NUREG-1143

Safety Evaluation Report

related to the full-term operating license for Millstone Nuclear Power Station, Unit No. 1

Docket No. 50-245

Northeast Nuclear Energy Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

October 1985

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ABSTRACT

The Safety Evaluation Report for the full-term operating license application filed by the Connecticut Light and Power Company, the Hartford Electric Light Company, Western Massachusetts Electric Company and the Millstone Point Company [(now known as Connecticut Light and Power Company (CL&P) and Western Massachusetts Electric Company (WMECO) having authority to possess Millstone - 1, 2, and 3, and the Northeast Nuclear Energy Company (NNECO) as the responsible entity for operation of the facilities)] for Millstone Nuclear Power Station Unit 1 has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located in the town of Waterford, Connecticut. Subject to favorable resolution of the items discussed in this report, the staff concludes that the facility can continue to be operated without endangering the health and safety of the public.

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ACRONYMS AND INITIALISMS

ACRS	Advisory Committee on Reactor Safeguards
AEC	Atomic Energy Commission, U.S.
ALARA	as low as is reasonably achievable
ANSI	American National Standards Institute
AOGS	Augmented Off Gas System
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient(s) without scram
BTP	branch technical position
BWR	boiling-water reactor
CCW	component cooling water
CFR	<u>Code of Federal Regulations</u>
cfs	cubic feet per second
CHF	Critical Heat Flux
CRD	control rod drive
DBA	design-basis accident
DG	diesel generator
ECCS	emergency core cooling system
EFPY	effective full-power year
ESF	engineered safety feature(s)
FES	final environmental statement
FR	<u>Federal Register</u>
FRC	Franklin Research Center
FTOL	full-term operating license
FWCI	Feedwater coolant injection
GDC	general design criterion(a)
GE	General Electric
gpm	gallon(s) per minute
HELB	high energy line break
HEPA	high-efficiency particulate air
ID	inner diameter
IE	Office of Inspection and Enforcement
IPSAR	integrated plant safety assessment report
ISI	inservice inspection
LLL	Lawrence Livermore Laboratory
LOCA	loss-of-coolant accident
LPCI	low pressure coolant injection
LWR	light-water reactor
MAPLHGR	maximum average power linear heat generation ratio
MCHFR	minimum critical heat flux ratio
mph	mile(s) per hour
MSL	mean sea level
MSLB	main steam line break
MWt	megawatts thermal
NNECO	Northeast Nuclear Energy Company
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association

NPSH	net positive suction head
NRC	Nuclear Regulatory Commission, U.S.
OBE	operating-basis earthquake
ODCM	Offsite Dose Calculation Manual
ORNL	Oak Ridge National Laboratory
PCT	peak cladding temperature
PMF	probable maximum flood
POL	provisional operating license
PORC	Plant Operations Review Committee
ppb	part(s) per billion
ppm	part(s) per million
PRA	probabilistic risk assessment
psia	pounds(s) per square inch absolute
psig	pounds(s) per square inch gage
RCP	reactor coolant pump
RCS	reactor coolant system
RETS	Radiological Effluent Technical Specification
RG	regulatory guide
RHR	residual heat removal
RPS	reactor protection system
SALP	Systematic Assessment of Licensee Performance
SDAOGS	Steam Dilution Augmented Off Gas System
SEP	Systematic Evaluation Program
SER	safety evaluation report
SRP	Standard Review Plan
SSE	safe shutdown earthquake
SWS	service water system
TER	technical evaluation report
TMI-2	Three Mile Island Unit 2
USGS	U.S. Geological Survey
USI	unresolved safety issue

1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

This report is a Safety Evaluation Report (SER) on the application for a full-term operating license (FTOL) for the Millstone Nuclear Power Station, Unit No. 1 (Millstone-1 or MP-1), based on an application filed by Northeast Nuclear Energy Co. (NNECO), the licensee. This report was prepared by the U.S. Nuclear Regulatory Commission (the staff) and summarizes the results of the staff's review of the proposed conversion from a provisional operating license (POL) to an FTOL.

From 1959 to 1971 the Atomic Energy Commission issued POLs to 15 power reactors for periods up to 18 months as an intermediate stage before issuing an FTOL. The purpose of the POL was to provide an interim period of routine operaton during which the licensee and staff could assess plant operating parameters and performance against predicted values and resolve generic concerns identified during the licensing process. POLs have been held longer than 18 months because each POL licensee submitted a timely application for renewal under Part 2.109 of Title 10 of the Code of Federal Regulations (10 CFR 2.109) (Ref. 1) and/or an application for conversion to a full-term license.

The Connecticut Light and Power Company (CL&P), Hartford Electric Light Company, Western Massachusetts Electric Company (WMECO) and the Millstone Point Company which later evolved to CL&P, WMECO, and NNECO filed an application to convert POL No. DRP-21 for Millstone-1 to an FTOL in a letter dated Sept. 1, 1972 (Ref. 7). The facility received its POL on October 7, 1970,* achieved initial criticality on October 26, 1970. A 250 hr power demonstration run was completed on March 23, 1971. The NRC policy with respect to conversion of Provisional Operating Licenses to Full Term Operating Licenses was presented in SECY 83-19 (Ref. 6).

In 1975, because of a large backlog of unresolved generic issues that were relevant to the operation of the POL plants, the staff stopped its review of the POL conversions and set out to establish the appropriate scope of review needed to support the full-term conversion.

In 1977 the NRC staff recommended to the Commission that POL facilities be included in Phase II of the Systematic Evaluation Program (SEP) because much of the review necessary for conversion of the POLs was similar to the scope of the review proposed for the SEP. That recommendation was adopted, and the major portion of the technical input supporting this SER comes from the SEP topic evaluations and the SEP Integrated Plant Safety Assessment Report (IPSAR) for Millstone-1 (NUREG-0824 Ref. 5).

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*The POL review is documented in a Safety Evaluation forwarded to the licensee by letter dated March 7, 1970.

The SEP was conceived in recognition that, because of the evolutionary nature of licensing requirements and advances in technology, better documentation was needed to substantiate the staff's opinion that currently operating plants are acceptably safe. The objectives established for the SEP were listed on page 3 of SECY-76-545 (Ref. 8) as:

(1) The Systematic Evaluation Program must assess the safety adequacy of the design and operation of currently licensed nuclear power plants.

(2) The program should establish documentation which shows how each operating plant reviewed compares with current criteria on significant safety issues, and should provide a rationale for acceptable departures from these criteria.

(3) The program should provide the capability to make integrated and balanced decisions with respect to any required back-fitting.

(4) The program should be structured for early identification and resolution of any significant deficiencies.

(5) The program should efficiently use available resources and minimize requirements for additional resources by NRC or industry.

Thus, the review provides (1) an assessment of the significance of differences between current technical positions on safety issues and those that existed when a particular plant was licensed, (2) a basis for deciding how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety. To document the results of the SEP review for MP-1, the staff has issued NUREG-0824. NUREG-0824 was initially published in draft format in November 1982 and was issued in final form after Commission review in February 1983 (Ref. 5). Some followup requirements for additional analysis by the licensee that may result in the need for facility modification or other corrective action were identified in the Final IPSAR.

Supplement 1 to NUREG-0824 documents the reviews performed for those issues that required refined engineering evaluations or the continuation of ongoing evaluations subsequent to issuance of NUREG-0824.

In a related activity, the licensee proposed in letters dated June 13, 1983, September 14, 1983, December 28, 1983, and May 17, 1985 to conduct an expanded integrated assessment for Millstone 1 which would address the outstanding SEP issues (Category 3), all pending licensing actions, and significant licensee-sponsored plant improvements. This effort is referred to as the Integrated Safety Assessment Program (ISAP).

On November 15, 1984, the Commission published a policy statement in the Federal Register (49 FR 45112) which describes the elements and objectives of ISAP, as a regulatory vehicle to develop plant-specific, integrated implementation schedules for plant modifications. MP-1 has been selected as one of two plants which will participate in an ISAP pilot program. Consequently, the results of the licensee's additional analyses for several of the issues discussed in this report refer to ISAP, where alternative corrective actions will be considered and a prioritized implementation schedule for any plant modifications will be

developed. The entire scope of the ISAP review for Millstone 1 is detailed in a July 31, 1985, letter to the licensee.

The major portion of the technical input supporting the staff SER was provided by the IPSAR. The remainder of this SER addresses other operating license issues not covered under the SEP. The SER includes consideration of major plant modifications that have occurred since the POL was issued, major substantive regulations adopted since the POL was issued, requirements stemming from the accident at Three Mile Island Unit 2 (TMI-2) (Appendix B), and unresolved safety issues (USIs - Appendix C). USIs are issues considered on a generic basis after the staff has made the initial determination that the safety significance of the issue does not prohibit continued operation or required licensing actions while the longer term generic review is under way.

The format of the SER follows the general format of SERs currently issued for new operating licenses, but for many of the major headings, particularly those covered in the SEP, the SER briefly summarizes the findings of the Final IPSAR. Similarly, when SERs have been issued on other topics, such as compliance with Appendix I, this SER for the FTOL briefly summarizes the previous SER and assesses whether the earlier findings are still valid.

Appendix A contains a list of references cited in this report.* For TMI Action Plan items, Appendix B identifies the status and plant-specific implementation of each TMI Action Plan item. For USIs, Appendix C not only discusses the status of the USIs but also satisfies the guidelines provided by the Atomic Safety and Licensing Appeal Board in the River Bend case (ALAB-444, 6 NRC 760 (1977) Ref. 3).

The staff plans to issue a supplement to this SER after the Advisory Committee on Reactor Safeguards review and their report to the Commission is available, as discussed in Section 18. The supplement will append a copy of the Committee's report, will address any comments made by the Committee, and will describe steps taken by the NRC staff to resolve any issues raised as a result of the Committee's review. There are a number of ongoing licensing actions for MP-1 that are currently under staff review as noted in this SER. The staff has determined that these items do not require resolution before the issuance of an FTOL and should not delay the POL to FTOL conversion process. All of these items will be addressed as routine operating reactor licensing actions after the FTOL is issued.

In accordance with the provisions of the National Environmental Policy Act (NEPA) of 1969, the staff prepared the Draft and Final Environmental Statements that set forth the considerations related to the proposed POL to FTOL conversion. The Final Environmental Statement (FES) was issued in June 1973. Because the FES was issued a number of years ago, the staff performed an Environmental Evaluation to determine if an FES supplement was necessary. The Environmental Evaluation issued concluded that an FES supplement is not necessary (Ref. 10).

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*Availability of all material cited is given on the inside front cover of this report.

The NRC Project Manager assigned to the FTOL review for MP-1 is Mr. James J. Shea. Mr. Shea may be contacted by calling (301) 492-7231 or writing:

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Washington, D.C. 20555

1.2 Description of Plant

The Millstone-1 plant, located in the town of Waterford, Connecticut, is a Boiling Water Reactor (BWR) designed by General Electric. The license is held jointly by Connecticut Light and Power Company (CL&P), Western Massachusetts Electric Company (WMECO), and Northeast Nuclear Energy Company (NNECO), with NNECO acting for itself and agent for CL&P and WMECO. The licensee filed the application for a construction permit and facility license by letter dated November 10, 1965. Construction permit No. CPPR-20 was issued by letter dated May 19, 1966. The Final Safety Analysis Report (Ref. 12) was filed on March 15, 1968 and the initial provisional operating license was issued on October 20, 1970 (Ref. 13). By letter dated September 1, 1972, the licensee applied for a full-term operating license (Ref. 7). The licensed thermal-power rating currently is 2011 megawatts thermal (MWt).

The reactor core, reactor vessel and core cooling system, steam lines and turbine/electric generator are shown schematically in Figure 1.1 in relation to the primary containment (a drywell which encloses the pressurized reactor coolant system and a torus or wet well that condenses steam released from a postulated primary coolant system break that could otherwise breach containment if pressure build up is excessive), the secondary containment i.e. reactor building (encloses the primary containment - drywell and torus), the turbine building and the 375 foot off-gas vent stack.

The single-cycle, forced circulation boiling water reactor produces steam which is used directly by the turbine. This reactor is generally similar to other operating boiling water reactors. Housed in the reactor pressure vessel are the reactor core and core support structure, the steam separators and dryers, the jet pumps, the control rod guide tubes, the feedwater distributors, the emergency core cooling system (ECCS) spray headers, the standby liquid poison system spargers and other components. The arrangement of major components within the reactor pressure vessel are illustrated in Figure 1.1. The inside diameter of the reactor vessel is approximately 18 feet 8 inches, and the inside height between heads is approximately 64 feet 8 inches. The main connections to the reactor pressure vessel are the steam lines, jet pump motive flow recirculation lines, feedwater lines, and control rod drive thimbles. Other connections are for the isolation condenser system, standby liquid control systems, ECCS, and instrumentation systems.

The major components of the reactor core are fuel assemblies and control rods. Each module of four fuel assemblies contains a cruciform shaped control rod. This modular system is the same as that used in the other 28 boiling water reactors currently operating within the United States.

The fuel rods consist of uranium dioxide pellets contained in sealed zircaloy tubes. The fuel rods are fabricated into fuel assemblies in an 8 x 8 matrix

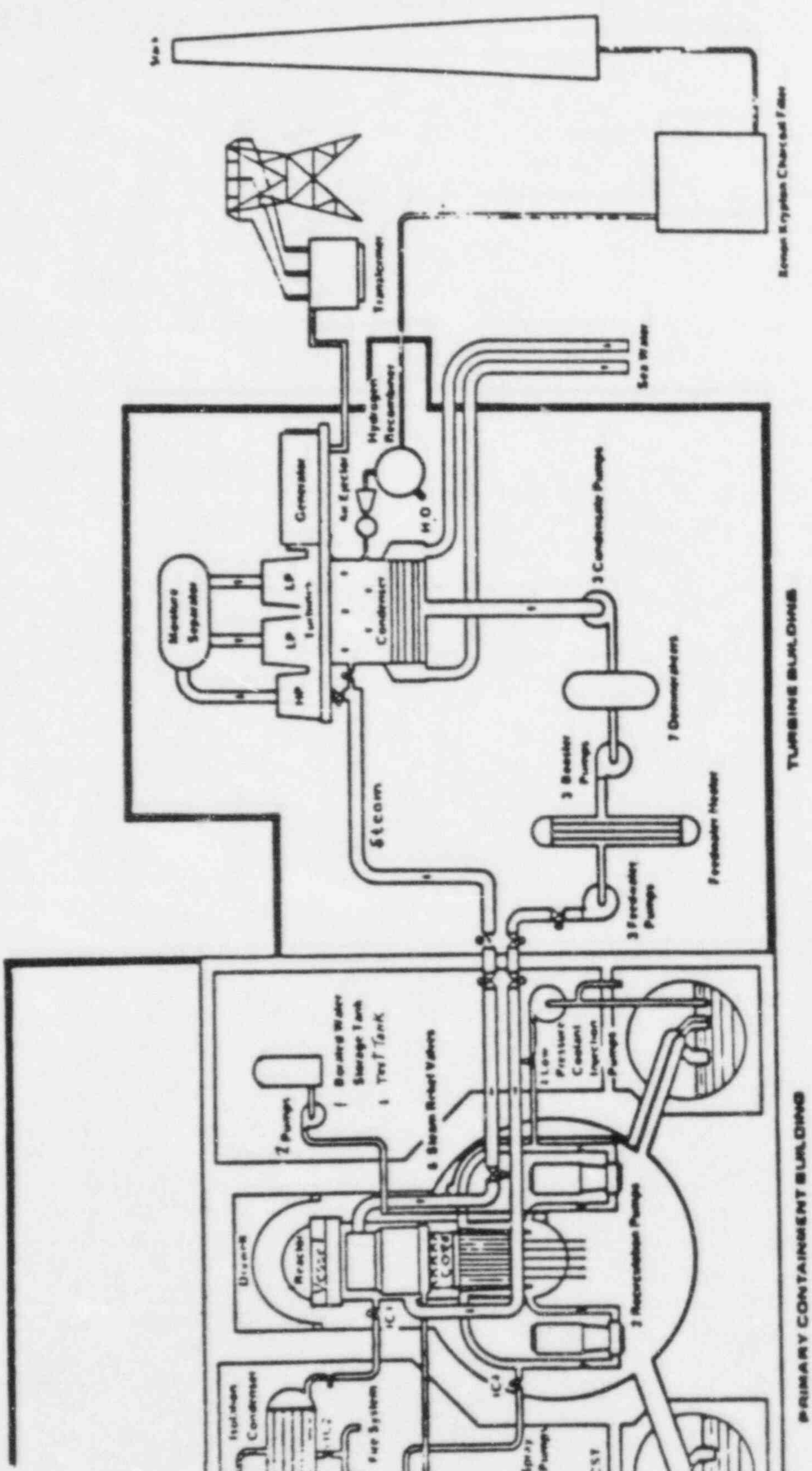

Fig. 1.1
Millstone Nuclear Power Station Unit #1

that includes water rods and gadolinia neutron absorbing (poison) rods. Each fuel assembly is fitted with a zircaloy-4 flow channel which surrounds the fuel rods. Water serves as both the moderator and coolant. The general nuclear and performance characteristics of the fuel are similar to those of the fuel in use at other operating boiling water reactors designed by General Electric. Improved fuel rod performance has been achieved by using smaller diameter fuel rods, increasing the matrix from 7 x 7 to 8 x 8, and using selected water filled and poisoned rods within the matrix.

The control rods are of two types, both of which contain assemblies of 3/16-inch diameter, sealed, stainless steel tubes filled with compacted boron carbide powder. These tubes are held in a cruciform array by a 1/16-inch thick stainless steel sheath which is fitted with castings at each end. For the newer type rods, performance has been increased by the introduction of hafnium into the blade tips. Both types of control rods are almost identical to the ones used in other operating General Electric BWRs. Individual rods are inserted into the core from the bottom and may be moved vertically by the hydraulically operated, locking piston control rod drives.

The control rod drive hydraulic system allows withdrawal or insertion of one rod at a time for power level control and flux shaping. Stored energy from gas-charged accumulators and from reactor pressure provides the hydraulic power to scram, i.e., to insert all control rods simultaneously at maximum speed to shut down the reactor. Each drive has separate control and scram devices. The control rod drive system is the same as the system used in other G.E. BWRs. It contains control rod velocity limiters and a control rod drive housing support structure to prevent excessive reactivity addition rates. The control rod velocity limiter is a specially designed lower casting on each control rod which limits the freefall velocity of the control rod to less than 5 ft./sec. in the unlikely event of a control rod dropout. The control rod drive housing support structure is located beneath the housings to prevent significant movement of any drive housing and mechanism in the unlikely event of a structural failure of the housing.

Cooling water flows upward from the bottom of the core through the fuel assemblies, and the heat transferred to the water from the fuel produces steam. Steam separators and dryers located above the core and within the reactor vessel separate the steam-water mixture which leaves the assemblies. The steam flows through steam lines to the turbine. The separated water mixes with the incoming feedwater and is returned to the core by the jet pumps in the reactor vessel. The jet pumps are driven by water from the two recirculation loops. Each loop has a variable speed centrifugal pump. The jet pump feature also povides a vessel within the reactor vessel for reflooding the core with water in the event of a loss of coolant because of a postulated recirculation line break. Excessive reactor coolant system pressure is prevented by safety/relief valves (see Section 1.2 d) that vent steam directly to the suppression pool where it is condensed. The number of safety relief/valves has been increased to 6 and the S/R valve discharge piping into the pool water has been modified extensively since initial operation to assure system reliability.

The primary containment consists of a drywell, a pressure suppression chamber, and interconnecting vent pipes, and is designed to accommodate the pressures and temperatures which would result from a failure equivalent to a circumferential rupture of a major recirculation line within the primary containment with

subsequent discharge of reactor water into the containment at the maximum rate. The torus-shaped pressure suppression chamber is a steel pressure vessel which is half filled with water. It is located below and encircles the drywell. The drywell is connected to the pressure suppression chamber by a system of vent pipes which terminate below the water level. Thus, steam released in the drywell due to pipe failure would pass to and be condensed in the water in the pressure suppression chamber. This transfer of energy would rapidly reduce the pressure in the drywell and thereby substantially decrease the potential for primary containment leakage.

Isolation valves on piping penetrating the drywell and pressure suppression chamber provide the required capability to close and isolate the primary containment. These valves are actuated automatically by signals received from the reactor protection system. Two independent, full-capacity containment cooling systems are provided to remove heat from the drywell and the pressure suppression chamber and thereby assure that primary containment integrity is maintained indefinitely following a postulated loss of coolant accident.

The drywell and pressure suppression chamber are designed to withstand pressure of 62 psig. Measurements are taken periodically to verify that the integrated leakage rate does not exceed the design target of 0.5 percent of the combined volumes per day.

The reactor building is a controlled leakage structure which provides secondary containment when the primary containment is in service and primary containment when the primary containment is open. A standby gas treatement system is provided (with redundant active components) to filter the reactor building ventilation exhaust and discharge it to the 375-foot stack during containment isolation conditions. The secondary containment system minimizes the ground level release of airborne radioactive materials and provides for controlled, filtered, elevated release of the reactor building atmosphere.

In addition to the turbine generator and main condenser system, the following auxiliary systems are provided to cool the reactor and primary containment during various normal and abnormal conditions:

a. The low pressure coolant injection (LPCI) system serves three functions:

    1. It injects water into the reactor vessel under the circumstances of the postulated double-ended rupture of a major water recirculation line rapidly enough to reflood the core and prevent excessive fuel clad damage.

    2. It removes heat from the water in the suppression chamber.

    3. It sprays water into the drywell and thereby removes energy from the drywell.

b. The shutdown cooling system may be used to remove reactor decay heat during shutdown.

c. The isolation condenser removes decay heat when the reactor is isolated.

d. The feedwater coolant injection (FWCI) system removes decay heat and provides coolant inventory control during postulated occurrences of slow depressurization. In addition, depressurization is automatically achieved by blowdown through automatic opening of relief valves which vent steam to the pressure suppression pool. This depressurizes the vessel quickly enough to allow the core spray or the LPCI system to prevent fuel clad melting.

e. The two core spray systems are designed to pump water from the pressure suppression chamber pool directly to the reactor core through a spray header mounted in the reactor vessel above the core. These systems prevent excessive fuel damage during such events.

f. A cross-tie between the emergency service water system and the feedwater system makes available an inexhaustable secondary supply of cooling water from Long Island Sound to the reactor core and containment independent of all other cooling water sources. The cross-tie, isolated by two normally closed manually operated valves, provides a flow path from the emergency service water system to the feedwater pumps via the condensate storage tank.

Since the issuance of the provisional operating license for Millstone Unit 1, other nuclear power facilities have been or are being constructed on the Millstone site. Adjacent to Unit 1, Millstone Unit 2, a 2700 MWt. Combustion Engineering PWR, Docket No. 50-336, has been constructed under Construction Permit CPPR-76 issued on December 11, 1970, and Millstone Unit 3, a 3411 MWt Westinghouse PWR, Docket No. 50-423, is being constructed under Construction Permit CPPR-113 issued on August 9, 1974. Millstone Unit 2 received full power, full term Operating License number DPR-65, on August 1, 1975. The SER related to operation of Millstone Nuclear Power Station, Unit 3, was issued July 1984 (Ref. 4).

The present and future potential effects on Millstone Unit 1 from these additional facilities are expected to be minimal.

1.3 Operating Experience

Preoperational tests to check the electrical and mechanical features of components, subsystems, systems and combined systems were performed with generally satisfactory results prior to fuel loading. Fuel loading and initial criticality tests followed without incident. The program of startup testing which provided confirmation of the design objectives is described below. In addition, the more significant events and plant modifications are also discussed below and in Appendix D, "Special Report on the Operation of Millstone Point Unit 1." This report was prepared by the Commission's Office of Inspection and Enforcement and covers the period through December 1973.

Certain events during the preoperational phase are historically notable because they relate to subsequent considerations. One such event occurred at Niagara Mohawk Power Corporation's Nine Mile Point Unit 1 on March 6, 1970 when cracks in a safe end attached to the reactor pressure vessel nozzle were discovered. The safe end was made of furnace sensitized stainless steel and the cause of the cracks was determined to be stress corrosion. The associated NRC investigation and review included discussions with the Millstone Unit 1 licensee. A

decision was subsequently made by the licensee to remove or clad overlay all of the furnace sensitized stainless steel components in the reactor vessel prior to fuel loading for startup. The replacement or overlaid weld material was of non-sensitized stainless steel resistant to stress corrosion. This proposal was reviewed by the ACRS and reported on by letter dated June 16, 1970.

The original schedule for startup of Millstone Unit 1 reflected the proposed issuance of a provisional operating license by publication in the Federal Register of a notice dated March 13, 1970. The corresponding Safety Evaluation Report was issued on March 9, 1970. The issuance of the license was delayed by the above described events related to the furnace sensitized stainless steel. The licensee's action was documented in Amendment Nos. 25, 26 and 28 to the FSAR. An Addendum to the Safety Evaluation Report (Ref. 13) was issued on October 7, 1970; this Addendum presented the staff evaluation of the FSAR Amendments involving the furnace sensitized stainless steel problem and modification of the Millstone reactor vessel. This Addendum was issued simultaneously with issuance of Provisional Operating License (POL) No. DPR-21.

1.3.1 Design Confirmation

A startup test program was performed by Millstone Unit 1; the licensee described the results of this program in a report entitled "Startup Test Program Results" submitted to the Commission on March 17, 1972. In connection with the overall review effort of the application for POL conversion, the staff reviewed the startup test report and found it acceptable. The results of the startup testing program showed satisfactory performance of components and systems to demonstrate that the design was adequate for operation at power levels up to 2011 MWt.

The startup test program began with fuel loading and continued until completion of the power warranty run. It consisted of four phases as follows: (1) initial fuel loading and open vessel testing, (2) initial heatup with nuclear heat, (3) power tests and escalation of power to 100%, and (4) warranty power run. In this way the plant was loaded and tested in a controlled, step by step program. During the power escalation and associated testing, extensive testing was performed at the 25 percent, 50 percent, 75 percent and 100 percent of read power. These tests and results included the following salient items:

(1) Fuel loading - the first fuel assembly was loaded on 10-8-70 and the last, or 580th, was loaded on 10-17-70.

(2) Shutdown margin - the core was demonstrated to be subcritical by at least 0.47 (0.25 required at that time) percent $\Delta k/k$ with the highest reactivity worth rod withdrawn.

(3) Control Rod Worth - maximum worth of a notch was 0.0484 percent $\Delta k/k$ as compared to the acceptance criterion of 0.1 percent $\Delta k/k$.

(4) Reactor Vessel Heatup - was maintained below the specified maximum of 100F per hour.

(5) System Expansion - movement of recirculation piping, feedwater piping and main stream piping within the drywell was recorded. All restraints and stresses were found within acceptance criteria.

(6) Core Performance Evaluation - basic performance parameters of total and specific core power, maximum heat flux, minimum critical heat flux ratio (MCHFR) were determined. At full power a peak heat flux of 120 w/cm^2 (382,000 $BTU/hr\text{-}ft^2$), a total peaking factor of 2.96 and a MCHFR of 2.6 were determined. These values confirm conservative design predictions of peak heat flux of 400,300 $BTU/hr\text{-}ft^2$, total peaking factor of 3.08 and a MCHFR greater than 1.9, respectively.

(7) Nuclear Instrumentation - the source range instrumentation (SRM), intermediate range monitors (IRM) and local power range monitors (LPRM) within the function of average power range monitoring (APRM) were checked out, calibrated and determined to be operable as required.

(8) Systems and Components including main stream isolation valves, isolation condenser, recirculation system, pressure regulator, bypass valves and relief values were tested for design performance and found to be adequate.

(9) Transient Behavior - the plant transient behavior was tested by performing two turbine trip tests (at 50 percent and 100 percent power) and a total of seven generator trips or full load rejections (one at 50 percent, two at 75 percent and four at 100 percent powers). All of the tests except the turbine trip at 50 percent power were performed without event to verify plant behavior. During the 50 percent power turbine trip the sudden closure of turbine stop valves resulted in a pressure wave which caused deformation of one of the main steam lines restraints which had not been properly designed for the dynamic loads associated with a turbine trip. The corrective action included a dynamic stress analysis and replacement of the faulty restraint and installation of two additional restraints.

The licensee submitted a report of the event and subsequent corrective action to the Commission by letter dated March 3, 1971. The staff reviewed the report and accompanying analysis and concluded that the corrective action was acceptable. The adequacy of the corrective action was confirmed by subsequent turbine trips which were accomplished without problem.

(10) System Vibration Performance - structures and equipment located inside the reactor vessel are subject to vibration induced by the flow of reactor coolant through the recirculation system, including the jet pumps and fuel assemblies, and by the flow of steam through the moisture separation and drying units. Consistent with the requirements of Regulatory Guide 1.20, vibration measurements were included in the startup test program for Millstone Unit I to assure that excessive vibrations, which could cause deterioration of the internal structures and equipment, would not occur due to normal operation of the plant or due to a range of off-normal conditions which might inadvertently or accidently occur.

The licensee met the intent of Regulatory Guide 1.20 by successful completion of the startup vibration test program and by extensive operation at full power with no evidence of deterioration of the structures, which support and restrain the core due to flow induced vibration. The staff finds, on the basis of this test program and the intervening years of successful reactor operation, that the licensee has demonstrated that Millstone Unit I may continue to be operated with assurance that the safety functions of

the reactor internal structures will be maintained throughout the remainder of the plant design lifetime.

The licensee reported cracking at some welds on the feedwater spargers. Investigations identified vibration as a causative factor. The phenomena involved are, however, separate and distinct from the flow induced vibration of the core support structures as discussed above and in Regulatory Guide 1.20. The driving forces which could cause vibration of the core support structures result primarily from the very complex hydrodynamics of high volume flows over and around the reactor internals. In contrast, the driving forces identified in the case of the feedwater spargers result from flow through the feedwater piping and, possibly, transmitted vibration originating at the feedwater pumps. The feedwater sparger problem is discussed in Section 1.3.2(2) of this report.

On the basis of satisfactory results from startup and power escalation testing and subsequent power operations including a new domestic BWR operating record for continuous time on line of 374 days, the staff concludes that the testing and successful operation for 15 years have demonstrated the design adequacy of Millstone Unit 1 to operate at the licensed full power for the remainder of the plant design lifetime.

1.3.2 Operating Problems

The significant operating problems experienced at Millstone Unit 1, when the plant was new, are discussed below. These items are also discussed in Appendix D to this report, "Special Report on the Operation of Millstone-1 by I&E." Additional information on these and other more recent problems can be found in the licensee's semi-annual (later changed to annual) operating reports and IPSAR (Refs. 5 and 11).

(1) Chloride Intrusion Incident - Main Condenser Tube Failure - On September 1, 1972 during a reactor startup, seawater leakage through the main condenser into the hotwell resulted in concentrations of chloride that saturated the condensate demineralizers allowing excessive chloride ions to enter the reactor primary coolant system. In the reactor primary coolant system, the chloride concentration reached 17 ppm and conductivity reached a level of about 84 micromhos per cm (umho/cm). These levels were in excess of the limits of 0.1 ppm chloride and 2 umho/cm conductivity set forth in the Technical Specification at that time.

Following the incident, the licensee conducted an investigation which included an assessment of damage to reactor components. This assessment revealed the essentially complete failure of 116 of the 120 Local Power Range Monitors (LPRMs). Other significant effects discovered during the investigation, but not necessarily the result of the chloride incident, included extensive cracking in the four feedwater spargers (see Section 1.3.2(2)) and cracking of the control rod cladding. The corrective action taken by the licensee to repair the damage included replacement of the LPRMs, feedwater spargers and all of the control blades. As reported by Millstone Point Company Special Report on Chloride Intrusion Incident Appendix H dated February 9, 1973 the main condenser has been retubed with 70/30 copper/nickel tubing as a corrective action for sea water leakage.

The copper/nickel alloy has been shown by experience to better withstand the pitting attack observed on the originally installed aluminum/brass tubes. The upper section of the condenser has been restaked to eliminate vibration. Also, isolated areas in the main bundle have been staked where vibration damage was apparent in tubes removed during the retubing operation.

As indicated above, the return to operations included on-going surveillance requirements. These requirements have been satisfied and reported by the licensee in three reports, "Appendix I, Special Report, Chloride Intrusion Incident" dated June 29, 1973, "Appendix J, Special Report, Chloride Intrusion Incident," dated March 8, 1974 and "Appendix K, Special Report, Chloride Intrusion Incident," dated January 8, 1975. These three documents describe the results of the licensee's in-service inspections of the reactor primary system. No indications attributable to the chloride incident were found.

The staff evaluation of the reported post-operation surveillance program results follow. The Reactor Component Surveillance program defined in Section 3.0 of Appendix H and summarized in Appendix K have been evaluated. All inspections defined in Table V-3.1 of Appendix H have been accomplished in a satisfactory manner. Inspections were performed on fuel assemblies, pipe welds, feedwater sparger, control rod drives, shroud head bolts, vessel clad, and other reactor internals. The Reactor Component Surveillance found no indications attributable to the chloride intrusion incident. Comparison of the volumetric inspection of selected highly stressed primary piping welds during the baseline, December 1973, April 1973, and September-October 1974 inspection demonstrate no increase in magnitude within inspection tolerances.

With regard to the utrasonic testing that was performed during these inspections, calibration of the longitudinal wave examination was accomplished with a calibration standard fabricated in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Appendix IX. Calibration of the 45-degree shear wave examination was accomplished with a 60-degree "V" notch calibration block machined to the depth of 1% to 4% of the wall thickness. The "V" notch block was determined to better simulate response from the type of indications being investigated, specifically stress corrosion cracking.

The staff concurs that the "V" notch calibration block was acceptable and appropriate for the specific stress corrosion cracking inspection defined in Section 3.0 of Appendix H. However, it was recommended that the "V" notch calibration block not be adopted for general ultrasonic inspection or Section XI Inservice Inspection without detailed evaluation. The correlating factors associated with the "V" notch blocks are dependent upon the materials and wall thickness and could result in a myriad of calibration standards.

The Reactor Operation Surveillance program defined in Section 4.0 of Appendix H and summarized in Appendix K revealed no abnormal conditions.

The staff concluded that the augmented surveillance inspection program conducted after resumption of operation at Millstone Nuclear Power Station Unit 1 described in the subject Appendix K was acceptable and conformed to the requirements and conditions as set forth in Section 3.0 and 4.0 of Appendix H "Special Report, Chloride Intrusion Incident." The staff further concluded that this action completed the requirements for resumption of operation following the chloride intrusion incident.

(2) Feedwater Sparger Cracking - Millstone Unit 1 was shutdown on April 17, 1973 for the scheduled surveillance inspection in accordance with the documented program requirements set forth in NRC letter to the licensee dated March 2, 1973 for return of the facility to service following the chloride intrusion incident. During the inspection of reactor vessel internals, cracks were observed in the feedwater spargers which had been installed when the original spargers were found severely cracked following the chloride intrusion incident. These second spargers had operated in the reactor for six weeks.

The corrective action following the second failure was to install spargers of a fundamentally different support design which was intended to reduce the probability of fatigue failure. Each of the modified spargers (i.e., the No. 3 design) was supported by a bracket welded to both the reactor vessel wall and to the sparger header adjacent to the feedwater nozzle; midway between this bracket and end of the sparger an amplitude limiting damper was attached; the rest of the design was not changed.

The licensee submitted reports describing the investigation of the failure and proposed corrective action. The staff reviewed the reports including the proposed changes and concluded that the reactor could be returned to operation with Design No. 3 feedwater spargers provided that certain minimum instrumentation requirements were maintained. This is documented in the staff Safety Evaluation enclosed with NRC letter dated July 12, 1973 authorizing resumption of reactor operations. However, return to power operations was delayed because of the probability of inverted poison tubes in the control blades which had been installed in the reactor during the recovery action phase of the chloride intrusion incident. This problem with control blades is discussed in Section 1.3.2(3) of this report.

Following the return to operation on July 28, 1973 the licensee continued the investigation program into the feedwater sparger failure mechanism by use of the installed instrumentation of strain gages, differential pressure taps, and temperature sensors. Vibration and pressure data were obtained at 25%, 50% and 75% power levels wth no significant deviations from normal. However, significant vibration was indicated at 90% power and above. The licensee informed the staff that they would operate the reactor at the 80% power level where vibrations were virtually non-existent and go above that power level only to collect additional data. The staff confirmed the operation at a reduced power level in a letter to the licensee dated September 4, 1973.

A GE study indicated that the failures of design #1 and #2 were caused by the effects of high cycle fatigue due to thermal transients and flow-induced resonance coupled with a loss of preload. Thus, design #3 was

intended to reduce stress levels and to separate the structural frequencies from flow frequencies by means of system stiffening via support modification and the use of rigid weld connections. Due to the occurrence of excessive vibration in design #3 when the plant power level exceeded 85%, GE conducted a full scale sparger model test, which consisted of sparger resonance frequency finding tests and flow tests. It was found that the sparger has natural frequencies exceeding 100 Hz, and that flow induced instability occurred at the range of 20-30 Hz. The cause of vibration was identified as the excitation of the by-pass flow through the clearance at the slip-fit between the thermal sleeve and vessel nozzle. Effects of clearance size on the pressure differentials, flow rates, and vibration amplitudes were also investigated. GE indicated that a forthcoming design #4 would take the test results into consideration by eliminating the by-pass flow via clearance restriction.

Subsequently, during the refueling outage of September-October 1974, the licensee removed the spargers of design #3 which were again found to be cracked. The corrective action of replacing them with design #4 was reviewed and was found acceptable. The final resolution can be achieved only through demonstration of satisfactory performance under operating conditions and subsequent confirmation of no loss of integrity in the spargers by an in-vessel inspection. That inspection performed during the 1975 fall refueling outage led to further improvements, design number 5, and finally design number 6 (Ref. 9) installed during the late 1980 refueling outage. Visual inspection during the 1982 and 1984 refueling outages confirm No. 6 sparger integrity.

(3) Inverted Poison Tubes - Millstone Unit 1 was shutdown on July 16, 1973 after receiving word from GE of possible manufacturing defects in the control rod blades for Millstone-1 and other BWRs. At the time of the shutdown, the Unit was in a startup phase of operation following replacement of the failed design #2 feedwater spargers. The manufacturing defect in the control blades was that the tubes containing boron carbide poison may have been installed upside down in some blades which could result in movement of the boron carbide within the tubes and a decrease in shutdown effectiveness of the tip of the control blade. The affected control blades were newly installed during the repair phase of the chloride incident to replace control blades which showed evidence of chloride-induced stress corrosion cracking. The staff reviewed the analyses provided by the licensee and the program by which the licensee proposed to monitor the continued reactivity effectiveness of the reactor control rod blade system and subsequently authorized the licensee to return Millstone Unit 1 to operation. This action with accompanying Safety Evaluation was issued by letter dated July 27, 1973. To offset the possible effect of boron carbide redistribution on the control rod drop accident, the calculated reactivity worth of control blades was increased by 0.2 percent $\Delta k/k$ in establishing compliance with the Technical Specifications and the licensee had to conduct frequent shutdown margin checks in accordance with technical specification change No. 16.

The final resolution of this problem on operations was effected during the refueling outage of October 1974. All one hundred forty-five (145) of the control rod blades were eddy-current tested to identify those poison tubes

that were fabricated into the control blades in an inverted position. Following the test, nineteen (19) control blades were rejected based on the GE acceptance/rejection criteria and were replaced with new control blades. Seven hundred seventy-six (776) inverted poison tubes were found in sixty-two (62) control rods. Replacement of the nineteen (19) control rods left ninety-eight (98) inverted poison tubes in the core. Replacement of an additional control blade for another reason left ninety-six (96) inverted poison tubes in the core. The loss in shutdown margin due to the sum of the calculated reactivity losses of each of the ninety-six (96) inverted poison tubes was calculated to be 0.08 percent $\Delta k/k$.

To offset the effect caused by using inverted poison tubes, an equivalent amount of reactivity was added to the shutdown margin of 0.25 percent $\Delta k/k$ to require an increased shutdown margin of 0.33 percent $\Delta k/k$. The corresponding change to the Technical Specifications including the supporting Safety Evaluation was effected by License Amendment No. 4 issued on November 1, 1974. This action resolved the problem at the Millstone Unit 1 reactor.

(4) Hydraulic Snubbers - During the summer of 1973 inspection at Millstone and another facility revealed a large number of inoperable hydraulic shock suppressors (snubbers) made by the Bergen Patterson Pipesupport Corporation. At Millstone Unit 1 on June 29, 1973 the licensee found that 20 of the 45 installed snubbers were inoperable due to loss of hydraulic fluid. As a result of these findings, the Commission required each operating reactor licensee to immediately inspect all Bergen Patterson snubbers utilized on safety systems and to reinspect them 45 to 90 days later. Snubbers by other manufacturers were also inspected but on a lower priority basis.

Follow-up inspections of the snubbers were conducted at Millstone Unit 1 on a monthly basis for September 1973 to March 1974. One or more units were found to be inoperable at each inspection. Subsequent inspections within the required 90 day intervals continued to show at least one unit to be inoperable until the Fall 1974 refueling outage at which time new filler plugs, O-rings and seals were installed in all hydraulic snubbers.

The resolution of this generic problem has been accomplished via Technical Specifications. An inspection program has been specified with the inspection frequency based on the observed snubber failures. The longest inspection interval after a record of no failures is 18 months. Where snubbers contain material which has not been demonstrated to be compatible with the operating environment, inspection would be required every 31 days until compatibility is established. Technical Specifications for Millstone Unit 1 which implement the snubber inspection program were issued as Amendment No. 10 together with Safety Evaluation Report dated August 25, 1975.

(5) Feedwater Nozzle Internal Cladding Defects - During the refueling and maintenance shutdown which was completed with startup on November 2, 1974, inspection of the reactor vessel interior revealed cracking of the cladding in the vicinity of the feedwater nozzles. A total of 20 cracks were found. The licensee stated that none of the cracks were found to penetrate base metal. All cracks were removed by grinding. Subsequently, after reactor vessel flooding and drain-down, three areas of oxidation

(i.e., rust) were observed indicating exposure of base metal. This exposure resulted from the grinding.

By letter dated October 21, 1974 the licensee submitted a "Special Report, Millstone Nuclear Power Station Unit 1, Feedwater Nozzle Cladding Defects." This report described the clad cracking, the probable causes, the corrective action taken, the planned surveillance and included a safety analysis. The clad cracking was attributed to thermal fatigue resulting from excessive feedwater leakage bypassing the thermal sleeve. The licensee expected resolution of this problem with installation of design #4 spargers.

Following grinding out of the cladding cracks, the reactor vessel was flooded for the refueling operations. Subsequently, the vessel was drained-down to install additional instrumentation (i.e., temperature sensors) on the feedwater spargers; at that time rust spots were noted at three of the ground-out areas. The licensee described the base metal penetration and its significance in "Addendum 1, Millstone Nuclear Power Station Unit 1, Special Report, Feedwater Nozzle Cladding Defects," dated October 29, 1974.

The licensee concluded that there was no unreviewed safety question related to the clad cracks or with the indications of base metal exposure. The staff found no basis for disagreement with this conclusion.

(6) Gas Turbine Generator Performance - The onsite emergency power is supplied to the essential busses by a diesel generator and a gas-turbine-generator. The gas-turbine-generator is a commercially available unit consisting of a modified jet engine, a 12 MW turbine-generator and exciter, and a central control and switchgear package. This unit had been used to provide utility peaking power as well as to serve as an onsite emergency power source during the early period of MP-1 operation. It is no longer used to meet peak load demand. To satisfy the requirements for an onsite emergency power source, the unit was required to reliably start and be capable of accepting loads in 48 seconds. Because this was the only nuclear power plant using a gas-turbine-generator as an onsite emergency power source the staff reviewed with particular interest the statistical performance of this unit as provided by the licensee. The application for full term license indicated that the mean gas turbine generator reliability (89.5%) was less than the staff's minimum requirement for the reliability of onsite energy sources (99% at a 50% confidence level).

The applicant has maintained records of the operation, testing, maintenance, modification, and repair of this unique feature of his design since 1970. The staff reviewed this information and the results of the evaluation for that period indicated that the failure rate (at a 99% confidence level) was less than 1.1 per 100 attempts to start with expectations for further reductions in the start failure rate as deficiencies are identified and corrected.

The method which was used in this analysis was to identify the operating and test events which had resulted in a failure to achieve the desired results (start, load, etc.) and to list this data on a yearly basis as % failure/try. Least squares fits to this data were made and the "goodness" of fit of the resultant curves was determined by the Chi-squared test.

Additional results indicate that the present failure rate for fast starts is now less than 1% and decreasing (at a confidence level greater than 99%). We have concluded that the reliability of the gas turbine generator is at least equal to that which is required of diesel generators for the present MP-1 nuclear application and the gas turbine is, therefore, acceptable. (Additional information - Ref. 5).

(7) Other Operating Problems - The remaining operating problems cover a spectrum of events; however, all were of less importance in the early plant operating history than the events described above. They include failure of main steam line isolation valve to close, protective instrumentation set point drift, failure of select rod insert to function, isolation condenser failure to operate, steam line movement with a turbine trip, low emergency service water pump pressure, failure of safety/relief valve to reseat after operation, reactor recirculation pump motor failure, malfunction of main turbine pressure control system, safety valve leaking, plant shutdowns due to excessive primary coolant system leakage, failure of pressure taps in main steam line flow detector instrumentation, dislocation of baffles in the torus from stresses associated with relief valve operations, and occasions when radioactive gaseous effluents released from the facility affected offsite locations. More recent operating problems are identified in IPSAR (Ref. 5) and Millstone Nuclear Power Station Annual Reports for the years 1973 through 1983 (Ref. 11).

These events highlight the operation of Millstone Unit 1 reactor to date. All of these problems have been or are being resolved in a satisfactory manner. On this basis we conclude that the Millstone Unit 1 has been operated in a safe manner and its continued operation is expected to be satisfactory.

1.4 Plant Modifications

As a result of operating experience at this and other operating BWRs, several modifications have been made or are in the process of being made. The most important are identified below:

(1) Provisions for Protection Against High Energy Pipeline Break Outside Containment:

Evaluation of a high energy pipe break analysis led to the encapsulation of the feedwater regulating station and a portion of the upstream and downstream piping.

(2) Implementation of As Low As Reasonably Achievable (ALARA):

An extensive addition was made to the radwaste systems to meet the ALARA criteria for radioactive releases. This is discussed in the staff Environmental Evaluation dated December 17, 1984 (Ref. 10).

(3) Feedwater Spargers:

All four spargers were replaced three times, as described in the preceding Section 1.3.2(2) of this report, prior to 1975 (and twice since 1975).

(4) Torus Baffles:

All of the torus baffles were removed during the Fall 1974 refueling outage.

(5) Containment Vacuum Breakers:

Additional instrumentation has been installed to improve the closure monitoring capability of the drywell to torus vacuum breakers.

(6) Reload Fuel:

One 8 x 8 segmented test rod fuel assembly was inserted in the core during the fall 1974 refueling. A normal one-quarter core of 8 x 8 fuel assemblies was loaded during the Fall 1975 refueling outage. All reloads since have utilized 8 x 8 fuel assemblies.

Other plant modifications during this period include changing the offsite power connections to provide a connection for Unit 2, addition of provisions for maintaining a "keep-full" condition in the core spray and low pressure coolant injection system pipelines, and installation of dry-test equipment for surveillance of the operability of the gas turbine generator.

The staff concluded that these plant modifications were acceptable based on reviews which were performed in accordance with 10 CFR Part 50 §50.59.

The licensee has reported (Ref. 14) that the total capital costs of backfit plant modifications made since the plant started operation is nearly double the initial cost of the Millstone-1 plant. These plant modifications are presented below under the categories identified in the report.

Category: Three Mile Island Related Backfits

Project Description

Supplement 1, NUREG-0737 Control Room Redesign, Plant Safety Parameter Display, Reg. Guide 1.97 and Emergency Support Facilities (Ref. 15).

Accident Monitoring Instrumentation
Post Accident Sampling
Control Room Habitability (continuing evaluation)
Emergency Operations Facility
Public Alerting
Radiation Monitoring

Category: NRC Imposed Backfits (non TMI)

Bulletin 79-02, 79-14 (Ref. 16 and 17)
Torus Modifications
Environmental Enclosures (EEQ) (Ref. 19)
Masonry Walls (Bulletin 80-11) (Ref. 18)
Security System Upgrade
Scram Discharge Volume Mods

Iso - Condenser Upgrade
Appendix R Modifications
Hydrogen Control Modifications
Misc. Seismic Mods
SEP Modifications (Various)
Fire Detection Equipment
Misc. Fire Protection
Recirculation Pump Trip

Category: Utility Initiated Backfits

FW Clad/Sparger
Core Spray Piping
Retube Condenser
FW Checkvalve Replacement
345 KV Breakers
FW Heater Repair

Category: Hybrid Backfits

Fuel Storage Racks
Off Gas Facilities
Radwaste Facilities
Process Computer Replacement
Training Facility
Process Computer Upgrade
Radwaste Storage
Plant Specific Simulator

2 SITE CHARACTERISTICS

2.1 Geography and Demography

Millstone Unit 1 is located in the town of Waterford, New London County, Connecticut, on the north shore of Long Island Sound. The 202-ha (500-acre) site occupies the tip of Millstone Point between Niantic Bay on the west and Jordan Cove on the east and is situated 5.1 km (3.2 mi) west-southwest of New London and 64 km (40 mi) southeast of Hartford. The Millstone Unit 1 containment structure is located immediately south of Millstone Units 2 and 3. The site characteristics described in the Millstone 3 SER, NUREG-1031 (Ref. 4) are generally applicable to Millstone 1.

2.1.1 Population Distribution

The town of Waterford, in which Millstone Unit 1 is located, had a 1980 total population of 17,843 (1980 census). New London is the closest population center to Millstone Unit 1 (i.e., a center with more than 25,000 residents, as defined by 10 CFR 100) with a 1980 population of 28,842. The distance between Millstone Unit 1 and New London is about 5.7 km (3.5 mi), which is beyond the minimum distance requirement of 5.1 km (3.2 mi) as set by 10 CFR 100. As noted elsewhere, Millstone 1 is one of three nuclear power plants located at the Millstone Nuclear Power Station. A more informative description of the population distribution in the vicinity of the Nuclear Power Station is presented in NUREG-1031 (Ref. 4).

SEP Topic II-1.B concluded that the site conforms to the current licensing criteria pertaining to population distribution.

2.1.2 Exclusion Area Authority and Control

The licensee has defined the exclusion area as equivalent to the area within the site boundary that is identified in Figure 2.1. The site, which is entirely within the exclusion area, is owned by a number of participants in ownership. Under contract to the owners, Northeast Nuclear Energy Company (NNECO), the operating company and lead licensee for all three units at the Millstone site, has the controlling authority for the exclusion area.

The site is traversed from east to west by a ConRail/Amtrak railroad right-of-way. The main line tracks are about 0.83 km (0.52 mi) from the Millstone Unit 1 containment structure. Control of this area is provided by written agreement between the applicant and ConRail/Amtrak. A portion of the exclusion area is leased to Waterford for public recreation and is used primarily for soccer and baseball games. A portion of the exclusion area is located off shore. Control of this area is provided by written agreement between the licensee and the U.S. Coast Guard.

By virtue of ownership, as well as arrangements made with the U.S. Coast Guard and the ConRail/Amtrak Company, the staff concludes that the licensee has the

authority to determine all activities within the exclusion area, as required by 10 CFR 100 (SEP Topic II-1.A).

2.2 Nearby Industrial, Transportation, and Military Facilities

Millstone Unit 3 (NUREG-1031 - Ref. 4) was reviewed in accordance with SRP Sections 2.2.1, 2.2.2, 2.2.3, 3.5.1.5, and 3.5.1.6 (NUREG-0800). The results are equally applicable to Millstone Unit 1.

2.2.1 Transportation Routes

The nearest major highway that may be used for frequent transportation of hazardous materials is I-95, which is located 6.4 km (4 mi) from the Millstone site. Other principal highways that pass near the site include U.S. Route 1, which is located 4.8 km (3 mi) from the site, and State Highway 156, located 2.4 km (1.5 mi) from the site. The separation distances of transportation routes from the plant preclude any significant hazards to the plant from either toxic or explosive materials.

As noted previously, the ConRail/Amtrak railroad traverses the site from east to west. The smallest distance between the mainline tracks and the Millstone Unit 1 containment structure is 0.83 km (0.52 mi). The licensee has ascertained the hazardous materials and their shipment frequencies for this rail line based on the basis of data obtained from ConRail for the period January 1978 through June 1979 and January 1982 through December 1982. On the basis of the survey data provided, the licensee concluded that the only hazardous material requiring a hazard assessment is liquefied petroleum (propane) gas. Hence, the licensee has analyzed the direct effects of an instant ignition and explosion, as well as one caused by delayed ignition. The staff has reviewed the licensee's analysis and concludes on the basis of the separation distances, size, frequency, and types of cargo shipped on this railroad, that the risk to this plant is below design requirement.

There are no major pipelines within 8 km (5 mi) of the site. The nearest natural gas distribution line is approximately 4.7 km (2.9 mi) from the site, located along Rope Ferry Road in Waterford. This is a 6-in. plastic pipeline carrying natural gas at 30 psi. There is a possibility of extending the gas distribution line along Rope Ferry Road to the intersection of Great Neck Road. This would bring the pipeline to 3.9 km (2.4 mi) from the Millstone site. The staff has evaluated this pipeline and concluded that the present and proposed locations do not represent a hazard to the plant. The licensee will keep the staff advised of any future extensions of this pipeline or introduction of new lines within 8 km (5 mi) of the site.

Ships that pass by the site in the shipping channels of Long Island Sound are of two types: general cargo freighters, which usually are partially unloaded with drafts of 20 to 25 ft, and deep draft tankers with drafts of 35 to 38 ft. Both of these classes of ships must remain at least 3.2 km (2 mi) off shore to avoid running aground on Bartlett Reef. On the average of once a month, a barge carrying 15,000 barrels of sulfuric acid is towed past the site outside of Bartlett Reef. No oil barges pass to the shore side of Bartlett Reef. The staff has concluded that the type of materials shipped and the distances maintained between the carriers and the site do not represent a hazard to the plant.

The air lane nearest to the site is V58, which is approximately 6.4 km (4 mi) northeast of the site. Other air lanes in the vicinity include V16, 9.6 km (6 mi) northwest, and V308, 12.9 km (8 mi) east. The nearest high-altitude jet route, J121-581, passes 14.5 km (9 mi) southeast of the site.

On the basis of these transportation route separation distances from Millstone Unit 1, the nature of the materials transported, and the specific evaluation of the rail line transient cargo passing through the station exclusion area the staff concludes that traffic along these transportation routes will not adversely affect the safe operation of Millstone Unit 1.

2.2.2 Nearby Facilities

The area in the vicinity of the Millstone site includes three major industrial facilities (Dow Chemical Corporation, Pfizer Corporation, and Electric Boat Division of General Dynamics Corporation), two transportation facilities (Groton/New London Airport and New London Airport), and four military installations (U.S. Navy Submarine Base, U.S. Coast Guard Academy, Camp O'Neil, and Stone's Ranch Military Reservation).

The Dow Chemical Corporation of Allen Point, Ledyard, Connecticut, is located on the east bank of the Thames River approximately 16.1 km (10 mi) north-northeast of the site. Dow Chemical is a producer of synthetic compounds and employs approximately 160 persons. Dow Chemical produces inorganic compounds, such as Styron, Styrofoam, and a base product of latex paints. All materials are moved to and from the company by truck and/or railroad.

The Pfizer Corporation of Eastern Point Road, Groton, Connecticut, is located on the east bank of the Thames River, approximately 8 km (5 mi) east-northeast of the site. The Pfizer Corporation is a producer of pharmaceutical and medical supplies, employing approximately 3,000 persons. Pfizer Corporation produces organic compounds and pharmaceutical materials, such as citric acid, antibiotics, synthetic medicines, vitamins, and caffeine. All materials are moved to and from the Pfizer Corporation by truck and/or railroad.

The Electric Boat Division of General Dynamics of Eastern Point Road, Groton, Connecticut, is located 8.9 km (5.5 mi) east northeast of the site. The Electric Boat Division employs approximately 20,000 persons, and is a producer of submarines and oceanographic equipment for the commercial industry and the U.S. Navy. The nature of products produced at Electric Boat requires that they handle substantial amounts of nuclear materials that are licensed under the Naval Reactors Division. All material is moved by truck, railroad, and/or barge to and from the company with the exception of completed ships that are launched.

The New London Airport located approximately 6.4 km (4 mi) north-northeast of the site is limited to handling small, private aircraft. Seven persons are employed at the airport on a full-time basis. Approximately 12 additional part-time persons may be employed at this airport, primarily during the summer months and on weekends. Scheduled commercial aircraft do not use this airport. The maximum runway length is 2,000 ft. The largest aircraft known to use this airport on a regular basis is a Piper Aztec, with a gross weight of 5,200 lb.

The Groton/New London Airport, located 11.3 km (7 mi) east-northeast of the site, handles regularly scheduled commercial passenger flights. Two hundred persons are employed at Groton/New London Airport on a full-time basis. The airport has three runways. These range from 3,000 to 5,000 ft. The largest commercial aircraft to use this airport on a regular basis is a Fokker-F27, with a gross weight of 45,200 lb, plus a fuel load of 11,000 lb.

The U.S. Navy Submarine Base, Groton, Connecticut, is located on the east bank of the Thames River, 11.3 km (7 mi) northeast of the site. There are about 14,000 military and civilian personnel stationed on or near this base. The U.S. Navy Submarine Base provides logistics as well as training and operation of the base and its ships (nuclear and non-nuclear). All materials are moved by truck, railroad, barge, and/or ship to and from this facility.

The U.S. Coast Guard Academy, New London, Connecticut, is located on the west bank of the Thames River, approximately 9.7 km (6 mi) northeast of the site. Over 900 cadets attend the academy. Approximately 500 military and 150 civilian personnel are employed here. All materials used at the academy are nonhazardous and are moved by truck.

Camp O'Neill, located approximately 3.2 km (2 mi) northwest of the site, is a training headquarters for the Connecticut Army National Guard. It is owned and operated by the Military Department of the State of Connecticut. On a full-time basis, it employs 24 persons (military and civilian) including the headquarters personnel for the Connecticut Military Academy, Post Operations personnel, and the 745th Signal Company. On a part-time basis, during various weekends, Camp O'Neill is occupied by varying numbers of troop units for administrative training, billeting, and supply functions for the Connecticut Army National Guard.

In addition to Camp O'Neill, the Military Department of the State of Connecticut also maintains a field training facility known as Stone's Ranch Military Reservation, located 11.3 km (7 mi) northwest of the site. Nineteen persons are employed here full time for two regional motor vehicle and equipment maintenance shops. It is also occupied on a part-time basis by varying numbers of troop units for periods of field training for the Connecticut Army National Guard. No significant ordnance is stored or used at this facility.

On the basis of the separation distances and the type of activities conducted at the above facilities, the staff concludes that these activities do not represent a hazard to the safe operation of the plant.

Based on the criteria given in 10 CFR 50, Appendix A, General Design Criterion (GDC) 4, and in SRP Section 2.2.3, the staff concludes that the plant is adequately protected and can be operated with an acceptable degree of safety considering activities at nearby transportation, industrial, and military facilities (SEP Topic II-1.C).

2.3 Meteorology

Evaluation of regional and local climatological information, including extremes of climate and severe weather occurrences that may affect the design and siting of a nuclear plant, assures plant design and operation within the requirements of Commission regulations (SEP Topic II-2.A). Information concerning atmospheric diffusion characteristics of a nuclear power plant site is required to determine

that radioactive effluents from postulated accidental releases, as well as routine operational releases, are within Commission guidelines (Ref. 4).

2.3.1 Regional Climatology

Cold air moving southeastward into the area of the Millstone site is modified by Long Island south of the plant. The Atlantic Ocean to the east also has a moderating effect on climate. Continental air masses dominate the region in winter and alternate with maritime tropical air masses in summer. The mean annual temperature in the area is about 52°F, ranging from about 30°F in January to about 74°F in July. Annual precipitation in the area is about 39 in.

The site lies near a principal track of storms that move northeast along the Atlantic coast and result in a variety of severe weather phenomena that affect the site area. Thunderstorms can be expected on about 22 days each year. About 60% of these thunderstorms occur between the months of June and August. Considering the frequency of thunderstorms, the applicant has estimated the number of lightning strikes to the ground per year at the Millstone site to be about two per year. Hail often accompanies severe thunderstorms.

During the period 1955 through 1967, an average 1.4 occurrences per year of hail with diameters 19 mm (3/4 in.) or greater were reported in the one-degree latitude-longitude square containing the site.

Tornados are uncommon in the region. For the two-degree latitude-longitude "square" (14,125 mi^2) containing the site, an average of about two tornados per year were reported for the period 1954 through 1981. On the basis of calculated expected mean tornado path area of 0.18 mi^2, the computed probability of occurrence for a tornado at the plant site is about 3.2×10^{-5} per year. The licensee has computed a higher probability of occurrence ($\sim 5.5 \times 10^{-4}$ per year) based on a larger tornado path area (2.82 mi^2) and a smaller annual frequency (0.7 tornado per year). The characteristics of the design-basis tornado considered by the licensee for the plant are based on the recommendations of Regulatory Guide (RG) 1.76, "Design Basis Tornado for Nuclear Power Plants," for this region of the country. The applicant's design-basis tornado has a 360-mph rotational velocity, with a translational velocity of 60 mph, a total pressure drop of 3 psi, and a rate of pressure drop of 2 psi/sec.

Hurricanes occasionally track northward along the Atlantic coast. In the period 1871 through 1981, about 15 tropical depressions, tropical storms, and hurricanes have passed within about 50 mi of the plant. Wind speeds associated with these storm systems are usually highest along the coast, with wind speeds diminishing inland.

High winds speed occurrences in the area are associated with severe thunderstorms, extratropical cyclones, tropical storms, and hurricanes. The highest "fastest mile" wind speed reported at Bridgeport, Connecticut, was 67 mph in January 1964.

Heavy snowfall is not uncommon in the region, and roof loads may accumulate as a result of wintertime precipitation mixture of snow, ice, and rain. The maximum monthly snowfall and the maximum snowfall in a 24-hour period observed in Bridgeport, Connecticut, were 74 in. and 16.7 in., respectively, during the month of February. Ice storms, which may disrupt offsite power, are relatively

infrequent. The licensee estimates that ice or freezing rain may occur about one time per year in the Millstone region, with a glaze accumulation of 0.25 in. Amounts greater than 0.5 in. can be expected about every 2 years. The applicant has estimated the weight on the ground of the 100-year return period snowpack to be 31 psf.

Occasional large-scale episodes of atmospheric stagnation occur in the region. From 1960 through 1970, 10 atmospheric high pollution potential periods were identified in the area.

2.3.2 Local Meteorology

Climatological data from Bridgeport, Connecticut, and available onsite data have been used to assess meteorological characteristics of the plant site.

Extreme temperatures of -10°F to 103°F have been measured during 1901 through 1981 at Bridgeport, Connecticut. Onsite temperature extremes have ranged from -4.9°F to 88.7°F during the period of January 1974 through December 1981.

Precipitation is well distributed throughout the year, ranging from about 2.6 in. in June to almost 4 in. in November. The maximum amount of precipitation in a 24-hour period at Bridgeport, Connecticut, was 6.89 in.

Long Island Sound, adjacent to the plant site, is used as the plant ultimate heat sink and is acceptable in accordance with the requirements of RG 1.27.

The wind distribution in the area, as determined on site, has an occurrence of 42% from a northwesterly quadrant direction with about 21% from the southwesterly direction. Remaining winds are distributed fairly uniformly in the remaining directions.

2.3.3 Onsite Meteorological Measurements Program

Onsite meteorological measurements are made on a 450-ft tower situated south-southeast of the plant located less than 1/4 mi away from the main plant structure in proximity to the Long Island Sound shore. Measurements of wind speed, wind direction, vertical temperature difference, ambient temperature, and dew point temperature are all made on the tower. Solar radiation measurements are made near ground level at the tower base.

The original onsite meteorological measurements program at Millstone began in 1965 and has continued in support of Units 1 and 2. The program was upgraded in 1973 to conform to RG 1.23.

The data being collected are recorded on strip chart recorders in the instrument shed near the tower, as well as in the control room. In addition, the information is recorded on magnetic tape for use on the plant microcomputers and the larger corporate computer systems.

