NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY
WESTERN MASSACHUSETTS ELECTRIC COMPANY
HOLYOKE WATER POWER COMPANY
NORTHEAST UTILITIES SERVICE COMPANY
NORTHEAST NUCLEAR ENERGY COMPANY

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May 22, 1984

Docket No. 50-423
B11184

Director of Nuclear Reactor Regulation
Attn: Mr. B. J. Youngblood, Chief
Licensing Branch No. 2
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Gentlemen:

Millstone Nuclear Power Station, Unit No. 3
Summary/Submittal of Responses to RSB
Draft SER Open Items

Attached is the status to all identified items within Enclosure 2 of the RSB Draft SER. The attached status reflects discussions held with the NRC in a meeting on May 9, 1984. Also attached are the responses to all RSB Draft SER, Enclosure 2 items except those listed with the remark "not attached" on the status listing. Additionally, it addresses items not identified within Enclosure 2 but within the text of the Draft SER. These are TMI item II.B.1 and the Draft SER item on the quantity of DWST water allocated exclusively to the AFWS, which we have designated as Item No. 23.

If you have any questions please contact our licensing representative directly.

Very truly yours,

NORTHEAST NUCLEAR ENERGY COMPANY ET AL
By Northeast Nuclear Energy Company, Their Agent

W. G. Counsil

W. G. Counsil
Senior Vice President

8001
1/45

STATE OF CONNECTICUT)
) ss. Berlin
COUNTY OF HARTFORD)

Then personally appeared before me W. G. Counsil, who being duly sworn, did state that he is Senior Vice President of Northeast Nuclear Energy Company, an Applicant herein, that he is authorized to execute and file the foregoing information in the name and on behalf of the Applicants herein and that the statements contained in said information are true and correct to the best of his knowledge and belief.

Lorraine J. D'Amico
Notary Public

My Commission Expires March 31, 1988

ATTACHMENT

Summary of the Status of RSB Items

from the NRC Meeting May 9, 1984

Item No.		Status	Required Actions/Comments
		o closed o confirmatory o open	
1	(440.14)	Closed	
2	(440.15)	Closed	
3	(440.24)	Closed	Closed contingent on NRC's verification of compliance with BTP 5.1
4	(440.28)	Closed	
5	(440.31)	Closed	
6	(440.32)	Closed	Closed contingent on verifying task analysis during CRDR of "switchover" procedures. (This is reflected in response as of May 21, 1984.)
7	(440.34)	Closed	
8	(440.36)	Closed	
9	(440.41)	Closed	
10	(440.46)	Closed	
11	(440.49)	Closed	

12 (440.50)	Open	*(Need to verify assumptions for fuel failures and the basis.) Additionally need to verify that the assumed most limiting single failure is correct and that it is not a stuck open relief valve.
13 (440.55)	Closed	Closed contingent upon NRC verification of the use of proper assumptions.
14 (440.56) and 440.57)	Open	Subsequently closed as indicated during telecon on May 11, 1984.
15	NA	This item was combined with #14
16 (440.59)	Confirmatory	
TMI II.B.1	Closed	Discussed in FSAR Section 1.10. Not assigned an open item number.
17 TMI II.K.3.10	Confirmatory	Provide further details of analysis
18 TMI II.K.3.17	NA	This item is NA to Millstone 3.
19	Closed	Item discussed during meeting (not attached).
20	Closed	Item discussed during meeting (not attached).
21	Closed	
22	Closed	Contingent upon <u>W</u> verifying, via testing results, that the capacity of RHR relief valves passing water is adequate (not attached).

23 Closed

(440.63) Revised response attached. This was not a Draft SER open item.

*During the meeting on May 9, 1984 the NRC expressed the concern that the assumption for fuel failures was low (.29%). This (.29%) represents the assumed fuel defects used ' ı the analysis to account for activity in the primary coolant from prior operation. Six percent of the fuel rods in the core are postulated to have clad damage, as stated in FSAR Section 15.3.3.

NRC Letter: May 31, 1983

Question Q440.14 (Section 5.2.2)

In Section 5.2.2.11.1 of the FSAR, you indicate that "an auctioneered system temperature is continuously converted to an allowable pressure and then compared to the actual RCS pressure. The system logic will first annunciate a main control board alarm whenever its measured pressure approaches within a predetermined amount of the allowable pressure, thereby indicating that a pressure transient is occurring. On further increase in measured pressure, an actuation signal is transmitted to the PORVs when required to mitigate the pressure transient." Our review of the low temperature overpressure protection design for certain other Westinghouse plants indicates that a failure in the temperature auctioneer for one PORV (signaling it to remain closed) could also fail the other PORV closed (by denying its permissive to open). Address this concern about a potential common mode failure in the low temperature overpressure protection system for Millstone.

Response:

The instrumentation and control and electrical power supply system for the Millstone 3 interlocks for RCS pressure control during low temperature operation is channelized and equipped with a manual arming feature to provide redundant train control for the redundant pressurizer PORVs such that instrumentation is not shared (i.e., common) to the redundant channels. Therefore, any single random failure in one train will not prevent protective action at the system level. Refer also to FSAR Section 7.6.8.

NRC Letter: May 31, 1983

Question Q440.15 (Section 5.4.7)

Recent plant experience has identified a potential problem regarding the loss of shutdown cooling during certain reactor coolant system maintenance evolutions. On a number of occasions when the reactor coolant system has been partially drained, improper reactor coolant system level control, a partial loss of reactor coolant inventory, or operating the RHR system at an inadequate NPSH has resulted in air binding of the RHR pumps with a subsequent loss of shutdown cooling. Regarding this potential problem, provide the following additional information:

1. Discuss the design or procedural provisions incorporated to maintain adequate reactor coolant system inventory, level control, and NPSH during all operations in which RHR cooling is required

2. Discuss the provisions incorporated to ensure the rapid restoration of the RHR system to service in the event that the RHR pumps become air bound

3. Discuss the provisions incorporated to provide alternate methods of shutdown cooling in the event of loss of RHR cooling during shutdown maintenance. These provisions should consider maintenance periods during which more than one cooling system may be unavailable such as loss of steam generators when the reactor coolant system has been partially drained for steam generator inspection or maintenance.

Response:

1. Reactor coolant inventory (level) control during maintenance operations is performed in accordance with specific maintenance procedures and Technical Specifications.

   Technical Specifications specify multiple heat removal paths be available from residual heat removal, operable steam generators, or a combination of both. The redundance and independance of these paths ensures a high degree of reliability in heat removal capability.

   Reactor coolant draining is to the point where the indicated level is stable and at the elevation of the center of the reactor vessel nozzles. At this point, reactor coolant level is monitored to ensure that the RHR system inlet lines do not become uncovered. Inventory makeup, if required, can be accomplished via the charging pump(s).

   Should a RHR inlet line become uncovered, air may be drawn into the suction piping and entrained in the fluid. a Factor

which minimize the effects of air entrainment on pump performance ~~are~~ is

The elevational difference between the inlets to the RHR suction piping and the RHR pumps provides for positive head at the pump inlets.

Provisions have been made to minimize the effects of air entrainment. Should such an event, however, preclude the use of the operating RHR subsystem, actions will be taken to restore reactor coolant inventory through use of the centrifugal charging pumps and, if necessary, alignment of the refueling water storage tank to the RHR system. Following these actions, the operator would attempt to start the standby RHR pump (or restart either pump if both subsystems were initially operating). Particular attention is placed on specific pump venting procedures to ensure that the second (or restarted) RHR pump does not become airbound.

Such actions (restoration of reactor coolant inventory followed by pump starting while using appropriate vent procedures) have been found acceptable through review of operating plant events involving loss of RHR systems due to inadequate control of reactor coolant inventory (level).[1]

Several methods for shutdown cooling are available in the event of loss of RHR cooling. These include the use of the steam generators and the auxiliary feedwater system when available. If the steam generators are not operable but the reactor coolant system remains pressurized and the reactor coolant pumps (RCPs) are operable, restarting or jogging of the RCPs can remove decay heat by mixing.

During extended shutdown periods when the steam generators are not available due to partial draindown of the reactor coolant system, consideration must be given to the reduced heat load placed on the RHR system. Such consideration permits the use of one RHR subsystem while the second RHR subsystem remains in standby mode.

Reference:

1. Vine, G. and Layman, W. Residual Heat Removal Experience Review and Safety Analysis, Pressurized Water Reactors. NSAC-52, Electric Power Research Institute. January 1983, pp 2-8, 2-11.

NRC Letter: May 31, 1983 1.10

Question Q440.24 (Section 5.4.7) 1.13

In accordance to Branch Technical Position RSB 5-1, the system(s) 1.14
shall be capable of bringing the reactor to a cold shutdown condition 1.15
with only offsite or onsite power available within a reasonable
period of time following shutdown, assuming the most limiting single 1.16
failure. A reasonable period of time is considered to be 36 hours. 1.17

Identify the most limiting single failure and provide the basis for 1.18
selection of this failure. Provide an analysis to show that the 1.19
reactor can be brought to the RHS entry conditions within 36 hours.
Identify and justify the assumptions used in the analysis. Also 1.21
identify the non-safety related systems for which credit is taken and
the basis for use of these systems. Provide a sequence of events and 1.22
actions and their time of occurrence.

Response: 1.23

The Millstone 3 cold shutdown capability is as follows. 1.24

General 1.26

The ability to bring a plant to safe shutdown conditions following 1.27
any postulated event has been the subject of several licensing 1.29
guidance documents in recent years. These documents have attempted 1.30
to provide the designer with adequate guidance in incorporating
appropriate systems, components, and procedures such that the plant 1.31
can reliably reach and maintain safe shutdown conditions.

This discussion displays the degree of compliance of the Millstone 3 1.32
design with the requirements as outlined, in Branch Technical 1.33
Position RSB 5-1, Revision 2. The attached Table Q440.24-1 provides ~~1.34~~
a brief line-by-line comparison of the Millstone 3 design with the
requirements listed in Table 1 of the BTP. 1.35

Design Approach 1.37

The cold shutdown capability of the plant has been evaluated in order 1.38
to demonstrate that the plant can achieve cold shutdown conditions 1.40
following any transient in which the primary system remains intact
(i.e., non-LOCA). The evaluation assumes a safe shutdown earthquake, 1.41
loss of offsite power, and the most limiting single failure. Under 1.42
such conditions, the plant is capable of achieving RHS initiation
conditions (approximately 350°F, 400 psig) within 36 hours. 1.43

To achieve and maintain cold shutdown, the following key functions 1.44
must be performed.

- residual heat removal, 1.47
- boration and inventory control, 1.48
- pressure control, and 1.49

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- plant status monitoring (instrumentation and control). 1.50

Residual Heat Removal 1.53

Following the insertion of the control rods, the plant is stabilized 1.55
at hot standby conditions until cooldown is initiated. The residual 1.58
heat removal function is accomplished in two stages from hot standby
to cold shutdown conditions.

During the first stage of cooldown, heat removal is accomplished via 1.59
the steam generators, the auxiliary feedwater system, and the main 1.60
steam pressure relieving valves. Should the reactor coolant pumps be 2.1
unavailable, transport of the residual heat from the core to the
steam generators occurs by natural circulation. 2.2

Feedwater to the steam generators is pumped from the demineralized 2.3
water storage tank (DWST) by the redundant auxiliary feedwater pumps. 2.4
The DWST has a capacity of 340,000 gallons, which is sufficient for 2.5
maintaining hot standby for more than 10 hours followed by a 6-hour 2.6
cooldown to 350°F. Backup water sources include the condensate 2.7
storage tank (200,000 gallon reserve capacity), the service water
system and the domestic water system. 2.8

A main steam pressure relieving valve is provided in each main steam line 2.9
outside the containment structure and upstream of the main steam 2.10
isolation trip valves. Each of the pressure relieving valves is 2.11
provided with a bypass valve to ensure that a relieving path exists
should the pressure relieving valve be inoperable. 2.12

Following cooldown to RHS initiation conditions, the second stage of 2.13
residual heat removal begins. The RHS is brought into operation by 2.14
accessing one or both of the redundant residual heat removal trains.
Startup of the RHS includes a warmup period during which time reactor 2.15
coolant flow through the heat exchangers is limited to minimize 2.16
thermal shock. This flow is regulated by flow control valves 2.17
downstream of the heat exchangers with total return flow provided by
the control valves in the bypass lines around the heat exchangers. 2.18
Should any of these control valves fail, residual heat removal flow 2.19
may be controlled through use of only one RHS train and/or operator 2.20
control of the residual heat removal pump(s).

Residual heat is transferred during this stage from the reactor core 2.21
through the RHS to the reactor plant component cooling water system, 2.22
the service water system, and finally, the ocean.

Boration and Inventory Control 2.25

Injection of boric acid into the reactor coolant system is required 2.27
to offset xenon decay and the reactivity change occurring through 2.28
cooldown. Four weight percent boric acid solution is pumped from the 2.30
boric acid tanks to the suction of the charging pumps by means of the 2.31
boric acid transfer pumps. Gravity drain lines are also provided 2.32
from the boric acid tanks to the suction of the charging pumps.

Should this source of boric acid be unavailable, 2000 ppm borated 2.33
water from the refueling water storage tank (RWST) can be used. 2.34

The borated water is then injected into the RCS via the normal 2.35
charging line and the reactor coolant pump seals. A backup means for 2.36
injection involves the use of the high pressure injection path within
the emergency core cooling system (ECCS). The normal charging and 2.38
the ECCS high pressure injection paths each contain a solenoid-
operated throttling valve that permits variable control of the 2.39
charging rate from the control room.

To accommodate the borated water addition to the RCS, letdown may be 2.40
established via either the normal or excess letdown paths to the 2.41
chemical and volume control system. Should both of these paths be 2.42
inoperable, an alternate means of letdown is provided via the safety
grade reactor vessel head letdown line to the pressurizer relief 2.43
tank. Throttling control of letdown via this line is provided by 2.44
either of two parallel hand control valves.

Reactor coolant shrinkage during cooldown also provides room to 2.45
accommodate the borated water addition.

Pressure Control 2.48

Adequate control of RCS pressure must be maintained throughout the 2.50
recovery process. This requires the operator to monitor and control 2.51
the secondary side heat removal function via the auxiliary feedwater 2.53
system and the main steam pressure relieving valves. On the primary 2.54
side, the operator would control RCS pressure in conjunction with
maintenance of reactor coolant inventory. 2.55

The pressurizer heaters and the charging pumps provide a means for 2.56
increasing RCS pressure, while the pressurizer sprays (normal and 2.57
auxiliary), the power-operated relief valves (PORVs), and the RCS
letdown lines (CHS normal and excess and the reactor vessel head 2.58
letdown lines) provide a means for decreasing RCS pressure (in
addition to the decrease in pressure due to cooldown). The reactor 2.60
vessel head letdown path also provides a means for venting gases from
the vessel head region. Intermittant use of this path to vent any 3.1
gases augments RCS pressure control during a natural circulation
cooldown.

Following boration and cooldown, the RCS must be depressurized to RHS 3.2
initiation conditions. Should it be available, depressurization will 3.3
be accomplished by use of the pressurizer auxiliary spray valve and
the normal charging line. Another means of depressurization involves 3.5
the use of the pressurizer PORVs. Two PORVs in parallel are 3.6
provided, either of which is capable of providing the
depressurization function.

To prevent water injection from the accumulators during the 3.7
depressurization process, the accumulators must be isolated from the 3.8
RCS. Each accumulator is equipped with a normally open motor- 3.9
operated valve in its discharge line. Prior to RCS pressure 3.10

decreasing below the accumulator discharge pressure, power to these valves will be restored and the valves closed. Should a discharge 3.12
valve fail to close the affected accumulator can be vented to the
containment via redundant vent valves both on the individual 3.13
accumulator itself and in the common nitrogen fill/vent header.

Plant Status Monitoring (Instrumentation and Control) 3.X6

Safety-related instrumentation is available in the control room to 3.18
monitor the key functions associated with achieving cold shutdown. 3.19
This instrumentation is detailed in FSAR Table 7.5-1 and includes the 3.21
following:

a. Reactor coolant system wide range temperature (T_{hot} and T_{cold}) ~~3.23~~

b. Reactor coolant system wide range pressure 3.24

c. Pressurizer water level 3.25

d. Steam generator water level 3.26

e. Auxiliary feedwater flow 3.27

f. Steam line pressure (per steam line) 3.28

g. Demineralized water storage tank level 3.29

h. Boric acid tank level (per tank) 3.30

i. Accumulator pressure 3.31

j. Refueling water storage tank level 3.32

k. Individual pump and valve status indication 3.33

This instrumentation is sufficient to monitor the key functions 3.35
associated with cold shutdown and to maintain the RCS within the 3.36
desired pressure, temperature, and inventory relationships.
Additional information regarding the addressment of Regulatory 3.37
Guide 1.97, Revision 2 has been submitted in conjunction with the 3.38
FSAR and is referenced in Section 1.8.

Performance Evaluation 3.40

Residual Heat Removal 3.42

The plant is cooled down to RHS initiation conditions through ~~the~~ use 3.X4
of the steam generators, the auxiliary feedwater system, and the main 3.47X
steam pressure relieving valves.

Should offsite power be available and the steam and feedwater systems 3.48
intact and functioning, the cooldown may be accomplished using the 3.49
condenser and normal secondary side cooldown procedures. However, 3.50

should offsite power be unavailable, the condenser and normal
feedwater system cannot be used. In this case, the auxiliary 3.51
feedwater system would be used to provide feedwater to the steam
generators.

The auxiliary feedwater system consists of two half capacity motor- 3.52
driven pumps, one full capacity turbine-driven pump, and the 3.53
associated piping and valves necessary to connect the DWST to the
pump suctions, and the pump discharges to the feedwater system. Each 3.55
motor-driven pump receives power from a separate, emergency ac bus.
The turbine-driven pump receives its control power from dc sources 3.56
only. An adequate supply of steam for the turbine-driven pump is 3.57
available, provided at least one steam generator and its associated 3.58
main steam loop from the steam generator to the main steam isolation
trip valve are intact.

Redundant flow paths from the pumps to the steam generators are 3.59
provided to ensure the required flow to at least two steam 3.60
generators, assuming a single failure. The turbine-driven pump by 4.1
itself or the two motor-driven pumps operating together are sized to
provide sufficient auxiliary feedwater to cool the plant until RHS 4.2
operation can be initiated.

