U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report: 50-245/85-24; 50-336/85-30

Docket Nos: 50-245/50-336 License Nos. DPR-21; DPR-65

Licensee: Northeast Nuclear Energy Company

Facility: Millstone Nuclear Power Station, Waterford, Connecticut

Inspection at: Millstone Units 1 & 2

Dates: September 4, 1985 through October 28, 1985

Inspectors:

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12/3/85
Date

Summary: Routine NRC resident (225 hours) inspection of plant operations, equipment alignment and readiness, radiation protection, physical security, fire protection, design changes, and surveillance. The preparations for and the actions during Hurricane Gloria, which struck on September 27, were included along with the detailed coverage of licensee actions concerning the discovery of plant design deficiencies. It was found that the actions taken before and during the storm were appropriate. In regard to design deficiencies recently identified within the Unit 1 LPCI pump control logic and the Unit 2 Charging pump logic, it appears that not testing these systems to Regulatory Guide 1.41 allowed acceptance of the systems following construction or modification without detection of control circuit errors. One Violation was identified for failure to make reports to the NRC as required by 10 CFR Parts 50.72 and 50.73 (Paragraph 4 and 5).

DETAILS

1. Plant Status

Unit 1:

The reactor operated at full power until September 18 at which time the reactor core reached its end of full power life for the current operating cycle and began a power coast down. The reactor was shut down on September 27 as a precaution against potential loss of off-site transmission lines due to Hurricane Gloria. After the hurricane passed through Connecticut, off-site power was restored on September 28 and the reactor was returned to power on September 30. A reactor trip occurred on October 7 due to low scram air header pressure. The trip, which occurred during surveillance testing, resulted from a decrease in air pressure while resetting a one-half scram required by the test. The reactor was returned to power on October 8.

A thirty-two day refueling/maintenance outage began on October 26. Prior to commencing the shutdown, reactor power had been reduced to 1932 MW(t), 96 percent of rated power, due to fuel depletion.

Unit 2:

The reactor operated at full power until September 27 when shut down in anticipation of Hurricane Gloria. On September 28, during the preparations for plant restart, one of the four Reactor Coolant Pump motors failed due to a ground fault. The failure mechanism appeared to be generic to the other three motors, requiring their removal for inspection and corrective action. This maintenance and reactor coolant pump seal problems kept the plant shutdown for the remainder of the inspection period.

2. Hurricane Gloria

Hurricane Gloria passed through the State of Connecticut on September 27. The center of the storm tracked to the NNE while passing about forty miles to the west of the Millstone site. At that time the wind was gusting above 90 mph from the southeast. The resident inspectors followed the licensee's preparations, actions during the storm, and the recovery actions. Based on previous experience, the licensee expected to lose off-site power as the 345 Kv switchyard insulators became coated with salt deposits. Prior to the storm, both units' reactors had been operating at full power. Each unit commenced a normal plant shutdown by 0830, September 27, and were shutdown with decay heat removal systems operating prior to loss of off-site power at 1335. Power to in-plant safeguards electrical buses was supplied by the three on-site Emergency Diesel Generators (EDGs) and the Emergency Gas Turbine Generator (EGTG) until off-site power was restored on September 28. An Unusual Event, which had been declared in anticipation of the impending hurricane at 0850, September 27, was terminated when off-site power was restored to the last station buses at 1530, September 28. Unit 1 was made critical at 2247, September 29 following the completion of storm related and other

maintenance. The plant reached full power at 0600, October 1. A ground fault occurred in the Millstone Unit 2 "C" Reactor Coolant Pump motor when energized at 1743, September 28. The motor failure has delayed the plant start-up.

There was no site flooding. The storm occurred at low tide and waters remained below grade. The most significant damage occurred at 1230, September 27 when wind damage occurred to the Unit 1 Turbine Building railway access door and several roof panels.

A detailed sequence of events is contained in Attachment Number 1 to this report.

Inspection Findings

The inspector determined that the licensee's actions taken in preparation for the storm were timely and appropriate. Management involvement extended to the Senior Vice President level on September 25 and to the Company President during the recovery. Specific observations follow:

Preparations:

The licensee began preparations for the storm on September 23 and 24 by moving objects which could become wind driven missiles into protective storage locations. The southern side of the site was clear of material previously stored in the open by the morning of September 25. That day emergency generator fuel tanks were filled and the chlorine tank cars, which are used for treatment of the circulating water systems, were disconnected and moved off site. Back-up security computers were moved to a safer location on September 26.

Cooling water was supplied to the Emergency Diesel Generators through the storm from their normal source, the service water systems. However, licensee preparations also included running hoses, which could be charged with fire water, to each machine. Flanges to make up the emergency supply were removed from storage and located at the machines.

The inspector found that the licensee had reviewed the provisions of the applicable Off Normal and Emergency Operating Procedures and had implemented preparatory actions before the storm became a direct threat.

Unit 1 Reactor Trip:

A Unit 1 reactor trip occurred when shifting the Mode Switch from Run to Startup during the shutdown. Reactor power was above the Average Power Range Monitor (APRM) reduced power high flux setpoint and a scram resulted. That trip function is bypassed while in the Run mode but becomes operable in Startup. The Technical Specification establishes its setpoint requirement at 15 percent of rated. For proper implementation of this requirement, plant instruments are calibrated such that the trip actually occurs at 13.5 percent. Although the scram was due to operator error in shifting the Mode Switch too

early, the plant instruments do not have a provision to alert the operator that reactor power exceeds the reduced power high flux setpoint while the mode switch is in the run position.

There were no unacceptable conditions identified.

Unit 1 Turbine Building Roof Damage:

Several of the Unit 1 Turbine Building roof sections were lifted up by high winds when a south facing railway access door was damaged. That door was not supported from the inside of the building to resist the wind loading. The licensee intends to replace the door and provide additional braces to better withstand wind loading.

The inspector reviewed the plant conditions following the door and roof failure. The Turbine Building ventilation is normally exhausted to the plant stack and monitored by installed radiation monitors. Based on the recordings of area and ventilation monitors, there was no evidence that this event had caused an unmonitored release of radioactive materials. The inspector also reviewed the damage and the subsequent repairs. These repairs were found to be appropriate.

Unit 1 Isolation Condenser Availability:

On the first attempt to place the Isolation Condenser in service, after the trip on September 27 the system isolated on high flow. At the time the plant had a 500 psig steam pressure. A subsequent attempt was successful and the plant cooldown continued on the Isolation Condenser. Prior to plant startup, the proper operation of the high flow differential pressure switches was verified. Those devices provide protection in the event of a line break in the Reactor Building. The licensee committed to further investigation into the operational characteristics of the Isolation Condenser and conducted testing on October 26 during a plant shutdown for a refueling outage. At that time, when flow was initiated in the Isolation Condenser, one of the four high flow differential pressure switches overshot the full flow value by a considerable amount. The licensee will investigate the surge dampening snubbers installed in these instrument lines during the outage. Pending the completion of this investigation, this item remains Unresolved (50-245/85-24-01).

Unit 2 Auxiliary Feedwater Pump Room Sump System:

The Unit 2 Auxiliary Feedwater (AFW) pumps were run during the period of time power was lost from off site. These pumps provided the water needed for decay heat removal through the steam generators. The plant design provides two electric motor driven pumps, each powered from an independent safeguards division, and a steam turbine driven pump. All three pumps are located below grade in the turbine building in rooms at elevation 1 foot 6 inches. External flood protection is provided by the flood wall system created by the building walls and foundations. Internal flooding is controlled by sump pumps located in those rooms. However, the sump pumps are powered from station service

electrical buses which can not be energized from on-site emergency generators. The licensee was aware of this and positioned an air operated pump in those rooms to replace the electric sump pumps. Since the pump required station service air for operation, preparations included the make-up of a hose connection from station fire water to the air compressor coolers.

The inspector observed that, during the loss of power, although the air driven pump was operating, about one inch of water had accumulated in the room occupied by the electric motor driven pumps. The water appeared to be leakage from the pump shaft packing box which is normally adjusted to provide some leakage for cooling. Water had accumulated because of the inability for the pump in use to take a suction from the floor. (The electric sump pump is located in a small pit.) Also, the hoses associated with that pump passed through the normally closed water tight door separating the two AFW pump rooms.

The inspector questioned the adequacy of this arrangement. Section 10.4.5.3 of the Final Safety Analysis Report addresses AFW pump system, the pump room location, and its sump system. However, it does not describe the sump pumps' power supply or the basis for the selection. The licensee agreed to investigate; this item is Unresolved (50-336/85-30-01) pending licensee assessment of whether the existing configuration fulfills the design bases.

Site Meteorological Instruments' Power:

The site meteorological tower has one source of power, a 23Kv above ground line supplied from a remote switchyard. Power was lost in that line at 1300, September 27; it remained out of service until 1027, September 28. During this period of time, wind speed and direction and differential temperature instruments were out of service. The licensee's emergency action procedures have a provision to use back-up data from a contract service and another tower. However, the inspector questioned the lack of a back-up power supply for the Millstone tower and the adequacy and reliability of data from remote sources during a severe storm. The licensee agreed to evaluate the capability of the present monitoring system. This is an inspector follow-up item (50-245/85-24-02).

3. Reactor Trip - Unit 1

A reactor trip occurred from full (97 percent of rated) power at 1119, October 7 due to low pressure in the scram air header. The plant is protected against scram valves drifting open in the event of low air header pressure by four pressure switches set at 54 psig. The scram occurred during surveillance testing which required tripping individual Reactor Protective System (RPS) channels and causing sequential one-half scrams. Apparently, one or more solenoid operated scram pilot air valves failed to fully reposition when the first one-half scram was reset. This air leakage path, along with a dip in air pressure caused by the air demand created during the attempt to reset the second RPS channel one-half scram, resulted in a momentary but actual low pressure in the air supply header. The protective instruments initiated the reactor trip.

The GE-BWR control rod drive system will scram a control rod when either the scram inlet or outlet valve is opened. The scram valves spring open but are normally held shut by air pressure. Closing air is supplied from the station air system through two scram pilot valves; its pressure is regulated at 70 psig. The solenoid operated scram pilot valves de-energize to remove the air pressure from the pair of scram valves at each hydraulic control unit (HCU) and then scram that control rod. Since two solenoid valves are provided per HCU, surveillance testing may be performed and not interfere with reactor operation. The solenoid operated pilot valve is a double diaphragm three-way valve. The two valves at an HCU are connected such that both valves must be de-energized to scram a control rod. Energizing one or both valves will keep the supply path open; de-energizing both valves will isolate the supply and vent the scram valves. Scram air header pressure is monitored and an automatic trip initiated to prevent an event in which a low pressure air supply allows scram outlet valves to drift open without closing scram discharge volume vent and drain valves. The concern is that such an event would flood the Reactor Building sumps.

After the reactor trip, one scram pilot valve was observed to be leaking air through its vent. Prior to the reactor startup on October 7, the licensee replaced or rebuilt the four scram pilot valves (No.117 and 118) in two HCUs (No. 38-03 and 42-07). These were successfully tested and the plant was returned to full (97 percent of rated) power at 2330, October 8.

During the inspector's review of this event, he found that the licensee had properly identified the cause of the reactor trip and that plant protective equipment had operated properly. The solenoid operated scram pilot valves were found to be addressed in a preventive maintenance program which requires their periodic disassembly and parts replacement. Bench testing is performed following rebuilding in the electrical shop. Scram pilot air valves have stuck on past occasions; the only result at those times was an individual rod scram.

Following discussions with the inspector, the licensee continued to investigate the root cause of the low air pressure. Although solenoid operated, internally the valve is also pilot operated. The two valves removed were bench tested. One was found to require about forty psi of supply air pressure to seat its main valve; the other only a few pounds of pressure. Supply air was vented from the first valve while energized below that pressure. A properly operating valve would reposition when energized and not establish a vent path from the supply header. The valve nameplate indicates a minimum operating pressure of ten psi.

The licensee has committed to investigate the performance of the air supply header pressure regulators and the associated filter. This is an inspector follow-up item (50-245/85-24-03). The licensee is continuing to investigate this problem and its relationship to a recent and apparently related problem at the Dresden Station in which reactor water was vented through the scram discharge header vent and drain.

A sequence of events is included as Attachment Number 2 to this report.

4. Design Deficiencies

The licensee discovered deficiencies in portions of the plant design at each of the two units. The problem at Unit 1 related to the control logic system for a Low Pressure Coolant Injection (LPCI) subsystem and the input which informs it of a loss of off-site power (or loss of normal power - LNP). In this case, the input to one of the two LPCI subsystems was provided from an LNP subsystem powered from the incorrect safety division. That LPCI subsystem would not receive LNP information in the event of a loss of DC power in the opposite safety division.

The problem at Unit 2 concerned the control of the "B" Charging Pump motor, which may be aligned to be powered from either safety division. A loss of AC power in the opposite safety division would stop the pump if running and prevent it from starting until the safety injection load sequencer had actuated.

Both of these deficiencies reflect a failure to adequately test systems after construction or modification. The testing of independent load groups was not performed effectively. Regulatory Guide 1.41, "Preoperational Testing of Redundant On-Site Electrical Power Systems to Verify Proper Load Group Assignments", specifies a series of functional tests to demonstrate proper system and component operation without on-site or off-site power outside of its own safety division. Independence of load groups is thereby demonstrated through equipment operation when other safety divisions are de-energized.

Unit 1:

The Low Pressure Coolant Injection (LPCI) pump start circuit receives information in the form of relay contact position to indicate a Loss of Coolant Accident (LOCA) from one set of contacts and in another case a loss of off-site or normal power (LNP). The LOCA signal starts the two LPCI pumps simultaneously in a sub-system; the LNP signal differs in that it provides a 5 second time delay between pump starts which allows the on-site emergency power source, a diesel generator, to recover speed and voltage before starting the second pump. In the discovered design deficiency, a loss of DC power to the opposite safety division prevents the sequential time delay starting so that both pumps start simultaneously on a bus powered by the Emergency Diesel Generator (EDG). In addition to violation of divisional separation, the concern is that this may overload the EDG.

The licensee discovered this design deficiency on July 30, 1985 while reviewing the design for a new undervoltage detection which is scheduled to be implemented during the October 1985 refuel outage. On September 6 in a conference call meeting with the NRC, Region I and NRR, the licensee presented the problem and their analysis to justify continued operation through the end of the current cycle with the installed logic. A refueling/maintenance outage is scheduled on October 26 during which time the design deficiency can be corrected. The licensee's justification for continued operation was based on the low probability of a simultaneous failure to the DC bus, an LNP and

a LOCA. The licensee also provided information on the expected successful operation of the diesel generator in the event both LPCI pumps were started simultaneously. The licensee also committed to specific precautionary measures concerning the integrity of the DC bus and the review of the appropriate operating procedures. This information is stated in Licensee Event Report (LER) 85-13-00, dated September 9.

The inspector has reviewed information constructing the basis for the licensee's conclusion that the EDG could start both LPCI pumps simultaneously. From the review of control diagrams the inspector found that the EDG output breaker would not trip in the event of a bus undervoltage or underfrequency as may accompany the application of a large load. Likewise, the safeguards pump motors are not load shed after starting on emergency power. The machine and its present governor setting have proven to be adequate for its design loading of sequence starting the two 500HP LPCI pumps and an 800 HP CS pump. (The design error did not affect the CS pump delay scheme). The Millstone Unit 1 EDG has not been tested in simultaneous starting of two 500 HP LPCI pumps. However, IEEE Conference Paper No. 69 CP 177-PWR reported the results of a test program which demonstrated the ability of a 2700 KW diesel generator to start 1250 and 2000 HP induction motors. Satisfactory results were published for sequential starting of the motors on a running diesel generator, and for starts of the 2000 HP motor while tied directly to the generator output from rest both unloaded and with a mechanically locked rotor.