Onsite data collected from January 1981 through December 1982 had a joint data recovery rate of over 90% for wind speed and wind direction, measured at the 10-m level, and temperature difference between 10 and 43 m. These data were used to evaluate both short- and long-term gaseous dispersion as described below.

Also, the meteorological data will be available to the site and corporate emergency operations facilities for use in the dose calculation model following an accidental release at the plant. The data will also be available to the technical support center.

The staff has reviewed the onsite meteorological measurements system in accordance with SRP Section 2.3.3 and concludes that the current meteorological measurements program has provided data to represent onsite meteorological conditions as required in 10 CFR 100.10 and 10 CFR 50, Appendix I. The staff concludes that the historical site data provide a reasonable basis for making conservative estimates of atmospheric dispersion conditions for estimating consequences of design-basis-accident and routine releases from the plant.

2.3.4 Accident Diffusion Estimates

By letter dated May 19, 1981, the licensee submitted an analysis of the atmospheric transport and diffusion characteristics for the Millstone site.

For the purpose of this evaluation, (SEP Topic II-2.C) a comparison was made between the values submitted by the licensee and values determined independently by the staff; the licensee utilized five years of data (1975-1979) and the staff used two years of data (1974-1975). The licensee computed the concentrations for each year separately, then selected the highest value that occurred in any year; the staff combined the two years of data and computed the values accordingly. The wind speed and wind direction were measured at the 10 m (33 ft) and 136 m (446 ft) levels; atmospheric stability was defined by the licensee and the staff using the vertical temperature gradient between the 10 m and 43 m (142 ft) levels for ground level releases. For the elevated releases, the licensee determined the horizontal stability by computing the wind direction variance at the 136 m (446 ft) level and the vertical stability by the vertical temperature gradient between the 10 m and 136 m levels; the staff determined the horizontal and vertical stabilities by the vertical temperature gradient between the 10 m and 114 m (374 ft) levels. The calculational methodology of the licensee produced generally smaller values than those calculated by the staff even though they used five years of data compared to two years. The staff values are the more conservative and are thought to be more in agreement with the guidance presented by Regulatory Guide 1.145. Therefore, we have determined that the staff values are appropriate for use in accident dose calculations.

The following relative concentration values for assumed ground-level and elevated releases have been determined at distances corresponding to the exclusion area boundary distances in each sector (EAB) and the outer boundary of the low population zone (LPZ) in an onshore direction; the building wake correction factor for the off-gas building of 82 m was used in the ground level release calculations and topographic variations were considered for the elevated release calculations.

GROUND LEVEL RELEASE

Time Period	Distance & Direction	X/Q (sec/m^3)
0-2 hours	EAB (566 m) NE	6.1×10^{-4}
0-8 hours	LPZ (3860 m) SSW/ENE	1.9×10^{-5}
8-24 hours	LPZ (3860 m) SSW/ENE	1.3×10^{-5}
1-4 days	LPZ (3860 m) SSW/ENE	5.5×10^{-6}
4-30 days	LPZ (3860 m) SSW/ENE	1.7×10^{-6}

ELEVATED RELEASE

Time Period	Distance & Direction	X/Q (sec/m³)
0-2 hours fumigation	EAB (496 m) NE	9.2×10^{-5}
0-4 hours fumigation	LPZ (3860 m) N	1.8×10^{-5}
4-8 hours	LPZ (3860 m) N	1.3×10^{-6}
8-24 hours	LPZ (3860 m) N	8.5×10^{-7}
1-4 days	LPZ (3860 m) N	3.6×10^{-7}
4-30 days	LPZ (3860 m) SE/NE	1.1×10^{-7}

The staff concludes that the X/Q values presented are appropriate for estimating exposures from postulated accidents and should be used in all accident calculations.

2.4 Hydrologic Engineering

The staff has reviewed the hydrologic engineering aspects of the licensee's design, design criteria, and design bases of safety-related facilities at the Millstone Unit 1 station. The acceptance criteria include the GDC, the reactor site criteria (10 CFR 100), and standards for protection against radiation (10 CFR 20, Appendix B, Table II). Guidelines for implementation of the requirements of the acceptance criteria are provided in RGs, American National Standards Institute (ANSI) standards, and branch technical positions (BTPs) identified in SRP Sections 2.4.1 through 2.4.14. Conformance to the acceptance criteria provides the bases for concluding that the site and facilities meet the requirements of 10 CFR 20, 50, and 100 with respect to hydrologic engineering.

2.4.1 Hydrologic Description (SEP Topic II-3.A)

The ground elevation at the site ranges from sea level to 40 ft above mean sea level (MSL). Mean high tide is about 1.3 MSL. Unit 1 plant grade is at el 14 ft MSL. Significant hydrologically related plant features include the intake structure and adjacent shore protective structures located at Niantic Bay. Surface drainage from the plant, yard, roofs, and catch basins flows into underground stormwater conduits or surface channels that discharge into Niantic Bay.

There are no perennial streams on or adjacent to the site. Precipitation falling on the site is conveyed to Long Island Sound by surface runoff and groundwater flow. Normal variations in the water levels of Long Island Sound and at the shores of the plant site are induced primarily by semidiurnal tides. Extreme variations in water levels are storm induced and result from tropical windstorms (hurricanes) and extratropical windstorms. During the past 45 years, six hurricanes have given rise to abnormally high stillwater levels ranging from 5 ft to approximately 10 ft MSL, not including waves.

Plant operation utilizes once-through cooling, extracting water from Niantic Bay and discharging it into an abandoned quarry that is connected to Long Island Sound.

There are no dams or other hydraulic control structures on the Niantic River (which flows into Niantic Bay) or any other drainageways in the area. Neither are there any stream flow gages on adjacent water sheds.

The primary source of flooding at the Millstone site is from hurricane surge flooding in Long Island Sound and the accompanying wind wave activity.

Natural drainage patterns on the point are into Niantic Bay and Long Island Sound, and a small area drains through the quarry. The land north and west of the point drains into Niantic Bay and Jordan Cove directly, with no major drainageways passing through the plant site.

Groundwater movement on Millstone Point is extremely slow, as evidenced by the fact that the average water level measured in the granite quarry was 17 ft below msl before the discharge canal connecting the quarry to Long Island Sound was built.

The hydrologic design bases used for plant construction are listed below:

- o The roof drains are designed to handle a 100 year recurrent rainfall - 3 inches in 1 hour; 7.10 inches in 24 hours.
- o The roofs of safety related buildings are designed for a live loading of 60 psf.
- o Exterior walls of safety related buildings are designed to protect against hydrostatic forces to elevation 19 ft msl through the use of emergency procedures to close flood gates.
- o The intake structure is designed for the forces resulting from wave runup to elevation 32.4 ft msl.
- o The design basis rainfall for the plant site storm sewers is 2.00 inches per hour for a 30-minute duration.
- o The design basis groundwater level is not known, however the licensee has stated that safety related structures are capable of withstanding hydrostatic and uplift pressures that would result from a water level to elevation 19.0 ft msl.
- o The emergency service water pumps are designed to operate at a minimum water level of -6.0 ft MSL.

The licensee has provided hydrologic descriptions of the site. The staff has reviewed the licensee's information in accordance with procedures in SRP Sections 2.4.1 and 2.4.2 and concludes that the general hydrologic descriptions of the site meet the applicable requirements of GDC 2 and 10 CFR 100.

2.4.2 Floods

2.4.2.1 Flood Potential

Flooding near the site has historically been caused by hurricanes. The licensee reported that the maximum historical flooding was the result of a hurricane on

September 21, 1938, which produced a flood level elevation of 9.7 ft MSL at New London, Connecticut.

The licensee considered several flooding sources in establishing the flooding design basis for the site. These events include stream flooding, precipitation induced flooding, flooding caused by seismically induced dam failure, ice flooding, tsunami-induced flooding, and surge and seiche flooding. The licensee states that the only sources of flooding that could affect Millstone Unit 1 are direct rainfall and storm surges and that the controlling event for flooding at the site is the result of a storm surge induced by the probable maximum hurricane (PMH). The staff concurs that the PMH and the local probable maximum precipitation (PMP) are the appropriate design-basis events for this site.

2.5 Geology and Seismology

2.5.1 Basic Geologic and Seismic Information

The geology and seismology of the site were reviewed in detail (1) before the construction permits and operating licenses were issued for Millstone Units 1 and 2, (2) for the systematic evaluation program (SEP) for Millstone Unit 1 SEP Topic II-4, and (3) before the construction permit was issued and the operating licensee review was performed for Millstone Unit 3. The reviews were performed by the staff of the U.S. Atomic Energy Commission (AEC), the predecessor to the U.S. Nuclear Regulatory Commission (NRC), and its geologic advisors, the U.S. Geological Survey (USGS), and its seismological advisors, the National Oceanic and Atmospheric Administration (NOAA). The findings of those reviews were published in the safety evaluation reports (SERs) relating to the construction permits and operating licenses for the Millstone Point Nuclear Power Station Units 1 and 2, SEP review topic II-4 safety evaluation for Millstone-1, and in the SER relating to the construction permit for Millstone Unit 3.

2.5.2 Regional Geology (SEP Topic II-4)

The Millstone site lies within the Seaboard Lowland section of the New England Physiographic Province (Fenneman 1938 and Thornbury 1965). The Seaboard Lowland is a maturely eroded and glaciated peneplain with elevations ranging from sea level to less than +200 feet msl.

The New England Physiographic Province is a northern extension of the Appalachian Mountains which has been modified by glaciation. Bedrock is generally overlain by a few feet to a few hundred feet of glacial deposits.

Based on review of the Pilgrim 2 and New England 1 and 2 and Millstone 3 sites, the staff concludes that the Millstone Unit 1 site is within the New England-Piedmont Tectonic Province, which is in accord with the tectonic province concept of King, Rodgers, Eardley and Hadley and Devine. The New England-Piedmont Province is comprised of Precambrian and Paleozoic basement and sedimentary rocks that have been extensively folded, faulted, metamorphosed, and intruded by igneous rocks during successive episodes of orogenic activity.

The New England-Piedmont Province consists of major northeast-southwest striking anticlinoria and synclinoria composed of metamorphic rocks and plutonic bodies. From the west in Vermont and western Massachusetts to the Atlantic

Coast these major folds are: the Green Mountain - Sutton Mountain anticlinorium, the Connecticut Valley - Gaspé, synclinorium, the Bronson Hill - Boundary Mountain anticlinorium, the Merrimack synclinorium, and the Coastal anticlinorium. The site lies near the southern end of the Merrimack synclinorium. The Merrimack Synclinorium is cut by the Honey Hill fault complex about 14 to 15 miles (22 to 24 kilometers) north of the site.

Although the staff accepts the larger tectonic province, the New England-Piedmont Province in New England can be further subdivided based on geology into the Southeastern New England Platform and the White Mountain Plutonic Series. The Southeastern New England Platform is separated from the New England-Piedmont Province in the site region by the Honey Hill-Lake Char thrust fault complexes. The boundary farther to the north and east is the Clinton-Newbury and Bloody Bluff thrust fault systems. It has been suggested (SEP Topic II-4B) that these generally northerly dipping thrust faults and associated rocks of high grade metamorphism represent a Paleozoic collision zone between a plate containing the Southwest New England platform and a plate containing the New England fold belt. The site lies on the southeastern New England Platform.

The southeastern New England Platform is composed of Precambrian granitic basement rocks, Silurian and Devonian volcanic and intrusive rocks, Cambro-Permian basins, an area of late Paleozoic intrusive and metamorphic rocks, and the zone of mid-Paleozoic, post-metamorphic thrust faulting represented in the site region by the Honey Hill-Lake Char fault zones. Except for the Honey Hill-Lake Char fault zones, the Southeast New England Platform has undergone relatively little structural deformation or metamorphic alteration since the Paleozoic (240 million years before present-mybp). Known faulting is related to basin development during the Cambrian-Permian (570 mybp to 240 mybp). These basins include the Narragansett, Boston, North Scituate, Woonsocket, and Norfolk areas.

The White Mountain Plutonic series is an elongate, north-northwest oriented group of alkaline intrusives that extend from northeastern Massachusetts through New Hampshire. They were emplaced from Permian to Cretaceous. As a result of reviews of the Indian Point 3, Seabrook, Montague, Pilgrim 2, and New England sites, the staff concluded that there was a spatial relationship between the zone defined by these intrusives, which represent the youngest significant deformation features in New England, and historic seismicity. The largest New England earthquakes occurred within this zone.

The section of southern Connecticut in which the site is located is dominated by a large recumbent, isoclinally folded syncline, the Hunts-Brook syncline, the axial trace of which lies west of the site beneath Niantic Bay (USGS, 1970 in SER Millstone 2). The axial trace of the syncline has a southerly trend but is sinuous due to later folding which produced secondary folds with east-west axial traces. The site is located on the south limb of one of these east-west folds. Numerous faults have been identified in the site region. These structures are described and evaluated in Section 2.5.6

2.5.3 Site Geology

The site is located on a bedrock controlled peninsula that juts out into Long Island Sound between Niantic Bay on the west and the mouth of Jordan Cove on the east. The topography in the site vicinity is attributable to Pleistocene

glaciation (2 mybp to 10,000 years bp). The site is located on the south flank of Durfy Hill, an elongated north-south oriented hill. Elevations slope from +50 feet mean sea level (msl) at the Penn Central railroad, about 1/2 mile (.8 kilometer) north of the site, to -50 msl about 1/2 mile (.8 kilometer) south of the site in Long Island Sound. Elevations at the site, and where Units 2 and 3 have been added north of Unit 1, range between +10 and +20 feet msl.

The site area is underlain by from approximately ten to fifty feet of soil over bedrock. The soil consists of fill, up to 20 feet of ablation till and up to 40 feet of lodgement till over bedrock. Bedrock is predominantly Monson gneiss, an early Paleozoic (pre-Silurian, more than 430 mybp) metamorphic rock. The gneiss is intruded by dikes, sills and veins of rocks similar to the Westerly granite, which was emplaced during and after the Pennsylvanian Era (younger than 320 mybp).

The crystalline bedrock is hard, sound and moderately jointed. Weathering occurs along the gneiss-granite contacts, joints, and foliation partings. All Category I structures are founded on bedrock, very compact lodgement till, or compacted structural backfill.

Sixty two minor faults were mapped in the Millstone, Unit 3 excavation. These faults were investigated extensively and found to be not capable within the intent of Appendix A to 10 CFR Part 100. The excavation for Unit 1 was not geologically mapped. It is likely that faults similar or equivalent to the ones mapped at Unit 3 are present in the rock beneath Unit 1. However, there is sufficient basis to conclude that these faults are not capable. The faults mapped in the excavation are discussed in Section 2.5.6 below.

2.5.4 Capability of Faults in the Site Region (SEP Topic II-4B)

Several major faults or fault systems have been recognized in the site region. Many of these have been identified and mapped during the NRC-sponsored New England Seismotectonic Research Program that has been underway for the last six years. The regional faults that are most significant to the Millstone site include: the Connecticut Valley border fault, the Honey Hill fault system, the New Shoreham fault, and mapped or postulated faults in the Narragansett Bay area.

The Connecticut Valley border fault forms the eastern boundary of the Connecticut Valley graben, or half graben. The border fault, and graben were formed as a result of continental rifting during early and middle Mesozoic (240 mybp to 190 mybp). There is no evidence that the fault has been active since that time. The border fault is about 30 miles (48 kilometers) north-northwest of the site.

The Honey Hill fault system is described as a zone of highly strained cataclastic rock trending from Chester, Connecticut to North Stonington, Conn., where it intersects the north striking Lake Char fault system (Lundgren, 1968 and Lundgren and Ebblin, 1972). It has been active during several tectonic regimes from Devonian through at least Late Permian (290 mybp to 240 mybp). During this time sense of movement along the fault system changed from strike slip to dip slip (thrust). The thrust faulting is believed to be the result of the collision between a plate containing the Southeast New England platform

and the plate containing the New England fold belt, during which the former was thrust under the latter.

Evidence of recent movement along the Honey Hill fault system was reported by Block and others (SEP Topic II-4). The evidence consisted of offset drill holes at highway rock cuts on Route 11 and Route 9, and along other artificial rock cuts. These features were evaluated by Northeast Utilities Service Company in response to NRC questions concerning the SEP review of the Connecticut Yankee site. As a result of that study it was concluded that the offsets were related to residual stress release caused by excavation of very large masses of mylonitic rock (SEP Topic II-4). This is not an uncommon phenomenon in quarries and other rock excavations in this region.

Geological mapping, LANDSAT imagery, and geophysical surveying during NRC-sponsored research efforts have identified other faults or postulated faults in the area around the Honey Hill fault system and the Moodus seismic area. The intersection of three major, apparently deep seated structures has been mapped in the area north of Moodus. These structures are the north-northwest striking Bonemill Brook fault, a large gravity anomaly that is apparently related to structure that controls the course of the Connecticut River between Long Island Sound and East Haddam, and the northeast trending Higgannum dike system. Whether this junction has anything to do with seismicity at Moodus has not been determined.

A fault east of, but probably part of the Bonemill Brook fault truncates southernmost splays of the Honey Hill fault system. However, northernmost splays of the Honey Hill cut the Bonemill Brook fault. The closest approach of the Honey Hill fault system is about 14 miles (22 kilometers) north of the site.

The New Shoreham fault was identified by McMaster (SEP Topic II-4) based on his interpretation of seismic reflection data. The fault strikes northwest and can be traced from about 42 miles (70 kilometers) out to sea to 6 miles (10 kilometers) west of Block Island. The mapped fault is about 7 miles (11 kilometers) southeast of the site at its closest approach.

Extensive investigations were conducted of the New Shoreham fault by the applicant during site studies for the New England Power Project, Units 1 and 2 and Millstone-3 Operating License Review. After reviewing the results of these investigations the staff concluded that the New Shoreham fault was not capable within the meaning of Appendix A to 10 CFR Part 100. The bases for that conclusion were: (1) sediment filled ancestral stream channels that crossed the fault were not offset. These channels were determined to be at least 43,800 years old, and more likely greater than 120,000 years old; (2) sediment that overlies the southern end of the fault is not offset. These deposits are estimated to be 20 million years old; and (3) the distribution of historic seismicity shows no indication that the New Shoreham fault is a zone of increased seismicity.

NRC-sponsored research in the Narragansett Bay area of eastern Rhode Island indicates that this area is one of a complex pattern of folding, thrust faulting and high-angle faulting. The youngest are the high-angle faults, which are interpreted to have last moved in Late Permian and during the Mesozoic Era. This area is more than 30 miles (48 kilometers) east of Millstone. However, a

northeast-southwest trending major fault extends from this area to about 15 miles (24 kilometers) east of the site. Topographic and aeromagnetic lineaments suggest that this fault continues northeastward, well into the Narragansett Basin. The fault, called the Watch Hill fault, separates two domains of slightly different structural trends. It is possible, though not demonstrated, that the Watch Hill fault could continue southwestward into Long Island Sound and thus could pass as close as 10 miles (16 kilometers) southeast of the site. There is no evidence that the fault is any younger than Mesozoic. The staff concluded that this fault if it exists, is associated with Triassic tectonic activity (205 mybp), and therefore not capable.

Closer to the site, the Millstone 3 SER (AEC, 1974) describes an unnamed, north-south trending inferred fault that is approximately 10 miles (16 kilometers) long as being present 10 1/2 miles (17 kilometers) northeast of the site. A projection of the inferred fault trace would bring it to about 7 miles (11 kilometers) east of the site. The staff concluded that this fault, if it exists, is associated with Triassic tectonic activity (190 mybp), and therefore not capable.

The staff reviewed the applicant's data, conducted numerous geological reconnaissances of the site and excavation, and contracted an independent consultant to review the fault dating techniques used by the applicant. Based on its review the staff concluded that the site faults were ancient, and therefore not capable according to the criteria set forth in Appendix A, 10 CFR Part 100. The staff concludes that the data that has become available since the original site review confirms the staff's conclusions made at that time, that there are no geologic hazards that would affect the safety of the Millstone Unit 1 site.

2.5.5 New Brunswick Earthquake Study (SER Millstone 3 OL Topic 2.5.1.4)

On January 9, 1982, a magnitude 5 3/4 earthquake occurred in south central New Brunswick, Canada, approximately 775 kilometers (485 miles) north of the Millstone site. The licensee has submitted reports prepared by Weston Geophysical (1983, 1984) to demonstrate that the Millstone site is situated a tectonic environment that is dissimilar to that of the epicentral area of the January 1982 earthquakes. These reports also present data to demonstrate a reasonable correlation of the New Brunswick seismicity to definable tectonic structure, as stated in Appendix A to 10 CFR Part 100. The New Burnswick tectonic structure is defined on the basis of surface geology, geophysical data, gravity modeling, and seismicity.

The staff's position on these submittals is that the applicant did not provide sufficient geologic and geophysical evidence to associate the January 1982 New Brunswick Earthquake with a specific existing structure. The applicant did not adequately demonstrate how the New Brunswick Tectonic Block which they proposed as the causative structure is uniquely structured to cause localization of seismicity in the region. However, the staff is of the opinion that there are compelling reasons to believe that a conjugate set of reverse faults, which are defined by the January 1982 seismicity, are the generators of the 1982 earthquake sequence. Furthermore, the conjugate faults may be associated with a larger still undefined tectonic structure within the Miramichi Anticlinorium. There is no assurance, however, that similar faults and tectonic structures do not exist in other areas of the eastern U.S.

Comparisons of the geologic and geophysical environment and the seismicity between the Millstone site and New Brunswick epicentral area were made by the licensee. The staff agrees that lithologic contrasts exist between the Millstone site area and the New Brunswick epicentral area. Also, the structural elements of the two areas are significantly different. The epicentral area is underlain by a Devonian granitic body, the North Pole pluton (Fyffe, 1982), which intrudes metamorphosed Cambro-Ordovician sedimentary, volcanic, and plutonic rocks of the Tetagouche Group. The Millstone site is underlain by early Paleozoic metamorphic rocks, the Monson gneiss, which as been intruded by Westerly granite of Pennsylvanian or Permian age.

Like most of the New England portion of the New England-Piedmont Tectonic Province, the New Brunswick region is characterized by northeasterly trending anticlinoria and synclinoria that were formed as a result of extensive deformation, primarily during the Acadian orogeny. The Bronson Hill anticlinorium and Merrimack synclinorium, which are southwesterly extensions of the regional structures that characterize New Brunswick, are truncated by the Honey Hill-Lake Char fault zone at approximately 24 kilometers (15 miles) north of the Millstone site. This fault zone is a low angle thrust fault boundary between the Avalonian rocks to the south and the units of the Merrimack sequence. Extensive Alleghenian deformation characterizes the Millstone site. Little Mesozoic deformation is evident in the New Brunswick epicentral region. However, considerable Mesozoic tectonics, such as the Connecticut Valley Triassic Basin containing thick Mesozoic clastic sediments and diabase intrusives, are present in the Millstone site region.

In conclusion there is no evidence of capable faulting in the Millstone site area. Petrographic and radiometric studies indicate that the latest movement on the faults in the site region occured during the Triassic-Jurassic rifting of the continent, approximately 142 mybp. Based on available geological and geophysical information, there is no evidence of capable faulting in the Millstone site region, and there no known tectonic structures that could be characterized as possible localizers of seismicity in the site vicinity.

2.5.6 Surface Faulting (SER Millstone 3 OL Topic 2.5.3)

Although none of the published geologic maps show faults in the vicinity of the plant site, sixty-two faults were found during the mapping of the rock excavation for Millstone Unit 3. Forty of the faults have apparent displacements of less than 1 foot, with the remaining faults having apparent displacements greater than 1 foot. Most of the faults trend northerly and dip at high angles either to the east of to the west. Eleven separate fault zones (T-1, T-2, T-3, 18, 471-1541, 1599, 1940, 2250, 2282-2295, 2339-2347, and 2380) were identified. The faults are evaluated and discussed in several reports (NNECO 1975, 1976, 1977, and 1982).

The licensee performed K/Ar age dating, petrographic analysis, x-ray diffraction studies, soils mapping, and detailed mapping of the fault zones, which indicated that the faults at Millstone are noncapable features. The petrographic analysis shows that the cataclasite in the faults has been silicified and hydrothermally altered, and that the fractures and cracks have been filled with chlorite. Prismatic quartz crystals, drusy quartz and the silicified cataclasite found in the fault zones would be fractured and/or granulated if any additional movement had occurred. The radiometric age dates on the fault gouge indicate

that the last activity along the faults occurred approximately 142 mybp. The petrographic and radiometric studies are reinforced by the published geologic history of the region.

The excavations for Millstone Unit 1 were not geologically mapped. It is likely that the larger throughgoing faults mapped at Unit 3 continue into the Unit 1 area. It is also likely that numerous minor faults similar to those mapped with limited extent within the Unit 3 excavation are present beneath Unit 1. Based on the study of the regional geology and the detailed work at Unit 3, the staff concludes that the faults beneath Unit 1 are also not capable.

Considering all the geologic data presented, the licensee concluded, and the staff concurs, that the faults at the Millstone site are not capable. The last activity along them occurred approzimately 142 mybp. This indicated that the faulting at the site is related to the Triassic-Jurassic rifting or older events as in the case of fault 1940. There is no evidence of capable faults within the 5-mile radius of the site.

2.5.7 Vibratory Ground Motion

The Millstone Unit 1 seismic design adequacy was reevaluated by NRC through the Systematic Evaluation Program (SEP). A major portion of this endeavor consisted of a study by Lawrence Livermore National Laboratory (LLNL) under contract to NRC, (NUREG/CR-1582) in which probabilistic seismic design spectra were developed for several nuclear plants in the Eastern U.S. (EUS) as well as deterministic spectra, specific to each plant involved in the SEP. In its review of the SEP (NUREG-0967) the staff (NRC) concluded that the calculated "1000 year" uniform hazard response spectrum for Millstone Unit 1 represents an adequate level of free field ground motion for the use in the reevaluation of the Millstone Unit 1 seismic design. This conclusion was based on several considerations (see NUREG-0967), two of which deserve mention because of arguments presented in this SER: (a) the Millstone Unit 1 SEP spectrum was compared to (deterministic) site specific spectra of a nearby magnitude 5.3 (m_b) earthquake (obtained from strong ground motion records) to assure that the SEP spectrum did not fall below the 50th percentile deterministic site specific spectrum; and (b) additional considerations indicate that the return period associated with the SEP "1000 year" spectrum should be more appropriately considered to be of the order of 1,000 to 10,000 years.

Since the completion of the SEP several related studies have been carried out which allow the staff to test the validity of some of the conclusions reached during the SEP review process:

The licensee undertook a study to define the probability of exceeding the specified Safe Shutdown Earthquake (SSE) spectrum at the Millstone Nuclear Plant Site, (Millstone Unit 3, Probabilistic Safety Study (PSS). A comparison of the peak ground acceleration (PGA) 200, 1000 and 4000-year return periods reported in the SEP (NUREG/CR-1582) to those derived from the PSS study reveal significant differences, e.g., the 50th percentile hazard curve reported in the PSS translates into return periods for similar PGA's which are more than one order of magnitude larger, which on face-value would indicate that the SEP 1000-year spectrum may, as previously suggested, be associated with a larger return period.

As a follow-up and also a broadening of the characterization of seismic hazard in the EUS, LLNL, under contract to NRc, undertook a comprehensive study generally known as the Seismic Hazard Characterization Program (SHCP), (NUREG/CR-3756 and UCID 20421). Among other results the SHCP developed uniform hazard spectra for the Millstone Nuclear Plant site and compared these to spectra developed in earlier studies such as those mentioned above. A comparison of the 1000-year constant percentage uniform hazard spectra (CPUHS) to the SEP spectrum (UCID 20421, Volume 1, Figure 6.4.5) shows that the SEP spectrum approaches the 84th percentile CPUHS at frequencies less than 2 Hertz (Hz), while for frequencies in excess of 10 Hz the SEP spectrum is close to the 50th percentile CPUHS 1000-year spectrum. After making similar comparisons with the CPUHS 10,000-year spectra the staff concluded that, while return periods associated with different spectrual values vary with frequency, the SEP spectrum falls between the 1000-year and the 10,000-year CPUHS 50th percentile spectra.

Comparisons indicate that significant differences exist between the results of the PSS and the SHCP. This question was addressed in the SHCP study. The conclusions reached were that much of the discrepancies could be attributed to differences in assumptions. For instance, if the ground motion models are restricted to comparable ones, the truncations of the peak ground acceleration is matched, and the lower limit of integration with respect to magnitude is made equal ($m_b = 4.5$), the results are much more in agreement even though the uncertainty bounds for the CPHCs are still wider than the PSS uncertainty bounds.

As discussed in Section 2.5.5, an earthquake of magnitude 5.7 (mblg) occurred in the New Brunswick, Canada area in 1982. In past licensing considerations the staff has maintained that this area is part of the New England Piedmont tectonic province. However, the staff conceded also that significant (tectonic) differences do exist between portions of this large tectonic province (Millstone Unit 3 SER, NUREG-1031). The licensee submitted seismicity and earthquake recurrence comparisons between the Millstone site region and the central New Brunswick region during OL review process of Millstone Unit 3. The staff concurred with the licensee that there was no need to change the existing design basis which is predicated upon a SSE of magnitude 5.25 (mb). Not withstanding this conclusion the staff reevaluated the SEP spectrum for Millstone in the light of data derived from earthquakes with magnitudes similar to the New Brunswick earthquake. Conclusions reached are as follows:

(a) The probabilistic spectra derived in the SHCP take into account earthquakes of all sizes including those of the 1982 New Brunswick earthquake. Therefore the SEP Millstone Unit 1 spectrum is adequate in this respect along arguments presented above.

(b) The Millstone Unit 1 SEP spectrum is either equal to or exceeds the 50th percentile of the deterministic spectrum of a magnitude 5.8 (mb) earthquake (NUREG/CR-1582 Volume 1, Figure 4-8).

In the light of the studies discussed above, the staff found nothing to question the adequacy and conservatism of the recommended SEP spectra, and still considers them appropriate for use at Millstone Unit 1.

2.5.8 Stability of Slopes (SEP Topic II-4.D)

The existing ground surface at the site is about 14.5 ft above mean sea level (El +14.5) and slopes gently to a few feet above sea level on the west, south and north borders of the site. The distance from the plant structures to the Sound is only a few hundred feet. The site is relatively flat and there are no significant slopes, except at the water's edge near the intake structure on the west side of the peninsula and near the discharge structure on the east side of the peninsula.

The intake structure is supported on a foundation which has been excavated into rock that is exposed on each side of the structure. An examination of this rock indicated that there is no likelihood of a slope failure in this rock.

The cooling water discharge structure is founded in rock at the west end of an abandoned quarry about 400 ft wide and 1000 ft long that is reportedly deeper than 100 ft below sea level. Cooling water from Millstone Unit 2 and Millstone Unit 3 also discharges into the quarry. Water from the quarry is conducted to Long Island Sound by a channel cut into bedrock at the east end of the quarry, about 1000 ft southeast of the Millstone Unit 1 discharge structure. The channel is not safety related.

Based on on-site observations and a review of the licensee's submittals listed under SEP Topic II-4.D, it is the staff's judgement that there is only a nominal depth of soil covering the bedrock in the vicinity of the discharge structure and any sloughing of this soil could not adversely affect the discharge of water from the plant. The bases for this conclusion are as follows:

(1) During the site visit the staff observed rock being excavated from the excavation for Millstone Unit 3 water discharge line excavation, and rock was exposed along the edges of the quarry and around the Millstone Unit 1 and 2 discharge structures.

(2) The boring logs in the plant area showed that the rock surface slopes upward from about El -25 in the plant area to existing ground surface (about El +10) near the Millstone Unit 1 discharge structure, a distance of about 150 ft from the plant area.

Based on the visual inspection of the site conducted by the NRC staff on, May 11-14, 1982, and a review of the referenced documents (Refer to SEP Topic II-4D), the staff concurs in the licensee's conclusion that there are no natural or man-made slopes at the site that could be or become unstable such as to affect safety-related structures, systems or components.

2.5.9 Settlement of Foundations and Buried Equipment (SEP Topic II-4.F)

10 CFR 50 (GDC 2 and 44) and 10 CFR 100, Appendix A as implemented by Regulatory Guide 1.132 and SRP Section 2.5.4, requires that foundations and buried equipment important to safety be adequately designed to perform their intended functions.

- Turbine Building

  In IPSAR Section 4.2.1 (App A-Ref. 5), the staff requested that the licensee demonstrate the adequacy of the pile foundation of the turbine building to

resist lateral and uplift loads developed during a safe shutdown earthquake (SSE) in light of only a 4 inch pile embedment into the pile cap. Additionally, the staff requested that potential corrosion of the pile be investigated considering the proximity of the sea water to the steel piles. The licensee addressed this issue by letter dated March 16, 1984.

The staff review of this submittal, and additional information from the licensee, is in progress.

- Gas Turbine Generator Building

  IPSAR Section 4.2.2 identified the same concerns related to the pile foundation of the turbine building as being applicable to the gas turbine generator building. Additionally, some of the piles under the gas turbine building are friction piles and, therefore, it should be demonstrated that they will perform adequately during a dynamic loading considering the possible loss of strength of the saturated granular soils surrounding these piles during an SSE. The licensee addressed this matter by letter dated March 16, 1984.

  The staff review of this submittal, and further information from the licensee is in progress.

- Buried Pipelines

  In IPSAR Section 4.2.3, the staff identified an area where safety-related buried pipelines may be supported by peat, a highly compressible material, and subjected to unacceptably large settlements. The licensee supplied a summary of the results obtained from recent borings in their submittal dated March 16, 1984.

  The staff is reviewing the material and awaiting further information from the licensee.

2.5.10 Probabilistic Estimates of Ground Motion at Millstone

Three different estimates of probabilistic seismic hazard are available for the Millstone site. The first is that which is available from the NRC's Systematic Evaluation Program (SEP), the second is a study completed by a consultant to the licensee as part of the licensee's Probabilistic Safety Study (PSS),* and the third is the ongoing joint Office of Nuclear Regulatory Research and Office of Nuclear Reactor Regulation Seismic Hazard Characterization Program (SHCP).

In studying earthquake hazards, there is concern about the probability that an earthquake or its associated ground motion will occur at a site during a specified period of time. The exceedance probability is the probability over some period of time that an earthquake will generate a level of ground shaking greater than some specified level. The return period is the reciprocal of the annual probability of exceedance on the average over long periods of time between events causing ground shaking exceeding a particular level at a site.

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*MP-3 PSS dated 8/83; MP-1 PSS dated 7/10/85.

An important part of completing a seismic hazard analysis involves the selection of an approach to incorporate the uncertainty of all input parameters into the analysis. Difficulty in accounting for this uncertainty is one of the reasons the staff has used probability studies in a limited sense. All the studies which have specific results for Millstone allow for the incorporation of uncertainties and alternative hypotheses on many of the hazard input parameters. These include seismic source zonation, earthquake occurrence rates and the upper magnitude cutoff, and ground motion attenuation equations and their associated uncertainty. Results for the SEP are not discussed here as they have been updated as part of the seismic hazards characterization program (SHCP).

The licensee has concluded that the return period (50th percentile) for a peak acceleration of 0.17 g at the Millstone site is about 12,000 years. Results included in the SHCP interim report (NUREG/CR-3756) are more conservative than this by about one order of magnitude. This large difference reflects input assumption differences, particularly with respect to ground motion attenuation. At this time the staff does not necessarily believe that one is wrong and the other is right. This difference also points out that specific reliance upon the absolute numbers is not warranted.

Both studies however provide valuable insights regarding the impact of ground motion above the 0.17-g response spectra. Although large absolute differences exist, both studies show that the actual seismic hazard would decrease by only a factor of about 3 if ground motion were 40 to 50% higher than the 0.17-g response spectra. The staff judges that the factor of 3 reduction in hazard is likely to be an upper bound because the 40 to 50% exceedance is likely an upper bound. The implication of this, is that a change in the acceleration of 40 to 50% implies a small relative risk difference. The PSS provides insights regarding the contribution of various acceleration ranges to the total probability of core melt. Results of both the licensee's and the staff's preliminary review indicate that the contribution to core melt from the seismic hazard for peak accelerations less than about 0.30 g are small. This would tend to support the conclusion that differences of 40 to 50% in ground motion at accelerations less than or equal to about 0.17 g to 0.25 g are not significant when viewed from the perspective of risk.

In conclusion, the staff finds the existing design basis adequate with respect to the impact of the New Brunswick earthquake on the Millstone site. This conclusion is supported by the earthquake-recurrence statistics and the valuable insights gained as part of probabilistic seismic hazard studies. Additionally, on the basis of available geological and geophysical information, there is no evidence of capable faulting in the Millstone site area, and there are no known tectonic structures that could be characterized as possible localizers of seismicity in the site vicinity.

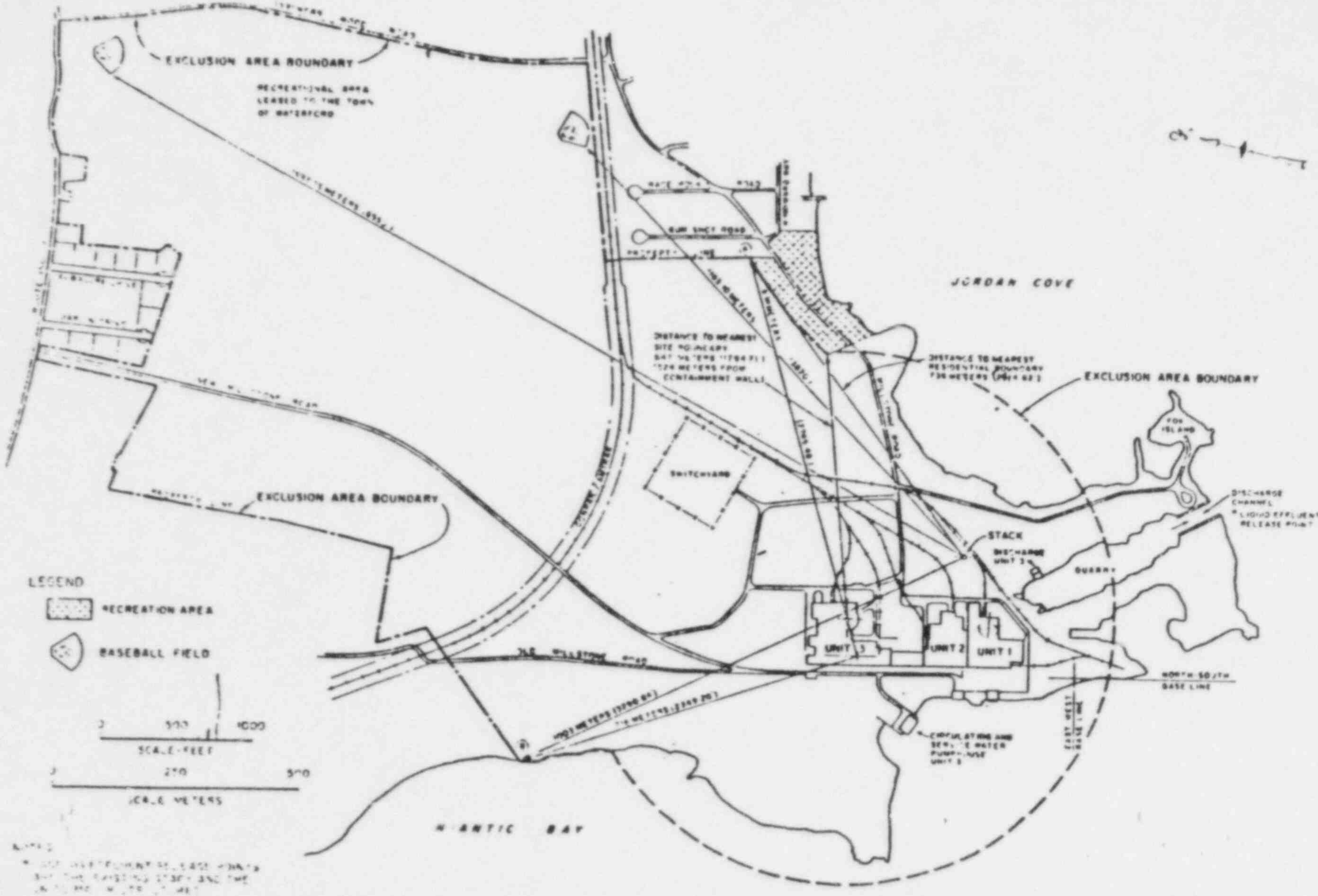

Figure 2.1 Site layout
Source: ER-OL Figure 2.1-3, Amendment 5, Jan. 1984

3 DESIGN CRITERIA - STRUCTURES, SYSTEMS AND COMPONENTS

3.1 General

The staff review of structures, components, equipment systems relies on industry codes and standards that have been used as the accepted industry practice. These codes and standards have been previously reviewed by the staff, found acceptable, and incorporated into the standard review plan (NUREG-0800).

3.2 Classification of Structures, Systems and Components (SEP Topic III-1)

As implemented by Regulatory Guide 1.26, GDC 1 requires that structures, systems and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

In Section 4.3 of the IPSAR, the staff concluded that insufficient information existed to complete the topic review and requested that the licensee supply additional information and analyses in the following topic review areas:

(1) radiography
(2) fracture toughness
(3) valves
(4) pumps
(5) storage tanks

The staff's position remains as stated in the IPSAR, namely, the licensee should complete the evaluations and incorporate the results in the Final Safety Analysis Report update. If the results indicate that modifications are required, those actions should be reported to the staff.

3.3 Wind and Tornado Loadings (SEP Topic III-2)

10 CFR 50 (GDC 2), as implemented by SRP Sections 3.3.1 and 3.3.2 and Regulatory Guides 1.76 and 1.117, requires that the plant be designed to withstand the effects of natural phenomena such as wind and tornados.

IPSAR Sections 4.4.1 through 4.4.6 identified some structures and components important to safety that do not meet current licensing criteria which require adequacy to resist tornado winds of 300 mph and differential pressure of 2.25 psi. The following were identified in the IPSAR:

(1) reactor building steel structure above the operating floor
(2) ventilation stack
(3) effects of failure of non-qualified structures
(4) components not enclosed in qualified structures
(5) roofs
(6) load combinations

The licensee responded to each of the above issues in submittals dated December 3, 1982, October 7, 1983, February 2, 1984, and March 16, 1984.

Related to the tornado wind issue is the issue of tornado missiles. IPSAR Section 4.7 identified structures and components considered vulnerable to tornado missiles. The staff's position was that the licensee must provide protection for sufficient systems and components to ensure the ability to safely shutdown (i.e., hot shutdown). The licensee addressed the issue of tornado missiles in their submittal dated December 2, 1983.

To address both the tornado wind issues and tornado missile issues, the licensee relied on attaining safe shutdown by means of the isolation condenser in conjunction with the existing capacity of structures which, although not meeting the criteria specified above, corresponds to a windspeed with a low probability of being exceeded. Attaining hot safe shutdown via the tornado protected isolation condenser is described in the licensee's submittal dated December 2, 1983. To provide a missile protected source of make-up to the isolation condenser, the licensee proposed to tie into the city water system and to store an engine driven pump in a tornado proof structure (NRC Ltr dated October 7, 1985) to pump water from the city water system to the isolation condenser and to provide a source of reactor vessel water if required.

The staff concluded that the method of attaining safe shutdown described by the licensee in conjunction with the existing capacities of structures at Millstone 1 provides an acceptable basis for concluding that Millstone 1 is adequately protected against tornado effects. As a confirmatory item, the staff required that the licensee assure that the anchor bolts of the condensate storage tank (CST) and firewater tanks provide substantial resistance against failure. The staff was concerned about these items because the CST and firewater tanks also supply make-up to the isolation condenser; if these tanks can withstand the wind loading, sole reliance need not be placed on the city water system. The issue of load combinations is discussed in Section 3.8.

3.4 Water Level (Flood) Design (SEP Topics II 3.B/C)

As implemented by Standard Review Plan Section 2.4.5 (NUREG-0800) and Regulatory Guide (RG) 1.59, General Design Criteria (GDC) 2 in 10 CFR 50, requires that structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as floods. The staff concluded that the probable maximum hurricane (PMH) flood level, including wave effects, is 22.3 ft msl (18.11 ft msl stillwater level plus wave action). Safety-related structures at Millstone 1 are protected by concrete floodwalls to elevation 19.0 ft msl. As a result of this higher water level including wave effects, it was identified that there would be intermittant inleakage and that the floodwalls have not been analyzed for these additional forces (Section 4.1 Ref. 5). The licensee submitted information addressing these issues by letters dated February 2, 1984 and March 16, 1984. The licensee relied on the isolation condenser, which is flood protected, to attain safe shutdown. To supply make-up to the isolation condenser, the licensee has relied on firewater pumps located in the fire pumphouse. The licensee has proposed to perform modifications to the flood doors of this structure to assure that it is flood protected.

The staff concludes that the proposed method of attaining safe shutdown is viable. A more thorough description of this safe shutdown method is given in

the licensee's submittal dated December 2, 1983. The staff, however, requires that the licensee assure that adequate flood protected diesel fuel exists for the diesel driven fire pump and that the masonry blockwalls of the fire pumphouse are adequate to resist the forces induced by the flood water, including wave effects.

IPSAR Section 4.1.6 noted staff concerns regarding the adequacy of the flood emergency procedures at Millstone 1. By letters dated January 31, 1983 and June 2, 1983 the licensee addressed these concerns including a discussion of required actions and the time required to perform them. As a result of this review, the licensee agreed to lower the water level at which the emergency procedures is initiated to allow sufficient time to complete flood protection actions. As noted in Inspection Report 84-27, the procedure is initiated at +8 foot instead of +14 foot above sea level.

Section 4.1.7 of the IPSAR concluded that some roofs with parapets may be overstressed as a result of a local PMP. As a result the licensee will install scuppers on the roofs of the turbine building, reactor building, warehouse and heating/ventilation areas in order to assure that the loads on these roofs remain below the design roof live loads. This course of action is described in the licensee's submittal dated February 2, 1984. The staff concluded that these proposed modifications are acceptable.

The effects of high water level on structures are addressed in Section 4.5 of NUREG-0824 (Ref. 5). The staff required that the licensee demonstrate that plant structures are capable of withstanding hydrostatic and uplift forces in combination with other loads. By letter dated February 2, 1984, the licensee supplied the results of their analyses. Staff review is continuing. Inservice Inspections of water control structures is discussed in Section 4.6 of NUREG-0824.

3.5 <u>Missile Protection</u>

3.5.1 Effects of Pipe Break on Structures, Systems and Components Inside Containment (SEP Topic III-5.A)

10 CFR 50 (GDC 4), as interpreted by SRP Section 3.6.2, requires, in part, that structures, systems and components important to safety be appropriately protected against dynamic effects such as pipe whip and discharging fluids.

In IPSAR Section 4.9, the staff identified three areas requiring further evaluation. The three areas are related to: 1) cascading pipe breaks, 2) jet impingement, and 3) pipe whip. The licensee responded by letter dated April 15, 1983 and the staff issued its SER on June 29, 1983.

Cascading Pipe Breaks.

In IPSAR Section 4.9.1, the staff was unable to conclude that cascading pipe breaks would not produce conditions more severe than those analyzed by the limiting design basis loss-of-coolant accident (LOCA). The staff also required that any leakage detection systems deemed necessary should be reviewed in conjunction with SEP Topic V-5, "Reactor Coolant Pressure Boundary Leakage Detection." The licensee concluded that the emergency core cooling systems are

physically isolated from each other in such a way that any cascading breaks that impact on one train could not affect the redundant train. Also, leaks in one recirculation loop cannot impact the other loop and cascading breaks that impact on one recirculation loop cannot impact the other loop. Therefore, sufficient shutdown methods exist to mitigate the consequences of cascading breaks. The licensee also concluded and the staff agreed that the ECCS core cooling analysis is not changed significantly due to cascading breaks and that the potential for cascading breaks doe not compromise the design basis accident analysis. The staff concluded that the licensee response is acceptable.

- Jet Impingement.

IPSAR Section 4.9.2 identified four areas of the licensee's jet impingement analysis which required further justification:

(1) The jet impingement model used by the licensee was based on a jet expansion caused by longitudinal breaks; current criteria require the consideration of both circumferential and longitudinal breaks.

(2) In the case of circumferential breaks, jets in conjunction with pipe whip have not been considered to sweep the arc traveled by the whip.

(3) The assumption used by the licensee appears to refer only to steam jets rather than all high-energy lines.

(4) From the information presented, it is uncertain whether the jet impingement effect on the impinged target pipe system conform with the staff position outlined in the letter transmitted to licensee on January 4, 1980.

The licensee responded that:

(1) NNECO's high energy pipe break analyses considered jet impingement due to both longitudinal and circumferential breaks.

(2) Jets resulting from circumferential breaks were assumed to sweep the arc traveled by the whipping pipe.

(3) Jet impingement effects were considered for all high energy line breaks.

(4) Although it is the licensee's position that the consideration of jet impingement regardless of pipe size is not a valid concern, an evaluation of the effects of jet impingement on piping targets was performed. Due primarily to the physical separation of the ECCS trains, it was determined that no jet impingement could result in the loss of both trains of redundant safety systems. Therefore, the licensee concluded that the plant could achieve a safe shutdown when considering the effects of jet impingement on piping.

Based on the information provided by the licensee, the staff concluded that this issue has been satisfactorily resolved.

Pipe Whip

In IPSAR Section 4.9.3, the staff required the licensee to evaluate the potential for and the consequences of pipes whipping into the drywell liner. The licensee's prior conclusion that high energy line breaks would not penetrate the drywell liner and thus violate containment integrity was based on a test of loads being applied to a spherical shell. The staff requested further justification that the test conditions were applicable to the pipe break scenarios at Millstone 1. In the test, the load was applied over a 14" diameter area and the shell deformed until it made contact with the concrete backing (3" gap). The staff was concerned that in the case of the application of a concentrated dynamic load over a small area, the steel plate may be perforated before the deformation could be backed up by the concrete shielding wall. Also, the test shell thickness was 3/4" and parts of the Millstone 1 liner were only 5/8". The licensee responded that it is not possible for the broken end of a pipe to impinge directly on the liner since the broken end is never the leading surface of the pipe. The thickness of the drywell liner plate varies from 11/16" to 1-7/16" and the gap between the liner and the concrete is only 2". Where the liner is less than 3/4", interactions between large bore piping and the liner plate occur at oblique angles such that only a fraction of the pipe whip energy is transmitted to the plate.

Based on review of this response and the analysis submitted previously, the staff concluded that the licensee has demonstrated that postulated high energy line breaks inside containment will not penetrate the drywell liner and thus this issue is closed.

3.5.2 Pipe Break Outside Containment (SEP Topic III-5.B)

10 CFR 50 (GDC 4) as implemented by SRP Sections 3.6.1 and 3.6.2 and Branch Technical Positions MEB 3-1 and ASB 3-1, requires in part, that structures, systems and components important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures.

The only open issue regarding this topic is IPSAR Section 4.10.2 on jet impingement where the jet impingement model used by the licensee was less conservative than that specified in current NRC criteria. In that section, the staff required the licensee to: 1) validate the Millstone 1 jet impingement evaluation methods, 2) demonstrate that the differences between the criteria used and those in SRP Sections 3.6.2 are not significant from the standpoint of consequences on systems, or 3) perform augmented ISI to demonstrate that unstable pipe failure is unlikely and implement local leakage detection.

The licensee responded by letter dated March 24, 1983, and the staff issued its SER on June 29, 1983. The licensee later reported (December 4, 1984) that the difference in cross-sectional area does not significantly alter the results since conservatisms in the analysis (jet propagation losses, consequence evaluation) more than compensate for any non-conservatism in the jet expansion model. Typically, jet impingement loads were determined for interactions with structures. In these cases, either the load resulted in failure (so remedial measures were required) or there was substantial margin. Thus, based on review of this submittal, the staff considers this issue resolved.

3.5.3 Turbine Missiles (SEP Topic III-4.B)

10 CFR 50 (GDC 4), as implemented by Regulatory Guide 1.115 and SRP Sections 3.5.1.3 requires that structures, systems and components important to safety be appropriately protected from dynamic effects including missiles.

In the interim until a turbine inspection frequency is established generically for GE turbines, based on GE's generic probability analysis, the IPSAR concluded that the low-pressure turbine discs and normally inaccessible parts which have not been inspected in the last three years should be inspected at the next refueling outage. Based on the results of this inspection, the licensee was requested to propose a schedule for future inspections. The staff also required that the main steam stop and control valves and reheat stop and intercept valves be disassembled and inspected at approximately 3-year intervals and be exercised at least weekly by full closure of the valves. By letter dated September 29, 1982, the licensee informed the staff that inspections and tests of the main steam stop, reheat stop, and intercept valves are performed in accordance with the staff's position except that they are not tested by fully closing the valves. The staff required that the licensee evaluate the potential improvement in control valve availability associated with weekly full closure testing and the feasibility of conducting such tests.

The licensee responded by letters dated June 22, 1983 and December 5, 1984. In the June 22, 1983 letter, the licensee concluded that no changes are warranted to the current testing program for the following reasons:

- At rated power and steam flow, the main steam control valve position is approximately 70% of full open. Due to the design and flow characteristics of these valves, this valve position does not mean that 30% of flow capacity remains. Close to rated steam flow, very small changes in steam flow result in large changes in valve position. A major reduction in reactor power would be required to insure that control valve capacity is not reached, which could result in a reactor pressure transient and subsequent neutron hi-hi flux scram.

- The above condition could be avoided by opening the turbine bypass valves during the test period. This alternative is not desirable, however, due to the high potential for main condenser tube failure. Past operating experience has demonstrated that bypassing steam to the main condenser at high flow rates can cause degradation and subsequent tube leaks, which may result in chloride contamination and high conductivity in the main condenser.

- The response time of the pressure regulating system and the control valves has not been adequately demonstrated. Additional testing would be required to determine whether the pressure regulating system will allow opening of the remaining control valves before a reactor pressure increase and possible reactor scram could occur.

- Closure of one main steam control valve can result in an imbalance in inlet steam to the high pressure turbine. The effect of this evolution on turbine reliability is not known, however the licensee has requested an evaluation of this from the turbine vendor.

- The main steam control valves serve to control reactor pressure and thus modulate constantly in response to changes in steam flow. Therefore, any malfunction in the main steam control valves would be noticed by the operators and corrective action would be taken. The fact that these valves are continually changing position provides additional assurance that they will close properly on demand to isolate the steam supply from the turbine.

- The main steam stop valves and reheat stop and intercept valves are cycled to the fully closed position once per week, thus assuring their reliability. Closure of these valves alone would be sufficient to isolate the turbine and prevent a severe overspeed condition.

Although reaching these conclusions, the licensee requested additional information from the turbine vendor. The staff is awaiting this information.

In the December 5, 1984 letter, the licensee stated that the "A" low pressure turbine had been ultrasonically inspected in 1982 and that the "B" low pressure and high pressure turbines were similarly inspected in 1980. during the 1984 refueling outage, the high pressure turbine was inspected using magnetic particle. Based on the results of these inspections, General Electric has recommended that the "B" low pressure turbine be inspected during the 1985-1986 refueling outage and that the "A" low pressure turbine be inspected during the 1987 refueling outage. The high pressure turbine will be inspected during the 1989 refueling outage. This schedule provides for inspection of all three turbines over the next three refueling outages. The staff will complete its evaluation of this issue for Millstone 1 when the licensee submits the additional information being developed by the turbine manufacturer (GE), as described previously. In a related effort, the staff is continuing its review of the generic methods being developed by GE to establish turbine surveillance and maintenance schedules. When these generic efforts are complete, the results will be appropriately applied to all operating plants with GE turbines, including Millstone 1. In the interim, the staff concludes that the proposed inspection schedules are acceptable; however, the licensee should continue to monitor developments from the generic program and modify the inspection schedules, as necessary.

3.5.4 Tornado Missiles (SEP Topic III-4.A)

10 CFR (GDC 2), as implemented by Regulatory Guide 1.117, prescribes structures, systems, and components that should be designed to withstand the effects of a tornado, including tornado missiles, without loss of capability to perform their safety functions. Regulatory Guide 1.117 requires that structures, systems, and components that should be protected from the effects of a design-basis tornado are (1) those necessary to ensure the integrity of the reactor coolant pressure boundary, (2) those necessary to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition (including both hot standby and cold shutdown), and (3) those whose failure could lead to radioactive releases resulting in calculated offsite exposures greater than 25% of the guideline exposures of 10 CFR 100 using appropriately conservative analytical methods and assumptions. The physical separation of redundant or alternate structures or components required for the safe shutdown of the plant is not considered acceptable by itself for providing protection against the effects of tornadoes, including tornado-generated missiles, because of the large number

and random directions of potential missiles that could result from a tornado as well as the need to consider the single-failure criterion.

The following structures and components were identified (Ref. 5) as vulnerable to tornado missiles:

(1) service water and emergency service water pumps
(2) emergency switchgear
(3) emergency batteries and battery chargers
(4) emergency diesel generator and fuel oil day tank
(5) gas turbine
(6) safe shutdown cables (turbine building, yard cable trenches, intake structure, and gas turbine building)
(7) condensate storage tank
(8) control room heating, ventilation, and air conditioning
(9) space coolers
    (a) turbine building ventilation servicing switchgear rooms, emergency diesel generator, and battery room
    (b) intake structure ventilation system.
(10) turbine building secondary closed cooling water system

During the topic review, the condensate and condensate booster pumps and their space coolers and the reactor feedwater pump M2-10C were identified as potentially vulnerable to tornado missiles, based on a review of drawings. The condensate and condensate booster pumps were identified as vulnerable because only masonry block walls existed between the pumps and the outside. During the site visit, however, it was noted that two masonry walls are separated by a large distance and that intervening equipment exists between the pumps and the exterior. The staff judged that this provided adequate protection.

Feedwater pump M2-10C was vulnerable because it is protected by a masonry block wall to the east. Masonry block is not considered adequate protection. During the site visit, however, it was noted that only a portion of the wall is made of masonry block; the rest is concrete. Feed pump M2-10C is located near the concrete wall and is adequately protected. Further, feedwater pump M2-10C is not safety related because it is not part of the emergency feedwater coolant injection system (FWCI).

The licensee believes that sufficient power and water source redundancy exist to ensure the capability to safely shut down the plant. This is described in the licensee's letter dated June 29, 1982. In that letter, the licensee described various shutdown methods if vulnerable components described in the SER (forwarded by letter dated May 25, 1982) are unavailable; however, the licensee had not described any method of shutdown using only systems and components protected from tornado missiles. The licensee's methods relied on redundancy of unprotected equipment. Experience with tornadoes indicates that debris, multiple missiles, and damage to exposed equipment is likely. This is also embodied in the NRC's regulations, 10 CFR 50, Appendix A, GDC 4. Because the reactor coolant pressure boundary is adequately protected, it is not recommended that all safety-related systems (i.e., accident-mitigating systems) be protected from tornado missiles. However, it is the staff's position that the licensee must provide protection for sufficient systems and components to ensure the ability to safely shut down (i.e., hot shutdown) in the event of damage from tornado missiles.

By letter dated September 22, 1982, the licensee disagreed with the staff's position; however, by letter dated December 27, 1982, the licensee proposed to (1) evaluate alternatives, (2) inform the staff of the results by April 1983, and (3) provide a shutdown method that is protected from the effects of tornado missiles by the end of the 1984 refueling outage. By letter dated February 7, 1985, the licensee proposed to include this issue as part of the MP-1 Integrated Safety Assessment Program.

3.5.5 Site Proximity Missiles Including Aircraft (SEP Topic III-4.D)

The safety objective of this topic is to ensure that the integrity of the safety-related structures, systems and components would not be jeopardized due to the potential for a site proximity missile.

General Design Criterion 4, "Environmental and Missile Design Basis," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Licensing of Production and Utilization Facilities," requires that nuclear power plant structures, systems and components important to safety be appropriately protected against events and conditions that may occur outside the nuclear power plant.

The review was conducted in accordance with the guidance given in Standard Review Plan (SRP) Section 2.2.3, "Evaluation of Potential Accidents," 3.5.1.5, "Site Proximity Missiles (except Aircraft)," and 3.5.1.6, "Aircraft Hazards."

An evaluation of nearby industrial, transportation, and military facilities is well documented in Section 2.2 of the Millstone Unit 3 FSAR.

The staff concluded that the Millstone site is adequately designed against aircraft hazards and since current regulatory criteria are met with respect to SEP Topic III-4.D, "Site Proximity Missiles," this topic is complete.

3.6 <u>Seismic Design Considerations (SEP Topic III-6)</u>

10 CFR 50 (GDC 2) and 10 CFR 100 Appendix A, as implemented by SRP Sections, 2.5, 3.7, 3.8, 3.9, and 3.10 and SEP review criteria (NUREG/CR-0098), require that structures, systems and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes.

IPSAR Section 4.11 (Ref. 5) identified the following areas as requiring further analysis:

(1) pile foundations
(2) motor operated valves
(3) transformer and control room panels
(4) qualification of cable trays
(5) reactor vessel internals

Pile Foundations

IPSAR Section 4.11.1 identified concerns related to the adequacy of the pile foundation of the turbine building. The concerns are the same as those discussed in Section 4.2 of the IPSAR and Section 2 of this safety evaluation.

- Motor-Operated Valves

  In Section 4.11.2 of the IPSAR, the staff required that the licensee demonstrate that the structural integrity of motor operated valves that are in lines 4 inches or smaller is adequate. By letter dated May 17, 1984, the licensee submitted the results of its review to the staff. The staff evaluation is in progress.

- Transformers and Control Room Panels.

  Section 4.11.4 of the IPSAR required demonstration of anchorage system adequacy for transformers and control room panels during a seismic event. The licensee had provided information to the staff by letter dated September 29, 1982, which the staff was reviewing at the time of IPSAR publication. The staff later requested additional information from the licensee and is awaiting a response.

- Qualification of Cable Trays.

  IPSAR Section 4.11.6 required the licensee to submit a plant-specific implementation program and schedule regarding the seismic qualification of cable trays. The licensee submitted final reports, on behalf of the SEP Owners Group, describing cable tray testing and results of the program on qualification of cable trays. The licensee has concluded that the testing and analyses conducted as part of the SEP Owners Group program adequately demonstrates the seismic capability of the cable trays in SEP plants. The staff is reviewing the results of the SEP cable tray program in concert with the generic resolution of Unresolved Safety Issue USI A-46, "Seismic Qualification of Equipment in Operating Plants," which will apply to all operating plants. When a generic resolution for USI A-46 is approved, the staff will determine whether any additional action is required to resolve the SEP cable tray program in a consistent manner.

- Reactor Vessel Internals.

  In IPSAR Section 4.11.8, the staff was unable to conclude that reactor vessel internals are adequate to resist a seismic event due to a lack of information. The licensee provided the required information by letter dated January 23, 1984. Staff evaluation is in progress.

3.7 Environmental Qualification of Electric Equipment Important to Safety and Safety-Related Mechanical Equipment (Ref. 23)

Equipment which is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement, which is embodied in General Design Criteria 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50, is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"

(which supplements IEEE Standard 323 and various NRC Regulatory Guides and industry standards), and "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" (DOR Guidelines).

The evaluation of the acceptability of the licensee's electrical equipment environmental qualification program is based on the results of an audit review performed by the staff of: (1) the licensee's proposed resolutions of the environmental qualification deficiencies identified in the December 13, 1982 SER and May 28, 1982 FRC TER; (2) compliance with the requirements of 10 CFR 50.49; and (3) justification for continued operation (JCO) for those equipment items for which the environmental qualification is not yet completed. By letter dated March 28, 1985, the staff authorized a schedular delay for replacement of 28 valve motor operators (Ref. 24).

With regard to the qualification of electric equipment important to safety within the scope of 10 CFR 50.49, the staff concluded:

- NNECO's Millstone Unit 1 electrical equipment environmental qualification program complies with the requirements of 10 CFR 50.49.
- The proposed resolutions for each of the environmental qualification deficiencies identified in the December 13, 1982 SER and .RC TER are acceptable with the exception of the inside containment P/T profiles which the licensee is required to resolve.
- Continued operation until completion of the licensee's environmental qualification program will not present undue risk to the public health and safety.

3.8 Design Codes, Design Criteria and Load Combinations (SEP Topic III-7B)

10 CFR 540 (GDC 1, 2 and 4), as implemented by SRP Section 3.8, requires that structures, systems, and components be designed for the loadings they may experience and that they conform to applicable codes and standards.

