U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report No. 50-245/81-01
50-336/81-01

Docket No. 50-245
50-336

License No. DPR-21
DPR-65

Priority --    Category C

Licensee: Northeast Nuclear Energy Company
P.O. Box 270
Hartford, Connecticut 06101

Facility Name: Millstone Nuclear Power Station, Units 1 & 2

Inspection at: Waterford, Connecticut 06385

Inspection conducted: January 1 thru February 14, 1981

Inspectors: J. T. Shedlosky
J. T. Shedlosky, Sr. Resident Inspector — 3/31/81 date signed

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T. H. Smith, Sr. Resident Inspector
Haddam Neck NPS (January 8 - 16) — 4-16-81 date signed

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(January 8 - 9) — 4/20/81 date signed

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(January 12 - 14) — 4-16-81 date signed

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R. R. Keimig, Acting Chief,
Reactor Projects Section 1B,
Division of Resident & Project Inspection — 4-16-81 date signed

INSPECTION SUMMARY:

Inspection on January 1 through February 14, 1981 (Combined Report Nos. 50-245/81-01 and 50-336/81-01).

Areas Inspected: Routine, onsite, regular and backshift inspection by the Senior Resident Inspector, a Senior Resident Inspector from another power station and

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three region based inspectors (55 hours, Unit 1· 275 hours, Unit 2). Areas inspected included response to two incidents involving Unit 2, inspections of the control rooms and the accessible portions of the Unit 1 reactor and turbine buildings; the Unit 2 containment, enclosure, auxiliary and turbine buildings; radiation protection; physical security; and reporting to the NRC.

Results: Of the five areas inspected, one item of noncompliance was identified in one area: failure to follow approved operating procedures, paragraph 4.h.

DETAILS

1. Persons Contacted

The below listed technical and supervisory level personnel were among those contacted:

J. Bangasser, Station Security Supervisor
J. M. Black, Unit 3 Superintendent
P. Callaghan, Unit 1 Maintenance Supervisor
A. Cheatham, Radiological Services Supervisor
J. Crockett, Unit 2 Engineering Supervisor
F. Dacimo, Quality Services Supervisor
E. C. Farrell, Station Services Superintendent
H. Haynes, Unit 2 Instrumentation and Control Supervisor
R. J. Herbert, Unit 1 Superintendent
J. Kangley, Chemistry Supervisor
J. J. Kelley, Unit 2 Superintendent
E. J. Mroczka, Station Superintendent
V. Papadopoli, Quality Assurance Supervisor
R. Place, Unit 2 Maintenance Supervisor
R. Palmieri, Unit 1 Engineering Supervisor
W. Romberg, Unit 1 Operations Supervisor
S. Scace, Unit 2 Operations Supervisor
E. Spruill, Health Physics Supervisor
F. Teeple, Unit 1 Instrumentation and Control Supervisor

2. Review of Plant Operation - Plant Inspections (Units 1 and 2)

The inspector reviewed plant operations through direct inspection and observation of Units 1 and 2 throughout the reporting period. Activities in progress at Unit 1 included refuel outage work and recovery following a reactor trip on 1/2/81. The unit was returned to power operation on 1/20.

a. Instrumentation

Control room process instruments were observed for correlation between channels and for conformance with Technical Specification requirements. No unacceptable conditions were identified.

b. Annunciator Alarms

The inspector observed various alarm conditions which had been received and acknowledged. These conditions were discussed with shift personnel who were knowledgeable of the alarms and actions required. During plant inspections, the inspector observed the condition of equipment associated with various alarms. No unacceptable conditions were identified.

c. Shift Manning

The operating shifts were observed to be staffed to meet the operating requirements of Technical Specifications, Section 6, both to the number and type of licenses. Control room and shift manning was observed to be in conformance with Technical Specifications and site administrative procedures.

d. Radiation Protection Controls

Radiation protection control areas were inspected. Radiation Work Permits in use were reviewed, and compliance with those documents, as to protective clothing and required monitoring instruments, was inspected. Proper posting of radiation and high radiation areas was reviewed in addition to verifying requirements for wearing of appropriate personal monitoring devices. There were no unacceptable conditions identified.

e. Plant Housekeeping Controls

Storage of material and components was observed with respect to prevention of fire and safety hazards. Plant housekeeping was evaluated with respect to controlling the spread of surface and airborne contamination. There were no unacceptable conditions identified.

f. Fire Protection/Prevention

The inspector examined the condition of selected pieces of fire fighting equipment. Combustible materials were being controlled and were not found near vital areas. Selected cable penetrations were examined and fire barriers were found intact. Cable trays were clear of debris.

g. Control of Equipment

During plant inspections, selected equipment under safety tag control was examined. Equipment conditions were consistent with information in plant control logs.

h. Instrument Channels

Instrument channel checks recorded on routine logs were reviewed. An independent comparison was made of selected instruments. No unacceptable conditions were identified.

i. Equipment Lineups

The inspector examined the breaker position on switchgear and motor control centers in accessible portions of the plant. Equipment conditions, including valve lineups, were reviewed for conformance with Technical Specifications and operating requirements.

3. Reactor Trip of Unit 2, January 2, 1981

At 0050 hours on 1/2/81, a reactor trip occurred when a breaker was opened, de-energizing one of the two station DC buses. The reactor had been operating at 100 percent power with a turbine load of 884 megawatts electric. An unlicensed Plant Equipment Operator intended to take ground readings on Class 1E, 125 volt DC bus 201A. Instead of rotating the ground detector switch located on the metal clad switchgear, he operated the control switch for breaker D0103 and opened the breaker. This de-energized DC Bus 201A and removed DC power from all Facility Z1 equipment. The reactor scram was caused by de-energization of four reactor trip switchgear breaker undervoltage coils.

The loss of facility Z1 DC power also de-energized all control room annunciators. Control room operators noted the scram by observing inward motion and full insertion of control elements as displayed on position indicators. Observing that there had been no turbine trip, it was tripped manually from the control room.

The Plant Equipment Operator reported his mistake and received permission from the control room to reshut breaker D0103. This was done 51 seconds after the loss of D.C. This initiated a trip of generator output breakers and a fast transfer of Z1 AC buses to the Reserve Station Service Transformer (RSST) from the Normal Station Service Transformer (NSST). The B Emergency Diesel Generator (B-EDG) was powering Facility Z2, 4160 volt Safeguards Bus 24D. The A-EDG was found shutdown with the "Start Failure" Circuit actuated.

At 0100 hours the B-EDG tripped and de-energized bus 24D. The ESFAS load shed signal was over-ridden and bus 24D energized from the RSST. The diesel generator had tripped and was inoperable due to a service water leak from piping above the governor. When the AC bus was re-energized, 96 instrument channels of reactor plant and balance of plant controls were found inoperable. All were supplied by a Non-Class IE regulated 120v. AC instrument panel which receives its power from the Class 1E 4160 volt safeguards bus 24D. The 96 instrument channels are GE/MAC 10 to 50 milliampere current loops and receive their power from 24 GE/MAC power supplies. Each was found with a "blown" input fuse. The plant was maintained in a hot shutdown condition until the instruments were returned to service by replacing fuses.

Pressurizer pressure was being maintained at 2250 to 2300 psia. At 0305 hours, pressurizer pressure increased to approximately 2380 psia. Both pressurizer power operated relief valves (PORV) opened momentarily and reclosed. Operators were aware of valve operation by PORV discharge pipe temperature instruments and annunciators. Quench tank level, pressure and temperature instrument response also indicated valve position. The acoustic valve position monitors did not alarm. The reactor operator had been controlling pressurizer pressure using heaters and spray. Two reactor coolant pumps were in operation. Some difficulty had been experienced in maintaining pressure control. Because of the ineffectiveness of spray, the operator concluded that a "hard bubble" had resulted from the collection of non-condensible gases in the pressurizer. Pressurizer level was cycled to assist in pressure control. This may have had the combined effect of over compensating pressure swings and reaching the PORV set point. Auxiliary spray was used to lower pressurizer pressure.

A cooldown to cold shutdown was commenced at 0600 hours.

a. Sequence of Events

0050 hours - The 125 volt DC Bus 201A de-energized by opening breaker D0103. That breaker is controlled locally in the switchgear room and has no automatic functions.

- Reactor trip switchgear breaker undervoltage coils de-energized causing a scram.

- The RPS system attempted to process a turbine trip signal to the EHC system. However, relay logic which required DC power from Facility Z1 could not operate. There was no turbine or generator breaker trip.

- All station electrical buses remained powered from the NSST, which is connected to the primary or generator side of the Unit transformer. The switchyard generator breakers remained shut.

- Turbine Control valves modulated shut as the EHC initial pressure regulator attempted to prevent reduction of turbine steam chest pressure below 90 percent of rated. This moderated the cooldown rate.

- Air start solenoid valves to the A-EDG de-energized open. It is assumed that the diesel engine started and accelerated to the mechanical governor speed setting. There was no DC power available for control on the electronic governor. The air flasks would continue to depressurize through the open air start valves.

0050h 29s - Control room operator operated the Master Trip pushbutton on the EHC control panel insert. The turbine tripped. The 24 volt DC to operate the EHC system was available from the shaft driven permanent magnet generator.

- The turbine trip signal operated trip lockout relaying, which then tripped and de-energized Facility Z2 6.9Kv Bus 25B, 4160v Bus 24B and 4160v safeguards Bus 24D. The breakers on Facility Z1 did not trip because DC control power was not available. 6.9Kv Bus 25A, 4160v Bus 24A and 4160 Safeguards Bus 24C remained connected to the main generator and unit transformer through the NSST. DC control power from Facility Z1 was not available to trip the generator output breakers after turbine lockout relay operation.

- Generator reverse power relays, powered by Facility Z2 DC, operated and initiated a 30-second timer. That time delay would have to be satisfied before a reverse power trip of the generator output breakers would occur.

- Relay logic, which causes the fast transfer of station loads from the NSST to the RSST, is powered by Facility Z1 DC. Buses 24B, 24D and 25B remained de-energized, although power was available from the RSST and Facility Z2 breaker control power remained energized. Undervoltage was sensed on Safeguards Bus 24D by the Engineering Safety Features Actuation System (ESFAS). Throughout the event, power was available to all ESFAS channels from four Class 1E Uninterruptible Power Supplies. The B-EDG started and powered Bus 24D. Buses 24B and 25B remained de-energized.

- The turbine trip stopped the reactor cooldown. T ave. dropped from 574$^{\circ}$F to 525$^{\circ}$F, pressurizer pressure from 2250 psia to 1760 psia, and pressurizer level from 56 percent to off-scale. All three parameters recovered promptly following the turbine trip. Pressurizer pressure did not reach the Engineered Safety Features Actuation Pressure (1600 psia).

0050h 51s - The Facility Z1 DC Bus 201A was re-energized.

- DC power was available to trip breakers supplying 6.9Kv Bus 25A, 4160v Bus 24A, and Safeguards Bus 24C from the NSST, through logic associated with the turbine trip lockout relay which had operated earlier. Facility Z1 DC relay logic also initiated a generator breaker trip through the trip lockout relay.

- Fast transfer logic was energized. Loads on Buses 25A, 24A, and 24C shifted to the RSST.

- The fast transfer logic also allowed Bus 25B, which was de-energized 22 seconds earlier by the turbine trip, to be energized from the RSST. This applied power simultaneously to the two reactor coolant pump motors and a high pressure condensate pump motor. Breakers associated with these pump motors do not automatically trip on undervoltage. The starting current from these loads caused the RSST supply breaker for Bus 25B to trip on overcurrent.

- The B-EDG continued to supply Bus 24D.

- Re-energizing Facility Z1 DC caused both MSIV's to shut. This was in agreement with the configuration of the control logic and the air operator pilot valve arrangement.

- The A-EDG was found shutdown with the start failure circuit having tripped the shutdown lockout relay. This condition became apparent when restoration of Facility Z1 DC power restored the control room annunciators. This is a potential design deficiency. Any time that DC power to the engine is interrupted, the pneumatic time delay relay associated with the failure to start circuit begins to time-out. When DC power is re-energized and the 15-second time delay has actuated, the engine will be shutdown. The shutdown lockout must be reset locally before the engine will restart.

0100 hours - The B-EDG tripped when a leak at a service water pipe flange sprayed salt water on the machine. The spray caused an electrical fault in an electrical connector associated with the electronic governor. This fault is believed to have caused the governor to have decreased the engine speed to the point of tripping the machine on low lubricating oil pressure. This would be 700 RPM or an electrical frequency of 46 Hertz. The safeguards bus was energized from the RSST after overriding the LNP signal. A failed gasket was replaced at the leaking flange. The failure may have been caused by improperly tightened bolts or pipe vibration. The licensee checked the tightness of other service water pipe connections; there were no deficiencies identified.

- When power was re-applied to the Safeguards Bus 24D, 96 reactor plant and balance of plant instruments were discovered to have failed. Those instruments are GE/MAC 10 to 50 milliampere current loops and receive this power from 24 GE/MAC power supplies. Each of these power supplies was found with a "blown" fuse on the primary of the supply transformer. The plant was maintained in a hot shutdown condition until the instruments were returned to service. All instruments responded properly after fuses were replaced.