The inspector also reviewed the station procedures which were in place for the DC distribution system (OP344A) and confirmed that they do address the failure of DC bus S1 and direct that the control room distribution panel supplying the associated LNP logic be transferred to S2 DC power. This operation was discussed with control room personnel who were found to be knowledgeable of the procedure, the circumstances under which it would be needed and the potential hazards to bus S2 if a fault was transferred. The licensee also committed to notify the NRC Emergency Operations Center and the Senior Resident Inspector immediately in the event of a loss of DC bus S1. The inspector concluded that the operations personnel were properly instructed concerning this problem.

In addition to the above the inspector reviewed the details concerning this design deficiency. Included within this review were the licensing basis stated in the FSAR Section 8.3.9, "Emergency Power System Design Evaluation," the applicable control system wiring diagrams, drawing No. 25207-31001, pages 288, 289, 759, 760, 761 and 762 and the station DC distribution system design. The inspector concluded that the problem was isolated to the single LPCI subsystem powered by the EDG and that the other two LPCI pumps and the Core Spray (CS) system were not affected. The inspector verified, through the review of the control wiring diagrams, that the deficiency would not affect the LNP detection logic associated with the EDG's safety division which includes the station service bus fast transfer (to the RSST) logic. The safeguards bus load shed logic, the load sequence, and breaker control also appeared to be unaffected except for the problem as described by the licensee in LER 85-13.

The inspector reviewed portions of the proposed changes to the LPCI pump start logic, which are to be implemented in the upcoming refueling outage, and concluded that they would correct the problem.

Licensee internal identification of and initiation of corrective action on this matter were evaluated as adequate. The inspector will follow the implementation of the new bus undervoltage protection system and the associated test program which is expected to be in accordance with Regulatory Guide 1.41. This is Unresolved (50-245/85-24-04) until that testing is completed satisfactorily.

The design deficiency had been identified by the licensee on July 30, 1985, however, the personnel involved elected to consider it for processing as a Potential Significant Safety Hazard, per 10 CFR Part 21. The requirements of 10 CFR Part 50 were not considered until the problem was discussed with the NRC Senior Resident Inspector on September 5. The failure to make notifications required by 10 CFR 50.72 (b)(1)(ii)(B) and 50.73 (a)(2)(ii)(B) is identified as a Violation. These reports were subsequently made. Licensee's corrective actions also included licensee development of an upgraded listing of items to be reported to the NRC. Subsequent application of reporting controls was evaluated by the inspector as conscientious and in accordance with NRC requirements.

Unit 2:

The licensee discovered a design error with the AC control circuit for the "B" Charging Pump motor. The "B" pump may be aligned to either of two 480 volt electrical buses. The design includes a key interlock for control of the power transfer and input to the control logic. The original plant design used inputs from the loss of off-site power (LNP) from both safety divisions. The Unit 2 LNP system provides bus undervoltage monitoring for each safeguards bus and can address a partial LNP in which only one safeguards bus is in an undervoltage condition.

The licensee discovered that, if an LNP condition develops on the safeguards bus of the division opposite that to which the "B" charging pump motor is aligned, the pump would be tripped and could not be restarted until Load Sequence Number 5 of a Safety Injection Actuation occurred. The other two charging pumps and other safety injection pumps were not affected. This was reported as LER 85-009 on July 10, 1985.

The licensee found this design error while conducting acceptance testing of the plant simulator. An investigation of the plant design confirmed this finding. The computer programs were written for the simulator by using the logic developed from system control circuits. The plant control wiring diagrams served as the reference material for writing the computer programs. This resulted in the plant simulator taking on the same operating characteristic as the plant control circuit which had a design error.

The licensee implemented a design change which acted to remove the LNP Sequence Time Zero signal from the non-selected safety division. The modification was accepted following testing. That testing was performed during the refueling outage by tripping a safeguards actuation module which simulated an LNP. That testing was successful. There were no additional items identified. This matter was evaluated as being adequately identified and addressed by the licensee.

5. Engineered Safety Feature Actuations - Unit 1

During the review of control room records, the inspector discovered that isolations of the Unit 1 Reactor Building normal ventilation occurred on July 18 and August 7. Isolation of the Reactor Water Cleanup System also occurred on August 7. In the first case, a steam tunnel radiation monitor tripped at a normal radiation level apparently due to the drift of its trip setpoint. The second occurrence was caused by an electrical fault which momentarily lowered instrument bus voltage. Since reports were not made to the NRC, either in the form of an ENS call to the NRC operations center or a 30 day LER, this is a Violation of 10 CFR 50.72 (b)(2)(ii) and 50.73 (a)(2)(ii). In discussions with the licensee, the inspector found that some confusion existed between the term Engineered Safety Feature (ESF) used in 10 CFR 50 and Engineered Safeguards appearing in Section 6 of the FSAR. The licensee took appropriate corrective actions which included providing an upgraded list of reportable items to control room personnel. The inspector found these corrective actions and subsequent licensee report processing to be acceptable.