As described in IPSAR Section 4.12, during the integrated assessment, the licensee proposed to perform, on a sampling basis, an evaluation of the code, load and load combination issues delineated by the staff in order to assess the adequacy of as-built structures at Millstone 1. By letter dated February 2, 1984, the licensee supplied the results of their review to the staff. The staff is currently reviewing the licensee's response.

4 REACTOR

The Millstone Unit 1 nuclear steam supply system (NSSS) was provided by the General Electric Company. The NSSS is a light water moderated and cooled boiling water reactor fueled with slightly enriched uranium dioxide. The excess reactivity designed for the early cores was partially compensated by temporary poison curtains in addition to the control rod system. Later, after the curtains were removed, burnable poison fuel rods were used to partially compensate for the increased reactivity resulting from additional U^{235} enrichment.

The as-designed core, i.e. 580 fuel assemblies and 145 control rods, continues to produce the design thermal output of 2011 MWt. All of the temporary control curtains initially installed in the core for partial control of excess reactivity have been removed. The 1985 fall refueling outage is the 10th fuel reload since the initial reactor power generation in 1970.

4.1 Fuel Design

Over the 15-year operating history of Millstone Unit 1 a number of fuel assembly design improvements have occurred. The improved fuel and rod integrity and power production capability (i.e., longer lifetime) were reviewed and approved by the NRC prior to startup following each refueling outage (Ref. 26-32).

The initial core fuel performance expectation was based on an average of 15000 megawatt days of thermal power per metric ton of uranium (MWD/MTU) at normal reactor operating conditions. In contrast to this Millstone Unit 1 technical specifications (Ref. 25) Section 3.11 identifies the various fuel assemblies that currently constitute the Millstone Unit 1 core. It can been seen that the most recently installed fuel assemblies are expected to produce an average of 45,000 MWD/MTU at normal operating conditions. These fuel assemblies contain 176 kilograms of uranium. Therefore, each fuel assembly can produce 7920 MWD of thermal energy. 580 fuel assemblies, the core inventory, yield 4×10^6 MWD thermal energy. Millstone Unit 1 with uninterrupted operation at rated power for one year, could produce 7.35×10^5 MWDt. From this it is evident that extended operating cycles between refueling outages, of 1.5^+ years, are possible by replacing the most depleted one third of the core fuel assemblies when the excess reactivity has diminished to the extent that control rods have reached the fully withdrawn condition. In reality, the refueling interval is dependent on the plant capacity factor as well as the fuel design lifetime. Operation at less than 100% power level stretches the period between fuel assembly replacement. Normal maintenance, inspection, and testing requirements for the NSS, turbine/generator, and related equipment, as well as unforeseen events, control the capacity factor.

The improved fuel integrity and performance have resulted from gradual design changes introduced when depleted fuel assemblies are replaced with unirradiated assemblies. Each of the initial core fuel assemblies contained 49 fuel rods in a square (7 x 7) array. Important descriptive information related to the original fuel assemblies is presented in Tables III- 1 and 3 and Figures III - 3.1, 4.1 and 4.2 of the FSAR (Ref. 12).

During reload 3 (Ref. 26) 143 7 x 7 fuel assemblies were replaced by assemblies with 8 x 8 square array fuel rods. During reloads 4 and 5 additional 7 x 7 fuel assemblies were replaced with 8 x 8s. The remaining 7 x 7s were finally removed from the core during reload 7 (the reload 7 outage extended, due to main turbine damage, to mid June 1981).

Table 4.1 (Ref. 26) presents a comparison of the typical 8 x 8 fuel assembly that has gradually displaced all off the 7 x 7 assemblies. Beginning with operating cycle 8, June 1981 the core has been fully composed of 8 x 8 fuel assemblies.

The importance of the change from 49 rods to 64 per fuel assembly becomes clear on close examination of the table. Approximately the same amount of uranium is distributed in both fuel assemblies but the 8 x 8 fuel assembly rod diameter is smaller. The net effect of the resultant increased heat transfer area and reduced power per rod, with nearly the same clad thickness, is a significant reduction in fuel rod temperature and improved fuel rod integrity. The peak linear heat generation rate for fuel rods decreased from 17.5 kW/ft to 13.5 kW/ft, resulting in less clad strain.

Table 4.1 Comparison of Parameters for 8 x 8 and 7 x 7 Rod Fuel Assembly Design

	7 x 7		8 x 8	
Pellet Outside Diameter (in.)	0.477		0.410	
Rod Outside Diameter (in.)	0.563		0.483	
Rod-to-Rod Pitch (in.)	0.738		0.640	
Water-Fuel Ratio (cold)	2.53		2.62	
U Bundle Weight (pounds)(kg)	412.8	187	390	177
Cladding Thickness (mils)	37		32	
Active Fuel Length (in.)	144		145.24	

During the changeover from 7 x 7s to 8 x 8s, the average fuel assembly enrichment increased from 2.07 w/o U^{235} (Ref. 12) to 3.0 w/o U^{235} (Ref. 32) and correspondingly average expected fuel assembly lifetime increased from less than 15000 MWD/MTU to 45000 MWD/MTU. To accommodate these important changes, more but smaller rods and increased U^{235} enrichment per fuel assembly, a number of other changes were made over the same period. Burnable gadolinium was introduced and used in increasing amounts to partially control excess reactivity resulting from increased amounts of U^{235} enrichment. Water rods near the fuel assembly center were added to help shape power. The active fuel length was increased slightly, the enrichment at the top and bottom of rods was reduced to limit flux peaking, the fuel rod top plenum volume was increased, hydrogen getters to prevent clad embrittlement and gap barriers to prevent fuel clad

interaction were added, each fuel rod was prepressurized with helium gas and lower tie plates were drilled and finger springs added to regulate bypass flow. These and other more subtle changes to fuel pellet fabrication have resulted in a significant improvement in fuel performance and clad integrity as evidenced by the longer fuel irradiation and increased power production with a noticeable reduction in coolant radioactivity. All of these changes were made without significant change to the reactor operating performance characteristics or safety shutdown margins.

4.2 Loose-Parts Monitoring and Core Barrel Vibration Monitoring (SEP Topic III-8.A)

10 CFR 50 (GDC 13), as implemented by Regulatory Guide 1.133, Revision 1, and SRP Section 4.4, requires a loose-parts monitoring program for the primary system of light-water-cooled reactors. Millstone Unit 1 does not have a loose-parts monitoring program that meets the criteria of Regulatory Guide 1.133.

A loose-parts monitoring program could provide an early detection of loose parts in the primary system that could help prevent damage to the primary system. Such damage relates primarily to

(1) damage to fuel cladding resulting from reheating or mechanical penetration

(2) jamming of control rods

(3) possible degradation of the component that is the source of the loose part to a level such that it cannot properly perform its safety-related function

Backfitting of a loose-parts monitoring program is being considered in Revision 1 to Regulatory Guide 1.133. If the staff decides to implement the recommendations of the revision, then the need to implement a loose-parts monitoring program on operating reactors will be addressed generically.

The following factors were considered in making a recommendation that no backfitting be done at this time:

(1) A summary of 31 representative loose-parts incidents at 31 reactors (from the value-impact statement of Revision 1 to Regulatory Guide 1.133) indicates that structural damage occurred as a result of loose parts in only nine incidents. None of these incidents caused a safety-related accident.

(2) Most loose parts can be detected during refueling inspections.

(3) The limited PRA of this issue for Millstone Unit 1 concluded that eliminating loose parts-induced transients by installing a loose-parts monitoring system would have no effect on risk.

4.3 Reactor Materials (SEP Topic III-8C)

The reactor internal components for the Millstone Nuclear Power Station, Unit No. 1, are described and analyzed in Section III-7.3.4 through Section III-7.3.8 of the Final Safety Analysis Report (Ref. 12). The internal components were designed to provide support for the fuel and maintain structural clearances during normal and accident conditions. In addition, the internal components

provide passageways for the coolant to cool the fuel and means for adequately separating the steam from the coolant water.

Components of the reactor coolant pressure boundary of the Millstone Nuclear Power Station, Unit No. 1, were designed, fabricated, inspected and tested to the requirements of Section III of the ASME Boiler and Pressure Vessel Code, 1965 Edition, including Summer 1965 Addenda plus applicable nuclear code cases. The internal reactor components were analyzed to withstand the combined loadings from pressure, temperature, fluid movement, and seismic acceleration. Calculated stresses were within the criteria required by the ASME Boiler and Pressure Vessel Code.

The primary criteria for material selection for the reactor internal components were the mechanical properties, the material stability and corrosion resistance in the reactor environment. The materials used for fabricating the reactor internals were identified in the FSAR as Type 304 stainless steel, Inconel, and minor quantities of special purpose alloys, such as Stellite.

These materials have been proven to be generally adequate for reactor internal service, as long as the primary water chemistry is kept within technical specification limits. There was an incident at Millstone 1 when the primary coolant became contaminated, and some stress corrosion problems did occur.

> In September, 1972, during reactor startup,, seawater leakage occurred through the main condenser into the hotwell, saturating the condensate demineralizer and allowing excess chloride ion into the primary coolant system. An inservice inspection and testing program was conducted to assess the damage to the reactor internal components. The program showed that intergranular stress corrosion cracking had occurred, causing the failure of the local power range monitors, five neutron source holders and the cladding on the control rod neutron absorber elements. Examination of the other components showed neither intergranular stress corrosion cracking nor evidence of material degradation.
>
> Stress corrosion cracking of areas of stainless steel cladding adjacent to reactor vessel head nozzles was identified in 1976. This was evaluated and a report was submitted to the NRC.

The staff concluded that the integrity of the reactor internal components could have been degraded because of the chloride intrusion and the corrosion attack upon the stainless steel components. The subsequent inservice inspection and testing procedures detected failures in the local power range monitors, neutron source holders and control rod cladding. Failure was attributed to intergranular stress corrosion cracking. After the chloride intrusion and repair and replacement of the failed components, no further incidents of stress corrosion cracking related to the chloride have been reported in the reactor internal components for the Millstone Nuclear Power Station, Unit No. 1.

Although the materials of construction have proven to be generally adequate in resistance to cracking in the absence of unusual contamination there have been some instances of stress corrosion related cracking in some BWRs. These have generally been attributed either to fabrication problems or Irradiation Assisted

Stress Corrosion Cracking (IASCC). These instances and their relevance to MP-1 are discussed below:

- Steam Dryer Assemblies

  Minor cracking, not considered to have safety significance has occurred in some BWRs. A two-inch long crack on a support stiffener was found at MP-1 in 1984. This was not considered to be of significant concern.

  The assembly was to be reinspected during the 1985 refueling outage.

- IRM/SRM Dry Tubes

  Cracking has occurred in dry tubes in several BWRs, and has been attributed to Irradiation Assisted Stress Corrosion Cracking (IASCC). No cracking of dry tube was found during the 1984 inspection, but these were to be reinspected during the 1985 outage.

- Core Spray Spargers

  Cracks in Core Spray Spargers have been found in several BWRs. Repairs have been made by installing clamps that will prevent failure of the component. The staff has concluded that this problem does not constitute a safety concern, but does require continued surveillance to ascertain if additional cracking occurs. Cracks were found at MP-1 and a staff approved clamp repair was performed. Inspection will continue in accordance with IE Bulletin 80-13 during every refueling outage. This action is considered acceptable to the staff.

Certain other reactor internals components are considered to possibly be subject to inter granular stress corrosion (IGSCC) or IASCC. These include CRD stub tubes, jet pumps, jet pump sensing lines, top guides and the shroud annulus. These will be visually inspected to the degree possible, depending on accessability during the 1985 outage. The staff has concluded that these inspection plans are adequate to reveal any significant cracking before any potential safety problem could occur, and therefore are satisfactory.

In summary, the known occurrences of stress corrosion cracking in BWR reactor internals have not constituted safety concerns, and the inspection plans proposed for Millstone 1 are considered to be completely acceptable to the staff.

4.4 Reactivity Control Systems, Including Functional Design and Protection Against Single Failures (SEP Topic IV-2)

10 CFR 50 (GDC 25), as implemented by SRP Section 7.7, requires that the reactor protection system be designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems. A preliminary PRA of the effects of multiple rod withdrawal on risk indicated that this issue is of low importance because (1) the single failures identified do not affect the ability of the scram function and (2) the limited exceedance of the fuel thermal limits is not significant to risk. All significant risk sequences involve core melt, and the issue of multiple rod withdrawal does not affect core-melt probability.

During the topic review, sufficient information was not available for the staff to complete a single-failure analysis of the rod control system. On the basis of the review of Dresden Unit 2, specific types of rod motion from postulated single failures were identified for Millstone Unit 1. These were used in the core analysis of SEP Topic XV-8, "Control Rod Misoperation." On the basis of the assumed rod motions, it was determined that the Millstone Unit 1 design meets current licensing criteria. By letter dated October 14, 1982, the licensee provided additional information on the design of the Millstone Unit 1 rod control system and the effect of single failures. On the basis of information provided in that letter and subsequent discussions with the licensee, it was determined that a single failure (rod select relay) can occur that would allow the operator to move two rods into the core while leading him to believe he was only moving one rod. No single failure could be identified that would permit more than one rod to be withdrawn from the core. Although moving more than one rod into the core has not been evaluated, it is the staff's judgment that unacceptable consequences would not result because this action does not result in a positive reactivity insertion and because, in the staff's judgment, even though the peaking factor would increase, power would decrease at a faster rate. Other possible types of rod motion have been bounded by the types of rod motions assumed in SEP Topic XV-8. Because the consequences of such rod motions have been found acceptable, the staff considers this topic adequately resolved.

4.5 Scram Discharge Volume (SDV)

4.5.1 SDV Modifications

As a result of events involving common cause failures of the Scram Discharge Volume (SDV) limit switches and drain valve operability, the NRC staff issued IE Bulletin 80-14 on June 12, 1980 and sent a letter dated July 7, 1980 to all operating BWR licensees requesting technical specification changes to provide surveillance requirements and limiting conditions of operation for SDV limit switches and drain valves. The changes were necessary because of extensive modifications to the SDV. The modifications completed during the Fall 1982 outage included: (Ref. 33)

- Installation of a second instrument volume tank (IVT) for the south SDV, i.e., two separate SDVs and associated piping where only one was available before the change

- Replacement of the 2-inch piping connecting the SDV and the IVT with 6-inch piping

- Installation of redundant vent and drain valves

- Increasing the SDV to allow for 3.34 gallons per control rod drive

The staff found the modifications and changes to the technical specification acceptable.

4.5.2 Scram Discharge System Level Instrumentation

The NRC staff issued a generic safety evaluation report (SER) on boiling water reactor (BWR) scram discharge systems in December 1980. This report required that:

"The scram discharge system instrumentation shall be designed to provide redundancy, to operate reliably under all conditions and shall not be adversely affected by hydrodynamic forces or flow characteristics."

Generic Letter 81-18 dated March 30, 1981, requested all operating BWR licensees to provide diversity for the SDIV level switches at their facilities. In response, the licensee submitted a letter dated December 9, 1981 requesting relief from this requirement. In its submittal, the licensee proposed alternative modifications to their SDIV design and pointed out that the proposed modifications would be significantly more effective in reducing the overall SDIV unavailability at Millstone, Unit 1, than would the provision of the staff requested diversification of SDIV level switches.

The staff determined that these modifications, particularly, the addition of of a second SDIV with its associated six level switches and the elimination of nonessential valves significantly improved the design and reliability of the Millstone, Unit 1 SDIV system. Further, it is noted from the licensee's submittals that horizontal acting type Magnetrol float switches are utilized for Millstone, Unit 1 SDIVs. These switches are not subject to the differential pressure problem that caused Magnetrol float switches of the vertical acting type to fail at some BWRs. In addition, Millstone, Unit 1 does not utilize floats of the type found to have venting problems in some BWRs and does not employ an SDV design which was suspected of causing large flow rates and/or waterhammer problems. From the licensee's submittals, it is noted also that in more than 10 years of operating history, Millstone, Unit 1 had never experienced a failure of these Magnetrol float level switches. The licensee confirmed that the existing plant TS require: 1) four level channels to be operable for automatic initiation of the scram function for each of the two SDIVs (i.e., scram level switches for each SDIV following a "1 out of 2 taken twice" logic initiate a scram signal on detection of high waterlevel in either SDIV), 2) two channels, one for each SDIV to be operable for automatic initiation of control rod withdrawal block on detection of high water level in either SDIV (this level is lower than that for the scram function), and 3) the surveillance requirements spelled out for the instrument channels to be applicable for each SDIV.

In view of the above considerations, the staff concluded that the SDV design modifications completed by the licensee in Fall 1982 are more effective in reducing the overall SDIV unavailability at Millstone, Unit 1 than would have been achieved by providing diversification of level switches for the SDIVs at Millstone, Unit 1 and are, therefore, acceptable.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

The reactor coolant system described briefly in Section 1.1 and shown schematically in Figure 1.1 includes the reactor vessel, the 2 loop recirculation system with 20 jet pumps, the main steam piping, the safety/relief valves, the reactor auxiliary system piping, and the isolation condenser system. The important parameters of the reactor coolant system are summarized in the FSAR (Ref. 12), but the following section related to safety/relief valves supersedes the FSAR information.

5.1 Safety/Relief Valve Modifications

Overpressure protection for the reactor vessel and reactor coolant piping was originally provided by 3 relief valves and 2 safety valves. The relief valves were sized to remove steam upon closure of the turbine stop valves coincident with failure of the turbine bypass system. The reactor safety valves were sized to protect the reactor vessel and piping against overpressure during:

- turbine trip from full power
- failure of the turbine bypass system
- failure of direct reactor scram based on stop valve position

5.1.1 Plant Modification - 6 Safety/Relief Valves

In the fall of 1974 NNECO began the installation of additional safety/relief valve capacity at the Millstone Nuclear Power Station, Unit 1 (Ref. 35). The modifications consisted of changing the safety and safety/relief valve configuration of three (3) safety/relief valves and two (2) spring safety valves (3/2 safety/relief configuration) to six (6) safety/relief valves (6/0 safety/relief configuration), all piped to the pressure suppression pool (torus). These plant modifications were necessary due to the loss of scram reactivity near the end of operating cycle 4 which resulted in potential violation of the 25 psi margin to safety valve operation at full power for the most limiting pressure transient (generator load rejection with bypass failure). (The 25 psi margin is a General Electric (GE) design criteria which reflects GE's concern regarding safety valves discharging to the containment dry well volume.) In order to maintain the 25 psi margin, NNECO proposed that Millstone Unit 1 undergo a power reduction near end of cycle 4 which was subsequently approved by the NRC staff and issued as part of License Amendment 16 on October 17, 1975. Installation of the 6 safety/relief valve configuration eliminated the need for the 25 psi margin since each of the safety/relief valves discharges directly to the torus.

The modifications to the safety/relief system involved removal of the two spring safety valves and installation of three safety/relief valves of identical design to the three existing units. The three newly installed valves have discharge piping to the torus identical in function and similar in layout to the three existing units. Since no modifications were made to the existing safety/relief

valves, the functioning of the Automatic Pressure Relief (APR) subsystem of the Emergency Core Cooling System (ECCS) was not affected at that time.

In addition to reanalyzing transients for their effect on minimum critical power ratio (MCPR), as a result of the change in the safety/relief valve configuration, the ASME Pressure Vessel Code compliance was also reevaluated. The ASME Nuclear Boiler and Pressure Vessel Code requires that each vessel designed to meet Section III be protected from the consequences of excessive pressure. The transient selected to demonstrate compliance was closure of all mainsteam isolation valves from full power operating conditions. Reactor scram was initiated from high neutron flux and only the safety function of the safety/relief valves was credited. With only 3 safety/relief valves operable, half of the eventual complement of 6 safety/relief valves, the transient pressure reached 1346 psig as compared with the ASME limit of 1375 psig. The 1375 psig limit represents 110% of the vessel design pressure of 1250 psig as required by the ASME code. Accordingly, the staff found that the safety/relief valve modification provided sufficient relieving capability to protect the pressure vessel against the most severe over-pressure conditions.

The overpressure analysis for the MSIV closure with high flux scram is the limiting overpressure event (Ref. 29). The staff agreed that there is sufficient margin between the peak calculated vessel pressure and the design limit pressure to allow for the failure of at least one valve. Therefore, the limiting overpressure event as analyzed by the licensee was acceptable.

The overpressurization analysis calculated using the revised Safety/Relief Valve (S/RV) setpoints, concluded that overpressurization protection was adequate. Moreover, the higher setpoints increase the margin between normal operating pressure and S/RV setpoint pressures (simmer margin), thus reducing unnecessary opening of the valves and increasing their reliability.

No. Valves	PSIG
1 Safety Set Pt.	1095 ± 1%
1 Safety Set Pt.	1110 ± 1%
4 Safety Set Pt.	1125 ± 1%

The licensee also examined the effects of the increased S/RV setpoints on the torus and on the main steam and relief valve piping. This examination demonstrated that the forces on these components during S/RV actuations are bounded by analyses previously accepted by the NRC staff. Therefore, the staff found the revised setpoint specifications acceptable.

In addition, the licensee replaced the S/RVs with a new two-stage design. This change necessitated some changes to the S/RV surveillance requirements. The revised surveillance requirements are consistent with those previously approved for other installations using the new two-stage valves. Therefore, the staff found them acceptable.

5.1.2 Automatic Depressurization System (ADS) Valve

The licensee has reported (Ref. 30) that an additional one, of the six existing safety/relief valves, was added to the automatic depressurization system (ADS), also known as automatic pressure relief system (APR), by modification of the

actuation logic. The result is that four of six S/RV's will open for the ADS function instead of three of six.

The reason for the change was to improve ECCS response to a small break LOCA by causing a more rapid vessel depressurization if ADS were required i.e., in the event of a loss of feedwater combined with a loss of Feedwater Coolant Injection (FWCI).

The staff concluded that the addition of the fourth ADS valve was adequate compensation for lowered planar heat generation limits that had been imposed during the preceding cycle (i.e., Technical Specification Maximum Average Planar Linear Heat Generation Rate Limits commonly referred to as MAPLHGR limits). The increased volume of steam released through the fourth ADS valve reduces pressure fast enough to allow low pressure coolant injection into a broken recirculation loop in the event of small break 0.10 ft^2 or less and failure of the gas turbine generator, without exceeding the peak clad temperature limit of 2200°F. It also allows the MAPLHGRs to be increased to a higher less restrictive value without increasing the risk of exceeding the clad temperature limit of 2200°F, hence it compensates for higher MAPLHGR limits. NRC Amendment No. 67 dated May 8, 1980 (Ref. 36), allowed credit for the isolation condenser used in the sequence of events considered by this analysis. This is discussed below.

5.2 Isolation Condenser

The isolation condenser provides a heat sink for the reactor decay and residual heat if the reactor is isolated from the main condenser or if all feedwater is lost. It does not require AC power for operation. It operates by natural circulation. The system is described in the FSAR (Ref. 12). As originally installed, the isolation condenser was not designed as an emergency safety feature. It was placed in operation by automatic opening of the condensate return line resulting from high reactor vessel pressure.

5.2.1 System Upgrade For Emergency Core Cooling

The licensee proposed changes responsive to a Low Pressure Coolant Injection (LPCI) loop selection logic insensitivity for small break mitigation. The Appendix A Technical Specifications changes added an automatic initiation of the Isolation Condenser on reactor vessel low-low water level and allowed credit for the Isolation Condenser system in the Emergency Core Cooling System (ECCS) performance calculations.

The licensee described the impact of the LPCI loop selection logic insensitivity to small break LOCAs, $\leq$0.1 ft. The change incorporated the isolation condenser as part of ECCS and took credit for its function during LOCA, i.e., increased MAPLHGR limits. The isolation condenser reduces the inventory loss during depressurization, increases the depressurization rate, and decreases the depressurization time which effectively results in earlier hot node recovery and lower peak clad temperatures (PCTs) for small break LOCAs.

The licensee provided the results of a revised ECCS performance analysis with credit for isolation condenser operation and assumed failure of the LPCI loop selection logic. The analysis covered an appropriate range of break sizes,

locations, and single failures, and utilized the standard General Electric Company (GE) ECCS performance methods with two additions to the analytical methods. The first of these additions was to determine the isolation condenser heat removal rate. GE calculated the heat removal rate at the pressure extremes for isolation condenser operation and used a linear interpolation to establish heat removal during depressurization. The second of these additions was to take credit for LPCI flow past the broken loop. GE calculated this flow rate based on conservative assumptions. The staff found the analysis and the changes to be acceptable (Ref. 36).

On the basis of documentary information provided by the licensee and the reevaluation and upgrading of the isolation condenser steam and condensate return line restraints the staff concluded that the isolation condenser and related piping and electrical systems met the reliability requirements of Engineered Safety Features.

5.2.2 40% Power Level Limitation

Whenever the isolation condenser is unavailable reactor power level is limited to 40% of rated power level. The staff concluded (Ref. 37) that for power levels below 40% the ultimate protection was provided by The Feedwater Coolant Injection (FWCI) system and the ability to manually depressurize the reactor and cooldown with low pressure core cooling systems. The reactor and/or the operator have sufficient time, capability, and indication to respond to postulated loss of feedwater events which are normally mitigated by the Isolation Condenser. The staff analysis indicated that with a complete loss of feedwater initiated from 40% of rated power, the operator has at least 10 minutes to manually depressurize via the Automatic Pressure Relief System and initiate low pressure emergency core cooling without uncovering the core. On the basis of this information the technical specifications were changed to limit reactor power level to 40% whenever the isolation condenser was inoperable.

5.2.3 Water Hammer

Isolation condenser water hammer (noise and pipe movement) was observed on one occasion. The incident is included in The "Summary of July 25, 1978 Meeting with Northeast Nuclear Energy Company Regarding Millstone-1 Isolation Condenser Water Hammer and Pipe Supports" dated August 10, 1978. Later inspection revealed some pipe weld cracks and damage to pipe supports. The system integrity has been restored by pipe replacement and weld repair as necessary and repair and strengthening of pipe hangers and supports. The cause of water hammer was attributed to excessive reactor vessel water that resulted in water slugs in the isolation condenser steam line.

NUREG-0927 "Evaluation of Water Hammer Occurrence in Nuclear Power Plants" dated March 1984 presents the NRC staff's technical findings regarding "Water Hammer," and presents the results of the concluding evaluations associated with resolving this safety issue. The major findings are that:

1. Total elimination of water hammer occurrence is not feasible, due to the possible coexistence of steam, water, and voids in various nuclear plant systems. Experience shows that design inadequacies and operator or maintenance-related actions have contributed about equally to initiating water hammer occurrences.

2. Since 1969, approximately 150 water hammer events have been reported through the NRC's Licensee Event Reports (LERs). Damage has been principally limited to pipe support systems. Approximately half of these events have occurred either in the preoperational phase or the first year of commercial operation. This suggests a learning period in which design deficiencies are corrected and operating errors are reduced.

3. Water hammer frequency peaked in the mid-1970s, at a time when the rate of introducing new plants into commercial operation was the highest. Experience led to corrective design changes (e.g., use of J-tubes to eliminate steam generator water hammer and "keep-full" systems, vacuum breakers, etc.) which reduced the frequency of occurrence.

4. Steam generator water hammer (SGWH) associated with top feedring SGs for PWRs appears to have corrected by the use of the design features.

The major conclusions reached are that the frequency and severity of water hammer occurrence can be and to some extent have been significantly reduced through design features such as keep-full systems, vacuum breakers, J-tubes, void detection systems and improved venting procedures, proper design of feedwater valves and control systems and increased operator awareness and training; and that the current potential for significant damage as a result of water hammer events is less than it was in the early and mid-1970's.

Total elimination of water (steam) hammers is not feasible, due to various inherent features of plant design and operation. Therefore, currently accepted design practices for including anticipated water (steam) hammers as occasional mechanical loads in the design of piping and their supports systems should be maintained.

The staff safety evaluation of the water hammer events at Millstone-1 was documented by letter to the licensee dated August 30, 1982. The staff concluded that the strengthened supports for the isolation condenser steam supply line piping are sufficient to withstand the effects of water hammer loads but that the X10A piping penetration through containment should be reevaluated to assure a safety factor of 4. In addition, the licensee was to install a high water level feedwater pump trip, improve feedwater control at low flow rates and lower the normal water level set point and the isolation set point for the reactor water cleanup system. These additional changes reduce the dependence on high water level feedwater pump trip to prevent water level from reaching the steam outlet to the isolation condenser, i.e., they reduce the probability of a water hammer event.

5.3 Integrity of Reactor Coolant Pressure Boundary

As implemented by Regulatory Guide 1.26, GDC 1 requires that structures, systems and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. SEP Topic III-1 addressed this issue which is not yet, as noted in Section 3.2 of this SER, fully resolved. Although not fully resolved the staff concluded, for those components where a comparison of codes was possible, that the changes in the codes since the original design do not significantly affect the safety of the plant. Based on the staff's sampling of code

comparisons, the remaining items are not expected to pose a significant hazard to plant safe operation. The items are currently under review by the licensee.

5.3.1 Inservice Inspection

Amendment 64 (Ref. 38) revised the technical specifications to meet the requirements of 10 CFR 50.55a. Relief from certain inservice testing requirements as described in the staff safety evaluation was also granted at the same time. The second ISI 10 year program was approved by NRC letter dated November 19, 1980. Generic Letter 83-15 dated March 23, 1983 recommended an alternative method related to "Implementation of Regulatory Guide 1.150 'Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations'." The safety evaluation of the Millstone Unit 1 inservice testing program for pumps and valves for the second 10 year operating cycle has been drafted. Copies of the report should be available before the end of 1985.

5.3.2 Reinspection, Analysis and Repairs of the Reactor Coolant System Piping

NUREG-0313 (Rev. 1) "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping" dated July 1980 sets forth the NRC staff's revised acceptable methods to reduce the intergranular stress corrosion cracking susceptibility of BWR ASME Code Class 1, 2, and 3 pressure boundary piping and safe ends. For plants that cannot fully comply with the material selection, testing, and processing guidelines of this document, varying degrees of augmented inservice inspection and leak detection requirements are presented.

During the Millstone Unit 1 1984 refueling outage (Ref. 40), a total of 215 intergranular stress corrosion cracking (IGSCC) susceptible welds were ultrasonically inspected. Of these, 98 welds were in the recirculation system, two (2) welds were in the shutdown cooling system, 11 welds were in the low pressure coolant injection (LPCI) system, 41 welds were in the reactor water cleanup (RWCU) system, 15 welds were in the core spray system and 48 welds were in the isolation condenser system. The percentage of welds inspected in each pipe size of each system varied from 24% to 100%. In the recirculation piping system, except for eight (8) 4" bypass branch and cap welds, all IGSCC susceptible welds with pipe size >4 inches were inspected. The licensee indicated that eight (8) flued-head penetration welds (2 in LPCI system, 2 in RWCU system, 2 in core spray system, and 2 in isolation condenser system) could not be ultrasonically examined because of access limitation.

The results of the UT inspections indicated that a total of 21 welds showed reportable linear indications. Of these, one was a 28" recirculation weld, six were 12" recirculation riser welds, two were 10" core spray welds, seven were 8" Reactor Water Cleanup (RWCU) welds, and five were isolation condenser welds. The reported linear indications were predominantly in circumferential orientation and were located in the heat-affected zone (HAZ). The deepest crack was reported in a RWCU weld with a crack depth of 0.34 inch. 360° intermittent indications with a maximum depth of about 0.1 inch were reported in a 10" core spray weld.

One 12" riser weld showed two small leaks after application of induction-heating-stress-improvement (IHSI). Prior to the application of IHSI, only geometry

indications were reported on this weld. Of the 21 welds showing linear indications, seven welds, six 12" riser welds and one 16" RWCU weld were over lay repaired, 13 welds were replaced with low carbon stainless steel material and one weld was not repaired (28" recirculation weld), which was justified by fracture mechanics analysis. This weld was reported to have a total crack length of about 11 inches and a maximum crack depth of 0.3 inch.

The licensee indicated that 83 welds in the recirculation system were IHSI treated during the outage. Because of geometry constraint or access limitations, 15 IGSCC susceptible welds in the recirculation system were not treated by IHSI. Ultrasonic examinations were performed on each weld before and after application of IHSI. There are no significant differences in UT results before and after IHSI. The defective, unrepaired 28" recirculation weld was treated by IHSI to prohibit further crack growth.

A total of 26 IGSCC susceptible welds in the isolation condenser core spray and RWCU system were replaced with low carbon stainless steel materials and welded with low carbon filler metals (308L and 316L). Fifteen of these welds were reported to show linear indications. Heat sink welding was applied to the joint connecting to the existing stainless steel materials. The licensee indicated that the piping replacements were performed in accordance with the requirements in ASME Code, Section XI, 1980 Edition through Winter 1980 Addenda.

The evaluations indicated that the 28" recirculation weld did not require weld overlay repair. The crack growth analysis was performed in accordance with the guidelines in SECY-83-267C. Analysis showed that calculated crack growth in the weld at the end of an 18-month period was well within the 2/3 of ASME Code, Section XI, IWB 3640 limits.

The weld overlay was designed and fabricated in accordance with the guidelines in Generic Letter 84-11. Seven defective welds (1 16" isolation condenser weld and 6 12" riser welds) welds were weld overlay repaired. The overlay thickness was designed to meet the ASME Code Section XI IWB 3640 limits. The designs were based on the conservative assumption that the reported cracks were through-wall cracks. The designed overlay thickness did not take credit of the first pass. Penetrant testing (PT) was performed after the first pass and at the completion of the weld overlay. UT was also performed to ensure the integrity in bonding and the soundness of the overlay. The licensee reported that the average as-built overlay thickness (average of minimum and maximum thickness measurements) varied from 0.255 inch to 0.465 inch.

In summary, a total of 215 IGSCC susceptible piping welds in the recirculation, shutdown cooling, LPCI, core spray, RWCU and isolation condenser systems were ultrasonically examined during the Millstone Unit 1 1984 refueling outage. The UT results indicated that 21 welds showed linear crack indications. Of these, seven welds were weld overlay repaired, 13 welds were replaced and one weld (12" riser weld) was not repaired, which was justified by fracture mechanics analysis. In addition, 83 welds, including the defective unrepaired weld in the recirculation system, were treated with IHSI. The staff approved for continued interim operation the use of all materials (NRC Ltr dated August 14, 1985), the weld overlays, and the reinspection program and concluded that leakage monitoring frequency should be increased. Also, because of residual concern for IGSCC, inspection plans for reload 10 outage, as well as plans for modification including replacement if appropriate, should be submitted for NRC review.

With respect to this issue, Millstone Unit 1 is not unique in that IGSCC is a generic problem for all operating BWR plants. The long term resolution will be achieved along with all other similarly affected BWR plants.

5.3.3 Reactor Coolant Pressure Boundary Leakage Detection (SEP Topic V-5)

10 CFR 50 (GDC 30) as implemented by Regulatory Guide 1.45 and SRP Section 5.2.5, prescribes the types and sensitivity of systems and their seismic, indication and testability criteria necessary to detect leakage of primary reactor coolant to the containment or other interconnected systems.

In IPSAR Section 4.16, the staff concluded that:

(1) The licensee should provide a seismically qualified method for determining reactor coolant pressure boundary (RCPB) leakage or provide procedures that specify actions to be taken in the case of a seismic event and failure of the leakage detection equipment (e.g., plant shutdown).

(2) The method should be testable during operation.

(3) The licensee should evaluate leakage detection sensitivity requirements in conjunction with the resolution of Topic III-5.A for the purpose of establishing appropriate limiting conditions for operation.

By letter dated November 1, 1983, the licensee proposed changes to the plant Technical Specifications to address the matter. The staff approved the Technical Specifications by letter dated May 23, 1984. The Technical Specification change requires initiation of an orderly plant shutdown if leak rate cannot be determined as required by item (1) above.

5.4 Reactor Vessel

NUREG-0569, "Evaluation of the Integrity of SEP Reactor Vessels" dated October 1979 reported that the Millstone 1 reactor vessel was designed to the 1965 Edition of ASME Code Section III. A complete preservice nondestructive examination was performed on components of the reactor vessel and no significant indications were reported. Based on review of design criteria and the results of the preservice examination, the staff concluded that the initial integrity of the reactor vessel was acceptable. Inservice inspections have been performed on the vessel in accordance with ASME Code Section XI rules since 1972. Except for flaws found in one feedwater nozzle safe end (see Section 1.3.2(5)), and in the control rod drive return line and feedwater nozzles, no serious flaws have been detected. The reactor vessel conforms with pressure-temperature operating limits that are in accordance with Appendix G, 10 CFR Part 50. NUREG-0744 "Resolution of The Reactor Vessel Materials Toughness Safety Issue" dated September 1981 describes the method acceptable to the NRC, for complying with 10 CFR 50, Appendix G, Section V.C.

5.4.1 Surveillance Specimens

The reactor vessel description in the FSAR (Ref. 12) notes that vessel material surveillance samples are located within the reactor vessel to enable periodic monitoring of material properties with exposure. The program includes specimens

of the base metal, weld zone metal, heat affected zone metal and standard specimens. These specimens receive neutron exposures more rapidly than the vessel wall material and, therefore, lead it in integrated neutron flux.

About 120 samples were initially inserted in the vessel and are being periodically removed for Charpy V-notch and tensile strength tests. The Millstone 1 material surveillance program was reviewed and accepted by the staff. By letter dated April 12, 1985 (Ref. 41), the licensee forwarded the results of the most recent inspection of surveillance specimens in accordance with 10 CFR 50 Appendix H, Section III A. At the end of Fuel Cycle 9, April-May 1984, surveillance capsule number 2 was removed from the Millstone Unit No. 1 reactor vessel. This capsule contained flux wires for neutron fluence measurement, and Charpy and tensile test specimens for material property evaluation.

In addition to the flux wire testing, a computer analysis established the vessel peak flux location and magnitude. The irradiation effects, as established in the Charpy and tensile testing, were projected to the vessel end-of-life (EOL). Pressure-temperature operating limits curves valid to 16 effective full power years (EFPY) were developed to the May 1983 requirements of 10 CFR 50, Appendix G.

The licensee reported the following significant results and conclusions:

(1) The vessel peak flux occurs at a height of 88 inches above the bottom of the active fuel, and at azimuthal locations 24.5 degrees to either side of the vessel quadrant references. The maximum accumulated neutron fluence at the vessel EOL (32 EFPY) is 1.2×10^{18} n/cm² (this includes a 25% addition to account for flux wire testing uncertainties).

(2) The irradiated plate and weld metal impact curves (as compared to the unirradiated data) show a RT_{NDT} shift of 58°F for plate material, and 35°F for weld material. The RT_{NDT} shifts were compared to those predicted per Regulatory Guide 1.99, Revision 1. The plate material RT_{NDT} shift is greater than the predicted shift of 38°F; and the weld material RT_{NDT} shift is less than the R.G. 1.99 prediction. The method used in calculating irradiation shift versus EFPY was modified to account for the surveillance test results of the plate material.

(3) The irradiated tensile specimens were tested and the results compared to the unirradiated data. Increased material strength due to irradiation was exhibited (as expected) and the increase represents a less than 10% change in properties.

(4) The calculated EOL values of RT_{NDT} and upper-shelf energy (USE) were compared to the limits in 10 CFR 50 Appendix G for vessel annealing. The EOL value of RT_{NDT} for the plate material (123°F) is the limiting value and is below the Appendix G annealing limit of 200°F. The USE values for both plate and weld materials are significantly above the Appendix G minimum limit of 50 ft-lb for annealing. Therefore, provisions for annealing the RPV before 32 EFPY of operation need not be considered.

(5) Pressure-temperature operating limits curves were developed for three reactor conditions: hydrostatic pressure tests; heat-up and cool-down without core critical; and core critical operation. The curves are valid up to 16 EFPY of operation. The licensee will evaluate the curves and prepare a Technical Specification submittal prior to July 1986.

The evaluation of this new information is in progress. The staff has nevertheless concluded that the combination of inservice inspections, conservative pressure-temperature operating limits and the use of materials having acceptable fracture toughness provides assurance that the vessel integrity will be maintained at an acceptable level throughout service life. The generic safety items applicable to Millstone 1 (low upper shelf toughness, sensitized stainless steel safe ends, and CRD return line and feedwater nozzle cracking) have been successfully resolved and will not adversely affect the integrity of the reactor vessel.

5.4.2 Reactor Water Quality (SEP Topic V-12A)

Reactor water quality is controlled to: 1) reduce damage to components of the power plant due to chemical and corrosive attack, 2) reduce the fouling of heat transfer surfaces and mechanical parts, and 3) reduce impurities available for activation in neutron flux zones. Reactor water quality is achieved and maintained by filtration and demineralization with the clean-up demineralizer system and condensate demineralizer system, and by suitable selection of system materials.

10 CFR 50 (GDC 14), as implemented by Regulatory Guide 1.56, requires that the reactor coolant pressure boundary (RCPB) have minimal probability of rapidly propagating failure. This includes corrosion-induced failures from impurities in the reactor coolant system. The safety objective of the SEP review is to ensure that the plant reactor coolant chemistry is adequately controlled to minimize the possibility of corrosion-induced failures.

IPSAR Section 4.19.1 required the licensee to revise its Technical Specifications for chlorides and conductivity to be consistent with Regulatory Guide 1.56 or provide justification for not doing so.

The licensee proposed Technical Specification changes by letter dated December 28, 1983. The staff approved the Technical Specifications by letter dated June 21, 1984. The staff concluded that the Technical Specifications regarding reactor water conductivity and chloride concentration met Regulatory Guide 1.56 limits and provided adequate protection for the primary coolant pressure boundary.

5.5 Component and Subsystem Design

5.5.1 Reactor Coolant Pumps

The FSAR (Ref. 12) describes the two main recirculation pumps, one in each of the two loops, as single stage, centrifugal units with mechanical shaft seals driven by variable speed induction motors. The flow from each recirculation pump becomes the driving flow for 10 jet pumps. The related SEP topic IV-3 "BWR Jet Pump Operating Indications" and III 10 C "Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves" are summarized below.

5.5.1.1 BWR Jet Pump Operating Indications (SEP Topic IV-3)

If a jet pump BWR operates with a degraded jet pump, it may become impossible to reflood the core in the event of a LOCA. The safety objectives of this topic were to assure that the core flow could be determined and jet pump failure could be detected for a range of crack/break sizes at various locations on the pump.

The plant design was reviewed (Ref. 39) with regard to General Design Criterion 35 of Appendix A to 10 CFR Part 50 as it relates to the ECCS design to provide an abundance of core cooling.

Reactor Operating Experience Newsletter 73-3, issued March 30, 1973, described three occasions where actual jet pump flow malfunctions had been identified by individual jet pump flow indicators. By letter dated September 19, 1975, Commonwealth Edison Company submitted a technical specification change request for Dresden and Quad Cities stations to eliminate license requirements for jet pump flow indication. Acceptance of the change would have resulted in deletion of established requirements for individual jet pump flow indicator checks. The request raised a concern with the staff due to a history of jet pump problems such as failures of retainer bolt keepers and related components. In February 1980, a jet pump holddown beam bar failed at Dresden Unit 3 and resulted in jet pump displacement. This event renewed interest in jet pump component integrity and assurance of jet pump operational integrity. As a result, the NRC issued IE Bulletin 80-07, "BWR Jet Pump Assembly Failure" on April 4, 1980, and a Supplement dated May 13, 1980. The Bulletin raised a concern that the holddown beam assemblies and a subsequent jet pump function could degrade significantly during operation and lead to jet pump disassembly and possibly reduced margins of safety during postulated accidents. Therefore, licensees of GE designed BWR-3 (Millstone-1 is a BWR-3) and BWR-4 facilities were required to take actions which would assure that adequate surveillance of jet pump operability is maintained.

Northeast Utilities responded to IE Bulletin 80-07 by letter dated April 29, 1980, and agreed to implement a modified jet pump surveillance program at Millstone 1.

On this basis, the staff concluded that the licensee's modified jet pump surveillance program was sufficient to detect jet pump failure and therefore acceptable.

5.5.1.2 Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves (SEP Topic III-10.C)

In July 1976, all BWR facilities which had completed the Low Pressure Coolant Injection (LPCI) system modification to remove the LPCI loop selection logic, were required to incorporate technical specification surveillance requirements on recirculation pump discharge and bypass valves. The recirculation pump discharge and bypass valves were required, for these plants, to close upon initiation of LPCI to prevent the loss of cooling water by reverse flow through the pump or its bypass line and out the break.

Millstone Unit No. 1 retained LPCI loop selection logic and therefore was not subject to this requirement. Furthermore, since the unmodified LPCI was susceptible to single failures that could eliminate all LPCI flow, no credit was given for any LPCI flow in the Millstone Unit No. 1 ECCS analysis.

The Millstone 1 LPCI logic network was designed to direct LPCI flow to the intact recirculation loop in the event of a loss of coolant accident (LOCA). The logic network also was designed to close the suction and discharge valves of the intact loop to prevent LPCI flow from bypassing the core and flowing out the break. The staff review of Topic III-10.C indicated that since the LPCI loop selection logic was not modified at Millstone Unit No. 1, the primary concern was not applicable. However, to provide redundancy, the Millstone 1 design incorporated automatic closure of both the suction and discharge valves (on the unbroken loop only) upon receipt of a LOCA signal.

Assumed single failure of the loop selection logic system could result in selection of the wrong loop as the broken loop. Therefore, General Electric Company recommended, and the staff required that the automatic closure feature on the suction valve be disabled. This makes break isolation a non-credible event which does not require analysis: Two independent failures are necessary, i.e., closure of the discharge valve in the broken loop (requiring loop selection logic failure), and closure of the suction valve in the same loop (for example, by operator error).

With the modification (suction valve closure disconnected), single failure to close of the discharge valve on the unbroken loop now causes failure of the LPCI system. However, this LPCI failure has already been taken into account by the ECCS-LOCA analyses on all BWR-3 plants. No credit is assumed for LPCI operation on BWR-3 plants, since single failure of the loop selection logic can cause complete failure of LPCI. Stated another way, the change merely creates another potential path to a failure that is already accounted for in the ECCS-LOCA analyses, that is failure of LPCI; however, the change precludes possibility of an event which has <u>not</u> been accounted for in the analyses, i.e., break isolation.

On May 24, 1979, the staff was informed that the LPCI loop selection logic was being changed to negate the LPCI signal that closes the recirculation line suction valves. This modification permits the closure of the suction valves by remote manual action but will remove any automatic closure associated with LPCI system operation. The staff found the change acceptable.

5.6 Residual Heat Removal System (RHR)

5.6.1 Residual Heat Removal (RHR) System Heat Exchanger Tube Failures (SEP Topic V-10A)

The safety objective of this review was to assure that impurities from the cooling water system were not introduced into the primary coolant in the event of shutdown cooling system heat exchanger tube failure. This was expanded to include adequate monitoring to assure no leakage of radioactive material in the other direction - into the service water and thus to the environment.

The bases for the review included: (1) the NRC's Standard Review Plan (SRP) 9.2.1, which requires that the service water system include the capability for detection and control of radioactive leakage into and out of the system and prevention of accidental releases to the environment; (2) SRP 9.2.2, which requires that auxiliary cooling water systems (such as the shutdown cooling system) include provisions for detection, collection and control of system leakage and means to detect leakage of activity from one system to another and preclude its

release to the environment; and (3) SRP 5.2.3, which discusses compatibility of materials with reactor coolant and requires monitoring and sampling of the primary coolant system. These Standard Review Plans were used only for comparison of Millstone 1 against today's criteria and not as licensing requirements when the plant incorporates other equally viable means of accomplishing the stated goals. The primary coolant is cooled by intermediate water which in turn is cooled by plant service water (salt water).

The primary coolant passing through the shutdown cooling system heat exchangers is at a pressure of approximately 150 psig at the heat exchanger inlet, 140 psig at the outlet. The shutdown cooling system (SCS) heat exchangers are cooled by reactor building closed cooling water (RBCCW) flow at a pressure of approximately 60 psig at the inlet and 50 psig at the outlet. Thus, it is evident that under normal conditions flow through leaking tubes would be in the direction of the RBCCW system. There is a requirement, both in the Millstone 1 Technical Specifications (3.6.C and 4.6.C) and in the plant procedures, to sample reactor coolant every four hours during the startup and at steaming rates less than 80,000 pounds per hour. The samples must be analyzed for conductivity and chloride. The Millstone 1 reactor coolant system includes a continuous conductivity monitor which would alert the operators to a highly unlikely contaminant intrusion from RBCCW or to a breakthrough in the feedwater system ion exchangers. The technical specifications also require, during operation at steaming rates greater than 80,000 pounds per hour, a reactor coolant sample for conductivity and chloride every 96 hours and any time that the continuous monitor indicates abnormal conductivity for more than one minute.

All SCS components through which the primary coolant flows (including the heat exchanger tubing) have been designed for 1250 psig at 350°F, according to the Millstone 1 Final Safety Analysis Report (Ref. 12). This design, plus the inservice inspection requirements required by CFR 50.55.a(g), adds assurance that the chances of leakage either into or out of the SCS will be minimized.

The RBCCW heat exchangers, through which RBCCW flows at an inlet pressure of approximately 75 psig (outlet 70 psig), are cooled by the service water system at a heat exchanger inlet pressure of approximately 10 psig. The RBCCW is designed to provide leakage detection either into or out of the system (and thus into or out of SCS/into service water). The means of detecting leakage from SCS into RBCCW is the combination of a system radiation monitor and the high level alarm on the RBCCW surge tank. Leakage from RBCCW into either SCS or service water would be detected by the low level alarm on the surge tank.

In addition to the design features, plant procedures require the weekly sampling of the RBCCW system, which includes monitoring hydrazine (used for corrosion inhibition), pH, conductivity and the volume of water added to the system (an indication of leakage). Monthly samples monitor activity and chloride.

As a final means of protection of the environment against discharge of radioactivity, the service water system includes a radiation monitor on its discharge to alert the plant operators to the highly unlikely leakage of any combination of the SCS heat exchangers (or any other radioactivity - carrying component cooled by RBCCW) and the RBCCW heat exchangers.

The staff concluded that the chances of radioactive leakage to the environment were minimized by the design of the SCS and the RBCCW system and the included

radioactivity monitors and that the chance of undetected leakage into the primary coolant system is acceptably small. The staff therefore concluded that Millstone Unit No. 1 satisfied the NRC requirements.

5.6.2 RHR System Reliability (SEP Topic V-10B)

The safety objective for this topic was to ensure reliable plant cooldown capability using safety-grade equipment subject to the guidelines of SRP 5.4.7 and BTP RSB 5-1. The Millstone 1 systems were compared with these criteria. The staff concluded that the Millstone 1 systems met the topic safety objective with the following comments:

- The Shutdown Cooling System is not considered to be a safety-grade system, but the ECCS systems, including isolation condenser, FWCI, ADS, LPCI, and Core Spray, can be used for reactor cooldown. (MP-1 Probabilistic Safety Study - NNECO Ltr July 10, 1985).

- Component redundancy and single-failure-proof requirements are not met in the case of the shutdown cooling system, in that failure of the AC-powered suction valve inside containment would result in loss of the system, but the ECCS systems would be available.

- Component redundancy (and single-failure-proof) requirements are also not met in the case of the isolation condenser. The single supply (steam) and return (condensate) lines each include an AC-powered isolation valve which is inside containment. However, these valves are normally open and fail open on loss of electrical power. It would take simultaneous spurious isolation of the condenser and loss of the power supply to create any problem. If this highly-unlikely scenario were to occur, the ECCS systems would be available.

- No procedure existed to perform a shutdown and cooldown to cold conditions with the systems identified. However, the licensee has since developed and implemented such a procedure.

5.6.3 RHR System High and Low Pressure Isolation and Interlocks (SEP Topics V-11A/B)

The shutdown cooling system (SDCS) at Millstone was designed to withstand reactor coolant system (RCS) design pressure. Therefore, the isolation valve interlocks required by BTP RSB 5-1 are not applicable. The isolation valves have interlocks to prevent opening and to automatically close when RCS temperature exceeds the 350°F design temperature of the SDCS.

A bypass line provides a flow path from each SDCS pump discharge to its suction to provide the necessary flow to prevent pump overheating due to a discharge isolation valve being closed. Cavitation protection is provided by the interlock which trips the pumps (and prevents their starting) if the suction pressure falls below 4 psig. A temperature interlock also protects the pump from overheating by tripping the pump if the temperature is greater than or equal to 350°F.

There are no requirements in the Millstone 1 Technical Specifications for testing the SDCS interlocks and isolation circuitry during SDCS operation. The

electrical circuitry is not designed to permit testing while the system is operating without a momentary interruption in system operation. Although licensed prior to the issuance of RG 1.68, concerning preoperational and startup testing, Millstone 1 conducted such tests and has demonstrated SDCS operability on several occasions as noted by the SEP Review of Safe Shutdown Systems.

The SDCS does not meet the current licensing criteria of BTP RSB 5-1 in accordance with SEP Topics V-10.B and V-11.A, in that the SDCS is not considered to be a safety-grade system and is subject to single failure of the valves inside containment. The SDCS does meet the criteria of SEP Topic V-11.B in that the SDCS is designed for full reactor pressure but less than full reactor temperature (for which temperature interlocks have been provided) and is therefore acceptable.

5.7 Feedwater and Control Rod Drive Return Line Nozzle Cracking

Inspections at boiling water reactor (BWR) plants in the United States that have feedwater nozzle/sparger systems disclosed some degree of cracking in the feedwater nozzles of the reactor vessels. Similar cracking has occurred in BWR control rod drive return line nozzles.

Feedwater is distributed through spargers that deliver the flow evenly to assure proper jet pump subcooling and help maintain proper core power distribution. An essential part of the sparger is the thermal sleeve, which projects into the nozzle bore and is intended to prevent the impingement of cold feedwater on the hot nozzle surface. This surface is usually heated to essentially reactor water temperature by the returning water from the steam separators and steam dryers. However, bypass leakage past the thermal sleeves allows relatively cold feedwater to impinge on the hot nozzles. The feedwater, when heated during power operation by extraction steam from the main turbine, is typically about 100°F to 200°F colder (depending on reactor design) than the reactor water. When the feedwater heaters are not in service, as during startups and shutdowns, the differential could be equal to or greater than 400°F. The bypass leakage past a loose thermal sleeve causes a fluctuation in the metal temperature of the feedwater nozzle and results in metal fatigue and crack initiation. The cracks are then driven deeper by the larger temperature and pressure cycles associated with startups, shutdowns, and certain operational transients.

All repaired feedwater nozzles at Millstone-1 and other BWRs have met the requirements and limits of the American Society of Mechanical Engineers (ASME) Boiler and Pressure vessel code. No additional action was necessary since only relatively small amounts of base metal have been removed by repair operations. The removal of cladding, as a means of minimizing crack initiation, has not altered the safety margins because the clad thickness is not considered in ASME Code reinforcement requirements.

NUREG-0619 "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking" dated November 1980 describes the technical issues, the independent technical evaluations performed by the staff and the General Electric Company (GE), and the staff's technical positions and plans for continued implementation of the technical positions.

5.8 Reactor Water Cleanup System

The RWCU system takes suction on the RCS, cools the water by circulation through regenerative and non-regenerative heat exchangers, and lowers the water pressure by the use of a pressure control valve. After passing through the low pressure filter and cleanup portions of the system, the water is pumped at high pressure through the regenerative heat exchanger and back to the reactor via the feed line. The suction side of the system has three motor-operated isolation valves, an inboard valve, a pump suction valve, and a pump bypass valve. Isolation on the discharge side is provided by a MOV and a check valve. The MOVs cannot open if the pressure in the low pressure portions of the system is higher than its designed pressure. They will automatically close on high RWCU system temperature, low flow, high RWCU system pressure, low reactor level, high drywell pressure, or loss of control power. However, the interlocks for these valves all use the same sensors and relays. Each MOV has position indication in the control room.

Isolation provisions of the RWCU system do not meet the current licensing criteria since the interlocks for the isolation valves are not independent as required by BTP EICSB-3.

The licensee committed in Section 4.18 of the IPSAR to install an independent pressure interlock. As part of ISAP, the licensee will reevaluate the merits of this proposed modification.

6 ENGINEERED SAFETY FEATURES (ESFs)

ESFs are provided to reduce the consequences of postulated accidents. They include emergency core cooling systens (ECCSs), steam line restrictors, control rod velocity limiters, control rod housing support, standby liquid control systems, and containment systems. Also included at the Millstone 1 plant are an emergency diesel generator and an emergency gas turbine generator. The ECCSs include feedwater coolant injection (FWCI), two core spray sub-systems (CSs) low pressure coolant injection/containment coolant subsystem (LPCI), an isolation condenser, an automatic pressure relief (APR) subsystem.

These ESFs, with the exception of the feedwater equipment, are not necessary for normal plant operation. During normal operation, when normal auxiliary power is available, heat is removed from the core through the steam-turbine-condenser cycle or through the use of the shutdown cooling system. These safety features, adequately described in the FSAR (Ref. 12), were selectively re-evaluated and modified where necessary (auto-pressure relief, Section 5.1 and isolation condenser, Section 5.2, for example).

6.1 Organic Materials and Post-Accident Chemistry (SEP Topic VI-1)

The design basis for selection of paints and other organic materials was not documented for most operating reactors. Topic V1-1 reviewed the plant design to assure that organic materials, such as organic paints and coatings, used inside containment do not behave adversely during accidents when they may be exposed to high radiation fields. In particular the possibility of coatings clogging sump screens should be minimized.

Low pH solutions that may be recirculated within the containment after a Design Basis Accident (DBA) may accelerate chloride stress corrosion cracking and increase the volatility of dissolved iodines. The objective of Topic V1-1 was to assure that appropriate methods are available to raise or maintain the pH of solutions expected to be recirculated within containment after a DBA.

An assessment of organic materials in the containment included the review of paints and other organic materials used inside the containment including the possible interactions of the decomposition products of organic materials with Engineered Safety Features (ESF), such as filters. The assessment of post accident chemistry included proper water chemistry in the containment spray during the injection phase following a DBA and methods to raise or maintain the pH of mixed solution in the containment sump

By letter dated September 30, 1981, the licensee provided references to the types and amounts and the environmental testing of organic coating materials used in the plant. Protective coating systems comprise the bulk of the organic material (outside of electrical cable insulation) in the containment. Accident effects on cable insulation are reviewed under NUREG-1458.

The torus ($73,000ft^2$) and the drywell ($20,000ft^2$) were originally coated with zinc rich epoxy primer. This was top-coated with phenolic paint.

Periodic visual inspections of the paint within the containment revealed that although the paint in the drywell was performing satisfactorily, paint in the torus was blistering and peeling. In November 1980, the torus was repainted to correct this problem. Areas containing loose paint were scraped, wet sanded, and spot primed with epoxy primer. This primer was qualified for use in the post-accident environment according to ANSI N5.9-1967 and ANSI N101.5-1970 criteria.

The torus was then repainted with water based epoxy, qualified for use under DBA conditions. Qualification was conducted to meet the requirements of ANSI N101.2-1972, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," and N5.12-1974, "Protective Coatings (Paints) for the Nuclear Industry."

Epoxy and phenolic based paints are among the most radiation resistant, remaining serviceable after radiation dosage in excess of 10^9 rads. For a severe Design Basis Accident (DBA), 10^8 rads would be a conservative dose estimate. Most paint areas would receive less than 10^7 rads.

Epoxy and phenolic resins are also stable to temperatures of the order of 300°F and to mildly acidic or basic aqueous solutions.

On the basis of the above information, the staff found that there is reasonable assurance that the radiation, thermal and chemical resistance of the organic coatings used in the plant is sufficiently high that deterioration under DBA conditions would not interfere with operation of engineered safety features.

Certain small surface areas of plant equipment were coated with industrial coatings whose radiation resistance has not been tested. However, because only small areas of these coatings are exposed in the containment, the staff concluded that their failure under accident conditions would not present a significant safety hazard.

Very small amounts of gas are evolved when aromatic organic compounds of the types found in radiation-resistant plastics are irradiated. For example, a phenolic plastic irradiated to a dose of 10^9 rads produced 3 ml (STP) of gas per gram of plastic. For the approximately 50 cubic feet of organic coating existing in the containment, approximately 15 cubic feet of gas would be generated for the conservatively estimated DBA dose of 10^8 rads. The gas is mostly hydrogen and less than a tenth of it is volatile organic compounds. The presence of this small amount of organic gases in containment after a DBA would not interfere with the adsorption of organic iodides by the charcoal filters in the standby gas treatment equipment.

The amount of hydrogen from this source is small compared to that which could be produced in a DBA from the zirconium-water reaction, from the radiolysis of water, or from the reaction of the zinc in inorganic zinc coatings with high temperature borated solutions. Hydrogen generation from the latter sources is reviewed later in Section 6.2.3.

The flaking and peeling of the originally applied paint in the torus indicated the need for periodic inspection of the protective coatings inside containment. In the letter of September 30, 1981, the licensee proposed such inspection, and specified that the inspection and documentation procedures would follow the

guidelines for the examination of test specimens from weathering and chemical exposure tests given in ANSI N101.2-1972, ANSI N101.4-1972 and ANSI N5.12-1974.

The licensee committed to inspect the coating during each refueling outage. The staff found that the proposed inspection procedures and frequency are acceptable for monitoring the condition of coatings.

Millstone Unit No. 1, uses high-purity demineralized water in the reactor vessel and for post-accident containment spray and core spray. The pressure suppression pool also contains demineralized water. Post-accident iodine control is accomplished through containment integrity and operation of the standby gas treatment system, and does not rely on chemical additive in the containment spray system.

The licensee indicated that the water in the Condensate Storage Tank and in the torus of the pressure suppression pool is sampled weekly and monthly, respectively, to ensure that chemical impurities do not exceed the normal plant operating limits. If necessary, the Condensate Storage Tank and the torus can be drained and flushed during maintenance. The sodium pentaborate solution in the Standby Liquid Control Tank contains less then 0.5 ppm chloride. The non-metallic thermal insulation materials for the austenitic stainless steel components inside containment are in compliance with the regulatory positions of Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel."

The staff determined that the use of demineralized water in the reactor vessel, in the post-accident containment and core spray, and in the pressure suppression pool provides reasonable assurance that, at the onset of an accident, the conductivity, pH, and chloride concentration of the water will remain within the normal plant operating limits, consistent with the acceptance criteria of Standard Review Plan Section 6.1.1 for boiling water reactors. The chloride content of the sodium pentaborate solution in the Standby Liquid Control System is also consistent with the acceptance criteria of Standard Review Plan 6.1.1 for boiling water reactors. The licensee complies with the provisions of Regulatory Guide 1.36. Compliance with the regulatory guide provides assurance that the levels of leachable chloride and flouride in non-metallic insulation materials that come in contact with austenitic stainless steel used in fluid systems important to safety, are properly controlled, so that stress corrosion cracking is not promoted.

Based on the above considerations, the staff determined that proper water chemistry can be maintained in the containment spray during injection following a design basis accident, and in the containment spray and sump water during recirculation, to reduce the likelihood of stress corrosion cracking of austenitic stainless steel in engineered safety feature materials after the accident.

The staff therefore concluded that the organic materials used in the plant are acceptable and will not interfere with the operation of required safety features.

6.2 Containment Systems

The containment system includes the primary containment which is a pressure suppression system, and the secondary containment which is the reactor building. The primary containment consists of a drywell, which encloses the reactor vessel

and primary coolant system, a pressure suppression chamber about half filled with water, a connecting vent system between the drywell and suppression chamber, isolation valves, containment cooling systems, and other service equipment. The reactor building completely encloses the reactor and the primary containment system to provide secondary containment. The primary containment is normally inerted during operation, i.e., insufficient oxygen to sustain combustion.

6.2.1 Containment Structural Integrity Tests (SEP Topic III-7D)

To assure that the containment structure responds satisfactorily to the postulated design pressure loads, a program of measurements, namely the Containment Structural Integrity Test Program, was required. The program was to demonstrate the correlation with theoretically predicted responses and provide the adequacy of the structure with respect to the quality of construction and material. The scope of this safety topic evaluation was to review the adequacy of the structural integrity testing procedure used by the licensee and, using current review criteria as a basis, to evaluate the measurements taken during the test.

A review of the static structural integrity testing procedures and the test data used by the licensee involved searching the docket files. A comparison of the testing procedures and test results with current requirements was made in order to assess their adequacy in relation to the safety objective.

The primary review document was the "Containment Report", Appendix "D" of the MP-1 FSAR. The following information was extracted from this document and from the 1971 and 1980 editions of the ASME Boiler and Pressure Vessel Code.

The drywell, suppression chambers and interconnecting vent system were constructed in accordance with the 1965 ASME Boiler and Pressure Vessel Code (ASME-B&PV). All materials, design, fabrication, inspection, and testing were, as stated in the Containment Report (Appendix D of the MP-1 FSAR), in accordance with Section III, Subsection B of that code. The drywell, suppression chamber and interconnecting vent system were constructed of ASTM-A516, grade 70 steel (ultimate stress = Su = 70 ksi, Yield Stress = Sy = 38 ksi, Allowable Stress = S = 17.5 ksi). A maximum internal design pressure of 62 psig at 281°F was specified under accident conditions. The drywell, suppression chamber and interconnecting vent system were subjected to a pneumatic test pressure of 71.3 psig (1.15 x design pressure) in June 1967. The test was conducted once with the system dry and again with the suppression chamber partially filled with water. For the test loading the allowable stresses were listed in the Containment Report as follows:

- General Primary Membrane Allowable Stress = 1.1 x 17.5 = 19.25 ksi
- Primary Membrane (general plus local) plus Primary Bending Allowable Stress = 1.5 x 19.25 = 28.88 ksi
- Primary Membrane plus Primary Bending plus Secondary Allowable Stress = 3 x 17.5 = 52.5 ksi

According to the Containment Report, none of these stress intensity levels were exceeded in the test.

The current (ASME - B&PY 1980 Code) criteria for the strength of ASTM-A516, grade 70 steel is : Su = 70 ksi, Sy = 38 ski and S = 19.3 ksi for class MC vessels. Based on a maximum internal design pressure of 62 psig at 281°F, the drywell, suppression chamber and interconnecting vent system would under current ASME-B&PV Code Requirements, be subjected to a pneumatic test pressure of 1.1 x 68.2 psi. The ASME-B&PV 1980 Code allowable stresses for the test loading would now be:

- General Primary Membrane Stress Intensity = 0.75 x 38 = 28.5 ksi
- Primary Membrane plus Primary Bending Stress Intensity = 28.5 ksi (for the most conservative requirement)
- Primary Membrane plus Primary Bending plus Secondary stress intensity is not directly stated (NE 6322) however, Table 3.8.2-1 of the NRC Standard Review Plan indicates that an appropriate value would be 3 x 19.3 = 57.9 ksi

From the above information it is noted that the static test loading/stress intensity requirements were the same or conservative in comparison to current standards.

The test procedure with respect to test duration and temperature was conservative in comparison to current ASME-B&PV requirements.

Based on the review, the staff concluded that the static structural integrity test procedures and results were conservative with respect to current requirements. No significant deviations in the test procedures were noted from current requirements.

6.2.2 Containment Isolation System and Leak Testing (SEP Topics VI-4 and VI-6)

These topics (Ref. 5) concern the adequacy of containment integrity during accident conditions. Because of the small size and (relatively) low design pressure of the Millstone-1 containment the pressure generated by steam and noncondensible gases during a postulated core melt will fail the containment if no other failure mechanism occurs first. The dominant portion of the risk from nuclear power plants is from core melt accidents, not other (low consequence) releases such as those due to non-core-melt accidents. Because of the characteristics and relative consequences of leakage releases and containment ruptures by overpressure, no benefit can be achieved by increasing the reliability of isolation of the containment since it will fail by overpressure anyway. The staff concluded therefore that neither of these issues has any effect on core melt frequency, exposure, or risk.

Nevertheless, all of the containment penetrations and the isolation capability were reviewed (SEP Topic VI-4). The results of the staff review are presented in the topic evaluation (October 8, 1982) and in Section 4.20 of NUREG-0824. This review concluded that for lines with remote manual isolation valves, leakage detection capability and appropriate procedures should be provided. Based on a license submittal dated February 23, 1983 a staff SER (Topic VI-4) dated July 7, 1983, concluded that adequate detection devices exist in the form of pressure and flow indications, surge tank levels, and sump alarms for the lines in question. These alarms and the operating station for the valves in question are located in the control room. Thus, operation of these valves is

possible during an accident. Additionally, plant procedures exist which describe the circumstances under which these lines should be isolated. Exemptions to the requirements of Appendix J to 10 CFR Part 50 "Primary Reactor Containment Leakage Testing For Water-Cooled Power Reactors" were granted by NRC letter dated May 10, 1985 (Ref. 42). A draft safety evaluation of "Pump and Valve Inservice Testing Program" for the second 10-year inspection interval was issued May 1985. (Ref. 43) Amendment No 94 (Ref. 44) dated December 19, 1983 "Integrated Containment Leak Rate Test of Duration Less Than 24 Hours" changed the technical specifications to allow completion of containment leak rate tests without a time constraint, i.e., eliminated test duration of at least 24 hours.

By letter dated April 17, 1985, notwithstanding SEP review (Topics VI-2D and VI-3) of the energy released within containment during design basis accidents, the NRC noted that the calculated containment pressure/temperature profiles could not be determined acceptable for qualification of electrical equipment inside containment on the basis of existing information and requested further evaluation. The staff based its concern on small steam line breaks inside containment that could result in superheated containment steam temperatures. However, this matter was resolved by staff safety evaluation report on "Environmental Qualification of Electrical Components Important to Safety" dated July 30, 1985.

6.2.3 Combustible Gas Control (SEP Topic VI-5)

The SEP topic VI-5 concerned the potential for combustible gas conditions, i.e., hydrogen production in the post accident conditions due to zirconium water reaction, water radiolysis, and corrosion of metals. As amended on December 2, 1981, 10 CFR 50.44, "Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors" delineated the requirements to prevent the accumulation of combustible gases in containment following design basis accidents. Generic Letter 84-09 dated May 8, 1984 noted the Commission determination that inerted Mark I BWR containments (for which notices on the construction permits were published before November 5, 1970) that do not rely upon safety grade purge/repressurization systems as the primary means of hydrogen control provided the following criteria are met:

(1) The plant has technical specifications (limiting conditions for operation) requiring that, when the containment is required to be inerted, the containment atmosphere be less than four percent oxygen, and

(2) The plant has only nitrogen or recycled containment atmosphere for use in all pneumatic control systems within containment, and

(3) There are no potential sources of oxygen in containment other than that resulting from radiolysis of the reactor coolant.

Amendment No. 101 to Provisional Operating License No DPR-21 for Millstone Nuclear Power Station, Unit No. 1 dated November 1, 1984 changed the technical specifications to limit the oxygen concentration, during normal reactor operation, to 4%. The basis for the change had been submitted earlier by NNECO letter dated August 6, 1982. The staff, therefore, concluded that the requirements for containment combustible gas control are satisfied.

TMI item II F 1.6 Containment Hydrogen Monitor (Ref. 45) requires that a continuous indication of hydrogen concentration in the containment atmosphere be provided in the control room. The staff safety evaluation dated July 30, 1984 concluded that the containment hydrogen monitor installed at Millstone-1 to meet Regulatory Guide 1.97 satisfies all the requirements except for redundancy. By letter dated October 24, 1984 the licensee responded to the staff evaluation and reiterated the logic for only one hydrogen monitor. The essential ingredient of this logic is containment inerting for combustible gas control. During a telephone conference call on February 25, 1985, the NRC staff informed licensee representatives that there was insufficient information concerning:

- Beyond DBA hydrogen monitoring capability
- Hydrogen Monitoring System (HMS) Reliability and Operability requirements
- Emergency Procedure Guidelines relating to the HMS and
- Hydrogen generation risk considering deinerting and reinerting periods.

By letter dated July 5, 1985 the licensee provided additional clarifying information and a commitment to respond to the staff concerns by August 30, 1985.

6.2.4 Primary Containment Structural Improvements

NUREG-0661 "Safety Evaluation Report - Mark I Containment - Long Term Program" dated July 1980 describes the NRC staff's evaluation of the generic criteria and analysis techniques proposed by the Mark I Owners Group for the measurement of the suppression chamber (torus) designs of BWR facilities with the Mark I containment design. The results of this evaluation were applied by a Millstone-1 plant-unigue analysis. The plant unigue analysis identified the plant modifications that were necessary to restore the intended margins of safety in the containment design. In this manner, the functional performance of the containment system was assured for both loss-of-coolant accident (LOCA) and safety-relief valve (SRV) discharge suppression pool hydrodynamic loading conditions.

The reassessment of facilities with the Mark I (Millstone-1 primary containment is the Mark I design) containment system design was required because, during the large-scale testing of the newer Mark III containment system, suppression pool hydrodynamic loads associated with a postulated LOCA were identified which had not been considered in the original design of the Mark I systems. These newly identified loads result from the dynamic effects of drywell air and steam being rapidly forced into the suppression pool during a postulated LOCA. Air injection results in a pool swell event of short duration in which a layer or slug of water rises and impacts structural components above the pool. Subsequent steam injection results in oscillatory condensation loads as a result of the rapid formation and collapse of steam bubbles in the pool. SRV discharge to the suppression pool from the primary system results in similar hydrodynamic loading conditions.

The Mark I Containment Owners Group concluded the generic aspects of the long-term program by submitting the Mark I Containment Program Load Definition Report and the Mark I Containment Program Structural Acceptance Criteria Plant-Unique Analysis Applications Guide. These reports describe the generic suppression pool hydrodynamic load definition and assessment procedures proposed by the Mark I Owners Group for use in plant-unique suppression chamber design analyses.

The proposed procedures were derived from a series of experimental and analytical programs specifically conducted for that purpose.

The staff reviewed the experimental and analytical programs conducted by the Mark I Owners Group, as well as information produced by related NRC research programs. Based on this review, the staff concluded that the proposed generic suppression pool hydrodynamic load definition techniques, as modified by the staff's requirements provide conservative estimates of the dynamic loading conditions resulting from LOCA and SRV discharge events.

The only exception concerned the lack of an acceptable definition of the downcomer "condensation oscillation" loads. The staff required that the Mark I Owners Group develop an acceptable load definition procedure for "tied" downcomers, based on full-scale test facility (FSTF) measurements, that adequately segregates the dynamic loading components in the downcomer-vent header connection and in the tie-bar.

In addition, the staff identified confirmatory requirements for additional FSTF testing to establish the uncertainty (i.e., relative error) in the magnitude of the "condensation oscillation" loads, and for analyses to establish the effects of compressibility on the magnitude of pool swell loads derived from scale testing facilities.

By letter dated September 12, 1984, the staff determined that except for some selected items still undergoing review all of the modifications to the Millstone-1 primary containment have been made in accordance with the generic acceptance criteria contained in Appendix A of NUREG-0661. On this basis the staff included that the licensee's analysis verifies that the modifications have strengthened the containment sufficiently to meet the originally intended design safety margins for the Millstone-1 Mark I containment.

6.3 Emergency Core Cooling Systems

As noted in the FSAR (Ref 12) the emergency core cooling system is automatically placed in operation whenever a loss of coolant condition is detected.

6.3.1 Emergency Core Cooling System Actuation System (SEP Topic VI-7A.3)

The staff evaluation resulted in two issues:

- Testing of Core Spray System Pump Space Coolers that cool the corner rooms in the reactor building

- Testing of the Emergency Service Water System (ESWS)

The licensee provided information by letter dated December 3, 1982, to demonstrate that ventilation is not required in the corner rooms of the reactor building to ensure core spray and LPCI pump operability. The basis for this conclusion relied on tests that were performed during initial plant start-up. The staff reviewed this information and transmitted the results of this review to the licensee by letter dated July 5, 1983. Even though worse conditions than those used in the test are possible, such conditions coincident with the need for this equipment are unlikel Additionally, a redundant train of

equipment serviced by a separate cooling system would remain available to perform the safety function. The staff concluded that no modifications to the system are required.

Technical Specification 3/4-5.B establishes limiting conditions for operation and surveillance requirements for the ESWS to maintain a high system availability. Station Procedure SP 623.19 addresses the testing requirements. SP 506 directs the operator to place the ESWS in operation using OP 322 when the suppression chamber approaches 90°F and plant electric load conditions permit. Since the ESWS is periodically tested and the operator will have sufficient time and information to start the system manually, the staff concluded that the issue is resolved.

6.3.2 Core Spray Nozzle Effectiveness (SEP Topic VI-7.A.4)

Information derived from Japanese core spray tests suggested that the central fuel bundles of cores with emergency core spray spargers and nozzles like Millstone-1 may not receive sufficient core spray during and following design basis accidents. The staff evaluated the related information and concluded that the Japanese data do not provide a basis for changing the original staff conclusion that core spray flows for Millstone-1 are not less than the minimum flow required for core spray heat transfer. The staff concluded that spray distribution adequacy is not a safety concern for the following reasons:

a. The Millstone-1 spray nozzle design is different from the nozzle used in the Japanese tests.

b. Even though there is no core spray test data in a steam condition for the Millstone-1 configuration, a BWR/6 30° sector steam test and 360° full-scale tests in an air environment performed in the U.S. indicate that the core spray overlaps the center bundles, causing high flow rate over the central region of the core. As a result, flow to each bundle is not less than the minimum spray flow required for core spray heat transfer as noted above.

c. In a conversation with the staff, GE noted that analyses showed that for limiting cases for a Millstone-1 design with core spray assumed to flow down peripheral channels to increase the reflood rate, as observed in the Lynn test, the calculated peak clad temperature did not exceed the 10 CFR 50.46 limit of 2200°F with no credit taken for the spray cooling effect.

Based on the above considerations, the staff concluded that the core spray distribution is not a safety concern for Millstone-1.

6.3.3 Appendix K - Electrical Instrumentation and Control Re-reviews (SEP TOPIC VI-7.C.1)

The purpose of SEP Topic VI-7.C.1 was to re-review the modified Emergency Core Cooling System (ECCS) to confirm that the system design meets the most limiting single failure. Redundant load groups and the redundant standby electrical power sources should be independent at least to the following extent:

(1) No provisions should exist for automatically connecting one load group to another load group.

(2) No provisions should exist for automatically transferring loads between redundant power sources.

(3) If means exist for manually connecting redundant load groups together, at least one interlock should be provided to prevent an operator error that would parallel their standby power sources.

The limited PRA for this topic was performed in conjunction with SEP Topic VII-3. The issue in SEP Topic VII-3 relates to the existence of a single instrument ac bus instead of redundant buses so that the failure of this single bus may result in the loss of essential instrumentation or controls needed to reach safe shutdown. Although not identified in the SEP topic list, the PRA review concluded that because of the interrelationship of the instrument ac bus and the vital ac power source, diverse instrumentation and vital ac power systems were considered along with the removal of the automatic bus transfers (ABTs) in the remainder of the ac power system (480-V ac bus transfers) and the removal of all dc system manual bus transfers. The PRA concluded that the above changes resulted in a reduction in core-melt frequency of 10% with a corresponding reduction in risk of 14%. The dominant contributor to this risk reduction was redesign of the instrument ac power system to provide redundant instrument ac buses. Redesign of the vital ac power system to make it more reliable and removal of the ABTs had no impact on risk. Removal of the ABTs alone may increase risk because the instrumentation system was subject to the failure of the remaining power supply. However, implicit in the removal of an ABT is the requirement to provide redundant trains of safety equipment. The staff identified the following issues:

- Automatic Bus Transfers

  Buses 2A-3NE, 2-3NE, and 22A-1, the 120-V ac instrument bus IAC-1, and the 120-V ac vital bus VAC-1 are supplied from automatic transfer switches that can transfer loads between redundant sources. The staff required that the licensee evaluate the ABTs and identify any necessary corrective action.

  The licensee responded by letter dated April 12, 1983, which was revised by letter dated December 6, 1983, and identified actions such as breaker coordination to resolve the issue. In that letter, the licensee stated that a project is currently underway at Millstone-1 to document the circuit breaker coordination. The licensee submittal dated February 7, 1985 proposed to continue this effort as part of the Integrated Safety Assessment Program (ISAP). This study will include consideration of the need for a redundant instrument ac bus.

- Manual Bus Transfers

  The staff identified three load centers that are manually transferred between redundant sources. Although they are under administrative control, there are no interlocks to prevent operator error that would parallel the emergency sources.

  By letter dated April 12, 1983, the licensee concluded that the present configuration combined with the fact that the plant operates with the

emergency transfer source deenergized provides an adequate level of independence between the DC systems. The staff will complete the review of manual bus transfers after the information on ABTs is provided.

6.3.4 Testing of Reactor Trip System and Engineered Safety Features, Including Response Time Testing (SEP TOPIC VI-10A)

The reactor protection system must be designed to permit periodic testing of its functioning, including a capability to test channels independently.

During the staff review, the following aspects were highlighted:

- Surveillance Frequency

For the reactor trip system at Millstone-1, three signals, average power range monitor (APRM)-flow biased high flux, APRM-reduced high flux, and intermediate range monitor (IRM) are not subjected to a channel check as frequently as normally required. The high steam line radiation signal is not subjected to a channel functional test as frequently as normally required, and the APRM-reduced high flux signal is not calibrated as frequently as normally required.

The PRA performed for these signals using existing test frequencies at Millstone Unit 1 revealed that these system components did not contribute to the dominant failure mechanisms of the reactor protection system (RPS). Rather, the RPS failure probability is dominated by common-mode mechanical failures. The PRA did conclude, however, that the increased testing required by the STS as compared with Millstone Unit 1 testing procedures would lower the failure probabilities of the affected instrumentation.

Millstone Unit 1 operating procedures and Technical Specifications did not include provisions for performing channel check on APRM-flow biased or APRM-reduced high-flux channels or channel checks every 8 hours on the intermediate range monitors.

The licensee has modified the operating procedures to include channel checks on the above channels every 8 hours. Also, the licensee proposed in the IPSAR to evaluate the potential improvement in APRM reliability associated with calibrating the APRMs according to current criteria defined in the GE Standard Technical Specifications.

Channel Functional Test Frequency

For the following channels, a channel functional test is required to be performed monthly by plant Technical Specifications. The Technical Specifications allow reduction to a quarterly test frequency, provided a certain level of satisfactory operational reliability is achieved; however, the licensee has not yet exercised this option.

(1) high reactor pressure
(2) high drywell pressure
(3) low reactor water level
(4) high water level in scram discharge
(5) main steam line isolation valve closure

(6) turbine stop valves closure
(7) manual scram
(8) turbine control valves fast closure
(9) APRM-flow biased high flux

Present test intervals as given in the Millstone Unit 1 Technical Specifications and operating procedures are the same as those required by GE Standard Technical Specifications. The Millstone Unit 1 operating procedures do not allow a test frequency reduction as do the Technical Specifications.

The staff did not require modification of the present Millstone Unit 1 Technical Specifications because (1) the staff had no philosophical disagreement with a reliability-based surveillance interval, (2) present plant operating procedures meet current criteria testing intervals, and (3) any change to present operating procedures would constitute a change in accordance with 10 CFR 50.59, which the staff could then review.

Response-Time Testing

There is no requirement to measure the Millstone Unit 1 channel response time between channel trip and the deenergization of the scram relay. However, there is assurance that this time would be within the Technical Specifications limit. The time from initiation of any channel trip, which is the time a GE type of HFA relay is deenergized, to the deenergization of the scram relay, which is the time the HFA relay contacts open, is given by the manufacturer as less than or equal to 14 msec. The licensee submitted a Technical Specification change request by letter dated September 9, 1980, to change the required response time from 100 to 50 msec. To support this change, the licensee conducted tests on a number of channels that determined the response times to be well below 50 msec.

This change was approved by the NRC by Amendment 78 to the license, dated September 8, 1981. The staff performed a limited PRA of this issue to estimate the improvement in overall safety if response-time testing of the reactor protection system (RPS) was required. The results of this PRA indicated that response-time testing has low safety significance. Response-time testing is concerned with events on the order of seconds and the PRA has shown that response times of minutes are sufficient for the RPS actuation to ensure the success of the subcriticality function in time to allow other safety systems to prevent core melt. Functional tests are sufficient to demonstrate function on the order of minutes, and these tests are performed at Millstone Unit 1. Therefore, the staff concluded that response-time testing of the RPS is not required.

7 INSTRUMENTATION AND CONTROL

The FSAR (Ref 12) describes the instruments and controls for the Millstone-1 plant, i.e.

- Reactor Protection Systems
- Neutron Monitoring System
- Radiation Monitoring Systems
- Primary Containment Isolation System
- Refueling Interlocks
- Turbine Plant Control System
- Process Computer System and Rod Worth Minimizer

Items of related interest are presented in the following subsections.

7.1 <u>Isolation Of Reactor Protection System From Non-Safety Systems, Including Qualification Of Isolation Devices</u> (SEP Topic VII-1.A)

Non-safety systems generally receive control signals from the reactor protection system (RPS) sensor current loops. The non-safety circuits are required to have isolation devices to insure the independence of the RPS channels. Requirements for the design and qualification of isolation devices are quite specific. Recent operating experience has shown that some of the earlier isolation devices or arrangements at operating plants may not be effective. The objective of the staff review was to verify that operating reactors have RPS designs which provide effective and qualified isolation of non-safety systems from safety systems to assure that safety systems will function as required.

Based on current licensing criteria and review guidelines, the plant reactor protection system complies with all current licensing criteria listed in Section 2.0 of the safety evaluation issued by letter dated June 4, 1981 except for the following:

- IEEE Standard 279, Section 4.7.2, requires isolation devices between RPS and control systems. There are no isolation devices between the nuclear flux monitoring systems and the process recorders and indicating instruments.
- Isolation devices are not provided to isolate the APRM system from the process computer.
- The power supplies for the RPS channels do not qualify as IE equipment. Isolation between each RPS channel and its respective power supply is inadequate.

By letter dated January 31, 1984, the licensee supplied the results of their test for isolation and their bases for concluding that modifications are not warranted. In summary, the licensee concluded that isolation between the components does not exist but noted that the probability of hot shorts of 125V DC or 120V AC is remote and that electrical failures due to inadequate isolation do not contribute significantly to the overall RPS failure probability. This issue is being evaluated as part of the ISAP.

7.2 Engineered Safety Features (ESF) System Control Logic And Design (SEP Topic VII-2)

During the staff review of the Safety Injection System (SIS) reset the staff determined that the Engineered Safety Features Actuation Systems (ESFAS) at both PWRs and BWRs may have design features that raise questions about the independence of redundant channels, the interaction of reset features and individual equipment controls, and the interaction of the ESFAs logic that controls transfers between on-site and off-site power sources. Review of the as-built logic diagrams and schematics, operator action required to supplement the ESFAS automatic actions, the startup and surveillance testing procedures for demonstrating ESFAS performance appeared to be required.

There were several specific concerns with regard to the manual SIS reset feature following a LOCA, i.e. (1) loss of offsite power after reset requiring operator action to remove normal shutdown cooling loads from the emergency bus and re-establish emergency cooling loads. (Time would be critical if the loss of offsite power occurred within a few minutes following a LOCA.) (2) loss of offsite power after reset preventing restart of some essential loads such as diesel cooling water. (3) loss of ECCS delivery for some time period before emergency power picks up the ECCS system. It was also decided to review the ESF system control logic and design, including bypasses, reset features and interactions with transfers between onsite and offsite power sources.

As a result of the staff's review of the scope of the several related generic efforts and the other SEP Topics, it was concluded that the only area that had not been covered was the independence of redundant logic trains. Independence might be compromised by sharing input signals and the use of common controls such as mode switches, reset switches, and logic test facilities.

A description of the isolation devices employed in Millstone 1 and a comparison with current design criteria are presented in Report EGG-EA-5724, "Engineered Safety Features (ESF) System Control Logic and Design," transmitted by letter dated February 1, 1982.

By letter dated June 8, 1982, the licensee certified the results of isolation testing conducted on the main steamline radiation monitors. Tests included short circuits, 120 V ac, and 125 V dc (both polarities) applied to the non-safety wiring. Changes in setpoints in the conservative direction were the only detected effects. The licensee also reported that this wiring is not subjected to potentially higher voltages.

As a result of the testing by the licensee and the June 8, 1982 licensee certification letter of separation the staff concluded that Millstone Unit 1 conforms to current licensing criteria and the concerns of SEP Topic VII-2 are resolved.

7.3 Systems Required for Safe Shutdown (SEP Topic VII-3)

The systems aspects of the Systems Required for Safe Shutdown were reviewed in Section 5.6.2. The following is limited to the electrical, instrumentation, and control systems required for safe shutdown. Plant systems needed to achieve and maintain a safe shutdown condition of the plant, including the capability for prompt hot shutdown of the reactor from outside the control room, are reviewed. Included also, is a review of the design capability and method of bringing the plant from a high pressure condition to low pressure cooling assuming the use of only safety grade equipment. The objectives of the review are to assure:

(1) The design adequacy of the safe shutdown system to (a) initiate automatically the operation of appropriate systems, including the reactivity control systems, such that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences or postulated accidents and (b) initiate the operation of systems and components required to bring the plant to a safe shutdown.

(2) That the required systems and equipment, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, are located at appropriate places outside the control room and have a potential capability for subsequent cold shutdown of the reactor using suitable procedures.

(3) That only safety grade equipment is required to bring the reactor coolant system from a high pressure condition to a low pressure cooling condition. The scope of this review includes the instrumentation, control, and electrical features necessary for operation of the identified safe shutdown systems. The review considers the systems for operability with and without offsite power and the ability to operate with any single failure.

The following is for reference purposes:

<u>INSTUMENTATION</u> (including support structures)

1. REACTOR LEVEL
2. REACTOR PRESSURE
3. REACTOR TEMPERATURE
4. REACTOR PROTECTION SYSTEM
5. NEUTRON MONITORING (including in-core monitoring)
6. AREA AND SYSTEM RADIATION MONITORING

<u>SYSTEMS</u> (includes pumps, valves, control, indication, and support structures)

1. SHUTDOWN COOLING SYSTEM
2. REACTOR BUILDING CLOSED COOLING WATER (RBCCW)
3. SERVICE WATER SYSTEM (SWS)
4. LOW PRESSURE COOLANT INJECTION SYSTEM (LPCI)
5. CONTAINMENT SPRAY SYSTEM
6. CORE SPRAY
7. EMERGENCY SERVICE WATER SYSTEM (ESW)

8. ELECTRO-PNEUMATIC RELIEF VALVE (AUTOMATIC PRESSURE RELIEF SYSTEM)
9. ISOLATION CONDENSER
10. FEEDWATER COOLANT INJECTION SYSTEM (FWCI)
11. CONTROL ROD DRIVE SYSTEM (scram function and level control during hot standby)
12. VESSEL HEAD COOLING SYSTEM
13. REACTOR WATER CLEAN UP SYSTEM (RWCU) (core excess inventory)

7.3.1 Instrumentation

The SEP review of Safe Shutdown Systems identified the instrumentation available in the control room necessary to bring the reactor from the hot shutdown to cold shutdown condition. This review included the nuclear instrumentation, since this instrumentation must be monitored to ensure the reactor achieves and maintains shutdown conditions. Various system parameters, such as pump running or valve position indications, were not included in the list of safe shutdown instruments, because indication is provided by the control/operate circuitry. Availability of control/operate circuitry to run the system also means availability of the required indication. Similarly, if the control/operate circuitry is unavailable such that system operation is not possible, then system indication is not mandatory.

The nuclear instrumentation, providing indication of each range of power level, is powered from two independent 24V DC buses, the Vital AC bus (VAC), the Instrumentation AC bus (IAC), and two independent Reactor Protection AC buses. There are no single failures that would result in the loss of all power sources to the nuclear instrumentation.

The instrumentation providing indication of critical reactor parameters (level, pressure, and temperature), are powered from independent 125 VDC sources, the VAC bus, and the IAC bus. There are no single failures that would result in the loss of all power sources to these instruments. The loss of the IAC bus would result in the loss of temperature recorders. However, temperatures could be determined from direct reading pressure indicators, located outside containment, with the use of appropriate tables.

Indication of Service Water, Emergency Service Water, Feedwater Coolant Injection, Core Spray, Isolation Condenser, Shutdown Cooling, and Low Pressure Coolant Injection system parameters such as flow, temperature level, and pressure available in the control room are powered by the IAC bus. While loss of the IAC bus would cause a loss of these indications, each of these systems (except for the Isolation Condenser System) has direct reading indicators available at local control stations. Status of flow for some systems such as LPCI can be inferred from the pump running/valve open indicators (not powered by the AC instrument bus) and by reactor parameters of level, pressure, and temperature.

The instrumentation necessary for reaching and maintaining cold shutdown at Millstone 1 does not meet current licensing criteria since a single failure (loss of the IAC bus) would result in loss of indication of flow, temperature, level, and/or pressure of the systems required to shutdown the reactor and/or maintain the reactor in shutdown condition. With the exception of the Isolation Condenser System, suitable direct reading local indications are available and could be used by operators stationed at the local indicators in communications with the control room.

As discussed under Section 6.3.3, the reliability of the instrument ac bus, including the automatic power supply transfer is still being evaluated in ISAP.

7.3.2 Safe Shutdown Systems

The review of Safe Shutdown Systems identified the systems required for short-term cooling (immediately after reactor shutdown) and long-term cooling (when the reactor is cooled to the shutdown cooling system (SDCS) design temperature limit of 250°F) with only offsite and only onsite power available.

Normal short-term cooling is provided by bypassing steam to the main condenser via the turbine bypass vaves. The circulating water pumps provide cooling to remove heat by condensing the steam. The feedwater system then returns the water to the reactor. This cooling method is available with or without offsite power. A full feedwater string can be powered by the onsite gas turbine generator, but this method of cooling, without outside power, could be rendered inoperative by failure of the 416-volt bus number 1 or 3.

Emergency or alternate short-term cooling involves operation of the Electro-Pneumatic Relief Valves (EPRV), the Feedwater Coolant Injection Injection System (FWCIS), and the Isolation Condenser System (ICS).

Initial pressure relief is provided by the six EPRVs which operate to prevent overpressurization of the reactor by venting steam into the torus, and backs up the FWCIS to depressurize the reactor. These valves may be manually controlled from the control room but are automatically actuated upon coincident indication of low level in the reactor vessel, high pressure in the drywell, and flow failure of the FWCIS. In this case, a means of adding water to the reactor (LPCI or Core Spray) is necessary to maintain reactor level and provide cooling. The relief valves can be supplied power from either motor control center (MCC) DC-1 or MCC DC-1A via a transfer switch and distribution panel bus would result in loss of relief valve control from the control room. In this case the valves would still operate when system pressure reaches the valve pressure relief set-points. Each valve has its own accumulator with sufficent compressed air for several valve actuations. In addition each valve can receive compressed air from station air compressors or bottles of compressed air. There are no single failures which would completely disable the pressure relief system.

The FWCI consists of one condensate pump, one condensate booster pump, and one feedwater pump, all powered by the gas turbine generator. Two complete "strings" of pumps are available for FWCI operation with selection of string A or B made from the control room. The pumps in the selected FWCI string will not start or restart automatically upon fill restoration of AC power (as provided by the gas turbine generator) unless a low-low reactor water level signal or high drywell pressure signal (or both) exists. In the absence of such automatic initiation, the operator will bring the FWCI system on manually as provided by procedure.

Because the gas turbine generator is not ready to load for 48 seconds after starting, the EPRVs will be required to relieve pressure until the FWCI system is operating. At that time, the injection, at rates up to 8000 gpm of cold water, will provide substantial depressurization, resulting in the reclosure of the EPRVs. If the FWCI system should provide such significant inventory that reactor vessel water level becomes too high (prior to depressurization and

concurrent temperature decrease to SCS initiation Limits), the operator can utilize the relief valves to continue depressurization, or can increase discharge from the reactor vessel through the reactor water cleanup system.

Loss of the gas turbine generator (GTG) or loss of 4160V bus 1 or 3 can render the FWCI system unavailable. In this case short term cooling could be provided by the electro pneumatic relief valves (EPRV's) and the isolation condenser system (ICS).

The ICS consists of a single steam line from the reactor to the ICS condenser, the ICS, and the discharge line into recirculation loop B. There are two normally open motor operated valves (MOVs) in the steam line from the reactor, one inside containment and one outside. The discharge line also contains two MOVs with the MOV outside containment normally closed and the MOV inside containment normally open. Flow through the system is initiated by opening the single closed MOV which allows the reactor to be cooled by condensing steam into the ICS condenser and returning the condensed steam to the reactor by natural circulation. Failure of the control power or motive power for this MOV would disable the system, although the valve may be manually operated.

The MOVs outside containment are DC powered with battery backup. The MOVs inside containment are AC powered and can be supplied from the diesel generator (DG) on loss of offsite power. Differential pressure switches, powered from independent DC buses, will close the MOVs and isolate the condenser upon sensing a line break in the ICS. The two condenser vent valves, the control room level, pressure, and temperature indicators, and the automatic level control system for the isolation condenser are powered from the single Instrument AC Bus (IAC). Failure of this bus would result in loss of venting capability, level control and control room ICS parameter indication. Condenser makeup can be from the Fire Water System or the Condensate System. Power supplies for these makeup sources are independent from each other and from the ICS power supplies. The ICS can be manually initiated or will automatically initiate on loss of offsite power and reactor scram.

Long-term cooling (below 350°F) is provided by the Shutdown Cooling System (SDCS). It consists of a single suction line, two parallel pump and heat exchanger loops, and a common discharge line. There are multiple single failures which can render the SDCS inoperable, including loss of motor control center (MCC) 2A-3 which powers the normally closed inlet MOV (located inside containment), or loss of MCC 2-3 which powers the normally closed discharge MOV (located outside containment). Loss of the IAC bus will result in the loss of control room indication of loop pressure, and loop and heat exchanger temperature. Also, the inlet MOV is inside containment and is therefore considered inaccessible for manual operation. If the inlet and discharge valves can be opened, there is sufficient power supply independence and redundancy in the two parallel SDCS loops and in the SDCS Heat Exchanger cooling, assuming a single power supply failure, to ensure at least partial operation of the SDCS. The SDCS is not a class 1E system but can be used to remove decay heat.

The LPCI system consists of two independent loops, each with two parallel pumps, which pump water from the suppression pool to the reactor via heat exchangers cooled by the Emergency Service Water System. Single failures exist which can cause loss of one loop of the LPCI system, but only one loop is needed to maintain reactor level and provide cooling water. On loss of offsite power

one loop is supplied by the gas turbine generator (GTG) and the other by the diesel generator (DG). Starting of the pumps is automatic only in a LOCA situation. All motor-operated valves in the LPCI system are outside containment and can be manually operated. Loss of the IAC bus will result in loss of system temperature and flow indications in the control room.

7.3.2.1 Onsite Power Unavailable

Millstone 1 normally operates with all of its auxiliary loads supplied by the main generator through the Unit Auxiliary Transformer. Loss of the main generator power during operation will result in a reactor scram and turbine trip. The buses normally powered by the generator will transfer to the Reserve Station Service Transformer which is supplied from the 345-kV switchyard. Only single failures involving buses, switchgear, or other equipment downstream of the transformer feed lines to the distribution system are considered.

Single failures of electrical instrumentation and control (EI&C) features, such as loss of the feedwater control system, exist which could disable the normal short-term cooldown methods. However, no EI&C single failure that renders the normal short-term cooldown methods inoperable can also cause failure of the isolation condenser, ADS, and/or FWCI system. There are multiple single failures previously mentioned which can render the SDCS inoperable. However, since only one LPCI loop is needed to maintain core level and provide cooling water, there are no single failures which can disable both the SDCS and LPCI systems. Therefore, the staff concluded the short-term and long-term cooling capability meets the current licensing criteria with only offsite power available.

7.3.2.2 Offsite Power Unavailable

During normal operation, a loss of offsite power would not automatically result in the loss of the main condenser and a reactor trip because the plant is designed to withstand this transient while dumping steam to the condenser. However, if there were a complete loss of power to the 4-kV buses, all loads on these buses and all 480V loads supplied from 4-kV Buses 5 and 6 would be shed. On completion of load shedding, simultaneous automatic start signals are sent to a gas turbine generator and to a diesel generator. The gas turbine generator supplies 4-kV buses 1, 3, 5 and 7 and the diesel generator supplies 4-kV bus 6. Both the diesel generator and the gas turbine generator are automatically started on an ECCS signal.

Assuming the diesel generator and the gas turbine generator are available, there are no single failures which would disable the ICS, ADS, and FWCI system. Failure of the gas turbine generator would prevent initiation of the FWCI system. However, the ADS, in conjunction with the ICS, would provide the required short-term cooling. The staff concluded that there are no single failures which would disable both long-term cooling systems (SDCS and LPCI) if AC power from the diesel generator or the gas turbine generator is available.

7.3.3 Shutdown and Cooldown Capability Outside the Control Room

The capability to maintain the plant in hot shutdown from outside the control room exists at Millstone 1. Reactor parameters such as level and pressure can be monitored at locations outside the control room. Reactor pressure can be monitored outside the control room; therefore, reactor temperature can be

determined from appropriate tables. Local control stations exist for the pumps and valves of the systems required for safe shutdown. Additionally, many of the valves which are outside containment are also capable of being manually operated.

The staff concluded that adequate capability exists to maintain the reactor at hot shutdown from outside the control room but there were no procedures for taking the reactor from hot to cold shutdown from outside the control room. However, as previously noted in Section 5.6.2 hot to cold shutdown procedures have been written and implemented at MP-1.

7.3.4 Residual Heat Removal (RHR) System Reliability and Interlocks

The SDCS at Millstone 1 is designed to withstand RCS design pressure. Therefore, the isolation valve interlocks required by BTP RSB 5-1 are not applicable. The isolation valves have interlocks to prevent opening and to automatically close when RCS temperature exceeds the 350°F design temperature of the SDCS.

A bypass line provides a flow path from each SDCS pump discharge to its suction to provide the necessary flow to prevent pump overheating due to a discharge isolation valve being closed. Cavitation protection is provided by the interlock which trips the pumps (and prevents restarting) if the suction pressure falls below 4 psig. A temperature interlock also protects the pump from overheating by tripping the pump if the temperature is greater than or equal to 350°F.

There are no requirements in the Millstone 1 Technical Specifications for testing the SDCS interlocks and isolation circuitry during SDCS operation. The electrical circuitry is not designed to permit testing while the system is operating without a momentary interruption in system operation. Although licensed prior to the issuance of RG 1.68, concerning preoperational and startup testing, Millstone 1 nevertheless conducted such tests and demonstrated SDCS operability on several occasions.

The staff concluded that the SDCS does not meet the current licensing criteria of BTP RSB 5-1 in that the SDCS is not considered to be a safety-grade system and is subject to single failure of the valves inside containment. The SDCS however is designed for full reactor pressure but less than full reactor temperature (for which temperature interlocks have been provided) and is therefore acceptable.

7.3.5 Conclusions

Millstone 1 satisfies all of the requirements for Safe Shutdown except for a lack of redundant instrument supplies. Local direct-reading indications of vital parameters are available. The need for a redundant instrument ac bus is being evaluated in ISAP (see Section 6.3.3).

Plant procedures now direct those evolutions needed to accomplish plant shutdown to a cold shutdown condition outside the control room (see IE Inspection Report 84-20).

During the SEP review of Topic VII-3, the staff evaluated the effect that the crossing of the Flanders 114 line and the 383 line had on offsite power

availability. Historical failure rate data and a plant specific computer model of the Millstone switchyard show that the crossed power lines have a negligible effect on the likelihood of a loss of offsite power.

7.4 Frequency Decay (SEP Topic VII-6)

Issue 9 of NUREG-0138 requires that a postulated rapid decay of the frequency of the offsite power system be included in the accident analysis and that the results be demonstrated to be acceptable. Alternatively, the reactor coolant pump (RCP) circuit breakers should be designed to protection system criteria and tripped to separate the pump motors from the offsite power system because rapid decay of the frequency of offsite power system has the potential for slowing down or braking the RCP thereby reducing the coolant flow rates to levels not considered in previous analyses.

Oak Ridge National Laboratory (ORNL), under a technical assistance program, reviewed the frequency decay rate phenomena and its effects on RCPs. The results of the review are presented in Section 4 of NUREG CR 1464, "Review of Nuclear Power Plant Offsite Power Source Reliability and Related Recommended Changes to the NRC Rules and Regulations." In summary, the report shows that the conditions required for dynamic braking of reactor coolant pumps are a sustained and rapid decrease in frequency while maintaining bus voltage. These conditions are only realized in a highly capacitive system using large amounts of buried transmission cables (such as Long Island). The Northeast Nuclear Energy system does not use large amounts of buried transmission cable. The conditions that could cause unacceptable frequency decay rate are not present in the Millstone offsite electrical distribution system and the issue is therefore not applicable to Millstone 1.

8 ELECTRIC POWER SYSTEMS

The station electrical power system, as originally installed when Millstone Unit 1 was the only power plant at the site, is described in the FSAR (Ref. 12). Portions of the Millstone Unit 3 FSAR (Ref. 46) are equally applicable to Millstone Unit 1. Selected areas of review included in the SEP, license amendments, and staff safety evaluations are described below.

8.1 Potential Equipment Failures Associated With Degraded Grid Voltage (SEP Topic VIII-1A)

Prior to modifications the undervoltage protection system design consisted of the following:

(1) Two undervoltage relays (induction disc type) connected to the Reserve Station Service Transformer (RSST) bushing potential devices to sense the 345 kV system. The RSST is the preferred off-site source. These relays (level 1 of undervoltage protection) were used to sense a loss of offsite power condition. The voltage setpoint for these relays was 71% 345 kV (246 kV) with a time delay of 6 seconds at 50% of 345 kV. The output of each relay supplied each of two identical and redundant "loss of normal power" (LNP) circc its. The LNP circuits initiated the start of the onsite sources (diesel generator and gas turbine), isolation of the Class 1E buses, and load shedding. Once the onsite sources reached operating speed, the output breakers were closed. A block of Class 1E loads was energized immediately while the remaining loads were sequenced on by the load sequencer.

(2) Four solid state bistable voltage sensors installed at the bushing potential devices on the RSST to sense degraded voltage conditions (level 2 of undervoltage protection). Two of the bistable sensors monitored phases one and two and the remaining two sensors monitored phases two and three. This sensing system made up two protective channels, each requiring a signal from both devices (2-out-of-2 logic). The setpoint for these devices was 336 kV (97% of 345 kV) with a time delay of one second. Actuation of any one of the four sensors alarmed in the control room. The trip signal from any one of the channels was interlocked with a SI signal. Therefore, for a degraded voltage conditions concurrent with a SI, automatic disconnection from the RSST and transfer to the onsite sources occurred. Otherwise, operator action was required to restore adequate voltage. The licensee's basis for not providing automatic disconnection under all degraded conditions was that the auto-tripping of the unit from the transmission grid could cause a "cascading effect". This cascading effect could cause other nuclear plants to subsequently trip, further degrading the system. By means of corrective measures the grid voltage could be increased to acceptable levels for continued plant operation.

The load shed feature was disabled once the onsite sources were supplying the Class 1E buses. Should the onsite sources trip, the load shed feature

was not auto-reinstated. The operator would manually load shed and re-energize the buses.

The licensee proposed the following modifications to the undervoltage protection system:

(1) Redesign the present loss of offsite power (level 1) undervoltage protection scheme and the level 2 protection scheme to provide undervoltage protection directly at the Class 1E buses as required by IEEE 279-1971. The redesign would include new undervoltage protection setpoints and time delays to allow for short duration transients and Class 1E equipment protection. System level actuation would remain the same as the existing undervoltage protection schemes. That is, automatic disconnection from the offsite source would only occur if a SI signal is present concurrent with level 2 actuation.

(2) Make circuit design changes, in addition to the above, to automatically reinstate the load shed feature following tripping of the onsite sources.

The licensee proposed to relocate the first level (loss of voltage) and second level (degraded grid voltage) relays, presently connected to the bushing potential devices, to the 4160 volt Class 1E buses. Due to a delay incurred in obtaining the first and second level relay panels, there was insufficient time to install, monitor, and test the relays during April 1984 outage. However, the relay panels were installed during the April-June 1984 refueling outage but the trip logic of the relays was not connected to the safety buses until necessary testing and monitoring of the relays are accomplished. The relay alarm circuits were activated during the 1984 outage. The licensee has committed to complete the circuitry connections and implementation of the degraded voltage protection relays no later than the next refueling outage scheduled for October 1985.

The proposed modifications for the second level undervoltage protection system retain the feature that will permit automatic separation of the Class 1E power system from offsite power only if a degraded grid exists coincident with a safety injection signal (LOCA). This approach provides protection to the Class 1E equipment needed to mitigate the consequences of an accident and is acceptable to the staff. For a degraded grid condition without a LOCA an alarm will be actuated and operator action will be taken to restore the grid to an acceptable level. In the event operator action is not successful in restoring grid voltage within an acceptable time period, the operator will manually start the onsite diesel/gas turbine generator and separate the Class 1E buses from the offsite power system. The Class 1E loads would then be sequenced onto the onsite emergency generators. This approach deviates from the staff position that requires automatic isolation of the offsite power system from such undervoltage after a time delay. Acceptability of this alternate approach requires that adequate safety systems be available for safe shutdown of the reactor for these conditions and that appropriate plant operating procedures are developed and available to the operator for the required manual operator action. The licensee provided a list of systems, that would not be exposed to degraded grid voltage, and which will be available to bring the plant to a safe shutdown under non-LOCA conditions. The staff concurred. The licensee made the Isolation Condenser make-up fill valve AC independent during the 1982 refueling outage and

noted that there was no need to make the condensate transfer pump AC independent, since make-up for the Isolation Condenser can be provided by the diesel-driven fire water pump, thus making the Isolation Condenser System AC independent. The licensee stated that the Isolation Condenser make-up fill valve was modified to operate with DC power only. The staff concluded that this modification provided a redundant capability to shut the plant down and, maintain it at safe shutdown under non-LOCA conditions. The staff concurs with the licensee that the diesel-drive fire water pump can be substituted for the condensate transfer pump when the latter pump is not available and that the isolation condenser systems is not dependent on AC power and therefore acceptable.

A redundant means of providing safe shutdown is provided by the Automatic Depressurization System (ADS), which uses N_2 operated valves, with backup bottled N_2 supply, to depressurize the system and allow placing the Low Pressure Coolant Injection (LPCI) and Core Spray (CS) system(s) in operation.

On the basis of the above and that protection devices i.e., circuit breakers, fuses, relays,...etc., are provided to prevent damage to the equipment required for plant safe shutdown and that an alarm is installed to alert the operator to this abnormal condition, the staff found the licensee's alternate approach for manual operator action under degraded grid condition without an accident acceptable. Acceptability of this approach is subject to institution of adequate procedures covering actions to be taken by the operator during a degraded grid under non-accident conditions.

The licensee committed to bypass load shedding while Class 1E buses are powered from onsite power system. The load shedding circuit will be bypassed once the emergency diesel generator or gas turbine is supplying power to the safety loads. The load shedding feature will be reinstated if the diesel generator or gas turbine breakers should trip.

The modified undervoltage protection circuitry at Millstone 1 consists of two power train undervoltage trip circuits S1 and S2. The S1 train provides voltage sensing for 4160 V safety buses 14A and 14C and 480 V safety bus 12E. Emergency ac power to the above buses is provided by a gas turbine. The S2 train provides voltage sensing for 4160 V safety bus 14F and 480 V safety bus 12F. Emergency ac power to the above buses is provided by an emergency diesel generator. Both S1 and S2 trip circuit trains provide first level and second level undervoltage protection. The first level (loss of power) undervoltage protection consists of six ITE-27HS relays on each 4.16 kV Class 1E bus (two per phase) with one out-of-two taken thrice coincident logic. These relays are set at 2828 ± 28 volts (approximately 71% of 4 kV rated Class 1E equipment) with associated time delay of 1.5±.015 seconds. The second level (degraded grid) undervoltage protection consists of three ITE-27NS relays (one per phase) on each 4.16 kV Class 1E bus with two-out-of-three coincident logic. These relays are set at 3654± 35 volts (approximately 90% of 4 kV rated Class 1E equipment). The time delays associated with the S1 and S2 trains second level undervoltage protection as 12 ± .12 seconds and 8 ± .08 seconds respectively.

Both emergency power supplies (gas turbine and diesel generator) start simultaneously with an accident signal after three seconds time delay. Under degraded grid condition coincident with an accident, the S2 train will automatically separate from the offsite source (Station Service Transformer (SST) after eight seconds time delay and after an additional two seconds loads will

reconnect to its respective onsite emergency diesel generator. Under the above condition the S1 train will automatically disconnect from the offsite source (SST), after 12 seconds time delay and after an additional 33 seconds loads will reconnect to its respective onsite emergency gas turbine.

The licensee's voltage analysis shows that the earlier separation of the S2 train from the offsite power will reduce the loading on the SST, common source of offsite power for both trains. With the grid voltage between 332 kV and 338 kV the studies show that the S1 degraded voltage relays may reset before its associated time delay expires thereby allowing the feedwater system and the ECCS motors which are supplied by the S1 train to continue to perform their safety functions without interruption. However, while the shutdown loads on the S1 trains are being supplied by the SST, the gas turbine continues to operate at no load. Further degradation of grid voltage will result in disconnection of offsite power from the S1 buses and transfer of the shutdown loads onto the gas turbine.

The Millstone 1 design implements the plant feedwater system (FWS) as a high pressure safety feedwater coolant injection (FWCI) system under a LOCA condition. The FWCI is designed to Category 1 Class 3 requirements and all electrical circuitry and pump motor drives are Class 1E.

The longer time delay associated with the S1 train degraded voltage relays does not delay the loading of the safety buses onto the gas turbine as long as this delay does not exceed the time required for the gas turbine to commence loading.

The staff discussed and evaluated longer time delay of the S1 buses relays to maintain the continuous operation of the feedwater system on the offsite power and concurs with the licensee that the additional four seconds time delay associated with the S1 degraded voltage relays is beneficial and does not adversely affect the plant safe shutdown during accident condition.

Actuation of any one of the six loss of power relays or any one of the three degraded grid relays will activate an alarm to notify the operator of the degraded voltage condition after 10 seconds when voltage on the 4160 V safety buses reduces to less than or equal to 90% of 4 kV.

With degraded voltage under non-accident conditions operator action is necessary to restore the voltage to an acceptable level. In the event operator action fails to restore the voltage to an acceptable level within a reasonable time period, the operator will manually start the onsite ac emergency power supply (diesel or gas turbine generator or both) and separate the Class 1E buses from the offsite power. These buses are then connected to the emergency ac supply and safety loads are subsequently sequenced onto these buses. However, with degraded grid voltage under accident condition, the proposed second level undervoltage protection system is activated to provide automatic starting of diesel/gas turbine generator, separation of Class 1E buses from offsite power source, initiation of load shedding and sequencing of loads onto these buses.

Voltage sensing of both S1 and S2 trains at 480 V bus level provides degraded grid voltage annunciation only. Each 480 V safety bus 12E and 12F is equipped with one relay which activates an alarm to notify the operator of degraded voltage condition when voltage on these buses reduces to 92% or less of 460 V after

one minute time delay. The licensee stated that the setpoint for the degraded voltage relays is based on the most limiting conditions of 90% terminal voltage on the 4 kv motors. The licensee also stated that installation of regulating transformers on the 120 V level during the current refueling outage will provide 120 V ± 1% at 120 V Class 1E buses over a wide range of input voltage (73% to 107%).

Technical specifications to cover relay setpoints and tolerances, limiting conditions for operation, and surveillance testing for the undervoltage relaying system will be provided when the system becomes fully operational in 1986.

In summary, the staff has found that: (Reference Amendment 98 dated June 14, 1984)

- The proposed degraded grid modifications will protect the Class 1E equipment from sustained degraded voltages of the offsite power system.

- The proposed load shedding circuit will block load shedding once the emergency generator (diesel or gas turbine) is supplying the safety loads. The load shedding feature will be reinstated if the gas turbine or diesel generator breaker should trip.

- The preliminary technical specification information supplied by the licensee is conditionally acceptable. However, the staff requires a formal submittal of the changes and additions to technical specifications after the necessary testing of the degraded grid protection relays are completed.

- The licensee's proposal to use operator action instead of automatic disconnection of the Class 1E buses from a degraded offsite power source under non-accident conditions does not meet the staff's position. To justify this alternate approach, the licensee has shown that redundant safety systems, which are not exposed to degraded voltage, are available to bring the plant to a safe shutdown condition. The staff has reviewed the licensee's proposal and finds that these systems will be available to effect a safe plant shutdown under non-accident conditions.

- Due to unanticipated delays incurred in receiving the relay panels for the degraded grid undervoltage protection system, there was insufficient time to monitor and test the relays during the April 1984 outage. However, the relay panels were installed during that outage but only the alarm logic is connected to the safety buses. The licensee will incorporate the tripping logic and complete the installation after testing of the relays is completed. The licensee has committed to complete the installation of the degraded grid protection system during a scheduled outage but not later than the next refueling outage scheduled for October-December 1985.

8.2 Onsite Emergency Power Systems (SEP Topic VIII-2)

The objective of the review was to determine if the onsite AC generators for the Millstone 1 Nuclear Station have sufficient capacity and capability to supply the required automatic safety loads during anticipated occurrences and/or in the event of postulated accidents after loss of offsite power.

Millstone 1 uses one diesel generator and one gas turbine generator for emergency on-site power. In the event that the diesel generator fails to start, the gas turbine generator can manually assume the loads normally powered by the DG, as well as its own loads.

The diesel generator has a continuous rating of 3330 kVA at 0.8 PF. The worst-case generator load is 3045 HP using nameplate data. With a 90% motor efficiency, as specified in R.G. 1.9, the worst-case load is 3155 kVA at 0.8 PF. The maximum step load change is 829 kVA or 25% of the continuous generator rating.

The gas turbine generator is rated at 11.5 MW peak load and 10 MW continuous load. The worst-case generator load is 13,240 HP (nameplate). Again using 90% motor efficiency, the worst-case load is 10.975 MW. The maximum step load change for the gas turbine generator is 5.8 MW or 58% of the continuous generator rating.

The total worst-case automatically connected diesel generator load is 3155 kVA or 95% of the generator continuous rating. This is within the criteria of R.G. 1.9. The total worst-case automatically connected gas turbine generator load is 10.975 MW or 99% of the generator continuous rating at 100°F. This meets the criteria of R.G. 1.9.

8.2.1 Diesel Generator

10 CFR 50 (GDC 17), as implemented by SRP Section 8.3.1 and BTP ICSB 17, requires that

(1) The design of standby diesel generator systems should retain only the engine overspeed and the generator differential trips and bypass all other trips under an accident condition.

(2) If other trips, in addition to the engine overspeed and generator differential trips, are retained for accident conditions, an acceptable design should provide two or more independent measurements of each of these trip parameters. Trip logic should be such that a diesel generator trip would require specific coincident logic.

In addition, GDC 17, as implemented by IEEE Std. 279-1971, requires that all the conditions that might render the emergency power generator incapable of automatic starting shall be unambiguously annunciated in the control room.

Diesel generators, which provide emergency standby power for safe reactor shutdown in the event of total loss of offsite power, have experienced a significant number of failures. The failures to date have been attributed to a variety of causes, including failure of the air startup, fuel oil, and combustion air systems. In some instances, the malfunctions were due to lockout. The information available to the control room operator to indicate the operational status of the diesel generator was imprecise and could have lead to misinterpretation. This was caused by the sharing of a single annunciator station by alarms that indicate conditions that render a diesel generator unable to respond to an automatic emergency start signal and alarms that only indicate a warning of abnormal, but no disabling, conditions.

Another cause was the wording on an annunciator window which did not specifically say that the diesel generator was inoperable (i.e., unable at the time to respond to an automatic emergency start signal) when in fact it was inoperable for that purpose. The review included the reliability, protective interlocks, fuel oil quality, and testing of diesel generators to assure that the diesel generator meets the availability requirements for providing emergency standby power to the engineered safety features.

The concern with regard to annunciators was pursued as a generic issue. The staff safety evaluation for Millstone 1 concluded that in order to provide the operator with accurate, complete and timely information pertinent to the status of the diesel generators, as required by IEEE Std. 279-1971, the following corrective actions were required:

1. Disabling and non-disabling conditions, currently alarmed at a common annunciator station, should be separated and annunciated at separate annunciator points.

2. The wording on the annunciator for disabling conditions should specifically state that the diesel generator is unavailable for an automatic emergency start.

By a letter dated May 12, 1978, the licensee agreed to make suitable modifications to the annunciator.

Also, as a result of the work done by the University of Dayton, a generic program for implementing most of the recommendations for reliability enhancement that are contained in the University of Dayton report is being conducted by NRC. This program will also determine the adequacy of the diesel generator testing program on a case-by-case basis and institute any necessary changes.

The question of fuel oil quality was addressed on a generic basis in January 1980, by letters to all licensees. The letters required that licensees include fuel oil in their Quality Assurance program. The periodic testing of the diesels was considered to be an adequate interim method for assuring acceptable quality in the fuel oil stored on site.

EG&G Report 0111J, "Emergency Generators," transmitted by letter dated June 3, 1981, presents a technical evaluation of the diesel generator protective interlocks and load capability at Millstone 1 against present licensing criteria. Diesel generator trips which are not by-passed under accident conditions are generator differential, voltage restrained overcurrent, and low engine oil pressure. The low oil pressure trip requires signals from two of three sensors before a trip occurs. The report notes that the diesel-generator protective trips are in agreement with current NRC guidelines. The staff concluded that the diesel generator protective interlocks are in conformance with BTP ICSB17.

8.2.1.1 Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability (Generic Letter 84-15 dated July 2, 1984)

The items covered by this letter fall into the following three areas:

1. Reduction in Number of Cold Fast Start Surveillance Tests for Diesel Generators

This item was directed towards reducing the number of cold fast start surveillance tests for diesel generators which the staff had determined results in premature diesel engine degradation. Licensees were requested to describe their current programs to avoid cold fast start surveillance testing or their intended actions to reduce cold fast start surveillance testing for diesel generators.

2. Diesel Generator Reliability Data

   This item requests licensees to furnish the current reliability of each diesel generator at their plant(s), based on surveillance test data.

3. Diesel Generator Reliability

   Licensees were requested to describe their program, if any, for attaining and maintaining a reliability goal for their diesel generators.

The licensee responded to GL 84-15 by letter dated February 4, 1985.

With regard to the first item the licensee reported that one source of emergency power at Millstone Unit No. 1 is a 12 cylinder, opposed piston turbocharged Fairbanks Morse diesel generator unit. When the diesel generator is in a shutdown condition, lubricating oil is continuously recirculated and heated to 135°F by a lube oil heater. In addition, engine cooling water heater is also heated by recirculation past a jacket cooling water heater.

Millstone Unit No. 1 Technical Specification 4.9.A.1.a requires monthly testing of the diesel generator unit in order to demonstrate operational readiness. This requirement is met by performance of manufacturer recommended weekly surveillance tests. All weekly surveillance testing of the diesel generator unit is preceded by a prelubrication period. The only unprelubed starts of the Millstone Unit No. 1 diesel generator unit occur as a result of loss of normal power on the 4160-volt buses, loss of the main generator; initiation of the emergency core cooling system or during a unit surveillance simulating a loss of coolant accident coincident with a loss of offsite power. This surveillance is performed every refueling outage per Technical Specification Surveillance Specification 4.9.A.1.b.

The licensee reviewed plant logs, incident reports, event reports and surveillance data records since the plant start up and reported, concerning the second item above:

	Mean	Variance
Failure to start on demand	6.7×10^{-3}/day	9.5×10^{-6}
Failure to run having started	1.1×10^{-3}/hour	1.08×10^{-6}
Unavailability due to maintenance	1.07×10^{-3}/day	7.8×10^{-6}

Total adjusted starts	652
Total adjusted running hours	1018
Total adjusted failures	4

Concerning the third item above the license noted that the reliability of the various onsite emergency power sources is enhanced through the implementation

of a well-documented, comprehensive preventive maintenance program. The objective of this program is to provide a detailed analysis of equipment condition and allow for the planning of periodic maintenance. This minimizes the total maintenance costs while maximizing the availability/reliability of critical equipment.

The benefits of a continuous, orderly and uniform Preventive Maintenance Program can be obtained only if the schedules are established and adhered to, with exceptions being limited to emergencies and operational constraints. The program itself is scheduled by station personnel using the tools of the Production Maintenance Management System. Periodic review and evaluation of the program is undertaken to measure the effectiveness of and monitor adherence to the program. The cost/benefit analyses of the various activities, and the application of new techniques and ideas help in the achievement of all goals and objectives.

To complement the preventative maintenance program, a performance testing program has been implemented at each nuclear unit to demonstrate emergency power source reliability. Adherence to manufacturer recommendations and NRC staff requirements have been utilized in the formation of the surveillance testing items. Refueling outages are utilized to perform complete inspection and overhaul of the diesel generator units under the guidance of manufacturer supplied field service representatives.

In addition to these programs, the maintenance of good interplant communications has been stressed throughout the Northeast Utilities system. By ensuring a meaningful transfer of information between utilities, via active participation in systems like the INPO operated "Nuclear Network", the reliability program is provided a means to detect potential areas of concern. Additionally, the findings of studies performed by groups such as the Electric Power Research Institute are reviewed for information which is pertinent to the issue of enhancing onsite power source reliability.

The licensee noted that the Integrated Safety Assessment Program (ISAP) includes an examination and evaluation of all plant equipment failure history, forced and planned shutdowns, licensing event reports etc to identify recurring events or trends which could significantly contribute to overall risk. The staff review of the responses to GL 84-15 is in progress.

8.2.2 Gas Turbine Generator

The gas turbine is rated at 10,000 kW continuous load and 11,500 kW peak load (compared with 2,700-kW base load and a 2-hour emergency load rated at 3,000 kW for the onsite diesel generator). This difference allows the gas turbine to power larger and more loads than the diesel generator; one of these loads is the emergency feedwater coolant injection system.

The limited Probablistic Risk Assessment (PRA) performed for Millstone Unit 1 concluded that the reduction in core-melt frequency gained by bypassing the protective interlocks is less than 1%. This was determined by subtracting the total failure probability for the protective interlocks (1×10^{-3}) from the failure probability of the gas turbine generator (6×10^{-2}) and requantifying the Millstone Unit 1 Interim Reliability Evaluation Program. Although bypassing the protective trips was not found to substantially reduce risk, the

PRA concluded that the issues of gas turbine generator and diesel generator reliability are important factors in contributing to risk resulting from core melt at Millstone Unit 1. The limited PRA found that failure of the gas turbine generator appears in cut sets that contribute approximately one-quarter of the dominant accident frequency and that the failure rate of the gas turbine generator is relatively high, but within the limits proposed in Generic Letter 84-15.

Because of the lack of specific licensing criteria for gas turbine generators as emergency power supplies in nuclear power plants, the staff reviewed the Millstone Unit 1 gas turbine generator against the criteria for diesel generators and identified the following issues.

There are 17 trips that are not presently bypassed during emergency operation of the gas turbine generator. Four of the trips are associated with the startup of the gas turbine, six are associated with the steady-state operation of the gas turbine, and seven are associated with the output circuit breaker of the electric generator.

The four protective trips that are associated with startup (i.e., turbine light off) are as follows:

(1) if light-off speed (930 rpm) is not reached in 20 sec (light-off speed is expected in 13 to 16 sec)

(2) if light-off temperature (400°F) is not reached 15 sec after light-off (light-off temperature is expected 5 to 8 sec after reaching 930 rpm)

(3) if starting air-ignition cutoff speed (3,400 rpm) has not been reached 60 sec after start (expected 15 sec after light-off)

(4) if generator excitation speed (540 rpm electic-generator speed) is not reached in 60 sec (expected 35 sec after start)

The actual operating time-delay settings allow for variations in performance of the applicable components and are set high enough to ensure a complete starting attempt and to preclude unnecessary shutdown of the system.

The licensee proposed to bypass the light-off speed and generator excitation speed trips under accident conditions. Both of these trips indicate a major problem on obtaining startup and are designed to trip the turbine and stop the fuel supply in order to prevent an explosion. However, the light-off temperature and starting air-ignition cutoff speed trips should be retained in order to provide protection against a potential explosion. The implementation of these changes is included in the Integrated Safety Assessment Program (ISAP).

The six protective trips associated with the steady-state operation of the gas turbine generator are as follows:

(1) <u>High Exhaust Gas Temperature</u> - The trip for emergency operation is set at 1300°F, whereas, for normal power operation, it is set at 1200°F. It is anticipated that, for normal operation on a maximum ambient day (105°F), the exhaust gas temperature will not be in excess of 1050°F. For machine

operation in the emergency mode on a maximum ambient day, the anticipated exhaust has temperature is in the range of 1150°F to 1175°F. This gives a margin of 125°F to 150°F between this temperature range and the trip setting of 1300°F.