Each auxiliary feedwater pump normally takes suction through a 4.3
separate supply line from the DWST. The DWST has a capacity of 4.4
340,000 gallons, which is sufficient for maintaining hot standby for
more than 10 hours followed by a 6-hour cooldown to 350°F. Should it 4.6
be available, the 200,000 gallons provided in the nonsafety-related
condensate storage tank would provide an additional water source. 4.7
The normally closed, air-operated valve connecting the condensate 4.8
storage tank and each auxiliary feedwater pump suction is under 4.9
administrative control.

The service water system is available as a long-term safety grade 4.10
source of auxiliary feedwater. Spool pieces, maintained onsite, must 4.11
be added to connect the service water system to the auxiliary
feedwater system. These spool pieces are provided, in lieu of 4.12
permanent piping, to preclude inadvertent discharging of service water × water
to the steam generators. A connection from the domestic water system 4.14
to the DWST fill line is also provided. Like the service water 4.15
system connection, a spool piece is required. ×

Auxiliary feedwater flow to each steam generator can be manually 4.16
adjusted from the control room, as dictated by the individual steam 4.17
generator and feedwater requirements. The auxiliary feedwater lines 4.18
from the turbine-driven pump have redundant, normally open, solenoid-
operated control valves that fail open. Each auxiliary feedwater 4.20
line from a motor-driven pump has a solenoid-operated valve that is
normally open and fails open, and a motor-operated valve normally 4.21
open that fails-as-is. Additionally, there are manually-operated 4.22×
valves in each auxiliary feedwater line to the steam generators.

A discussion of auxiliary feedwater system reliability is provided in 4.23
FSAR Section 10.4.9.3.

Each main steam line contains five safety valves and a pressure 4.24
relieving valve located outside the containment structure and 4.25
upstream of the main steam isolation trip valve. The safety valves 4.26
provide overpressure protection while the pressure relieving valve
provides a means for manually adjusting (reducing) steam pressure as 4.27
required to cool down the reactor coolant system. Two steam 4.28
generators and their associated pressure relieving valves are
sufficient to bring the plant to RHS initiation conditions. 4.29

The main steam pressure relief valves are air-operated and can be 4.30
controlled to maintain a predetermined pressure from either the main 4.31
control board or the auxiliary shutdown panel. The main steam 4.32
pressure relief valves are normally closed and fail closed on loss of
air. On receipt of a steam line isolation signal, the valves are 4.33
automatically closed.

Each main steam pressure relief valve has a normally closed, motor- 4.34
operated bypass valve. The bypass valves can be operated from either 4.35
the main control board or the auxiliary shutdown panel. The bypass 4.36
valves are powered from the Class 1E buses and the valves fail-as-is
on loss of power.

A normally open, motor-operated main steam isolation valve is located 4.37
upstream of each set of pressure relief and bypass valves. The 4.39
isolation valves can be operated from either the main control board
or the auxiliary shutdown panel. The isolation valves are powered 4.40
from the Class 1E buses and the valves fail-as-is on loss of power.

Following cooldown and depressurization to RHS initiation conditions, 4.41
the RHS is brought into operation. Two redundant RHS trains are 4.42
provided, either of which is capable of cooling the RCS to cold
shutdown conditions. Startup of an RHS train is accomplished by 4.43
opening the three series isolation valves in the suction line to each
RHS pump. A discussion of the reliability considerations for these 4.45
valves is provided in FSAR Sections 5.4.7.2.6 and 7.6.2.

Cooling water to the RHS heat exchangers is provided by the reactor 4.46
plant component cooling water system. A throttling valve (3CCP*FV66A 4.47
and B), powered from a Class 1E power supply, is provided in the
cooling water discharge line from each heat exchanger (see FSAR 4.48
Section 9.2.2.1).

Flow control through each RHS train is provided by a normally open, 4.49
control valve downstream of each heat exchanger (3RHS*HCV606 and 607) 4.50
in conjunction with a normally closed, control valve located in a
bypass line around each heat exchanger (3RHS*FCV618 and 619). Should 4.52
these control grade valves fail, RHS pump runout is precluded by the
use of pre-set throttling valves located in the discharge lines to 4.53
the RCS. In addition, minimization of thermal shock to the RHS heat 4.54
exchangers may be controlled through use of only one RHS train and/or 4.55
operator control of the RHS pumps.

Boration and Inventory Control 4.58

Boric acid to offset xenon decay and the reactivity change occurring 4.60
through cooldown is provided in the boric acid tanks. Each of the 5.3
two safety-related tanks has sufficient capacity to borate the RCS to
cold shutdown conditions immediately following refueling and with the 5.4
most reactive control rod assembly not inserted. Boric acid solution 5.5
(3.6 to 4.1 percent) from either tank is gravity fed to either of the
two boric acid transfer pumps and then pumped via valve 3CHS*MV8104 5.6
to the suction of the charging pumps. Should this path be 5.7
unavailable, boric acid solution may be delivered directly to the
suction of the charging pumps via a gravity drain line provided from 5.8
each tank. A single, normally closed motor-operated valve 5.9
(3CHS*MV8507A and B) is provided in each gravity drain line. All 5.10
three of the valves mentioned are powered by Class 1E emergency
buses.

An alternate source of borated water is the refueling water storage 5.11
tank. Redundant paths from this tank, each containing a single 5.12
Class 1E powered isolation valve (3CHS*LCV112B and C), are provided. 5.13
The boric acid solution is injected into the RCS via the normal 5.14
charging and reactor coolant pump seal injection lines. Both of 5.15
these pathways contain air-operated throttling control valves which
fail open upon loss of instrument air. Under such conditions, 5.16
charging flow control is possible by use of a safety-related
throttling flow path that bypasses the normal charging flow control 5.17
valve. The valves in this bypass flow path (3CHS*HCV190A and 5.18
3CHS*MV8116) are electrically operated and powered from the same
Class 1E bus. A different throttling valve (3CHS*HCV190B), powered 5.20
from the opposite Class 1E bus, can be used to throttle flow through 5.21
the seal injection lines or to throttle flow through the high
pressure ECCS injection lines.

Letdown capability is provided by the normal and excess letdown lines 5.22
to the CHS and the reactor vessel head vent line. Both the normal 5.24
and excess letdown lines contain air-operated valves which fail
closed upon loss of instrument air. The reactor vessel head vent 5.25
line, however, contains parallel paths with electric solenoid-
operated valves powered from the Class 1E buses. Parallel hand 5.27
control valves are provided (3RCS*442A and B) permitting throttling
control of the letdown rate, with letdown routed to the pressurizer 5.28
relief tank. A detailed discussion of the reactor vessel head vent 5.29
system is provided in Section 5.4.15.

Pressure Control 5.32

During the recovery process, control over reactor coolant system 5.34
pressure must be maintained. Initially, RCS pressure must be kept 5.35
high to maintain coolant subcooling margins and to facilitate natural 5.37
circulation. Later, the RCS pressure must be reduced to permit entry 5.38
onto the residual heat removal system.

Reactor coolant system pressure is controlled by balancing the heat 5.39
and mass input and removal processes.

Heat input is provided by the core residual heat, the reactor coolant pumps (if used), and the pressurizer heaters. Each of these mechanisms acts to increase RCS pressure. Heat removal occurs (initially) via the steam generators as the feedwater is heated and exhausted to the atmosphere as steam. Later, heat removal occurs via the RHS with reactor coolant heat transferred to the reactor plant component cooling water system, the service water system, and eventually, the ocean.

The reactor coolant pumps are normally assumed unavailable (due to loss of offsite power). Should they be used, their heat input (approximately 3 Mwt per pump) must be considered by the operator.

Two banks of pressurizer heaters are connected to Class 1E power supplies, one per safety-related train, as indicated in FSAR Table 8.3-1.

Additional details of pressurizer operation are described in FSAR Sections 5.4.10 and 5.4.11.

Heat removal via the steam generators is primarily controlled by adjusting the steam flow through the main steam pressure relieving valves. Increasing the steam flow acts to reduce steam system pressure and, consequently, affects the temperature differential across the steam generator tubes. Opening the main steam pressure relieving valves increases the heat removal rate from the RCS and causes RCS pressure to decrease.

Balancing RCS inventory also provides a means for controlling RCS pressure. During cooldown, reactor coolant must be added to counteract the contraction due to cooling. Throttling control of mass addition is provided by the electric-solenoid valves (3CHS*HCV190A and B) in the discharge lines from the charging pumps to the RCS normal charging, reactor coolant pump seal injection, and ECCS high pressure injection lines. These valves are Class 1E powered and operable from the control room and the auxiliary shutdown panel.

Adjustment of reactor coolant letdown provides a means for RCS pressure control as well as a means for removing noncondensibles and/or steam from the reactor vessel head region. A safety grade reactor vessel head vent system (RVHVS) is provided. A detailed discussion of the RVHVS is provided in FSAR Section 5.4.15.

Following cooldown to approximately 350°F, the RCS must be depressurized to below approximately 425 psig in order to satisfy the "permit-to-open" interlocks on the RHS suction valves (3RHS*MV8701A and B and 3RHS*MV8702A and B). These interlocks are discussed in FSAR Sections 5.4.7.2.2, and 7.6.2 and depicted on FSAR Figures 5.4-5 and 7.6-1.

