U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/95-23 & 50-410/95-23
September 3 to October 14, 1995

SAFETY ASSESSMENT/QUALITY VERIFICATION

The inspectors reviewed and closed six Unit 2 Licensee Event Reports; all met the requirements of the technical specifications. During the review, it was determined that three of the LERs were violations of the technical specifications. The first one related of a safety relief valve tail pipe temperature recorder being inoperable for an extended time, due to the control room operators failure to recognize the problem. The second was a failure to properly restore the suppression pool spray mode of the residual heat removal system to operation after a test, due to an inadequate procedure and poor communications. And the third event was the failure of one division of the hydrogen recombiner system, due to poor work controls during the initial installation of the system. All three of these were licensee identified; the three LERs resulted in non-cited violations.

In addition to the above, other events discussed in the inspection report were due, in part, to procedure weaknesses and inadequacies. Unit 2 experienced a loss of both reactor recirculation pumps during a reactor startup due to a inadequate test procedure, and a Unit 1 primary containment isolation valve was found unlocked (see below). Also, a Unit 2 suppression pool spray valve was not reopened after a test because of a failure to incorporate the requirements for independent verification of safety related valves into the test procedure.

PLANT OPERATIONS

During the inspection period, both units operated safely. The status of the various pressure relief valves are monitored at both units via temperature and acoustic monitors; neither unit had any indication of leaking valves as of this report period. Two examples were noted of weak operator awareness of plant conditions: Unit 1 operators were not aware of a cleared Unit 1 nitrogen tank level and pressure alarm (indicating a full tank) with the tank being empty (Section 2.5); and, Unit 2 operators were not aware of failed SRV tailpipe temperatures recorder (Section 6.1).

On September 6, while in cold shutdown, Unit 2 experienced a loss of one of the two offsite 115Kv power supplies as the result of a ground fault on one phase of the secondary side of "B" reserve transformer. The response of the control room shift was appropriate, with good command and control on the part of the shift supervision. Their approach to stabilizing the plant was cautious and methodical. The additional support provided by maintenance and engineering staffs was very helpful, with good communications between the organizations.

Several weaknesses were also identified during the efforts to repair RRCS. During the reactor startup, both RRPs tripped after RRCS was deenergized for

EXECUTIVE SUMMARY (continued)

troubleshooting. The command and control of the shift supervision, and the response of the operating staff, were good and resulted in the plant being returned to a stable condition in a timely manner. However, the problem could have been avoided if the appropriate guidance had been in the operating procedure.

During a tour of the Unit 1 reactor building, an NRC inspector found a primary containment isolation valve locking chain improperly secured. The procedure for reactor startup prerequisites includes a verification that the valve is locked. The valve had potentially been unlocked since the pre-startup checkoff was completed after the last outage. This is a violation of the Unit 1 TS. **(VIO 50-220/95-23-01)**

During a tour of the Unit 1 control room, an inspector noted that the low level alarm and the low pressure alarm for the #12 N_2 tank was clear; although the tank had been drained for maintenance. The inspectors were concerned that the operators did not recognize or question that the alarms did not come in as designed. NMPC is tentatively planning a design change. **(URI 50-220/95-23-02)**

MAINTENANCE

Unit 2 had a problem while troubleshooting recurring test faults on the Division II redundant reactivity control system. The test faults were identified by the self-test feature of the system, starting on September 10 and was finally repaired and returned to service on September 18. The inspectors were concerned with the lack of thoroughness demonstrated in the troubleshooting of the RRCS failures that allowed the system to be declared operable numerous times before the root cause was ultimately determined, and corrected. The malfunction would not have prevented the system from performing the required safety functions. In addition, during the troubleshooting, numerous module cards were identified as being faulty, even though they were requisitioned from the storeroom, and bought as safety related equipment; making the problem potentially 10 CFR 21 reportable.

During performance of a surveillance on the Unit 1 containment spray raw water (CSRW) system, control room operators noted that pump motor amps decreased and indicated flow dropped to zero. Visual inspection of the deep-draft pump revealed that the bottom coupling was cracked through, causing the lowest section of the shaft to become decoupled. Several years earlier, a thicker walled coupling had been installed on similar type pumps due to industry information. As a result, NMPC reviewed maintenance history for all the deep draft pumps, and replaced the old couplings with the new design. The focus of the operations and maintenance crews, and system engineers, was on the safety and availability of the containment spray system and the associated raw water system. The post maintenance testing was satisfactory and all pumps were declared operable. The work and evolution was well planned.

EXECUTIVE SUMMARY (continued)

ENGINEERING

During the followup to the Unit 2 partial loss of offsite power, NMPC identified excessive building inleakage due to accumulated rain water on the roof of the normal switchgear building. Among other areas, water was leaking onto electrical equipment on the 261' elevation; specifically, on to the bus duct between the "B" reserve transformer and normal switchgear 2NPS-SWG001. In addition, there had been an effort to set up a catch containment to prevent the water from impacting the electrical equipment, but no DER had been initiated to document this specific condition. In 1994, a DER had been generated to investigate and resolve station building roof problems. Discussions with management and the cognizant system engineer indicated that they were unaware of this specific condition. The inspectors considered this matter represented a potentially serious plant material condition, in that the water could cause a fault that may result in a plant trip.

The inspectors reviewed three NRC open items for root cause analysis and corrective actions. One was closed, and two were updated.

PLANT SUPPORT

During a recent drill, the inspectors noted that emergency preparedness accountability and evacuation procedures were not implemented for personnel in offsite buildings. For most personnel, they had never been required to participate in the drills and were not knowledgeable of the accountability procedures. In addition, the site announcements cannot be heard in most locations in these buildings.

The inspectors accompanied security guards on portions of their rounds and noted that all were knowledgeable about their duties and responsibilities. The guards has a good understanding of the various aspects associated with medical and fire contingencies, and how to implement search and rescue and accountability.

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1.0 SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

During this inspection period, Nine Mile Point Unit 1 (Unit 1) operated at full power with only minor power reductions for maintenance and control rod pattern adjustments.

Unit 2 started the period in a forced shutdown for repairs to a recirculation control valve and a turbine control valve. On September 5, operators commenced a plant startup; but, the next day, operators shutdown the plant to repair a testable check valve on the high pressure core spray system. On September 6, one of the two offsite power supplies was lost due to "corona effect" degradation of insulation on the 13.8Kv non-segregated bus on the secondary side of the "B" reserve transformer. After completing all repairs, the plant was restarted on September 12, and achieved full power on September 17. The plant maintained essentially full power during the remainder of the inspection period.

