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Licensee: Northeast Nuclear Energy Company
P.O. Box 270
Hartford, Connecticut 06141-0270

Facility Name: Millstone Nuclear Power Station, Unit 3

Inspection At: Waterford, Connecticut

Inspection Conducted: January 3-7, 1991

Inspectors: D. Jaffe
H. Kaplan
S. Kościelny
O. Meyer
J. Shedlosky
E. Trager Jr.
J. Yerokun

J M Trapp — 2-7-91
J. Trapp, Sr. Reactor Engineer, AIT Leader — date

Approved by: Jacque Durr — 2/11/91
J. Durr, Chief, Engineering Branch, DRS, AIT Manager — date

Areas Inspected: The AIT inspected those areas necessary to ascertain the facts and probable cause(s) of the December 31, 1990 event, involving the rupture of two six-inch diameter moisture separator drain lines. The team also evaluated the licensee's erosion/corrosion program analysis and corrective actions taken to recover from this event.

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1.0 INTRODUCTION

1.1 Scope of Inspection

On December 31, 1990, at Millstone Unit No. 3, two six-inch diameter moisture separator drain lines ruptured and discharged secondary plant steam/water into the turbine building. The control room operators manually tripped the reactor in response to this failure. On January 2, 1991, the NRC Regional Administrator dispatched an Augmented Inspection Team (AIT) to the Millstone site. The team was tasked with documenting relevant facts, determining the probable cause(s), evaluating the licensee's erosion/corrosion program, reviewing corrective actions, and evaluating the potential generic aspects of this event. This report describes the findings and evaluations of the AIT.

The NRC AIT held an entrance meeting with plant management and support personnel on January 3, 1991. The inspection was performed during the period of January 3-7, 1991. An exit meeting was held with plant management on January 7, 1991. Attendees at the entrance and exit meetings are listed in Appendix A. Attachment 1 is the memorandum of assignment (AIT Charter) of the AIT, to the Millstone Unit 3 event.

2.0 EXECUTIVE SUMMARY

2.1 Event Summary

A catastrophic failure of two six-inch diameter pipes associated with the plant moisture separator drain system occurred at 4:33 p.m. on December 31, 1990. The reactor was at 86% power in an end of cycle coast down prior to the event. The system involved return water collected by the turbine-generator steam supply moisture separators to the condensate system at the feedwater pump suction. The pipe failure allowed a significant amount of hot condensate system water and steam to be released into the turbine building.

The release of steam/water into the turbine building caused the failure of two non-safeguards (non-Class 1E) 480 volt load centers and a non-safety related D.C. to 120 volt A.C. inverter. This failure resulted in the loss of the plant process computer at about 16:38 hours.

A manual reactor trip and a manual main steam line isolation were initiated by the control room operators at 16:35:45 hours. The licensee informed the NRC of the event through the Emergency Notification System at 17:38 hours. The NRC Millstone Resident Inspector and the Haddam Neck Plant Senior Resident Inspector were dispatched to the site and arrived at about 20:00 hours.

A loss of instrument air to containment occurred when the instrument air containment isolation valve closed as a result of the loss of its non vital control power. The loss of containment instrument air caused the letdown isolation valves and the pressurizer spray valves to close. The closure of these valves resulted in a primary system pressure increase which was controlled by the pressurizer power operated relief valves (PORV).

Immediate recovery actions included securing fire water in sections of the turbine building, reestablishing instrument air to containment, and processing the water from the turbine building for release. Subsequent recovery actions included repairing/replacing several components in the turbine building which were damaged by the condensate and fire water which had been discharged into the turbine building. The reactor remained in Hot Standby, Operational Mode 3, during the period of time when repairs were made to the secondary plant equipment. Repairs were completed and the reactor was made critical on January 8, 1991.

2.2 Assessment Summary

Operations staff acted expeditiously to mitigate the effects of the ruptured steam drain lines and the loss of instrument air to containment. As a result of these actions, the transient on the plant was minimized. The licensee's management post event analysis and corrective actions were thorough. Several deficiencies were identified which, if corrected, could have prevented this failure from occurring or have reduced the consequences of the event. The following deficiencies were identified by the team:

- o The ruptured moisture separator drain lines had inadvertently been omitted from the erosion/corrosion program. Poor communication between the site and corporate engineering staff and the absence of independent program quality reviews were the root causes of this omission.

- o A number of input errors existed in the erosion/corrosion program. The overall verification, documentation, and control of this program were weak.

- o The flow velocities in the six-inch diameter ruptured lines were higher than are normally recommended for design flow velocities in piping systems. The high fluid velocity enhanced the erosion rate of these lines.

- o The isolation of the instrument air containment isolation valve, in response to the loss of a non-vital power supply, induced a transient on the primary plant. The control circuitry design was questionable, in light of recent plant design changes which removed the containment instrument air compressors.

Based on the deficiencies identified with regard to the erosion/corrosion program the AIT Team concluded that the licensee failed to provide adequate oversight of the erosion/corrosion program. Had appropriate oversight been provided, the program would have identified the moisture separator drain lines as high wear rate components. A properly administrated erosion/corrosion program would have prevented the personnel hazard these lines provided and would have eliminated the transient this failure induced on the plant.

2.3 Safety Summary

The sequence of events was reviewed to ascertain that plant control and safety systems responded correctly to mitigate the consequences of the plant transient. The plant control and safety systems responded as expected for a secondary steam drain line break and a loss of instrument air to containment. The safety significance with regard to the public health and safety for this event was determined to be minimal.

The personnel safety significance of this event was determined to be high. Licensee personnel were performing work and inspections in the vicinity of the ruptured pipes shortly before the failure. Had the pipes ruptured with personnel in the vicinity of the failed pipes, the consequences could have resulted in substantial personnel injury for the individuals involved. The team found that deficiencies in the erosion/corrosion program resulted in significant, unnecessary, personnel safety risk to the licensee's staff.

3.0 Sequence of Events:

3.1 Events Prior to Pipe Failure

Initial observation of a pipe leak was made by an operations department supervisor during a routine inspection of the turbine building at approximately 13:00 hours on December 31 (See Appendix B for chronology of events). The supervisor, who was also the licensee's Management Duty Officer, was concerned about the rapid growth of a puddle of hot water on the concrete floor of the turbine building (elevation 14' 6"). This was the initial evidence of the developing problem. Mechanics working on vacuum priming pumps in the area confirmed that the leak was rapidly increasing.

The leak was found to be under the thermal insulation package around air operated level control valve, 3DSM-LCV-20A1 (LCV V6). This valve is in the discharge line of the "A" moisture separator reheater (MSR) drain pump, 3DSM-P1A. It is used to regulate the flow of water being returned to the condensate system, and automatically operates to control level within the moisture separator drain collection tank. This tank is the suction source for the moisture separator drain pump. A sketch of this configuration is shown in Appendix E.

At full power, the two MSR drain pumps return approximately 1.56 million pound mass per hour (lbm/hr) of 360 degree Fahrenheit (F) water to the steam generator feedwater pumps' suction. The feedwater pumps have a normal suction pressure and temperature of 550 psia and 360.7 F. The suction pressure to the MSR drain pumps is approximately 173 psia. The control valve is located below the turbine operating floor (elevation 64' 6") and is accessible by ladders and catwalks from the turbine operating floor, above; or, from the turbine building mid-level (elevation 38' 6'), below.

The area of the leak was inspected by maintenance department supervision who agreed with operations personnel that the leak should be promptly isolated and repaired. Although the maintenance workers intended to remove the insulation package for a better inspection of the leak, the force of the leak had blown the insulation off of the pipe at a location adjacent to the control valve. The leak was observed to be through the pipe wall about four inches from the control valve body and located at the 12:00 O'clock position. All of the fluid leaking from the pipe was steam in an approximate one-eighth inch diameter jet. Station management decided to isolate, inspect and repair the leak early during the second shift on December 31. That shift assumed the watch at approximately 15:30 hours.

