurrence process for the approval of activities that included non-routine maintenance, temporary modifications, and field change requests. The team also assessed the adequacy of the licensee's control of vendor supplied services and products, including the process for communicating identified deficiencies to the vendor.

Finally, the team reviewed a sample of condition reports to assess the effectiveness of corrective actions for deficiencies involving design activities.

b. Findings

b.1 480 Vac and Emergency Diesel Generator System

The 480 Vac system provides power to safety and non-safety related equipment. The safety-related equipment is powered by a four bus, three train arrangement normally supplied from off-site power through the 6.9 kV buses. Upon loss of the normal off-site supply, the safety-related buses are powered from three emergency diesel generators. An alternate source of power to the buses is also available from three gas turbine generators that connect to the electrical system at the 13.8 kV level. The 480 Vac system is supported by the 125 Vdc system for switchgear and EDG control power and the 118 Vac system provides power for the safety injection initiation instrumentation.

The team reviewed the important design control aspects of the 480Vac and emergency diesel generator system. A number of performance issues and weaknesses were identified. The following observations are representative of the issues identified by the team.

EDG Building Ventilation System

The team reviewed the ventilation system for the three site EDGs. The EDGs occupy a common building. Calculation GMH-00006-00 determined the maximum building temperature under worst case conditions, assuming three of the six EDG building exhaust fans were unavailable, to be 126°F. In response to the team's questions on the capability of the electrical equipment in the building to operate at the maximum calculated building temperature, the licensee found that the control power auto-transfer switches for the diesels had not been qualified for the maximum building temperature.

The team also reviewed the settings of the thermal overload devices for the ventilation exhaust fan motors and found that the thermal overload ambient compensation had not been designed for the maximum building temperature. As a result, the trip point required derating for the higher temperature. The team also noted that the thermal overload calculation was based on a different device than what was actually installed in the circuits and did not account for the manufacturing tolerance which the team later found to be ± 20%. The team also observed that the thermal overloads were not periodically checked as part of the preventive maintenance program. In addition, the team found that the voltage drop calculation for the exhaust fan power circuits did not consider the maximum possible building temperature.

The above errors were a result of the licensee failing to confirm the adequacy of these components in a maximum ambient temperature of 126°F, which was 22°F above their nominal rating of 104°F. The licensee performed calculation FCX-00421-00 and determined that there was no immediate operability concern since, with two fans operating the building temperature would not exceed 104°F with an outside temperature up to 73°F.

The licensee subsequently revised the thermal overload calculation using derating factors obtained from the manufacturer for the higher room temperatures. The calculation indicated that the specified dial setting of 9 would have been satisfactory because the original setting included a 15% margin for the motor service factor. However, the calculation also concluded that a dial setting of 10 would be implemented to provide additional margin to the trip point. The team later found that the licensee had not verified the as-built settings of the overloads prior to revising the calculation and a field verification determined that five of the six fans were set at a dial setting of approximately 8.66 and the sixth fan, added by modification CPC-91-06847-H, was set at a dial setting of 9.0. The licensee reviewed the operability of the fans for the setting of 8.66 and concluded that there was sufficient margin to prevent tripping at an ambient temperature of 126°F.

The team determined these issues to be of very low significance (Green) because the as-found thermal overload settings would not have resulted in the loss of ventilation at the maximum building temperatures, the effects of elevated temperature on the voltage drop calculation would have been negligible and information obtained from the vendor indicated that the control power transfer switch power circuitry would have remained functional at the elevated temperature.

The team considered the failure to verify the adequacy of the design temperature ratings of components in the EDG building to be a violation of 10 CFR Part 50, Appendix B, Criterion III," Design Control." This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). These issues were entered into the corrective action program as CRs 200100780, 200101447, 200101852 and 200102336 **(NCV 05000247/2001-002-002)**.

<u>EDG Manual Load Control</u>

The team reviewed the EDG loading calculation, FEX 000148-00, and observed that the sizing of the diesels was acceptable, but that little design margin was available when the required design basis assumptions were applied. The team also found that some of the assumptions and conclusions of the calculation regarding operator actions had not been formally transmitted to operations procedures.

The team reviewed the assumptions for frequency tolerance and individual motor load data.[10] The EDG vendor instruction manual, (VIM)-2351, included a section on setpoints which indicated a frequency tolerance of +/- 0.5 % which was included in the loading calculation. However, the team found that the surveillance tests for the EDGs either failed to include an acceptance criterion for frequency (Procedure PT-R14) or contained an acceptance criterion different than that assumed in the EDG loading calculation (Procedures PT-M21 and PT-R84).

The calculation also contained an assumption that the auxiliary feedwater pump flow would be throttled by operators during the accident (versus in a runout condition) prior to the transition to the recirculation phase following a loss-of-coolant accident (LOCA). However, that assumption had not been formally transmitted to operations for inclusion in plant procedures. The team also found that the emergency operating procedures (EOPs) had been recently updated to include revised motor loads but the update failed to include the correct loading values from the EDG load calculation. In many cases, the errors observed were non-conservative.

The team determined these issues were of very low safety significance (Green) because the ability of the EDGs to provide emergency power was not affected and the procedure issues would not have impacted safe operation of the affected systems.

The failure of the licensee to translate the design requirements for EDG loading into appropriate procedures and instructions is considered an additional example of the non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." These issues have been entered into the corrective action program as CRs 200100777, 200100599, and 200100943 **(NCV 05000247/2001-002-002)**.

Alternate AC Power Source Voltage

The team reviewed the capability of the gas turbine (GT) generators to power the safety-related shutdown loads. The licensee was unable to locate a voltage drop calculation to demonstrate that adequate voltage could be supplied to the required loads. Subsequently, the licensee performed an evaluation to address this issue. The team reviewed this evaluation and found that the licensee failed to confirm the actual tap setting of the 13.8 kV to 6.9 kV transformer which connects the alternate AC source to the plant. This resulted in a non-conservative input to the evaluation. The team also noted the evaluation was performed for GT-1 which is located on site and did not initially evaluate the voltage available from GT-2 or GT-3 which are located offsite and may have been more limiting due to voltage drop considerations.

The team determined this issue did not have a credible impact on safety because the load assumed in the evaluation was significantly higher than actual expected safety bus loads. Even with this resultant voltage drop, sufficient voltage would be available to power the safety-related loads. Although this issue should be corrected, it constitutes a

[10] Frequency affects motor speed for the driven loads; a higher frequency results in additional load to the EDGs

violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue was entered into the corrective action program as CR 200101298.

480 Vac Load Ampacity Calculations

The team reviewed the ampacity rating for selected 480 Vac feeders, including the feeds to the 480 Vac switchgear and the service water pump motors. The licensee's calculation EPG-00027-00 indicated that the loss-of-coolant-accident (LOCA) load, with offsite power available, could be 2,420 kVA or 2,911 Amps. The team found that the calculation for the feeder to Bus 6A contained an incorrect input for the rating of the bus connection and used incorrect units. Based on the information supplied, it appeared that the bus would have been overloaded by 400 Amps. The licensee was subsequently able to demonstrate that the connection from the EDG to the bus had been analyzed for the re-rating of the EDG to carry 3,300 Amps.

The licensee could not produce a calculation for the service water pump motors that evaluated the adequacy of the feed from the Unit 2 buses (original design) or from the Unit 1 alternate supply. The licensee subsequently identified relevant correspondence from the original architect engineer from the 1969 time frame and also evaluated the cable size using the guidance in Okonite Engineering Bulletin EHB-98. Although a formal calculation had not been completed by the completion of the inspection, it appeared there was an acceptable basis for the original design. The team determined this issue did not have a credible impact on safety because the design was subsequently determined to be acceptable to support plant operations. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. These issues have been entered into the corrective action program as CRs 200101463, 200100584 and 200100796.

Design Inputs for Load Flow and Voltage Drop

The licensee's design basis calculations included voltage drop or load flow studies for the 480 Vac, 118 Vac, and 125 Vdc systems to demonstrate sufficient voltage at the safety-related loads. The team found that the 480 Vac load flow calculation, FEX-000144-00, included a number of unverified assumptions and inputs. These included the lack of a controlled basis for the impedance diagram and conflicting motor data. Also, the offsite system operating conditions were inconsistent with those used in the degraded voltage studies.

These issues did not have a credible impact on safety because the team reviewed a sample of assumptions and inputs and found that the variations in input data would not have affected the conclusion of the calculation. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. These issues have been entered into the corrective action program as CR 200100583 and CR 200100591.

Instrument Power Supply Voltage Automatic Transfer Point

The team reviewed the operation of the 118 Vac system safety-related inverters which power the safety-related instrument buses. The inverters have a solid state transfer switch on their outputs that transfers the output from the inverter to a transformer supply in the event of a degraded input or output voltage. The team found that there was no engineering evaluation to support the transfer set point for the inverters.

The team determined this issue did not have a credible impact on safety because the inverter output is periodically monitored and verified to operating at an acceptable value specified in the daily log. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue has been entered into the corrective action program as CR 200100908.

Auxiliary Feedwater Pump Motor Loading

The team reviewed the sizing of the auxiliary feedwater pump motor and found that the as-built rating of 400 horsepower at a 1.15 service factor would be exceeded with an assumed runout load of 490 horsepower as indicated in the loading calculation. The licensee could not locate correspondence from the motor manufacturer that was referenced in the loading calculation. However, the licensee had a manufacturer's performance test of the motor at 500 horsepower and a thermal stress calculation that indicated there would be an acceptable operating life at 500 horsepower. The failure of the licensee to clearly document the design bases for this pump was considered a design control weakness. The licensee initiated CR 200100972 to further evaluate this issue.

Alternate AC Supply Transformer Replacement Modification

The team reviewed safety evaluation 99-339-MD associated with the modification that replaced the GT-1 transformer. The team found that the safety evaluation failed to document that, while the transformer was non-safety related, it did in fact perform a function important-to-safety as the alternate ac power source. The modification package also lacked any references to important bases documents, including the calculations for the no-load tap setting. The team determined that these issues represented weaknesses in the licensee's design control process.

b.2 Service Water System

The service water system provides cooling to safety-related and non-safety-related components through two separate main supply headers. Flow to each header is provided by three pumps, each rated at 5,000 gallons per minute (gpm) at 220 feet of water discharge head. The pumps take suction from a common intake bay supplied from the Hudson River through two parallel traveling screens. In addition to the traveling screens, there are rotating strainers installed between the pump and the main headers to remove any particles or debris that could obstruct the flow paths through the components.

The main headers are aligned and designated as “essential” and “non-essential” headers. The essential header supplies cooling to all of the safety components except the component cooling water system heat exchangers. The non-essential header supplies the component cooling water system heat exchangers and the non-safety related components. The system design ensures that both headers will be able to perform their safety functions following any single active failure in the system.

In the event of a LOCA, operators are required to isolate the non-safety components from the non-essential header prior to entering the recirculation phase. The system can also be aligned for three header operation during which both the essential and non-essential headers supply only their respective safety-related components and the non-safety-related components are supplied by a separate river water system. The team reviewed the important design control aspects of the service water system. A number of performance issues and weaknesses were identified. The following observations are representative of the issues identified by the team.

Non-Essential Header Flow

The team identified that the licensee did not have a documented analysis or test that verified the ability of the service water system to supply the post-accident design flow to the component cooling water (CCW) heat exchangers. The licensee had a hydraulic model, Calculation PGI-00371, Rev. 0, which addressed the normal system lineup with the non-essential header supplying both the non-safety related components and the CCW heat exchangers. However, the analysis did not confirm the ability of the system to provide the required 2,500 gpm to each heat exchanger following an accident.

In response to this finding, the licensee used the flow model to evaluate the adequacy of flow to the heat exchangers under design basis accident conditions while assuming the service water pump was at the maximum degraded condition of 7%. This analysis showed that one of the CCW heat exchangers would receive 2,725 gpm and the other 3,054 gpm. Although this analysis was preliminary, it was determined that the service water system and CCW heat exchangers were operable.

The team found the licensee’s immediate actions to address this issue, including the operability determination, to be acceptable. The system would have been able to perform its intended functions, as such, the team determined this issue did not have a credible impact on safety. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. This issue was entered into the corrective action program as CR 200100566.

Containment Fan Cooler Radiation Detector Analysis

The containment fan coolers were equipped with two radiation detectors in the service water system outlet flow paths to provide for monitoring effluent discharge paths for radioactivity that could be released from postulated accidents. This feature was incorporated into the design since the service water system pressure at locations inside the containment with the system in the incident mode alignment could be below the containment post-accident design pressure of 47 psig. These detectors were designed to actuate an alarm in the control room whenever their set points were exceeded. The team reviewed the detector set point calculation, RS-92, Rev. 2, to verify that it was appropriate to prevent exceeding the allowable accident radiation exposure limits specified by the regulations. The team found that the analysis had been performed for normal operating conditions assuming a total service water flow of approximately 16,000 gpm and a 600,000 gpm dilution flow from the circulating water system. The team noted therefore under design basis accident conditions the circulating water system may not be operating and that this assumption was non-conservative.

The licensee acknowledged this finding and performed another calculation that credited other conservative assumptions in the original calculation. The results of the revised calculation showed that the setpoint would have ensured that the accident exposures would have remained within regulatory limits, as such, the team determined this issue did not have a credible impact on safety. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. This issue was entered into the corrective action program as CR 200100879.

Essential Header Flow Verification

The team reviewed test procedure PT-R93, “Essential Service Water Header Flow Balance,” Rev. 3, which performed an operational test of the essential service water header to verify that design flow was provided to all system components. The test is normally performed at the end of each refueling outage on the header that is aligned as the essential header and using the two lowest performing pumps to simulate worst case design basis accident conditions.

The team noted that during plant operation the system was realigned every six months to equalize the time each header functioned as the essential or non-essential header to more evenly distribute pump wear. However, the team also noted that there were no requirements in the test procedure, or other plant procedures, to ensure that the refueling interval testing would alternate between the two headers. The licensee was able to verify from operating records that both headers would function properly as the essential header. The team considered the lack of directions to alternate headers during testing to be a weakness with the flow testing procedure. The licensee initiated CR 200100511 to address this issue.

Strainer Blowdown Flow Safety Evaluation

The team reviewed test procedure PT-R93, “Essential Service Water Header Flow Balance” that was performed on August 24, 1998, following the replacement of all six service water pumps during 1997 and 1998 (Modification Number FMX-96-10376-M). During the test, the pumps were unable to deliver the design basis flows to all of the safety-related components and CR 199807295 was generated. In reviewing this issue the licensee discovered that the service water strainer blowdown flow was at approximately 600 gpm. The flow was adjusted to the required value of 225 ± 25 gpm and the test was re-performed successfully. The licensee then implemented a temporary facility change (98-222) to maintain the blowdown valves at the new throttled setting.

The team reviewed the documents associated with the temporary modification and determined that safety evaluation 98-322-EV, Rev. 2, did not clearly address the required strainer blowdown flows. The safety evaluation indicated that UFSAR Table 9.6-1 specified the minimum essential service water pump strainer blowdown flow as 100 gpm. The safety evaluation further identified that service water operability could be maintained with as little as 0 gpm and as much as 250 gpm without reconciling these differences with the UFSAR specified minimum flow. In addition, the strainer supplier recommended a blowdown flow rate of 2 to 3% of the through-strainer flow.[11] Calculation FFX-00713, Rev. 0, documented that the maximum through-flow was approximately 6,923 gpm. Using 2% of this value would yield a minimum allowable blowdown flow of 138 gpm. The calculation showed that with the throttle valves set at the new normal operating minimum flow of 200 gpm, the actual blowdown for worst case accident conditions would be 164 gpm, thereby meeting the vendor's recommended minimum flow. Therefore, the team determined that, although the 225 gpm ± 25 gpm setting for normal operating blowdown flow was adequate to maintain strainer operability, the safety evaluation was weak since this value had not been evaluated against the correct basis provided by the vendor (138 gpm). Additionally, the safety evaluation did not identify that the 100 gpm UFSAR minimum value was inadequate and would have incorrectly allowed 0 gpm blowdown flow. The licensee initiated CR 200101133 to address this concern.

b.3 General Design Control Observations

The team observed that there appeared to be a general difficulty in retrieving design basis information to support design control, testing and plant modification efforts. This issue had been previously identified and slow progress has been made to improve in this area. Additionally, this deficiency appeared to have had additional plant staff impact in that some inconsistencies in the review of certain technical issues were observed. The team noted that the licensee's business plan incorporated long-term initiatives to address this issue.

2. Procedure Quality

a. Inspection Scope

The team reviewed licensee event reports, NRC inspection reports, self-assessments, and condition reports to evaluate the extent that procedure quality has contributed to previous performance issues. The team reviewed a sample of procedures involved in performance problems to assess the technical adequacy of those procedures. The reviews included a verification that the procedure steps would achieve the required

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[11] The lowest blowdown flow would occur at maximum through-strainer flow conditions that would correspond to the lowest pump discharge pressure

system performance for normal, abnormal, remote shutdown and emergency operating conditions. Procedures were also reviewed to ensure the activity was accomplished within the plant design bases and regulatory requirements, and that procedure inadequacies did not exist that would cause an initiating event. The team reviewed maintenance procedures to ensure they were sufficient to perform the task, that they included independent quality verification of important attributes, and that they resulted in the task being performed consistent with the equipment vendor instructions and specifications. A sample of important vendor manuals were also reviewed to ensure they were complete and up-to date. The team reviewed the effectiveness of the licensee in ensuring current copies of documents were in place in the working files and that procedures affected by modifications or industry experience were updated in a timely manner.

The team reviewed the procedure change process to ensure it was in accordance with regulatory requirements and that appropriate personnel were involved in the development, review and approval of procedure changes. The team also reviewed the adequacy of controls for developing special or complex procedures to ensure that they were adequately validated and discussed with the plant personnel prior to implementation.

The team evaluated a sample of temporary procedure changes to ensure the changes were reviewed and approved in accordance with technical specification requirements and that the changes were consistent with the plant design and licensing bases. The team reviewed night orders, work orders and other documents to ensure that they did not result in uncontrolled procedure changes. The team also reviewed a sample of condition reports involving procedure quality to assess the effectiveness of corrective actions.

b. Findings

b.1 General Procedure Issues

Emergency Fuel Oil Transfer Procedure

The team reviewed AOI 27.3.1, “Emergency Fuel Oil Transfer Using the Trailer,” Rev. 0, and found that the instructions for filling the trailer from the gas turbine fuel oil storage tank were deficient. This procedure is used to transfer fuel oil from the gas turbine fuel oil storage tank to replenish the fuel oil supply to the onsite emergency diesel generators. The procedure improperly directed the operator to connect the trailer fill hose to a drain line on the tank connection manifold rather than the fill line. Further, the precautions and limitations of the procedure stated that a flush of the trailer fuel lines may be required to remove ethylene glycol used for freeze protection. However, there were no instructions for performing this task and an operator interviewed by the team was unaware of how that particular flush evolution would be accomplished.