NRC Staff Activities

The inspectors conducted inspection activities during normal, backshift, and weekend hours. There were no specialist inspections conducted during this inspection period.

2.0 PLANT OPERATIONS (71707, 92901, 93702)*

2.1 Operational Safety Verification

The inspectors observed overall operation and verified selectively that NMPC operated the units safely and in accordance with their procedures, license, and Technical Specifications (TSs). The inspectors conducted regular tours of all accessible plant areas. The tours included walkdowns of safety systems and components for leakage, lubrication, cooling, and general material conditions that might affect safe system operation. No significant deficiencies were noted, minor deficiencies were discussed with the appropriate management.

2.2 Safety Relief Valve Leakage

Based on a recent event at another boiling water reactor involving leaking safety relief valves, the inspectors reviewed the status of the pressure relief valves at both units.

Unit 1 has two distinct systems for pressure relief: six electromatic relief valves (ERVs) and nine safety relief valves (SRVs). Both the ERVs and SRVs were manufactured by Dresser. The ERVs are electromatically actuated, associated with the automatic depressurization system (ADS), located upstream

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* **The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.**

of the main steam line isolation valves, and discharge to the torus (suppression chamber). The SRVs are mechanically actuated only, mounted on the reactor vessel head, and relieve directly to the drywell atmosphere. Both type valves have temperature tailpipe and acoustic (noise) monitoring. In addition, the ERVs have control room panel indication of valve position. The ERVs normal temperature range is 125-130°F, the SRVs normal reading is ≈250°F; the temperatures are read from the computer, and are printed hourly. There is a common alarm in the control room for the ERVs and the SRVs on high noise and an alarm for ERV open indication. None of the ERVs or SRVs are indicating any leakage, either by temperature or acoustics.

At Unit 2, the pressure relief system consists of 18 safety relief valves (SRVs), seven of which are designated as ADS valves. The SRVs were manufactured by Dikkers. Flow through these valves is monitored by both acoustic monitors and tailpipe thermocouples. The position indication for each SRV is derived from the associated acoustic monitor, and is provided above each SRV control switch. SRV tailpipe thermocouples provide a signal to a chart recorder and to a common alarm. The alarm setpoint is 334°F, with the current temperatures ranging between 180°F to 215°F. Presently, there are no indications of SRV leakage by either acoustic or temperature monitoring.

The inspectors routinely monitor the status of the pressure relief valves as part of the daily control room inspection.

2.3 Unit 2 Partial Loss of Offsite Power

2.3.1 Introduction

The inspectors reviewed the actions taken by NMPC regarding the availability of offsite power to Unit 2. The unit experienced a partial loss of offsite power on September 6, 1995, at 2:20 p.m. This was the result of a ground fault occurring on phase "C" of the non-segregated bus which supplies power from the 13.8Kv secondary of reserve transformer 2RTX-XSR1B to the station service switchgear 2NPS-SWG003. A 4-hour event report was made to the NRC. NMPC initiated a Deviation/Event Report (DER 2-95-2538) to document the event, root cause(s) and corrective actions.

2.3.2 Initial Conditions and Event Details

The reactor was in cold shutdown with offsite power supplied from the Scriba Substation, via 115Kv (kilovolt) Lines 5 and 6, to the two reserve station service transformers 2RTX-XSR1A and 2RTX-XSR1B, respectively. The switchgear was aligned such that 2RTX-XSR1A was supplying the 13.5Kv station service transformer 2NPS-SWG001 and the 4160v (volt) Division I safeguards bus; similarly, 2RTX-XSR1B was supplying the 13.5Kv station service transformer 2NPS-SWG003 and the 4160v Division II safeguards bus. Line 5 was also supplying the Division III 4160v safeguards bus. (See Attachments 1 and 2).

The design of Unit 2 is such that the safeguards buses are normally supplied by offsite power, via the reserve transformers. The unit generator supplies the station service buses (2NPS-SWG001 and 2NPS-SWG003) during power operation, and offsite sources power the station buses when shutdown. With this design, any time a 115Kv transmission line is lost, several engineered safety features (ESFs) are initiated, including automatic start and loading of one or more of the emergency diesel generators (EDGs).

On September 6, power was interrupted to the Division II safeguards bus 103 due to the loss of Line 6. The Division II EDG started and re-energized the bus. Line 5 continued to supply power to the Division I and Division III safeguards buses. At the time of the event, the Division III EDG was in parallel operation with offsite power, as part of a surveillance test. All ESFs actuated as designed. Since the reactor was already shutdown, no control rods moved. Post event recovery identified several minor equipment issues that were documented on individual DERs.

2.3.3 Unit 2 Organizational Response

Operations

The inspectors observed the control room operators' response to the event, and considered their actions appropriate. The shift supervision demonstrated good command and control. The unanticipated loss of switchgear 2NPS-SWGR001, following the loss of Line 6, complicated the operators' efforts to restore the plant to a stable condition. The response of the shift was in accordance with the appropriate procedures. Proposed actions were thoroughly discussed before being implemented, as evidenced by their evaluation of the potential consequences of securing of Division III EDG parallel operations and the need for restoration of shutdown cooling.

The inspectors also considered the additional support provided to the on-shift operating staff to be very helpful. The inspectors considered the communications between the operating staff and the technical organizations to be good. The operating staff relied frequently on the information provided by the technical staff for their evaluation of restoration of the electrical distribution system. Senior station management provided direction during the recovery phase. The performance of the operating staff was considered a strength by the inspectors.

Maintenance

The maintenance department conducted troubleshooting, investigations, and repairs on a round-the clock schedule, in support of the identification of the cause(s) and/or contributing factors. Their efforts facilitated the timely return of equipment to service; thus, increasing the options available to the operators for maintaining the plant in a safe shutdown condition. Activities observed by the inspectors included the inspection, meggering, and high voltage (Doble) testing of various electrical equipment involved in the event. NMPC sampled the oil in reserve station service transformer 2RTX-XSR1B to ascertain if any fault conditions had occurred. A comparison of the oil sample results from before and after the event indicated that no changes had occurred within the transformer.