The isolation of the "A" MSR drain pump discharge line was to be accomplished, in part, through Section 7.2 of system operating procedure OP 3317, Reheat and Moisture Separator, Revision 4, dated December 31, 1990 which addressed removing the pump from service. Flow from the drain tank was to be stopped by locally closing the pump discharge manual isolation valve, 3DSM-V4, and stopping the pump motor from the control room main control board. Closing the pump discharge valve caused the MSR drain tank to fill to a higher level at which time the emergency high level dump valve opened and allowed water to flow from the drain tank to the condenser hotwell.

The leak was then to have been isolated from the condensate header (pressure of approximately 600 psia) by shutting the manual isolation valve, 3DSM-V7, located on a short run of straight pipe at the outlet of the level control valve, 3DSM-LCV-20A1. There are no check valves in the discharge line to prevent back flow from the condensate system. The interconnection of this piping sub-system was made to the condensate system at a 44" diameter manifold which provides cross-tie between the outlet of the three feedwater heater strings and the inlet to the three feedwater pumps.

Following the on-coming shift briefing, the shift Supervising Control Operator (SCO), who is a senior licensed operator, elected to assist the plant equipment operators and perform the local valve manipulations. He initially inspected the leak; and, then closed the drain pump discharge isolation valve, 3DSM-V4, located in the turbine building lower level (elevation 14' 6").

The SCO called the control room to report this action from a location near the pump. While on the telephone with the licensed control operator (CO) responsible for the balance of plant equipment operation, the CO opened the motor circuit breaker for pump 3DSM-P1A. At approximately the same time, the SCO witnessed the pipe failure. He heard a loud "bang" and saw a cloud of steam above his head.

3.2 Events Following the Pipe Failure

A rapidly forming steam cloud blocked the SCO's exit to the north to the service building. He elected to use the turbine building north-west stairs from the 14' 6" elevation and cross the solid concrete deck of the 64' 6" elevation as the quickest safe path to the control room via the service building. Upon reaching the control room, he informed the control room personnel of the turbine building steam break and directed a manual reactor trip and a manual main steam isolation valve closure. These occurred at 16:35:45 and 16:36:02 hours, respectively. A turbine trip automatically followed the reactor trip.

At that time, the operators were not sure of the break location. Flow through the break continued until the system was depressurized. The "B" moisture separator drain pump motor breaker tripped and both condensate pumps tripped off automatically due to low condenser hotwell level. The time at which the condensate pumps tripped was not recorded, however a mass balance of the secondary plant indicated approximately 230,000 gallons of water were spilled. In addition to the condensate system, the fire water system discharged water into the turbine building.

Prior to the SCO arriving in the control room, the operators had indications of a problem with the secondary plant as the SCO had shouted before dropping the telephone and leaving the turbine building. Also, main control board indicators and annunciators reflected a developing problem. The condensate demineralizer differential pressure alarmed high and flow mismatch between feedwater flow and steam flow annunciated for all four steam generators. This is believed to be the first indication of the line break and resulted from the reduction of feedwater pump suction pressure due to the line break.

Although the licensee had been taking action against a leak in the "A" MSR drain pump discharge line, lines from both the "A" and "B" MSR drain pumps were found to have failed due to severe pipe wall thinning. The failures occurred in near identical locations, in six inch diameter outlet pipes from the level control valves, 3DSM-LCV-V6 in the "A" sub-system and 3DSM-LCV-V13 in the "B" sub-system. The thinned piping in the "A" sub-system was found to have "pealed" open about 270 degrees of pipe wall; the "B" sub-system pipe failed 360 degrees circumferentially.

3.3 Plant Response

The effects of the release of steam and water mixture rapidly caused an increasing number of problems to develop:

- Battery No. 6 <u>trouble</u> annunciator (probably caused by grounds),

- Battery and inverter No. 6 <u>trouble</u> annunciator,

- Steam generator "A" <u>level deviation</u>,

- Bus No. 32A, a 480 volt load center, <u>ground</u>,

- Main control board annunciator input <u>ground</u>,

- Various fire suppression sprinkler heads <u>melted</u> due to high temperature; this resulted in the deluge system operating in portions of the turbine building.

- Inverter No. 3 <u>trouble</u>,

- Inverter No. 1 <u>trouble</u>,

- The 4160 volt feeder breaker for bus 32A <u>tripped</u>.

The loss of pressure in the condensate header resulted in a low suction pressure trip of the "A" turbine driven feedwater pump.

The manual reactor trip was effective and resulted in a turbine trip. The "A" and "B" auxiliary feedwater pumps' drive motor breakers closed to automatically start the auxiliary feedwater system. The steam supply to the turbine driven auxiliary feedwater pump opened. The operators entered emergency operating procedure E-0 for post reactor trip recovery.

The process computer (which also performs Safety Parameter Display functions) was lost because inverter 6 which supplies two electrical distribution panels located in the control building computer room was lost. These panels have an alternate supply through a solid state switch from motor control center 3NHS-MCC7B2, Bus 32-2P. However, due to the loss of 480 volt load center 32P, this alternate supply was not available. A list of instruments that lost power is summarized in Appendix D.

The 4160 volt feed to 480 volt load center, 32P, was lost. Both load centers 32A and 32P are located at the north end of the turbine building (elevation 14" 6"), they were directly below the steam plume resulting from the break. Their 4160 to 480 volt transformers are located adjacent to the load centers. Load centers 32A and 32P are powered from the normal station service transformer through 4160 volt buses 34A and 34B, respectively.

A list of loads which lost power when these two load centers were de-energized is summarized in Appendix C.

The instrument air supply to the reactor containment was lost at the time of the line break because outside containment isolation valve (31AS*PV-15) failed close. This valve was designed as a combined containment isolation valve and pressure regulating valve. The pressure regulating feature was to operate as required to provide backup air supply to the containment, when the containment air compressors were still installed as part of the plant design. The containment air compressors were subsequently removed.

Power from inverter No. 6 is required for operation of valve PV-15 in the pressure regulating mode. When a loss of power from Inverter No. 6 occurred, the valve shut. Although the plant design provided for small pressurized air storage volumes, the pressure in these depleted rapidly. The result was that the reactor coolant system letdown isolation valves and the pressurizer spray valves closed due to loss of air pressure.

Pressurizer power operated relief valve PORV-455A operated two times as the system decay heat and the increase in pressurizer level raised RCS pressure to the PORV setpoint of 2350 psia. The valve operation was monitored by the control room operators who observed that it appeared to close after each opening. Additionally, the pressurizer relief quench tank parameters were monitored to verify PORV closure.

The main steam line isolation was reset at 17:13 hours, allowing the operators to use the steam generator atmospheric dump valves. Instrument air was restored to the containment, after a bypass jumper was installed on PV-15, which allowed charging and letdown to be restored. The plant entered technical specification limiting condition for operation (LCO) 3.7.8 when the "A" control building air pressurization bank pressure dropped low. The air compressors for this air bank are powered from electrical bus 32A which was de-energized.

4.0 DESIGN, MATERIAL ANALYSIS AND REPAIRS

4.1 Valve/Pipe Design

The configuration of each of the two ruptured pipes was a six-inch diameter control valve located in a six-inch diameter pipe installed in a ten-inch diameter piping system (See Appendix E). The total length of six-inch pipe in the "A" loop was seven feet six inches and in the "B" loop, nine feet six inches. The flow control valves (V6 and V13) are each one foot eight inches long. The system is not safety related and the pipes were installed per ANSI B31.1, Power Piping Standards. The technical requirements in the Valve's Design Specifications (U-12179-465C) specifies that all air operated control valves shall generally be no more than two nominal sizes smaller than the line in which installed. The As-built pipe specifications indicates that the installed control valves are of ASTM A-216, WCB carbon steel cast material. The valves' data sheets show that they are Masoneilan valves of A-216, WCB carbon steel material with a flow coefficient of 240.