The team considered this issue to be of very low safety significance (Green) because the use of this procedure has never been required and would require minor changes to resolve the discrepancies. The failure to establish adequate procedure directions is considered an additional example of the non-cited violation of TS 6.8.1. This issue was entered into the corrective action program as CR 200100944 **(NCV 05000247/2001-002-003)**.

Temporary Procedure Change Process

Addendum VI to SAO 100, “Indian Point Station Procedure Policy,” Rev. 3, described the process for implementing temporary procedure changes (TPCs). A TPC provides guidance for plant operations when existing plant procedures cannot be performed as written. The procedure stated that if not required for immediate operation of the plant, then the procedure shall be revised in accordance with SAO 100. The team reviewed TPC 00-0853 which was implemented to change alarm response procedure (ARP) AS-1 (Accident Assessment Panel 1; windows 5-4 and 6-4) because a temporary modification had disabled the associated alarm inputs. Since the alarm inputs had already been disabled and the change was not required for immediate operation of the plant, the team determined that a TPC was not the appropriate mechanism to change the procedure.

The team considered this issue to be of very low safety significance (Green) because the use of this TPC had minimal affect on plant operations. However, the failure to implement the requirements of SAO 100 for the use of TPCs is considered an additional example of the non-cited violation of TS 6.8.1. This issue was entered into the corrective action program as CR 200100866 **(NCV 05000247/2001-002-003)**.

Biennial Procedure Reviews

The team found that the licensee did not implement biennial procedure reviews in a manner consistent with existing administrative guidance. SAO 100, “Indian Point Station Procedure Policy,” Rev. 31, stated that biennial procedure reviews apply to documents which implement the regulations of 10 CFR 50, Appendix B. The procedure also stated that procedures which are used routinely (at least every two years), may be excluded from biennial reviews. Examples included calibration procedures, check-off lists (COL), maintenance procedures, plant operating procedures (POP), surveillance test procedures, system operating procedures (SOP), alarm response procedures (ARP), and abnormal operating instructions (AOI). The team found that the generation support department personnel interpreted this guidance to mean that all COLs, POPs, SOPs, ARPs, and AOIs are exempted from biennial procedure reviews. However, the team noted that there was no mechanism to identify procedures that are not used within a two year interval, and would therefore require a biennial review. The licensee researched the basis for this interpretation and found that the quality assurance program description stated that routine plant procedures that have not been used for two years shall be reviewed before use to determine if changes are necessary or desirable.

The failure to implement the SAO-100 procedure was not subjected to a cornerstone significance determination process. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue was entered into the corrective action program as CR 200101449.

Incomplete Plant Operating Procedures

Operations Administrative Directive (OAD) 33, "Procedure Adherence and Use," Rev. 15, requires that operators verify the completion of steps in POPs. While reviewing a controlled procedure binder in the control room, the team identified that two POPs used for the recent plant startup (December 2000) contained several procedure steps that were not properly signed off. Specifically, POP 1.1, "Plant Restoration From Cold Shutdown to Hot Shutdown Conditions," Rev. 55, and POP 1.2, "Reactor Startup," Rev. 30, had numerous procedure steps that were apparently completed, but not initialed by licensed operators. This was considered to be an example of a minor violation of a failure to follow procedures since it appeared that the affected procedure steps had actually been performed and only the associated signatures were missing.

The failure to implement the OAD 33 procedure was not subjected to a cornerstone significance determination process. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

Environmental Qualification Engineer Review of Work Orders

Station procedure SAO-430, "Environmental Qualification (EQ) Program," Section 2.2.12 required that the EQ engineer review all work packages on EQ equipment to assure that EQ considerations have been addressed. The team identified that this review was not performed for work order NP-99-06573. The team interviewed an EQ engineer, who stated that he was not aware of this procedure requirement and did not review all the completed work packages. The EQ engineer stated that he had reviewed and approved the general procedures that were used during the performance of the associated work. He also noted that he did not review all completed packages as a routine matter.

The team determined this issue did not have a credible impact on safety because there were no actual equipment deficiencies identified that were due to a lack of the EQ engineer review. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue was entered into the corrective action program as CR 200100872.

Procedure Change Backlog

The team reviewed the backlog of operations procedure changes and noted there were about 650 Communications to Staff (CTS) items in the backlog. Many of the CTS items represented change requests for multiple procedures. Accordingly, the backlog of affected procedures requiring changes was substantially higher than 650. The team discussed the backlog with licensee personnel in the generation support department (operations procedure writers) and reviewed the backlog and found that there was no formal mechanism to prioritize individual items. The only prioritization occurred when CTS items were received, and judgement calls were made as to whether immediate changes were necessary. The team identified a number of items which should have received elevated priority. The following examples are representative of the team's findings in this area:

- CTS 98-1248, dated October 21, 1998, referred to an Abnormal Operating Procedure (AOI 29.6) that implemented an operating principle that was inconsistent with current practice.

- CTS 99-0265, dated April 14, 1999, documented that a procedure check-off list (PCO 3.2) did not properly reposition two valves (residual heat removal heat exchanger motor-operated valves) following a safety injection.

- CTS 99-0535, dated July 28, 1999, identified that operations log sheet DSR-8M, associated with the gas turbine north and south fuel oil storage tanks, did not accurately reflect the proper minimum and normal tank levels.

The items listed above had been in the system for some time (nearly 2 ½ years for CTS 98-1248), and were more than minor editorial changes. The team considered the extent and age of the procedure change backlog to be a weakness in the maintenance of plant procedures. The team also noted that nearly all of the operations procedures had not received biennial reviews due to the misinterpretation of SAO 100 as discussed earlier, contributing to the time it takes for incorporating proposed changes by way of periodic procedure reviews and revisions.

Document Control

The team identified several minor document control issues associated with station procedures. For example, uncontrolled, and out-of-date copies of the post-run attachments of the diesel generator operating procedures (SOP 27.3.1.1, 27.3.1.2, and 27.3.1.3) were found in the EDG building. However, it did not appear that any out-of-date attachments had been used for obtaining and recording actual EDG data. The licensee promptly removed the uncontrolled attachments from the EDG building and initiated CR 200101382 to further review this issue.

The team also found that there was no mechanism or instruction to remove expired temporary operating instructions (TOI) from the controlled, active TOI binder located in the control room. Previously, the generation support supervisor removed outdated TOIs during routine tours. During the course of this inspection the team identified two expired TOIs that were still in the control room binder. The licensee promptly removed the expired TOIs from the control room binder and initiated CR 200101383 to further review these issues.

Procedure Use and Quality

The team determined that OAD 33, “Procedure Adherence and Use,” Rev. 15, allowed broad flexibility for place keeping while using implementing procedures. The procedure recommended, but did not require, place keeping for continuous use procedures and operating instructions by placing a mark on the sign off line upon completion of the step (marks can be made in pencil and then erased). The team observed that during the power ascension on January 19, 2001, the status of ongoing evolutions was not apparent because place keeping within an active procedure was not consistently conducted. Although a panel walk down by the team did not identify any mis-positioned components or missed procedural steps, the team concluded that place keeping guidance and implementation was a weakness and made it difficult for operators to ascertain accurate system configurations.

The team also identified quality weaknesses associated with the procedure associated with scheduling, approving and assessing overtime. The team determined that procedure OAD 9, “Operations Section Organization,” Rev. 27, did not institute maximum limits for excessive overtime. Rather, the procedure allowed workers to surpass the overtime limits for planned overtime with the advance approval of the assistant operations manager or higher. Further, excessive unplanned overtime required only the approval of the shift manager. The team also found that excessive overtime approvals did not require any assessment with respect to worker fitness for duty. The team reviewed overtime request and approval records, and did not identify instances where procedure requirements were violated. However, the team concluded that the procedure weaknesses represented the potential for inappropriate overtime hours being worked without including an assessment for fitness for duty concerns.

b.2 480 Vac and Emergency Diesel Generators Procedure Issues

Procedure Acceptance Criteria

The team reviewed various procedures associated with the 480 Vac and EDG systems and identified a number of performance issues. The following examples are representative of the team’s findings in this area:

- The team noted that the EDG loading calculation assumed a frequency variation of +/- 0.5% based on the vendor setpoint tolerance. The team found that the safety injection with loss of off-site power surveillance test did not contain an acceptance criteria for EDG frequency. Based on the available design data the acceptance criterion should have been 60 Hz, +/- 0.3 Hz. Although the procedure did not specify an acceptance criterion, the team found that the results of the most recent testing performed during the 2000 outage confirmed that the frequency was within the values assumed in the calculation. The team also noted that the monthly EDG surveillance procedure and the 24 hour load test procedures specified an acceptance criteria tolerance of +/- 1.5 Hz which was not consistent with the loading calculation. In addition the team noted that the procedure for verifying the capacity of the EDGs did not include considerations of instrument uncertainty for the maximum loading (2300 kW) condition testing.

- The team reviewed control room operator log, DSR-1, and found that the minimum and maximum ranges specified for the instrument bus voltage were not bounded by the 118 Vac instrument power system voltage calculations.

- The team found that the vendor requirement to restrain the end cells of battery 23 had not been adequately translated into installation drawings.

- The team reviewed instrumentation and control preventive maintenance package for the undervoltage relays (ICPM 1741) for the 125 Vdc control power automatic transfer switches that supply EDG and 480 Vac switchgear control circuits. The team observed that the specified acceptance criteria of 100 +/- 2.0 volts was not consistent with the 125 Vdc voltage drop calculations FEX-00044-02 through FEX-00046-02 and FEX-00048-02 and would not ensure acceptable voltage at the dc loads prior to transfer.

The team determined these issues were of very low safety significance (Green) because none of the test results or operating data identified instances where equipment was operating outside of its design limits.

The team considered the failure of the licensee to include appropriate acceptance in the procedures and drawings to ensure activities have been satisfactorily accomplished to be a violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.” This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). These issues were entered into the corrective action program as CRs 200100777, 200100531, 200100908, 200101576 and 200100750 **(NCV 05000247/2001-002-004)**.

b.3 Service Water System Procedure Issues

Service Water Header Pressure Analyses

The team reviewed Alarm Response Procedure (ARP) Window 4-6, “Service Water Hdr 21, 22, 23, 24, 25, 26 High/Low Press,” Rev. 25, and DSR 1, “Unit 2 Central Control Room Log,” Rev. 77, and found that the service water header low pressure alarm set point was 53 psig and the minimum acceptable header pressure in the control room log was 48 psig . The team found that the bases for the low pressure alarm set point was to ensure there would be adequate pressure to supply flow to the main turbine lube oil coolers. The control room log minimum appeared to have been based on the same requirement but without an elevation head correction that should have been considered. The licensee did not have an engineering analysis to demonstrate that all safety-related components would receive adequate flow if header pressure was controlled based on these limits.

The licensee performed a preliminary analysis assuming a header pressure of 53 psig and it was determined that acceptable flows would be delivered to the system. However, the control room log limit of 48 psig was found to be inadequate, and it was raised to 58 psig by Revision 78 during the inspection to provide a 5 psig margin above the set point.

This issue was of very low safety significance (Green) because the team did not identify any instances of operation at less than 53 psig.

The failure to properly translate the header pressure design bases into plant procedures is considered an additional example of the non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.” This issue was entered into the licensee’s corrective action program as CRs 200100707 and 200101410 **(NCV 05000247/2001-002-002)**.

Service Water Strainer Pit Flooding

The team reviewed the service water system for potential failure modes. It was noted that an event that requires the automatic starting of the service water pumps results in the potential for one of the service water pump vacuum breaker valves to fail open. These valves were located in the strainer room and would discharge directly into the space whose floor elevation (5' - 9") is several feet above normal Hudson River elevation. As a means of relieving an internal flood in the strainer pit, there was an eight inch drain line that discharges to the service water pump bay. This line included butterfly valve MD-501 that was maintained normally open by procedure COL 24.1.1, “Service Water and Closed Cooling Water Systems,” Rev. 30.

Procedure AOI 28.0.4, “Plant Flooding-Conventional Side,” Rev. 2 required closing MD-501 if river water level reached 5' - 8" to prevent flooding the room from the river (external flood). However, in this configuration, an internal flood from a failure, such as a vacuum breaker valve, could cause failure of all of the service water strainer motor operators. In response to this finding, the licensee initiated TPC 01-0039, dated January 24, 2001, which revised Procedure AOI 28.0.4. to continuously monitor the service water strainer pit for evidence of water in-leakage when the river water level reaches 5' - 8" and valve MD-501 is closed.

The team determined this issue was of very low risk significance (Green) because it involved the relatively low probability of a valve failure coupled with the low probability of an external flooding event.

The failure to properly translate the design bases into plant procedures is considered an additional example of the non-cited violation of 10 CFR 50, Appendix B, Criterion III, “Design Control.” This issue was entered into the corrective action program as CR 200100878 **(NCV 05000247/2001-002-002)**.

Service Water Strainer Pit Drain Check Valve

The team noted that in addition to the manually operated valve discussed above, the strainer room drain line also contained check valve, MD-500, located on the outboard side of the room in the service water pump bay. This valve had safety-related functions to close to prevent river water from entering the room in the event of high river level and to open to prevent internal strainer pit flooding. The valve has a counter-balanced disk designed to assure opening at the very low differential pressure that would be associated such flooding. The team discovered that valve MD-500 was not included in the plant testing program to verify its ability to fulfill its function. In response to this finding, the licensee took immediate action to demonstrate operability by manually cycling the valve from the full open to full closed position and observing that the valve opened with minimal effort and that there was no restriction in movement. The team considered this issue to be of very low safety significance (Green) because the valve was confirmed to be operable.

The failure to test the valve by periodically exercising it to its safety function position is considered a violation of 10 CFR 50.55a, “Codes and Standards,” paragraph (f), “Inservice Testing Requirements.” This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). This issue was entered into the corrective action program as CR 200101466 **(NCV 05000247/2001-002-005)**.

Inservice Testing Procedure

The team reviewed the results of performance test PT-Q26A, Rev. 7, “21 Service Water Pump,” performed on September 13, 2000, and found that the test acceptance criteria reflected the original Aurora pump criterion for operability of $\geq$ 253 feet differential pressure at 1,500 gpm. The team noted that the licensee had not revised the acceptance criteria following the replacement of the Aurora pumps with Johnston pumps in 1997 and 1998 to properly reflect the characteristics of the new pumps.

The licensee indicated that the basis for the acceptance criteria corresponded to the 10% degraded head point for the Aurora pumps as documented in Calculation PGI-00371, Rev. 00. The calculation demonstrated that, with 10% degradation, the Aurora pumps could still provide the required design basis flow to all of the safety-related components. Although the replacement Johnston pumps’ vendor curves showed better performance than the Aurora pumps at the 1,500 gpm test point, they showed somewhat lower performance at the 5,000 gpm design point. The team noted that there were several missed opportunities for the licensee to discover and correct this discrepancy. Preliminary analyses by the licensee during the inspection showed that if the pumps had been allowed to degrade to the acceptance criteria values in this test procedure and the other service water pumps’ corresponding IST procedures, their performances would not have been adequate to meet the design basis requirements.

The licensee evaluated this issue and determined that if individual pump performance remained above the 95% “alert” value in the test procedures, the pumps would be capable of providing the design basis flows. The licensee also confirmed that all of the pump actual test results remained above the alert values and as a result all were considered operable.

The system would have been able to perform its intended design functions, as such, the team determined this issue did not have a credible impact on safety. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. This issue was entered into the corrective action program as CR 200100170.

Service Water System Test Correction Factors

The team reviewed procedure PT-R93, “Essential Service Water Flow Balance,” Rev. 3, and identified that the acceptance criteria for minimum flows to the various safety-related components had not been adjusted to compensate for several factors that could result in accident flows being less than design basis requirements. These factors included test instrument uncertainty, actual river levels versus the design basis minimum level, and the effect of pump strainers at design basis maximum differential pressure. The team also noted that the procedure directed the installation of temporary flow instrumentation without provisions to ensure consistent installation from one test to the next.

The licensee evaluated this issue and determined that, although the factors discussed above were not accounted for in the procedure, there were sufficient margins in the established flows to ensure that all components were operable. The team determined this issue did not have a credible impact on safety because the system was capable of performing its design function. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. This issue was entered into the corrective action program as CR 200100970.

Service Water Strainer Differential Pressure

The team reviewed design documents and operating and test procedures associated with the service water system strainers. Several procedures reflected a 9 psid design differential pressure limit across the strainer, and the strainer vendor manual documented 15 psid as the structural differential pressure limit. The team observed that during normal operation the flows in both the essential and non-essential headers were significantly lower than design basis accident flows due to flow throttling for temperature control. In an accident, however, the flow control valves would be either full open or bypassed in order to maximize heat removal. The differences between normal and accident flows were at the maximum in winter when throttling was maximized. An example of the difference was observed on February 5, 2001, when, with ice in the river, in three-header operation, the non-essential header flow was observed to be 3,250 gpm. The licensee had determined that the minimum accident flow would have been 5,780 gpm. Since the differential pressure is proportional to the square of the flow rate, for this particular day the strainer differential pressure would have increased by a factor of 3.2 for accident flow conditions. Since the actual differential pressure was 1.3 psid on this date the non-essential header would not have exceeded the design limit of 9.0 psid as a result of expected post-accident flow rates. However, higher normal strainer differential pressure, well below the procedure limit would result in strainer differential pressures in excess of the design limit or the vendor's structural limit after accident flow conditions were established. Therefore, these normal operation procedural limits were inadequate.

The team also identified a weakness in the alarm response procedure, "Service Water Strainers Trouble," Rev. 25, which had an alarm set point at 8.5 psid. The alarm response procedure stated, "IF differential pressure remains above 15 psid, PLACE standby service water pump in service and shutdown service water pump associated with affected strainer." This direction would allow strainer operation above 15 psid for a limited period, which was contrary to the vendor's direction and could cause permanent damage. The licensee had no basis or analysis to demonstrate that its operating limit was adequate to prevent exceeding the strainer structural limit of 15 psid for accident conditions.

The team determined that these issues did not have a credible impact on safety because the differential pressure across the strainers was low enough that the design limit would not have been challenged even at the higher accident flow rates. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue was entered into the corrective action program as CR 200101404.

Service Water System Operating Procedure

The team found that procedure SOP 24.1, "Service Water System Operation," Rev. 40, contained a precaution which stated "Do not operate 23 and 24 SWPs simultaneously, if it can be avoided by existing operational considerations, due to the potential for creating vortexing in the service water bay." The procedure contained a similar note following step 4.1.1.

