U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/ Report No.	50-213/94-03
License No.	DPR-61
Licensee:	Connecticut Yankee Atomic Power Company (CYAPCo) P. O. Box 270 Hartford, CT 06141-0270
Facility:	Haddam Neck Plant
Location:	Haddam Neck, Connecticut
Dates:	January 16 to February 26, 1994
Inspectors:	William J. Raymond, Senior Resident Inspector Peter J. Habighorst, Resident Inspector Suresh Chaudhary, Senior Reactor Engineer

Approved by: Lawrence T. Doerflein 4/7/94

Lawrence T. Doerflein, Chief Date
Reactor Projects Section 4A

Areas Inspected: NRC resident inspection of plant operations, outage activities, maintenance, engineering and technical support and plant support activities.

Results: See Executive Summary

EXECUTIVE SUMMARY
HADDAM NECK PLANT INSPECTION 50-213/94-03

Plant Operations

Plant operators performed very well during this period responding to transient conditions, completing an orderly shutdown to cold shutdown, and implementing controls to minimize shutdown risks. The operators also provided good support to engineering to identify all service water system stagnant legs. The compensatory measures to address degraded service water piping were appropriate and thorough. A licensed senior reactor operator demonstrated excellent knowledge of the plant configuration and procedures by his recognition of a potential vulnerability when in the sump recirculation mode of reactor cooling following postulated accidents.

Maintenance

Maintenance investigations following the failure of both pressurizer PORVs on February 19 were good. The root cause determination for the failures, and the actions to improve the PORV air system is an unresolved item **(UNR 94-03-01)**. The use of mechanical restraining bars while testing the main steam trip valves will be reviewed on a subsequent inspection **(IFI 94-03-02).** The licensee promptly investigated the operability of the main steam safety valves following the receipt of test information from the vendor. Although an acceptable method was developed to test the installed valves, the decision to not test the valves with the plant operating at power reflects a conservative safety ethic. Some main steam safety relief pilot valves failed when tested during cold shutdown plant conditions. The causal analysis was not complete at the end of the inspection period. Future NRC inspection will review the CYAPCo's root cause analysis and the corrective actions **(UNR 94-03-03)**.

CYAPCo staff performed well investigating the failure of the MCC-5 automatic bus transfer (ABT) during this inspection period. This item is considered unresolved pending the completion of the root cause investigation of the failure, and the implementation of corrective actions **(UNR 94-03-04)**. CYAPCo management and engineering did not aggressively pursue indications of corrosion induced degradation in service water piping, and had lost the initiative in resolving this problem prior to substantial NRC involvement on the issue. This item is considered open pending the completion of actions to replace degraded SW piping, and to address the root cause for the corrosion **(UNR 94-03-05)**.

Engineering and Technical Support

The discovery of silt and macrofouling in the service water supplies to the RHR heat exchangers revealed an inadequacy in CYAPCo's actions in response to NRC Generic Letter 89-13. This is an inspector follow item **(IFI 94-03-06)**.

CYAPCo's identified discrepancies between the of "as-built" conditions for the low pressure safety injection system and the original piping specification. The deviations from the specifications were acceptable. This item is open pending the completion of actions to assure the accuracy of plant design basis information used for engineering evaluations **(IFI 94-03-07)**.

Plant Support

Radiological controls were well implemented. Actions to investigate and correct an unsecured gate providing access to a locked high radiation area were prompt and thorough. The security officer who discovered the unsecured gate during a routine tour demonstrated good attention to detail and regard for radiological controls. Licensee measures to control and monitor radiological releases while purging the containment were good. Licensee actions during contract negotiations with the security force were thorough.

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Note: The NRC inspection manual procedure or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

The plant was operating at 100% full power at the start of the period on January 16. On January 20, plant load was reduced to 85% at 4:40 p.m. due to fluctuating temperatures on the main generator hydrogen coolers. The load reduction was stopped after finding the temperature controller for control valve SW-TCV-1711 had failed. The valve was placed in manual control and temperatures returned to normal. Plant load was increased to 100% on at 7:15 p.m.

The plant continued operating at 100% power until February 12, when both service water system headers to the emergency diesel generators were declared inoperable. An Unusual Event was declared due to the Technical Specification required shutdown. The plant was in cold shutdown at 6:10 p.m. on February 13, commencing an anticipated 55 day outage. The plant remained shutdown at the end of the period. The major work in progress included: activities to inspect and replace service water system piping, replacement of the seal on the #1 reactor coolant pump, painting the reactor cavity, and replacement of the coolers for containment air recirculation fans #2 and #3.

2.0 PLANT OPERATIONS (71707 and 93702)

In addition to normal utility working hours, the inspectors routinely conducted the review of plant operations during portions of backshifts (evening shifts) and deep backshifts (weekend and night shifts). Inspection coverage was provided for fifty five hours during backshifts and forty five hours during deep backshifts.

2.1 Operational Safety Verification

This inspection consisted of selective examinations of control room activities, operability reviews of engineered safety feature systems, plant tours, review of the problem identification systems, and attendance at periodic planning meetings. Control room reviews consisted of verification of staffing, operator procedural adherence, operator cognizance of control room alarms, control of technical specification limiting conditions of operation, and electrical distribution verifications. Administrative control procedure (ACP) - 1.0-23, "Operations Department Shift Staffing Requirements," identifies the minimum staffing requirements. During the inspection period, the inspectors verified these requirements were met.

The inspectors reviewed the onsite electrical distribution system to verify proper electrical line-up of the emergency core cooling pumps and valves, the emergency diesel generators, radiation monitors, and various engineered safety feature equipment. The inspectors also verified valve lineups, position of locked manual valves, power supplies, and flow paths for the high pressure safety injection system, the low pressure safety injection system, the containment air recirculation system, the service water system, and the emergency diesel generators. No deficiencies were noted.

Bypass jumpers were reviewed against the requirements of ACP 1.2-13.1, "Jumper, Lifted Lead, and Bypass Control," with emphasis on proper installation and the content of the safety evaluations. The inspector reviewed all jumpers for age, and verified that Plant Operations Review Committee (PORC) evaluations were completed to disposition longstanding evaluations. The jumpers reviewed were found to be in accordance with administrative requirements.

Log-Keeping and Turnovers

The inspectors reviewed control room logs, night order logs, plant information report logs, and crew turnover sheets. No discrepancies or unsatisfactory conditions were noted. The inspectors observed crew shift turnovers and determined they were satisfactory, with the shift supervisor controlling the turnover. Plant conditions and evolutions in progress were discussed with all members of the crew. The information exchanged was accurate. During attendance at daily planning meetings the inspector noted discussions were held which identified maintenance and surveillance activities in progress. The inspectors conducted periodic plant tours in the primary auxiliary building, turbine building, and intake structures. The inspectors noted plant housekeeping was satisfactory.

2.2 Plant Shutdown - Unusual Event

With the plant operating at 100% full power on February 12, plant workers prepared two welds in the service water system for ultrasonic (UT) examination. The UT exam was planned to better characterize degradation caused by corrosion in two welds in the service water supply piping to the emergency diesel generators (EDGs). While grinding the crown of weld #22, the weld began to weep through a pin hole sized defect. The leaky weld was on the upstream side of the isolation valve for the 'A' EDG supply header, was not isolable from the main SW header, and thus potentially affected the supply to the 'B' EDG as well. Although the weld still had structural integrity and both supply lines to the diesels were functional, the licensee declared both service water system headers inoperable.

The loss of two service water headers exceeded the minimum requirements for the SW system specified in Technical Specification (TS) 3.7.3. The licensee entered the action statement for TS 3.0.3 at 9:50 a.m. and began a controlled shutdown. An Unusual Event emergency was declared due to a shutdown required by the TS, which required that the plant be placed in Mode 5 (cold shutdown) within 36 hours. The reactor entered Mode 3 (reactor subcritical) at 3:23 p.m. on February 12, and Mode 5 at 6:10 p.m. on February 13, at which time the Unusual Event was terminated.

The resident inspector responded to the plant and observed control room operators implement normal operating procedure (NOP) 2.2-1, "Changing Plant Load." During the plant downpower, the inspector observed steam generator blowdown radiation monitor response, conformance with selected technical specification limiting conditions of operations, emergency core cooling alignments, offsite power availability and reactor coolant pump seal flow. The inspector observed appropriate controls. The inspector followed the shutdown activities through termination of the event.

The licensee actions to repair the leaky weld and to address degraded piping in the service water system to are described in Section 3.5 of this report. The degraded conditions will be addressed prior to returning the plant to power operation. The inspector identified no inadequacies in the licensee actions to meet the technical specification requirements. The inspector determined the plant operators performed well in completing the orderly plant shutdown.

2.3 Service Water System Stagnant Line Verification and Alignment for Isolation

On February 2, the licensee began a systematic review to identify stagnant lines in the service water (SW) system. This effort was part of the review to identify the scope of the service water system piping and welds potentially degraded by corrosion. The CYAPCo review was performed by a senior reactor operator. The inspector independently reviewed the licensee's service water piping and instrument drawings, normal operating procedure valve line-up and plant walkdowns to verify stagnant lines within the service water system.

The lines identified by the licensee were consistent with the list developed by the inspector. Thirteen areas were identified not including the service water supply to the emergency diesel generators. The areas include both safety and non-safety related portions of the system. The areas were:

- Manual screenwash line from SW pump discharge (North and South headers)
- Diesel Fire Pump discharge to service water pump discharge header
- SW to control room, chemistry lab and office building air conditioning units
- Fire header to turbine lube oil cooler
- Standby lube oil cooler supply and return
- Lube oil cooler Bypass line
- Exciter cooler inlet Kinney Filter Bypass
- Exciter cooler outlet Throttle Valve
- Generator hydrogen cooler outlet bypass
- Waste Liquid Evaporator Overhead Condenser
- Adam Filter Bypass Motor-operated Valves
- Component Cooling Water Stand-by Heat Exchanger
- 'B' Spent Fuel Pit Heat Exchanger inlet and outlet lines

The inspector reviewed CYAPCo's selection criteria and the system alignment necessary for components to be considered stagnant. The inspector found CYAPCo's review was complete and thorough.

2.4 Compensatory Measures for a Postulated Service Water System Line Break

On February 4, CYAPCo made changes to enhance existing procedures, trained operators and pre-staged materials to align fire water to the emergency diesel generators. CYAPCo developed an operability determination for the service water system that accounted for potentially degraded conditions in SW system welds and piping. The operability determination was discussed with the NRC staff on February 3. The operability determination was not rejected by the NRC; however, some questions and concerns were raised by the staff. The compensatory measures were meant to provide alternate means to provide EDG cooling upon loss of the SW headers, and not to compensate for an inoperable SW system.

The inspector verified procedure changes to abnormal operating procedure (AOP) 3.2-5, "Natural Disasters," and AOP 3.2-19, "Loss of Service Water." AOP 3.2-5 was altered to refer operators to AOP 3.2-19 upon a postulated natural disaster. The inspector observed the training of operator crews pursuant to lesson plan CY-OP-LORT-93-5-L93502. The training made the operators aware of the service water pipe degradation, and the actions necessary to isolate and compensate for a postulated failure of the piping.

The inspector verified the licensee actions to pre-stage materials needed to align a supply of cooling water to the emergency diesel generators from the fire water system. This included the placement of three lengths of 50 foot reels of fire hose at the north door for each generator room. The inspector verified that 100 feet of hose was sufficient to reach from the diesel to either of two fire hydrants located in the yard. The inspector verified the presence of tools in a fire hose station needed to complete the connections. The plans included coordination with plant security to assure prompt access to the diesels.

The inspector determined the licensee was thorough in defining the compensatory measures to provide an alternate means of EDG cooling, and the measures were properly implemented.

2.5 Power Reduction Due to Loss of Generator Cooling

During routine operations at full power on January 20, the temperature controller for the generator hydrogen cooler failed at 4:30 p.m. The reactor operators noted increasing temperatures on the generator, and received alarms on "hydrogen hot gas temperature" and "hydrogen stator temperature." The shift supervisor directed the operators to start an immediate plant load reduction and dispatched the nuclear side operator (NSO) to investigate the status of the generator cooling.

The NSO determined that service water temperature control valve SW-TCV-1711 had failed to the closed position. The NSO was directed by control room operators to take manual control and to open the TCV. This action was completed to restore cooling to the generator, and once generator temperatures had stabilized, the operators stopped the load reduction at 85% full power. Licensee investigation determined that the temperature controller had failed to 87 degrees (°) Fahrenheit (F), which provided a false indication that the generator was overcooled, causing the TCV to go to the closed position. After assuring generator cooling was stable in manual control, plant operators began a power increase at 4:45 p.m. to return the plant to full power operation. The temperature control valve was left in manual, a trouble report was written to effect repairs, and a plant information report was initiated.

The inspector reviewed plant status from the control room and at the hydrogen cooling station in the turbine building. The inspector noted the operator closely monitored the limits in the abnormal operating procedures which require that the turbine be tripped when stator temperature reaches 176° F, and generator differential temperature reaches 14.4° F. The temperatures reached during the transient were 172° F and 11.8° F, respectively. The inspector determined the plant operators performed very well, and in a timely fashion, in responding to the degraded cooling conditions. The inspector had no further comments in this area.

2.6 Shutdown Operations

The inspector reviewed plant operations during the load reduction on February 12 and after the plant was placed in cold shutdown. The review included the licensee actions to minimize shutdown risk. The shutdown risk assessment was completed for the service water (SW) outage schedule, once the full work scope was established. The licensee established controls for key safety functions (decay heat removal, reactor inventory, power availability, reactivity control, containment and support systems) and set up a status board in the control room to track changes to in service equipment. The status of essential equipment was summarized in the daily "plan of the day" for consideration by plant management and staff during the planning meetings. Contingency plans were established in the emergency and abnormal operating procedures.

The outage occurred because the licensee declared both service water headers inoperable due to corrosion induced degradation. The inoperable service water system impacted the operability of the diesel generators, which rely on the SW system for cooling. The emergency diesel generators were considered functional (when the associated SW headers were in service), but not "technical specification operable". SW headers were removed from service sequentially to allow for pipe inspections and replacement. The licensee's shutdown risk controls included assurance that the alternate diesel was functional and unaffected by the construction activities whenever one diesel was out of service for the pipe replacement. The licensee assured that at least three class 1E power supplies (one diesel plus two off site lines) were operable at all times. In addition, the licensee obtained a portable, trailer mounted air cooled diesel. The temporary diesel was set up at the site and made available to the operators to power shutdown cooling loads.

The inspector reviewed operator actions to implement shutdown risk controls during daily reviews of plant status and operations. The inspector identified no inadequacies with the licensee's plans. The inspector concluded the licensee's implementation of shutdown risk controls was a strength.