6. Allegation Follow Up, RI-85-A-0097

On September 4, 1985, NRC Region I received an allegation via telephone concerning potentially radioactive material from the Millstone Nuclear Power Plant. That material was allegedly disposed of in a scrap yard. The alleger stated that on August 8, 1985, he and a friend had discovered that structural-type steel (I-beams) having radioactive material labels affixed to them were being processed as scrap at a local scrap yard (Calimari Brothers Company, New London, Connecticut). The alleger stated that he had photographs of the material.

On September 5, 1985, NRC Region I informed the State of Connecticut Department of Environmental Protection of the allegation. The State dispatched a representative to the scrap yard to determine if any immediate threat to public health and safety existed. No potentially radioactive material was found by the state's representative.

On September 11, 1985, an NRC inspector and the State's representative met with the alleger in Gales Ferry, Connecticut. The alleger provided further details and photographs.

On September 12, 1985, the inspector informed the licensee of the nature of the allegation. Following that conversation, the licensee directed their Health Physics Supervisor and a Backfit Engineer to survey the Calimari scrap yard for possible radioactive material.

The inspector accompanied the licensee personnel to the Calimari scrap yard. The owner was informed of the nature of the allegation and permitted the licensee to conduct surveys of the facility. The owner recalled that, about a month earlier, two individuals had been interested in fact that radioactive material labels were affixed to some steel beams in the yard and had taken pictures of the items. He stated that the steel beams in question were still on the site and that no material had been shipped off the premises.

Examination of the steel beams and associated material by the licensee confirmed that the material was from the Millstone Nuclear Power Plant. However, radiological surveys of the material showed that the material was not radioactive or contaminated. While no radioactive material labeling was evident, the scrap yard owner indicated that such labeling might have been affixed to the steel prior to processing, i.e., torch cutting.

The licensee personnel identified the material as a support platform used to stage components that were removed from Millstone Unit 2 during the last outage. The support platform was located outside the radiologically controlled area and not expected to become contaminated. Radioactive material labeling had been affixed to certain parts of the platform as a precaution because of proximity to the equipment hatch and because hoses used to support steam generator decontamination were also supported by the platform. The licensee stated that the platform was surveyed when it was dismantled but that the labeling must have been inadvertently left in place.

Following disassembly, the device was stored at the licensee's warehouse and storage facility in the vicinity of the Calimari scrap yard. It was later sold to the yard as scrap.

The licensee stated that procedures for handling such material would be reviewed to prevent recurrence of this type of problem.

Although items with radioactive material labeling were not properly re-classified prior to disposal, there was no actual radioactivity detected on the material. Public health and safety was not affected by this oversight. The licensee's actions to prevent recurrence will be examined in a subsequent inspection. (50-336/85-30-02)

7. Reactor Coolant Pump Motor Failure - Unit 2

The "C" Reactor Coolant Pump (RCP) motor breaker tripped open immediately when attempting to start the pump on September 28; preparations were in progress for a plant startup at that time. The breaker was tripped by a protective instrument which detected a ground fault in the 6.9 Kv circuit. That instrument is set up to trip at 5 amperes of fault current. Further investigation found one phase winding in the motor was breaking down to ground at just under 5Kv. The motor is in an ungrounded "Y" configuration and routinely tested to 14Kv during an outage.

After disassembly, the licensee found that a rotor spider finger had come loose and damaged eleven stator windings. The spider fingers are used to compress the rotor lamination stack; there are 132 fingers at both the top and bottom of the rotor. The fingers are held in place by rings. Each ring is secured with ten bolts which are torqued to 400 ft. lb. The loading force on these fingers had relaxed during the life of the motor. This was sufficient to allow one of the spider fingers at the bottom of the rotor to slip out and nick the stator windings. Although the rotor construction will not allow a spider finger to be thrown out from the rotor, a loose finger can contact and damage the stator windings.

The ring bolts were found to be under considerably less tension than their original torque valve; many were found at about 30 ft. lb. Bolt tightness was checked through inspection covers on other motors and found to be low. Each of the motors was removed from the pump, disassembled, re-torqued and inspected. All of the bolt locking devices were in place.

The motors are General Electric Model 295X290, Type K, Frame No. 6396 and are rated at 6500 HP and 900 rpm.

The loose spider finger was removed from the rotor of the failed motor and a balance weight welded in place. The stator windings which were damaged were re-insulated. There was insufficient clearance between the point of damage and the stator core to allow repair of a conductor which was partially cut. At its worst location, the copper conductor was cut to one-half thickness. It was reinsulated without other repair. Repairs were also required to be made to the lower motor bearing. The damaged motor was re-assembled and successfully tested on October 22.

There had been indications of a potential problem during plant operation. The RCP motors have been included in the Inservice Test Program since August 1, 1985. In the measurements taken on the "C" RCP, the measured pump displacement RMS velocity was observed to increase from 0.35 inches per second to 0.53 inches per second prior to failure. The other pumps were constant at 0.09, 0.13 and 0.3 inches per second. The "C" RCP had also developed a significant peak at 5.26 Hz, the bearing oil swirl frequency. Also, during operation on August 17 at 2355, the pump motor lower guide bearing developed a high temperature of 195 degrees F. A plant shutdown was initiated but was terminated at 0130, August 18 when it was concluded that a wiring fault, located in the containment, had caused an indication problem. Since motor bearing repair was required in this case, the temperature alarm may have been indicative of more than a wiring fault. While these items may have been valid measures of RCP problems, no violations of NRC requirements were identified in the review of the RCP failure.