The ability of these pumps to operate together safely was further called into question by a July 1994 evaluation report on a 1-to-6.4 scale model hydraulic study of the service water pump intake. The study had been commissioned by the licensee in response to three pump failures that occurred over a period of a few weeks. The report indicated that there were severe sub-surface vortices for almost all pump combinations tested, and because of the large length-to-diameter ratio, the pump columns were sensitive to flow imbalances and fluctuations. The report also indicated that the hydraulic performance of the existing service water intake did not meet the acceptance criteria selected for the study because of adverse sub-surface vortices. The most severe vortexing was noted with pumps 2,3,4, and 6 operating.

The licensee initiated CR 200100912 to document and further review this issue and determined that the procedure statements associated with vortexing were added by a procedure change in response to the report. This change had been reviewed by the Station Nuclear Safety Committee on August 25, 1994. The reason stated in the meeting minutes for the changes was "only because of the possible long-term effects of potential vortexing." The licensee also informed the team that the pump configurations were in accordance with the Hydraulic Institute Standards and that the new Johnston pumps, installed in 1997 and 1998, were more heavily constructed than the original Aurora pumps. In addition, the three pump failures that precipitated the original study had ultimately been attributed to improper coupling assembly and foreign object ingestion. Based on this information, and the fact that during normal operation no excessive wear or vibration had been observed in any of the pumps, the licensee concluded that the precaution and note were unnecessary and planned to revise the procedure to remove the procedure statements. The team considered the failure of the licensee to correct the procedure to be a weakness, in that it unnecessarily restricted operators from certain operating configurations.

3. Equipment Performance

a. Inspection Scope

The team reviewed various maintenance related issues for the selected systems to determine the licensee's effectiveness in identifying the causes and extent of equipment problems as well as in developing and implementing corrective actions. Additionally, an assessment of the implementation of maintenance rule (MR) requirements was conducted. The team reviewed maintenance related documents, observed maintenance activities and conducted plant tours to assess the effectiveness of the licensee in entering maintenance issues into the corrective action program. The team also reviewed open condition reports and corrective maintenance work orders for the selected systems to assess their potential impact on operability.

The review also included surveillance and post-maintenance tests to assess the effectiveness of the licensee in specifying appropriate acceptance criteria and to verify the effectiveness of controls to restore equipment to operation following testing. The team also reviewed the scope of the calibration program for the selected systems and sampled system instrumentation loops to ensure instrumentation important to safety was included. Additionally, the team reviewed the preventive maintenance programs for the selected systems to assess the program adequacy and to verify that design document, vendor manual and generic communication information were incorporated into the maintenance program. Observations of in-progress maintenance and testing on the selected systems were conducted.

b. Findings

b.1 480 Vac and Emergency Diesel Generators

Gas Turbine Performance

The team reviewed the performance of the GTs that provide a backup electrical supply in the event of a station blackout condition and for alternate safe shutdown in the event of a fire. Based on these functions, the GTs were included within the scope of the licensee's 10 CFR 50.65 maintenance rule program. The licensee established an availability goal of 80% (less than 3,504 hours unavailability in a 24 month period) and a reliability goal of less than 2 maintenance preventable functional failures (MPFF) and zero repetitive MPFF's in a 24 month period. The team noted that the GTs had not been meeting these goals since 1995. In addition, a review of the performance history documented in the existing site maintenance rule basis document for the gas turbines indicated that none of the goals (availability and reliability) were being met at that time and that the GTs remained classified as (a)(1) under the MR.

The team reviewed the system health report for the gas turbines for the 4th quarter of 2000 and noted that GT-2 was still not meeting the goals for availability and none of the GTs were meeting the goal for reliability due to numerous failures. Discussions with licensee personnel indicated that several outstanding issues impacted the station's ability to adequately maintain the GTs. For example, the preventive maintenance program lacked specificity and rigor and there was poor design information, such as electrical schematics and mechanical drawings available to the staff. The team also noted that there was a significant decline in performance of the GTs during the 4th quarter of 2000 that included several repetitive maintenance preventable failures. The licensee attributed these problems, in part, to a lack of preventive maintenance during the 2000 steam generator replacement outage.

The team determined these issue were of very low safety significance (Green) because the technical specification requires only one GT to be operable. In addition, the team did an independent calculation of the change in core damage probability associated with the current unavailability of GT-2 for an estimated repair length of 60 days and determined that the risk increase to be within the very low safety significance band (<1E-6).

The failure of the licensee to effectively implement corrective actions to ensure that the established maintenance rule goals would be met is considered a violation of 10 CFR 50.65 (a)(1). This violation of 10 CFR 50.65(a)(1) is being treated as a non-cited violation (**EA-01-055**), consistent with Section VI.A of the NRC Enforcement Policy, issued on May 1, 2000 (65FR25368). This issue was entered in the corrective action program as CR200100233 **(NCV 05000247/2001-002-006)**.

480 Vac and Emergency Diesel Generator Performance

The team reviewed the maintenance history, equipment performance and maintenance rule program aspects associated with the emergency diesel generators and 480 Vac systems. The review focused on system performance in the post-1999 time period since extensive follow-up was performed following the August 1999 loss of offsite power and reactor trip. The team determined that while minor equipment problems had been observed, the overall performance of the systems had been adequate.

b.2 Service Water

Instrumentation and Controls Preventive Maintenance

The team reviewed several EDG instrument calibrations which were performed using instrumentation and controls preventive maintenance (ICPM) packages and found that in several cases the entire instrumentation circuit was not tested. For example, several packages[12] were completed without control power available to test the resultant circuit actuations. The specified sensors were tested through verification of relay contacts, but in some cases, the resultant actuations such as alarm and annunciation were not tested. The incomplete PMs referenced a condition report, however, the inability to test the specific condition was not included in the report.

The team also reviewed ICPM package 1350, Rev. 3, that tested instrumentation associated with service water flow control valves FCV 1176 and 1176A. These valves control the flow of cooling water from the EDGs. The control circuitry includes contacts to open the valves if a high jacket water or high lube oil temperature is sensed on an operating EDG. Although the ICPM checked and calibrated the setpoint of the temperature switches, there was no testing to verify that the associated relay and circuitry would open the valves on a high temperature condition. The team reviewed CR 199900576 which documented that the licensee had identified this same issue during the development of the component function matrix. The CR recommended testing to improve plant reliability but also stated the devices are not important to nuclear safety since the valves also open on a safety injection signal, which was routinely tested. However, the team noted that a single failure of flow control instrumentation for the valves could result in a close signal to both valves. Consequently, during operation of the EDGs without the presence of a safety injection signal, the high temperature circuitry was important to nuclear safety since it was necessary to prevent the loss of the emergency power safety function due to a single failure that could isolate all cooling water to the diesels. The licensee reviewed the issue further and concluded that the high temperature circuitry was not tested but also identified a previous modification

[12] PM Packages No. 1779-1, Diesel Generator 22 Lube Oil System, Rev. 2, PM package No. 1778-1, Diesel Generator Jacket Water System, Rev. 2, and PM package no. 1776, Diesel Generator 21 Fuel Oil System, Rev. 4

which added a mechanical stop to prevent full closure of the 1176A valve. While the purpose of this modification was to provide sufficient flow velocity to prevent fouling of the system, the licensee was also able to show that with the valve closed to the mechanical stop, adequate flow would be provided to the EDGs.

The team discussed these findings with licensee personnel and found that the station had recognized the need to improve the ICPM program and developed a program to convert the packages to procedures that used the surveillance test procedure format. Further, the team also noted that the ICPM program did not include all of the various safety and non-safety related instruments. There were approximately 650 existing ICPM packages requiring action and approximately 600 instruments not included in the ICPM program scope. As a result of the team raising this issue, the licensee subsequently reviewed a random sample of approximately 100 ICPMs to assess the adequacy of testing and identified 7 additional discrepancies. Based on these results, the licensee completed a review of all safety-related instrumentation ICPM packages and verified that there were no concerns with equipment operability due to inadequate testing.

The team determined this issue did not have a credible impact on safety because none of the deficiencies affected any component operability. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue was entered into the corrective action program as CRs 200100974, 200101411, 200101467 and 200101468.

Service Water Pump and Motor Replacement

Between July 1997 and January 1998, all six service water Aurora pumps were replaced with Johnston pumps. Also, in 2000, the motors for pumps 21 and 24 were replaced. Each pump and motor replacement was followed by a post-maintenance test (PMT) in accordance with procedure TP-SQ-11.016, "Post Maintenance Test Program." The test involved a performance of the applicable quarterly test procedure, PT-Q26A - F, which involved a single point (low-flow, high-head) pump test. The team reviewed this guidance and found it to be in accordance with the licensee's commitments to ASME OM Part 6. The team also noted that following a pump or pump motor disassembly or replacement, the procedure requires a single point capacity test for flow verification as well as checks for vibration levels, operating temperature and fluid leakage. The team further observed, that subsequent to the pump replacements, the pump vendor identified a nonconformance associated with pump performance curves in that the curves could be in error up to 3.8% due to a failure to take into account instrument uncertainties during the development of the curves. Capacity testing at more than one point would have increased the potential for identifying this discrepancy since at the test point (1,500 gpm at 307 ft) the original curve had negligible deviation from the curves that were subsequently adjusted for the potential error. Although the testing was in accordance with the station procedure, the team considered flow testing at a single point to be a weakness in the test program since it may not be adequate to verify pump performance over the full range of flows that would be experienced during normal and post-accident operation.

Emergency Diesel Generator Heat Exchanger Flow Measurements

The team reviewed PT-R93, "Essential Service Water Header Flow Balance," performed in July 2000, and noted that the procedure did not have an acceptance criteria for the flow through the individual emergency diesel generators. Instead, it contained an acceptance criteria for the combined flow of 1,200 gpm for all 3 EDGs. The team found that the licensee had previously initiated CR 200005646 to address deficiencies associated with the test and included the issue described above. The licensee had determined that, based on factors such as regular inspection and cleaning of the heat exchangers and the similarity of the parallel flow paths to the EDGs, that there was adequate assurance that each EDG had adequate flow. The team considered this item to be another example of testing program weaknesses. The licensee planned to improve the test procedure.

Motor Operated Valve "T" Drains

During a plant walkdown the team noted that the "T" drains for motor operated valve (MOV) SWN-44-4A were not installed at the low point of the motor as required. The licensee reviewed this condition and determined that the environmental qualification of this particular valve was not affected based on the expected post-accident pressure and temperature conditions. However, the licensee also found that the maintenance procedures for the MOVs were weak in that they did not include directions to ensure the drains were installed at the low point and the procedure did not specify the number of drains to be installed. CR 200101007 was initiated to further evaluate this issue.

Service Water System Performance

The team reviewed the maintenance history, equipment performance and maintenance rule program aspects associated with the service water system. The team determined that while minor equipment problems had been observed, the overall performance of the system had been adequate and that adequate flows would be delivered to important system components.

4. Configuration Control

a. Inspection Scope

The team reviewed operability evaluations performed for the selected systems to assess their thoroughness, technical adequacy and to ensure that they did not result in plant operation outside of the design and licensing bases. The team reviewed temporary modifications for the systems to evaluate whether they had been reviewed and approved by the appropriate personnel and that controls were in place to limit the duration of the installation. Additionally, the team reviewed whether procedures and drawings were updated where necessary. The assessment included a review of selected configuration control issues from the corrective action program data base to assess the adequacy of the licensee's problem identification and resolution program.

The team performed detailed walkdowns of the systems to determine whether the as-built configurations and lineups were consistent with plant procedures, drawings, UFSAR and design basis documents. The team also assessed the material condition of the system and support system components to determine if any conditions existed that could adversely impact operability. Additionally, the team performed a verification that system components were properly labeled, cooled and lubricated to support the performance of their design function requirements and that power was available and correctly aligned to support automatic activations where appropriate. The team also reviewed selected system instrumentation to verify it was properly installed and calibrated. The team reviewed overall cleanliness, control of ignition sources and flammable material in the vicinity of the systems and control of temporary storage of materials and equipment to determine whether they impacted equipment operation or access by plant operators.

The team reviewed the backlog of corrective and preventive maintenance for the systems to assess whether any items or combinations thereof could impact equipment operability. The team assessed the process for controlling maintenance, including the assessment of risk and the inclusion of emergent work into the schedule. A sample of tag-outs were reviewed to assess the adequacy of the configuration for the planned work and the methods for controlling equipment status changes, including the control of entry and exit from Technical Specification (TS) action statements. A walkdown was performed to independently verify a sample of tag placements and component alignments. Long term tag-outs, control room deficiencies, operator work-arounds and equipment deficiencies were reviewed to assess the significance of these conditions. The review included an assessment of work control procedures for the control of hot work (welding, open flame, etc.) and the control of scaffolding in the vicinity of safety related and important operating equipment. The team also reviewed the process for performing maintenance using the Fix-It Now (FIN) team.

The team reviewed primary and secondary system chemistry controls to assess their effectiveness in preventing degradation of the reactor coolant system (RCS) pressure boundary. The inspection included a review of chemical analyses records, trends of water quality data and corrective actions taken when chemical variables exceeded established limits. The adequacy of the licensee’s measures to prevent the introduction of chemical contaminants into the primary and secondary coolant water and measures to detect any inadvertent contamination were also reviewed.

The team further assessed the adequacy of the fission product barriers by verifying a selected portion of the containment isolation lineup, including attributes such as component positions and power availability to ensure that components were properly controlled in accordance with Technical Specifications. The team also reviewed a reactor coolant system leak rate determination and reviewed procedures for ensuring the containment atmosphere met design basis assumptions.

The team reviewed the operating performance history for the selected systems and components and compared the out-of-service time to the assumed time in the individual plant examination. The team also reviewed the licensee’s efforts to integrate preventive and corrective maintenance to minimize unavailability.

The team performed a walkdown of the containment spray system to independently verify the system configuration. Temporary modifications for the system were also reviewed to ensure proper installation in accordance with design information.

b. Findings

b.1 480 Vac and Emergency Diesel Generators

Control of Setpoints for Delta - Temperature Annunciation

During power ascension, the control room alarm for abnormal Delta-Temperature (Delta-T) between reactor coolant loops was received. The operators took appropriate actions as specified in the alarm response procedure for the deviation. However, it was determined that the actual physical reactor coolant temperature differential was below the setpoint for the alarm. The operators stopped the power increase and contacted maintenance to investigate the alarm. Upon further investigation, it was determined that the setpoint for the delta-T deviation loop 2 channel was incorrect which resulted in the alarm actuating prematurely. Additionally, the preventive maintenance procedure used to calibrate the instrument contained incorrect setpoint values.

Although the setpoints were incorrect for the delta-T deviation alarm, there was minimal safety significance associated with the event. The delta-T deviation alarm prompts the operators to investigate a possible core flux distribution or instrument problem and is not part of any protective circuitry. Accordingly, this issue was determined to have very low safety significance (Green). The licensee took corrective actions which included adjustment of the setpoint to the proper setting.

The team considered the failure to properly adjust the setpoints of the Delta-Temperature circuitry as required by procedure an additional example of the non-cited violation of TS 6.8.1. This issue was entered into the corrective action program as CR 200100669 **(NCV 05000247/2001-002-003)**.

Oil Pads in EDG Instrumentation Cabinet

The team identified two oil absorbent pads inside the emergency diesel generator (EDG) 21 instrumentation cabinet. The system engineer indicated that the pads were used on October 26, 2000, to contain the oil from a leaking oil pressure switch (PC-5440-S). The leak had been repaired but the pads were not removed. The oil soaked pads represented an ignition hazard due to the presence of 120 volt direct current. Several components in the cabinet could fail in the presence of heat and flame and result in diesel unavailability. Technical Specification 6.8.1 specifies that written procedures shall be implemented which cover the Fire Protection Program. Portions of the Fire Protection Program are implemented at Indian Point 2 by procedure SAO-701, “Control of Combustibles and Transient Fire Load,” Rev. 8. The finding was determined to have very low safety significance (Green) because the issue did not represent a fire impairment, degradation of a fire protection feature, or a reduction in defense in depth.

The team considered the failure to remove the oil pads from EDG 21 gauge panel as required by procedure SAO-701 an additional example of the non-cited violation of TS 6.8.1. This issue was entered into the corrective action program as CR 200101448 **(NCV 05000247/2001-002-003)**.

Drawing Errors

The team identified a number of minor configuration control errors related to component labeling and drawing discrepancies. Representative examples included:

- Drawing 9321-F-4046, “Diesel Generator Building Floor Drains & Ventilation Control Air Piping Plans and Sections,” did not show the 6th building exhaust fan which had been added to the system. Additionally, another drawing had mislabeled the exhaust fan.

- Drawing 243683, Revision 2, showed SOV-7215 as a two way solenoid valve whereas the installed valve was a three way solenoid valve. The installed valve also did not match the bill of materials listed on the drawing.

- Drawing 9321-F-3278, for heat trace panel 21, was not updated following a modification.

- Loop diagram 252686 had an error involving the depicted valve type.

- One line diagram 208088 contained an error associated with the service water cable size.

The team considered these to reflect weaknesses in the area of drawing controls.

Temporary Power Cord

The team discovered that an uncontrolled, temporary power cord was plugged into an energized power source outside the EDG building and fed under the building door to power a maintenance air compressor. The compressor had not been used recently nor had the power cord been disconnected as specified by Station Administrative Order (SAO) 218, “Housekeeping Policy,” Rev. 14. The temporary power cord was disconnected and CR 2900100786 was initiated to document this issue. The team concluded that this represented a weakness in the configuration control process.

Control of Licensing Basis Information

The team identified examples of incomplete or inaccurate licensing basis information. It was noted that Technical Specification 4.6.D.1 indicated the gas turbine generator would provide a minimum of 750 kilowatts (KW) for alternate safe shutdown loads. The team questioned the basis for the 750 KW load rating and determined from a review of the station’s fire protection analysis that in fact, approximately 1,700 KW was required. The system engineer concurred that TS 4.6.D.1 appeared incorrect and initiated several CRs[13] to prompt further engineering investigation. This apparent Technical Specification discrepancy did not appear to be a safety concern since the GT load ratings were well above (> 10,000 KW) the necessary loads required for the plant to achieve a cold shutdown condition. In addition, they are tested monthly in accordance with station test procedures PT-M38A, B & C.

The team also identified incomplete licensing basis information associated with UFSAR Section 8.2.3.2. This section of the analysis dealt with the emergency fuel supply for the diesels and stated that “19,000 gal of storage ensures that at least two diesels can operate to power the minimum engineered safeguards load for 73 hr.” However, unless

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[13] CRs 200101386, 20011386, and 200101486

one diesel fails following a demand signal, all three EDG's would start and load their respective emergency buses. The calculation which determined the minimum EDG operation of 73 hours did not account for the fuel consumption from the third diesel. The team estimated that if all three diesels were operating, the fuel storage capacity would provide for only approximately 50 hours of diesel operation. The licensee initiated CR 200100782 to revise this incomplete UFSAR description and include the fuel supply given all three EDGs are operating. This issue did not present a safety concern as adequate fuel monitoring capability was available to the operators when the EDGs are operating and an adequate supply of fuel oil was available on-site with the necessary transfer capability.

b.2 Service Water System

Systems not Operated as Designed

The team identified equipment related to the service water system in which the automatic controls were degraded or long-term temporary fixes were installed. For example, following the replacement of the service water pumps, the blowdown flow for the strainers had to be reduced to ensure sufficient flow was provided to the service water loads. This was accomplished using TFC 98-222 to throttle the blowdown stop valves. The team noted that although these were ball valves which are not designed to be used as throttle valves, a permanent modification has not yet been implemented and the temporary change has remained installed since 1998.

