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Facility Name: Vermont Yankee Nuclear Power Corporation

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Inspection Summary: See Executive Summary

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TABLE OF CONTENTS

		Page
1.0	Executive Summary	5
1.1	Event Summary	5
1.2	Assessment Summary	5
2.0	Introduction	8
2.1	Scope of Inspection	8
2.2	Team Composition	8
3.0	Event Description	8
4.0	Equipment Performance	11
4.1	Electrical Systems	11
4.1.1	Electrical Distribution System	11
4.1.1.1	System Description	11
4.1.1.2	Switchyard Performance During the Event	14
4.1.1.3	Recovery of Offsite Power	15
4.1.2	Switchyard DC Distribution System	17
4.1.2.1	System Description	17
4.1.2.2	Operations During the Event	18
4.1.3	Breaker Relay Protection	19
4.1.3.1	Description of Relay Protection	19
4.1.3.2	Performance of Relay Protection During the Event	23
4.1.4	Previous Related Similar Events	24
4.1.5	Root Cause Analysis	25
4.1.6	Short Term Corrective Actions	27

Table of Contents

			Page
4.2	Mechanical Systems		29
	4.2.1 HPCI/RCIC Vessel Water Level Control		29
		4.2.1.1 Systems Description	29
		4.2.1.2 System Operations and Problems During Event	30
		4.2.1.3 Corrective Actions	31
	4.2.2 Torus Water Volume Control/Liquid Radwaste System		33
		4.2.2.1 Performance Considerations During the Event	33
		4.2.2.2 Assessment of Performance	34
	4.2.3 Service Water System		35
		4.2.3.1 Service Water System Description	35
		4.2.3.2 Performance Considerations During the Event	36
		4.2.3.3 Evaluation of System Problems	37
		4.2.3.4 Short Term Corrective Actions	39
5.0	Human Performance		40
5.1	Event Classification and Notification		40
5.2	Operator Actions		42
5.3	Emergency Plan Implementation		43
5.4	Management Activities		44
5.5	Related Safeguards and Fire Protection Activities		45
5.6	Support Organizations and Personnel		46
5.7	Work on the Switchyard DC Control Power System		48
	5.7.1 Work Leading to the Event		48
	5.7.2 Work at full power		49
	5.7.3 Use of Procedures and QA Practices		51
		5.7.3.1 Maintenance Work Documents	51
		5.7.3.2 QA Practices	53
	5.7.4 Switchyard Operational and Maintenance Organizations		54

Table of Contents

		Page
6.0	Safety Assessment	55
6.1	Loss Of Offsite Power	55
6.2	Service Water Problems	56
6.3	HPCI/RCIC Problems	57
6.4	Torus Water Volume and Liquid Radwaste System Problems	58
7.0	Long Term Corrective Actions and Potential Generic Issues	59
7.1	Long Term Corrective Actions	59
7.1.1	Switchyard Activities	59
7.1.2	Service Water Activities	60
7.2	Potential Generic Issues	61
8.0	Exit Meeting	63

APPENDICES

APPENDIX A:	Entrance and Exit Interview Attendees
APPENDIX B:	Licensee Developed Sequence Of Events
APPENDIX C:	System Sketches
APPENDIX D:	Photographs
APPENDIX E:	Acronyms and Initialisms
APPENDIX F:	Licensee Developed Post Trip Review
APPENDIX G:	Licensee Exit Meeting Slides
APPENDIX H:	Augmented Inspection Team (AIT) Charter
APPENDIX I:	Licensee Developed Backfeeding Time Line
APPENDIX J:	Licensee Event Report (LER) 84-22
APPENDIX K:	Summary of Unresolved Items

1.0 EXECUTIVE SUMMARY

1.1 Event Summary

On April 23, 1991, at 2:48 p.m., a complete loss of offsite power (LOOP) occurred at Vermont Yankee Nuclear Power Station (VYNPS) as a result of maintenance activities being conducted on switchyard batteries. A subsequent turbine-generator trip and automatic reactor scram from 100% power occurred. The emergency diesel generators (EDG) automatically started and accepted load on the emergency buses. An Unusual Event was declared at 3:07 p.m. as a result of the loss of offsite power. At 7:45 p.m., offsite power was partially restored to the 115 kV bus via the limited capacity "Keene" line. During the event, problems were encountered with two station air compressors. In addition, reduced service water flow to the emergency diesel generators was observed. These problems were primarily attributed to a high discharge pressure in the service water system. The torus water volume exceeded the maximum volume allowed by the Technical Specifications by a small amount during most of the time of the Unusual Event until 7:25 p.m. on April 24. At 4:17 a.m. power backfeed through the station main transformer from the 345 kV switchyard was achieved. The emergency diesel generators were secured by 4:45 a.m. on April 24. The licensee's Unusual Event was terminated at 7:50 p.m. on April 24, 1991. The reactor was in a cold shut down condition by 3:57 a.m. on April 25.

1.2 Assessment Summary

The Vermont Yankee LOOP event involved a loss of the 345 kV and the 115 kV offsite AC power sources. The cause of the LOOP was related to maintenance activities associated with connecting a battery to its switchyard DC control power source. Two normally independent buses in the DC control system were cross tied through a common battery charger. One of the two buses was operated without a connected battery. Upon opening the charger output breaker, a voltage spike was generated on the DC bus that did not have a connected battery. This voltage spike damaged sensitive components (Zener diodes) in the "stuck breaker failure trip relays" powered by the affected bus. This resulted in the breakers in the 345 kV and the 115 kV yard tripping open. Other factors that contributed to this event were: inadequate maintenance of the battery chargers in the switchyard DC distribution system leading to hardware problems with three of four battery chargers; and design of the switchyard breaker failure relay system which resulted in all of the "stuck breaker failure trip relays" being powered from the same bus.

During the event, several abnormalities were observed in the operation of the service water system. These abnormalities resulted in overheating of two of the station air compressors and reduced service water flow to the two emergency diesel generators. These problems were primarily a result of an unexpectedly high pressure in the service water (SW) discharge header. This was attributed to a change in the SW alignment in 1987 when the SW discharge was redirected from the river to the cooling tower deep basin. The original Final Safety Analysis Report (FSAR) lineup directed SW discharge to the river. The discharge to the cooling tower involved a relatively high resistance discharge path which increased the discharge pressure. This realignment was inadequately analyzed at the time of the change.

The overall response of the licensee's operational staff to the event was good. The operators responded well to the event and adequately coped with equipment problems. One operator error resulted in an overspeed trip of the reactor core isolation cooling system (RCIC) turbine. However, this trip was inconsequential and the equipment was quickly recovered. Plant management was actively involved in the management of and recovery from the event. The operations support staff performance was generally adequate in response to the equipment failures and the recovery from the event. However, the time to restore the 345 kV and 115 kV offsite power sources was excessive. The effort to reclose important switchyard breakers was hampered by the time delay required for New England Power Service Company (NEPSCO) relay technicians to travel to the site to establish the 345 kV backfeed through the main transformer. This operation took about 13 hours in contrast to the 6 hours specified in the VY Technical Specification bases.

Some delay was also encountered with electrical personnel experiencing difficulty exiting from the radiologically controlled area (RCA) due to contamination from radioactive noble gases in the plant. A three hour delay was attributed to communication problems and differences in priorities between Vermont Yankee and Rhode Island, Eastern Massachusetts, and Vermont Energy Control (REMVEC).

The licensee's event classifications were appropriate and the licensee's notifications to the NRC were generally adequate. Some problems were noted with the timeliness of one report, the completeness of one report, and the licensee's failure to report an additional entry condition for an Unusual Event.

A problem was encountered with the high pressure coolant injection system (HPCI) gland seal exhaust condenser. However, HPCI was operable and available during the entire event. In addition, the licensee exceeded the torus maximum water volume specified in plant Technical Specifications due to limitations in the liquid radwaste storage and processing capability. However, the licensee had other acceptable means to accommodate the excess coolant inventory in the torus, should there have been a need.

Safety margins associated with available AC power sources and service water cooling were reduced during the April 23 event as a result of the LOOP and the reduced SW flow to the EDGs and the air compressors. However, the EDGs accepted the safeguard loads and operated satisfactorily during the entire event. Furthermore, the Vernon hydroelectric plant was available as a backup AC power source. The service water problems during the event limited the availability of one of the station air compressors during the event. A transportable diesel air compressor was connected to the station air system to satisfy plant needs, during the event. No other significant safety problems were identified as a result of the event.

The licensee's short term (prior to restart) activities to identify and correct deficiencies associated with the event were adequate. A licensee corrective actions team, consisting of 13 technical and maintenance personnel, was assembled to address the switchyard problems.

Prior to startup, the following actions were taken by the licensee: each of the two buses in the switchyard DC control system was provided with a battery charger that was known to be free of problems; the maintenance guidance that allowed cross tying the two buses in the switchyard DC control system was canceled; susceptible voltage sensitive components in the breaker failure instrumentation (BFI) relay cards were removed and the BFI cards were subsequently tested and reinstalled; and communication problems with VY and REMVEC were addressed. With regard to the service water problems, a five member interdisciplinary task force was assembled. A series of tests were performed on April 26 to understand the problems and confirm the proposed corrective actions. The service water system was realigned such that SW discharge was redirected from the cooling tower to the river. A problem with the HPCI gland seal exhauster was addressed by a temporary modification to the gland seal exhauster that consisted of the addition of a drain to the exhauster housing with a loop seal. The plant was restarted on the morning of April 30, 1991.

The licensee identified a number of potential activities to be pursued in the long term to followup on the hardware and human performance deficiencies observed during the event, and to minimize the probability for recurrence of the observed switchyard and service water problems. The licensee has agreed to send a letter to the NRC by July 15, 1991 that identifies important activities in their long term program along with their schedule for completion of these activities.

Seven unresolved items were identified during this inspection. A summary of these items is provided in Appendix K.

Several potential generic issues associated with the April 23 event were identified by the Augmented Inspection Team (AIT). These are issues that may apply to other nuclear power plants. These issues include the following: 1) a review of maintenance practices on non 1E electrical equipment that can adversely affect the availability of GDC 17 offsite power sources; 2) a review of breaker lockout relays manufactured by Westinghouse/Brown Boveri for Zener diodes that are vulnerable to voltage surges; 3) a review of switchyards to determine if they are vulnerable to DC control system failures; 4) a review of the adequacy of surveillance tests to identify system/equipment problems; and 5) a review of switchyard activities to establish the adequacy of utility control under emergency conditions.

2.0 INTRODUCTION

2.1 Scope of Inspection

In response to the loss of offsite power event at the Vermont Yankee Nuclear Power Station on April 23, 1991, the NRC formed an Augmented Inspection Team (AIT) to: determine the circumstances and events which led to the loss of offsite power; evaluate the licensee's actions in response to the event; evaluate the response of the plant systems to the event; and determine if there are any potential generic issues associated with the event.

The NRC AIT arrived on-site to start the inspection at noon on April 25, 1991. The charter for this inspection is provided as Appendix H. Attendees at the entrance and exit meetings are identified in Appendix A.

2.2 Team Composition

The team was composed of a team leader, the resident inspector, three regional specialists, and an observer from the state of Vermont. The team had expertise in plant operations, electrical distribution systems, mechanical equipment, maintenance practices, and safety assessment.

3.0 EVENT DESCRIPTION

On April 23, at 2:48 p.m., Vermont Yankee lost the capability to supply or receive 345 kV and 115 kV offsite power. The cause of the loss of offsite power was related to maintenance activities associated with connecting battery DC-4A to its switchyard DC control power bus. Several "breaker failure relays" failed and initiated a complex switchyard breaker opening sequence. This isolated the plant from normal offsite power sources. The turbine generator was automatically removed from service and an automatic reactor shut down resulted from the main turbine control valve fast closure. All control rods inserted to at least position 02 and reactor power was below 2 percent of full rated power.

As a result of the loss of offsite power, Instrument Alternating Current (AC) was deenergized. The loss of Instrument AC resulted in partial actuation of Primary Containment Isolation System (PCIS) Groups 1, 2, 3, and complete isolation of PCIS Group 5. The Reactor Protection System (RPS) motor-generators were also deenergized and during subsequent coastdown, the RPS motor-generator output breaker opened causing complete actuation of RPS logic and PCIS logic. All PCIS Group 1, 2, 3 valves closed as required. The RPS motor generators were subsequently restarted and their buses reenergized at approximately 3:15 p.m.

The Emergency Diesel Generators (EDGs) automatically started, achieved required speed and voltage, and connected to their associated electrical distribution buses 3 and 4 within the Technical Specification required time of 13 seconds. Safety-related electrical equipment functioned as expected.

The PCIS Group 1 isolation of the main steam isolation valves (MSIVs) resulted in a sudden increase in reactor pressure vessel (RPV) pressure and control room operators manually opened safety relief valve (SRV) "A" to reduce RPV pressure. The high pressure coolant injection (HPCI) system was concurrently placed in service for RPV water level and pressure control. The "A" side of the residual heat removal (RHR) system was placed in the torus cooling operating mode. Subsequently the "B" RHR system was also placed in the torus cooling operating mode.

At approximately 2:52 p.m., control room operators entered procedure OT 3122, "Loss of Normal Power." Service water valve SW-20 was closed, isolating unnecessary turbine building service water loads. Control room operators verified station air compressors "A" and "B" were in operation and backed-up the automatic transfer of station air compressors "A" and "B" cooling from Turbine Building Closed Cooling Water (TBCCW) to service water. At 3:07 p.m., the Shift Supervisor declared an Unusual Event due to zero voltage on the 345 kV and 115 kV electrical distribution buses. Notifications to the States of Vermont, New Hampshire and the Commonwealth of Massachusetts were completed within 15 minutes. Initial NRC notification was made within 1 hour.

At approximately 3:33 p.m., control room operators entered emergency procedure OE 3104, "Torus Temperature and Level Control Procedure," due to the torus water volume exceeding the maximum specified in the plant Technical Specifications. The inventory of water in the torus was slowly increasing, primarily due to HPCI system exhaust. Torus water was transferred to Radwaste processing tanks and the emergency procedure OE 3104 exited at approximately 3:51 p.m.

At approximately 3:34 p.m., RPV water level dropped below the RPV low water level scram setpoint and a RPS scram signal was actuated. The drop in water level was primarily due to removing HPCI from service. The reactor core isolation cooling (RCIC) system was subsequently placed in service for RPV water level and pressure control. RPV pressure was maintained between 600 and 1000 psig. The NRC was notified of this RPS actuation within 4 hours.

At approximately 3:42 p.m., station air compressor "A" automatically shut down. At approximately 5:31 p.m., station air compressor "B" automatically shut down. The cause of these automatic shut downs was determined to be inadequate service water cooling flow. Off-normal procedure ON 3146, "Low Instrument/Scram Air Header Pressure," was entered. The "B" station air compressor was restarted. Adequate cooling water flow for the "B" station air compressor was established via back flow through an open relief valve. At approximately 5:59 p.m., a diesel air compressor was connected to the "D" station air compressor outlet to help supply plant air loads.

At approximately 5:16 p.m., the RCIC system automatically shut down due to RPV water level exceeding a high level setpoint. The high water level was the result of "swell" associated with opening of SRV "C", during the RPV pressure reduction. The RCIC system was restarted for RPV water level and pressure control and remained in service until approximately 7:04 p.m. when a control room operator error resulted in an RCIC turbine overspeed automatic shut down. At 7:12 p.m., the RCIC overspeed trip was reset and RCIC restarted for RPV water level and pressure control. RCIC continued to operate for RPV water level and pressure control until 1:46 p.m. on April 24; maintaining RPV pressure between approximately 600 and 1000 psig.

Normal power to the 115 kV switchyard, through breaker K186, was restored at approximately 7:25 p.m. on April 23. Offsite power was restored to inplant non-emergency buses 1 and 2 by 7:50 p.m. The power available through the K186 breaker is administratively restricted below 10 MW. The emergency buses remained energized by the EDGs.

HPCI was operated intermittently in the full flow test mode for RPV pressure control until approximately 7:30 p.m. when plant management decided to restrict the operation of HPCI due to failure of the HPCI Gland Exhauster. The degradation of this support system did not affect the ability of the HPCI system to perform its safety function and the HPCI system remained operable.

At approximately 9:12 p.m., a RPV Low Water Level scram actuated. The RPV low water level was the result of "shrink" following closure of SRV "D". RPV water level dropped to approximately 125 inches. Concurrently, the Shift Supervisor determined that water volume in the torus would remain above the maximum specified in the plant Technical Specifications (70,000 cubic feet) and emergency procedure OE 3104 was entered. Torus water was transferred to radwaste, however the inventory of liquid radwaste and the rate of radwaste processing restricted the amount of torus water transfer. After considering alternatives for reducing torus water level, plant management decided to maintain the level above 70,000 cubic feet. The NRC was notified of the RPS actuation (low water level scram) at 10:00 p.m. At approximately 10:25 p.m., Vermont Yankee notified the NRC of a Technical Specification required shut down resulting from inability to maintain torus water level below 70,000 cubic feet.

At approximately 4:17 a.m., on April 24, offsite power was restored from the 345 kV switchyard through a backfeed electrical alignment. By approximately 4:37 a.m., offsite power was supplying power to buses 1, 2, 3, and 4 and the EDGs were placed in a normal standby configuration. Immediately prior to shutting down the EDGs, an auxiliary operator recorded EDG operating parameter data. This data indicated lower than expected service water flow through the EDGs.

SRVs were used, when needed, to reduce RPV pressure. When the operation of the HPCI system was administratively restricted, SRVs were cycled to reduce reactor pressure. The intermittent use of SRVs to reduce pressure continued until approximately 8:50 a.m. on April 24, when the heat removal capabilities of the RCIC system were sufficient to maintain RPV pressure within an acceptable operating band.

The main condenser was established as a heat sink by 1:38 p.m. on April 24. Vermont Yankee commenced a reactor plant cooldown.

Transfer of water from the torus to radwaste continued at a rate consistent with system limitations and plant restoration and safety priorities. At 7:25 p.m. water in the Torus was reduced below 70,000 cubic feet and emergency procedure OE 3104 exited. The Unusual Event was terminated at 7:50 p.m. on April 24.

The temperature difference between RPV steam dome temperature and RPV bottom drain temperature exceeded an administrative limit and delayed initiation of RHR shut down cooling. RHR shut down cooling was placed in service at 2:07 a.m. on April 25 and the reactor was in a cold shut down condition by 3:57 a.m. on April 25.

4.0 EQUIPMENT PERFORMANCE

4.1 Electrical Systems

4.1.1 Electrical Distribution System

4.1.1.1 System Description

Offsite electric power is supplied to the VYNPS from the transmission network to the on-site electrical distribution system by two independent circuits designed and located in order to minimize the likelihood of their simultaneous failure under normal operating and postulated accident conditions. One circuit is supplied from either the 345 kV transmission system via a ring bus (through the 345/115 kV, 400 MVA autotransformer) or from the 115 kV "Keene" line. When supplying plant loads from the Keene line, the line is limited to 10 MW capacity which is sufficient to supply emergency buses 3 and 4 electrical loads. The second circuit is a delayed access circuit available by removing the generator links and establishing a feed from the 345 kV switchyard through the main generator step-up transformer and unit auxiliary transformer to the in-plant 4160 volt buses (Figure C1). The offsite power

distribution system consists of a 345 kV switchyard with three transmission lines and one 115 kV Keene line. In addition, a hydroelectric power supply is available from the "Vernon" Hydro 4160 volt line to backup emergency power. The Vernon line has a limited capacity of approximately 3 MW, and has sufficient capacity to supply power for only one of the two 4160 volt emergency buses at a time. The Vernon line power supply is 30 degrees out of phase with the rest of the power supplies in the VYNPS station; therefore, transfer to the Vernon Hydro line is a dead bus transfer.

The 345 kV switchyard distribution system consists of a ring bus. The ring bus is divided into North and South buses with five circuit breakers and their associated line connections and disconnect switches. The ring bus has three tie lines to the "Scobie", "Coolidge" and "Northfield" lines.

The 115 kV switchyard is located adjacent to the 345 kV switchyard. It consists primarily of the 115 kV Keene line. An autotransformer is connected to the 115 kV switchyard from the 345 kV switchyard side which provides the normal source of power to the 115 kV switchyard. The two circuit breakers associated with the 115 kV switchyard are oil circuit breakers rated for 145 kV service.

The main generator connects to the 345 kV ring bus via the main transformer and a motor operated disconnect switch (T-1). The main generator also supplies power to inplant electrical loads via auxiliary transformer No. 2. The North bus section of the ring bus supplies power via autotransformer No.4 to the 115 kV switchyard bus (Figure C1). All the 345 kV breakers are 115 kV air blast circuit breakers. Three 115 kV breakers are connected in series for each phase of the 345 kV system. The ring bus and the transmission lines are arranged such that the failure of any of the 345 kV transmission lines or the 345/115 kV autotransformer tie line will not result in the loss of the main generator. Additionally, the loss of the 115 kV Keene line will not cause an automatic trip of the main generator. The transmission system is protected using carrier relaying on the lines and high speed differential protection on the transformers. Overcurrent, ground differential, and distance relays protect station components within the switchyard.

Both the 345 kV and the 115 kV switchyards are equipped with local breaker failure (LBF) protection relay schemes. The 345 kV and 115 kV switchyard bus systems each have an independent overcurrent bus differential protection system. One will not cause tripping of breakers in the other with the exception that the 115 kV secondary-side breaker of the autotransformer will trip for a fault on the 345 kV switchyard's North bus. The 345 kV and 115 kV breakers are controlled directly from the main control room. However, the operation of the breakers and disconnects in the 345 kV switchyard are under the direction of Rhode Island Eastern Massachusetts and Vermont Energy Control System (REMVEC). Breaker position indication and line voltage for both switchyards are monitored in the main control room.

Unit AC Power Sources

The station main generator provides power through the iso-phase bus at 22 kV to both the main transformer No.1 and the station unit auxiliary transformer No. 2. The generator voltage is stepped up through the main transformer to the 345 kV ring bus voltage. The generator voltage is also stepped down to 4.16 kV through the auxiliary transformer for the station auxiliary power system (Figure C1). The unit auxiliary transformer has two secondary 4.16 kV windings, X and Y. The X winding feeds 4.16 kV buses 1 and 3 while the Y winding feeds buses 2 and 4, (Figure C2). Buses 3 and 4 only power safeguard loads; both of the buses can be energized from either of the plant startup or auxiliary transformers.

The startup transformer AC power source provides a source of offsite AC power to the auxiliary power system which is adequate for startup, operation, and emergency shut down of the station. The two startup transformers, 3A and 3B, supply power to the station auxiliary power distribution system whenever the main generator is offline. After the main generator is synchronized to the 345 kV system and partially loaded, the auxiliary power distribution system is manually transferred from the startup transformers to the unit auxiliary transformer. One exception is the cooling tower load (bus 5A). The startup transformers remain energized with startup transformer (3B) carrying the cooling tower load. Automatic fast transfer capability is provided to restore the AC power source to the station auxiliary power distribution system in the event the unit AC power source is lost. Breaker control for the startup transformer AC source is interlocked to prevent interconnection with the unit auxiliary AC power source.

Two standby emergency diesel generator sets are connected to the station switchgear to provide emergency power. These emergency diesel generators are manufactured by Fairbanks Morse and have a continuous rating of 2750 kW at 0.8 power factor. One of the diesel generators is provided for each of the 4160 volt emergency buses 3 and 4. Emergency buses 3 and 4 cannot be tied together. If a loss of normal AC power takes place, loss of voltage at each emergency bus will occur and the respective emergency diesel generator starts. The normal power source tie breaker opens and selected loads on the buses are shed. When proper voltage and frequency are developed, the diesel output breaker closes. Within 13 seconds of the diesel start signal, the diesel generator is available to assume the necessary load of the station engineered safeguard systems. In the event one of the diesel generators is not available, the Vernon Hydroelectric station is available to the other emergency bus. The tie-in of the Vernon station to an emergency bus is done manually.

4.1.1.2 Switchyard Performance During the Event

Prior to the loss of offsite power, the 345 kV ring bus was fully energized with all breakers closed. Auxiliary transformer No. 2 was supplying the 4.16 kV buses 1, 2, 3, and 4. In the 115 kV switchyard, the Keene line outgoing breaker K186 (Figure D1) was closed along with the load side supply breaker K1 of autotransformer No. 4. Both of the diesel generators were in a standby mode.

In the 345 kV switchyard, work associated with the replacement of switchyard battery 4A was in progress. Two 125 V DC buses DC-4A and DC-5A (Figure C3) supply the switchyard protective relaying circuits associated with the switchyard breakers. Normal AC power is converted to DC power for these buses via four battery chargers (4A, 4A-5A, A and B). The detailed operation of the switchyard DC distribution system is described in Section 4.1.2. Prior to the event, DC bus 4A was connected to bus 5A via the battery charger 4A-5A load side breakers. Battery charger 4A-5A was connected to both of the DC buses. The 4A battery had recently been replaced, but it was not connected to bus 4A. Battery 5A along with the remaining battery chargers connected to the respective buses were supplying power to the normal switchyard relay protective circuits. Battery 5A was connected, via battery charger 4A-5A, to both switchyard electrical distribution buses.

At 2:48 p.m. the load side breaker of battery charger 4A-5A, which was connected to the DC bus 5A, was opened. A voltage transient experienced in DC bus 4A caused inadvertent actuation of the 345 kV 81-1T and the 115 kV K1 breaker failure logic. A control room alarm indicating a "Generator Trip-345 kV Breaker Failure" was received. The alarm cleared immediately following the trip of the 1T and 381 breakers in response to the breaker 81-1T protection logic. At about the same time, main generator backup and primary lockout relays tripped in response to the breaker 1T differential logic actuation. The generators's primary and backup logic signal also opened the exciter field breaker and provided the main turbine trip signal input, as expected. Also, simultaneously, the 115 kV switchyard breaker failure logic for breaker K1 opened up breakers K186 in the 115 kV switchyard, and 381 (Figure D2) and 379 in the 345 kV switchyard, respectively.

The opening of breakers 381 and 379 removed all power sources of the 345 kV ring bus to autotransformer No. 4. Those breakers openings in conjunction with the 115 kV breaker K186 trip from the Keene line removed all offsite AC power to the plant. Later, following the loss of offsite power, the DC load side breaker of the battery charger 4A-5A connected to the DC bus 5A was reclosed and subsequently opened again. The opening of the DC load side breaker for the second time initiated the breaker failure logic of breaker 381 in the 345 kV switchyard. This logic actuation again provided an open signal to the already tripped breakers K1, 379 and 81-1T. The breaker failure relay logic and other differential lockout relay control logic functions are further discussed in Section 4.1.3. At about the same time, the unit AC power source loss was detected by the undervoltage relay logic. Auxiliary transformer load breakers 12 and 22 connected to buses 1 and 2 opened. Simultaneously, the startup transformers load breakers 13 and 23 to buses 1 and 2 closed. Both of the emergency

diesel generators automatically started and achieved rated voltage and speed. At 2:48:39 p.m., both diesel breakers closed successfully, energizing emergency buses 3 and 4. The emergency diesel generators accepted the necessary safeguard loads within the 13 seconds specified by the Technical Specifications.

4.1.1.3 Recovery of Offsite Power

Subsequent to the total loss of offsite power, the operations and maintenance department investigated the cause of the breaker failures and the various lockout conditions in the switchyard. Vermont Yankee personnel recognized that the breaker failure instrumentation (BFI) logic activation had tripped various breakers. A team was put together under the direction of the Maintenance Supervisor, and was given the responsibility to recover the offsite power sources, stabilize the switchyard and perform a root cause analysis. The team consisted of two maintenance engineers, three construction engineers (one supervisor and two engineers), an assistant maintenance foreman, and two maintenance electricians. The team also included two relay technicians from NEPSCO and four individuals from VELCO (two maintenance technicians and two linemen). In addition, YNSD started an engineering review of the switchyard relay performance. The next day the team was split into two shifts, and round-the-clock work started in the yards. Troubleshooting and testing efforts were followed with a root cause analysis.

115 kV Keene Source

The licensee had a plan to restore power from either the 345 kV or the 115 kV switchyard. NEPSCO relay technicians were called in along with a bucket truck to facilitate the backfeed process. Concurrently, maintenance qualified team members prestaged the work. This included setting up of the equipment, tools and tagging. Contact with the REMVEC dispatcher was established, and after coordinating with REMVEC, work in both of the switchyards started. Powering the startup transformers by the Keene line was perceived to be the easiest restoration source. A delay of about two hours was experienced while the licensee commenced troubleshooting the relay logic. This work was crucial to clear the relay lockout conditions in the yards. The relay technicians from NEPSCO arrived on-site within a couple of hours from the Providence, Rhode Island NEPSCO facility.

In order to power the startup transformers, the breaker K186 BFI injection signal had to be removed. A shorted Z2 Zener diode in the K1 breaker (in the 115 kV switchyard) BFI logic was found. This failed Zener diode in the trip logic output card (Figure D5 and D6) of the K1 breaker produced an output signal which prevented the closure of the K186 breaker. The failed K1 breaker was manually opened locally. At approximately 3:55 p.m., breaker K1 was manually tripped open. At about 6:15 p.m., the decision was made to remove the faulty BFI relay logic out of the K1 breaker. Then, the K1 breaker and its associated lockouts were

satisfactorily reset. At approximately 7:25 p.m., reclosure of the K186 (Figure D1) breaker was accomplished. Restoration of the 115 kV power source (limited to 10 MW) from the Keene line to the startup transformers No. 3A and 3B was completed. The non emergency buses 1 and 2 breakers 13 and 23 were closed to energize these buses via the startup transformers.

345 kV Switchyard Backfeed Source

As described above, a parallel effort was started to resolve the problems in the 345 kV and 115 kV switchyards. It was determined that backfeed was possible via the south bus through breaker 1T since both the Coolidge and the Scobie lines were still available in the yard. Full emphasis was given by the licensee to the backfeed operation after the 115 kV line source was established. The licensee believed that the 345 kV switchyard had a more complex protection scheme and more breakers were tripped open than in the 115 kV switchyard. Equipment condition in the 345 kV switchyard was not fully known. At approximately 7:00 p.m., the actual work associated with backfeeding started. Previously established procedure OP 2209, "Backfeeding the Main Transformer", which allows power to flow via main transformer to 4.16 kV buses 1 and 2, was used. Within about one hour, tagging of all associated equipment for backfeeding was completed.

Relay technicians from New England Power Service Company (NEPSCO), linemen from Vermont Electric Power Company (VELCO), and Vermont Yankee maintenance engineers pursued correction of the breaker and relay logic problems in the switchyards. This work had to be done in coordination with the control room operators and REMVEC. The initial phase of this work required grounding of the 4.16 kV breakers, surge cubicles and associated relay protective circuits. This work was completed by approximately 9:30 p.m.. Maintenance crews assigned to ground the other side of the main transformer and auxiliary transformer windings outside the plant experienced a slight (approximately 45 minutes) delay in exiting the RCA of the plant due to contamination from noble gases. At approximately 1:40 a.m., April 24, all the tagouts associated with the backfeed work, other than the switchyard breakers and relaying work were completed.

During the breaker troubleshooting effort, an unscheduled time delay occurred in the backfeeding operation. This delay was due to problems communicating priorities for troubleshooting the various breakers of the ring bus. The VY maintenance team members were pursuing a different approach for supplying the backfeed power source from the 345 kV ring bus than the REMVEC staff. Once VY management became aware of this problem, it was quickly resolved. The functions of breakers 1T and 81-1T were verified. The associated lockouts were then cleared. The functions of the disconnect switches and other associated components were also verified. After clearing breaker interlocks and coordinating with REMVEC, the VYNPS Operation Department energized the 1T breaker. Backfeed was established via auxiliary transformer No. 2 at about 4:17 a.m., on April 24, 1991.

Restoration of Power 4.16 kV Buses

Once backfeed of power to the main/unit auxiliary transformer No. 2 was complete, the plant operators initiated manual transfer of the 4.16 kV buses 1 and 2 from the 115 kV power source to the 345 kV switchyard source. This was done by manually closing breaker Nos. 12 and 23 (Figure C2). At 4:25 a.m. emergency bus 4 was paralleled to bus 2 and emergency diesel generator A was shut down. At approximately 4:37 a.m., emergency bus 3 was paralleled to bus 1 and emergency diesel generator B was shut down.

Following the restoration of the backfeed power source, corrective action priorities shifted to breakers K1, 81-T, 379 and 381 and reestablishing the Northfield transmission line. By this time, the licensee started to review the condition of the equipment in the yards. The breaker failure relay vendor was contacted to review concerns applicable to the yard relays. The individual relay and lockout control circuit testing started. All breakers and associated trip circuits in both switchyards were tested before they were returned to service.

DC Battery and Chargers

Approximately two hours into the event, the licensee determined that the 4A battery should be placed in service to stabilize bus voltage. Thus, the load side breaker of battery charger 4A-5A to bus DC-5A, which had been previously reclosed, was opened. This time BFI signals were received on breakers K1, 81-1T, and 381. Since three breakers were open at this time, no switchyard breaker realignment occurred. However, it was noticed that the DC bus DC-4A output voltage had dropped to approximately 100 V from approximately 129 V. At this time the 4A battery breaker was closed and the bus DC-4A voltage was stabilized. This work was performed under MR 91-0251 and applicable maintenance department guidelines.

4.1.2 Switchyard DC Distribution System

4.1.2.1 System Description

The purpose of the relay house battery system is to ensure that a high level of power reliability is available to the control and protection circuits of the switchyard equipment. For this purpose, Vermont Yankee has provided battery - battery charger combinations that are normally supplied from an essential AC bus. In this configuration, the system is capable of providing uninterruptible DC power to the loads for several hours following an extended loss of normal AC power.

The equipment associated with the relay house battery system is not safety related. However, because of its importance to the availability of the station's offsite power, its operability requirements are specified in Section 3.10.A.2.c of the Technical Specifications.

In battery - battery charger combinations, the function of the battery charger is to convert,

through rectification and filtration, the AC input power into an equivalent DC output power. This DC source has, in turn, the function of supplying the required normal power to the loads that it serves and of maintaining the associated battery in a constant state of charge. In the event of a loss of AC power to the battery charger, the battery automatically and without interruption provides the required power to the connected loads.

For Vermont Yankee's relay house battery system, the input AC source is derived from 480 V distribution panel AC-DP-4 which is, in turn, normally fed from essential switchgear bus No. 8. This assures the availability of power to the switchyard relays during those events which result in the loss of normal station service AC power. An alternate source of 480 V AC power is also provided from normal station service bus No. 11. A mechanical interlock between the two input circuit breakers prevents paralleling of the two AC sources.

The DC power is arranged in two buses supplying two 125 V DC, 225 Amp distribution panels, DC-4A and DC-5A. A single line diagram of the switchyard DC distribution system is shown in Figure C3. This figure also provides a listing of the loads supplied by each bus. Buses and associated distribution panels are physically and electrically independent. The sources for distribution panel DC-4A consist of a 60 cell, 425 Ampere-hour Gould battery 4A, and two 75 Amp DC, Exide battery chargers 4A and 4A-5A. The sources for distribution panel DC-5A consist of a 60 cell, 360 Ampere-hour Exide battery 5A, and two 50 Amp DC, Exide battery chargers A and B (Figure D3). Batteries and battery chargers can be electrically isolated from their respective buses by means of molded case circuit breakers that are sized in accordance with their interrupting and carrying duty. The 75 Amp DC, Exide battery charger 4A-5A, is arranged so that it can perform backup duty for battery chargers A and B, This is accomplished by means of two load breakers which connect the charger to either DC bus. A mechanical interlock between the two battery charger load breakers prevents tying the DC buses together.

The significant loads supplied by distribution panel DC-4A include secondary trip relays, differential relays, and local breaker failure relays. The significant loads supplied by distribution panel DC-5A include primary trip relay, differential relays, and breaker close circuits.

4.1.2.2 Operation During the Event

Under normal operating conditions and in accordance with Section 8.3.4 of the FSAR, distribution panels DC-4A and DC-5A operate independently and are maintained energized by their respective batteries and battery chargers. In this configuration, the two battery supply breakers and all AC breakers (and motor starter contacts, where applicable) supplying power to the battery chargers are closed. Also closed are all DC breakers which connect the battery chargers to the DC buses, except for the DC breaker in battery charger 4A-5A which supplies distribution panel DC-5A. As mentioned in Section 4.1.2.1, above, to prevent cross connection of two DC distribution buses, this breaker is mechanically interlocked with the other DC output breaker of battery charger 4A-5A, such that only one breaker at a time can

be closed.

Some time before the event, in conjunction with the replacement of battery 4A, the licensee decided to alter the breaker configuration described above. The altered configuration consisted of the simultaneous closure of both DC output breakers of battery charger 4A-5A. The mechanical interlock between the two breakers had been previously removed. In addition, the supply breaker from battery 4A, breaker No. 51 of distribution panel DC-4A, was opened and left open throughout the battery replacement period and during the initial phase of the event. In this altered configuration, all battery chargers were operating in parallel to energize both DC buses and to supply the required power to the control and protective circuits of the switchyard equipment.

A safety evaluation in accordance with 10CFR 50.59 to review the cross connection of the DC buses had been previously performed in November 1989 in conjunction with the design and implementation of temporary modification No. 89-55. This modification entailed the temporary removal of the mechanical interlock between the DC output breakers of battery charger 4A-5A to conduct corrective and preventive maintenance on either switchyard battery. The safety evaluation had found the cross connection of the two DC buses acceptable. The reason for the removal of the mechanical interlock was to allow the licensee to connect the two DC buses together and to use the remaining battery, 5A, in a backup function, in the event of a loss of AC power. In addition, as described in the safety evaluation, the cross connection would "allow both buses to have a smooth supply from the battery that will remain in service." The work leading to the LOOP and the maintenance work documents associated with this activity are discussed further in Sections 5.7.1 and 5.7.3.1, respectively.

The loss of offsite power occurred during the process of returning to the normal from the altered configuration described above. The return to normal required the opening of the DC output breaker between battery charger 4A-5A and distribution panel DC-5A and the subsequent closure of the battery 4A output breaker.

4.1.3 Breaker Relay Protection

4.1.3.1 Description of Relay Protection

The Vermont Yankee transmission system consists of a 345 kV ring bus and a 115 kV substation. The 345 kV ring bus is composed of five air blast circuit breakers and associated disconnect switches. The 115 kV loop includes two oil circuit breakers and associated disconnect switches. The 345 kV and the 115 kV substations are interconnected through a 400 MVA autotransformer which constitutes the normal source for the 115 kV line. Together, the substations comprise the source of Vermont Yankee's offsite power. The VY main generator supplies power to the plant auxiliary equipment through the auxiliary transformer during normal operation. During shut down and startup, power to the plant auxiliaries is supplied by the 115 kV substation through the startup transformer. In order to

ensure availability of offsite power under normal, abnormal and accident conditions, transformers, breakers and connecting lines are protected by various types of relays which operate to trip appropriate breakers and isolate faults.

The protection scheme provided by Vermont Yankee to isolate faults affecting the 345 kV and the 115 kV substations consists of two separate protective relay groups, both acting upon the same circuit breakers with which they are associated. They are identified as "primary" and "backup" protection. However, either relay group is capable of tripping and locking out the circuit breakers within its zone of protection. The groups monitor different parameters, use diverse relays, operate independently from each other, and function to back up each other. Diversity is obtained through the use of relays which utilize different protection principles and/or different components, e.g., solid state versus electro-mechanical type relays. Independence of actuation is achieved by using separate current and potential transformers for the relays' sensors and separate power supplies for the control and trip signals. In addition, the trip signals act upon separate trip coils of the associated circuit breakers. The two protection schemes are physically as well as electrically independent. Zones of protection associated with adjacent breakers are overlapped to ensure that all portions of the system are adequately monitored. For each circuit breaker, the protection scheme also includes a breaker failure relay which actuates to trip adjacent circuit breakers, if the breakers closest to the fault fail to clear the fault within a preset time.

Different breakers use slightly different protection schemes. This is primarily due to the fact that they protect different types of equipment and, therefore, different relay applications are involved. The protection schemes for the breakers which were affected by the event are described below. Also described is the operation of the breaker failure relays, which were primarily responsible for the event. The circuit breakers involved are 1T, 81-1T, 379 and 381 on the 345 kV ring bus and K1 and K186 on the 115 kV substation.

345 kV Circuit Breaker 1T

Circuit breaker 1T connects the main Transformer to the South Bus and to the Coolidge line. It will trip upon actuation of any of the following protective relays:

a. Local breaker failure;
b. Generator primary lockout;
c. Generator backup lockout;
d. Main transformer tie line differential;
e. Carrier trip;
f. Incomplete sequence.

For circuit breaker 1T, "local breaker failure" signifies actuation of breaker failure relays associated with the Coolidge line breaker and ring bus breakers 81-1T and 79-40, i.e., any one of the three breakers failed to trip and clear a fault for which they had primary isolation responsibility.

Actuation of the generator primary lockout relay includes: failure (to open) of generator breaker 81-1T; failure of generator breaker 1T; generator differential; auxiliary transformer differential; 345 kV main transformer tie line differential lockout; main transformer manual reset lockout from fault pressure relay; and various other signals not significant to the event.

Actuation of the generator backup lockout relay includes: failure (to open) of generator breaker 81-1T; failure of generator breaker 1T; negative phase sequence overcurrent; generator main transformer differential; main transformer ground; auxiliary transformer manual reset lockout from fault pressure relay; and various other signals not significant to the event.

345 kV Circuit Breaker 81-1T

Circuit breaker 81-1T connects the Main Transformer to the Northfield line and the North Bus. Automatic tripping of this circuit breaker is similar to that of breaker 1T, except that, in this circuit, local breaker failure denotes actuation of breaker failure relays associated with the Northfield line breaker or the ring bus breakers 1T and 381.

345 kV Circuit Breaker 381

Circuit breaker 381 connects the Northfield line to the North Bus and, through the autotransformer, to the 115 kV substation. It will trip upon actuation of the following protective relays:

a. Local breaker failure;
b. Carrier trip;
c. Incomplete sequence;
d. North Bus differential;
e. Autotransformer differential.

For circuit breaker 381, local breaker failure signifies actuation of breaker failure relays associated with the Northfield line breaker, 345 kV breakers 379 and 81-1T, and 115 kV breaker K1.

345 kV Circuit Breaker 379

Circuit breaker 379 connects the Scobie line top the North Bus and, through the autotransformer, to the 115 kV substation. Automatic tripping actuation of this breaker is similar to that of circuit breaker 381, except that local breaker failure results in the actuation of breaker failure relays associated with the Scobie line breaker, 345 kV breakers 381 and 79-40, and 115 kV breaker K1.

115 kV Circuit Breaker K1

Circuit breaker K1 connects the startup transformer to the 345 kV substation through the autotransformer. It will trip on actuation of any of the following protective relays:

a. Local breaker failure;
b. 345 kV bus to autotransformer tie line differential;
c. Autotransformer to breaker K1 tie line differential;
d. 115 kV Bus differential;
e. Startup transformer lockout;
f. Overcurrent;
g. Overcurrent to ground.

For circuit breaker K1, local breaker failure denotes actuation of breaker failure relays associated with 345 kV breakers 379 and 381, and 115 kV breaker K186.

115 kV Circuit Breaker K186

Circuit breaker K186 (Figure D1) connects the startup transformer to the Keene line. It will automatically trip upon actuation of any one of the following protective relays:

a. Local breaker failure;
b. Incomplete sequence;
c. Carrier trip;
d. Overcurrent;
e. Distance;
f. Directional overcurrent.

For circuit breaker K186, local breaker failure means actuation of the breaker failure relay associated with circuit breaker K1.

Protective relays are, in general, associated with lockout relays to prevent automatic or inadvertent reclosure of the affected breakers, when the fault is cleared. Lockout relays require an intentional manual reset. Protective and associated lockout relays may impact more than one breaker, as in the case of the local breaker failure relays. Because of their significance in the subject event, the operation of the local breaker failure relays is described below.

The breaker failure relays used at Vermont Yankee are Westinghouse type static breaker failure units (SBFU) (Figure D4). The SBFU relay is a solid state, rack mounted package containing a phase and ground overcurrent unit fault detector, an output trip device, an input logic module, an adjustable timer board, and a power supply. Its operation is based on using trip signals from the protected circuit with internally generated signals to perform its function. Thus, energization of primary or backup relays associated with the protected circuit energize, along with the circuit breaker's trip coil, two auxiliary relays, 62X and 62Y, respectively. Contacts from these relays are then used in an AND logic with the overcurrent unit fault detector to operate an adjustable timer module. A persisting flow of current, after a preset time delay, is a clear indication that the breaker has failed to open. In this case, the timer output actuates either a trip module or an output relay driver. The output of either module is used to drive lockout relay 86BF, whose contacts are, in turn, used to trip the backup breakers. When a thyristor output is used, as in the case of the Vermont Yankee's protection system, a trip module is required to provide a pulse for triggering the thyristor's gate. The isolated output of the trip module contains a Zener diode (Z2) across pins 8 and 9, whose function is to protect the thyristor from transients. Figure C4 depicts, in logic form, the operation of an SBFU relay with thyristor output. Figure C5 shows the internal wiring of a trip module card (Figure D5) for thyristor output.

4.1.3.2 Performance of Relay Protection During the Event

As determined from the post event investigation and the root cause analysis performed by the licensee, the following describes the operation of the relay logic at the moment battery chargers 4A and 4A-5A were separated from battery 5A by opening the battery charger 4A-5A output breaker, as described in Section 4.1.2.2, above.

As the battery charger output breaker was opened, the trip modules of two SBFU relays actuated simultaneously: the first relay was associated with breaker K1 and the second with breaker 81-1T. As described under Section 4.1.3.1 above, the circuit breakers which cause the opening of breaker K1, as a result of the actuation of their local breaker relay,are the 115 kV breaker K186 and the 345 kV breakers 381 and 379. In the same manner as the failure to open of any of these three circuit breakers results in the tripping of breaker K1, failure of circuit breaker K1 causes the same three breakers to trip and open. This can be derived from a review of the protective relays associated with breakers K186, 379, and 381. Such was the case with the actuation of the K1 breaker failure relay. Opening of the affected three breakers, K186, 381 and 379, resulted in the loss of both power sources (the Keene line and the autotransformer) to the startup transformers. Similarly, actuation of the SBFU trip

module associated with breaker 81-1T caused circuit breakers 1T and 381 to open. In addition, the breaker 81-1T trip module provided actuation signals to the generator primary and backup lockout relays which, in turn, signaled breakers 1T and 81-1T to trip. Opening of circuit breakers 1T and 81-1T and subsequent shut down of the main generator resulted in the loss of power sources to the station through the auxiliary transformer.

Following the loss of offsite power, the DC output circuit breaker connecting battery charger 4A-5A to battery 5A was reclosed and subsequently reopened. The reopening of the circuit breaker resulted in a second voltage transient on the DC-4A bus which caused the actuation of the SBFU relay associated with circuit breaker 381. In turn, this actuation resulted in a trip signal to breakers 379, 81-1T, and K1 (already open).

All trip signals opened and locked out the affected breakers as designed.

4.1.4 Previous Related Similar Events

The Vermont Yankee plant experienced a loss of offsite power in 1972. At that time, the cause was attributed to the loss of the startup transformer. The normal power source via the auxiliary transformer was not available due to a previous failure. At that time, there was only one startup transformer. The present design has two startup transformers (3A and 3B). Under those conditions none of the offsite power sources were available to energize the unit auxiliary load. However, the Vernon 4.16 kV power source was available throughout the event. The plant was subsequently upgraded to improve reliability. As a result, one additional startup transformer was added.

On October 22, 1984, the Vermont Yankee station experienced an emergency diesel generator lockout trip on emergency diesel generator "A". This was caused by a differential relay trip. The next day, emergency diesel generator "B" experienced a lockout trip for the same reason. At that time, the reactor was shut down and an Unusual Event was declared. The differential relay trips were due to a failure of Zener diodes. Vermont Yankee personnel met with Westinghouse (the manufacturer of relay SA-1) and jointly concluded that the specific cause of the Zener diode failures could not be positively determined. It was believed by the licensee that the Zener diode failures resulted from component end of life or from cumulative damage from normally experienced switching transients within the DC system. The polarity of the suppression circuit of the lockout relay may have contributed to increased stress and shortened life of the diodes. The corrective action consisted of installing a new version of the Westinghouse SA-1 relay. This relay no longer used the Zener diode across the output SCR. Resistors were used for surge protection. The 1984 emergency diesel failures are described in LER 84-22 in Appendix J.

4.1.5 Root Cause Analysis

A root cause analysis of this event was prepared by the licensee and presented to the Plant Operation Review Committee (PORC) prior to the restart of the plant. As evaluated by the licensee and confirmed by the NRC, Vermont Yankee's loss of offsite power can be traced to a combination of four causes: (1) a procedure that allowed paralleling of battery chargers with no battery on the bus; (2) rare maintenance of the battery chargers; (3) vulnerability of the Zener diodes to voltage transients of the magnitude experienced by the system during the opening of the battery charger's DC output breaker; and (4) use of the same power source for all breaker failure relays. Potentially, the absence of any one of the above conditions could have prevented the event.

As determined through tests conducted by the licensee following the event, opening of the DC output breaker from battery charger 4A-5A resulted in a voltage transient. This transient caused a spurious actuation of the breaker failure relay associated with circuit breaker 81-T1 and the failure of Zener diode Z2 associated with the trip module of the breaker K1 SBFU relay (Figures D5 and D6). The result of the spurious relay actuation and of the Zener diode failure was the firing of the associated thyristor and the consequent actuation of the respective lockout relays (86BF). As described in Section 4.1.3.2 above, these events were the immediate cause of the loss of offsite power. A short time later, a second transient initiated by the reclosure and reopening of the same breaker resulted in the failure of Zener diode Z2 associated with the trip module of breaker 381 SBFU relay. The failure of this second diode and consequent actuation of the relative lockout relay was only significant to the recovery process and to the analysis of the failure.

Following the event, to clearly establish the root cause of the event and demonstrate credibility of the postulated voltage transient, the licensee initiated a test of battery charger 4A-5A. The test involved monitoring of the battery charger voltage during the opening of the breaker in question. For the purpose of the test, the licensee separated the battery charger from the system and added appropriate resistive loads to the output of both DC breakers. Separation of the battery charger from the system was acceptable since battery 4A was charged and battery charger 4A was available for supplying the loads and keeping the battery charged. Monitoring was done using a recording scope, which was set to monitor both the input and output of the breaker in question. As evidenced by Figures C6, C7 and C9, the tests performed by the licensee showed that: (1) with no load applied at the output of the charger, the voltage was very "noisy," with harmonics of different amplitude and frequency superimposed on the normal rectified sine wave (Figures C6 and C7); (2) when a load was applied to the output of the battery charger, most of the noise disappeared and then returned as the loads were dropped by the opening of the breaker (Figure C7); and (3) opening of the breaker resulted in a voltage transient (Figures C7 and C9).

For an understanding of the results recorded by Figures C6 to C9, the following describes the test setup:

(a) In Figure C6, both channels of the scope were set to monitor the battery charger output, with probes connected at the line side of the breaker. The scope sensitivity was on the order of 10 V per major division, according to the technician performing the test. With both DC breakers open, no load was applied to the output of the battery charger.

(b) In Figure C7, Channel 1 (left curve) was monitoring the output of the charger with the probe connected to the line side of the breakers. Channel 2 was set to record the DC voltage at the load side of the breaker feeding bus DC-4A. With load(s) applied to the output of the breaker(s) (bottom of the curve) no noise was evident. However, as the loads were dropped, the noise reappeared. A spike was evident when the first load was dropped.

(c) Figure C8 represents calibration of the recording scope. Sensitivity was decreased to capture the amplitude of the transient.

(d) For Figure C9, the set up was the same as that of C7, but Channel 2 failed for lack of ink. A transient is equally evident as the load breaker opened.

The results obtained from the test not only confirmed the licensee's theory but also revealed an inconsistency with the information provided in the Exide battery charger instruction manual which, under Section 9.4, Description of Operation, states: "The filter reduces the ripple (of the rectified voltage) from several volts to 30 MV (millivolts) RMS or less. The results obtained prompted the licensee to conduct complete preventive maintenance tests of the battery charger which resulted in the discovery that the filter section fuses were blown. Replacement of these fuses corrected the problem experienced with the battery charger output voltage, as seen by Figure C10.

Preventive maintenance tests conducted on the other battery charger, 4A, provided similar results, i.e., noisy output voltage and blown filter section fuses (Figure C11). However, in this case, replacement of the fuses did not clear the output voltage problem. Therefore, the services of the manufacturer's representative were obtained. By the end of the inspection, it was discovered that a third switchyard battery charger, B, was similarly faulty. The fourth battery charger could not be tested until the problems of battery charger B were resolved. It was noted by the AIT that operability of the battery chargers in the switchyard DC control system is specified in the VY Technical Specifications. However, no battery charger surveillance tests are specified. Adequacy of the surveillance tests conducted by the licensee, with respect to the battery chargers, is an unresolved item (UNR 50-271/91-13-03).

In view of the test results, the licensee concluded that paralleling of the two battery chargers, without the dampening effects of the battery, was responsible for the transients which resulted in the failure of two Zener diodes and the spurious actuation of a third SBFU relay.

Ensuing discussions with the licensee revealed that the switchyard equipment had been treated

as non nuclear safety equipment for only a few years. Maintenance of the switchyard battery chargers had been rare. A review of the preventive maintenance program for the switchyard battery chargers confirmed the licensee's statement and revealed that maintenance had been of a corrective nature and directed primarily to the batteries. Adequacy of the battery charger maintenance is an unresolved item (UNR 50-271/91-13-02).

A review of the sensitivity of the Zener diodes to voltage transients was conducted by the licensee. The relay manufacturer, in a telephone conversation on April 26, 1991, stated that the Zener diodes were prone to failures as a result of voltage transients in the DC supply. The manufacturer also advised that the removal of the diode would improve the operability and the reliability of the relays. This fact had been recognized by the manufacturer. In a later design of the same relay the diode was removed. Therefore, as a corrective action, the manufacturer suggested the modification of the relay trip card and the removal of diode Z2.

The analysis of the event included a review of potential vulnerabilities of the switchyard equipment from external causes, particularly with respect to the protective relaying and the DC system. A review of the single line and elementary diagrams associated with the protection and control of the switchyard equipment revealed that the power for the seven SBFU relays associated with the seven switchyard circuit breakers had been derived from the same DC bus, 4A. On the basis of this observation, it was concluded that the transient experienced by bus 4A , when it was separated from battery and bus 5A, affected all breaker failure relays at the same time. It was also concluded that any or all of the SBFU relays could have failed as a result of that single event. The random failure of only two Zener diodes, as well as the spurious actuation of the third relay, could be attributed to manufacturing tolerances of equipment and components. With respect to the use of the same power supply for all breaker failure relays, the licensee indicated that the philosophy used was consistent with the IEEE standards which recommend the use of two power supplies, one for the primary and one for the backup protective relays. In the case of the breaker failure relays, they were considered to perform a backup function.

4.1.6 Short Term Corrective Actions

In view of the results of the root cause analysis performed, the licensee concluded that several corrective actions were required, some of which needed to be addressed in a relatively short time. The licensee divided the corrective actions into three categories: start-up concerns, short term recommendations, and long term recommendations.

With respect to start-up concerns the licensee performed the following corrective actions:

1. Removed from its files the guideline which had been used to override the mechanical interlock between the two DC output breakers of battery charger 4A-5A and to parallel the chargers. This action will prevent a reoccurrence of the circumstances that created the event.

2. Performed necessary corrective and preventive maintenance on the battery chargers and ensured that the DC output met the manufacturer's specifications. By start-up, battery charger 4A-5A met the output requirement and was connected to feed bus and battery 4A. For bus 5A a spare portable battery charger was connected in parallel with battery charger A.

3. Removed the Zener diode from each of the SBFU relay trip cards, in accordance with the manufacturer's recommendations. This action increased the reliability of the relay with respect to transients of the magnitude experienced during the loss of offsite power event.

4. Performed corrective and preventive maintenance on the switchyard's motor operated disconnect switches T-1 and T-3. This action was in response to the problem experienced by T-1 during the event.

5. Reviewed the transformer gas analysis as a preventive measure.

6. Performed a time-line analysis of the recovery from the loss of offsite power to demonstrate that backfeed can be achieved in less than 6 hours.

With regard to short term actions, the licensee plans to:

1. Evaluate and correct the communication problems experienced between REMVEC and Vermont Yankee personnel, and between field and management personnel experienced during the recovery from the loss of offsite power.

2. Review the need for procedures in lieu of the guidelines currently in use by the Maintenance Department and evaluate the need for further review of the guidelines, if these were considered to be acceptable.

3. Perform further review of the steps necessary for backfeeding the normal station service buses through the auxiliary transformer in order to further reduce the time necessary to execute the action.

4.2 Mechanical Systems

4.2.1 HPCI/RCIC Vessel Water Level Control

4.2.1.1 Systems Description

HPCI

The High Pressure Coolant Injection (HPCI) system is designed to provide adequate core cooling and reactor vessel depressurization following a small break loss of coolant accident. HPCI can also provide reactor pressure and level control during reactor shut down and isolation. The HPCI system is designed to pump water into the RPV while it is fully pressurized and will provide adequate core cooling until reactor pressure drops sufficiently to enable low pressure coolant injection systems to be placed in operation.

The HPCI system consists of a turbine-driven pump assembly which utilizes reactor steam pressure to pump water into the RPV via the feedwater line at the rate of 4250 gallons per minute over a wide RPV pressure range. The HPCI system can initiate and perform its intended function independent of AC power systems. A gland seal condenser collects steam leakage in order to prevent contamination of the HPCI room and atmosphere. A gland seal exhauster prevents the gland seal condenser from gas binding due to the buildup of noncondensible gases. Shut down of the HPCI system can be accomplished either manually or automatically. Figure C12 contains a one-line diagram of the HPCI system.

The HPCI system normally takes a suction from the Condensate Storage Tank (CST). When operated in the test mode (RPV pressure control), the HPCI pump takes suction from the CST and recirculates the water through a test line back to the CST. A minimum flow line and flow control regulated valve direct water to the torus during low flow conditions to prevent pump overheating. The HPCI turbine can draw steam from the reactor at a rate approximately equivalent to 4 percent of full rated steam flow. The HPCI turbine exhaust is directed to the torus.

RCIC

The Reactor Core Isolation Cooling (RCIC) system provides makeup water to the reactor vessel during shut down and isolation in order to prevent the release of radioactive materials to the environs as a result of inadequate core cooling. The RCIC system can function independent of AC power systems.

The RCIC system consists of a steam-driven turbine-pump and associated valves and piping capable of delivering makeup water to the RPV. The steam supply to the turbine comes from the RPV. The turbine exhaust is directed to the torus. The RCIC system pump normally takes a suction from the CST. The pump discharges either to the feedwater line (RPV pressure and water level control) or to a full-flow return test line to the CST (RPV pressure

control). A minimum flow bypass line to the torus protects the pump. The RCIC is capable of injecting makeup water at a rate of 400 gpm over a wide RPV pressure range. The design flowrate of the RCIC pump is approximately one tenth the design flow of the HPCI system. Figure C13 contains a one-line diagram of the RCIC system.

Shut down of the RCIC system can be accomplished either manually or automatically. The system will automatically shut down when the RCIC turbine overspeeds; when RPV water level exceeds the high level setpoint; when RCIC pump suction pressure is low; when RCIC turbine exhaust pressure is high or when RCIC steam supply valves shut during a PCIS Group 6 isolation.

4.2.1.2 System Operations and Problems During the Event

HPCI

The HPCI system was manually started for RPV pressure and water level control at approximately 2:50 p.m. on April 23. The HPCI system was shut down at approximately 3:37 p.m. on April 23. Concurrent with the HPCI system shut down, the RCIC system was started and alternated between RPV water level and pressure control operating modes. Injection to the core from the HPCI system was apparently interrupted by the shut down sequence prior to placing the RCIC system in service. This resulted in a RPV water level transient which actuated the RPS low water level scram signal.

The rate of decay heat generation was greater than the rate of decay heat removal associated with the RCIC system. Control room operators determined that the HPCI system provided a controlled means for removing additional decay heat. The HPCI system was started and subsequently shut down five additional times for RPV pressure control. During one of these subsequent starts, control room operators noted that the gland exhauster was binding and apparently operating at higher than expected amperage. This condition in the gland exhauster persisted and control room operators and management decided to restrict the operation of the HPCI system. RPV pressure reductions, when required, were accomplished using one of the four SRVs. The HPCI system remained operable, although administratively restricted from operation.

The cause of this HPCI gland exhauster condition was the buildup of moisture in the casing of the HPCI gland exhauster. This condition most likely resulted from the cyclic operation of the HPCI system where moisture laden steam was carried over to the HPCI gland exhauster. A three minute time delay for the initiation of cooling water to the HPCI gland seal condenser, installed to help maintain the integrity of the HPCI turbine seals, may have contributed to the degradation of the HPCI gland exhauster. The configuration of the gland exhauster and associated piping makes the gland exhauster housing a collection point for condensate. Vermont Yankee had previously noted water build-up in the HPCI gland exhauster in 1972 and in 1989.

RCIC

The RCIC system was started at approximately 3:37 p.m. on April 23 and operated in the RPV pressure and/or water level control modes. At approximately 5:16 p.m. on April 23, The RCIC system automatically shut down due to RPV water level exceeding the high level shut down setpoint. The high RPV water level resulted from RPV water level swell associated with opening of SRV "C". The high water level RCIC shut down signal was reset and the RCIC system was subsequently restarted at approximately 5:18 p.m. on April 23.

RCIC remained in operation until approximately 7:04 p.m. on April 23, when the RCIC turbine shut down automatically due to overspeed. The RCIC system was being operated in the "MANUAL" mode prior to the RCIC automatic shut down and the control room operator was attempting to switch from the "MANUAL" operating mode to the "AUTO" operating mode. In the "MANUAL" mode of operation, operators determined that RPV water level could be more closely controlled. In the "MANUAL" mode, turbine speed is controlled and flow rate varies in response to RPV pressure. In the "AUTO" mode, RCIC turbine speed is varied to maintain a constant flow rate as specified on the RCIC flow controller setpoint tape.

During the switch from the "MANUAL" operating mode to the "AUTO" operating mode, control room operators must ensure that the difference between the "MANUAL' signal and the "AUTO/BALANCE" signal is approximately zero. A deviation meter is provided on the RCIC flow controller to aid the control room operator. Maintaining the deviation near zero helps preclude abrupt turbine speed and flow changes when switching operating modes.

Vermont Yankee determined that the control room operator failed to properly reduce the deviation prior to attempting to transfer from the "MANUAL" to the "AUTO" operating mode. Vermont Yankee determined that the deviation signal present at the time of the operating mode transfer was significant and resulted in an overspeed trip of the RCIC turbine.

The RCIC overspeed trip was manually reset locally at the RCIC turbine, and the RCIC system was restarted at approximately 7:12 p.m. on April 23. The RCIC system remained in operation until the main condenser was established as a heat sink and a reactor feedwater pump was injecting water into the RPV. The RCIC system remained in operation until approximately 1:46 p.m. on April 24 when the system was manually shut down.

4.2.1.3 Corrective Actions

HPCI

A Maintenance Request (MR 91-927) was generated to troubleshoot and correct the cause of the binding/high amperage/tripping of the HPCI gland exhauster. The fan motor was energized with water still in the casing, and an amperage reading indicated the fan was drawing approximately 17 amperes. The full load design amperage of the fan is 7.4

amperes. Vermont Yankee maintenance personnel drained water (approximately one gallon) from the housing of the HPCI gland exhauster. Post maintenance testing verified that the motor was operating at less than full load amperage (6.2 amperes) and determined that several HPCI gland seal exhaust fan motor (FN-2-1A) vibration measurements were in the ALERT range. The fan motor was meggered satisfactorily and a visual inspection of the commutator, brushes and connection box identified no discrepancies.

A Temporary Modification (TM 91-025) was developed, approved by PORC, and implemented. This mechanical modification installed drain tubing on the HPCI turbine gland seal exhauster. The drain tubing contained a loop seal and drained to a container on the HPCI room floor. The purpose of the drain tube was to provide a drain path for condensate from the gland seal exhauster housing. Any condensate should continuously drain from the gland exhauster housing to the container, thus preventing buildup of condensate in the gland exhauster housing and precluding an associated high amperage condition. On April 26, the Maintenance Department requested that the Engineering organization prepare a permanent design change to the HPCI gland seal exhauster for the permanent addition of a drain for removal of water that could become trapped in the lower section of the housing.

A similar temporary modification was previously installed to prevent condensate buildup in the gland exhauster due to HPCI-14 valve leak-by. Maintenance request 89-2010 removed and rebuilt the HPCI gland seal exhauster and the temporary modification was removed and determined to no longer be needed because HPCI-14 had been repaired.

RCIC

The RCIC system operated as designed during the Unusual Event. The automatic shut down of the RCIC system due to RPV high water level appeared to result from, at least in part, improper system coordination during the manual shut down of the HPCI system and the manual start-up of the RCIC system. Immediate corrective actions which reset the high water level RCIC shut down signal and restarted the RCIC system were appropriate.

Immediate corrective actions associated with the RCIC overspeed turbine shut down appeared appropriate. The RCIC overspeed shut down trip was reset and the RCIC system was subsequently restarted. Vermont Yankee identified a long term corrective action to provide operators with additional training in the proper methods of operation of both the RCIC and HPCI system controllers, especially when transferring between operational control modes.

4.2.2 Torus Water Volume Control / Liquid Radwaste System

4.2.2.1 Performance Considerations During the Event

The torus water volume exceeded the maximum volume specified in the plant Technical Specifications (TS) at approximately 3:33 p.m. on April 23. Water was transferred from the torus to radwaste system processing tanks and the water volume in the torus reduced below the maximum TS volume at approximately 3:51 p.m. on April 23. The torus water volume again exceeded the plant TS maximum at approximately 9:12 p.m. on April 23. Torus water was transferred to the radwaste system. However, the inventory of liquid radwaste and the rate of radwaste processing restricted the amount of torus water transfer. After considering alternatives for reducing torus water level, plant management decided to maintain level above the maximum specified in the plant TS. At approximately 7:25 p.m. on April 24, torus water volume was reduced below the maximum specified in the plant TS.

The Vermont Yankee TS establishes minimum and maximum torus water volumes whenever primary containment is required. The maximum torus water volume specified in the TS is 70,000 cubic feet. If torus water volume can not be maintained below 70,000 cubic feet, then a reactor shut down must be initiated immediately and the reactor must be placed in a cold shut down condition within 24 hours. The maximum torus water volume attained during the Unusual Event was approximately 72,000 cubic feet. During this Unusual Event, the TS Action statement was exited prior to reaching the action statement time limit.

Emergency procedure OE 3104, "Torus Temperature and Level Control Procedure," was designed to maintain primary containment integrity and protect primary containment equipment. Procedure OE 3104 was entered when torus water volume exceeded 70,000 cubic feet. This procedure directs the operator to reduce torus water volume using the RHR system, the HPCI system or the RCIC system. In the case of the RHR system, torus water is transferred to the radwaste system for processing. In the cases of the HPCI and the RCIC system, unfiltered torus water is transferred to the condensate storage tank (CST). If torus water level can be maintained in the safe region of the OE-3104 SRV Tail Pipe Level Limit Curve, no further actions are taken within OE 3104 with the exception of continuing the torus water volume reduction until volume is reduced below the 70,000 cubic feet limit.

The SRV Tail Pipe Level Limit is defined to be the highest torus water level at which opening an SRV will not result in exceeding the capability of the SRV tail pipe, tail pipe supports, quencher, or quencher supports. This water level is a function of RPV pressure, and the limit is utilized to preclude SRV system damage and primary containment failure. The minimum torus water level defined on the SRV Tail Pipe Level Limit Curve is approximately 16 feet. This torus water level corresponds to a volume of approximately 112,000 cubic feet.

For this event, the RHR system was the preferred torus water volume reduction system. Vermont Yankee determined that a rapid reduction in Torus water volume below 70,000 cubic feet was not required and the use of filtration, processing, and sampling features associated with RHR system torus water volume reduction were prudent and conservative. This determination was based on a perceived lower probability for a Loss of Coolant Accident (LOCA), a heat generation rate below that assumed in FSAR accident analyses, known and controllable sources of water causing the torus water volume increase, and the slow increase in torus water volume. A more detailed explanation of Vermont Yankee torus water volume considerations during the Unusual Event are described in an excerpt from the Vermont Yankee Post Trip Report contained in Appendix F to this report.

The radwaste system receives electrical power from non-vital busses. Consequently, the processing capability of the radwaste system was severely restricted until shortly after restoration of power to non-vital buses 1 and 2, approximately 4.5 hours after the declaration of the Unusual Event. Radwaste inventory rapidly increased during the first 4.5 hours of the event and remained near the radwaste system maximum capacity until after the termination of the Unusual Event. Radwaste electrical equipment functioned as expected following restoration of electrical power. The backwashing, precoating, and decanting of radwaste system filters and demineralizers, following the restoration of electrical power, resulted in additional liquid radwaste processing delays.

Vermont Yankee developed a detailed Sequence of Events to describe radwaste operation during the Unusual Event. The radwaste Sequence of Events was developed from the Operating Log, the Radwaste Log, radwaste parameter recorder plots and discussions with Vermont Yankee Operations Department personnel. Based on this sequence of events, most water transfers from the torus were directed to either the waste collector tank or the waste surge tank. The use of these tanks was preferred over the floor drain collector tank to ensure adequate volume remained in the floor drain collector tank to accept sump discharges. In addition the processing flow rate through the waste collector filter and the waste collector demineralizer was determined to be less than the processing flowrate through the two fuel pool demineralizers. Consequently, the two fuel pool demineralizers were the preferred filtration medium.

4.2.2.2 Assessment of Performance

Plant management and operator responses to the high torus water volume were appropriate. Decisions regarding torus high water volume and operation of the radwaste system appeared timely, considered the impact on plant safety, and prioritized processing operations. Based on the information provided by Vermont Yankee, all radwaste system equipment functioned as expected after offsite power was restored. No significant radwaste equipment degradations were noted following restoration of power. The delays in radwaste processing associated with backwashing, precoating, and decanting, and other required system operational requirements did not appear to be excessive.

4.2.3 Service Water System

4.2.3.1 Service Water System Description

The Vermont Yankee service water (SW) system (Figures C14 and C15) normally supplies cooling water from the Connecticut River (Vernon Pond) to the reactor and turbine building auxiliary equipment, and also provides cooling for normal reactor shut down and miscellaneous plant heat loads. The system consists of two independent cross-connected supply headers which remain in continuous operation during all plant operating modes. Both system trains conduct waste heat to a common discharge header which normally empties directly into the main condenser circulating water returning to the river. Four vertical, two-stage SW pumps, each rated at 3350 gpm, supply all station SW needs. As specified in the VY FSAR, at least three SW pumps would be required to operate under normal plant conditions if the inlet river water were to reach a temperature of 95°F. Both SW headers supply cooling to two reactor building component cooling water (RBCCW) heat exchangers (HXs), various reactor building room coolers (RRUs), two recirculation motor-generator lube oil coolers, two turbine building component cooling water (TBCCW) heat exchangers, various turbine building room coolers, and other main turbine generator coolers. Four residual heat removal service water (RHRSW) pumps supplying the RHR heat exchangers provide shut down cooling capability (one pump minimum required). These pumps remain in an idle condition during all normal plant operations except shut down.

The SW system was also designed to provide an inexhaustible source of cooling for vital systems and components required to mitigate severe transient or accident conditions and to achieve a safe plant shut down. For these functions, SW provides cooling to the two emergency diesel generators (EDGs), two station air compressors, the RBCCW and TBCCW heat exchangers; and the RHRSW pumps supply cooling to standby ECCS equipment through the RHR heat exchangers. The SW system can supply makeup water to the RHR system, and is also capable of supplying emergency fill to the main condenser hotwell for injection to the reactor via the feedwater system. After a loss of offsite power (LOOP), two SW pumps and two RHRSW pumps are powered from the emergency buses to maintain SW flow to the EDGs, two station air compressors, the RHR heat exchangers, reactor building RRUs, and other vital coolers. In the event of a LOOP concurrent with a LOCA, two SW pumps on EDG power can supply the necessary cooling flow. One RHRSW pump can provide the minimum flow necessary for RHR shut down cooling. Non-vital heat loads in the reactor and turbine buildings can be isolated from the system by operators in the control room. In the event that a total loss of river water disables the SW pumps, the system can be reconfigured to operate in a recirculation mode between the RHRSW pumps and one of the station's cooling towers (ultimate heat sink).

Approximately four years ago (1987), the SW system discharge header was realigned to bypass the condenser and redirect outlet flow to the station cooling towers. This realignment allowed for a constant makeup supply to the tower basin; it provided de-icing for the towers during winter months; it helped to stabilize erratic performance in the SW radiation monitor

located at the discharge header; and it was expected to reduce the effects on the system from potential water hammer events. This lineup did not strictly conform to the normal flow path described by the FSAR. Since the discharge flow can be realigned only by manual valve manipulations, the system continued to discharge to the cooling towers during this LOOP event.

4.2.3.2 Performance Considerations During the Event

Within 8 seconds following loss of normal voltage on the 4160 volt safety buses 3 and 4, both diesels started and came up to full speed as required (≤13 seconds). Since SW bypasses the EDGs when they are in an idle condition, the SW flow control valves (FCVs) opened to permit inlet flow as soon as the diesels approached full speed. No indications of abnormal EDG performance were observed by station operators who monitored them on approximately ten occasions during the LOOP event. However, no SW performance data was recorded until normal offsite power was restored just before the EDGs were shut down. During the event, the EDGs were each at approximately 33% of their rated load (2750 kW continuous), and the river water inlet temperature was at approximately 48°F. Just before the diesels were shut down, the SW flow rate was observed to be above the assumed minimum required for adequate cooling. According to a recent YNSD analysis, the limiting conditions for adequate EDG cooling was 190 gpm with EDGs stretched to full load, and river water inlet temperature at 85°F. This analysis was based upon the calculated heat rejection rate for a fully loaded diesel, and the calculated mass flow rate through the engine coolers (based upon the observed pressure drop). The diesel manufacturer recommends that 700 gpm should be maintained at rated load with the SW inlet temperature at 95°F.

The SW discharge piping near the air compressors experienced pressures over 80 psig during the LOOP event. This unusually high backpressure significantly reduced flows through both the EDGs and the station air compressors. Apparently, the high backpressure also caused the self regulating pressure control valves (PCVs) to throttle down and further reduce inlet flow to both the EDGs and had completely blocked normal flow to both the air compressors. The EDG flow control valves (FCVs) apparently responded normally by attempting to regulate SW flow at 700 gpm through the diesels (Figure C16). The FCVs would have fully opened on demand from the upstream controllers - their orifices sensing the inadequate inlet flow. Under the high backpressure conditions flow was reduced to 32% (255 gpm) in the "A" diesel and to 42% (336 gpm) in the "B" diesel. Each diesel engine has three internal systems linked to SW through the turbocharger after cooler, the lube oil cooler, and the water jacket cooler. All three coolers have internal controls which regulate on temperature to remove the necessary amount of engine heat to the SW system.

Although the EDGs operated continuously during the event, the "A" air compressor tripped out on high temperature after its upstream PCV closed from the high backpressure. The PCV for the "B" compressor also closed, however, the high pressure lifted its safety relief valve and caused SW to reverse flow through the compressor. This provided some limited amount of cooling which allowed the compressor to run. The "B" compressor eventually

tripped out on high motor current, but was returned to service after approximately five minutes when the SW backflow again provided sufficient cooling to allow the compressor motor to restart. The station air header pressure dropped to approximately 85 psig (100 psig normal) during this time when no compressors were available. Installation of a portable diesel powered air compressor was completed shortly thereafter, which helped supply station air needs.

No signs of adverse performance in other plant equipment cooled by SW (e.g., RRUs, RBCCW HXs, RHR HXs) were observed by the station operators monitoring them during the event. Normal operator logs were taken each shift; however, no additional performance data was recorded by the operators until after offsite power was restored to the plant. No concerns other than high SW flow resistances were later observed when post-event system testing simulated some of the conditions which existed during the event.

4.2.3.3 Evaluation of System Problems

Evaluation of SW system performance both during and after the LOOP event was partially based upon a known history of increased backpressure problems and decreased localized flow conditions in various components throughout the system. Station operators evaluated the system conditions during the event; however, the specific causes of high backpressure were not readily apparent. When the "A" compressor was lost, operators immediately requested that the portable diesel air compressor be installed. They recognized the high SW pressure when the safety relief valve lifted on the "B" air compressor. Since the portable compressor was not yet available, they returned the "B" compressor to service within about five minutes when reverse SW flow provided sufficient cooling. It was not apparent if reverse flow occurred in other flow paths through plant components (e.g., RRUs) during the event. The possibility of decreased flow through the RHR HXs was a concern to the operators; however, abnormal torus cooling was not apparent. Increased thermal loads on the torus from HPCI, RCIC and SRV operation were adequately removed through the RHR HXs and torus water temperature was not raised near the technical specification limit of 100°F. After entering into RHR shut down cooling, no adverse torus or RHR HX conditions were apparent. Operators returned SW to non-vital turbine building heat loads after approximately two hours into the LOOP event. This provided cooling to the TBCCW HXs since they anticipated entering the main condenser cooling mode upon return of offsite power to the non-safety buses.

Operators monitoring EDG performance during the event focused mainly upon primary engine and generator parameters such as cylinder head temperatures, lube oil and water jacket temperatures, and generator output. SW flow was noted to be lower than normal; however, this did not appear to be a significant concern since the engines were not overheating and the generator output was steady. Operators stated that no EDG alarms were present in the control room during the event, and with other primary indications normal, they did not observe any degradation in diesel performance. The following data indicates the observed EDG parameters at shut down versus alarm and shut down setpoints:

	EDG-A	EDG-B	Alarm	Shut down
Stator Amps	300A	280A	640A	740A
L.O. Temp - High	188°F	198°F	226°F	-
- Low	-	-	115°F	-
Water Jacket Temp - High	164°F	160°F	195°F	205°F
- Low	-	-	88°F	-
Water Jacket Pressure - Low	34 psig	33 psig	-	10 psig
Service Water Flow	32%	42%	-	-

Subsequent to the event, the SW engineering task force assembled at the plant to evaluate the performance of the SW system and to determine what actions would be necessary to assure that the system could be operated normally. A series of system tests were performed in various operating configurations in an effort to simulate some of the conditions observed during the event, and to develop sufficient corrective actions to demonstrate that the system could perform adequately under design basis conditions. System tests confirmed the existence of the high header pressure with various combinations of RHRSW pumps, EDGs, and air compressors running, with SW discharging to the cooling towers (valves SW-1 closed and SW-11 open). After some analyses, this group concluded that the high backpressure was caused by the increased overall system pressure and flow supplied by the operating RHRSW pumps, and the increased elevation head and flow resistance present in the SW discharge piping to the cooling towers. The same tests were performed with SW-1 open and SW-11 closed (discharging directly to the river), and this resulted in a three to fourfold reduction in the SW discharge header pressure (10-15psig). Redirecting the discharge path in this manner represented a net decrease of approximately 670 feet of SW piping and a net loss of approximately 25 feet of elevation head. These tests also demonstrated that SW flow to the "A" EDG increased to approximately 74 - 85% (592 - 680 gpm). Additional testing was conducted in this configuration with various operating equipment combinations to confirm that normal operation and design service requirements could be fulfilled. The task force concluded that the discharge lineup should be permanently changed to this (pre-1987) configuration. The licensee may also consider throttling valves on the SW outlet of the RBCCW HXs.

The task force expressed some concern that the low header pressures could adversely affect the thermal performance of the RBCCW HXs due to the relatively high elevation of their discharge pipes and the potential for internal void formation when SW temperatures were elevated. Tests performed with valve SW-1 repositioned to 80% open indicated that throttling could help alleviate this condition by slightly increasing backpressure while permitting an insignificant overall reduction in SW discharge flow. This was not currently expected to be necessary, but further investigations will be performed by the licensee.

4.2.3.4 Short Term Corrective Actions

After the return of normal offsite power and the initiation of normal shut down cooling, the SW task force performed tests and analyzed SW flow conditions present during the LOOP event. Their principle tasks were to simulate the SW symptoms present during the LOOP event to the extent possible, and to identify the specific causes of the high SW discharge header pressure. They also performed testing to ensure that system performance improved when discharging to the river with the cooling tower isolated. They issued a test summary report to the VY Plant Operations Review Committee (PORC) which provided the significant conclusions from system testing. They plan to issue a formal SW test report at a later date.

After system testing was completed, the first pre startup corrective action taken by the licensee was to revise operating procedure OP-2181, "Service Water/Alternate Cooling Operating Procedure," to require that the normal SW discharge valve lineup would keep valves SW-1 fully open and SW-11 fully closed. The Plant Operations Department provided additional assurance that the complete system configuration was known and correct for operation after testing and after changes were made in the SW discharge path. Rebalancing of flows in the system was identified as important; however, this was deferred to a later time.