8. Engineered Safety Features (ESF) System Walk-Down - Unit 2

In addition to cursory inspection of safety-related systems and components during routine daily facility tours, the inspector conducted a detailed walk-down of the auxiliary feedwater system including both electric pump

and the turbine-driven pump. The inspector observed steam supply piping for the turbine-driven pump as well as suction and discharge paths for all three pumps. The inspector also verified that sight glasses showed acceptable lubrication levels at all pump and motor bearings. The two electric pumps are physically separated from the turbine-driven pump by a concrete wall and a flood control door. That door was observed to be in good condition. Both rooms were clean and free of debris. Floor drain sumps in both rooms were also free of debris. Recent licensee efforts to paint the walls in the auxiliary feedwater pump rooms have been successful in brightening the area and promoting general cleanliness. No unacceptable conditions were observed.

9. Facility Tours

The inspector toured accessible plant areas throughout the inspection period. In the past, the extent of surface contamination in the Unit 2 Auxiliary Building -45 foot level had been identified as a cause for concern. The inspector noted significant improvement in this area. Specifically, the Aerated Waste Pump Room, the "C" Safeguards Room, and the general open area (cask loading area) have been sufficiently decontaminated to permit access without protective clothing. Continued progress in cleaning and decontaminating the "A' and 'B' Safeguards Rooms is desirable.

10. Extended Observation of the Control Room Environment - Unit 2

Observation of Unit 2 control room practices was conducted over an extended period on September 16. The shift included two Senior Reactor Operators, four Reactor Operators, and two unlicensed Equipment Operators. Two Reactor Operator license holders were assigned Equipment Operator duties. Logs were up-to-date and sufficiently detailed to permit reconstruction of plant conditions and events. The control room was clean and free of debris. The inspector viewed the interiors of control boards and found only a very light layer of dust with no excessive buildup on cables or housings.

Routine control room transactions (including the approval of Radiation Work Permits, the approval of a minor maintenance activity, and the conduct of surveillance) were conducted smoothly and with due prudence. Procedures were observed to be in use and handily placed. Personnel were not loitering in the control room. Extraneous reading material was not present. The control room has recently been refurnished with new desks, chairs and printer enclosures. The new furniture plan has improved the Control Operators' view of the panels. Operators were found to be responsive to changing plant conditions.

The licensee is staffing six shifts of eight persons each. Three shifts are on watch rotation, one shift is a "day relief" shift to assist with surveillance and other evolutions, one shift is in training, and one shift is "off". Thus, training is an integral part of the shift rotation. The existence of a relief shift for supplemental tasks helps make training time essentially inviolate. This is a strength in the licensee's staffing plan.

11. Monthly Observation of Surveillance and Maintenance

Unit 1:

-- Emergency Gas Turbine Generator Fast Start which simulates a loss of power, started and loaded in 42.85 seconds on September 17.

-- B and C LPCI pump operational readiness test on October 9.

-- B Core Spray (CS) pump operational readiness test on October 9.

Unit 2:

-- Test of Reactor Protection System (RPS) switchgear per PT 21432, "Reactor Trip Switchgear Undervoltage Response Test," Revision 0, on September 12. Each breaker was tripped using its undervoltage device only. The breaker was not "racked-out" of its switchgear prior to the test but operated in place using a modified circuit which allowed disabling the shunt trip device. The scram breakers had remained shut for about one month since RPS Matrix testing. The breaker response time was considered to be the time measured from de-energizing the undervoltage device when the main control board manual scram push button was operated until the "Breaker Open" position switch closed. The times measured were between 30 and 40 milliseconds for each breaker. (The acceptance value is 100 milliseconds or less.)

-- High Pressure Safety Injection (HPSI) pump operational readiness demonstrations for both the 'A' and 'B' HPSI pumps were observed. Testing included hydraulic evaluation-flow versus differential pressure and vibration analysis. Procedures EN21111 "HPSI Pump 'A' Operational Readiness Test" Revision 3 (data sheets revision 4) and EN21112 "HPSI Pump 'B' Operational Readiness Test" Revision 3 were found to describe pump readiness testing. Procedure EN21137 "Pump Vibration Monitoring Equipment Operating Procedures" Revision 4 was found to describe the details of the actual vibration measurements. The clarity of the latter procedure, which includes sketches of the various pumps and motors showing test points and transducer axis orientation, is particularly noteworthy. Test personnel were interviewed in depth by the inspector and found to be knowledgeable of their speciality - vibration measurement and diagnosis.

-- CEA partial movement and CEA group deviation verification per SP2620A and SP2620B on September 12.

-- CEDS rod motion logic verification per IC2420E on September 12.

-- RPS Matrix Logic and Trip Path Test per IC2401D on September 12.

-- LPSI pump A testing per SP2604C, 26046 and 21114 on September 12. These tests verified pump operability, system alignment and valve operability and inservice performance testing including vibration analysis.

-- Containment Spray pump A testing per SP2606A, 2606C, and 21116 on September 12. These tests also verified pump operability system alignment and valve operability and inservice performance testing including vibration analysis.