The MSR drain system consists of two drain pumps, each taking suction from a MSR drain tank. Each pump discharges into a ten inch diameter pipe and through a flow control valve and two isolation valves. The discharge pipe is then reduced to a six inch diameter pipe (five feet long in the "A" loop and seven in the "B") before entering level control valves V6 ("A" loop) and V13 ("B" loop). Downstream of these valves, are six inch diameter pipes which are 2 feet 6 inches long on each loop. The discharge pipes are then enlarged into ten inch diameter pipes which discharge into the suction header of the feedwater pumps. The drain pumps are rated for 2050 gpm at 652 feet total discharge pressure at 375 degrees F. The nominal discharge pressure is 425 psig, with a maximum of 736 psig. At a flow rate of 2050 gpm, the flow velocity in each of the ten inch diameter pipes is about 8 feet per second. However, in the six inch diameter pipe with the control valve, the velocity is about 22 feet/second (f/s). For this type of application, a flow velocity of 8 to 15 f/s is generally recommended. The plant has notified the Architect Engineer of the potential design problems with this type of configuration.

4.2 Material Analysis

The inspectors examined the failed six-inch diameter Schedule 40 pipes in loops A & B. The fractures in both pipes were circumferential breaks. The pipes appeared to fail in a similar manner at areas in which the wall had been significantly reduced. The failed ends in both loops were located 1/4" - 1/2" downstream of the pipe to valve weld. The failure in the "A" line was about 270 degrees around, while the "B" line was a complete 360 degree break. The pipe was specified A106 Grade B, carbon steel pipe. Although localized minor pitting was observed on the inside diameter surface of the valve outlet, no pitting was found in the area adjacent to the fractured ends of the pipe. After removing a 29" long section of the failed six-inch diameter pipe from each loop, several metallurgical samples were removed from one of the pipes (downstream of valve 3DSM-LCV-20B1N) which included the fracture and the opposite end of the pipe. Microscopic examination indicated the following:

- The wall thickness at the failed end was .041" compared to the opposite end which measured .175"; ASTM A106 requires .280" nominal.

- The failure appeared to be ductile in nature as evidenced by the slight "necking down" at the fractured end.

- The microstructure consisting of ferrite and pearlite was typical of as-rolled, carbon steel. Severe strain lines associated with the necked down were observed at the fracture edge.

- No evidence of decarburization or other anomalies was observed at or away from the failure.

- Hardness testing disclosed Rockwell B values of RB78-79 corresponding to an approximate tensile strength of 70,000 psi which meets ASTM A106 Grade B material requirements.

Failure of the pipes in MSR loops A & B was attributed to a loss of wall thickness caused by erosion. The pipes which were found to be typical of ASTM A106 Grade B carbon steel pipe, exhibited no deficiencies or anomalies.

4.3 Repair

After the six-inch diameter pipes ruptured, the system was temporarily modified using Bypass Jumper 391-09. The Bypass Jumper is a temporary repair to make the system operational for a three week period until the refueling outage when a permanent change will be made. This temporary modification consisted of cutting off portions of the six-inch pipes including the ruptured sections (approximately two feet and six inches total from each line) and removing level control valves V6 and V13. On the feedwater suction header side, the ends of the cut six-inch pipes were capped upstream of valves V7 and V14. The one-inch bypass lines around these valves were also cut and capped upstream of bypass valves V953 and V952. On the drain pumps side of the cut section, discharge valves V4 & V5 and V11 & V12 will be maintained closed to isolate this line. With this temporary modification, the MSRs will be operated using the high level dump to the condenser and without the drain pumps. The licensee is performing engineering reviews to determine a permanent modification. A sketch of the configuration is shown in Appendix E.

5.0 PLANT SYSTEM RESPONSE

5.1 Instrument Air Line Containment Isolation Valve

Instrument air is supplied to containment through a single isolation valve located outside the containment. The containment isolation valve (PV-15) is in a three inch diameter instrument air line which supplies instrument air to the containment air ring header. Instrument air is supplied to air operated valves in the containment, such as on the Chemical and Volume Control System (CVCS) letdown, alternate letdown system, and the pressurizer spray valve, through valve PV-15. The controller for PV-15 is powered from inverter 6, which was lost during the incident. When power was lost to the controller, the valve failed closed (safe position). The ensuing loss of instrument air caused the air operated valves on the CVCS and pressurizer spray lines to fail closed and hence caused a loss of letdown and pressurizer spray capabilities.

Following the incident, pressurizer level increased to about 82%. In order to regain letdown capabilities, the operators opened valve PV-15, so that air could be available for letdown valves operation. The valve controller was temporarily modified (Index No. 390-58) by installing a wedge in the I/P converter simulating a full open demand signal, which allowed the valve to open. The inspector reviewed the jumper control sheet and instrument loop diagram and verified that the temporary modification did not degrade the ability of the valve to respond to a containment isolation signal. The licensee had considered the safety function of the valve before installing the modification. The modification was installed upstream of the containment isolation signal solenoids and as such would not have prevented the isolation valve from closing if the solenoid had de-energized on a containment isolation signal. The temporary modification was removed after the plant recovered from the incident.

The inspector reviewed the design and application of valve PV-15. The valve controller modulates the valve open or closed as required. However, since a plant modification removed the containment air compressors, this air line is the sole containment air supply line and remains open. This removes the need for modulating functions provided by the valve's controller. The plant is reviewing the design of the valve to determine an appropriate modification that would prevent future inadvertent losses of instrument air to containment.

5.2 Component Cooling Water Valves 3CCP-066A and 066B

Valves 66A and 66B are outlet valves on the residual heat removal (RHR) heat exchangers. These air operated, normally closed valves are opened only during the shutdown cooling mode of RHR. The valve controllers regulate the opening of the valves as required to maintain discharge flow from the heat exchangers (component cooling water flow) at a preset value. Power is provided to the controllers from inverter 6 which was lost during the incident. Following loss of power (120VAC), the valve's controller failed the valves open.

The opening of these CCW valves diverted component cooling water through the RHR heat exchangers. The licensee determined that this diversion was not enough to cause any safety related equipment to be starved of cooling water.

5.3 Environmentally Qualified (EQ) Instruments

The inspector reviewed the status of the following EQ instruments in the turbine building:

- Turbine stop valves limit switches (4); 3MSS-ZS59, 60, 61 and 62.
- Electrohydraulic controller pressure switches (3); 3TMB-PS150A, B and C.
- Turbine first stage impulse pressure transmitters (2); 3MSS-PT505 and 506.

All instruments survived the incident. However, proper indication and function of limit switch 3MSS-ZS62 was lost in the control room. The licensee inspected these instruments for moisture intrusion. The inspector witnessed inspection of limit switch 3MSS-ZS62 and its junction box. The switch appeared undamaged; however, the junction box was full of water and the terminal block in the box was rusted and damaged. An inspection of the junction boxes for the other switches revealed some water in one other box. While the switches were EQ, the junction boxes were not. The licensee indicated that these boxes were supposed to be EQ and that it was an oversight of the licensee's design that they were not. The licensee replaced all the junction boxes for the limit switches with EQ Raychem splices.

6.0 EROSION/CORROSION PROGRAM REVIEW

6.1 Scope of Inspection

Safety related piping is inspected in accordance with the ASME, B&PV Code Section XI. Non-safety related piping is not included in the ASME inspection program. A secondary plant pipe wall thickness measurement program to ensure the integrity of non-safety related high energy piping systems was established in response to NRC Generic Letter 89-08 "Erosion/Corrosion-Induced Pipe Wall Thinning." The NRC has also issued Information Notices 82-22 "Failures in Turbine Exhaust Lines", 86-106 "Feedwater Line Break" and supplements 1,2,3, 87-36 " Significant Unexpected Erosion of Feedwater Lines", 88-17 "Summary of Responses to NRC Bulletin 87-01. As a result of the feedwater elbow failure at Virginia Power's Surry Unit 1 in December 1986, the NRC issued NRC Bulletin 87-01 "Thinning of Pipe Walls in Nuclear Power Plants" requesting information concerning programs for monitoring the thickness of pipe walls in high energy single and two-phase carbon steel piping systems.

A detailed review of the licensee's erosion/corrosion program was conducted. The scope of the erosion/corrosion program inspection was to determine why the ruptured moisture separator drain lines were not identified as a high wear rate system by the erosion/corrosion program. In addition, an overall erosion/corrosion program review was conducted to assure that the licensee's erosion/corrosion program was adequate enough to identify other potentially high wear rate secondary system components. The review was performed by:

- Reviewing the adequacy of licensee's procedure for implementing the erosion/corrosion program.