The team also found that the EDG temperature control valves, FCV-1176 and FCV-1176A, are usually operated in automatic but are periodically placed in manual when one or more of the valves begin to hunt. This problem was documented in CR 200006702 but had not been resolved at the time of the inspection. This issue was determined to be of minor safety significance because at the time of the inspection one valve was in manual and the other was in automatic and in the event of a high temperature condition on any diesel generator or a safety injection signal the valves receive open signals which override the automatic controls.

The team also reviewed a similar control problem associated with two automatic control valves which control service water flow to the hydrogen cooler. Pressure control valve PCV-1180 is on the inlet side of the hydrogen cooler and limits flow such that service water pressure inside the cooler is always below the hydrogen pressure. Temperature control valve, TCV-1101, is on the outlet of the hydrogen cooler and automatically controls the outlet temperature of the cooler. The team found that the temperature control valve for the generator hydrogen cooler could not always be operated in the automatic mode because of interactions between the two valves.

The team noted an additional example of problems with automatic control of the service water traveling screen 27. When the screen was actuated by the automatic control system the control room incorrectly received a loss of spray water pressure alarm. This condition was created when valve FCV-6983 and its actuator were replaced with a different model valve and actuator. The newly installed valve operated slower than the previous valve, resulting in the alarm circuitry actuating just prior to system pressure being reached. Although operation of the screen system was not affected, the change has resulted in unnecessary nuisance alarms.

These are examples of operating with known degraded conditions for extended periods of time. While these issues are individually of very low safety significance, they present a burden to operators.

EDG Temporary Facility Change

The team identified several administrative deficiencies associated with TFC 99-083 installed on the EDGs including: a caution tag on valve SWN 77-6 with an incorrect tag number, an unsigned TFC tag on valve SWN 77-6, absence of a date and signature on the deficiency tag on the 22 EDG raw water pressure gauge, and absence of a date on the tag hanging on valve SWN 77-5. In addition, TPC 2000-0055 was incorporated into SOP 27.3.1.3, "23 Emergency Diesel Generator Manual Operation," but was not documented on the TFC. These issues were of minor significance and did not affect the safe operation of the plant.

Drawing and Document Discrepancies

The team identified UFSAR descriptions of radiation monitoring on the service water outlets from the containment fan coolers that did not accurately describe the arrangement of these devices. UFSAR Section 6.4.2.1.4 stated that the cooling water discharge from the cooling coils flows to the discharge canal and is monitored for radioactivity by routing a small bypass flow from each through a common radiation monitor. The team noted that the bypass flow did not come from the discharge of each cooling coil, but rather from common headers into which coolers discharged, and the bypass flow was monitored by two monitors and not one common monitor. Also, UFSAR Section 9.6.1.2 stated that the ventilation cooler and motor cooler discharge lines will be monitored by routing a small bypass flow from each through redundant radiation monitors. The team noted that the bypass flow did not come from the discharge of each cooling coil, but rather from common headers into which the coolers discharged. The licensee initiated CR 200100849 to address these inaccuracies.

The team also identified that service water system drawing, 9321-2722 Rev. 99, showed valve SWN-68-1 which could not be located in the plant. The licensee investigated this discrepancy and determined that this valve was associated with a service water flow instrument that was retired in place in 1991 when an improved flow instrument was installed. In 1993, a generic piping modification removed this valve and capped the elbow tap. However, this modification was never updated in the system drawings. The licensee initiated CR 200100910 to address this deficiency.

The team also identified six strainer drain valves which were not reflected on the system drawings. The licensee investigated this issue and determined that these drain lines had been installed by a modification in August 2000. The control room did not receive an as-built marked-up version of the drawing until January 23, 2001, after the team questioned the condition of these valves. The licensee initiated CRs 200101483 and 200101488 to address this issue.

The team noted discrepancies in the Service Water System Lineup, COL 24.1.1. The check off list required that the seal[14] numbers on the strainer blowdown stop valves be checked by comparing the number on the seal with the number recorded in the most recent documentation of acceptable flow. During the system walkdown, the team noted that the seals installed on these valves did not contain specific identification numbers. The licensee indicated numbered seals are no longer used at the plant, however, the plant procedures had not been updated to reflect this fact. The team also noted that the last service water system lineup performed on December 21, 2000, did not identify the problem with a lack of numbers on the seals. The licensee initiated CR 200100923 to address this issue. The team also noted that COL 24.1.1 had two entries for a valve identified as “Service Water Cooling Water to R-46, R-49 and R-53 (Header 4) Stop” labeled with two different numbers, once as SWN-5 and the other time as SWN-56. The team verified with that both situations referred to the same valve, and that the number should have read SWN-56 in both cases. The team determined this issue did not have a credible impact on safety. Although this issue should be corrected, it constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policies. However, they demonstrate a lack of attention to detail on the part of the licensee staff and weaknesses in the control of design drawings and documents. The licensee initiated CR 200100774 to address this issue.

b.3 Findings - Fission Product Barrier Control

During the walkdown of the containment spray system the team noted that a portion of the suction pipe between the refueling water storage tank and the containment spray pumps was outside of the building and above grade. The team reviewed the adequacy of the freeze protection on the exposed piping and noted that there could be an undetected loss of freeze protection in the event the neutral wire connection was lost. Further, it was determined that minimal measures were in place to ensure the continued

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[14] The seal are installed to ensure that the valves remain in the required throttled positions

reliability and availability of the freeze protection circuitry for this portion of the system. The licensee acknowledged this potential and initiated CR200100858 to document and further review this issue.

B. Chemistry Controls

a. Inspection Scope

The team reviewed primary and secondary system chemistry controls to assess their effectiveness in preventing degradation of the reactor coolant system (RCS) pressure boundary. The inspection included a review of chemical analyses records, trends of water quality data and corrective actions taken when chemical variables exceeded established limits.

A confirmatory measurements radio-chemistry inspection was performed to review the licensee's ability to measure radioactivity in plant systems and effluent samples and the ability to demonstrate the acceptability of analytical results through implementation of a laboratory quality assurance program. Water, charcoal cartridge, (particulate) filter, and gas samples were analyzed by both the licensee and by the NRC Region I Mobile Radiological Measurements Laboratory.

Inspection of this area included a review of the licensee's internal laboratory quality program as described in Procedure No. CH-SQ-13.003, “Quality Assurance/Quality Control of Analyses,” Rev. 5. This procedure, as well as other licensee procedures, provided for the control of analytical results through a number of mechanisms including: definition of personnel responsibilities, the use of traceable standards, implementation of instrument control checks, and participation in an interlaboratory quality control program.

b. Findings

During a review of the secondary chemistry data sheets in the control room, the team found an out-of-specification reading for feedwater hydrazine concentration that was not circled in red and not noted by the control room supervisor who had reviewed the logs. It was later determined that the actual value was not out-of-specification due to the fact that the limits had been recently changed by a temporary procedure change. In reviewing this issue the team found that TPC 01-0015 changed the acceptable hydrazine requirement in the chemistry administrative procedure to greater than 100 ppb. This change was carried into the control room chemistry log book but not into the chemistry administrative procedure or the watch chemist logs. As a result, the apparent out-of-specification (70 ppb) readings were not red circled or noted in the control room log book since the watch chemist’s log sheet still indicated that the 70 ppb reading was acceptable. Further, the team’s review of watch chemist logs showed numerous red circled readings. These included: in-line instruments out-of-service, in-line sample temperatures high, low hydrazine levels and low primary lithium concentrations. The team noted that there were no condition reports written to document these out-of- specification conditions. The team determined that these issues were of minimal safety significance; the out-of-specification conditions were of short duration and properly corrected. These issues represented minor violations of regulatory requirements.

The team conducted a comparison of the split sample results of various radio-chemistry samples. It was concluded that the licensee was able to accurately quantify concentrations of radioactive material in effluent and in-plant samples. The comparisons for the sample results indicated that all of the measurements were in agreement under the criteria for comparing results. The comparison data associated with the sampling activities are presented in Table I.

The licensee's primary and secondary chemistry procedures and analysis were found to be satisfactory and in accordance with the Electric Power Research Institute guidance. The team concluded that the licensee had an adequate internal laboratory quality assurance and quality control program and had appropriately participated in an acceptable interlaboratory program.

C. Human Performance

1. Organizational Practices

a. Inspection Scope

The team conducted in excess of 50 hours of control room observations, including a 24 hour continuous coverage period. Operators were observed performing evolutions, tests, and responding to annunciators. The team also accompanied operators during the performance of operator rounds. Written logs and shift status reports or updates were reviewed for completeness and accuracy to ensure they provided sufficient detail.

Additionally, the team observed the performance of six operating crews in the simulator (on-shift, initial license, and staff crews). The team evaluated shift communications and turnover, operator knowledge of plant conditions and activities in progress, and operator response to alarms.

The team observed scheduled and non-scheduled maintenance activities, the control room command function, and implementation of compensatory measures as required by risk and safety evaluations. The team observed pre-job and pre-evolution briefings, evaluated communication between operations and other departments, and interviewed operators to determine their awareness and understanding of ongoing activities.

Activities of field support supervisors and nuclear plant operators were observed to determine whether operations personnel were knowledgeable about the status of systems, structures, and components, equipment performance, and the impact of ongoing work activities.

b. Findings

The team determined that a resource limitation existed with respect to the number of licensed operators. There were 6 shift managers one of whom is the assistant operations manager, 5 control room supervisors, and 5 watch engineers at the site. The team noted that this level of staffing had the potential to increase the amount of planned and unplanned overtime deviations. In fact, several instances of planned as well as unplanned deviations from the administrative overtime limits were observed since January 1st, 2001. The team noted that the licensee had initiated efforts to requalify several individuals holding inactive senior operator licenses. Additionally, nine individuals were currently enrolled in a senior operator licensing class and were expected to be evaluated for operating licenses by the NRC in July 2001. Additional licensing classes were scheduled to start in April 2001 and early in 2002.

The team reviewed a number of self-assessments and third party assessments of operations training. It was observed that these assessments were self-critical and had identified a number of training weaknesses. The team concluded that although a number of significant challenges existed with respect to the operator training program, that the licensee had recognized these challenges and had initiated measures to improve the overall training program. However, progress in this area has been slow and the effectiveness of these measures had yet to be realized.

The team observed a weakness with respect to management reinforcement of standards associated with the use of plant operating procedures. It was observed that during the preparations to reduce power to repair a leak on the heater drain pump, that plant management believed that the abnormal operating instruction (AOI 21.1.1) for the loss of the drain pump provided an adequate basis for the ultimate power level to be achieved. However, the AOI guidance conflicted with the more conservative guidance contained in plant operating procedure (POP) 3.1 which governed a plant load decrease.[15] The team observed control room discussions concerning which procedure should be used. Ultimately, after discussions with the Chief Nuclear Officer, the licensee determined that the power should be reduced in accordance with POP 3.1. However, a night order written that evening to the plant operators suggested that it would have been acceptable to have terminated the load reduction at 900 MW. The team determined that the guidance in the abnormal operating instructions, while suggesting that an acceptable basis for the power level may exist at 900 MW, did not necessarily establish the most desirable plant conditions to conduct corrective maintenance. Rather, the abnormal operating instructions were written to place the plant in a safe and stable configuration from which additional actions and assessment can be made. The team determined that the management standards regarding the use and adherence to procedures were weak in this case. The team noted an additional weakness in that the planning and discussions associated with this evolution were concentrated in the control room versus being planned by engineering and maintenance with operations support.

In general, the command and control function in the control room was adequate. However, the team observed several problems in this area. For example, the team noted in one instance that shift management had difficulty prioritizing actions in response to multiple, simultaneous alarms. In another instance, the operating crew was not aware

[15] AOI 21.1.1 would lead to a power level of 900 MW whereas POP 3.1 would have led to a level of 650 MW

of post-maintenance testing being conducted. Additionally, during the start of a main boiler feedwater pump (MBFP), the control room supervisor exhibited weak operational oversight of activities when he became directly involved in the restart of the pump rather than directing overall activities.

On one occasion, the control room operators and maintenance personnel did not display conservative actions following erratic behavior of the main feedwater pump control system. On January 21, 2001, the 'B' MBFP flow oscillated and the 'A' MBFP control system and pump responded accordingly. Operators promptly placed the 'B' MBFP control system in manual, which stabilized the flow oscillations. On January 22, the team observed that the 'B' MBFP had been returned to automatic. When questioned, the operators stated that no troubleshooting work had been performed and the suspected control system inputs had not been instrumented. The operators felt that if the flow oscillations occurred again, they would be able to quickly respond. A second flow oscillation occurred the evening of January 23. System traces were not available to evaluate the pump's response or to positively identify the cause of the flow oscillation. Subsequent troubleshooting isolated the suspected channel but the failure to instrument the channel represented a missed opportunity and demonstrated the willingness of operators to accept a potential operational challenge.

During the 24 hour continuous control room coverage, a period when the plant was engaged in power ascension activities, minimal senior station management presence was observed in the control room. Lack of management involvement in control room activities had been identified in previous licensee self-assessments and NRC inspection efforts.

The team also observed during the control room observations that maintenance personnel suggested a potentially disadvantageous approach to repairing a service water leak on the generator hydrogen cooler. The recommended approach involved introducing a vulnerability of losing the only inservice hydrogen cooler, increasing the probability of a plant shutdown. After discussions between the operating crew and maintenance personnel, the crew conservatively determined that the alternate cooler should be placed in service prior to maintenance. The control room staff effectively managed the risk of the evolution. However, poor maintenance planning in this instance resulted in additional burden on the control room operating crew.

Problems in control room logkeeping were noted for the 1999 reactor trip with complications, the 2000 tube failure, the fall 2000 operator requalification inspection, and the recent turbine trip. It was again noted during the continuous control room coverage that the operating logs in the control room do not consistently contain an appropriate level of detail to allow a reconstruction of many operational activities.

In most cases, licensed operators were observed to use self-checking and peer checking in both the simulator and the control room. However, one instance was noted in which the balance of plant operator did not self-check during a valve manipulation. Instead of waiting for the valve to fully stroke, the operator walked away while the valve was in mid-stroke.

On one occasion, weak teamwork was exhibited by a shift crew when repeated alarms for a failed main steam line radiation monitor occurred simultaneously with repeated alarms associated with an in-progress post-maintenance test. These simultaneous alarms challenged the crew's effectiveness in prioritizing their actions to respond. In addition, the performance of the post-maintenance testing was not communicated to the crew, further contributing to the confusion. Also during this period, the crew was visibly frustrated with respect to a separate issue related to the power ascension ramp rate. The reactor engineer's instructions were to increase power at a maximum rate of 3% per hour. Some crew members wanted to be more conservative and proceed at a rate of about 2%. The shift manager, however, informed the crew that they were being overly conservative and the reactor engineer's instructions were meant to be an average ramp rate versus a maximum rate. This disagreement was eventually settled and discussed during the pre-evolution brief for the power ascension.

Several instances of a weak accounting of the status of ongoing evolutions were observed. For example, it was noted that place keeping within active procedures was not consistently conducted. During the power ascension it was not apparent which actions in SOP 21.1, "Main Feedwater System," had been completed. For example, several pages had missing signoffs and other pages were incomplete with respect to the steps which had been completed.

2. Training and Qualification

a. Inspection Scope

The team verified the training and qualifications of station personnel with respect to the level of work assigned. The team conducted observations of training using the guidance and checklists found in NUREG-1220 Rev. 1, "Training Review Criteria and Procedures." The team conducted interviews of trainees, supervisors, and instructors. The team assessed whether personnel were able to evaluate hypothetical conditions or data, identify respective emergency action levels, evaluate or perform dose calculations, classify emergencies, and recommend appropriate protective actions. Personnel were interviewed to determine their awareness and understanding of procedure changes, and whether they had received adequate training for their use.

b. Findings

Interviews were conducted with plant operators with respect to the quality of the site training program. Many operators stated that they believed that licensed operator continuing training was improving. Many of the operators noted that, while the overall industry operating experience level of the licensed instructors was good, the site specific experience level of the instructors warranted improvement.

The licensee had issued SL1 CR 200004471 as result of an adverse trend in the quality of nuclear training lesson plans. This trend was identified when initial licensed operator training was rescheduled due to inadequate lesson plans. The team reviewed the condition report and associated root cause assessment. It was determined that the overall assessment was adequate and that the corrective actions identified, if properly implemented, should address this significant issue. The actions planned to improve the lesson plans were scheduled for March and August 2001. Additionally, the team reviewed the licensee's assessment of the 2000 operator requalification examination. The licensee's evaluation included a root cause assessment of examination performance difficulties. The team concluded that the root cause assessment appeared to be adequate and that the corrective actions, if properly implemented, should address issues related to improving the fundamental knowledge level of the licensed operators. The licensee indicated that a review of the effectiveness of the actions taken will be conducted during the next licensed operator requalification examination.

A third party assessment of the simulator was conducted in March 1999 using the criteria in ANSI/ANS-3.5-1985, “Nuclear Power Plant Simulators for Use in Operator Training.” The conclusion of the assessment was that the simulator appeared to meet the requirements of the standard. Five weaknesses related to the simulator were identified and entered into the condition reporting system. Four of the five condition reports had been satisfactorily completed. The actions for the fifth weakness associated with the computer were in progress.

The fuel handler’s training provided to licensee personnel during the Fall 2000 outage was evaluated by the team. The training program included the refuel equipment course conducted by Westinghouse training and operational services at the Waltz Mills facility. The refuel equipment course was the same course for licensee and Westinghouse personnel and was conducted at the same facility, using the same course materials and instructors. In addition to the refuel equipment course, the fuel handler’s training program included site-specific crane training and qualification, based on the existing site crane operator training program. As part of the site-specific training, the fuel handler candidates completed a spent fuel tool, bridge crane, and upender refueling operator qualification guide containing three tasks and two refueling job performance measures. The three tasks were “operate the fuel storage building bridge crane,” “operate the spent fuel handling tool,” and “operate the upender.” The two job performance measures involved moving dummy assemblies and operation of the upender. The fuel handler training program was designed using systems approach to training techniques and should ensure that employees are satisfactorily qualified to safely move and handle nuclear fuel.

