Entergy

Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, MA 02360

Robert G. Smith, P.E.
Site Vice President

November 09, 2011

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: Entergy Nuclear Operations, Inc.
Pilgrim Nuclear Power Station
Docket No.: 50-293
License No.: DPR-35

FSAR Update Revision 28, Technical Specifications Bases Changes, 10 CFR 50.59(d) Report, and Commitment Changes

LETTER NUMBER: 2.11.057

This letter submits Final Safety Analysis Report (FSAR) Revision 28 update pages for Pilgrim Nuclear Power Station. This update is submitted in accordance with 10 CFR 50.71(e) requirements and includes changes implemented during fuel cycle 18, ending with refueling outage 18 as contained in Attachments 1 & 2.

Also included are Technical Specification (TS) Bases changes performed during the last cycle in accordance with TS 5.5.6(b) (Attachment 3). Additionally, a list of new 10 CFR 50.59 evaluations performed during this period are summarized in Attachment 4. There were no commitment changes during this period.

There are no commitments contained in this letter. If you have any questions regarding the information contained in this letter, please contact Joseph R. Lynch, Licensing Manager at (508) 830-8403.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on the 9th day of November 2011.

Sincerely,

R G Smith

Robert G. Smith P.E.
Site Vice President

RMB/rmb

A001
A053
NRR

Attachment 1: Filing Instructions for FSAR Revision 28, Change-out pages (7 Pages)
Attachment 2: FSAR Revision 28 Change-out pages (See Filing Instructions)
Attachment 3: Changes to the Technical Specifications Bases (6 Pages)
Attachment 4: List of 10 CFR 50.59(d) Evaluations (2 Pages)

cc:

Mr. William M. Dean
Regional Administrator, Region 1
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406-1415
(w/o Attachments)

Mr. Richard V. Guzman, Project Manager
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Mail Stop O-8-C2
Washington, DC 20555

Senior Resident Inspector
Pilgrim Nuclear Power Station

ATTACHMENT 1

Filing Instructions for FSAR Revision 28, Change-out pages

(7 Pages)

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 1

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP1 – Rev 27	EP1 – Rev 28
Section 1 TOC	Entire Section 1 TOC	Section 1 TOC – Rev 28*
Section 2 TOC	Entire Section 2 TOC	Section 2 TOC – Rev 28*
Section 3 TOC	Entire Section 3 TOC	Section 3 TOC – Rev 28*
3.2	Pages 1-11	Pages 1-11
3.2	Table 3.2-1, page 1 of 1	Table 3.2-1, page 1 of 1
3.2	Figure 3.2-1, pages 1 of 3	Figure 3.2-1, pages 1 of 4
3.4	Pages 7,8,16-38	Pages 7,8,16-38
3.6	Page 5	Page 5
3.7	Pages 1-11	Pages 1-12
3.7	Table 3.7.1 page 1 of 1	Table 3.7.1 page 1 of 1
3.8	Pages 1-7	Pages 1-8
3.9	Pages 1-3	Pages 1-3

*Text without revision bars was reformatted only.

Filing Instructions

PNPS-FSAR

Revision 28 – October 2011

Volume 2

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP2 – Rev 27	EP2 – Rev 28
Section 4 TOC	Entire Section 4 TOC	Section 4 TOC – Rev 28*
4.2	Pages 1-24	Pages 1-21
4.4	Pages 1-9	Pages 1-10
4.4	Table 4.4-1	Table 4.4-1
4.4	Figure 4.4-1	Figure 4.4-1 page 1 of 2
4.4	Figure 4.4-2	Figure 4.4-2 page 2 of 2
4.7	Pages 1-6	Pages 1-7
4.10	Pages 1-7	Pages 1-8
Section 5 TOC	Entire Section 5 TOC	Section 5 TOC – Rev 28*
5.2	Page 8	Page 8
5.2	Table 5.2-4 page 6 of 15	Table 5.2-4 page 6 of 15
5.2	Table 5.2-4 page 11 of 15	Table 5.2-4 page 11 of 15
5.2	Table 5.2-4 page 12 of 15	Table 5.2-4 page 12 of 15
Section 6 TOC	Entire Section 6 TOC	Section 6 TOC – Rev 28*
6.3	Table 6.3-1 page 1 of 1	Table 6.3-1 page 1 of 1
6.4	Pages 1-8	Pages 1-9
6.5	Pages 1-11	Pages 1-13
6.6	Pages 1-3	Pages 1-4

*Text without revision bars was reformatted only.

Filing Instructions

PNPS-FSAR

Revision 28 – October 2011

Volume 3

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C – Rev 28
LOEP	EP3 – Rev 27	EP3 – Rev 28
Section 7 TOC	Entire Section 7 TOC	Section 7 TOC – Rev 28
7.4	Pages 1-28	Pages 1-31
7.4	Table 7.4-1 page 1 of 1	Table 7.4-1 page 1 of 1
7.14	Page 1	Page 1

*Text without revision bars was reformatted only.

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 4

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C – Rev 28
LOEP	EP4 – Rev 27	EP4 – Rev 28
Section 8 TOC	Entire Section 8 TOC	Section 8 TOC – Rev 28
8.2	Pages 1-8	Pages 1-9
8.3	Pages 1-4	Pages 1-4
8.8	Pages 1-4	Pages 1-5
8.9	Pages 1-7	Pages 1-8
Section 9 TOC	Entire Section 9 TOC	Section 9 TOC – Rev 28
Section 10 TOC	Entire Section 10 TOC	Section 10 TOC – Rev 28
10.3	Pages 1-9	Pages 1-10
10.8	Pages 1-14	Pages 1-16
Section 11 TOC	Entire Section 11 TOC	Section 11 TOC – Rev. 28*
11.9	Page 1	Page 1
Section 12 TOC	Entire Section 12 TOC	Section 12 TOC – Rev 28*
12.4	Pages 1-6	Pages 1-7

*Text without revision bars was reformatted only.

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 5

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP5 – Rev 27	EP5 – Rev 28
Section 13 TOC	Entire Section 13 TOC	Section 13 TOC – Rev 28
13.2	Pages 1-10	Pages 1-9
Section 14 TOC	Entire Section 14 TOC	Section 14 TOC – Rev 28
14.4	Pages 1-8	Pages 1-9
14.5	Pages 1-32	Pages 1-34
14.5	Table 14.5-4 page 1 of 1	Table 14.5-4 page 1 of 1
14.5		Table 14.5-4A page 1 of 1
14.5	Table 14.5-5 page 1 of 1	Table 14.5-5 page 1 of 1
14.7	Page 2	Page 2
Appendix A TOC	Entire Appendix A TOC	Appendix A TOC – Rev 28*
Appendix A.1	Pages 1-3	Pages 1-7
Appendix B TOC	Entire Appendix B TOC	Appendix B TOC – Rev 28*
Appendix B.1	Pages 1-22	Pages 1-26

*Text without revision bars was reformatted only.

Filing Instructions

PNPS-FSAR

Revision 28 – October 2011

Volume 6

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP6 – Rev 27	EP6 – Rev 28*

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 7

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP7 – Rev 27	EP7 – Rev 28
Appendix L TOC	Entire Appendix L TOC	Appendix L TOC – Rev 28*
Appendix L.3	Pages 1-12	Pages 1-13
	Table L.3-1 Page 1 of 1	Table L.3-1 Page 1 of 1
Appendix Q TOC	Entire Appendix Q TOC	Appendix Q TOC - Rev 28
Appendix Q.1	Pages 1-3	Pages 1-4

ATTACHMENT 2

FSAR Revision 28 Change-out pages

(See Filing Instructions)

ATTACHMENT 3

Changes to the Technical Specifications Bases

(6 pages)

3.9 AUXILIARY ELECTRICAL SYSTEM (Cont)

The Pilgrim battery system is comprised of two 125 volt and one 250 volt systems each normally supplied by a battery charger. In addition, (1) a 125 volt shared back-up battery charger is supplied, which can be used for either 125 volt battery and (2) a 250 volt back-up battery charger is supplied. On loss of a normal battery charger, the back-up charger can be used.

The battery systems are normally maintained at greater than 132.6 volts for the 125 volt battery system and greater than 265.3 volts for the 250 volt battery system by their individual battery chargers.

Battery voltage will decrease below the normally maintained voltage if the battery charger is disconnected. The magnitude of the voltage decrease is related to the load being supplied by the battery and the time the battery has been isolated from the battery charger. The voltage of a fully charged battery disconnected from the battery charger with normal station operating loads would remain greater than 119.0 volts for the 125 volt system and 238.0 volts for the 250 volt system. A battery terminal voltage of equal to or greater than 119.0 volts for the 125 volt system or 238.0 volts of the 250 volt system under normal station load is capable of supporting bounding accident shutdown loads over the 8-hour service load period. The battery terminal voltage will decrease further with higher load levels but will still remain capable of performing its design function, based on the Pilgrim DC load flow studies results.

The battery terminal voltage of 105 volts for the 125 volt system and 210 volts for the 250 volt system are the voltage values used during the battery performance testing to denote a fully discharged battery. A battery that maintains a terminal voltage during performance test of greater than 105 volts for the 125 volt system (or 210 volts for the 250 volt system) for longer than 8 hours at rated load has a capacity of greater than 100% of its rating. If the battery terminal voltage reaches 105 volts (or 210 volts) at rated load in less than 8 hours the battery capability is less than 100%.

Automatic second level undervoltage (Degraded Voltage) protection is installed on the startup transformer and is available when safety related loads are being supplied from this source. During normal operation, the unit auxiliary transformer supplies safety related buses. Automatic second level undervoltage protection is not installed on the unit auxiliary transformer. The Safety Bus Degraded Voltage Alarm System and Degraded Voltage Operating Procedure will be relied upon to guide Operator action to preclude operation with a degraded bus voltage condition.

Each of the two motor generator sets and the alternate power supply for the Reactor Protection System (RPS) have two Electrical Protection Assemblies (EPAs), installed in series, between the RPS 120 Volt 60H_Z power source and its respective RPS bus. A random, or seismically-induced abnormal voltage or frequency condition on the output of an MG Set or on the alternate supply would trip one or both of the EPAs. This protects the RPS components and auxiliaries from damage due to sustained abnormal voltage conditions (overvoltage, undervoltage or underfrequency).

BASES:

3/4.6 PRIMARY SYSTEM BOUNDARY (Cont)

B. Coolant Chemistry

The reactor vessel coolant chemistry requirements are discussed in Subsection 4.2 of the FSAR.

A radioactivity concentration of 20 μ Ci/ml total iodine can be reached if there is significant fuel failure or if there is a failure or a prolonged shutdown of the cleanup demineralizer. Calculations performed by the AEC staff for this activity level results in a radiological dose at the site boundary of 8 rem to the thyroid from a postulated rupture of a main steam line assuming a 5 second valve closing time and a coolant inventory release of 3 x 10^4 lbs.

A reactor sample will be used to assure that the limit of Specification 3.6.B.1 is not exceeded.

The iodine radioactivity will be monitored by reactor water sample analysis. The total iodine activity would not be expected to change over a period of 96 hours. In addition, the trend of the stack off-gas release rate, which is continuously monitored, is an indication of the trend of the iodine activity in the reactor coolant. Since the concentration of radioactivity in the reactor coolant is not continuously measured, coolant sampling would be ineffective as a means to rapidly detect gross fuel element failures. However, some capability to detect gross fuel element failures is inherent in the radiation monitors in the off-gas system and on the main steam lines.

BASES:

3/4.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage

Allowable leakage rates of coolant from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes and on the ability to makeup coolant system leakage in the event of loss of offsite a-c power. The normally expected background leakage due to equipment design and the detection capability for determining coolant system leakage were also considered in establishing the limits. The behavior of cracks in piping systems has been experimentally and analytically investigated as part of the USAEC sponsored Reactor Primary Coolant System Rupture Study (the Pipe Rupture Study). Work utilizing the data obtained in this study indicates that leakage from a crack can be detected before the crack grows to a dangerous or critical size by mechanically or thermally induced cyclic loading, or stress corrosion cracking or some other mechanism characterized by gradual crack growth. This evidence suggests that for leakage somewhat greater than the limit specified for unidentified leakage, the probability is small that imperfections or cracks associated with such leakage would grow rapidly. However, the establishment of allowable unidentified leakage greater than that given in 3.6.C on the basis of the data presently available would be premature because of uncertainties associated with the data. For leakage of the order of 5 gpm, as specified in 3.6.C, the experimental and analytical data suggest a reasonable margin of safety that such leakage magnitude would not result from a crack approaching the critical size for rapid propagation. Leakage less than the magnitude specified can be detected reasonably in a matter of a few hours utilizing the available leakage detection schemes, and if the origin cannot be determined in a reasonably short time the plant should be shut down to allow further investigation and corrective action.

Verification of the integrity of the reactor coolant system (3.6.C.1.a.1: No Pressure Boundary Leakage) is provided during RPV Class I system hydrostatic and leak tests.

Two leakage collection sumps are provided inside primary containment. Identified leakage is piped from pump seal leakoffs, reactor vessel head flange seal leakoff, selected valve stem leakoff including recirculation loop and main steam isolation valves, and other equipment drains to the drywell equipment drain sump. The second sump, the drywell floor drain collection sump receives leakage from the drywell coolers, control rod drives, other valve stems and flanges, floor drains, and closed cooling water system drains. Drainage into the drywell floor drain sump is generally considered Unidentified Leakage. Both sumps are equipped with level and flow monitoring equipment to alert operators if allowable leak rates are approached.

A drywell sump monitoring system, as required in 3.6.C.2, consists of one equipment sump pump and one floor drain sump pump, plus associated instrumentation. The basic instrument system for the drywell floor drain sump is comprised of a flow integrator that is used to record the flow of liquid from the drywell floor drain sump. The drywell equipment drain sump is equipped similarly. A manual system whereby the time interval between sump pump starts is utilized to provide a back-up to the flow integrator if the instrumentation is found to be inoperable. This time interval determines the leakage flow using the tested capacity of the pump.

The 2 gpm limit for unidentified coolant leakage rate increase within any 24 hour period is a limit specified by the NRC in Generic Letter 88-01: "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping". This limit applies only during the RUN mode to accommodate the expected coolant leakage increase during pressurization.

The total leakage rate consists of all leakage, which flows to the drywell equipment drain sump (Identified leakage) and floor drain sump (Unidentified leakage).

E. Jet Pumps

The jet pumps are part of the Reactor Coolant Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. Jet pump OPERABILITY is an explicit assumption in the design basis loss of coolant accident (LOCA) analysis. The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two-thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the Reactor Coolant Recirculation System will be consistent with the assumptions used in the licensing basis analysis.

The jet pumps are required to be OPERABLE when the reactor is operating in the Run or Startup Modes since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the Reactor Coolant Recirculation System.

An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding during a design basis LOCA. If one or more of the jet pumps are inoperable, the plant must be brought to a Mode in which the LCO does not apply. To achieve this status, the plant must be brought to Hot Shutdown within 12 hours. The Completion Time of 12 hours is reasonable, based on operating experience, to reach Hot Shutdown from full power conditions in an orderly manner and without challenging plant systems.

The surveillance is designed to detect significant degradation in jet pump performance that precedes jet pump failure. The surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures. Each recirculation loop must satisfy one of the performance criteria provided. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation, off-normal operating conditions, and changes in monitoring equipment may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns", engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

E. Jet Pumps (Cont)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in GE SIL No. 330, June 9, 1980.

The 24 hour frequency has been shown by operating experience to be timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

The surveillance is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation. Note 2 allows the surveillance not to be performed when thermal power is ≤ 25% of rated thermal power. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data.

F. Recirculation Loops Operating

The LPCI loop selection logic has been previously described in the Pilgrim Nuclear Power Station FSAR. For some limited low probability accidents with the recirculation loop operating with large speed differences, it is possible for the logic to select the wrong loop for injection. For these limited conditions the core spray itself is adequate to prevent fuel temperatures from exceeding allowable limits. However, to limit the probability even further, a procedural limitation has been placed on the allowable variation in speed between the recirculation pumps.

The licensee's analyses indicate that above 80% power the loop select logic could not be expected to function at a speed differential of 15%. At or below 80% power the loop select logic would not be expected to function at a speed differential of 20%. This specification provides a margin of 5% in pump speed differential before a problem could arise. If the reactor is operating on one pump, the loop select logic trips that pump before making the loop selection.

The flow mismatch restriction also derives from the "Core Flow Coastdown" concern. This concern postulates that if the recirculation loop with the higher flow is broken, the "effective core flow" is determined by the loop with the lower flow. Compared to a matched flow condition, this would start pump coastdown from a lower flow/speed with the reactor power effectively above the rated rod line. Therefore, boiling transition may occur earlier during a postulated LOCA event, which could result in higher calculated peak cladding temperatures (PCTs). Therefore, the purpose of the "Core Flow Coastdown" flow mismatch restriction is to maintain Pilgrim within its analyzed conditions.

F. Recirculation Loops Operating (Cont)

A plant specific LOCA analysis has been performed assuming only one operating recirculating loop. This analysis has demonstrated that, in the event of a LOCA caused by pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly.

The transient analyses of Chapter 14 of the FSAR have also been performed for single loop operation and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During single loop operation, modification of the Reactor Protection System average power range monitor (APRM) instrument setpoints is also required to account for the different relationships between recirculation drive flow and the reactor core flow. The APLHGR, MCPR and APRM limits for single loop operation are specified in the COLR

ATTACHMENT 4

List of 10 CFR 50.59(d) Evaluations

(2 pages)

50.59 Evaluation Summary SE-3404

Description of Change:
PNPS Procedure 2.2.21.5 "HPCI Injection and Pressure Control" provides detailed instruction for personnel to operate the High Pressure Coolant Injection (HPCI) System during injection and pressure control modes of operation. Attachment 1, Section 8.0 "PREVENTING HPCI INJECTION" places P-229, HPCI AUX OIL PUMP control switch in "PULL-TO-LOCK" which precludes HPCI from performing its design function to automatically initiate to inject water into the reactor via the Feedwater System to maintain adequate core cooling. This procedure section was originally added in Revision 8 in March of 2000 and was subsequently revised again in April 2010. The safety evaluation addresses both the Revision 8 and the Revision 17 changes.

Summary of 50.59 Evaluation:

Procedure 2.2.21.5, Section 8.0 to Attachment 1, was added by Revision 8:

"8.0 PREVENTING HPCI INJECTION

NOTE

This section is to be performed when it becomes necessary to prevent HPCI from initiating. This section should only be used when:

- Another Procedure is directing you to prevent injection from HPCI.
  OR
- Upon direction from the Operations Shift Superintendent."

Procedure 2.2.21.5, Section 8.0 to Attachment 1, was subsequently revised in Revision 17 to identify the following:

"8.0 PREVENTING HPCI INJECTION

NOTE

1. Performance of this section makes HPCI INOPERABLE but available.

2. This section is to be performed when it becomes necessary to prevent HPCI from initiating. This section should only be used when:

- Another Procedure is directing you to prevent injection from HPCI.
  OR
- Upon direction from the Shift Manager/Control Room Supervisor in response to an increasing drywell pressure condition with adequate core cooling verified by two independent instruments.

[1] **DECLARE** HPCI is being made INOPERABLE, BUT AVAILABLE

[2] ...."

Revision 17 clarified limitations for procedure step usage.

Taking manual control of the actuation of the HPCI System by placing the HPCI AUX OIL PUMP control switch in "PULL-TO-LOCK" is in conflict with the literal interpretation of Safety Design Basis 4 (the automatic initiation of HPCI upon the occurrence of a drywell high pressure condition and/or reactor water low-low level condition).

The procedure changes are predicated on:

1. The operating staff observing that the plant is approaching a condition (high drywell pressure) which would automatically result in HPCI System initiation and injection into the reactor at a time when adequate core cooling is assured (reactor water level is above the Emergency Operating Procedure (EOP) EOP-01 entry condition of +12 inches); <u>or</u>

2. The EOPs are directing that HPCI System injection be prevented to control reactor water level. Performance of these actions during execution of the EOPs was analyzed in the Boiling Water Reactor Owners Group (BWROG) Emergency Procedures Guidelines (EPGs), Rev 4. The Nuclear Regulatory Commission (NRC) approved operation in accordance with the EPGs in NRC letter to the BWROG dated September 12, 1988 "Safety Evaluation of the BWR Owner's Group – Emergency Procedure Guidelines, Revision 4, NEDO 31331, March 1987". In 2001, SE 3389 reaffirmed the safety of the EOP guidance upon adoption of BWROG EPGs/SAGs Rev 2. (SAGs are Severe Accident Guidelines).

NOTE: The HPCI automatic initiation signal setpoints are parameter values that are reached at or after the EOP entry conditions are met.

Since PNPS 2.2.21.5 Rev 8, Attachment 1, Section 8.0 did not restrict placing the HPCI Aux Oil Pump to the "PULL-TO-LOCK" position only when the EOPs are being executed, defeating of the <u>automatic</u> initiation of the HPCI System by the taking of manual control of the actuation of the HPCI System by placing the HPCI AUX OIL PUMP control switch in "PULL-TO-LOCK" <u>prior to</u> entering the EOPs required a 50.59 Safety Evaluation to be performed.

A detailed 50.59 safety evaluation review of HPCI System response to the accident types, transients, and special events as defined in the PNPS Updated Final Safety Analysis reports was performed. The evaluation concluded that prior NRC approval is not required for the situations during which the procedure revisions were intended (i.e., water level verified, adequate core cooling safety function satisfied, and HPCI system injection would be terminated as allowed by EOPs when or if the high drywell pressure setpoint was reached).

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 1

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP1 – Rev 27	EP1 – Rev 28
Section 1 TOC	Entire Section 1 TOC	Section 1 TOC – Rev 28*
Section 2 TOC	Entire Section 2 TOC	Section 2 TOC – Rev 28*
Section 3 TOC	Entire Section 3 TOC	Section 3 TOC – