U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 88-17/88-17

Docket No. 50-220/50-410

License No. DPR-63/NPF-69

Licensee: Niagara Mohawk Power Corporation
301 Plainfield Road
Syracuse, New York 13212

Facility: Nine Mile Point, Units 1 and 2

Location: Scriba, New York

Dates: July 7 thru August 24, 1988

Inspectors: W.A. Cook, Senior Resident Inspector
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Approved by: Jon R. Johnson 9/14/88
J. R. Johnson, Chief, Reactor Projects Section 2C Date

INSPECTION SUMMARY

Areas Inspected: Routine inspection performed by the resident and region-based inspectors and the project manager of station activities including Unit 1 outage, Unit 2 power operations, licensee action on previously identified items, plant tours, safety system walkdowns, surveillance testing reviews, maintenance reviews, NRC Bulletin and Notice reviews, LER reviews, Temporary Instruction followup, 10 CFR 50.59 reviews and a loss of special nuclear material followup. This inspection involved 323 hours by the inspectors which included 33 hours of backshift and weekend inspection coverage.

Results: A violation of Unit 1 fire protection Technical Specifications is discussed in Section 1.1.c. Licensee identified violations are reviewed regarding Unit 1 limit switch settings (Section 1.1.b), Unit 2 drywell air lock testing (Section 1.2.d), and Unit 2 sample pump operability (Section 1.2.h). An unresolved item concerning the development of a program for adjusting circuit breaker overcurrent trip setpoints at Unit 1 is discussed in Section 5.1.b. A review of the requirement to designate a principle alternate for the Station and Unit 1 Superintendents and the recent station reorganization is discussed in Section 12. A review of the 10 CFR 50.59 process is documented in Section 14. Concerns regarding poor housekeeping practices at Unit 1 and cracking observed on the Unit 1 reactor building wall are discussed in Sections 3.1.a and 3.1.b, respectively. The Unit 1 commitments regarding plant restart are described in NRC Confirmatory Action Letter No. 88-17 and are outlined in Section 11.

DETAILS

1. Review of Plant Events (71707, 71710, 93702)

1.1 Unit 1

a. The unit remains in the REFUEL MODE awaiting completion of Inservice Inspections (ISI) on systems required for fuel load.

b. On July 7, the licensee determined that the inside containment Main Steam Isolation Valves (MSIV) reactor protection system (RPS) valve closure limit switches had not been set at the Technical Specification (TS) Limiting Safety System Setting (LSSS) of less than or equal to 10% of stem travel. The Bases section of the Technical Specifications allows 2.5% drift in the setpoint due to instrument and operator setting errors, and drift with time. The licensee determined that the setpoints used included the 2.5% allowable drift. This was found when performing a review of associated surveillance procedures prompted by a Problem Report (PR) issued on MSIV limit switch overlap problems.

There are two main steam lines, each has an inside and an outside containment MSIV. The inside MSIVs are motor operated and the outside MSIVs are air operated. Each of these MSIVs contains a 7% and 10% limit switch. The 7% limit switch is designed for valve operability surveillance testing while the 10% limit switch is designed to initiate a RPS scram signal. The 7% and 10% limit switches are checked and adjusted as necessary during each refuel cycle. The proper overlap relationship must be established between the switches to prevent undesired half scram signals when performing valve functional checks.

Total MSIV stem travel is 300mm corresponding to a setting limit of 30mm for the 10% MSIV limit switch and a possible allowable drift setpoint of 37mm (12.5%). On May 29, 1986, the 10% inboard MSIV limit switches were checked and adjusted using Electrical Surveillance Test Procedure NI-EST-CI. This procedure used 23mm to 37mm (10% +/- 2.5%) as acceptance criteria. The "As Found" settings were 30mm and 29mm. The technicians subsequently set the switches to 37mm as authorized by the procedure. The criteria should have been less than 30 mm for the actual setting of the switch. Switch adjustment would only have been necessary if the setting had drifted beyond 30mm or close to the 7% limit switch setpoint. The licensee would have to report a LSSS violation if the "As Found" settings were above 37mm. On June 22, 1988, the limit switches were checked per Electrical Surveillance Procedure NI-ESP-001-RF130 and found to have drifted to 27mm. This value is acceptable per the Technical Specifications and

the surveillance procedure. However, this surveillance procedure also used incorrectly specified acceptance criteria of 10% +/- 2.5%. This event is documented in LER 88-16.

The safety significance of this incorrect setting is minimal since the TS Bases indicates a setpoint drift of +2.5% is acceptable and the actual setting never exceeded 10% +2.5% (37mm). The inspector concluded that the preparers and reviewers of the associated surveillance procedures misinterpreted the TS due to inattention to detail. The licensee stated that the same problem did not exist for the outside MSIVs since they were under cognizance of another functional group (I&C Department), and that this problem was reviewed and not found to be a concern with the MSIVs at Unit 2. The licensee has revised the associated Unit 1 surveillance procedures to include the proper acceptance criteria. No previous violations of this type have occurred. In accordance with the provisions of the Enforcement Policy guidance of 10CFR2, Appendix C, no notice of violation is being issued for this licensee-identified violation (50-220/88-17-01).

c. On July 14, the licensee discovered the failure to post a continuous firewatch in the plant within time limits prescribed by Technical Specifications (TS). Earlier on July 14, Fire Door 234 had a breach permit issued on it and the fire detection system on one side of this fire door and its associated fire barrier (Turbine Building Elevation 250, Column F-G and Row 5-6) was tagged out of service for welding being performed in the area. In accordance with procedures, a fire patrol was established for this condition as required by TS 3.6.10.1. A fire patrol is permitted if the detection system on the other side of the barrier remains functional. However, later on July 14 the licensee discovered that the fire detection system on the other side of this barrier (DA-2022N) had been removed from service since July 13. Upon discovery, a continuous firewatch was established.

Technical Specification 3.6.10.1, Fire Barrier Penetrations and Fire Department Procedure S-FDP-3, Breach Permit, require that a continuous fire watch be posted within one hour with a fire barrier penetration non-functional and the detections systems on both sides of the barrier out of service. The failure to comply with the administrative requirements of the above stated procedure is a violation (50-220/88-17-02).

d. On July 21, 1988, a corporate engineer, having completed an inspection of electrical connectors under the reactor vessel, alarmed a whole body frisker upon exiting the radiologically controlled area. Initial licensee investigation determined that the source of the alarm was not external contamination, but a discrete radioactive source localized in the gastrointestinal (GI) tract. An initial whole body count verified the location and estimated the activity at about one microcurie (uCi) of Cobalt 60. The localized nature of the

activity, the lack of nasal contamination and the fact that the activity could be tracked through the GI tract with a hand held detector, all indicated the possible ingestion of a hot particle. All excreta was collected from the individual following the incident. Subsequent analysis of the excreta by gamma spectroscopy revealed approximately 1.4 uCi in the feces. Followup whole body counts indicated no residual activity in the individual. Initial dose calculations performed by the licensee indicated that the total radiation dose received by the individual was less than 100 millirem. This event was reviewed by region based radiation protection specialists and documented in NRC Inspection Report 50-220/88-27.

e. On August 6, the licensee identified a temporary loss of emergency communications with the Oswego County Sheriff's Department. Lightning struck the communications center at the sheriff's station and both the dedicated telephone and radio communications to Nine Mile Point were lost. Backup communications were available via the Fire Department radios. Normal communications were restored later that day.

f. On August 16, the licensee Quality Assurance Department issued Stop Work Order 88-004, placing a hold on Inservice Inspection (ISI) examinations being performed by the ISI program contractor, Nuclear Energy Services (NES). The Stop Work Order cites a breakdown of the required 10CFR50, Appendix B, quality controls necessary to properly complete the ISI program. NES is currently developing an action plan for the licensee's review, prior to lifting of the Stop Work Order.

1.2 <u>Unit 2</u>

a. During the period there were two reactor scrams, one manual and one automatic, due to leakage of hydraulic fluid from the turbine's Electrohydraulic Control (EHC) System.

On July 11, an EHC leak was detected from the trip supply fitting for the #3 Control Valve. Attempts to stop the leak by tightening the fitting were unsuccessful. Reactor power at the discovery of this problem was 67%. A shutdown was commenced, and the reactor was manually scrammed from 40% power when the EHC system low oil level alarm was received. As a result of the scram, the turbine control valves went shut, as designed, thus relieving the hydraulic pressure and essentially stopping the leakage. Post-scram recovery actions were performed and no complications were encountered. The licensee initiated a Work Request to tighten the loose fitting. This event is documented in LER 88-28.

On August 6, operators observed a rapidly decreasing EHC pressure and commenced reducing power. All station electrical loads were transferred to offsite reserve power prior to an automatic reactor scram. The reactor scram occurred from approximately 42 percent power due to

a turbine trip on low EHC pressure. The low EHC pressure was found to be caused by fatigue failure on the threaded portion of a 1/2 inch diameter pipe coupling on the B EHC pump air bleed line. This coupling and a similar coupling on the A EHC pump bleed line were both replaced. The licensee attributes the fatigue failure to pump induced vibration.

The licensee's evaluation of this event included the services of a GE representative on site on August 8 to review the EHC system design. The inspectors will follow any corrective actions that are taken and update this item in a subsequent report.

b. Three automatic isolation signals were generated for the reactor core isolation cooling (RCIC) system during this inspection period.

On July 12, one of the RCIC high steam flow transmitters failed upscale, resulting in a RCIC isolation signal. The reactor was in the STARTUP MODE at that time, and the RCIC system was still isolated per procedure, so there was no automatic valve actuation. The licensee determined the cause of the transmitter upscale signal to be "Rosemount transmitter particle syndrome". The failure could not be reproduced following exercise via a prescribed method developed by the vendor. The isolation signal was subsequently cleared and the transmitter returned to service. This is the first time this particular transmitter has experienced this problem. The "particle syndrome" was earlier reported and this event is documented in LER 88-29.

On August 2, the RCIC steam isolation valve MOV-121 tripped shut due to an isolation signal generated during surveillance testing. The Division I turbine exhaust diaphragm high pressure transmitter 2ISC*PIS2A had been tested earlier and returned to service. The trip unit for the PIS2A transmitter subsequently failed in the tripped condition, but went undetected. This failure was not observed by the control room operators or technicians performing the surviellance. When the other Division I transmitter (2ISC*PIS2C) was placed in the tripped condition per the surveillance procedure the logic for the isolation was satisfied. The licensee was unsuccessful in determining the cause of the trip unit failure and subsequently replaced the unit and sent it to the vendor for failure analysis. The inspector determined that the trip unit failure went unnoticed because the Panel 601 audible alarm was out of service and the control room personnel did not detect the annunciator light and computer alarm. The inspectors will continue their review of this event in the subsequent inspection period.

On August 3, while operating at low reactor power levels, the RCIC high steam line flow instruments caused a spurious isolation signal for the system while it was already isolated. The licensee determined

that the instruments were acting erratically due to trapped water in the steam line. The licensee instituted procedure changes to drain the trapped water during system warm-up.

c. On July 15 the licensee's engineering staff identified a potential design inadequacy as a result of their current review of the Unit 2 Failures Modes and Effects Analysis (FMEA). The FMEA is being reviewed, in part, in preparation for the Final Safety Analysis Report annual update. The specific design concern involves the control circuit for the reactor building recirculation cooler fans (UC-413A and 413B). These fans receive an automatic initiation signal upon normal reactor building ventilation (RBV) isolation and standby gas treatment (SBGT) system initiation. They function to promote homogeneous mixing and cooling of the secondary containment atmosphere and thereby ensure adequate SBGT system drawdown of secondary containment following a design basis accident.

The engineering staff determined that an improperly designed start circuit seal-in relay would prevent the fan motor from restarting following a loss of power to the motor after either an automatic or manual start of the unit. The licensee's supposition is that a loss of coolant accident (LOCA) occurs and is followed by a Loss of Offsite Power (LOOP). With a LOOP the Emergency Diesel Generators would start to repower the emergency buses and safety related loads. If an initiation signal was still present, the SBGT trains would restart but the previously operating recirculation cooler fans would not reenergize. Assuming a single failure of the previously not operating recirculation fan cooler, the required secondary containment drawdown time could not be guaranteed. Accordingly, the operations staff declared both trains of SBGT inoperable on July 15 and commenced an orderly shutdown in accordance with the Technical Specifications (TS). The unit shutdown was secured at approximately 75% reactor power on July 16 after the licensee completed a modification to bypass the start circuit seal-in relays.

On July 19, the engineering staff discovered another circuit problem which would have prevented the cooler fans from restarting after a LOOP. The operations staff made a temporary change to their operating procedures to have the switch taken to TRIP/OFF or PULL-TO-LOCK to reset the seal-in function following a loss of power to the motor. Action taken by the licensee to declare SBGT inoperable on July 15 and to commence a shutdown per TS was viewed as a conservative approach.

On July 21, the licensee decided to further modify the recirculation fan cooler starting circuits and ensure the fan motors would restart automatically upon restoration of electrical power following a LOOP. These modifications were completed on July 22 and reviewed by the inspector. Post modification testing was determined to be adequate. No discrepancies were noted.

The inspectors determined that the licensee is conducting a detailed review of the recirculation fan cooler design basis and the inspectors will review this evaluation in a subsequent report period.

d. On July 18, the licensee discovered that a surveillance on the drywell emergency air lock had been performed outside of the Technical Specification (TS) required time period. TS 4.6.1.3 requires that the overall air lock leakage test be conducted at least once per 6 months. It is further stated that the provisions of TS 4.0.2, which allow the 25% time factor, do not apply. The surveillance was to have been performed on April 28, but was not performed until April 30. Failure to perform the leak rate test by April 28, 1988 is a violation of TS 4.6.1.3. This event is also documented in LER 88-33.

The inspector determined that the licensee identified this violation while taking corrective action in response to a previous violation (VIOLATION 50-410/88-07-01) involving the failure to meet a containment penetration Type B leak rate test for which TS 4.0.2 also does not apply. In accordance with the Enforcement Policy Guidance of 10 CFR 2, Appendix C, no Notice of Violation is being issued for this event. (50-410/88-17-01)

e. On July 27, the Security Department informed the resident inspector that a company employee had tested positive for the use of marijuana. The testing was done as part of the pre-promotion physical. The individual's badge was pulled while the licensee evaluated what further action would be taken. A verification test was completed with negative results. The employee has denied drug use and has returned to work. The employee will now be subject to random drug testing for a period of two years.

f. On July 28, during a surveillance test, the Division II emergency diesel generator had to be secured shortly after being started due to failure of the service water supply outlet valve to open on the start signal. The licensee investigated the cause and determined that the failure was due to a hung up contact in the remote shutdown switch. This switch is used to transfer the control of the service water system from the control room to the remote shutdown panel. The contact was cleaned and the diesel returned to an operable status on July 29. The inspector observed that the required Technical Specification Limiting Condition for Operation with an inoperable diesel generator was followed. No discrepanices were noted.

g. There have been several automatic isolations of reactor building ventilation (RBV) and subsequent starts of Standby Gas Treatment (SBGT) trains during this inspection period.

On July 14, while performing the monthly functional check on the RBV below the refuel floor radiation monitor, the RBV isolated and SBGT system started automatically. This was caused, in part, by improper

performance of the surveillance procedure (N2-RSP-RMS-M107). This procedure requires that, during testing, the SBGT trains and unit coolers be placed in Pull-To-Lock (PTL) prior to installing a jumper which bypasses the radiation monitors trip signals. The technician failed to inform the control room so that the systems could be placed in PTL prior to installing the jumper. The jumper fell off and shorted to ground causing the high radiation trip signal to be generated.

On July 21, August 1, and August 7, automatic initiations of SBGT system occurred as a result of RBV isolations. The causes of these reactor building ventilation isolations were spurious radiation monitor trip signals. The licensee has experienced numerous malfunctions of the radiation monitors in the recent months. Troubleshooting during this inspection period isolated the problem to a failed CPU card. The card has been replaced and no further spurious actuations have occurred.

The inspectors will continue to monitor licensee progress in resolving the frequent spurious RBV isolations and SBGT system actuations.

h. On July 14, the licensee determined that one of the two below the refuel floor radiation monitors was inoperable from July 9. The Division 1 radiation monitor sample pump had been secured on July 9 by an I&C technician who was confused when told to secure a service water radiation monitor. At that time an operator caught the mistake and had the technician supposedly restart the refuel floor sample pump and secure the designated service water monitor sample pump. The technician failed to verify that his actions to start the refuel monitor sample pump were successful, since the pump did not start. Technical Specification Table 3.3.2-1 item 3.b requires that, with this refuel floor radiation monitor inoperable, reactor building integrity be established using SBGT within one hour. This monitor was inoperable from July 9 until July 14 without the appropriate compensatory action being taken.

The licensee has taken action to ensure that operators verify proper operation of this type of radiation monitor including the shiftly verification of their operablility. Reverification of monitor operability following surveillance testing has also been emphasized. During the time period this Division 1 radiation monitor was out of service a redundant Division 2 monitor was operable and capable of independently performing the same monitoring and reactor building ventilation isolation function. In accordance with the provisions of the Enforcement Policy guidance of 10 CFR 2, Appendix C, no notice of violation is being issued for this TS violation. This event is documented in LER 88-30 (50-410/88-17-02).

i. On the afternoon of August 19, while operating at 100% power, the licensee declared the primary containment inoperable and commenced a shutdown to comply with Technical Specifications (TS) 3.6.1.1. An Unusual Event was also declared and the appropriate notifications made. The containment was declared inoperable because of the inability of the licensee to readily produce a completed leak rate surveillance test or record of completion of the test on the Drywell North equipment hatch.

While reducing reactor power at a rate of approximately 50 MWe/hr, the licensee implemented a procedure change to an existing surveillance procedure (N2-ISP-CNT-R@001) to perform the required leak rate test on the Drywell North equipment hatch. The test was completed satisfactorily and the power reduction halted by early evening. The unit remained at a reduced power level until the licensee completed a comprehensive review of other TS required surveillances. After this review identified no additional discrepancies, the unit returned to 100% power.

This problem was identified while preparing for the upcoming outage and determinations were being made on which penetrations leak rate testing must be completed. Responsible supervision discovered that they did not have a surveillance test procedure for the North equipment hatch. During their subsequent review of other surveillance procedures, the licensee did find a preoperational test procedure, MP-GENE-05B, which documented the performance of this test on the North equipment hatch on August 26, 1986. Based on this procedure and documented test results, the required frequency of this leak rate surveillance test was not exceeded.

The performance of MP-GENE-05B was under cognizance of the preoperational testing group. This group consisted of contractors and Niagara Mohawk personnel. In September 1986, the sole responsibility of surveillance testing of this hatch was transferred to Niagara Mohawk. A contractor (Nuclear Energy Services) was charged with developing the test procedures for all primary containment access hatches. The procedure developed (N2-ISP-CNT-R@001) was reviewed by all appropriate levels of the licensee technical staff and then by the Site Operations Review Committee (SORC) for adequacy, but the Drywell North equipment hatch testing portion was erroneously excluded. The licensee's action to declare the containment inoperable was considered a conservative approach. Inspection of the leak rate test program will be performed in future inspections.