2.7 Charging System Valve Leakage

The inspector reviewed actions by plant operators on February 14 to identify and correct apparent leakage by valves in the charging (CHG) system. Actions were in progress to align the charging and residual heat removal systems to supply cooling water to the reactor coolant pump seals. Seal cooling was being established for shutdown operations in accordance with NOP 2.6-1A, "Mode 5 or Mode 6 RCP Seal Water Supply." The operators noted an unexpected increase in the level in the volume control tank (VCT), which was not in the valve lineup boundary for the intended seal cooling. The leak rate was determined to be about 5 gallons per minute. The leak was secured by closing CHG system valves 276 and 267, while investigations continued.

Subsequent investigations determined that charging valve CH-TV-334 was not fully closed even though it was in the closed position. The trip valve was a boundary valve in the lineup to establish seal cooling. Leakage past this valve on February 14 would allow seal injection water to enter the VCT. As corrective action, a work order was implemented to exercise and reset the stroke for the valve. The valve was satisfactorily leak tested following the repair. Seal cooling for shutdown operations was subsequently established without further problems.

The work control supervisor (a licensed senior reactor operator) initiated plant information report (PIR) 94-025 for this issue due to a plant safety issue identified by his review of the as found charging system conditions. The supervisor demonstrated good integrated system knowledge by recognizing that the charging system boundary valve leakage had implications when plant emergency systems were aligned to the sump recirculation mode in the post accident condition. The same charging system boundary valve leakage would exist while implementing emergency procedures ES-1.3, "Transfer to Sump Recirculation," and ES-1.4, "Transfer to Two Path Recirculation," following a postulated loss of coolant accident. The inspector noted the leak path would be isolable in the post accident mode.

Licensee review of this issue was in progress at the end of the inspection period. The PIR was assigned to plant engineering to evaluate the issue and recommend follow up actions. The inspector had no further comment on this matter at the present time. Licensee actions on PIRs are reviewed during routine inspection of plant operations.

3.0 MAINTENANCE (61726 and 62703)

3.1 Maintenance Observations

The inspectors observed various corrective and preventive maintenance activities for compliance with procedures, plant technical specifications, and applicable codes and standards. The inspectors also verified appropriate quality services division (QSD) involvement, appropriate use of safety tags, proper equipment alignment and use of jumpers, adequate radiological and fire prevention controls, appropriate personnel qualifications, and adequate post-maintenance testing. Portions of activities that were reviewed included:

- AWO 94-0969, Investigate EG2B Supply Pipe Welds
- AWO 94-0077, Replace Pipe Elbow in EG2B Supply Line
- AWO 94-0065, Replace 'A' AFW Pump Hydraulic Hose
- AWO 94-0071, Replace 'A' AFW Pump Discharge Relief Valve
- AWO 94-0089, Hydrostatic Test of Service Water Piping

The inspector did not identify any deficiencies with the observed maintenance activities.

3.1.1 Failure of the Pressurizer Power Operated Relief Valves

On February 19, during cold shutdown plant conditions, CYAPCo identified that both pressurizer power operated relief valves (PORVs) failed to fully stroke open during scheduled surveillance testing. Surveillance test SUR 5.7-112, "Inservice Testing of Power Operated Relief Valves PR-AOV-568 and PR-AOV-570 and associated SOV's," is written to demonstrate operability each cold shutdown of valve opening times for valves PR-AOV-568 and PR-AOV-570. Both valves opened to approximately 50% during the surveillance.

Upon discovery of the failures, CYAPCo reported the event to the NRC pursuant to 10 CFR 50.72(b)(2)(iii)(D) as a condition that alone could have prevented the fulfillment of the safety function of systems necessary to mitigate the consequences of an accident. The valves are credited in the emergency operating procedures as an alternate means to cooldown the reactor coolant system (feed and bleed mode) following a postulated steam generator tube rupture, and as a flow path in the alternate heat sink function for certain post accident conditions. The PORVs are not relied upon in the present plant mode (cold shutdown). Another set of spring loaded relief valves are used for the LTOP function while in cold shutdown.

SUR 5.7-112 implements the technical specifications surveillance requirements 4.0.5, 4.4.4.1, and 4.4.4.6. During the surveillance, each PORV is stroked through one complete cycle of travel, the air and control power is manually transferred from the normal to the emergency power and air supplies, and the valves are operated through another complete cycle of travel. The valve's design basis and technical specification basis is to open within 15 seconds, and to close within 2 seconds. The in-service test acceptance criteria opening time varies between 1.8 to 7.0 seconds depending on the valve; each valve is required to close in less than 2 seconds.

System Description

The primary purpose of the pressurizer PORVs is to limit reactor coolant system pressure to below the pressurizer safety valve setpoint, thus limiting the operating frequency of the safety valves. The control room operators have the ability to open either PORV manually to establish a "bleed" path for use in the "feed-and-bleed" method of core cooling. The inspector noted in emergency operating procedure E-0, "Reactor Trip or Safety Injection," step 15 that if secondary heat removal is inadequate due to insufficient auxiliary feedwater flow, operators are directed to functional recovery procedure FR-H.1. This procedure discusses the use of the PORV's as a method for core cooling. The PORV's may also be used to reduce reactor coolant system pressure during a postulated steam generator tube rupture.

The pressurizer PORVs receive an air supply from the containment control air system and an air accumulator. The 107 gallon emergency air accumulator supports PORV operation for "feed-and-bleed" core cooling in the event of a failure of both non-safety related containment air compressors. The air supply lines which lead to the PORVs are each provided with a pressure regulator (CA-PRV-836A & B). The regulators reduce the air pressure supplied from the containment air system at a nominal pressure of 120 psig to 85 psig. An air relief valve (CA-RV-838A & B) is provided on each PORV operator to protect it from overpressurization in the event that the regulator fails open. The relief valves are set to open at 100 psig (maximum design operating pressure of the PORV diaphragms).

The feed-and-bleed method of core heat removal is important in the Haddam Neck probabilistic risk assessment (PRA) core melt frequency goal and is credited as an available safe shutdown method for loss of main and auxiliary feedwater, high-energy pipe breaks, internally generated missiles, and tornado missile/wind protection. The design of the PORV's is to remain operable for thirty hours, with a total of four valve strokes during feed-and-bleed scenarios.

Maintenance History

The inspector reviewed the past performance of the PORV's and the pressure regulators (CA-PRV-836A & B) based on surveillance results and corrective maintenance activities. During the past refueling outage (June 1993), both PORV diaphragms and covers were replaced. The diaphragms were replaced because of a valve surveillance failure, and due to the required preventive maintenance frequency. The replacement was controlled under replacement item evaluation (RIE) form PEG-CYOE-93-0062, which upgraded the operator to allow for a longer time interval between diaphragm replacement. The replacement diaphragms were of different material and bolt hole configuration. The revised diaphragms were developed by the valve vendor (Copes-Vulcan) for model D-100-160 operators. The new material used was ethylene propylene rubber (EPR) versus Buna N. EPR has a 50 degree Fahrenheit higher temperature limit. The replacement diaphragm has a twenty-four hole configuration versus the twelve hole configuration in the original diaphragm.

The diaphragms had been replaced prior to June, 1993 for both PORV's. In 1991, the PORV (PR-AOV-568) diaphragm was replaced due to air leakage around the valve shaft, and the PR-AOV-570 diaphragm was replaced after air leak around the diaphragm was identified during surveillance testing.

The two pressure regulators PRV-836A & B have had various corrective maintenance activities during the last four years. Valves PRV-836A & B were replaced in June, 1993 primarily due to water intrusion from the containment air system. The event was documented by CYAPCo in licensee event report (LER) 93-007-00. Between 1990 and 1992, corrective maintenance activities involved repairing air leakage around the regulator identified by the failure of the pressure decay test during technical specification surveillance SUR 5.7-98, "Inservice Testing of Containment Control Air Supply Check Valves to PORV's and PORV Air Receiver."

The CYAPCo department responsible for the pressure regulators (PRV-836A & B) has initiated a preventive maintenance request since 1986 to replace the regulators every refueling outage. However, the regulators were not changed between 1986 and 1993 even though an active purchase order (277937) existed, because the regulator vendor (Conoflow) was unable, until recently, to satisfactorily pass the required pressure test to show conformance with Grinnel report No. 3412 for the regulators.

The inspector noted a CYAPCo engineer recommendation in early 1992 to develop a project assignment to reevaluate the PORV air system design basis, and to recommend modifications to increase the maintainability of the system. The recommendation was based on the failure to procure a replacement air regulator within a reasonable time frame, and the restrictive technical specification limit of 0.3 psi/hour leakage from the air accumulator to PORV's.

Corrective Actions

CYAPCo initiated authorized work orders (AWO's) CY 9401631 and 940164 to troubleshoot the failure of the PORV's. CYAPCo's troubleshooting activities identified various deficiencies in the air supply to the PORV's. The deficiencies included air leakage between the diaphragm and the cover assembly, loose cover assembly capscrews, pressure regulators (PRV-836A and B) low "as-found" setpoints, and small radial cracks in both PORV diaphragms. At the end of the inspection period, the licensee was reviewing the failures to determine the root cause of the air leakage from the PORV diaphragms. Additionally, the Unit Director assigned the engineering department a significant unresolved issue to evaluate the PORV air system and propose upgrades. The recommendations from engineering were to be developed by May, 1994.

Based on the failures on February 19, CYAPCo changed procedure PMP 9.5-264, "PR-AOV-568 & 570 Pressurizer Power Operated Relief Valve Maintenance," in the section involving valve diaphragm replacement. The basis of the changes were to provide better controls on seating and forming the diaphragm in the operator during replacements. The revision added cleaning the sealing surface of the cover and actuator base, application of permatex aviation form-A gasket around the bolt circle on both sides of the diaphragm, and application of loctite 242 to the case capscrews and nuts. The procedure revision also changed the torque value of the capscrews from 24 +/-2 ft-lbs to 25 +/-1 ft-lb. The inspector verified the incorporation of the changes, and discussed the basis of the changes with maintenance personnel and the system engineer.

Summary

The inspector noted from the maintenance history for the PORVs that system air leakages and subsequent surveillances failures have existed. The licensee has implemented hardware and procedure changes to PMP 9.5-264 to provide better maintenance controls to properly seat the diaphragm. CYAPCo recognizes the need to review the PORV air system design. The issuance of a significant unresolved issue, and a proposed project assignment to address this area is appropriate.

The inspector considers the root cause of the surveillance failure and resolution of the air supply problems as an unresolved issue. This item is unresolved pending issuance of the licensee event report by the licensee and subsequent review of the operability determination by the NRC. Actions to resolve this problem prior to entering a plant operating mode that requires the PORVs be operable will be reviewed during a subsequent routine resident inspection **(UNR 94-03-01)**.

3.2 Surveillance Observations

The inspectors witnessed selected surveillance tests to determine whether: frequency and action statement requirements were satisfied; necessary equipment tagging was performed; test instrumentation was in calibration and properly used; testing was performed by qualified personnel; and, test results satisfied acceptance criteria or were properly dispositioned. Portions of activities associated with the following procedures were reviewed:

ENG 1.7-4, Inservice Testing of Emergency Diesel Generator Heat Exchangers

On February 8, the inspector observed the performance of ENG 1.7-4, "Inservice Testing of Emergency Diesel Generator Heat Exchangers," by a nuclear system operator (NSO). The objective of the test was to obtain the hydraulic resistance of the service water to both emergency diesel generator jacket water heat exchangers. The test frequency is weekly. The inspector observed good procedural adherence by the NSO; the hydraulic resistance data was acceptable. The inspector independently calculated the hydraulic resistance which was consistent to that of the CYAPCo system engineer calculations.

SUR 5.7-148B, A and B Service Water Pumps Substantial Flow Test

On February 15, 1994, with the plant in cold shutdown, the licensee completed a substantial flow test for the 'A' and 'B' service water (SW) pumps in accordance with SUR 5.7-148B, Revision 3. During the test, the total dynamic head (TDH) for pump 'A' was in excess of the required action acceptance criteria. In addition, the TDH for all other curve points was higher than the baseline curve generated on July 11, 1993.

The licensee was unable to identify the specific root cause for the excessive TDH. The licensee suspects that the installation of new pump discharge check valves and service water piping has decreased system resistance, resulting in the higher pump hydraulic performance.

The licensee performed an engineering evaluation of the pump's performance and determined that the pumps have undergone no degradation and, therefore, are acceptable for all modes of operation. The inspector reviewed the engineering evaluation and was satisfied with the licensee's conclusion.

SUR 5.1-12, Main Steam Line Isolation Valve Trip Valve Test

On January 26, the inspector observed operators perform SUR 5.1-12, "Main Steam Line Isolation Trip Valve Test," for valve MS-TV-1211-3. The surveillance test, which partially strokes the main steam trip valve, was performed as post-maintenance testing following adjustment of the valve's "live-load" packing. The inspector questioned the acceptability of the use of mechanical bars in the valve yoke casing during the surveillance. The mechanical bars prevent the main steam trip valve from closing in the event of a test solenoid failure. The surveillance test was successful. This is an inspector follow-up item (**IFI 93-04-02**).

3.3 Main Steam Safety Relief Valve Testing

The inspector reviewed CYAPCo plans to test the main steam safety relief valves during power operation, and the surveillance test results obtained during the plant shutdown.

On January 20 during power operations, CYAPCo initiated plant information report (PIR) 94-011 that documented a test failure of the "active" pilot valve for main steam safety relief valve MS-SV-14 at the vendor facility. Prior to disassembly of the safety relief valve for investigation of the root cause of a previous body-to-bonnet leakage, the vendor placed the valve on a boiler for preliminary testing. The testing included verifying leakage from the gasket area and measuring pressure to the unloader, as well as setpoint testing of the pilot valves. The vendor (Anderson Greenwood) identified that the setpoint of the safety valve was at 1430 psig instead of the required 1034 psig +/-3%. The valve tested by the vendor had been removed from the main steam system during a November, 1993 plant shutdown (reference inspection report 50-213/93-21).

The main steam safety valves are operated with two pilot valves that control the pressure in the valve unloader. The safety valve operates when differential pressure across the unloader reaches a set value. One of the two pilot valves is considered "active" in that it is valved in to sense steam inlet pressure. The other pilot valve is considered "inactive" in that it is isolated from the steam inlet to the safety relief valve. The setpoint of the safety valve is directly related to the setpoint pressure of the pilot valve. The relief valve function is provided by a solenoid valve that bypasses the pilot valve to allow for remote operation.

The vendor disassembled the failed pilot valve and identified oxide build-up on the disc. The pilot valve spindle and guide showed smooth travel and no signs of foreign material or deposits. The vendor recommended to the licensee, that the installed valves be tested, first with the "inactive" pilot valves, then transfer to the "active" pilots to verify the "as-found" setpoints.

CYAPCo did not declare the installed safety relief valves inoperable. The basis of operability was that no specific cause of failure in the pilot valve was evident, and the valve that failed was no longer in service. Nonetheless, the licensee initiated a plan to test the main steam line safety relief valves during power operation to acquire additional information. The valves installed in the main steam system had successfully passed the setpoint surveillance during the last refueling outage in July, 1993.