(2) High Lube Oil Temperature

(3) High Gas Generator Speed - This trip is set at 7,586 rpm, which represents a 3% overspeed condition for the emergency mode of operation. In the emergency mode of operation, because the breakers are closed and loading of the electrical generator starts at approximately 98% of synchronous speed, the chance of a spurious gas generator overspeed excursion is very low. Any indications of overspeed would be indicative of a load rejection or governor failure in the gas generator.

(4) High Turbine Overspeed - 6,050 rpm

(5) High Vibration Jet

(6) Low Lube Oil Pressure - 14 lb

The licensee proposed to bypass the high lube oil temperature trip under accident conditions; however, the remaining five trips are maintained, since each protects against severe mechanical damage and hazardous conditions. This modification was to be performed during the 1984 refueling outage. The licensee has stated that the high gas generator speed and high turbine overspeed trips are analogous to engine overspeed on a diesel generator and are necessary to prevent overspeed failures. The high exhaust gas temperature trip protects the unit against melting of mechanical parts. The high vibration jet trip protects against total mechanical degradation of the gas turbine. Since high vibration in a high-speed rotating piece of equipment is indicative of a severe problem, this trip must be maintained to protect against destructive failure of the machine.

The licensee stated that the specific temperature parameters are monitored by a number of thermocouples, which provide a high degree of reliability. Speed sensing is accomplished with a shaft-mounted tachometer. For all of the unbypassed trips, the addition of another channel to monitor critical parameters to provide coincident logic would not provide significant improvement in reliability because coincident logic modifications involve the starting sequence and normal operating circuits, potentially making the gas turbine generator less reliable.

The licensee reported a total of 31 gas turbine generator failures in the last 12 years. Many of them were due to problems associated with the speed switch in the early 1970s. In 1979, the licensee replaced the speed switch and governor. There were no failures reported in 1980. Since 1981, most failures were caused by rust on resistors and in the air pressure system. Because of these failures, the licensee has replaced the carbon steel air start lines down stream of the air receiver tank with stainless steel lines and sandblasted/coated the inside of the air tank. In almost all cases when a failure of the generator occurred, it occurred because of an actual component failure and not because of spurious signals. This is evident by the corrective actions taken

in each case. Many of the failures were associated with maintenance and could have been prevented with an improved preventive maintenance program.

Since the majority of failures were not due to faulty measurements and the addition of another channel to monitor critical parameters to provide coincident logic would involve the starting sequence, potentially reducing reliability, the staff found the proposed trip bypasses acceptable. However, the Millstone Unit 1 IREP study concluded that a loss-of-normal-ac-power event is a significant contributor to core-melt events. Loss of normal ac power accounts for 85% of the total core-melt probability. The major causes of core-melt, during loss of normal ac power, identified were the high level of dependence of the high-pressure cooling systems on the gas turbine emergency power source, the generally low reliability of the emergency power system, and the need for the operator to manually depressurize the reactor coolant system, if high-pressure injection failed. The licensee will continue efforts to improve the gas turbine generator reliability in the ISAP.

Because failure of the gas turbine generator appears in approximately one-quarter of the dominant accident sequences, the staff considered the matter of onsite ac power at Millstone Unit 1 to be an area where a substantial reduction in risk can be attained. Since many of the gas turbine failures might have been eliminated with an effective preventive maintenance program, the staff concluded that such a program should be developed and implemented, or if such a program already exists, the licensee should review the program for areas where it can be improved or justify the adequacy of the existing program.

By letter dated December 27, 1982 the licensee agreed to conduct such a review. The results were provided in a letter dated February 4, 1985 in response to Generic Letter 84-15.

The seven protective trips associated with the output breaker of the gas turbine generator are

(1) loss of excitation
(2) opening of the exciter breaker
(3) generator differential
(4) negative sequence
(5) reverse power
(6) generator underspeed
(7) voltage restrained overcurrent

The licensee proposed to maintain generator differential and voltage-restrained overcurrent trips and bypass the remainder under accident conditions as is currently done on the diesel generator.

The staff found this proposal acceptable. These modifications above were to be implemented during the 1984 refueling outage but will undergo further evaluation in the ISAP.

With regard to the gas turbine annunciator, the licensee has reviewed the alarm and control circuitry. The results of this evaluation of both the diesel and gas turbine were provided to the staff in a letter dated May 31, 1977. The staff indicated in a letter dated March 31, 1978 that the

modifications to the gas turbine proposed by the licensee were acceptable. These modifications were installed during the 1980 refueling outage.

8.3 Station Battery Test Requirements (SEP Topic VIII-3A)

The objective of this review was to assure that the onsite class IE batteries have the capacity to supply all safety related DC loads verified by periodic testing. The staff found that there was no requirement for periodic battery service tests in the technical specifications for Millstone Unit 1. However, by letter dated December 13, 1983, the licensee proposed technical specification changes to require periodic testing to determine battery capacity and demonstrate that the batteries will provide sufficient power under accident conditions.

The proposed change was reviewed (Section 4.29 of NUREG-0824 Ref. 5) by the staff and approved by Amendment 99 to the Provisional Operating Licensee for Millstone Unit-1 dated June 21, 1984.

The Millstone Unit 1 battery surveillance requirements are now included in Section 4.9.B of the station Technical Specifications. The licensee agreed to change the Technical Specification to require battery tests in accordance with IEEE Std 450-1975, IEEE Std 308-1974, BTP EICSB 6, and the "Standard Technical Specifications for Boiling Water Reactors" (NUREG-0123). The tests are:

(1) At least once every 18 months, during shutdown, a battery service test should be performed to verify that the battery capacity is adequate to supply and maintain in operable status all of the emergency loads for 2 hours.

(2) At least once every 60 months during shutdown, a battery discharge test should be performed to verify that the battery capacity is at least 80% of the manufacturer's rating.

These changes (T.S.4.9 B.1 C 1 and 2) satisfied the NRC requirements and were, therefore, acceptable.

8.4 DC Power System Bus Voltage Monitoring and Annunciation (SEP Topic VIII-3B)

To assure the design adequacy of the dc power system battery and bus voltage monitoring and annunciation schemes such that the operator can (1) prevent the loss of an emergency dc bus; or (2) take timely corrective action in the event of loss of an emergency dc bus, the staff reviewed the dc power system battery, battery charger, and bus voltage monitoring and annunciation design with respect to dc power system operability status indication to the operator.

Millstone Unit 1 has two 125-V dc buses (DC-1 and DC-1A) and two 24-V dc systems. The staff's review found that the Millstone Unit 1 control room has no indication of battery current, charger output current, bus voltage (24-V dc systems), charger output voltage, bus undervoltage (24-V dc systems) or overvoltage, bus ground (24-V dc systems), battery breaker/fuse status (24-V dc systems), or charger output breaker/fuse status.

The limited PRA performed to determine the importance to risk of dc instrumentation, indication, and alarms determined that additional monitoring devices would reduce the battery unavailability. In the Millstone Unit 1 IREP analysis, dc battery failure, contributed 5.5% to the total risk resulting from core melt.

The limited PRA concluded that improved instrumentation would reduce battery unavailability by 50% and that this would reduce core-melt frequency by 0.6%. The PRA found that the major contributor to dc unavailability is maintenance, because the Technical Specifications allow operation for 128 hours with one battery out of service. If maintenance unavailability is reduced by 50% in addition to improved instrumentation, a reduction of core-melt frequency of 2.5% results. The PRA recommended that allowable outage times for a battery be reviewed.

Because the 24-V system is used only for neutron monitoring, the staff considered the existing 24-V system indications acceptable.

The staff's positions for the 125-V system required that sufficient dc parameters have local indication and alarms in the control room so that the operator is alerted to the operability of the power system. Also, breaker status should be monitored in the control room or administratively controlled.

It was determined that the 125-V dc bus system has the following status indications in the control room:

(1) battery charger trouble alarm
(2) dc system ground alarm
(3) dc bus voltage
(4) battery/bus undervoltage alarm
(5) bus parallel to dc-1A alarm
(6) battery breaker open alarm

Also, all of the feeders to the dc buses, control room distribution panels, the 4-kV ac buses, the 480-V emergency load center buses, and vital equipment are individually alarmed for loss of dc power in the control room.

The licensee has evaluated the need to provide battery current alarms or indications in the control room and concluded by letter dated December 27, 1982 that present indications in the control room are sufficient. The staff is reviewing this response.

The PRA identified that existing battery outage limits allowed in plant Technical Specifications were too long. The licensee proposed to evaluate this concern and either propose a revision to the Technical Specifications for staff approval or justify existing outage limits. This issue is still being evaluated by the licensee.

8.5 Electrical Penetrations of Reactor Containment (SEP Topic VIII-4)

The objective of this review was to determine the capability of the electrical penetrations of the reactor compartment to withstand short circuit conditions of the worst expected transient fault current resulting from single random failures of circuit overload protection devices.

The review examined the protection of typical electrical penetrations in the containment structure to determine the ability of the protective devices to clear faults prior to exceeding the penetration design ratings under LOCA temperatures.

The following criteria were used to determine compliance with current licensing requirements:

1. IEEE Standard 317, Paragraph 4.2.4 -- "The rated short circuit current and duration shall be the maximum short circuit current in amperes that the conductors of a circuit can carry for a specified duration (based on the operating time of the primary overcurrent protective device or apparatus of the circuit) following continuous operation at rated continuous current without the temperature of the conductors exceeding their short circuit design limit with all other conductors in the assembly carrying their rated continuous current under the specified normal environmental conditions."

   This paragraph is augmented by Regulatory Guide 1.63, Paragraph C-1 -- "The electric penetration assembly should be designed to withstand, without loss of mechanical integrity, the maximum possible fault current versus time conditions that could occur given single random failures of circuit overload protection devices."

2. IEEE Standard 317, Paragraph 4.2.5 -- The rated maximum duration of rated short circuit current shall be the maximum time that the conductors of a circuit can carry rated short circuit current based on the operating time of the backup protective device or apparatus, during which the electrical integrity may be lost, but for which the penetration assembly shall maintain containment integrity."

3. IEEE Standard 317, paragraph 6.4.14 -- "The maximum duration of rated short circuit shall be verified by the test. The test shall be conducted at maximum postulated design basis event temperature and pressure and relative humidity. The test current and duration shall be in accordance with Section 4.2.5 plus margin. The test duration shall be not less than the time required for the backup overcurrent protection device to function."

The results of typical containment penetrations at LOCA temperature concurrent with a random failure of the circuit protective devices were analyzed.

The following formula was used to determine the time allowed before a short circuit would cause the penetration to heat up to the temperature limit.

$$^{*}t = \frac{A^2}{I^2} \quad .0297 \log \frac{T_2+234}{T_I+234}$$

where

t = time in seconds

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*Based on the heating effect of the short circuit current on the conductor. Does not take into account heat losses of the conductor. For times less than several seconds, this heat loss is negligible.

I = current in amperes

A = conductor area in circular mils

T_1 = initial temperature (138°C, LOCA condition)

T_2 = maximum penetration temperature before failure.

In evaluating the capability of the penetration to withstand a LOCA temperature with a short circuit current, the above formula was used to calculate the time required to heat the conductor from the LOCA temperature to penetration failure temperature for currents from rated current to maximum short circuit in 20% increments. Times for the primary and secondary overcurrent devices to interrupt these fault currents were calculated. Where breaker ratings provided by the licensee indicated minimum and maximum fault clearing times, the maximum time was used for conservatism.

8.5.1 Typical Low Voltage (0-1000V) Penetrations

Northeast Utilities identified penetration X-105D (GE type NS04) as typical of low voltage penetrations. This penetration provides 480 V ac power to motor-operated valve 1-IC-1.

This penetration uses two #8 AWG cables in parallel and has a continuous current rating of 20 amps per conductor. The maximum available short circuit current determined by NU is 1600 amps. With a temperature limit of 352°F (177°C) before seal failure and the maximum short circuit current (1600 amps), overtemperature is reached in 0.64 second from LOCA temperature initially.

From LOCA temperature initially, the secondary breaker will not operate to clear any fault currents before penetration seal limiting temperature is attained. However, NU has determined that the outboard seal of this penetration will have an initial temperature of not more than 90°C. From this temperature initially, the secondary breaker will still not operated to clear the fault before the conductor reaches 177°C. However the #10 AWG cable external to the penetration will fuse before this temperature is reached. The primary breaker will clear the fault currents before seal limiting temperature is attained provided that both conductors are intact. There are no Technical Specification requirements to verify that both conductors have continuity. However, NU verifies continuity upon penetration installation. The staff concluded that the penetration meets current requirements for short circuit faults if the primary breaker operates as designed provided that both cables in the penetration are operable.

8.5.2 Typical Medium Voltage (>1000 V) Penetration

Northeast Utilities has identified penetration X-101A (GE type NS03) as being typical of medium voltage penetrations. This penetration provides 4160 V ac power to Reactor Recirculation Pump 1.

This penetration uses two 500 MCM cables in parallel and has a continuous current rating of 550 amps per conductor. The maximum available short circuit current has been determined by NU to be 1700 amps. A temperature limit of

352°F (177°C) has been established based on testing. At the maximum short circuit current (1700 amps), overtemperature will be reached in 440 seconds from LOCA temperature initially.

Overcurrent protection is provided by a differential current sensing relay and a line overcurrent sensing relay, each of which will operate to trip the motor generator by securing power to the motor generator motor and opening the generator field windings. At ≥156 amps of current difference between the output of the generator and the input to the motor, the differential relay will cause a trip of the motor generator in 0.133 second or less. At line current in excess of 780 amps, the overcurrent relay will cause a trip of the motor generator in 0.18 second or less.

The line overcurrent relay will operate to clear all fault currents in excess of 780 amps prior to reaching the penetration seal temperature limit from LOCA temperature initially. For fault currents less than 1100 amps, the conductors will carry less than their rated continuous current (550 amps) provided both conductors have continuity. If one conductor is open, the overcurrent device will not operate for faults between 550 and 780 amps and penetration overheating may occur. There are no Technical Specifications requiring continuity of the conductors to be checked. However, continuity is verified during installation of the penetration. The staff concluded that the penetration met requirements for all fault currents provided that both conductors in the penetration are operable.

8.5.3 Typical Direct Current Penetration

Northeast Utilities has identified penetration X-100A (GE type NS04) as being typical of DC penetrations. This penetration provides 125 V dc power to the solenoid valve on main steam isolation valve 203-1A.

This penetration uses #14 AWG cable and has a continuous current rating of 10 amps. The maximum available short circuit current has been determined by NU to be 95 amps. With temperature limit of 352°F (177°C) before seal failure and the maximum short circuit current (95 amps), overtemperature will be reached in 2.38 seconds from LOCA temperature initially.

The staff concluded that both the primary and secondary fuses will operate to clear all fault currents before the penetration seal temperature limit is reached.

8.6 Environmental Qualification of Electric Equipment Important to Safety

Equipment used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement, which is embodied in General Design Criteria 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50, is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment were provided in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment" (which supplements

IEEE Standard 323 and various NRC Regulatory Guides and industry standards), and "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" (DOR Guidelines).

The staff issued a Safety Evaluation Report (SER) on environmental qualification of safety-related electrical equipment to the licensee on June 10, 1981. This SER directed the licensee to "either provide documentation of the missing qualification information which demonstrated that safety-related equipment met the DOR Guidelines or NUREG-0588 requirements or commit to a corrective action (requalification, replacement (etc.))." In response to this the licensee submitted additional information regarding the qualification of safety-related electrical equipment. This information was evaluated for the staff by the Franklin Research Center (FRC) in order to: 1) identify all cases where the licensee's response did not resolve the significant qualification issues, 2) evaluate the licensee's qualification documentation in accordance with established criteria to determine which equipment had adequate documentation and which did not, and 3) evaluate the licensee's qualification documentation for safety-related electrical equipment located in harsh environments required for TMI Lessons Learned Implementation. A Safety Evaluation Report was subsequently issued to the Northeast Nuclear Energy Company (NNECO) on December 13, 1982, with the FRC TER as an attachment.

A final rule on environmental qualification of electric equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, Section 50.49 of 10 CFR 50, specified the requirements of electrical equipment important to safety located in a harsh environment. In accordance with this rule, equipment for Millstone Unit 1 may be qualified to the criteria specified in either the DOR Guidelines or NUREG-0588, except for replacement equipment. Replacement equipment installed subsequent to February 22, 1983 must be qualified in accordance with the provisions of 10 CFR 50.49, using the guidance of Regulatory Guide 1.89, unless there are sound reasons to the contrary.

On April 10, 1984, a meeting was held to discuss NNECO's Millstone Unit 1 proposed method to resolve the environmental qualification deficiencies identified in the December 13, 1982 SER and FRC TER. The minutes of the meeting and proposed method of resolution for each of the environmental qualification deficiencies were documented in a February 11, 1985 submittal from the licensee.

The acceptability of the licensee's electrical equipment environmental qualification program was based on the results of an audit review performed by the staff of: (1) the licensee's proposed resolutions of the environmental qualification deficiencies identified in the December 13, 1982 SER and FRC TER; (2) compliance with the requirements of 10 CFR 50.49; and (3) justification for continued operation (JCO) for those equipment items for which the environmental qualification was not complete.

The majority of deficiencies identified were documentation, similarity, aging, qualified life and replacement schedule. All open items identified in the SER dated December 13, 1982 were also discussed and the resolution of these items has been found acceptable by the staff with the exception of the inside containment pressure/temperature service conditions. By letter dated June 11, 1985 the licensee proposed to do a plant specific analyses of temperature/pressure conditions within containment following design basis accidents and provide the results by December 11, 1985.

The approach described by the licensee for addressing and resolving the identified deficiencies included replacing equipment, performing additional analyses, utilizing additional qualification documentation beyond that reviewed by FRC, obtaining additional qualification documentation and determining that some equipment is outside the scope of 10 CFR 50.49, and therefore not required to be environmentally qualified, e.g., located in a mild environment. The staff discussed the proposed resolutions in detail on an item by item basis with the licensee during the April 10, 1984 meeting. The licensee's equipment environmental qualification files will be audited by the staff during follow-up inspections to be performed by Region I, with assistance from IE Headquarters and NRR staff as necessary.

The primary objective of the file audit will be to verify that they contain the appropriate analyses and other necessary documentation to support the licensee's conclusion that the equipment is qualified. The inspections will verify that the licensee's program for surveillance and maintenance of environmentally qualified equipment is adequate to assure that this equipment is maintained in the as analyzed or tested condition. The method used for tracking periodic replacement parts, and implementation of the licensee's commitments and actions, e.g., regarding replacement of equipment, will also be verified.

The staff found that the licensee's approach for resolving the identified environmental qualification deficiencies acceptable (Ref. 23). The licensee's approach for identifying equipment within the scope of paragraph (b)(1) is in accordance with the requirements of that paragraph, and therefore acceptable. The staff found the methodology used by the licensee acceptable since it provides reasonable assurance that equipment within the scope of paragraph (b)(2) of 10 CFR 50.49 has been identified. Also the staff found the licensee's approach to identifying equipment within the scope of paragraph (b)(3) of 10 CFR 50.49 acceptable.

In summary the staff concluded that:

- NNECO's Millstone Unit 1 electrical equipment environmental qualification program complies with the requirements of 10 CFR 50.49.
- The proposed resolutions for each of the environmental qualification deficiencies identified in the December 13, 1982 SER and FRC TER are acceptable with the exception of the inside containment P/T profiles which the licensee is required to resolve.
- Continued operation until completion of the licensee's environmental qualification program will not present undue risk to the public health and safety.

9 AUXILIARY AND EMERGENCY SYSTEMS

The original installations are listed and described in the FSAR (Ref. 12).

9.1 Fuel Storage (SEP Topic IX-1)

The purpose of SEP Topic IX-1 was to review the storage facility for new and irradiated fuel, including the cooling capability and seismic classification of the fuel pool cooling system of the spent fuel storage pool in order to assure that new and irradiated fuel are stored safely with respect to criticality, cooling capability, shielding, and structural capability.

By letters dated August 31, 1981 and December 14, 1981 the licensee provided a safety assessment report. The staff reviewed these submittals and noted that on June 30, 1977, the Commission issued Amendment No. 39 to Facility License No. DPR-21 for the Millstone 1 plant. The amendment permitted changes in the design of the spent fuel storage racks allowing spent fuel storage capacity to be increased from 1100 to 2184 fuel assemblies.

A full core for Millstone Unit No. 1 consists of 580 fuel assemblies. In 1976, eleven additional racks of the same design as the original racks were installed in the Millstone Unit No. 1 Spent Fuel Pool (SFP) in space originally provided for the possibility of such expansion. This increased the original spent fuel storage capacity by 220 assemblies to a total of 1100 assemblies utilizing storage racks with a center-to-center spacing of fuel bundles of approximately 6.6 inches in the rows and 11.9 inches between rows. Each rack could hold 20 assemblies in two rows of ten assemblies each. The second fuel rack modification at Millstone Unit No. 1 (Amendment 39 above) involved removal of these racks and replacement with racks that provide a uniform 6.5 inch center-to-center spacing of the fuel assemblies. The new racks incorporate B_4C neutron absorber plates between each assembly location in each rack to insure subcriticality, and increased the storage capability of the SFP from 1100 to 2184 assemblies.

The new spent fuel storage racks consist of 1/8 inch thick type 304 austenitic stainless steel square tubes with 6.5 inch center-to-center spacing separated by cylindrical spacers at the tube corners. B_4C plate absorbers are placed in the cavity between the square tubes. The tubes are flared at each end and welded together at the ends to form a unitized array which is subsequently welded to a pre-assembled base. The edge welding provides a watertight seal for the B_4C plates and assures that the design center-to-center spacing of 6.5 inches is maintained.

The elevated base plate contains an opening at each storage location to accept the bottom flow nozzle of the fuel assembly. Natural circulation of pool water through the nozzle and up the assembly removes decay heat. The tubes and base plate openings were designed to accept the General Electric 7 x 7 and 8 x 8 fuel assemblies and other assemblies with the same external dimensions and similar lower nozzle design. The absorber plate is B_4C powder bonded together in

a carbon matrix. The absorber is a minimum of 25% B_4C by volume with the remainder being carbon and voids. The absorber is fabricated of 0.21" (minimum) thick x 6" wide x 31" long plates which are inserted in the cavity between the square tubes.

Since the existing fuel rack design is the same as that reviewed and approved in the previous NRC safety evaluation for Amendment No. 39 the staff conclusions concerning the criticality analysis, rack structural, mechanical and material review, radiation level, nuclear, thermal and hydraulic aspects and heat removal capability of the spent fuel pool cooling system remain valid.

The design of the storage pool includes a leak collection network behind the pool liner welds to detect and collect leakage through the welds, a pool water level monitoring system, and radiation monitoring systems with indications and alarms. Syphon breaks are provided on those segments of piping which enter the pool to prevent the water level from dropping below the safe shielding depth. These features satisfy the requirements of GDC 63, Monitoring Fuel and Waste Storage, and the guidelines of Regulatory Guide 1.13 Position C.6 and C.7.

Normal makeup to the pool is from the condensate demineralizer system via the spent fuel pool cooling system. A backup makeup supply is provided by the fire protection system. The fire protection system is capable of providing the maximum makeup requirement. Thus the guidelines of Regulatory Guide 1.13 Position C.8 have been met.

The staff concluded that the spent fuel storage facility met the requirements of GDC 61, 62 and 63 as related to radiation protection, prevention of criticality and monitoring provisions, and the guidelines of Regulatory Guide 1.13 regarding the facility design and is, therefore, acceptable.

In response to a staff request, the licensee stated that the spent fuel pool cooling system was not Seismic Category I, but that it was designed to meet the requirements of USAS B31.1.0, predecessor to ANSI B31.1. A major difference between USAS B31.1.0 requirements and those shown in Regulatory Guide 1.26 (i.e., ASME Boiler and Pressure Vessel Section III Class 3 requirements) is that ASME Section III Class 3 requires documentation of the material requirements and a prescribed nondestructive examination of the weld surfaces. Considering the benign service conditions of the spent fuel pool cooling system as compared to primary coolant systems (also included in Regulatory Guide 1.26), the number of successful years of operation without deficiencies becoming manifest and the normal spread in the composition in materials the staff concluded that the Millstone 1 spent fuel pool cooling system is acceptable as it relates to Regulatory Guide 1.26.

The structural response of the Millstone 1 plant with respect to seismic capability has been reviewed and presented in NUREG/CR-2024, "Seismic Review of the Millstone Nuclear Power Station, Unit No. 1 as Part of the Systematic Evaluation Program." This review concluded that the reactor building structure (which houses the spent fuel pool and new fuel storage vault) has sufficient strength to withstand the postulated safe shutdown earthquake loads.

The staff therefore concluded that the spent fuel storage facility at Millstone 1 is acceptable with respect to the requirements of Standard Review Plan Sections 9.1.2 and 9.1.3.

The new fuel storage area is located in the reactor building. New fuel is stored dry in the fuel storage area. The primary concern would be flooding of the storage area with the potential for inadvertent criticality.

The new fuel storage racks are designed to store the fuel assemblies in a rectangular lattice at a center to center spacing of approximately 6.6 inches by 11 inches. This spacing is sufficient to maintain subcriticality of the fuel assuming fully flooded conditions. The construction of the racks is such that the fuel assemblies can only be inserted in prescribed locations. To prevent the sudden flooding of the storage vault environment, concrete covers are emplaced over the vault during normal plant operations. These covers also prevent objects from being dropped into the vault. Drainage is provided in the vault to prevent liquid accumulation.

Based on the above the staff concluded that the new fuel storage facility meets the guidance of Standard Review Plan 9.1.1.

The monthly operating data reports (dated March 13, 1985 for example) have been reporting that following the 1987 refueling outage there will not be sufficient capacity in the spent fuel pool to remove and store the full core. By 1991 the current projection is that the spent fuel pool will be full (i.e., reactor vessel full with 580 fuel assemblies and spent fuel pool full with 2146 spent fuel assemblies). By letter dated May 17, 1985, the licensee, as part of the Integrated Safety Assessment Program (ISAP), indicated plans for:

a. Engineering evaluation including design, licensing, fabrication and installation, of high density spent fuel racks in the Millstone Unit 3 spent fuel pool to accommodate BWR spent fuel from Millstone Unit 1. Analysis to include evaluation of a spent fuel transportation cask for fuel shipment between Unit 1 and Unit 3.

b. Feasibility study of re-racking the Millstone Unit 1 Spent Fuel Pool to enlarge spent fuel storage capacity at the station.

The need for such a program is evident, since continued operation beyond 1991 is dependent on new capacity to store spent fuel assemblies from Millstone Unit 1.

9.2 Station Service and Cooling Water Systems (SEP Topic IX-3)

The safety objective of this topic was to assure that the cooling water systems have the capability, with adequate margin, to meet design objectives and, in particular, to assure that:

a. systems are provided with adequate physical separation such that there are no adverse interactions among those systems under any mode of operation;

b. sufficient cooling water inventory has been provided or that adequate provisions for makeup are available;

c. tank overflow cannot be released to the environment without monitoring and unless the level of radioactivity is within acceptable limits;

d. vital equipment necessary for achieving a controlled and safe shutdown is not flooded due to the failure of the main condenser circulating water system.

In determining which systems to evaluate under this topic, the staff used the definition of "systems important to safety." The definition states systems important to safety are those necessary to ensure (1) the integrity of the reactor coolant pressure boundary, (2) the capability to shut down the reactor and maintain it in a safe condition, or (3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines of 10 CFR Part 100, "Reactor Site Criteria." This definition was used to determine which systems or portions of systems are "essential."

The systems reviewed are listed below.

- Turbine building closed cooling water system
- Turbine building secondary closed cooling water system
- Reactor building closed cooling water system
- Service Water System
- Emergency Service Water System

9.2.1 Turbine Building Closed Cooling Water System

The Turbine Building Closed Cooling Water System (TBCCW) is a closed loop system with three 33% capacity heat exchangers and three 50% capacity pumps. The system contains a surge tank which provides net positive suction head for the pumps and surge volume to accommodate system fluid expansion and contraction. The TBCCW system cools the following equipment:

Generator H_2 Coolers (4)
Stator Windings and Rectifier Coolers (2)
Turbine Lube Oil Coolers (2)
Alternator Cooler (1)
Generator Leads Cooler (1)
Recirculating Pump MG Coupling Coolers (2)
Evaporator Vacuum Pump (1)
Priming Pump Coolers (3)

The only safety function performed by equipment serviced by the TBCCW, is that of the recirculating pump MG coupling coolers. The coolers help maintain seal integrity. However these pumps are not required to operate as part of the plant's shut down scheme or post incident, and the licensee indicated that cooling is not required for seal integrity once pumps are secured. Therefore, the staff determined that the TBCCW system is not important to safety.

9.2.2 Turbine Building Secondary Closed Cooling Water System

The turbine building secondary closed cooling water system supplements the turbine building cooling system by providing 80°F cooling water to other auxiliary equipment in both the turbine and reactor buildings.

The system consists of two pumps, two heat exchangers and control and support equipment. Each of the two full capacity cooling water pumps delivers 1800 gpm, which is sufficient to supply all cooling for the following equipment.

Reactor Building Space Cooler (1)
Condensate Pump Motors (3)
Station Air Compressor (1)
Instrument Air Compressor (1)
Condensate Booster Pump Oil Coolers (3)
Reactor Feed Pump Oil Coolers (3)
Turbine Building Sample Coolers (9)
Reactor Building Sample Coolers (2)
Cleanup Pump Space Cooler (1)
Motor Generator Set Space Coolers (3)
Spray Pump Space Coolers (2)
Rod Drive Space Cooler (1)
Control Rod Drive Pumps (2)
Condensate Pump Space Coolers (1)
Reactor Feed Pump Space Coolers (2)
Diesel Generator Space Coolers (2)
Air Conditioning Units (2)
Condensate Booster Pump Space Cooler (1)
Steam Tunnel Space Coolers (2)
Makeup to Diesel Generator Expansion Tank

The turbine building secondary closed cooling water system is considered essential because of the dependency of both the plant's ventilation and feedwater coolant injection systems.

The two half-capacity heat exchangers are capable of removing the maximum expected heat load from the system. Each heat exchanger is designed to remove 4.9×10^6 Btu per hour. Either heat exchanger is capable of handling the reduced cooling loads during accident conditions.

A single tank is located above the highest point in the system to handle system fluctuations and to supply makeup when necessary. A low level alarm is provided for the head tank. A chemical feeder is provided for addition of corrosion inhibitor. Control equipment is supplied as needed. All equipment is supplied with flow control devices for regulation of flow through the heat exchangers.

Water level is manually maintained in the expansion tank with makeup being supplied from the demineralized water transfer system. A low level alarm is provided for the expansion tank.

As indicated previously, each secondary closed cooling water pump of the system handles 100% load; therefore, system redundancy is provided. A signal is annunciated in the control room upon loss of a pump. This alerts the operator, who

manually actuates the alternate pump. The pumps are supplied by emergency power from either the diesel generator or gas turbine.

Based on review of turbine building secondary cooling water system, the staff concluded that the design of this system provided sufficient redundancy to ensure reliable operation except for common piping.

9.2.3 Reactor Building Closed Cooling Water System

The Reactor Building Closed Cooling Water System (RBCCW) is a closed loop system with two 100% capacity pumps and three 50% capacity heat exchangers. The system also contains a surge tank which provides net positive suction head for the pumps and a surge volume to accommodate system fluid thermal expansion and contraction. The RBCCW system cools the following equipment:

- Fuel Pool Heat Exchangers
- Recirculation Pumps and Motors
- Drywell Coolers
- Reactor Water Clean-up Nonregenerative Heat Exchangers
- Reactor Building Equipment Drain Tank
- Filter Recirculation Coolers
- Waste Concentrator Condenser
- Sparging Air Compressors
- Drywell Sump Cooler
- Three Concentrator Waste Surge Tanks
- Cleanup and Precoat Pump Coolers
- Shutdown Cooling Heat Exchanger
- Shutdown Cooling Pump Cooler
- Xenon/Krypton Equipment

No credit is taken for the containment drywell coolers in accident analyses for the Millstone Unit 1 plant, and, therefore, they are not necessary for safe plant shutdown.

The specific equipment and/or systems to which the RBCCW supplies cooling water which are considered safety related are the spent fuel pool coolers, recirculation pumps (pressure boundary integrity only), and shutdown cooling system. Cooling is not required to the recirculation pumps to maintain pressure boundary integrity in the short term. Spent fuel pool cooling can be accomplished by other methods along with sufficient time being available to reestablish cooling. The capability to provide long term cooling to the spent fuel pool was addressed as part of SEP Topic IX-1, Fuel Storage. The shutdown cooling system is not required to bring the plant to safe shutdown or to achieve cold shutdown conditions.

The staff determined that the RBCCW system is not important to safety.

9.2.4 Service Water System

Four (4) service water pumps provide seawater for cooling the station systems listed below. The service water pumps are vertical centrifugal pumps each capable of delivering 10,000 gpm. Any three of the pumps are capable of supplying sufficient cooling water flow for full power operation of the plant. The heat

exchangers are of various capacities depending on the cooling loads of the system. Temperature and pressure indicators located near the heat exchangers indicate a malfunction in the system. The service water system supplies cooling for the following equipment:

Location	Normal Flow Salt Water (gpm)	Heat Transfer (10^6 Btu/hr)
Turbine Building Closed Cooling Water	9,900	34.0
Reactor Building Closed Cooling Water	12,000	78.34
Diesel Generator	700	5.0
Turbine Building Secondary Closed Cooling Water	5,000	8.8
Evaporator (one in operation)	1,350	

The Service Water System is considered essential because it services the Emergency Diesel Generator and the Turbine Building Secondary Closed Cooling Water System.

In the event of loss of normal power one service pump is supplied from each emergency power source (i.e., emergency diesel generator and gas turbine generator). All non-essential loads are automatically shut off (i.e., TBCCW, RBCCW and evaporators) and essential load cooling capability is maintained. During normal operation, if one of the service water pumps fail, the spare pump takes up the pumping load until repairs can be made. During accident or abnormal conditions, one service water pump is required to cool the diesel generator and the turbine building secondary cooling water system. The immediate and long-term effect of losing the service water system results in shutting down the diesel generator. In this event, the gas turbine generator is used to supply emergency power since its cooling requirements are independent of the service water. The loss of service water then results in the loss of the turbine building closed cooling water system.

The staff concluded that the design of the SWS provides sufficient redundancy to ensure reliable operation with the exception of common piping.

9.2.5 Emergency Service Water System

The station emergency service water system provides cooling water from the Long Island Sound to the low pressure core injection (LPCI) system heat exchangers.

The emergency service water system consists of four (4) pumps, two heat exchangers, piping, and control and support equipment. The four pumps are grouped into two sets of two pumps. Each set of pumps provides 5,000 gpm (2,500 gpm/pump) of seawater to one LPCI heat exchanger. Either set of pumps and heat exchanger is capable of handling the heat load of the LPCI system. Each set of pumps is individually piped to the respective heat exchanger, resulting in two completely segregated emergency service water systems. Support equipment includes two self-cleaning strainers, one in each line to the heat exchangers.

In the event of loss of normal AC power, power for either set of emergency service water pumps can be supplied from the emergency power sources. This system power alignment is a manual operation.

Should either set of pumps or the respective heat exchanger fail, the other set of pumps are placed in operation until repairs are made.

The pressure of the emergency service water system is maintained at a 15 psi differential above the LPCI cooling system pressure for the entire range of operation with a differential pressure control valve. This is done so that if a leak occurs in the LPCI cooling system, the leakage is into the cooling system instead of permitting the release of possibly radioactive contaminants to the service water and thereby into the Long Island Sound.

Isolation of leaking ESWS components is accomplished by securing the associated pumps either manually by isolating the containment spray/cooling heat exchanger, or closing the motor operation discharge valve of the affected loop.

The LPCI pumps are activated on either a signal of reactor low water level and low reactor pressure, or a signal of high dry-well pressure. The containment cooling function can be performed with the LPCI system after the core is flooded.

Two of the LPCI pumps can then be shut down and two containment cooling emergency service water pumps will be started manually to provide cooling water to the containment spray/cooling heat exchangers. The suppression chamber is equipped with temperature alarms at approximately 85°F; after receiving these alarms operator action is required to establish emergency service water flow through the heat exchangers.

The staff concluded that the design of the ESWS provides sufficient redundancy to ensure reliable operation, in the event that it is required to supply cooling to the containment spray/cooling heat exchangers following an accident.

Based on the review of service and cooling water systems, the staff concluded that the essential systems and functions are:

Service Water System: Diesel Generator and Turbine building secondary closed cooling water heat exchanger

Emergency Service Water System: Low pressure core injection heat exchanger

Turbine Building Secondary Closed Cooling Water System: Plant ventilation systems and feedwater core injection system

The staff determined that these systems are in conformance with current criteria for this topic except for non-redundant piping in the service water system and the turbine building secondary closed cooling water system. A single failure in nonredundant pipe runs of the service water system and the turbine building secondary closed cooling water system could result in loss of system function.

The service water system is susceptible to a single passive failure in the pipe run from the intake structure to essential equipment located in the reactor and turbine buildings. The essential equipment serviced by the service water system

is the diesel generator and the turbine building secondary closed cooling water system heat exchangers. The equipment serviced by the turbine building secondary closed cooling water system consists primarily of components of the feedwater coolant injection (FWCI) system. Since loss of this equipment will not inhibit safe shutdown of the plant, the turbine building secondary closed cooling water system can be considered nonessential for the purposes of this review.

A passive failure in the service water line would also result in loss of cooling to the diesel generator; however, the gas turbine generator, which is air cooled, could provide emergency power. Should the gas turbine also be unavailable, the isolation condenser, which is independent of ac power, could be used to maintain the plant in a safe shutdown condition.

The limited PRA of this issue found that failure of the station service and cooling water systems that appeared in the dominant accident sequences had probabilities of approximately 10^{-3} and pipe segment failure had probabilities of about 10^{-9}; thus, the effect on core-melt frequency or risk is negligible. The limited PRA did not consider the issue of the service water lines underlain by peat. These pipes may experience excessive settlement resulting in excessive pipe stresses. Rather, the limited PRA performed was based on historical passive pipe failure rates per unit length of pipe. The potential affect of the pressure of peat moss has not been resolved at this time.

9.3 <u>Ventilation Systems</u> (SEP Topic IX-5)

It was necessary to review the design and operation of ventilation systems to assure capability to provide a safe environment for plant personnel and for engineered safety features. For example, the function of the spent fuel pool area ventilation system is to provide ventilation in the spent fuel pool equipment areas, to permit personnel access, and to control airborne radioactivity in the area during normal operation, anticipated operational transients, and following postulated fuel handling accidents. The function of the engineered safety feature ventilation system is to provide a suitable and controlled environment for engineered safety feature components following certain anticipated transients and design basis accidents.

The Integrated Plant Safety Assessment Report for Millstone Nuclear Power Station, Unit 1 (NUREG-0824 Ref. 5), identified a concern related to the loss-of-ventilation event for several areas housing safety-related equipment. By letter dated April 18, 1983 the licensee provided an assessment of the outstanding issues. These items are discussed below.

9.3.1 Core Spray and Low-Pressure Coolant Injection (LPCI) Ventilation Systems

The emergency core spray pumps and LPCI pumps are located in corner rooms on the basement level of the Reactor Building. Post-incident cooling units for these areas are not redundant. Thus, a single failure could result in a loss of room cooling. This could adversely affect the performance of the safety-related equipment located in these areas.

The licensee responded that the coolers are not essential for maintaining the components located in these rooms within thermal design limits. To support this conclusion, the licensee, by letter dated December 3, 1982 provided the results of an earlier test performed on April 22, 1970. The objective of this

test was to verify the extent of the conservatism in the calculations of ECCS pump room heat up under the most adverse postulated conditions which included: only one LPCI cooling loop available; one core spray pump available in the same corner room; suppression pool at highest allowable initial temperature prior to accident; highest ambient air temperature for the site; and loss of pump room air coolers.

The staff reviewed the licensee's evaluation and referenced test and concluded that failure of the ventilation cooling would not likely cause a failure of the safety-related equipment in the room. Although worse conditions than those used in the test might occur, such conditions coincident with a need for the equipment are highly unlikely. Even if such a combination of conditions were to occur and cause a failure of the equipment in the room, the redundant train of equipment located in another room, which is served by a separate cooling system, would still be available to accomplish the safety function. Consequently, the staff concluded that loss of room cooling would not adversely affect performance of CS and LPCI.

9.3.2 Turbine Building Ventilation System

The Turbine Building Ventilation System services all areas within the Turbine Building, which includes ventilation for the following equipment which is considered safety-related; feedwater coolant injection system (condensate pumps, condensate booster pumps, and reactor feedwater pumps), switchgear rooms, emergency diesel generator, battery room, secondary closed cooling water pumps, and related piping valves and controls.

Following a loss of offsite power event, operator action is required to reinitiate the Turbine Building Ventilation System. Thus, cooling of this equipment would be lost for such events, until ventilation is restored. In addition, this ventilation system serves as the hydrogen control mechanism for the battery rooms.

The results of the licensee's evaluation indicated that the components which contribute the largest heat loads in the Turbine Building during a loss of offsite power event are the 480 volt load centers 1, 2, and 2A and both the load center and switchgear heaters. The licensee's analysis of the heat gain during the summer in the area of this equipment indicates that the ambient temperature would increase to 104°F (design temperature) in approximately 30 minutes. Of these heat sources, all of the load center and switchgear heaters and 480 volt load centers 1 and 2 receive power from the gas turbine generator. Only the 480 volt load center 2A is powered by the diesel generator. The evaluation that was performed for this area assumed that both the diesel and gas turbines start and run.

However, the licensee's evaluation found that should the gas turbine fail to start, the heat loads in this area would be significantly reduced (i.e., loss of heaters and load centers 1 and 2) to the point where ventilation in the area would not be required. Therefore, since ventilation in this area is required only when the gas turbine generator is operating, and sufficient time (a minimum of 30 minutes) is available for operator action, the licensee committed to revise the plant operating procedures to instruct the operator to start both the supply and exhaust ventilation fans in the switchgear area if the gas turbine starts successfully during a loss of offsite power event.

With respect to the accumulation of hydrogen, the licensee calculated the maximum rate of hydrogen production in each battery room to be approximately 0.207 cubic feet per hour. Considering the size of the battery rooms, an increase of 1% hydrogen by volume in the smaller battery room is expected to take approximately six (6) days. Therefore, it would require considerable time for hydrogen concentration to reach combustible concentration. Due to the low hydrogen production rate and the presence of the combustible gas detector systems, the staff concluded that sufficient time (i.e., days) is available for the operator to either restore offsite power or to successfully start the diesel generator to provide ventilation before the limit of combustion is reached.

Based on this information and the licensee's commitment to modify the plant operating procedures, the staff considered these issues resolved.

9.3.3 FWCI and Diesel Generator Area Coolers

The staff had indicated that insufficient information was provided on the design and operation of the area space coolers for the FWCI and diesel generator areas. This precluded the staff from completing its review of these units. Subsequently, the licensee evaluated the design and operation of both area cooling systems.

The licensee's evaluation of the heat gain during the summer in the vicinity of the FWCI components indicates that the area coolers must be operable to maintain these areas below the 104°F design temperature. The cooling capacity of these area coolers is sufficient even with the loss of one cooler. If the area coolers are operating, the ventilation system is not essential, however, the heat removal capacity of the ventilation system alone is not sufficient to cool these areas without operation of the area coolers.

The FWCI area space coolers did not receive emergency power. However, the licensee committed to modify these units so that the area coolers will be automatically sequenced onto the gas turbine generator. Since the diesel generator does not power the FWCI system, these area coolers would only be required if the gas turbine is operating. Therefore, redundant power supplies are not required.

As a result of the licensee's review of the space coolers in the diesel generator area it was determined that both area coolers are automatically sequenced onto the diesel generator. Each area cooler has a heat removal capacity of 500,000 BTU/hr, which is sufficient to cool this area without requiring the ventilation system to be operable.

Based on this information and the licensee's commitment to automatically sequence the FWCI area space coolers onto the gas turbine generator, the staff considered these issues resolved.

9.3.4 Intake Structure Ventilation System

In the topic evaluation, the staff indicated that insufficient information was provided to support the licensee's position that active ventilation is not required for the intake structure.

The licensee subsequently evaluated the heat buildup in the intake structure during the summer due to operation of the service water and emergency service

water pumps and determined that starting one of the 20,000 cfm exhaust fans will provide sufficient cooling. Operation of only one fan will provide a complete air change in the affected area in approximately four (4) minutes.

The two 20,000 cfm exhaust fans did not receive power from an emergency bus. However, the licensee committed to modify the exhaust fans so that one unit is automatically sequenced onto the diesel generator and the other unit is automatically sequenced onto the gas turbine generator.

Based on this information and the licensee's commitment to modify the power supplies for the exhaust fans, the staff considered this issue resolved.

9.4 Fire Protection

Following a fire at the Brown's Ferry Nuclear Station in March 1975, the Nuclear Regulatory Commission initiated an evaluation of the need for improving the fire protection programs at all licensed nuclear power plants. As part of this continuing evaluation, the NRC, in February 1976, published the report by a special review group entitled, "Recommendations Related to Browns Ferry Fire," NUREG-0050. This report recommended that improvements in the areas of fire prevention and fire control be made in most existing facilities and that consideration by given to design features that would increase the ability of nuclear facilities to withstand fires without the loss of important functions. To implement the report's recommendations, the NRC initiated a program for reevaluation of the fire protection programs at all licensed nuclear power stations and for a comprehensive review of all new licensee applications.

The NRC issued new guidelines for fire protection programs in nuclear power plants which reflect the recommendations in NUREG-0050 and all licensees were requested to: (1) compare their fire protection programs with the new guideines; and (2) analyze the consequences of a postulated fire in each plant area.

The staff reviewed the licensee's analyses and visited the plant to examine the relationship of safety-related components, systems and structures with both combustibles and the associated fire detection and suppression systems. The staff's review of the fire protection program was documented in a Safety Evaluation report dated September 26, 1978.

The staff review was limited to the aspects of fire protection related to the protection of the public from the standpoint of radiological health and safety. It did not consider aspects of fire protection associated with life safety of onsite personnel or property protection, unless they impacted the health and safety of the public due to the release of radioactive material. Fire protection improvements are included in the following amendments:

9.4.1 Amendments No. 53, 70 and 71 to Provisional Operating License No. DPR-21 dated September 26, 1978, November 19, 1980, and February 13, 1981

These amendments added license conditions relating to the completion of facility modifications and implementation of administrative controls for fire protection, and modified the Technical Specifications to require three operable fire pumps and additional spray and/or sprinkler systems and fire hose stations to be operable in the turbine building. The limiting conditions for operation with two inoperable fire pumps require a fire watch.

All modifications were to be completed by the end of the 1980 spring refueling outage. The modifications are:

9.4.1.1 Fire Detection Systems

Early warning automatic fire detection systems in the following areas:

(1) Control boards and cabinets in the control room
(2) Reactor building elevation 82 feet
(3) Reactor building elevation 65 feet
(4) Reactor building elevation 42 feet
(5) Reactor building elevation 14 feet
(6) Turbine building elevation 14 feet
(7) Turbine building elevation 26 feet
(8) Turbine building elevation 34 feet
(9) Turbine building ventilation equipment room elevation 54 feet
(10) Screen house building
(11) Liquid radwaste building

The power supply for fire detection systems to provide for a power source from the plant emergency power supply or a nonvital power supply with battery back-up.

9.4.1.2 Yard Hydrants

Additional manual fire fighting tools in each hose house.

The undermining of the hydrant adjacent to the gas turbine building repaired and the cause corrected.

A hydrant inspection program to insure proper hydrant operation during an emergency (inspecting the hydrants in the fall and in the spring).

9.4.1.3 Hose Stations

Hose nozzles of the high velocity Rockwood spray type with ball shutoff replaced with 1-1/2-inch "All Fog" adjustable nozzles to provide adequate reach. Hose nozzles capable of the straight stream mode provided, if required, to insure hose stream reach to cable trays located at higher levels.

Hose racks to store 100 feet of hose where provided, or 50 feet of hose stored in a donut roll.

The hose station on the east wall of the reactor building at elevation 108 feet relocated to the southeast stairwell.

The hose station in the northeast corner of the reactor building at elevation 65 feet relocated to an accessible location.

The hose station on the south wall of the machine shop lowered.

The hose station at the lower elevation of the liquid radwaste building relocated to the stairwell entrance.

A low flow capacity booster hose station provided in the area of safety-related electrical equipment, motor control centers, and switchgear located on the southeast end of the turbine building at elevation 36 feet.

9.4.1.4 Water Suppression Systems

The gate valve in the feed to the deluge system for the diesel generator room replaced with an outside stem and yoke valve.

The sprinkler in the miscellaneous oil storage room piped to a system capable of sounding a water flow alarm.

A post barricade provided to protect the actuation valve for the gas turbine area deluge system. The valve labeled and painted red.

An automatic sprinkler system to provide coverage over the curbed area of the motor generator sets.

Automatic sprinklers in the vicinity of redundant safety-related cable trays in the reactor building on elevation 14 feet.

Automatic sprinklers in the reactor building railroad airlock area.

Automatic sprinklers over the lubrication systems for the condensate booster pumps, reactor feedwater pumps, and in the turbine building unloading area.

Automatic sprinklers in the area of the cable trays in the turbine building mezzanine at elevation 26 feet.

Sprinkler heads to provide a water curtain to protect the louvered openings in the south wall of the auxiliary boiler room and the rollup doors in the west wall.

9.4.1.5 Gas Suppression Systems

A disable switch for the CO_2 system protecting the gas turbine generator located in the gas turbine control cubicle to actuate a control room alarm when the CO_2 system is disabled.

A pre-engineered Halon suppression system in the Unit 1 fire pump house. An alarm in the control room to indicate system actuation.

9.4.1.6 Portable Extinguishers

Two 17-pound Halon 1211 extinguishers in the control room.

Portable fire extinguishers for the following areas:

(1) Refueling floor of the reactor building.

(2) Entrance to the standby liquid control system area.

(3) Reactor building elevation 65 feet.

(4) Reactor building motor generator set area.

(5) Reactor building reactor cleanup system area.

(6) Reactor feed pumps.

(7) Auxiliary boiler room.

9.4.1.7 Fire Doors

The doors from the condenser bay area to adjacent areas where safety-related electrical equipment is located replaced with three-hour rated fire doors.

The door to the turbine building unloading area replaced with a 1-1/2-hour rated fire door.

9.4.1.8 Supervision of Fire Doors

Fire doors for safety-related areas inspected semiannually to verify that self-closing mechanisms and latches are in good working order. Unsupervised and unlocked self-closing fire doors in safety-related areas inspected daily to verify that they are in the closed position.

9.4.1.9 Fire Dampers

Ventilation penetrations in the diesel generator room protected by the addition of three-hour rated fire dampers.

The ventilation openings in the west wall of the auxiliary boiler room provided with three-hour rated fire dampers.

9.4.1.10 Valve Supervision

All post-indicator valves and isolation valves in the fire water piping systems to be electrically supervised or administratively controlled by the use of locks or seals. Periodic inspections to verify that valves are in the proper position.

9.4.1.11 Ventilation Equipment

Three fire service smoke ejectors of the explosion-proof type, rated for 9500 cfm each, at the site for fire brigade use.

9.4.1.12 Air Breathing Equipment

An onsite recharge capability for air breathing equipment capable of recharging 30 air bottles within a period of 4 hours.

9.4.1.13 Fire Barrier Penetrations

Fire barrier penetration seals with a fire rating equal to the rating of the fire barrier penetrated up to a limit of 3 hours for the following areas:

(1) Reactor building elevation 82 feet.

(2) Reactor building elevation 65 feet.

(3) Reactor building elevation 42 feet.

(4) Reactor building elevation 14 feet.

(5) Turbine building elevation 14 feet.

(6) Turbine building elevation 34 feet.

(7) Diesel generator room

9.4.1.14 Control of Combustibles

Styrofoam, used as a dam when penetrations were sealed, removed.

Combustible file storage boxes and combustible furniture in the kitchen area removed from the control room.

All wood used in safety-related areas replaced with treated fire retardant lumber or treated with a fire retardant coating. Plastic barrels used in safety-related areas for collecting used protective clothing replaced with steel barrels.

A curb provided to enclose the primary coolant pump motor generator sets to limit an oil spill.

Curbs provided at the door to the turbine lube oil storage room and separating the main condensate pumps and the condensate booster pumps.

Air flow supervision for the battery room exhaust with an alarm in the control room.

Wood blocks and scaffolding stored in the turbine building at elevation 54 feet treated with a fire retardant coating.

Waste oil and wood dunnage removed from the gas turbine building.

The wooden stop blocks in the screen house treated with a fire retardant coating.

9.4.1.15 Protection of Structural Steel

The structural supporting members of the boiler room roof protected with three-hour fire rated protection.

Structural steel in the turbine lube oil storage room provided three-hour fire rated protection.

9.4.1.16 Water Damage Protection

Safety-related electrical equipment protected from water damage in areas where additional water suppression systems are being provided.

9.4.1.17 Emergency Lighting

The operation of fixed lighting units periodically checked in accordance with the manufacturer's recommendations. Batteries for portable handlights dated and periodically replaced in accordance with the manufacturer's recommendations.

9.4.1.18 D.C. Power Sources

A normally open circuit breaker provided in the dc bus cross tie.

An administrative control established to maintain the circuit breakers in the open position for the alternate sources of dc control power for switchgear.

9.4.2 Amendment No. 83 to Provisional Operating License No. DPR-21 dated April 2, 1982

The amendment incorporates limiting conditions for operation and surveillance requirements for the fire protection modifications implemented in accordance with the staff Fire Protection Safety Evaluation Report (FPSER) (License Amendment No. 53).

The staff concluded that the proposed Technical Specification changes are in accordance with the staff FPSER and consistent with the fire protection requirements contained in the BWR Standard Technical Specifications. These modifications represent an increased effectiveness of the Fire Protection System for Millstone Station Unit 1. On this basis, the staff found the proposed technical specification changes acceptable.

9.4.3 Amendment No. 93 to Provisional Operating License No. DPR-21 dated November 2, 1983

This amendment authorized changes to the technical specifications to allow standardized testing on Carbon-Dioxide and Halon 1301 fire control systems.

Because water is not injected into gaseous fire suppression system piping and because the areas in which piping and nozzles are located do not contain dusting or corrosive atmospheres, there is no significant potential for rust or debris formation within the system components. A blockage, if one should occur, would be more likely to arise at the nozzles. However, the licensee's inspection procedures, which conform to the requirements of National Fire Protection Association Standards Nos. 12 and 12A for carbon dioxide and halon fire suppression systems respectively, will provide reasonable assurance that any blockage is discovered and corrective action taken. The staff concluded that the substitution of visual inspection procedures for discharge tests on carbon dioxide and halon fire suppression systems is acceptable.

9.4.4 Title 10 Code of Federal Regulations Part 50 Appendix R Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979

In February, 1981, the Fire Protection Rule (10 CFR 50.48 and Appendix R to 10 CFR 50) became effective. By letter dated March 1, 1982 and July 16, 1982, the license requested ten exemptions from the specific provisions of Section III.G of Appendix R to 10 CFR Part 50. The staff concluded in the draft

SER issued January 6, 1983 that the licensee's alternate fire protection configuration in the Turbine Building Cable Vault (T-16) and Switchgear Area (T-19B) represented an equivalent level of safety to that achieved by compliance with Section III.G of Appendix R but recommended that exemptions for the remaining eight areas be denied.

By letters dated April 15, 1983, and December 4, 1984, August 7 and 23, 1985, the licensee provided additional information, including commitments to provide added fire protection in support of the 8 previously requested exemptions that the NRC had indicated would be denied.

The licensee reassessed the safe shutdown concept at Millstone 1 based on a redefinition of Reactor Building and Turbine Building fire areas. As a result of this reassessment, the licensee withdrew two exemptions, combined three others into one, and requested one new exemption. The resulting exemptions requested by the licensee are as follows:

9.4.4.1 Main Control Room (Fire Area T-21)

The licensee requested an exemption from the technical requirements of Section III.G.2.b to the extent that it requires that redundant shutdown divisions be separated by more than 20 feet free of intervening combustibles, in an area protected by automatic fire detection and automatic fire suppression systems.

The room is bounded on three sides by reinforced concrete walls. The fourth side consists of a metal panel and glass wall which separates the Units 1 and 2 control rooms. The floor and ceiling are reinforced concrete. Openings into the room are protected by doors, dampers or fire-rated penetration seals.

Combustible material in the room consists primarily of cable insulation and paper which represents a combined fire loading of about 14,000 BTU/ft^2.

The control room contains the controls for normal station operation and for shutdown of the plant under all anticipated conditions. Operating indicators, controls, and alarms are mounted on an L-shaped walk-through control board. Auxiliary electrical equipment cabinets are located in the area behind the control boards.

Existing fire protection includes: a smoke detection system located above the main control board and in areas that are out of the line of vision of the operators at the control console; portable fire extinguishers; a manual-hose station; portable smoke exhaust fans; and self-contained breathing apparatus.

The licensee proposed the following modifications:

1. Customized administrative controls to minimize introduction of flammable liquids in the control room.

2. Normal operating procedures to require an inspection each shift in the control room for flammable materials.

3. All openings between the cabinets and the floor that would allow a spilled, flammable liquid to enter the cabinets sealed.

4. A Halon 1301 suppression system to provide fire suppression inside the entire control room with detection consisting of both ionization and photoelectric sensors to automatically initiate the suppression system. (The system will also have manual activation capability).

5. Protective material around MSIV control cables to eliminate their susceptibility to hot shorts.

6. Disconnecting devices in ADS valve control circuitry to assure closure of these valves during a control room fire.

7. The Millstone Unit No. 1 - Millstone Unit No. 2, 4-kV cross-feed bus to facilitate the alignment of Unit 2 emergency AC power to the Unit 1 emergency busses.

8. Procedures to assure the following:

   - Capability to achieve safe shutdown with the loss of equipment in any one of the four control room fire zones.

   - Spurious operation of affected equipment can be compensated for using alternate systems and manual actions.

   - Actions being taken outside the control room are achievable considering a fire in the control room, time needed to accomplish the function and manpower required.

   - Repairs to power cabling to ensure local operation of a CRD pump during a control room fire.

9. Fire stops in enclosed overhead cable trays leading to ACB 950. (The fire stops will be installed at the boundaries of the four fire zones in the control room.)

The licensee has developed alternate shutdown methods under the assumption that a control room fire will cause the loss of function of all systems in any one of four overlapping fire zones.

The control room is not in compliance with Section III.G because of the lack of adequate physical separation between redundant shutdown divisions and the lack of an alternate shutdown capability independent of the control room.

The Unit 1 control room is enclosed by complete reinforced concrete construction except at the Unit 2 Control Room, where a smoke barrier (metal panel and glass) is installed. Openings are protected by doors, dampers or fire-rated penetration seals. Also, in all other plant locations, redundant safe shutdown divisions are separated and protected so that one division will remain free of fire damage. The staff, therefore, had reasonable assurance that a fire that occurs outside of the control room would effect only one shutdown division within the control room and because the control room is a separate fire area from the rest of the plant, a fire that occurs anywhere else in the plant will not endanger control room operators.

The fire hazard within the control room is low. In situ combustible materials consist mainly of paper, cable insulation within the control panels, and small quantities of anticipated transients combustibles. The quantity, nature, and distribution of the in-situ combustibles is such that if a fire were to occur, it would not propagate quickly or extend over a large area of the control room. The hazards associated with transient combustible materials will be further mitigated to a limited extent by the shift inspections and licensee's administrative controls. These measures reduce the probability of accumulating additional combustible materials. Because the control room is continuously manned and because a fire detection system is present in all areas outside of the normal line of sight of the operators, it is expected that any potential fire would be detected in its incipient stages. This early fire warning capability, coupled with the portable fire fighting equipment in the room, provides reasonable assurance that a fire will be discovered and suppressed before reaching a significant magnitude. The staff therefore concluded that a fire located away from the control panels would not pose a direct threat to safe shutdown systems in the panels.

Because of the limited spatial separation between redundant shutdown divisions in either the auxiliary panels or the main control console, a fire at or within the panels has the potential for damaging both divisions. Protection against this hazard is achieved by the installation of seals at the floor around the panels and console which will prevent a spilled liquid from flowing into the cabinets. Additional protection against this hazard will be the automatic Halon 1301 fire suppression system that will be installed to provide fire suppression inside the entire control room. The customized administrative controls and the need to keep the space around the panels free of obstruction for operator access, will help preclude accumulations of combustibles to a significant degree.

If a fire should occur at, near, or within the panels, it is possible that the fire or fire suppression activities, such as the discharge of a portable fire extinguisher, may cause a loss of function of a portion of the main control board or auxiliary control panels. Safe shutdown conditions could still be achieved and maintained via the alternate shutdown capability.

Within the control room, the licensee has committed to provide an automatic halon fire suppression system. The suppression system also has the capability for manual activation if the operators become aware of a fire at an earlier stage. The staff concluded that any fire within the control room would be rapidly detected and either automatically or manually suppressed before serious damage could occur.

Local fire damage to the panels is possible. It is the staff's opinion that, because of the limited nature of the fire hazards and the level of fire protection in the control room, the worst damage expected would be complete loss of two adjacent panels in the main control console or one enclosed auxiliary control panel. The licensee has demonstrated that safe shutdown can be achieved if fire causes a loss of function to the shutdown systems in any one of the four control room fire zones. The staff found this acceptable.

The remaining concern related to the effects of a fire on control room habitability. Because the achievement of safe shutdown after a fire in the control room is dependent on some undamaged safe shutdown systems in the room, fire

effects have to be limited so that safe shutdown can be achieved and maintained if control room evacuation becomes necessary for a period of time.

Considering the limited fire hazards in the control room, the continuous presence of control room operators and the added fire protection proposed by the licensee, including an automatic fire suppression system in the control room, the effects of a fire in the control room would not be serious enough to cause long term evacuation. It is the staff's judgment that control room habitability could be reestablished within one hour after evacuation became necessary, with reliance upon the manual smoke removal system, portable exhaust fans, and self-contained breathing apparatus.

The licensee has demonstrated that safe shutdown can be achieved and maintained if either the control room remained habitable during a fire or if evacuation became necessary for at least one hour. The staff therefore, had reasonable assurance that under all credible fire scenarios for the control room, a capability to achieve and maintain safe shutdown conditions will remain free of fire damage.

Based on the above evaluation, the staff concluded that the existing fire protection with the proposed modifications provides a level of fire protection equivalent to that of Item III.G.2. Additional modifications needed to meet the requirements of Section III.G. of Appendix R would not significantly increase fire safety of the plant. Therefore, the licensee's request for exemption from Section III.G.2 of the Appendix R to 10 CFR 50, for the control room was granted by NRC letter dated October 1985.

9.4.4.2 Elevation 14'-6", Turbine Building Reactor Feed Pump Area (Fire Area T-5B and C)

Exemption Requested

The licensee requested an exemption from the technical requirements of Section III.G.2.c to the extent that it requires an area-wide fire suppression system where redundant shutdown divisions are protected by a 1-hour fire barrier and an automatic fire detection system. The Turbine Building is considered a single fire area. Within it, the licensee has identified the Reactor Feed Pump Area as a location where automatic sprinkler protection has not been provided per Section III.G.2.c.

Safe shutdown equipment present in this location consists of reactor feed pumps A and B; supporting lube oil pumps A and B; and motor control centers (MCC) 2-4 and 2A-4 and shutdown-related cables.

Combustible material includes cable insulation, lubricating oil, and health physics gear (clothing and paper), which represent a combined fire load of about 110,000 BTU/ft^2.

Installed fire protection includes: partial automatic sprinkler protection, a fire detection system; cable tray fire stops, manual hose stations and portable fire extinguishers. The licensee committed to protect one train of the redundant emergency diesel generator power and control cables in a 1-hour fire-rated barrier and to protect the cables by an automatic sprinkler system.

The technical requirements of Section III.G.2 were not met because of the lack of an area-wide automatic fire suppression system. The staff was concerned that a fire of significant magnitude would cause the loss of redundant shutdown systems. However, the feed pump area is protected by an automatic fire detection system which alarms in the Control Room. If a fire shoud occur, it would be detected in its formative stages before significant temperature rise or flame propagation occurs. The plant fire brigade would then be dispatched to the area to extinguish the fire using the manual fire fighting equipment available in the area.

If rapid fire spread occurred before the arrival of the brigade, the existing and proposed sprinkler systems would actuate to limit fire spread, reduce room temperatures and protect the shutdown-related components. The cable fire-barrier will protect one division of redundant shutdown-related cables from damage until the fire is extinguished.

All other shutdown systems have redundant counterparts in other fire areas or are required only for cold shutdown and can be repaired within 72 hours. The staff therefore, has reasonable assurance that if a fire occurs in the feed pump area, safe shutdown could be achieved and maintained.

The staff concluded that the licensee's alternate fire protection configuration, will achieve an acceptable level of fire protection equivalent to that provided by Section III.G.2. Therefore, the licensees request for exemption for the Reactor Feed Pump Area was granted by NRC letter daterd October 1985.

9.4.4.3 Elevation 34'-6", Turbine Building Switchgear Area (T-19A)

The licensee requested an exemption from the technical requirements of Section III.G.2.c to the extent that it required an area-wide fire suppression system and a complete 1-hour fire-rated barrier in an area where redundant shutdown systems are protected by a fire detection system. The Turbine Building is a single fire area. Within it, the licensee has identified the Switchgear Area T-19A as a location where automatic sprinkler protection has not been provided throughout. Safe shutdown equipment in this location consists of a motor generator, redundant shutdown related switchgear, and shutdown cables.

Combustible material in the switchgear area consists primarily of cable insulation, which represents a fire load of about 32,300 BTUs/ft^2.

Installed fire protection includes a complete fire detection system, manual hose stations and portable fire extinguishers. The licensee committed to install an automatic heat deluge-type water spray system actuated by heat detectors and a concrete curb/dike to protect switchgear in this location from its redundant counterpart in Switchgear Area T-19CDE. The licensee also committed to protect one division of shutdown-related cables from a fire in zone T-19B to a point 60 feet beyond its redundant switchgear located in fire area T-19A.

The technical requirement of Section III.G.2 are not met because the redundant switchgear and associated cables are not completely separated by a 1-hour fire-rated barrier and are not completely protected by an automatic fire suppression system.

The staff was concerned that a fire of significant magnitude would cause the loss of these systems. However, the principal fire hazard to the switchgear and cables is combustible cable insulation. Because these cables are coated with a fire retardant, it is expected that a fire in them will not burn rapidly or with high heat release. A fire would be detected early by the fire detection system. The fire brigade would then be dispatched to extinguish the fire using the manual fire fighting equipment that it available. Pending arrival of the brigade, the deluge system between the switchgear would activate and discharge water automatically in a "curtain" pattern. This concept has been used successfully to protect openings in fire walls and floor/ceiling assemblies and, therefore, provides reasonable assurance that switchgear from one division will remain undamaged. Also, the combination of a 1-hour fire-rated barrier with the 60 feet of separation between shutdown cable and its redundant switchgear would provide sufficient passive protection until the fire is put out.

The staff concluded that the licensee's alternate fire protection configuration, achieves an acceptable level of fire protection equivalent to that provided by Section III.G.2. Therefore, the licensees request for exemption for the Switchgear Area (T-19A) was granted by NRC letter dated October 1985.

9.4.4.4 Elevation 34'-6" Turbine Building Switchgear Area (T-19C, D and E)

The licensee requested an exemption from the technical requirements of Section III.G.2.c to the extent that it requires a complete, area-wide fire suppression system in an area where redundant shutdown systems are protected by a 1-hour fire-barrier and an automatic fire detection system. The Turbine Building is a single fire area. Within it, the licensee has identified Switchgear Area T-19C, D and E as a location where automatic sprinkler protection has not been provided throughout. Safe shutdown equipment in this location consists of redundant switchgear; 125-VDC motor control center DC 11-A-3; battery chargers 1, 1A, and 11A; the 4kV bus tie from bus #7 to bus #3 and shutdown cables.

Combustible material in this location consists of lubricating oil for a hydrogen seal oil unit and lift pumps and cable insulation which represent a combined fire load of about 80,000 BTUs/ft^2.

Existing fire protection includes a pre-action type sprinkler system for the seal oil unit and lift pumps; a fire detection system; manual hose stations and portable fire extinguishers. The licensee committed to install a 1-hour fire barrier to protect all the S-2 train shutdown related cables, the service water pump cables and the S-2 D.C. switchgear. In addition, an automatic deluge system and curb/dike will be installed to protect the switchgear in this location from its redundant counterpart in Switchgear Area T-19B.

The technical requirements of Section III.G.2.C were not met because redundant switchgear were not completely protected by a 1-hour fire barrier and were not completely protected by an automatic fire suppression system.

The combustible loading in this location is moderate. However, the areas where the combustible are concentrated, such as at the lift pumps, are protected by an automatic fire suppression system.

The switchgear area is protected by an early-warning fire detection system which alarms in the control room. There is reasonable assurance that if a fire should occur, it will be detected and suppressed early by the plant fire brigade. Until the fire is suppressed, the proposed deluge system and 1-hour fire-rated barriers will provide protection to one division of shutdown systems so that a safe shutdown capability will be available during and after a fire.

The staff concluded that the licensee's alternate fire protection configuration, will achieve an acceptable level of fire protection equivalent to that provided by Section III.G.2. Therefore, the licensee's request for exemption for the Switchgear Area (T-19C, D and E) was granted by NRC letter dated October 1, 1985.

9.4.4.5 Elevation 42'-6" Reactor Building-Northeast (Fire Area R-19)

The licensee requested an exemption from the technical requirements of Section III.G.2.a to the extent that it requires a complete 3-hour fire-rated barrier to protect redundant shutdown-related instrument racks.

The Reactor Building is a single fire area. Within it, the licensee has identified the northeast corner of elevation 42'-6" as a location where a complete 3-hour fire rated barrier does not exist between redundant instrument racks.

Safety shutdown systems in this location consists of the following equipment:

Reactor Building closed cooling water pumps
Reactor Building closed cooling water heat exchangers
Reactor and recirculation pump instrument racks
Isolation condenser condensate return valve
Isolation condenser valve transfer switches
Motor control center

Combustible materials consist of cable insulation, lubricating oil and PVC piping which represents a combined fire loading of about 10,000 BTUs/ft^2.

Existing fire protection consists of an automatic deluge sprinkler system for the motor generator set areas; a wet pipe sprinkler system for cable tray protection; a fire detection system; manual hose stations and portable fire extinguishers. The licensee justified the exemption on the basis of the existing fire protection, the construction of the instrument racks and related pneumatic tubing, and the 30-40 feet of spatial separation between redundant racks and tubing.

The technical requirements of Section III.G.2.a were not met because the redundant instrument racks and related pneumatic tubing were not completely separated by a 3-hour fire-rated barrier.

The staff was concerned that because a complete 3-hour wall did not exist between the redundant instrument racks, they would both be damaged if a fire occurred in this location. The areas where combustible materials are concentrated are protected by automatic fire suppression systems. In addition, this location is protected by a fire detection system which alarms in the control room. If a fire should occur, it would be detected in its formative stages,

before significant flame propagation or temperature rise occurred. It would then be suppressed by the fire brigade using manual fire fighting equipment.

If a fire originated on either side of the existing wing wall which separates both instrument racks, the wing wall would act as a shield to protect the instrument rack from direct flame impingement and radiant energy. If a fire was located at the leading edge of the wall, the automatic sprinkler system would actuate to suppress the fire, reduce room temperatures and protect the racks. Until the fire is suppressed, the 40 feet of spatial separation between the racks and the 1/4-inch steel plate rack enclosures would provide a degree of passive fire protection to provide reasonable assurance that at least one rack would remain free of fire damage.

The staff concluded that the licensee's alternate fire protection configuration would achieve an acceptable level of fire protection equivalent to that provided by Section III.G.2. Therefore, the licensee's request for exemption for the northeast corner of the Reactor Building on elevation 42'-6" fire area R-19 was granted by NRC letter dated October 1985.

9.4.4.6 Post Fire-Safe Reactor Shutdown

By submittal dated April 15, 1983, the licensee provided the results of the analyses to demonstrate that safe shutdown can be achieved with operator actions performed inside and outside the control room assuming the complete loss of adjacent main control board (MCB) or auxiliary control board (ACB) panels.

Postulating a fire in the main control board or auxiliary control board which renders the power supply or control of any hot shutdown system component inoperable, or causes spurious operation, would necessitate the operation of that component from a remote location. The alternate shutdown operator actions assuming a control room fire were developed to achieve the following:

1. assure reactor remains scrammed;
2. remove decay heat via the Isolation Condenser and ADS safety relief valves;
3. isolate the primary system to maintain inventory and restore control rod drive pump flow to accommodate reactor coolant loss; and
4. monitor safe shutdown system instrumentation.

To compensate for the shutdown functions damaged by the fire, the licensee proposed some plant modification and safe shutdown procedures. Plant modifications required to implement the operator actions consist of modifications so that a Millstone Unit 2 diesel generator can be used to supply emergency power to Millstone Unit 1 during a fire at Unit 1. A summary of the proposed procedures for operator actions needed to achieve safe shutdown in the event of a fire in the main control board or auxiliary control board was provided for staff review.

The alternate safe shutdown procedures would utilize three (3) operators who would perform various tasks in the control room, switchgear room, and reactor building. Operations in the control room consist of closing the automatic depressurization system (ADS) valves, isolating the reactor water cleanup system and closing the main steam isolation valves (MSIVs), and ensuring reactor trip.

External to the control room, RCS makeup can be provided within 6 minutes. Decay heat removel is initially begun via the safety/relief valve(s) until within the isolation condenser heat removal capacity (less than 5 minutes after scram). Operator actions are taken within 3 minutes to prevent hot well overfill. Other operator actions are taken for hot shutdown within 5 minutes. Cold shutdown will be achieved within 72 hours.

The following safe shutdown related instrumentation is located outside and independent of the control room:

1. Reactor coolant system level
2. Reactor coolant system pressure
3. Isolation condenser level
4. Condensate storage tank level

The staff concluded that for fires in the control room

- there is sufficient time and capability for operator action inside and outside the control room to assure safe shutdown of the plant

- the safe shutdown capability meets the performance goals for alternative shutdown capability as required by Section III.L of Appendix R

- the safe shutdown capability meets the independence requirements of Section III.G.3 of Appendix R.

The staff therefore concluded that the licensee proposed acceptable safe shutdown capability in the event of a fire in the main control board or auxiliary control boards.

9.5 Control of Heavy Loads at Nuclear Power Plants

All plants have overhead handling systems that are used to handle heavy loads in the area of the reactor vessel or spent fuel in the spent fuel pool. Additionally, loads may be handled in other areas where their accidental drop may damage safe shutdown systems. Therefore in accordance with NUREG-0612 "Control of Heavy Loads at Nuclear Power Plants" dated July 1980, all plants should satisfy each of the following for handling heavy loads that could be brought in proximity to or over safe shutdown equipment or irradiated fuel in the spent fuel pool area, in the reactor building, and in other plant areas.

1. Safe load paths should be defined for the movement of heavy loads to minimize the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent fuel pool, or to impact safe shutdown equipment. The path should follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. These load paths should be defined in procedures, shown on equipment layout drawings, and clearly marked on the floor in the area where the load is to be handled. Deviations from defined load paths should require written alternative procedures approved by the plant safety review committee.

2. Procedures should be developed to cover load handling operations for heavy loads that are or could be handled over or in proximity to irradiated fuel or safe shutdown equipment. At a minimum, procedures should cover handling of those loads listed in Table 3-1 of NUREG-0612. These procedures should include: identification of required equipment; inspections and acceptance criteria required before movement of load the steps and proper sequence to be followed in handling the load; defining the safe load path; and other special precautions.

3. Crane operators should be trained, qualified and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, "Overhead and Gantry Cranes."

4. Special lifting devices should satisfy the guidelines of ANSI N14.6-1978, "Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 pounds (4500 kg) or More for Nuclear Materials." This standard should apply to all special lifting devices which carry heavy loads in areas as defined above. For operating plants certain inspections and load tests may be accepted in lieu of certain material requirements in the standard. In addition, the stress design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used.* This is in lieu of the guideline in Section 3.2.1.1 of ANSI N14.6 which bases the stress design factor on only the weight (static load) of the load and of the intervening components of the special handling device.

5. Lifting devices that are not specially designed should be installed and used in accordance with the guidelines of ANSI B30.9-1971, "Slings." However, in selecting the proper sling, the load used should be the sum of the static and maximum dynamic load.* The rating identified on the sling should be in terms of the "static load" which produces the maximum static and dynamic load. Where this restricts slings to use on only certain cranes, the slings should be clearly marked as to the cranes with which they may be used.

6. The crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, "Overhead and Gantry Cranes," with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency.

7. The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, "Overhead and Gantry Cranes" and of CMAA-70, "Specifications for Electric Overhead Travelling Cranes." An alternative to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied.

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*For the purpose of selecting the proper sling, loads imposed by the SSE need not be included in the dynamic loads imposed on the sling or lifting device.

A plant conforming to these seven guidelines will have developed and implemented, through procedures and operator training, safe load travel paths such that, to the maximum extent practical, heavy loads are not carried over or near irradiated fuel or safe shutdown equipment. A plant conforming to these guidelines will also have provided sufficient operator training, handling system design, load handling instructions, and equipment inspection to ensure reliable operation of the handling system. It has been found that load handling operations at Millstone Nuclear Power Station Unit 1, based on NNECO letters dated December 22, 1980 and January 14, 1985, can be expected to be conducted in a highly reliable manner consistent with the staff's objectives as expressed in these guidelines.

NUREG-0612, Section 5.3 also lists certain measures that should be initiated to provide reasonable assurance that handling of heavy loads will be performed in a safe manner until final implementation of the general guidelines of NUREG-0612 is complete. Specified measures include: the implementation of a technical specification to prohibit the handling of heavy loads over fuel in the storage pool; compliance with Guidelines 1, 2, 3, and 6 identified above; a review of load-handling procedures and operator training; and a visual inspection program, including component repair or replacement as necessary of cranes, slings, and special lifting devices to eliminate deficiencies that could lead to component failure. The evaluation of information provided by the Licensee indicates that Millstone Unit 1 complies with the staff's measures for interim protection.

By Generic Letter 85-11, dated June 28, 1985, the staff concluded that Millstone-1 along with other plants has provided sufficient protection such that risk associated with potential heavy load drops is acceptably small and that the objective identified in Section 5.1 of NUREG-0612 for providing "maximum practical defense in depth" is satisfied.

10 STEAM AND POWER CONVERSION SYSTEM

The turbine, condensate and feedwater systems are those portions of the steam to power cycle which are located outside the containment vessel and can be isolated from the reactor by closing the containment isolation valves. The systems, described in greater detail in the FSAR (Ref. 12), are designed to meet the following objectives:

a. Produce electrical power from the steam generated in the reactor up to 652,100 net kw(e), condense that steam into water, and return the water to the reactor as heated feedwater with essentially all gaseous, dissolved and particulate impurities removed.

b. Assure that all radioactivity associated with the steam and condensate during normal operation or accident conditions is safety contained inside the system or released to the environs in accordance with the limits of 10CFR20.

c. Provide steam for the steam jet air ejectors and the steam seal regulator.

d. Allow electrical load rejections up to full load rating of the generator without a turbine trip or reactor scram.

10.1 Main Steam Isolation Valves

The steam passes from the reactor vessel through the containment wall via four 20 inch carbon steel pipes. Welded into each steam line is a simple venturi flowmeter to limit steam flow to 200% in the event of a large downstream steam line break. Each steam line also has one isolation valve located just inside containment and a redundant isolation valve located just outside containment. The valves are designed to close in less than 5 seconds (tested between operating cycles) and be leak-tight during the worst conditions of pressure, temperature, and steam flow following a break in the main steam line outside of containment. The valves, open during normal plant operation, will close on signals from low reactor vessel water level, high radiation in steam tunnel, high temperature in the steam tunnel, excess steam flow or low steam line pressure at the main turbine inlet. Technical specification acceptance limits for main steam isolation valves are 11.5 scf/hr per valve at 25 psig and valve closure times of less than 5 seconds with tests performed between each operating cycle (about 18 month intervals).

SEP Topic VI-4 "Containment Isolation System" (Ref. 5) compared Millstone-1 containment isolation capabilities to 10CFR50 (GDC 54, 55, 56 and 57) as implemented in SRP Section 6.2.4 and R.G. 1.11 and 1.141 and made no recommendations for changes to the main steam isolation valves or valve operators. The valve test and maintenance history since Millstone-1 start up has been acceptable.

10.2 Turbine Condenser

The condenser was designed to produce a back pressure of 1.5 in. Hg absolute when operating at turbine design steam flow with 60°F cooling water and 85 percent clean tubes. It will also accommodate a load rejection of 105 percent of the design steam flow. The condenser (Ref. 12) is of the single pressure, deaerating type with single pass, perpendicular-flow and divided water boxes. A condenser shell is located beneath each of the two low pressure exhaust elements with the tubes running perpendicular to the turbine shaft. Each shell is rigidly supported on a foundation with a rubber belt type expansion joint between the low pressure turbine exhausts and the condenser steam inlet connections.

The main condenser was retubed with 70/30 copper nickel tubing as a correction for sea water leakage discussed earlier in Section 1.3.2(1). The copper/nickel has heen shown by experience to better withstand the pitting attack observed on the originally installed aluminum/brass tubes. The condenser water boxes are of close grained, cast iron construction. The water boxes are divided to permit individual operation of half of a condenser shell.

Each condenser shell has a divided hotwell with equalizing lines which contains a baffle system in the form of a retangular labyrinth to provide a minimum two-minute retention time within the condenser for any given particle of condensate. This retention allows time for radioactive decay of short-lived isotopes from the time condensate enters the hotwell until it is removed by the condensate pumps. Deaeration of condensate is provided in the condenser for removal of air and non-condensible gases contained in the turbine steam. Heating coils are provided at each condenser condensate outlet to insure proper deaeration at low plant loads. The condenser is designed to provide condensate with an oxygen content of 0.005 cc/litre over a flow range of 10 to 100 percent.

Although it has been necessary to plug a number of condenser tubes, since the condensers were retubed with 70/30 nickel tubing, the loss in heat transfer capability up to this point has not significantly reduced plant operating efficiency or steam dump capability.

10.3 Feedwater Flow Control

The feedwater control system was designed to regulate the feedwater flow to the reactor vessel and maintain proper reactor vessel water level. The level of the water is controlled by a feedwater controller that receives input from reactor water level, steam flow, and feedwater flow transmitters. The feedwater control system regulates the position of the valves in the feedwater lines to maintain reactor vessel water at the desired level. Since the initial plant operation there have been several changes to the feedwater control system because of plant problems attributed in part to the control of feedwater flow.

It was concluded that the thermal effects caused by wide flow variations at low power level conditions had harmful effects on reactor vessel feedwater nozzle welds where cracks had been detected. At very low flows valve control was not smooth but was observed to cycle between the closed position and a more widely open position with a resultant thermal effect at the nozzle. A by-pass flow control valve was installed for finer and steadier flow control

at the low flow conditions where the original feedwater valve characteristics were unsuited to stable operation.

Water hammer in the isolation condenser system caused iso-condenser valves to close that prevented use of the isolation condenser for removing reactor decay heat when the main condenser heat sink was unavailable after a reactor scram. Damage to isolation condenser piping supports also resulted from the abnormal pipe movement. The cause of water hammer was attributed to excessive reactor vessel water level, i.e., up to the isolation condenser steam line, that resulted in slugs of water entrained with the steam passing to the iso-condenser. To reduce the probability of water hammer and improve the reliability of the emergency condenser capability, the permissible high reactor vessel water level set point was lowered and feedwater pump trips due to high water level were installed. The latter modification was made to further reduce the risk of excessive water level due to failure of the control valve to close when required. Since these modifications there have been no reports of water hammer in the isolation condenser system.

10.4 Safety/Relief Valves

The primary purpose of the safety/relief values is to prevent over-pressurizing the reactor vessel or any of the attached piping or components. The relief function of the valves is also designed to rapidly depressurize the reactor vessel and coolant system so that emergency core spray and low pressure coolant injection systems can function to cool the core. Originally there were three relief valves and two safety valves for a combined steam relief capacity in excess of 3,640,000 lbs/hr. The valves are located on the steam line inside the containment. In the fall of 1974 NNECO installed additional safety/relief valve capacity at the Millstone Nuclear Power Station, Unit 1. The modifications consisted of changing the safety and safety/relief valve configuration of three (3) safety/relief valves and two (2) spring safety valves (3/2 safety/relief configuration), to six (6) safety/relief valves (6/0 safety/relief configuration), all piped to the pressure suppression pool (torus). These plant modifications were necessary due to the loss of scram reactivity near the end of operating cycle 4 which resulted in potential violation of the 25 psi margin to safety valve operation[1] at full power for the most limiting pressure transient (generator load rejection with bypass failure). Installation of the 6 safety/relief valve configuration increases the steam relief capacity to more than 4,680,000 lbs/hr with all valves open.

The modifications to the safety/relief system involved removal of the two spring safety valves and installation of three safety/relief valves of identical design to the three existing units. The three newly installed valves have discharge piping to the torus identical in function and similar in layout to the three original units. Amendment 20 issued February 23, 1976 authorized these changes and the appropriate changes to the technical specifications.

In addition to reanalyzing transients for their effect on MCPR, as a result of the change in the safety/relief valve configuration, the ASME Pressure Vessel Code compliance was also reevaluated. The ASME Nuclear Boiler and Pressure

[1]The 25 psi margin is a General Electric (GE) design criteria that reflects GE's concern for lifting safety valves too frequently with the attendant risk of sticking open.

Vessel Code requires that each vessel designed to meet Section III be protected from the consequences of excessive pressure. The transient selected to demonstrate compliance was closure of all mainsteam isolation valves from full power operating conditions. Reactor scram was initiated from high neutron flux and only the safety function of the safety/relief valves was credited. With only 3 safety/relief valves operable, half of the eventual complement of 6 safety/relief valves, the transient pressure reached 1346 psig as compared with the ASME limit of 1375 psig. The 1375 psig limit represents 110% of the vessel design pressure of 1250 psig as required by the ASME code. Accordingly, the staff found that the safety/relief valve modification provides sufficient relieving capability to protect the pressure vessel against the most severe over-pressure conditions.

Amendment 61 dated May 29, 1979 revised the set point, maintenance and surveillance requirements. Amendment 79 dated October 5, 1981 revised requirements for valve position indicators, and Amendment 98 dated June 14, 1984 revised safety/relief valve operability requirements.

Amendment 73 dated March 11, 1981, among other changes, authorized acoustic monitors for the six (6) S/R valves to detect valve position and added the requirement for auto depressurization capability for four of the six S/R valves. The licensee reported that an additional one of the six existing safety/relief valves was added to the automatic depressurization system (ADS), also known as automatic pressure relief system (APR), by modification of the actuation logic. The result is that four of six S/RV's will open for the ADS function instead of three of six.

The reason for the change was to improve ECCS response to a small break LOCA by causing a more rapid vessel depressurization if ADS is required. This is only needed in the event of a loss of feedwater combined with a loss of FWCI.

10.5 Damage to the 14th and 15th Stage of "B" Low Pressure Turbine

The turbine includes one double-flow, high pressure and two double-flow low pressure elements. The Millstone-1 turbine is a tandem four flow, three casing, non-reheat condensing, 1800 RPM General Electric turbine with 43-inch last row blades in the low pressure elements. Damage to the Millstone-1 turbine which occurred on April 21, 1981 (with the plant at 30% power and ascending to 100% after a six-month outage) was confined to the 14th and 15th stages of the "B" low pressure turbine on the end closest to the generator.

The broken blades caused damage to the top rows of the Cu-Ni condenser tubing directly under the damaged LP turbine and resulted in a significant increase of chlorides in the condensate.

Eventually the 14th stage blades were cut from the three undamaged low pressure turbines, the damaged condenser tubes were plugged, and plant operation resumed for one cycle (cycle 7) while new blades were fabricated. Operation without the four 14th stages caused a slight reduction in electrical output. The damage was attributed to either a piece of 14th stage shroud or a 14th stage blade(s).

The 14th and 15th stages on the opposite end of the "B" rotor and both ends of the "A" low pressure turbine were also examined. A temporary pressure plate

was installed in place of the damaged 14th stage because there were no replacement buckets. The damaged buckets (blades) in the 15th stage were replaced or repaired.

The 14th stages to the low pressure turbines were repaired between operating cycles 7 and 8 and normal turbine generator operation was restored for cycle 8 operation.

11 RADIOACTIVE WASTE SYSTEMS

The radioactive waste systems are designed to collect, process, and dispose of radioactive waste in a safe manner. Operation of Millstone-1 produces radioactive gas, liquid and solid waste while generating heat and electricity.

11.1 Radioactive Liquid Effluent

Radioactive liquid wastes are processed according to their degree of chemical and radioactivity purity. Following processing and sampling, liquids are returned to service, discharged to the circulating water at the discharge structure, or solidified. Amendments 12 and 21 issued December 19, 1975 and February 1, 1976 established lower radioactive liquid release limits and an extended implementation date due to reported problems with the newly installed Augmented Liquid Radioactive Waste System. The system problems have since been resolved and is now in satisfactory operation. The modifications were made in 1974 and consisted of increased tank capacity, a new concentrator, a new waste demineralizer and a waste solidification system. Appendix B to NNECO submittal entitled "Review of Final Environmental Statement" (Ref. 22) describes the liquid radioactive waste cleanup system after the modifications. Also included is an ultrasonic resin cleaner in the condensate demineralizer system to reduce chemical radioactive wastes requiring treatment. Figure 11.1 shows the modified liquid radioactive waste system flow diagram.

The liquid radwaste system is divided into several subsystems so that liquid wastes from the various sources can be kept segregated and processed separately. These are the low conductivity waste subsystem, the high conductivity waste subsystem and the chemical waste subsystem. Cross-connections between subsystems provide additional flexibility for processing of the wastes by alternate methods. The wastes are treated according to their conductivity, suspended solids content and radioactivity.

The low conductivity waste subsystem handles reactor grade water collected from such sources as drains from piping and equipment, including wastes from auxiliary systems. It also includes backwash liquid from the cleanup demineralizers, condensate demineralizers, fuel pool demineralizers, the reactor coolant system, condensate system, feedwater system and the distillate from the waste concentrators in the chemical waste system. The low conductivity waste is collected in the waste collector tanks.

The high conductivity waste subsystem handles wastes from the radwaste building floor drains, reactor building floor drains, turbine building floor drains and liquids accumulated in the drywell sump. The floor drains are collected in the floor drain collector tanks. The floor drain collector tanks also receive decontamination solutions from the reactor and turbine buildings.

The chemical waste subsystem receives wastes from laboratory drains, personnel decontamination, cask decontamination and regulated shop drains. These wastes are collected in the waste neutralizer tank.

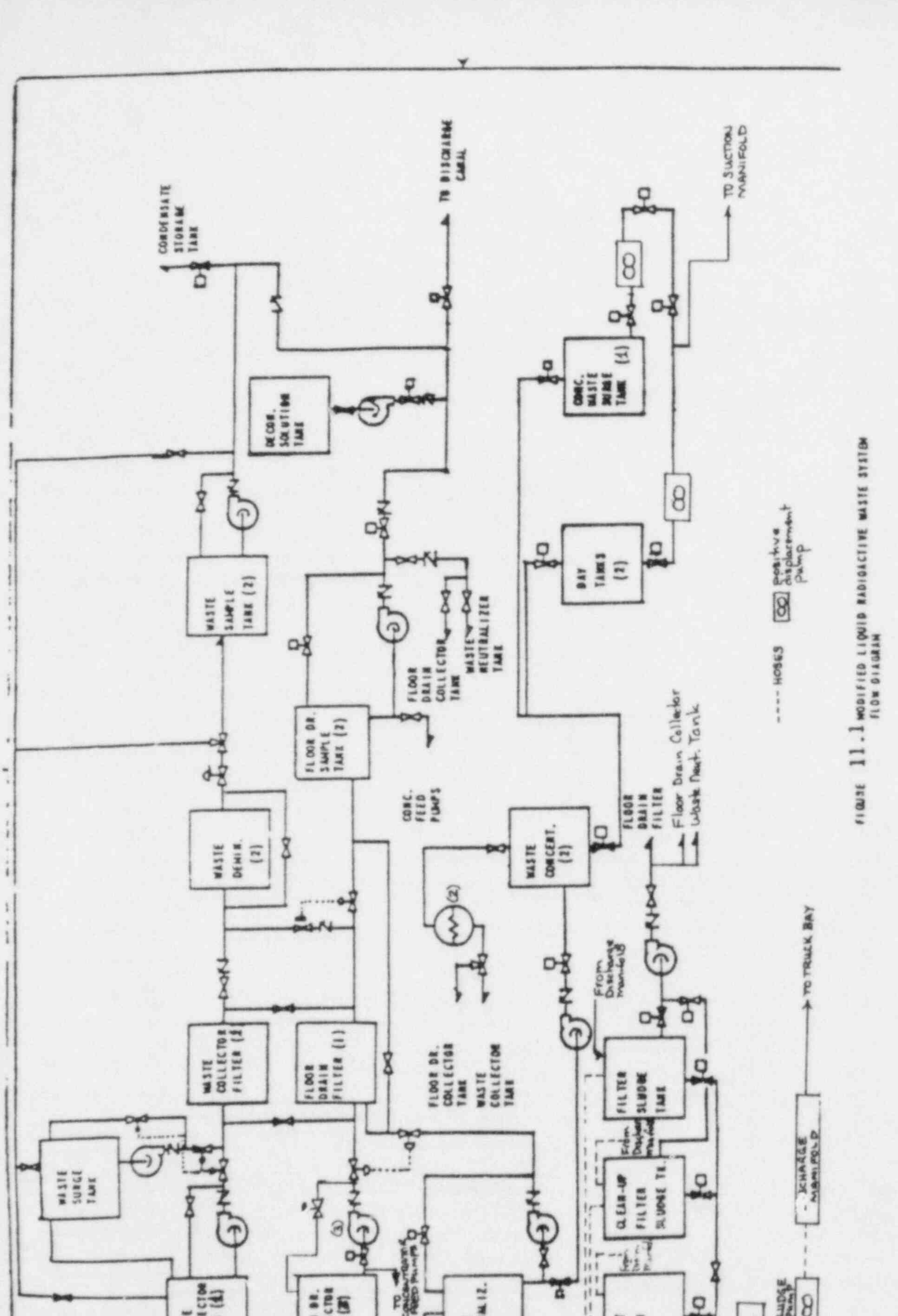


FIGURE 11.1 MODIFIED LIQUID RADIOACTIVE WASTE SYSTEM FLOW DIAGRAM

11.2 Gaseous Radioactive Waste

The off gas system and containment, reactor building and radwaste building ventilation system discharge to atmosphere through the 375 foot stack. The FTOL application (Ref. 7) committed to install an augmented radwaste system by 1974 and the Environmental Statement (Ref. 21) briefly described the modification. Amendment No. 50 to the Millstone-1 Operating License issued on June 19, 1978 authorized new technical specification limits associated with activation of the newly installed Steam Dilution Augmented Off-gas System (SDAOGS).

The augmented radioactive off-gas treatment system (AOGS) which NNECO originally installed prior to 1974 to meet the radioactive effluent limits of the Nuclear Regulatory Commission is described in previous NNECO reports dated July 1973 and August 1975. The gaseous waste was to be treated sequentially by (1) a hydrogen recombiner system and (2) a xenon-krypton treatment system. During testing in the last quarter of 1975, an inherent deficiency, referred to as the catalyst migration problem, was discovered which raised questions concerning the future operability of the recombiner portion of the off-gas system. This problem related to the air recycle concept employed in the Millstone Unit No. 1 off-gas recombiner system. This air recycle feature made the entire system susceptible to contamination with small particles of catalyst, a substance used to initiate the recombination of the hydrogen and oxygen gases in the recombiner. During preoperational testing, it was found that fine particles of this catalyst material had contaminated parts of the recombiner system which would normally contain explosive mixtures of hydrogen and oxgen during reactor operation, thus creating the potential for hydrogen explosions. NNECO therefore modified their AOGS to a steam dilution recombiner system to eliminate the problem related to air recycle and catalyst migration.

The SDAOGS is a modification of the AOGS to utilize steam dilution instead of recycle air dilution of the off-gas stream. The second stage ejector of the steam jet air ejector (SJAE) is modified to bypass the aftercondensers and discharge the motive steam and gas to the process pipe. The process stream, containing a gas/steam mixture, with hydrogen concentration diluted to below 4.0 volume percent, is transported to the recombiner system.

The recombiner system consists of two full capacity redundant trains each containing a preheater, a catalytic recombiner, an off-gas condenser, a jet compressor, an after-cooler condenser and an associated instrumentation and control system. The preheater utilizes plant auxiliary steam to preheat the gas/steam off-gas mixture from 250°F to 320°F. The superheated steam-diluted mixture enters the recombiner where free hydrogen and oxygen react in the presence of precious metal-coated metal base grid catalyst bed to form water. The gas exits the recombiner at approximately 730°F and enters the off-gas condenser where it is cooled to 130°F. The condensed water is drained to a subcooler, cooled to 110°F and returned to the main condenser. A jet compressor provides the motive force for the offgas leaving the off-gas condenser. The gas exits the jet compressor at 340°F and enters the after-cooler condenser before being transported to the xenon-krypton treatment system (XKS). The jet compressor

is capable of discharging 50 SCFM at 22.7 psia. A minimum flow of 25 SCFM is required by the XKS. Makeup air from the plant station air system is injected automatically into the gas steam at the preheater to maintain system flow at 25 SCFM if condenser air inleakage falls below 25 SCFM.

The XKS is a low temperature (-20°F) charcoal adsorption system. The system consists of two sections: pretreatment and charcoal adsorption. The pretreatment utilizes glycol cooler units which are designed to cool the off-gas to -20°F and dryers to dehumidify the steam to a dewpoint of -90°F. Two charcoal beds operate in series, each containing 11,000 pounds of activated charcoal. There are three thermocouples in the first bed and one in the second bed. Each of the thermocouples has temperature indication and high temprature alarm in the control room. The high temperature alarm is set at 20°F above the operating temperature of -20°F. After decay in the charcoal beds, the offgas flows to HEPA filters prior to being released to the environs from the 375 foot stack.

The Xe-Kr Building which houses the XKS is a seismic Category I structure. In addition, the charcoal beds and associated process stream piping and valving in the Xe-Kr Building and the plant stack are designed to seismic Category I criteria.

Prior to this modificaton the unrecombined off-gas was transported to the stack via a buried delay pipe that provided approximately 50 minutes of delay. Routing the off-gas through the SDAOGS provides additional delay of the noble gases and removal of the iodine isotopes by adsorption on the charcoal contained in the charcoal beds. When the system is in operation, the charcoal beds are expected to provide delay times of 1.3 days for krypton and 50 days for xenon, while removing essentially all radioiodine isotopes.

The staff evaluation considered SDAOGS malfunctions, unplanned hydrogen deterioration, charcoal fires and potential accidents and concluded that the technical specifications should be changed to further reduce radioactive off gas releases to the atmosphere when the SDAOGS was placed in service. The consequences of radiological releases from Millstone-1 during normal plant operation with the SDAOGS in service is evaluated in the environmental evaluation for conversion of the POL to a FTOL (Ref. 10). The staff concluded that the SDAOGS reduces the volume of explosive off gas and decreases radioactive releases to the environment to meet the "as low as reasonably achievable" criteria per 10 CFR Part 50, Appendix I.

11.3 Solid Radioactive Waste

The general practice relating to solid radioactive waste is to store, temporarily on-site to allow decay to lower levels of radioactivity, all solid wastes in suitable containers (e.g., fiber or steel drums). Ultimate disposal is by shipment to off-site storage after processing.

Typical of solid radioactive wastes are:

a. filter sludges and spent resins

b. air filters from off-gas and radioactive ventilation systems

c. contaminated clothing, tools and small pieces of equipment which cannot be economically decontaminated

d. miscellaneous paper, rags, etc. from contaminated area

e. used reactor equipment such as spent control rod blades, fuel channels, and in-core ion chambers

The systems and procedures for safe handling and transportation of solid wastes are discussed in the FSAR (Ref. 12). NNECO letter dated May 2, 1980 described a temporary solidification system and procedures for solidifying spent resin and filter sludge using cement. NNECO also reported in a letter dated Jan. 11, 1983 (Ref. 22) that a radioactive waste solidification system had been installed in conjunction with the modification to the liquid radioactive waste system. This solidification system is located in the radwaste shipping building. The system receives concentrated liquid wastes from either the concentrated waste sludge storage tank or the concentrated waste day tank. The waste is transferred by pipe to a shipping container on the transport vehicle where it is mixed with the solidifying agent (cement). This solidification of concentrated waste will reduce the releases of liquid waste to the environs. The potential for radioactive water leakage from the storage liners is eliminated by drying up any residual water.

By letter dated October 25, 1978 the licensee notified the NRC of its plan to construct a refueling outage building. In a second letter dated August 17, 1979, the licensee responded to legal questions posed by the NRC. The building has been constructed and is used to service all three Millstone nuclear plants as an administrative support facility in connection with refuelings and other outages.

11.4 Radiological Effluent Technical Specifications (RETS)

The staff reviewed the licensee's Radiological Effluent Technical Specifications (RETS) and Offsite Dose Calculation Manual (ODCM) for compliance with Appendix I 10 CFR 50. By NNECO letters dated August 12, 1982, September 22, 1982, November 22, 1982 and March 16, 1984, RETS were submitted for NRC review and evaluation by NRC. The staff met with NNECO representatives on September 28, 1984 to clarify several aspects of the NNECO submittals. According to an NRC summary of the meeting the differences between NRC and NNECO were resolved and there were no open items at the conclusion of the meeting. By letters dated May 29 and June 19, 1985, the final RETS and Radiological Effluent Monitoring and Offsite Dose Calculation Manual were submitted to the NRC. The proposed technical specification changes were approved by Amendment No. 106 dated October 1, 1985.

12 RADIATION PROTECTION

The radiation protection measures incorporated at Millstone-1 are intended to ensure that internal and external radiation exposures to station personnel, contractor personnel, and the general population resulting from station conditions, including anticipated operational occurrences, will be within applicable limits and, furthermore, will be as low as is reasonably achievable (ALARA).

The basis for staff acceptance of the M-1 Radiation Protection Program is that doses to personnel will be maintained within the limits of 10 CFR 20 and that the radiation protection designs and program features are also consistent with the guidelines of Regulatory Guide 8.8, "Information Relevant to Ensuring That Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable," Revision 3. Shielding is provided to reduce levels of radiation. Ventilation is arranged to control the flow of potentially contaminated air. Radiation monitoring systems are used to measure levels of radiation in potentially occupied areas and to measure airborne radioactivity throughout the plant. A health physics program is provided for plant personnel and visitors during reactor operation, maintenance, refueling, radwaste handling, and inservice inspection.

The staff concludes that these and other radiation protection features will help ensure that occupational radiation exposures are maintained ALARA during plant operation and during decommissioning. The staff periodically reviews the licensee's Radiation Protection Program during routine onsite inspections.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure

Since the start of commercial operation in March 19, 1971 there have been a number of organizational changes.

Amendment 96 to the Provisional Operating License dated March 19, 1984 authorized the offsite organization shown in Figure 13.1 as well as other changes related to the composition of the nuclear review boards. Amendment 95 dated February 16, 1984 specifies minimum shift crew composition and qualifications for radiation protection managers.

Amendment 91 dated May 5, 1983 reflects the merger of Connecticut Light and Power Company and the Hartford Electric Light Company. The Millstone-1 license now shows that the Connecticut Light and Power Company and Western Massachusetts Electric Company have authority to possess Millstone Station, Units 1 and 2, and that the Northeast Nuclear Energy Company is the responsible entity for operation of the facilities. Amendment 85 dated June 25, 1982 increased the number of fire brigade members from three (3) to five (5). Amendment 79 dated October 6, 1981 concerned, among other items, requirements for the shift technical advisor. Amendment 72 dated February 13, 1981 concerned management title changes.

Amendment 63 dated July 19, 1979 inserted a new facility organization chart as shown in Figure 13.2 that detailed organizational information relating to individuals. Other changes such as Amendment 57 and 56 issued January 12, 1979 and December 8, 1978 are no longer applicable with respect to organization because of more recent changes as reported above, a reflection of the continuous process of organizational change. Therefore, organizational changes prior to this time, but after the request for FTOL, have not been listed because for the most part they have been superseded.

The expansive nature of many of the organizational changes since the request for conversion of the POL to a FTOL (Ref. 7) is more clearly evident by the increase in the number of Millstone-1 employees from approximately 150 to 360 (Ref. 10).

The staff periodically reviews the licensee's operating performance i.e. Systematic Assessment of Licensee Perfomance (SALP). The most recent SALP reports, dated October 31, 1983 and May 20, 1985, reviewed and evaluated the performance of licensed activities at Millstone Units 1 and 2. The NRC concern focused on performance in plant operations. As noted in the report summaries it was determined that NNECO achieved overall a satisfactory level of performance with respect to operational safety. The involvement and attention of management and plant personnel was evident and contributed to the good performance noted. However, the staff noted in the 1983 report a negative trend relative to personnel errors and off site support in the areas of Plant Operation, Surveillance, and Emergency Preparedness. The staff recognized, however, performance improvement

in Security and Safeguards to a category 1 rating. Category 1 rating indicates that reduced NRC attention may be appropriate. Licensee management attention and involvement are aggresive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety is being achieved.

The results of the 1983 NRC SALP report were discussed at a meeting in the corporate offices in Berlin, Connecticut on November 29, 1983. By letter dated December 19, 1983, NNECO provided written comments to the staff SALP evaluation and expressed strong disagreement with the NRC assessment that NNECO performance in the emergency preparedness area has declined from a category 1 to a category 2 level. Category 2 indicates that NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and are concerned with nuclear safety; licensee resources are adequate and reasonably effective such that satisfactory performance with respect to operational safety or construction is being observed. By letter dated March 16, 1984, the staff reiterated its finding that the category 2 performance for emergency performance was justified. The NRC SALP review board met in April 1985 and by letter dated May 20, 1985 issued a written report of its findings. The most recent NRC SALP report covered an 18 month period ending February 28, 1985 and concluded that the overall level of performance was acceptable. The staff met with NNECO management on June 4, 1984 to discuss the SALP. The licensee's written response to the staff findings was presented by letter to Dr. Thomas E. Murley, dated July 5, 1985.

13.2 Emergency Preparedness Evaluation

NUREG-0737 identified Item III.A.2.1 as "Emergency Preparedness, Upgrade Emergency Plans to Appendix E, 10 CFR 50." It also stated that licensee emergency plan and procedure submittals were due January 2, 1981, and March 1, 1981, respectively, and that this onsite emergency preparedness program was to be implemented by April 1, 1981. Upgraded emergency plans and procedures have been received and the Millstone emergency preparedness program has been implemented.

During January 1982, a comprehensive 2-week onsite emergency appraisal was conducted at the Millstone facility during which deficiencies and improvement items were identified and a subsequent inspection report was issued by letter dated June 11, 1982. The licensee has taken corrective actions based on the findings in the report. Emergency exercises involving licensee and State and local government personnel were conducted at Millstone in March 1982, October 1983 and October 1984. The licensee was informed of areas needing improvement in exercise reports. The NRC region is continuing to verify the status of emergency preparedness for Millstone through followup inspections, drills, and exercises.

The evaluation of the status of offsite preparedness by the Federal Emergency Management Agency (FEMA) is a continuing process involving review of State and local plans and the observation of full-scale exercises. The FEMA report did not identify any significant deficiencies. By letter dated October 9, 1984, in accordance with FEMA rule 44 CFR 350, FEMA determined that the State and local plans and preparedness for Millstone are adequate to protect the health and safety of the public in the event of a radiological emergency. Although a

formal report of the October 1984 exercise has not yet been issued by FEMA, preliminary indications are that there were no significant deficiencies identified.

On the basis of the above considerations, the staff has found that onsite and offsite emergency preparedness is adequate at Millstone, that emergency plans have been upgraded in accordance with NUREG-0737 Item III.A.2.1, and that there is reasonable assurance that prompt protective measures can and will be taken to protect the public in the event of a radiological emergency at Millstone.

13.3 Physical Security Plan

The physical security, guard training and qualification, and safeguards contingency plans were reviewed against the requirements of 10 CFR 73.55(b) through (h) and approved based on acceptance criteria in effect at the time of the review. Each of the plans have subsequently been revised by the licensee under the provisions of 10 CFR 50.54(p).

As required by the Commission's regulation, the physical security plan was implemented on February 23, 1979, the contingency plan was implemented on April 5, 1983, and the guard training and qualification plan was implemented on March 10, 1982.

The amendment 90 dated April 5, 1983 modified the Millstone 1 license to include a requirement to maintain a Safeguards Contingency Plan. The staff found that the plan:

(a) sets forth decisions and actions satisfying the stated objectives of contingency plans;

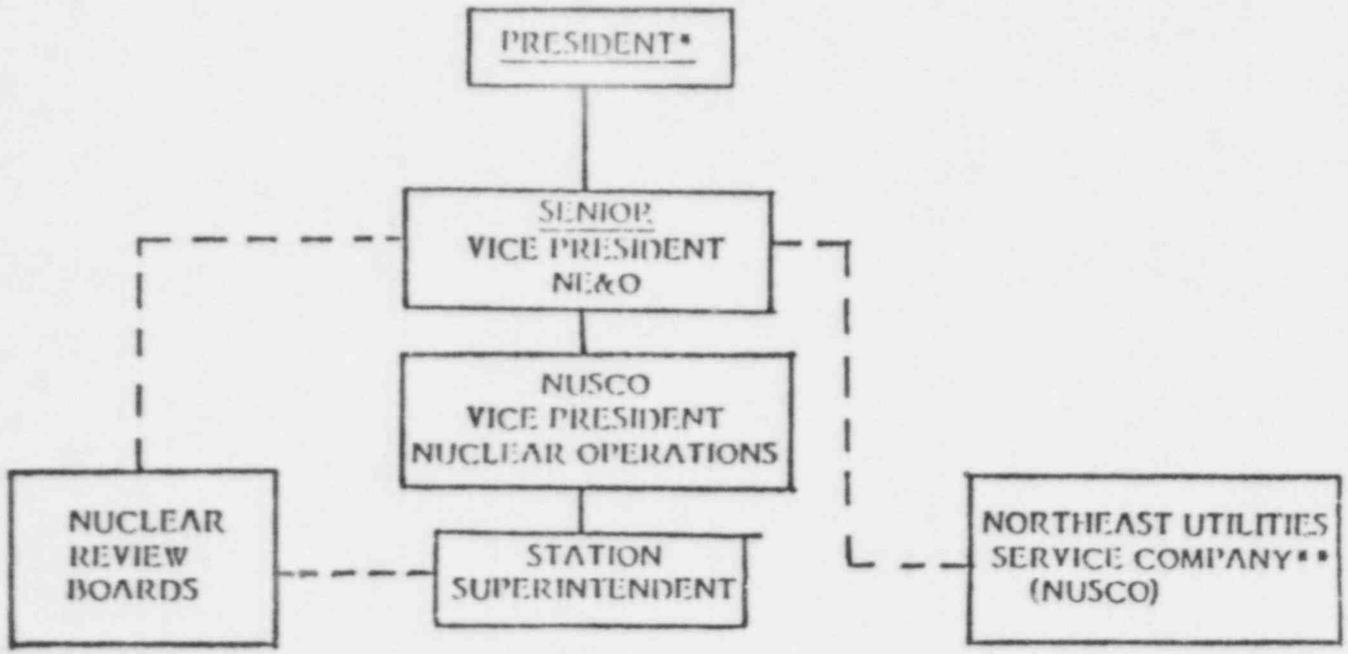
(b) identifies data, criteria, procedures and mechanisms to carry out these decisions and actions; and

(c) specifies individuals, groups or organizational entities responsible for each such decision and action.

Based on the considerations discussed above, the staff concluded that the plan, when fully implemented, will meet the requirements of 10 CFR 73.40(b), 73.55(h) and Appendix C to 10 CFR 73 and is therefore acceptable.

Amendment 82, dated March 10, 1982 modified the Millstone-1 License to include the requirement to maintain a guard training and qualification plan. The staff, based on review of the plan, concluded that the Guard Training and Qualifications Plant for Millstone-1 is acceptable.

NORTHEAST NUCLEAR ENERGY COMPANY



*Overall Corporate Responsibility for Fire Protection
** Provides Operating and Engineering Support by Contractual Arrangement

Figure 13.1 Offsite Organization for Facility Management and Technical Support

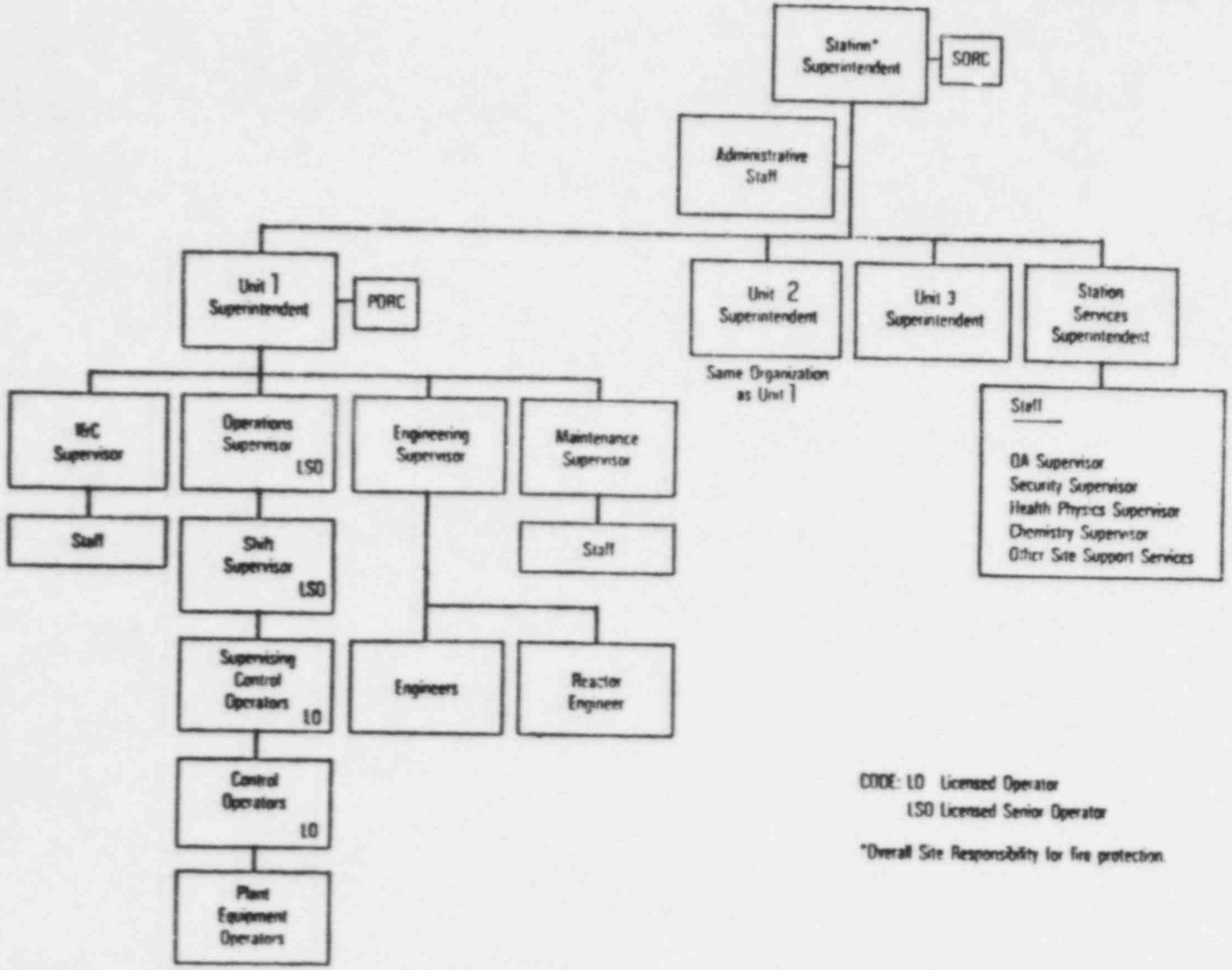


Figure 13.2 Facility Organization - Millstone Nuclear Power Station - Unit 1.

14 INITIAL TEST PROGRAM

The preoperational test program and the operational and transient tests for Millstone-1 operation up to 2011 MWt, the rated power level, were successfully completed and reported to the Commission on March 17, 1972. The report title is "Startup Test Program Results."

The following chronology lists the various accomplishments. The items are discussed in more detail in section 1.3.1 and Appendix D of this FTOL safety evaluation report.

October 7, 1970	Core loading began
October 17, 1970	Core loading completed
October 26, 1970	Initial criticality achieved
October 27 - November 8, 1970	Outage for repairs to gas turbine and cleanup system (AO-70-3)
October 30, 1970	Zero power test program completed
November 16, 1970	Outage for repairs to cleanup system
November 22 - November 25, 1970	Outage for turbine balance and training
December 6, 1970	25% power test program completed
December 8, 1970	Outage to report cleanup system valve to reactor (AO-70-4)
December 23, 1970	Outage to repair weld or main condenser
December 27, 1970	50% power test program completed
December 29, 1970	Outage to repair bypass valve linkage
January 1, 1971	75% power test program completed
January 2, 1971	Outage due to high level in drain tank
January 3, 1971	100% power test program completed
January 14, 1971	Outage to repair condenser leak
January 17, 1971	Outage to conduct overspeed trip tests of the turbine

January 25, 1971	Outage to effect repair of Core Spray Injection Valves and to reset turbine over-speed trips (AO-71-2)
January 27, 1971	Outage while conducting hot AEC demonstration criticals
February 19, 1971	Outage to conduct SUT No. 17, Generator load reject form 100%
March, 1971	Commercial operation

15 ACCIDENT ANALYSIS

As part of SEP the staff reevaluated the ability of Millstone-1 to withstand normal and abnormal transients and a broad spectrum of postulated accidents without undue hazard to the health and safety of the public. The results of these analyses are used to show conformance with GDC 10 and 15 of 10 CFR 50 Appendix A.

During its review of the transients and accidents analyses of Section 15, the staff has considered GDC 21, 27, and 28 and Regulatory Guides 1.53 and 1.105 as they apply to the events analyzed to ensure that the applicable requirements have been met.

For each event analyzed the worst operating conditions were assumed, and credit was taken for minimum engineered safeguards response. Parameters specific to individual events were conservatively selected.

Two types of events were analyzed:

(1) those incidents that might be expected to occur during the lifetime of the reactor (anticipated transients)

(2) those incidents not expected to occur that have potential to result in significant radioactive material release (accidents)

The following is a list of the M-1 events reviewed by the staff: (Ref. 5)

SEP Number	Title
XV-1	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief/Safety Valve
XV-3	Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)
XV-4*	Loss of Nonemergency AC Power to the Station Auxiliaries
XV-5*	Loss of Normal Feedwater Flow
XV-7*	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break
XV-8*	Control Rod Misoperation (System Malfunction or Operator Error)

*Plant meets current criteria or acceptable on another defined basis.

XV-9* Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate

XV-11* Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (BWR)

XV-13* Spectrum of Rod Ejection Accidents (PWR)

XV-14* Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory

XV-15* Inadvertent Opening of a PWR Pressurizer Safety/Relief Valve or a BWR Safety/Relief Valve

XV-16 Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment

XV-18 Radiological Consequences of Main Steam Line Failure Outside Containment

XV-19* Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

XV-20* Radiological Consequences of Fuel-Damaging Accidents (Inside and Outside Containment)

The staff's review of a feedwater controller failure Topic XV-1 has determined that the acceptance criteria are met only if the turbine bypass system is operable. Currently, the licensee does not have Technical Specifications that require surveillance of the turbine bypass system or that limit the reactor power or minimum critical power ratio (MCPR) when the turbine bypass system is found to be inoperable. Because the feedwater controller failure with failure of the turbine bypass may be a limiting transient, the fuel design limits could be exceeded. It is also possible that another transient limits MCPR or reactor power and no change is required.

The staff concluded that analysis of feedwater controller failure without bypass should not be required for the following reasons:

(1) At Millstone Unit 1, the turbine control valves and bypass valves are controlled by a common system referred to as the mechanical-hydraulic control (MHC) system. The system components, with the exception of the final valve actuators, are common to both the control and bypass valves. Thus, it is improbable that a failure could occur in the bypass valve portion of the system without affecting the control valve portion of the system. A malfunction in the MHC system that renders the bypass system inoperable would also most likely affect operation of the turbine control valves and would necessitate immediate repair in order to continue operation. The control valve final actuators and the common components of the

*Plant meets current criteria or acceptable on another defined basis.

MHC system are exercised continuously while performing the normal reactor pressure control function. Therefore, continuous operability of the MHC system is ensured.

During startups, the bypass valves are used, thus providing assurance of their operability.

(2) The limited PRA performed for Millstone Unit 1 concluded that the historical rate of turbine bypass unavailability has been small compared with other causes of loss of the power conversion system so that limitations on reactor operation when the turbine bypass is unavailable would result in a negligible reduction in core-melt frequency.

By letter dated April 9, 1984 and supplement dated May 15, 1984, NNECO requested a number of changes to the Technical Specifications relating to changes made during the Reload 9 plant outage which began on April 14, 1984. One of the proposed changes resulted from the NRC request to provide surveillance requirements for the turbine bypass system. NNECO proposed new specifications 3.14 and 4.14 to require operability of the turbine bypass system while in the "run" mode and to functionally test the system once per cycle. The staff had previously concluded (Ref. 5) that such a change was acceptable and that further analysis of feedwater controlled failure without bypass was not justified. Accordingly, the changes were authorized by Amendment 98 to the Technical Specifications, dated June 14, 1984, and this issue was closed.

During the staff's review of Topic XV-3 the following concern was identified: At Millstone Unit 1, the MCPR was calculated based on an initial power level of 100%. Current criteria require that the initial power level be taken as 100% power plus an allowance of 2% to account for power measurement uncertainties. The higher actual power level might lead to an MCPR that exceeds the safety limit.

The licensee analyzed this transient for Reload 8 using the NRC-approved ODYN code. Although this analysis assumed an initial power level of 100%, an uncertainty factor of 1.044 was used to determine the maximum reduction in the critical power ratio. This 4.4% overall uncertainty factor more than compensates for the difference in initial power level assumed. On this basis the staff concluded that further analysis of this event was not warranted.

The staff determined that Millstone Unit 1 did not comply with current licensing criteria for Topic XV-16. Based on the existing Technical Specification limits for primary coolant activity, the calculated potential offsite doses would substantially exceed the applicable dose limits. It was the staff's position that reactor coolant activity limits should be maintained within the limits imposed on new operating reactors, that is, within the limits of the Standard Technical Specifications (STS) for General Electric Boiling Water Reactors (NUREG-0123). It was necessary to limit plant operation so that the radiological consequences of events that do not damage fuel but do involve a release of reactor coolant to the environment will be low. Reducing reactor coolant activity to the STS level will not result in calculated doses, using current licensing criteria, that are within the limits specified. This is due to the quantity of primary coolant that would be released at Millstone Unit 1 if an instrument line or other typical small line were to fail. New plant designs use flow-restricting devices or valves capable of being remotely closed. However, for the following

reasons, the staff concluded that backfitting flow-restricting devices (orifices or flow-restricing check valves) were not appropriate:

(1) The analysis of radiological consequences used the conservative assumptions specified in the Standard Review Plan (NUREG-0800).

(2) Risk assessments have shown that events that do not involve core melt are not dominant contributors to risk.

(3) The costs associated with hardware modifications are not justified based on the results of risk assessments.

The staff concluded that the General Electric Standard Technical Specification reactor coolant activity limits would ensure that the radiological consequences to the environment from small line failure is acceptably low. By letter dated December 28, 1983, NNECO proposed such changes, i.e., limits for dose-equivalent iodine-131 in the primary coolant, and Amendment No. 99 issued on June 21, 1984 authorized the new iodine Technical Specification limits. For the above reasons, the staff has concluded that the concern of Topic XV-16 has been satisfactorily resolved.

10 CFR 100, as implemented by SRP (Ref. 20) Section 15.6.4, requires that the radiological consequences of failure of a main steam line outside containment be limited to small fractions of the exposure guidelines of 10 CFR 100. On the basis of an independent assessment of the radiological consequences of a main steam line failure outside containment, Topic XV-18, the staff determined that Millstone Unit 1 did not meet the current acceptance criteria for this topic. If the then existing Technical Specification limits for primary coolant activity were used, the calculated potential offsite doses substantially exceeded the allowable dose limits.

The limited PRA for Millstone Unit 1 concluded that this issue did not affect any core-melt sequence and thus had no effect on core-melt frequency or risk. Since the staff's analysis showed that the small-line failure was more limiting than the main steam line failure, resolution of Topic XV-16 also resolved the concerns of Topic XV-18

On the basis of the SEP topic safety evaluations listed above, the staff concludes that operation of the plant will not result in any violation of fuel design or reactor coolant pressure boundary design limits and that operation of the plant is in conformance with GDC 10 and 15 and therefore acceptable. Also the staff has concluded that the licensee has provided adequate protection systems to mitigate accidents in compliance with Title 10 "Energy" Code of Federal Regulations Parts 50 and 100.

However, the staff position on anticipated transients without scram (ATWS) has been a subject of continuing controversy since its publication in the "Technical Report on Anticipated Transients Without Scram for Water-Cooled Power Reactors," WASH-1270, in 1973. The status of the implementation of this position, including the staff's review of each reactor manufacturer's analysis methods and results, was published in 1975 in a series of reports. These status reports were criticized by the nuclear industry as being excessively conservative.

NUREG-0460 "Anticipated Transients Without Scram for Light Water Reactors, dated April 1978 is, in the part, a response to the industry criticism and has the purpose of reviewing and evaluating the information now available on the subject of ATWS, in particular, the material developed subsequent to the publication of the status reports.

The significance of ATWS in the evaluation of reactor safety is that some ATWS events could result in melting of the reactor fuel and the release of a large amount of radioactive fission products. The questions in contention concern whether the probability of such events is great enough to justify their consideration and if so, what degree of protection is required.

Based on the occurrence of transients in currently operating nuclear power plants, the staff now concludes that transients that would result in serious consequences if accompanied by scram failure could be expected to occur in the future population of plants at a rate of five to eight per reactor-year. The staff also estimates that the probability of scram failure, based on nearly 700 reactor years of operating experience in foreign and domestic commercial power reactors with one observed potential scram failure, is in the range of 10^{-4} to 10^{-5} per demand. Thus, the expected frequency of ATWS events that could result in serious consequences is approximately 2×10^{-4} per reactor-year. The report recommends a safety objective of 10^{-6} unacceptable ATWS events per reactor year, and therefore, some corrective measures to reduce the probability or consequences of ATWS are required.

Although reducing the frequency of anticipated transients might be a means of reducing the probability of ATWS events, the difficulty in accomplishing the necessarily large reduction appears to make this approach impractical. Alternatively, improvement of the reliability of scram systems, particularly with regard to potential for common mode failures, by providing a second independent, separate and diverse scram system has been considered, but no completely acceptable design has been proposed. These considerations lead to the recommendation that the provision of systems to mitigate the consequences of ATWS events, should they occur, is the most promising alternative for meeting the safety objective.

The staff developed a set of requirements for the design and performance of systems provided to reduce the consequences or probability of ATWS events. Acceptance criteria are stated that address radiological dose limits; reactor coolant system, fuel and containment integrity; core cooling capability; and mitigating system design and performance. Requirements are given for the analysis of postulated ATWS events. The requirements provide reasonable assurance that, considering the frequency of ATWS events, the probability of additional system failures, and the uncertainty and variation in initial conditions and parameters, the acceptance criteria are not violated.

The staff also considered the value and impact of these requirements. Estimates of the impact, primarily the costs associated with implementing the requirements, range from 1 to 43 million dollars per plant, depending on the type of plant and its stage of construction or operation. The direct value consists of the cost of the averted radiological and economic consequences. Estimates of the value range from approximately 1 to 47 million dollars per plant and are generally larger than the corresponding impact for any one type

of design. The averted potential for shutdown of a number of operating reactors, should an ATWS with severe offsite consequences occur, has been estimated to translate into an additional indirect value ranging from 1.5 to 23 million dollars.

The staff found that, considering the expected frequency of occurrence of transients, the reliability of current reactor scram systems necessary to meet the safety objectives has not been demonstrated and may well have not been attained. Therefore, the staff recommended that means of reducing the probability or consequences of ATWS events should be provided.

As a result the Commission amended its regulations, effective July 26, 1984, to require improvements in the design and operation of light water-cooled nuclear power plants to reduce the likelihood of failure of the reactor protection system to shutdown the reactor (scram) following anticipated transients and to mitigate the consequences of anticipated transients without scram (ATWS) event (ATWS Rule 10 CFR 50.62 Requirements). The final rule requires the installation of certain equipment (i.e., a diverse alternate rod injection system, a standby liquid control system with a minimum control capacity of 86 gallons per minute of 13 weight percent sodium pentaborate, and equipment to trip the reactor coolant recirculation pumps automatically under ATWS conditions). It also encourages the development of a reliability assurance program for the reactor trip system. For Millstone-1, the changes are to be completed by the refueling outage in 1987.

16 TECHNICAL SPECIFICATIONS

The Technical Specifications in a license define certain features, characteristics, and conditions governing the operation of a facility that cannot be changed without prior approval of the staff. The current Technical Specifications for Millstone-1 are part of the provisional operating license and will be made part of the full-term operating license. Included are sections covering definitions, safety limits, limiting safety settings, limiting conditions for operations, surveillance requirements, design features, and administrative controls.

In the course of the staff's review of the individual SEP topics, the Millstone-1 Technical Specifications were compared with the Standard Technical Specifications for deviations. Where significant differences existed, they were identified and the staff considered them for upgrading. Table 4.1 of the IPSAR (NUREG-0824-Ref. 5) identifies the Technical Specifications that the staff has identified as requiring upgrading. The other sections of the Technical Specifications are reviewed only to the extent that reloads, license amendments, or generic problems require.

17 QUALITY ASSURANCE

17.1 General

The description of the quality assurance (QA) program for the operations phase of Millstone Unit 1 is referenced in the latest NRC-accepted revision of the report entitled "Northeast Utilities Quality Assurance Program Topical Report" (NU-QA-1, Rev. 7, NRC Ltr on August 9, 1985). The staff's evaluation of this QA program is based on a review of this information, discussions with representatives from NNECO and NNECO responses.

The staff assessed NNECO's QA program for operations to determine if it complies with the requirements of 10 CFR 50, Appendix B, SRP Section 17.2 (NUREG-0800); SEP Topic XVIII also addresses this topic (Ref. 5) and the applicable QA-related regulatory guides listed in Table 17.1 of this SER.

17.2 Organization

The structure of the Northeast Utilities' organization responsible for the operation of Millstone Unit 1 and for the establishment and implementation of the QA program for the operations phase is shown in Figure 17.1. The President and Chief Operating Officer has ultimate responsibility for the establishment and execution of the operational QA program. Authority for the establishment and execution of this QA program is delegated to the Executive Vice President, Engineering and Operations. He is responsible for engineering, construction, operation, maintenance, modification, and QA within Northeast Utilities. Authority for the nuclear engineering, operation, maintenance, modification, and QA for Millstone Unit 1 is delegated to the Senior Vice President, Nuclear Engineering and Operations. He has the specific responsibility for the program management in accordance with the Nuclear Engineering and Operations Policy Statement, "Quality Assurance Program," and he resolves disputes arising from a difference of opinion between QA personnel and other department personnel that are not resolved by lower management. The three vice presidents reporting to the Senior Vice President, Nuclear Engineering and Operations, are:

1. The Vice President, Generation Engineering and Construction, is responsible for modification, backfit, and betterment projects during the operation of Millstone Unit 1. Within his organization is a Construction Quality Control Branch that performs inspections of activities performed as part of these projects.

2. The Vice President, Nuclear Operations, is responsible for the operation and maintenance of Millstone. Within his organization is the Millstone QA Supervisor who reports through the Quality Services Supervisor and the Station Services Superintendent to the Millstone Station Superintendent, independent of the Superintendent, Millstone Unit 1, who is responsible for Millstone Unit 1 operation. Overall responsibility for implementing the requirements of the Millstone Unit 1 operational QA program is assigned to the Unit Superintendent. The Millstone QA Supervisor is responsible for first-line verification of implementation of the requirements. He is

supported by a staff of quality assurance/quality control (QA/QC) engineers and technicians. He is present or represented at Millstone Unit 1 work schedule and status meetings and is thus aware of day-to-day assignments throughout the plant and can provide adequate QA/QC coverage. He provides nuclear generation facility management and the Manager, Quality Assurance, with objective evidence of the implementation of the QA program within the facility. He has the authority and organizational freedom and is sufficiently removed from undue cost and schedule influences to perform QA functions effectively, including responsibilities (a) to stop unsatisfactory work and control further processing, delivery, or installation of nonconforming materials as delineated in writing; (b) to identify quality problems; (c) to initiate, recommend, or provide solutions; and (d) to verify implementation of solutions.

3. The Vice President, Nuclear and Environmental Engineering, is responsible for nuclear engineering and operations services, which include QA. The Manager, Quality Assurance, reports through the Director Nuclear Engineering and Operations Services, to the Vice President, Nuclear and Environmental Engineering. The Manager, Quality Assurance, is responsible for the preparation and issuance of the "QA Program Topical Report" and verification of the implementation of its requirements. Verification is performed by a planned program for audits, inspections, and surveillances. He provides management with objective evidence of the performance of activities affecting quality, independently of the individual or group directly responsible for performing the specific activity. He has the authority and organizational freedom to ensure all necessary quality-affecting activities are performed. He is independent of undue influences and responsibilities for schedules and costs. He has the responsibility and authority, delineated in writing, to stop unsatisfactory work and control further processing, delivery, or installation of nonconforming materials.

The staff finds the applicant's organization for QA acceptable.

17.3 Quality Assurance Program

In addition to descriptive material contained in the Northeast Utilities' topical report on quality assurance, the operations phase of the QA program has detailed company procedures. A summary of the topics addressed in these procedures and their relationship to the QA requirements of Appendix B to 10 CFR 50 is presented in the topical report.

Procedures and work instructions necessary to implement the requirements of the operations phase program are developed by the organization responsible for the activity. Lower tier procedures and instructions are contained in manuals, station procedures and/or administrative instructions. Onsite implementation of procedures and work instructions is the responsibility of the Unit Superintendent of Millstone Unit 1. QA personnel verify that the procedures are followed by means of inspections, audits, and other surveillance. Procedures for such inspections, audits, and surveillance are developed, approved, and implemented by the QA organization.

Inspections are performed using preplanned checklists in accordance with written and approved inspection plans. The qualifications of inspectors (and their

current status) to conduct inspections, tests, and examinations are based on applicable codes, standards, and Northeast Utilities' training programs.

The QA organizations are responsible for the content and control of the audit program. Audits are performed in accordance with written procedures or check-lists by appropriately trained QA personnel who do not have direct responsibility in the area being audited. The audit activities and their required frequency are described in the topical report. Audit activities may be performed on a more frequent basis as determined by the QA organization. These include an objective evaluation of QA practices, procedures, and instructions; work areas, activities, processes, items, and effectiveness of implementation of the QA program.

The QA program requires that both documentation of audit results and formal notification of the audit findings be provided to the Manager Quality Assurance, and to the management of the audited function. Audit findings, which indicate quality trends and the effectiveness of the QA program, are also reported to the Senior Vice-President, Nuclear Engineering and Operations. Management for the area audited implements any corrective action needed. Followup audits are performed to determine that nonconformances are effectively corrected and that the corrective action precludes repetitive occurrences.

An indoctrination and training program is established to ensure that persons involved in quality-related activities are knowledgeable in QA instructions and requirements and demonstrate a high level of competence and skill in the performance of their quality-related activities. A program for retraining of such persons is provided to ensure that they maintain their proficiency.

17.4 Conclusion

On the basis of its detailed review and evaluation of the QA program description of NU-QA-1 as referenced therein, the staff concludes that

1. The Northeast Utilities' organization gives QA personnel sufficient (a) independence from cost and schedule (when opposed to safety consideration), (b) authority to effectively carry out the operations QA program, and (c) access to management at a level necessary to perform their QA functions.

2. The QA program describes requirements, procedures, and controls that, when properly implemented, comply with the requirements of Appendix B to 10 CFR 50 and with the acceptance criteria contained in SRP Section 17.2 (NUREG-0800).

Accordingly, the staff concludes that Northeast Utilities' description of the QA program for operations is in compliance with applicable NRC regulations, meets the requirements of Appendix B to 10 CFR 50, and is acceptable.

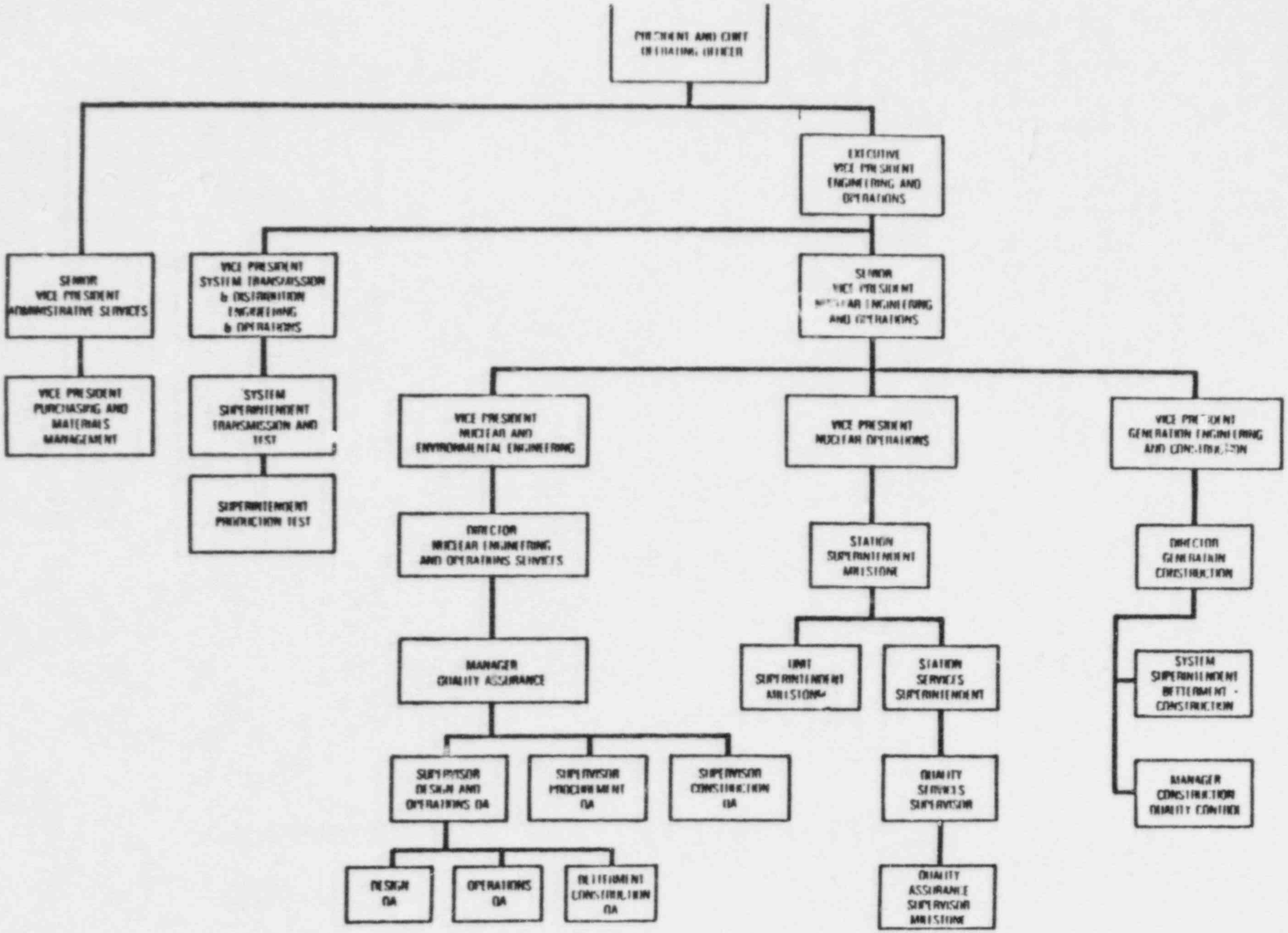


Figure 17.1 Organization for operations quality assurance

Table 17.1 Regulatory guidance applicable to quality assurance program

Regulatory Guide, revision, and date	Title
1.8 Rev. 1-R May 1977	Personnel Selection and Training
1.30 Aug. 11, 1972	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment
1.33 Rev. 2 Feb. 1978	Quality Assurance Program Requirements (Operation)
1.37 Mar. 16, 1973	Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants
1.38 Rev. 2 May 1977	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants
1.39 Rev. 2 Sept. 1977	Housekeeping Requirements for Water-Cooled Nuclear Power Plants
1.58 Rev. 1 Sept. 1980	Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel
1.64 Rev. 2 June 1976	Quality Assurance Requirements for the Design of Nuclear Power Plants
1.74 Feb. 1974	Quality Assurance Terms and Definitions
1.88 Rev. 2 Oct. 1976	Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records
1.94 Rev. 1 April 1976	Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants
1.116 Rev. 0-R May 1977	Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems

Table 17.1 (Continued)

Regulatory Guide, revision, and date	Title
1.123 Rev. 1 July 1977	Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
1.144 Rev. 1 Sept. 1980	Auditing of Quality Assurance Programs for Nuclear Power Plants
1.146 Aug. 1980	Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

18 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The NNECO application for a full-term operating license is being reviewed by the Advisory Committee on Reactor Safeguards. The NRC staff will issue a supplement to this Safety Evaluation Report after the Committee report to the Commission is available. The supplement will append a copy of the Committee's report, will address comments made by the Committee, and will describe steps taken by the NRC staff to resolve any issues raised as a result of the Committee's review.

19 COMMON DEFENSE AND SECURITY

North East Nuclear Energy Company (NNECO) is not owned, dominated, or controlled by an alien, a foreign corporation, or a foreign government. The activities that will continue to be conducted do not involve any restricted data, but NNECO has agreed to safeguard any such data that might become involved in accordance with the requirements of 10 CFR 50. The licensee will continue to rely upon obtaining fuel as it is needed from sources of supply available for civilian purposes, so that no diversion of special nuclear material from military purposes is involved. For these reasons, and in the absence of any information to the contrary, the staff has found that issuance of the full-term operating license will not be inimical to the common defense and security.

20 FINANCIAL QUALIFICATIONS

On March 31, 1982, the NRC published in the Federal Register (47 FR 13750) amendments to its regulations that entirely eliminate the review relating to the financial qualifications of applicants for construction permits and operating licenses. Because these amendments were effective immediately, there will be no further review of the financial qualifications of the Northeast Nuclear Energy Company.

21 FINANCIAL PROTECTION AND INDEMNITY REQUIREMENTS

Pursuant to the financial protection and indemnification provisions of the Atomic Energy Act of 1954, as amended (Section 170 and related sections), the Commission has issued regulations in 10 CFR 140. These regulations set forth the Commission's requirements with regard to proof of financial protection by, and indemnification of, licenses for facilities such as power reactors under 10 CFR 50.

Under the Commission's regulations, 10 CFR 140, a license authorizing the operation of a reactor may not be issued until proof of financial protection in the amount required for such operation has been furnished, and an indemnity agreement covering such operation has been executed. The amount of financial protection that must be maintained for the Millstone-1 plant (which has a rated capacity in excess of 100,000 electrical kilowatts) is the maximum amount available from private sources (that is, the combined capacity of the two nuclear liability insurance pools; this amount is currently $160 million).

The NRC and NNECO entered into Indemnity Agreement No. B-39 on May 9, 1969. Therefore, the staff concludes that the licensee complies with the provisions of 10 CFR 140 applicable to operating licenses, including those that relate to proof of financial protection in the requisite amount and to execution of an appropriate indemnity agreement with the Commission.

22 CONCLUSIONS

On the basis of its evaluation of the application as set forth above, the staff has determined that:

1. The application for a full-term operating license (FTOL) for the Millstone Nuclear Power Station Unit 1 filed by NNECO dated September 1, 1972, as supplemented and as revised, complies with the requirements of the Atomic Energy Act of 1954, as amended (Act), and the Commission's regulations set forth in 10 CFR Chapter I, except as duly exempted therefrom.

2. Construction of the Millstone-1 Nuclear Power Plant has been completed in conformity with Construction Permit No. CPPR-20, as amended, the application as amended, the provisions of the Act, and the rules and regulations of the Commission.

3. The provisions of Provisional Operating License No. DPR-21 have been met.

4. The facility will operate in conformity with the FTOL application as amended, the provisions of the Act, and the rules and regulations of the Commission.

5. There is reasonable assurance (a) that the activities authorized by the FTOL can be conducted without endangering the health and safety of the public and (b) that such activities will be conducted in compliance with regulations of the Commission set forth in 10 CFR Chapter I.

6. The licensee is technically qualified to engage in the activities authorized by the FTOL, in accordance with the regulations of the Commission set forth in 10 CFR Chapter I.

7. The issuance of the FTOL will not be inimical to the common defense and security or to the health and safety of the public.

8. The FTOL for the Millstone-1 Nuclear Power Plant should be authorized by the NRC.

APPENDIX A
References

1. Title 10 (10 CFR) Code of Federal Regulations "Energy" U.S. Government Printing Office, Washington, D.C. (includes general design criteria)

2. Federal Register (47 FR 13750) "Final Rule - Nuclear Power Plant - Elimination of Review of Financial Qualifications of Electric Utilities in Licensing Hearings - 10 CFR Parts 2 and 50" U.S. Regulatory Commission, March 31, 1982.

3. Atomic Safety and Licensing Appeal Board, ALAB 444, 6 NRC 760 "Gulf States Utilities Co., River Bend, Units 1 and 2," November 23, 1977.

4. NUREG-1031-July 1984 "Safety Evaluation Report Related to the Operation of Millstone Nuclear Power Station Unit 3" Docket No. 50-423.

5. NUREG-0824 - February 1983 "Integrated Plant Safety Assessment - Systematic Evaluation Program - Millstone Nuclear Power Station, Unit 1." and Supplement 1 dated 1985

6. SECY-83-19 Policy Issue "Conversion of Provisional Operating Licenses to Full Term Licenses"

7. Millstone Nuclear Power Station - Application for Full Term Operating License Unit-1 September 1, 1972 and Appendices A September 28, 1973, B January 24, 1974, C April 1, 1974, D April 26, 1974, and Supplement May 15, 1974, E July 2, 1974, F October 18, 1974, G November 1, 1974, H November 18, 1974, I February 18, 1975 and J March 21, 1975.

8. SECY-76-545 "The Systematic Evaluation of Operating Nuclear Power Plants" November 12, 1976.

9. NED 21821A GE BWR Design Feedwater Sparger February 1980 and NRC SER Eisenhut/ Gridley dated January 17, 1980.

10. Environmental Evaluation Relating to the Conversion of the POL to FTOL- Docket 50-245 dated December 17, 1984.

11. Millstone Nuclear Power Station Semi Annual and Annual Reports for the years 1973 through 1983.

12. *Final Safety Analysis Report (FSAR) Unit 1 Millstone Nuclear Power Station Dated March 15, 1968.

*Final Safety Analysis Report Update due March 1985 (per Ref. 5) pursuant to 10 CFR 50.71 (e)(3)(ii) NRC letter dated April 11, 1985 granted a 6 month delay for NNECO to prepare a new schedule for the FSAR update.

13. Provisional Operating License - Millstone Point Company Docket 50-245 License DPR-21 - Transmitted by Letter Peter A. Morris to Millstone Point Co. Dated October 7, 1970.

14. NNECO Letter Counsil/Tourtellotte dated March 21, 1983 - Backfit costs.

15. Generic Letter 82-33 Supplement 1 to NUREG-0737 Requirements for Emergency Response Capability - Dated December 17, 1982.

16. Bulletin 79-02. Pipe Support Base Plate Designs Using Concrete Expansion Bolts March 5, 1979, Rev. 1 June 21, 1979, Supplement August 17, 1979, Rev. 2 November 8, 1979.

17. Bulletin 79-14. Seismic Analysis for As-Built Safety-Related Piping Systems July 2, 1979, Rev. 1 July 17, 1979, Supplement August 15, 1979, Supplement 2, September 6, 1979.

18. Bulletin 80-11. Masonry Wall Design May 6, 1980.

19. NNECO Letter. "Environmental Qualification of Electrical Equipment" dated October 31, 1980.

20. NUREG-0800 Standard Review Plan (Formerly NUREG-75/087) July 1981.

21. Environmental Statement Millstone Nuclear Power Station Units 1 and 2 dated June 1973.

22. NNECO submittal "Review of Final Environmental Statement dated January 11, 1983.

23. Safety Evaluation Report for Final Resolution of Environmental Qualification of Electric Equipment Important to Safety dated July 30, 1985.

24. Schedular Extension for Equipment Qualification dated March 28, 1985

25 Millstone Nuclear Power Station, Unit No. 1 Technical Specifications Appendix A to License No. DPR-21

26. Amendment No. 16 dated October 17, 1975 "Millstone-1 Reload 3"

27. Amendment No. 34 dated November 19, 1976 "Millstone-1 Reload 4"

28. Amendment No. 47 dated April 12, 1978 "Millstone-1 Reload 5"

29. Amendment No. 61 dated May 29, 1979 "Millstone-1 Reload 6"

30. Amendment No. 73 dated March 11, 1981 "Millstone-1 Reload 7"

31. Amendment No. 87 dated November 12, 1982 "Millstone-1 Reload 8"

32. Amendment No. 98 dated June 14, 1984 "Reload 9"

33. Amendment No. 86 dated November 12, 1982 "Scram Discharge Volume"

34. Safety Evaluation Report dated March 6, 1985 "Scram Discharge System Level Instrumentation"

35. Amendment No. 20 dated February 23, 1976 "Safety/Relief Valve Modifications"

36. Amendment No. 67 dated May 8, 1980 "Automatic Initiation of Isolation Condenser as an Engineered Safety Feature"

37. Amendment No. 65 dated January 17, 1980 "Operation Limit of 40% Power Without Isolation Condenser"

38. Amendment No. 64 dated September 19, 1979 "In Service Inspection and Test Program"

39. NRC letter dated February 22, 1982 "SEP Topic IV-3" "BWR Jet Pump Operating Indications - Millstone-1"

40. NRC letter dated June 26, 1984 "Reinspection, Analysis, and Repairs of the Reactor Coolant System Piping"

41. NNECO letter Council/Director of NRR dated April 12, 1985 "Reactor Vessel Material Surveillance Program Results"

42. NRC letter dated May 10, 1985 "Appendix J Review Millstone Station, Unit-1"

43. NRC letter dated May 22, 1985 "Safety Evaluation of Millstone Unit One Inservice Testing (IST) Program for Pumps and Valves for the Second 10 year Inspection Interval"

44. NRC Amendment 94 dated December 19, 1983 "Integrated Containment Leak Rate Test of Duration Less than 24 Hours"

45. NUREG-0737 dated November 1980 "Clarification of TMI Action Plan Requirements"

46. Millstone Unit 3 FSAR - transmitted to NRC by letter dated February 2, 1983

APPENDIX B

THREE MILE ISLAND - LESSONS LEARNED REQUIREMENTS

The accident at Three Mile Island Unit 2 (TMI-2) resulted in requirements that were developed from the recommendations of several groups established to investigate the accident. These groups include the Congress, the General Accounting Office, the President's Commission on the Accident at Three Mile Island, the NRC Special Inquiry Group, the NRC Advisory Committee on Reactor Safeguards, the Lessons Learned Task Force, the Bulletins and Orders Task Force of the NRC Office of Nuclear Reactor Regulation, the Special Review Group of the NRC Office of Inspection and Enforcement, the NRC Siting Task Force and Emergency Preparedness Task Force, and the NRC Offices of Standards Development and Nuclear Regulatory Research. NUREG-0660, entitled "NRC Action Plan Developed as a Result of the TMI-2 Accident" (referred to as Action Plan), was developed to provide a comprehensive and integrated plan for the actions judged necessary by NRC to correct or improve the regulation and operation of nuclear facilities. The Action Plan was based on the experience from the TMI-2 accident and the recommendations of the investigating groups.

With the development of the Action Plan (NUREG-0660), NRC transformed the recommendations of the investigating groups into discrete scheduled tasks that specify changes in regulatory requirements, organization, or procedures. Some actions to improve the safety of operating plants were judged to be necessary before an action plan could be developed, although they were subsequently included in the Action Plan. Such actions came from the Bulletins and Orders issued by the Commission immediately after the accident, the first report of the Lessons Learned Task Force, and the recommendations of the Emergency Preparedness Task Force. Before these immediate actions were applied to operating plants, they were approved by the Commission.

The NRC identified a discrete set of licensing requirements related to TMI-2 in the Action Plan for the Millstone-1 plant. NUREG-0737 entitled "Clarification of TMI Action Plan Requirements" was issued in November 1980. This report identifies the specific items from NUREG-0660 that were approved by the Commission for implementation at nuclear power plants. It also includes additional information about schedules, applicability, method of implementation review, submittal dates, and clarification of technical positions. By letter dated December 17, 1982, Supplement 1 to NUREG-0737 was issued to provide additional clarification regarding safety parameter display systems, detailed control room design reviews, Regulatory Guide 1.97 application to emergency response facilities, upgrading of emergency operating procedures, emergency response facilities, and meteorological data. Schedules for completing the topics in Supplement 1 were negotiated with the licensee and were confirmed by an NRC order dated June 12, 1984.

Of the TMI Action Plan Requirements for Boiling Water Reactors (MP-1 is a BWR) documented in NUREG-0737, eight (8) have yet to be satisfied. The eight open items are:

TMI Item	Title
1C1.3A	Abnormal Transient Operator Guidelines
1D1.1	Detailed Control Room Design Review (DCRDR)
1D1.2	DCRDR Summary Report
1D2	Safety Parameter Display System (SPDS)
IIIA.1.2	Technical Support Center
	Operational Support Center
	Emergency Operations Facility
IIIA.2.2	Meteorological Data Upgrade
IIE4.2	Containment Isolation Dependability
IIID3.4	Control Room Habitability

As noted above Supplement 1 to NUREG-0737 - "Requirements for Emergency Response Capability" (Generic Letter No. 8233) was issued on December 17, 1982. The schedule for completing the first 6 of these 8 open TMI requirements was affected by this supplement. TMI requirement IIE4.2 "Containment Isolation Dependability" is part of an on-going active effort and much correspondence that is summarized later in this appendix. Also included later is an explanation for the delay in completing TMI requirement IIID3.4 "Control Room Habitability". Since most of the TMI requirements that are not fully resolved at this time are affected by G.L. 82-33 mentioned above, the status of these requirements is presented first.

Supplement 1 to NUREG-0737 represents the staff's attempt to distill the fundamental requirements for nuclear plant Emergency Response Capability from the wide range of guidance documents that the NRC had previously issued. Its purpose was to place all of the earlier staff guidance in perspective by identifying the elements that the NRC staff believes to be essential to upgrade emergency response capabilities. The requirements set forth in this supplement were approved by the Commission and were, therefore, to be accorded the status of approved NUREG-0737 items. In this connection, the resultant schedules superceded those previously listed in NUREG-0737.

The supplement discusses coordination and integration of initiatives related to the Safety Parameter Display System (SPDS), Detailed Control Room Design Review (DCRDR), Emergency Operations Facility (EOF), Technical Support Center (TSC), the Operational Support Center (OSC), and Emergency Operating Procedures (EOPs). The TSC and EOF are dependent on control room improvements in terms of communication and instrumentation needs among the TSC, EOF, and control room. TSC and EOF facilities are not necessarily dependent on each other. The OSC is independent of TSC and EOF.

The three groups of initiatives--SPDS, control room improvements, and emergency response facilities (TSC, EOF, OSC)--have the following interrelationships:

a. The SPDS is an improvement because it enhances operator ability to comprehend plant conditions and interact in situations that require human intervention. The SPDS could affect other control room improvements that licensees may consider. In some cases, a good SPDS could obviate the need for extensive modifications to control rooms.

b. New instrumentation that may be added to the control room should be considered a requirement for inclusion in the design of the TSC and EOF only

to the extent that such instrumentation is essential to the performance of TSC and EOF functions.

c. The SPDS and control room improvements are essential elements in operator training programs and the upgraded plant-specific emergency operating procedures

d. Acquisition, processing, and management of data for SPDS, control room improvements, and emergency response facilities should be coordinated.

Specific implementation plans and reasonable, achievable schedules for improvements to satisfy the requirements were to be established by agreement between the NRC Project Manager and each individual licensee. By letter dated June 12, 1984, the Commission issued an order confirming the commitments on emergency response capability. These commitments are shown in Table 1.

The Commission requirements and a brief status summary for each of the 6 open TMI items encompassed by Supplement 1 and the Commission Order are listed below followed by similar information for the remaining 2 open TMI items.

- 1C13A Abnormal Transient Operator Guidelines

  Requirements

  Submit a procedures generation package to NRC for approval. The procedures generation package should include:

  Plant-Specific Technical Guidelines--plant-specific guidelines for plants not using generic technical guidelines. For plants using generic technical guidelines, a description of the planned method for developing plant specific EOPs from the generic guidelines, including plant specific information.

  A Writer's Guide that details the specific methods to be used by the licensee in preparing EOPs based on the Technical Guidelines.

  A description of the program for validation of EOPs.

  A brief description of the training program for the upgraded EOPs.

  Status

  As shown in Table 1, the Procedures Generation Package was submitted on May 13, 1983. It was later revised on March 9, 1984 when a response to an NRC request for additional information was provided. The staff issued a safety evaluation dated September 24, 1984. The licensee letter dated January 30, 1985 responded to the staff's safety evaluation comments and included revision 1 to EOP Writers' Guide. The staff evaluation continues.

TABLE 1

LICENSEE'S COMMITMENTS ON SUPPLEMENT 1 TO NUREG-0737

TITLE		REQUIREMENT	LICENSEE'S COMPLETION SCHEDULE (OR STATUS)
1. Safety Parameter System (SPDS)	1a.	Submit a safety analyses and an implementation plan to the NRC.	04/09/87
	1b.	SPDS fully operational and operators trained.	Submit schedule by 04/09/87.
2. Detailed Control Room Design Review (DCRDR)	2a.	Sumbit a program plan to the NRC.	03/02/87
	2b.	Submit a summary report to the NRC including a proposed schedule for implementation	Submit schedule by 03/02/87
3. Regulatory Guide 1.97-Application to Emergency Response Facilities	3a.	Submit a report to the NRC describing how the requirements of Supplement 1 to NUREG-0737 have been or will be met.	Complete 02/29/84
4. Upgrade Emergency Operating Procedures (EOPs)	4a.	Submit a Procedures Generation Package to the NRC.	Complete 05/13/85
	4b.	Implement the upgraded EOPs.	Complete 06/29/83
5. Emergency Response Facilities	5a.	Technical Support Center fully functional.	Interim TSC Operational* +
	5b.	Operational Support Center fully functional.	Complete*
	5c.	Emergency Operations Facility fully functional.	Complete* (**EOF Backup siting relief requested by NNECo letter dated August 3, 1983.)

*Except for any additional changes that may be required as a result of other items in this Order.

**Approved Corporate Emergency Operation Center in Berlin, Connecticut by NRC letter dated 6/7/84.

+Operational TSC temporarily relocated to EOF pending completion of Millstone site TSC (tentatively mid-1985).

1D1.1 Detailed Control Room Design Review (DCRDR)

Requirements

Improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them. To accomplish this:

A. Conduct a control room design review to identify human engineering discrepancies. The review shall consist of:

   (i) The establishment of a qualified multidisciplinary review team and a review program incorporating accepted human engineering principles.

   (ii) The use of function and task analysis (that had been used as the basis for developing emergency operating procedures Technical Guidelines and plant specific emergency operating procedures) to identify control room operator tasks and information and control requirements during emergency operations. This analysis has multiple purposes and should also serve as the bases for developing training and staffing needs and verifying SPDS parameters.

   (iii) A comparison of the display and control requirements with a control room inventory to identify missing displays and controls.

   (iv) A control room survey to identify deviations from accepted human factors principles. This survey will include, among other things, an assessment of the control room layout, the usefulness of audible and visual alarm systems, the information recording and recall capability, and the control room environment.

B. Assess which human engineering discrepancies are significant and should be corrected. Select design improvements that will correct those discrepancies. Improvements that can be accomplished with an enhancement program (paint-tape-label) should be done promptly.

C. Verify that each selected design improvement will provide the necessary correction, and can be introduced in the control room without creating any unacceptable human engineering discrepancies because of significant contribution to increased risk, unreviewed safety questions, or situations in which a temporary reduction in safety could occur. Improvements that are introduced should be coordinated with changes resulting from other improvement programs such as SPDS, operator training, new instrumentation (REG. Guide 1.97, Rev. 2), and upgraded emergency operating procedures.

Status

By letter dated November 28, 1983, the licensee provided a schedule for completing the DCRDR. According to this schedule design details will be forthcoming by January 8, 1987, and the plans for this effort will be submitted to NRC by March 2, 1987. The schedule for implementation of the changes will be prepared by February 2, 1988.

1D1.2 DCRDR Summary Report

Requirement

Submit a summary report of the completed DCRDR outlining the proposed control room changes, including the proposed schedules for implementation. The report should also provide a summary a summary justification for human engineering discrepancies with safety significance to be left uncorrected or partially corrected.

Status

The licensee schedule for preparation of the Summary Report is February 2, 1988.

1D2 Safety Parameter Display System (SPDS)

Requirements

a. Provide a concise display of critical plant variable to the control room operators to aid them in rapidly and reliably determining the safety status of the plant. Although the SPDS will be operated during normal operations as well as during abnormal conditions, the principal purpose and function of the SPDS is to aid the control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core. This can be particularly important during anticipated transients and the initial phase of an accident.

b. Locate the SPDS convenient to the control room operators. This system should continuously display information from which the plant safety status can be readily and reliably assessed by control room personnel who are responsible for the avoidance of degraded and damaged core events.

c. Provide the operators with the information necessary for safe reactor operation under normal, transient, and accident conditions. The SPDS should be used in addition to the basic components and serves to aid and augment these components. Thus, requirements applicable to control room instrumentation are not needed for this augmentation (e.g., GDC 2, 3, 4 in Appendix A; 10 CFR Part 100; single-failure requirements). The SPDS need not meet requirements of the single-failure criteria and it need

not be qualified to meet Class 1E requirements. The SPDS should be suitably isolated from electrical or electronic interference with equipment and sensors that are in use for safety systems. The SPDS need not be seismically qualified, and additional seismically qualified indication is not required for the sole backup for SPDS. Procedures which describe the timely and correct safety status assessment when the SPDS is and is not available, should be developed by the licensee in parallel with the SPDS. Furthermore, operators should be trained to respond to accident conditions both with and without the SPDS.

d. Select the specific information for the SPDS based on engineering judgement.

e. The SPDS display shall be designed to incorporate accepted human factors principles so that the displayed information can be readily perceived and comprehended by SPDS users.

f. Provide sufficient information for plant operators to accurately assess

   (i) Reactivity control
   (ii) Reactor core cooling and heat removal from the primary system
   (iii) Reactor coolant system integrity
   (iv) Radioactivity control
   (v) Containment conditions

g. Submit a written safety analyses describing the basis on which selected parameters are sufficient to assess the safety status of each identified function for a wide range of events, which include symptoms of severe accidents.

Status

The licensee has scheduled integration of the SPDS with the ongoing programs to upgrade the process computer at Millstone-1. It is expected that the new replacement computer for M-1 will be in service by January 14, 1988 (NNECO 11/28/83 letter). On this basis, the safety parameters will be identified by January 8, 1987 and a safety analysis report will be submitted to NRC by April 9, 1987.

IIIA.1.2 Emergency Response Facilities (ERFs)

The Technical Support Center (TSC), Operational Support Center (OSC), and The Emergency Offsite Facility (EOF) are included as integral parts of the ERFs. The licensee plans to have the upgraded ERFs fully functional following Control Room Redesign and SPDS implementation by September 1988.

The final upgraded facilities will be considered acceptable when:

1. Physical Facilities

   a. Structures completed and operational
   b. Ventilation systems installed and operational
   c. All furniture and hardware in place
   d. All instrumentation and communications equipment installed and operational
   e. All radiation and meterological monitoring equipment and other equipment installed and operational

2. Data Acquisition Systems

   a. All hardware, firmware and software designed, installed and operational
   b. All detectors and indicators installed, connected to interrogation systems and operational
   c. All information displays and calculational models designed, installed and operational
   d. Verification of all data system displays and models complete and documented
   e. SPDS complete and operational if part of the data acquisition system

3. All necessary procedures completed in final form for operation of all facilities, instrumentation, equipment and functions.

4. Personnel trained to carry out ERF functions and operation of all data systems, communications, instrumentation and equipment.

5. All plant records, drawing and other information essential for determining plant accident status available to ERFS.

The TSC, OSC, and EOFs are discussed below in more detail:

<u>Requirements for Technical Support Center</u>

a. When activated it should be the onsite technical support center for emergency response staffed by predesignated technical, engineering, senior management, and other licensee personnel, and five pre-designated NRC personnel. During periods of activation, the TSC should operate uninterrupted to provide plant management and technical support to plant operations personnel, and to relieve the reactor operators of peripheral duties and communications not directly related to reactor system manipulations. It should perform EOF functions for the Alert Emergency class and for the Site Area Emergency class and General Emergency class until the EOF is activated when the emergency personnel have arrived.

b. Locate within the site protected area so as to facilitate necessary interaction with control room, OSC, EOF and other personnel involved with the emergency.

c. Accommodate and support NRC and licensee predesignated personnel, equipment and documentation in the center.

d. Build in accordance with the Uniform Building Code.

e. Control environment to provide room air temperature, humidity and cleanliness appropriate for personnel and equipment.

f. Provide radiological protection and monitoring equipment necessary to assure that radiation exposure to any person working in the TSC would not exceed 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

g. Provide reliable voice and data communications with the control room and EOF and reliable voice communications with the OSC, NRC Operations Centers and state and local operations centers.

h. Provide capability for reliable data collection, storage, analysis, display and communication sufficient to determine site and regional status, changes in status, forecasts and appropriate actions. The following variables should be available in the TSC:

   (i) the variables in the appropriate Table 1 or 2 of Regulatory Guide 1.97 (Rev. 2) that are essential for performance of TSC functions; and

   (ii) the meterological variable in Regulatory Guide 1.97 (Rev. 2) for site vicinity and National Weather Service data available by voice communication for the region in which the plant is located.

   Principally those data must be available that would enable evaluating incident consequences, mitigating actions, damages and determining plant status during recovery operations.

i. Provide with accurate plant records (drawings, schematic diagrams, etc.) essential for evaluation of the plant under accident conditions.

j. Staff with sufficient technical, engineering, and senior designated licensee officials to provide needed support, and be fully operational within approximately 1 hour after activation.

k. Design using good human factors engineering principles.

Status

By letter dated January 31, 1984, the licensee informed the NRC of the necessity to relocate the existing TSC which was located in the M-1 computer room to the Emergency Offsite Facility (EOF) on a temporary basis. The M-1 TSC will be permanently located within the

Millstone-3 facility currently nearing construction completion, but until this space is available the TSC will be within the EOF. Preparations for the installation of the replacement plant process computer necessitated this temporary relocation of the TSC. By letter dated April 2, 1984, the NRC approved the temporary relocation of the Millstone-1 TSC with the understanding that the TSC would be moved to its permanent location within the Millstone-3 facility by May 1985. The effectiveness of the TSC has been demonstrated during recent emergency exercises and drills at Millstone-1.

Requirements for Operational Support Center

a. The OSC should, when activated be the onsite area separate from the control room where predesignated operations support personnel will assemble. A predesignated licensee official shall be responsible for coordinating and assigning the personnel to tasks designated by control room, TSC and EOF personnel.

b. Locate onsite to serve as an assembly point for support personnel and to facilitate performance of support functions and tasks.

c. Provide capability for reliable voice communications with the control room, TSC and EOF.

Status

A suitable area near the Millstone-2 condensate polishing equipment has been designated as the OSC. Its effectiveness has been acceptably demonstrated during recent emergency exercises and drills at the Millstone-1.

Requirements for Emergency Operations Facility

a. Provide for the acquisition, display and evaluation of radiological and meteorological data and containment conditions necessary to determine protective measures. When the EOF is activated, it will be staffed by predesignated emergency personnel identified in the emergency plan. A designated senior licensee official will manage licensee activities in the EOF. The EOF is a licensee controlled and operated facility. The EOF provides for management of overall licensee emergency response, coordination of radiological and environmental assessment, development of recommendations for public protective actions and coordination of emergency response activities with Federal, State and local agencies.

b. Locate and provide with radiation protection features (as described in Table 1 of Generic Letter 82-33) and with appropriate radiological monitoring systems.

c. Accommodate and support Federal, State, local and licensee predesignated personnel, equipment and documentation.

d. Build in accordance with the Uniform Building Code.

e. Provide room air temperature, humidity and cleanliness appropriate for personnel and equipment.

f. Provide with reliable voice and data communications facilities to the TSC and control room, and reliable voice communication facilities to OSC and to NRC, State and local emergency operations centers.

g. Provide capability for reliable collection, storage, analysis, display and communication of information on containment conditions, radiological releases and meteorology sufficient to determine site and regional status, determine changes in status, forecast status and take appropriate actions. Variables from Table 1 of Regulatory Guide 1.97 (Rev. 2), including the meteorological variables for site vicinity and regional data available via communication from the National Weather Service shall be available in the EOF.

h. Provide with up to date plant records (drawings, schematic diagrams, etc.), procedures, emergency plans and environmental information (such as geophysical data) needed to perform EOF functions.

i. Staff during emergencies using Table 2 of GL 8?-33 as a goal. Reasonable exceptions to goals for the number of additional staff personnel and response times for their arrival should be justified and will be considered by NRC staff.

j. Provide for industrial security, when it is activated, to exclude unauthorized personnel and when it is idle to maintain its readiness.

k. Design taking into account good human factors engineering principles.

Status

Construction of the EOF building was completed and the facility was operable in July 1981 (Ref. NNECO 8/3/83 letter). The EOFs are described as substantial structures having protection factors greater than 500 from a semi-infinite cloud airborne source, both high efficiency particulate air filters and charcoal absorbers, concrete reinforced two-foot thick walls and ceilings, airtight doors upon activation, dedicated emergency diesel generators, kitchen facilities and decontamination facilities - located within 1 1/2 miles of the Millstone Nuclear Power Station. These features and the physical distance form the postulated radiation source, result in a sheltered facility that can be fully operational for any design basis accident. By letter dated June 7, 1984, the staff responded to NNECO letter dated February 3, 1984. NNECO had proposed, in this letter, consolidation of certain EOF functions at an alternate location in the

Corporate Emergency Operations Center in Berlin, Connecticut, approximately 40 miles from the Millstone Nuclear Power Station. The Corporate Emergency Operations Center is a facility with communications to the TSC where offsite officials gather to communicate with the plant in the unlikely event that they cannot reach the highly protected EOF because of the environmental radiological conditions near the EOF. The staff response noted that the Commission found the location of this alternate facility acceptable.

- IIIA2.2 Meteorological Data Upgrade

Requirements

Provide reliable indication of the meteorological variables (wind direction, wind speed, and atmospheric stability) specified in Regulatory Guide 1.97 (Rev. 2) for site meteorology. No changes in existing meteorological monitoring systems are necessary if they have historically provided reliable indication of these variables that are representative of meteorological conditions in the vicinity (up to about 10 miles) of the plant site. Information on meteorological conditions for the region shall be available via communication with the National Weather Service.

Status

By letter dated April 9, 1984, NNECO noted that Regulatory Guide 1.97 requirements for wind direction, speed, and stability are satisfied by the existing instrumentation. NRC letter dated March 11, 1985 concurs.

IIE4.2 Containment Isolation Dependability

Except for the following requirements, all the TMI lessons learned positions listed in NUREG-0737 item IIE.4.2 have been satisfied.

Requirements

Provide debris screens in the drywell to protect purge/vent valves.

Provide automatic closure of all purge/vent valves on signal of abnormal containment radiation level.

Assure standby gas treatment system (SGTS) integrity following loss of coolant accident (LOCA).

Test purge/vent valves with resilient seat material (i.e, leakage integrity tests) at 3 month intervals.

Status

The staff safety evaluation, dated February 25, 1985, is based on a number of submittals by the utility. The status of each of the above requirements was abstracted from the staff evaluation.

Debris screens: The utility has concluded that debris of the type that could prevent purge/vent valve closure is not expected. Pipe scale, if there is any, should not adversely affect valve closure capability due to the short length of upstream piping at containment isolation valves and the open flow path characteristic of the butterfly valves. The staff disagrees.

Automatic P/V valve closure on radiation signal: The licensee requires that a dedicated operator be stationed at panel 903 to monitor drywell conditions and close the purge/vent valves if there is any indication abnormal conditions within the containment environment. The 18 inch purge/vent valves are opened infrequently - i.e., during startups or shutdown when human access to containment is required. For these reasons NNECO has concluded that automatic valve closure from high containment radiation signal is not justified. The staff disagrees.

SGTS: The licensee has reported that the SGTS and purge inlet are automatically isolated if drywell containment pressure increases to 2 psig. If a design basis accident results in containment pressure increases of 20 to 43 psig the integrity of the SGTS cannot be assured. Valve-closure times up to 10 seconds are permitted by the Technical Specifications and following DBA, such pressures are possible. NNECO concluded that the probability of damage is low. The staff concluded however that the risk of SGTS damage is unacceptable.

Purge/Vent valve tests: The licensee contends that the Appendix J test frequency for these valves (2-year test interval) is adequate. The basis for this is that there has been no degradation to date more rapid than predicted by the manufacturer. The staff disagrees.

The staff safety evaluation, dated February 25, 1985, included consideration of the licensee alternatives for the remaining IIE4.2 requirements listed above but concluded that NNECO alternative actions were unacceptable. The NRC letter requested that NNECO commit to the NRC Requirements by mid April 1985.

IIID3.4 Control Room Habitability

Requirements

Assure that control room operators will be adequately protected against the effect of accidental release of toxic and radiocative gases and that the nuclear power plant can be safely operated or shutdown under design basis accident conditions. Criterion 19, "Control Room" of Appendix A, General Design Criteria for Nuclear Power Plants, to 10 CFR Part 50 requires that a control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition

during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Status

By letter dated November 7, 1984, NNECO proposed to amend its operating license by removing the required completion data for Item IIID3.4 of December 31, 1984 (NRC orders confirming licensee commitments on post TMI related issues dated March 14, 1983) and replacing it with "to be determined". The basis for this delay is that NUREG 0737 is to be reevaluated in its entirety and a new implementation schedule that reflects its safety significance is to be established as part of the Integrated Safety Assessment Program (ISAP) review of Millstone Unit 1. ISAP in its later phases of review is similar to the "Living Schedule" concept endorsed by the NRC in Generic Letter 83-20 issued May 9, 1983.

The staff had previously reviewed deferral of the modifications to satisfy control room habitability requirements (letter dated April 5, 1984) and concluded that the proposed delay was justified and acceptable. An earlier staff evaluation dated April 16, 1982 identified the outstanding commitments at that point in time.

Conclusion: All post TMI lessons learned items of NUREG 07[illegible] have been resolved satisfactorily for the Millstone Nuclear Power Station Unit 1 except for those included in Supplement 1 to NUREG 0737 issued as GL 82-33 on December 17, 1982 and two others concerning reactor containment integrity and control room habitability.

Numerous exchanges between NNECO and NRC have explored and evaluated alternatives to the NRC requirements for containment integrity causing the satisfactory resolution of TMI item II.E.4.2 requirement to slip beyond projected completion dates. The staff safety evaluation dated February 25, 1985 identifies the precise issues that must be resolved to satisfactorily close this TMI item.

Generic Letter No 82-33 specifically relaxes the earlier completion schedules for the emergency response items and permits a more relaxed schedule of implementation so that the related activities can be integrated to effectively utilize the various resources.

Similarly, delay in implementing the control room habitability TMI item III.D.3.4 will permit this TMI item to be included in an Integrated Safety Assessment Program (ISAP) and prioritized for more effective use of resources.

APPENDIX C
NUCLEAR REGULATORY COMMISSION (NRC)

C.1 Introduction

The NRC staff evaluates the safety requirements used in its reviews against new information as it becomes available. Information related to the safety of nuclear power plants comes from a variety of sources including experience from operating reactors; research results; NRC staff and Advisory Committee on Reactor Safeguards (ACRS) safety reviews; and vendor, architect/engineer, and utility design reviews. After the accident at TMI, the Office for Analysis and Evaluation of Operational Data was established to provide a systematic and continuing review of operating experience. Each time a new concern or safety issue is identified from one or more of these sources, the need for immediate action to ensure safe operation is assessed. This assessment includes consideration of the generic implications of the issue.

In some cases, immediate action is taken to assure safety, e.g., the derating of boiling water reactors as a result of the channel box wear problems in 1975. In other cases, interim measures, such as modifications to operating procedures, may be sufficient to allow further study of the issue prior to making licensing decisions. In most cases, however, the initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. If the issue applies to several or a class of plants the issue is evaluated further as a "generic safety issue." This evaluation considers the safety significance of the issue, the cost to implement any changes in plant design or operation and other significant and relevant factors to establish a priority ranking of the issue. Based on this ranking, resolution of the issue is scheduled for near term resolution, deferred until resources become available or dropped from further considerations.

These issues with the highest priority ranking are reviewed to determine whether they should be designated as "unresolved safety issues" (NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," dated January 1, 1978). However, as discussed above, such issues are considered on a generic basis only after the staff has made an initial determination that the safety significance of the issue does not prohibit continued operation or require licensing actions while the longer term generic review is underway.

These longer term generic studies were the subject of a Decision by the Atomic Safety and Licensing Appeal Board of the Nuclear Regulatory Commission. The Decision was issued on November 23, 1977 (ALAB-444) in connection with the Appeal Board's consideration of the Gulf States Utility Company application for the River Bend Station, Unit Nos. 1 and 2. These issues were also considered in the operating license proceeding Virginia Electric and Power Company (North Anna Nuclear Power Station, Unit Nos. 1 and 2), ALAB-491, NRC 245 (1978). A further discussion of these issues is contained in a decision by the Atomic Safety and Licensing Appeal Board in connection with its considerations of the Pacific Gas and Electric Company operating license application for the Diablo

Canyon Nuclear Power Plant, Units 1 and 2 (ALAB-728, issued May 18, 1983). In the ALAB-728 Decision, the Board stated with regard to an operating license proceeding that: "it would be helpful to us if the staff would include in an SER supplement an explanation of the unresolved safety issues affecting the facility under review and the reasons the facility could nonetheless safely operate pending resolution of those issues." This appendix is provided in response to the Board's request.

C.2 Unresolved Safety Issues

In a related matter, as a result of Congressional action on the Nuclear Regulatory Commission budget for Fiscal Year 1978, the Energy Reorganization Act of 1974 was amended (PL 95-209) on December 13, 1977 to include, among other things, a new Section 210 as follows:

UNRESOLVED SAFETY ISSUES PLAN

> SEC. 210. The Commission shall develop a plan providing for specification and analysis of unresolved safety issues relating to nuclear reactors and shall take such action as may be necessary to implement corrective measures with respect to such issues. Such plan shall be submitted to the Congress on or before January 1, 1978 and progress reports shall be included in the annual report of the Commission thereafter.

The Joint Explanatory Statement of the House-Senate Conference Committee for the Fiscal Year 1978 Appropriations Bill (Bill S. 1131) provided the following additional information regarding the Committee's deliberations on this portion of the bill:

SECTION 3 - UNRESOLVED SAFETY ISSUES

> The House amendment required development of a plan to resolve generic safety issues. The conferees agreed to a requirement that the plan be submitted to the Congress on or before January 1, 1978. The conferees also expressed the intent that this plan should identify and describe those safety issues, relating to nuclear power reactors, which are unresolved on the date of enactment. It should set forth: (1) Commission actions taken directly or indirectly to develop and implement corrective measures; (2) further actions planned concerning such measures; and (3) timetables and cost estimates of such actions. The Commission should indicate the priority it has assigned to each issue, and the basis on which priorities have been assigned.

In response to the reporting requirements of the new Section 210, the NRC staff submitted NUREG-0410 to Congress on January 1, 1978. This NUREG describes the NRC generic issues program. The NRC program was already in place when PL 95-209 was enacted and is of considerably broader scope than the unresolved safety issues plan required by Section 210. In the letter transmitting NUREG-0410 to the Congress on December 30, 1977, the Commission indicated: "the progress reports, which are required by Section 210 to be included in

future NRC annual reports, may be more useful to Congress if they focus on the specific Section 210 safety items."

It is the NRC's view that the intent of Section 210 was to ensure that plans were developed and implemented on issues with potentially significant public safety implications. In 1978, the NRC undertook a review of more than 130 generic issues addressed in the NRC program to determine which issues fit this description and qualify as unresolved safety issues for reporting to the Congress. The NRC review included the development of proposals by the NRC staff and review and final approval by the NRC Commissioners.

The review is described in a report, NUREG-0510, "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants - A Report to Congress," dated January 1979. The report provides the following definition of an unresolved safety issue:

> An Unresolved Safety Issue is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed that involves conditions not likely to be acceptable over the lifetime of the plants it affects.

Further, the report indicates that in applying this definition, matters that pose "important questions concerning the adequacy of existing safety requirements" were judged to be those for which resolution is necessary to (1) compensate for a possible major reduction in the degree of protection of the public health and safety, or (2) provide a potentially significant decrease in the risk to the public health and safety. Quite simply, an unresolved safety issue is potentially significant from a public safety standpoint and its resolution is likely to result in NRC action on the affected plants.

All of the issues addressed in the NRC program were systematically evaluated against this definition as described in NUREG-0510. As a result, 17 unresolved safety issues addressed by 22 tasks in the NRC program were identified.

An in-depth and systematic review of generic safety concerns identified between January 1979 and March 1981 was performed by the staff to determine if any of these issues should be designated as Unresolved Safety Issues. The candidate issues originated from concerns identified in NUREG-0660, "NRC Action Plan as a Result of the TMI-2 Accident"; from ACRS recommendations; from abnormal occurrence reports; and from other operating experience. The staff's proposed list was reviewed and commented on by the ACRS, the Office of Analysis and Evaluation of Operational Data (AEOD), and the Office of Policy Evaluation. The ACRS and AEOD also proposed that several additional Unresolved Safety Issues be considered by the Commission. The Commission considered the above information and approved the four Unresolved Safety Issues A-45 through A-48. A description of the review process for candidate issues, together with a list of the issues considered, is presented in NUREG-0705, dated March 1981. An expanded discussion of each of the new Unresolved Safety Issues is also in NUREG-0705. In addition to the four issues identified above, in December 1981 the Commission approved another issue, A-49, Pressurized Thermal Shock, as an Unresolved Safety Issue.

The issues are listed below. The number(s) of the generic task(s) (for example, A-1) in the NRC program addressing each issue is indicated in parentheses following the title.

Unresolved Safety Issues (Applicable Task Nos.)

(1) Waterhammer (A-1)
(2) Asymmetric blowdown loads on the reactor coolant system (A-2)
(3) Pressurized water reactor steam generator tube integrity (A-3, A-4, A-5)
(4) BWR Mark I and Mark II pressure suppression containments (A-6, A-7, A-8, A-39)
(5) Anticipated transients without scram (A-9)
(6) BWR nozzle cracking (A-10)
(7) Reactor vessel materials toughness (A-11)
(8) Fracture toughness of steam generator and reactor coolant pump supports (A-12)
(9) Systems interaction in nuclear power plants (A-17)
(10) Environmental qualification of safety-related electrical equipment (A-24)
(11) Reactor vessel pressure transient protection (A-26)
(12) Residual heat removal requirements (A-31)
(13) Control of heavy loads near spent fuel (A-36)
(14) Seismic design criteria (A-40)
(15) Pipe cracks at boiling water reactors (A-42)
(16) Containment emergency sump reliability (A-43)
(17) Station blackout (A-44)
(18) Shutdown decay heat removal requirements (A-45)
(19) Seismic qualification of equipment in operating plants (A-46)
(20) Safety implications of control systems (A-47)
(21) Hydrogen control measures and effects of hydrogen burns on safety equipment (A-48)
(22) Pressurized thermal shock (A-49)

Seven of the 25 tasks identified with the unresolved safety issues are not applicable to Millstone 1 because they apply to PWRs only. These tasks are A-2, A-3, A-4, A-5, A-12, A-26, and A-49. Also, Task A-8 is applicable only to Mark II BWR containments. With regard to the remaining tasks that are applicable to this facility, the NRC staff has issued NUREG reports providing its proposed resolution for eleven of these issues (Table 1). Each of these has been addressed in this Safety Evaluation Report or will be addressed in a future supplement. The Table I below lists those issues and the section of this SER in which they are discussed.

The remaining issues applicable to this facility are

A-17 Systems interaction in nuclear power plants
A-40 Seismic design criteria
A-43 Containment emergency sump reliability
A-44 Station blackout
A-45 Shutdown decay heat removal requirements
A-46 Seismic qualification of equipment in operating plants
A-47 Safety implications of control systems
A-48 Hydrogen control measures and effect of hydrogen burns on safety equipment

The Task Action Plans for Unresolved Safety Issues for which no staff NUREG report has been issued and for which work is continuing are provided in NUREG-0649, Revision 1, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants." Each Task Action Plan provides a description of the problem; the staff's approach to its resolution; a general discussion of the bases upon which continued plant licensing or operation can proceed pending completion of the task; the technical organizations involved in the task and estimates of the manpower required; a description of the interactions with other NRC offices, the ACRS, and outside organizations; estimates of funding required for contractor-supplied technical assistance; prospective dates for completing the task; and a description of potential problems that could alter the planned approach or schedule.

In addition to the Task Action Plans, the staff issues the "Office of Nuclear Reactor Regulation Unresolved Safety Issues Summary, Aqua Book" (NUREG-0606) on a quarterly basis; this report provides current schedule information for each of the Unresolved Safety Issues. It also includes information relative to the implementation status of each Unresolved Safety Issue for which technical resolution is complete.

The staff has reviewed the Unresolved Safety Issues listed above as they relate to Millstone 1. Discussion of each of these issues, including references to related discussions in the Safety Evaluation Report, is in Section C.3. Based on its review, the staff concludes for the reasons set forth in Section C.3 that there is reasonable assurance that Millstone 1 can be operated before the ultimate resolution of these generic issues without endangering the health and safety of the public.

C.3 Discussions of USIs as they Relate to Millstone Units 1

This section provides the NRC staff's evaluation of Millstone 1 for each of the applicable Unresolved Safety Issues. This includes the staff's bases for licensing before ultimate resolution of these issues.

Task A-17 Systems Interactions in Nuclear Power Plants

Millstone 1 was evaluated against licensing requirements that were founded on the principle of defense-in-depth. Adherence to this principle and conformance to the regulations (e.g., the General Design Criteria) results in design provisions such as physical separation and independence of redundant safety systems. Furthermore, the quality assurance program that is followed during design and construction contributes to the adherence to these provisions. Therefore the staff concludes that the design and construction as well as the licensing process can provide for a significant degree of plant safety with respect to the potential for adverse system interactions.

The Systematic Evaluation Program was initiated in 1977 to evaluate operating facilities to reconfirm and document their safety in light of the current regulatory requirements. The Systematic Evaluation Program derived a list of significant safety topics from existing issues. Although the 137 topics doe

not explicitly address systems interactions reviews, the acceptance criteria for some topics include reviews for hazards created by intersystem dependencies. the Systematic Evaluation Program also includes a systematic review of the operating experience of the plant under evaluation. The Systematic Evaluation Program has been completed for Millstone 1. Although the Systematic Evaluation Program objective was not intended to resolve USI A-17 on Millstone 1, the acceptance criteria for the topics within SEP are derived from the acceptance criteria within the SRP. Some of the acceptance criteria inherently address potentially adverse systems interactions. The corrective actions resulting from the SEP reviews will help preclude adverse systems interactions for the operating plants reviewed, in the same way the SRP review provides protection against systems interactions.

Operating reactor experience is continually monitored to detect precursors to various event sequences. As such events occur, corrective actions are taken for all affected facilities. Thus, the performance of a systematic review of older plants against current requirements and the continuing generic reaction to isolated events contribute to the prevention of adverse systems interactions in operating plants.

An additional measure of safety has been taken on all plants (both those operating and those under licensing review) in the area of operator information. Specifically, Generic Letter 82-33 (Supplement 1 to NUREG-0737), dated December 17, 1982 provided "Requirements for Emergency Response Capability." As part of these requirements, utilities will be adding a Safety Parameter Display System as well as demonstrating the adequacy of their post-accident monitoring capabilities as outlined in Regulatory Guide 1.97. Both these requirements, and the other requirements of that letter, will enhance the ability of the operator to perform mitigating actions in response to events including those due to adverse systems interactions.

Based on the foregoing discussion, the staff concludes that there is reasonable assurance that Millstone 1 can be operated before the ultimate resolution of this generic issue without endangering the health and safety of the public.

Task A-40 Seismic Design Criteria - Short-Term Program

NRC regulations require that nuclear power plant structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. Detailed requirements and guidance regarding the seismic design of nuclear plants are provided in the NRC regulations and in regulatory guides issued by the Commission. However, there are a number of plants with construction permits and operating licenses issued before the NRC's current regulations and regulatory guidance were in place. Task A-40 is, in effect, a compendium of short-term efforts to upgrade the Standard Review Plan to reflect the status of current technology and to support reevaluation of older operating plants.

Seismic reevaluation of the Millstone 1 facility is being conducted as part of the Systematic Evaluation Program (SEP). The development of site specific spectra at Millstone 1 was performed under the SEP program. The SEP conducted

a seismic review using the spectra specified in Regulatory Guide 1.60 with a peak ground acceleration of 0.2g. The seismic review for Millstone 1 has been completed and the results of the staff's evaluation are reported in NUREG-0824. However, a few open items were identified and presented in NUREG-0824. Resolution of these open items is being undertaken and will be reported in a supplement to the SER.

On the basis of these above consideration, and subject to the satisfactory resolution of the open items identified in NUREG-0824, the staff concludes that there is reasonable assurance that Millstone 1 can be operated before ultimate resolution of this generic issue without endangering the health and safety of the public.

Task A-43 Containment Emergency Sump Reliability

USI A-43 safety concerns deal with post-LOCA conditions which can degrade long term recirculation capability. For PWRs the containment emergency sump is the water source for RHR and CSS pumps, for BWRs the torus or wetwell suction intakes serve a similar function. These safety concerns deal with potential loss of pump NPSH margin due to: (a) air ingestion to the pumps, and (2) suction strainer blockage resulting from LOCA generated insulation debris being transported to the torus and being drawn onto the suction strainers.

These A-43 safety concerns have been investigated in full scale hydraulic experiments, by plant surveys and through generic studies. The findings have shown that vortexing and air ingestion are of much lesser concern than previously hypothesized.

Full scale experiments of BWR type suction strainers have demonstrated that for typical submergences and flow rates, the debris strainers act as effective vortex suppressors and that air ingestion levels are nearly zero (see NUREG/CR-2772). Thus for Millstone 1, air ingestion in the post LOCA period does not appear likely if design conditions are maintained.

With respect to debris blockage potential, the blowdown and transport of insulation debris to the torus region will be impeded by the plant design and layout. The breaks of principle concern are within the drywell. Direct blowdown to the torus will be impeded by baffles at the inlets to the torus downcomers, followed by transport to the suction strainers which is a function of the bulk fluid velocity in the torus, which is generally low. Furthermore, in Millstone 1, the insulation employed is a mix of reflective metallic and "blanket" type. Due to the elevation of the intakes (relative to the torus bottom) metallic debris will not likely be drawn to the intakes.

The "blanket" insulation debris, if it were fibrous in nature could gradually transport to the intakes since calculated near field velocities are on the order 1 to 4 ft/sec. Debris deposition and increasing head loss due to accumulation would then take place over a number of hours (i.e., 4 to 6). Since RHR flow is monitored, detection of the onset flow reduction could be compensated for by the operators by reducing recirculation flows. This would be possible since later in the LOCA sequences, the initially high ECCS flow rates are not required. Thus operator actions could be relied on to mitigate such a situation.

In the event that the resolution of USI A-43 identifies new requirements that apply to Millstone 1, they will be implemented after the resolution of USI A-43 is completed. Accordingly, the staff concludes that there is reasonable assurance that Millstone 1 can be operated before ultimate resolution of this generic issue without endangering the health and safety of the public.

Task A-44 Station Blackout

Electrical power for safety systems at nuclear power plants must be supplied by at least two redundant and independent divisions. The systems used to remove decay heat to cool the reactor core following a reactor shutdown are included among the safety systems that must meet these requirements. Each electrical division for safety systems includes two offsite alternating current power connections, a standby emergency diesel generator alternating current power supply, and direct current sources.

Task A-44 involves a study of whether or not nuclear power plants should be designed to accommodate a complete loss of all alternating current power, that is, a loss of both the offsite and the emergency diesel generator alternating current power supplies. This issue arose because of operating experience regarding the reliability of alternating current power supplies. There have been numerous reports of emergency diesel generators failing to start and run in operating plants during periodic surveillance tests. In addition, a number of operating plants have experienced a total loss of offsite electrical power, and more occurrences are expected in the future. In almost every one of these loss-of-offsite power events, the onsite emergency alternating current power supplies were available immediately to supply the power needed by vital safety equipment. However, in some instances, one of the redundant emergency power supplies has been unavailable. In a few cases there has been a complete loss of ac power, but during these events, AC power was restored in a short time without serious consequences.

A loss of offsite power involves a loss of both the preferred and backup sources of offsite power. If all offsite power were lost, the onsite emergency AC power system will provide AC power to safety-related equipment. With respect to emergency onsite AC power, the Millstone 1 emergency generators are powered by a diesel engine and a gas turbine. These systems have been evaluated as SEP Topic VIII-2 and found acceptable. The staff's evaluation is presented in Section 4.28 of NUREG-0824.

A loss of all AC power was not a design-basis event for the Millstone 1 facility. Nonetheless, a combination of design, operating, and testing requirements has been imposed to ensure that this unit will have substantial resistance to a loss of all alternating current and that, even if a loss of all AC power should occur, there is reasonable assurance the core will be cooled.

The current licensing criteria require licensees to provide redundant emergency AC power supplies, to demonstrate emergency AC power supply reliability (R.G. 1.108), and include the capability of removing decay heat using at least one

shutdown cooling train independent of AC power. Boiling water reactors contain various systems to remove core decay heat following the total loss of AC power. These systems at Millstone 1 consist of an isolation condenser which will provide an adequate heat sink for at least several hours. This allows time for restoration of AC power from either offsite or onsite sources.

Based on the above considerations, the staff concludes that there is reasonable assurance that Millstone 1 can be operated before the ultimate resolution of this generic issue without endangering the health and safety of the public.

Task A-45 Shutdown Decay Heat Removal Requirements

Following a reactor shutdown, the radioactive decay of fission products continues to produce heat (decay heat) that must be removed from the primary system. The principal means for removing this heat in a boiling water reactor at high pressure is through the steamlines to the turbine condenser. The condensate is normally returned to the reactor vessel by the feedwater system; however, the steam turbine-driven reactor core isolation cooling (RCIC) system is provided to maintain primary system inventory if ac power is not available. When the system is at low pressure, the decay heat is removed by the residual heat removal (RHR) systems. Work on this unresolved safety issue will evaluate the benefit of providing alternate means of decay heat removal that could substantially increase the plant's capability to handle a broader spectrum of transients and accidents. The study will consist of a generic system evaluation and will result in recommendations regarding the desirability of and possible design requirements for improvements in existing systems or an alternative decay heat removal method if the improvements or alternative can significantly reduce the overall risk to the public.

The Millstone 1 reactor has various methods for the removal of decay heat. As discussed above, the decay heat is normally rejected to the turbine condenser and condensate is returned to the vessel by the feedwater system. If the condenser is not available (for example, because of loss of offsite power), heat can be removed by means of the safety/relief valves to the suppression pool. The isolation condenser provides an alternate means of removing heat and supplying makeup water (i.e. condensate return) to the vessel. The isolation condenser is operated by natural convection. The single closed valve in the return condensate line is opened either automatically or manually, and reactor steam passes through the isolation condenser tubes boiling off water in the secondary side of the condenser. Makeup water to the secondary side of the condenser is provided by taking suction from the fire water tanks or the condensate storage tank. If the isolation condenser is not available, the high pressure feedwater coolant injection system (FWCI) will provide the reactor cooling.

If the isolation condenser and feedwater coolant injection are unavailable, the reactor system pressure can be reduced by the automatic depressurization system (ADS) so that cooling by the residual heat removal system can be initiated. When the condenser is not used, the heat rejected to the suppression pool is subsequently removed by the residual heat removal system. The staff's

evaluation of the Millstone 1 safe shutdown systems is presented in the final evaluation report on SEP Topic VII-3 "Systems Required for Safe Shutdown," dated May 1981.

On the basis of these considerations, the staff concludes that there is reasonable assurance that Millstone 1 can be operated before the ultimate resolution of this generic issue without endangering the health and safety of the public.

Task A-46 Seismic Qualification of Equipment in Operating Plants

The design criteria and methods for the seismic qualification of mechanical and electrical equipment in nuclear power plants have undergone significant changes during the course of the commercial nuclear power program. Consequently, the margins of safety provided in existing equipment to resist seismically induced loads and perform intended safety functions may vary considerably among plants licensed in different time frames. The staff has determined that the seismic qualification of the equipment in operating plants should be reassessed to ensure the ability of the equipment to perform its design safety functions during and/or after a seismic event. The objective of USI A-46 is to establish explicit guidelines that can be used to judge the adequacy of the seismic qualification of mechanical and electrical equipment at all operating plants instead of attempting to backfit current design criteria. This guidance will concern equipment required to perform a safety function, as well as equipment that is not required to perform a safety function, but whose failure could result in adverse conditions that might impair the safety functions of other equipment or systems.

The Systematic Evaluation Program, through the Senior Seismic Review Team, performed an audit of the Millstone 1 safety-related structures, systems, and components. The results of the audit are provided in NUREG/CR-2024. Most equipment was found to be capable of withstanding the Millstone 1 safe shutdown earthquake. In certain areas sufficient documentation was not available. Reanalysis and, in some cases, redesign or resupport are being conducted. The status of these items is provided in NUREG-0824 (February 1983).

In addition, the anchorage of major equipment was addressed. Experience from major earthquakes has shown that almost all seismically induced equipment failures in industrial facilities have occurred because the components were not adequately anchored to their foundations and that few equipment failures have occurred in equipment that was anchored. As a result of the review of electrical equipment anchorage, modifications to upgrade the anchorages of a number of safety-related electrical components at Millstone 1 were made.

NNEC has also been a participant in a Seismic Qualification Utility Group (SQUG) that has completed a pilot program to explore an alternative method for seismically qualifying selected nuclear plant components based on experience with similar equipment installed in non-nuclear facilities which have undergone strong motion earthquakes. Additional work on this program now underway is expected to provide for (1) the developing of qualification methodology for

installed equipment at operating plants, (2) a procedure for the review and assessment of equipment anchorages and supports and (3) possibly the qualifying of certain classes of equipment on a generic basis.

On the basis of the above discussion, the staff concludes that Millstone 1 can be operated before the ultimate resolution of this generic issue without endangering the health and safety of the public.

Task A-47 Safety Implications of Control Systems

This issue concerns the potential for transients or accidents being made more severe as a result of control system failures or malfunctions. These failures or malfunctions may occur independently or as a result of the accident or transient under consideration. One concern is the potential for a single failure--such as a loss of a power supply, short circuit, open circuit, or sensor failure--to cause simultaneous malfunction of several control features. Such an occurrence could conceivably result in a transient more severe than those transients analyzed as anticipated operational occurrences. A second concern is that a postulated accident could cause control system failures that would make the accident more severe than analyzed. Accidents could conceivably cause control system failures by creating a harsh environment in the area of the control equipment or by physically damaging the control equipment. Although it is generally believed that such control system failures would not lead to serious events or result in conditions that safety systems could not safely handle, indepth studies have not been rigorously performed to verify this belief. The potential for an accident that would affect a particular control system, and effects of the control system failures, may differ from plant to plant. Therefore, it is not possible to develop generic answers to all these concerns; it is possible to develop generic criteria that can be used for future plant-specific reviews. The purpose of this Unresolved Safety Issue task is to verify the adequacy of existing criteria for control systems or propose additional generic criteria (if necessary) that will be used for plant-specific review.

The Millstone 1 safety systems have been designed with the goal of ensuring that control system failures (either single or multiple) will not prevent automatic or manual initiation and operation of any safety system equipment required to trip the plant or to maintain the plant in a safe shutdown condition following any anticipated operational occurrence or accident. This has been accomplished by either providing independence between safety- and nonsafety-grade systems or providing isolating devices between safety- and nonsafety-grade systems. These devices preclude the propagation of nonsafety-grade system equipment faults so that operation of the safety-grade system equipment is not impaired.

Additional studies probing the interaction of safety and nonsafety systems were performed during Millstone 1 fire protection reviews in response to 10 CFR 50, Appendix R. Within designated fire zones, it was assumed that damage to any equipment (or its control cables, if affected) could cause failure of any type. The dedicated shutdown system proposed by NNEC as a result of the fire protection study will incorporate the required separation of safety and nonsafety systems.

Also, the licensee has been required (NRC Information Notice 79-22) to review the possibility of consequential control system failures that exacerbate the effects of high energy line breaks (HELBs) and adopt new operator procedures, where needed, to ensure that the postulated events would be mitigated. NNEC performed an evaluation of those potential harsh environment effects. By letter dated October 5, 1979, NNEC concluded that none of the scenarios identified in the information notice constituted potential failure modes that could compromise a safe shutdown of the Millstone 1 plant.

The staff is also evaluating the qualification program to ensure that equipment that may be exposed to HELB environments has been adequately qualified or an adequate basis has been provided for not qualifying the equipment to the limiting hostile environment. The status of this review is contained in the discussion of USI A-24.

In addition, IE Bulletin 79-27 was issued to the licensee requesting that evaluations be performed to ensure the adequacy of plant procedures for accomplishing shutdown on loss of power to any electrical bus supplying power for instruments and control. The licensee responded to this IE Bulletin by letter dated February 29, 1980. The staff reviewed the NNEC submittal and concluded that the response and design were acceptable.

On the basis of these above considerations, the staff concludes that there is reasonable assurance that Millstone 1 can be operated before the ultimate resolution of this generic issue without endangering the health and safety of the public.

Task A-48 Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

Following a loss-of-coolant accident in a light water reactor plant, combustible gases, principally hydrogen, may accumulate inside the primary reactor containment as a result of (1) metal-water reaction involving the fuel element cladding; (2) the radiolytic decomposition of the water in the reactor core and the containment sump; (3) the corrosion of certain construction materials by the spray solution; and (4) any synergistic chemical, thermal, and radiolytic effects of postaccident environmental conditions on containment protective coating systems and electric cable insulation.

Because of the potential for significant hydrogen generation as the result of an accident, 10 CFR 50.44, "Standards for Combustible Gas Control System in Light Water Cooled Power Reactors," and GDC 41, "Containment Atmosphere Cleanup," in Appendix A to 10 CFR 50, require that systems be provided to control hydrogen concentrations in the containment atmosphere following a postulated accident to ensure that containment integrity is maintained.

10 CFR 50.44 requires that the combustible gas control system provided be capable of handling the hydrogen generated as a result of degradation of the emergency core cooling system so that the hydrogen release is five times the amount calculated in demonstrating compliance with 10 CFR 50.46 or the amount corresponding to reaction of the cladding to a depth of 0.00023 inch, whichever is greater.

The accident at TMI-2 on March 28, 1979, resulted in hydrogen generation well in excess of the amounts specified in 10 CFR 50.44. It became apparent to NRC that specific design measures are needed for handling larger hydrogen releases, particularly for small, low-pressure containments. As a result, the Commission determined that a rulemaking proceeding should be undertaken to define the manner and extent to which hydrogen evolution and other effects of a degraded core need to be taken into account in plant design. An advance notice of this rulemaking proceeding on degraded core issues was published in the Federal Register (45FR65474) on October 2, 1980.

Recognizing that a number of years may be required to complete this rulemaking proceeding, a set of short-term or interim actions relative to hydrogen control requirements was developed and implemented. These interim measures were described in a December 2, 1981 Federal Register (46FR58484) Notice.

The interim measures require an inerted containment atmosphere for BWR Mark I and II containments. Millstone 1 uses a Mark I containment, which is inerted with nitrogen gas during power operation in order to preclude hydrogen burn. Based on the foregoing, the staff concludes that Millstone 1 can be operated before ultimate resolution of this generic issue without undue risk to the public health and safety.

C.5 References

U.S. Nuclear Regulatory Commission, NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," July 1977.

---, NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," January 1978.

---, NUREG-0460, "Anticipated Transients Without Scram for Light Water Reactors," Vol 4, March 1980.

---, NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Revision 1, July 1981.

---, NUREG-0606, "Office of Nuclear Reactor Regulation Unresolved Safety Issues, Aqua Book," issued quarterly.

---, NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," July 1980.

---, NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line and Nozzle Cracking," November 1980.

---, NUREG-0626, "Generic Evaluation of Feedwater Transients and Small Break Loss of Coolant Accidents in GE-Designed Operating Plants and Near-Term Operating License Applications," January 1980.

---, NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants," February 1980.

---, NUREG-0660, "NRC Action Plan as a Result of the TMI-2 Accident," May 1980.

---, NUREG-0705, "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plants, Special Report to Congress," March 1981. ---, NUREG-0744, "Resolution of the Task A-11 Reactor Vessel Materials Toughness Safety Issue," Vols I and II, Revision 1, October 1982.

---, NUREG-0800, "Standard Review Plan," July 1981.

---, NUREG-0802, "Safety-Relief Valve Quencher Loads Evaluation Report, BWR Mark II and III Containments," October 1982.

---, NUREG/CR-0660, "Enhancement of Onsite Emergency Generator Reliability," February 1979.

---, NUREG-0927, "Evaluation of Water Hammer Occurrence in Nuclear Power Plants," March 1984.

---, NUREG-0661, "Safety Evaluation Report, Mark I Containment Long-Term Program, Resolution of Generic Technical Activity A-7," July 1980.

---, NUREG-0824, "Integrated Plant Safety Assessment System Evaluation Program, Millstone Nuclear Generation Unit 1," February 1983.

---, NUREG/CR-2024, "Seismic Review of the Millstone 1 Nuclear Power Plant as Part of the System Evaluation Program," July 1981.

---, NUREG/CR-2772, "Hydraulic Performance of Pump Suction Inlets for Emergency Core Cooling Systems in Boiling Water Reactors," June 1982.

Table C.1 Unresolved Safety Issues (USIs) for which a resolution has been developed applicable to Millstone 1 addressed in this report

Task No.	NUREG Report and Title	SER Section
A-1	NUREG-0927, "Evaluation of Water Hammer Occurrence in Nuclear Power Plants"	5.2
A-6, A-7	NUREG-0661, "Safety Evaluation Report Mark I Containment Long-Term Program"	6.2.4 A-30
A-9	NUREG-0460, "Anticipated Transients Without Scram for Light Water Reactors," Vol 4. Final requirements provided in the ATWS Rule (46FR5721).	15.
A-10	NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking"	1.3 5.7
A-11	NUREG-0744, "Resolution of the Task A-11 Reactor Vessel Materials Toughness Safety Issue," Vols I and II, Revision 1.	5.4
A-24	NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Revision 1. Final Requirements provided in the Rule on Environmental Qualification (48FR2729).	8.6
A-31	SRP 5.4.7 and BTP 5-1, "Residual Heat Removal Systems," incorporate requirements of USI A-31.	5.6.2
A-36	NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants"	9.5
A-42	NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," Revision 1	5.3 A-31

APPENDIX D

Special Report on the Operation

of Millstone Unit 1 by the

Office of Inspection and Enforcement

IN CONNECTION WITH MILLSTONE UNIT 1

FULL-TERM OPERATING LICENSE

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INTRODUCTION

The Directorate of Regulatory Operations has prepared this report on the operations of the Millstone Point 1 Nuclear Power Plant for consideration by the Director, Directorate of Licensing, in connection with the Northeast Nuclear Energy Company's request for a full-term operating license. The report is based on the results of our inspection program, including a review of the licensee's reports; our evaluation of the operating experience of the plant; the performance of engineered safeguards; the adequacy of the operating and emergency procedures; and the competence of the operating organization.

CONCLUSION

The results of our overall inspection program show that Millstone Point Unit 1 has operated safely since initial startup in 1970. The performance characteristics of the reactor and other systems important to safety have been in accordance with design objectives with the exception of excessive vibrations in the feedwater spargers. Deviations from the Technical Specifications are indicated in this report. The operating organization has been generally responsive to Commission updated regulations and recommendations for safe practices. New regulations and regulatory standards have been promulgated. We will continue to evaluate the licensee's progress in these and the following areas during our inspection program:

1. Environmental Monitoring (Section VIII).

2. Site Emergency Planning (Section IX).

3. ALAP (Section VII).

Based on our review and evaluation, as presented herein, we conclude that the Provisional Operating License can be converted to a Full-Term Operating License with reasonable assurance that the health and safety of the public will not be endangered, predicated upon the licensees attention to Items 1-3 as listed above.

DISCUSSION

The operation of the Northeast Nuclear Energy Company, Millstone Point Unit 1 station has been reviewed on a continuing basis by the Directorate of Regulatory Operations since the issuance of the Provisional Operating License. This review was accomplished through a total of 42 inspections involving the expenditure of approximately 188 man-days at the plant site.

In addition to these inspections, we have had frequent informal contact with the operating organization and have reviewed the operating reports and other submissions to the NRC made by the Northeast Nuclear Energy Company. The significant results of the inspection program are discussed and evaluated below:

I. OPERATING HISTORY

Provisional Operating License No. DPR-21 was issued on October 7, 1970. Initial criticality was achieved on October 26, 1970 and commercial power operation was started in March 1971. A chronology of significant events given in Table I includes each outage since initial criticality. The number of reactor trips which have occurred and other pertinent operating statistics are summarized below:

Year	No. of Times Brought Critical	No. of Reactor Trips*	% of Time Critical	Thermal MWD/STU
1970	55	8	11.85	95.92
1971	186	27	70.82	3704.60
1972	8	4	59.01	3229.80
1973 (to 12-31-73)	39	7	53.50	1990.20
TOTAL (to 12-31-73	288	46	46.80	9020.52

* Unplanned trips from critical status (not manual). The dates and associated causes of reactor trips are given in Table II.

II. UNUSUAL OCCURRENCES

This section summarizes the more significant occurrences associated with the safety of the reactor since startup of the plant.

A. Reactor and Auxiliary Systems

1. On December 23, 1970 during startup testing, the select rod insert function failed upon initiation. The investigation revealed a wiring error had been made during a circuit change. The wiring error was corrected and the system functionally tested to insure system performance.

2. On four occasions (12/5/70, 12/10/71, 6/8/72 and 4/5/73) the isolation condenser failed to operate. In each case the failure of a valve was the cause of the malfunction. The cause was determined in each case, repairs made, the system tested and returned to service and the incident was reported to the AEC.

3. There have been three instances where a main steam isolation valve (MSIV) either failed to close or was slower than TS limits in closing (11/19/70, 11/21/70 and 8/29/71). The difficulty in each case was caused by sticking or sluggish operation of the main power slide valve due to crud build up. The problem was resolved by installing a filter in the air supply line and preventative maintenance on a routine basis.

4. The pressure control system malfunctioned 7 times during 1971 after initiation of commercial power operation. This was the first of the 100% bypass systems by GE and a number of problems were experienced. On two occasions the GE large steam turbine test engineers were called on to completely overhaul and tune the system. By the end of December 1971, all of the major problems had been resolved and since that date only minor problems have been experienced.

5. A setpoint drift on the automatic pressure relief (APR) valves (10/10/71) caused a pressure vessel blowdown from 1040 to 263 psig. The setpoint drift was caused by a relaxation of the pilot valve spring. The spring was designed to operate at 350°F but because of excess lagging the actual operating temperature was in excess of 500°F. The lagging was removed and the springs were replaced with springs made of higher grade material. On 2/9/72 another setpoint drift was discovered during surveillance testing. No major problems have been experienced with these valves since that date.

6. On August 29, 1972, one of the two safety valves was found to be leaking 5.6 gpm. The valve was replaced

with a spare. The valve was then inspected and foreign deposits were found on the pilot valve disc.

7. During the month of February 1972, problems were experienced with the main steam line flow restrictors vibrating. The restrictors were modified to reduce the vibrations and subsequently replaced with a new design.

8. A chloride intrusion into the pressure vessel was experienced on September 1, 1972, through sea water entering the condensate system when some of the main condenser tubes failed. The chlorides caused a gross failure of LPRM chambers and other damage to the primary system. The plant was shutdown six months for repairs, maintenance and flushing of systems.

9. On two occasions (3/21/73 and 9/22/73), a bearing failed on one of the condensate booster pumps. (The booster pumps are a part of the feedwater coolant injection system (FWCI)). On May 17, 1974, one pump experienced a bearing failure and a second pump a seal failure. On each occasion that FWCI subsystem was declared inoperable, the bearings were replaced and the pump functionally tested and returned to service.

10. Because of stress corrosion cracking during the chloride intrusion incident of item 8 above, all 145 control blades were replaced (January, 1973). The new blades contained a fabrication error consisting of the failure of GE to provide a specified chamfer at the junction weld between the CR blade sheath and the CR velocity limiter casting. Corrective action consisted of machining the specified chamfer on each control blade assembly at the Millstone site.

11. During July 1973, Millstone was informed by GE that some of their new control rods had entire sheaths and/or individual pins installed upside down. Millstone ran shutdown margin tests in July, September and December 1973, and found that the existing margin was more than adequate and that the possible defective blades had as yet no effect. Because of the possibility of future compaction of the boron carbide, Millstone is proposing to replace all 145 CR's during the summer of 1974.

12. During the six month outage starting September 1, 1972, the feedwater spargers were inspected and found degraded. The spargers were replaced with a new design and instrumented for testing and startup. During startup at greater than 85% of power, vibrations were observed above

desirable levels indicating a second failure and the licensee self imposed a restricted power of 80% of rated. The data obtained during the testing is being evaluated by the General Electric Company to design new spargers which will be installed during the summer of 1974.

13. On June 29, 1973, an examination of the shock suppressors showed that either no or insufficient hydraulic fluid was present in 19 of 44 units installed in the plant. The suppressors were modified to prevent leakage and refilled. A surveillance program was set up to insure that the shock suppressors remained operable.

14. On June 24, 1973, CR No. 18-35 was found to be uncoupled and repeated attempts proved that the rod could not be re-coupled. A subsequent change out of the associated rod drive unit failed to re-establish coupling integrity. The rod was fully inserted and electrically disarmed. The rod will be changed out during the next refueling outage (summer of 1974).

B. Radiological Controls

On four occasions during the last four months of 1971, the Naval Reactors Group (Groton), at Groton, Connecticut detected airborne activity at the Electric Boat Company from gaseous

effluents from Millstone 1 facility. The range of concentrations were measured to be from 2.5 to 5 x 10^{-9} μCi/cc. The range of stack release rates at Millstone were from 30,000 to 125,000 μCi/sec and the power level was reduced to maintain a release rate below 100,000 μCi/sec (TS limit is 800,000 μCi/sec). All leaking fuel elements were replaced during February 1973, and the stack release rate has been below 30,000 μCi/sec since that time.

C. Fish Kills

There have been two fish kills at Millstone. The first, August 1971, was 1" to 2" small fish being caught on the intake screens for the condenser cooling water. The second, May 1972, was 10" to 14" adult menhaden in the discharge quarry of the site. No cause could be determined for the first kill but the second was determined to be from thermal shock caused by the fish entering the warm water in the discharge quarry from the cold water of Long Island Sound. A permanent barrier was installed at the exit from the quarry so that fish can no longer enter the quarry.

D. Radiation in Unrestricted Area

Six construction workmen were excavating for foundations for a main station transformer sound isolation wall. Unknown to

them at the time was the fact that in one of the holes, they were removing the dirt over a section of the concrete encased 1.75 min hold up pipe and the off gas pipe. When it was determined that the latter was exposed the Health Physics Department was notified. A survey of the concrete encasement gave a dose rate of 200 mr/hr at 2 ft from the surface. The estimated dose to the 6 men ranged from 20 to 355 mrem. To prevent recurrence 1) a print was made showing all underground conduits and pipes on a site plot plan, 2) Health Physics will conduct surveys daily, during the work week, while there is construction on site, 3) there will be signs posted along the route of the off gas pipe and any other radioactive liquid or gas pipe stating "Caution Radioactive Pipe Buried. Do not dig without permission from Plant Management", 4) any excavation or digging on the operating site, shall require PORC approval, 5) Health Physics will be notified immediately if a pipe or conduit which is not in the composite drawing, is struck during excavation.

III. RADIOACTIVE WASTE DISPOSAL

A. Gaseous Effluents

Radioactive waste gases are released through the plant stack which provides dilution before dispersion of the radioactive material to the atmosphere. During normal operation, the

gaseous radwaste system operates on a continuous basis, with monitoring and control, allowing a hold up time of approximately 30 minutes to permit radioactive decay. Our inspection findings are that the gaseous activity releases during the period of the plant's operation have been substantially below the applicable AEC license limits as shown by Table III.

B. Liquid Effluents

There are four categories for sources of liquid radwaste with disposition as follows:

1. High purity from equipment drains accepts liquids in the waste collector tank and also the waste surge tank if needed. Processing consists of filtering and demineralizing. The processed liquid is sampled and returned to the condensate storage tank.

2. Low purity liquids from floor drains are routed to the floor drain collector tank. These wastes are filtered and stored. A sample analysis determines the rate at which these wastes are discharged to the effluent canal. The discharge activity and flow rates are continuously monitored during discharge.

3. Chemical waste from laboratory drains are collected in the waste neutralizer tank and concentrated in an evaporator. The distillate is routed to the high purity system for re-use. The concentrate is processed in the low purity system for ultimate discharge.

4. The detergent waste from laundry and decontamination operations are collected in a tank, filtered and either routed to the waste collector tank for recycle or discharged, depending upon the concentration of radioactivity.

   Our inspection findings are that the liquid activities released to the environment since the plant commenced operation have been substantially below applicable AEC license limits as shown by Table III.

C. Independent Measurement by Regulatory Operations

Regulatory Operations periodically performs independent measurements of liquid and gaseous radioactive effluents released from the Millstone Point facility. Results to date show that their analyses are adequate to identify and measure radionuclides in liquid and gaseous effluents.

IV. ENGINEERED SAFEGUARDS

A. Containment

Our inspection findings are that the integrity of the primary containment was demonstrated successfully during the performance of integrated primary containment leak rate testing in September 1970 and March 1973.

B. Emergency Electrical Power System

Our inspection findings are that the plant's diesel and gas turbine generators have been surveillance tested as per the Technical Specifications to verify proper operation of the emergency power system. Although the gas turbine has failed to start and accept load in the required 48 seconds, on 11 occasions as a result of a number of equipment failures and operator errors, which were promptly corrected, an emergency power supply has been available at all times. In June, 1974, discharge tests had not been conducted within the required time interval. The licensee has applied for a TS change from DL.

C. Emergency Core Cooling System (ECCS)

Our inspection findings are that there have been isolated problems experienced with the subsystems of the ECCS since

initial plant operation. The redundancy of subsystems, however, has proven to be adequate as the ECCS has always been available to meet Technical Specification requirements since plant startup. The principal problems that have been experienced are discussed below:

1. Monthly tests of the Low Pressure Coolant Injection (LPCI) and Core Spray subsystems have been performed to verify their operability. In January 1971, both injection valves on the LPCI and both injection valves on the core spray system failed. All four failures were not in the same mode, in that three of the valves failed to close. No back seat requirements existed with these valves and the opening torque switches were eliminated. The limit switches in the opening direction were utilized and the closing switches were reset as the manufacturer recommended. Since the margin to locked rotor motor output could be too low, under the new settings, later it was decided that the motors on the two LPCI valves were to be replaced. The valves were then successfully tested several times and then one of the core spray valves failed. The cause of this failure was due to the valve stem thread and the bushing nut's lack of lubrication. This resulted in the replacement of several stems and nuts that showed signs of wear and the institution of a lubrication program.

Low Pressure Coolant Injection Cross Tie Supports

During a licensee inspection of hangers on the core spray and LPCI suction headers in June 1972, it was discovered that one specified pipe restraint had been omitted and seven of the eleven pipe supports had subsequently been shifted by LPCI cross tie line deflection. The latter indicated that the 18 inch LPCI cross tie line had been subjected to horizontal deflections which caused damage to the pipe supports. Temporary wood shoring supports were installed to replace the damaged pipe supports at three points along the length of the LPCI cross tie line. The licensee and consultant's evaluation indicated that the movement which caused the damage probably occurred during the early operational phases of the system while the stay full line of the LPCI system was not in service. New pipe supports were subsequently fabricated and installed.

2. The surveillance requirements of the isolation condenser has been met since startup. During December 1970, the isolation condenser tripped on high flow and could not be reset. The condenser was modified to prevent recurrence. In December, 1971, the inboard condensate valve failed and in June, 1972, the outboard supply valve failed. These problems were promptly corrected.

3. The Feedwater Coolant Injection (FWCI) subsystem has been tested at required frequencies since plant operations commenced to demonstrate the operability of the system. On two occasions in 1973, the FWCI system was declared inoperable as a result of bearing failure in a condensate booster pump. In each case the alternate surveillances were performed and the bearings replaced.

D. High Energy Piping Restraints

During a turbine trip test at 50% power on December 9, 1970, the seismic restraint on the main steam line in the turbine plant failed. This restraint was designed for a seismic load of 3,000 pounds per pipe and additionally was designed to handle the load resulting from normal thermal movement. When the turbine stop valve closes a pressure wave is created at the valve which subsequently moves back up the steam line causing unanticipated dynamic loading of the piping restraints. At 100% power the associated pressure wave was calculated to be 120 psi. The force imposed on the seismic restraint by this effect was about 30,000 pounds per pipe. The seismic restraints were redesigned and reinstalled based on a design value of 60,000 pounds per pipe to provide a 100% margin.

Additional restraints were added both upstream and downstream of the seismic restraint to restrict twisting action. Multiple restraints were also added to the 10 main steam bypass lines to accomodate the total anticipated dynamic force for two lines acting simultaneously, plus a 50% margin.

V. SAFETY SYSTEM PERFORMANCE

A. Reactor Safety System

Our inspection findings are that performance of the sensors and associated circuits in the reactor safety system has been demonstrated in that the system has never failed to initiate a reactor trip signal whan a trip condition occurred. The plant instrumentation monitoring reactor power, system pressure, coolant flow, coolant temperature, vessel level and related parameters have been tested and calibrated as required by the Technical Specifications. Surveillance testing of the intermediate power range monitor and the reactor level switches trip setpoints were discovered to be out of limits on separate occasions; however, these occurrences were unrelated and did not inhibit the redundant circuitry from assuring proper plant protection.

About one and a half hours after the chloride intrusion incident of September, 1972, while the reactor was subcritical and in the process of being cooled down, 116 of 120 LPRM's failed. During the failure the source and intermediate range monitors were operable. The failures were common mode and intergranular corrosion was present, caused by the high chlorides and low pH water condition. Malfunctions of the LPRM's in the manner observed does not constitute a safety issue, for upon malfunction of specific numbers of detectors by any mechanism, reactor shutdown will result automatically due to APRM action.

B. Reactivity Control

Our inspection findings are that the rod system has performed satisfactorily since initial operation of the plant in that the rods have always responded to action-initiating signals. Two deficiencies relating to operation of the control rod system have been encountered. On one occasion in March, 1973, two control rods exceeded the Technical Specification limits for drop times. Subsequently the two drive units were rebuilt and the inner filter, which is in the water flow path during a reactor trip was found plugged. In July, 1973, a control rod drive went to the overtravel position indicating that the

rod was uncoupled. Repeated attempts did not recouple the rod and it was inserted and electrically disarmed. The drive and the rod will be changed out during the next refueling outage.

C. Reactor Pressure Relief System

Our inspection findings are that the pressure relief system has demonstrated its ability to protect the reactor from overpressure. During a turbine pressure control system malfunction in October, 1971, a pressure transient caused a reactor trip. The main steam isolation valves were manually closed and the resulting pressure increase caused the relief valves to operate. One of the relief valves stuck open for 18 minutes, cuasing a pressure vessel blowdown from 1040 psig to 263 psig. The pilot valve spring was determined to be the cause and the springs were replaced with springs of a new design in all valves.

VI. PRIMARY SYSTEM INTEGRITY

Our inspection findings are that the leakage from the primary system has been limited to leakage through valves, valve packings and recirculating pump seals. These conditions have caused outages for maintenance and repairs during the operating history of the plant.

On one occasion during August, 1972, the TS limit of 5 gpm was exceeded due to a safety valve leaking. The valve was changed out and the plant restarted. In March, 1974, the TS limit of 2.5 gpm (reduced value) was exceeded. In this instance inner packing on a recirculation system equalizer valve was leaking. The valve leak off was closed, the valve inspected at rated pressure and the plant restarted.

No significant problems affecting the integrity of the primary system have been encountered to date. Requirements for inservice inspection of the primary system boundary are established and the program is formulated. A part of the program was conducted during the 1972 refueling outage.

Methods of criteria for determining primary system leakage and procedures for responding to detected and suspected leakage have been implemented. The methods available to detect leakage include containment sump monitors and containment sump, sump pump flow integrators. In addition, drywell pressure, temperature and radioactivity measurements are also used as indicators of primary system leaks.

VII. RADIATION PROTECTION PROGRAM

A. Area Radiation & Airborne Radioactivity Monitoring Instrumentation

Thirty Area Radiation Monitors (ARM) are maintained. Locations and set points are identified in the Radiation Protection Procedures. Calibration is scheduled effective 1974 at 6 month intervals.

Continuous Air Monitors for particulates (CAM) are provided at 3 locations: outside the Control Room with suction on the Turbine Building deck, radwaste control room and second floor reactor building. These are supplemented by 2 low volume and 3 hi-vol air samplers which are used to evaluate particulate and radioiodine activity. The licensee, in a recent inspection, committed to a review of the airborne radioactivity monitoring program using ICRP Report 12, "General Principles of Monitoring for Radiation Protection of Workers", and ANSI N13.1, "Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities" as reference documents.

Effluent monitors are provided as follows: 2 NaI detectors monitoring measured volumes of stack effluent; 1 NaI detector on the side of the discharge line from the waste sample tanks

to the canal, and 1 NaI detector on the side of the service water discharge line to the canal.

Laboratory instrumentation for Health Physics consists of 2 GPM High Voltage Supply and scaler systems, (2 additional on order), 1 3" x 3" NaI detector and 1024 channel gamma analyzer, 1 60 cc GeLi detector and 4096 channel gamma analyzer and one well counter, high voltage supply and scaler.

Survey instrumentation consists of approximately 12 ion chamber type survey meters, 17 GM survey meters, 2 alpha meters, 12 "friskers", 4 portal monitors, and 1 neutron survey meter. Calibrations are scheduled, effective 1974, for 6 month intervals.

Instrumentation appear to be of types and quantity to enable adequate evaluation of radiological conditions encountered.

B. General Health Physics Operations and ALAP

1. Organization and Staffing

The Unit 1 and 2 Health Physics Programs are directed by the Health Physicist. HP staff is available to both units. Separate Chemistry staffs (and supervisors) are maintained for Units 1 and 2. Health Physics reports to

the Chemistry and HP Supervisor, and who in turn, reports to the Service Group Supervisor who reports to the Site Superintendent. Currently, 6 HP technicians are on board. Qualifications of supervising personnel appear to meet the ANSI N18.1-1971 Standard for Selection and Training for Nuclear Power Plant criteria.

2. Procedures

Radiation Protection Procedures have been under continual revision. The last revisions were approved by PORC April 2, 1974. ALAP is identified as an individual's responsibility but is not clearly identified in the policy statement which references Regulatory limits: (dated April 6, 1974): "It is the policy of the company to minimize personnel radiation exposure and always stay within the AEC and State regulations".

The first part of the RP procedures are general in nature and as a group are provided to employees as the radiation protection manual. The procedures require the use of RWP's to provide radiation safety where significant exposure is possible. Conditions requiring an RWP are specified. "Blanket" RWP's may be issued for routine

work by Operators, HP, Chemistry and for supervisory personnel inspections. A recent inspection revealed that the licensee failed to terminate an RWP following a change in radiological conditions as required by the procedures. This inspection also revealed failures to follow procedural requirements for investigating a suspected exposure to airborne radioactivity incident and to restrict personnel whose exposures were unevaluated from possible additional exposure. It was also noted that the procedures, which require a report on an exposure incident be written, do not specify to whom it goes and what use is to be made of it. Instances were noted where procedures call for certain actions to be taken but do not identify individuals who are responsible for assuring they are carried out.

3. Personnel Monitoring

External doses are monitored thru monthly film badges and self reading dosimeters. TLD's have been used on certain occasions to supplement this equipment to enable day-by-day monitoring of dose.

Internal exposure to radioactive material is monitored thru annual whole body counts of station personnel supplemented by more frequent counts as circumstances merit, e.g., a suspected exposure and fecal and urine analyses, as appropriate.

4. ALAP

The licensee does not strongly identify ALAP as a policy. There are no administrative limits on radiation exposure more restrictive than those identified in 10 CFR 20 except there exists a limitation of 300 m Rem for weekly exposure. The licensee does not evaluate man-rem doses except as a result of compliance with T/S requirements and 10 CFR 20.407(b).

C. Plant Cleanliness

Two recent inspections of the radwaste building by different inspectors resulted in adverse findings regarding housekeeping practices. Construction activities, partly associated with Unit 2 activities, and partly attributed to Unit 1 backfitting work and which involve contractor personnel have been identified as causes of poor housekeeping by the licensee. This subject is an unresolved item. Licensee representatives

stated positive efforts which include personal inspections by the Site Superintendent are being made to improve housekeeping.

D. Training

The HP staff indoctrinates all employees, company and non-company, in radiation protection, including 10 CFR 19. Lesson plans have been formulated. Retraining is currently being implemented in conjunction with the training requirements for Unit 2. The respiratory protection training program is consistent with T/S requirements and ANSI Z88.2 "Practices for Respiratory Protection" except that a recent inspection found that there are no provisions for testing the fit of respiratory protection facepieces under realistic test conditions, a procedural requirement. Also, although nasal surveys are reported to be performed on personnel following the use of respiratory protection equipment, a requirement for this practice is not documented.

VIII. ENVIRONMENTAL MONITORING PROGRAM

A. General

A detailed inspection of the facility's Environmental Monitoring Program was made in April 1973. The inspection revealed

four items of violation against the present Technical Specifications. In addition, the inspection identified several areas where improvements and changes were needed to satisfy current criteria for environmental monitoring as specified in Regulatory Guides 4.1 and 1.4/2. These recommendations have been forwarded to DL for review and incorporation into updated Technical Specifications, as appropriate. Millstone Point's non-radiological program, including such items as Thermal Plume Studies, Chlorination and other Water Quality Measurements, was reviewed in this inspection as well as all areas pertaining to the radiological program. The inspector verified that action was being taken and that overall upgraded environmental programs were scheduled for implementation in the near future.

IX. EMERGENCY PLANNING

An in-depth inspection of the facility's emergency planning was conducted in April, 1973. Criteria of Appendix E to 10 CFR 50, were considered to have been met, but the inspection indicated that emergency planning could be significantly upgraded in the areas of detailed implementation procedures, alternate control centers, and in particular arrangements with State agencies. (Questions have been raised with respect to the ability of the State of Connecticut

to effect an adequate emergency response to an incident at the Millstone site). The facility's plant management anticipates completion of this upgrading prior to issuance of the full term operating license for Millstone Unit No. 2. Personnel training in revised procedures and a full scale drill are planned in conjunction with this action.

X. NONCOMPLIANCE ITEMS

The plant has been operated in accordance with the requirements of the facility license and the rules and regulations of the Commission except for the following instances of noncompliance:

1. Surveillance Test Number 608.8 which was performed on November 4, 1970, showed that the measured closing times of the cleanup demineralizer system valves 1-CU-2 and 1-CU-5 were 18.1 seconds and 19.0 seconds, respectively. Table 3.7.1 of the Technical Specifications requires that the closing times for these valves be $\leq$18 seconds. This failure to meet T.S. limits was not reported in accordance with the requirements as specified in Section 6.6.A.1 and 6.6.B.1 of the Technical Specifications.

2. The 0800 hour to 1600 hour shift on November 27, 1970, failed to check the status, in the control room, of the pressure and level alarms for each accumulator as required by Section 4.3.D of the Technical Specifications.

3. On December 2, 1970, the reactor operators failed to follow station emergency procedures and trip the turbine following a reactor scram caused by too rapid a release of a bypass button during the performance of a setpoint adjustment on the proportional band of the "B" recirculation pump.

4. On December 8, 1970, the cleanup demineralizer isolation valve (1-CU-28) could not be reopened, following system isolation, because of a galled driving nut on the valve drive mechanism. The reactor was shutdown on December 9, 1970, and the valve drive mechanism was replaced. This failure of the cleanup system isolation valve was not reported in accordance with the requirements as specified in Sections 6.6.A.1 and 6.6.B.1 of the Technical Specifications.

5. Contrary to the requirements, as specified in 10 CFR 50.59, no written documentation was available when facility records were audited on January 20, 1971, to substantiate the basis for the determination that the modification made to the Millstone 1 auxiliary power fast transfer system did not involve an unreviewed safety question.

6. On January 10, 1971, with the reactor operating at rated pressure and 100% of rated power, the simultaneous full closure of all main steam isolation valves was initiated to test the reactor transient behavior under these circumstances. During

this test, an apparent malfunction of the feedwater valve controls caused the reactor vessel water level to increase to approximately 20 inches below the main steam line nozzles and subsequently pressurize the reactor vessel until two main steam relief valves opened. This apparent failure of the feedwater valve controls was not reported in accordance with the requirements as specified in Sections 6.6.A.1 and 6.6.B.1 of the Technical Specifications.

7. The licensee failed to comply with applicable Technical Specifications and establish a cold shutdown condition within 24 hours when test data for the emergency service water pumps did not indicate the required flow-head requirements were being met.

8. T.S. 6.1.1.f.(2) - The Nuclear Review Board (NRB) failed to report in writing to the President of the Millstone Point Company the results and recommendations relating to their September, 1971 audit.

9. On August 7, 1971, the rod worth minimizer was disabled and placed in bypass. While bringing the reactor critical in Rod Group 6, Sequence B-1, Rod 50-23 was notched out to Notch 20. Sequence B-1 limits Rod 50-23 to Notch 12 while in Rod Group 6 per Technical Specification 3.3.B.3.b.

10. The plant Operating Review Committee (PORC) failed to investigate AO-71-23 and recommend corrective action in writing to the Chairman of the Nuclear Review Board (NRB) per T.S. 6.1.1.d. (5).

11. The NRB failed to investigate AO-23 per TS 6.1.1.d.(5).

12. Contrary to the requirements of Paragraph 4.5.B.2 of the Technical Specifications, when an ESW pump was determined to be inoperable on October 25, 1970, November 4, 1970, and May 20, 1971, the remaining pumps in the containment cooling subsystem were not demonstrated to be operable immediately and the remaining ESW pumps were not demonstrated to be operable daily thereafter.

13. Contrary to the requirements of Paragraph 4.5.F.3 of the Technical Specifications, the gas turbine generator had been inoperable from 1735 hours to 1937 hours on November 30, 1971, but action was not taken to demonstrate operability of required equipment.

14. Contrary to the requirements of Paragraph 6.1.E.1.a of the Technical Specifications, the members of the Nuclear Review Board did not collectively provide expertise in metallurgy.

15. Contrary to the requirements of Paragraph 6.1.E.1.c of the Technical Specifications, a quorum of the NRB was not present for meeting No. 71-3.

16. Contrary to the requirements of Paragraph 6.1.E.1.d(2) of the Technical Specifications, no audit of station operations was made by the NRB during the period October 7, 1970, to September, 1971.

17. Contrary to the requirements of Paragraph 6.1.E.1.d(3) of the Technical Specifications the NRB did not make an adequate review of design change 13-72.

18. Contrary to the requirements of Paragraph 6.1.E.1.f(3) of the Technical Specifications, during NRB meeting No. 72-5, a TS violation was not reviewed specifically to recommend actions to prevent recurrences.

19. Contrary to the requirements of Paragraph 6.1.E.1.g of the Technical Specifications, the NRB did not have written administrative procedures for its operations.

20. Contrary to the requirements of Paragraph 6.1.E.2.d(7) of the Technical Specifications, the Plant Operations Review Committee (PORC) did not have a systematic approach for the review of plant operations.

21. Contrary to the requirements of Paragraph 6.2 of the Technical Specifications, several deficiencies in the development, review, approval and implementation of procedures were noted.

22. Contrary to the requirements of Paragraph 6.3 of the Technical Specifications, required actions were not taken when Limiting Safety System Settings were exceeded on March 3, 1971; May 12, 1971; May 15, 1971; October 12, 1971; April 9, 1972; April 19, 1972; May 12, 1972; and June 16, 1972.

23. Contrary to the requirements of 10 CFR 50.59, there was no written safety evaluation for the design modification which added a two-inch connection to the plant air system so that portable air compressors could be connected during periods of high air consumption.

24. Contrary to the requirements of Appendix B to 10 CFR 50, Criterion V, several surveillance test procedures do not have adequate acceptance criteria.

25. Contrary to the requirements of Appendix B to 10 CFR 50, Criterion XII, no program for calibrating installed instruments had been established.

26. Contrary to the requirements of Appendix B to 10 CFR 50, Criterion XVII, test results were not fully recorded for Test Numbers 602.8 and 602.22.

27. The licensee operated the reactor with both conductivity and chlorides in excess of Technical Specification requirements.

28. The Plant Operations Review Committee (PORC) meeting minutes (up to October 3, 1972) failed to record that a prompt review was made of the abnormal occurrence of the chloride intrusion into the reactor on September 1, 1972.

29. There were no detailed and approved flush procedures, acceptance criteria for flushes or flush program found on October 27, 1972, to provide assurance that the systems were free of chloride contaminated water.

30. On October 17, 1972, there was no overall documented and approved licensee program and detail procedures to assure the quality, conduct, and implementation of the chloride intrusion incident investigation.

31. The licensee did not perform certain activities directly related to the reliability of critical non-destructive test results, in violation of Criterion V, Appendix B, of 10 CFR 50.

32. A non-destructive test was performed without evidence of review and approval by authorized personnel in violation of Criterion VI, Appendix B, 10 CFR 50.

33. The NRB failed to audit station operations as required by Technical Specifications (since April 12, 1972).

34. The NRB failed to investigate abnormal occurrence No. 72-15 as required by Technical Specifications.

35. The PORC approved and placed in use a revised surveillance procedure without proper review.

36. Records of periodic surveillance checks indicate instances during 1972, when protective switches tripped out of ranges stated by the Technical Specifications.

37. Records of periodic surveillance checks indicated that on July 13, 1972, three of the four reactor vessel high pressure protective switches apparently tripped at 2 to 11 psig above the 1085 psig maximum limit stated by the Technical Specifications.

38. Records of surveillance test during refueling indicated that 3 protective switches and 3 time delay follower relays tripped outside of the range specified in the Technical Specifications.

39. Records of periodic surveillance checks indicated two instances during 1972 when one or more of the high flow protective switches for the reactor isolation condenser apparently tripped outside the range specified in the Technical Specifications.

40. Records of periodic surveillance checks indicated that on July 19, 1972, three time delay relays in the average power range monitor system logic circuitry apparently tripped later than specified by the Technical Specifications.

41. Records indicate that periodic checking of the pressure suppression chamber reactor building vacuum breakers was not performed up to November 21, 1972, although the Technical Specifications require quarterly checks.

42. Records indicate that the radiation limits given by 10 CFR 20.105 for unrestricted areas apparently were exceeded during March 15-21, and again on July 24, 1972, when pipes that conduct radioactive gas to the exhaust stack were uncovered.

43. Records indicate that on August 29 and 31, 1972, an unidentified reactor primary coolant leakage apparently exceeded the T.S. limit of 5 gpm.

44. Accumulator plating failures were not reported as required by Technical Specification 6.6.A.1.

45. Contrary to Appendix B of 10 CFR 50, 145 control elements were purchased, installed, and used in the reactor and subsequently found upon inspection to be nonconforming and to require re-work.

46. Certain detail requirements of 10 CFR 50, Appendix B, have been omitted from the quality assurance program for the operation phase.

47. Contrary to Technical Specification 4.5.C.3., the Automatic Pressure Relief Subsystem was not demonstrated to be operable immediately after the Feedwater Coolant Injection Subsystem was declared inoperable.

48. Contrary to Paragraph V.4.3 of Appendix H (Chloride Intrusion Incident), a summary of the weekly overall Control Rod Drive System review was not being maintained.

49. The Environmental Monitoring Program was not conducted as described in Section 4.8 of the Technical Specifications, as follows:

   a. Air Particulate sampling was not conducted continuously from 11 locations.

   b. Well water was not sampled from one of three locations as of January, 1972.

   c. No milk samples were obtained for the first half of 1972.

   d. Bottom sediment was not sampled within 500 feet of the discharge for the first and third quarters of both 1971 and 1972.

50. Violations of the requirements of Criteria I, II, III, IV, V, VI, IX, X, XV, XVI, and XVIII of Appendix B were identified during a QC/QA inspection.

51. Violations of the requirements of Criteria V and VI were identified with regard to the Feedwater Sparger Installation Procedure for Weld Pad Build-up and associated work items.

52. No documentary evidence in the site contractor's QC records to assure that the maximum allowable amperage specified by ISE-WS-817 was not exceeded.

53. The Reactor Vessel Clean-Up Procedure as issued, reviewed, and approved did not require QC verification that activities had been satisfactorily completed.

54. Contrary to 10 CFR 50.59, a plant design change was completed in March, 1971, which was subsequently determined to constitute an unreviewed safety question.

55. Contrary to Technical Specification 4.9.B.2.b. the quarterly surveillance requirement was not performed on the station battery in June, 1973.

56. Contrary to Technical Specification 4.9.B.2.a. the temperatures of all adjacent cells to the pilot cells were not measured between January 1 and March 12, 1973.

57. The Nuclear Review Board had reviewed only 35 of 131 minutes of the Plant Operating Review Committee for the year 1973.

58. Contrary to Technical Specification 6.4.B failures to maintain and adhere to radiation protection procedures were identified as follows:

    a. Three (3) employees failed to notify all persons to vacate an area involving a spill of radioactivity and the presence of airborne activity.

    b. Two (2) individuals exposed to airborne radioactivity on March 25, 1974, were not restricted in their work assignments until their exposures were evaluated.

    c. A Shift Supervisor did not terminate the applicable RWP following the airborne radioactivity problem on March 25, 1974, and a determination by Health Physics that conditions had changed.

    d. An investigating committee had not conducted an official investigation of the March 25, 1974 incident.

    e. Potential users of respirators did not test facepiece fit under realistic test conditions.

59. Contrary to T.S. 6.4.B.2.f protection factors in excess of those specified were assigned to respiratory protection equipment.

60. Contrary to T.S. 3.6.D unidentified leakage limits in excess of 2.5 gpm were exceeded.

61. Contrary to T.S. 4.9.B.c battery testing was not conducted at the required frequency.

62. Contrary to T.S. 3.6.A.1 the average rate of reactor coolant change exceeded 100° during a reactor cooldown.

XI. OPERATING ORGANIZATION

The basic organization structure for the plant is shown in Figure 1, attached. There have been a number of changes in personnel due to Millstone's program for training and upgrading of middle management employees. Certain site management personnel have been transferred to Units 2 and 3's staff but are still used to aid the Unit 1 staff as necessary. On May 16, 1973, the present operating organization was established to begin staffing of Units 2 and 3. The plant superintendent is the same person for all three units with an assistant plant superintendent for each unit.

The Safety Committees have generally functioned as required by the Technical Specifications, however, during the early months of operation, it appeared that several operating events had not received the full attention of management. As a result of AEC discussions with Utility Management and related formal correspondence, audits were begun and both committees begin to function more formally.

The personnel comprising the reactor operating organization and supporting staff have the experience and training needed to satisfy the Technical Specifications.

Records of plant operations are being maintained in accordance with administrative orders and the requirements of the Technical Specifications.

The Millstone plant staff has generally demonstrated itself to be competent to operate the plant in a safe manner.

XII. PHYSICAL PROTECTION PROGRAM

The revised physical protection plan was submitted June 29, 1973. This plan was accepted by DOL by letter dated May 24, 1974, upon full implementation of all requirements by June 15, 1974. Regulatory Operations inspection of plan implementation is imminent.

TABLE I

CHRONOLOGY OF OPERATION

October 7, 1970	Core loading began
October 17, 1970	Core loading completed
October 26, 1970	Initial criticality achieved
October 27 - November 8, 1970	Outage for repairs to gas turbine and cleanup system (AO-70-3)
October 30, 1970	Zero power test program completed
November 16, 1970	Outage for repairs to cleanup system
November 22 - November 25, 1970	Outage for turbine balance and training
December 6, 1970	25% power test program completed
December 8, 1970	Outage to repair cleanup system valve to reactor (AO-70-4)
December 23, 1970	Outage to repair weld or main condenser
December 27, 1970	50% power test program completed
December 29, 1970	Outage to repair bypass valve linkage
January 1, 1971	75% power test program completed
January 2, 1971	Outage due to high level in drain tank
January 3, 1971	100% power test program completed
January 14, 1971	Outage to repair condenser leak
January 17, 1971	Outage to conduct overspeed trip tests of the turbine

ary 25, 1971	Outage to effect repair of Core Spray Injection Valves and to reset turbine over-speed trips (AO-71-2)
January 27, 1971	Outage to repair traveling screen and circulating water pump
January 30 and 31, 1971	Outage while conducting hot AEC demonstration criticals
February 19, 1971	Outage to conduct SUT No. 17, Generator load reject from 100% power
March, 1971	Commercial operation begun
March 2, 1971	Outage to repair leak on main steam line safety valve blank flange
March 12, 1971	Outage due to high level in moisture separator drain tank
April 9, 1971	Outage for planned maintenance
April 14, 1971	Outage to repair commutator rings and brushes on recirc M-G Sets A and B
April 22, 1971	Outage due to high level in moisture separator drain tank
May 1, 1971	Outage to effect repair of a condensate test line
May 12, 1971	Outage to repair an air leak in the drywell
May 30, 1971	Outage to repair steam leak at a flange on the main steam line
June 5, 1971	Outage for general maintenance

e 11, 1971	Outage due to high level in moisture separator drain tank
June 24, 1971	Outage due to turbine full load reject
August 30, 1971	Outage to repair traveling screen
September 22, 1971	Outage to investigate problem with emergency service water pumps (AO-71-17)
October 3, 1971	Outage to repair turbine control valve
October 20-22, 1971	Outage for training criticals
October 22, 1971	Outage due to failure of "B" APR to Seat
October 24, 1971	Outage due to "B" APR bellows leak
December 11, 1971	Outage to work on Isolation Condenser inboard return isolation valve (AO-71-26)
February 11, 1972	Outage to repair leaky main steam line blank flange gaskets in the drywell
February 14, 1972	Outage to investigate improper response of main steam line Venturi dp cells (AO-72-1)
February 23, 1972	Outage to repair main steam line Venturi (AO-72-8)
August 29, 1972	Outage due to excess leakage to drywell floor drain sump (AO-72-21)
September 1, 1972 to March 8, 1973	Outage for refueling

[illegible] 9, 1973	Outage due to high level in moisture separator
March 10, 1973	Outage due to excessive turbine vibration
March 11, 1973	Outage to repair Main Steam Isolation Valve
March 13, 1973	Outage to investigate reactor recirc pump oil level alarm
March 19, 1973	Outage to investigate reactor recirc pump lube oil alarm
April 18, 1973	Outage for reactor vessel inspection requirements as a result of chloride intrusion incident
April 18, 1973 to July 13, 1973	Outage for reactor vessel inspection requirements as a result of chloride intrusion incident and feedwater sparger replacement
July 16, 1973	Outage due to inverted poison pins in the control rods
August 10, 1973	Outage due to instrument defect (reactor water level)
August 13, 1973	Outage for maintenance on reactor water level instruments
September 14, 1973	Outage to inspect hydraulic shock absorbers and conduct shutdown margin tests
October 6, 1973	Planned shutdown to test recirc pump motor and inspect shock absorbers

October 27, 1973	Planned shutdown to run recirc loop test
November 23, 1973	Planned shutdown to inspect shock absorbers
December 21, 1973	Outage to replace a recirc pump motor and shutdown margin tests

TABLE II

REACTOR SCRAMS

October 27, 1970	Reactor trip (AO-70-3)
November 19, 1970	Reactor trip due to inadvertent closure of main steam isolation valves
November 21, 1970	Reactor trip due to inadvertent closure of main steam isolation valves
December 2, 1970	Reactor trip during Startup Test (SUT) No. 15, recirc flow changes
December 3, 1970	Reactor trip during SUT No. 12, main steam isolation valve closure
December 4, 1970	Reactor trip during SUT No. 29, turbine trip with a total loss of off-site power
December 5, 1970	Reactor trip due to spurious low level
December 9, 1970	Reactor trip during SUT No. 16, turbine trip at 50% power
January 10, 1971	Reactor trip during SUT No. 12, Main Steam Isolation Valve closure from 100% power
January 15, 1971	Reactor trip during SUT No. 17, generator load reject from 100% power
January 19, 1971	Reactor trip when ECCS Motor Operated valves failed to operate during test (AO-71-1)
February 2, 1971	Reactor trip due to spurious low reactor water level trip

February 14, 1971	Reactor trip during SUT No. 17, 100% Turbine Generator Load Reject (Manual trip)
February 15, 1971	Reactor trip due to a turbine trip on high level in a moisture separator drain tank
February 16, 1971	Reactor trip during SUT No. 16, Turbine trip from 100% power
February 18, 1971	Reactor trip during SUT No. 17, generator load reject from 100% power
February 21, 1971	Reactor trip due to a turbine trip (AO-71-5)
March 23, 1971	Reactor trip while testing turbine control valve, due to pressure transient that resulted in flux perturbation (AO-71-6)
April 19, 1971	Reactor trip due to spurious low reactor water level trip
April 19, 1971	Reactor trip due to a main steam line sensing line leak
April 21, 1971	Reactor trip on high level in a moisture separator drain tank
May 25, 1971	Reactor trip due to control valve malfunction which caused a low reactor water level (AO-71-11)
May 27, 1971	Reactor trip due to failed shut turbine control valves resulting in high flux (AO-71-12)
June 25, 1971	Reactor trip (manual) due to full load reject and turbine trip resulting in loss of normal power
June 26, 1971	Reactor trip due to spurious IRM trip while pulling a critical

August 6, 1971	Reactor trip due to operator error during normal plant shutdown
August 12, 1971	Reactor trip due to a high level in a moisture separator drain tank
August 28, 1971	Reactor trip due to failure of traveling screens and consequent loss of circ water pumps
August 30, 1971	Reactor trip due to main condenser low vacuum
September 23, 1971	Reactor trip on low pressure due to operator error (AO-71-18)
September 29, 1971	Reactor trip due to a malfunction in the turbine pressure control system (AO-71-19)
October 10, 1971	Reactor trip due to a high-flux condition as a result of a severe turbine control valve transient (AO-71-20)
December 11, 1971	Reactor trip due to an instrumentation error on main steam line flow detectors
December 11, 1971	Reactor trip due to inadvertent make-up of the 600 psi reactor pressure switches
December 12, 1971	Reactor trip while recalibrating the 600 psi reactor pressure switches
December 20, 1971	Reactor trip due to electric pressure regulator failure (AO-71-27)
February 4, 1972	Reactor trip due to high flux caused by induced pressure oscillations resulting from turbine stop valve testing (AO-72-2)

, 1972	Reactor trip while testing thrust bearing wear detector which induced a turbine trip
March 12, 1972	Reactor trip due to a low level in reactor vessel
August 18, 1972	Reactor trip on turbine trip during testing of thrust bearing wear detector
September 1, 1972	Reactor trip (manual) when survey of coolant chemistry indicated excessive values (AO-72-22)
March 6, 1973	Reactor trip due to low reactor water level
March 14, 1973	Reactor trip due to low reactor water level
July 30, 1973	Fault in reactor water level transmitter
August 10, 1973	Fault in reactor water level transmitter
August 10, 1973	High reactor water level due to operator error
August 15, 1973	Trip caused by fault in mode switch
September 21, 1973	Fault in EPR/MPR caused Group I isolation
December 7, 1973	Reactor water level instrument rack bumped

(Total of 49 trips, 3 of which were manual).

TABLE III

RADIOACTIVE RELEASES

...E RELEASES	1970	1971	1972	1973
Total Noble Gases (Ci)	4.1×10^{2}	2.76×10^{5}	7.92×10^{5}	7.89×10^{4}
Total Halogens (Ci)	3.2×10^{-10}	3.94×10^{0}	1.233×10^{0}	1.54×10^{-1}
Total Particulate (Ci)	<MDA	5.87×10^{-2}	5.57×10^{-2}	4.10×10^{-2}
Total Tritium (Ci)	-	3.209×10^{0}	4.21×10^{0}	1.69×10^{0}
Max Noble Gas Release				
Rate (μCi/sec)	6.0×10^{3}	4.45×10^{5}	3.75×10^{5}	8.45×10^{4}
Percent of Limit (%)				
a) Noble Gases	1.6×10^{-3}	3.48×10^{-1}	2.37×10^{0}	4.53×10^{0}
b) Halogens	1.5×10^{-8}	3.92×10^{0}	1.45×10^{0}	2.01×10^{0}
c) Particulate	-	4.83×10^{-2}	5.22×10^{-2}	2.79×10^{-1}
d) Tritium	-	-	-	-
LIQUID RELEASES				
Gross Radioactivity				
Total Release (Ci)	3×10^{-1}	1.965×10^{1}	5.158×10^{1}	3.34×10^{1}
Ave. Conc. Released (μCi/ml)	7.99×10^{-9}	3.34×10^{-8}	1.06×10^{-7}	5.68×10^{-8}
Max. Conc. Released (μCi/ml)	8.2×10^{-8}	9.66×10^{-7}	1.0×10^{-6}	9.74×10^{-7}

NRC FORM 335
(2-84)
NRCM 1102,
3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

SEE INSTRUCTIONS ON THE REVERSE

1. REPORT NUMBER (Assigned by TIDC, add Vol. No., if any)

NUREG-1143

2. TITLE AND SUBTITLE

Safety Evaluation Report related to the Full-Term Operating License for Millstone Nuclear Power Station, Unit No. 1

3. LEAVE BLANK

4. DATE REPORT COMPLETED

MONTH	YEAR
October	1985

5. AUTHOR(S)

6. DATE REPORT ISSUED

MONTH	YEAR
October	1985

7. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

Division of Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

8. PROJECT/TASK/WORK UNIT NUMBER

9. FIN OR GRANT NUMBER

10. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

Same as 7 above

11a. TYPE OF REPORT

Staff technical

b. PERIOD COVERED (Inclusive dates)

12. SUPPLEMENTARY NOTES

Docket No. 50-245

13. ABSTRACT (200 words or less)

The Safety Evaluation Report for the full-term operating license application filed by Northeast Nuclear Energy Company for Millstone Nuclear Power Station, Unit No. 1 has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located in New London County, Waterford, Connecticut. The staff concludes that the facility can continue to be operated without endangering the health and safety of the public.

14. DOCUMENT ANALYSIS – a. KEYWORDS/DESCRIPTORS

b. IDENTIFIERS/OPEN-ENDED TERMS

15. AVAILABILITY STATEMENT

Unlimited

16. SECURITY CLASSIFICATION

(This page)
unclassified

(This report)
unclassified

17. NUMBER OF PAGES

18. PRICE

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

FIRST CLASS MAIL
POSTAGE & FEES PAID
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WASH D.C.
PERMIT No. G-67

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US NRC
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POLICY & PUB MGT BR-PDR NUREG
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