Information related to the investigation and repair activities was openly communicated between the involved maintenance personnel, their cognizant supervisors, and support departments. Field work observed by the inspectors was conducted in accordance with established work plans. Where appropriate, NMPC used outside vendor expertise to assess bus bar issues and conduct specialized electrical testing.

Engineering and Technical Support

From the beginning of the event, through the investigations, troubleshooting, and repairs, the engineering and technical support groups were actively involved. The system engineers, and their management, coordinated the use of outside expertise, ensured that engineering and maintenance work plans were coordinated, performed safety evaluations and procedure changes, and conducted root cause reviews to support the development of the Licensee Event Report (LER). They were also involved in the development of a shutdown safety plan and the distribution of related information on the industry nuclear network. Their initial field walkdown observations, obtained immediately following the event, were transmitted to the control room staff and aided the plant establishing an effective operational response.

2.3.4 Root Cause and Corrective Actions

Bus Bar Failure

The ground fault occurred on phase "C" of the secondary side (13.8Kv) of transformer 2RTX-XSR1B, at a wall penetration transition piece where the non-segregated bus enters the south side of the normal switchgear building. The transition piece provides a fire and vapor barrier, and connects the aluminum bus bars on either side of the wall. The transition piece is bolted to the square aluminum bus bars; and consists of two flat copper pieces, each covered with a bakelite sleeve and supported at mid-length by a ceramic feed through bushing. NMPC replaced all of the phase transition pieces for both reserve transformers, based on early signs of degradation.

An inspection by NMPC of the 4160v transition pieces associated with the reserve transformers, which are of a similar design to the 13.8Kv bus ducts, found no potential problems. NMPC also inspected the 13.8Kv normal station service transformer (2STX-XNS1) which supplies power to 2NPS-SWG001 and 2NPS-SWG003 during normal plant operations. No evidence of insulation breakdown was observed. The auxiliary boiler service transformer, 2ABM-X1, powered from Line 5 or Line 6, provides an alternate supply to the safeguards electrical buses. The transition pieces for the 13.8Kv and 4160v bus ducts were inspected after the plant returned to power operations. No degradation was identified.

The inspectors examined the original phase "C" transition piece. The bakelite insulation covering the copper bars showed clear evidence of a carbon track along the approximate one foot length from the bus connection to the ceramic bushing. The track indicated a pattern of "corona" discharge from the section of bus that had been outside the building to the ceramic insulator bolt hole. There was no evidence of dirt or dust on the transition pieces. Corona affects are those caused by electrical stresses at the conductor surface, resulting in the ionization of the surrounding air. Corona usually occurs at voltages in the range of 12 to 25Kv, and can have a damaging effect on the surrounding insulation.

The NMPC preliminary investigation indicated an insulation breakdown in the area where the bus transitions between the outside and inside of the building. The breakdown was attributed to corona affects, but it is not known at this time what the specific initiating action was that caused the breakdown. Part of the disposition of DER 2-95-2538 included an external and independent failure analysis of the bus bars and associated insulation. The failure analysis is expected to be completed by February 15, 1996, and the formal root cause by March 15, 1996.

The inspectors noted that when the bus enclosures external to the building were first opened for inspection, moisture was observed within the enclosures. As part of the repair process, the enclosures were resealed, additional low point drain holes were added, and electrical heaters in the bus ducts and transformer enclosures were tested and restored to service, if defective. The buses and enclosures were not part of the preventive maintenance (PM) program. The LER and DER identified that the PM practices for this equipment will be reviewed and revised, as necessary, based upon the outcome of the bus bar failure analysis. Additionally, changes to the cognizant electrical PM procedure were identified and included bus duct visual inspections, heater operation, inspection and sealing of outside bus duct, and meggering and possible high voltage testing of the bus duct.

Adequacy of Protective Relaying

During the transient, protective relays actuated to clear the ground fault by de-energizing Line 6 at the Scriba Substation (breaker R60) and opening the 13.8Kv feed (breaker 3-1) to normal bus 2NPS-SWG003 from reserve station service transformer 2RTX-XSR1B. The protective relaying scheme also interrupted the feed from 2RTX-XSR1A to normal bus 2NPS-SWG001 by tripping open breaker 1-1.

The ground fault resulted in neutral current being sensed by an overcurrent protective relay (51N-2SPRY05) connected to the neutral of transformer 2RTX-XSR1B. This relay actuated to clear the fault by opening R60 in the Scriba Substation as well as the feeder supply breaker (3-1) to the 13.8Kv station service bus 2NPS-SWG003. NMPC speculated that a ground directional overcurrent relay (67N2-2NPSN01) picked up due to a momentary ground potential generated by the initial electrical fault and caused the tripping of the supply feeder breaker (1-1) for the 13.8Kv station service bus 2NPS-SWG001. The event investigation and troubleshooting activities included a review of established calibrations for the subject protective relays and verification that the current calibrations were within established acceptance criteria.

While the loss of switchgear 2NPS-SWG003 was expected based upon the design of the protective relay system and the fault, the electrical isolation of switchgear 2NPS-SWG001 was neither anticipated nor required for this event. The DER documented that the protective relay scheme for the subject non-safety 13.8Kv switchgear will be evaluated and appropriate changes implemented to improve reliability for similar types of events. Outside consultants will be involved in the NMPC engineering review. A completion date of June 30, 1997 was established for this corrective action.

2.3.5 Reliability of Offsite Supply

The inspectors reviewed the history of loss of offsite power at Unit 2 and discussed their background and corrective actions with NMPC representatives. The inspectors noted that previous NRC concerns about the adequacy and reliability of the offsite power supply for Units 1 and 2 was the subject of a 1993 inspection (NRC Inspection Report 93-15). That inspection concluded that the offsite power sources were reliable and that further enhancement measures were being considered.

The history of incidents affecting the 115Kv offsite power was being tracked by NMPC, along with individual causes and corrective actions. Because of a high incidence of human performance issues associated with these incidents, NMPC instituted a special training program for both plant and transmission department personnel to establish a better appreciation of plant requirements. The Scriba Substation was also placed under additional controls including requiring the approval of the Unit 2 shift supervisor for work activities and personnel access to the substation. Additionally, NMPC replaced the Scriba Substation 115Kv circuit breakers associated with Lines 5 and 6 because the original breakers exhibited poor reliability resulting from unnecessary trips.