The licensee developed a draft special test (ST) 11.7-135, "Special Setpoint Testing for Main Steam Safety Relief Valves MS-SV-14, 24, 34, and 44," that allowed for testing of the two pilot valve setpoints during power operation. The inspector discussed with CYAPCo the prudency of performing the surveillance at power, and the potential consequences if a safety relief valve were to inadvertently open during testing of the pilot valves. The inspector performed a field walkdown of the special test, and reviewed the consequences of an excessive steam demand event as documented in the Updated Final Safety Analysis Report Chapter 15. The inspector reviewed the emergency operating procedure actions, and the results of CYAPCo's simulator test of the plant response following a postulated failure of the safety relief valve (with and without a manual reactor trip). The inspector reviewed the expected actions in the emergency plan implementing procedures on emergency classifications, and reviewed "critical" procedure steps in ST 11.7-35. Critical steps were those action steps where a human error could result in the safety relief valve opening. The inspector identified no inadequacies in the proposed test method. Subsequently, CYAPCo decided to not perform the pilot setpoint verification during power operations because, even though the test method provided assurance the test could be done safely, the consequences of opening a valve at power were deemed unacceptable.

On February 12, the licensee commenced a plant shutdown to a cold shutdown condition to repair the service water system piping (see report detail 2.2.). On February 15, during a cold shutdown condition, CYAPCo initiated the performance of surveillance procedure SUR 5.5-69, "MS-SV-14, 24, 34, & 44 Main Steam Safety Valve Surveillance Testing." The testing indicated that the "active" pilot valves for MS-SV-34, 44 and 14 did not lift at a nitrogen pressure of 1,500 psig. The licensee stopped testing of the valves, and initially concluded that the failures were due to low ambient temperatures (approximately 20 degrees Fahrenheit). CYAPCO reperformed SUR 5.5-69 on February 17. The inspector observed the surveillance. The pilot valves sensing lines were warmed by the installation of heat lamps and insulation. All eight pilot valve setpoints were outside the setpoint range of 1034 +/-3% psig. The licensee identified that the test nitrogen pressure indication was out of calibration. The pressure indication was calibrated prior to the start of the surveillance as required by the test; however, due to either cold ambient temperatures, or mishandling of the sensor it was out of calibration approximately 180 to 200 psig.

CYAPCo performed a third test on February 20 using a different test pressure sensor. All pilot valve setpoints were acceptable except for the "active" pilot of MS-SV-34 and the "active" and "inactive" pilot valves for MS-SV-44. CYAPCo reported the surveillance failures as a condition prohibited by technical specifications. At the end of the inspection period, the licensee was working with the vendor to understand the cause of setpoint variation on the pilot valves. The licensee was reviewing the industry experience with pilot valves, and implementing a root cause investigation.

Summary

CYAPCo reversed an initial decision to test the main steam safety relief valves during power operation. This demonstrated thorough management and engineering review of the technical issue, and reflected a conservative safety ethic. The valves subsequently failed the surveillance during cold shutdown. The root cause of the setpoint failures for the main steam safety relief valves was not conclusive at the end of the inspection period. The inspector will evaluate CYAPCo's proposed actions and implementation, and will review the operability assessment and corrective actions documented in the licensee event report. This item is unresolved pending completion of the above licensee actions and subsequent review by the NRC **(UNR 94-03-03)**.

3.4 MCC-5 ABT Testing

The inspector reviewed activities in progress throughout this period to test the automatic bus transfer (ABT) for motor control center 5 (MCC-5). The inspection was initiated following the licensee's report that the MCC-5 failed during a test on February 16. The ABT failure during testing was the second such occurrence in nine months. The ABT failures are safety significant since: MCC-5 is not single failure proof; MCC-5 powers redundant plant valves in the emergency core cooling system; and, the proper operation of MCC-5 is essential to mitigate certain design basis accidents.

Past NRC inspections have described licensee testing of the MCC-5 ABT. The transfer scheme was the focus of a special NRC inspection (reference Reports 50-213/93-80) after it failed a test during the 1993 refueling outage. The inspector witnessed the performance of test PMP 9.5-285, "MCC-5 Supply Breaker X-relay Drop-Out Verification," on November 10, 1993 (reference 50-213/93-21). The November 10 test was the first performance of a surveillance written to implement the new technical specification requirements issued on November 1, 1993 as part of Amendment #169 to the plant license. Technical Specification 3.8.3.1.2 provided a limiting condition for operation for MCC-5 and its ABT and allowed for the test of the ABT with the plant operating at power.

The test of the ABT on November 10 was successful and was repeated periodically with the plant operating at power. The last successful test at power was performed on January 28. The purpose of the test was to assure continued operability of the ABT by de-energizing the 52X relay in the Westinghouse AK-25 breaker supplying power to MCC-5. A schematic of the MCC-5 bus and the ABT logic diagram are enclosed with this report as Figures 1 and 2, respectively. For the tests at power, the normal supply was from 480 volt Bus 5, which fed MCC-5 via breakers 9C on Bus 5. The test plan was to de-energize control power to breaker 9C to drop the 125 Vdc supply to the associated 52X relay. The 125 Vdc power was removed by opening the knife switch in the Bus 5 control power supply cabinet. Once control power was removed, test personnel verified proper operation of the 52X relay by listening for the drop sound of the moveable core piece, and by visually verifying the that core piece was in the down position. This action occurred satisfactorily when the test was done periodically during operation at power.

ABT Failure - Initial Testing on February 16

On February 16, the ABT was tested in accordance with ST 11.7-126, "Functional Test of the MCC-5 Automatic Bus Transfer." This was the first test of the ABT with the plant in cold shutdown. The transfer scheme was functionally tested by actually de-energizing the associated MCC-5 supply buses, first Bus 5 and then Bus 6, while verifying that the MCC-5 remained energized. Essential plant loads were transferred to alternate power supplies prior to the test of the ABT.

The first test phase was completed on February 16 in accordance with Section 6.1 of ST 11.7-126 with Bus 5 as the preferred source for MCC-5. Bus 5 was deenergized by opening the transformer feeder circuit breaker 4851. The loss of Bus 5 was sensed by the ABT, and the 9C supply breaker from Bus 5 opened as required, and the 11C supply breaker from Bus 6 closed as required. Plant personnel then reenergized Bus 5 by closing breaker 4851. The ABT sensed that Bus 5 was energized, and opened breaker 11C from Bus 6, and then closed breaker 9C from Bus 5, as required. MCC-5 remained energized. Plant personnel reset the associated lockout relays and returned plant loads to the normal configuration.

Upon completion of phase 1, plant personnel began procedure step 6.2 to test the scheme in a transfer from Bus 6 to Bus 5. To set up for the phase 2 test, plant personnel placed selector switch SS43 from position 1 to position 2 at 1:40 a.m. This action should have caused breaker 9C to open, and breaker 11C to close. Breaker 9C did open, but breaker 11C did not close as required. MCC-5 deenergized. After consultation with the control room operators, testing was secured and test personnel were directed to reenergize MCC-5 from Bus 5. Test personnel first placed switch SS43 in position 1; but MCC-5 remained deenergized. MCC-5 was reenergized when test personnel manually closed breaker 9C at Bus 5. Test personnel observed the 52X relay in both the 9C and 11C breakers, and noted that both relays were deenergized, the moveable core pieces were in the "down" position, and the relays were ready for a close signal. Further testing was suspended pending the development of a troubleshooting and test plan to investigate the failure in the "as-found" condition. Since the 52 X relays appeared to have operated correctly, the licensee investigation focused on switch SS43 and on a cell switch as the potential cause of the failure.

Failure Investigation and Subsequent Testing on February 16

The licensee developed a troubleshooting plan in accordance with authorized work order CY 94-01445 to investigate the failure. The troubleshooting plan used instrumentation to monitor contacts in the ABT as the loss of power test per ST 11.7-126 was repeated. The sequence of testing during the evening of February 16 and the results were as follows. After establishing conditions per ST 11.6-126, test personnel initiated a transfer per Section 6.1 by de-energizing Bus 5 at 7:44 p.m. The ABT failed to transfer MCC-5 to Bus 6. Bus 5 breaker 9C opened as required, but breaker 11C attempted to close and then tripped clear. Test personnel checked the cell switches for both breakers, and then manually reclosed breaker 11C with a hand tool. MCC-5 was energized from Bus 6. After checking the status of monitoring instrumentation and the ABT, Bus 5 was re-energized at 7:47 p.m. The ABT sensed the presence of power on Bus 5 and successfully transferred MCC-5 back to Bus 5.

Since no anomalies were noted in the operation of the ABT, and since breaker 11C was involved in the ABT failures at 1:40 a.m. and 7:44 p.m., the investigation focused on the misoperation of the breaker. Breaker 11C was removed for inspection and a spare breaker (marked 16C) was installed in Bus 6 compartment. The ABT operated properly during subsequent testing on February 16 with the new breaker in Bus 6. Specifically, MCC-5 remained energized when Step 6.1 was performed which caused the ABT to transfer MCC-5 from Bus 5 to Bus 6 and back to Bus 5, in a test sequence starting at 9:00 p.m. At 9:49 p.m., test personnel placed switch SS43 in position 2 to set up for the Bus 6 test. The ABT operated properly at that time. Finally, MCC-5 remained energized when Step 6.2 was performed which caused the ABT to transfer MCC-5 from Bus 6 to Bus 5 and back to Bus 6, in a test sequence starting at 9:50 p.m.

The ABT functioned properly again at 9:51 p.m. when MCC-5 was restored to the normal configuration (energized from Bus 5 with SS43 in position 1). Further investigation was deferred pending the development of additional plans to troubleshoot breaker 11C and to test breaker 16C in the ABT scheme. During the test activities on February 16, the licensee noted and corrected a problem with a loose fuse holder (primary side of fuse B13), which powered the agastat relays used in the ABT. The licensee determined that the fuse holder problem could not have caused the noted ABT failures. The inspector independently confirmed this conclusion (reference drawing 16103-31035, Sheet 6).

Visual Inspection of Breaker on February 19, 1994

Breakers 9C and 11C are Westinghouse Model DB-25 air circuit breakers. Figures 3 through 5 show the relevant features of the DB-25 design details. The licensee conducted visual inspections of the breaker 11C components on February 19. Covers to the auxiliary switches were removed and the auxiliary switch wiring and contacts were visually inspected. No abnormalities were identified during the visual examination of the auxiliary switches. The amptector (overcurrent device) and the cover to the closing/trip linkage was removed. During a visual inspection of the linkage, the licensee identified that the snap ring on the manual closing linkage was not properly located in the snap ring slot (see Figure 5). The snap ring was back away from the slot, toward the manual closing handle, approximately 1 to 1 1/2 inches. This allowed the manual breaker closing linkage to protrude into the closing/trip linkage.

The manual breaker closing linkage interfered with the breaker trip linkage due to the improper position of the snap ring. The licensee was able to demonstrate that a slight rotation of the manual closing linkage tripped the breaker. The licensee then protracted the manual linkage to it's normal position and bench tested the breaker by providing a dc power to the breaker from a test source. The breaker operated 2 times satisfactorily and then tripped free and failed to close on the third attempt. This test was repeated and the breaker again failed on the third attempt. The snap ring being improperly located would cause the 11C breaker to have intermittent failures. Vibrations of the breaker would cause the trip to occur at times and not to occur at other times. This condition would result in intermittent failures of the MCC-5 ABT. The ability to manually close the breaker using the manual close handle would not be impaired by the mislocation of the snap ring. The operation of the breaker using the handle would tend to retract the manual linkage when the handle is removed, which would allow the breaker to successfully operate during the subsequent few cycles.

Based on the presence of dust on the lubrication on the manual close linkage, it appears that the snap ring was mispositioned for quite some time. There was no apparent recent scrapping of lubricant off the linkage. It does not appear that if the snap ring was properly placed in the groove that the snap ring could jump out of the groove. The Westinghouse engineer stated that the snap rings are sometimes removed to facilitate lubrication of the breaker linkage. The licensee's PM procedure did not remove the snap ring or inspect for the proper location of the snap ring. The inspector concluded that the snap ring was most likely mispositioned during past breaker assembly or maintenance. The licensee is revising the PM procedure to address the snap ring. The licensee conducted visual inspections to verify that the snap rings in other breaker are properly installed. This inspection was done without disturbing the installed breakers by visual examination and the use of a "rod" to verify the location of the snap ring. The inspector independently confirmed the proper placement of snap rings by examining a randomly selected sample of 27 of 48 breakers in the 480 bus sections.

Evaluation of the February 16 Test Failures

The first failure occurred (1:40 a.m. on February 16) when the licensee selected position 2 on the preferred bus selector switch. Breaker 9C opened and 11C failed to close. If this mechanism were the cause of the failure, the breaker would always attempt to close and then trip open. The licensee personnel located at the breaker stated that they did not hear any motion of the 11C breaker. However, at the time of this failure the licensee had just tested the ABT and did not believe their was a problem with the ABT. Therefore, the maintenance staff located in the area of the ABT may not have heard 11C tripping free. It would also have been difficult to here breaker 11C trip free when breaker 9C was tripping in the same area. If the manual breaker close mechanism were to interfere with the trip linkage the breaker would not have closed. This failure mechanism would explain the events that occurred.

The second failure of breaker 11C occurred when Bus 5 was deenergized (7:44 p.m. on February 16). At this time breaker 9C properly opened and breaker 11C failed to close. During this test, maintenance staff were specifically focused on observing breakers 9C and 11C operation and heard breaker 11C momentarily closing and then opening. The operators then locally closed breaker 11C. When power was restored to Bus 5, by closing breaker 4851, the ABT automatically swapped back to Bus 5 by closing breaker 9C. The breaker close latch problem would also explain this sequence of events. When Bus 5 was deenergized breaker 11C tripped free. The bus selector was in position 1 and when power was restored to Bus 5 the ABT swapped back and breaker 9C closed. The events can be directly attributed to the 11C breaker in the trip free condition. The manual close linkage snap ring being dislocated would cause this condition to occur.

The failure observed in June 1993 may also be attributed to this failure mechanism. This test was a 6-5-6 MCC-5 transfer sequence. Bus 6 was the preferred source of power for MCC-5. When Bus 6 was deenergized the ABT swapped to Bus 5 but did not swap back to Bus 6 when power was restored to Bus 6 by the diesel generator. Again a trip free condition by breaker 11C would cause this to occur. Following the ABT failure the operator changed the position selector switch to position 1. The swap to Bus 5 did not occur because the 52X relay was never deenergized. The licensee conducted bench tests to verify that the momentary closing of the 11C breaker in the trip free condition does not rotate the auxiliary switch and close the 52/b auxiliary contacts. The 9C breaker was then manually closed.

Prior to the June 27, 1993 failure during the 6-5-6 test sequence, the ABT initially operated properly in a 5-6-5 test sequence on June 26. Both the June 26 and the June 27 tests were performed with the ABT MCC-5 in the "as-found" condition. This test history demonstrates that the failure mechanism is intermittent, and allows for successful ABT operation. This test history also suggests that the maintenance that resulted in the mispositioned snap ring most likely occurred some time prior to the 1993 outage.