The GE/MAC power supplies are loads supplied by a 120v AC regulated instrument panel VR21. Although that panel is Non-Class 1E, it is supplied by Class 1E Safeguards Bus 24D. Prior to the shutdown caused by saltwater spray, the diesel was running in the emergency mode. The only engine trips were two out of three low lube oil pressure, engine overspeed and generator differential current. The engine was found with low lube oil pressure annunciated. The calculated engine speed to reach the two out of three low lube oil pressure is 697 rpm or 46.5Hz. This frequency transient was carried through to the regulated instrument bus and the input to the GE/MAC power supplies. Bus voltage is assumed to have remained stable, since the automatic voltage regulator was unaffected. A test was conducted to determine input current to a GE/MAC power supply as frequency was varied from 50 to 70 Hz. The range was limited by the equipment available. Extrapolated data below 50Hz indicates a primary RMS current of 1 amp at 120 VAC would be reached at 45Hz. The GE/MAC primary fuses are 1 amp quick-blow.

0305 hours - Both PORV's opened momentarily at 2380 PSIA pressurizer pressure. Discharge pipe temperature indicators and quench tank parameters responded; control operators were aware of valve operation and reduced pressure using auxiliary spray. The acoustic valve position monitors did not annunciate. The position monitors were later tested and verified to be operable. This was performed on 1/18 at 2300 hours with three of the four channels alarm setpoints at 30 percent of the 30g. range (9g.). During the test opening of one PORV, that channel, with the original setting of 20 percent of 100g. (20g.), did alarm properly. The three other channels did not alarm due to cross-talk. The test was conducted at normal pressure and temperature (2270 psia, 533°F) and four reactor coolant pumps operating. Quench tank parameters and valve discharge pipe RTD's responded properly.

0350 hours - Commenced reactor cooldown.

b. Status of Open Items

RPS, Turbine and Generator Trip Schemes -
The licensee has verified that all circuits operated as designed. When either DC facility is de-energized, a turbine trip may not occur automatically following a reactor scram. Station operating procedures require that Control Room Operators follow an RPS trip with a manual Scram, manual turbine trip and manual generator output breaker trip. Independent sources of power are available for turbine and generator manual trips.

Class 1E, 125v. DC System and Associated Control Logic -
The licensee has commenced a design review to determine: if the present DC system battery, battery chargers,battery bus, DC load center and breaker arrangement provides optimum service; and, if the turbine and generator trip scheme and fast transfer logic requires redundant components or power supplies. The inspector will review this analysis during a future NRC inspection. This is an open item pending that review. (336/81-01-01)

Ground Detector/Breaker D0103 Switch Positions -
Both switches are located on the face of metal clad switchgear and are adjacent to each other. The switchgear is located in a locked vital area. The switch handles are of different styles, the breaker control switch is covered with a plastic cover plate. The inspector concurs with the licensee's position that any additional physical protection of the breaker control switch would interfere with possible requirements for rapid manual operation of the breaker. The licensee has completed actions and closed an open item by upgrading switchgear component labels.

Trip of A - Emergency Diesel Generator -
The licensee completed an investigation and testing of the diesel protective shutdown circuit. It was determined that, due to the configuration of relay circuits, if DC control power to the engine is interrupted for greater than 15 seconds the engine will be shutdown when power is reapplied. A shutdown lockout must be reset locally before the engine will restart. The licensee's engineering department is evaluating the acceptability of this arrangement, and evaluating the need for a start failure circuit during an ESFAS run. This item remains open pending the results of that evaluation and the implementation of any resultant design changes (336/81-01-02). This has also been identified to other NRC offices as a potentially generic problem.

Trip of B - Emergency Diesel Generator -
The inspector concurs with the licensee's analysis and conclusion that the saltwater spray caused the governor to go to minimum speed position resulting in a low lube oil pressure trip. The licensee is conducting an evaluation as to the cause of the amphenol connector failure, and the need for spray protection. This item is open (336/81-01-03).

Failure of GE/MAC Instruments -
The inspector concurs with the licensee's analysis and conclusion that the bus under-frequency condition resulted in high primary current in power supply transformers and fuse failures. The licensee has acted on a vendor recommendation and replaced the one amp quick-acting fuse with one-half amp slow-blow fuses in all GE/MAC supplies. Given a two amp current inrush, the one-half amp slow-blow fuse would blow in five seconds, opposed to two seconds for the one amp fuse. The licensee has closed an open item by these actions.

Acoustic Valve Position Monitors for the PORV's and Safety Valves -
The licensee has closed an open item by completing a functional test of those monitors on 1/18. The cause of the failure of the instruments to respond to valve operation on 1/2 remains undetermined.

Control Room Annunciators -
All annunciators are powered from Bus 201A. A design for redundant power supplies has been completed in response to a previous incident. It is scheduled to be implemented during the next refueling outage. This item (336/79-30-01) remains open.

Procedural Coverage -
The licensee has revised OP 2519, "Electrical Emergency (Loss of Main DC Bus)" to incorporate the lessons learned during this incident. The inspector has no additional open items.

Pressurizer Spray Water Differential Temperature -
When auxiliary spray was initiated, the 350°F differential temperature limit of Specification 3.4.9.2 was exceeded due to the dead leg of

ambient temperature water in the auxiliary spray line. The spray water temperature differential is the difference between the pressurizer steam space temperature and the regenerative heat exchanger outlet temperature. The use of the auxiliary pressurizer spray system resulted in a maximum spray water differential temperature of 385°F. The licensee has completed the analysis required by that specification. That evaluation concluded that the transient had negligible effect on the maximum auxiliary spray system piping usage factor. However, the thermal transient will affect the usage factor of the pressurizer spray nozzle, but did not compromise the structural integrity of the pressurizer spray nozzle. The licensee will be performing a detailed stress analysis to evaluate the exact impact of the thermal transient upon the fatigue life of the pressurizer spray nozzle and auxiliary spray piping. This item is open and will be reviewed during a future inspection (336/81-01-04).

c. Compliance with Operating License Technical Specifications

AC Electrical Sources, Operating (3.8.1.1) - With both diesel generators inoperable, the reactor was in Hot Standby (Mode 3) and two sources of offsite power were available. The reactor was in Cold Shutdown (Mode 5) at 2100 hours, 1/2. The A-EDG was returned to service after testing at 0755 hours, 1/2. This is within the Specification Action statement.

AC Electrical Sources, Modes 5 and 6 (3.8.1.2) - The minimum requirements of one offsite source, and one diesel generator were exceeded.

Onsite D.C. Electrical Distribution, Operating (3.8.2.2) - Power was restored to Bus 201A in 50 seconds, which is within the action statement requirement.

Pressurizer Spray Water Differential Temperature (3.4.9.2) - In accordance with the action statement, the temperature was restored within 30 minutes, an evaluation on the fracture toughness properties of the pressurizer was performed and the reactor was in Cold Shutdown at 2100 hours, 1/2.