The station 115Kv switchyard and switchgear areas were inspected along with the Scriba Substation. The inspectors discussed a recently completed expansion of the switchyard that supported interconnections to a new 345Kv line No. 25. During that construction, both the North and South 345Kv busses were extended and ties constructed to that line. The inspectors discussed with NMPC the specific controls in place for those construction activities affecting Nine Mile, the controls were thorough and provided a good basis for reducing personnel related incidents.

2.3.6 Assessment of Licensee Performance

The inspectors observed strong performance by plant operators, the applicable abnormal and system procedures were used, and unexpected conditions were discussed before actions were taken. The shift supervision applied a cautious and methodical approach in responding to a number of off-normal plant conditions created by the loss of an offsite transmission line. Engineering and technical support personnel were quick to provide a very good level of support, including the use of internal and external expertise. The corrective action processes, were effective in resolving equipment and program deficiencies, and in identifying longer term issues that may prevent recurrence. The response of the Unit 2 organization to the event, and resolution of resulting issues reflected a very strong safety focus. Senior station management was involved in the event recovery planning and discussions. This was evident in the inspectors' observations that the resolutions of issues by the organization were properly focused on first returning equipment to service that supported safe plant shutdown, secondly on facilitating the event investigation, and finally on plant restart.

2.4 Unit 1 Primary Containment Valve Found Unlocked

On October 13, during a tour of the Unit 1 reactor building, an NRC inspector found the service water outside containment isolation valve (#72-479) locking chain unlocked. The control room was notified and immediate corrective action included verifying the valve closed and properly securing the locking chain.

The inspector's review of the pertinent documents/procedures identified conflicting requirements as to whether or not the valve was required to be locked; all applicable procedures required the valve to be closed. The service water system procedure, N1-OP-18, required the valve to be closed. The procedure for reactor startup prerequisite verifications, N1-PM-V16, Form III, "Primary Containment Pre-Startup Checkoff," step 6, required the inside and outside service water drywell valves to be locked closed. The Updated Final Safety Analysis Report (UFSAR), Table VI-3b, "Primary Containment Isolation Valves," listed the service water inside and outside valves as closed; however, the valve numbers in the table are reversed. Also, the locked valve program requires an independent verification; N1-PM-V16 did not require that second verification. Subsequently, an NMPC review of all accessible locked valves determined that all were in the proper position and that the locking device was properly secured.

As of the end of the reporting period, NMPC had not identified any activity associated with this valve which would have caused the chain to be left unlocked. DER 1-95-2847 was initiated to track the issue and resolve the inconsistency of the locking requirement. The NRC staff expressed concern that the valve had potentially been unlocked since the pre-startup checkoff was completed after the last outage (April 1995).

The failure to follow procedures is a violation of the Unit 1 Technical Specifications, Section 6.8.1, which requires written procedures to be implemented; and N1-PM-V16, Form III, which required the valve to be locked closed. **(VIO 50-220/95-23-01)**

2.5 Unit 1 N_2 Tank Level and Pressure Annunciators Inoperable

Due to frequent low level alarms on the #12 nitrogen (N_2) tank at Unit 1, operators investigated and identified a valve near the tank that was leaking. On October 11, the tank was drained to facilitate repairs to the valve. The next morning, an inspector noted that the low level alarm for the #12 N_2 tank was clear; although the control room operator informed the inspector that the tank was still empty. The inspector questioned why the low level alarm and the low pressure alarm for the #12 tank were not annunciated. The shift supervisor initiated a problem identification report (PID) to investigate the problem.

The inspectors were concerned with the operators' control board awareness. Specifically, that they did not recognize or question that the annunciator for low level cleared when the tank was emptied; nor that the annunciator for low pressure did not come in as designed. Early investigation by NMPC identified a design change completed several years ago which may have left an annunciator ground wire disconnected. Pending NRC review of the NMPC resolution of these concerns, this will remain an unresolved item. **(URI 50-220/95-23-02)**

2.6 Unit 2 Reactor Start-Up

On September 12, during the Unit 2 reactor startup, both reactor recirculation pumps (RRPs) tripped after the redundant reactivity control system (RRCS) was deenergized for troubleshooting. The inspectors noted that the root cause of the RRP trip was an inadequate procedure, as identified by NMPC. The operating staff responded to the RRP trip and returned the plant to a stable condition. The reactor start-up and the RRCS troubleshooting activities were suspended until the cause of the recirculation pump trip was understood. The inspectors considered the operating crew's response to the event satisfactory, including the command and control demonstrated during the event and recovery. The inspectors evaluation of the RRCS troubleshooting and recirculation pump trip is documented in Section 3.2 of this report.

Following the resolution of the recirculation pump trip, the reactor start-up was resumed. The inspectors considered the level of command and control demonstrated during the reactor start-up to be appropriate. Additionally, the inspectors considered the briefings provided by the Assistant Station Shift Supervisor (ASSS) to be good.

However, the failure to provide the appropriate cautions in the work order test procedure, and the failure of the shift crew to challenge the impact of the RRCS test failure combined with de-energizing the system, demonstrated a weak questioning attitude.

3.0 MAINTENANCE (61726, 62703, 92902, 60705)

3.1 Maintenance and Surveillance Observations

The inspectors observed maintenance and surveillance activities to ascertain if safety-related work was conducted according to approved procedures, the TSs, and the appropriate industry codes and standards. Observation of activities verified that: LCOs were satisfied, removal and restoration of equipment were controlled, administrative authorizations and tag outs were obtained, procedures were adequate, certified parts and materials were used, test equipment was calibrated, radiological requirements were implemented, system prints and wire removal documentation were used, quality control hold points were established, deficiencies were documented and resolved, and records were complete and accurate. In general, the activities observed and reviewed were effective with respect to meeting the safety objectives. No significant concerns were identified during the inspectors' review except as noted below.

3.2 Unit 2 RRCS Inoperable

Prior to the Unit 2 reactor start-up on September 12, NMPC was troubleshooting recurring test faults on the Division II redundant reactivity control system (RRCS). The RRCS is a microprocessor-based control system used to prevent or mitigate the potential consequences of an anticipated transient without scram

(ATWS) event; i.e., a scram signal is received but the control rods do not insert. The RRCS limits the reactivity in the core by an alternate rod insertion, tripping the reactor recirculation pumps (RRPs), reducing feedwater flow, and initiating injection of a boric acid solution.