-- Auxiliary Feedwater System pump tests of both motor driven and steam driven pumps per SP 2610A, 2610B, 2610C, 2611A, 2660, 21105, 21106, and 21107 on September 16. These tests verified pump and regulating valve operability system alignment and inservice performance testing including vibration analysis.

12. Review of Previously Inspected Items

Items Common to Both Units 1 & 2:

50-245/84-15-01 & 50-336/84-15-01 (Closed) This item was opened to track a licensee commitment to incorporate into plant procedures specific prohibitions against storage of flammable liquids within 50 feet of permanent buildings. The inspector reviewed the most recent revision to Administrative Control Procedure ACP 2.05B "Control of Combustible Materials, Flammable Liquids, Compressed Gases and Ignition Sources," Revision 10. Section 6.2.2 specifically addressed these storage concerns. This item is closed.

50-245/85-15-02 & 50-336/85-15-02 (Closed) This item was opened to track a licensee commitment to clarify instructions in plant procedures regarding protection for lower building levels from sparks and molten metal dropping from upper levels. The inspector reviewed the most recent revision to Administrative Control Procedure ACP 2.05B "Control of Combustible Materials, Flammable Liquids, Compressed Gases and Ignition Sources," Revision 10. Section 6.4.1 was found to address these concerns. This item is closed.

Unit 2:

50-336/84-15-05 (Closed) This violation involved the piercing of fire barriers in the Battery Room with a fiberglas drain pipe not qualified as part of the fire barrier. The licensee committed to replace the fiberglas pipe with a seismically supported iron pipe during the succeeding refueling outage. This work was accomplished as described in Plant Design Change Request 2-54-85 during the recently completed refueling outage. The inspector confirmed the piping replacement by physical inspection. This item is closed.

50-336/84-21-01 (Closed) This item was opened to track licensee actions to assure that personnel remain alert to containing contamination through proper use of survey instruments ("friskers"). The inspector observed that personnel contamination, decontamination, contamination control and related radiation worker topics were addressed in detail with acceptable emphasis in the recently completed cycle of the "General Employee Retraining Program." This item is closed.

13. Exit Interview

At periodic intervals during the inspection, meetings were held between licensee site management concerning the inspection scope and findings. No proprietary information was identified as being in the report findings.

The following new items were identified in this report:

Unit 1:

50-245/85-24-01: Resolution of high flow isolation of Isolation Condenser when initiated at 500 psig reactor pressure (Report Paragraph 2).

50-245/85-24-02: Failure of meteorological instruments due to the loss of 23 Kv off-site power (Report Paragraph 2).

50-245/85-24-03: Investigate the condition of scram air header pressure regulators and filter for possible relation to October 7 reactor trip and other single rod scrams (Report Paragraph 3).

50-245/85-24-04: Complete full testing of safeguards systems and modified bus under voltage logic (Report Paragraph 4).

Unit 2:

50-336/85-30-01: Loss of AFW pump room sump pumps with the loss of off-site power (Report Paragraph 2).

50-336/85-30-02: Radiological Protection Program improvements to insure that all radioactive material labels are removed prior to disposal of material as scrap (Report Paragraph 6).

ATTACHMENT 1

Millstone Units 1 and 2 Shutdown for Hurricane Gloria Sequence of Events:

The position of Hurricane Gloria was plotted by Unit 2 operators from National Weather Service information provided by the Connecticut Valley Electrical Exchange starting on September 25. Because of the storm track on September 26, the licensee scheduled the Emergency Response Organization to be activated at 0730, September 27. In addition, all but essential personnel were instructed not to report to work that day.

At 0830, September 27, both plants commenced a normal shutdown from full power, and an Unusual Event was declared at 0850 in anticipation of reaching the Emergency Plan Emergency Action Level of sustained wind speed in excess of 75 mph (at the 142 ft. elevation). As reactor power was reduced, station service electrical bus loads were transferred to each plant's Reserve Station Service Transformer (RSST), and the turbine generators were removed from service.

Unit 1

An inadvertent reactor trip occurred at 1206 during the shutdown of Unit 1 when the mode switch was placed in the start-up position without clearing the reduced power scram (15%) setpoint. That reactor protective function, which is bypassed while in the run mode, does not annunciate until it is activated with the mode switch. A plant cooldown was commenced in a normal manner by use of the turbine steam bypass system.

Since the licensee expected a loss of off-site power, the Emergency Gas Turbine Generator was started at 1110 and the Isolation Condenser placed in service. The main condenser would not be available as a heat sink because the circulating water pumps, which provide cooling to the condenser, would be de-energized with a loss of off-site power.

On the first attempt to manually establish flow through the Isolation Condenser, at 500 psig reactor pressure, the system containment isolation valves were shut due to a Group IV Isolation. That protective function actuates on high system flow in steam or condensate lines. The system integrity was verified by the control room operators and the reactor cooldown was then resumed using the Isolation Condenser. Shell side water was supplied from its normal source, fire water. With a loss of off-site power two fire pumps are available. One is driven by its own diesel engine and the second is powered by the Unit 1 EGTG.