4. Introduction of Reactor Coolant into the Unit 2 Nitrogen System

Following the reactor trip of 1/2/81, the plant remained shutdown for maintenance including the replacement of pressurizer safety valve 2-RC-201. This activity required that the pressurizer bubble be collapsed and the pressurizer be partially drained. The safety valve was replaced on 1/3-4. However, the replacement valve indicated seat leakage at 1000 psia pressurizer pressure. A second cooldown was commenced at 1400 hours, 1/5.

The pressurizer is drained with a nitrogen overpressure. Nitrogen is supplied to the high point of the pressurizer spray line through two Class 1 manual valves (2-RC-015 and 2-RC-030). Those valves isolate the pressurizer from a nitrogen service header. That service header is normally pressurized to 45 psig with low pressure nitrogen supplied from an evaporator.

With the replacement of safety valve 2-RC-201 complete, the licensee commenced to fill and heat up the pressurizer at 1810 hours, 1/6. Although the pressurizer vent valves were shut during this evolution, the nitrogen supply valves remained open due to an oversight by operations personnel. At 2330 hours, 1/6, the RCS was at 112$^{o}$F, 100 psia. As the heatup and pressurization continued, reactor coolant was injected into nitrogen piping within the containment. The flooded piping was bounded by the open pressurizer nitrogen supply valves 2-RC-15, & -20; shut Steam Generator nitrogen supply valves 2-GAN-65A, & -65B; quench tank/primary drain tank nitrogen supply pressure regulator 2-LRR-52.1; air operated nitrogen supply to No. 1 Safety Injection Tank 2-SI-612 and a check valve in the nitrogen supply header 2-LRR-122. As pressurizer pressure was increased, leakage occurred through the reverse seated check 2-LRR-122 and the differential pressure across the Safety Injection Tank supply valve 2-SI-612 forced the valve off its seat.

The plant reached 370$^{o}$F, 1000 psia at 1515 hours, 1/7. At that time, a routine inspection was conducted of systems within the containment. Conditions were normal and pressurizer pressure was increased above 1000 psia at 1630 hours.

At 1640 hours, a high pressure alarm on the No. 1 Safety Injection Tank (SIT) annunciated in the control room. Main control board and process computer alarm printer indicated that the pressure transmitter (P311) associated with the tank nitrogen space was overranged. The instrument has an indicating range of 0-250 psig. The high pressure alarm is actuated by a separate switch. Primary pressure at this time was 1270 psig and Reactor Coolant System (RCS) temperature was 430$^{o}$F, pressurizer steam space temperature was 574$^{o}$F. Reactor coolant had pressurized the nitrogen system and entered the #1 SIT through 2-SI-612. Pressure on the underside of valve 2-SI-612 disc acted to lift the disc and allow flow into the #1 SIT.

Operations personnel attempted to determine the reason for the high pressure condition of the tank. The tank was periodically drained because of slowly increasing level. The first high level alarm was received at 1707 hours, when the tank alarmed at 58%. The maximum level increase was 2% per hour. The tank is normally maintained at 56% borated water level and 220 psig nitrogen overpressure. The high pressure alarm actuates at 225 psig.

The RCS backleakage pressure indicator, which monitors the pressure between injection check valves, was observed to be 350 psig. Operators suspected back leakage through the No. 1 SIT outlet check valve to be causing the level and pressure increase. However, draining the tank to the normal level band of 55 - 58% did not restore the pressure. The tank could not be vented until a cap was removed from the tank vent line. The SIT vent valve discharge piping is normally capped to preclude nitrogen leakage during operation. The RCS pressure was stabilized at 1580 psia at 1800 hours.

I&C technicians and operators entered the containment to validate the pressure indication, and at 2030 hours, they reported that the No. 1 SIT upper half appeared discolored and that conductive heat waves could be seen coming from the tank. They reported that the lower half of the tank was at ambient temperature. The people in the containment were directed to uncap the No. 1 SIT vent valve and leave the containment.

The No. 1 SIT was vented several times. With the vent open, pressure decreased to between 160 and 180 psig. The nitrogen space pressure instrument overranged with the vent closed. A reactor cooldown was commenced at 2046 hours. The No. 1 SIT outlet motor operated isolation valve was shut and the tank filled between 2100 and 2220 hours. At 2245 hours, the pressure in the No. 1 SIT was indicated at 0 psig; RCS pressure at this time was 1410 psia.

Containment airborne activity indicated 1E-5 microcuries per ml. Xenon; Hydrogen analyzers indicated a steady 0.4%, which was later determined to be due to a calibration deficiency.

At 2335 hours, a heat detection fire alarm was received from the A-RCP area which is located underneath the No. 1 SIT.

The containment was entered at 2345 by personnel in self-contained breathing apparatus. The containment atmosphere appeared hazy. A steady stream of water was issuing from the vent, and the tank was warm to the touch. There was no fire in the A-RCP area. The stream of water from the vent slowed and began to chug steam.

At 0300 hours, 1/8 operations personnel in the containment discovered that the nitrogen supply line to the No. 1 SIT was hot. That line is not insulated. Surface pyrometer readings indicated 400°F upstream of 2-SI-612 (nitrogen supply to No. 1 SIT) and 200°F downstream of the valve. Investigation determined that the nitrogen supply valves to the pressurizer spray line (2-RC-015, and -030) were open; the valves were shut at 0305.

Operations personnel inspected the nitrogen system to determine the extent of cross-contamination. The portion of the nitrogen system to which reactor coolant was injected is classified as the station high-pressure nitrogen system. It is used to pressurize the Safety Injection Tanks or leak test the Steam Generators. The system is normally supplied from a low pressure nitrogen system and a nitrogen evaporator. High-pressure nitrogen system pressure can be increased by use of normally isolated bottles or truck connection from a nitrogen pumper.

It was determined that the system outside containment was contaminated; the nitrogen purge supply to the containment electrical penetrations was affected. There were no indications of an unmonitored release.

The plant was in Cold Shutdown (Mode 5) at 1040 hours, 1/8.

a. Notifications and NRC Response

Station management initially notified the NRC Duty Officer that an unexplained event involving the No. 1 SIT was occurring via the ENS at 2130 hours, 1/7.

The Senior Resident Inspector (SRI) was called at 2200 hours and proceeded to the site after informing Region 1 management. The SRI arrived on site at 2300 hours and proceeded to the control room.