The inspectors reviewed the DERs, work orders, and procedures associated with the RRCS troubleshooting, and discussed the issue with the operating and technical staffs. Additionally, the inspectors observed the management meeting to discuss the operability of the RRCS system and the potential reportability concerns. During this meeting, the licensee discussed the need for a vendor performed failure analysis of the deficient cards to confirm the root cause.

RRCS test faults were identified by the self-test feature of the system and were documented in the SSS's logs, starting on September 10, 1995. Based on the indications, NMPC declared Division II RRCS inoperable. NMPC initially replaced the suspected analog trip module (ATM) card, retested the system and declared it operable. The system failed again several hours later, and a second ATM card was installed, which failed immediately. Next they reinstalled the original ATM card and three other system cards. The system again failed immediately, but this time due to a faulty isolated lamp driver (ILD) card. A detailed analysis identified the root cause to be the original ATM card. After obtaining an acceptable ATM card, the card was installed, the system was retested, and declared operable on September 18, 1995. RRCS has operated satisfactorily since. A deviation/event report (DER 2-95-2591) was written to track the failure modes analysis of the intermittent RRCS test failure. NMPC determined the root cause to be in the self-test feature of the ATM card. The malfunction would not have prevented the RRCS from performing the required function in response to an ATWS condition.

During the troubleshooting of the RRCS failures, NMPC determined that the two initial replacement ATM cards were faulty. In addition, the ILD card was also faulty. After determination of the root cause and based on the earlier experience with deficient cards, NMPC decided to bench test the ATM cards received from the storeroom. The bench testing identified another faulty ATM card. Since the cards were purchased a "safety-related", NMPC wrote additional DERs to assess the deficient cards, and to evaluate the potential for 10 CFR 21 reportability.

Over the course of the maintenance activity, RRCS failed at least five times, with the system being declared operable after each repair. The inspector expressed concern with the lack of thoroughness demonstrated in the troubleshooting of the RRCS failures that allowed the system to be declared operable numerous times before the root cause was ultimately determined, and corrected.

3.3 Unit 1 CSRW Pumps Inoperable

On October 3, during performance of a surveillance on the Unit 1 containment spray raw water (CSRW) system, control room operators noted that the #121 CSRW pump motor amps dropped significantly and indicated flow dropped to zero. An operator at the pump reported a loud noise which sounded like the discharge check valve slamming shut. The containment spray (CS) system consists of two divisions, two subsystems per division. The CSRW pumps provide cooling to the CS heat exchangers, each pump dedicated to an associated heat exchanger. The shift supervisor declared the pump inoperable, placing the unit in a 15 day limiting condition for operation (LCO), per TS 3.3.7.

The inspectors reviewed related industry events, including NRC Bulletin 79-15, NRC Information Notice 94-45, and the associated NMPC responses. They also monitored the maintenance activities, reviewed the work packages, and discussed potential operational concerns with the unit management.

Boroscopic inspection of the pump shaft and the check valve by NMPC identified nothing unusual. The pump is a deep-draft type, manufactured by Worthington. The pump shaft is 410 stainless steel, 25 foot long, comprised of two ten-foot lengths and a top section of five foot. Unit 1 management decided to remove the pump for a visual inspection, revealing that the bottom coupling was cracked through, causing the lowest section of the shaft to become decoupled. Several years earlier, a thicker walled coupling had been installed on some other pumps due to industry information about degraded couplings. As maintenance was performed on the various deep draft pumps, the couplings were replaced. As a result of this event, NMPC reviewed maintenance history for all of the CSRW pumps, and the other deep draft pumps, and replaced all of the old couplings with the new design.

The focus of the operations and maintenance crews, and system engineers, was on the safety and availability of the CS system and the CSRW system. The post maintenance testing was satisfactory and all pumps were declared operable. The inspectors considered the evolution well planned and the work well controlled.

4.0 ENGINEERING (37551, 92903)

4.1 Unit 2 Normal Switchgear Building Roof Deficiencies

On the evening prior to the Unit 2 partial loss of offsite power event, the area experienced heavy rain, resulting in water leaking onto electrical equipment on the 261' elevation of the normal switchgear building. The water originated from upper floors inside the building, that had accumulated due to roof and roof drain deficiencies. Specifically, the 13.8Kv bus duct between transformer 2RTX-XSR1B and switchgear 2NPS-SWG001 had water on the upper cover; but, when opened, the internal areas of the bus duct were dry and clean. Electrical checks were performed to confirm that the rainwater was not the cause of the phase 'C' fault. While DER 2-95-2538 had documented the problem as part of the initial investigation and troubleshooting efforts, the rainwater problem was treated as a peripheral matter and root cause and corrective actions were not addressed.

The inspectors noted from the walkdown of the building on the day of the event that water had been getting into the 261' elevation for some period of time. In addition, there had been a prior effort to set up a catch containment to prevent the water from impacting the electrical equipment. There was no DER documenting this specific condition. In 1994, a DER had been generated to investigate and resolve station building roof problems. On September 7, 1995, a service request was issued to resolve the building roof deficiencies.

The inspector's discussions with Unit 2 management and the cognizant system engineer indicated that they were unaware of this specific condition, although they had a general knowledge of the roof related problems. The subject equipment was non-safety related and the water leakage issue into the 261' elevation had not had any adverse impact on operating high voltage electrical equipment. Notwithstanding the above, the inspectors considered that this problem could result in an electrical fault causing a plant trip, and it represented a potentially serious plant material condition. As such, the problem was not identified in a recent DER. The use of this corrective action system would have appropriately escalated the matter for station management's attention, and aided the establishment of timely corrective actions that would have more rapidly resolved the issue of rainwater impinging on high voltage electrical equipment. The inspectors verified that roof repairs were generally effective. Although a few small roof leaks were still being pursued, no adverse conditions within the room were identified.

4.2 (Closed) URI 50-410/94-18-01: Degradation of Unit 2 Scram Discharge Volume Capability

On September 29, 1994, Unit 2 operators received a scram discharge volume (SDV) high level alarm and control rod block signal while draining the reactor core isolation cooling (RCIC) system drain pot. The operators secured the RCIC system draining and SDV level returned to normal. The SDV drain line, with its normally open drain valves, ties into a common line with the RCIC system and the residual heat removal (RHR) system drains prior to entering the equipment drain collection tank. This issue remained unresolved pending the completion of the NMPC root cause evaluation and the development of corrective actions.

The equipment drain system interconnections have historically been a problem at Unit 2 with drainage from RCIC and RHR backing up through open equipment drain funnels. In May 1994, a modification was implemented which separated the SDV/RCIC/RHR pressurized drains from the open equipment drain funnels. However, during the development of the modification, the potential interaction with the SDV system was not fully understood by NMPC.

NMPC determined that the September 29, 1994, event was caused by excessive two phase flow from the RCIC system. The drainage from the RCIC system drain pot put a large steam/water mixture into the equipment drain header and resulted in the carryover of water into the SDV. The development and review of the May 1994 modification to the equipment drain system did not adequately evaluate the effects of this two phase flow.

Corrective actions included the development of a simple design change to install a separate collection tank to the SDV drain system. During the recent Unit 2 refueling outage (RF04), the connections and valves were added to the SDV drain line to provide for the installation of the collection tank while the plant is on-line. The modification is scheduled to be completed by March 1, 1996. NMPC completed a review of the design process implemented to develop the original May 1994 modification and concluded that it was adequate to resolve the problem. Training was performed for NMPC operations and engineering staff on this event and two phase flow phenomenon.

4.3 (Updated) URI 50-410/94-32-01: Incorrect Fuses Installed in the Reactor Protection System

While performing maintenance to replace a relay in the reactor protection system (RPS), the licensee identified that incorrect fuses were installed. During fuse reinstallation, plant operators noted that 10 amp fuses had been installed, but the controlled plant drawings showed 5 amp fuses. Operations and engineering personnel determined the 5 amp fuse to be correct, and that the proper fuses had not been installed in RPS. This event was left open pending licensee review of the root cause of the event and the completion of corrective actions.

DER 2-95-0154 was initiated by the licensee to document this event. The work history for RPS was reviewed by the licensee and there was no documentation of any previous replacement of the fuses in question. Thus, the licensee was unable to identify the exact time when the incorrect fuses were installed. NMPC engineering completed an operability determination and concluded that the function of RPS had not have been adversely affected with the wrong fuses installed. The licensee compared ten additional RPS fuses against design documentation, in accordance with work order. No additional incorrect fuses were found in the RPS system.

The NRC reviewed the corrective actions taken for this event. The engineering operability determination was thorough and demonstrated the continued operability of RPS even with the wrong fuses installed. The inspector reviewed maintenance administrative procedure S-MAP-MAI-0501, Rev. 2, "Guidelines for Fuse Replacement," and determined that it provided adequate instruction. However, the inspector was concerned about the scope of the fuse check performed. As of the end of the inspection period, the licensee was not able to provide adequate justification as to why the small sample size was adequate to verify that all the fuses installed throughout the plant are correct. NMPC is reevaluating their initial corrective actions to determine if a larger sample size is warranted. This item will remain open pending further licensee NRC staff review.

4.4 (Updated) IFI 50-410/95-11-05: Revise Switch Settings/Capability Calculations

During the NMPC evaluation of motor operated valve (MOV) switch settings per NRC Generic Letter (GL) 89-10, the licensee revised calculations to increase the design margin necessary to address degradation, rate-of-loading, and testing instrumentation errors. While reviewing the revisions, NMPC identified several MOVs with torque switch settings outside the new design window. NMPC initiated two DERs: DER 2-95-2484 described MOVs requiring adjustment of the torque switch settings, and DER 2-95-2485 described MOVs requiring replacement of gear sets. The engineering preliminary assessment identified no immediate operability concerns.

The inspectors reviewed the DERs and discussed the operability of the MOVs with the licensee and with NRC Regional-based specialist inspectors. NMPC's engineering staff based the operability of the identified MOVs on the safety function of the valve, the normal valve position, and a qualitative review of the margins assumed within the calculations. NMPC established tentative plans to complete the selected torque switch setting and gear set changes. The inspectors considered NMPC's actions appropriate; however, this item remains open pending the completion of NMPC's action and subsequent NRC review.

5.0 PLANT SUPPORT (71707, 71750, 92904)

5.1 Observations of Plant Support Activities

The inspectors routinely monitor activities in the areas of radiation protection, emergency preparedness, security, fire protection, and general housekeeping during tours. Minor weaknesses were discussed with the appropriate supervision; no significant deficiencies were identified, except as noted below.

5.2 Emergency Preparedness

Due to various weaknesses observed during earlier emergency preparedness (EP) drills and exercises, the inspectors paid particular attention to accountability and evacuation procedures during the drill on October 3. The participation and leadership within the protected area was greatly improved.

However, the EP procedures require the personnel in buildings outside of the protected area (specifically, the training center and the processing building) to assemble in designated locations if site evacuation or accountability is required. For most personnel in these areas, they had never been required to participate in the drills and were not knowledgeable of the requirement to assemble. In addition, many thought that they were exempt from participation because it was only a drill. Finally, it was noted that site announcements cannot be heard in most locations in the buildings outside of the perimeter fence.

EP drills are intended to be a learning experience, with interaction between the participants and the evaluators; weaknesses are expected to be corrected immediately. Exercises, on the other hand, are evaluated with no interaction between the participants and the evaluators. Being that this was a drill, the inspectors were satisfied with the NMPC corrective action of management touring the areas and informing the staff of the requirements. The inspectors considered the actions of the Nine Mile managers a good initiative to improve the level of performance on subsequent EP drills and exercises.

5.3 Security

The inspectors accompanied various security guards on portions of their rounds. All of the guards were knowledgeable about their duties and responsibilities, and exhibited an appropriate level of cautiousness while performing their rounds. In addition, the inspectors questioned the guards about how those duties could change in the event of an emergency. The guards interviewed had a good understanding of the various aspects associated with medical and fire emergencies, and how to implement search and rescue and accountability.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707, 90712)

The below listed Licensee Event Reports (LERs) were reviewed for accuracy and compliance with the requirements of technical specifications.