The adequacy of the licensee's pre-startup corrective actions was based on the fact that a prior LOOP event occurred with this lineup without significant SW problems. Furthermore, the plant operated for approximately 17 years in this configuration, and the post event tests demonstrated that SW performance improved significantly.

The SW task force investigated the potential for water hammer in the system with valve SW-1 open, since this was one consideration leading to the SW configuration change in 1987. Concerns for the possibility of water hammer in the SW system were expressed during the original plant startup testing and during the 1972 LOOP event. The initial results of the SW tests conducted after the April 23, 1991 event indicated that the potential for water hammer is low if the system is operated properly. No operating procedure changes were considered necessary, however; the licensee intends to investigate the concern further at a later time.

The licensee investigated means to ensure that the SW radiation monitor would perform satisfactorily with the changed SW lineup. The adequacy of SW cooling of the radiation monitor was an important consideration leading to the 1987 SW configuration change. In the event that this monitor could not be made to operate stably and reliably, backup measures were prepared to obtain daily grab samples to satisfy radiation monitoring requirements.

The SW task force identified several post startup short term corrective actions for the SW system. One of the short term actions was the need to develop another means to de-ice the cooling tower deep basin during winter months since the service water discharge would now bypass the tower (SW-11 closed). Also, the need was identified to develop a method to provide a keep-fill source of water for the deep basin.

The task force determined that the maximum amount that valve SW-1 could be throttled would be 80% open. However, until further testing and review of the SW system is performed, the licensee will maintain valve SW-1 fully open under existing administrative and operational controls governing the required position of plant valves. In the event that RBCCW HX performance ever becomes a concern with high river temperatures and low SW discharge pressures, a "deviation valve lineup" with PORC approval would be required before valve SW-1 could be throttled below full open. A conclusion was reached by VY that this valve should not be throttled below the amount that was tested, and that throttling the RBCCW HX discharge valves should be considered first.

Long term corrective actions associated with the SW system that are under consideration by VY are discussed in Section 7.1.2.

5.0 HUMAN PERFORMANCE

5.1 Event Classification and Notification

The loss of offsite 345 KV and 115 kV power occurred at 2:48 p.m. on April 23. The operating crew Shift Supervisor declared an Unusual Event at 3:07 p.m. Notifications to the states of Vermont, New Hampshire and the Commonwealth of Massachusetts were completed by 3:17 p.m. and initial notification to the NRC was completed by 3:31 p.m. At 3:34 p.m. an RPS Low Water Level scram signal actuated RPS and PCIS logic. Concurrently, control room operators entered emergency procedure OE 3104 due to high torus water volume. At approximately 4:10 p.m., Vermont Yankee notified the NRC of an RPS Low Water Level scram actuation and informed the NRC that Vermont Yankee had entered and subsequently exited emergency procedure OE 3104 due to torus water volume exceeding the maximum Technical Specification value. At 9:12 p.m., control room operators received a RPS Low Water Level RPS scram and PCIS logic actuation due to low RPV water level. Also at 9:12 p.m., the operating crew Shift Supervisor determined that torus water volume was above the maximum value specified in the TS (70,000 cubic feet) and again entered emergency procedure OE-3104. At approximately 10:00 p.m., Vermont Yankee notified the NRC of the of the RPS and PCIS logic actuation. At approximately 10:25, Vermont Yankee notified the NRC that they had entered a Technical Specification action statement which required a shut down due to inability to maintain torus water volume below the maximum specified in the Technical Specifications. At approximately 7:50 p.m., on April 24, Vermont Yankee terminated the Unusual Event. State notifications regarding termination of the Unusual Event were completed by 8:05 p.m. The NRC was notified that the Unusual Event had been terminated at 8:17 p.m.

Vermont Yankee notifications to the NRC were communicated via the Emergency Notification System (ENS). In addition, Vermont Yankee plant management periodically briefed NRC regional and headquarters personnel, on a commercial telephone bridge, during the first six hours of the Unusual Event.

State notifications of the declaration of an Emergency Class (Unusual Event) were made within 15 minutes. In accordance with 10 CFR 50.72, licensees must notify the NRC immediately after notification of the appropriate State or local agencies and not later than one hour after the licensee declares one of the Emergency Classes. Vermont Yankee notified the NRC approximately 14 minutes after completion of the state notifications and within the one hour specified in 10 CFR 50.72.

In addition, 10 CFR 50.72 requires licensees to notify the NRC within four hours of any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESF), including the Reactor Protection System. The three actuations of the RPS were reported in accordance with 10 CFR 50.72. The low RPV water level signal which actuated the RPS logic also actuated PCIS logic. The PCIS is considered an ESF. These two ESF actuations were properly reported to the NRC; however, the PCIS actuation associated with the initiating event was not reported to the NRC.

With regard to the ability to maintain torus water volume below the maximum specified in Technical Specifications, Vermont Yankee determined that each time the water volume in the torus exceeded the maximum specified in Technical Specifications (TS) an TS action statement requiring immediate reactor shut down and to be in cold shut down within 24 hours applied. Vermont Yankee also determined that the 10 CFR 50.72 one hour reporting requirements for the initiation of any shut down required by the plant's TS applied. Furthermore, Vermont Yankee determined that these TS required shut downs met the requirements specified in procedure AP 3125, "Emergency Plan Classification and Action Level Scheme," for an additional Unusual Event entry condition.

The torus water level initially exceeded the maximum specified in TS at approximately 3:33 p.m. on April 23. An emergency procedure was entered and subsequently exited approximately 18 minutes later when torus water volume was brought below the maximum volume. Vermont Yankee notified the NRC of entry into the emergency procedure for high torus volume, but did not specify their determination of a TS required shut down or of an additional entry condition for an Unusual Event.

Torus water level again exceeded the maximum specified in TS at approximately 9:12 p.m. on April 23. Vermont Yankee decided to keep torus water level above the maximum level. Based on the Vermont Yankee reportability determination, this occurrence required an additional 10 CFR 50.72 one hour report. This event was reported to the NRC at approximately 10:25 p.m. and exceeded the one hour reporting time specified in 10 CFR 50.72. Vermont Yankee again determined that the TS required shut down met the requirements for an additional Unusual Event entry condition; however, the additional Unusual Entry condition was not reported to the NRC.

10 CFR 50.72 (c) "Followup notification," requires that any further degradation in the level of safety of the plant or other worsening plant condition be immediately reported. Plant management kept the NRC informed of all significant changes in plant condition; however, information concerning Emergency Class entry conditions for the torus high water volume was not adequately characterized. NRC management was unaware that Vermont Yankee had an additional entry condition for an Unusual Event.

In general, Vermont Yankee notifications and briefings kept NRC management adequately aware of changing plant conditions and provided sufficient technical detail for independent NRC safety assessment. Vermont Yankee completed a critical self-assessment of event reportability associated with the Unusual Event and identified appropriate corrective actions to help ensure information communicated to the NRC is complete, timely, and adequately characterized. The event reportability discrepancies are an unresoved item (UNR 50-271/91-13-07).

5.2 Operator Actions

Based on control room operator interviews, review of the Vermont Yankee Post Trip Report, and plant management interviews, the inspector determined that operator performance during the event was good. The event started during an operating crew shift turnover and the excess man power expedited some immediate corrective and restoration operations. One operator error was noted which resulted in an overspeed trip of the RCIC turbine. The overspeed trip of the RCIC turbine was previously discussed in Section 4.2.1.2.

The inspectors "walked through" the emergency and off-normal procedures used during the event with the Supervisory Control Room Operator. Operational assessments appeared to adequately characterize emergency or off-normal situations during the event and the appropriate procedure was effectively implemented. Actions taken by control room and auxiliary operators appeared timely and appropriate. Conservative and cautious operator decisions expedited the installation of the diesel air compressor.

5.3 Emergency Plan Implementation

Vermont Yankee procedure AP 3125, "Emergency Plan Classification and Action Level Scheme," provides a mechanism for classifying off-normal events and plant conditions into one of the four emergency classifications described in the Vermont Yankee Nuclear Power Station Emergency Plan. Vermont Yankee procedure OP 3500, "Unusual Event," outlines the actions required of plant personnel, visitors, and contractors when an Unusual Event is declared.

Vermont Yankee defines an Unusual Event as an event in progress or which has occurred which involves potential degradation of plant safety margins, which is not likely to affect personnel on-site or the public off-site or result in radioactive releases requiring off-site monitoring. The initial responsibility and authority for classifying the level of emergency is assigned to the duty operating crew Shift Supervisor. Subsequent escalation or de-escalation of the emergency classification is the responsibility of the senior Vermont Yankee manager who assumes the overall supervision of the emergency response organization.

The operating crew Shift Supervisor declared an Unusual Event at 3:07 p.m. on April 23, due to zero voltage indication on the 345 kV and 115 kV electrical distribution buses. This emergency classification was in accordance with the procedural emergency classification guidelines. The Primary and Secondary Duty Call Officers (DCOs) were on-site and responded to the Control Room. The DCOs assume the roles of Technical Support Center (TSC) Coordinator and Emergency Operations Facility (EOF) Coordinator, as necessary. For this event neither the TSC or EOF were required to be manned. The DCOs assumed responsibility for managing the event and ensuring event information was communicated to the appropriate person or persons. The Plant Manager was on-site, actively involved in the event, and remained the primary management point of contact for NRC management event briefings. The Vermont Yankee Senior Vice President, Operations initially reported to the site.

State notifications were completed within 15 minutes from the declaration of the Unusual Event. Subsequently, the NRC was notified within one hour. When torus water volume first exceeded the maximum volume specified in the plant Technical Specifications, plant personnel did not appear to completely understand how to assess and classify this off-normal condition. Later, when Torus water volume exceeded the maximum level approximately 6 hours into the Unusual Event, the DCO clearly determined that an additional entry condition for an Unusual Event existed. The reportability relating to Torus water volume exceeding the maximum was previously discussed in Section 5.1.

The Unusual Event was terminated at 7:50 p.m. on April 24. State notifications regarding termination of the Unusual Event were completed within 15 minutes and the NRC was similarly notified within 30 minutes.

The Vermont Yankee Emergency Plan was effectively implemented. Notifications to the States and to the NRC regarding declaration and termination of the Unusual Event were accurate and timely. A press release was issued and Vermont Yankee corporate communications demonstrated their capability to respond appropriately to the Unusual Event. The emergency personnel call-in procedure was appropriately implemented; however immediate offsite resources were not required. The TSC, EOF, or Operational Support Center (OSC), were not required to be manned. Adequate technical and operational assistance was available on-site and, although the TSC was not formally manned, plant management characterized plant personnel response as "in the TSC mode." An open, continuous communication channel was not required by the NRC, however plant management provide periodic event status briefings to senior NRC management during the initial 6 hours of the Unusual Event.

5.4 Management Activities

Corporate management was actively involved and provided oversight and organizational interface support. The Senior Vice President, Operations was on-site shortly after the initiation of the event. Corporate communications and emergency preparedness support was readily available.

The Plant Manager and the Duty Call Officers (DCOs) assumed immediate responsibility for managing the Unusual Event. The DCOs immediately responded to the control room to perform their duties. The Operations Supervisor was the Primary DCO. When the Operations Supervisor became involved in the oversight of control room activities, the Secondary DCO (the Technical Services Superintendent) appropriately assumed responsibility for direction of activities of the emergency response personnel. The DCOs provided an appropriate level of management oversight and provided a communication and information interface with the Plant Manager.

Plant management decisions during the Unusual Event were conservative. In general, these decisions reflected a deliberate safety perspective which adequately considered both short and long term plant safety. For example, plant management decided to restrict the operation of the HPCI system due to degradation of the HPCI gland exhauster. Other methods for controlling RPV water level and pressure were available and the long term radiological and maintenance consequences of operating the HPCI system without the gland exhauster outweighed any short term consideration.

Plant management decisions regarding actions taken to reduce torus water volume below the maximum specified in the plant Technical Specifications also adequately considered both short and long term plant safety. Plant management considered several options to reduce the inventory of water in the torus including transferring torus water to the condensate storage

tank, and draining torus water to the radwaste floor. The long term effects on reactor plant chemistry, primary plant component corrosion, and the resultant increased potential for fuel failures outweighed the short term safety benefit. Similarly, Vermont Yankee did not drain radwaste to the radwaste floor and management determined that this practice would have significant and unnecessary long term radiological consequences.

Plant management decisions during the Unusual Event benefitted from department supervisors' input. Meetings were periodically conducted to update department representatives, prioritize plant and site recovery activities, and resolve problem or conflict areas.

Plant management determined that some problem areas were encountered during the Unusual Event. Specifically, command and control of initial switchyard maintenance activities were poor. In response to this determination, plant management established a single point of contact for switchyard maintenance activities. Several weaknesses in completing the delay power backfeed operation were also noted by plant management. Communication weaknesses with the operational power supply control authority (REMVEC) contributed to the delay associated with the backfeed operation.

Plant management effectively implemented the Vermont Yankee Emergency Plan, actively provided oversight of event related plant and switchyard activities, and consistently demonstrated an adequate safety perspective.

5.5 Related Safeguards and Fire Protection Activities

Safeguards

Security personnel responded appropriately to the loss of 345 kV and 115 kV offsite power. Alternate power supplies to security equipment functioned as expected during this Unusual Event. Based on information contained in security logs, compensatory measures for posting of vital areas were established in the required time. The security computer was off-line for approximately 12 minutes and a subsequent access door operability test was completed satisfactorily. The intrusion detection system remained operable throughout the event and no security intrusion alarm occurred during the Unusual Event. Proper security compensatory measures were implemented as necessary.

The Security Shift Supervisor is assigned responsibility for implementing the emergency call-in, notifying outside law enforcement, as necessary, and notifying the New England Power Hydro Station in Vernon, VT. These actions were completed. The plant switchboard remained manned for several hours after the declaration of the Unusual Event. Consequently, information transfer and routing of calls were handled by Vermont Yankee personnel.

Fire Protection

The fire protection suppression and detection systems remained operable during the Unusual Event. The fire protection detection systems have power supplied from a battery back-up. The firemain remained pressurized from the service water system. No fire protection related alarms occurred during the Unusual Event.

The diesel fire pump was declared inoperable for LCO-maintenance. A post maintenance test run was completed directly prior to the event; however additional testing of the diesel fire pump was required. The diesel fire pump remained inoperable during the event and would not have automatically started if service water pressure dropped below the starting setpoint of approximately 75 psig. In an emergency situation, the diesel fire pump could have been manually started and operated for an undetermined period of time. The electric fire pump was available and did automatically start when service water pressure to the firemain dropped below the starting setpoint of approximately 85 psig.

One conservative fire protection compensatory measure was implemented during the Unusual Event. A sealing material in the pitch pocket below the EDG muffler had been recently replaced and had not completely cured. The sealing material, when not cured, was considered flammable. A firewatch was posted on the roof of the diesel generator room to monitor this sealing material.

5.6 Use of Support Organizations and Personnel

The Maintenance Department was responsible for all switchyard activities and restoration of offsite power. This included coordination of subcontractors, vendors and other organizations associated with the yards. The yard recovery team consisted of experienced personnel from maintenance, VY corporate offices, and YNSD. The personnel had the necessary knowledge to review the event activities. This was reflected in their root cause analysis and their PORC presentation of the electrical issues related to this event. The recovery team addressed concerns raised by management. Follow-up activities, post-trip troubleshooting and testing were adequately planned and performed. Comprehensive long term and short term corrective actions programs were developed. A number of short term corrective actions were implemented or were well under way prior to restart of the plant.

During the LOOP event, plant operators faced challenges in analyzing SW system behavior and understanding the potential impact of abnormal SW performance upon plant equipment in the effort to proceed toward a normal cooldown. Continuous and direct management involvement was a key element in correctly assessing plant conditions, establishing department priorities, and coordinating the activities of station personnel. Communications between the operations and maintenance departments, management, and other support organizations appeared, for the most part, to work effectively in dealing with SW problems. One of the more significant concerns related to the performance of the SW system during the event was the loss of one station air compressor, and reverse cooling flow through the only

other compressor available. Very soon after the first compressor was lost, assistance from plant support organizations became necessary to retrieve the portable diesel air compressor from storage, to transport it to a suitable location for installation, and to provide the necessary hookups to put it into service. Although the entire process took approximately two hours, the portable compressor was moved, prepared, and put into service without significant delay or coordination problems. The equipment needed to perform this task was available on-site. Most of the time to place the compressor in service was involved in moving the equipment pallet. The importance of placing the portable compressor into service increased significantly when the "B" station air compressor was shut down, and no source of air was available. However, the "B" compressor was returned to service in about five minutes and the portable compressor installation was completed approximately 15 minutes thereafter.

After offsite power was restored, the plant proceeded toward normal cooldown, the EDGs were shut down, two additional station air compressors became available, and the need for site support organizations to deal with SW concerns was greatly reduced. However, the need to analyze and evaluate the abnormal SW symptoms soon became a significant concern which required resolution prior to restart of the plant. Consequently, a SW engineering task force team was assembled at the site to perform operational tests, evaluate the performance of the SW system, and determine what actions would be necessary to demonstrate that it could operate under all design conditions. The appropriate level of design cognizant engineering personnel were placed under the direction of the VY Corporate Engineering Vice President to manage these tasks. The primary team consisted of a corporate principal engineer, a mechanical engineering and construction supervisor, a plant operations engineer, a YNSD engineering manager for VY, and a YNSD senior engineer. Most of these individuals had prior experience analyzing and resolving SW problems at Vermont Yankee. This group interfaced directly with the plant Operations Department and station management in the efforts to conduct the system testing, and to gain additional insight into system performance. Operations personnel directly supported the system test activities and assisted in interpreting the results.

Operations personnel expressed their concerns about the potential for degraded RBCCW heat exchanger performance and for water hammer in the SW system. These required analysis and recommendations for system operation from the task force. Although these concerns had not been well documented over the history of plant operations, the test group provided recommendations for operators to monitor SW performance and to avoid increasing the possibility of these conditions occurring.

The task force made several presentations to the Plant Operations Review Committee (PORC) to request approval for temporary plant modifications to install test equipment, to review the results of tests and analysis, and to approve recommendations for changing the SW discharge path. Findings and recommendations of the group were submitted for PORC approval in a summary report with short and long term corrective actions identified.

One proposed corrective action involves continuation of the task force activities by the YNSD

and VY Corporate Engineering groups. The hydraulic model for the SW system will require further development and refinement based upon results of the system tests. This effort will be ongoing in support of additional system analysis.

5.7 Work on the Switchyard DC Control Power System

5.7.1 Work Leading to the Event

Recent maintenance work in the switchyard relay house which was directly related to this event, for the most part involved preventive maintenance, testing, and replacement of the switchyard DC control batteries 4A and 5A. The large transformers and breakers in the switchyard have been subjected to various preventive and corrective maintenance work, and to post maintenance testing over recent years; however, activities outside the DC control/relay house apparently had no direct effect upon the factors leading to this event. The DC control power battery chargers have not been a part of any regular preventive maintenance or testing program, and the limited inspections which were performed on them were not well controlled or documented. The lack of formal inspections and preventive maintenance on these chargers contributed directly to this event due to the physical condition of components within them.

Weekly and quarterly surveillance tests were performed on the 4A and 5A batteries in accordance with the PORC approved station procedure OP-4210, "Maintenance and Surveillance of Lead Acid Storage Batteries". These tests include checks of specific gravity, individual cell voltages, temperatures, and terminal resistances. The procedure is also used to perform annual battery maintenance, and to perform a capacity discharge test. These regular inspections of the batteries have enabled the Maintenance Department to assess their general condition, and to determine when corrective maintenance or replacement was necessary. No significant corrective maintenance of the batteries has been considered necessary during the past several years. The treatment of excessive external corrosion was required for the 4A batteries in 1988, and cell connector maintenance was required in 1991. The 5A batteries were replaced in 1983 and have required very little maintenance since then. However, surveillance tests conducted on the 5A batteries in late 1989 indicated that the specific gravity of the electrolyte in several cells was at or below the limit. The Maintenance Department initiated preparations to conduct a full capacity discharge test to reconstitute the electrolyte and to restore its specific gravity above the lower limit. At approximately the same time, the condition of the 4A battery appeared to be approaching its end of life, and the decision was made to replace the entire battery bank.

To conduct the 5A battery discharge test and the 4A battery replacement, while the plant was at power, the maintenance department developed special work instructions and prepared a temporary plant modification (TM 89-55) for the DC control system (reference Section 5.7.3.1). The TM was written to allow the mechanical interlock in the 4A-5A charger to be removed (Figure C3), permitting the 4A and 5A buses to be interconnected during maintenance on one battery. A formal safety evaluation was written and approved in

October 1989, since this modification deviated from the FSAR description of the system. The "Department Guidelines for Switchyard House Battery Systems" was prepared and issued in May 1990 when the 5A test was eventually scheduled. The guidelines provided detailed instructions for removing the battery from its bus and restoring it after maintenance was completed. Since the switchyard DC control system is not safety related, the maintenance guideline was not issued as a formal station procedure and consequently it did not require PORC approval. The 5A battery was removed from its bus in May 1990 to conduct a discharge test, after which it was fully recharged. The battery was reconnected to the 5A bus while it was still linked to the 4A bus through the 4A-5A charger. When the 4A-5A output breaker to the 4A bus was opened, the 5A bus was already afforded protection from the 5A battery. These steps were explicitly detailed in the guideline instructions.

Subsequent to the 5A battery test, the maintenance guideline was changed to include additional instructions for adjusting charger voltage before the battery was reconnected to the bus. It also altered the sequence of steps to require that the 4A and 5A buses be decoupled by opening the 4A-5A output breaker before reconnecting the battery. This change was made without a thorough review by the maintenance department management and without strict regard for the safety evaluation on the TM for the 4A-5A charger interlock.

In February 1991, replacement of the 4A battery and refurbishment of its support rack were scheduled by the Operations Planning Group based upon a request from the Maintenance Department. This work was reviewed under the recently developed "LCO Maintenance Program" guidelines as part of the planning process for maintenance conducted while the plant is at power. Both the operations and maintenance groups perceived this work to be essentially the same as the 5A battery test in 1990, since it required that the battery be removed from the bus in the same manner for the purpose of performing maintenance (ie., changeout). However, since the guidelines had been changed to disconnect the 4A-5A charger before reconnecting the new 4A battery to its bus, the 4A bus was left unprotected from voltage surges. When the 4A-5A output breaker was opened, the voltage spike that was generated was passed through the 4A bus relay circuits and the LOOP event was initiated. Based on the importance to safety of the associated activities with the reliability of the offsite power system, the adequacy of the VY maintenance procedure associated with the maintenance activities that led to the LOOP is an unresolved item (UNR 50-271/91-13-01).

7.2 Work at Full Power

For over a year, Vermont Yankee has been developing and implementing a program to conduct maintenance on Technical Specification equipment during power operations. This type of maintenance requires a voluntary and planned entry into a Technical Specifications limiting condition for operation (LCO) to perform preventive and corrective maintenance. The "LCO Maintenance Program" was developed for the purpose of increasing equipment and plant reliability, and reducing the overall length of maintenance outages. The program is administered by the Operations Department to ensure that the effects on other plant systems can be reviewed and that all Technical Specification requirements can be met. Preplanning is

coordinated by the operations planning coordinator who identifies all current maintenance, tests, and inspections which could be performed in the interest of reducing the overall time that the equipment or system would be inoperable. When possible, the activities are scheduled just prior to surveillance testing which could serve as a post maintenance test. The LCO maintenance planning process requires the planning coordinator to use an established checklist to ensure that the items mentioned above have been addressed, and to justify conduct of the activity while at power. The necessary management review and approvals are documented in the checklist. The control of LCO maintenance work is provided by station procedure AP-0125, "Plant Equipment Control." This procedure specifies the administrative guidelines for the removal of safety related or technical specification plant equipment to complete modifications, maintenance, or surveillance testing.

On April 10, 1991, the LCO checklist was completed for replacement of battery bank 4A in the switchyard relay house. The principal justification for performing this work at power was that the current number of corrective maintenance work requests would be reduced for the batteries and their racks. Approval of the battery changeout while at power was also supported by the (incorrect) assumption that this work was essentially the same as that performed on the 5A batteries approximately one year ago when the plant was also at 100% power (reference Section 5.7.1). The 5A battery work was performed before the LCO Maintenance Program was implemented. A maintenance department foreman and the operations planning coordinator provided the final approvals for the 4A battery work.

Subsequent to the LOOP event, the inspection team and the licensee conducted a review of the battery maintenance and the resulting problems generated in the switchyard DC control system. This review indicated that the probability of the initiating event producing the immediate results in the switchyard was not influenced by the power level of the plant. The same departments would have planned and performed this work in the switchyard if the plant had been shut down in a maintenance condition. Since the battery maintenance was identified and planned by the VY maintenance organization, this work would have also been conducted under the same department guidelines. There is no indication that the licensee's maintenance department would have been better able to support troubleshooting of switchyard equipment, or the restoration of offsite power had the plant already been shut down when this LOOP occurred. A LOOP would have likely resulted even if this event had occurred during shut down.

The specific path to restoration of the switchyard and offsite power would have depended upon the plant conditions prior to a LOOP. This event was complicated by the primary plant transients which occurred and the difficulties associated with no power being available to non-safety equipment. However, the electrical loads on the safety buses would have been essentially the same if the plant had been initially shut down. Restoration of the non-safety loads would still have depended on the return of offsite power.

VY management review of the LCO Maintenance Program identified a need to improve the level of administrative controls in the planning of maintenance activities which could have a significant effect on safe plant operation. The root causes behind this event indicated that inadequate controls within the Maintenance Department permitted the specific work instructions to be changed without proper regard for the original safety evaluation. The licensee suggested that this event demonstrated a need to upgrade the LCO maintenance checklist to a formal station procedure. The existing AP-0125 procedure appeared to be adequate for controlling LCO work in progress. However, a more formal procedure for planning LCO activities appeared to be warranted. This event might have been prevented if a formal review had verified that the maintenance work instructions were properly controlled under the conditions and requirements stipulated in the safety evaluation associated with the PORC approved temporary modification.

Station management concluded that the decision to perform this maintenance at power did not represent an overall problem with the LCO Maintenance Program. Maintenance work on the switchyard batteries had been successfully completed in the past with the plant at full power.

5.7.3 Use of Procedures and QA Practices

5.7.3.1 Maintenance Work Documents

Following plant startup in 1972, equipment in the Vermont Yankee switchyard was not considered to be "plant equipment." Consequently, formal work instructions were not used for maintenance activities in the yard, and complete records were not maintained. After the 1974 switchyard upgrade which added the 4A bus and relay circuits, the maintenance department required that all switchyard work fall under the same administrative controls as all other plant equipment. Station procedure AP-0021, "Maintenance Requests," requires that an individual Maintenance Request (MR) be utilized to fully document the authorizations and specific work activities performed on plant equipment. In addition, maintenance work on switchyard equipment required an engineering evaluation. Formal 10 CFR 50.59 safety evaluations were required for any modifications involving changes to the facility as described in the FSAR.

Preventive maintenance and surveillance testing of all class 1E and non-class 1E battery systems (e.g., the 125 VDC Main Station Batteries, the 125 V DC Switchyard Batteries, the 24 V DC ECCS Batteries, 430 V DC UPS Batteries, the 125 V DC Alternate Shut down Batteries, and the 250 V DC ERFIS Battery) are performed in accordance with procedure AP-4210, "Maintenance and Surveillance of Lead Acid Storage Batteries." This procedure is used to perform inspections and to record individual cell voltages, the level and specific gravity of the electrolyte, battery cell temperatures, and terminal resistances. It is also used to conduct periodic capacity discharge tests.

Since the temporary modification to remove the 4A-5A battery charger mechanical interlock was outside the FSAR description of the system, a 50.59 safety evaluation was prepared. PORC approval was obtained prior to implementing this modification. The engineering review for the evaluation acknowledged that a form of single failure protection was provided for this equipment by design. However, the evaluation stated that each bus would have a minimum of two chargers to supply adequate power and would have one battery between the two buses to smooth voltages on the buses resulting from battery charger ripple. It further stated that the two buses would be tied together by closing the four DC breakers associated with charger 4A-5A. This was to allow both buses to have a smooth power supply from the battery that would remain in service. The evaluation concluded that "all protective relaying and tripping functions would remain available to protect the switchyard and other electrical components." This evaluation was approved, in part, because the station Technical Specifications permitted one battery to be taken out of service. The intent of the Technical Specifications were apparently met since all system functions would be maintained.

Corrective maintenance work for class 1E electrical and battery systems is controlled by formal procedures which receive Maintenance Department management review. Procedures for this work may also receive Operations Department and PORC approval. However, non-class 1E systems have not required a formal station procedure for corrective maintenance. Consequently the maintenance guideline written for conducting the 5A battery discharge test and the 4A battery replacement did not receive a review by maintenance management, plant management, or PORC. The maintenance guidance was approved by an engineer in the Maintenance Department.

"Department Guidelines for Maintenance of Switchyard House Battery Systems" (Appendix F, Attachment 2) was issued by the Maintenance Department in May 1990 for work on the 5A battery discharge test. The preliminary discussions within the guidelines indicated that the opposite battery provided ripple smoothing and surge mitigation while one of the batteries was taken out of service. The guidelines contained a statement which cautioned technicians to monitor charger output and voltage while operating in parallel, adjusting DC output voltages as necessary to maintain proper battery float voltages and load sharing of the parallel chargers. The instructions which restored the battery to its bus first required closing the battery panel breaker to reconnect the battery to the bus. The sequence then opened the 4A-5A charger breaker, to bus 5A, to separate bus 4A from bus 5A.

The battery restoration sequence was altered when the guidelines were changed in June 1990 in preparation for the 4A battery replacement. The battery restoration sections were revised to include special instructions for readjusting charger voltages prior to reconnecting the battery if the battery had been removed to conduct a discharge test. The sequence for battery restoration was altered to require the 4A-5A charger output breaker to be opened before reconnecting the battery. This step did not conform to the initial assumption in the guidelines that both buses would always be protected by a battery.

The maintenance guideline was originally issued after a safety evaluation had been performed on the DC control equipment. This evaluation concluded that switchyard breaker protection was not degraded in the altered configuration since both buses would be always be connected to a battery to dampen voltage fluctuations. The revised version of the guidelines deviated from the 50.59 evaluation. The revised sequence was also contrary to the statements within the guideline which described the protective features provided for the buses. This issue is also discussed in Section 5.7.1 of this inspection report.

5.7.3.2 QA Practices

With the exception of five YNSD QA auditors located at the plant, the licensee does not have a separate quality control organization which monitors operations or maintenance activities. Instead, the licensee utilizes the "Peer Inspection" methods prescribed by ANSI N45.2.6, which is administered within each department under station procedure AP-6025, "Peer Inspection." Department supervisors specifically designate on a case basis which activities will receive "independent" peer inspections. These inspections are performed by department personnel qualified to a "Level II" as defined in the ANSI standard. The individuals must be skilled in the specific work tasks subjected to inspection, but not directly responsible for the work being performed. The peer inspection program at Vermont Yankee has been specifically limited to work on safety related systems and equipment. No independent inspection is performed on non-nuclear safety (NNS) equipment at VY because the licensee relies heavily upon the experience and proficiency of plant personnel to provide adequate quality control. Accordingly, independent inspection of work within the switchyard is not performed.

NRC Inspectors reviewed maintenance department logs kept on specific safety related work activities which have received peer inspections, and noted many occasions over recent years where inspections were performed on maintenance work required by procedure OP-4210, "Maintenance and Surveillance of Lead Acid Storage Batteries." Since maintenance and inspections of safety related batteries have been subjected to periodic peer inspections, maintenance personnel have developed quality work practices for those systems which are acceptable to their department supervisors.

Technicians performing the same OP-4210 activities on the switchyard 125 V DC batteries are expected to apply the same work practices used on all safety related batteries. Interviews with maintenance technicians, and reviews of the work in progress just prior to the LOOP event suggested that the specific work practices involved did not suffer from a lack of quality control in this case. Electricians and operators working in the switchyard relay house had apparently adhered to detailed work instructions in the maintenance guidelines, and had performed their work in the required sequence. The work which required technical proficiency largely involved balancing battery charger currents and adjusting charger voltages to match the bus and battery just prior to connecting or disconnecting the battery. The sequence of charger adjustments for the 4A bus had changed from the same adjustments on the 5A bus performed in 1990; however, these steps were clearly defined by the procedure.

The required breaker manipulations did not demand a high level of skill or proficiency. No abnormal system conditions were apparent to the technicians prior to opening the 4A-5A charger breaker. A walkdown of the relay house indicated that all electrical components were properly identified and that nomenclature labels matched the descriptions contained in the maintenance procedure.

The inspectors concluded that neither a lack of technical proficiency nor any degradation in work quality existed on the part of the technicians or the auxiliary operator; and that these did not play a role in the activities which lead up to the event. Although the electrical maintenance technicians and the auxiliary operator did not foresee the vulnerability of the 4A bus to voltages surges with the bus unprotected by its battery, this did not represent an unsatisfactory quality of work on their part.

YNSD auditors indicated they had previously suggested that QA audits of work in the switchyard would be beneficial to Vermont Yankee. However, audits were not performed because these battery systems are not safety related equipment.

5.7.4 Switchyard Operational and Maintenance Organizations

The 345 kV and the 115 kV switchyards located at Vermont Yankee were constructed between 1969 and 1971 and are the property of Vermont Yankee. Vermont Yankee has overall responsibility for maintenance of all switchyard equipment and determines the frequency, priority, and scope of switchyard maintenance activities. All contracted switchyard maintenance is coordinated through the Vermont Yankee Maintenance Department. The two 125 V DC switchyard battery systems are maintained by Vermont Yankee. The switchyard batteries are maintained similar to other Non-Nuclear Safety batteries; however, the switchyard battery chargers have not been included in a rigid testing program and were subjected to infrequent, cursory inspections. A Vermont Yankee Switchyard Organizational Responsibility Chart is provided as Figure C17.

Since 1972, switchyard maintenance has been contracted to the Vermont Electric Power Company (VELCO) who also owns or services transmission lines within the state of Vermont which originate from Vermont Yankee switchyards. VELCO has historically subcontracted Central Vermont Public Service Company (CVPS) for performance of certain maintenance activities. Vermont Yankee also contracts with New England Power Service Company (NEPSCO) for maintenance and testing of protective relay equipment and metering equipment in the 345 kV and 115 kV switchyards. Vermont Yankee contracts to NEPSCO and CVPS for transformer Doble testing. Yankee Nuclear Services Department (YNSD) provides engineering and technical support for switchyard maintenance activities. YNSD also performs some switchyard thermography.

Maintenance records for switchyard maintenance activities performed following plant start-up in 1972 were incomplete or not maintained. As the maintenance philosophy at Vermont Yankee evolved, Vermont Yankee required that all work performed in the yard be documented on a Maintenance Request. This allowed Vermont Yankee to control all work activities and maintain accurate records of switchyard work efforts. Currently, most switchyard equipment is treated as any other plant equipment and requires an engineering evaluation for selected activities, design documents for modifications, and 10 CFR 50.59 safety evaluation reviews for changes to the facility as described the Vermont Yankee Final Safety Analysis Report.

Operation of the bulk power supply system in New England, including the Vermont Yankee switchyard circuit breakers is the responsibility of the New England Power Exchange (NEPEX). NEPEX's authority extends to decisions, instructions, and orders for the day-to-day operation of 99 percent of all generation and transmission facilities in New England. Four satellite control centers control segments of the bulk power supply system. The Rhode Island, Eastern Massachusetts, and Vermont Energy Control satellite (REMVEC) is assigned operational responsibility for the Vermont Yankee switchyards. Vermont Yankee personnel routinely act as REMVEC switchmen for operation of these circuit breakers. Control of switchyard switching activities is coordinated through the Vermont Yankee control room.

6.0 SAFETY ASSESSMENT

6.1 Loss of Offsite Power

During the April 23, 1991 event, Vermont Yankee lost access to its preferred offsite power source for an extended period of time. Restoration of offsite power to the full capacity 345 kV power source took about 13 hours.

The Vermont Yankee Nuclear Power Station auxiliary AC system is designed to provide required AC power to operate emergency safeguards equipment under normal and accident conditions. Under normal operating conditions, power is provided from the main generator through the auxiliary transformer. Upon loss of the unit AC source, operation of primary and backup relaying initiates an automatic fast transfer of the load to the startup transformers. In the event of total loss of AC power, the emergency diesel generators start automatically within 13 seconds of the diesel start signal, and supply power to their respective engineered safety feature loads. In the event that one or both of the diesel generators is not available, the Vernon Hydroelectric station line is available to energize a safeguards bus.

During the current loss of offsite power event, both diesel generators started automatically and assumed their respective engineered safeguard loads within a 13 second time period. In addition, the Vernon hydroelectric line was available throughout the event. Offsite power was restored through the limited capacity Keene line within five hours. Full offsite power was restored from the 345 kV switchyard through the main transformer in approximately 13 hours. The AIT concluded that safety margins associated with the available AC power

sources were reduced during this event, in that the preferred offsite source of power was not immediately available after the main generator tripped. However, it is noted that a LOOP event is an analyzed event in the VY FSAR.

6.2 Service Water Problems

Problems were observed with the service water system, during the LOOP event at VY. These problems consisted of reduced or blocked flow to SW system heat loads. These problems resulted in the overheating of two air compressors and a significant reduction in the SW flow to the EDGs.

The licensee's assessment of EDG performance indicated that the diesels were not near their operating temperature limits with the reduced SW flow. Prior to the event, the licensee assumed that the minimum SW flow required for the diesels was 350 gpm with the river temperature at 85°F. During the event, control room operators received frequent information related to overall diesel performance; however, they did not use SW flow to the diesels as a key indication of possible adverse performance trends. The EDG power output was relatively constant, and they were not stressed near their full load. The existing SW flow was able to supply the required diesel cooling. The EDGs continued to provide the sole source of electrical power to the safety buses and there was no need to tie into the backup Vernon line. YNSD subsequently performed an analysis of the diesel's heat rejection rate at maximum load, and concluded that the minimum SW flow that would be required was 190 gpm with the SW inlet temperature at 85°F. Consequently, the EDGs were considered to have performed adequately, but the degraded SW conditions represented some loss of cooling margin. The licensee's analysis suggests that this flow would have been adequate under all accident conditions.

The importance of the station air compressors was recognized in the priority actions taken by the operators to maintain an air supply after the air compressors tripped. The station air system is not safety related and the system is not credited in the plant's accident analysis. However, a total loss of the air system could create problems in the control of plant systems, especially while at power, since the compressors supply air to the instrument air system. Instrument air is required for manipulation of significant plant valves, including the SW flow control valves for regulating cooling to the EDGs and the station air compressors. These valves fail open upon a loss of instrument air. Since the instrument air system is designed not to bleed down on loss of station air, the loss of both compressors for approximately five minutes during this event did not immediately affect operation of any of these valves. Return of the "B" compressor to service and installation of the portable diesel compressor precluded the disabling or loss of either air system.

The decision to change the SW discharge lineup in 1987 achieved several operational objectives in system performance. Primarily, it increased the reliability of the SW radiation monitor, and it provided a constant supply of water to the cooling tower for de-icing and keeping the deep basin full. Since this lineup would maintain a continuously full system, it appeared to reduce the possibility of a water hammer event and its potential effects. The system P&ID in the FSAR indicates that the normal valve lineup in the SW system keeps the cooling tower isolated from the system. The FSAR text indicates that the SW discharge is piped to the circulating water discharge where it is released to the river. The text also indicates that the cooling tower will not be in operation for normal service, but that warm service water would be discharged from the plant to keep the basin full and to prevent freezing. The FSAR does not imply that the SW system would continuously discharge full flow to the cooling tower; however, there is not an explicit prohibition against it. Nonetheless, the licensee did not perform a formal safety evaluation or conduct a system analysis to determine the effect of this change during abnormal plant conditions (eg., during a LOOP). SW flows were not significantly decreased during normal operation or surveillance tests when the RHRSW pumps were not in operation. Operation of the RHRSW pumps increased the overall system pressure. System testing to demonstrate the effects of the change in the system lineup was not performed since this would have required operating the EDGs, the RHRSW pumps and reconfiguring the SW system for abnormal operation. The SW system is a system that is important to safety, and its normal flow paths are designated by the FSAR. Further, portions of the SW system that support safety related systems are also designated as safety related. The need to perform a safety evaluation in 1987 at the time the discharge path of the SW system was changed is an unresolved item pending the licensee's review of the circumstances associated with this change, their assessment of this change on plant safety, and a subsequent NRC review (UNR 50-271/91-13-04).