As a result of telephone conversations between the licensee and Region I management on 1/9 and 13, it was agreed that the plant would not enter any operational mode requiring containment integrity without NRC concurrence. In addition, it was agreed that the licensee's reviews and analysis of this event would, as a minimum, include:

1. A determination of the conditions (temperature and pressure) to which No. 1 Safety Injection Tank, Nitrogen Supply System piping (and valves), and Containment Electrical Penetrations were subjected;

2. An evaluation of the effects of the event including stress and safety analyses of the No. 1 Safety Injection Tank and Nitrogen Supply System (and interface with Class 1 systems), and including the performance of physical inspections as necessary;

3. An analysis of the effects (short and long term) of reactor coolant on the containment electrical penetrations, including effects of temperature and pressure to which they were subjected;

4. A determination of actions necessary to prevent cross contamination (radiological and chemical) from nitrogen supply system to other plant systems;

5. The performance of insulation resistance testing on a representative sampling of containment electrical penetration conductors;

6. The performance of local leak rate testing on all containment electrical penetrations; and,

7. A review of the management controls over manipulations of valves, switches and breakers and verification that these apparatus are correctly positioned prior to mode changes and upgrade the management systems where necessary.

The Senior Resident Inspector assigned to the Haddam plant assisted in the inspection to follow this event 1/8 through 1/16; two region based inspectors assisted on 1/8 and 9.

b. Station Procedural Requirements

The inspector reviewed the procedural controls which had been established prior to this incident. The procedure for plant cooldown OP 2207 directs taking the plant to Cold Shutdown with the pressurizer filled and vented. The plant conditions required for the replacement of the pressurizer safety valve involved cooling and draining the pressurizer. Procedure OP 2301E, "Draining the Reactor Coolant System", Revision 6, dated 7/21/80 was used to establish those conditions. However, the procedure did not address partial draining of the pressurizer. Paragraph 7.1 "Draining the RCS to the Center Line of the Hot Leg", was only used in part. That procedure directed the operators to drain the pressurizer while maintaining a slight nitrogen overpressure. Step 7.1.8 of the procedure directs the operators to secure the nitrogen purge and vent off the gas pressure when the RCS was drained to the required level. However, on January 6, the manual nitrogen supply valves 2-RC-015 and -30 were left open and the remote operated nitrogen supply containment isolation valve (2-SI-312) was shut. Prior to the valve replacement, pressurizer level was cycled to cool vessel temperature. The remote valve was operated to support these activities. Protection of personnel during the maintenance action included safety tagging the containment isolation valve shut.

The RCS was filled per OP 2301D, Revision 6, Change 2, dated 10/8/80. That procedure did not require that valves 2-RC-015 and -030 be shut as a procedural step. However, the valve alignment check-off list did include these and other reactor coolant pressure boundary valves. Operations Department management did not elect to perform this alignment check due to the nature of the outage and the work performed.

Beyond this point there were no other procedural controls to being the operators back to the mispositioned valves. OP 2333, "Nitrogen System", deals with operating the nitrogen supply. It does not involve the system alignment to supply nitrogen to the pressurizer or other components in the containment. Its valve alignment check-off list does not include the reactor coolant pressure boundary valves or the containment isolation valve. OP 2201, "Plant Heatup" assumes initially that the plant has been filled, vented, and pressurized.

The licensee's corrective actions have included additional administrative controls addressing "System Valve Alignment Control". ACP-QA-2.12, Revision 0, was implemented on 1/16. The procedure establishes a program to ensure that valve alignments are performed periodically and following maintenance actions and system outages. The need to perform system lineups when starting-up following an outage at cold shutdown is now evaluated by the Operating Shift Supervisor and another Senior licensed individual who is cognizant of the activities performed during the outage. In addition, following maintenance, restoration lineups are to be performed on completion of the maintenance activity and not deferred. The restoration valve line-up check-list is now to be filed with the applicable Safety Tag Log Sheet.

OP 2301E,"Draining the RCS", has been revised by Changes 1 and 2 dated 1/13/81. Change 1 implemented a new section to the procedure which addresses Partial Draining of the Pressurizer. Change 2 added valve 2-RC-030 to step 7.1.8.2 of the original procedure.

OP 2301D, "Filling and Venting the RCS", has been revised by change 4, dated 1/13/81. That change added as a prerequisite to the procedure the requirement to perform valve lineups. This will insure the proper position of all RCS pressure boundary valves prior to filling. The change also added a caution statement in the body of the procedure to ensure that valves 2-RC-015 and -030 are closed.

OP 2201, "Plant Heatup", has been revised by changes 4, 5 and 6, dated 1/13, 1/13, and 1/15 respectively. Change 4 adds another caution statement to ensure that valves 2-RC-015 and -030 are closed prior to filling the pressurizer. Change 5 changes a prerequisite to now require a complete valve alignment anytime the RCS is filled and vented per OP 2301D.

Station Valve Check-Off List Forms have been revised to meet the January 8, 1981 commitment in the licensee's letter to Region 1, dated October 16, 1980.

The inspector reviewed these revisions and the new administrative controls established in ACP-QA-2.12 and agrees that it reflects a substantial upgrade in the administration of valve control. These actions resolve unresolved items identified to the licensee during this inspection and closes a previously reported open item (336/80-09-01) which was associated with an item of noncompliance concerning the failure to adequately control manual valves. This noncompliance had been identified by letter to the licensee dated September 22, 1980.

ACP-QA-3.02, "Station Procedures and Forms", Revision 16, dated 2/19/81 now requires that if a procedure is not to be completed in its entirety, the balance of the procedure should be reviewed for applicability to the evolution being performed.

c. Resolution of Material Deficiencies

Bounding Conditions -

The licensee has established upper bounds for temperature and pressure to which the No. 1 Safety Injection Tank, the nitrogen system piping and valves, and the containment electrical penetrations were exposed.

The engineering analysis for these systems and components assumed that the nitrogen system piping located between the No. 1 SIT and the pressurizer was subjected to 1600 psig at 600$^{o}$F. These were the maximum saturation conditions recorded for the pressurizer. The remaining system piping was assumed to have been subjected to 305 psig, a header relief valve set point, and 340$^{o}$F, by examination of the nylon seat in a valve.

The Safety Injection Tank was assumed to have been subjected to 350 psig and 600$^{o}$F. The pressure was observed on the control room main control board and was due to the pressure breakdown across valve 2-SI-612 and tank venting through a 250 psig relief valve 2-SI-211.

The tank bulk fluid was assumed to be 120$^{o}$F. The tank relief valve was tested and found to lift at 254 psig.

The upper half of the No. 1 SIT was overheated to the point of scorching and blistering an epoxy paint. A zinc based primer remained intact. The paint, Carboline Epoxy 305, has characteristics of blistering at 140$^{o}$F and discoloring at 180-250$^{o}$F.

Evaluation of Safety Injection Tank -

The licensee completed a stress evaluation of the tank and determined the following:

No gross plastic deformation occurred based on the assumed peak pressure of 350 psig at 600$^{o}$F. The thermal stress evaluation considered the initial thermal shock due to injecting 600$^{o}$F steam/water and the subsequent thermal stress resulting from the upper tank region being at 600$^{o}$F and the bottom remaining at 120$^{o}$F. The licensee determined that no local yielding occurred in the tank due to thermal stresses. The combined effect of pressure and thermal loading resulted in a usage factor of 0.01. The thermal shock stresses did not degrade the cladding integrity.