Should offsite power be available, the RCS may be depressurized by means of the pressurizer spray valves. The auxiliary spray valve in conjunction with the normal charging line provides an additional

depressurization means. If the normal and auxiliary spray valves are 6.13
unavailable, the pressurizer power-operated relief valves
(3RCS*PCV455A and 456) may be used for RCS depressurization. Two 6.15
safety grade PORVs are provided with only one required. The PORVs 6.16
are solenoid-operated, Seismic Category I, and powered from the
Class 1E buses. A detailed discussion of the pressurizer PORVs is 6.17
provided in FSAR Section 5.4.13.

To preclude accumulator injection during RCS depressurization, the 6.18
accumulators must be isolated or vented. Each accumulator discharge 6.19
line has a single Class 1E-powered isolation valve (3SIL*MV8808A, B,
C, and D). The power to these valves must be restored and the valves 6.20
closed. Should the operator be unable to close any of the isolation 6.21
valves, the affected accumulator(s) may be vented to the containment. 6.22
Each accumulator has parallel, Class 1E-powered nitrogen vent valves 6.23
(3SIL*SV8875A through H). The common vent header also has parallel, 6.24
Class 1E-powered vent valves (3SIL*HCV943A and B).

TABLE Q440.24-1

COMPLIANCE COMPARISON WITH BRANCH TECHNICAL POSITION RSB 5-1

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants (see Note 1)	Degree of Compliance (see Note 2)
1. Functional Requirements for taking to cold shutdown a. Capability using only safety grade systems b. Capability with either only onsite or only offsite power and with single failure (limited action outside control room to meet single failure) c. Reasonable time for cooldown assuming most limiting single failure and only offsite or only onsite power	Long-term cooling [RHR drop line]	Provide double drop line (or valves in parallel) to prevent single valve failure from stopping RHR cooling function. (Note: This requirement in conjunction with meeting effects of single failure for long-term cooling and isolation requirements involves increased number of independent power supplies and possibly more than four valves.)	Compliance will not be required if it can be shown that correction for single failure by manual actions inside or outside of containment or return to hot standby until manual actions (or repairs) are found to be acceptable for the individual plant.	Two drop lines, each containing three normally closed valves in series are provided. Limited manual action would be required to overcome loss of a power train. (see Sections 5.4.7.2.4 and 7.6.2 and Figures 5.4-5 and 7.6-1)
	Heat removal and RCS circulation during cooldown to cold shutdown. (Note: Need SG cooling to maintain RCS circulation even after RHS in operation when under natural circulation) [steam dump valves.]	Provide safety-grade dump valves, operators, and power supply, etc. so that manual action should not be required after SSE except to meet single failure.	Compliance required.	Complies. Main steam pressure relieving bypass valves are safety grade, Class 1E. (See Section 10.3.3)
	Depressurization [Pressurizer auxiliary spray or power-operated relief valves]	Provide upgrading and additional valves to ensure operation of auxiliary pressurizer spray using only safety-grade subsystem meeting single failure. Possible alternative may involve using pressurizer power-operated relief valves which have been upgraded. Meet SSE and single failure without manual operation inside containment.	Compliance will not be required if a) dependence on manual actions inside containment after SSE or single failure or b) remaining at hot standby until manual actions or repairs are complete are found to be acceptable for the individual plant.	Complies. Depressurization is via upgraded pressurizer power operated relief valves. (See Sections 5.4.7.2.3.5 and 5.4.13, and Figure 5.1-1)

TABLE 440.24-1

COMPLIANCE COMPARISON WITH BRANCH TECHNICAL POSITION RSB 5-1

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants (see Note 1)	Degree of Compliance (see Note 2)
	Boration for cold shutdown [CVCS and boron sampling]	Provide procedure and upgrading where necessary such that boration to cold shutdown concentration meets the requirements of I. Solution could range from (1) upgrading and adding valves to have both letdown and charging paths safety grade and meet single failure to (2) use of backup procedures involving less cost. For example, boration without letdown may be acceptable and eliminate need for upgrading letdown path. Use of ECCS for injection of borated water may also be acceptable. Need surveillance of boron concentration (boronometer and/or sampling). Limited operator action inside or outside of containment if justified.	Same as above.	Complies. Boration is accomplished by use of the boric acid tanks, the charging pumps, and the normal charging, reactor coolant pump seal injection and ECCS high pressure injection lines. A backup source of boric acid is the refueling water storage tank. Throttling valves for boric acid injection are provided in the normal charging and the ECCS high pressure injection lines. Safety grade letdown capability is provided by the reactor vessel head vent system. Surveillance of boron concentration is by samples drawn from each reactor coolant system leg. (See Sections 5.4.7, 5.4.15, 6.3, 9.3.2 and 9.3.4 and Figures 5.1-1, 6.3-2 and 9.3-8)
II. Residual Heat Removal System isolation	Residual Heat Removal System	Comply with one of allowable arrangements given.	Compliance required. (Plants normally meet the requirement under existing SRP Section 5.4.7.)	Complies. (See Sections 5.4.7.2 and 7.6.2)
III. Residual Heat Removal System pressure relief Collect and contain relief discharge	Residual Heat Removal System	Determine piping, etc., needed to meet requirement and provide in design.	Compliance will not be required if it is shown that adequate alternate methods of disposing of discharge are available.	Complies. Residual heat removal pump suction relief valve discharge is piped to the pressurizer relief tank. (See Section 5.4.7.2.4 and Figure 5.4-5).

TABLE 440.24-1

COMPLIANCE COMPARISON WITH BRANCH TECHNICAL POSITION RSB 5-1

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants (see Note 1)	Degree of Compliance (see Note 2)
V. Test requirement Meet R.G. 1.68 for PWRs, test plus analysis for cooldown under natural circulation to confirm adequate mixing and cooldown within limits specified in Emergency Operating Procedures.		Run tests and confirming analysis to meet requirement.	Compliance required.	Meets the intent of R.G.1.68. Test data and analysis for a plant similar in design to Millstone 3 has verified adequate mixing and cooldown under natural circulation conditions. ~~A revised special low power testing program, as discussed in Westinghouse letter NS-EPR-2465 dated July 8, 1981, will be provided later.~~
VI. Operational procedure Meet R.G. 1.33. For PWRs, include specific procedures and information for cooldown under natural circulation.		Develop procedures and information from tests and analysis.	Compliance required.	Generic procedures as developed by the Westinghouse Owners Group will be used as the basis for plant specific procedures.

NATURAL CIRCULATION TESTING IS DISCUSSED FURTHER IN FSAR SECTION 14.2, UNDER STARTUP TEST N-21, "NATURAL CIRCULATION".

3 of 4

TABLE Q440.24-1

COMPLIANCE COMPARISON WITH BRANCH TECHNICAL POSITION RSB 5-1

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants (see Note 1)	Degree of Compliance (see Note 2)
VII. Auxiliary Feedwater Supply Seismic Category I supply for auxiliary feedwater for at least four hours at hot shutdown plus cooldown to residual heat removal cut-in based on longest time for only onsite or only offsite power and assumed single failure.	Emergency feedwater supply AUXILIARY	From tests and analysis obtain conservative estimate of auxiliary feedwater supply to meet requirement and provide Seismic Category I supply.	Compliance will not be required if it is shown that an adequate alternate seismic Category I source is available.	Complies. The demineralized water storage tank has a reserve capacity of 340,000 gallons which is adequate for 10 hours at hot standby followed by 6 hour cooldown to residual heat removal system initiation. Backup is provided by the 200,000 gallon reserve capacity in the condensate storage tank and the service water system. (See Sections 9.2.1, 9.2.6, 10.4.9 and Figures 9.2-1, 9.2-9 and 10.4-6)

Note 1. The implementation for Class 2 plants does not result in a major impact while providing additional capability to go to cold shutdown. The major impact results from the requirement for safety-grade steam dump valves.

Note 2: Millstone 3 falls within the category of a Class 2 plant as defined by Section H "Implementation" of Branch Technical Position RSB 5-1, Revision 2.

NRC Letter: May 31, 1983

Question Q440.28 (Section 6.3)

Certain automatic safety injection systems are blocked to preclude unwanted actuation of these systems during normal shutdown and startup conditions. Describe the alarms available to alert the operator to a failure in the primary or secondary system during this phase of operation, operator actions and time frame available for the operator to mitigate such an accident, and the consequences of the accident.

Response:

As discussed in FSAR Section 7.3.2.2.6, manual block features are provided for low pressurizer pressure and low compensated steam line pressure. The same interlock (P-11) allows steam line isolation on high steam line negative pressure rate (FSAR Table 7.3-3).

If a steamline rupture occurs while both of these SI actuation signals are blocked, steamline isolation will occur on high negative steam pressure rate. An alarm for steamline isolation will alert the operator of the accident.

For large LOCAs, sufficient mass and energy would be released to the containment to automatically actuate SI when the containment high pressure setpoint (Hi-1) is reached. Additionally, the operator would be alerted to the occurrence of a LOCA by the following safety-related indications:

A. Loss of pressurizer level (a low level alarm is provided)

B. Rapid decrease of RCS pressure

C. Increase in containment pressure

In addition to the above, the following indications are normally available to the operator at the control board:

A. Radiation alarms inside containment

B. Increase in sump water level

C. Decrease off scale of accumulator water levels and decrease in pressure (a low water level alarm and low pressure alarm is provided for each accumulator)

D. ECCS valve and pump position indication, status lights, and annunciators

E. Flow from ECCS pumps

For small LOCAs (approximately less than 2-inch diameter) in which the containment high pressure setpoint may not be reached, the operator would observe the safety-related indications plus the first two ~~noramlly~~ normally available indications. In addition, a charging flow/letdown mismatch would provide the operator with another indication of leakage from the RCS.