6.1 (Closed) LER 50-410/95-01: Technical Specification Violation Caused by Failure to Identify a SRV Tail Pipe Temperature Recorder Malfunction

On January 12, 1995, an operator noted that all safety relief valve (SRV) tail pipe temperatures were reading the same on the temperature recorder, the recorder was declared inoperable. After repairs and testing, the recorder was returned to service about 13 hours later. Investigation identified that the temperatures began reading identical on January 2. Technical Specification 3.3.7.5-1 requires a plant shutdown if the minimum number of required channels of accident monitoring instrumentation cannot be restored within 7 days. A TS violation existed from January 9 (7 days after the temperature recorder failed) to January 13, when the recorder was returned to service.

The failure of the recorder was due to a bad print/index card in the recorder. This caused the recorder to only read one of the temperature monitors. The root cause for the failure to identify the malfunction for 10 days was inadequate monitoring of the recorder by the control room operators.

Immediate corrective actions included repair of the recorder and initiation of a preventive maintenance procedure to improve reliability. To prevent recurrence, supervisors reinforced expectations with respect to attention to detail; and a clarification of how to determine if a recorder is operating.

The inspectors reviewed the LER and determined that it satisfactorily described the event, the root cause evaluation, and corrective actions to prevent similar occurrences in the future. This violation was not cited in accordance with the NRC "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600, (60 FR 34381; June 30, 1995), Section VII.B.1.

6.2 (Closed) LER 50-410/95-05, Supplement 1: Reactor Manual Scram to Protect Turbine-Generator from High Vibration

On May 30, 1995, during a plant startup, the main turbine exhibited excessive vibration resulting from packing rub following installation of the new mono-block low pressure turbine rotors. The original LER was reviewed and closed in NRC inspection report 95-16. The supplement elaborated on the root cause of the event being due to the close clearances associated with the new design. Additional corrective actions as a result of the review included development of a special procedure for bringing the turbine on line during subsequent startups. The inspectors had no additional questions relating to this event.

6.3 (Closed) LER 50-410/95-06: Technical Specification Violation Caused by Not Following Procedural Requirements

On May 30, 1995, with Unit 2 at 15% reactor power, NMPC discovered that the suppression chamber spray mode of residual heat removal system (RHS) loop "A" had been inoperable since May 23, 1995. During this period, Unit 2 changed from a shutdown condition to at-power operation. Specifically, during restoration from a test to check leakage between the drywell and the suppression chamber, a manual blocking valve (2RHS*V315) for the suppression spray in RHS "A" was not reopened as required. The valve was found closed during an attempt to spray the suppression chamber.

The inspector independently investigated the event and verified the NMPC root cause. The requirements of NIP-PRO-01 for use of procedures was not followed. A reactor operator (RO) was assigned to control the restoration of the system. Two auxiliary operators (AOs) performed the restoration and initialed the field copy of the procedures to indicate which valves had been manipulated; the AOs did not initial V315 as being opened. The RO confirmed verbally with the AOs that system restoration was complete. The RO did not review the field copy to verify that each individual valve had been returned to the correct position. The primary contributing cause was that the requirements of NIP-PRO-01 for an independent verification of position of all safety related valves (V315 is safety related), was not incorporated into the test procedure.

Corrective actions included opening V315, and a verification that all emergency core cooling system valve lineups (outside of primary containment) were in accordance with the controlling procedure. Actions to prevent recurrence included a review of surveillance procedures to ensure that independent verifications are included, when required; and incorporation of this event in the operator requalification training with emphasis on proper communications between procedure controllers and performers

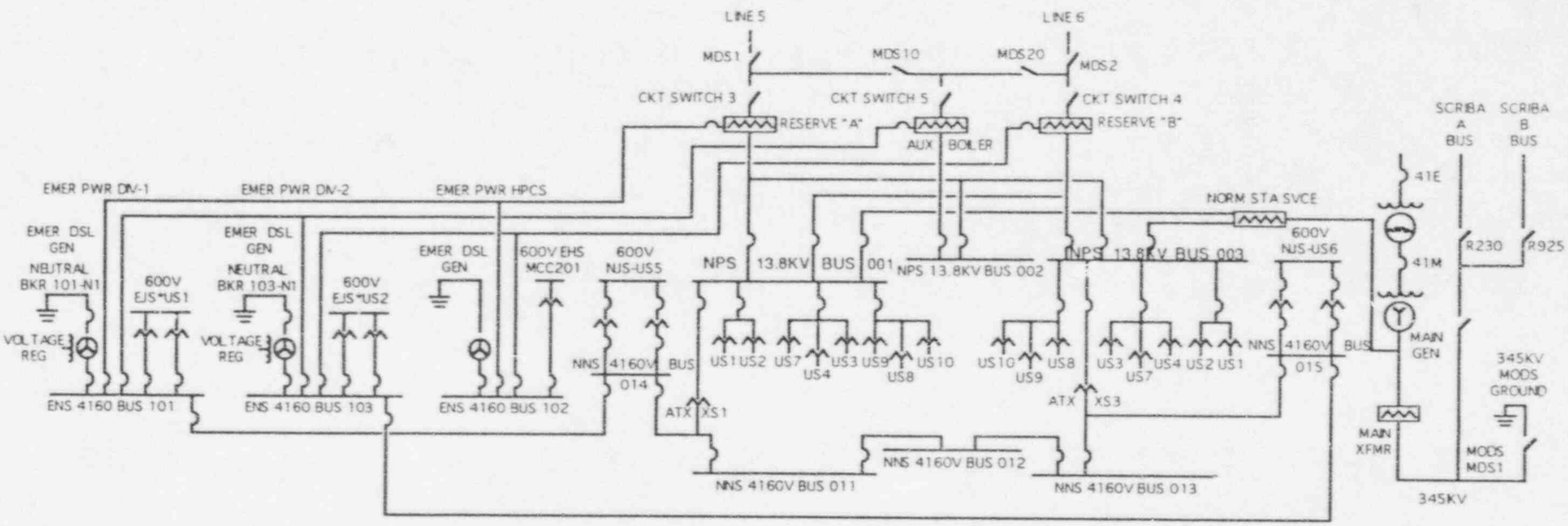
The inspectors reviewed the LER and determined that it satisfactorily described the event, the root cause evaluation, and corrective actions to prevent similar occurrences in the future. This was a violation of TS LCO 3.0.4, which states that entry into an operational condition shall not be made unless the conditions for the LCO are met. This violation was not cited in accordance with the NRC "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600, (60 FR 34381; June 30, 1995), Section VII.B.1.