3. Communications

a. Inspection Scope

The team assessed the quality of communications and whether communications were consistent with the licensee’s procedures during the conduct of operations, maintenance, and testing activities. The team also evaluated the communications between various site departments and licensee management.

b. Findings

The team observed that overall crew communications were adequate. In most cases, operators announced expected and unexpected alarms, used three-way and, when appropriate, two-way communications. During the power ascension, communications between the control room supervisor and the operator at the controls were adequate.

The quality of pre-job and pre-evolution briefings was mixed but the briefings generally described expected indications and potential problems that could be encountered during the evolution.

4. Control of Overtime and Fatigue

a. Inspection Scope

The team reviewed the process for controlling overtime. Interviews were conducted with personnel who had worked overtime to determine how management ensures that personnel are not assigned to safety related duties while in a fatigued condition. A review of records was conducted to identify indications of recurrent or routine use of overtime.

b. Findings

The hours worked for operations personnel were reviewed. The team noted that while there did not appear to be an excessive use of overtime, that several instances of both planned and unplanned deviations from the overtime policy had occurred in recent months. During the continuous control room coverage, two operator trainees were observed to have worked a significant amount of overtime in order to acquire needed qualification requirements. A review of the audits conducted in calendar year 2000 through September 16, 2000, did not identify any working hour deviations that were not approved.

5. Human System Interface

a. Inspection Scope

The team conducted an evaluation of human-system interfaces, including work area design and environmental conditions. During both the control room coverage and simulator observations, the team walked down control panels and evaluated displays, controls, and alarms. The team assessed whether panels and equipment were correctly labeled and evaluated work areas.

b. Findings

The team did not identify any human-system interface problems with control room displays, controls, and alarms.

D. Emergency Preparedness

1. Problem Identification and Resolution

a. Inspection Scope

The team evaluated the effectiveness of corrective actions for emergency preparedness (EP) performance issues to determine whether identified problems were appropriately reviewed, prioritized, and resolved in a technically adequate and timely manner. The review included an assessment of 120 action items in the licensee's condition report system, QA audit report No. 00-05-A, and various self-assessments and exercise reports. In addition, interviews were conducted with the EP Manager and individuals responsible for overseeing the corrective action program within the EP group.

b. Findings

The team found that the licensee was self-critical of the EP program and had generated a number of condition reports to address identified performance issues. In particular, a number of thorough self-assessments were generated following the February 15, 2000, steam generator tube failure event. With respect to the overall program for identifying and correcting deficiencies in the EP area, the team determined that most condition reports were concise and well-written and that corrective actions had been appropriately specified. However, the team found several examples where the condition report responses were not sufficiently descriptive, or did not describe the actual corrective action taken.

The team reviewed surveillance test records for the Emergency Response Data System (ERDS) and found the system was operable in the 2^{nd} and 3^{rd} quarter of 2000. However, the system was found inoperable during an exercise in November 2000, and also during a test conducted in the 1^{st} quarter of 2001. The system engineer stated that the cause of this failure was that the modem assigned to the ERDS had been borrowed and reconfigured prior to both tests. The NRC conducted an ERDS test during the inspection and found both the system and the backup to be operable. However, the team noted there were no procedures for activating the backup system. The licensee generated CR 200100964 to address this issue. Overall, the team concluded that the corrective actions taken as a result of a drill deficiency were inadequate to prevent a recurrence with respect to the failure of the ERDS. The finding was determined to have very low safety significance (Green) because the licensee retained capability to communicate via the telephone system. 10 CFR 50.54(q) states that licensees will follow and maintain in effect an E-Plan which meets the planning standards of 10 CFR 50.47(b) and the requirements of 10 CFR Part 50, Appendix E. This is considered a Severity Level IV violation of 10 CFR 50.47(b)(14), which states that deficiencies identified during a drill/exercise will be corrected. This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368) **(NCV 05000247/2001-002-007)**.

The team noted that the licensee was responsive in resolving most identified issues. However, in some cases the licensee was not effective in diagnosing the underlying causes for the problems to prevent recurrence. Some examples of this included the ERDS issues discussed above and issues involving qualification lapses in the emergency response organization. Additionally, the licensee had identified several deficiencies in exercises that appeared to be repetitive (section D.5). The corrective actions focused on conducting an additional exercise, post-exercise critiques and lessons learned with emergency response organization emergency facility leads. However, the actions did not include an assessment of, for example, the effectiveness of training for resolving these issues, qualifications of the responders, or lessons-learned from discussions with the affected individuals.

During drills conducted in the past two years, the licensee consistently identified problems with the site public address system. After several attempts by EP to have engineering address this issue, a contingency measure was established to use a bullhorn in areas determined to be inaudible. The licensee indicated that the system needed to be upgraded and that repairing the system had not been considered a priority and entered into the corrective action system. While the EP work around was an adequate temporary corrective action, the team considered the continual delays by engineering to fix this issue a weakness.

The team identified a weakness with respect to the process for conducting the 2000 nuclear quality assurance audit in the emergency planning area. The team determined the audit report met the 10 CFR 50.54(t) requirements; however, the licensee did not maintain checklists for the team to verify the conduct of the audit and for supporting the conclusions in the audit report. In addition, the audit report did not include an assessment of the adequacy of corrective actions for previously identified deficiencies listed in the corrective action system. The team concluded that due to the number of emergency planning weaknesses in the past year, an independent assessment of ongoing corrective actions would have been appropriate.

Interviews with the EP manager indicated that he was knowledgeable of the corrective actions taken for identified performance issues. However, an EP staff member was delegated the responsibility for maintaining the condition reporting system. The site corrective action program manager stated that the use of a “surrogate” is considered to be an acceptable practice at the site. However, the EP manager did not routinely review the narrative of how condition reports were closed. This issue is considered a weakness and was entered into the licensee’s corrective action system (CR 200101416) for resolution.

2. Emergency Response Staffing

a. Inspection Scope

The team reviewed the licensee’s emergency response organization to ensure the minimum on-shift staffing met the applicable regulatory requirements and that staffing was sufficient to fill positions needed in the emergency facilities. The team also reviewed drill records and call-in procedures to determine if augmentation and off-hour drills were held as required by the E-Plan, whether augmentation goals were met, and that off-shift personnel were available if needed. In addition, interviews were conducted with emergency response organization responders to verify their understanding of the call-out process and their responsibilities for reporting to their facilities during an event.

b. Findings

The team verified that the emergency response organization assignment roster met the minimum on-shift staffing requirements as stated in the E-Plan. Key positions were divided into three teams with most positions having alternates as additional backups. Although the licensee designated a team per week to be on-call, they required all teams to report during an event to ensure complete coverage. Weekly pager tests were performed for the on-call team. A review of records indicated acceptable pager performance. The licensee conducted an unannounced off-hours augmentation drill in April 2000 and met the 60 minute requirement in all emergency facilities. The licensee had been conducting off-hours testing of a new automated dialer system (section D.4), and test records indicated that they would have been able to fill all key positions should there have been a real event. The EP manager stated that an unannounced off-hours drill would be conducted in 2001 to further verify that changes made to the notification system were adequate. During the planned drill, the ability to staff the Joint News Center will also be verified. Interviews with individuals who were recently added to the emergency response organization indicated they were knowledgeable of the call-out process and understood their responsibilities during an event.

3. Emergency Plan and Procedure Quality

a. Inspection Scope

The team performed a review of E-Plan changes since June 2000 to determine if any changes had decreased the effectiveness of the plan. In addition, a review of the plan's implementing procedures relative to the significant planning standards was performed. The team evaluated the 10 CFR 50.54(q) review documentation and applicable procedures to assess the adequacy of the method for reviewing the E-Plan and implementing procedure changes.

b. Findings

The team noted an instance where the licensee's review of changes made to the E-Plan and implementing procedures was not thorough. The issue involved a change to implementing procedure IP-1035, "Technical Support Center," Attachment 2. The change stated that prior to activation, a minimum staffing level of three individuals was required. This change appeared to contradict the E-Plan which stated that a minimum staffing level of seven people was needed for activation. The licensee continued to commit to the 60-minute activation staffing level (seven people), as set forth in the E-Plan. However, the licensee stated that the intent of IP-1035, was that a minimum of three people could begin to assist the control room. The licensee acknowledged that the word "activation" may have been misused in the implementing procedure relative to its use in the E-Plan. This issue was entered into the corrective action system (CR 200100813) and the discrepancy was corrected.

4. Emergency Facility Equipment

a. Inspection Scope

The team reviewed surveillance test records and maintenance procedures for offsite sirens, emergency pagers and communication equipment to determine if the tests were performed in accordance with regulations and E-Plan commitments. In addition, the team conducted an inventory of the emergency equipment located in the emergency facilities using the appropriate inventory checklists.

b. Findings

The team found a number of discrepancies with respect to the equipment inventories. These included: (1) five radiological instruments were out of calibration at the Emergency Operations Facilities (EOF); (2) the monthly inspection of full face respirators was not conducted in April and June 2000; (3) a radiological instrument located in one of the field kits had low batteries, and no batteries were found in the kit; (4) an expired calibration sticker on a meter was not replaced when calibrated the previous month; and, (5) inventory lists were not updated to reflect the addition of several radiological check sources.

According to Section 8.3 of the E-Plan, facility inventories are to be conducted on a quarterly basis. The licensee could not provide inventory records for the third quarter nor verify that those inventories were actually conducted. The EP manager stated that due to limited resources, the responsibility for conducting the inventories was given to another department within the past year. The team concluded that the emergency planning organization was not proactive in making sure the inventories were being conducted and properly documented. These issues were entered into the corrective action system (CR 200100815) and out-of-calibration instruments were immediately replaced. The team considered this issue to be of very low safety significance (Green) because notwithstanding the discrepancies which were identified, the licensee had sufficient resources in the facilities to properly respond to an event. 10 CFR 50.54(q) states that licensees will follow and maintain in effect an E-Plan which meets the planning standards of 10 CFR 50.47(b) and the requirements of 10 CFR Part 50, Appendix E. This is considered a Severity Level IV violation of 10 CFR 50.54(q) and the licensee's E-Plan, Section 8.3 which states that quarterly inventories will be conducted. This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368) **(NCV 05000247/2001-002-008)**.

In July 2000 the licensee's system performance group began an extensive initiative to address emergency response organization pager problems. These actions included: (1) evaluation of the current vendor for compatibility; (2) consolidation of pagers under one vendor; (3) installation of a repeater system to ensure pager operability in "dead" zones; and, (4) establishment of specific testing criteria. The work was completed by October 2000, and since that time, weekly pager test records indicated significant improvements in reliability. The licensee had installed and was testing an automated telephone system which would backup the pager system by simultaneously telephoning responders. The responders would call back the system which would log and track the number of responders needed to fill ERO positions. The licensee stated that this system would be operational by April 1, 2001.

Finally, the inspectors noted that Section 8.1.3 of the E-Plan stated that emergency communication links between facilities will be operationally checked on a quarterly basis. The communication tests would include the dedicated NRC communication links used in each facility. The team reviewed communication records for the year 2000 and found that the licensee was not able to produce the 3rd quarter records and could not verify that the required tests had been conducted. This issue was entered into the licensee's corrective action system (CR 200101776). The team determined this issue to be of very low safety significance (Green) because the licensee had installed spare operable telephone lines. 10 CFR 50.54(q) states that licensees will follow and maintain in effect an E-Plan which meets the planning standards of 10 CFR 50.47(b) and the requirements of 10 CFR Part 50, Appendix E. This is considered a Severity Level IV violation of 10 CFR 50.54(q) and Section 8.1.3 of the E-Plan. This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368) **(NCV 05000247/2001-002-009)**.

5. Emergency Response Organization Performance

a. Inspection Scope

A review was conducted of the licensee's training program to ensure it was in compliance with the applicable regulations and the E-Plan. The team reviewed the following: (1) EP-AD-03, "ERO Training Program"; (2) various lesson plans; (3) conduct of training; (4) experience and qualifications of instructors; and (5) ERO qualification training records. The team also conducted interviews and observed training to identify any observed weaknesses. In addition, the team reviewed reports for several recent training exercises to determine the adequacy of training and the ability to identify and correct exercise deficiencies in a timely manner.

The team evaluated four mini-evaluation drills of simulated events that tested the performance of key members of the emergency response organization in understanding their assignments, responsibilities and authority. These drills provided an independent assessment of the licensee's capabilities to make and assess emergency classifications, dose assessment calculations and protective action recommendations (PAR). In addition, the team reviewed the documentation generated as a result of the exercises and evaluated the licensee's critique process.

b. Findings

The team observed that the licensee had recently revised their training program. The revision included procedure and exam development, classroom training, and a tracking process for qualifications. However, the team found that the program procedure did not describe if a drill or exercise was needed for initial qualifications or for requalification. Additionally, the procedure lacked specificity regarding the tracking of deficiencies.

The team reviewed the critique comments from classroom training conducted in December 2000 and found that while the comments were primarily administrative in nature, several had some technical significance. For example, comments involved confusion with terminology, questions on activation, request for additional practice for making classifications, and confusion regarding what procedures are current (versus changes expected to be made). The team further noted that there was no formal mechanism for reviewing critique comments and documenting their resolution. The team concluded that this represented a weakness with respect to documenting and tracking training issues.

The team interviewed a number of staff in key emergency response organization positions. There was a consensus that training had improved and that the EP staff were receptive to critical feedback and program enhancement suggestions. The team also observed an operations support center facility walkthrough class and noted the instructor was knowledgeable of the facility. The team further observed that the training appropriately emphasized the use of procedures and that the participants were actively involved in the training session.

The team reviewed qualification records and the training matrix listed in the licensee's administrative procedures. Overall, the team found that emergency responder qualifications were current. However, ten individuals assigned to the offsite and onsite monitoring teams had let their respirator qualifications lapse. It was determined that there was confusion between the EP and the health physics organizations regarding the necessity for maintaining respirator qualifications for emergency responders. Upon further review, the EP manager determined that all individuals that would be expected to wear respirators must be respirator qualified. This issue was entered into the licensee's corrective action system (CR 200100290) and at the end of the inspection the issue had been resolved. The team determined this issue to be of very low safety significance (Green) because there were sufficient responders with respiratory qualifications to fill the positions. 10 CFR 50.54(q) states that licensees will follow and maintain in effect an E-Plan which meets the planning standards of 10 CFR 50.47(b) and the requirements of 10 CFR Part 50, Appendix E. This is considered a Severity Level IV violation of 10 CFR 50.54(q) and E-Plan Section 8.1.2 of the licensee's E-Plan which describes the qualifications necessary to maintain proficiency as an emergency responder. This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368) **(NCV 05000247/2001-002-010)**.

Since the June 2000 NRC evaluated exercise, the licensee conducted four exercises[16] with the "blue" and "red" emergency response teams. The exercise reports were found to be self-critical and had identified areas for improvement. The NRC team trended the deficiencies identified in the four exercise reports and found repetitive issues in the exercises that were reflective of past performance, particularly in the area of plant assessment and the dissemination of the information to the general public.

[16] August, November (2), and December 2000

The team reviewed the condition report generated following the August 2000 exercise and found it to be descriptive; however, the corrective actions were general, simply indicating that more exercises were needed and lessons learned should be discussed with the facility leads. In this case, the affected team had one additional exercise and the lessons learned discussion was not performed until November. The condition reports associated with the second exercise did not capture the deficiencies in the joint news center and the corrective actions were only generally described and not pertinent to all the significant issues. The licensee provided two lesson plans for classes conducted in November 2000 and the instructor notes indicated some of the repetitive issues were addressed, but the classes were limited to only the facility leads and not the organization as a whole. Further, the team noted that the licensee did not retain any original player or controller comments, or trend and assess exercise performance. The emergency planning organization expressed their belief that significant improvement in the TSC has been observed, but that other facility personnel were not fully aware of the improvements and tend to be overly critical. However, the team noted that irrespective of the adequacy of the TSC, that a lack of confidence on the part of other key organizations could limit the effectiveness of the TSC.

While it appears the licensee implemented some corrective actions, the team determined that the licensee's training program was not fully effective in preventing recurrence of issues to ensure consistent emergency response organization performance. The team determined this issue to be of very low safety significance (Green) because these performance issues did not deal with the risk significant planning standards (classifications, notifications, PARs). The licensee entered this issue into the corrective actions system (CR 200101775). 10 CFR 50.54(q) states that licensees will follow and maintain in effect an E-Plan which meets the planning standards of 10 CFR 50.47(b) and the requirements of 10 CFR Part 50, Appendix E. Section 8.1.2 of the licensees E-Plan states a training program is established to train employees and exercising, by periodic drills to ensure that employees maintain the proficiency of their specific emergency response duties. This is considered a Severity Level IV violation of 10 CFR Part 50.54(q) and Appendix E.IV.F.2.g for inadequate training. This violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368) **(NCV 05000247/2001-002-011)**.

The team observed and evaluated the licensee's performance in response to two drills and four separate scenarios. The licensee used a limited emergency operations facility staff and simulated support from the technical support center to conduct the drill. The scenarios both required an upgrade to the protective actions recommendations due to a wind shift in one case, and increased radiological release in another. Dose assessment calculations were performed with the two shift managers and their control room supervisors and was independent of the training class. The team determined that the licensee effectively evaluated plant conditions and the emergency classifications. The required notifications and protective actions recommendations were accurate and timely. The licensee conducted an adequate critique of each performance and identified areas for improvement.

6. Emergency Preparedness Off-site Interface

a. Inspection Scope

The team evaluated the licensee's interface with off-site state and county agencies. This included a review of documentation of off-site state and county meetings, letters of agreement with offsite organizations and training drills. Also, the team conducted telephone interviews with the lead contacts from the New York State Emergency Management Agency, Orange County Office of Emergency Management, Rockland County Office of Fire and Emergency Services, Westchester County Office of Emergency Management and the Putnam County Office of Emergency Management.

The team reviewed documentation of radiological orientation training provided to the media as required by the regulations and the E-Plan. An interview was conducted with the site communications manager regarding the status of corrective actions from deficiencies identified during the Alert Event on February 15, 2000, and the June 1, 2000, exercise at the joint news center.

b. Findings

Following the steam generator tube failure event of February 15, 2000, the licensee has met with state and county officials on numerous occasions to gain a better understanding of their needs and requirements. While expressing concerns about the extent of past overall communications, most of the state and county officials indicated that the licensee has made an effort to improve communications and address their needs with respect to emergency preparedness. The team verified that all required offsite training and drills had been conducted and that letters of agreement for offsite assistance were current. The team also observed that the licensee conducted the required annual training session for the local media as required in Section 8.4 of the E-Plan.

E. Conclusions Regarding Performance in the Reactor Safety Strategic Performance Area

The team determined that overall performance was acceptable in the reactor safety strategic performance area. However, a number of issues were identified in the areas of design control, procedures, equipment and human performance, and emergency preparedness which indicated weaknesses in these areas as well as the need for continued improvement. The issues identified by the team have, individually, been evaluated under the risk significance determination process as being minor in nature or having very low safety significance (Green). However, the issues provide evidence of some program and process weaknesses similar to those which contributed to previous plant events.