2. Followup on Previous Identified Items (92702, 71707)

2.1 Unit 1

a. (Closed) UNRESOLVED ITEM (50-220/80-18-03): License actions regarding post accident sampling per NUREG 0578, Item 2.1.8.a. This item identified the apparent lack of adequate interim procedures for sampling the reactor coolant and containment atmosphere following a severe accident resulting in fuel damage. Subsequent to this review, the licensee installed adequate means for post-accident sampling in accordance with NUREG 0737. The Unit 1 post-accident sampling hardware and procedures implementation have been reviewed in detail by the NRC as documented in Inspection Reports 50-220/84-14 and 50-220/87-12. Licensee ability to properly conduct post-accident sampling has been verified; however, some discrepancies were identified and tracked for follwoup as documented in the above mentioned reports. Consequently, this unresolved item has been superseded by events and is no longer applicable. This item is closed.

b. (Closed) INSPECTOR FOLLOW ITEM (50-220/83-28-03): Licensee QA to verify that Technical Specification (TS) changes are implemented. This item was opened to verify that QA is reviewing TS amendments to ensure that new requirements imposed by these changes are incorporated into procedures, as necessary. The inspector reviewed QA surveillance packages on several TS amendments for both Unit 1 and 2. The QA checklist used was noted to be performed within thirty days of issuance of the TS amendments. The surveillance covers any required testing or inspection frequency changes and any needed procedural changes. In several cases, attributes to verify training and the accuracy of the amendment were added. Based on this review the inspector determined that the licensee QA does review Amendments to TS for both units. This item is closed.

c. (Closed) UNRESOLVED ITEM (50-220/84-07-02): Review licensee procedure for dispositions of nonconforming conditions identified by the ISI program. This item pertains to 1984 ISI inspections. Specifically, the inspector noted that a non-conformance report was not written when non-conforming conditions were discovered during ISI examinations. This deficiency resulted in a recent Violation and Civil Penalty (reference NRC Inspection Report 50-220/87-21-03). This item is closed.

d. (Closed) INSPECTOR FOLLOW ITEM (50-220/84-11-04) Licensee to set up a program to test overcurrent devices on GE AK type circuit breakers. The inspector reviewed Electrical Preventative Maintenance Procedure (EPM), N1-EPM-GEN-R151, Type AK Breaker/Motor Inspection and Load Test, Rev. 0, dated 9/8/87, revised July 1988. The procedure has enclosures that list all AK breakers, their locations and the required test frequency. Safety related breakers supplying environmentally qualified (EQ) equipment receive a test once per operating

cycle. Safety related breakers not supplying EQ equipment receive testing once every two operating cycles. Non-Safety related breakers are tested once in three cycles. The procedure requires that "as found" and "as left" data be obtained during load testing. Data is gathered as applicable for current pickup points and time delay points for long, short and instantaneous time delay trips. Based on the existence of this procedure this item is closed.

e. (Closed) INSPECTOR FOLLOW ITEM (50-220/85-01-02): Adequacy of fire protection for Fire Break Zones in the Reactor Building. During the Appendix R safe shutdown team inspection (Inspection Report 50-220/85-01) it was noted that automatic fire suppression had not been provided throughout the reactor building. Also noted was the fact the the fire break zones, although provided with automatic suppression, contained electrical cabling coated with flamastic. The inspection report required that these issues be directed to NRR for evaluation. The licensee submitted a letter describing these issues on February 11, 1985.

A safety evaluation was issued on August 6, 1986 by NRR. This evaluation accepts the licensee analysis since redundant safety trains are at either end of the building, automatic preaction sprinklers are installed in the fire break zones, and combustible material loading in the zones is low. The cabling passing through the zones is acceptable if it is coated with flamastic, run in conduit, or run in cable trays with approved fire stops at each end. Based on NRR acceptance of the licensee submittal this item is closed.

f. (Closed) UNRESOLVED ITEM (50-220/88-08-02): Main steam piping between blocking valve and ERVs not hydrostatically tested. As documented in Inspection Report 50-220/88-16, the inspectors reviewed the hydrostatic test procedure and witnessed portions of the testing. The inspectors noted no discrepancies. The discovery of the missed hydrostatic testing was made by the licensee in conjunction with corrective actions being taken for Inservice Inspection (ISI) Program implementation violations previously cited. The inspector determined that the licensee intends to submit a supplemental Licensee Event Report upon conclusion of their ISI Program review. This item is closed.

g. (Open) UNRESOLVED ITEM (50-220/88-15-02): Fire barrier installation verification and review. As a result of inoperable fire barrier penetrations discovered in 1983 and documented in Licensee Event Report (LER) 83-44, the licensee was to have taken action to assure future integrity of fire barrier penetrations. These actions are documented in a Special Report, dated April 24, 1984, and include increased surveillance/inspection and revised installation procedures and penetration detail drawings. The licensee has subsequently

submitted Special Reports, dated October 22 and December 6, 1984, and LERs 87-07, 87-08, and 87-19; all dealing with inoperable fire barrier penetrations.

While performing routine tours, the inspector noted several banks of cable penetrations in the north-west corner of the Turbine Building at the 250' elevation which were unmarked and several of which were sealed with red putty. Upon questioning the licensee, the inspector was informed that the penetrations were within duct bank 11D & 11E, and the exterior walls through which the duct banks penetrated are non-rated fire barriers. The duct banks contain numerous four inch conduits that run approximately forty feet in length from the Reactor Building to the Turbine Building. Since the barriers are non-rated, Red Flameseal Putty is an acceptable gas/smoke seal.

This item remains open pending licensee review of previous corrective action and NRC review of the Fire Protection Program.

3. Plant Inspection Tours (71707, 71710, 71881, 64704)

During this reporting period, the inspectors made tours of the Unit 1 and 2 control rooms and accessible plant areas to monitor station activities and to make an independent assessment of equipment status, radiological conditions, safety and adherence to regulatory requirements. The following were observed:

3.1 Unit 1

a. The inspectors toured portions of the reactor building and the drywell with the following results:

-- The inspectors noted poor housekeeping practices inside the drywell. Large amounts of material such as scaffolding, grinding tools, and drills, were piled up in areas of the drywell. Also, empty cans of WD-40, tie wraps, and other small items were simply left lying around the perimeter of the drywell. The licensee has been informed that further efforts are needed to cleanup this area. Grafitti was written on most walls in the drywell. This generates two ALARA concerns. One, the people are taking time to write grafitti, and secondly, people will have to take time to clean it up; all of this in a high radiation area. This concern will be closely monitored as the licensee proceeds toward plant restart.

-- The inspectors noticed several concerns related to fire break zones. At the north fire break zone at the 237' level, and the north and south fire break zones on the refueling floor, the inspectors noted that wood, paper, or plastics were stored in these areas, even though they are clearly marked that no combustibles are to be stored there. In the overhead areas of the

north fire break zone on the 237' level several 600 volt cables suspended from ropes were noted to pass through the zone, without being coated with flamastic. Also, in the south fire break zone at the 289' elevation, cables, not coated with flamastic, were noted to run through cable trays. This item will be tracked with previous unresolved item 50-220/88-15-02 (see paragraph 2.1. above).

-- From their tours of the refueling floor area, the inspectors have noted that the spent fuel pit has quite a few items stored in it other than spent fuel. Items stored range from metal boxes with pipe sections in them and other objects sitting directly on top of the spent fuel racks, to a large number of metal objects suspended around the sides of the spent fuel pit from the spent fuel pool's railing. As the spent fuel pit is a seismic structure, the inspectors questioned the licensee as to the advisability of imposing additional loads on the spent fuel racks (loads being those directly imposed on the racks as well as those imposed, potentially, from suspended objects falling on top of the racks). The licensee responded that this has been examined by them within the last year and that their analysis would be presented to the inspectors. This matter will be updated in a subsequent report pending review of the licensee provided information.

b. On August 18, the NRC Region I Regional Administrator toured portions of the plant along with members of his staff and Niagara Mohawk senior site managers. As requested by Mr. Russell, the plant tour was led by a Unit 1 licensed operator, and was to be representative of the things that the operator would look at, and look for, during a normal shift tour in the plant.

Areas toured included most areas of the Turbine Building (261' elevation and up) as well as the 261', 281' and 298' elevations in the Reactor Building. These areas were generally clean and equipment was stored and organized in a neat manner. Improvements in these areas from previous tours were noticeable. The knowledge and skill of the operator leading the tour was noteworthy.

However, from touring the Reactor Building at the 237' level, near the hydraulic control units, it is evident that more attention needs to be paid to housekeeping in this area. Also, on exiting the Southwest Corner Room at the 237' level, large cracks (up to five feet in length) were observed in the concrete near several large piping penetrations. The licensee was requested to determine if the wall is load bearing (or for biological shielding only) and to evaluate the condition of the observed cracks. This item will be reviewed in a subsequent report.

3.2 Unit 2

a. On August 2, operators in the Control Room noticed that Feed Control Valve (FCV) 10A was not operating properly as witnessed by no valve movement. The licensee decided to secure the A and start the B feed pump. In order to do this, power had to be lowered to the point where one feed pump's output could maintain reactor vessel level. The procedure for securing a feed pump is to throttle the FCV shut, while reducing power, ensuring that as the valve is shut the other feed pump can maintain water level. The FCV would not function in automatic and the licensee suspected that the valve might fail full open or closed if operated manually. A temporary modification was made to the feedpump discharge valve circuitry. This allowed the discharge valve to be used as a throttle valve and to perform the function of the FCV. The inspector observed the temporary modification and necessary procedure change process, the lowering of reactor power and feed pump flow, and the starting of the B feed pump. The operations were well coordinated and completed in a professional manner.

b. On August 23 and 24, the inspector toured the control room and noted an unusually high number of lit annunciators (approximately 55 alarms). Maintaining a large amount of alarmed annunciators could "mask" a potential problem. It would be beneficial to the operators if the number of lit annunciators was kept to a minimum. The licensee has a program in place to reduce the number of lit annunciators. This includes the evaluation of alarms that are annunciated for long periods of time for possible setpoint changes and/or deletion of unnecessary or nuisance alarms. Licensee progress in this area will be updated in a subsequent report.

4. Surveillance Review (61726)

The inspectors observed portions of the surveillance testing listed below to verify that the test instrumentation was properly calibrated, approved procedures were used, the work was performed by qualified personnel, limiting conditions for operations were met, and the system was correctly restored following the testing.

4.1 Unit 1

Followup of surveillances required for MSIV limit switches and inoperable fire detection equipment are described in section 1.1 above.

4.2 Unit 2

The inspector observed the performance of the Division I emergency diesel generator operability test on July 28 as part of the Technical Specification Limited Conditions for Operations (LCO) requirements described in section 1.2 above. The inspector noted that the annunciator for the

diesel turbocharger low lube oil pressure was alarming prior to and after that diesel was started. This annunciator is supplied from a pressure switch and trip unit which when tripped should cause the diesel to stop, if started in the test mode. The Assistant Shift Supervisor (ASSS) was asked why this annunciator was alarming and how the machine could have been started in that condition. The ASSS said that the reason that the alarm was in was a faulty annunciator circuit and that the pressure switch was functioning properly. The operator at the diesel was aware of this and was paying special attention to the turbocharger lube oil pressure gage.

No violations were identified (see actions regarding lit annunciators in Section 3.2.b above).

5. Maintenance Review (62703, 64704)

The inspector observed portions of various safety-related maintenance activities to determine that redundant components were operable, that these activities did not violate the limiting conditions for operation, that required administrative approvals and tagouts were obtained prior to initiating the work, that approved procedures were used or the activity was within the "skills of the trade", that appropriate radiological controls were implemented, that ignition/fire prevention controls were properly implemented, and that equipment was properly tested prior to returning it to service.

5.1 Unit 1

a. The inspector observed ongoing work on various fire barrier penetrations. No discrepancies were noted.

b. The inspector reviewed completed copies of procedure N1-EMP-GEN-R151 discussed in section 2.1.d. above. Nine procedures were reviewed for safety related breakers. Out of these nine there were numerous cases where the "as-found" overcurrent device settings were not within the given ranges prior to breaker rework. In five of the nine cases "as-left" overcurrent device settings were not in the prescribed ranges. The data sheets reviewed have spaces for maximum and minimum allowable settings for the long, short and instantaneous time delay trip amperage setpoints. In all cases these were not filled out. The only information given for these settings was the percent over rated current and the specific current value. The data for each breaker is obtained from a data base, which is based on the selective tripping design of the specific load center.

The inspector requested that the licensee review the program for determining the required setpoints and review the previously performed procedures to determine if any corrective action might need to be taken to ensure that these breakers are able to function in their designed load capacities. This item is unresolved (50-220/88-17-03).

5.2 Unit 2

a. On August 2, the inspector observed the replacement of the Division I emergency diesel start switch located on the control room panel. The switch was an SBM type control switch and was being replaced due to a 1982 GE Service Advice Letter. The letter stated that switches of this type manufactured between August and October 1982 were subject to contact failure. The licensee had not experienced any problems with this switch, it was being replaced based on an engineering review which found that this particular switch was manufactured in the suspect time period. The work was observed to be completed properly, with good use of the lifted lead log and quality control review.

6. Safety System Operability Verification (71707, 71710)

On a sample basis, the inspectors directly examined portions of selected safety system trains to verify that the systems were properly aligned in the standby mode. The following systems were examined:

6.1 Unit 1

-- Emergency power supplies.

No discrepancies were noted.

6.2 Unit 2

-- RHR
-- LPCI
-- Diesel Generators

No violations were noted. Comments regarding general plant conditions are noted above.

7. Physical Security Review (71881)

The inspector made observations to verify that selected aspects of the station physical security program were in accordance with regulatory requirements, physical security plan and approved procedures.

7.1 Unit 1

The inspector observed proper access controls being used at the gate house.

7.2 Unit 2

The inspector was informed on August 19 that the inner truck bay door, although alarmed, was not adequately controlled by the use of a lock. This was determined by a guard who was posted at the personnel door located in the truck bay. The licensee is pursuing a modification to properly secure the door.

No violations were noted.

8. Radiological Protection Review (71709)

The inspector reviewed selected aspects of the licensee's radiological protection program to verify that the station policies and procedures were in compliance with regulatory requirements and that station employees were properly implementing the program.

8.1 Unit 1

a. On July 27, the inspector noted a radiation survey sheet at the access to the north-east corner room that had been completed on June 23. The sheet said that the survey should be completed monthly. The inspector asked licensee radiation protection if this was acceptable. They said that at 25% tolerance was applied to these surveys. The inspector found the practice to be acceptable.

b. Followup to the ingestion of radioactive material is described in Section 1.1.d. above.

8.2 Unit 2

No discrepancies were noted.

9. Review of Licensee Event Reports (LERs) (90712, 92702)

The LERs submitted to the NRC were reviewed to determine whether the details were clearly reported, the cause(s) properly identified and the corrective actions appropriate. The inspectors also determined whether the assessment of potential safety consequences had been properly evaluated, whether generic implications were indicated, whether the event warranted an on site follow-up, whether the reporting requirements of 10 CFR 50.72 were applicable, and whether the requirements of 10 CFR 50.73 had been properly met. (Note: the dates indicated are the event dates)

9.1 Unit 1

The following LERs were reviewed and found to be satisfactory:

-- 88-02, 4/27/88, TS violation due to failure to establish a fire watch.

-- 88-15, 6/25/88, Reactor scram (core offloaded) due to a lighting strike.

-- 88-16, 7/7/88, TS violation, MSIV limit switches set greater than the LSSS setpoint.

9.2 Unit 2

The following LERs were reviewed and found to be satisfactory:

-- 88-07, Supplement 1, 2/1/88, Shutdown cooling isolation while venting an instrument line.

-- 88-28, 7/11/88, Reactor scram due to EHC fluid leakage.

-- 88-29, 7/12/88, RCIC isolation due to equipment failure.

-- 88-30, 7/14/88, TS Violation due to inoperable radiation monitor.

-- 88-31, 7/14/88, ESF initiation due to jumper grounding.

10. Licensee Action on NRC Bulletins and Information Notices (92701,92703)

The inspector reviewed licensee records pertaining to the NRC Bulletins and Notices identified below to verify that: the Bulletins and Notices were received and reviewed for applicability; written responses were provided, if required; and the corrective action taken was adequate.

10.1 Unit 1

a. (Closed) Bulletin 78-12, Atypical weld material in reactor pressure vessel welds. The licensee submitted a letter dated June 28, 1979 stating that a report by Combustion Engineering Incorporated, the manufacturer of the Unit 1 reactor vessel, was submitted on June 8, 1979. This report contains the required information requested by the bulletin. This bulletin is closed.

b. (Closed) Bulletin 79-27, Loss of non-class 1E instrument and control power system bus during operation. During a previous review of the licensee's response to this bulletin in Inspection Report 50-220/87-13, it was noted that the licensee did not have procedures in place to deal with the loss of the emergency battery boards or the instrument and control bus 130. The licensee subsequently committed in a letter, dated November 6, 1987, to revise procedures to reflect actions to be taken on loss of these buses.

The inspector reviewed:

-- Operating procedure N1-OP-47A, Operation of 125V DC power supplies. The procedure contains the necessary instructions on how to transfer load when one battery bus is lost. The procedure also lists components that would potentially be affected if a bus was lost and not able to be reenergized.

-- Operating procedure N1-OP-40, Reactor Protection System. This procedure gives instructions on what to do if bus 130 is lost and also what loads would be affected.

Based on this review, this bulletin is closed.

c. (Closed) Bulletin 80-25: Operating problems with Target Rock Safety Relief Valves at BWRs. As documented in Inspection Report 87-13 the licensee's original response was incomplete. In a letter dated October 14, 1987 the licensee committed to revising surveillance procedure N1-ST-C2, "Manual opening of the solenoid actuated pressure relief valves and flow verification", to include the requirements that if a valve fails to function as designed, except for setpoint requirements, and the cause can not be determined, the valve will be removed from service, disassembled, inspected and adjusted prior to returning the valve to service. The inspector reviewed this surveillance procedure and determined that the appropriate change was made in November 1987. This bulletin is closed.

11. Unit 1 Confirmatory Action Letter 88-17 (30702, 71707)

a. On July 12, NRC Region I management met with Niagara Mohawk senior management at the site to discuss licensee commitments for a Confirmatory Action Letter (CAL) which was formally presented to the licensee on July 25, 1988, by the NRC Regional Administrator, William T. Russell and the NRC Executive Director for Operations, Victor Stello. The Confirmatory Action Letter, dated July 25, 1988, specifies the general actions committed to by the licensee to be taken prior to authorization of Unit 1 restart being granted by the Regional Administrator.

b. The licensee has established a Unit 1 Restart Task Force to oversee the restart actions described in the CAL. The inspector reviewed: an internal licensee memorandum appointing Mr. J. Perry (Vice President of Quality Assurance) as the Task Force Director; Mr. Perry's internal memorandum delegating his normal QA responsibility to Mr. R. Palmer; and the Restart Task Force Charter and list of Task Force members. In the Perry memorandum, the inspector questioned whether Mr. Perry retaining control of QA policy and personnel issues would be a conflict of interest. These responsibilities were also subsequently tranferred to Mr. Palmer.

c. On August 18, the Regional Administrator and the resident inspectors met with licensee senior management, including: W. Donlon, CEO; J. Endries, President; C. Mangan, Senior Vice President; and J. Perry Restart Task Force Director. The discussions were held at the licensee's nuclear headquarters concerning the licensee's progress in response to the CAL. The NRC and licensee discussed the required process and feedback from other utilities in similar situations approaching restart issues.