- Assuring that licensee's commitments made to the NRC regarding the erosion/corrosion program were implemented.

- Conducting an independent NRC review of the Electric Power Research Institute (EPRI), CHEC and CHECMATE computer analysis for selected sections of the feedwater system and moisture/separator drain systems.

- Reviewing the ultrasonic wall thickness measurements (UT) data collected by the licensee during the 1987 and 1989 refueling outages.

- Independently reviewing the licensee's erosion/corrosion program to assure that systems which require erosion/corrosion analysis were evaluated by the licensee.

- Reviewing the qualification and training of station inservice inspection (ISI) personnel and corporate engineers responsible for implementing the Millstone Unit 3 erosion/corrosion program.

6.2 Findings

The moisture separator reheater drain pump discharge piping which failed had not been analyzed for erosion/corrosion. The root cause of this omission was attributed to an informal, undated, memorandum sent from the Millstone Unit 3 Technical Support Staff to corporate engineering. This memorandum listed the spool piece numbers associated with the MSR system under the heading "Reheat drains is exempted due to operating temperature above 530 F." The licensee's screening criteria allows systems above 480 F to be exempted from the erosion/corrosion program. This caused the misunderstanding which led to both moisture separator drain lines being inadvertently omitted from the erosion/corrosion program.

The division of responsibility for the conduct of the erosion/corrosion analysis is not adequately specified in station procedure EN 3 125, Rev. 2, in that the basis for selection of inspection locations is not documented in a formally auditable manner. The selection of inspection locations was conducted by the engineer who conducted the analysis utilizing engineering judgement and CHEC or MIT computer code analysis. The procedure does not address the retention of analysis data, how the inspection data evaluation is to be utilized in selection of subsequent locations or how erosion/corrosion records are to be maintained.

Personnel turnover caused an approximate nine month period from January 1990 to September 1990 where responsibility for the analysis portion of the program was not assigned. The current personnel assigned at the corporate office have not yet received training on the use of the EPRI CHEC or CHECMATE computer codes used to analyze the piping systems for erosion/corrosion. Additional training in the use of EPRI CHEC and CHECMATE computer codes by the site personnel is needed. The use of the CHECMATE chemistry and network flow analysis modules also have not been implemented by site personnel.

The CHEC computer code model utilized by the licensee has not been updated to reflect the requirements of CHEC version 2.0 which is currently used. This later version contains significant enhancements to the CHEC computer code and allows analysis of geometry configurations not included in the original EPRI CHEC code. During erosion/corrosion Program development, no verification was made to ensure that all systems required to be analyzed were included. A verification would have detected that the moisture separator drain system was not analyzed.

The inspector performed a selected verification of CHEC and CHECMATE computer code input data. Two isometric pipe drawings were reviewed and six input errors were identified such as a 90 degree elbow coded as a 45 degree elbow. The licensee conducted a review of six isometric drawings of the feedwater system (approximately 5% of the program), and walkdown portions of the feedwater system. The licensee noted two coding errors in its review (90 degree elbow coded as a 45 degree elbow).

The licensee performed erosion/corrosion inspections during the 1987 and 1989 refueling outages using ultrasonic thickness measuring techniques. The inspections included the following systems and components:

PIPING SYSTEMS	NO. OF COMPONENTS	
	1987	1989
Feedwater	25	11
Condensate	20	10
Blowdown	5	2
Heater Drain	4	4
Extraction Steam	5	4

During the 1989 inspections a number of inspection points previously inspected in 1987 were repeated (6 feedwater, 2 condensate, 2 blowdown, 2 heater drains, and 2 extraction steam). All components inspected in 1987 and 1989 were within nominal wall thickness tolerance. The inspection data are maintained onsite and well documented in accordance with EN 31125. The following areas of similar configurations to the failed MSR piping were inspected following the MSR line rupture: trains "A" and "C" heater drain pump level control valves to the fourth point feedwater heaters, train "A" turbine driven feed pump recirculation valve, train "A" first point feedwater heater normal level control valve, train "A" MSR tank emergency level control valve, train "A" moisture separator reheater drain tank normal level control valve.

Selection of systems to be analyzed for erosion/corrosion was performed by site ISI personnel. Analysis of selected systems to determine inspection locations is performed by corporate engineering personnel. The inspectors conducted an independent review of the piping systems which were included in the licensee's erosion/corrosion program. A secondary side heat balance diagram was highlighted to identify which piping systems were included in the erosion/corrosion program. Using this diagram, the inspectors concluded that no other secondary piping system had been inadvertently omitted from the erosion/corrosion program.

The licensee conducted an erosion/corrosion analysis using CHECMATE of the alternate moisture separator drain flow path to the main condenser and an inspection of the piping downstream of the flow control valves in both trains. The licensee's analysis indicated operation in this manner would be acceptable for up to a two year period. This alternate flow path is to be utilized for approximately 3 weeks until the third refueling outage.

The licensee stated that the alternate moisture separator reheater drain system is exempt from the erosion/corrosion program. This system is not listed in Table 1 "Piping Systems Eliminated from Inspection Program" in EN 31125.

6.3 Erosion/Corrosion Program Conclusions

The licensee's program for erosion/corrosion analysis and implementation needs review. This conclusion is based on the fact that the failed moisture separator drain system had not been analyzed and input errors were identified during a review of the erosion/corrosion analysis. However, operation until the next refueling outage (approximately three weeks) is acceptable based on the UT inspections conducted during this forced outage following the pipe ruptures and the inspections conducted during the 1987 and 1989 outages which revealed nominal pipe wall thickness.

7.0 HUMAN FACTORS

7.1 Personnel Performance as a Root Cause

The inspectors interviewed operations and management personnel involved in the event, including the shift supervisor, shift control operator, the reactor control operator, and the balance of plant operator. The inspectors also reviewed operator logs and written statements by operators.

The root causes of the event do not appear to include operator personnel error, as a direct or indirect contributing factor. However, it appears that it may have been less than prudent for plant personnel to try to evaluate the significance of the through-wall leak without obtaining a formal evaluation by engineering. Millstone 3 has no administrative procedure governing the steps that should be taken to evaluate through-wall leaks in this system.

7.2 Command and Control

When the Senior Control Room Operator (SCO) elected to personally isolate the leaking pipe section, he was temporarily placing himself out of command. The SCO was relieved by the Shift Supervisor (SS) and minimum licensed staffing levels in the control room were maintained throughout this event. There was no Plant Equipment Operator (PEO) with the SCO and the turbine building PEO was not aware of the presence of the SCO and activities at the 3DSM-V4 valve. The communications between the SCO and turbine building PEO with regard to isolating this line were minimal.

7.3 Problem Diagnostics and Resolution by the Control Room Crew

A problem in maintaining control of reactor pressure and inventory was created by the loss of instrument air to the pneumatic operated control valves within containment. The indications of this problem were the increasing pressure and level in the pressurizer, which were first detected by the Reactor Operator (RO). The RO diagnosed the cause of the increasing pressure and level to be the closed RCS letdown valves and pressurizer spray valves. The SRO and RO recognized that the pressure increase would be limited by the automatic action of the PORVs or by the ASME Code safety valves. No automatic means of limiting the increase in level was present.

The SRO/RO took immediate action to limit the rate of increase in level by manually reducing the charging flow to the minimum required flowrate for the RCP seals. Manually securing seal injection to the RCP's would have been performed to stop the increase in pressurizer level if it were necessary.

The SCO/RO recognized the loss of instrument air to containment and identified that the instrument air valve PV-15 was closed. The control logic diagram for this valve was used to confirmed that PV-15 was controlled by an electrical-to-pneumatic signal converter. Since indications of loss of some electrical power load centers were present, it was concluded that PV-15 had failed closed due to a loss of electrical power to its regulator. At this point the SCO/RO team was joined by an instrument and control (I&C) specialist who was not assigned to the shift, but who volunteered his help to the control room operators.