The carbon steel tank is stainless clad by the Lukens Steel Roll Bonded process. The licensee assumed that while the thermal shock stresses primarily affect the cladding integrity, the steady state stresses have the potential for distortion or local yielding.

The licensee conducted a hydrostatic test to verify structural integrity on 1/17 at 250±10 psig. No signs of any pressure boundary leakage were found during the test.

All loose and blistered epoxy paint was removed by scraping. The remaining paint was tested for greater than 200 psi adhesion per ANSI N512-1974, "Protective Coatings for the Nuclear Industry". The adhesion test was necessary to demonstrate that loose paint will not clog containment sump screens. The area of affected paint is more than five times greater than the area of sump screens. Although the zinc primer generally remained intact, there are some exposed carbon steel surfaces. The licensee concluded that these areas will corrode less than 0.6% of the wall thickness before the next refuel outage. The damaged top coat of epoxy paint exposed the zinc-based primer. The licensee examined the potential for increased hydrogen generation in the containment during a Loss of Coolant Accident. The licensee concluded that the pressure of a top coat does little to stop hydrogen generation and, therefore, the damaged top coat will have a negligible effect on the calculated hydrogen generation. The licensee has committed to repainting the No. 1 SIT during the next refuel outage (336/81-01-05).

Because of the possible deleterious affects of paint fumes on the Enclosure Building Filtration System activated charcoal filters, those filters were replaced.

Equipment Associated with the No. 1 Safety Injection Tank -

The No. 1 SIT relief valve (2-SI-221) was confirmed to have been operable by a pressure test which demonstrated its set pressure at 254 psig. No leakage was detected. The valve was inspected and stroke tested several times to demonstrate freedom of movement. The valve was rebuilt to replace the disc assembly which contains an ethylene-propylene O-ring. The relief valve was tested following maintenance.

Other boundary valves of the No. 1 SIT nitrogen system were inspected by disassembly. No unacceptable conditions were found in the nitrogen vent and manual isolation stop valves.

The nitrogen inlet valve (2-SI-612) has a nylon disc insert. That nylon part, which begins decomposition at 340°F, was found to be missing during valve disassembly. The valve was rebuilt and tested.

Evaluation of the Nitrogen System -

The licensee evaluated the effects of the reactor coolant on the nitrogen system piping. A portion of that system was exposed to fluid at 1600 psia and 600°F; the remainder to no more than 305 psia. Pressure breakdown occurred across a reverse seated check valve (2-LRR-122). The piping exposed to full RCS pressure was bounded by the pressurizer spray line and open RCS pressure boundary valves 2-RC-015 and -030, the nitrogen inlet to the No. 1 SIT (2-SI-612), 2-LRR-122, the supply pressure regulator to the quench tank and primary drain tank (2-LRR-52.1), and shut nitrogen supply valves to the steam generator (2-GAN-65A and -65B). The nitrogen supply valve to the No. 2 SIT (2-SI-622) was disassembled and inspected.

The nylon seat showed no signs of overtemperature. The conclusion is that the temperature in this portion of the piping did not exceed 340°F.

The portion of nitrogen piping exposed to full RCS pressure and pressurizer steam space temperature consists of a Class 1, Class 2, and B31.1 sections.

The Class 1 section is a run between the pressurizer spray line through the nitrogen stop valves 2-RC-015 and -030. The transient was within the design conditions for that piping. However, the expansion loads caused by the interconnecting B31.1 piping caused an inspection to be performed of an anchor at the Class 1/B31.1 interface. The nitrogen piping at the pressurizer spray line connection was also examined by liquid penetrant. No unacceptable conditions were identified.

Thermal expansion of the No. 1 SIT Class 2 nitrogen supply piping resulted in three areas of local high stress. These were examined by liquid penetrant. A one-eighth inch linear indication was found in the No. 1 SIT nitrogen supply boss fillet weld. It is assumed that the indication resulted from tank construction because of overlying file marks. The indication was removed and the weld repaired.

The analysis of the interconnecting B31.1 stainless piping exposed to 1600 psig fluid at 600°F indicates that several areas were overstressed by thermal expansion and may have undergone plastic deformation. Although the transient did impact the piping fatigue life, the licensee considers that this piping remains serviceable at 250 psig.

The peak pressure of the transient was in excess of the design pressure for Class 2 and B31.1 piping. The calculated membrane stress of 7.9 Ksi is less than the allowable stress of 15.9 Ksi at 600°F. The licensee has concluded that the piping had adequate structural margin against the transient peak pressure loading, and that the piping is acceptable for continued service for the original design conditions.

Several nitrogen system valves which were exposed to 1600 psig 600°F fluid were disassembled and inspected. There were no problems identified. These valves included No. 1 SIT nitrogen supply manual stop (2-SI-054), the check valve in the nitrogen header which was reverse seated (2-LRR-122), the pressure regulating valve providing the nitrogen supply to the quench tank and primary drain tank, and the pressurizer nitrogen supply valves (2-RC-015 and -030).

A visual examination was made of piping and supports by the licensee and the inspector. Other than scorched paint on hangars for the pressurizer nitrogen supply piping, there was no damage observed.

The nitrogen header check valve, 2-LRR-122, was reverse seated by the pressure transient. As noted above, although the valve was disassembled and inspected, the valve did leak. The valve acted to break down pressure in the header. That header is protected by a relief valve. The valve (2-GAN-48) was tested and found to have a set pressure of 305 psig. There was no evidence of radioactive material or boron contamination in the valve; this indicates that the valve did not relieve during the transient and, therefore, nitrogen header pressure did not reach 305 psig. As noted above, the nitrogen supply isolation valve to the No. 2 SIT was disassembled and inspected. The valves nylon seat did not show signs of temperature damage, therefore, it was not exposed to fluid exceeding 340°F. There are no concerns of this piping being overstressed by the transient.

The licensee addressed three areas of concern regarding the boric acid and radiological contamination of the nitrogen system. They were the effects on operation of system valves, corrosion of carbon steel piping, and radiological contamination and cross-contamination of this previously clean system.

Five of the nitrogen supply valves were disassembled and inspected. Only light boric acid powder was found; there were no crystals found which may have impeded valve operation. Valve 2-LRR-122, which acted to break down pressure, was included in the inspection. The nitrogen header containment isolation valve, 2-SI-312, was local leak rate tested and found to be acceptable. In addition, the licensee conducted a nitrogen blow to each safety injection tank. The nitrogen blow and repressurization of each tank to 225 psig was followed by a pressure drop test to verify the integrity of the nitrogen isolation valves and check valves, 2-SI-612, -622, -632, -642, -083, -682, -081, and -080.