Current surveillance testing of the EDGs, the SW, and RHRSW systems do not individually provide sufficient information to determine that critical equipment (especially the EDGs) would be operable or could perform adequately when these systems are simultaneously actuated, automatically realigned, and operated in response to a LOOP. The existing surveillance tests did not predict the abnormal SW system behavior when two EDGs and two RHRSW pumps were operated during this event. The need to perform SW surveillance tests to demonstrate the operability of vital plant equipment during a LOOP and other design basis conditions is an unresolved item pending issue of the licensee's corrective action report and subsequent NRC review (UNR 50-271/91-13-05).

6.3 HPCI/RCIC Problems

The HPCI gland seal exhauster mechanical problem was of minor safety significance. Plant management's decision to administratively restrict the operation of the HPCI system minimized the potential for adverse long term radiological considerations. The HPCI system remained operable during the Unusual Event. The HPCI gland seal exhauster mechanical problem would not have affected the ability of the HPCI system to perform its design safety function.

The RCIC system operated as designed during the Unusual Event. Automatic RCIC system shut down signals, actuated during the Unusual Event, adequately protected the mechanical integrity of the RCIC system. The shut downs of the RCIC system resulted in a minor RPV water level transient; however, RPV water level did not drop below the RPV low water level alarm setpoint during these water level transients. The RPV pressure transients induced by the automatic shut downs of the RCIC were also considered minor. RPV pressure was maintained between 600 psig and 1000 psig using SRVs, the HPCI system, and the RCIC system. The control room operator induced overspeed RCIC turbine shut down was expeditiously reset and of minor safety significance.

6.4 Torus Water Volume and Liquid Radwaste System Problems

The high torus water volume did not result in a significant reduction of any safety margin or capability to meet design basis accident mitigation requirements. According to Vermont Yankee, ASME Code allowable stresses are not approached until torus water level exceeds 16 feet, the lower limit of the SRV Tail Pipe Level Limit Curve. This corresponds to approximately 112,000 cubic feet of water. The maximum water volume in the torus was approximately 72,000 cubic feet; only 2,000 cubic feet above the maximum level specified in the Technical Specifications. The inspectors concluded that sufficient margin existed at all times during the Unusual Event to assure that primary containment integrity would not be threatened, as a result of Torus high water volume, following a LOCA. Moreover, all systems specified in OE-3104, for maintaining torus level, were operable and could have been configured to reduce the torus water volume if necessary.

All Technical Specification requirements associated with the torus high water volume were met. The action statement, which required the reactor to be in a cold shut down condition, was exited prior to exceeding the 24 hour time limit. Vermont Yankee's bases for maintaining the torus water volume above the maximum, until radwaste processing capability and inventory were available, were conservative and appeared to demonstrate a net safety benefit. The plant was operated in accordance with the Technical Specifications.

The inspectors concluded that the liquid radwaste system was operated in accordance with established plant procedures. Delays associated with processing of liquid radwaste did not appear to be excessive. Radwaste equipment functioned as expected. The inability to operate the liquid radwaste system (due to loss of power) during approximately the first 6 hours of the Unusual Event was of minor safety significance.

7.0 LONG TERM CORRECTIVE ACTIONS AND POTENTIAL GENERIC ISSUES

7.1 Long Term Corrective Actions

During the inspection, VY identified a number of activities that they were pursuing in the long term to address hardware and human performance deficiencies that were identified as a result of the event. These activities would assist in minimizing the recurrence of the observed switchyard and service water problems at VY. It was determined that these activities were not urgent. The long term activities discussed in this section represent potential activities currently under consideration by VY. The licensee agreed at the AIT inspection exit meeting on May 14, 1991 to finalize this list of long term activities and send a letter to the NRC by July 15, 1991 that identifies the important activities in their long term program along with their schedule for completion. The adequacy of the licensee's long term program is an unresolved item subject to receipt and NRC review of the VY letter (UNR 50-271/91-13-06).

7.1.1 Switchyard Activities

Long term corrective actions associated with the switchyard deficiencies were discussed by the VY staff at a licensee pre-startup PORC meeting. Specific long term activities identified during that meeting are noted below:

1. Continue to review the use of maintenance guidelines versus procedures for activities in the switchyard;

2. Resolve communication problems between Vermont Yankee and REMVEC through management involvement;

3. Improve the availability and response time of offsite relay technicians;

4. Establish and conduct training necessary to optimize the time required for backfeeding the normal station service buses through the auxiliary transformer;

5. Purchase an updated version of the SBFU relays. The licensee indicated that for this action procurement efforts are already underway;

6. Review all battery charger specifications and determine the preventive maintenance necessary to maintain them within the specification requirements;

7. Evaluate the acceptability of all operations performed by plant personnel in conjunction with all station battery chargers;

8. Review the adequacy of the switchyard preventive maintenance;

9. Perform engineering reviews of potential common mode failures associated with the switchyard DC circuitry. The review will include an evaluation of the power source used for the breaker failure relays;

10. Review vulnerabilities of other static protective relays installed at Vermont Yankee;

11. Evaluate the need for reporting under 10CFR Part 21 the problems experienced with the breaker failure relays. The licensee indicated that a Notepad entry had already been completed and that an evaluation of the reportability was underway;

12. Conduct a review of the FSAR statements regarding availability of offsite power and perform an update, if necessary.

During the AIT exit meeting, VY discussed planned long term corrective actions associated with the switchyard. The VY slides related to this presentation are provided in Appendix G.

7.1.2 Service Water Activities

The SW test group performed approximately seven different integrated SW system tests and analyzed both current and previous system performance prior to startup, after the April 23 event. Their tests and analyses provided a sufficient basis for concluding that if realigned to the condenser discharge, the SW system could adequately perform under design basis conditions. However, the tests and analyses did not provide the basis for a sufficient understanding of the SW system for design engineers to fully utilize the current hydraulic model of the SW system, since the observed test data did not always match the results predicted by the model. Consequently, the licensee intends to reassess the model and to refine it over time so that it will more accurately represent the existing system.

Although testing provided assurance that the SW system could operate as designed, the test group identified other short and long term items that would allow VY to better understand the system's performance capabilities and flow characteristics. The following short and long term SW corrective action items were discussed by the VY staff at a pre startup PORC meeting:

1. Investigate the apparent higher than expected SW piping resistances experienced during post-event system testing;

2. Substantiate the conclusion, through additional observations, that no degradation of thermal performance will occur in RBCCW heat exchangers;

3. Resolve the concerns over SW Radiation Monitor operability;

4. Develop the method to be used for de-icing the cooling tower deep basin during winter months;

5. Investigate the specific reason(s) for the 1987 change in the SW discharge valve lineup. Further evaluate any decrease in plant safety margins which would have existed by discharging normal SW flow to the cooling towers during severe transient or accident conditions.

During the AIT exit meeting, VY discussed planned long term corrective actions associated with the service water system. The VY slides related to their presentation are provided in Appendix G.

7.2 Potential Generic Issues

The charter of the AIT addressed the need to review the VY event to determine if there are any generic issues associated with the event. These are issues that have applicability to more than one nuclear power plant and there is a significant safety benefit associated with addressing the issues. A number of potential generic issues were identified by the AIT. These issues are discussed below. These issues will be studied further by the NRC to determine if the issues are generic and if there is sufficient safety benefit to warrant their being addressed at other nuclear power plants.

Contributing to the VY LOOP initiating event was the fact that three of the four battery chargers in the switchyard DC control system were in a degraded condition at the time of the event. In each of the faulted Exide battery chargers the output filter circuit was not functioning properly. This was a result of a combination of problems including: blown fuses, incorrect fuses and failed capacitors in the charger filter circuit. These problems were a direct result of the infrequent preventive maintenance on the battery chargers. There was no regular preventive maintenance program for the chargers. It appeared that the last maintenance on these chargers was in 1985. Battery chargers and other electrical equipment in the switchyard of a nuclear power plant are not usually subjected to the 10CFR 50, Appendix B, programmatic controls applied to 1E electrical equipment or safety related equipment. However, this equipment is important to safety since it is part of the 10CFR 50, GDC17, offsite power source and the importance of adequate programmatic controls on such equipment needs to be assessed.

A voltage spike in the switchyard DC control system damaged the Zener diodes of two SBFU relay trip cards currently manufactured by Brown Boveri (previously Westinghouse) and caused a third trip card to activate erroneously. This led to the tripping and locking open of almost all the breakers in the 345 kV and 115 kV switchyard and a LOOP at VY. A similar failure occurred in 1984 at VY when failure of Zener diodes in Westinghouse SA-1 relays caused lockout trips of both EDGs A and B. VY personnel stated they recently made a Notepad entry regarding this issue. As a part of the VY long term program they are evaluating this issue for Part 21 reportability.

The AIT review of the SBFU stuck breaker relay configuration at VY established that all of the stuck breaker relays for the yard breakers were powered by the same bus. This bus is one of two DC busses in the switchyard DC control system. A voltage spike on this bus led to the opening of almost all of the yard breakers. Thus, all of the yard breakers were subject to a common cause failure. The design of the switchyard protective relaying at other facilities may be such that they are similarly vulnerable to a common cause failure that could result in a loss of offsite power.

Service Water problems were noted during the April 23 event. These problems were a result of a high pressure in the SW discharge header. The high pressure in turn was primarily the result of a 1987 change in the lineup of the SW discharge from the river to the cooling tower. The discharge flow path to the cooling tower involved a relatively high resistance flow path. Contributing to the high flow resistance problem was the flow contribution in the SW discharge header from the RHRSW pumps that were in operation during the LOOP. In 1987, when the lineup of the VY Service Water system was changed, no engineering analysis was documented and no system testing was performed to demonstrate that the SW system would perform adequately under a LOOP or under any other design basis condition. Furthermore, surveillance testing of the EDGs and the SW system was inadequate to identify the SW deficiencies associated with the SW discharge lined up to the cooling water tower. Surveillance testing typically does not involve a reconfiguration of system sections beyond local areas undergoing tests and integrated system tests are not routinely performed.

Another surveillance test deficiency that related to the performance of the switchyard DC control system was identified during the VY event. As noted above, three of four battery chargers were in a degraded condition at the time of the event. The fourth battery charger had not been tested by the end of the inspection. The operability of these battery chargers is specified in the VY Technical Specifications. However, no surveillance requirements are specified in the Technical Specifications. Specific generic problems may exist with SW and battery charger surveillance tests. The above SW and battery charger surveillance test inadequacies may be a potential generic problem involving the ability of other surveillance tests to demonstrate that equipment and systems can perform adequately in accordance with their design bases.

During the VY LOOP event, approximately a three hour additional delay was encountered in the switchyard activities leading to the restoration of offsite power. This problem was the result of communication problems and differences between priorities between VY and REMVEC personnel. Under normal conditions, REMVEC has operational responsibility for the VY switchyard. Under emergency conditions, a VY procedure specifies that this responsibility is to be transferred to VY. However, the procedure does not define what constitutes an emergency condition. These operational problems in the VY switchyard during the VY LOOP event suggests the need for a clarification of utility authority under LOOP or other plant emergency conditions when timely switchyard activities are important.

8.0 EXIT MEETING

The AIT completed the site portion of the inspection on April 29, 1991. A pre-exit meeting was held with the licensee at the site. A list of attendees at the pre-exit is provided in Appendix A-1. A final exit meeting was held on May 14, 1991 in the NRC Region I office at King Of Prussia, Pennsylvania. A list of attendees at the final exit meeting is provided in Appendix A-2. The inspectors discussed the scope and findings of the inspection. The licensee discussed their response to the AIT findings. The agenda for the exit meeting and a copy of the licensee's slides that were discussed at the exit meeting are provided in Appendix G.

APPENDICES

APPENDIX A Entrance and Exit Interview Attendees

APPENDIX A-1 Entrance Interview Attendees
APPENDIX A-2 Exit Interview Attendees

APPENDIX B Licensee Developed Sequence Of Events

APPENDIX C System Sketches

APPENDIX D Photographs

APPENDIX E Acronyms and Initialisms

APPENDIX F Licensee Developed Post Trip Review

APPENDIX G Exit Meeting Slides

APPENDIX G-1 Exit Meeting Agenda
APPENDIX G-2 Chronological History Of Events
APPENDIX G-3 Analysis Of Service Water Problems
APPENDIX G-4 Evaluation Of Command, Control And Communications During The 4/23/91 LOOP Event
APPENDIX G-5 Service Water Sketches Presented By Licensee At Exit Meeting

APPENDIX H Augmented Inspection Team (AIT) Charter

APPENDIX I Licensee Developed Backfeeding Time Line

APPENDIX J Licensee Event Report (LER) 84-22

APPENDIX K Summary of Unresolved Items

APPENDIX A

Entrance and Exit Interview Attendees

APPENDIX A-1 Entrance Interview Attendees

APPENDIX A-2 Exit Interview Attendees

APPENDIX A-1

Entrance Interview Attendees
APRIL 25, 1991

Vermont Yankee Nuclear Power Corporation

* B. Buteau, Engineering Director
* D. Reid, Plant Manager
  R. Garppardi, QA Supervisor
**J. Hoffman, Engineering Manager
  S. Jefferson, Asst. To Plant Manager
* D. McElwee, Liason Engineer
**S. Miller, Project Manager
* W. Murphy, Sr. Vice President, Operations
  M. Palionis, Sr. Operations Engineer
* J. Pelletier, Vice President, Engineering
* R. Wanczyk, Operations Superintendent

United States Nuclear Regulatory Commission

* C. Anderson, Chief, Electrical Section, RI
* R. Bhatia, Reactor Engineer, RI
* A. Della Greca, Sr. Reactor Engineer, RI
* P. Drysdale, Sr. Reactor Engineer, RI
  A. Finkel, Sr. Reactor Engineer, RI
* T. Hiltz, Resident Inspector, Vermont Yankee, RI

State of Vermont

* W. Sherman, Nuclear Engineer

* Indicates attendance at pre-exit meeting on April 29, 1991
**Indicates attendance only at pre-exit meeting on April 29, 1991

APPENDIX A-2

Exit Interview Attendees
MAY 14, 1991

Vermont Yankee Nuclear Power Corporation

F. Baxter, Principal Engineer
B. Buteau, Engineering Director
J. Herron, Operations Supervisor
P. Johnson, Lead Electrical Engineer
R. Lopriore, Maintenance Supervisor
W. Murphy, Sr. Vice President, Operations
J. Pelletier, Vice President, Engineering
D. Reid, Plant Manager

United States Nuclear Regulatory Commission

K. Abraham, Public Affairs Officer, RI
C. Anderson, Chief, Electrical Section, RI
R. Bhatia, Reactor Engineer, RI
S. Chaudhary, Sr. Reactor Engineer, RI
A. Della Greca, Sr. Reactor Engineer, RI
P. Drysdale, Sr. Reactor Engineer, RI
M. Fairtile, Project Manager, NRR
T. Hiltz, Resident Inspector, Vermont Yankee, RI
J. Johnson, Branch Chief, DRP, RI
P. Kang, Electrical Engineer, NRR
L. Kay, Reactor Engineer, RI
W. Lanning, Deputy Division Director, RI
T. Martin, Regional Administrator, RI
J. Rogge, Chief, Reactor Projects, RI
J. Tatum, Sr. Reactor Engineer, NRR

State of Vermont

W. Sherman, Nuclear Engineer

APPENDIX B

Licensee Developed Sequence Of Events

Event Description:

The following event description was obtained from the ERFIS SOE, Alarm Typer and Alarm Report Logs, the Operations Log, the REMVEC Log and discussions with Operations Department personnel present during the event.

Date	Time	Description
4-23-91	1448:28	DC Control Power transient occurs in Switchyard DC Distribution Panels DC-4A and/or DC-5A. Breaker Failure Interlock (BFI) signals occur at 345KV Breaker 81-1T and 115KV Breaker K-1 Breaker 81-1T BFI results in: - 345 KV Breaker Failure Signal - Opening of 345KV Breakers 381 and 1T - Generator Primary and Backup Lockout Relays Breaker K-1 BFI results in: - Opening of 115KV Breaker K-186 - Opening of 345KV Breakers 379 and 381 115KV POWER LOST Generator Primary and Backup Lockout Relays result in: - Turbine Trip (Vacuum Trip #1). - Opening of 345KV Breaker 81-1T - Attempted Fast Transfer of 4 KV Buses 1 and 2 to the Startup Transformers but no power available in 115KV yard due to above DC Control Power transient. 345KV POWER LOST LOSS OF OFFSITE POWER

1448:29 REACTOR SCRAM due to Turbine Control Valve Fast Closure with Turbine first stage pressure above 192 psig. All control rods inserted to or beyond position 02, reactor power less than 2%, OE 3100 entered.

1448:29 Loss of Instrument AC results in PCIS Groups 1 Inboard, 2A, 3A, and 5A&B.

PCIS Group 5 - RWCU - Valves CU-15, 18 and 68 close as required.

RPS MG Sets A&B trip due to loss of power.

1448:31 Breakers 3T1 and 4T2 open to disconnect Buses 1 and 2 from Buses 3 and 4.

1448:35 RPS MG Sets A&B coast down sufficiently to trip output breakers on low frequency. Results in trip of RPS and PCIS Group 1 Outboard, 2B and 3B.

PCIS Group 1, 2 and 3 valves close as required.

1448:39 MSIV closure complete.

DG-A and DG-B to rated speed and voltage, Output Breakers close.

1448:41 Reactor Mode Switch placed in REFUEL in accordance with OE-3100.

1448:45 4KV Buses 3 and 4 at rated voltage.

1449:20 RPV pressure increases to approximately 1065 psig due to MSIV closure. SRV-A manually opened to reduce RPV pressure to approximately 900 psig in accordance with OE-3100.

1450	HPCI placed in service for RPV water level and pressure control. RHR-A placed in Torus Cooling Mode.
1452	OT 3122 entered. Station Air Compressors A and B verified in operation. Valve SW-20 closed.
1507	Shift Supervisor declared UNUSUAL EVENT due to 345KV and 115KV Bus Voltages to zero.
1513	RHR-B placed in Torus Cooling Mode.
1515:24	RPS MG Set A restarted and bus reenergized.
1515:42	RPS MG Set B restarted and bus reenergized.
1517	State Notifications completed in accordance with OP 3500.
1525	Corporate Notification completed in accordance with AP 0156. CRD Pump A restarted for RPV water level control, Control Rod Drive cooling, accumulator recharging and Recirculation Pump seal purge.
1528	APRM A, C, E power supply transferred from Vital AC to RPS. Transfer of APRM B, D, F power supply from Instrument AC to RPS not attempted. Indication lights inoperable.
1531	NRC Red Phone Notifications completed. (See Attachment 13)
1533	Scram reset. All control rods show indication at position 00. OE-3104 entered due to high Torus water volume.

1534 REACTOR SCRAM due to RPV Low Water Level during securing of HPCI. RPV water level at approximately 130 inches.

1537 HPCI secured and RCIC started for RPV water level and pressure control. RPV pressure at approximately 600 psig.

1542 Station Air Compressor A tripped due to inadequate cooling water flow. Auxiliary Operator sent to investigate cause.

Note: Order given to connect Diesel Air Compressor to station air system at approximately this time.

1544 Transfer of water from Torus to Radwaste using RHR started to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14)

1548 Scram reset. PCIS Group 2, 3 and 5 reset.

1551 Secured transfer of Torus water to Radwaste. OE-3104 exited.

1555 115KV Breaker K1 manually opened. Had previously been stuck closed.

1610 NRC Red Phone Notification performed on RPV low water level scram and entry to and subsequent exit from OE-3104. (See Attachment 13)

1615 HPCI started in full flow test mode for RPV pressure control.

1621 Valve SW-20 opened to restore service water flow to Turbine Building.

1627 HPCI secured. RPV pressure at approximately 600 psig.

1645	CRD Pump A secured. RPV water level control being maintained via RCIC.
1716	SRV-C manually opened to reduce RPV pressure from approximately 1000 psig to approximately 800 psig. RCIC trip on RPV high water level due to swell resulting from RPV pressure reduction.
1717	SRV-B manually opened to reduce RPV pressure from approximately 990 psig to approximately 800 psig.
1718	RCIC restarted for RPV water level and pressure control.
1731	Transfer of water from Torus to Radwaste using RHR started to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14) Station Air Compressor B tripped due to inadequate cooling water flow. ON-3146 entered due to loss of all station air compressors. Instrument Air header pressure drops to approximately 85 psig.
1736	Station Air Compressor B restarted. Cooling water flow path established via back flow from discharge through open relief valve.
1742	HPCI restarted in full flow test mode for RPV pressure control. RPV pressure at approximately 1000 psig.
1746	Instrument Air header pressure restored to normal.
1747	Secured transfer of Torus water to Radwaste.
1752	HPCI secured.

1759	Diesel Air Compressor connected to outlet of Station Air Compressor D to supply plant air loads.
1825	HPCI restarted in full flow test mode for RPV pressure control. RPV pressure at approximately 970 psig.
1830	HPCI secured.
1855	HPCI restarted in full flow test mode for RPV pressure control. RPV pressure at approximately 1000 psig.
1901	HPCI secured. RPV pressure at approximately 750 psig.
1904	RCIC tripped due to overspeed. (See Attachment 12)
1912	RCIC overspeed trip reset and RCIC restarted for RPV water level and pressure control.
1914	Transfer of water from Torus to Radwaste using RHR performed to reduce Torus water volume in accordance with OE-3104. (See Attachment 14)
1917	HPCI restarted in full flow test mode for RPV pressure control.
1925	NORMAL POWER RESTORED TO 115KV YARD. 115KV Breaker K186 manually closed.
1930	HPCI secured.
1949	4KV Breaker 13 manually closed. Power restored to Bus 1.
1950	4KV Breaker 23 manually closed. Power restored to Bus 2.
2005	HPCI restarted in full flow test mode for RPV pressure control.
2014	HPCI secured.

2053	HPCI restarted in full flow test mode for RPV pressure control.
2056	HPCI secured.
2112	SRV-D manually opened to reduce RPV pressure to approximately 600 psig. REACTOR SCRAM due to RPV Low Water Level resulting from pressure increase following closure of SRV-D. RPV water level at approximately 125 inches. OE-3104 entered due to high Torus water volume. Shift Supervisor decides to remain in OE-3104 due to inability to maintain Torus water volume between 68,000 and 70,000 cu ft.
2127	Scram Reset. Transfer of water from Torus to Radwaste using RHR performed to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14)
2155	Commenced De-inerting of Primary Containment. Drywell/Torus dP < 1.7 psid.
2200	NRC Red Phone Notification performed on RPV low water level scram. (See Attachment 13)
2225	NRC Red Phone Notification performed on entry into OE-3104. (See Attachment 13) SRV-A manually opened to reduce RPV pressure from approximately 1000 psig to approximately 750 psig.

	2302	CRD Pump A restarted. RPV pressure control being accomplished by a combination of RCIC operation and SRV opening. RPV water level control being accomplished by CRD and periodic RCIC injection.
	2321	SRV-C manually opened to reduce RPV pressure.
	2330	OP 0109 entered.
	2355	SRV-B manually opened to reduce RPV pressure.
4-24-91	0008	SRV-D manually opened to reduce RPV pressure.
	0011	T-4 Motor Operated Disconnect closed.
	0013	SRV-A manually opened to reduce RPV pressure.
	0036	SRV-C manually opened to reduce RPV pressure.
	0047	SRV-B manually opened to reduce RPV pressure.
	0048	345KV Breaker 81-1T closed.
	0109	PROs submitted on 1448, 1523, and 2112 Reactor Scrams.
	0116	SRV-D manually opened to reduce RPV pressure.
	0128	SRV-A manually opened to reduce RPV pressure.
	0136	PRO submitted on 1533 entry into OE-3104 on high Torus water volume.
	0201	SRV-C manually opened to reduce RPV pressure.

0215 SRV-B manually opened to reduce RPV pressure.

0217 PCLRT of Drywell Personne. \irlock satisfactorily completed in preparation for Drywell entry.

0250 Transfer of water from Torus to Radwaste using RHR performed to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14)

0252 345KV Breaker 81-1T reopened.

0257 SRV-D manually opened to reduce RPV pressure.

0315 SRV-A manually opened to reduce RPV pressure.

0352 345KV Breaker 1T testing performed. Breaker closed, opened and closed.

0355 SRV-C manually opened to reduce RPV pressure.

0410 SRV-B manually opened to reduce RPV pressure.

0417 OFFSITE POWER RESTORED FROM 345KV. Started back feed of power from 345KV switchyard through Auxiliary Transformer. Breakers 12 and 22 closed, Breakers 13 and 23 opened.

0425 Bus 4 paralleled to Bus 2. DG-A secured.

0437 Bus 3 paralleled to Bus 1. DG-B secured.

0452 SRV-D manually opened to reduce RPV pressure.

0457 345KV Breaker 379 closed.

0530 RHR-B secured from Torus cooling mode.

0538 115KV Breaker K-1 closed.

0543	SRV-A manually opened to reduce RPV pressure.
0631	Transfer of water from Torus to Radwaste using RHR performed to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14)
0705	SRV-C manually opened to reduce RPV pressure.
0756	SRV-B manually opened to reduce RPV pressure.
0845	APRM B, D, F power supply transferred from Instrument AC to RPS. Note 4-23-91 1528 entry.
0850	SRV-D manually opened to reduce RPV pressure.
1056	Condensate Pump B started and system placed in long path recirculation mode for system cleaning prior to resumption of RPV injection.
1125	Drywell inspection completed. Inspection noted leakage from valve bonnet on RHR-46A. Probable cause of 2.0-2.5 gpm drywell leakage noted prior to event.
1205	Transfer of water from Torus to Radwaste using RHR performed to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14)
1325	Steam Packing Exhauster started. MSIV-86A-D, MS-74 and MS-77 opened to admit sealing steam to the Turbine.
1329	Mechanical Vacuum Pump started.
1338	MAIN CONDENSER ESTABLISHED AS A HEAT SINK. Condenser vacuum approximately 14.9 in. Hg.

1344	Reactor Feedwater Pump B started with injection to the RPV.
1346	RCIC Secured.
1434	345KV Breaker 81-1T closed.
1550	Reactor Feedwater Pump B secured. RPV injection provided from Condensate System.
1650	MSIV-80A opened.
1805	CRD Pump A secured.
1825	Transfer of water from Torus to Radwaste using RHR performed to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14)
1925	Transfer of water from Torus to Radwaste using RHR performed to reduce Torus water Volume in accordance with OE-3104. (See Attachment 14) Torus water volume reduced below 70,000 cu ft. OE-3104 entry condition no longer present. OE-3104 exited. Torus water volume able to be maintained between 68,000 and 70,000 cu ft.
1950	UNUSUAL EVENT TERMINATED. Based on normal offsite power having been restored and Torus water volume having been reduced below 70,000 cu ft.
2005	State Notifications completed.
2017	NRC Red Phone Notification completed.
2200	Transfer of water from Torus to Radwaste using RHR performed to further reduce Torus water volume. (See Attachment 14)

	2210	RHR-A secured from Torus cooling mode. Torus cooling now secured in both RHR subsystems.
	2246	CRD Pump A restarted.
4-25-91	0203	Started RHR-B Pump for Shutdown Cooling operation. PCIS Group 4 - RHR-17&18 - isolation occurs as anticipated per Shutdown Cooling Test Plan.
	0205	PCIS Group 4 isolation reset.
	0207	Started RHR-D Pump for Shutdown Cooling operation. Operation successful, no PCIS Group 4 isolation occurs.
	0239	345KV Breaker 381 closed.
	0357	REACTOR IN COLD SHUTDOWN CONDITION. Reactor coolant temperature , 212 degF.
	0415	345KV Breaker 81-1T opened.
	0445	Station Air Compressors A and B restarted. Diesel Air Compressor secured.
	0525	345KV Breaker 81-1T closed.

APPENDIX C

System Sketches

Figure	Title
C1	Vermont Yankee Switchyard and Main Distribution System
C2	Vermont Yankee 4160 V Auxiliary One Line Diagram
C3	Switchyard House DC Distribution One Line Diagram
C4	Logic Drawing of SBFU With Thyristor Output
C5	Trip Module For Thyristor Output Internal Schematic
C6	As Found Output Voltage With No Load For Battery Charger 4A-5A
C7	As Found Output Voltage With Loads Applied For Battery Charger 4A-5A
C8	Calibration of Recording Scope
C9	As Found Output Voltage With Loads Applied For Battery Charger 4A-5A
C10	As Left Output Voltage For Battery Charger 4A-5A
C11	As Found Output Voltage With Various Loads Applied For Battery Charger 4A
C12	High Pressure Coolant Injection
C13	Reactor Core Isolation Cooling
C14	Service Water Simplified Diagram
C15	Simplified Service Water - Relative Elevations
C16	Diesel Generator Cooling
C17	Vermont Yankee Switchyard Organizational Responsibility Chart

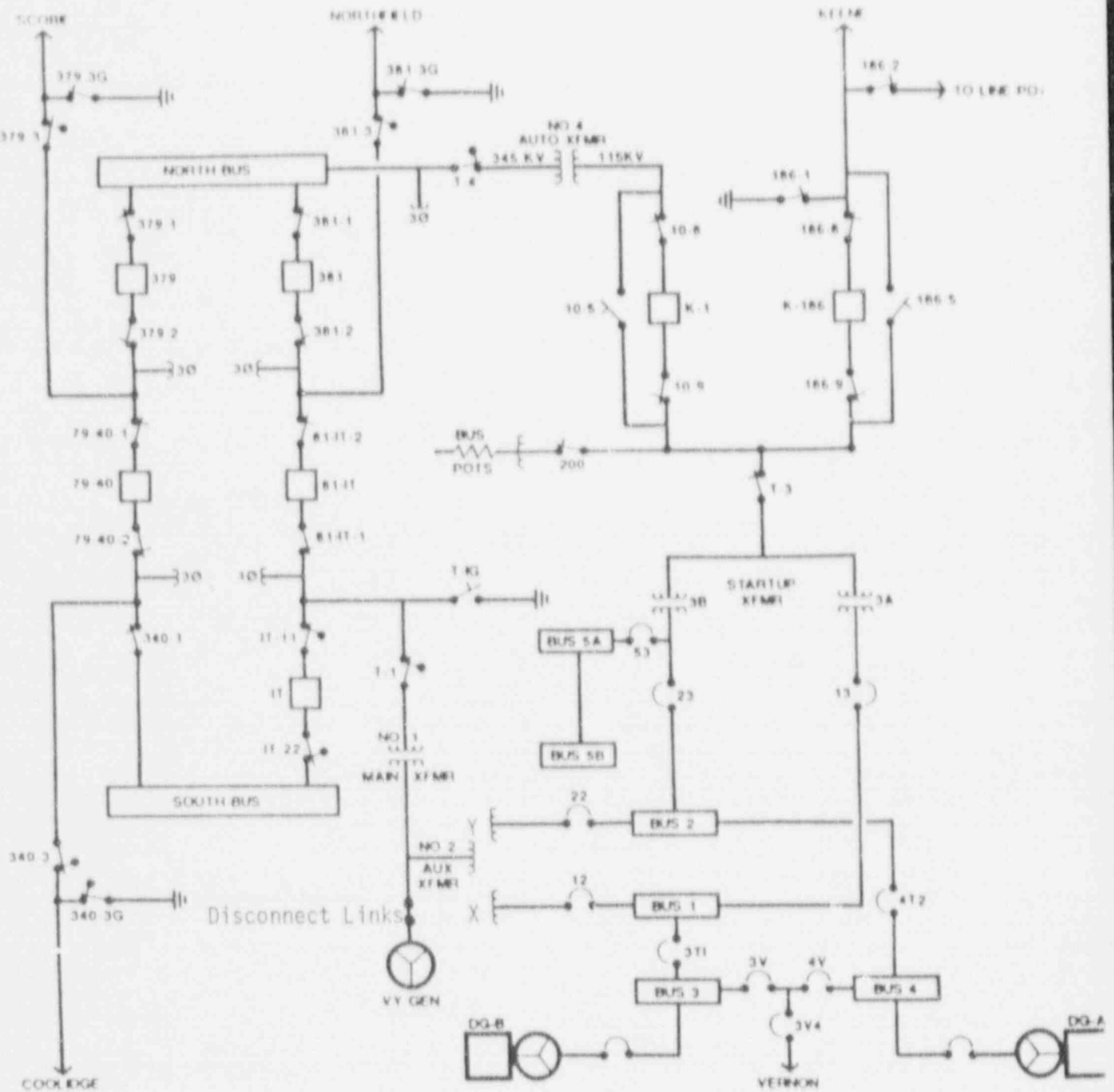


Figure C1: Vermont Yankee Switchyard and Main Distribution System

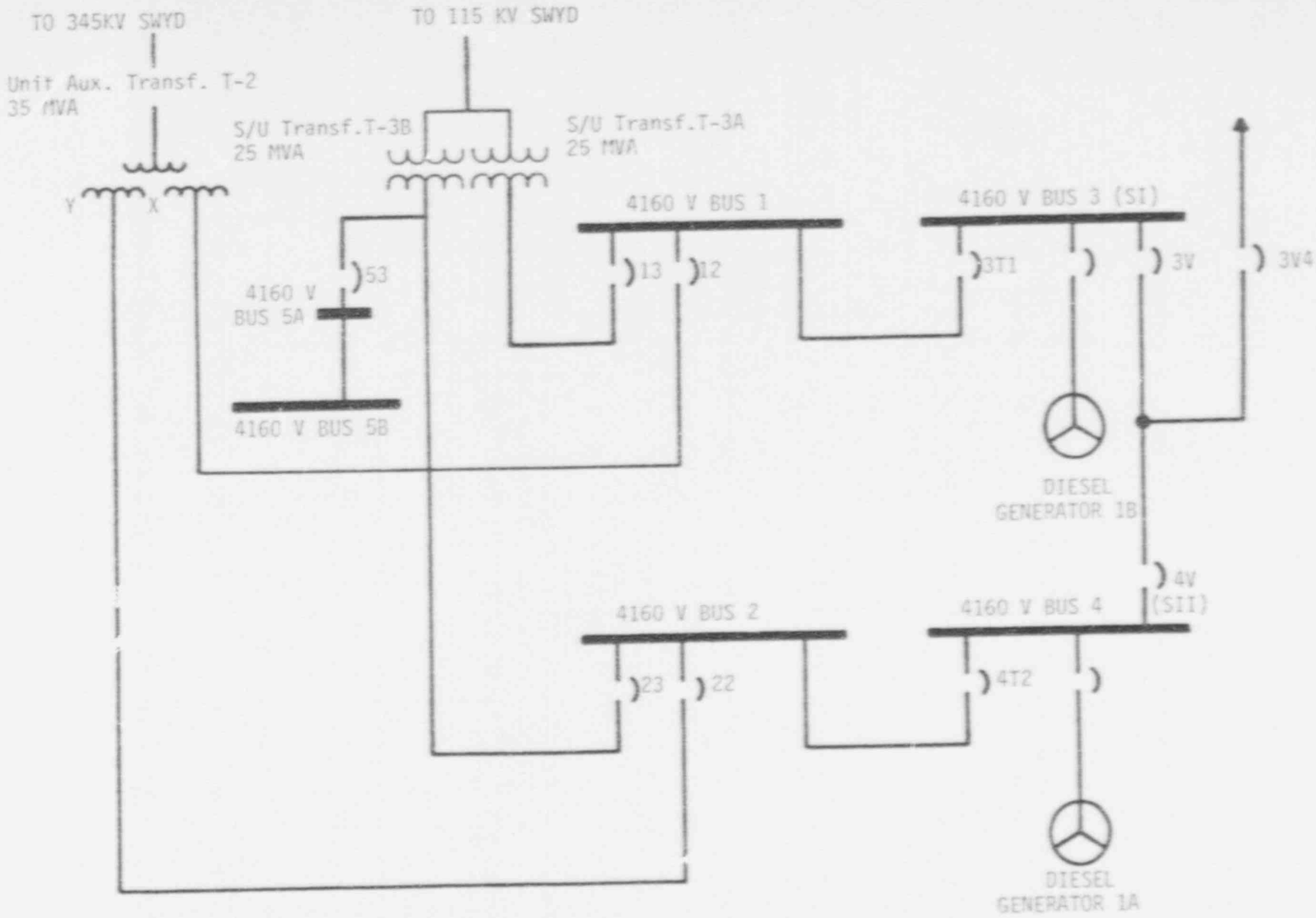
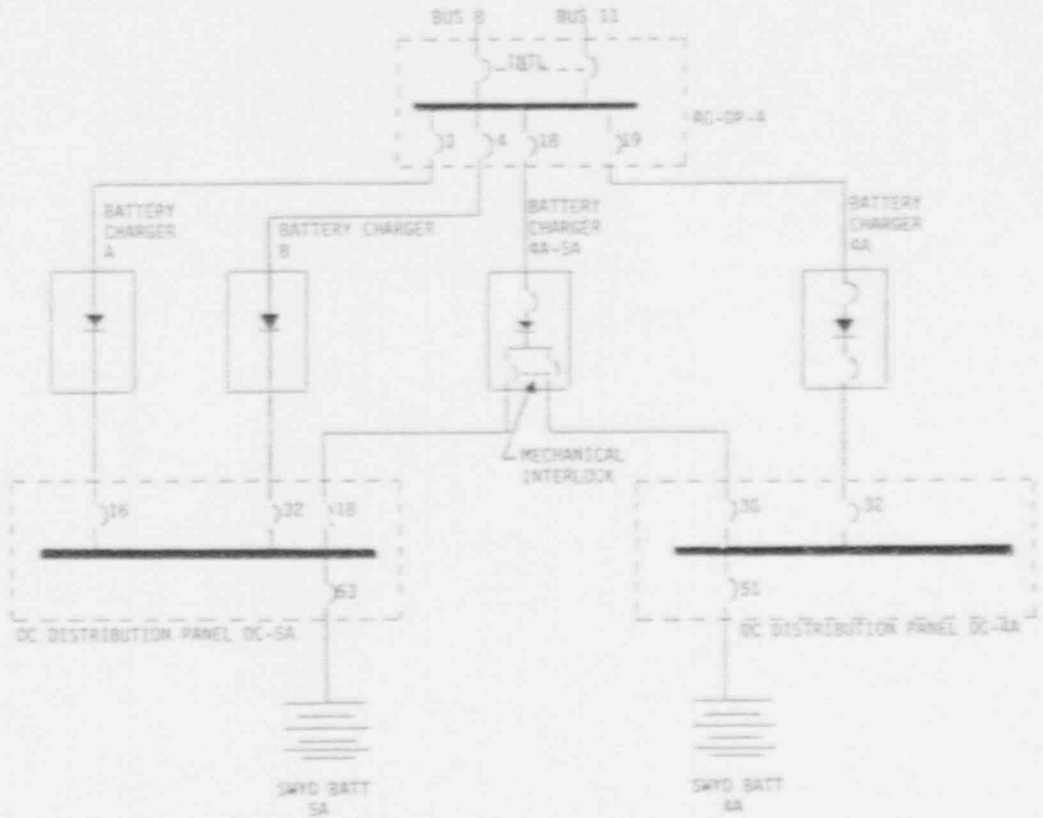


Figure C2: Vermont Yankee 4160 V Auxiliary One Line Diagram

DC DISTRIBUTION PANEL DC-5A

CKT #	
1	SPARE
2	115 KV KEENE CARRIER
3	345 KV NORTHFIELD NO.1 CARRIER
4	SPARE
5	345 KV COOLIDGE TRANS TRIP CLOSE
6	345 KV COOLIDGE SECONDARY CARRIER
7	SPARE
8	SPARE
9	SPARE
10	SPARE
11	115 KV KEENE OCB K186 CLOSE
12	115 KV KEENE DIFF & B.F.
13	AUTO TR OCB K1 CLOSE
14	AUTO TR DIFF & B.F.
15	SPARE
16	BATTERY CHARGER B
17	345 KV ATB 79-40 CLOSE
18	BATTERY CHARGER 4A-5A
19	ATB-379
20	SPARE
21	ATB-381
22	SPARE
23	ATB IT
24	SPARE
25	SPARE
26	SPARE
27	SPARE
28	SPARE
29	SPARE
30	AUTO TR & 115 KV BUS BKR DIFF
31	SPARE
32	BATTERY CHARGER A
33	SCOBIE MICROWAVE XMTR/RCVR
34	115 KV KEENE OCB K186 PRIM TRIP
35	345 KV BKR 81-1T PRIM TRIP & CLOSE
36	AUTO TR OCB K1 PRIM TRIP
37	ATB 379
38	SPARE
39	ATB 379
40	345 KV ATB 1T PRIM TRIP
41	ATB 381
42	SPARE
43	SPARE
44	SPARE
45	SPARE
46	SPARE
47	345 KV NORTHFIELD PRIM RELAY PWR
48	SPARE
49	345 KV COOLIDGE PRI RELAYS
50	SPARE
51	SPARE
52	345 KV SCOBIE PRI RELAY
53	MAIN BREAKER