Further Test and Repair Plans

The licensee initiated plans on February 19, to proceed with testing of the ABT. The test would be contingent upon the installation of a jumper that will provide power to MCC-5 via a source other than breakers 9C and 11C. This would allow test personnel to conduct repeated tests of the ABT without disrupting power to MCC-5. It would also provide additional time to troubleshoot the ABT if a failure were to occur. The jumper development and approval took 2 days to complete. The licensee removed the close/trip mechanism from breaker 11C. A new close/trip mechanism was installed. The licensee plans to use the rebuilt breaker as a spare. The rebuild of the breaker was a precautionary measure. The licensee conservatively chose to install a new trip/close mechanism rather than just returning the snap ring to the appropriate position.

Safety Impact

The proper operation of MCC-5 is important to assure the reliable power to redundant valves in the low pressure safety injection and high pressure safety injection systems. These engineered safety system valves are credited to operate for postulated loss of reactor coolant accidents that occur with the plant operating at full power, and assuming the concurrent loss of normal power for the plant. Since the plant was in Mode 5 (cold shutdown) at the time of the test, the impact of the ABT failure on actual plant safety was minimal.

Based on the test and troubleshooting sequence detailed above, and the successful test history per PMP 9.5-285 during the latter part of 1993 and the tests on February 16, the inspector concluded that the MCC-5 ABT would have operated at least once in the as-found condition. Thus, the ABT was operable if called upon during the period of plant operation from July 1993 (plant startup) until February 1994 (plant shutdown). However, the ABT was unreliable due to the intermittent failure mechanism. The licensee determined this issue is reportable to the NRC and intends to submit a licensee event report (LER). The licensee concluded the loss of redundancy in the ABT constituted operation in a condition not allowed by the technical specifications. The operability issue will be reviewed further by the NRC upon completion of the licensee's formal root cause analysis of the failure.

Findings

The inspector determined that CYAPCo staff performed well investigating the ABT failure during this period. The actions to inspect and investigate Breaker 11C were very good. The inspector observed good coordination and cooperation between operations, maintenance and testing personnel. The root cause investigation started on February 18 was thorough. The support by the site engineering and design engineering groups was good. The inspector observed good performance regarding procedure controls, including the activities to test the ABT, install the bypass jumper; and to implement the troubleshooting plan.

NRC review of licensee activities for this issue were in progress at the end of the inspection period. This item is considered open pending: completion and NRC review of the operability determination; completion of formal root cause investigation; review of long term actions to address the root cause; completion of actions to report the issue; and, completion of the ABT modifications and acceptance testing (**UNR 94-03-03**).

3.5 Examination and Replacement of Service Water Piping

History

In May 1993 with the plant shutdown for a refueling outage, the licensee replaced a defective segment of service water (SW) pipe in the supply line to the 'B' emergency diesel generator (EDG). The defect was initially identified by through wall leaks in a weld, and was characterized as localized (refer to NRC Inspection Report 50-213/93-03, Detail 4.2). Actions were completed during the outage to replace the pipe containing the degraded weld. Two welds on either side of the degraded weld were also replaced with the section of pipe. The adjacent welds were destroyed during the replacement process and were not available for subsequent evaluation. After removing an extensive coating of macrofouling (tubercles), subsequent examination by site personnel identified apparent lack of weld penetration (LOP) and extensive corrosion over the full inside diameter (ID) circumference of the weld that leaked. A similar section of pipe in the supply to the 'A' EDG was also replaced due to similarities in geometry and conditions. The similar weld in the 'A' header also showed extensive degradation. The samples of degraded welds from both headers were sent to the Berlin materials laboratory to evaluate the root cause of the condition. The root cause evaluation proceeded in parallel with actions on site to complete the outage and to restart the plant.

The materials laboratory provided the results of its evaluation in a memorandum (CTS-93-754) to site engineering dated June 21, 1993. The laboratory could not perform a complete analysis because the samples had been disturbed (i.e., the tubercles were removed along with scale and deposits), to expose the degraded weld. The laboratory evaluation concluded that extensive degradation existed in a crevice running on the inside diameter of the weld. The defect was enhanced by the original poor quality weld (concavity and ID mismatch), and was accentuated by corrosion. The pits and "worm holes" in the defects were characteristic of microbiologically influenced corrosion (MIC). Although the corrosion had the characteristics of MIC, live samples would be required to prove this potential root cause conclusively. Cultures of the welds necessary to positively identify MIC as the corrosion mechanism were not obtained with the May 1993 sample, because MIC was not a suspected failure mechanism. The laboratory recommended that future samples be submitted immediately after removal with all deposits intact to confirm the influence of MIC.

An engineering evaluation was completed in the summer of 1993 to assess the structural integrity of the degraded joint, and assuming that flaws similar to the weld removed from the system flawed welds existed in other locations of the SW system. This evaluation concluded that the pipe would be able to withstand design stresses, including seismic loads. The SW lines (and EDGs) were considered operable and actions were initiated to assess the condition of the remaining welds in the supply pipe to the EDGs where MIC could develop. The structural assessment was formally provided in a NUSCo memorandum (DECY-94-502) to CY engineering dated January 5, 1994.

Due to limitations in the ability to fully characterize the defects by ultrasonic (UT) and radiographic (RT) examination, the licensee made plans to cut out an elbow in the supply line to the 'B' EDG to allow full non-destructive and destructive examination of two welds contained in the sample. The actions to replace the elbow in the 'B' EDG header were completed within a 72 hour action statement for the diesel on January 25-27, 1994. The plans were to RT the samples removed from the system on the as-found condition, and in this manner "benchmark" the RT process for future examination of other welds in the SW system while the plant was on-line and the SW system was in service. A conceptual design change was drafted and piping material was procured in advance of the January EDG outage in anticipation of the need to shutdown the plant to replace SW piping, if that action was indicated by an evaluation of the welds in the elbow sample.

NRC inspection of this topic began with a review of the elbow replacement work within this inspection period. A chronology of licensee activities regarding the service water corrosion issue was developed during this inspection period as described above; additional details are provided in Attachment A to this inspection report. The CYAPCo actions developed over the Fall of 1993 under the presumption of continued operability of the SW system.

Scope

The scope of the NRC inspections for this topic during this period included reviews by the resident inspector, and on February 8 and 9, the reviews by the Chief, Materials Section, and the Acting Deputy Director of the Division of Reactor Safety, NRC Region I. In addition, numerous phone conversations and telephone conferences between the NRC staff and the licensee occurred as necessary to understand the licensee's position and to solicit commitments for supplemental actions.

The inspection included reviews of: the actions to replace the elbow in the supply line to the 'B' EDG; the actions to complete full non-destructive and destructive examination of the pipe samples; the engineering and NU Materials Laboratory evaluations of the pipe samples removed in May 1993 and January 1994, and of the cause(s) for the accelerated corrosion evident in the SW samples; the engineering evaluation of the degraded welds removed from the SW headers in May 1993, including (i) uniform wall thinning analysis and (ii) a fracture mechanics analysis per ASME Section XI, Appendix H; the initial and updated operability evaluation for the SW system and its bases; the NDE (RT, UT & ECT) activities conducted to support the operability evaluations; actions to complete RT examinations of SW piping to identify the presence of severely degraded welds and to bound the scope of the corrosion; chemistry controls to address corrosion; sampling and analysis for MIC; the detailed examination of degraded welds #21 & #12 and #22 in the SW supply to the EDGs, and actions to characterize the defects in these welds; and, the decision to shutdown the plant following the development of a pin hole leak in the 'A' diesel supply line. Following the plant shutdown, the inspector reviewed the continuing actions to inspect and examine SW piping to identify the scope of the corrosion.

Elbow Removal in January 94 and Sample Evaluation

The licensee completed work under AWO 94-0077 on January 25 - 27, 1994, to replace a elbow on line 6"-WS-121-168 in the supply to the 'B' EDG. The work was completed during a scheduled EDG outage, and provided two welds for evaluation for the suspect corrosion. The NRC inspected the replacement activities, the history on the issue, and the condition of the two welds removed from the system. Samples of the pipe corrosion material were obtained and were cultured for MIC. Both welds showed some evidence of degradation and corrosion, but in general were in much better condition than the samples removed in May 1993. In particular, the weld had full penetration over most of the circumference, and showed much less severe corrosion. While the welds showed various indications that require dispositioning (including porosity, surface indications, pits and undercut), the indications were characterized as not significant enough to jeopardize the integrity of the joint.

The results of the MIC cultures were provided in a NUSCo letter (CES-94-554) dated February 10, 1994, based on work performed by an independent vendor (Thomas M. Laronge, Inc). The samples were cultured for sulfur reducing bacteria (SRB), acid-producing bacteria (APB), general anaerobic bacteria, and general aerobic bacteria. Very little growth was seen after 14 days of growth for APBs, aerobic bacteria and anaerobic bacteria. SRB was present, but a minimum detectable levels. Due to the sometimes slow growth periods, plans were set to measure the cultures after 30 days. Examination of the pipe wall found evidence of conditions typical of oxygen concentration cell corrosion (OCCC).

Second Operability Assessment

The NRC review in January 1994 of the licensee's initial operability assessment identified no inadequacies in its conclusions, within the limits of the methodology used. Subsequent NRC review on February 2, noted that the assessment was based on the stresses attendant with uniform wall thinning, and that this method might not be conservative when the stress risers associated with the lack of weld penetration (LOP), pits and "worm holes" were considered.

The licensee completed a more detailed analysis assuming the combination of LOP/MIC corrosion was a "crack", using the fracture mechanics analysis (FMA) of the ASME Code, Section XI, IWB 3650 and Appendix H. The analysis was documented in NUSCo Calculation CY-LOE-1014-MY, and showed with as little as 0.095 mils remaining in the degraded pipe samples (nominal wall thickness for new pipe was 0.280 inches), the pipe was capable of withstanding the stresses attendant to normal and faulted conditions, including seismic loading. The NRC staff discussed the results of the fracture mechanics analysis on February 3, which showed the piping system was still operable if defects of the type removed were still in the system. An advanced copy of the calculation was provided to the NRC staff on February 4. The NRC performed the same analysis using the licensee's data for input, and arrived at the same conclusion. The licensee chose 100 mils as the acceptance limit for defects to assure a degraded weld was bounded by the FMA.

The licensee initiated a program to radiograph (RT) as many welds in both service water headers that are accessible. Based on NRC questioning, the licensee revised the RT planned schedule so that the RTs would be done as expeditiously as possible and with a quality sufficient only to identify the gross "lack of penetration" obvious in the first samples. All accessible welds would be examined in this manner, and defects would be further characterized as necessary for comparison with the bounding defect analyzed in the operability assessment. For any one weld found to constitute an inoperable condition, the licensee intended to declare both service water headers inoperable and shut the plant down in accordance with the technical specifications.

The licensee instituted compensatory measures starting on February 4 to enhance existing procedures and operator training for responding to earthquakes and a complete loss of service water. The compensatory actions included pre-staging materials needed to align a supply of EDG cooling water from the fire water system. The compensatory measures were meant to provide alternate means to provide EDG cooling, and not to compensate for an inoperable SW system. The inspector reviewed the revised procedures, witnessed the operator training, and walked down the staged equipment. No inadequacies were identified.

The licensee committed on February 3 to submit on the docket the results of his examinations, and would include a description of his long term plans, including his considerations to replace affected portions of the SW system, a program to monitor the MIC corroded piping until replacement, and a program to address MIC. Once the RTs of the welds in the SW piping to the EDGs were completed, the licensee planned to evaluate other susceptible lines in the SW system. The initial plans included the performance of ultrasonic examination of susceptible pipe for corrosion. This information was subsequently provided to the NRC in letter (B14755) dated February 22, 1994. Calculation CY-LOE-1014-MY was included with the submittal.

Although the NRC staff did not reject CYAPCO's operability decision, the staff expressed concerns regarding the status of the remaining pipe and the potential for the presence of defects that were worst than those identified. While the licensee planned initially to perform RT examination of the piping by April, 1994, based on NRC concerns, that schedule was advanced to begin the exams as soon and the work could be organized. The licensee chose to remove the pipe insulation to enhance the quality of the RT results. The RTs were taken with water in the process lines.

Examination of Additional Service Water System Welds

During the period from February 3 - 5, RTs were completed for 19 welds in the SW supply to the EDGs, and on 6 welds in the SW supply to the travelling screenwash system at the intake structure. Three other welds (for a total of 22 accessible welds in the EDG supply piping) were not RT'd because of structural interferences. The inspector reviewed a sampling of the RTs for the entire set of welds to verify the overall characterization of the findings. The completed NDE exam sheets accurately reflected the indications present in the RT films.

The welds at the intake structure had backing rings. None of the welds in the screenhouse showed the LOP/MIC type indications that are of concern. Those welds did have indications that require dispositioning, including porosity, surface indications, concavity, and slag. This evaluation continued during the week of February 7. The welds in the EDG supply piping also showed various indications that require dispositioning, including porosity, surface indications, concavity, pits, lack of fusion, lack of penetration, corrosion, erosion, burn through, undercut, and slag. The indications for sixteen (16) of the 19 EDG supply line welds were characterized as not significant degradation, and did not jeopardize the integrity of the joint. Thus, most welds were similar to the overall quality of the SW pipe segment taken out of the 'B' EDG supply line on January 25.

Three of the remaining EDG welds had indications that resemble the LOP/MIC indications observed on the weld removed in May 1993. The welds were #22 on the 'A' EDG header, and #21 and #12 on the 'B' EDG header. The welds locations were as follows (See Figure 6): Weld # 21 - 'B' EDG supply, first "old" weld downstream of main SW header and just upstream of the first header isolation valve V-146B; Weld # 12 - 'B' EDG supply, second "old" weld downstream of main SW header and just downstream of the header isolation valve V-146B; and, Weld # 22 - 'A' EDG supply, first "old" weld downstream of main SW header and just upstream of the first header isolation valve V-144A.

<u>Summary of RT Results For the Three Worst Welds</u>

The inspector reviewed the NDE results for the three welds in detail. Weld #21 showed lack of fusion over 6 inches in 3 of 4 sectors of the weld, plus localized areas of concavity, porosity and voids. The vendor remarked the weld showed possible MIC. The indication follows the root pass around the circumference and was mostly narrow - showing MIC irregularities along the surface of the base material. Weld #22 showed LOP/MIC similar to that on weld #21, but the indication was less severe and did not cover the full extent of the weld. This is consistent with the findings with the May samples in which the weld on the 'A' header show somewhat less severe degradation. For weld #12, the indications were also similar to the weld #21, but the LOP noted in the other welds was not apparent. Instead, the general area of MIC corrosion was broad along the root pass, and covered most of the extent of the weld. Significantly, the area covered by the MIC corrosion appeared to widen from the root toward the toe of the weld. Of concern was whether the MIC was merely staying shallow but reaching into the base metal of the pipe, or travelling up the heat affected zone of the weld, resulting in a partially circumferential defect that was about to break through the surface.