The inspectors reviewed the licensee's determined root causes for identified problems. The identified root causes were regarded more as symptoms rather than the underlying problems because the licensee had generalized causes into groups. The licensee stated that a meeting would be scheduled in the near future at the NRC Region I office to provide the NRC staff with details of corrective actions to date, and a proposed restart program and schedule.

12. Site Organization Changes (36700)

On August 1, the licensee implemented several management changes. The previous Unit 1 Superintendent, Mr. T. Roman, was replaced by Mr. K. Dahlberg. Mr. Roman has been assigned Technical Assistant to the Vice President of Nuclear Engineering and Licensing. Mr. Dahlberg previously held the position of site Maintenance Superintendent. As part of the station reorganization, the site instrument and control (I&C) group has become part of the Maintenance Department. Mr. W. Drews, previously the site Technical Superintendent replaces Mr. Dahlberg as site Maintenance Superintendent. Mr. M. Falise, previously the site Mechanical Maintenance Superintendent will be an assistant to Mr. Drews. Mr. K. Sweet, previously the site Electrical Maintenance Superintendent, and Mr. L. Lagoe, previously the site I&C Superintendent, will become Unit Maintenance Superintendents for Unit 1 and Unit 2, respectively. A new Training Superintendent, Mr. A. Rivers, has been assigned replacing Mr. K. Zollitch. Mr. Zollitch has been appointed the position of special assistant to Mr. J. Willis, Station Superintendent.

The inspector reviewed the appropriate standards for selection and training of nuclear power plant personnel, ANSI N18.1-1971 (Unit 1) and ANSI 3.1-1978 (Unit 2), to which the licensee is committed, to verify that the persons selected for new positions met the minimum qualification requirements. The inspector noted that Mr. J. Willis, the Station Superintendent, and Mr. Dahlberg, Unit 1 Superintendent, do not meet the requirements and operating experience equivalent to that normally required to be eligible for a Senior Reactor Operator's (SRO) license.

Designation of a principle alternate who meets the SRO or equivalent requirement is allowed by the ANSI Standards for both individuals. The individuals designated for Mr. Willis are Mr. R. Abbott, Unit 2 Superintendent, and Mr. R. Randall, Unit 1 Operations Superintendent. Mr. Dahlberg's principle alternate is also Mr. R. Randall.

On August 23, Mr. C. Mangan, Senior Vice President committed to formalize the chain of command at both units. He also committed to develop a plan such that Mr. Willis and Mr. Dahlberg will receive additional training. This item will be monitored by the inspectors in future inspection periods.

13. Temporary Instruction (TI) Followup - Unit 2 (71707, 61726, 37828)

a. TI 2515/93 Diesel Generator Fuel Oil: This TI was developed due to instances of clogged fuel oil strainers and/or filters. This type of clogging can cause reduction in fuel oil flow and subsequently affect the ability of the generator to produce the required output. The material causing the clogging in some cases was found to be biological debris.

The Nine Mile Point Unit 2 Technical Specifications 4.8.1.1 specifies the surveillance requirements relating to the diesel generator (DG) fuel oil. These requirements include periodically verifying the fuel level in the DG fuel oil day tanks, sampling the fuel oil in accordance with ASTM D4057-81 to ensure that the limits of ASTM D975-1981 are met, periodically checking for and removing water if found, and draining, cleaning, and removing sediment from each fuel oil storage tank once every ten years. The Technical Specifications specify action statements in the event that these requirements are not met.

The inspector reviewed the licensee's actions for the three Emergency Diesel Generators (EDGs) to ensure that adequate precautions to preclude problems such as those discussed above are taken. Surveillance procedures were reviewed and found to address the TS requirements. However, the inspector noted that two of the procedures (Procedures N2-OSP-EGS-M001 and M002) did not give clear directions for verifying the fuel oil level following removal of water. The licensee initiated three temporary change notices to correct these two and one other procedure to include clear directions for verifying tank levels following water accumulation check and removal.

The inspector observed the following:

-- Procedure N2-CSP-8V requires sampling and chemical analysis of any new fuel.

-- A diesel fuel oil preservation is added to the fuel oil storage tanks and the oil is reinhibited when new oil is added or during yearly intervals as needed. The oil preservation prevent formation and settling out of organic sludge, acts as a rust preventative, keeps trace amounts of water dispensed in the fuel, and contains a bactericide which prevents bacteria and slime formation and destroys any existing organisms.

-- Operational and Surveillance procedure requires that the following be performed: 1) the differential pressure across the lube oil full flow filter and strainer be monitored during operation, 2) the fuel oil filter/strainer elements be replaced when the differential pressure limit is reached during operation, and 3) that each fuel oil transfer pump discharge stainer and strainer housing be cleaned every 18 months.

-- In addition, alarms are provided to indicate low level in the DG fuel oil or day tanks.

The inspector had no further questions. This TI is complete.

b. TI 2515/95 Recirculation Pump Trip: One of the requirements of 10 CFR 50.62 "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water cooled nuclear power plants" was a requirement for each boiling water reactor (BWR) to include equipment to trip the reactor recirculation pumps automatically under conditions indicative of an ATWS. The Nine Mile Point Unit 2 design includes recirculation pump trip on either low water level or high reactor vessel pressure. The inspector reviewed the checklists for Instrument Surveillance Procedure N2-ISP-RRS-@101, "Alternate ATM Setpoint and Gross Failure Calibration" 5/19/88, to verify that these modifications had been completed. This procedure contains the surveillances for the recirculation pump trips on high vessel pressure and low vessel level. The surveillances on the subject instrumentation were completed during the period of June 21-23, 1988. No problems were identified. This TI is complete.

c. TI 2515/96 Drywell Vacuum Modifications: Generic Letter 83-08 identified concerns relating to a potential failure mode of the vacuum breakers on Mark I containment under LOCA loads. The Nine Mile Point Unit 2 FSAR Section 6.2 discusses the modified Nine Mile Point Unit 2 vacuum breakers as being of the same size and similar design as the LaSalle vacuum breakers which have undergone modifications and testing to ensure that they can withstand the pool swell phenomena. In addition, a modified Nine Mile Point Unit 2 valve was tested to determine the opening and closing velocities and these values were compared with the LaSalle values and found to be within an acceptable margin. In Supplement 3 to the Safety Evaluation Report (SER) the staff concluded that the modified design of the vacuum breakers was acceptable for Nine Mile point Unit 2. The inspector reviewed Stone and Webster Licensing Document Change Notice 16-72 which confirmed that the required modifications had been completed. No problems were identified. This TI is complete.