The three incoming 345 Kv transmission lines were de-energized at 1335 after a series of fault indications. The Emergency Diesel Generator was started just prior to the loss of off-site power, which also de-energized the reactor recirculation pumps. Decay heat removal and reactor cooldown continued using the isolation condenser in natural circulation until power was restored to all station service electrical buses at 1210, September 28. Although two

buses were re-energized from off-site power at 0909 through the RSST, the diesel and gas turbine were run until the stability of the switchyard had been demonstrated and two incoming lines were restored. During the reactor cool-down, make-up water was provided by the control rod drive pump.

Unit 1 sustained wind damage at 1230, September 27, when two Turbine Building roof panel sections blew off. The corrugated sheet metal sections evidently lifted when a South facing roll-up railway door blew in. This was the only significant storm damage. There were no personnel injuries.

Recovery operations required that all 345 Kv insulators be water washed and that testing be performed on transmission lines, switch yard buses and breakers prior to energizing those components. Off-site power was first supplied to 4.16 Kv buses 14B and 14D from the RSST at 0909, September 28. At that time, Reactor Recirculation Pump "B" was started, restoring forced recirculation flow, and the "C" Condensate Pump was started to restore the normal feedwater system. Buses 14A, 14C and 14E, which had been supplied by the Emergency Gas Turbine Generator were transferred to the RSST at 1205 and bus 14F, which had been supplied by the Emergency Diesel Generator, was transferred to the RSST at 1210. The Emergency Diesel Generator and Gas Turbine Generator were secured at 1225; they had operated without any problems during the loss of off-site power under a nominal load of about 1 Mw.

A stem packing leak occurred on valve 1-LP-12A, a LPCI manual isolation valve located in the primary containment, during the plant heat up on September 28. This required a second reactor cooldown and containment entry for maintenance which was completed at 1505, September 29. The turbine building roof was repaired with replacement steel plate. The plate was installed and the roof insulated on September 29.

The licensee verified the proper operation of the differential pressure switches used to detect high flow in the Isolation Condenser steam supply and condensate return lines. These instruments were found to operate within the required Technical Specification. A reactor startup commenced at 1730 following an evaluation and acceptance of the Isolation Condenser availability by the licensee. The reactor was made critical at 2247 and the turbine placed on line at 0644, September 30. The plant reached full power, which in the end of core life power coast down was 98% of full power, at 2130, October 1.

Unit 2:

As part of the September 27 shutdown, the reactor was sub-critical at 1118 and all control rods were fully inserted at 1308. The auxiliary feedwater (AFW) system was placed in service at 1303, Main Steam Isolation Valves shut and the reactor coolant system maintained in hot shutdown, that is 535 degree F average temperature and 2250 psia. Decay heat was removed by allowing the atmospheric steam dumps to operate automatically modulating their position with average reactor coolant system temperature. The main condenser cannot be used as a heat sink without power to the circulating water pumps. In anticipation of the loss of 345 Kv power, all Reactor Coolant Pumps (RCP) were stopped at 1314 and the station bus tie breaker to the RSST opened at 1319.

This was done intentionally to take advantage of automatic load shed and tie breaker control. The emergency diesel generators started and powered the safeguards buses. Natural circulation cooling was verified at 1325 with steam generator feed water being supplied by the two electric AFW pumps. The second AFW pump was secured as demand decreased. The plant remained in this condition until power was restored to the station electrical buses at 1525, September 28.

Although power was restored to the switchyard and the Unit 2 RSST in the morning of September 28, a lightning arrestor failed on one phase of the line supplying the transformer and required replacement. This was accomplished and the RSST energized at 1505. Safeguards electrical buses 24C and 24D were powered from the RSST at 1525 allowing the Emergency Diesel Generators to be secured. Station service electrical buses 24A and 24B which had been de-energized since 1319, the day before, were energized at 1530. The site secured from the Unusual Event at that time. Forced recirculation flow was restored at 1630 when the "A" RCP was started.

Technical Specification 3.7.5, "Flood Level" requires that a service water pump be protected against flooding if certain conditions exist or are forecasted. This device was installed on the "B" Service Water Pump and was in place from 1200 until 1730, September 27. Installation required the removal of the pump motor power cables and was completed in one-hour fifty minutes.

At 1743 when starting the "C" RCP, the motor breaker was tripped by the switchgear ground fault protection (50GS). The plant remained in hot standby while the licensee investigated its condition. Testing revealed a fault condition when the 6.9 Kv motor was tested at 5 Kv. A plant cooldown was commenced at 1058, September 30, to start an unplanned maintenance outage; the reactor reached Mode 5, Cold Shutdown, at 0145, October 1.

ATTACHMENT 2

Millstone Unit 1 Reactor Trip - October 9,1985 Sequence of Events:

11:14:19.9	RPS Trip Channel A (Surveillance)
11:15:00.1	RPS Channel A Trip Reset
11:18:33.2	RPS Trip Channel B (Surveillance)
11:18:33.3	Alarm-Low Pressure Scram Pilot Air Header
11:18:36.9	RPS Channel B Trip Reset
11:19:02.5	Rod Drift Alarm (38-03 and 42-07)
11:19:39.0	RPS Trip Channels A and B due to low air header pressure

The surveillance in progress at that time was SP408P, Scram Air Header Low Pressure Calibration and Function Test. The procedure requires functionally testing each pressure switch; in each case causing a one-half scram. Although this was the plant parameter causing the trip, it does not appear that the personnel performing the surveillance introduced a spurious trip. During the performance of SP408P, the associated pressure switches are individually isolated and tested.