The licensee concluded that the indications required further characterization, but appeared to be bounded by the analysis for the May 1993 sample, because the indications on welds #22 and #12 did not appear to be as deep and did not cover the full extent of the weld. The indications for weld #21 did cover the full extent of the weld and most closely resembled the May sample taken for the 'A' header, in which the MIC had not progressed as deep as on the 'B' header. Still all 3 welds required further characterization to assure the FMA was still bounding.

<u>Initial ECT and UT Evaluations</u>

Welds #12, 21 and 22 were selected for further evaluation using ultrasonic and eddy current (subsurface) examination to better characterize the depth of the defects and to allow for comparison with the bounding defect that was subjected to the fracture mechanics analysis. A calibration standard for ECT was selected using machined blocks and portions of the May 1993 SW pipe samples with circular and groove defects cut into it. After extensive trials to calibrate to a multitude of defects on February 6, the calibration block selected was one containing a defect that was 65% through wall, or had about 0.100 inches of wall material left. This depth corresponded to the wall assumed for the FMA analysis. Thus, any signal on the ECT would represent a defect that was approaching the FMA acceptance criteria thickness. The initial examinations were completed on February 5 - 6.

The UT standards were similarly chosen. The NU examiner chose two probes: (i) a straight beam for shooting down the crown of the weld; and, (ii) a 70 degree 'L' wave probe, which could be used to shoot under the crown of the weld. However, field measurements quickly revealed that the surface of the weld was too rough to provide a reliable measurement through the crown - there was too much noise. The 'L' probe was effective in shooting under the crown to help investigate indications found by ECT.

For welds #21 and #22, no ECT signals were observed around the circumference of either weld (or the pipe wall - which was randomly sampled near the weld). All areas examined clearly passed the 0.100 inch criteria. For weld #12, the general wall thickness on the crown and on either side of the weld met the 0.100 inch criteria around the entire circumference. There were four highly localized signals (two in sector 2 - 3 and two in sector 3 - 0) where ECT showed some signal below the baseline - indicating the presence of pinholes (worm holes) that might be approaching the 0.100 inch thickness. All four defects were on the toe of the weld (rather than the crown).

Follow up UT exams using the straight and 'L' wave probes to scan the pipe wall confirmed: (i) the apparent lack of indications climbing up the heat affected zone of the weld from the root to the toe; and (ii) generally good pipe wall (mostly >0.200 inches) around the weld. However, the results near the weld were still considered inconclusive due to roughness of the surface of the pipe and the weld crown.

Continuing Operability Assessment on February 9 - 11

The licensee's initial NDE evaluations (RT, UT & ECT) for welds #21, #22, & #12 showed that the degradation caused by LOP/MIC was still bounded by the FMA provided for the May sample. Based on the above, CYAPCo engineering concluded that the SW piping was operable. This conclusion was presented to plant management on February 7 for consideration in developing the action plan to address the SW system welds. The inspector followed the RT, UT and ECT calibrations and the conduct of the examinations. The inspector independently confirmed the conclusions reached by the licensee.

These results were discussed in detail with NRC Region I personnel who visited the site on February 8 and 9 to review the licensees activities. At the time of the reviews on February 9, the final accuracy of the ECT results could not be determined. The licensee continued to refine the ECT measurements by using the May 1993 welds in a standard to correlate the degraded weld conditions against the ECT signal obtained from a calibration standard made from electro-discharge machined notches. To help improve the confidence in the NDE results, the licensee used a segment of the May samples in a mockup of the pipe geometry with water to obtain additional RTs of the flaws.

No additional FMA or stress calculations were performed on February 6. However, the stress analyst noted that the pipe stresses used in the bounding FMA analysis are the worst case stresses found in the headers supplying the EDGs. The highest stresses occur in the locations of the welds removed from the system in May 1993. The stresses at welds #21, #22 and #12 are about 40% to 50% of the stresses used in the bounding analysis. Notwithstanding the above conclusions, the licensee committed to install clamps on the degraded welds with the intention to use the clamps as a temporary measure to restore margin to the stress load limits. The clamps would be installed on the known degraded welds by February 25.

During reviews of the calculations on February 9, the NRC noted that the licensee intended to refine the analysis further by using dynamic loadings for the piping system, instead of applying the worst case loading at the location of the known defect. It was expected that the results of the refined calculation would be bounded by the preliminary results, and that the operability conclusion would not change. The licensee estimated that the refined calculation would show acceptable results with a little 80 mils of ligament remaining in the pipe wall.

Further NDE was planned to better characterize the defects and to quantify the flaw depths. This plan included the need to prepare the welds for UT examination. The NRC staff discussed the CYAPCo operability determination and on February 11 reviewed the plans to prepare the weld joints for further evaluation. Due to NRC staff concerns regarding the status of the EDG supply piping located underground and not inspectable, the licensee committed on February 11 to replace the untested piping. The pipe would be replaced during an outage scheduled to occur prior to river water temperature exceeding levels necessary to support diesel operability with the temporary fire hoses, or June 15, 1994, whichever occurred first. This commitment was made in a telephone conversation with the NU Executive Vice President.

<u>Weld Preparation - Through Wall Defect</u>

With the plant operating at 100% full power on February 12, plant workers prepared two welds in the service water system for UT examination. The plan was to prep both welds #21 and #22 by grinding the weld either flush with the pipe, or by flattening the crown as necessary to perform a UT examination. The plan was to grind the crowns about 30 to 40 mils in this manner. The amount to be ground and the locations was chosen with consideration from the pipe stress analyst and the RTs to assure the 0.100 inch criteria would be met throughout the process. The plan included grinding both welds over a portion of the circumference in this manner. The piping was marked on February 11 to designate the areas to be ground in areas determined from the RTs to have "good" wall thickness.

On February 12, plant engineering requested that test sites be ground out first in areas where the pipe wall was known to have excess wall thickness, but only over a sector about 2 to 3 inches in length. This approach was chosen to gain confidence in the technique before grinding a large section of the weld. A segment of weld #21 on the 'B' EDG header was ground by about 40 mils on February 12 without incident. UT examination of the segment confirmed the eddy current findings that at lease 0.100 inches of wall was present in that location.

A three inch segment on weld #22 ('A' EDG header) was ground about 40 mils. However, while this operation was in progress, the NDE personnel noted weepage from a pin hole defect in the weld. The leaky weld was on the upstream side of the isolation valve for the 'A' EDG supply header, was not isolable from the main SW header, and thus potentially affected the supply to the 'B' EDG as well.

The leakage was noted at 9:45 a.m. and was reported to the control room operators. Subsequent review by the licensee noted that the actual location ground was about two inches to the left of the intended area. Thus, instead of grinding in an area where the RT had shown what was expected to be good wall thickness, the area ground was actually over the site of two pin hole "pits" noted on the RT. However, the previous ECT exams had not identified that the pits were within 0.100 inches of the surface. Subsequent UT measurements on the segment confirmed the presence of 0.100 inches of wall over most of the 3 inch segment of weld, except in the area of the two wormhole defects.

Since the grinding operation caused a through wall defect in an area that was thought to have wall thickness margin based on the best available NDE data, the licensee management concluded the event called into question the ECT inspection process used to characterize the defects, and based on which the operability evaluation for welds #12, #21 and #22 were dependent upon. Although the weld still had structural integrity and both supply lines to the diesels were functional, the licensee declared both service water system headers inoperable.

Plant Shutdown - Unusual Event

The loss of two service water headers exceeded the minimum requirements for the SW system specified in Technical Specification (TS) 3.7.3. The licensee entered the action statement for TS 3.0.3 at 9:50 a.m. and began a controlled shutdown. An Unusual Event emergency was declared due to a shutdown required by the TS, which required that the plant be placed in Mode 5 (cold shutdown) within 36 hours. The reactor entered Mode 3 (reactor subcritical) at 3:23 p.m. on February 12, and Mode 5 at 6:10 p.m. on February 13. At which time the Unusual Event was terminated. The licensee notified the NRC Duty Officer at 9:59 a.m. on February 12. The resident inspector responded to the plant and followed the shutdown through termination of the event. This began an outage to inspect SW piping for corrosion and replace affected piping.

The licensee initiated actions to first repair the leaky weld and to complete nondestructive examinations of other welds and piping in the service water system to identify other MIC induced degradations. All known degraded SW welds/piping would be repaired as needed prior to returning the plant to power operation. This included the replacement of the entire service water header to each EDG, including the underground piping. The minimum job scope for SW replacement includes the headers to both EDGs, the headers to the RHR heat exchangers, and the Adams filter bypass lines. The plant outage was scheduled to last about 55 days.

Following removal from the system, the NRC inspector visually examined welds #21, 22 and 12 and noted defects similar to those removed from the SW system in May 1993: extensive corrosion around welds with initial construction defects, with "wormhole" type defects penetrating the crevice. Each sample contains a significant circumferential ligament with a wall thickness estimated to exceed 100 mils.

Most other welds examined by RT in the SW system (both stagnant and flowing sections) were similar to the type of defects noted in the sample removed from the SW system in January 1994. Two welds in the RHR lines had defects similar to those noted in the May 1993 sample. CYAPCo actions were in progress at the end of the period to characterize the SW defects and to complete an operability assessment in accordance with the bounding Appendix H analysis.

Management Responsiveness/Assessment

During the week of February 7, site management concluded the plant organization did not have the initiative in addressing the SW corrosion issue. The Unit Director initiated actions and plans starting on February 8 to regain the initiative in solving the problem. This message was addressed in a meeting with the principle plant staff on February 10 in which expectations on the approach to the problem were discussed, along with the need to accelerate the pace of the investigations. The approach taken would be one in which the staff would not assume the problem has been limited. Station management recognized the weaknesses in its own and the engineering group's past actions relative to the issue. The Unit Director accelerated plans to conduct a service water system operability review (SWOPI). Further, the licensee directed that a third party assessment be completed to evaluate the management and engineering decision making process. The NUSCO Nuclear Safety Engineering group was tasked with the work.

Findings

The sequence of CYAPCo actions described in the February 22 letter to the NRC were reviewed and found to accurately capture the facts and chronology of events to address SW. Following substantial interactions with the NRC staff and in response to questions regarding the degraded pipe and weld conditions, on February 10 CYAPCo successfully demonstrated that the SW system remained operable to the extent the defects were known and accurately characterized.

The decision to shutdown the plant following the development of the through wall leak on February 12 was good and necessary in light of the uncertainties in flaw characterization based on the then available RT and ECT examinations. Post shutdown examination of the defects (welds #21, 22, 12) showed conditions similar to that noted for the May 1993 sample. CYAPCo actions are appropriate to complete its evaluation of the worst case flaws identified in the SW piping and to finalize the operability determination for the SW system. The licensee stated this matter will be further reviewed for reportability upon completion of that evaluation.

CYAPCo management and engineering did not display the usually strong questioning attitude in the pursuit of the issue and had lost the initiative to address this problem prior to substantial involvement by the NRC staff. The initiative was lost during the 1993 outage when inspections and analyses of degraded welds identified the potential for a wide spread problem affecting piping and welds in the SW system. These adverse conditions were not thoroughly investigated when the initial operability assessment was made. The anomalous conditions were not promptly investigated following the outage when plans were made to gather data to investigate the status of the SW system. The underlying assumption of presumed continued operability was not conservative in the face of the substantial uncertainty regarding the status of the SW pipe and welds, the exact mechanism causing the identified corrosion, and the uncertainty in how rapidly the corrosion progressed. CYAPCo appears to have regained the initiative on this issue starting from about February 7.

NRC review of this are was in progress at the end of the inspection period. A meeting between the NRC and CYAPCo staffs is planned on March 16 to further the NRC review of this topic. This item is considered unresolved for the following actions: (i) completion of modifications to SW system and acceptance testing; (ii) completion of the evaluation of the degraded welds/SW pipe to assure root cause is identified and addressed; (iii) completion of actions to meet commitments made in the February 10 conference calls and as described in the February 22 letter, including: the development of a MIC mitigation program by April 1, 1994, the reassessment of CYAPCo's response to Generic Letter 89-13, and the performance of a SWOPI; (iv) completion of the operability determinations for the historical condition and submittal of the licensee event report; and, (v) completion the third party root cause evaluation to understand how the SW corrosion issue was handled by CYAPCo engineering and management. This item is open **(UNR 94-03-05)**.

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

The inspectors reviewed selected engineering activities. Particular attention was given to safety evaluations, plant operations review committee approval of modifications, procedural controls, post-modification testing, procedures, operator training, and UFSAR and drawing revisions.

4.1 Loose Sediment in Service Water Line to Residual Heat Removal (RHR) Heat Exchanger

On February 19, during cold shutdown (Mode 5) plant conditions, CYAPCo was removing sections of service water supply piping to the 'B' RHR heat exchanger. The pipe was removed due to corrosion (see report detail 3.5). During the pipe removal, the licensee identified approximately twenty five pounds of sedimentary material in two horizontal supply legs. The sediment was composed of fine silt and benthic material. Based upon the amount of sediment, and the potential to affect the RHR heat exchanger safety function, CYAPCo declared the service water supply piping inoperable. The inoperability resulted in a 10 CFR 50.72 (b)(2)(i) notification to the NRC at approximately 9:10 a.m. CYAPCo initiated plant information report (PIR) 94-033 to document the event, and to identify potential corrective actions. The inoperability did not directly affect shutdown cooling operations, since the heat exchanger is normally cooled by component cooling water, and the post-accident safety function (post-LOCA sump recirculation) was not applicable in cold shutdown.

Background

The RHR heat exchangers are normally used for shutdown cooling operation. Each heat exchanger is aligned to component cooling water as described in normal operating procedure (NOP) 2.9-1, "Placing the RHR System in Service." The service water supply is normally isolated from the RHR heat exchanger and is used during emergency operating procedures ES-1.3, "Transfer to Sump Recirculation," as the safety-grade cooling supply to the RHR heat exchangers to cool containment sump water.

Two twelve inch service water supply headers (12"-WS-121-257 and 12"-WS-121-104) are stagnant lines with some limited stream flow. The limited stream flow is provided by one and one half inch supply lines to the steam generator sample chiller condensers. On a quarterly basis, the normally closed motor-operated valves (SW-MOV-5 and SW-MOV-6) are cycled for the ASME Section XI inservice test program per SUR 5.7-67, "Inservice Testing of SW Isolation Valves, SW-AOV-8,-9, SW-FCV-129, and SW-MOV-5 and -6." During the test, the twelve inch supply header is flushed via a 1 1/2 inch drain line downstream of the motor-operated valves for at least two minutes. The licensee performs this test to assure silt does not accumulate above the seats of MOV 5 and MOV 6.

The inspector evaluated CYAPCo's program against the actions identified in NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." CYAPCo's response to NRC Generic Letter 89-13 dated January 25, 1990, stated that the RHR heat exchangers baseline performance will be verified during the current refueling outage. CYAPCo's response further stated that the RHR heat exchangers are not susceptible to biofouling concerns, and therefore no subsequent testing or monitoring will occur. The NRC's guidance, as documented in NRC Generic Letter 89-13, was that performance testing of infrequently used cooling loops should include an initial test frequency of each refueling cycle, but after three tests the licensee could determine the best frequency. The inspector verified that during the 1991 refueling outage, the licensee performed a baseline thermal performance test using component cooling water versus service water. The test results were satisfactory.