The SCO/RO concluded that the regulator for PV-15 should be bypassed, even though PV-15 was a containment isolation valve, because there were two solenoid-operated isolation valves in series with the regulator which would still provide the containment isolation function. The SCO obtained the proper authorization for bypassing PV-15 and then directed the I&C specialist to install a bypass around the regulator for PV-15. The I&C specialist examined the instrument air tubing around PV-15 and suggested to the SCO that the I/P regulator for PV-15 be wedged open since this would be more efficient than installing bypass tubing. The SCO agreed and the wedge was installed. This opened PV-15, restored instrument air to containment, and restored control of the pressurizer spray valve and letdown system valves. The team consisting of the SCO, the RO, and the I&C specialist had thus moved efficiently through problem identification, diagnostics, action selection, and action to restore normal control of pressurizer pressure and level. The pressurizer level was limited to 83% and the PORVs had cycled, as designed, to prevent lifting of the ASME Code safety valves.

Among those who volunteered to assist the control room operators were other I&C specialists, four PEOs from Unit 2, and two engineers from Unit 3 Engineering.

7.4 Awareness of the Significance of the Observed Leak

The Unit 3 Duty Officer, a maintenance engineer, an engineering supervisor, a maintenance supervisor, operators, and other Unit 3 staff had observed the steam leak prior to the pipe rupture. There was apparently a lack of awareness by these individuals that the through-wall pipe leak could be a precursor to a catastrophic failure. Other through-wall leaks in the secondary systems piping had been experienced during operation. These leaks had been due to localized flaws, such as those caused by jet impingement, where a small pipe tee'd into a larger diameter pipe. There was little awareness that a through-wall leak might be due to thinning of a large area of the pipe wall by erosion-corrosion mechanisms. As a result, precautions to protect personnel against a pipe rupture were not taken.

7.5 Management Response

The inspectors reviewed the licensee's management response to the incident. In this regard, the inspectors interviewed the Unit 3 Director concerning the actions taken in response to the incident. The Unit 3 Director indicated that he had been serving as the Director of Site Emergency Organization (DSEO) at the time. The DSEO is the senior on-site manager within the emergency response organization and is a responsibility which is shared, on a rotating basis, among the five Site Directors at the Millstone site. The DSEO stated that he arrived at the site, in response to his pager, at 6:20 PM and found that the shift crew was handling the incident well and did not need additional direction. He proceeded to contact the Site Director and subsequently the Maintenance Supervisor - Mechanical and the Engineering Supervisor to assure that resources were available for plant recovery. The DSEO continued to interface with his management, engineering and maintenance managers, and the shift crew during the incident.

Based upon interviews with the licensee's personnel and review of the course of the incident, the inspector concluded that plant management provided the required support to the shift crew to assure proper assignment of corporate resource and provided guidance as needed for successful handling of the incident and subsequent plant recovery.

7.6 Event Classification and Notifications

The inspector also reviewed the licensee's response in the areas of event classification and subsequent notifications. Emergency Plan Implementing Procedure (EPIP) 4112, "Incident Communications" defines the notification procedures for various emergency response levels. Once the nature of the incident was established, the Shift Supervisor (SS) determined that Incident Class/Posture Code "ECHO" was appropriate. The definition of the "ECHO" classification is contained in EPIP Form 4701-5, "State of Connecticut Incident Classification Scheme" as follows : " Minor event of general interest b ublic hazard with no radioactive release". EPIP Form 4701-5 indicates that c ation "ECHO" requires no emergency or protective actions. Consistent with the "Ec classification, the licensee determined that the event should be reported to the NRC in accordance with 10 CFR 50.72(b)(2)(ii) which is a four-hour report for "Any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESAF), including the Reactor Protection System."

At the direction of the SS, the Shift Supervisor Staff Assistant (SSSA) completed Emergency Plan Implementing Procedure (EPIP) Forms 4112-1 ,"Nuclear Incident Report Form" and 4112-3, "NRC ENS Event Notification" as required by EPIP 4112. Using an incident initiation time of 1634 hours, EPIP Form 4112-1 shows a classification time of approximately

31 minutes, and a notification time of approximately 9 additional minutes. This satisfies the requirement of EPIP 4112, Section 2.1 that the State be notified within 1 hour of the initiating event and within 15 minutes of classification. In addition, based upon information from the NRC Staff, the NRC was notified via the ENS in approximately 1 hour and 4 minutes from the initiating event.

Based upon the above, the inspector concluded that the incident was properly classified in accordance with the definitions in EPIP Form 4701-5 and that classification and notification times were in accordance with EPIP 4112 and 10 CFR 50.72(b)(2)(ii).

7.7 Turbine Building Water Recovery

Approximately 200-300 thousand gallons of water were discharged into the turbine building when the six-inch diameter moisture separator drain lines ruptured. The source of the water was from the condensate/reheat steam systems and the fire protection system which activated due to the high temperatures in the turbine building caused by the steam released. The flooding which occurred in the turbine building caused the turbine building oil separator to become submerged. This resulted in an estimated 100 to 200 gallons of oil being released into the water. Expedient operator actions were necessary to reduce the water level in the turbine building to prevent non-safety equipment from contacting the water.

The turbine building oil separator became inoperable due to the flooding. To separate the oil from the water, so that the water could be discharge, the oil/water separator in the auxiliary feedwater building was used. Operators used three submersible pumps to transfer the water/oil from the turbine building to the auxiliary feedwater building where a permanently installed oil separator was used to process the water/oil mixture. The operator continuously monitored the auxiliary feedwater building oil separator to preclude any possibility of flooding the auxiliary feed pump building were the separator to malfunction.

To further assist in the rate of water/oil separation a second oil water separator located in the diesel building was subsequently used to process the oil/water mixture. The diesel building oil separator is located outside the diesel building and therefore flooding of the diesel building was not a concern. During this process the licensee monitored the discharged water for oil and radiation. No unacceptable levels of oil or radiation were detected in the discharged water.

7.8 Human Factors Conclusions

Licensee personnel performed well during this event. They quickly identified the problem, manually tripped the reactor, isolated the main steam system, and initiated recovery activities. During recovery the operators kept the plant in a stable condition, in spite of problems due to equipment damage resulting from steam and flooding, including a loss of instrument air to the containment, and numerous alarms due to both real equipment problems and to false electrical signals.

8.0 GENERIC ASPECTS

The ruptured moisture separator drain lines had flow velocities which exceeded normal design standards. The line was also longer than most designs where line size is reduced for installation of a control valve. These unusual design features may have been contributing factors to the high erosion/corrosion rates experienced in these lines. The licensee has reviewed other plant systems for similar design features and found this system to be unique. The Architect Engineering firm responsible for this design has been informed by the licensee of the high erosion/corrosion rate seen in this line.

9.0 OVERALL CONCLUSIONS AND ASSESSMENTS

The plant staff was found to have identified the leakage shortly after it began, and was aggressive in isolating the leak and pursuing additional inspections to identify the root cause of the leakage. Operations shift personnel performed expeditiously following the moisture separator drain line rupture to trip the reactor and isolate the main steam lines. Recovery actions such as bypassing the instrument air containment isolation valve and securing fire water in the turbine building minimized the plant transient and protected non-safety related equipment in the turbine building.

The calculations of flow velocities in the ruptured moisture separator drain lines indicated flow velocities as high as 22 feet per second could have been present. This velocity exceeds the nominal design of 7-15 feet/second. The high flow velocity in the six-inch diameter line was a contributing factor in the rapid erosion/corrosion rate in this pipe section.

The licensee elected to install caps on these lines and return the moisture separator drains directly to the condenser. This temporary repair was reviewed and found adequate for the three weeks remaining prior to the refueling outage. The team found the use of the bypass to the condenser acceptable from an erosion/corrosion program aspect, based on UT inspections and erosion/corrosion analysis conducted on this line.

The erosion/corrosion program was reviewed to identify the root cause for the ruptured line not being included in the erosion/corrosion program. In addition, a review was conducted to identify any other system which may have been inadvertently omitted from the program. The root cause of the moisture separator drain lines being inadvertently left out of the erosion/corrosion program was attributed to human error. The error was not identified due to the inadequate review of the programs input and output. A review by the team of the erosion/corrosion program input identified several additional coding errors. No additional systems were found to have been inadvertently left out of the program. The team concluded that the licensee's program for erosion/corrosion analysis and implementation needs review.