In the design control area, the team identified several examples of performance issues related to weaknesses in translating important design assumptions into plant operating procedures, drawings, calculations, and testing programs. These examples point to weaknesses in the design control process which indicate the need for continued improvement in this area. Additionally, the team observed that there appeared to be difficulties in retrieving design basis information necessary to support design control, testing and plant modification efforts. This issue had been previously identified and slow progress has been made to improve in this area. Notwithstanding the performance issues identified, the team determined that while weaknesses, some of a longstanding nature, existed in the design control area, that the 480 Vac/emergency diesel generator and service water systems were capable of performing their safety functions.

In the area of procedures, the team found that while overall procedure quality was adequate, performance weaknesses in both procedure quality and usage existed at the facility. The team found deficiencies related to procedure clarity, consistency, and accuracy in administrative and implementing procedures. The team also noted that flexible guidance in some administrative procedures allowed for wide variation in procedure use and interpretation and there were several instances where the team identified that design, vendor, or modification information was not properly translated into procedures.

In the area of equipment performance, the team determined that the reliability, material condition and overall performance was acceptable for the systems which were reviewed. However, a number of equipment issues were observed which presented challenges to both the plant as well as the operators. It was observed that emergent equipment failures in secondary plant systems continue to challenge the plant operators and require plant power changes. The team also noted a decrease in reliability and a concurrent increase in unavailability of the gas turbine generators which appeared to be partly attributable to a decrease in the emphasis on maintenance for this equipment. Finally, the team noted that the station work backlog continued to pose a significant challenge to the station. It was also determined that a number of important work items had not been accurately captured in the accounting for the backlog, indicating that the backlog may be somewhat larger than stated.

In the area of human performance, the team noted an increased emphasis on overall improvement and a recognition of the need for an improved training program. However, a number of program and process issues were identified. In particular, a challenge existed with respect to the number of licensed operators which posed complications with respect to overall scheduling and overtime considerations. The team observed that there was a management recognition of this problem and that steps have been undertaken to increase the number of licensed operators. The team also observed that operator performance issues have contributed to recent events and that some performance problems continue to occur. Specifically, performance errors were observed in the August 1999 reactor trip, February 2000 steam generator tube failure and as recently as the January 2001 turbine trip. Additionally, inconsistencies continue to exist with respect to procedural quality and adherence, owing, in large measure, to inconsistent reinforcement of management expectations in this area. However, the team did observe that during the inspection, overall crew performance was acceptable, and in particular, crew communications were good, indicating some improvements.

In the area of emergency preparedness, the team determined that the overall program was adequate and provided reasonable assurance that the emergency response organization could respond effectively to an emergency. Additionally, while issues were identified that indicated the need for continued improvement, improvements were noted in a number of previously identified problem areas. Notwithstanding the improvement which was observed, the team concluded that the remediation for some of the previously identified performance issues in the technical support center, emergency operations facility and joint news center had not been fully effective. The team acknowledged that although some corrective actions had been implemented, the licensee's training program has not been fully effective in preventing the recurrence of issues to ensure consistent emergency response organization performance. However, risk significant planning standards continue to be met.

3. Root and Contributing Cause Assessment

The team, in accordance with Inspection Procedure 95003, integrated the inspection findings, with the results of similar, previous efforts in order to provide insight into the upper level causes of performance issues at the site. It should be noted, however, that this effort was not intended to be a substitute for a more focused root cause study or self-assessment by the licensee.

The team identified four specific causes:

- Inconsistent management application and reinforcement of existing standards with respect to staff performance, particularly in the areas of procedural quality and adherence and in implementation of the corrective actions programs.

- Weaknesses existed with respect to the ability to retrieve, verify, and assure the quality of engineering products, particularly design basis information. These weaknesses contributed to problems in developing and validating calculations, testing methodologies and acceptance criteria.

- The plant staff tended to accept degraded conditions. This was true of both equipment and documentation issues. However, it was noted that improvement has been made in this area, in particular, the increased emphasis on problem identification.

- A number of performance problems may have been influenced by resource issues. In particular staffing issues (in operations and instrumentation and control) and training resources.

4. Management Meetings

Exit Meeting Summary

The team conducted a detailed debriefing with the licensee on February 15, 2001.

An exit meeting, open for public observation, was conducted on March 2, 2001, at the Cortlandt Town Hall, Cortlandt, New York. The inspection results were presented to Mr. J. Groth and other members of the licensee staff who acknowledged the findings. This exit meeting was followed by a public question and answer session with elected officials and members of the public.

ITEMS OPENED, CLOSED AND DISCUSSED

Opened And Closed During This Inspection

05000247/2001-002-001	NCV	10 CFR 50 Appendix B, Criteria XVI, Corrective Action
05000247/2001-002-002	NCV	10 CFR 50 Appendix B, Criteria III, Design Control
05000247/2001-002-003	NCV	Technical Specification 6.8.1, Procedures
05000247/2001-002-004	NCV	10 CFR 50 Appendix B, Criteria V, Instructions, Procedures, Drawings
05000247/2001-002-005	NCV	10 CFR 50.55.a, Inservice Testing
05000247/2001-002-006	NCV	10 CFR 50.65(a)(1), Maintenance Rule
05000247/2001-002-007	NCV	10 CFR 50.47(b)(14), EP Drill Deficiencies
05000247/2001-002-008	NCV	10 CFR 50.47(b)(8), Emergency Equipment
05000247/2001-002-009	NCV	10 CFR 50.54(q), E-Plan 8.1.3, Communication Tests
05000247/2001-002-010	NCV	10 CFR 50.54(q), E-Plan 8.1.2, Emergency Responder Proficiency
05000247/2001-002-011	NCV	10 CFR 50.54(q), Appendix E.IV.F.2.g, Inadequate Training

TABLE I
INDIAN POINT 2 RADIOCHEMISTRY TEST RESULTS

SAMPLE	RADIONUCLIDE	NRC VALUE	Con Ed VALUE	COMPARISON
Liquid Radwaste 0945 hrs 2-8-01 (Detector NUC3) (Results in microCuries per milliliter)	Co-60 Cs-137 Co-58 Sb-125	(2.81±0.09) E-6 (6.00±0.10)E-6 (1.76±0.08)E-6 (2.62±0.04)E-5	(2.71±0.10) E-6 (5.81±0.11)E-6 (1.81±0.07)E-6 (2.60±0.04)E-5	Agreement Agreement Agreement Agreement
Reactor Coolant Particulate Filter (Crud Filter) 1200 hrs 1-31-01 (Detector NUC3) (Results in microCuries per milliliter)	Co-60 Co-58 Mn-54 Cr-51 Zr-95 Sb-124	(3.62±0.02)E-4 (5.16±0.02)E-4 (3.74±0.09)E-5 (1.522±0.008)E-3 (1.158±0.016)E-4 (6.6±0.6)E-6	(3.50±0.03)E-4 (5.04±0.03)E-4 (3.85±0.16)E-5 (1.553±0.014)E-3 (1.15±0.03)E-4 (6.1±0.7)E-6	Agreement Agreement Agreement Agreement Agreement Agreement
Reactor Coolant (First Count) 0828 hrs 2-8-01 (Detector NUC2) (Results in microCuries per milliliter)	I-132 I-133 I-134 I-135	(1.46±0.06)E-3 (7.8±0.3)E-4 (2.41±0.11)E-3 (1.50±0.14)E-3	(1.54±0.07)E-3 (8.3±0.7)E-4 (3.14±0.10)E-3 (1.80±0.16)E-3	Agreement Agreement Agreement Agreement
Reactor Coolant (Second Count) 0828 hrs 2-8-01 (Detector NUC2) (Results in microCuries per milliliter)	I-131 I-132 I-133 I-135	(1.1±0.2)E-4 (1.8±0.2)E-3 (7.9±0.2)E-4 (1.82±0.14)E-3	(9±2)E-5 (1.52±0.16)E-3 (8.7±0.3)E-4 (1.7±0.2)E-3	Agreement Agreement Agreement Agreement

SAMPLE	RADIONUCLIDE	NRC VALUE	Con Ed VALUE	COMPARISON
Waste Gas Decay Tank 1409 hrs 2-8-01 (Detector NUC2) (Results in microCuries per milliliter)	Xe-133 Xe-135	(2.63±0.03)E-5 (1.68±0.06)E-6	(2.48±0.04)E-5 (1.62±0.06)E-6	Agreement Agreement
Plant Vent Charcoal Cartridge 1235 hrs 2-7-01 (Detector NUC2) (Results in microCuries per milliliter)	I-131 I-133	<6E-13 <1E-12	<9E-13 <1E-12	No comparison, no radionuclides were detected in this sample.
Plant Vent Particulate Filter 0948 hrs 2-6-01 (Detector NUC2) (Results in microCuries per milliliter)	Co-60 I-131 I-133	<1E-13 <9E-14 <7E-13	<2E-13 <2E-13 <8E-13	No comparison, no radionuclides were detected in this sample.
Air Ejector 1308 hrs 2-7-01 (Detector NUC3) (Results in microCuries per milliliter)	Kr-85 Xe-133 Xe-135	<6E-6 <6E-8 <3E-8	<1E-6 <9E-9 <4E-9	No comparison, no radionuclides were detected in this sample.

SAMPLE	RADIONUCLIDE	NRC VALUE	Con Ed VALUE	COMPARISON
Steam Generator Blowdown (Water) 0900 hrs 2-7-01 (Detector NUC2) (Results in microCuries per milliliter)	Mn-54 Co-58 Co-60 I-131 I-133 Cs-137	<8E-8 <8E-8 <1E-7 <9E-8 <9E-8 <1E-7	<9E-8 <9E-8 <1E-7 <6E-8 <7E-8 <9E-8	No comparison, no radionuclides were detected in this sample.
Service Water 0900 hrs 2-9-01 (Detector NUC3) (Results in microCuries per milliliter)	Mn-54 Co-58 Co-60 I-131 I-133 Cs-137	<9E-8 <8E-8 <1E-7 <9E-8 <8E-8 <1E-7	<2E-7 <5E-8 <1E-7 <1E-7 <1E-7 <2E-7	No comparison, no radionuclides were detected in this sample.

NOTE: Reported uncertainties are ± 1 Standard Deviation counting uncertainties for both NRC and licensee results.

ATTACHMENT TO TABLE I

CRITERIA FOR COMPARING ANALYTICAL MEASUREMENTS

This attachment provides criteria for comparing results of capability tests and verification measurements. The criteria are based on an empirical relationship which combines prior experience and the accuracy needs of the program.

In these criteria, the judgement limits are variable in relation to the comparison of the NRC Reference Laboratory's value to its associated uncertainty. As that ratio, referred to in this program as "Resolution," increases, the acceptability of a licensee's measurement should be more selective. Conversely, poorer agreement must be considered acceptable as the resolution decreases.

Resolution[1]	Ratio for Comparison[2]
<4	No Comparison
4 - 7	0.5 - 2.0
8 - 15	0.6 - 1.66
16 - 50	0.75 - 1.33
51 - 200	0.80 - 1.25
>200	0.85 - 1.18

1. Resolution = (NRC Reference Value/Reference Value Uncertainty)

2. Ratio = (Consolidated Edison Value/NRC Reference Value)

ATTACHMENT 1

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.

ATTACHMENT 2

LIST OF ACRONYMS USED

AAC	Alternate AC
AFW	Auxiliary Feedwater
AOI	Abnormal Operating Instruction
ARP	Alarm Response Procedure
ASSD	Alternate Safe Shutdown
CARB	Corrective Action Review Board
CCHX	Component Cooling Heat Exchanger
CCR	Central Control Room
CCW	Component Cooling Water
CFR	Code of Federal Regulations
COL	Check-Off List
CR	Condition Report
DBD	Design Basis Document
ECP	Employee Concern Program
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
FMEA	Foreign Material Exclusion Area
GT	Gas Turbine Generator
GPM	Gallons Per Minute
ICPM	Instrument & Controls Preventive Maintenance
IMC	Inspection Manual Chapter
IPE	Individual Plant Examination
KVA	Kilo Volt Ampere
KW	Kilo Watt
LOCA	Loss Of Cooling Accident
MCC	Motor Control Center
MOV	Motor Operated Valve
MPFF	Maintenance Preventable Functional Failure
MR	Maintenance Rule
NCV	Non-Cited Violation
OAD	Operations Administration Directive
P&ID	Piping and Instrumentation Diagram
PM	Preventive Maintenance
PMT	Post Maintenance Test
POP	Plant Operating Procedures
QA	Quality Assurance
RCS	Reactor Coolant System
SAO	Station Administration Order
SDP	Significance Determination Process
SGRO	Steam Generator Replacement Outage
SL	Significance Level
SOP	System Operating Procedures
SOV	Solenoid Operated Valve
SSC	Structures, Systems and Components
SW	Service Water

SWSOPI	Service Water System Operational Performance Inspection
TFC	Temporary Field Change
TOL	Thermal Overload
TP	Test Procedure
TPC	Temporary Procedure Change
UFSAR	Updater Final Safety Evaluation Report
VAC	Volts AC
VDC	Volts DC
VMI	Vendor Manual Index

ATTACHMENT 3

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection, including documents prepared by others for the licensee. Inclusion on this list does not imply that NRC inspectors necessarily reviewed the documents in their entirety but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Calculations/Studies/Engineering Analyses

NSL-EDG-900430A, Emergency Diesel Generator Fuel Oil Minimum Storage Requirements, Rev. 0
Con Edison study, "Update of the Indian Point Unit 2 Emergency Diesel Generator Loading Study," dated December 18, 2000
FEX-00152-00, Revision 0, 1/22/01, EDG Generator Ratings Analysis
Westinghouse Motor Company Engineering Report WMC-EER-90-005, dated October 23, 1990
FEX-00143-00, IP2 LOAD FLOW ANALYSIS OF THE ELECTRICAL DISTRIBUTION SYSTEM, 12/14/00
FEX-00120-01, Analysis of EDG Load Sequencing for Blackout & Unit Trip with and without an SI
FEX-00029-02, MINIMUM VOLTAGE ANALYSIS FOR INSTRUMENT BUSES 21 THRU 24 &21A THRU 24A, dated 2/3/98
FEX-00019-01, FEX-00020-01, FEX-00021-01, FEX-00022-01 INSTRUMENT BUS LOADING FOR INSTRUMENT BUSES
FEX-00025-02, Minimum Voltage Analysis for the Loads on Instrument Buses 21 & 21A, dated 2/3/98
EGE-00001-02, Indian Point - Class 1E Motor Minimum Starting Voltage and Acceleration Time Calculations, Rev. 2, 6/24/98
FEX-00101-00, revision 01, 4/21/00, 13.8 kV and 6.9 kV cable ampacity for primary and secondary leads of the new GT-1 transformer
125Vdc Protective Device Coordination Study No. SGX-00007-03 - Ebasco - Original, date 9/25/91, revision 3, approved 4/16/98
EPG-00006-00, Verify Adequacy of 480 Volt DB-50 Switchgear to interrupt Worst Case Short Circuit, Rev. 0, 9/5/91
SGX-00013-04, Setpoint Change for Undervoltage Relays on 480 Volt Buses 2A, 3A, 5A and 6A, Modification EGP-91-06786-E, Revision 4, dated 9/10/99
SGX-00004-00, Indian Point 2 - Calculate Fault Current at 480V Switchgear including 6.9 kV Motor Contributions, Rev. 0, 5-28-92
DA-EE-93-107-07, 480 Volt Coordination and Circuit Protection Study, Rev. 2
FFX-00822-01, Stress Analysis of Jacket Water Header for EDG JW Expansion Tank due to Replacement of Valve JW-5 (CR 200007667).
FMX-00107-00, EDG-JW/LOC Bundle Replacement - Seismic Evaluation.

Calculations/Studies/Engineering Analyses (Cont.)

MEX-00041-00, Seismic Evaluation of EDG Jacket Water and Lube Oil Coolers.
GMS-00014-01, Pipe Stress Analysis of Diesel Fuel Oil System to Determine if Piping is Over stressed due to Replacement of FO Valves to Day Tanks.
FFS-00131-00, Evaluation of Diesel Gen 21, 22 & 23 Air Compressors
FFX-00408-01, Evaluation of Diesel Generator Starting Air Line and "Supports Due to Installation of Hose at Motor.
FPX-00009-01, Installation of Check Valves in Discharge Lines from EDG 21, 22, and 23, Seismic Support Evaluation.
GCC-00155-00, Compressor Mounting in EDG Building - Seismic.
MMM-00014-00, IP Sluice Gate Flow, 1/29/92
PE-SW-910830A, SWP Submergence & NPSH, 8/30/91
PGI-00111-01, EDG JW and LO Heat Exchanger Tube Velocity, 3/10/95
(No document number),Update of the Indian Point Unit 2 Emergency Diesel Generator Loading Study, Final Report, Rev 0
Technical Report No. 97222-TR-28, Indian Point Unit 2 GL 98-13 Heat Exchanger Performance Assessment Program, Rev 1, June 2000
(No document number), Hydraulic Model Study of Service Water Intake by Alden research Laboratory, Inc., July 1994
PGI-00354, Generic Letter 89-13 Heat Exchanger Performance Assessment Program, Rev 1
PGI-00371-00, Service Water System Hydraulic Model, 7/29/98
MAA-00001, Service Water DBD Item 035, CFCU Outlet Flashing, Rev 00
FFX-00713, Evaluation of Service Water Strainer Minimum Blowdown Flow Through Throttled Valves, Rev 0
FFX-00300, Evaluation of Line 405, New & Existing Supports Due to t he Replacement of Valves SWN-35 & 35-1, Rev 2
FMX-00102, EDG Jacket Water Cooler & Lube Oil Cooler Performance, Rev 00
PGI-00162, 22 EDG Jacket Water Heat Exchanger Performance, Rev 0
PGI-00163, 22 EDG Lube Oil Heat Exchanger Performance, Rev 0
SMX-00005, FCU Service Water Flow Transmitter Replacements, Rev 1
FMX-00128, EDG-JWC/LOC Bundle Replacement: Vendor Thermal and Mechanical Design Calc., 4/29/99
GE Report NBR DER-1703, Emergency Diesel Flow Test, 9/19/91
RS-92, Service Water System Radiation Detector Alarm Set point, Rev 2
FEX-00003-00, Heat Trace of Lines 155, 161 and 181 for RWST, Rev. 0
EGE-00001-02, Class IE Motor Minimum Starting Voltage and Acceleration Time
EGE-00006-00, EDG Upgrade DB-75 and Switchgear Testing
EGE-00022-01, DB-75 Overload Capability During Degraded Voltage Conditions
EGP-00018-00, Service Water Improvement / Electrical Power Supply Ampacities
EGP-00027-00, Power Cable Ampacities for 480 VAC and 125 Vdc Systems
EGP-00110-00, Summary of Degraded Voltage Study
EGP-S36-001-00, EDG Bldg. Ventilation System Upgrade Control Panel Feeder Sizing
EGP-S36-002-00, EDG Bldg. Ventilation System Upgrade Ampacity & Voltage Drop
EPG-00006-00, Verify Adequacy of DB-50 Switchgear to Interrupt Worst Case Short Circuit

Calculations/Studies/Engineering Analyses (Cont.)

FCX-00421-00, Maximum Outside Ambient Air Temperature to Maintain 104°F Inside EDG Bldg.
FEX-00019-xx, 118VAC Instrument Bus Loading
FEX-00025-02, Minimum Voltage Analysis for Loads for Instrument Buses 21 &21A
FEX-00048-02, Minimum Voltage Analysis for 125 Vdc Power Panels
FEX-00066-00, Auxiliary Feedwater Pump Operability at 500 HP
FEX-00087-00, EDG 21, 22 & 23 KW Meter Accuracy
FEX-00139-00, EDG Loading
FEX-00143-00, Load Flow Analysis of the Electrical Distribution System
FEX-00148-00, Plant Startup with Pending EDG Load Study Revision
FEX-00152-00, EDG Generator Ratings Analysis
GMH-00006-00, Ventilation System for the EDG Building
SGX-00004-00, Fault Current at 480 Volt Switchgear Including 6.9 KV Motor
SGX-00005-00, EDG Bldg. Ventilation System Upgrade Protective Device Selection
SGX-00005-01, EDG Bldg. Ventilation System Upgrade Protective Device Selection
SGX-00013-04, Setpoint Change for Undervoltage Relays on 480 V Buses
SGX-00048-00, 480 V Protective Devices Coordination Review

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CR 199802561 Response to Information Notice 95-52
CR 199802596, 21EDG Took 17.5 Seconds to Come Up to Voltage
CR 199802858, 21EDG Failed to Start on Right Hand Air Start Motor
CR 199802979, 21EDG Air Start Motors Lack of Lubrication
CR 199803069, 21EDG Failed to Start Within Required Time
CR 199805606, Analysis of Service Water Header Cross-Tie Requires Procedure Revision
CR 199807295, ESW flow balance fails its acceptance criteria, 8/24/98
CR 199807530, 22EDG Declared Inoperable Due to Failed Start Time.
CR 199807706, EDG Start Time Measurement Methods Not Very Accurate
CR 199807866, 22EDG Failed to Start Within Required Time
CR 199809212, No Procedure for Program/Procedure Changes Following TS Amendments
CR 199810682, EDG system walkdown deficiencies
CR 199810840 Degradation of Fire Protection Foam Under Freezing Conditions
CR 199810884 CVCS Weld Failures Due to Cavitation Erosion
CR 199810933, 24 SW strainer blowdown valve indicator 90 degrees out of alignment, 12/22/98
CR 199810988 Part 21 Review for Valcor Valve Model V70900-11
CR 199811021, 22EDG Jacket Water Exp Tank Level Control Valve Leaks.
CR 199900210, SW strainer pit access hatch leaks, 1/10/99
CR 199900216, RWST instrumentation heat trace alarm
CR 199900327, 25 service water pump in alert range, 1/14/99
CR 199900401, Shaft stop on valve SWN-617 not consistent with other similar valves, 1/19/99
CR 199900470, EDG 21 overspeed trip reset lever pin broken

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CR 199900499, EDG 21 overspeed trip reset lever pin hole oversized
CR 199900536, Multiple problems with 24 SW strainer, 1/25/99
CR 199900576, No procedure for checking function of DG SW outlet valves FCV-1176 & 1176A
for DG jacket water high temperature, 1/26/99
CR 199900600 Loss of RHR During Maintenance
CR 199900653, New DG heat exchanger titanium tube bundles do not fit, 1/28/99
CR 199900698, 21EDG SW to lube oil cooler pressure indicates 0 reading, 130/99
CR 199900719, SWN-618 indication is backwards, 1/31/99
CR 199900830, SPIN database missing setpoints, dated 02/04/1999
CR 199900851, Valve SWN-41-2B Dual Indication
CR 199900869, Request for TS interpretation on failure of containment isolation valve leak test failure, 2/5/99
CR 199901326, EDG ICPM discovered loose wire on lube oil heater temperature switch
CR 199901424, Conduct of training
CR 199901438, Use of controlled procedures
CR 199901816, Lack of feedback to simulator students
CR 199901818, Lack of controlled procedures in simulator
CR 199901819, Simulator CPU weaknesses.
CR 199901821, Communications between training and computer applications
CR 199901822, Simulator operator performed surveillance testing.
CR 199901856, Chipped epoxy coating in 21 CWHX, 3/9/99
CR 199901944, UFSAR Table 6.2-12 discrepancy, 3/11/99
CR 199902505, EDG Jacket Water Exp Tank Float Valve Leaks
CR 199902527, EDG 50.54f identified discrepancies
CR 199902586, 23 SW strainer knocking and slipping in rotation, 3/27/99
CR 199902626, Point Beach cold weather freeze event
CR 199902675, Retire or Resolve Issues with TSC Diesel Generator Alarm Panel
CR 199902815, Knocking sound in 23 SW strainer getting worse, 4/6/99
CR 199903103, 21EDG Jacket Water Exp Tank Level Control Valve Leaks.
CR 199903369, Requirement for Second CCW Pump not Modeled in EDG Study
CR 199903467, 21, 22 & 23 EDG Over Speed Trip Reset Lever Resting On Pin Which Could Cause Premature Failure of Trip Reset Pin.
CR 199904088, 480V cable spreading room smoke detector testing adequacy review
CR 199904447 Fire Induced Failure of VCT Outlet Valve LCV-112C
CR 199905093, New 25 SW pump had only four holddown bolt holes drilled, 6/29/99
CR 199905487, EDG 21 inappropriate mechanical governor venting
CR 199905843, Lack of procedure Guidance to Initiate Data Archive During GT-3 Operation
CR 199906210, 21 SW pump discharge pipe expansion joint is cracked, 8/11/99
CR 199906411, EDG load sequencing relays single failure analysis
CR 199906681, EDG 23 unexpected load reduction from 900kW to 100kW
CR 199906815, 480v bus undervoltage relays without reset values
CR 199906901, Self Identified and Corrected Procedure Violation
CR 199907198, 480v breaker current transformer configuration
CR 199907277, Ability to hear public address systems during emergency

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CR 199907506, TSC DG Room Has an Alarm Panel But No Alarm Response Procedure
CR 199907665, 480v 3A to 6A crosstie breaker bent cell switch
CR 199907767, Concern about questioning attitude, 10/13/99
CR 199908666, EDG engine analysis PM deferral
CR 199908715 Operating Experience Program Enhancements
CR 199908743, Management review of contractor developed lesson plans
CR 199908802 CRS Training Deficiencies
CR 199908817, Timing of Project Completion and Filing of Report Installation
CR 199908826, Drawing and Procedure Discrepancies Associated with Fuel Oil Shipments
CR 199908884, EDG 21 overspeed trip reset lever pin missing
CR 199908999, Technical accuracy of contractor developed lesson plans
CR 199909125, Roll up of deficiencies found during various audits and self-assessments
CR 199909153, ICPM program
CR 199909417, Common Cause Analysis of Events at IP-2
CR 200000128, Qualification record keeping
CR 200000285, NRC Severity Level IV violations for inadequate exercise critiques
CR 200000288, Emergency exercise weakness due to overall poor performance in the TSC
CR 200000289, Emergency exercise weakness due to poor performance in the OSC
CR 200000290, Lapse of ERO Qualifications
CR 200000634, Operations Training extent of condition
CR 200000968, Questions retarding the backup methods for notifying offsite authorities
CR 200000994 CRS Training Needs
CR 2000010694, Service Water Traveling Screen 27 Stops on Zero Speed Alarm
CR 200001093, Logkeeping standards were not met during the Alert of 2/15/2000
CR 200001126, A 50.54(q) review may not have been done on changes made to PI-1023 & IP-1035
CR 200001183, Questions Deleted from Re-qual Test without EP Manager Approval
CR 200001221, Some phones in the OSC/TSC were inoperable during the Alert of 2/15/2000
CR 200001229, Changes to EOF IP were a hindrance to ERO operations regarding step-off pads
CR 200001240, Initial lesson plans not reviewed and updated to reflect plan changes
CR 200001241, Self study modules have not been revised to reflect plan changes
CR 200001301, Failure to conduct event critique with county and State following Alert
CR 200001356, ERO Training Program did not ensure Personnel were Trained in all Positions
CR 200001361, Accountability deficiencies identified during the Alert of 2/15/2000
CR 200001366, 6 year requirement to test off-hours emergency drill not conducted
CR 200001521, 480V undervoltage panel dc power indicating lights not lit
CR 200001621, 21EDG Over Speed Trip Reset Lever Slips to Tripped Position but EDG Remains Reset.
CR 200001874 CAG Procedures for Routine Activities
CR 200002109, Issues concerning off-site monitoring and post accident sampling
CR 200002247, Onsite contractors raising concerns with being in the trailers and not hearing alarms or announcements and what they do in an evacuation

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CR 200002274, 25 SW strainer not rotating smoothly, 3/30/00
CR 200002329, EP Pre-restart plan includes action that could potentially impact the restart of IP2
CR 200002522, Station failed to meet 30 minute requirement for completing accountability
CR 200002591, Employee concern regarding message left at his home for a pager test
CR 200002618 Continued Problems with the OE Program
CR 200002713, Deficiencies identified with the ERO notification system and process
CR 200002788, Deficiencies identified during a drill on 4/17/2000
CR 200002924 Response to Information Notice 2000-06
CR 200002952, Concerns of the PA system and evacuation during an event
CR 200002968, Internal SW piping inspection found shells, 4/24/00
CR 200003182, Compliance with SAO-112 for CR Closure
CR 200003560, Drill weaknesses identified from 5/10/2000 drill
CR 200003568, CR system training attendance
CR 200003578, 22 FUC inspection found tubercles in waterbox, 6/4/00
CR 200003838, Questions regarding Accountability process
CR 200003865 Extent of Condition Information for CRs
CR 200003868 Root Cause Determination Deficiencies
CR 200003890, Deficiencies identified during a 5/14/2000 drill
CR 200003891, Drill weaknesses identified from 5/25/2000 drill
CR 200003945, EDG 21 overspeed trip reset lever pin found on floor
CR 200003978, EDG21 unexpected load change from 750kW to 2300kW
CR 200003987, No page system in NSB location
CR 200004008, EDG prints didn't match as-found wiring
CR 200004012, Valve SWN-44-5B failed leak test, 5/30/00
CR 200004059, Unable to hear alarm or announcement
CR 200004142, Simulator problem noted during the 6/1/00 evaluated exercise
CR 200004149, During 6/1/00 exercise, personnel were walking around and in between the new simulator building and the energy education center because they had not heard any announcements in the building concerning the drill
CR 200004153, JNC did not demonstrate the ability to coordinate clear, accurate and timely information to the news media during the 6/1/00 exercise
CR 200004181, 23 FCU inlet SW relief valve failed Appendix J leak test, 6/3/00
CR 200004265, Training and Drill weaknesses observed during 6/1/00 exercise
CR 200004311 Self-Assessments for the CAP
CR 200004312, failure of supply cable to MCC 21 due to damage to underground duct bank, dated 6/7/00
CR 200004345, Adequacy of offsite monitoring kits was questioned
CR 200004374, Siren 317 failed growl test
CR 200004393, Weaknesses identified in the JNC during the 6/1/00 exercise
CR 200004471, Contractor developed lesson plans
CR 200004545, 6/14/00 E-Plan training did not meet red team EOF participant's standards

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CR 200004578, EDG 21 mechanical governor mis-adjustment
CR 200004759 Roles and Responsibilities of the CAG
CR 200004766 No Action Plan for CAP
CR 200004839, Frisker failed source check in OSC locker
CR 200004907 Review of INPO SEN 214
CR 200005014 Contract Security Personnel Involvement with Condition Reporting System
CR 200005032, 21EDG Over Speed Trip Reset Lever Will Not Remain Locked in Reset Position.
CR 200005040, Maintaining respirator qualifications
CR 200005153, Training section computer upgrades
CR 200005260, Program deficiencies identified as a result of an root causes analysis
CR 200005332, Procedures, processes and training for the JNC do not allow for adequate information dissemination
CR 200005371, NPSH calculation not adequate, 7/19/00
CR 200005446, Re-evaluation of 1999 Common Cause Analysis corrective actions
CR 200005491, NRC identifies three white findings from Alert event of 2/15/2000
CR 200005516, Valve SWN-71-2B failed stroke test, 7/25/00
CR 200005585 Statement Regarding Technical Specifications
CR 200005640, On 7/28/2000, lost two phone circuits which service Reuter-Stokes at EOF
CR 200005646, PT-R93 doesn't assure design requirements of UFSAR Table 9.6-1 are met, 7/31/00
CR 200005704, TCV-1113 plugged with shells and sediment, 8/2/00
CR 200005815, Questions not trending beeper problems previous to 8/99 may have prevented current problems. Questions continual approval by CARB for extensions of due dates
CR 200005975, Several beepers did not activate during test
CR 200006021, 22 SW strainer not rotating, 8/15/00
CR 200006057, Heat trace functional tests
CR 200006156, Equipment deficiencies found during 8/16/2000 drill, including at JNC
CR 200006157, Deficiencies identified from August 16, 2000 emergency exercise
CR 200006170, Containment Recirculation Pump Effects on EDG Study
CR 200006180, 21 SW strainer dp switch reads 2.5 # when secured and drained, 8/21/00
CR 200006345, 24 SW strainer not rotating, 8/28/00
CR 200006357, LOR-08-00, Operations Training Section Training Program Self-Assessment
CR 200006369, 24 SW strainer tripped on thermals, 8/30/00
CR 200006377, Could not hear message in stairwell
CR 200006381 Noted Decrease in CRs Initiated
CR 200006501, Personnel in VC should not hear alarm
CR 200006508, Personnel unable to clearly understand announcement
CR 200006556, Page speaker in screen well house does not work
CR 200006565, High Head Safety Injection Pump HP Increase
CR 200006619 Training Personnel on Use of Operating Experience
CR 200006658 QA Auditor Training Needs
CR 200006663 Use of Risk Significance in QA

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CR 200006674, Heat trace panel discrepancies
CR 200006702, Flow instability with both FCV-1176 and 1176A in automatic, 9/10/00
CR 200006764, Inadequacies found with facilities and equipment implementing procedures
CR 200006794, Incorrect operability call on CR 200004534, 9/13/00
CR 200006944, FC-5032-A Alarm will not clear
CR 200006965, EDG Fuel Oil Transfer Pump Level Switch Tolerances Were Incorrect
CR 200007026, HPES training
CR 200007070 SAO-112 Procedure Deficiencies
CR 200007072 Effectiveness and Timeliness of Corrective Actions
CR 200007073 Training Needs to Prevent Recurrence
CR 200007078 Engineering Manager Understanding of CR Threshold
CR 200007108, EDG 21, 23 GE CR120A relay failure analysis report
CR 200007265, Johnson SW pumps do not meet hydraulic requirements, 9/27/00
CR 200007418, Relief valve SWN-86 IST failure
CR 200007509, 26 SWPS auto blowdown valve failed to stroke, 10/4/00
CR 200007600, Increase in Service Water Pump Load on EDGs
CR 200007667, Yoke Bushing Broke While Closing Valve JW-5.
CR 200007718, Stranded issues from “inappropriately” closed CR
CR 200007740, 480 V DBD Missing Reference
CR 200007742, 480 V DBD Missing Reference
CR 200007815, SWPS 24 not rotating, 10/13/00
CR 200007923, During the monthly notification drill, CAN was found inoperable
CR 200008089, Water Hammer Potential on Non-Essential SW Header, 10/23/00
CR 200008090, SW System flow model calculation deficiencies, 10/23/00
CR 200008156, EDG Loading Study Requires Revision
CR 200008249, Instrument Air Compressor smoke detector indicating light failure
CR 200008293, Licensed Operator Requalification Program
CR 200008448, Pager vendor inadvertently activated all ERO pagers while testing two. Used wrong test code and caused confusion
CR 200008472, Operator requalification examination results
CR 200008478, 21 SWP oil sample trending toward dilution of oil., 11/2/00
CR 200008487 Use of Circular Logic in CR Closure
CR 200008774, Radiological equipment deficiencies found during drill on 11/9/2000
CR 200008786, Valves SWN-6 and SWN-7 appear to not be properly supported, 11/9/00
CR 200008813, Deficiencies identified from November 9, 2000 emergency exercise
CR 200008829, SW Zurn strainer dp greater than 4 psid acceptance criterion, 11/10/00
CR 200008854, Oil in 24 SW pump appears to be emulsified, 11/11/00
CR 200008981, ERDS Inoperable During Training Session
CR 200009752, Inadequate Safety Evaluation 98-402-PR Regarding Changing EDG Start Time From 10 seconds to 10.5 seconds.