14. Review of Licensee Safety Evaluations at Unit 2 (37702; 37703)

10 CFR 50.59 permits the licensee to (a) make changes to a facility as described in the safety analysis report, (b) make changes to a procedure as described in the safety analysis report, and (c) conduct tests or ex-

periments not described in the safety analysis report without prior Commission approval, unless the proposed change, test or experiment involves a change in the Technical Specifications incorporated in the license or an unreviewed safety question. The inspector reviewed ten evaluations performed by the licensee pursuant to 10 CFR 50.59. The evaluations covered a period from October 31, 1986 through June 24, 1988. The inspector also reviewed the licensee's procedure for performing evaluations pursuant to 10 CFR 50.59, NT100.B, Rev. 5 "Preparing and Control of Safety Evaluations." The inspector noted during the review of the evaluations that the quality of the evaluations performed appeared to get progressively better with time (i.e., the later packages were better than the earlier ones). The inspector had the following specific comments as a result of the review:

a. The technical justification for SE 87-053 was incomplete. This change involved a revision to the service water (SW) pump trip setpoint for low discharge flow from 2500 gpm to 1000 gpm with a 10 second time delay. The vendor recommended a minimum allowable flow of 2300 gpm to protect the pump. The change to the 1000 gpm setpoint was made to prevent the pump from tripping during flow transients during the startup period.

   The safety evaluation referenced calculation 12177-CS-SWP*01 for verification that a setpoint of 1000 gpm was satisfactory. The inspector reviewed the referenced calculation. The calculation evaluated the allowable setpoint for the trip considering such things as instrument drift and uncertainties. It did not evaluate the effect of a 1000 gpm flow on the SW pump. The calculation contained a statement that the only way the pump would experience a reduction of flow to less than 2600 gpm would be if the discharge valve downstream of the pump were to be closed. In that event, the flow would be below 1000 gpm and a trip would be initiated. The discharge valve is a motor-operated valve which is designed to be either fully opened or fully closed. However, the inlet valve upstream of the pump is a manually operated butterfly valve. This valve could be inadvertently left in a partially open position permitting a flow of between 1000 and 2300 gpm. The licensee has committed to review the change to the trip setpoint and provide a complete justification for the change pursuant to 10 CFR 50.59.

b. The licensee's procedure for the review of changes, tests, and procedures pursuant to 10 CFR 50.59, NT-100.B, "Preparation and Control of Safety Evaluations," requires an environmental evaluation to be performed to determine whether an unreviewed environmental question exists. The environmental review is not required to meet the requirements of 10 CFR 50.59, however, the review is specified in the Environmental Protection Plan (EPP), Appendix B, of the facility operating license. A number of the packages reviewed did not provide evidence that an environmental review was performed. The inspector

obtained a commitment from the licensee that a review of all safety evaluations performed under 10 CFR 50.59 would be conducted to ensure that environmental impact reviews are performed and documented.

c. The licensee is required under 10 CFR 50.59 to submit annually a report of any changes, tests, and experiments. The licensee submitted its report on January 21, 1988 to cover the period from October 31, 1986 to October 31, 1987. The report listed six modifications and did not indicate any other changes for this period. A review of the evaluations for this period indicated that the list was substantially incomplete, even allowing for the modifications that had been evaluated and which were still not completed. The licensee indicated this was an oversight and committed to update the list through the end of August 1988 and submit it by October 31, 1988.

The inspector will review licensee action on the above commitments in a subsequent report.

15. Loss of Special Nuclear Material at Unit 1 (83526)

On July 8, the inspector met with licensee representatives to discuss the corrective actions following the June 30 discovery of the loss of special nuclear material (SNM). Vice previously reported in Inspection Report 50-220/88-16, the amount of U-235 lost was 2.2 milligrams not 6 milligrams. The original estimate of the quantity lost was based upon new local power range monitor (LPRM) fission chambers and not the actual type lost (General Electric NA-100s). Corrective actions taken or planned by the licensee included the following: 1) revision to the procedure governing the control of special nuclear materials (AP36) involving improved accountability during the use and transport of these materials; 2) reactor analysts (station staff accountable for SNMs) will be physically present during the transport of SNM; 3) physical inventory requirements of SNM will be increased in frequency to once every six months (same frequency as NMP Unit 2 inventory requirements); and 4) training will be conducted for station personnel in the use and control of SNM.

In addition to the corrective actions mentioned above, the licensee conducted a 100% inventory of all SNM at both units and found no further inventory discrepancies. The inspector determined that licensee actions to address this SNM loss were appropriate.

16. Assurance of Quality (30702, 30703)

The Unit 1 ISI Stop Work Order issued by QA shows that that organization can be critical of work that is ongoing. However, the oversight provided by Engineering that led to the April 1988 violation and civil penalty regarding ISI does not appear to have improved, as evidenced by the Stop Work Order.

Engineering staff identified problems with the Unit 2 secondary containment recirculation cooler fans, during the FMEA review, indicate good technical review. The fact that this condition existed from the initial design indicates that the licensee relied too heavily upon contractor design reviews.

Unit 2 operator actions taken on the failure of the diesel generator service water outlet valve and on the failure of the FCV-10A to operate demonstrate good cognizance on the part of the operators.

The number of Unit 2 reactor building isolations and Standby Gas Treatment automatic initiations show that the actions taken by the licensee to prevent or minimize these occurences have not been fully effective. The inspectors recognize that long awaited modifications are scheduled during the upcoming outage that should eliminate these types of unnecesary actuations.

The poor housekeeping conditions in the Unit 1 drywell and lower elevations of the reactor building indicate a lack of effective management oversight in this area.

17. Exit Meetings (30703, 30702)

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of this inspection. Based on the NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain Safeguards or 10 CFR 2.790 information.