6.4 (Closed) LER 50-410/95-08: Reactor Manual Scram on High Turbine Generator Vibration

This event was previously reviewed and documented in NRC Inspection Report 50-410/95-18. The inspectors verified that the LER contained an appropriate level of detail and that the corrective actions were completed.

ATTACHMENT 1

NRC INSPECTION REPORT NOS. 50-220/95-23; 50-410/95-23



TITLE
Mimic of Electric Plant Control Panel

6.5 (Closed) LER 50-410/95-09: Division I Hydrogen Recombiner Inoperable due to Obstruction in Flow Path

On August 28, 1995, the Division I hydrogen recombiner was declared inoperable due to low system flow, as identified on a failed surveillance test. Subsequent investigation discovered a wooden plug in the piping from the suppression chamber to the recombiner. Due to the size and location of the plug, it was assumed to have been in the system since initial construction.

The cause of the event appears to be attributable to poor controls during the vendor's fabrication process and an inadequate inspection during the installation of the system. A review of system maintenance history identified no activities after initial construction that would have introduced the plug into the system. Corrective actions included boroscopic inspections of both Division I & II hydrogen recombiner system piping.

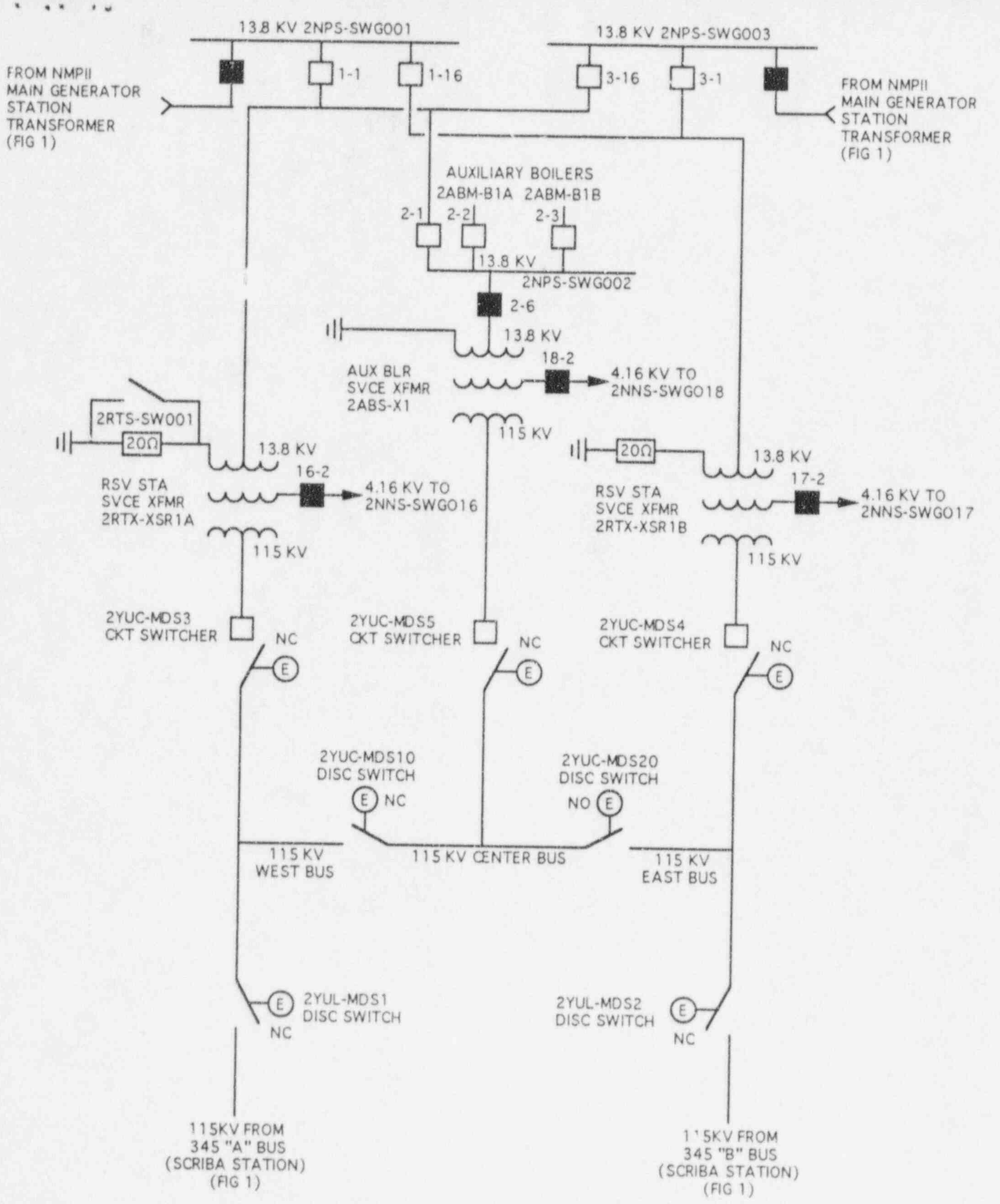
The inspectors reviewed the LER and determined that it satisfactorily described the event, the root cause evaluation, and corrective actions to prevent similar occurrences in the future. This was a violation of TS 3.6.6.1, which requires two independent hydrogen recombiners subsystems when in power operation. This violation was not cited in accordance with the NRC Enforcement Policy, as described in NUREG-1600, Section VII.B.1.

6.6 (Closed) LER 50-410/95-10: Multiple ESF Actuation Caused by Partial Loss of Offsite Power

The inspectors reviewed the Unit 2 partial loss of offsite power event in Section 2.3 of this inspection report. The LER is accurate and contains an appropriate level of detail.

7.0 MANAGEMENT MEETINGS

At periodic intervals and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection. The final exit meeting occurred on November 9, 1995. Based on the NRC Region I review of this report, and discussions held with NMPC representatives, it was determined that this report does not contain safeguards or proprietary information.



ATTACHMENT 2

NRC INSPECTION REPORT NOS. 50-220/95-23;
50-410/95-23

NORMALLY OPEN POWER CIRCUIT BREAKER

NORMALLY CLOSED POWER CIRCUIT BREAKER

NC NORMALLY CLOSED

NO NORMALLY OPEN

TITLE

115 KV Switchyard and Transformers