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CR 200009753, Inadequate Operability Determinations 98-012 and 98-013 Regarding Exceeding the EDG 10 second Start Time.
CR 200009927 Part 21 Review of Foxboro Relay for RWST Level Alarm
CR 200009963, Offsite Monitor procedure inadequacies regarding TLDs
CR 200009972, Instrument Air Compressor smoke detector timer failure
CR 200010025, Offsite Monitor procedure inadequacies
CR 200010120, Qualification to operate a crane
CR 200010268, SOP 1.7 discrepancy`
CR 200010277, QA audit finding regarding procedure for making an "emergency repair" under a
declared emergency condition
CR 200010278, QA audit finding regarding EP-AD-02 containing inadequacies and ambiguities
CR 200010279, QA audit finding regarding the adequacy of JNC procedure for preparing initial news releases during an event
CR 200010284, QA audit finding regarding alternating ERO requalification exams
CR 200010322, Alternate location for decontamination and applicable procedures
CR 200010476, Emergency Alarms & pagers are inaudible in Plant Cafeteria
CR 200010490, Does E-Plan training use the systematic approach to training which is used in operator training and technical training programs?
CR 200100170, No basis calculation for SW pumps IST quarterly tests' acceptance criteria, 1/5/01
CR 200100201, Maintenance planning area page
CR 200100290, Respirator qualification lapses for Onsite and Offsite monitors
CR 200100487 Automatic Self Locking Door for Employee Concerns Program Office
CR 200100499, pipe wrench left above instrument air compressors
CR 200100502, Heat trace circuit light intermittent
CR 200100510, Concern with 21 CCW heat exchanger holddown bolts, 1/17/01
CR 200100511, Balance of SW flows through DG heat exchangers, 1/17/01
CR 200100512, Corrosion on stainless steel line in CCW Heat exchanger
CR 200100513, Nuts on 21CCHX do not have full thread engagement, 1/17/01
CR 200100520, Leak rate program
CR 200100533, Page party speaker in NPO office
CR 200100545 Employee Concern Regarding Discontinuance of Posting CRs on Intranet
CR 200100549, NRC Found Instrument Out of Calibration.
CR 200100566, No test of non-essential SW header, 1/18/01
CR 200100577, unfastened deck plates in EDG building
CR 200100586, No condition report generated for failed acceptance criteria in PT-R93, 1/18/01
CR 200100599, Conclusions for Calculation FEX-00148-00
CR 200100606, Dwg 9321-F-4046, EDG Building Control Air Did Not Show 6th Building Exhaust Fan.
CR 200100611, Dwg 9321-F-1460-11, EDG Building Incorrectly Labeled 6th Building Exhaust Fan as #322 (number for the 5th fan) Versus #323.
CR 200100619 Employee Concerns Program Deficiencies

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CR 200100657, Loop 2 Delta-T Deviation Alarm
CR 200100663, scaffolding around instrument air compressor unsupported at base
CR 200100667, housekeeping items in EDG building
CR 200100669, ICPM 1508, Delta -T Deviation Alarm Setpoints
CR 200100700, oil pad fire protection assessment
CR 200100702, untimely generation of CR for instrument air scaffolding operability question
CR 200100714, past operability of instrument air scaffolding
CR 200100749, EDG 22 control room undervoltage annunciator alarming
CR 200100759, Field operator confusion over 125v DC control power indication
CR 200100773, 480V work orders incorrectly categorized (CM vs. other)
CR 200100782, EDG Fuel Oil Storage Issues
CR 200100783, Reduced SW flow to instrument air coolers, 1/23/01
CR 200100786, Temporary power cord connected to Air Compressor in EDG building
CR 200100788, EDG building sump backflow valves dirty
CR 200100795, dated 1/23/01, 118V system, consideration of inrush current for solenoid valves
CR 200100810, Dwg. 243683, Rev. 2, Shows Incorrect Type Solenoid Valve.
CR 200100811, EDG work orders incorrectly categorized (CM vs. other)
CR 200100812, Addition of word “MAY” in Plan changed the intent
CR 200100813, Procedure changes regarding activation of facilities conflicts with Plan.
CR 200100815, Facility inventories not being properly conducted
CR 200100816, Comments made by NRC regarding ERO Training Program Procedure
CR 200100827, Deficiencies not identified in CRS 2000-08813
CR 200100849, UFSAR description of SW radiation monitors incorrect, 1/24/01
CR 200100860, Deficiencies identified from December 14, 2000 drill
CR 200100878, Concern with service water strainer pit flooding, 1/24/01
CR 200100879, Calculation for SW radiation monitors set point, 1/24/01
CR 200100880, SW pump upper vacuum release valve not shown on P&ID, 1/24/01
CR 200100894 Failure to Review RHR Procedure During OE Review
CR 200100904 Failure to Place Relay on Administrative Hold
CR 200100908, dated 1/25/01, 118V system, control room logs/transfer switch setting
CR 200100972, AFW motor overload condition
CR 200100974, ICPM Extent of Condition Review Needed
CR 200101007, Tee drain on MOV SWN-44-4A
CR 200101379, Rescheduling of EDG 23 Work Schedule Idles I&C Crew
CR 200101386, Gas Turbine TS 750 KW Rating
CR 200101396, Relief Valve IST Test Failures
CR 200101416, Examples where descriptions for closing condition reports was inadequate.
CR 200101434, UFSAR Section 8.5 Gas Turbine Incomplete Information
CR 200101448, EDG Oil Rag Concern not put into CRS
CR 200101467, EDG Lube Oil Temperature Switch Calibration
CR 200101468, EDG Jacket Water Temperature Switch Calibration
CR 200101484, Information on Completed Mods Provided to NRC Inspector Incorrect.
CR 200101775, Inadequate training for correcting exercise deficiencies
CR 200101776, Third quarter communication drills were not conducted

Drawings

9321-F-2030-36, Flow diagram, Fuel Oil to Diesel Generators, Rev. dated 1/10/00
9321-F-2028-35, Flow diagram, Jacket Water to Diesel Generators, Rev. dated 8/16/99
A207698-25, Flow Diagram, Lube Oil for Diesel Generators No. 21, 22 & 23, Rev. dated 4/01/99
9321-F-2722-99, Flow Diagram, Service Water System Nuclear Steam Supply Plant, Sheet 1 of 2, Rev. dated 9/08/00
9321-H-2029-47, Flow Diagram, Starting Air to Diesel Generators, Rev. dated 12/13/99
A208377-08, Main One Line Diagram - UFSAR Figure 8.2-3, Rev. dated 10/12/00
A208088-34, One Line Diagram of 480 VAC SWGRS 21 & 22, Bus 2A, 3A, 5A and 6A, UFSAR Figure No. 8.2-6, Rev. dated 4/14/00
A250907-15, Electrical Distribution and Transmission System, Rev. dated 12/16/99
A214529-9, Control Building Fire Dampers, Rev. dated 10/10/00
9321-LL-3129-08, Control Building Wall Exhaust Fans 213, 215 & 216, Sheet 4, Rev. dated 6/15/95
B208476-13, Schematic Diagram of Control of Louver Fire Damper, Rev. dated 6/08/00
9321-LL-3133-18, Schematic Diagram Diesel Generator 21 Compressor, Fuel Oil Pump & Jacket Water & Lube Oil Heaters, Sheet No. 2 and 4, Rev. dated 7/13/00
A208376-09, Single Line Diagram of Unit Safeguard Channeling and Control Train Development, Rev. dated 5/19/93
A249956-14, One Line Diagram 480V MCC 24 & 24A, Rev. dated 3/29/00
A249956-16, One Line Diagram 480V MCC 29 & 29A, Rev. dated 7/6/99
9321-F-3006-89, Single Line Diagram 480V MCC 26A and 26B, Rev. dated 6/9/00
9321-LL-3133-15, Diesel Generator 22 Compressor, Fuel Oil Pump, Jacket Water & Lube Oil Heaters, Sheet No. 3, Rev. dated 7/13/00
9321-LL-3133-13, Diesel Generator Fuel Oil Storage & Day Tanks Level Control & Indication, Sheet No. 6, Rev. dated 10/31/00
9321-LL-3133-14, Schematic Diagram Fuel Oil Pumps Interlocking Relay, Sheet No. 5, Rev. dated 2/24/99
A207577-18, Internal Wiring for Diesel Generators 21, 22 & 23, Rev. dated12/18/00
IP2–S-000284-10, D.C. Schematic for Diesel Generator 21, Rev. dated 10/31/00
9321-F-272, Flow Diagram, Service Water System, Nuclear Steam Supply Plant, Sheet 1 of 2, Rev 99.
A209762, Flow Diagram, Service Water System, Nuclear Steam Supply Plant, Sheet 2 of 2, Rev 61.
D252680, EGG's Jacket Water & Lube Oil Coolers Cooling Water System, Loop No's: 1176, 5919, Rev 3.
9321-F-3004, One Line Diagram 480V Motor Control Centers 21, 22, 23, 25, & 25A, Rev 76.
9321-F-3006, Single Line Diagram 480V MCC 26A and 26B, Rev 89.
A208088, One Line Diag. of 480 VAC Swgrs 21 & 22, Bus 2A, 3A, 5A & 6A, Rev 34.
B227535-0, Outline and Assembly Dwg., Component Cooling Heat Exchanger, 8/7/89.
D-7317, Details, Component Cooling Heat Exchanger, Rev 0.
9321-F-4022, Flow Diagram Ventilation System Containment, Primary Aux. Bldg, Fuel Stg Bldg, Rev 51.
1996MB4165, Service Water Pumps (Johnson Pumps), 10/96.

Drawings (Cont.)

A200009, Intake Structure, Concrete - Cross Sections, Rev 17.
A200008, Intake Structure, Concrete - Plan Thru Walls, Rev 13.
A200737, Containment Building, Service Water Piping to Recirc. Fan Motor Coolers - Sheet 2, Rev 12.
A200735, Containment Building, Service Water Piping to Recirc. Fan Motor Coolers - Sheet 1, Rev 13.
D264097, Loop Diagram S. W. Containment S. W. Ctrl. Valve, Loop Numbers: 1104, 1170, 5004, Rev 00.
D264098, Loop Diagram S. W. Containment S. W. Ctrl. Valve, Loop Numbers: 1105, 1171, 5005, Rev 00.
A208368, Flow Diagram - Screen Wash System & Bearing Cooling Wtr. for Circ. & S. W. Pumps, Rev 29.
9321-F-2033, Flow Diagram - Service & Cooling Water, River Water & Fresh Water, Rev 71.
B225141-14, Elementary Wiring Diagram of Service Water Pump #25
D252680-03, EDG's Jacket Water & Lube Oil Coolers Cooling Water System
9321-F-2735-128, Flow Diagram - Safety Injection System
9321-F-3252-23, Indian Point No. 2 Heat Trace Cables - Service Water Piping Intake Structure
9321-LL-3137-07, Intake Structure Elec. Heat Tracing Panel 21, Sheet 13
9321-F-3278-04, System Impedance Diagram 480 Volts
A250907, revision 12/16/99, Electrical Distribution and Transmission System
9321-LL-3132-10, Schematic Diagram Pilot Wire and Misc. Lock-Out Relays, Sheet 5
9321-LL-3113-13, Schematic Diagram Breaker 52/UT1-ST5#1-5 Tie, Sheet 3
9321-LL-3114-11, Schematic Diagram Breaker 52/UT4-ST6#4-#5 Tie, Sheet 5
9321-LL-3114-11, Schematic Diagram Breaker 52/UT4-ST6#3-#5 Tie, Sheet 3
A208377-08, Main One Line Diagram
A231592-15, 6900 Volt One Line Diagram
ALCO drawing No. 5904S310750-Z6, Revision dated 9/5/00, Schematic Exciter Voltage Regulator (EDG21, EDG22, EDG23)
207698-25, Lube Oil Flow Diagram
208088-34, 480 VAC Switchgear 21 and 22 One Line Diagram
208241-23, MCC 28A & 211 Single Line Diagram
208377-08, Main One Line Diagram
208540-07, Breaker Control
225016-11, Safeguards Actuation Schemes
225139-19, Service Water Pump Elementary Wiring Diagram
231592-15, 6900 Volt One Line Diagram
248513-10, MCC 26C & CCR Ventilation Distribution Panel 21 Single Line
249955-16, MCC 29 & 29A One Line Diagram
250907-15, Electrical Distribution and Transmission System One Line
252680-03, EDG Cooling Water Schematic Wiring Diagram
252686-01, EDG Fuel Oil Control Instrument Loop Diagram
253799-03, Starting Air Control Instrument Loop Diagram
523802-04, Lube Oil Control Instrument Loop Diagram

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253805-02, Jacket Water Control Instrument Loop Diagram
254451-00, Replacement of Battery 23
9321-F-2028-435, Jacket Water Flow Diagram
9321-F-2029-47,Starting Air Flow Diagram
9321-F-2030-36, Fuel Oil Flow Diagram
9321-F-3004-76, MCC 21,22,23,25 & 25A One Line Diagram
9321-F-3005-98, MCC 27 & 27A One Line Diagram
9321-F-3006-89, MCC 26A & 26B One Line Diagram
9321-F-3007-17, Diesel Generator Low Voltage Three Line Diagram
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JS333-033-A2, ASCO Control Power Automatic Transfer Switch Wiring Diagram
Moeller Catalog Section 4, Thermal Overload Relays
NLI-Q-309, Data on Basler Voltage Regulator Components supplied by Nuclear Logistics

Work Orders and Post-Maintenance Tests (PMT)

NP-01-19913 WSL 1, Generator Hydrogen Cooler SW Piping Repair, Rev. 0
NP-01-19826 WSL 3, Generator Hydrogen Cooler SW Piping Repair, Rev. 0

NP-99-12858, EDG 21 Governor Voltage Readings and PMT
NP-99-12859, EDG 21 Replacement of Motor Operated Potentiometer and PMT
NP-00-19085, Replacement of MCC 28 Fuse Clips and PMT
NP-00-15890, Replacement of EDG 23 Unit Parallel Switch and PMT
NP-00-16300, Repair EDG 21 Governor and PMT
NP-99-10747, Replace EDG 23 Governor Raise/Lower Switch and PMT
NP-00-18640, Repair of MCC 26A Breaker Operating Handle and PMT
NP-00-19106, Repair of Distribution Panel Lead
NP-00-18111, Repair EDG 21 Day Tank Transfer Switch
NP-00-18162, Repair EDG 23 Cylinder Thermocouple Loose Fittings
NP-00-18270, Calibration of EDG 21 Voltage Meters
NP-00-18164, Repair EDG 21 Cylinder Thermocouple Loose Fittings
NP-00-18140, Replacement of EDG 22 Degraded 86 Relay and PMT
NP-00-17924, Replacement of EDG 21 Control Relays and PMT
NP-00-17921, Replacement of EDG 23 Control Relays
NP-00-17949, Replacement of EDG 23 Control Relays
NP-00-17926, Replacement of EDG 23 Control Relays
NP-93-65938, Inspect Breaker and Megger Motor for 23SWP
NP-98-80081, Megger 24 CRF Motor
NP-00-15881, Megger 23 AFP Motor
NP-00-16109, Megger 21 AFP Motor
NP-97-90734, Woodward Electronic Governor, 22EDG
NP-98-02487, Woodward Electronic Governor, 21EDG
NP-98-83218, Woodward Electronic Governor, 23EDG
NP-00-17433, PMT of 23EDG

ATTACHMENT 4

PARTIAL LIST OF PERSONS CONTACTED

Adams, E. - Dosimetry Technician
Altic, Bill - Senior Instructor, Shift Training Advocate
Andreozzi, Vincent - 480 Vac Electrical System Engineer
Baumstark, J. - VP Engineering
Bishop, Dave - Work Week Manager
Blatt, Michael - External Affairs
Blichfeldt, C. - Maintenance
Brooks, Kevin - Operations
Brovarski, C. - Communications Manager
Browne, F. - Maintenance
Buletta, John - Watch Engineer
Burns, T. - Supervisor, Nuclear Environmental Manager
Burns, R. - Emergency Planning Analyst
Carpenter, S. - Response Team Maintenance Contact
Cornax, Denis - Watch Engineer, Operations
Dahl, George - Fire Protection Engineer
Dean, Greg - Assistant Operations Manager
Dean, Roger - Senior Instructor, Shift Training Advocate
DeGasperis, Eddie - Nuclear Plant Operator
DiUglio, Anthony - Employee Concerns Program Manager
Dong, Ang - I & C Supervisor
Donnegan, M. - HP Manager
Dunleavy, C. - Administrative Officer, Orange County Office of Emergency Management
Durr, B. - Shift Manager,
Elam, T. - Outage Planning Supervisor
Entenberg, M. - Section Manager, Electrical Design and Facilities Engineering
Ferraro, T. - Sr. Emergency Planning Engineer
Finucan, Ken - Senior Quality Assurance Examiner
Freer, S. - Computer Applications
Gibb, J. - New York Emergency Management Agency
Ginsburg, Arthur - Chemistry Department
Goebel, Joseph - Lead Auditor - Quality Assurance
Gotchius, Ed - Manager of Safety Analysis
Greeley, D. - Asst. Director, Rockland County Office of Fire & Emergency Service
Greene, D. - Asst. Director, Orange County Office of Emergency Management
Griffith, Phil - PRA Supervisor
Gross, G. - Instrument Supervisor
Hale, J. - Senior Consultant
Horner, T. - Electrical Design Engineer
Hornyak, Michael - Corrective Action Group
Huestis, M. - Outage Manager
Inzirillo, F. - EP Manager
Jayaraman, Vadakkant - Engineering
Kempski, Mike - EDG System Engineer
Klein, Tom - Electrical Design Technical Specialist
Langerfeld, R. - Senior Reactor Operator, Generation Support

Lasley, R. - Department Manager, System Performance
Lee, A. - Sr. Emergency Planning Consultant, OSSI
Libby, Earl - Senior Instructor
Lijoi, J. - Control Room Supervisor
MacKenzie, Bruce - Corrective Action Group
Mansell, Jon - Outage Coordinator
Marguglio, Ben - Quality Assurance Auditor
Margulio, B. - Quality Assurance Auditor
McCaffrey, T. - Electrical System Engineer
McKee, Tom - Test Engineer
Meek, Brian - EDG and Gas Turbine System Engineer
Miele, Michael - Radprotection and Chemistry
Miller, Mark - Operations
Murdock, John - Shift Manager
Murphy, L. - Director, Westchester County Office of Emergency Management
Murphy, Diedre - Nuclear Training Manager
Naku, Klaus - Inspection Response Team Member
Nichols, John - Operations Training Section Manager
Parker, D. - Maintenance Section Manager
Parry, J. - Project Manager
Pehush, J. - 50.54(f) Reviewer, Setpoint Group
Poplees, Frank - Chemistry Instructor
Porrier, Tom - Work Control Manager
Pries, D. - Maintenance
Rampolla, M. - Director, Putnam County Office of Emergency Management
Ready, Jim - Field Support Supervisor
Reynolds, Joseph - Corrective Action Group
Robinson, H. - Senior Electrical Design Engineer
Rogers, Mike - Shift Training Advocate, Computer Applications Liaison
Rohla, Ross - Operations
Rowland, J. - 50.54(f) Reviewer, Configuration Management Group
Rumold, Jerry - Field Support Supervisor
Russell, Pat - Corrective Action Group Manager
Santini, Phil - Watch Engineer
Shah, Dean - Engineering
Shalabi, Khalil - Work Process Manager
Shoen, P. - Shift Manager
Smith, Bill - Assistant Operations Manager for Planning
Smith, L. - Section Manager, Civil Design Engineering
Speedling, Paul - Fire Protection Specialist
Teague, Thomas - Chemistry Department
Toscano, Jim - Unit Coordinator
Townsend, Larry - Shift Manager, Operations
Tumicki, Michael - Corrective Action Group
Tuohy, J. - Department Manager, Design Engineering

Ventosa, John - Site Engineering
Villani, L. - Response Team Engineering Lead Contact
Von Staden, Pat - Assistant Operations Manager (Corrective Actions/Training Coordinator)

Waddell, Tom - Maintenance Manager
Walker, K. - Sr. Emergency Planning Consultant, Operations Support Services, Inc. (OSSI)
Walsh, Kevin - Operations
Walther, Matthew - Engineering
Wassmann, P. - Administrative Assistant
Woody, Erin - I & C Manager
Xing, Michael - PSA Contractor
Zulla, S. - Response Team Electrical Design Contact