Since the operator would observe the pressurizer level and receive additional indications that a LOCA occurred, a manual SI would be initiated immediately. As presented in WCAP-8356, the time to uncover the core following a small break is relatively long (e.g., greater than 10 minutes for a 2-inch break). The operator would, therefore, have sufficient time to manually initiate SI.

NRC Letter: May 31, 1983

Question Q440.31

When operator action is required to complete the switchover to the recirculation mode, SRP Section 6.3 states that a time greater than 20 minutes should be available for the operator to respond. What is the minimum time from initiation of a LOCA to the start of switchover to the recirculation mode for Millstone?

Response:

Refer to revised FSAR Section 6.3.2.8 for a discussion of the minimum time from the initiation of a LOCA to the start of switchover to the recirculation mode of safety injection.

NRC Letter: May 31, 1983

Question Q440.32 (Section 6.3)

You state in Section 6.3.2.8 that the low-low RWST level signal is also alarmed to inform the operator to initiate the manual action required to realign the charging, safety injection, and containment recirculation pumps for the recirculation mode. What is the minimum time available for completion of switchover before the RWST water is exhausted? Provide your basis for this minimum time. Provide the detailed actions for switchover including actions to restore power to valves and an evaluation of the maximum time required for each operator action in switchover to recirculation. Identify the most restrictive single failure and its impact on the time required for switchover. What are the consequences of premature operator switchover to recirculation? Also discuss the consequences of the operator failing to act promptly within the minimum available time for switchover.

Response:

The initiating event for switchover is the redundant and automatic trip of the RHS pumps. Premature operator switchover is not credible because the automatic trip must be verified before continuing with the switchover procedure, and attaining the low-low level can be monitored by the RWST level indicator in the main control room. The switchover procedure is outlined in FSAR Table 6.3-7.

As discussed in revised FSAR Section 6.3.2.8, single failure of one RHS pump to trip is the most limiting single failure that can occur during the switchover procedure as it causes the RWST level to drop faster than normal. However, this failure would be quickly corrected as the first action of the switchover procedure is verification of the pump trip. If one pump fails to stop, the flow would be stopped manually before proceeding on with the switchover procedure.

Because of the substantial volume of water remaining in the RWST at the initiation of switchover at the low-low level (FSAR Figure 6.3-6) and since there is significant margin in the NPSH available to the ECCS pumps (FSAR Section 6.3.2.2.3), there would be no adverse consequences to the ECCS if the operator failed to act promptly and complete switchover in the 10 minutes assumed for switchover. However, some water assumed available to the quench spray pumps for containment heat removal would be used by the ECCS. The loss of a portion of the QSS water is not a limiting condition since the assumed single failure to trip one RHS pumps allows full containment recirculation spray system operability to be assumed. Minimum ESF is the limiting failure in the containment depressurization design basis accidents discussed in FSAR Section 6.2.1.

The design of the switchover instrumentation and controls, the selection of the RWST signal levels, and the large size of the RWST

all provide for proper completion of switchover without any adverse effect on ECCS operation.

The Control Room Design Reviews ~~with~~ + task analysis will evaluate the ~~time~~ → operator - action time sensitivities associated with switchover

QUESTION 440.34

What are the initiation and completion times of actions of the ECCS components that were used in the Chapter 15 analysis with and without offsite power? What are the bases for these times and will they all be verified during pre-operational testing?

RESPONSE TO QUESTION 440.34

The following action times for ECCS were assumed in Chapter 15 non-LOCA analysis.

SIMULATES

- 2 second delay - Logic delay
- 10 second delay - This delay only used for loss of offsite power cases. This delay stimulates the time required to start diesel generators and loading of ~~changing~~ Charging/SI pumps
- 10 second ramp - SI flow is brought up to full flow over a 10 second ramp. This stimulates bringing charging/SI pumps to full speed and aligning valves.

1*

These times are verified during preoperational testing.

ACTUATION

Early evacuation of the ECCS on an SI signal is conservatively assumed in the SGTR analysis. A 25 second delay is assumed between the initiation of the SI signal and safety injection to account for logic delay, loading the pumps on the diesels (since offsite power is conservatively assumed to be lost) and for the pumps to reach full flow. Since the operator actions (including termination of SI) are not explicitly modeled in the analysis, the SI pumps are conservatively assumed to keep running from 25 seconds after the SI signal until 30 minutes after the initiation of the accident.

In large and small break LOCA analyses it is conservatively assumed that offsite power is lost at the time of the LOCA. Following a loss of offsite power the diesel generators must activate automatically and then be loaded with the ECCS components sequentially.

No credit can be taken for any Safety Injection until the end of bypass which occurs at 32.5 seconds. Following bypass, sufficient ECCS pump flow is available to accomodate analysis assumptions.

NRC Letter: May 31, 1983

Question Q440.36 (Section 6.3)

Recently, a similar plant has indicated that a design error existed in the sizing of their RWST. This error was discovered during a design review of the net positive suction head requirements for the containment spray and residual heat removal pumps. The review showed that there did not appear to be sufficient water in the RWST to complete the transfer of pump suction from the tank to the containment sump before the tank was drained and ECCS pump damage occurrred.

It was reported that in addition to the water volume required for injection following a LOCA, an additional volume of water is required in the RWST to account for:

1. Instrument error in RWST level measurements

2. Working allowance to assure that normal tank level is sufficiently above the minimum allowable level to assure satisfaction of Technical Specifications

3. Transfer allowance so that sufficient water volume is available to supply safety pumps during the time needed to complete the transfer process from injection to recirculation

4. Single failure of the ECCS system which would result in larger volumes of water being needed for the transfer process. In this situation, the worst single failure appears to be failure of a single ECCS train to realign to the containment sump upon low RWST signal. This results in the continuation of large RWST outflows and reduces the time available for manual recirculation switchover before the tank is drawn dry and the operating ECCS pumps are damaged.

Additionally, some amount of water above the suction pipes may also be unusable due to NPSH considerations and vortexing tendencies within the tank.

Preliminary indications are that approximately an additional 100,000 gallons of RWST capacity were needed to account for these considerations.

In light of the above information, discuss the adequacy of your refueling water storage tank design. Provide a discussion of the necessary water volumes to accommodate each of the considerations indicated above. Justify your choice of volumes necessary to account for each consideration of tank suction lines, and level sensors.

Response:

Refer to revised FSAR Section 6.3.2.8 for a discussion of RWST water volumes for the necessary allowances.

Vortex formation at the inlet of the ECCS pumps suction line in the RWST will not occur, as the minimum RWST water level at termination of switchover is approximately 16 feet above the top of the ECCS suction line. Refer to revised FSAR Section 6.2.2.2 for a discussion of vortexing at the quench spray pump suction nozzles.

above freezing by means of heat tracing and insulation. See Section 6.2.2.4.3 for a further discussion of this subsystem. 8

The pH of the spray from the quench spray headers into the containment structure is approximately 8.0. However, the final pH of the water in the containment structure sump after a DBA, including the contents of the RWST, is between 7.0 and 7.5.

The borated water in the RWST is maintained at a maximum temperature of 50°F by circulating the RWST water through the refueling water coolers, which use chilled water from the chilled water system (Section 9.2.2.2). The RWST is insulated to limit the temperature rise of the water to 1/2°F, or less, per 24 hour period whenever the chilled water system is inoperable. Periodic sampling of the RWST water monitors the water's chemistry. Provisions are made to purify the water when necessary, by circulating the water through the fuel pool cooling and purification system (Section 9.1.3).

A vortex suppression assembly is installed in the RWST at the quench spray suction lines to eliminate vortex formation. The assembly consists of a single horizontal plate above both suction nozzles, 440.36 supported off the bottom of the tank by vertical vanes. The quench spray pumps are automatically tripped at the low-low-low RWST level, which is set so that, with allowance for negative instrument error, vortex formation will not occur.

The RWST also has a connection for supplying water to the ECCS. The RWST is provided with a manhole for inspection access during refueling periods.

Refer to Section 6.3.2.8 for a discussion of RWST design relative to instrument error, working allowance, ECCS switchover allowance, most 440.36 limiting single failure, and compliance with design basis.

Each quench spray pump is capable of supplying approximately 4,000 gpm of sodium hydroxide/borated water solution to the two 360 degree quench spray headers located approximately 101 and 116 feet above the operating floor in the dome of the containment structure. The pumps are located in the engineered safety features building adjacent to the containment structure. Each quench spray discharge line contains a check valve inside containment and a motor-operated isolation valve outside the containment structure.

The preoperational test is described in Section 6.2.2.4. The design evaluation of the system is contained in Section 6.2.2.3. Small diameter drain lines, located downstream from the check valves within the containment structure, drain the quench spray headers should any water enter the headers during periodic testing. The size of the drain lines does not significantly decrease the capacity of the quench spray system during operation.