The inspector reviewed past service water flow tests through the RHR heat exchangers. Special test (ST) 11.7-10, "Service Water System Throttle Setting," verified that the heat exchanger outlet throttle valves (SW-V-250A and 250B) were in the proper position to provide the specified flow based on a Westinghouse design basis analysis, (WCAP-121916, "CY Ultimate Heat Sink Temperature Design Basis Change." ST 11.7-10 was performed in November 1989 and in January 1990. The design basis minimum service water flow through one RHR heat exchanger post accident is 2,250 gallons per minute (gpm). The recorded service water flow in January, 1990 was 2,300 gpm to the 'A' RHR heat exchanger, and 2,500 gpm to the 'B' RHR heat exchanger. The November 1989 flows were 2,500 gpm and 2,400 gpm to the 'A' and 'B' heat exchangers, respectively.

Assessment

On February 24, CYAPCo retracted the 10 CFR 50.72 report issued on February 19. The engineering analysis concluded that the RHR heat exchangers were operable in the "as-found" condition when supplied with service water. The operability determination was based on engineering judgements regarding the adequacy of service water flow, and the prevention of heat exchanger shell side fouling. CYAPCo concluded that the sediment would not foul the vertically mounted heat exchangers for the following reasons: the sediment was a fine silt and would readily form a suspended solid in solution; and, the service water flows through the shell side of the heat exchanger from a top to bottom direction, resulting in a continuous flushing action. Finally, the past heat exchanger performance tests were conducted with a likely similar buildup of silt in the stagnant lines. The inspector reviewed the licensee's basis for operability of the service water supply lines to the RHR heat exchangers. Although no recent (since 1990) tests have occurred to support the judgements presented in the operability assessment, the bases for operability determination were reasonable, and the conclusion was acceptable.

The inspector also concluded that CYAPCo's actions in regard to RHR heat exchanger monitoring was not consistent with the expectations in Generic Letter 89-13. Specifically, CYAPCo elected to not perform heat exchanger monitoring since the baseline test in 1991, based on the assumption that fouling would not be a concern due to the chemically treated component cooling system water normally in the heat exchangers. However, it is evident from the February 19, 1994, inspections that fouling has occurred in the stagnant service water lines to the RHR heat exchangers. The inspector presented this issue to licensee management on February 25. At the end of the inspection period, the licensee stated that performance monitoring using the component cooling water would occur to both RHR heat exchangers, and both stagnant lines were being replaced. The inspector considers this item open tc verify the performance monitoring of the RHR heat exchangers, and to review future activities planned by the licensee **(IFI 94-03-05).**

4.2 Improper Pipe Flanges on the Low Pressure Safety Injection System

On January 11, CYAPCo identified that the discharge pipe flanges for flow element (FE-660) were A182-F304 300 psi class. The piping specification (Class 603) requires that flanges between 2.5 inches to 16 inches to be A182-F304 600 psi ratings. The flange size on flow element FE-606 was a 10 inch flange. The system engineer identified the incorrect pipe flange during a preliminary walkdown supporting plant design change PDCR 1461, "Removal of FE-660." The engineer was measuring flange thickness to determine the gasket raised face dimension, when he noticed that the flange was the wrong class.

Upon discovery of the discrepancy, CYAPCo initiated a walkdown of all accessible pipe flanges in the low pressure safety injection (LPSI) system. The walkdown also identified that both LPSI pump discharge flanges were carbon steel lap-joint flanges with a 300 psi rating. Piping specification CYS-1550A class 603 does not allow lap-joint flanges, but the suction piping class 153B for the LPSI suction piping allows lap joint flanges for sizes ranging between 0.5 to 4 inch sizes. The LPSI pump discharge flanges are 10 inch. Additionally, the LPSI pump suction flanges were 300 psi lap-joint flanges whereas piping specification 153B requires a weld neck type flange with an ASTM specification A183-F304 150 psi rating.

CYAPCo performed an operability evaluation of the LPSI piping system based on the identification of the "as-built" construction deficiencies. The operability determination compared the 300 psi flange rating using ANSI B 16.5 table 2-300 to that of LPSI design conditions. Engineering standard ANSI B 16.5 is the reference in the original piping specification CY-1550A. The licensee concluded that the system pressure boundary integrity was maintained and the system was considered operable in the "as-found" condition. The inspector verified the licensee's conclusion by reviewing ANSI B 16.5 for the grade identified and found the following flange ratings: 620 psig/100° F and 550 psig/300° F. The Updated Final Safety Analysis Report states that the LPSI pumps are designed for 350 psig and 100° F with normal operating temperatures ranging between 50 to 100 degrees F. CYAPCo further evaluated worst case conditions at FE-660 and concluded that worst case temperature was residual heat removal entry conditions (300° F) and a system pressure of 430 psig. The worst case temperature and pressure at FE-660 assumes that the upstream check valves (SI-CV-103 and SI-CV-107A or B) between the RHR and LPSI systems are leaking excessively. The inspector determined that the licensee's operability decision was appropriately supported.

At the end of the inspection report period, CYAPCo was evaluating the acceptability of the flange bolting pursuant to ASME section 3650 evaluations. The evaluations were being performed on static as well as dynamic conditions.

The inspector noted that the differences between the piping specification and the "as-built" configuration might affect other engineering evaluations (i.e. SEP seismic calculations, and future plant modifications). Procedure NEO 5.05, "Design Inputs, Design Verification, and Design Interface Reviews," states that a design input source document is the original equipment design documents, such as calculations, specifications, and calibrations. NEO 5.05 step 6.5.3 states that design deficiencies identified by other project personnel, audits, tests, or failures during operation shall be reported via the appropriate corrective action program mechanisms. This matter was discussed with the Unit Director on February 26, who stated actions would be taken to assure that these noted as-built deviations from the construction specifications would be included in the plant design basis documentation. The inspector considers the accuracy of piping specifications as related to past engineering evaluations an open item **(IFI 94-03-06).**

4.3 Modification to MCC-5

The documentation for Plant Design Change Request PDCR 1434, Rev 0, "MCC-5 Automatic Bus Transfer (ABT) Re-Design," was reviewed. The intent of this modification, in part, is to prevent unnecessary ABT operations caused by the preferred bus position logic. The modification added some complexity to the current ABT logic. Included in the modification were two new breaker control switches, a new automatic/manual relay, a new control room alarm, and a change in the function of the existing preferred bus position switch. The inspector questioned whether the additional relays and contacts would reduce the overall ABT reliability.

The addition of the manual to automatic transfer of the breaker control adds several additional components to the logic. The licensee technical staff stated that the new breaker control switches will be located at the breakers. The additional controls would facilitate breaker testing when racked out in the bus compartment. The DB-25 breaker design already includes a manually actuated breaker close and trip capability. This capability is completely separate from the ABT logic. Therefore, if the ABT were to fail, the proper operator action would be to manually close the breakers using the existing manual close handle on the breaker.

The present ABT design provides a needless transfer of the ABT when both bus 5 and 6 had power. If the ABT had transferred to a energized bus it would leave the perfectly good bus and transfer back to the preferred bus. This feature of the ABT could be eliminated by removing the preferred bus feature from the ABT logic. The rest of the logic would remain as-is. The ABT would still always seek and find the energized bus as it presently does.

The licensee acknowledged the inspector's comments. The licensee stated the proposed design change was reviewed by the probabilistic risk assessment (PRA) group and was included in the PRA model for Haddam Neck. The PRA group found that, although the proposed modification added complexity to the ABT, the overall impact of the new design would result in an improvement in the core melt frequency for Haddam Neck by an order of magnitude. The licensee stated the details of this calculation would be provided for inspector review.

The changes described above could simplify the ABT logic and make the ABT more reliable. The licensee stated the inspector's comments would be considered in the ongoing plant and engineering evaluation of the proposed ABT modification. Licensee actions in this area will be included in future routine inspections of engineering activities.

5.0 PLANT SUPPORT (40500, 71707, 90712, and 92701)

5.1 Radiological Controls

During routine inspections of the accessible plant areas, the inspectors observed the implementation of selected portions of the licensee's radiological controls program. The inspector reviewed utilization and compliance with radiation work permits (RWPs) to ensure that they provided detailed descriptions of radiological conditions and that personnel adhered to RWP requirements. The inspectors observed controls of access to various radiologically controlled areas and the use of personnel monitors and frisking methods upon exit from those areas. During the period, the inspectors periodically observed health physics controls during radiography of service water piping welds. Appropriate pre-job briefings, postings, and surveys were performed in accordance with radiation protection manual (RPM) 2.5-1, "Radiography." The inspectors verified that posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were in accordance with licensee procedures. The inspectors determined that the health physics technician control and monitoring of these activities were good.

5.1.1 Locked High Radiation Controls

The inspector reviewed licensee actions on February 7, in response to an issue involving a locked high radiation area (HRA) gate. While conducting a routine tour of the radiation control area (RCA) at about 9:00 am on February 7, a plant security guard noted that the gate to the ion exchange pipe trench was closed but not locked. The guard locked shut the gate and contacted the health physics supervisor.

Licensee investigation determined that gate had last been opened at 7:19 a.m. that morning by a health physics technician. The gate was opened as part of checks per Attachment A of procedure RPM 2.3-2, "Daily Routine Checklist," which is completed to assure gates are secured. The technician performing the gate check failed to assure the gate latched completely after it was opened to check the gate alarms. A radiological posting sign hung on the gate had interfered with full closure and prevented the gate from latching securely.

As corrective action, the licensee immediately verified the status of all other gates listed in procedure RPM 2.3-2 and confirmed that the gates were secure. The technician who performed the daily check was subjected disciplinary action. The posting was moved so it could not interfere with gate closure. The licensee evaluated the incident and noted that the access to the high radiation area was lessened but not compromised during the period the gate was not secure. A hatch providing access to the high radiation area controlled by the gate was locked in place with both security and health physics padlocks. Thus, no violation of the Technical Specification 6.12.1 requirements for controlling access to a locked high radiation area occurred.

Nonetheless, the failure to secure the gate during the checks completed at 7:19 a.m. was contrary to the requirements of procedure RPM 2.3-2. Licensee health physics supervision demonstrated a high regard for the control of locked high radiation areas, and the need to address personnel performance issues. Thus, no violation will be issued since, in accordance with the NRC Enforcement Policy in Section VII.B of 10 CFR 2, Appendix C, the violation was identified by the licensee, it was classified as a Severity level IV, it could not be prevented by the corrective action from a previous violation, and the licensee corrective actions were appropriate. The inspector concluded that the security officer who noted the open gate displayed a good regard for plant radiological controls.

5.1.2 Containment Purge Operations

The inspector reviewed the controls implemented by the licensee to monitor and control the release of radioactivity during the shutdown for the service water piping replacement. The inspector reviewed stack releases using the process radiation monitor readouts in the main control room, and reviewed the release calculations provide in gaseous release permit G-19 dated February 25, 1994. The permit was written to allow the initiation of purge operation for the primary containment. Containment purging began on February 25, which was 13 days after the shutdown from full power, and became continuous as the containment was opened for outage related work.

The inspector reviewed the licensee calculations for the number of curies of the isotope xenon-133 released. The initial discharge resulted in a release of 9.86 curies of radioactivity over 24 hours, with a release rate of 114 micro-curies per second. The release rate was 0.05% of the amount allowed by the technical specifications. The estimated total site boundary dose rate was 0.0036 milliRem. No inadequacies were identified.

5.2 Plant Operations Review Committee

The inspectors attended several Plant Operations Review Committee (PORC) meetings. The inspectors verified Technical specification 6.5 requirements for member attendance were met. The meeting agendas included procedural changes, proposed changes to the Technical Specifications, Plant Design Change Records, and minutes from previous meetings. PORC meetings were characterized by frank discussions and questioning of the proposed changes. The major issues were reviewed very well and included the work this period on the main steam safety valve test plan and failures, the MCC-5 ABT failure and investigations, and the activities to investigate the SW system corrosion. Items for which adequate review time was not available were postponed to allow committee members time for further review and comment. The inspector determined that the committee closely monitored and evaluated plant performance and conducted a thorough self-assessment of plant activities noted above.

5.3 Follow-up of Previous Inspection Findings

The inspectors reviewed licensee actions taken in response to open items and findings from previous inspections. The inspectors determined if corrective actions were appropriate and thorough and whether previous concerns were resolved. Items are closed where the inspector determined that corrective actions would prevent recurrence. Those items for which additional licensee action is warranted remain open. The following item was reviewed:

(Closed) Inspector Follow Item 92-15-02, Corrective actions and Root Cause for Licensee Event Report 92-020-00

This item was open pending review of the licensee root cause determination, and the corrective actions for the failure of the '2B' steam generator wide range level indicator. Licensee event report (LER) 92-20-00 documented a condition prohibited by technical specification. The basis for the report was CYAPCo's inability to insert a trip signal within one hour on the '2B' wide range level instrument. The trip signal was necessary based on a momentary failure of the instrument in July 1992.

CYAPCo's root cause investigation of the momentary failure of the '2B' wide range steam generator level instrument was inconclusive. The operating experience since the July 1992 event has not identified any failures.

The inspector verified the licensee's corrective actions to review technical specification instrumentation in regard to insertion of trip signals, and implementation of a plant modification to install permanent trip switches for the eight channels of the steam generator wide range level instruments. CYAPCo's review of instrumentation design identified that the 4,160 volt bus 8 and 9 undervoltage level signals could not be placed in a tripped condition within the one hour allowed by the technical specifications. CYAPCo developed procedure CMP 8.8-1, "Installation and Removal of UV Trip Signals Bus Levels 1, 2, and 3." The inspector reviewed the adequacy of the procedure, and concluded that appropriate actions were identified to accomplish the removal of one of the UV channels. The inspector verified that the applicable control room annunciator procedures reference CMP 8.8-1 to be accomplished by the generation test personnel when a channel failure is evident.

Plant modification PDCR 1344, "Install Steam Generator Wide Range Level Trip Switches," was implemented and successfully tested on June 26, 1993. The steam generator low level, and feed flow/steam flow differential control room annunciators direct the operators to have instrument and control specialists perform corrective maintenance procedure (CMP) 8.2-26, " Insertion and Restoration of Trip Signals."

The inspector considers this issue a violation that is not subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in section VII.B of 10 CFR Part 2, Appendix C. This item is closed.

5.4 Union Negotiation Contingency Plans (IP 92709)

Plant security officers are represented by the United Plant Guard Workers of America (UPGWA) Union, Local 538. The expiration date for the existing union contract was January 31, 1994. Burns International Security Services prepared a time line of events and a plan to promote ratification of a new contract. The inspector reviewed the licensee's plans and actions for responding to a work stoppage in the event of a job action. Licensee planning was formalized four months before the expiration date.

The inspector reviewed the licensee's plans to meet the minimum shift complement for normal security and contingency staffing requirements. The inspector also reviewed various licensee and contractor documents. The licensee kept the resident inspector and the NRC Region I Division of Radiation Safety and Safeguards Section informed of the contract negotiations and the planning status.