The nitrogen system piping outside of the containment (and its isolation valve), is constructed of carbon steel. To minimize the corrosive effects of boric acid, that piping was flushed in conjunction with a program to remove radiological contamination from that system. Samples of contaminants were taken from piping and analyzed for boron and radioactive materials. These samples were gathered to determine the extent of the reactor coolant contamination and to measure the effectiveness of the demineralized water flush. The radiological analysis proved to be more sensitive than the chemical analysis for boron.

The surveys found that the reactor coolant contamination was confined to the high pressure nitrogen system in and out of the containment. That system is normally supplied from the low pressure (45 psig) nitrogen system. Initial surveys verified that there had been no contamination of the low pressure system. The high and low pressure systems are separated by a check valve. (However, during the flush operation a section of the low pressure system became cross-contaminated with flush water.) Nitrogen piping was flushed and the effluent water sampled. After the flush, samples were less than minimum detectable activity for the analysis. Following the flush, the piping was blown dry with air and nitrogen.

The licensee did not flush the stainless nitrogen piping located in the containment. Dry nitrogen was blown through portions of the piping into the four Safety Injection Tanks. The low point of this piping is the supply manifolds to the steam generators. The lack of flushing this piping is considered to be an open item (336/81-01-06). The licensee intends to complete the flushing during an outage of sufficient duration. The steam generators are isolated from the contaminated nitrogen system by three shut valves which are in series.

d. Containment Electrical Penetrations

The containment electrical penetrations are constructed with a free volume between the inner and outer sealing blocks of each penetration module. The solid electrical conductors pass through those seals. The inner seal and an "O" ring, which seals the module in a header plate, provides the containment boundary. A second sealing block and O-ring act as a double barrier. The volume between the seals was pressurized with nitrogen at 20 psig. Local leak rate testing pressurizes that volume to 54 psig. The nitrogen was supplied from the high pressure nitrogen header through a pressure regulator set at 70 psig. That regulator supplied nitrogen through two headers to the east and west electrical penetration rooms. In each penetration area nitrogen is processed through a cyclic dryer and a filter. Nitrogen is applied to the electrical penetrations through a reducer set at 20 psig. The piping down stream of the 70 psig reducer was protected by a relief valve which was tested after the transient and found to lift at 110 psig. Relief valves, which were found to lift at 33 and 34 psig, were downstream of the 20 psig regulators.

Water was found in the bowl of the filter-separators and issuing from the dryer purge valve at about 0330 hours on 1/8. Water was collected from the piping and analyzed as containing 530 to 842 ppm Boron and gross activity of 1.3E-3 to 1.8E-2 microcuries per cc and having the RCS isotopic mix. Connections to each penetration assembly were broken and moisture drained from the piping. The licensee has bounded the transient at the penetrations as less than 34 psig fluid at a temperature close to room ambient. No activity was found at the discharge port of any of the three relief valves identified above. The water and piping was at ambient ($80^{\circ}F$) when drained. The licensee also evaluated the temperature based on the length of the pipe run.

Insulation resistance testing was performed using a 500 volt DC megger. Measurements were taken of all conductors in four modules. Testing was performed between adjacent conductors and to ground. The following table includes the modules tested:

| Penetration - Module | Type | No. of Conductors |
|---|---|---|
| ED3 - Module 4-2 | Instrument (14AWG) | 76 |
| EB9 - Module 8-19 | 480V (250 mcm) | 2 |
| WB3 - Module 6-23 | CEDM Power (2 AWG) | 12 |
| EDI - Module 15-2 | Excore NI (Coax) | 10 |

All readings were greater than 100 megohms before and after an effort was made to remove moisture by vacuum drying and a pressurized nitrogen purge.

Moisture removal was accomplished by draining residual moisture from the piping. A vacuum was applied to the penetration modules and maintained greater than 29 inches Hg. for 24 hours. During this evolution, vacuum and dew point of the piping was monitored. The penetrations were then pressurized with dry nitrogen to 25 psig, depressurized and re-pressurized twice. The final time pressure was allowed to stabilize for at least four (4) hours and then de-pressurized through a device to measure relative humidity. These evolutions were conducted in accordance with Special Procedure 81-2-1, "Electrical Penetration Moisture Removal", Revision 0 and Inservice Test T-81-6, "Electrical Penetration Relative Humidity Test". The acceptance criteria was a measured relative humidity of less than 90%. This value is the specified long-term maximum design value. The licensee confirmed that specification acceptable with the vendor. Several modules with higher measured relative humidity (66%) were repressurized and found less than 10% relative humidity.

The nitrogen connections were left open to the enclosure building during plant heatup to allow any remaining moisture to be driven out by the electrical heating in the penetration and by the ambient temperature of the containment. The electrical penetrations were then pressurized to 20 psig with dry nitrogen supplied from bottles located in the east and west electrical penetration areas.

Following the vacuum dryout and nitrogen purging evaluation, all electrical penetrations were local leak rate tested. One 6.9Kv reactor coolant pump power module (SEXA4-Tube 3) showed an increase in leakage. The module was found to leak at 7400 standard cubic centimeters per minute (sccm) on 1/16 and 7393 sccm on 1/17. After the reactor coolant pump was energized, the leakage decreased to 300 sccm measured on 1/19, and 1/23; testing on 2/21 and 3/20 found that leakage had decreased to below the sensitivity of the flow instrument (less than 20 sccm).

The licensee is committed to performing local leak rate testing of electrical penetrations monthly for one year. In addition, the licensee will verify the insulation integrity by performing resistance measurements of the four penetration modules referenced above once per week for a month, then once per month for eleven months. The acceptance criteria remains that the insulation resistance be greater than 100 megohms. This testing will be followed during future inspections (336/80-01-07).

e. Effects of Reactor Coolant on the Containment Electrical Penetrations

The licensee, through the vendor, Conax Corp., determined that the electrical penetrations are suitable for service and will suffer no degradation of mechanical, electrical or seal integrity due to the nitrogen system transient. This conclusion was reached after the vendor analyzed the effects of a 749 ppm Boron solution of pH 7.78 at 150°F for 40 hours on the penetration module materials. An open pot test was conducted of "O" rings, insulation covered wire, and penetration module component parts. An evaluation of the material disclosed no loss of electrical or seal integrity.

The licensee has committed to additional testing which will include artificially exposing a representative penetration module and seal to a similar intrusion of reactor coolant. The components will be environmentally aged to duplicate plant operating conditions. Their electrical and mechanical properties will be inspected periodically to identify a failure mode in advance of any affecting an installed module.

The results of this evaluation of possible long-term effects will be reviewed during a future inspection (336/80-01-08).

f. Effects on Other Equipment Located in the Containment

Inspections were conducted to identify any components which may have been damaged by the discharge of fluid from the No. 1 SIT vent or relief valve. Areas were inspected and any components showing signs of external moisture were listed and subsequently opened and inspected. Equipment included pull boxes, junction boxes, pressurizer heater distribution boxes and instruments. A fire detector in the A-RCP area reset after being dried and an unrelated ground in a GE/MAC pressurizer level transmitter was cleared. There were no indications of any moisture intrusion into any components or instrumentation. Instrument loops were ground checked and found satisfactory.