TABLE 6.2-3

CONTAINMENT DESIGN EVALUATION PARAMETERS

	I. General Information - Containment	
	A. Interior minimum design pressure (psia)	8.0
	B. Internal design pressure (psig)	45
	C. Design temperature (°F)	280
	D. Minimum free volume (ft^3)	2.26×10^6
440.31	E. Design leak rate (vol percent/day)	0.9
440.32		
440.36		
	II. Initial Conditions	
	A. Reactor and Reactor Coolant System	
	1. Reactor - maximum calculated power MWt	3,636
	2. Total water in system (lbm)	515,660
	3. Reactor coolant system volume (ft^3)	10,471
	4. Temperature (°F) (mass av)	583.5
	5. System pressure (psia)	2280
	B. Emergency Core Cooling System	
	1. Safety injection accumulators minimum water volume (ft^3)	850
	2. Pressure (maximum) (psia)	660
	3. Temperature (°F)	80-120
	C. Containment	
	1. Pressure, (psia)	9.11-12.34
	2. Inside temperature (°F)	80-120
	3. Outside temperature (°F)	60-100
	4. Relative humidity (percent)	46-100
	5. Service water temperature (°F)	33-75
	D. Refueling Water Storage Tank	
440.31		
440.32	1. Usable volume (gal)	Later
440.36	2. RWST temperature (°F)	40-50

TABLE 6.2-61

CONTAINMENT HEAT REMOVAL SYSTEMS COMPONENT DATA

Quench Spray Pumps	Data	
Number	2	
Type	Horizontal centrifugal	
Rated flow (gpm)	4,000	
Rated head (ft)	288	
Horsepower (normal Bhp)	386	
Material	304 SS	
Containment Recirculation Pumps		
Number	4	
Rated flow (gpm)	3,950	
Rated head (ft)	342	
Horsepower (normal Bhp)	443	
Material	304 SS	
Refueling Water Storage Tank		
Number	1	
Volume (gal.) (see Figure 6.3-6)	1,166,000 min 1,207,000 max	440.31 440.32 440.36
Boron concentration (ppm)	2,000 min 2,100 max	
Design pressure (psig)	Hydraulic head	
Design temperature (°F)	150	
Operating pressure (psig)	Hydraulic head	
Operating temperature (°F)	40-50°F	
Material	A240-T304L	
Design code	ASME III, Class 2	

TABLE 6.2-61 (Cont)

Refueling Water Chemical Addition Tank	Data
Number	1
Type	Vertical
Usable volume (gal.)	20,570 max 19,800 min
Design pressure (psig)	Hydraulic head
Design temperature (°F)	150
Operating pressure (psig)	Hydraulic head
8 Operating temperature (°F)	36 - 120
NaOH concentration, wt (percent)	2.00 max 1.35 min

Spray Headers	CRS		QSS	
Elevations (ft) (operating floor elevation = 51'4")	145.3	141.7	168	153
Azimuth coverage (degrees)	360	360	360	360
Diameter (ft)	105	107.5	44	91
Pipe diameter (in.)	12	12	6	10
No. of nozzles per header	322	322	70	192
Mean diameter of spray droplets (microns)	<1,000	<1,000	<1,000	<1,000
Maximum diameter that will pass through nozzles (in.)	3/8	3/8	3/8	3/8

Sump Screens	
Fine mesh (in.)	3/32
Coarse mesh (in.)	3/8
Trash bars (in.)	1.5

6.3.2.8 Manual Actions

No manual actions are required of the operator for proper operation of the ECCS during the injection mode of operation. During the injection mode, the ECCS pumps (charging, safety injection, and residual heat removal) and quench spray pumps operate automatically, drawing water from the RWST and delivering it to the RCS and quench spray headers, respectively. The switchover to the recirculation mode is initiated automatically and completed manually by operator action from the main control room. The operator actions required for switchover are delineated in Table 6.3-7.

The residual heat removal pumps stop automatically upon receipt of an RWST low-low level signal coincident with the safety injection signal. A one-out-of-two protection logic (see Figure 7.6-3) is used to trip each pump.

RWST level indication is available to the operator to monitor the water level and prepare for switchover to the recirculation mode. The RWST level indication system (see Figure 7.6-3) consists of four level channels with each channel assigned to a separate process control protection set. Four RWST level transmitters provide level
8 signals to four level indicators (through isolation devices) on the main control board. Two of these level channels are recorded on the main control board, and two of the channels provide indication (through isolation devices) on the auxiliary shutdown panel, to indicate and record zero to 100 percent level in the RWST. The level indication logic is separate from the pump trip logic described above.

440.31 The RWST low-low level signal is also alarmed to inform the operator
440.32 to initiate the manual actions required to realign the charging,
440.36 safety injection, and containment recirculation pumps for the recirculation mode.

Minimum Injection Mode Time

In order to determine the maximum time available to prepare for switchover, the minimum elapsed time from a LOCA to the receipt of the RWST low-low level signal has been calculated to be 36 minutes. The analysis conservatively assumes the following:

1. The ECCS and quench spray pumps are assumed to start coincident with the LOCA and to deliver at a constant rate throughout the injection mode period.

2. The containment and RCS pressures are assumed to be 0 psig to maximize flow out of the RWST.

3. The pump flowrates are the maximum calculated (system runout) flowrates, assuming two pumps of each type are operating. These flowrates are:

Quench spray pump	- 3000 gpm per pump
Charging pump	- 410 gpm per pump
Safety injection pump	- 445 gpm per pump
Residual heat removal pump	- 4850 gpm per pump

The total flowrate out of the RWST during the injection mode of operation is 17,410 gpm.

4. The RWST volume available during the injection mode is that contained between the technical specification limit and the low-low level setpoint with allowance for positive instrument error at the low-low level setpoint. The technical specification limit (tank elevation = 57 feet 0 inches) is 3 inches below the makeup alarm setpoint and permits a working allowance of approximately 5,100 gallons. Instrument error for the makeup alarm setpoint is ±0.84 inch. The volume of water contained between the technical specification limit and the low-low level setpoint (tank elevation = 25 feet 5 inches) is approximately 646,000 gallons. When instrument error at this setpoint is considered, this volume of water is reduced to approximately 629,000 gallons.

   The minimum time that would elapse from initiation of a LOCA to initiation of switchover to the recirculation mode is then 629,000 gallons divided by 17,410 gpm, or approximately 36 minutes. This is the minimum time available for the operator to prepare for switchover. Refer to Figure 6.3-6 for a presentation of RWST water levels and volumes. 440.31 440.32 440.36

Switchover Allowance

The time required by the operator to complete the actions required to realign the ECCS for the recirculation mode has been evaluated. A period of 10 minutes is considered conservative based upon human factors review of the actions needed (refer to Table 6.3-7).

The residual heat removal pumps stop automatically upon receipt of the low-low level signal coincident with the safety injection signal. This action significantly reduces the RWST outflow during the switchover period. Additionally as each safety injection and charging pump is realigned to sump recirculation, the RWST outflow is further reduced. To conservatively determine the amount of water utilized during the switchover, the RWST outflow rate was assumed to remain constant at 7,710 gpm; no credit was assumed for the reduction in outflow due to pump realignment of the charging and safety injection pumps. At this flowrate, approximately 77,100 gallons of water would be used during the assumed 10-minute switchover time.

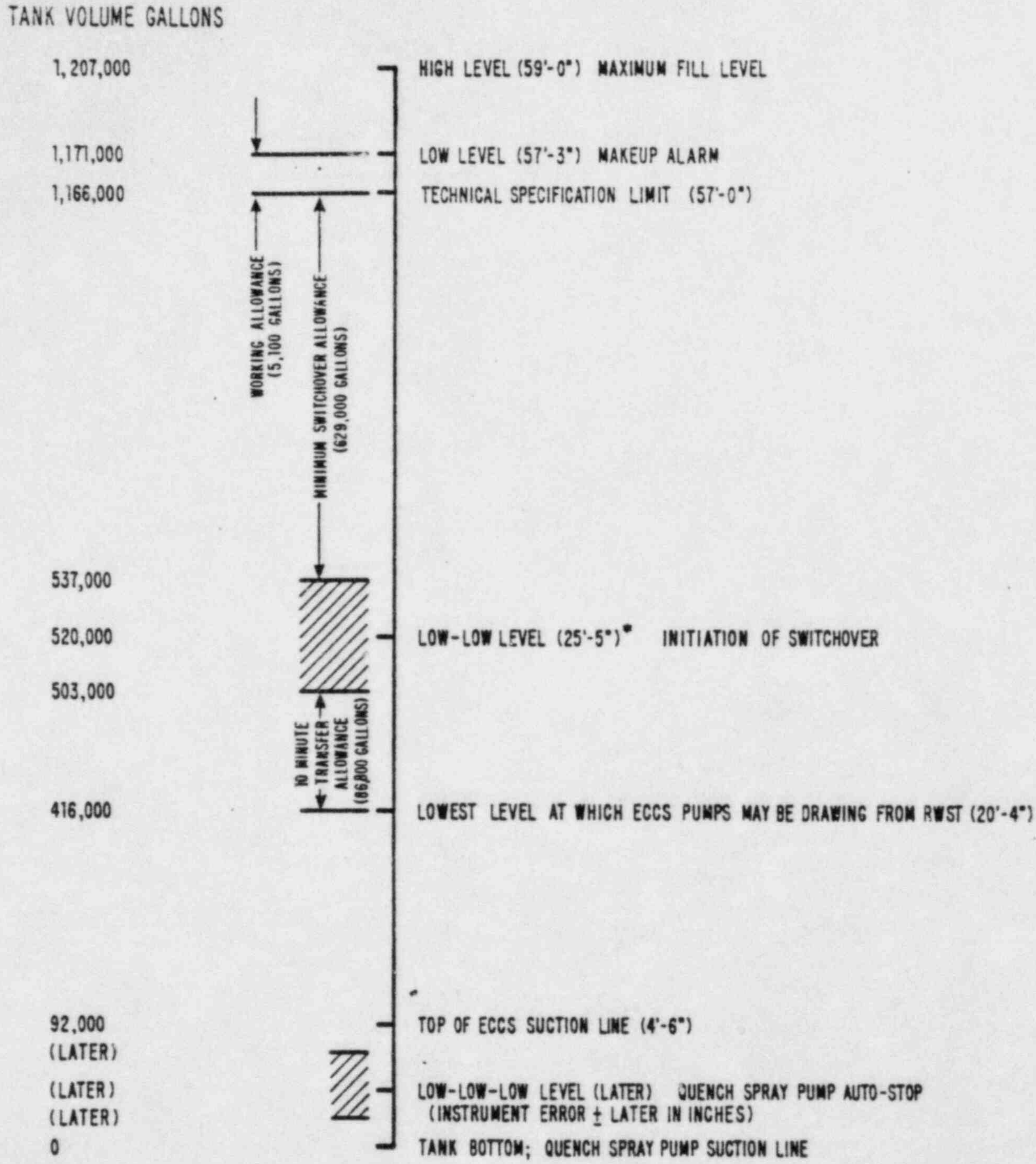
Should one of the residual heat removal pumps fail to stop automatically (limiting single failure), the RWST outflow would remain at a higher level until the operator took action to stop the flow from the RHS pump. This higher total outflow is conservatively assumed to be 12,560 gpm. The time to isolate RHS flow is

conservatively estimated to be 2 minutes. Assuming the higher outflow for 2 minutes, and then a constant outflow of 7,710 gpm for 8 minutes, approximately 86,800 gallons of water would be used during the assumed 10 minute switchover time.

Initiation of switchover is conservatively assumed to occur at the low-low level setpoint with allowance for negative instrument error (tank elevation = 24 feet 7 inches). This level has approximately 503,000 gallons of water remaining within the RWST. The amount of water remaining within the RWST at the completion of switchover would then be approximately 425,900 gallons (tank elevation = 20 feet 10 inches) assuming both residual heat removal pumps automatically stop, and approximately 416,000 gallons (tank elevation = 20 feet 4 inches) assuming one pump fails to stop. Adequate margin in available NPSH for the ECCS pumps exists at this lower RWST level
440.31 (Refer to Section 6.3.2.2.3).

440.32
440.36 Following the completion of the switchover sequence, two of the four containment recirculation pumps would take suction from the containment sump and deliver borated water directly to the RCS cold legs. A portion of the recirculation pump discharge flow would be used to provide suction to the two charging pumps and the two safety injection pumps, which would also deliver directly to the RCS cold legs. As part of the switchover procedures, the suctions of the charging and safety injection pumps are cross-connected in the event of failure of either recirculation pump.

Section 7.5 lists the process information available in the control room to assist the operator in performing the switchover actions.



NOTE:

*INSTRUMENT ERROR IS APPROXIMATELY ±10 INCHES

FIGURE 6.3-6
REFUELING WATER STORAGE TANK WATER LEVELS

MILLSTONE NUCLEAR POWER STATION
UNIT 3
FINAL SAFETY ANALYSIS REPORT

included because of revisions

NRC Letter: May 31, 1983

Question Q440.37 (Section 6.3)

Figure 6.3-1 did not show the flow rate for the containment spray pump. Provide the flow rate for this path. Justify that with the inclusion of this flow rate it will not affect (a) the RWST size, (b) the minimum usable volume remaining in the RWST at initiation of switchover to the cold leg recirculation, and (c) the available NPSH to the ECCS pumps.

Response:

The maximum flow for the quench spray system is approximately 6000 gpm. The actual flow varies with the number of pumps operating, the containment pressure, and the height of the water in the RWST. Section 6.2.2 describes the operation of the quench spray system. A discussion of the RWST volumes has been submitted in the response to NRC Question 440.36. Refer to the response to NRC Question 440.30 for a discussion of available NPSH to the ECCS pumps.

NRC Letter: May 31, 1983

Question Q440.41 (Section 6.3)

Provide a discussion on excessive boron concentration in the reactor vessel and hot leg recirculation flushing related to long-term cooling following a LOCA. During hot leg injection, what will be the minimum expected flow rate in the hot leg, and what is the required flow rate to match boil-off?

The staff position concerning boron dilution is as follows:

1. The boron dilution function shall not be vulnerable to a single active or limited passive failure (i.e., leakages of seals). Specifically, the limiting single active failure should be considered during the short-term period of cooling. During the long-term period of cooling, the limiting single active failure should be considered and so should a limited passive failure be considered, but not necessarily in conjunction with each other

2. The inadvertent operation of any motor-operated valve (open or closed) shall not compromise the boron dilution function, nor shall it jeopardize the ability to remove decay heat from the primary system

3. All components of the system which are within containment shall be designed to Seismic Category I requirements and classified Quality Group B

4. The primary mode for maintaining acceptable levels of boron in the vessel should be established. Should a single failure disable the primary mode, certain manual actions outside the control room may be allowed, depending on the nature of the action and the time available to establish the backup mode

5. The average boric acid concentration in any region of the reactor vessel should not exceed a level of four weight percent below the solubility limits at the temperature of the solution

6. During the post-LOCA long-term cooling, the ECCS normally operates in two modes: the initial cold leg injection mode, followed by the dilution mode. The actual operating time in the cold leg injection mode will depend on plant design and steam binding considerations, but in general, the switchover to the dilution mode should be made between 12 and 24 hours after LOCA

7. The minimum ECCS flow rate delivered to the vessel during the dilution mode shall be sufficient to accommodate the boil-off due to fission product decay heat and possible

liquid entrainment in the steam discharged to the containment and still provide sufficient liquid flow through the core to prevent further increases in boric acid concentration

8. All dilution modes shall maintain testability comparable to other ECCS modes of operation (HPI-short term, LPI-short term, etc). The current criteria for levels of ECCS testability shall be used as guidelines (i.e., Regulatory Guide 1.68, 1.79, GDC 37)

Discuss your conformance to this position.

Response:

Boric acid buildup considerations during long-term cooling have been addressed in the letter from C. Caso of Westinghouse to T. Novak of the NRC dated April 1, 1975. This letter presents the method, assumptions, and results of analysis for a typical 4-loop plant at a core power level of 3411 MWt. During cold-leg recirculation for a cold-leg pipe break, the analysis shows that the boric acid concentration within the reactor vessel and core regions remain at acceptable levels up to the time of hot-leg recirculation.

The maximum allowable boric acid concentration will not be exceeded if hot-leg recirculation is initiated 15 hours after LOCA inception. At this time, the decay heat mass boiloff rate is approximately 20.4 lbm/sec. Assuming failure of one ECCS train, the minimum hot-leg safety injection flow rate for a DECLG break during hot-leg recirculation will be 85 lbm/sec. This flow rate is adequate to match boiloff and to establish a subcooled flow path through the core, from the hot-leg injection point to the cold-leg break location. This hot-leg flow will effectively reduce the vessel boron concentration by delivering relatively dilute recirculation solution to the core. In addition, high head charging flow will continue to be provided to the reactor coolant system cold-legs and will preclude any boron concentration buildup in the vessel for breaks in the hot-leg.

Millstone 3 will utilize simultaneous hot-leg/cold-leg injection to accomplish long-term core cooling following a LOCA. Once hot-leg recirculation is established, the simultaneous injection mode could be maintained indefinitely.

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Question Q440.46 (Section 15.1.5)

You indicate in Table 15.1-2 that in the event of a rupture of a main steam line, the Auxiliary Feedwater System (AFWS), including pumps, water supply, system valves, and piping must be available to supply water to the operable steam generators no later than 10 minutes after the incident. Since the AFWS starts on low-low SG water level or SIS signal, discuss the consequences of additional cooldown caused by early introduction of AFW or the failure of the operator to isolate the AFW to the faulty steam generator.

Response:

The amount of core cooldown is dominated by the conditions of the faulted loop. The FSAR analysis, which is performed consistent with the methodology in WCAP-9227, assumes that at time zero all of the main feedwater flow plus all of the auxiliary feedwater flow is delivered to the faulted steam generator until feedwater isolation occurs. After this time only auxiliary feedwater flow is delivered to the faulted steam generator. Early introduction of auxiliary feedwater flow to the intact steam generators would yield lesser core cooldown (a benefit for DNB) than currently predicted in FSAR Section 15.1.5.

Failure of the operator to isolate the auxiliary feedwater flow to the faulted steam generator would not impact the results because the limiting point of the transient occurs well before the assumed operator action time.

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Question Q440.49 (Section 15.2.8)

What operator actions, if any, are assumed in your analysis of the feedwater system pipe break? If operator actions are assumed, show that sufficient time is available for completion of these actions.

Response:

No operator actions are assumed in the feedwater system pipe break analysis. The operator actions discussed in FSAR Section 15.2.8 and listed in Table 15.2-1 are emergency operating procedures. These procedures are used by the operator to bring the plant to a safe shutdown condition following a secondary system pipe failure.

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Question Q440.50 (Section 15.3.3)

In the reactor coolant pump shaft seizure analysis it is not clear whether a loss of offsite power coincident with the accident has been assumed. The SRP requires that this event should be analyzed assuming turbine trip and coincident loss of offsite power and coastdown of undamaged pumps. Appropriate delay times may be assumed for loss of offsite power if suitably justified. The event should also be analyzed assuming the worst single failure of a safety related active component. Maximum Technical Specification primary system activity and steam generator tube leakage at the rate specified in the Technical Specification should be assumed. Describe how your analysis has considered these assumptions.