No inadequacies were identified regarding the contingency plans. A new four year contract was accepted by the union on January 29, 1994. The inspector found that the licensee security supervisor performed very well in promptly and fully informing the inspector of the status of the contract negotiations. The inspector identified no inadequacies in this area.

6.0 MEETINGS

6.1 Exit Meetings

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. At the close of the inspection period, an exit meeting was held to summarize the conclusions of the inspection. No written material was given to the licensee and no proprietary information related to this inspection was identified.

In addition to the exit meeting for the resident inspection held on March 4, the following meetings were held for inspections conducted by Region I based inspectors.

Report No.	Inspection Dates	Reporting Inspector	Areas Inspected
50-213/94-04	2/7-2/8/94	Mayfield	Service Water Pipe Weld Degradation

6.2 Meeting with Local Officials

On February 18, the inspector met with the First Selectwoman for the Town of Haddam, CT. The purpose of the meeting was to meet the local official, to describe the role of the NRC, and discuss the inspection of activities at Haddam Neck. The types of information available to the public and the Town of Haddam on the 50-213 Docket were also discussed. The inspector felt the meeting was beneficial for enhancing communications with the town.

ATTACHMENT A

INSPECTION REPORT NO. 50-213/94-03

EDG SERVICE WATER EVENTS SUMMARY

The following chronology of licensee activities regarding the service water corrosion issue was developed during this inspection period in response to an inspector request.

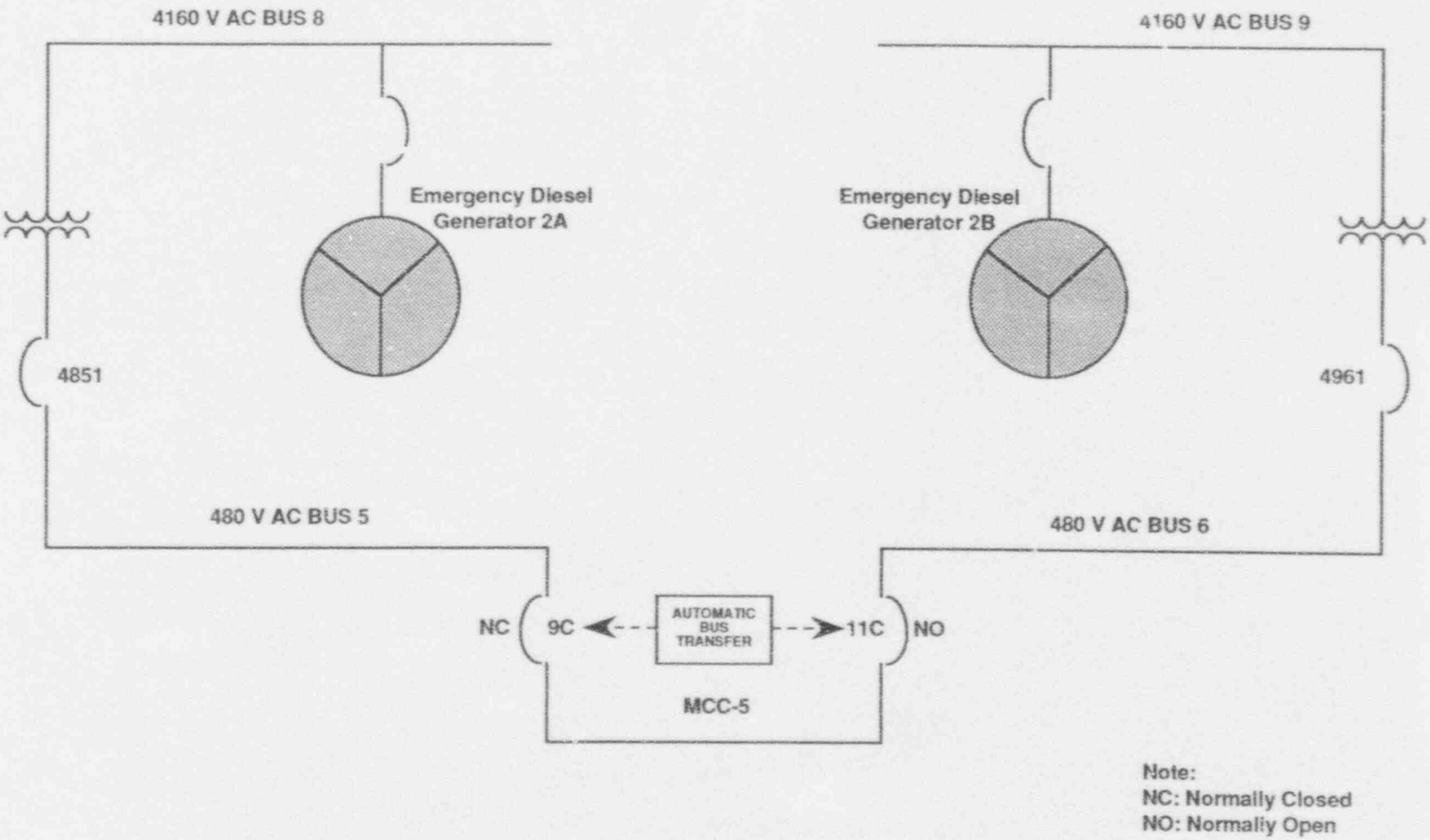
3/8/93	PIR 93-07 initiated for pinhole leak in 'B' EDG supply. UT of surrounding base metal SAT. Relief request initiated in accordance with 90-05.
5/93	6" Piping from 12" east and west supply headers up to and including first elbows replaced on 'A' and 'B' EDG supply piping during RFO.
5/93	Sample of weld which leaked sent to NUSCO Materials for root cause evaluation.
6/93	Root cause memo (CTS-93-754) issued stating poor weld quality with possibility of MIC (no active samples acquired with welds).
7/93	PIR 93-027 and CR 93-240 for pinhole leak accepted and closed out by PORC withdrawal of previous relief request submitted.
8/93	Informal discussion began between NUSCO and CY personnel on need to inspect for other potential poor weld quality or MIC attack if present. Sample qualitatively evaluated and results consistent with PIR findings.
9/93	Investigated feasibility of performing RT inspections of potentially affected areas (i.e., stagnant, low flow service water).
10/93	Began developing inspection plan to evaluate potentially affected service water subsystems.
11/16/93	RHR and EDG piping inspection action plan memo issued. Inspections delayed by management to develop contingency plans. Decision acceptable based on weld operability.
12/93	Numerous meetings held and contingency plan developed to perform inspections and take necessary actions if operability is not met. Including shutdown and piping replacement PDCR if necessary.
12/22/93	NRC Region I Administrator , Tim Martin visits site, visually inspects samples and notes significant corrosion.

1/7/94	CYAPCo decided to remove an elbow with welds during diesel outage to clean HX on 1/25/94 at which time full metallurgical, RT and visual inspections will be performed. This data would "benchmark" the RTs for future inspection of in service piping. Further RT's without removing pipe discussed.
1/94	Documentation of operability assessment provided by Stress Engineer which reaffirmed samples are acceptable/operable, based on measurements and calculations.
2/2/94	NRC question regarding existing preliminary operability assessment prompts a flaw analysis IAW Section XI Appendix H to be performed by NUSCO. This analysis reconfirms operability to the extent known defects are characterized.
2/3/94	Began acquiring additional RTs of all accessible welds to EDGs to assess operability.
2/7/94	Initial screening of preliminary RT data identifies 3 welds (#21, 22 & 12) with flaws similar to those removed in May 1993, and which require further characterization to verify the defects are bounded by the Appendix H analysis. Eddy Current (ECT) examination confirms presence of at least 100 mils of ligament. Efforts continue to benchmark the ECT calibration standards against samples with the flaws removed from the system.
2/12/94	A through wall leak develops on weld #22 during actions to prepare the weld crown for UT examination. CYAPCo declares both SW headers inoperable based on loss of confidence in NDE methods to characterize weld defects. An Unusual Event is declared and a plant shutdown is started.
2/13/94	The plant reached cold shutdown on February 13. This began an expected 55 day outage to inspect SW piping for corrosion and replace affected piping.
2/26/94	End of period status: Minimum job scope for SW replacement includes the headers to both EDGs, the headers to the RHR heat exchangers, and the Adams filter bypass lines. Visual examination of welds #21, 22 and 12 after removal from the system note defects similar to those removed from the SW system in May 1993; extensive corrosion around welds with initial construction defects, with "wormhole" type defects penetrating the crevice. Each sample contains a significant ligament with a wall thickness estimated to exceed 100 mils. CYAPCo actions in progress to characterize the defects and to complete an operability assessment in accordance with the bounding Appendix H analysis.