This is based on the fact that the failed moisture separator drain system had not been analyzed and input errors were identified during a review of the erosion/corrosion analysis. However, operation until the next refueling outage (approximately three weeks) is acceptable based on UT inspections conducted during the forced outage following the pipe ruptures and inspections conducted during the 1987 and 1989 outages, which revealed nominal pipe wall thickness.

10.0 EXIT MEETING

The inspectors met with those denoted on Appendix A on January 7, 1991, to discuss the preliminary inspection findings. The inspectors did not provide any written material to the licensee. The licensee did not indicate that the inspectors were provided any proprietary information during this inspection.

Appendix A

Entrance/Exit Meeting Attendees

Northeast Nuclear Energy Company Corporate and Station Personnel

*J. Barile	ISI Engineer, Unit 3
S. Chandra	Supervisor, Stress Analysis & Comp. Engr.
*C. Clement	Director, Unit 3
*D. Dickerson	ISEG
*B. Enoch	I&C Unit 3
*M. Gentry	Operations Manager Unit 3
*J. Harris	Engineer, Unit 3
*M. Hess	Engineering Supervisor, Unit 3
*B. Hutchins	Licensing, Unit 3
*S. Jackson	Public Information Supervisor
*K. Jensen	Engineer, Unit 3
*R. Laudenet	Assistant Station Director
*L. Loomis	ISI Coordinator, Unit 3
*T. Lyons	ISI Supervisor, Unit 3
*N. Madden	Construction, Unit 3
*D. McDaniel	Engineering Supervisor, Unit 3
*T. McNalt	Engineer, Unit 3
*G. van Noordennen	Supervisor, Nuclear Licensing
*M. Pearson	Operations Assistant, Unit 3
*T. Quinlee	ISI Engineer, Unit 2
*W. Richter	Engineering Supervisor, Unit 3
*R. Rothgeb	Manager, Maintenance, Unit 3
*R. Sachatello	Health Physics, Unit 3
W. Varney	Manager, Plant Quality Services

U. S. NRC Personnel

*J. Durr	Chief, Engineering Branch, RI
*W. Hodges	Director, DRS, RI
*D. Jaffe	NRR/PD14
H. Kaplan	Sr. Reactor Engineer, RI
K. Kolacyck	Resident Inspector, Millstone
*S. Koscielny	NRR/EMCB
*O. Meyer	INEL
*W. Raymond	Sr. Resident Inspector, Millstone
*J. Shedlosky	Sr. Resident Inspector, Haddam Neck
*E. Trager Jr.	AEOD/ROAB
*J. Trapp	Sr. Reactor Engineer, RI
J. Yerokun	Reactor Engineer, RI

* Denotes present at exit meeting on January 7, 1991. Durr and Hodges were connected to exit meeting from RI via phone link.

Appendix B

SEQUENCE OF EVENTS

Monday 12/31/90

1300(approx.)	Initial observation of leak in the turbine building. Leak source traced to pipe at valve 3DSM-LCV-20A1.
1430-1500	Operations notified maintenance of leak.
1500-1530	Maintenance inspection of leak. Insulation around valve removed.
1615-1630	Operations personnel inspected leak. Moisture separator drain pump discharge isolation valve, 3DSM-V4 closed in preparation for line isolation.
1633:49	Motor circuit breaker for pump 3DSM-P1A opened in the control room. Operator in Turbine building heard loud "bang", observed a cloud of steam overhead, and ran to the control room.
1633:52	Steam Generator flow mismatch (STM > FW) in all 4 Steam Generators observed in the Control Room.
1633:55	Battery No. 6 trouble indication.
1633:56	Battery and Inverter No. 6 trouble indication.
1634:20	S/G "A" level deviation.
1634:25	Bus 32A Ground Alarm.
1634:32	Main Control Board Annunciator input grounds.
1635:14	Turbine Driven Feed Pump A suction Low Alarm. Turbine Driven Feed Pump A Trip.
1635:15	Feeder Breaker at 34A for 32A Open. Inverter No. 1 trouble indication. Inverter No. 3 trouble indication.
1635:45	Reactor Trip (Manual). Turbine Trip (From Reactor Trip).

1635:46	Auto start of "A" and "B" motor driven aux. feedwater pumps.
1635:59	Steam supply to steam driven aux. feedwater pump opened.
1636:01	Condenser hotwell low level alarm received.
1636:02	Automatic feedwater isolation completed. Main Steam Isolation (Manual).
1636:03	MSIVs closed.
1636:14	Unit generator output breaker tripped.
1636:25	Motor circuit breaker for pump 3DSM-P1B opened.
1638:13	Inverter 6 trouble - process computer lost.
1700	Instrument air supply to containment had been lost causing the following valves to automatically shut: RCS letdown isolation valves Pressurizer isolation valves
1703-1708	Power operated relief valve PORV-455A cycled as RCS pressure reaches its setpoint of 2350 psia.
1713	Main steam line isolation signal reset to allow operators to use atmospheric dumps.
1738	NRC informed of event through the Emergency Notification System by the licensee.
1835	Bypass jumper installed on containment isolation valve to restore instrument air to valves in the containment.
1840	Charging and letdown restored.
1859	Turbine driven auxiliary feedwater pump secured.
2000(approx.)	NRC inspectors arrived on site.

Appendix C

List of Electrical Loads Affected by De-energized Buses

400 Volt Electrical Bus 32A, (3NJS-US-7A):

Turbine Building Supply Ventilation Fan (3HVT-FN2C)
Turbine Auxiliary Oil Pump (3TML-2P)
75% Capacity Bus Tie to Bus 32P
Turbine Building Motor Control Center (MCC) (3NHS-MCC7A1)
Turbine Building MCC (3NHS-MCC7A2)
Turbine Building MCC (3NHS-MCC7A3)

480 Volt Electrical Bus 32P, (3NJS-US-7B):

Instrument Air Compressor (3IAS-C1A)
Condenser Vacuum Priming Pump (3VPS-P1B)
75% Capacity Bus Tie to Bus 32A
Turbine Building MCC (3NHS-MCC7B1)
Turbine Building MCC (3NHS-MCC7B2)
Turbine Building MCC (3NHS-MCC7B3)

Turbine Building MCC 3NHS-MCC7A1, 480 Volt Bus 32-1A

Three Condenser Cleaning System Control Panels
Three Turbine Building Sump Pumps
Two Steam Line Drain Isolation Valve Motors
Four High Pressure Feedwater Heater Isolation Valve Motors
Two Condenser Water Box Cathodic Protection Rectifier Supplies
Five Turbine Building Electric Heaters
One Seal Water Supply Booster Pump
Two Turbine Plant Instrument Sample Pumps
One Turbine Electro Hydraulic (EHC) Control Unit Fluid Pump
One EHC Fluid Filter Transfer Pump
One 480 volt Receptacle
One Lubricating Oil Conditioner Recirculation Pump
Four Extraction Steam Valves
Three Condenser Cooling Water Valve Motors
Two Turbine Building Lighting Panels
Two Turbine Plant Component Cooling Water Valve Motors
One EHC Unit Electric Heater

Turbine Building MCC 3NHS-MCC7A2, 480 Volt Bus 32-2A

Three 120/240 volt Electrical Distribution Panels (3SCA-PNL1N, -PNL3N and -PNL 17N)
One Turbine Driven Feedwater Pump (TDFWP) Exhaust Isolation Valve Motor
One TDFWP Turning Gear Motor
Fourteen Extraction Steam Isolation Valve Motors
Two Steam Line Drain Isolation Valve Motors
One Condensate Pump Discharge Isolation Valve Motor
Four Feedwater Heater Isolation Valve Motors
Four Turbine Shaft Steam Seal Valve Motors
One Steam Generator Blowdown Valve Motor
One Condenser Water Box Vacuum Priming Seal Pump
Three Turbine Building Exhaust Fans
One Turbine Building Transfer Exhaust Fan
One Turbine Lubricating Oil Room Exhaust Fan
One Turbine Lubricating Oil Transfer Pump
One Turbine Lubricating Oil Vapor Extractor
One Condenser Vacuum Breaker Valve Motor
Two Condenser Water Box Cathodic Protection Rectifier Supplies
One Lighting Panel
Four 480 volt Receptacles