DC DISTRIBUTION PANEL DC-6A

CKT #	
1	115 KV ANNUNCIATOR(E) * RELAY HOUSE, ALARM ONLY NO PROTECTIVE FUNCTION
2	345 KV ANNUNCIATOR (E) *
3	START UP TRANSF. MOD T-3 OPEN
4	EMERG LGT LP-1AC
5	GE/TAC REMVEC REMOTE STA B COMMUNICATIONS-OPERABLE
6	OSCILLOGRAPH
7	EVENT MARKER
8	NORTHFIELD AND SCOBIE TELEMETERING (E) BLOWS FUSE
9	SPARE
10	AUTO TRANSF RELAYS
11	SPARE
12	115 KV KEENE OCB K186LCL BKR FAIL (E)
13	345 KV BKR 81-1T LCL BKR FAIL (E)
14	345 KV ATB 79-40 LCL BKR FAIL (E)
15	ATB 381 LCL BKR FAIL (E)
16	ATB 379 LCL BKR FAIL (E)
17	ATB 1T LCL BKR FAIL (E)
18	SPARE
19	SPARE
20	SPARE
21	SPARE
22	115 KV AUTO TR OCB K1LCL BKR FAIL (E)
23	START UP TRANSF DIFF RELAY
24	BUS DIFF RELAY
25	345 KV NORTH BUS DIFF RELAY
26	345 KV SOUTH BUS DIFF
27	AUTO TRANSF DIFF RELAY
28	SPARE
29	SPARE
30	BATTERY CHARGER 4A-5A
31	RELAY TEST BOX
32	BATTERY CHARGER 6A
33	NORTHFIELD SEC RELAY PWR
34	345 KV COOLIDGE SEC RELAY
35	SCOBIE TRANSF. TRIP R/U CARRIER PWR
36	SCOBIE LINE SEC. CARRIER PWR
37	SCOBIE SEC RELAY
38	345 KV ATB-1T SEC TRIP
39	345 KV BKR 81-1T SEC TRIP
40	SPARE
41	ATB 79-40 SEC TRIP
42	SPARE
43	ATB 379 SEC TRIP
44	SPARE
45	ATB 381 SEC TRIP
46	SPARE
47	SPARE
48	115 KV KEENE OCB K186 SEC TRIP
49	AUTO TR OCB K1 SEC TRIP
50	SPARE
51	MAIN BREAKER

Figure C3: Switchyard House DC Distribution One Line Diagram

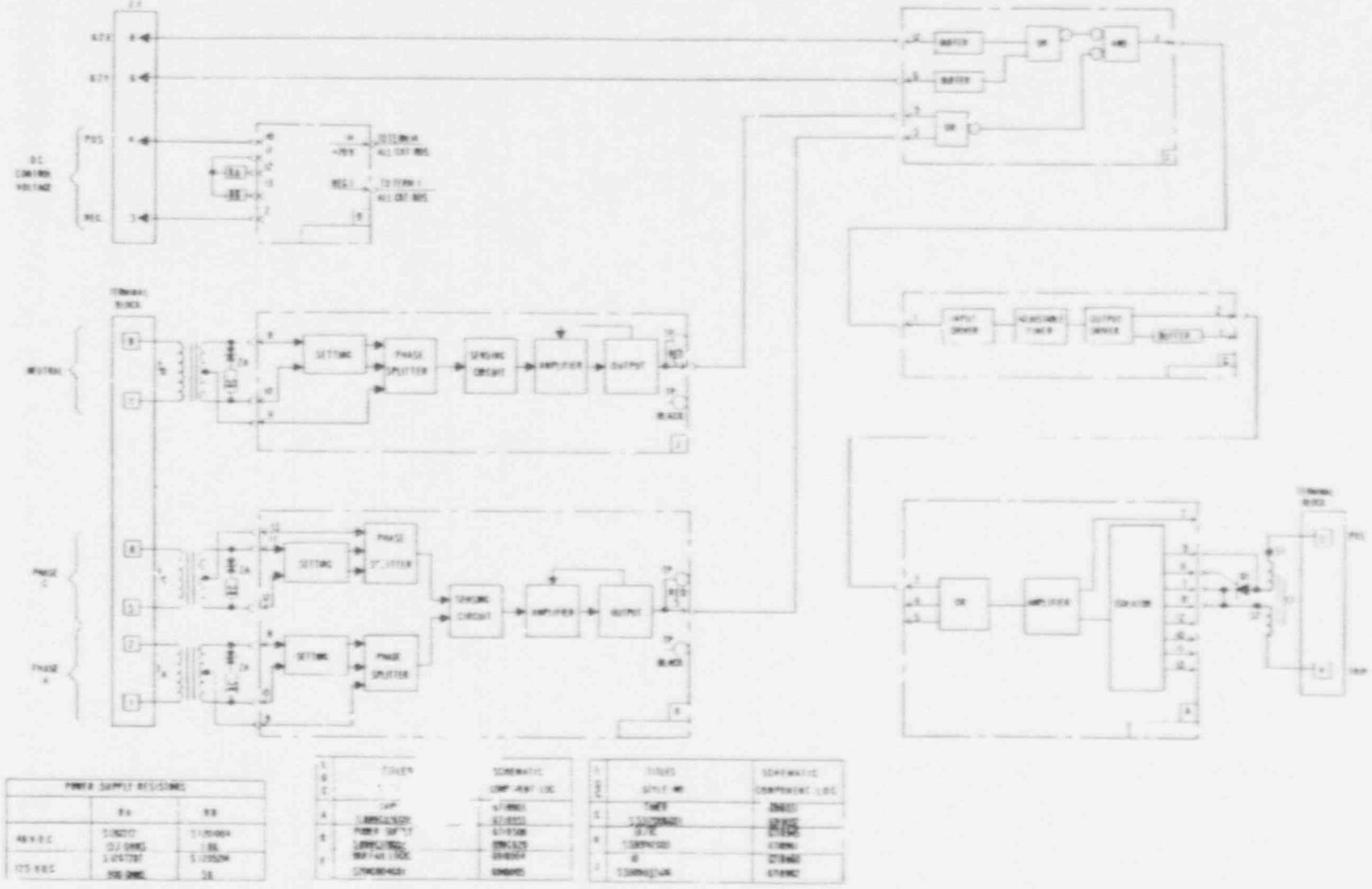
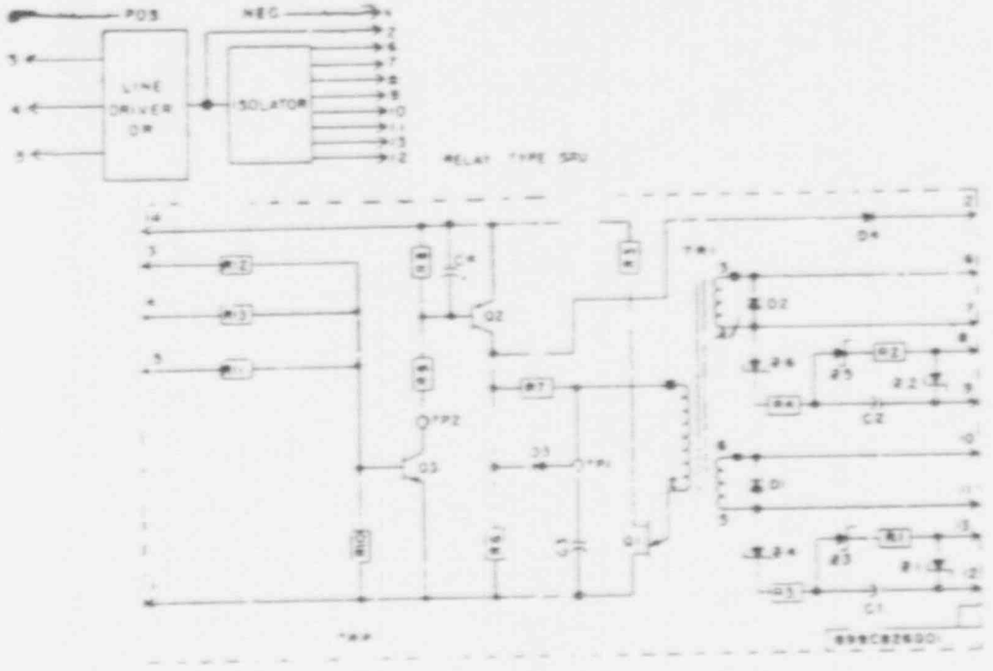


Figure C4: Logic Drawing of SBFU With Thyristor Output



CAPACITOR	STYLE	REQ	REF
C1 C2	[illegible]	2	2 MFD
C3 C4	[illegible]	2	27MFD
DIODE			
D1 TO D4	837A482H03	4	1N645A
RESISTOR *			
R1 TO [illegible]	879A843H08	3	470Ω 1W 5%
R5	629A533H18	1	500Ω
R6	629A533H80	1	5K
R7	629A533H46	1	4.7K
R9	629A533H55	1	6.8K
R10 - R8	629A539H56	2	10K
R11 TO R13	629A533H66	3	27K
TRANSFORMER			
T1	629A372H01	1	PT505
TRANSISTOR			
Q1	629A435H02	1	2N5655
Q2	849A844H01	1	2N3645
Q3	849A825H02	1	2N3417
ZENER DIODE			
VR1 TO VR4	629A369H01	4	1N200

*-ALL RESISTORS TO BE 1/2 WATT ± 2% UNLESS OTHERWISE SPECIFIED

TRIP EQUIPMENT [illegible] 6719753

Figure C5: Trip Module For Thyristor Output Internal Schematic

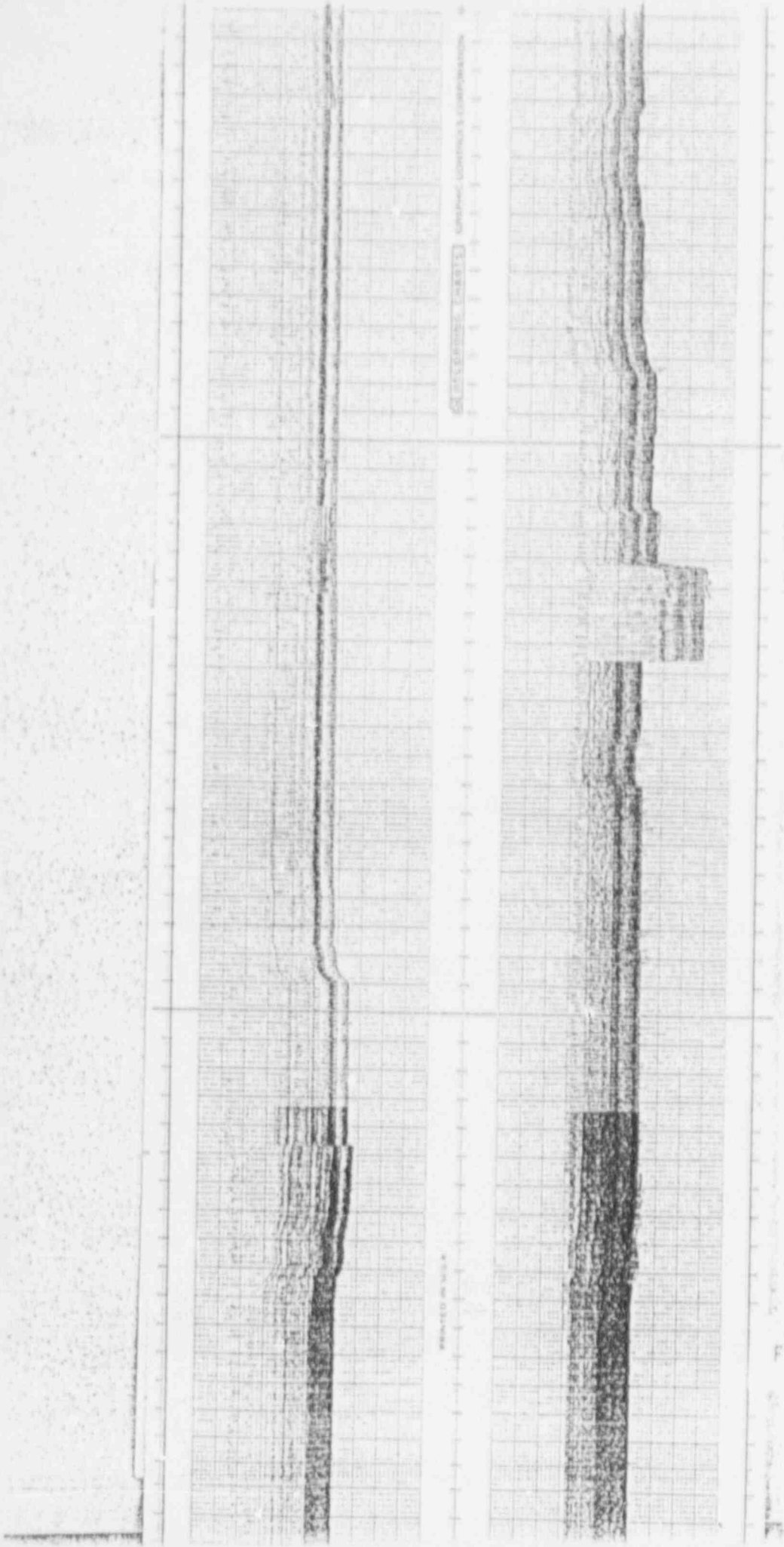


Figure C6: As Found Ouput Voltage With No Load for Battery Charger 4A-5A

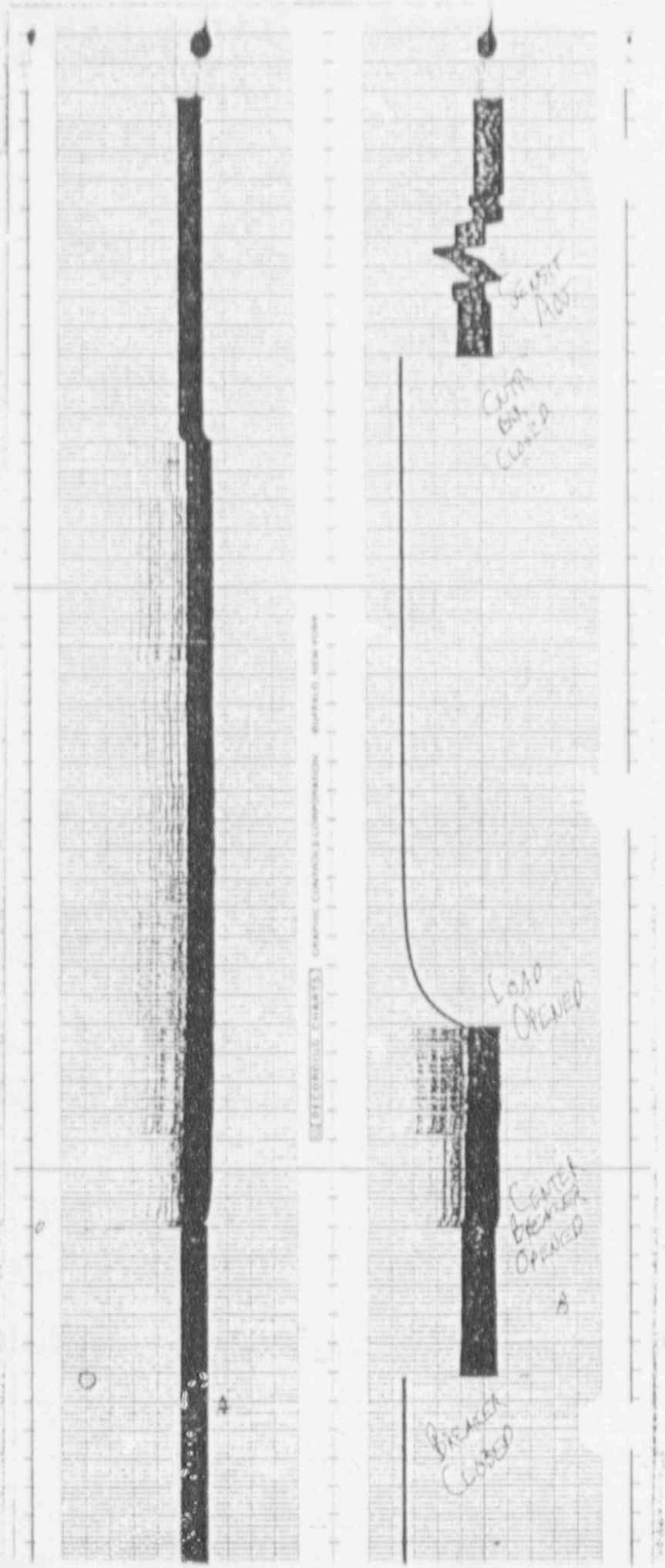


Figure C7: As Found Output Voltage With Loads Applied for Battery Charger 4A-5A

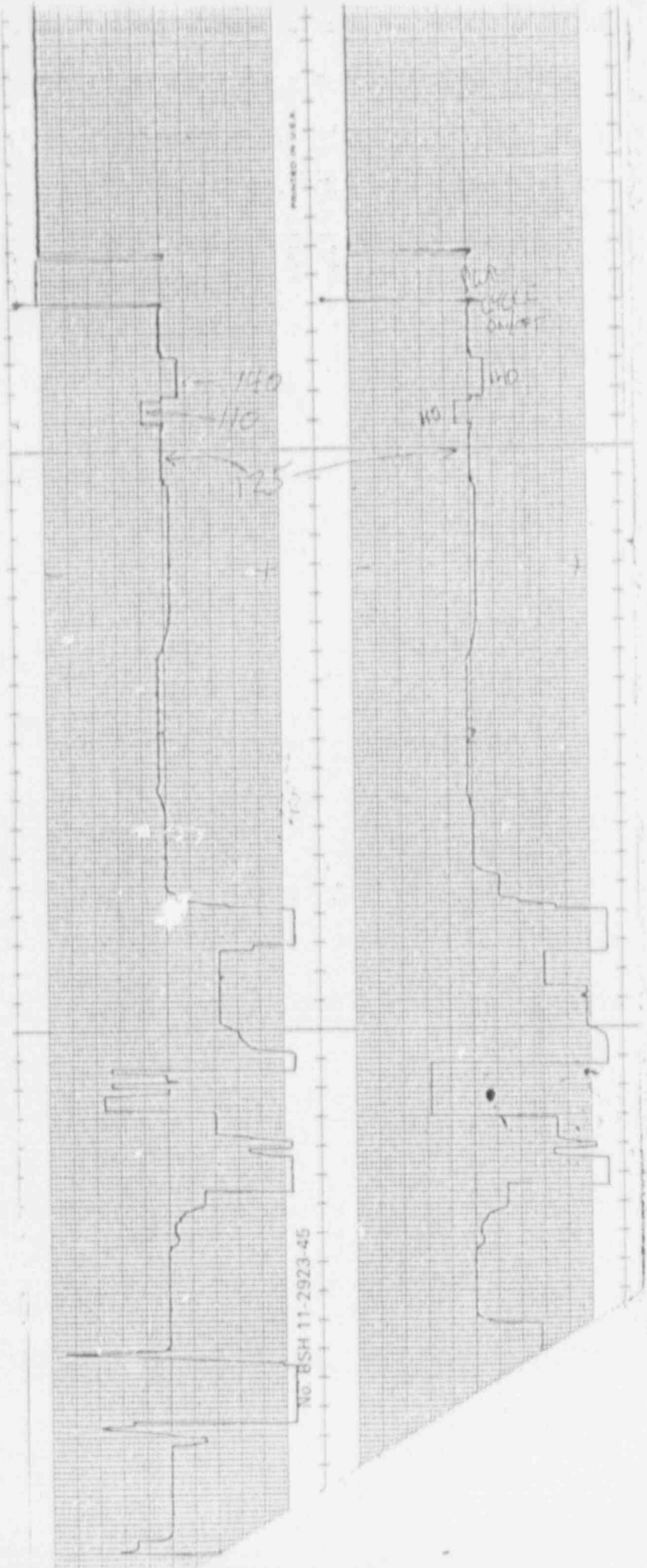


Figure C8: Calibration of Recording Scope

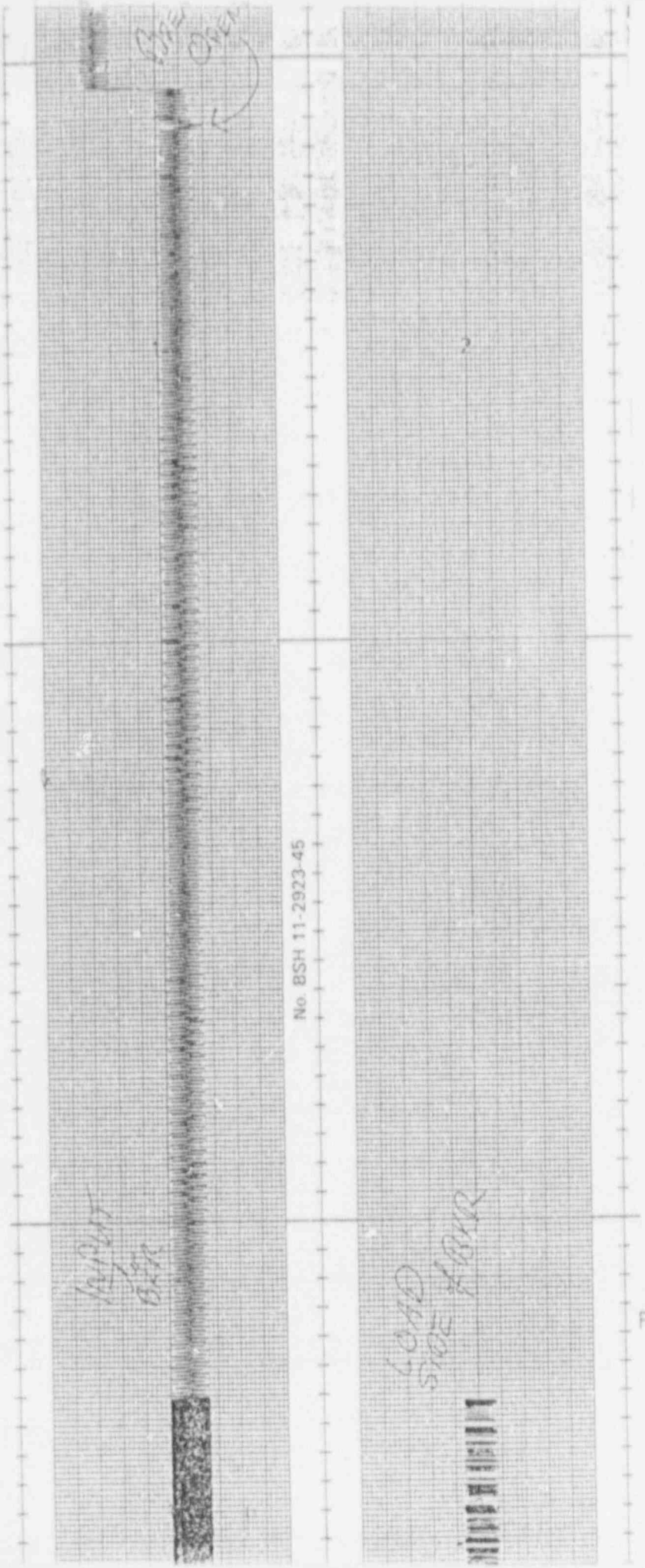


Figure C9: As Found Output Voltage With Loads Applied for Battery Charger 4A-5A

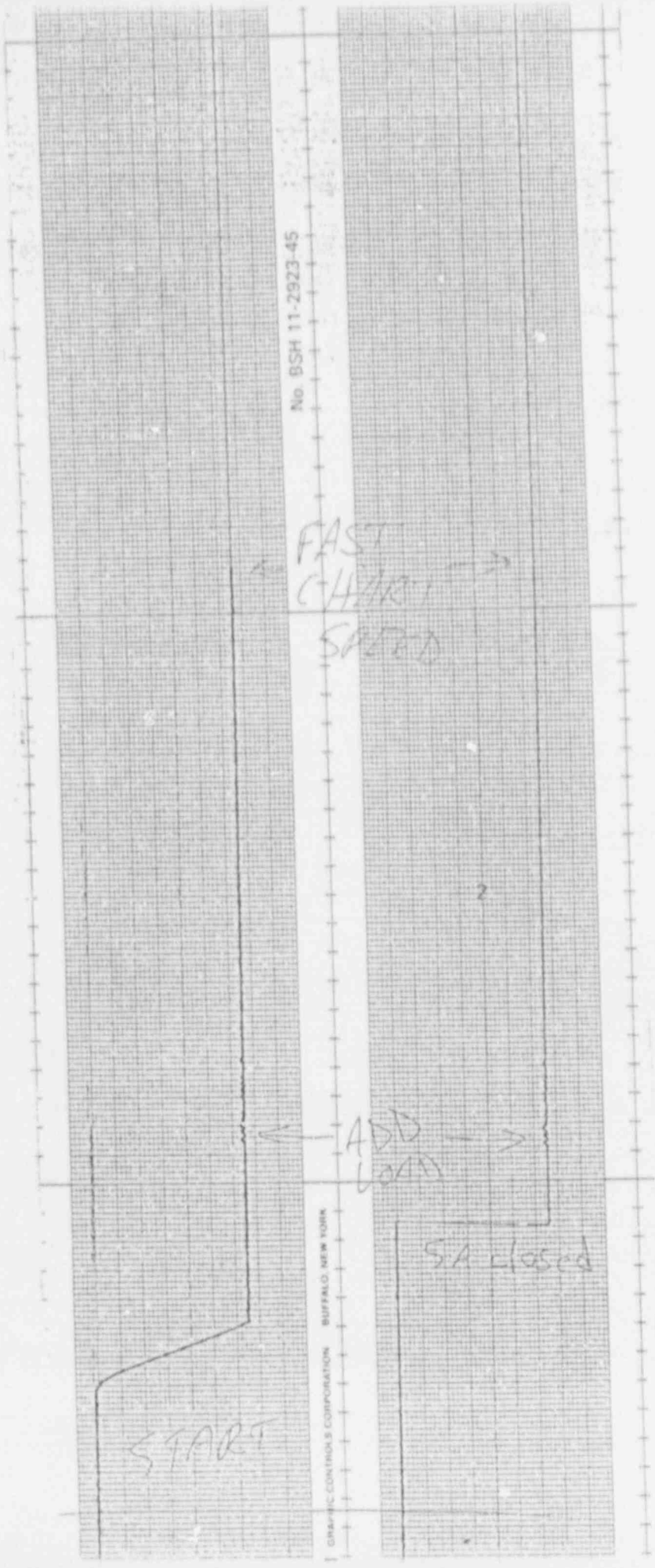


Figure C10: As Left Output Voltage for Battery Charger 4A-5A

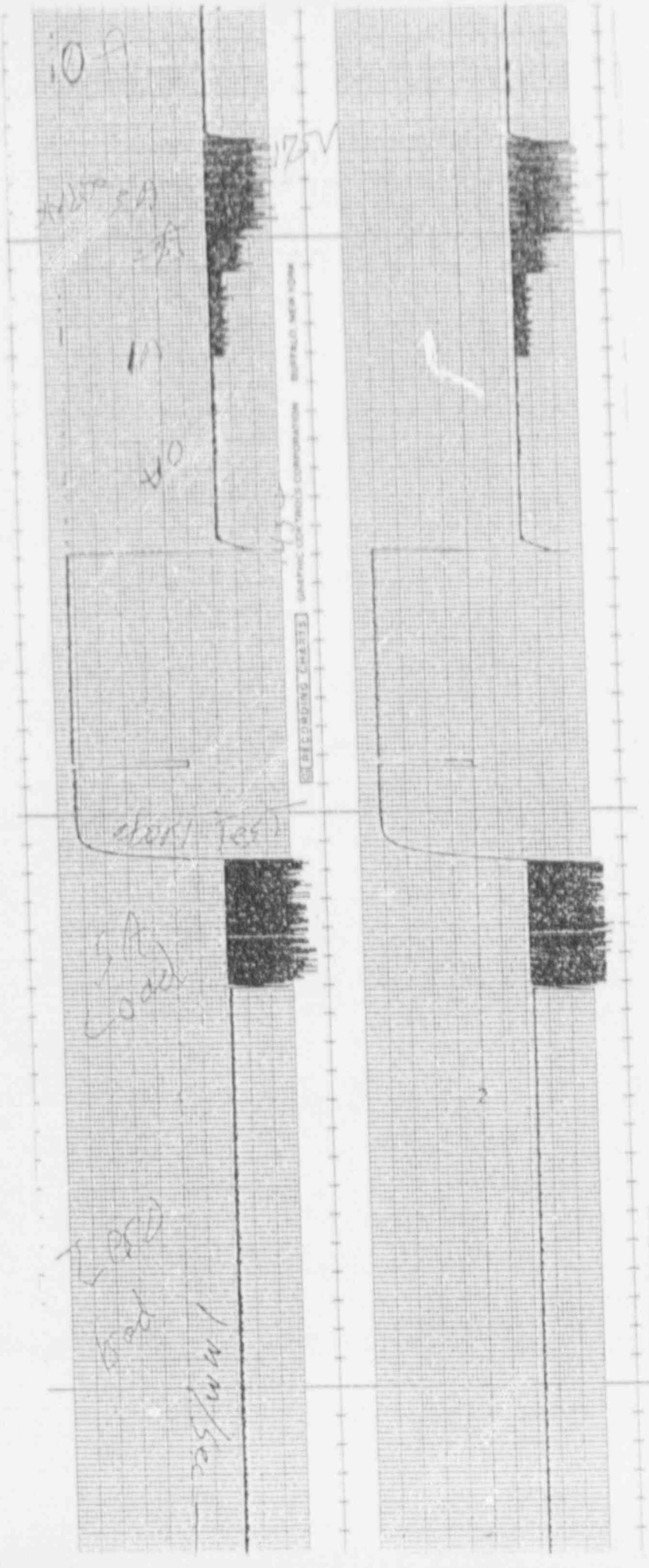


Figure C11: As Found Output Voltage With Various Loads Applied for Battery Charger 4A

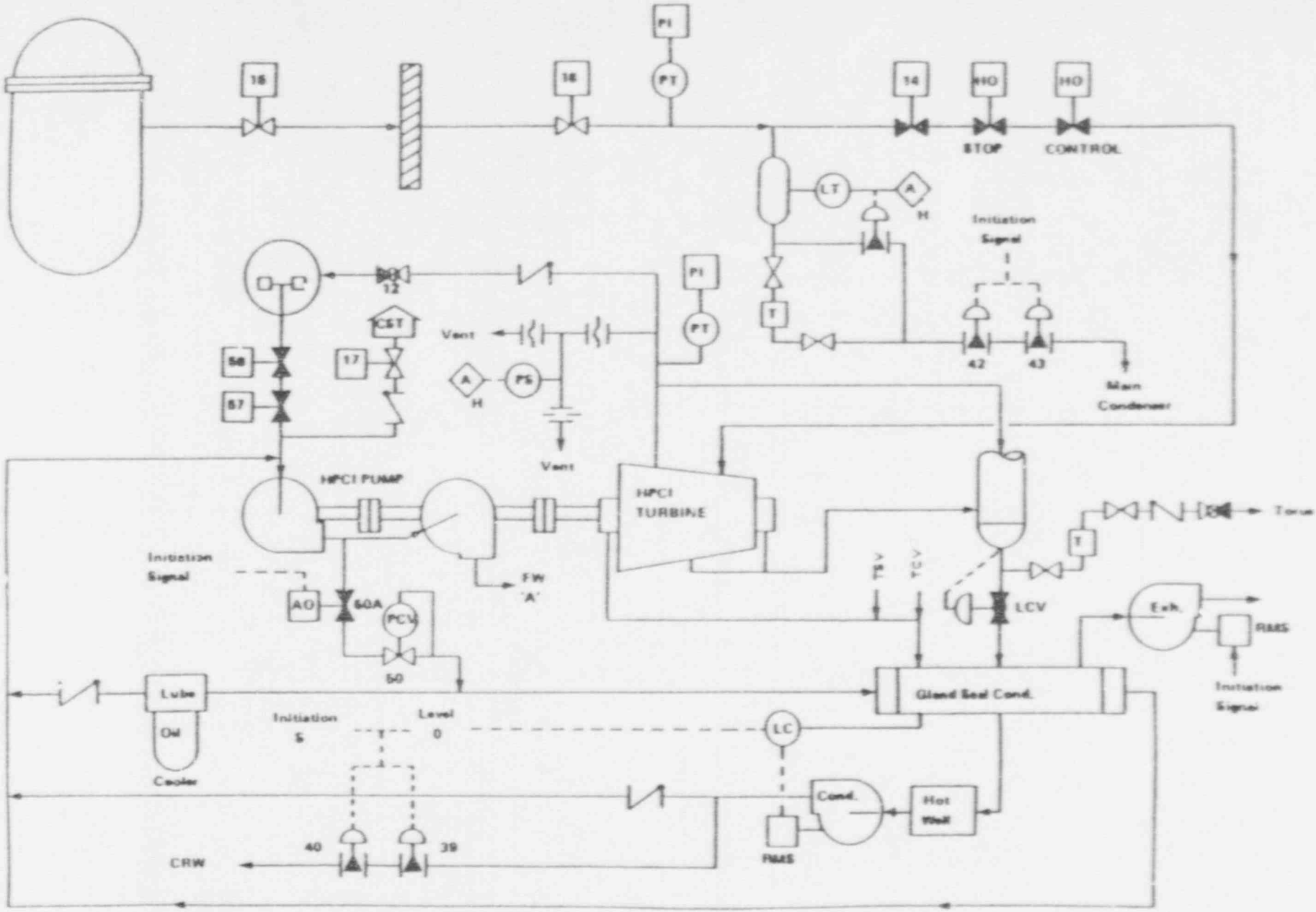


Figure C12:High Pressure Coolant Injection

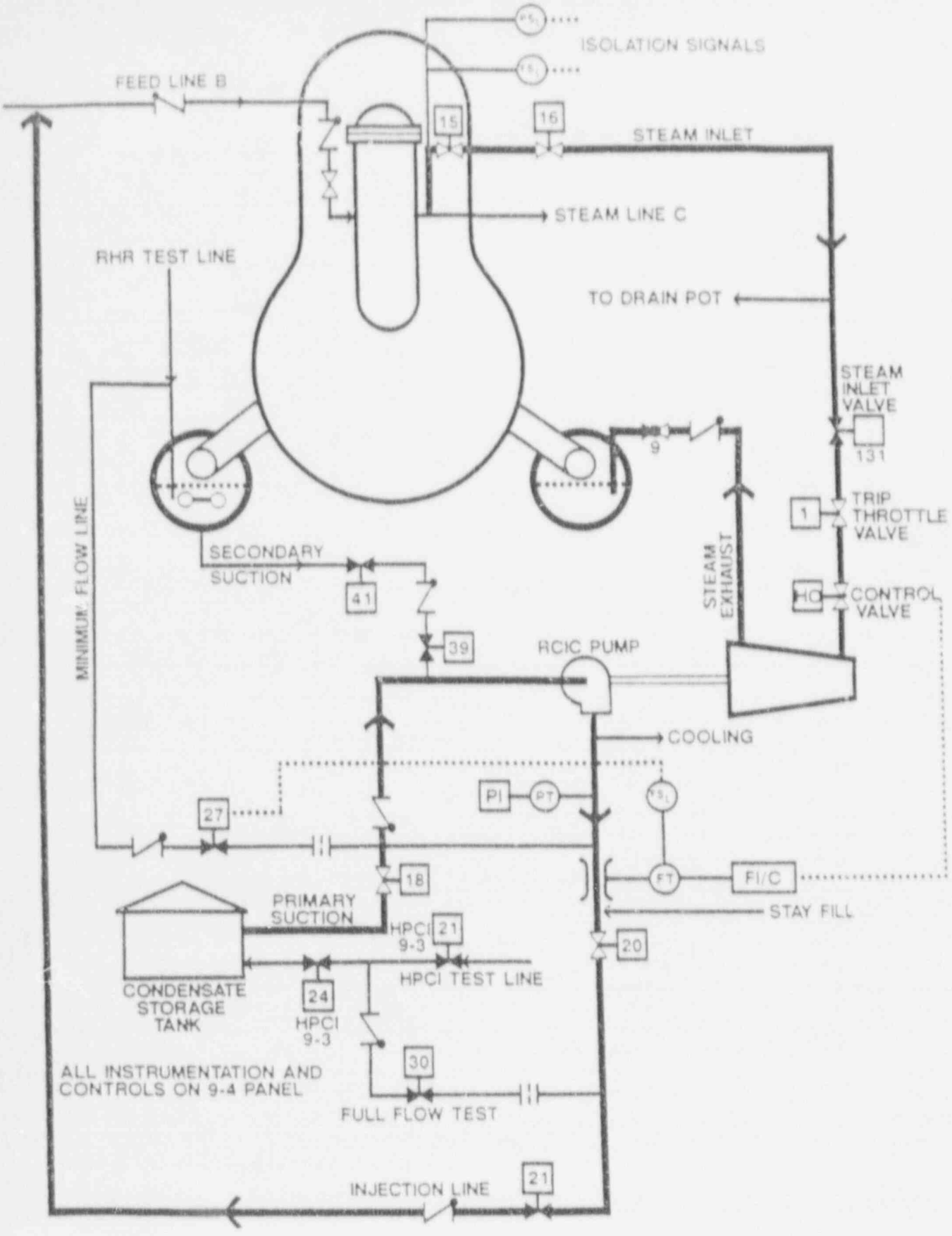


Figure C13: Reactor Core Isolation Cooling

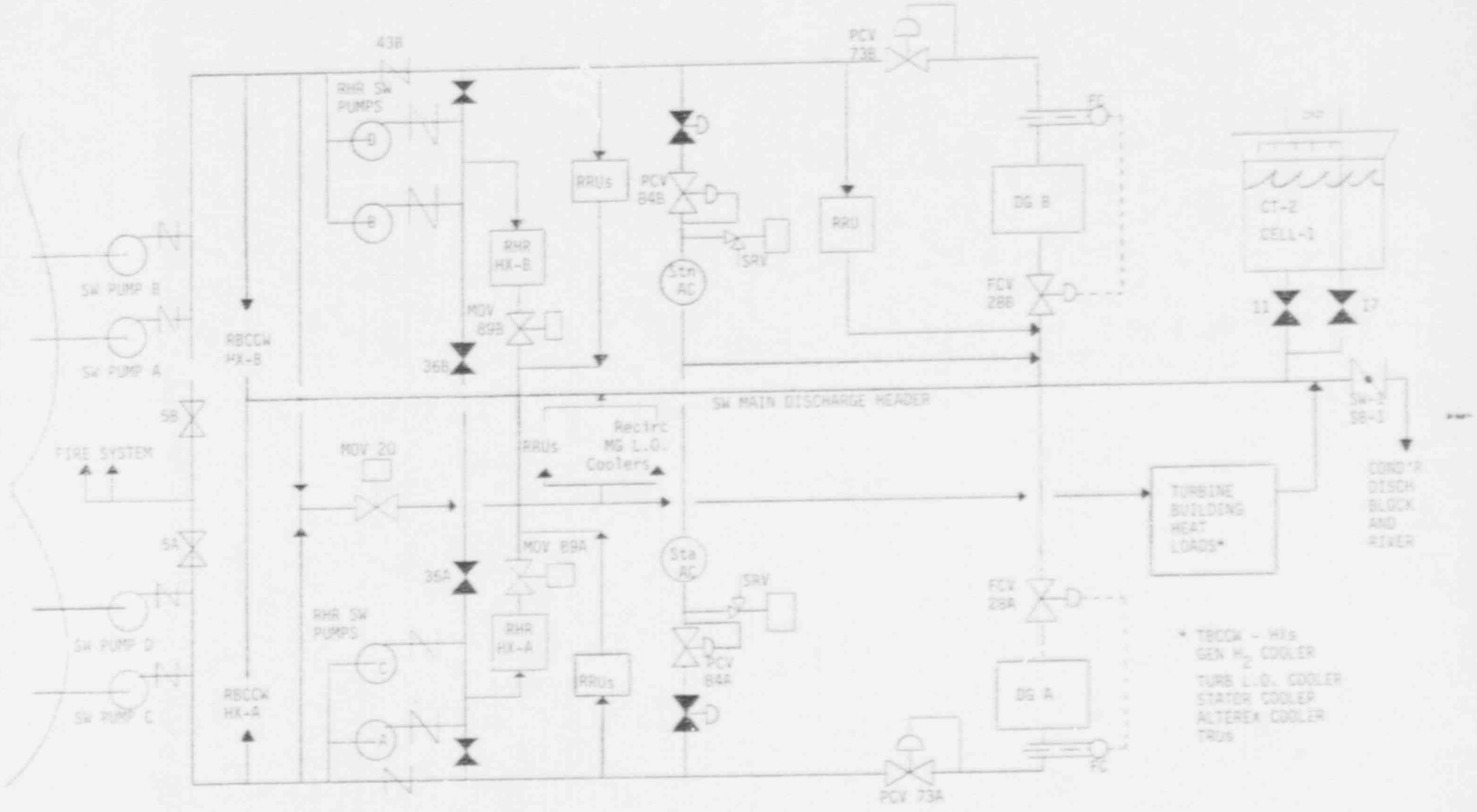


Figure C14:Service Water Simplified Diagram

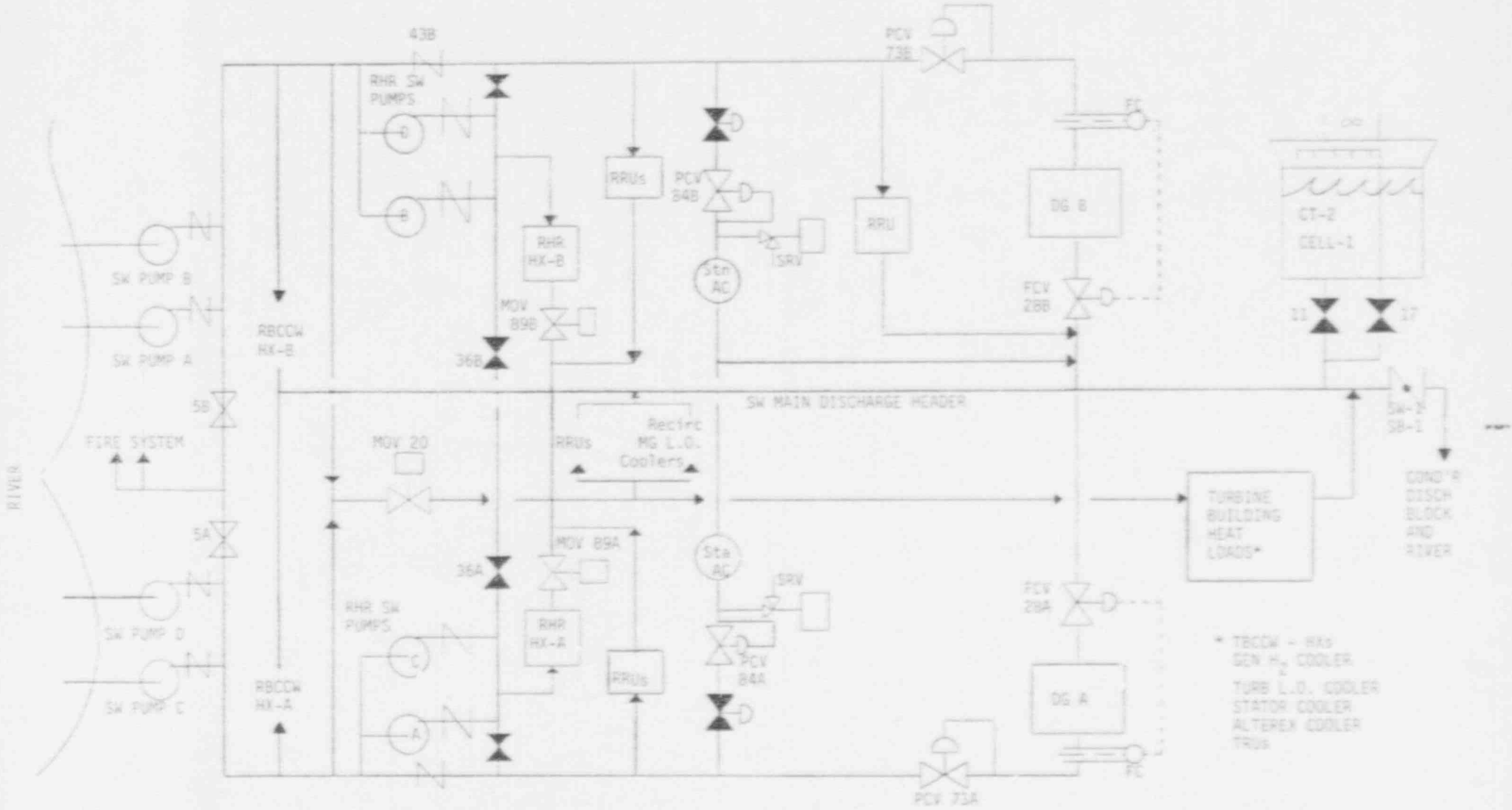


Figure C14:Service Water Simplified Diagram

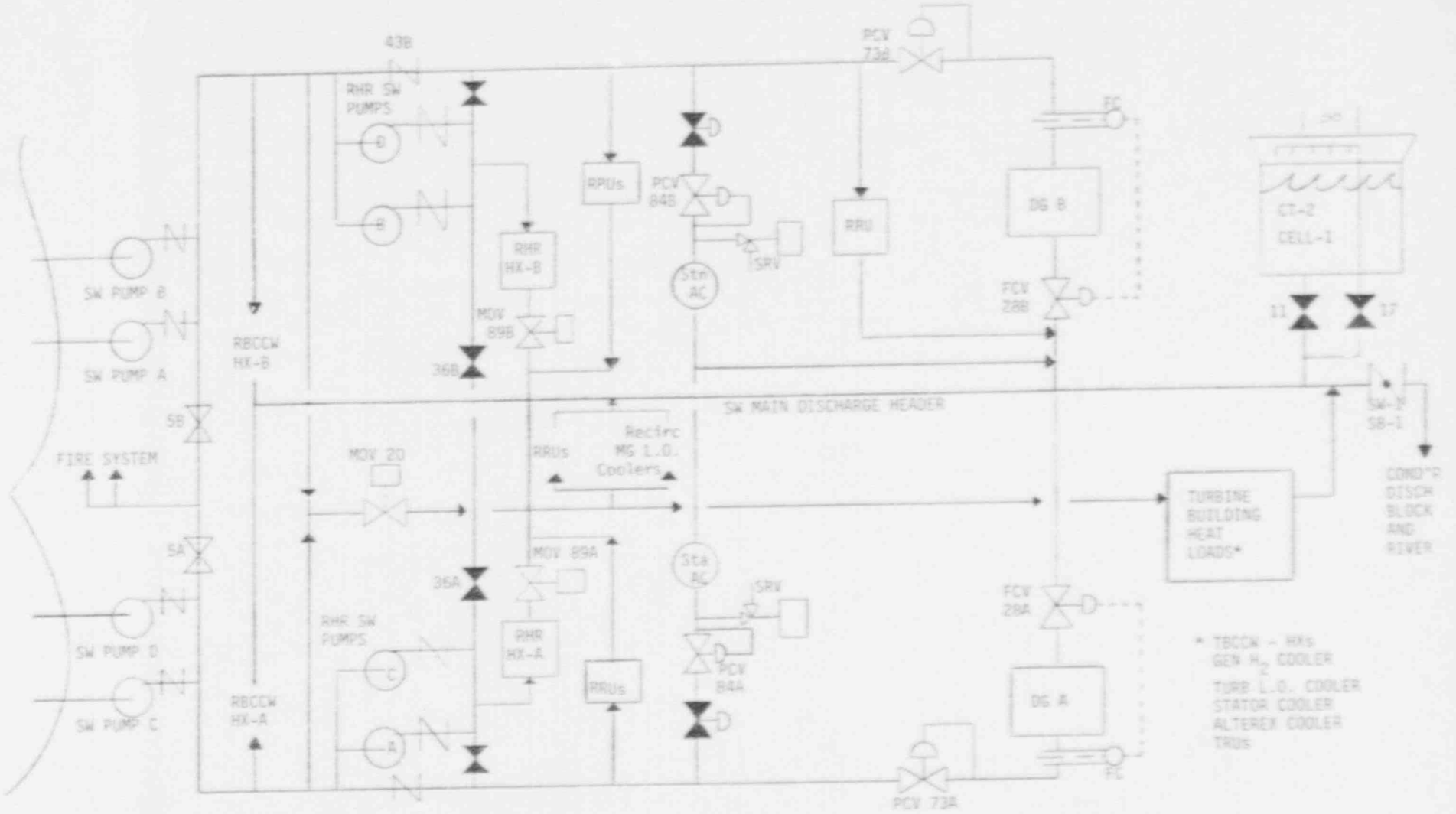


Figure C14:Service Water Simplified Diagram

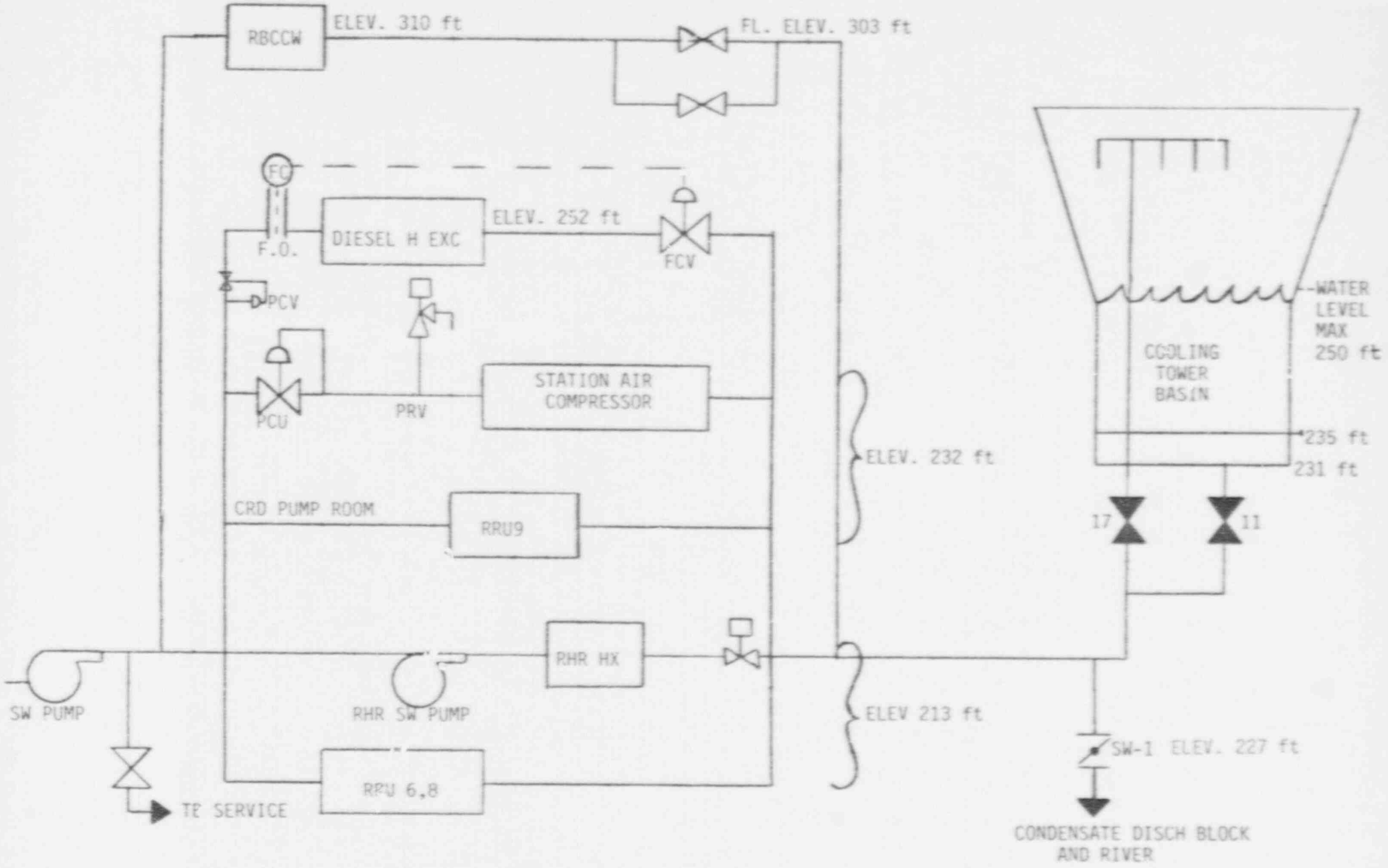
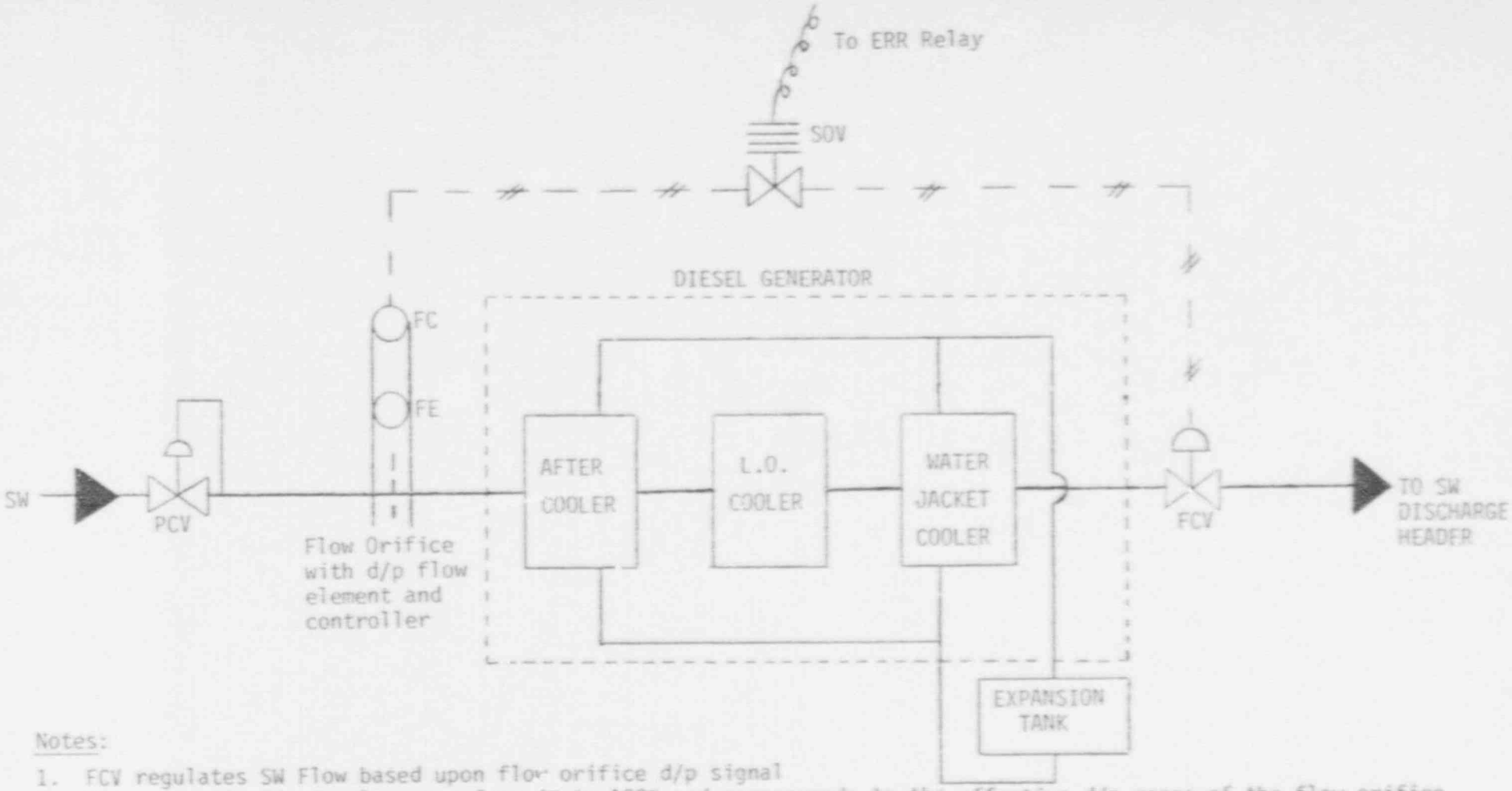


Figure C15: Simplified Service Water - Relative Elevations



Notes:

1. FCV regulates SW Flow based upon flow orifice d/p signal
2. The pneumatic FC signal ranges from 0% to 100% and corresponds to the effective d/p range of the flow orifice
3. 87% on the controller corresponds to approx. 700 gpm. If SW flow drops below 700 gpm, the FCV opens accordingly. In the full open position, the FCV can pass approx. 800 gpm.
4. The SOV in the pneumatic line opens in response to an engine running relay which energizes when the diesel reaches 810 rpm (rated speed is 900 rpm).
5. The after cooler, L.O. cooler, and water jacket cooler each have their own internal temperature control valves that open after temperature exceeds a preset limit.
6. The FCV self regulates to reduce SW pressure to approx. 60 psi.

Figure C16: Diesel Generator Cooling

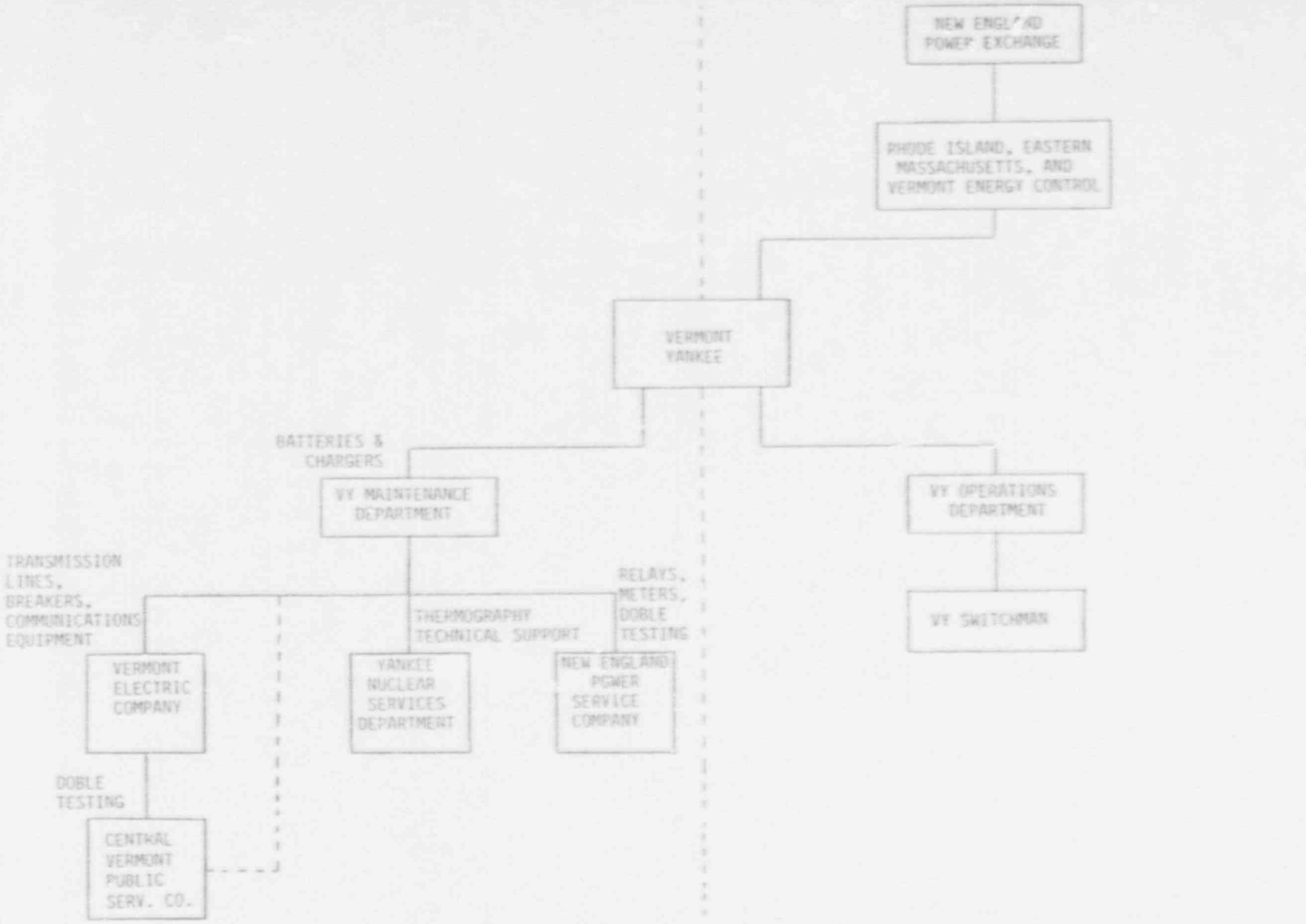


Figure C17: Vermont Yankee Switchyard Organizational Responsibility Chart

APPENDIX D

Photographs

Figure Number	Description
D1	115 kV Oil Circuit Breaker (OCB) K186
D2	345 kV Air Blast Circuit Breaker 381
D3	Battery Chargers A and B for the 5A Bus
D4	Breaker Failure Relay for OCB K40 Westinghouse (now ABB) Model SBFU
D5	Trip Card from Breaker Failure Relay (SBFU) showing Zener Diode Z2 Removed
D6	Zener Diodes (Z2) Removed from BFR Trip Cards Left - Operable Diode, Right - Shorted Diode from BFR for ATB 381

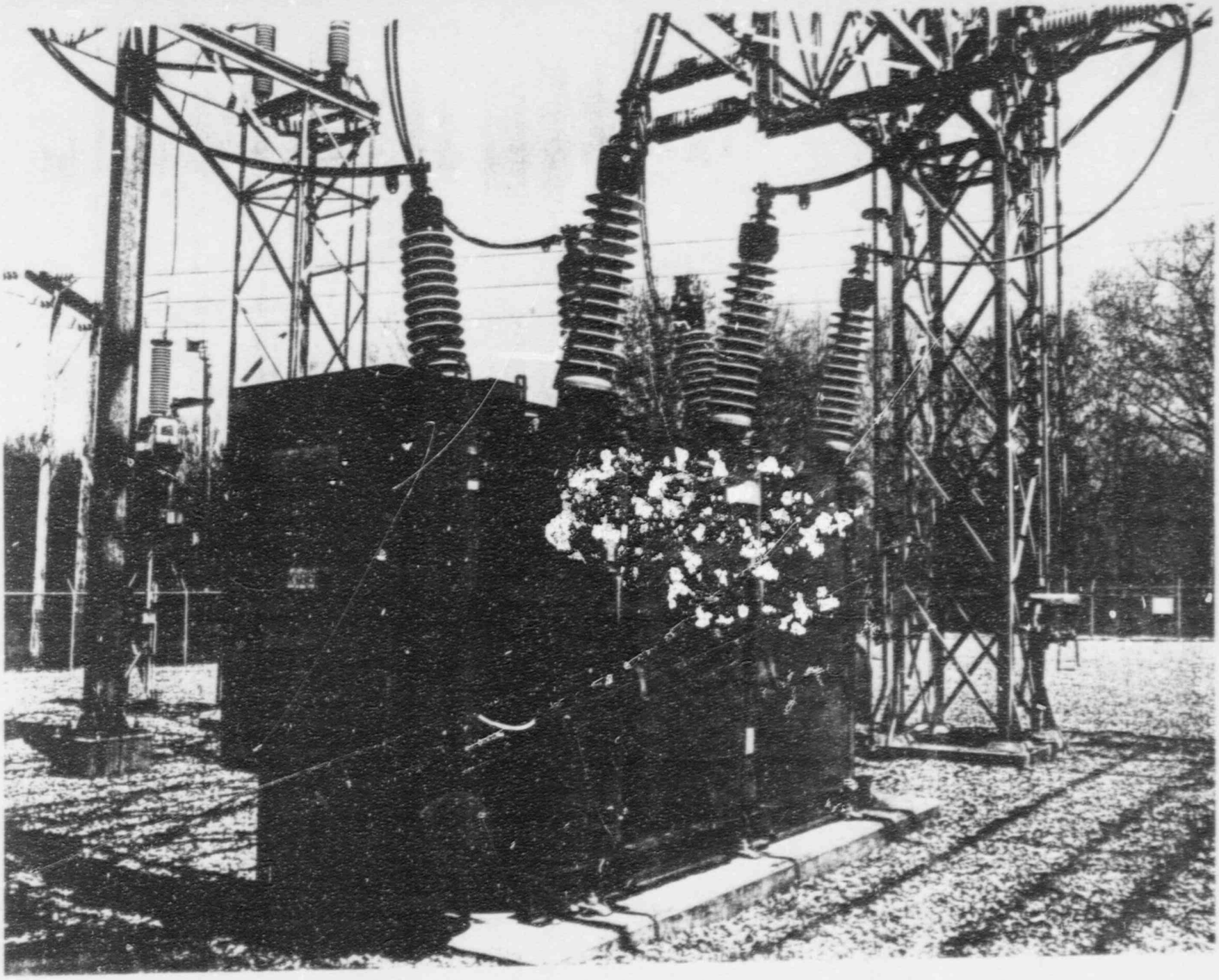


Figure D1 115 kV Oil Circuit Breaker (OCB) K186

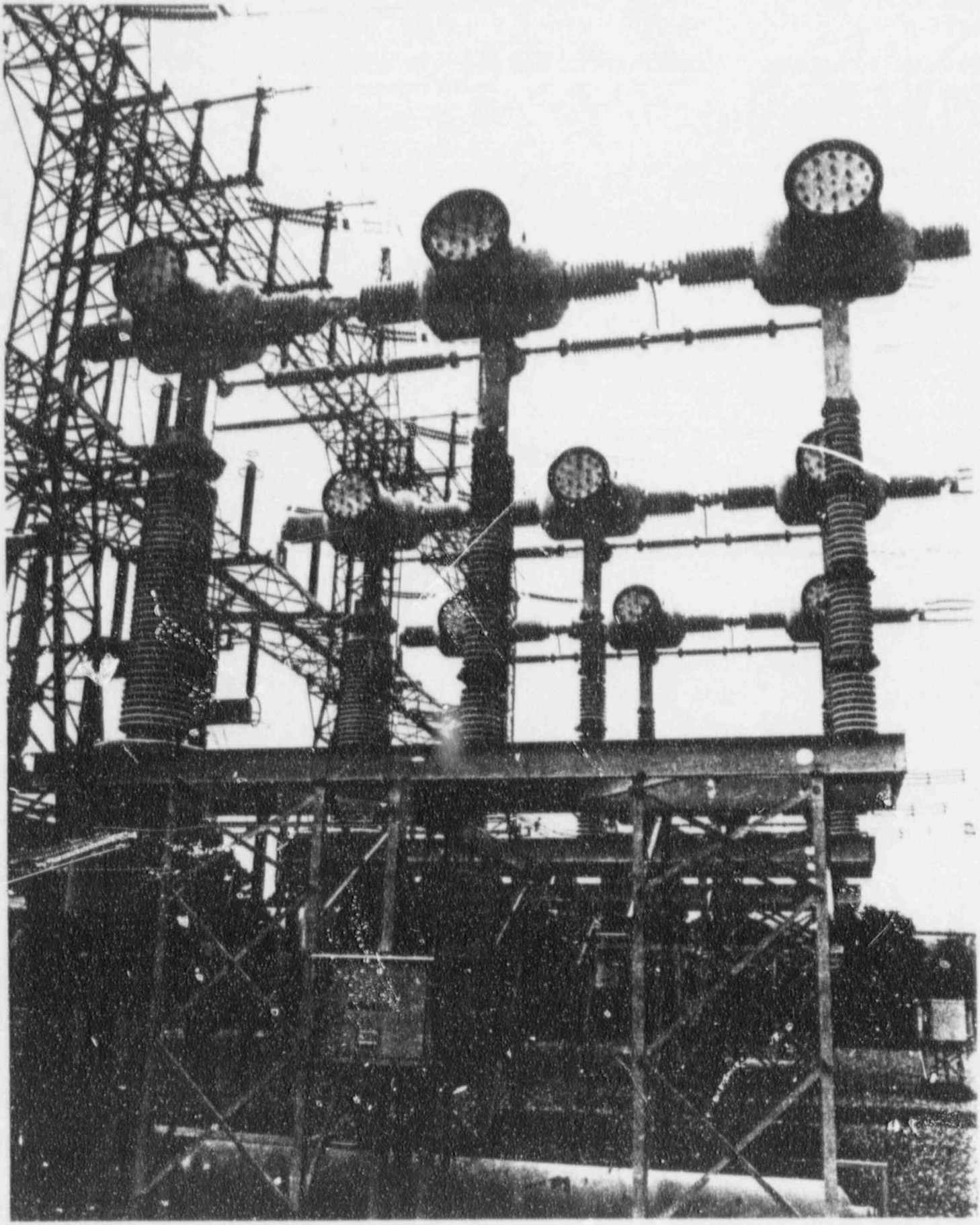


Figure D2 345 kV Air Blast Circuit Breaker 381

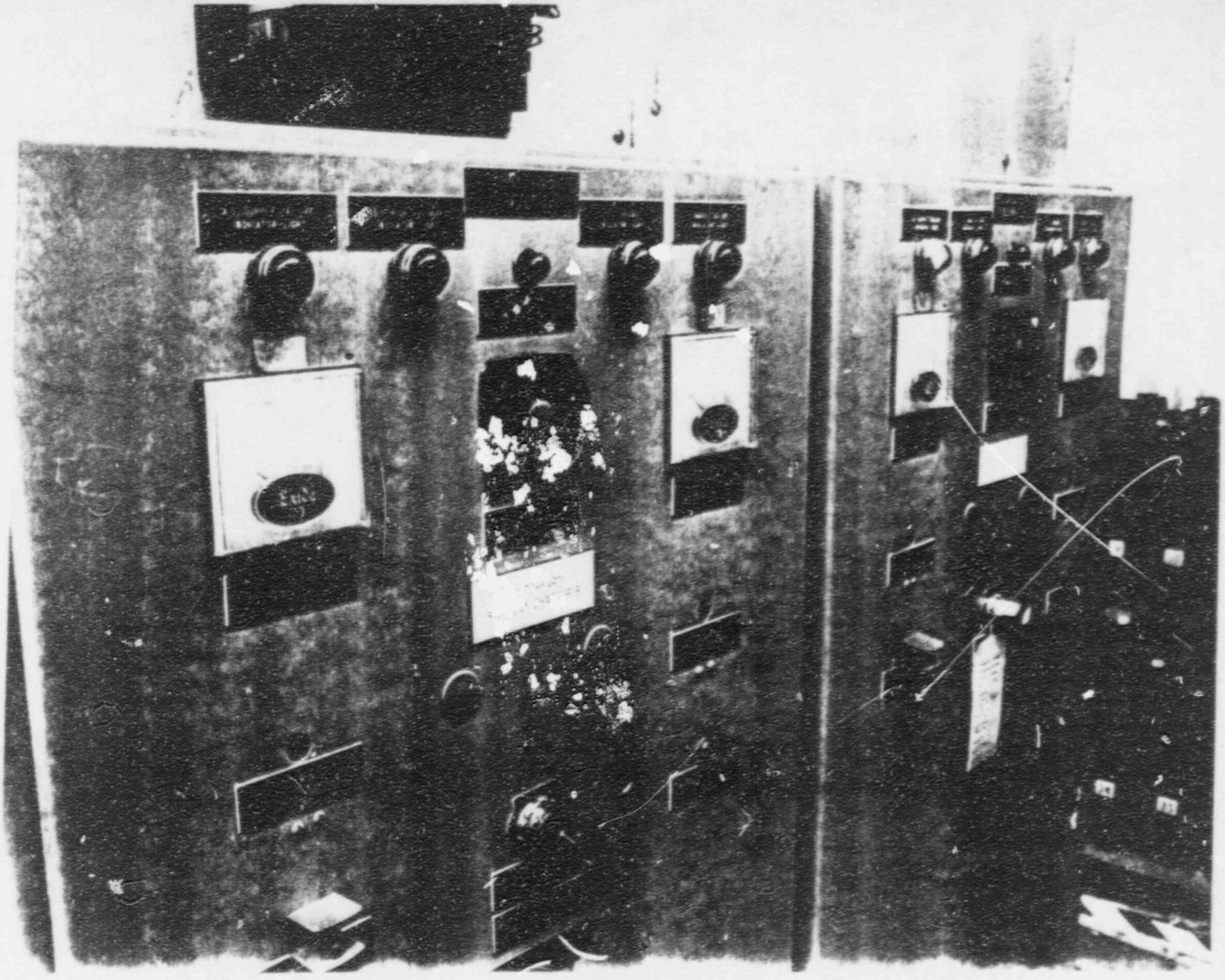


Figure D3 Battery Chargers A and B for the 5A Bus

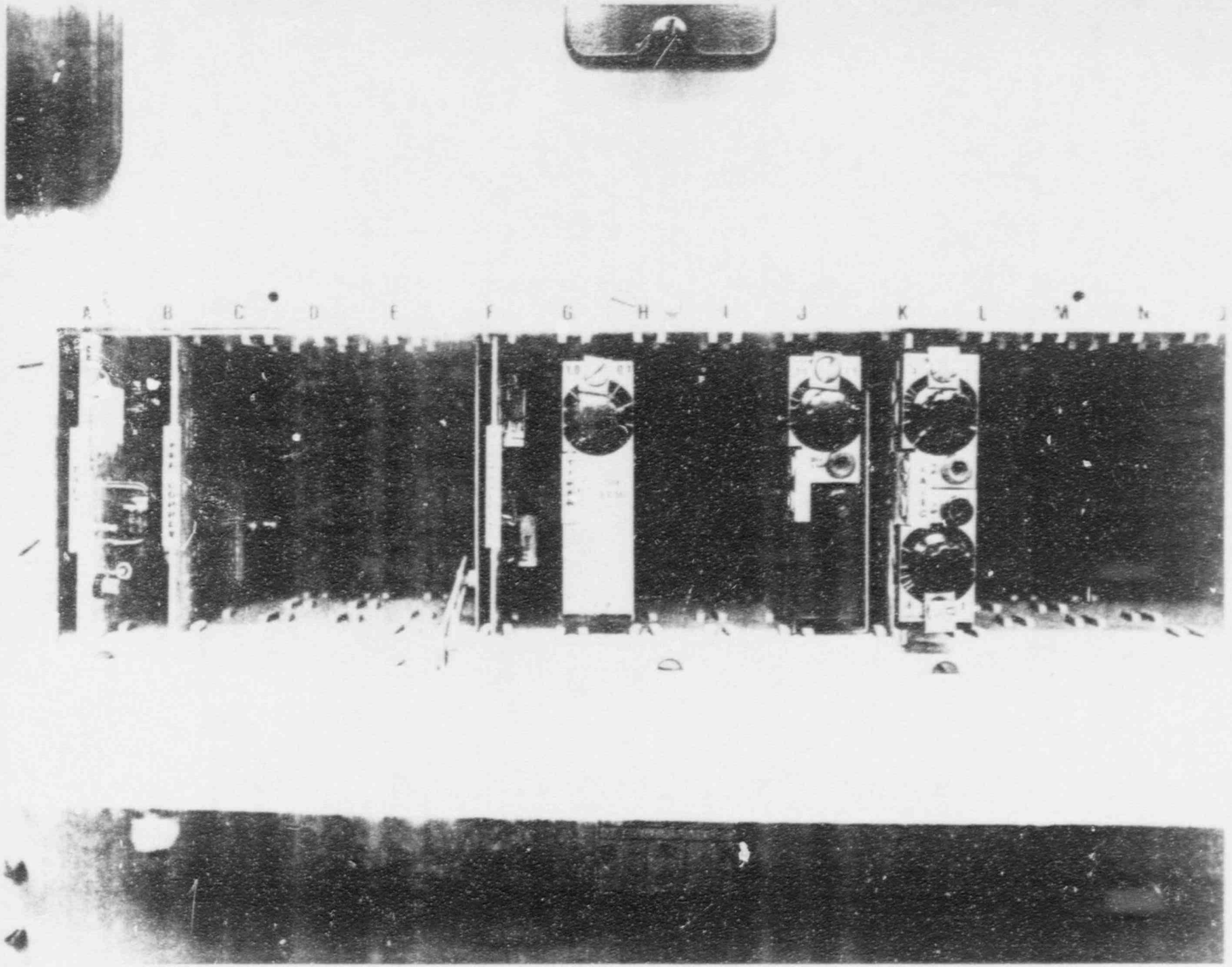


Figure D4 Breaker Failure Relay for OCB K40 Westinghouse (now ABB) Model SBFU

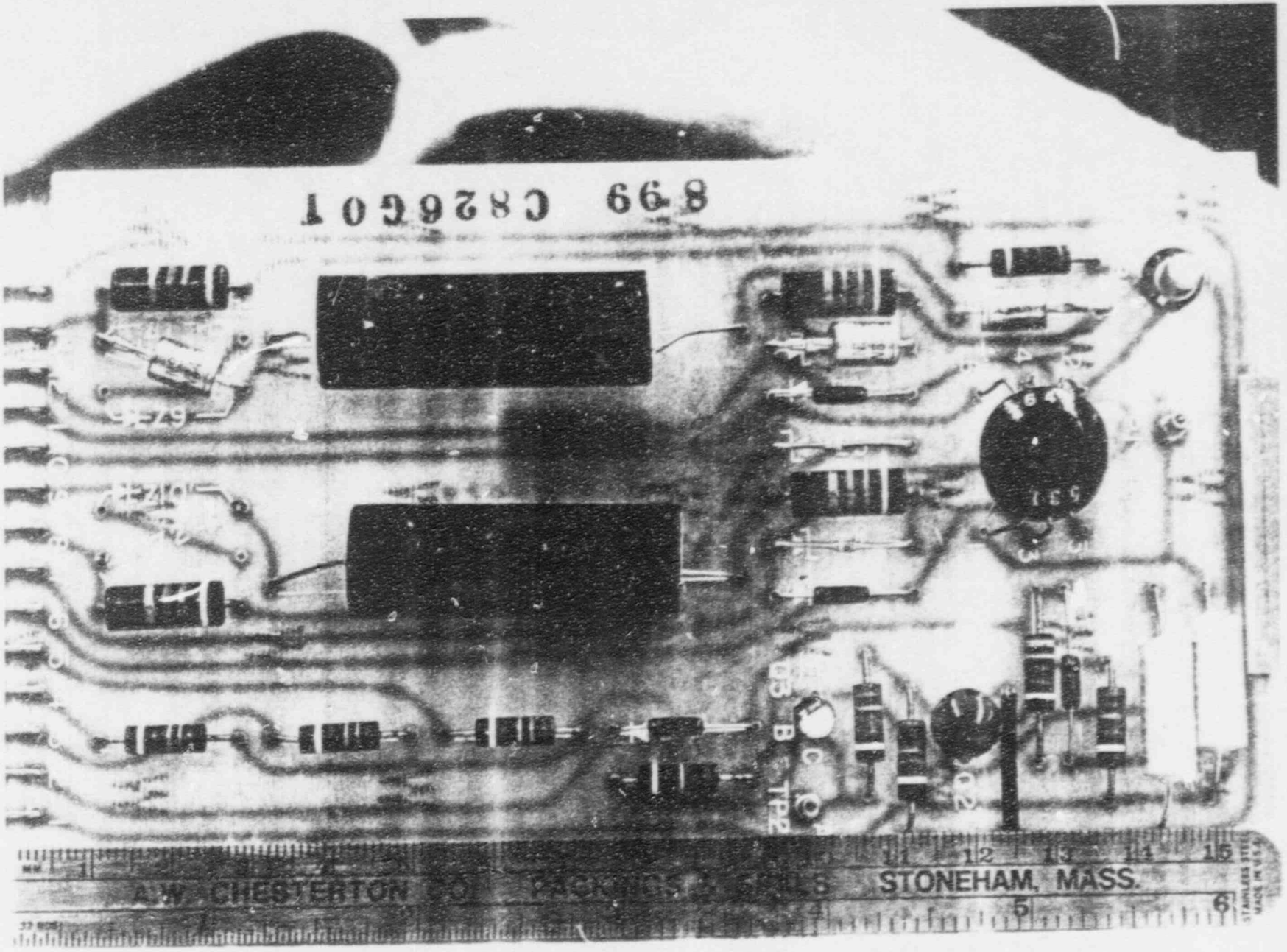


Figure D5 Trip Card from Breaker Failure Relay (SBFU) showing Zener Diode Z2 Removed

Figure D6 Zener Diodes (Z2) Removed from BFR Trip Cards
Left - Operable Diode, Right - Shorted Diode from BFR for ATB 381

APPENDIX E

Acronyms And Initialisms

1E	Class 1E electrical
ABB	ASEA-Brown Boveri
AC	alternating current
AEOD	office for Analysis of Events and Operational Data
AIT	augmented inspection team
AMP	amperes
APRM	average power range monitor
ARP	alarm report printout
ATB	air trip breaker
BFI	breaker failure instrumentation
BFR	breaker failure relay
BOP	balance of plant
CAR	corrective action report
CFR	Code of Federal Regulations
CRD	control rod drive (mechanism)
CRP	control room panel
CST	condensate storage tank
CVPS	Central Vermont Public Service Company
DC	direct current
DCO	duty call officer
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EB	Engineering Branch (of DRS)
EDG	emergency diesel generator
ENS	emergency notification system
EOF	emergency operations facility
ERFIS	emergency response facilities information system
ESF	engineered safety feature
EST	eastern standard time
FC	flow controller
FCV	flow control valve
FE	flow element
FO	flow orifice
FSAR	final safety analysis report
GDC	general design criteria
HPCI	high pressure coolant injection
HX	heat exchanger
IEEE	Institute of Electrical and Electronics Engineers
kV	kilovolts
LBF	local breaker failure
LCO	limiting condition for operation
LNP	loss of normal power

LOCA	loss of coolant accident
LOOP	loss of offsite power
MAINT	Maintenance Department
MC	Manual Chapter
MG	motor generator
MOD	motor operated disconnect
MR	maintenance request
MSIV	main steam isolation valve
mV	millivolts
MVA	mega volt-amperes
MW	megawatts
NEPEX	New England Power Exchange
NEPSCO	New England Power Service Company
NNS	non nuclear safety
NRC	Nuclear Regulatory Commission
NRR	office for Nuclear Reactor Regulation
NSS	non-safety system
OCB	oil circuit breaker
OPS	Operations Branch (of DRS) or Operations Department
OSC	operational support center
PCIS	primary containment isolation system
PCV	pressure control valve
PORC	plant operation review committee
psig	pounds per square inch (gauge)
QA	quality assurance
RBCCW	reactor building closed cooling water
RCA	radiologically controlled area
RCIC	reactor core isolation cooling
REFUEL	refueling mode of operations
REMVEC	Rhode Island, Eastern Massachusetts, and Vermont Energy Control
RHR	residual heat removal
RHRSW	residual heat removal service water
RMS	root mean square
RPS	reactor protection system
RPV	reactor pressure vessel
RRU	reactor (building) recirculation unit (room cooler)
SBFU	static breaker failure unit
SCR	silicon controlled rectifier
SOE	sequence of events
SRV	safety relief valve
SW	service water
TBCCW	turbine building closed cooling water
TRU	turbine (building) recirculation unit (room cooler)
TS	technical specifications
TSC	technical support center

V	volts
VA	volt-amperes
VELCO	Vermont Electric Power Company
VY	Vermont Yankee
VYNPS	Vermont Yankee Nuclear Power Station
YNSD	Yankee Nuclear Services Department

APPENDIX F

Licensee Developed Post Trip Review

Portions of the Licensee Developed Post Trip Review were selected from the list of attachments shown below. These selections have been provided herewith as Appendix F, however, the full attachments listed below are not provided in this report.

ATTACHMENT 1	Operations and REMVEC Logs
ATTACHMENT 2	Maintenance Department Guideline For Maintenance of Switchyard House Battery Systems and TM 89-55
ATTACHMENT 3	December 27, 1972 Scram Information
ATTACHMENT 4	Copy of OP 3500, Appendicies I, III and IV
ATTACHMENT 5	ERFIS SOE and ARP Logs
ATTACHMENT 6	CRP Recorder Outputs and ERFIS Plots
ATTACHMENT 7	Information on Unexpected Aspects
ATTACHMENT 8	ERFIS BOP/NSS Logs
ATTACHMENT 9	ERFIS Turbine Logs
ATTACHMENT 10	Management Status/Tracking List, dated 4-25-91, 1500
ATTACHMENT 11	Torus Water Inventory Control Recovery Operations For 4-23-91 Scram
ATTACHMENT 12	RCIC Overspeed Trip During 4-23-91 Scram
ATTACHMENT 13	Review of NRC Red Phone Notifications During 4-23-91 Scram
ATTACHMENT 14	Radwaste Operations Sequence of Events During 4-23-91 Scram

Prepared by:_____
Reviewed by:_____

DEPARTMENT GUIDELINE FOR MAINTENANCE OF SWITCHYARD HOUSE BATTERY SYSTEMS

1.0 PURPOSE

To provide instructions for placing the switchyard batteries out of service for maintenace while providing an adequate and ripple free source of power to both Switchyard DC Distribution Panels.

2.0 DISCUSSION

Whenever OP 4210 quarterly and weekly battery surveillances indicate the need for corrective battery maintenance, or to perform annual battery maintenance per OP 4210 or perform a discharge test of either battery, one of the two batteries serving the switchyard are required to be placed out of service. Although not classified as Safety Related, these battery systems are required to be operable per Vermont Yankee Technical Specification 3.10. Since the loads on these dc systems (4A and 5A) are not redundant, neither system can provide complete switchyard breaker protection control power on its own. To perform maintenance on either of the Switchyard Batteries or their chargers, an adequate supply of power to DC Distribution Panels DC-4A and DC-5A must be maintained.

This department guideline details the lineups necessary to maintain both Switchyard DC Distribution Panels operable with either Switchyard Battery out of service. DC Distribution Panel 5A is cross tied with DC Distribution Panel 4A through Battery Charger 4A-5A. The opposite battery provides ripple smoothing and surge mitigation while the battery to be maintained is placed out of service. Multiple chargers are placed in parallel to provide an adequate power source for any large power demands greater than that which could be handled by the breakers which cross tie the panels.

3.0 PRECAUTIONS

3.1 Monitor the charger output currents and voltage while operating in parallel, adjusting DC output voltage as necessary to maintain proper battery float voltage and load sharing of the paralleled chargers.

4.0 PREREQUISITES

4.1 Notify REMVEC Dispatcher that one battery will be out of service but that both both primary nad secondary functions will remain available. This notification should be made 48 hours in advance, if possible. 11-10-91

5.0 PROCEDURE

5.1 SWITCHYARD BATTERY 4A:

To perform maintenance on this battery, it must be disconnected from DC Distribution Panel DC-4A. Sufficient power to DC Distribution Panel DC-4A will be provided by the combination of Battery Charger 4A, Battery Charger 4A-5A and backup power from battery 5A. To perform maintenance on Battery 4A while maintaining adequate power to DC Distrubution Panel DC-4A, perform the following:

5.1.1 PLACING SWITCHYARD BATTERY 4A OUT OF SERVICE

5.1.1.1 Verify Battery Charger 4A is supplying panel DC-4A. ____ / 4-10-91

5.1.1.2 Adjust Battery Charger 4A output voltage such that Battery 4A terminal voltage is as close as practical to battery 5A terminal voltage. ____ / 4-10-91

5.1.1.3 Defeat (remove) the mechanical interlock on the output DC breaker on charger 4A-5A. ____ / 4-10-91 (TM)

5.1.1.4 Close the Circuit 30 (90 A) breaker on DC Distribution Panel DC-4A from Battery Charger 4A-5A to connect Battery Charger 4A-5A to DC Distribution Panel DC-4A. ____ / 4-10-91

5.1.1.5 Close the Circuit 18 (90 A) breaker on DC Distribution Panel DC-5A from Battery Charger 4A-5A to connect Battery Charger 4A-5A to DC Distribution Panel DC-5A. ____ / 4-10-91

5.1.1.6 Close the DC output breaker on Battery Charger 4A-5A which feeds DC Distribution Panel DC-4A. ____ / 4-10-91

5.1.1.7 Close Battery Charger 4A-5A AC input breaker to place the charger in service in parallel with Battery Charger 4A. ____ / 4-10-91

5.1.1.8 Adjust Battery Charger 4A-5A output voltage such that Battery 4A voltage is as close as practical to Battery 5A voltage and the outputs of Battery Chargers 4A and 4A-5A are shared. ____ / 4-10-91

5.1.1.9 Close the DC output breaker on Battery Charger 4A-5A to DC Distribution Panel DC- 5A. This cross-connects DC Distribution Panel DC-4A to DC Distribution Panel DC-5A. ____ / 4-10-91

5.1.1.10. Adjust outputs of Battery Chargers A, B, 4A, and 4A-5A to obtain normal float voltage on battery 5A with the Battery Chargers sharing the loads equally. ____ ____/ 4-10-91

5.1.1.11 Open the battery breaker (circuit 51) on DC Distribution Panel DC- 4A. ____ ____/ 4-10-91

5.1.2 RETURNING SWITCHYARD BATTERY 4A TO SERVICE

5.1.2.1 Open the DC output breaker on Battery Charger 4A-5A to DC Distribution Panel DC-5A to split DC Distribution Panel DC-5A from DC Distribution Panel DC-4A. ____ ____/ ____

5.1.2.2 Adjust the float voltage on Battery 5A with Battery Charger A and B. ____/ ____

Note:

After a test discharge, the following step will require turning the charger output voltage down to approximately 115 volts. If the battery has not been significantly discharged after other maintenance/testing, the following step is not required.

5.1.2.3 If a test discharge had been performed, adjust the voltage of Battery Chargers 4A-5A and 4A to approximate the terminal voltage of Battery 4A.

5.1.2.4 Close the battery breaker (circuit 51) on DC Distribution Panel DC-4A. ____/ ____

NOTE:

If a test discharge had been performed, the following step may require several hours because the chargers will load limit before the desired voltage can be obtained.

5.1.2.5 Adjust the charger output to obtain the desired battery terminal voltage (either float or equalize).

NOTE:

If a test discharge had been performed, the following step may have to be deferred until the charge current is decreased to within the capability of Battery Charger 4A, i.e., less than 50 amps.

5.1.2.6 Open the Battery Charger 4A-5A DC output breaker to DC Distribution Panel DC-4A. ____/ ____

5.1.2.7 Adjust the voltage on Battery 4A with Battery Charger 4A to the desired voltage. ____/ ____

5.1.2.8 Open the AC breaker to Battery Charger 4A-5A to place it out of service. _____/_____

5.1.2.9 Replace the mechanical interlock on the DC breakers on Battery Charger 4A-5A. _____/_____

5.1.2.10 Open the 90 amp breaker (circuit 18) on DC Distribution Panel DC-5A which connects Battery Charger 4A-5A to the panel. _____/_____

5.1.2.11 Open the 90 amp breaker (circuit 30) on DC Distribution Panel DC-4A which connects Battery Charger 4A-5A to the panel. _____/_____

5.2 SWITCHYARD BATTERY 5A:

To perform maintenance on this battery, it must be disconnected from DC Distribution Panel DC-5A. Sufficient power to DC Distribution Panel DC-5A will be provided by the combination of Battery Charger A, Battery Charger B, Battery Charger 4A-5A and backup power from battery 4A. To perform maintenance on Battery 5A while maintaining adequate power to DC Distrubution Panel DC-5A, perform the following:

5.2.1 PLACING SWITCHYARD BATTERY 5A OUT OF SERVICE

5.2.1.1 Verify Battery Charger A and B are both supplying DC Distribution Panel DC-5A. If not, place the idle charger in operation sharing the DC-5A load. N/A /_____

5.2.1.2. Adjust Battery Charger A and B output voltage such that Battery 5A voltage is as close as practical to battery 4A voltage and the load is shared between Battery Chargers A and B. N/A /_____

5.2.1.3 Defeat (remove) the mechanical interlock on the output DC breakers of charger 4A-5A. N/A /_____

5.2.1.4 Close the circuit 30 (90 A) breaker on DC Distribution Panel DC-4A to connect Battery Charger 4A-5A to DC Distribution Panel DC-4A. N/A /_____

5.2.1.5 Close the circuit 18 (90 A) breaker on DC Distribution Panel DC-5A to connect Battery Charger 4A-5A to DC Distribution Panel DC-5A. N/A /_____

5.2.1.6 Close the DC output breaker on Battery Charger 4A-5A which feeds DC Distribution Panel DC-5A. N/A /_____

5.2.1.7 Close the AC input breaker on Battery Charger 4A-5A to place the charger in service in parallel with Battery Charger A and B. N/A /_____

5.2.1.8 Adjust Battery Charger A, B, and 4A-5A output voltage such that Battery 5A voltage is as close as practical to Battery 4A voltage and the outputs of chargers A, B, and 4A-5A are shared. N/A /_____

5.2.1.9 Close the DC output breaker on Battery Charger 4A-5A to DC Distribution Panel DC-4A. This cross-connects DC Distribution Panels DC-4A and DC-5A. N/A /_____

5.2.1.10 Adjust outputs of Battery Chargers A, B, 4A, and 4A-5A to obtain normal float voltage on battery 4A with the battery chargers sharing the load equally. N/A / _____

5.2.1.11 Open the battery breaker (circuit 53) on DC Distribution Panel DC-5A. N/A / _____

5.2.2 RETURNING SWITCHYARD BATTERY 5A TO SERVICE

5.2.2.1. Open the Battery Charger 4A-5A DC output breaker to DC Distribution Panel DC-4A to split DC Distribution Panel DC-4A from DC-5A. N/A / _____

5.2.2.2 Adjust the float voltage on Battery 4A with Battery Charger 4A. N/A / _____

Note:

After a test discharge, the following step will require turning the charger output voltage down to approximately 115 volts. If the battery has not been significantly discharged after other maintenance/testing, the following step is not required.

5.2.2.3 If a test discharge had been performed, adjust the voltage of Battery Chargers A, B and 4A-5A to approximate the terminal voltage of Battery 5A.

5.2.2.4 Close the battery breaker (circuit 53) on DC Distribution Panel DC-5A. N/A / _____

NOTE:

The following two steps may be skipped at the option of Operations to keep Battery Charger A and Battery Charger B both operating.

5.2.2.5 Open the AC breaker on Battery Charger A or B to place it out of service. N/A / _____

5.2.2.6 Open the DC breaker on the same Battery Charger as above. N/A / _____

NOTE:

If a test discharge had been performed, the following step may require several hours because the chargers will load limit before the desired voltage can be obtained.

5.2.2.7 Adjust to obtain the desired float or equalizing voltage on Battery 5A with Battery Chargers A, B (if left on line) and 4A-5A. N/A / _____

NOTE:

If a test discharge had been performed, the following step may have to be deferred until the charge current is decreased to within the capability of Battery Charger A and B, i.e., less than 50 amps per charger.

5.2.2.8 Open the AC breaker to Battery Charger 4A-5A to place it out of service. N/A / _____

5.2.2.9 Open the Battery Charger 4A-5A DC output breaker to DC Distribution Panel DC-5A. N/A / _____

5.2.2.10 Adjust the float voltage on Battery 5A with Battery Charger A and B. N/A / _____

5.2.2.11 Replace the mechanical interlock on the DC breakers on Battery Charger 4A-5A. N/A / _____

5.2.2.12 Open the 90 amp breaker (circuit 18) on DC Distribution Panel DC-5A which connects Battery Charger 4A-5A to the panel. N/A / _____

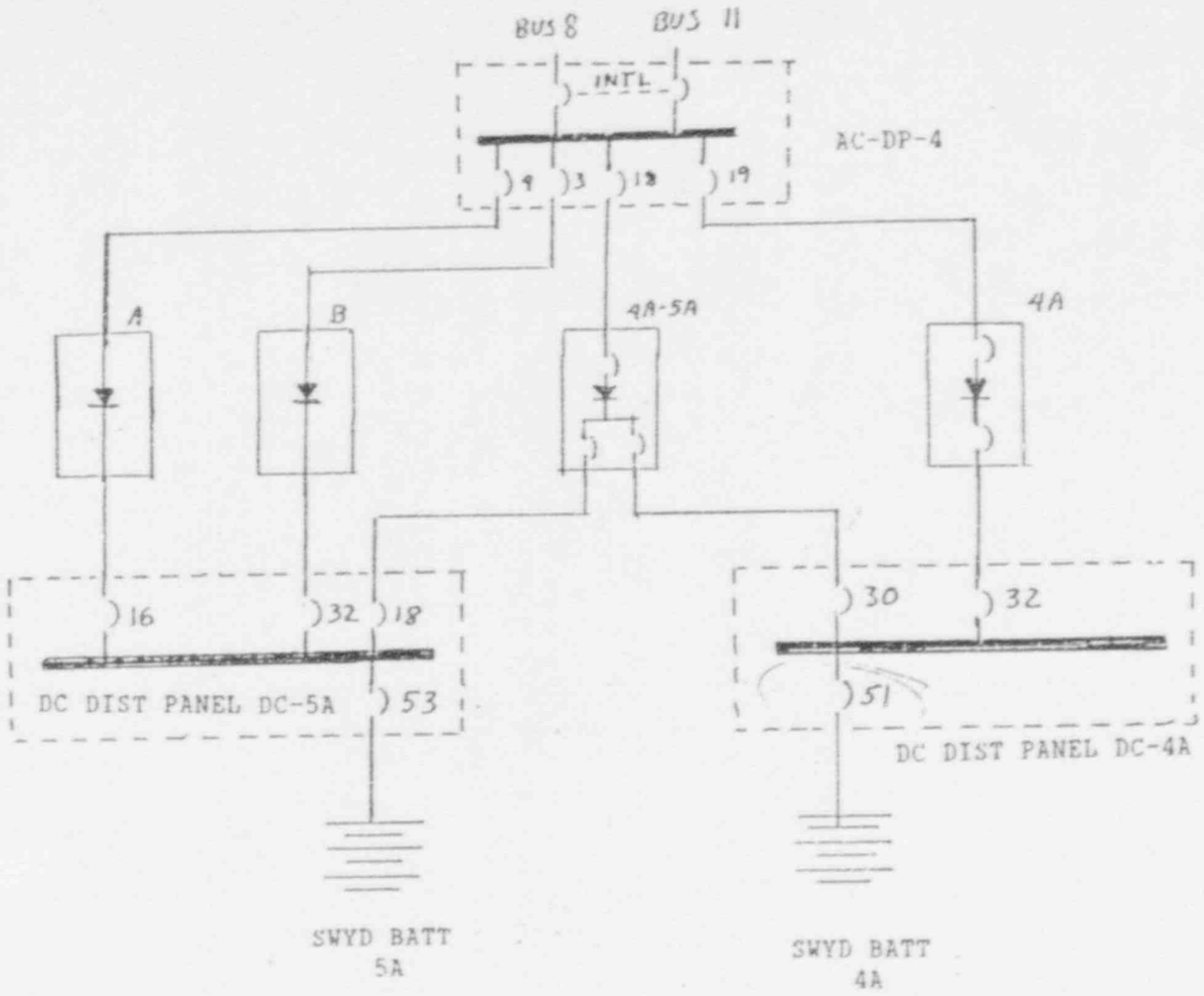
5.2.2.13 Open the 90 amp breaker (circuit 30) on DC Distribution Panel DC-4A which connects Battery Charger 4A-5A to the panel. N/A / _____

6.0 FINAL CONDITIONS

6.1 Panel DC-4A is energized with Battery 4A maintained at float voltage by Battery Charger 4A. _____ / _____

6.2 Panel DC-5A is energized with Battery 5A maintained at float voltage by Battery Charger A and/or B. _____ / _____

Note: Call when Battery has been returned to Service, for REMVEC notification. _____ / _____



SWITCHYARD HOUSE DC DISTRIBUTION ONE-LINE DIAGRAM

Review of Torus Water Volume Control
and
Radwaste Operations During 4-23-91 Scram

Introduction:

On April 23, 1991, a reactor scram and a loss of offsite power occurred at Vermont Yankee due to a DC control power transient in the Switchyard DC Distribution Panels DC-4A and/or DC-5A. During response to this event, Emergency Operating Procedure OE-3104, "Torus Temperature and Level Control Procedure" was twice entered due to Torus water volume exceeding the Technical Specifications maximum limit. This also resulted in the entry into the required Technical Specifications LCO action statement. In both occurrences, actions were taken in accordance with OE-3104 to reduce Torus water volume.

This report will review the actions taken in response to the April 23, 1991 event to determine if the actions were taken in a timely, prudent, conservative and technically correct manner.

Torus Water Volume Limits Basis:

Vermont Yankee Technical Specifications Section 3.7.A.1 establishes minimum and maximum Torus water volumes of 68,000 cubic feet and 70,000 cubic feet, respectively, whenever primary containment is required. Primary containment is required at all times when the reactor is critical or when the reactor water temperature is above 212 °F and fuel is in the reactor vessel.

When combined with the Technical Specifications Section 3.7.A.9 requirement to maintain the drywell-suppression chamber differential pressure of 1.7 psid, the above volume limits correspond to a Torus water level range of 10.97 to 11.21 feet and a downcomer submergence range of 4.29 to 4.54 feet. Within these ranges, all stresses in the suppression chamber structure, including shell, external supports, vent system, internal structures, and attached piping meet the structural acceptance criteria of NUREG-0661 when subjected to post-LOCA suppression pool hydrodynamic forces. It should be noted that the ASME Code allowable stresses are not approached for any of the above components until Torus water level exceeds 16.0 feet, the lower limit of the SRV Tail Pipe Level Limit Curve provided in OE-3104. This corresponds to a Torus water volume of 112,360 cubic feet.

As such, primary containment integrity and proper function following a LOCA was assured at all times during the April 23, 1991 event.

Technical Specification LCO Action Statements:

Vermont Yankee Technical Specifications Section 3.7.A.8 requires that an orderly shutdown be initiated immediately and the reactor be in a cold shutdown condition within 24 hours if the Torus water volume cannot be maintained between the limits of 68,000 and 70,000 cubic feet. The reactor is shut down and RPV pressure reduced in a timely manner to lessen the suppression pool hydrodynamic forces in the event a LOCA should occur. During the time Torus water volume exceeded the 70,000 cubic foot limit, the concern was to ensure that the hydrodynamic forces would not exceed the previously analyzed NUREG-0661 value range. As described above, containment integrity was still assured.

A detailed sequence of event for the April 23, 1991 event is provided later within this report and in Post Trip Report 91-02. However, in summary, a review of Operations and computer logs indicate that the maximum Torus water volume of 70,000 cubic feet was first exceeded at 1533. At that time, the above LCO action statement was entered and Torus water volume reduction actions were undertaken in accordance with OE-3104. These actions were successful and Torus water volume was reduced and maintained below 70,000 cubic feet. The LCO action statement and OE-3104 were exited at 1551. Torus water volume exceeded the Technical Specifications limit for a total time period of 18 minutes.

Further in the event, at 2112, Torus water volume was not able to be maintained below 70,000 cubic feet, the LCO action statement was again entered and Torus water volume reduction actions were again undertaken in accordance with OE-3104. The Torus water volume remained above 70,000 cubic feet until 1925 on April 24, 1991. The LCO action statement and OE-3104 were exited at this time and Torus water volume exceeded the Technical Specifications limit for a total time period of 23 hours, 3 minutes.

As such, in both cases the Technical Specifications LCO action statement was complied with.

OE-3104 Actions:

The Vermont Yankee Emergency Operating Procedures (EOPs) provide comprehensive technical direction for the operation of plant during emergency response conditions. The EOPs are symptom based, rather than event based, and address all mechanistically possible plant conditions for which generic operational guidance can be provided. The operational guidance is specified to derive the best possible success paths for a wide spectrum of events.

The purpose of OE-3104, "Torus Temperature and Level Control Procedure," is to maintain primary containment integrity and protect equipment in the primary containment with respect to the consequences of all mechanistic events. The procedure is entered whenever Torus water temperature is above the Technical

Specifications Section 3.7.A.1 normal operating limit of 100 °F or Torus water volume is below 68,000 cubic feet or above 70,000 cubic feet.

Two parallel action legs are established in OE-3104, one for each of the parameters being controlled, i.e., Torus water temperature and volume. Since action taken to control one of the parameters may affect control of the other, the parameters are controlled concurrently. In the case of Torus water temperature control, the temperature was maintained below the 100 °F limit for the course of the event by the use of the RHR System in the Torus Cooling mode.

For the high Torus water volume condition, the operator is first directed to reduce Torus water volume using one or more of the following systems:

- RHR - Operated in accordance with OP 2124, "Residual Heat Removal System". In this case, Torus water is transferred to Radwaste where filtration, processing and sampling occur prior to return to the Condensate Storage Tank (CST). Further explanation is provided later within this report

- HPCI- Operated in accordance with Appendix F of OE-3104. In this case, Torus water is transferred directly to the CST with no filtration, processing or sampling.

- RCIC- Operated in accordance with Appendix G of OE-3104. Similar to HPCI, Torus water is transferred directly to the CST with no filtration, processing or sampling.

Should use of the above systems be successful in terminating the rise in Torus water volume and maintaining Torus water level in the safe region of the OE-3104 SRV Tail Pipe Level Limit Curve, no further actions are taken within OE-3104 with the exception of continuing the water volume reduction efforts are continued until Torus water volume is reduced below the 70,000 cubic foot limit. Such was the case during the April 23, 1991 event.

Use of Torus Water Volume Reduction Systems:

As described above, three systems are available for use in reducing Torus water volume in accordance with OE-3104. Two of these systems, HPCI and RCIC, transfer water directly from the Torus to the CST. Use of these systems has the following advantages:

1) Greater flow rates may be obtained. HPCI may pump approximately 4000 gpm and RCIC approximately 400 gpm, whereas RHR may pump approximately 300 gpm.

2) Volume limitations do not exist. Unlike the use of RHR, which is limited by the Radwaste system tanks and processing capacities, use of HPCI or RCIC provides a closed loop configuration. Water is drawn from the CST for RPV makeup. Steam is then transferred from the RPV to the Torus either by HPCI, RCIC or SRVs where it is condensed. The water is then returned to the CST via HPCI or RCIC for reuse.

However, use of these systems result in the following disadvantages and increased risks to the health and safety of the public:

1) The direct transfer of Torus water to the CST, with no filtration, processing or sampling, may result in the release of radioactive gases directly to the atmosphere. The CST is equipped with a 12-inch atmospheric vent.

2) The direct transfer of Torus water to the CST, with no filtration, processing or sampling, may result in the contamination of the CST water. The CST contains high purity, low conductivity, reactor grade water compared to the lower purity, higher conductivity water present within the Torus. Mixing of these two water sources will necessitate the filtration and processing of the entire CST contents, with the resulting increase in spent resin waste.

In summary, RHR is used in preference to HPCI and RCIC, unless the flow rate or volume limitations of RHR are not acceptable. Such was not the case during the April 23, 1991 event. A rapid reduction in Torus water volume below 70,000 cubic feet was not required and the use of filtration, processing and sampling features of RHR was prudent and conservative based on the following:

1) The Recirculation System pumps were secured at the time of the reactor scram. As such, the probability of a LOCA due to a system upset was reduced.

2) All control rods fully inserted at the time of the reactor scram and the reactor heat generation rate was reduced to decay heat levels. As such, the consequences of a LOCA from the heat generation level would be less than those provided in FSAR Chapter 14, which assumes reactor operation at 110% of rated power at the time of the LOCA.

3) The Torus water volume increase was from known sources, i.e., HPCI, RCIC and SRVs, as compared to primary system leakage. As such, the extent of the concerns were known to the operators.

4) The rate of increase was not rapid and the highest Water volume achieved was approximately 72,000 cubic feet, well below the 112,360 cubic foot water volume of concern described earlier in this report. As such, the performance of additional actions in accordance with OE-3104 was not a concern.

Summary of Radwaste Operations:

The purpose of the RHR and Radwaste Systems, when used to reduce Torus water volume, is to collect, store and process the potentially radioactive and high conductivity water in a controlled, safe and economical manner prior to return to the CST for re-use.

Figure 1 provides a comparison of Torus water volume to Radwaste System capacity from the time of the reactor scram at 1448 on April 23, 1991 to the termination of the Unusual Event at 1950 on April 24, 1991. A review of Figure 1 indicates that the Radwaste System was operated at or near capacity during this time period. A detailed sequence of event for Radwaste System Operations is provided later in this report.

Figure 2 provides a simplified flow diagram of the portions of the Radwaste System of interest during the Torus water volume reduction efforts. The following discussion summarizes the operation of this system.

Three tanks are available to collect the discharge of water from the Torus. These are:

1) The Waste Collector Tank - This 25,000 gallon capacity tank normally receives high purity, low conductivity water from the sources shown on Figure 2.

2) The Waste Surge Tank - This 35,000 gallon capacity tank normally receives high purity, low conductivity water from either the RHR or the Reactor Water Cleanup System during transient plant operations or tests. For processing, water is transferred from this tank to the Waste Collector Tank, where further filtering and processing proceeds as described below.

3) The Floor Drain Collector Tank - This 25,000 gallon capacity tank normally receives lower purity, higher conductivity water from the sumps shown on Figure 2 or from the Detergent Waste Tank. For processing, water is transferred from this tank, through the Floor Drain Collector Filter and then either directly to the Waste Collector Tank or to the Floor Drain Sample Tank prior to transfer to the Waste Collector Tank. Irregardless, further filtering and processing proceeds as described below.

For processing, water is transferred from the Waste Collector Tank through either:

a) The Waste Collector Filter and the Waste Collector Demineralizer to either of the two 10,000 gallon capacity Waste Sample Tanks for sampling prior to discharge to the CST.

b) Either one of the two Fuel Pool Demineralizers to either of the two 10,000 gallon capacity Waste Sample Tanks for sampling prior to discharge to the CST.

The rate at which water can be filtered, processed, sampled and discharged to the CST is governed by the Waste Collector Pump. This pump is rated at 110 gpm at 120 psig TDH. Due to system configurations and resistance, processing flow rate is limited to approximately 60 gpm when using the Waste Collector Filter and Waste Collector Demineralizer and 100 gpm when using the Fuel Pool Demineralizer.

Based on the above, the preferred flow path for water discharged from the Torus is as follows:

1) To either the Waste Collector Tank or the Waste Surge Tank. Use of these tanks in preference to the Floor Drain Collector Tank decreases loading on the Floor Drain Collector Filter and allows for the maintenance of adequate volume in the Floor Drain Collector Tank to accept discharge from sumps.

2) Through one of the two Fuel Pool Demineralizers. Use of the demineralizers provides for a greater flow rate and processing volume than the Waste Collector Filter and Waste Collector Demineralizer.

As shown in the below sequence of events, this preferred flow path was used where practicable.

APPENDIX G

Exit Meeting Slides

APPENDIX G-1	Exit Meeting Agenda
APPENDIX G-2	Chronological History Of Events
APPENDIX G-3	Analysis Of Service Water System Problems
APPENDIX G-4	Evaluation Of Command, Control And Communications During The 4/23/91 LOOP Event
APPENDIX G-5	Service Water Sketches Presented By Licensee At Exit Meeting

APPENDIX G-1

Exit Meeting Agenda

VERMONT YANKEE
April 23, 1991 LNP EVENT
AIT Exit
Meeting Agenda

- Introductory remarks, NRC

- Formal Exit Comments, NRC

- Licensee Response to AIT Exit Comments, VY

- VY Corrective Actions, VY
  (Discussion of the problems; role, scope, timing, documentation of related corrective actions, CAR timing, and VY letter to NRC)

    *Switchyard Issues
    *Service Water Issues

- Broader Issues, VY

    *Preventive Maintenance of NNS Equipment, LCO Maintenance

    *Engineering Reviews of Maintenance activities and system changes, 50.59 Reviews

- Concluding Remarks, NRC

APPENDIX G-2

Chronological History Of Events

Chronological History of Events

- **4-1-91** Replacement of Relay House Battery 4A, PMR M91-0251

- **4-23-91** At 1448, the 4A/5A battery charger DC supply breaker to the 5A bus was opened and initiated the event.

  Instantaneous loss of 345 KV and 115 KV switchyards occurred.

  An Unusual Event was declared at 1507.

  Recovery efforts commenced immediately.

- **4-24-91** Investigations begin: the cause of the event; repair, testing, and analysis of the associated equipment and design.

Background Information

- April, 1988 — MR88-0814 (Battery 5A) and MR88-0871 (Battery 4A)
- October, 1989 — Temporary Modification 89-55 -- output breakers for the 4A/5A battery charger
- January, 1990 — Use of a Maintenance Guideline successfully connecting DC busses was performed
  - Battery breakers were opened and closed without incident
- March, 1990 — PMR M91-0251 -- replaced North Switchyard Battery (4A)
- June, 1990 — Revised Maintenance DC Bus Guideline
- April, 1991 — Implement revised Guideline:
  - 4A battery removed without incident
  - Loss of power initiated during battery restoration

System Response

- Initiation of 345 KV and 115 KV Breaker Failure Protective Relay circuitry
- Only one breaker remained closed feeding 345 KV South Bus
- Main Turbine trip, Reactor SCRAM, loss of Normal Power initiated

Available Plant Power Sources

- Two (2) diesel generators
- One (1) delayed power source from Vernon Hydro

Chronology of Response Teams & Assignments

- Tuesday, April 23
  - The team's purpose was to recover off-site power, stabilize the switchyard and begin root cause analysis research.
  - The team consisted of the following:
    - Maintenance Supervisor
    - Senior Maintenance Engineer/Electrical
    - Two (2) Maintenance Engineers/Electrical
    - Senior Engineer Electrical Engineering/Construction
    - Engineer Electrical Engineering/Construction
    - Electrical Engineering/Construction Supervisor
    - Maintenance Assistant Foreman/Electrical
    - Two (2) Maintenance Electricians
    - Two (2) NEPSCO Relay Technicians
  - Home office support from YNSD

Response Team Chronology (cont.)

- Wednesday, April 24
  - Formalized task team organization.
- Thursday, April 25
  - YNSD engineers report to site task team.
  - Contacted ABB Relay Engineering/Manufacturing division.
- Friday, April 26
  - Corporate engineering reports to site task team.
  - ABB assembles team at their factory.
- Saturday, April 27
  - Additional YNSD on-site engineering support

Recovery from LNP & Plant Stabilization

- Immediately closed K186, 115 KV Keene line breaker.
- 4 KV busses 1 & 2 remained disconnected from safety busses 3 & 4.
- DG continued to provide power to busses 3 & 4.
- Human resource and communication problems experienced.
- Backfeeding of plant completed the next morning at approximately 0340.
- Diesel generators secured.

Technical Analysis of Event

- Relay house bus 4A charger failures
- DC Bus control circuit voltage disturbances
- Breaker failure protective relay circuit failure

115 KV & 345 KV Yard Recover

- All 345 KV and 115 KV breakers restored to service
- Repair of breaker failure protective relay logic cards
- Removal of Zener diode from breaker failure relay logic cards per ABB recommendation
- Post maintenance testing on all components receiving preventive or corrective maintenance
- Engineering assessment of all technical and programmatic event-related issues
- Identify start-up, short term, and long term corrective action

Investigation of Similar Events

- 1972 loss of off-site power
- 1984 Zener Diode failures in diesel generator differential relays

Summary Root Cause of Events

ROOT CAUSE

- The repair department's failure to recognize the implications of operating a DC bus without a connected battery.

CONTRIBUTING FACTORS

- 345 KV and 115 KV breaker failure relays were susceptible to false initiation due to control voltage transients.
- The switchyard battery chargers were in a degraded mode.
- Lack of switchyard battery charger and overall switchyard preventive maintenance.

Corrective Actions

- All start-up concerns resolved and reviewed by PORC
- Short term recommendations presented
- Long term recommendations presented

Short Term Recommendations

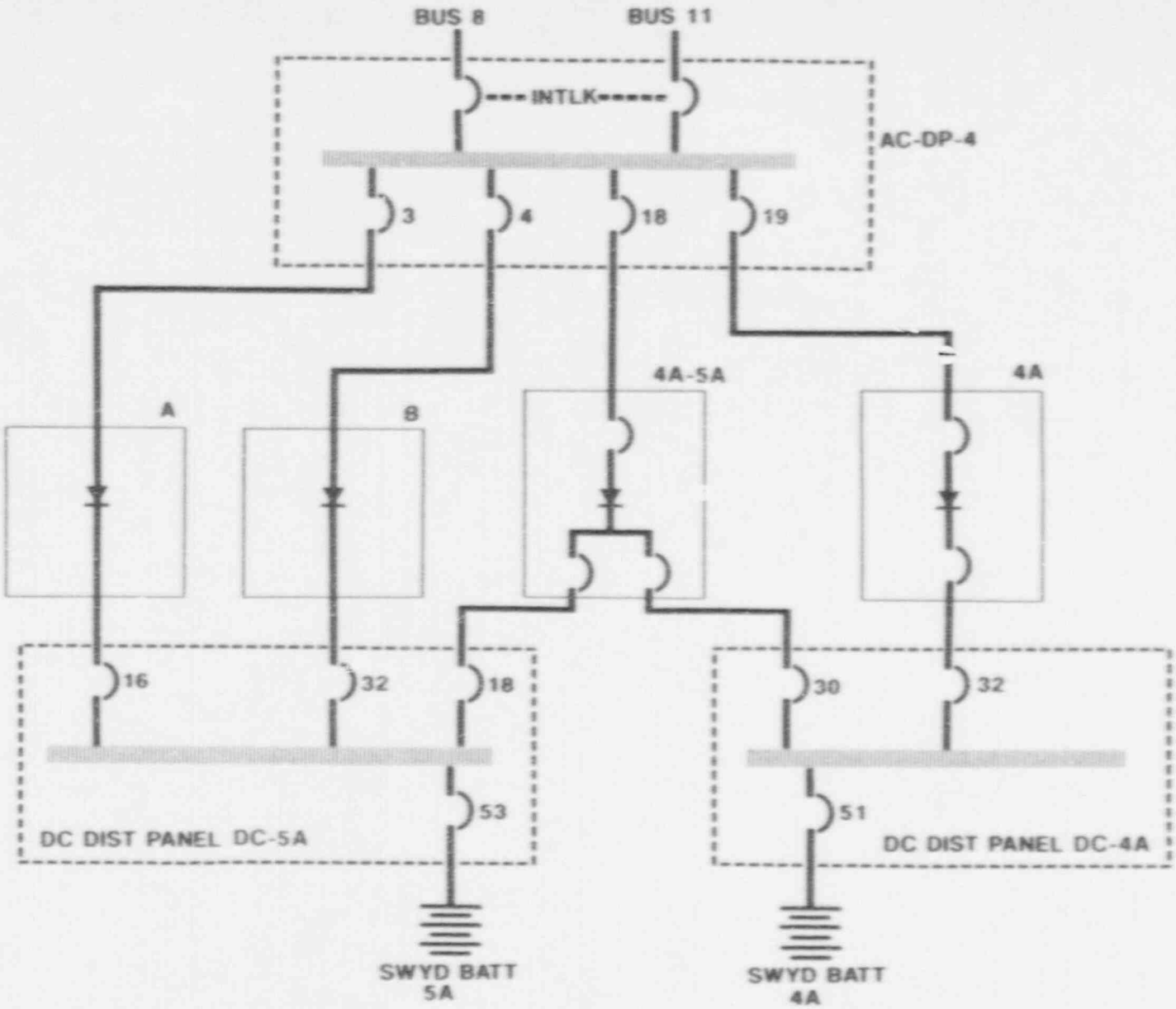
- Communications
- Use of Guidelines
- Backfeeding execution enhancements

Long Term Recommendations

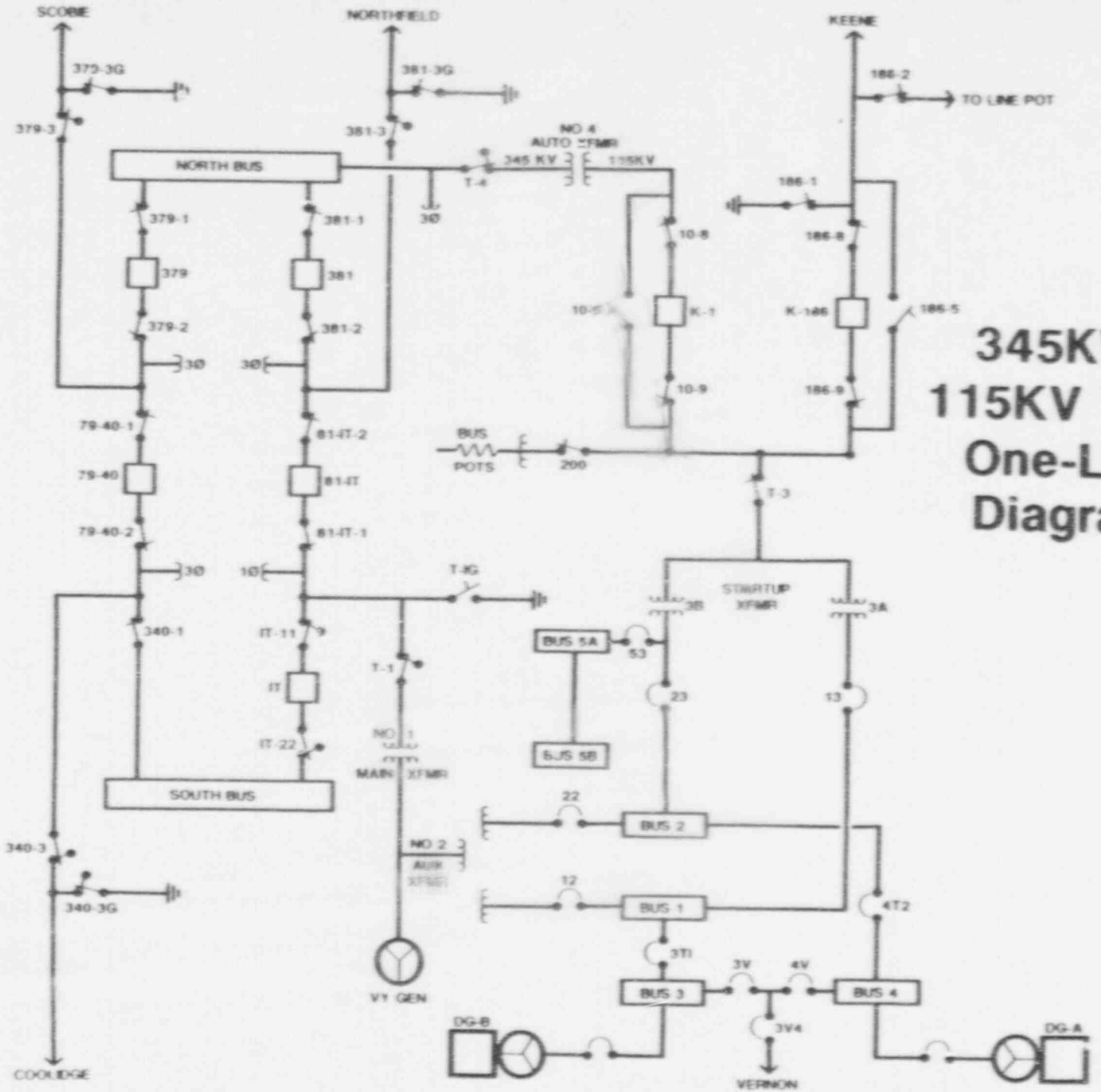
- Review the use of Guidelines versus procedures.
- Purchase updated version of breaker failure relays.
- Resolve communication problems between VY and REMVEC.
- Review Plant battery charger specifications and preventive maintenance.
- Improve relay technician availability and response.
- Evaluate other station battery charger operations.
- Optimize time required to backfeed.

Long Term Recommendations (cont.)

- Review adequacy of switchyard preventive maintenance.
- Perform engineering reviews:
  - Breaker failure power supply sources
  - Other static protective relays installed at VY
  - Common mode failure in switchyard DC circuitry
  - Review and update FSAR if required



DC Distribution One-Line Diagram



345KV & 115KV Yard One-Line Diagram

Start-up Concerns Resolved

- Switchyard reliability
- Time necessary to backfeed
- Controls in place preventing reoccurrence of the circumstance creating this event
- Transformer gas analysis reviewed

APPENDIX G-3

Analysis Of Service Water System Problems

VERMONT YANKEE
NUCLEAR POWER CORPORATION

LOSS OF NORMAL POWER EVENT

EVENT DATE - APRIL 23, 1991

ANALYSIS OF SERVICE WATER SYSTEM PROBLEMS

SERVICE WATER SYSTEM PROBLEMS EXPERIENCED DURING APRIL 23 LNP EVENT

- REDUCED SW FLOW TO THE EMERGENCY DIESEL GENERATOR HEAT EXCHANGERS

- ISOLATION OF SERVICE WATER INLET FLOW TO THE STATION SERVICE AIR COMPRESSORS

CAUSE OF SERVICE WATER SYSTEM FLOW PROBLEMS

- THE SW FLOW PROBLEMS RESULTED FROM HIGH BACKPRESSURE EXPERIENCED IN THE EDG HEAT EXCHANGER AND STATION AIR COMPRESSOR SW DISCHARGE LINE

- THE HIGH BACKPRESSURE CAUSED THE FOLLOWING ACTIONS TO OCCUR:
  - PRESSURE CONTROL VALVE CLOSED ON AIR COMPRESSOR SW INLET LINE
  - REDUCED FLOW THROUGH THE EDG HEAT EXCHANGER

CAUSE OF HIGH SW DISCHARGE HEADER PRESSURE

- HIGH BACKPRESSURE CAUSED BY DISCHARGING SERVICE WATER FLOW THROUGH SW-11

THREE REASONS FOR INCREASED BACKPRESSURE WHEN DISCHARGING THROUGH SW-11:

- PIPE DIAMETER REDUCTION FROM 20" to 14"
- INCREASE IN PIPING LENGTH/RESISTANCE
- ELEVATION HEAD DIFFERENCE

CONSEQUENCES OF SERVICE WATER SYSTEM FLOW PROBLEMS

- EMERGENCY DIESEL GENERATOR EFFECTS
- STATION AIR COMPRESSOR EFFECTS

IMMEDIATE ACTIONS TAKEN

- TASK FORCE FORMED TO INVESTIGATE THE PROBLEMS IDENTIFIED
- TEST PLAN GENERATED AND EXECUTED TO ATTEMPT TO IDENTIFY THE CAUSE OF THE PROBLEMS
- OPERATIONS DEPARTMENT SERVICE WATER PROCEDURE OP 2181 CHANGED TO MODIFY THE VALVE LINEUP SUCH THAT SW-1 IS FULLY OPEN AND SW-11 IS FULLY CLOSED
- ADDITIONAL TEST DATA WAS TAKEN DURING THE REACTOR RESTART
- THE PLANT OPERATIONS REVIEW COMMITTEE (PORC) REVIEWED RESULTS OF THE TESTING

SHORT-TERM ACTION PLAN

- SW SYSTEM LOAD BALANCING
- REVIEW THE REASONS FOR CHANGING TO THE "SW-11" LINEUP
- MAINTAIN SW-1 FULL OPEN

LONG-TERM ACTION PLAN

- SERVICE WATER FLOW MODEL
- DEEP BASIN DEICING AND MAKEUP
- REVIEW FSAR

COMPARISON OF SERVICE WATER SYSTEM OPERATING REGIMES AS DETERMINED VIA TESTING

VALVE LINE-UP	EQUIP. IN SERVICE	SW-1 PRESSURE	RHRSW PRESSURE	EDG FLOW METER	SW PUMP PRESSURE
SW-11 OPEN	1 RHRSW	44 PSIG	100 PSIG	N/A	103 PSIG
SW-11 OPEN	2 RHRSW 1 DIESEL	54 PSIG	93 PSIG	49%	98 PSIG
SW-1 OPEN	1 RHRSW	10 PSIG	98 PSIG	N/A	100 PSIG
SW-1 OPEN	1 RHRSW 1 DIESEL	10 PSIG	98 PSIG	85%	99 PSIG
SW-1 OPEN	2 RHRSW 1 DIESEL	16 PSIG	86 PSIG	74%	90 PSIG

APPENDIX G-4

Evaluation Of Command, Control And Communications During The 4/23/91 LOOP Event

EVALUATION OF COMMAND, CONTROL AND COMMUNICATIONS DURING THE 4/23/91 LOOP EVENT

BASED ON FIRST HAND OBSERVATION, AS WELL AS INTERVIEWS WITH THOSE INVOLVED AND A REVIEW OF POST-TRIP EVENTS, IT IS MY OPINION THAT THE COMMUNICATIONS, COMMAND, AND CONTROL SKILLS DEMONSTRATED BY THE OPERATING CREWS DURING THE 4/23/91 LOOP EVENT WERE ACCEPTABLE.

- The Shift Supervisor maintained the "big picture" of the plant, assigning personnel according to the changing course of events and the conditions existing in the Switchyard, Radwaste, Instrument Air System, etc.

- Based on a review of the events, we have concluded that the Control Room Supervisory Personnel correctly prioritized and appropriately directed plant restoration activitites.

EVALUATION OF EQUIPMENT RESPONSE DURING THE 4/23/91 LOOP EVENT

- The Control Room Operators closely monitored the operation of vital plant equipment during the event and subsequent recovery operations:
  - HPCI
  - RCIC
  - SRVs
  - Emergency Diesels
  - Instrument Air system
  - Service Water system

- During the initial hours following the LOOP event, the AOs closely monitored, but did not log, operating parameters of the EDGs locally to ensure continued reliable service was maintained.

- AOs were closely involved in the activities relating to restoration of off-site power (i.e., switching and tagging evolutions).

- AOs provided local monitoring of operating parameters and conditions of vital equipment:
  - Emergency Diesels
  - HPCI
  - RCIC
  - Instrument Air system
  - Service Water system

- AO involvement in restoration of Radwaste functions to maximize utilization of facilities in restoration activities.

LESSONS LEARNED:

- Continue to emphasize the need for enhancing command, control and communications skills during licensed operater training

- Include a module on communications techniques in the AO initial and continuing training programs.

LESSONS LEARNED:

- Ensure that expectations of requests made to individuals to "periodically monitor" equipment performance are clear. This should be emphasized in both LOR and AOR training programs.

- Based on the importance of the EDGs, provide an AO workstation in each of the EDG rooms to provide a means for local logging of information gathered during events.

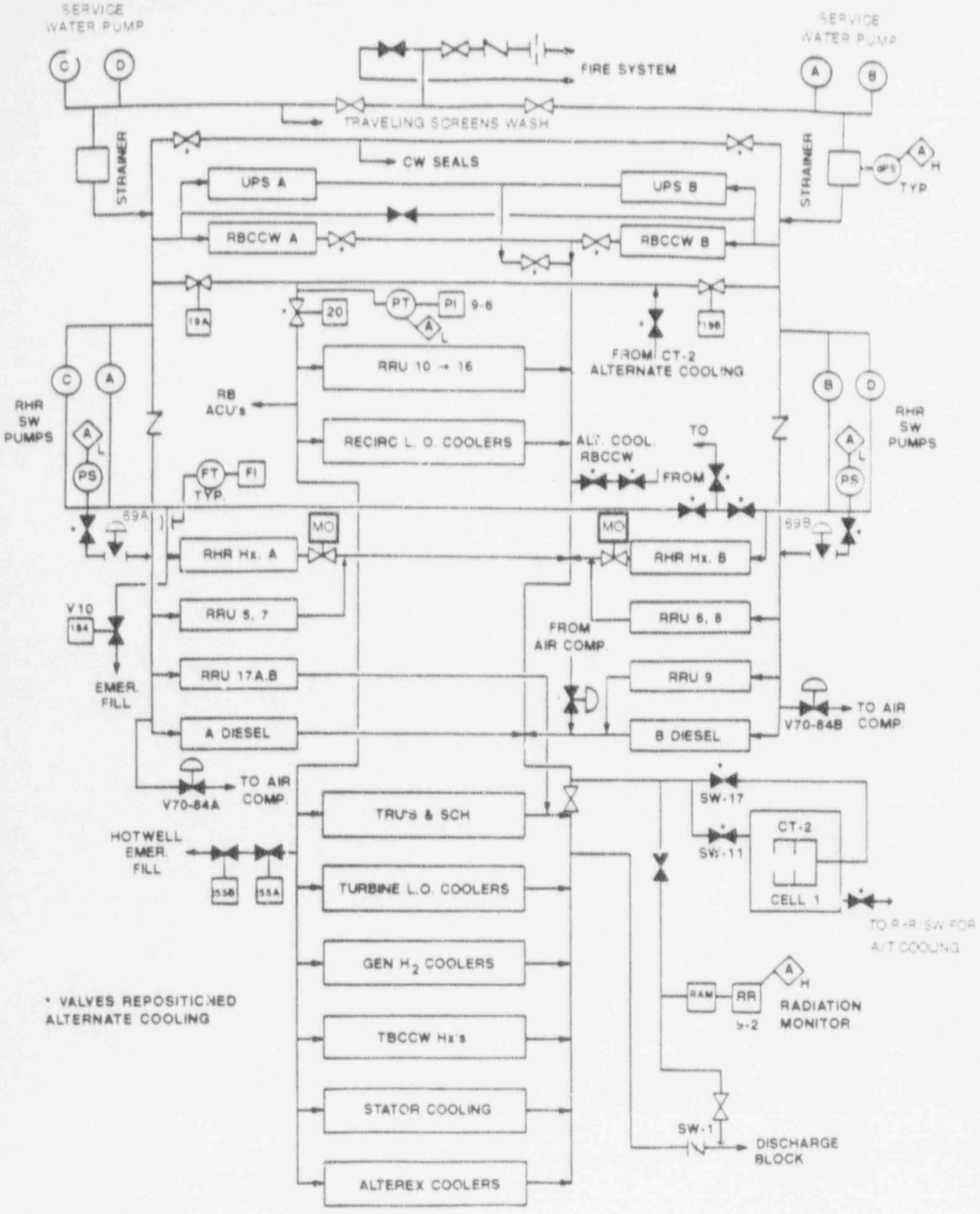
- Operations, together with Training, will consider development of additional scenarios dealing with Switchyard and Service Water system problems as part of the continuing operator requalification program.

- The Training Department will conduct a detailed review of this event during both LOR and AOR training.

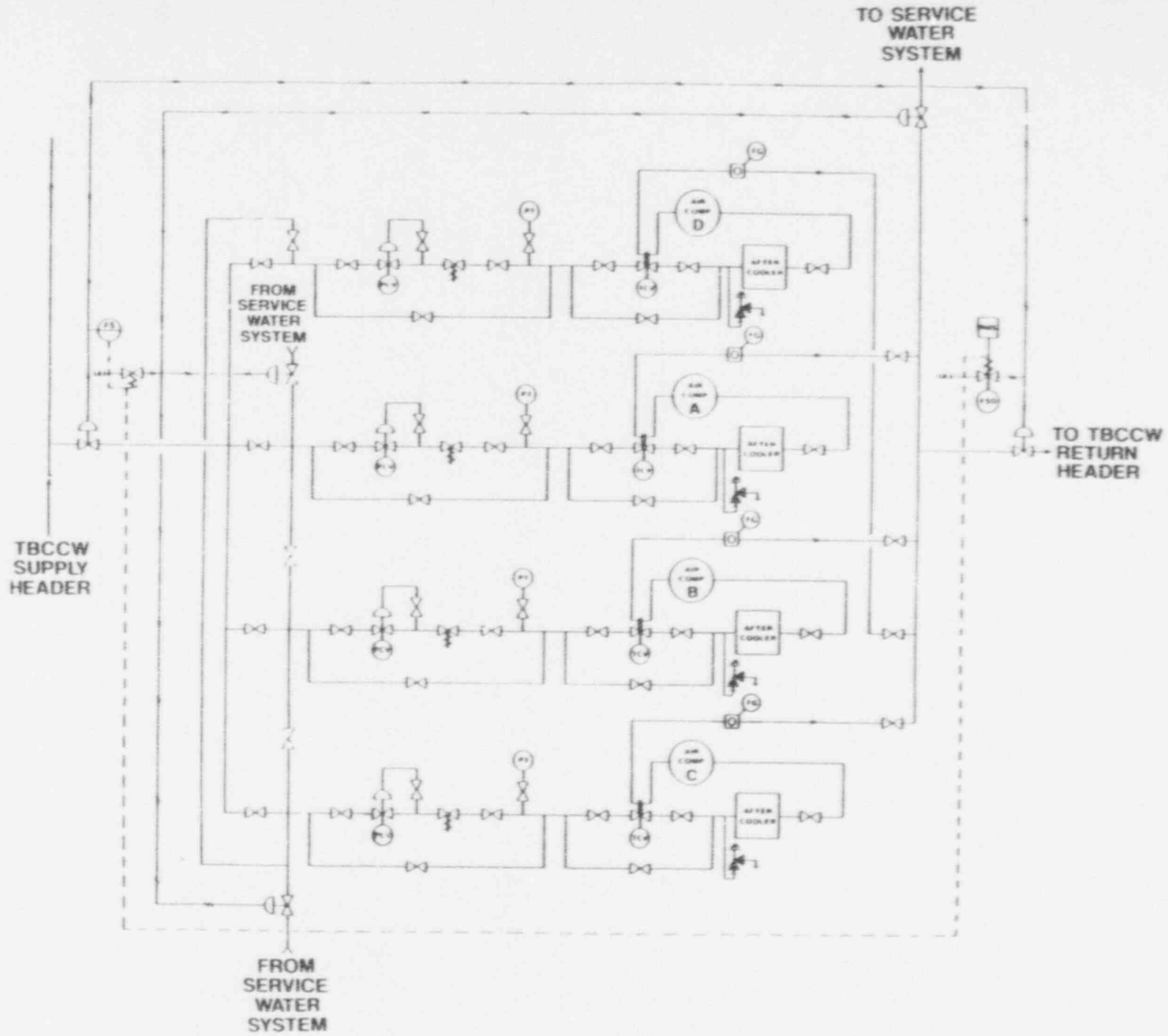
APPENDIX G-5

Service Water Sketches
Presented By Licensee At Exit Meeting

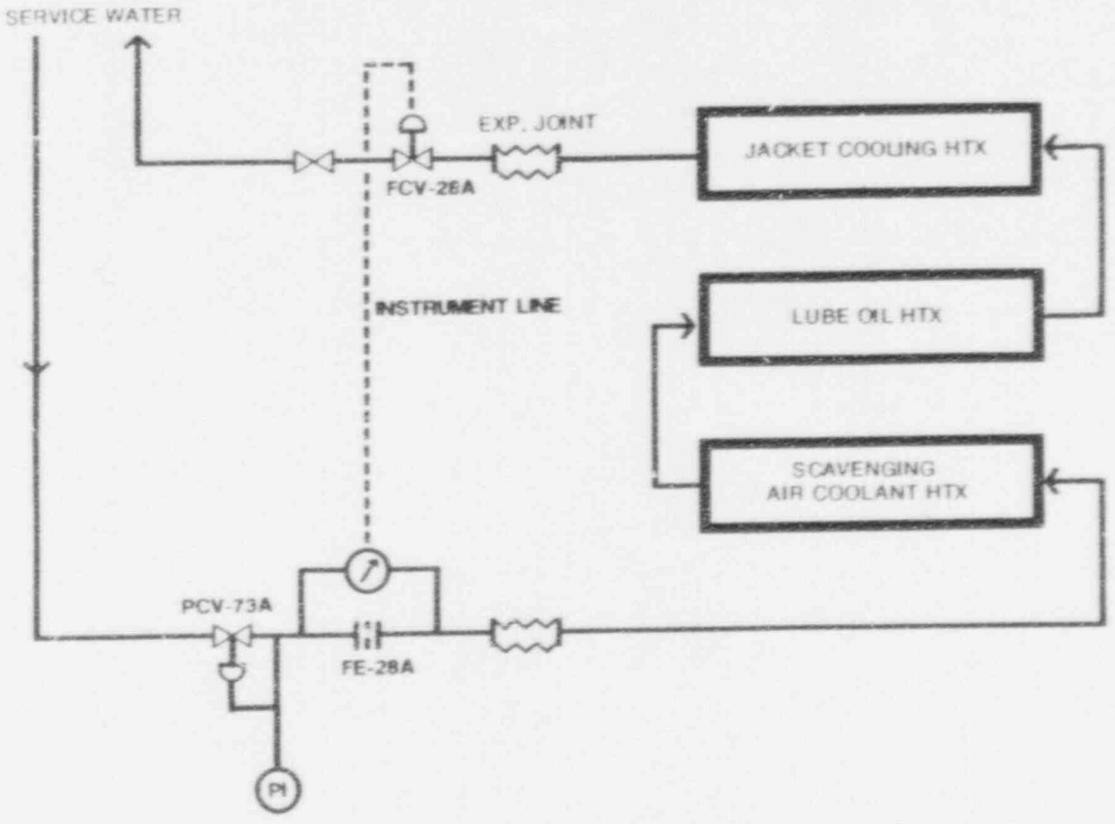
- Service Water System and Alternate Cooling
- Service and Instrument Air Compressor Cooling
- Service Water Flow through Emergency Diesel Generator Heat Exchangers
- Service Water Elevation Sketch



Service Water System and Alternate Cooling

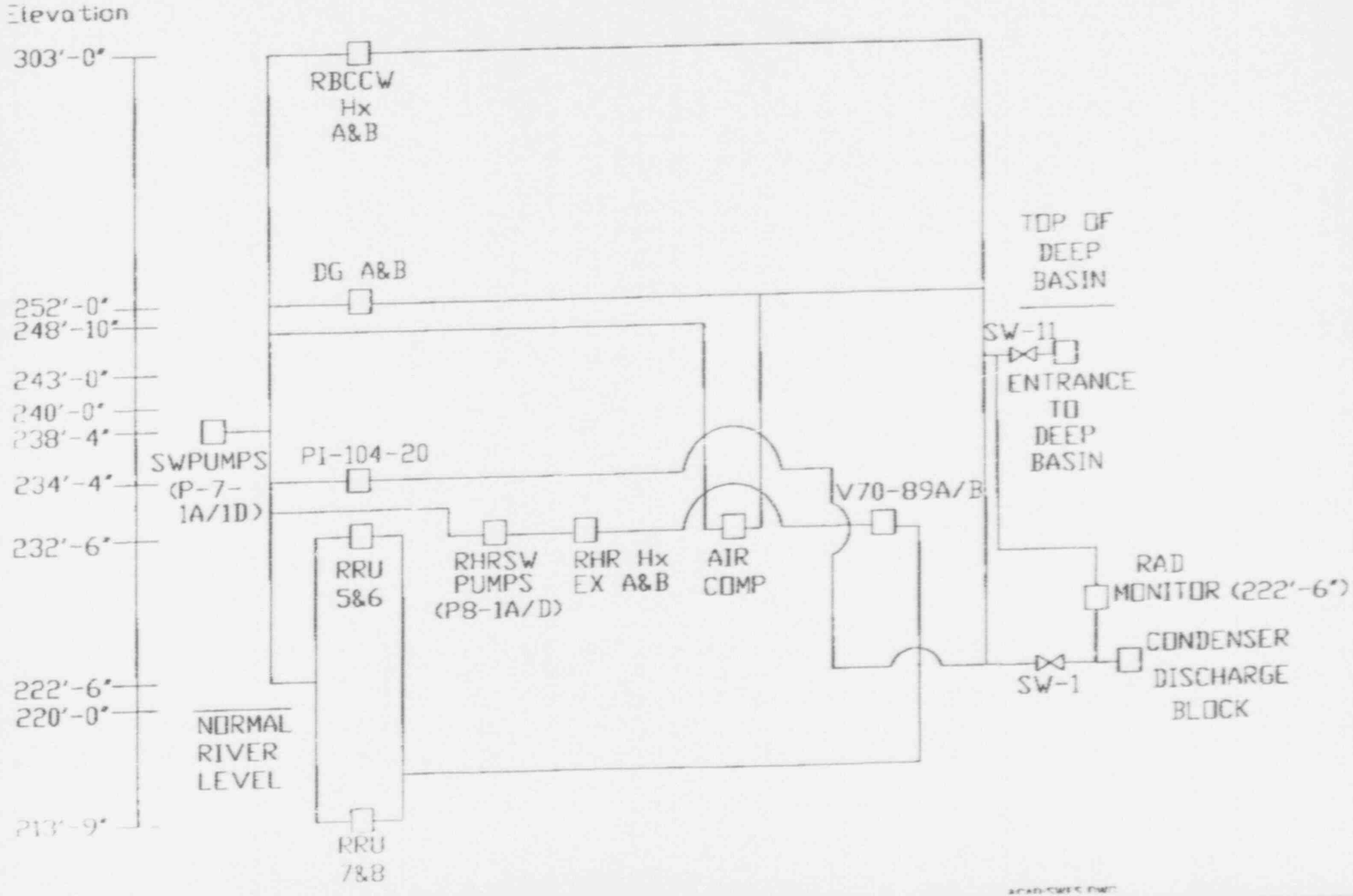


Service and Instrument Air Compressor Cooling



Service Water Flow through Emergency Diesel Generator Heat Exchangers

Service Water Elevation Sketch



APPENDIX H

Augmented Inspection Team (AIT) Charter

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406

April 24, 1991

Docket No. 50-271

MEMORANDUM FOR: M. Wayne Hodges, Director, Division of Reactor Safety

FROM: Thomas T. Martin, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER FOR REVIEW OF THE APRIL 23, 1991 LOSS OF OFFSITE POWER EVENT AT VERMONT YANKEE

As a result of the April 23, 1991 loss of offsite power at Vermont Yankee, I, along with NRR and AEOD senior management determined that an Augmented Inspection Team (AIT) inspection should be conducted to verify the circumstances and evaluate the significance of the subject event.

The Division of Reactor Safety (DRS) is directed to conduct that AIT with Clifford J. Anderson, Chief, Electrical Section, as the Team Leader. Further, DRS, in coordination with the Division of Reactor Projects, is responsible for the timely issuance of the inspection report, the identification and processing of potentially generic issues found, and the completion of any enforcement action warranted as a result of the Team's review.

Enclosed is the charter for the Augmented Inspection Team delineating the scope of this inspection. The inspection shall be conducted in accordance with NRC MC 0513, NRC Inspection Manual 0535, Inspection Procedure 93800, and this memorandum. The basis for this inspection, per MC 0513, is the staff's need to determine if there are potential generic issues worthy of staff action associated with the event, its causes or its effects.

Thomas T. Martin
Regional Administrator

Enclosures:
1. Augmented Inspection Team Charter
2. Team Membership/Schedule

cc:
T. Murley, NRR
J. Partlow, NRR
M. Virgilio, NRR
J. Calvo, NRR
C. Rossi, NRR
M. Fairtile, NRR
R. Wessman, PD I-3, NRR
F. Miraglia, NRR
W. Russell, NRR
J. Richardson, NRR
A. Thadani, NRR
B. Grimes, NRR
J. Roe, NRR
D. Ross, AEOD
J. Taylor, EDO
J. Sniezek, EDO
E. Jordan, EDO
K. Brockman, EDO
W. Kane, RI
C. Hehl, RI
J. Wiggins, RI
J. Rogge, RI
H. Eichenholz, SRI - Vermont Yankee
C. Anderson, DRS
W. Sherman, State of Vermont (copy to be provided by Team Leader)

ENCLOSURE 1

AUGMENTED INSPECTION TEAM CHARTER

VERMONT YANKEE LOSS OF OFFSITE POWER

ON APRIL 23, 1991

The Augmented Inspection Team (AIT) is to perform an inspection and accomplish the following:

1. Determine the specific circumstances and events which led up to the loss of offsite power (LOOP). Include sequence of work on the switchyard DC control power system, use of procedures and QA practices, propriety of doing work during full power operation, use of qualified personnel, an investigation of whether this type of maintenance has been performed previously and the results of such previous maintenance. Also, determine the root cause of the event and identify whether any significant offsite power supply vulnerabilities exist.

2. Verify and evaluate the licensee's actions following the event. Include proper implementation of Emergency Plan, response of operators, response of management, availability of sufficient cognizant staff in a timely manner, and implementation of any additional needed safeguards, fire protection, or emergency preparedness measures and event reporting.

3. Determine and evaluate the response of the engineered safety features and other plant systems needed to cope with this event. Include the trip sequence, start of EDGs, availability of Vernon Dam power, problems with breaker K1 and K186 restoration, and restoration of offsite power. Evaluate the performance of the Instrument Air system, especially compressor problems; operation of CRD, RCIC and HPCI systems in maintaining vessel level and pressure; maintenance of torus water level within Technical Specification limits. Evaluate operation and performance of Liquid Radwaste System in connection with efforts to maintain torus level.

4. Determine if there are any potential generic issues associated with this event.

5. Prepare a report documenting the results of this review for signature by the Regional Administrator within 30 days of the completion of the inspection.

ENCLOSURE 2

TEAM MEMBERSHIP/SCHEDULE

Team Membership:

Cliff Anderson, Chief, Electrical Section, EB, DRS
Neil Della Greca, Senior Reactor Engineer, PSS, EB, DRS
Pete Drysdale, Senior Reactor Engineer, OPS, DRS
Tom Hiltz, Resident Inspector, VY, RPS 3A, PB 3, DRP
William Sherman, Observer from State of Vermont

Tentative Schedule:

4/25/91	1200	Arrive onsite, badging, set up interviews.
4/25/91	0100	Entrance meeting at site with licensee management.
4/25/91	0130	Begin inspection.
4/25/91	1600	Debrief with RI management.
4/26/91	1600	Debrief with RI management.
4/27/91	1600	Debrief with RI management.
4/28/91	1600	Debrief with RI management.
4/29/91	1100	Complete inspection.
4/29/91	1400	Exit with licensee management onsite.
5/29/91		Issue report.

APPENDIX I

Licensee Developed Backfeeding Time Line

TO: POKC VERNON DATE: 4/29/91

FROM: R.P.LOPRIORE VERNON FILE:

SUBJECT: ADDENDUM TO EVENT REPORT

TIME LINE TO BACKFEEDING - 4/23/91 EVENT

	DATE	TIME
PLANT TRIP	4/23/91	1448
STARTED SET UP FOR BACKFEED - ORDERED MARK LIFT FOR GROUNDING THE MAIN XFMR - CONTACTED CENTRAL VERMONT FOR MANPOWER AND BUCKET TRUCK - INITIATED TAGGING REQUESTS FOR BACKFEEDING - INITIATED CHECK OUT OF GROUNDING CABLES, TOOLING AND TEST EQUIPMENT TO SET UP BACKFEEDING		1530
RECIEVED ORDER TO START OP2209 - ELECTRICAL FOREMAN RECEIVED CALL FROM SHIFT SUPV. AND REQUESTED CONFIRMATION FROM TSC COORDINATOR. RECEIVED CALL FROM JTH		1900
STARTED TAGGING EQUIPMENT PER OP2209		1915
COMPLETED TAGGING		2015
STARTED CONFIGURING ELECTRICAL BUS FOR BACKFEEDING - BKR 12 & 22 CHECK DEAD AND INSTALL GROUND - SURGE CUBICLE CHECK DEAD AND INSTALL GROUND - HAD PROBLEMS EXITING THE BUILDING DUE TO GAS - STARTED INSTALLTION OF MAIN TRANSFORMER HIGH SIDE GOUNDS - MARK LIFT BROUGHT IN WAS DIFFERENT THAN USED PREVIOUSLY AND MOVEMENT OF UNIT INTO POSITION REQUIRED EXTRA CARE AND TIME - COMPLETED HIGH SIDE GROUNDING - DISCONNECTED GENERATOR LINKS AND ESTABLISHED ISOPHASE BUS OPERATION - CLEARED MAIN TRANSFORMER HIGH SIDE GROUNDS - CLEARED SURGE CUBICLE GROUNDS - CLEARED BKR 12 & 22 GROUNDS		2015 2200 2400
CLEARED TAGS AND CLOSED TAGGING ORDER - PLANT ELECTRICAL SYSTEM AVAILABLE FOR BACKFEEDING THROUGH THE MAIN TRANSFORMER	4/24/91	0140
1T ACB CLOSED PER REMVEC		0352
1T ACB OPENED PER REMVEC		0353
CLOSED T1 PER REMVEC		0407
CLOSED 1T ACB PER REMVEC		0409
BACKFEEDING THROUGH THE MAIN TRANSFORMER INITIATED	4/24/91	0417

STANDARD BACKFEEDING EVOLUTION

- THIS EFFORT REQUIRES 2 FOUR MAN CREWS

RECEIVE ORDER TO START OP2209		0000
INITIATE TAGGING REQUEST AND ASSEMBLE WORK CREW	(MAINT)	15 MIN
WRITE UP NECESSARY TAGS	(OPS)	30 MIN
ASSEMBLE AND CHECK OUT EQUIPMENT	(MAINT)	
HANG TAGS	(OPS & MAINT)	60 MIN
COMPLETE EQUIPMENT CHECK OUT	(MAINT)	
SET UP ACCESS TO WORK AREAS	(MAINT)	
GROUNDING ACTIVITIES - BKR 12 & 22 - SURGE CABINET - MAIN TRANSFORMER HIGH SIDE	(MAINT)	90 MIN
DISCONNECT GENERATOR LINKS AND START ISOPHASE BUS FANS	(MAINT) (OPS)	30 MIN
CLEAR GROUNDS - MAIN TRANSFORMER GROUNDS - SURGE CUBICLE - BKR 12 & 22	(MAINT)	60 MIN
CLEAR TAGS	(OPS & MAINT)	45 MIN
ESTABLISH BACKFEEDING	(OPS)	5 MIN
TOTAL TIME TO BACKFEED		335 MIN (5 HRS 35 MIN)

THE ABOVE TIME LINE REPRESENTS THE WORST CASE SENARIO FOR EFFECTING A BACKFEED THROUGH THE MAIN TRANSFORMERS. BY WORKING WITH TWO CREWS; I.E., ONE INSIDE AND ONE OUTSIDE THE BUILDING; THE ELECTRICAL SYSTEM CAN BE MADE READY IN THE IDENTIFIED DURATION. COORDINATED EFFORTS BETWEEN THE CREWS IS ESSENTIAL BOTH FOR PERSONNEL AND EQUIPMENT SAFETY AND THE ABOVE DURATIONS HAVE TAKEN THAT INTO ACCOUNT.

THE CREW TO DO THE WORK CAN BE COMPRISED OF ALL ELECTRICIANS, OR A COMPOSITE CREW OF LEAD ELECTRICAL PERSONNEL WITH MECHANICS.

ANOTHER OPTION IS TO CALL FOR A LINE CREW FROM CENTRAL VERMONT'S BRATTLEBORO OFFICE TO WORK THE GROUNDING EVOLUTIONS ON THE MAIN TRANSFORMER RELEIVING THE PLANT STAFF TO SUPPORT OTHER PLANT NEEDS. THIS CREW CAN BE MOBILIZED WITHIN ONE HOUR, WITH THE NECESSARY EQUIPMENT, AND BE ON SITE BY THE TIME TAGGING IS COMPLETED.

MANAGEMENT WILL MAKE FORMAL ARRANGEMENTS WITH CENTRAL VERMONT TO HAVE THE APPROPRIATE PERSONNEL TRAINED IN VERMONT YANKEE TAGGING PROCEDURES AND PLACED ON THE TAGGING LIST. ONCE THIS IS IN PLACE, IT WILL BECOME THE PREFERRED METHOD FOR THE OUTSIDE WORK EFFORTS IN ARRANGING FOR BACKFEEDING.

APPENDIX J

Licensee Event Report (LER) 84-22

VERMONT YANKEE NUCLEAR POWER CORPORATION

P. O. BOX 157
GOVERNOR HUNT ROAD
VERNON, VERMONT 05354

November 20, 1984

VYV84-587

U.S. Nuclear Regulatory Commission
Document No. 50-271
Washington, D.C. 20555

REFERENCE: Operating License DPR-28
Docket No. 50-271
Reportable Occurrence No. LER 84-22

Dear Sirs:

As defined by 10CFR50.73, we are reporting the attached Reportable Occurrence as LER 84-22.

Very truly yours,

VERMONT YANKEE NUCLEAR POWER CORPORATION

James P. Pelletier
Plant Manager

RDP/jbb

cc: Regional Administrator
USNRC Office of Inspection and Enforcement
Region I
631 Park Avenue
King of Prussia, Pennsylvania 19406

NRC Form 366
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)
Vermont Yankee Nuclear Power Corporation

DOCKET NUMBER (2): 0 5 0 0 0 2 7 1 1

PAGE (3): 1 OF 0 3

TITLE (4)
Diesel Generator Lockout Trip of Both Generators

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)		
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR
1 0	2 3	8 4	8 4	— 0 2 2	— 0 0	1 1	2 0	8 4

OTHER FACILITIES INVOLVED (8)	
FACILITY NAMES	DOCKET NUMBER(S)
	0 5 0 0 0
	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: James P. Pelletier, Plant Manager

TELEPHONE NUMBER: AREA CODE 8 0 2 2 5 7 - 7 7 1 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	E K	8 7	W 1 2 0	Y							

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On 10/22/84 at 1335 EST, diesel generator 1-1-A experienced a generator lockout trip caused by a differential relay trip. At 0140 EST on 10/23/84, Control Room personnel noted a loss of diesel generator 1-1-B, also resulting from generator lockout trip caused by differential relay trip.

The differential relay trips resulted from the failure of a Zener diode in each of the differential relays. The Zener diode is in parallel with a silicon-controlled rectifier in the Westinghouse type SA-1 differential relays.

On 10/23/84 at approximately 1730 EST and on 10/24/84 at approximately 2000 EST, the relays for diesel generators 1-1-B and 1-1-A respectively were repaired and the diesels were declared operable.

Corrective action will consist of installing the newer version of the Westinghouse SA-1 relay which is designated for Class 1E applications and no longer uses the Zener diode across the output SCR.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Vermont Yankee Nuclear Power Corp.	0 5 0 0 0 2 7 1	8 4	— 0 2 2	— 0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

With the plant at normal full power on 10/22/84 at 1335 EST, Control Room personnel received diesel generator 1-1-A lockout and differential alarms. Local investigation revealed that the lockout relay had tripped due to differential relay trip and that it would not reset. This occurrence happened 11 days after completion of monthly technical specification surveillance on the diesel generator.

At 2105 EST on 10/22/84, alternate surveillance testing on diesel generator 1-1-B was successfully completed.

At 0140 EST on 10/23/84, Control Room personnel received diesel generator 1-1-B lockout and differential alarms. Local investigation again revealed that the lockout relay had tripped due to differential relay trip and that it would not reset.

Since both diesel generators were inoperable, a reactor shutdown was initiated in accordance with Tech. Spec. Section 3.5.H.1 and an Unusual Event was declared.

On 10/23/84 at approximately 1730 EST, the relay for diesel generator 1-1-B was repaired and, after satisfactory testing, the diesel was declared operable. The reactor shutdown was terminated and ascension to full power began. On 10/24/84 at approximately 2000 EST, the relay for diesel 1-1-A was repaired and, after testing, the diesel was declared operable.

The cause of the Westinghouse SA-1 differential relay malfunction was determined to be due to failure of a Zener diode in each of the relays. The Zener diode is installed across the anode and cathode of the SCR on the output of the differential relay. The diode short-circuited, which resulted in actuation of the lockout relay.

During investigation of the cause of the differential relay trip it was noted that surge protection across the lockout relay coils of both diesel generators lockout relays were installed backwards. The surge protection consists of a 47 ohm resistor and a 180 volt Zener diode. It was determined that the surge protection circuit did provide some protection as it was installed since the diode was a Zener diode, and any time the voltage exceeded the 180 volt breakdown voltage, the Zener diode would conduct. The diode was, however, reversed so that the anode was connected to the positive side of the DC supply.

Due to the unusual circumstances of the same diode failure occurring in redundant systems, an investigation to attempt to determine the cause of the diode failures was conducted. Vermont Yankee personnel met with Westinghouse Relay-Instrument Division and it was mutually concluded that the specific cause of the Zener diode failures could not be positively determined. The Zener diode failures probably resulted from component end of life or from the cumulative damage from normally experienced switching transients within the DC system. The polarity of the suppression circuit of the lockout relay may have contributed to increased stress and shortened life.

The corrective action will consist of installing the newer version of the Westinghouse SA-1 relay which is designated for Class 1E applications. The relay no longer uses the Zener diode across the output SCR but has a resistor capacitor network across the SCR. The circuit also uses two additional capacitors for surge protection.

It was also determined during the meeting with Westinghouse that use of the repaired relays did not place the system in immediate jeopardy of another Zener failure.

In order to have the best possible system reliability, the latest Westinghouse design commercial grade relays, which have been evaluated to be a one-for-one replacement for the existing relays, are being installed on an interim basis until receipt of relays designated for Class 1E service. These relays are electrically and functionally the same as those designated for Class 1E use.

Another significant item was discovered during troubleshooting of one of the failed differential relays. It was determined that replacement of the relay trip indicating lamp with an incorrect voltage bulb can prevent the relay from tripping. When the relay simulated a trip upon Zener diode failure, illumination of the indicating lamp was expected. Since the bulb did not light as expected, it was replaced. Inadvertent replacement of the bulb with one with a lower voltage rating resulted in the relay not tripping when tested. Due to the higher amperage through the bulb, insufficient current was available for firing the output SCR. It should also be noted that the part number for the bulb is not contained in the parts list for either the relay in service at Vermont Yankee or for the present Westinghouse design relay. The correct part number of the bulb was obtained and the installed bulbs were verified correct.

No similar occurrences of this type have been reported to the Commission.

APPENDIX K

Summary of Unresolved Items

A. Unresolved Items

	Description of Item	Discussed in Paragraph	Item Number
1.	Adequacy of the DC Control System Battery Maintenance Procedure	5.7.1	50-271/91-13-01
2.	Inadequate maintenance for the DC Control System battery chargers	4.1.5	50-271/91-13-02
3.	Inadequate surveillance testing of the DC Control System battery chargers	4.1.5	50-271/91-13-03
4.	Analysis of 1987 Service Water System Lineup	6.2	50-271/91-13-04
5.	Adequacy of the surveillance testing of the Service Water System	6.2	50-271/91-13-05
6.	Long Term Corrective Actions associated with Service Water and Switchyard problems	7.1	50-271/91-13-06
7.	Event reportability discrepancies	5.1	50-271/91-13-07