FIGURES

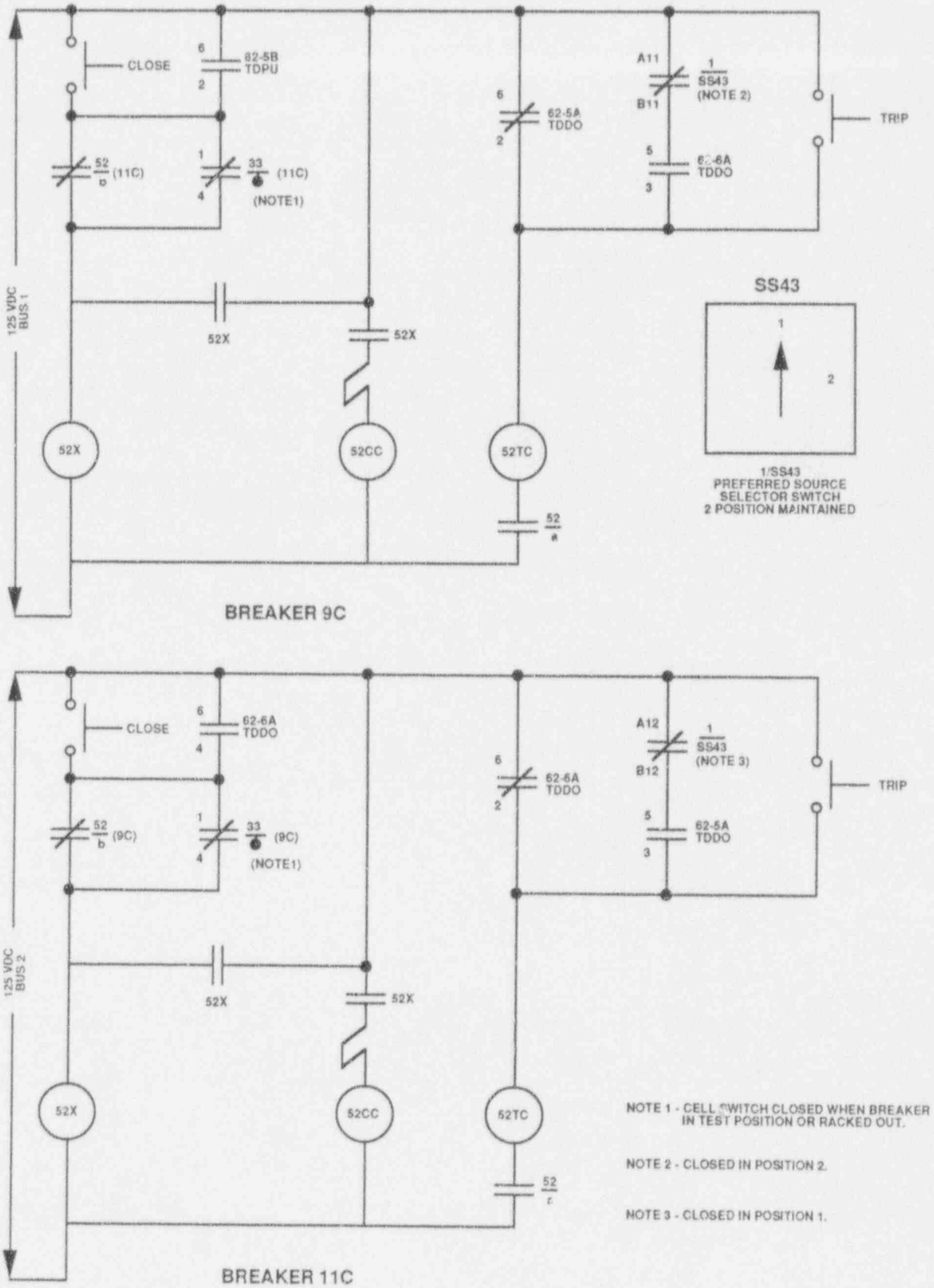
INSPECTION REPORT NO. 50-213/94-03

EDG SERVICE WATER EVENTS SUMMARY



MCC-5 SIMPLIFIED DIAGRAM

FIGURE 1



ABT LOGIC DIAGRAM
FIGURE 2

FIGURE 3
VIEW OF DB-25 BREAKER

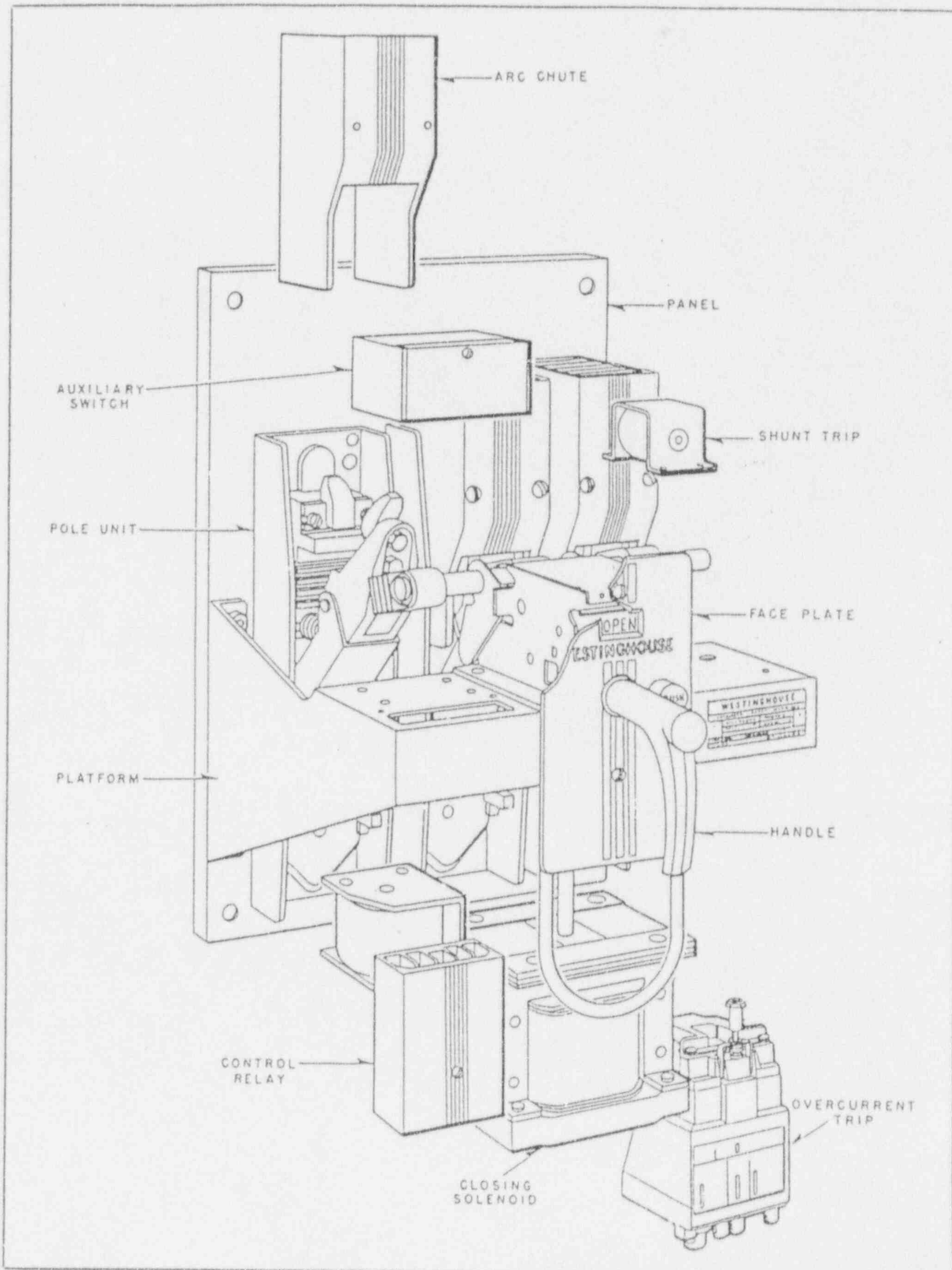


FIGURE 4
Cross Sectional View of DB-15/25 Breaker

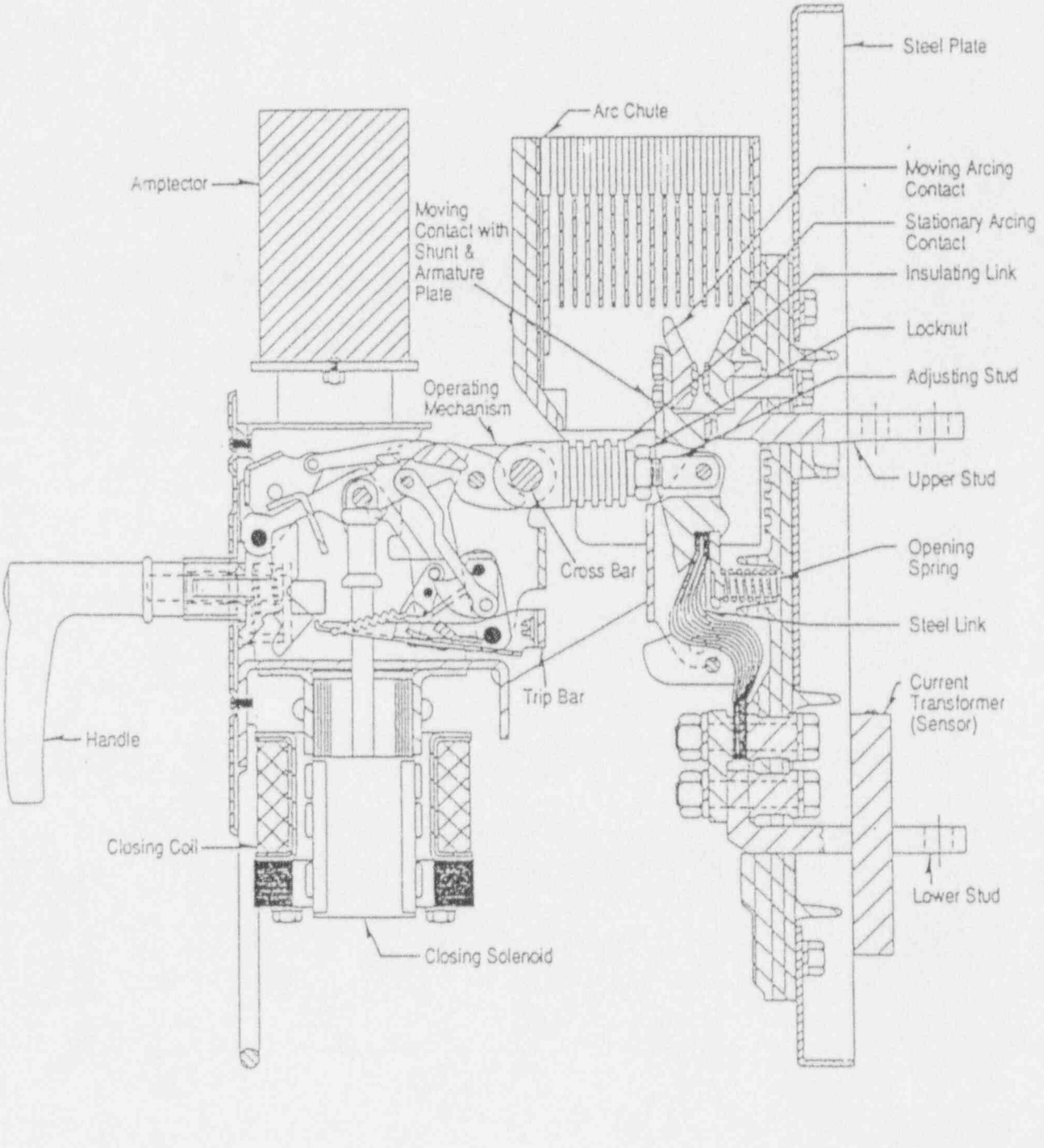
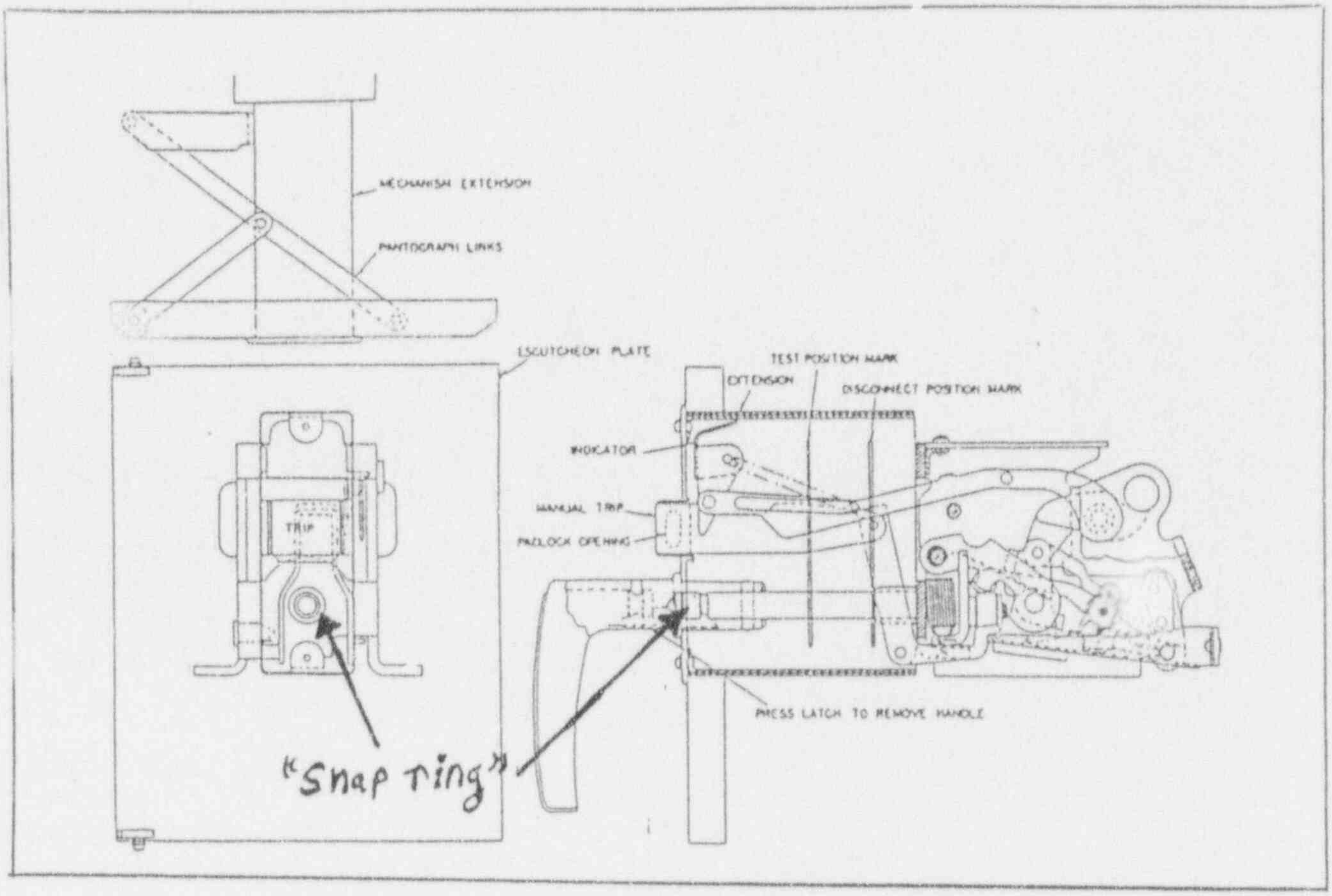
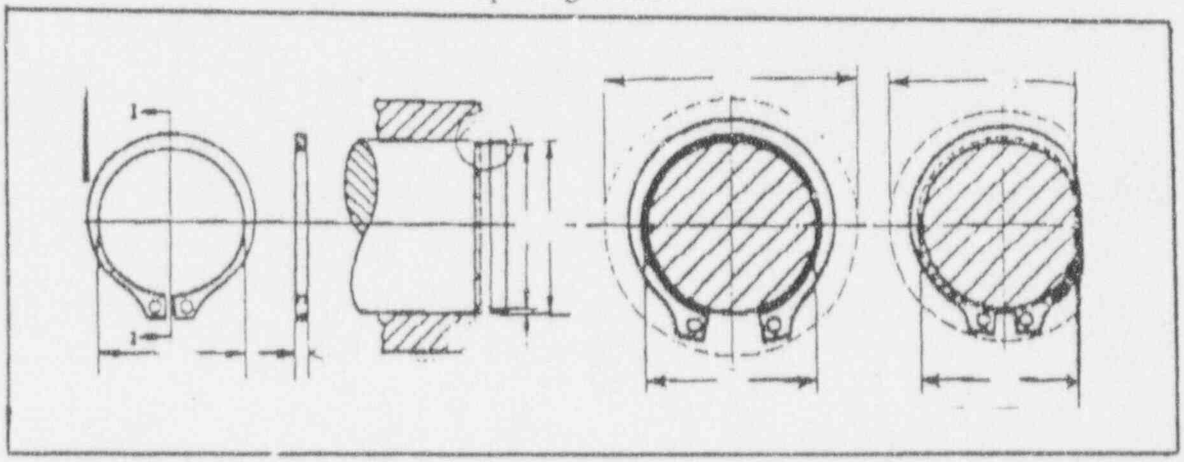
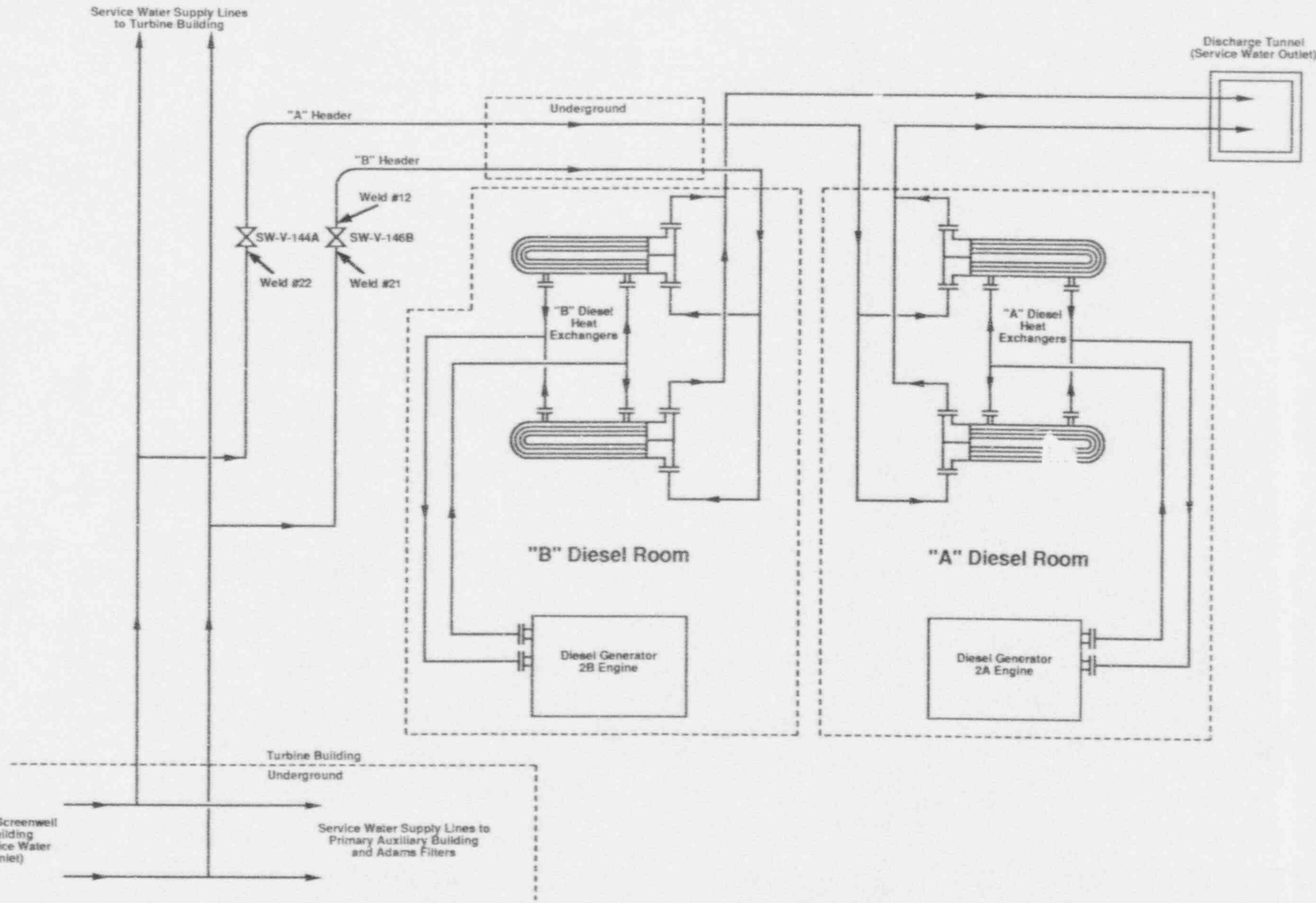


FIGURE 5
DB-25 BREAKER OPERATING MECHANISM



Snap-Ring Detail





Service Water to Diesel Generator Heat Exchangers
Figure 6

IR 94-03