Turbine Building MCC 3NHS-MCC7A3, 480 Volt Bus 32-3A

Four Exhaust Fans
Four Transfer Exhaust Fans
One 120/240 volt Distribution Panel (3SCA-PNL18N)
One Steam Packing Exhaust Blower
One Condenser Vacuum Breaker Valve Motor
Six Condensate Demineralizer Regeneration Pumps
Six Steam System Drain Valves
Three Extraction Steam Valve Motors
One Feedwater Heater Isolation Valve Motor
One Generator Neutral Enclosure Vent Fan
Two Supply Fans
One Turbine Exhaust Hood Spray Isolation Valve Motor
Six Turbine Building Heaters
Turbine Building Elevator

Turbine Building MCC 3NHS-MCC7B1, 480 Volt Bus 32-1P

One Feedwater Pump Auxiliary Lubricating Oil Pump
One Extraction Steam Isolation Valve Motor
Eight Water Storage Tank Heater Circuits
Two Condenser Water Box Cathodic Protection Rectifier Supplies
Three Condenser Cooling Water Valve Motors
Three Generator Hydrogen Seal Oil Pumps
One Component Cooling Water Makeup Pump
Two Chemical Feed Pump
Two Condensate Demineralizer Regeneration Pumps
Eight Water Treatment System Pumps
One Turbine Building Lighting Panel
One Heat Tracing Panel
Two Support Circuits for No. 1 Carbon Dioxide Fire Suppression
Storage Tanks.
Two 480 volt Receptacles
Five Turbine Building Heaters

Turbine Building MCC 3NHS-MCC7B2, 480 Volt Bus 32-2P

Alternate Supply to 120/208 volt Non-vital Distribution Panels 3VBA-PNL-6A(-N) and
3VBA-PNL-6B(-N).
Two Floor Drain Sump Pumps
One Condenser Air Removal Seal Water Pump
Three 120/240 volt Distribution Panels (3SCA-PNL2N, -PNL4N and -PNL20N)
Two Condenser Cleaning Control Panels
Five Extraction Steam Valve Motors
Three Feedwater Heater Isolation Valve Motors
Two Condenser Cooling Water Valve Motors
Four Steam Drain Isolation Valve Motors
One Turbine Plant Component Cooling Water Valve Motor
One Condenser Vacuum Breaker Valve Motor
One Steam Generator Blowdown Flash Tank Isolation Valve Motor
One EHC Fluid Pump
One Condenser Cleaning Control Panel
Two Lighting Panels
One Heat Tracing Panel
One Vacuum Priming Seal Water Pump
Two Condenser Water Box Cathodic Protection Rectifier Supplies
Four Turbine Building Heaters
One Sample Cooler Compressor
One Sample Sink Exhaust Fan

<u>Turbine Building MCC 3NHS-MCC7B3, 480 Volt Bus 32-3P</u>

One Condensate Pump Discharge Isolation Valve Motor
One Condenser Cooling Water Valve Motor
One 120/240 volt Distribution Panel (3SCA-PNL21N)
Seven Condensate Demineralizer Pumps
Three Turbine Building Exhaust Fans
One Steam Packing Exhaust Blower
Four 480 volt Receptacles
One Turbine Building Lighting Panel
One Seal Water Supply Booster Pump
One Feedwater Heater Isolation Valve Motor
One Warehouse Supply Fan
Turbine Building Rolling Steel Door

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL1N</u>

Includes Supplies to:
- Neutron Flux Mapping RacK "A"
- Radiation Monitoring Panel
- Fire Detection Panel
- Turbine Driven Feedwater Pump Turning Gear

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL2N</u>

Includes Supplies to:
- Vibration Monitoring Instruments
- Turbine Driven Feedwater Pump Turning Gear
- Fire Suppression Halon Control - Computer Room
- Control Building Air Conditioning Control

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL3N</u>

Includes Supplies to:
- Loose Parts Monitoring
- "B" Turbine Driven Feedwater Pump Speed Control

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL4N</u>

Includes Supplies to:
"A" Turbine Driven Feedwater Pump Speed Controller
Control Building Temperature Transmitter

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL17N</u>

Includes Supplies to:
Hydrogen Analyzer

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL18N</u>

Includes Supplies to:
Turbine Plant Floor Drain Radiation Monitor
Condenser Air Removal System Radiation Monitor
Hydrogen Detection Panel
Waste Water Treatment Panel
Generator Core Monitor
Auxiliary Boiler Controls

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL20N</u>

Includes Supplies to:
Fire Protection System Water Spray Control Panels

<u>Turbine Building 120/240 Volt Distribution Panel 3SCA-PNL21N</u>

Includes Supplies to:
Fire Protection Panel
Condensate Storage Tank Heater Controls
Regeneration Sump Discharge Monitor
Auxiliary Boiler Controls
Service Air Compressor Control

<u>Control Building 120 volt Non-Vital Distribution Panels 3VBA-PNL-6A(-N) and 3VBA-PNL-6B(-N)</u>

Supply to Computer Room Distribution Including:

- Process Computer
- SPDS Console
- Modem

Appendix D

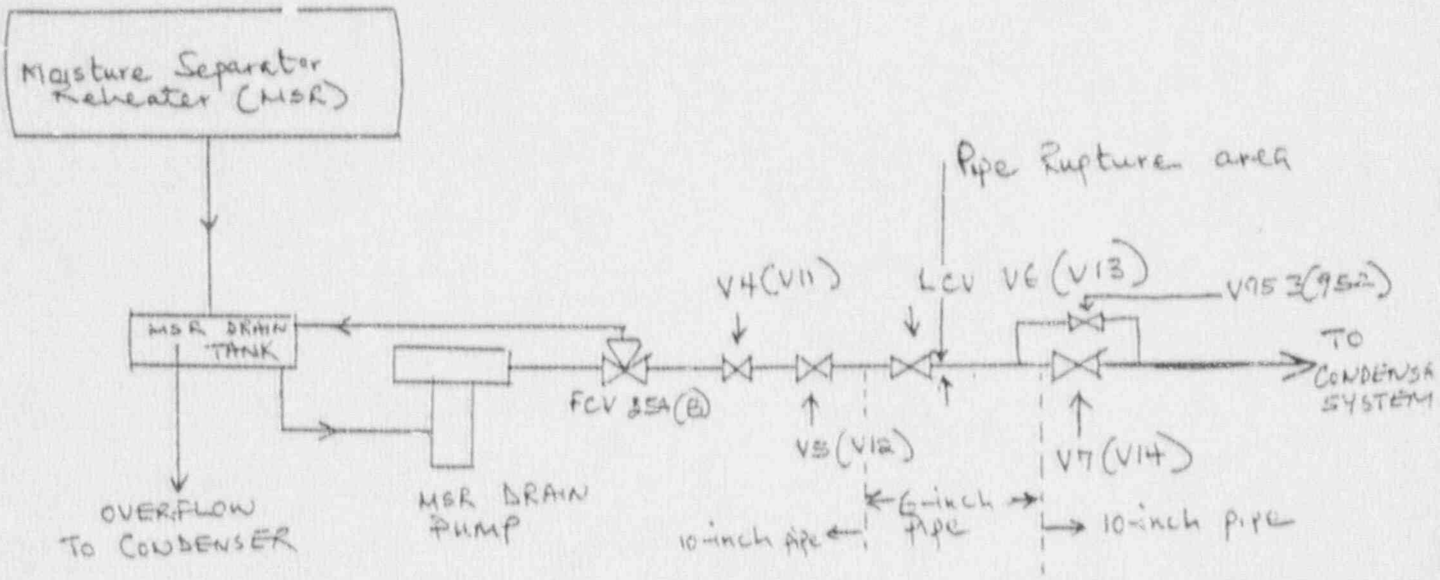
List of Instruments Powered by Inverter No. 6