The licensee conducted a review of installed instruments and electrical components and their specified design limits. Instrument calibration checks were made on each of the affected instruments.

The inspector questioned the licensee as to the possible effects of high temperature on several components. These included the tank mounted level switches (CS-312 and -313) and position switches and solenoid air pilot valves associated with No. 1 SIT valves.

The licensee concluded that with the exception of tank mounted level switches, instruments did not see an abnormal temperature excursion because of a loop seal configuration in the instrument tubing. The tank pressure of 350 psig is well below the design for the switches.

Stem mounted limit switches and air operator solenoid pilot valves are sufficiently removed from piping to prevent an over temperature condition of the component. The licensee's evaluation was supported by observations of paint on support members. The paint was not discolored.

The only component which approached its rated temperature were the microswitches in the tank-mounted level switches. Those items are rated at 350$^{O}$F. The licensee evaluated these switches per the environmental qualification requirements of Bulletin 79-01B and its supplements. It was concluded that the instrument is not required to mitigate the consequences of a LOCA, Main Steamline Break or High Energy Line Break inside containment. The instruments are not used to bring the plant to cold shutdown, operate per emergency operating procedures, or perform a post accident function following the four previously mentioned accidents. The switches actuate control room annunciators, and performed satisfactorily during functional testing.

g. Additional Items

During the event, the containment post accident hydrogen analyzers indicated a 0.4% concentration in the containment. It was found that this had been the analyzers indicated zero base line valve. The monitors are normally in standby. The instrument's manufacturer was contacted, and it was found that it had been incorrect to use nitrogen as the zero hydrogen concentration calibration gas. The correct gas is pure hydrocarbon free air. The licensee has modified the surveillance procedures and ordered the proper calibration gas. This is an open item pending proper calibration of these instruments (336/81-01-09).

The licensee has commenced a review of all auxiliary systems interfacing with the reactor coolant pressure boundary. This review is to identify any modifications necessary to prevent future incidents of inadvertent reactor coolant contamination of other systems. This is an open item pending completion of this review (336/81-01-10).

h. Compliance with Operating License Technical Specifications

Reactor Coolant System Leakage (3.4.6.2) - In Modes 1,2,3, and 4 reactor coolant system leakage is limited to: no pressure boundary leakage; one gpm unidentified leakage; one gpm primary-to-secondary leakage (0.5 gpm through one steam generator), and ten gpm identified leakage. The specification action statement requires that the plant be in Cold Shutdown (Mode 5) within 36 hours. (Pressure boundary leakage is leakage through a non-isolable fault in a reactor coolant system component body, pipe or vessel wall, except steam generator tube leakage. Identified leakage is leakage into closed systems and conducted to a sump or collecting tank or leakage into the containment atmosphere from specifically located known sources which don't interfere with the operation of leakage detection systems and is not pressure boundary leakage.)

The introduction of reactor coolant into the station nitrogen system had resulted in some of that fluid being released to the containment atmosphere through the No. 1 SIT nitrogen space relief valve. Additionally, a small amount of coolant was spilled onto the floor of the Enclosure Building 14 foot 6 inch elevation electrical penetration rooms. Because the plant was being heated and pressurized,steady state conditions required for a RCS water inventory did not exist. The leakage from the relief valve which was collected in the containment sump did not exceed the specification. The plant was cooled to Mode 5 at 1040 hours, 1/8, which was eighteen hours after the initial high pressure alarm on the No. 1 SIT and the likely opening of the relief valve.

Emergency Core Cooling Systems, Safety Injection Tank (3.5.1) - Four Reactor Coolant System Safety Injection Tanks are required to be operable during Modes 1,2 and 3 (with pressurizer pressure equal to or greater than 1750 psia). Operability of a tank is defined as: the isolation valve open and the power to the valve operator removed; between 1107 and 1170 cubic feet of borated water (55 to 58% of total tank volume); minimum boron concentration of 1720 ppm, and a nitrogen cover-pressure of between 200 and 250 psig. The specification action statement requires that in the event that a tank is inoperable, it be returned to an operable status within one hour or the plant be in Hot Shutdown (Mode 4) within the next eight hours.

During the reactor coolant intrusion incident of 1/7, the maximum pressurizer pressure was 1580 psia. The plant was cooled to Mode 4 at 0200 hours, 1/8, which was nine hours and twenty minutes after the initial high pressure alarm on the No. 1 SIT.

Containment Systems, Combustible Gas Control, Hydrogen Analyzers (3.6.4.1) - Two hydrogen analyzers are required to be operable in Modes 1 and 2. The specification surveillance requirement requires a channel calibration using sample gases containing one volume percent and four volume percent hydrogen with the balance being nitrogen.

Although there had been an error in the zero concentration gas, the monitors remained operable and in calibration at the specified concentrations.

Administrative Controls, Procedures (6.8.1) - Requires that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33 November 1972. OP 2301E, "Draining the Reactor Coolant System", Revision 6, dated 7/21/80, was written in response to this requirement. Paragraph 7.1.8 of that procedure required that, "When RCS is drained to the required level vent off the excess nitrogen to ambient ..... Close 2-RC-015, nitrogen to pressurizer."

The failure to shut reactor coolant system pressure boundary valve 2-RC-015 as required by the above requirement is identified as an item of noncompliance.

The corrective action taken by the licensee is addressed in paragraph 4.b, above.

OP 2301D, "Filling and Venting the Reactor Coolant System", Revision 6, Change 2 dated 10/8/80, Section 9, "System Check Lists" references OPS Form 2301D-1, "Reactor Coolant System Valve Alignment". Valves 2-RC-015 and -030 are required to be closed. OP 2301D did not contain specific requirements to perform the Valve Alignment. ACP-QA-3.02, "Station Procedures and Forms", Revision 15, dated 10/8/80, paragraph 6.8.3, "Valve Lineups/Checklists" states, "Under certain conditions, it may not be desirable to complete a valve lineup .... or only a partial lineup or checklist may be required. Under these conditions, the Shift Supervisor may authorize a deviation from the lineup...."

5. Review and Audit

During this inspection the inspector(s) attended portions of Nuclear Review Board (the off-site safety committee) meetings on January 5 and 12, 1981. The Board was observed to be conducting its review as required by Technical Specification 6.5.3.6. The Board composition and quorum met the requirements of specification 6.5.3.

6. Exit Interview

At periodic intervals during the course of the inspection, meetings were held with senior facility management to discuss the inspection scope and findings.

In addition, telephone conversations were held on January 9, 13 and 16, 1981, between licensee and NRC management to discuss the events described in this report.