Response:

Revised FSAR Section 15.3.3 reflects the reactor coolant pump shaft seizure analysis without offsite power available. It also delineates the time delay for loss of offsite power. The worst single failure assumed is the loss of one protection train.

As stated in FSAR Section 15.3.3.4, Technical Specification primary system activity and Technical Specification steam generator tube leakage rate have been used to evaluate the radiological consequences of a reactor coolant pump shaft seizure accident.

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Question Q440.55 (Section 15.4.4)

Reference or describe the analytical model used to obtain the results in Section 15.4.4.2. Discuss the degree of conservatism incorporated in your analysis.

Response:

The LOFTRAN code (WCAP-7588) was used for the analytical model for the analysis described in FSAR Section 15.4.4.2. Conservative assumptions used are: (1) the maximum relief line flowrate from the isolated loop to the RCS active volume, (2) cold unborated water in the isolated loop and, (3) beginning of life reactivity conditions. Assumption 1 maximizes the core boron dilution rate. Assumption 2 maximizes the amount of reactivity added to the core due to startup of the inactive loop. The third assumption minimizes the reactivity change required for the core to become critical. All of these assumptions combine to yield the most conservative consequences for a startup of an inactive loop event.

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Question Q440.56 (Section 15.4.6)

In Section 15.4.6 you state that "based upon the Applicant's evaluation of current industry reviews, the risk of an inadvertent boron dilution is small. The cost benefit of performing the modification is questionable and the fix does not appreciably increase the safety of the protection system at Millstone 3". You further state that "considering the low frequency of boron dilution events, the work necessary for performing the analysis would not be justified by the likely reduction in risk." We take exception to your justification for not performing an analysis, since a boron dilution event occurs during reactor shutdown the event will not be mitigated by any automatic safety system. Millstone should provide an analysis in accordance to the guidelines of SRP Section 15.4.6. Further, all of the following plant initial conditions should be considered in the analysis: refueling, startup, power operation, (automatic control and manual modes), hot standby, hot shutdown, and cold shutdown.

Response:

This question will be addressed in the boron dilution analysis to be submitted in response to NRC Question 440.8.

Question Q440.57 (Section 15.4.6)

Provide a list of all the instruments and alarms available to alert the operator of the boron dilution event. For each of the cases evaluated in the analysis, identify the alarm that alerts the operator, provide the time interval from this alarm to when the core would go critical, and identify limiting conditions of operation for the Technical Specifications related to the sensors, alarms, and equipment to mitigate all of these events.

Response:

The following reactor trip functions have instruments and alarms associated with them to alert the operator of a boron dilution event.

- Source Range High Flux
- Power Range High Flux
- Overtemperature ΔT

is

For Modes 1 and 2 (start-up and power operation) the MP-3 Probabilistic Safety Study explicitly considers the above instruments and alarms. Since a boron dilution event during Modes 1 and 2 are readily detectable and inconsequential with respect to the plant specific boron dilution analysis, only instrumentation and alarms with respect to Modes 3-6 (Hot Standby, Hot Shutdown, Cold Shutdown and Refueling) are considered within the "Millstone 3 Boron Dilution Analysis for Failures in the Chemical and Volume Control System." These consist primarily of those instruments and alarms associated with the Source Range High Flux signal. Limiting conditions of operation related to the sensors, alarms and equipment to mitigate boron dilution events, as assumed within our analysis, are defined in the Westinghouse Standard Technical Specifications, NUREG-0452, Rev. 4.

In addition to the above mentioned instrumentation and alarms a boronometer alarm and a flow differential alarm, which indicates improper proportioning of reactor make-up water and boric acid solution, warn the operator of a potential boron dilution event. The Volume Control Tank high level alarm provides the operator with indirect indication of a potential boron dilution event.

Question Q440.59 (Section 15.6.3)

You state that with indications provided at the control board and the magnitude of the break flow, the accident diagnostics and isolation procedure can be completed within 30 minutes of initiation of the event. However, the recent steam generator tube rupture events at Ginna, Point Beach, and Prairie island indicate a longer equalization time substantiated by an evaluation of the operator actions necessary to effect pressure equalization and a conservative estimate of the amount of time necessary for each action, as well as an initial delay time. The event should also be analyzed by assuming a most limiting single failure following the accident. A stuck open atmospheric steam dump valve (ADV) may be the most limiting single failure associated with this accident. If another failure is found to be more limiting, we require the Applicant to substantiate that the case of a stuck open ADV on the damaged steam generator is less limiting.

Response:

Northeast Nuclear Energy Company (NNECO) is a member of the Westinghouse Owners Group (WOG) Steam Generator Tube Rupture (SGTR) Licensing issues Subgroup. This subgroup has been formed to address the current licensing issues associated with the Steam Generator tube rupture event. The overall program consists of the following items:

1. Determination of licensing basis operator response time following a design basis SGTR.

2. Development of appropriate analysis methodology for calculating the margin to steam generator overfill based on results from (1).

3. Identification of minimum set of equipment required to recover from an SGTR.

4. Identification of the worst case single failure.

The SGTR Subgroup and Westinghouse representatives met with the NRC in Bethesda, Maryland on February 23, 1984 to discuss the program to resolve the SGTR licensing issues. The overall program which is proposed to resolve the generic aspects of the SGTR licensing issues was outlined. The schedule for resolution of the SGTR licensing issue was also discussed. It is expected that the final report will be completed in October, 1984. During discussions following the subgroup presentation, the NRC stated they would consider changing the licensing issues to confirmatory issues based on a commitment by the applicant to resolve the issues as a part of the WOG SGTR subgroup. NNECO will take the necessary actions to conform with the WOG SGTR subgroup/NRC agreed upon resolutions of this issue.

With this commitment it was agreed during a May 9, 1984 meeting with the RSB reviewer, that this item could be categorized as confirmatory.

TABLE 1.10-1 (Cont)

Item and Title	Position	FSAR Reference
II.K.3.10 Proposed Anticipatory Trip Modification	The MNPS-3 design incorporates this trip modification. The NRC has raised the question of whether the pressurizer power-operated relief valves would be actuated for a turbine trip without reactor trip below a power level of 50 percent (P-9 set point). An analysis has been performed using realistic yet conservative values for the core physics parameters (primarily reactivity feedback coefficients and control rod worths), and a conservatively high initial power, average reactor temperature (T_{avg}), and pressurizer pressure level to account for instrument inaccuracies. The transient was initiated from the setpoint for the P-9 interlock, namely 50 percent of the reactor full power level plus 2 percent for power measurement uncertainty. This is a conservative starting point, and would bracket all transients initiated from a lower power level. The core physics parameters used were the ones that would result in the most positive reactivity feedbacks (i.e., highest power levels). The steam dump valves were assumed to be actuated by the load rejection controller. Based upon the results from the analysis, the peak pressure reached in the pressurizer would be 2,302 psia. The set point for the actuation of the pressurizer power-operated relief valves is 2,350 psia. Even including the ±20 psi pressure measurement uncertainty, there is still a margin of 28 psi between the peak pressure reached and the minimum activation pressure for the pressurizer power-operated relief valves.	10.4.4.1 7.2.1
II.K.3.11 Justification Use of Certain PORVs	The PORVs used in the MNPS-3 design are pilot-operated relief valves supplied by Garrett. This item is not applicable until a plant-specific position regarding MNPS-3 is taken by the NRC.	* 4
II.K.3.12 Confirm Anticipatory Trip	The MNPS-3 design includes an anticipatory reactor trip on turbine trip as discussed in FSAR Section 7.2.1.1.2 (Item 6). The logic for this trip is shown on Figure 7.2-1 (Sheet 16).	7.2.1.1.2
II.K.3.17 Report on Outages of Emergency Core Cooling Systems Licensee Report and Proposed Technical Specification Changes	NNECo. will compile information to determine the frequency and duration of ECCS outages and will use this information to determine if future systems or Technical Specification modifications are necessary.	*

RSB Item 21

Is RWST temperature indicated and alarmed in the control room?

Response: RWST temperature instrumentation is described in FSAR Section 7.3.1.1.5, item 3 under Quench Spray System Instrumentation.

RSB Item 23 What portion of the DWST is dedicated to the auxiliary feedwater system? What instrumentation is provided to ensure the portion of the DWST volume dedicated to the AFWS is available to that system?

Response: The entire volume of the DWST is dedicated to the auxiliary feedwater system. DWST level instrumentation is described in FSAR Sections 7.3.1.1.5 under Auxiliary Feedwater System, and 10.4.9.5.

To be provided on docket.

NRC Question 440.63

The input parameters used in the ECCS analysis as indicated in Table 15.6-8 shows the total peaking factor (F_Q) assumes the value of 2.14, while Table 4.3-2 shows a peaking factor of 2.32 as a nuclear design parameter. Clarify the discrepancy and justify why the higher peaking factor of 2.32 should not be used for the ECCS anlysis. Discuss the effects of using a higher peaking factor in the ECCS analysis.

Response

The ECCS large break analysis has been recalculated resulting in a peaking factor (F_Q) of 2.32. Appropriate FSAR modifications will be provided in a future amendment to the FSAR.