Steam Generator Blowdown Flow Control
Charging Pumps Cooling Pump Discharge Pressure and Suction Temperature and Bearing Temperature
Charging Pump Cooler Temperature Control
Charging Pump Discharge Pressure
Charging Pump Suction Pressure and Recirculation Flow
Charging Pump Oil Cooler Outlet Flow
Reactor Plant Component Cooling Water Supply Header Pressure, Flow and Temperature
Reactor Plant Component Cooling Water Heat Exchanger Outlet Flow and Temperature
Reactor Plant Component Cooling Water Pump Suction and Discharge Pressure
Turbine Plant Component Cooling Water Pressure and Flow
Residual Heat Removal Heat Exchanger Outlet Temperature and Flow
Residual Heat Removal Pump Suction Pressure
Auxiliary Feed Water Flow to Condensate Surge Tank
Condensate Flow to Condensate Storage and Condensate Surge Tanks
Condensate Storage and Condensate Surge Tanks Make-up Flow
Primary Drains Transfer Tank Flow and Level
Component Drains Transfer Tank Level
Pressure Relief Tank Drains Flow
Auxiliary Feedwater Flow to Steam Generators
Instrument Air Pressure
Reserve Instrument Air Pressure
Turbine Throttle Pressure
Primary Grade Water Supply Flow
Refueling Water Storage Tank Inlet Water Temperature
Refueling Water Storage Tank Temperature
Refueling Water Storage Tank Recirculation Temperature
Quench Spray Pump Flow
Containment Cooling Heat Exchanger Shell Outlet Temperature and Flow
Containment Cooling Heat Exchanger Tube Side Flow
Containment Spray to Test Nozzle Flow
Containment Cooling Recirculation Pump Suction and Discharge Pressure and Discharge Flow
High Head Safety Injection Pump Suction Pressure
Safety Injection Pump Cooling Pump Suction and Discharge Pressures and Minimum Flow and Pump Temperature and Bearing Temperatures
Boric Acid Transfer Pump Discharge Pressure
Make-up Pump Discharge Flow
Containment Drain Sump Pump Discharge Pressure
Containment Unidentified Leakage Sump Pump Discharge Pressure
Containment Instrument Air Supply Valve Pressure Control
Containment Drains Transfer Pump Discharge Pressure and Flow

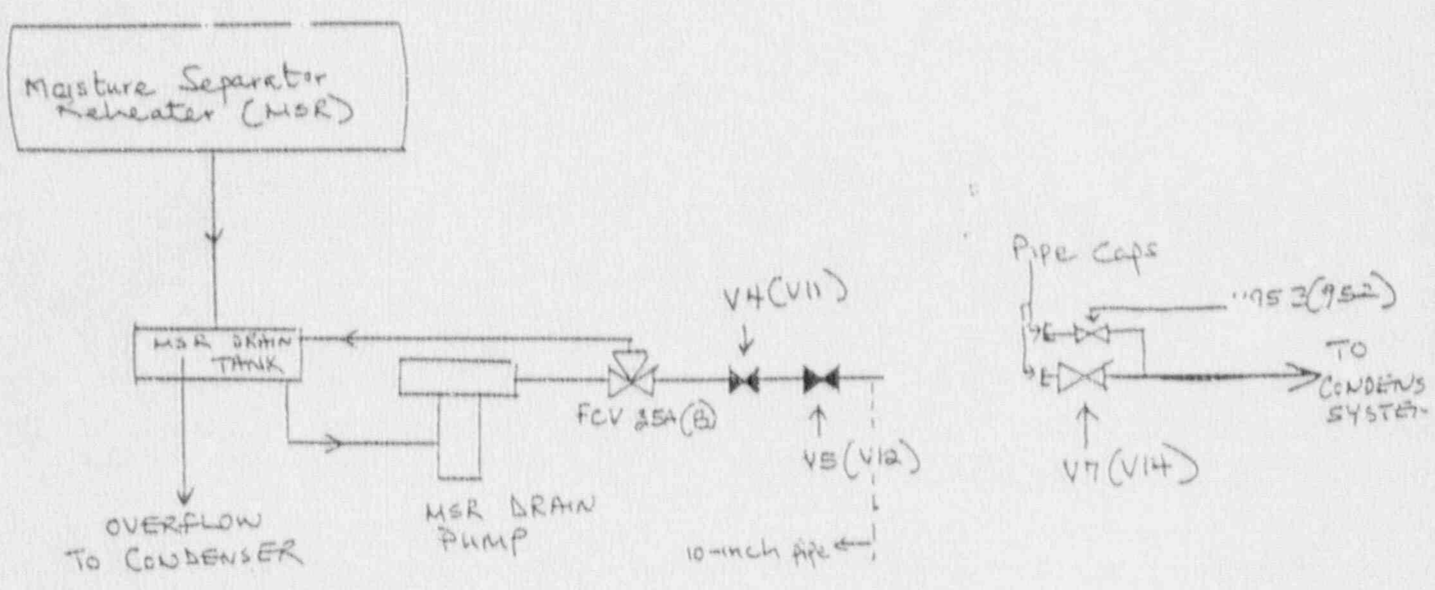
Refueling Water Chemical Addition Tank Level and Temperature
Containment Structure Sump Pump Temperature
Fuel Pool Cooling Pumps Discharge Pressure
Fuel Pool Water Temperature and Pool Level
Fuel Pool Cooling Heat Exchanger Flow
Control Building Air Conditioning Booster Pump Suction and Discharge Pressure and Pump Bearing Temperatures
Containment Air Temperatures
Containment Air Recirculation Cooling Coil Outlet Temperature
Containment Air Recirculation Cooler Chiller Outlet Flow
Containment In-core Sump Pump Discharge Pressure
Engineered Safety Features Building Sump Pump Discharge Flow
Neutron Shield Tank Level
Neutron Shield Surge Tank Level
Neutron Shield Tank Cooling Water Supply and Return Temperatures
Service Water Pump Differential Pressure
In-core Temperature Reference Junction Temperature
Moisture Separator Reheat Steam Temperature
Turbine Driven Auxiliary Feedwater Pump Bearing Temperatures
Motor Driven Auxiliary Feedwater Pump Bearing Temperatures
Steam Generator Feedwater Inlet Temperatures
Feedwater Pump Discharge Temperatures
Feedwater Pump Bearing Temperatures
Feedwater Pump Motor Stator and Speed Increaser Temperatures
Electrical Bus A, B and C Transformer Temperatures
First through Sixth Point Heater Feedwater Inlet and Outlet and Extraction Steam Inlet and Normal and Emergency Drain Temperatures
Heater Drain Pump Stator Temperature
Moisture Separator Reheater Relief Vent Temperature
Quench Spray Pump Bearing and Motor Stator Temperatures
Reactor Coolant Pump Bearing and Motor Stator Temperatures
Reactor Coolant Pump Seal Temperatures
Residual Heat Removal Pump Bearing and Motor Stator Temperatures and Seal Cooler Temperatures
Containment Recirculation Pump Bearing and Motor Stator Temperatures
Fuel Pool Cooling Pump Bearing Temperature
High Head Safety Injection Pump Bearing and Motor Stator Temperatures
Service Water Pump Motor Bearing and Stator Temperatures
Feedwater Pump Turbine Steam Supply Temperature
Component Cooling Water Pump Bearing and Motor Stator Temperatures
Charging Pump Bearing and Motor Stator Temperatures
Condenser Hotwell Temperature Steam Packing Exhaust Condenser Inlet Temperature
Condensate Pump Bearing and Motor Stator Temperatures Condenser Cooling Circulating Water Inlet and Outlet Temperatures

Circulating Water Pump Bearing and Motor Stator Temperatures
Moisture Separator Drain Pump Suction and Discharge Temperatures
Reheater Drain Tank Discharge Temperature
Generator Bus Enclosure Temperatures
Chilled Water Pump Oil Temperature
Turbine Bypass Control Valve Temperature
Steam Jet Air Ejector Inlet Temperature
Chiller Motor Bearing Temperatures

Appendix E



MSR Drain Pipe Configuration



Temporary Modification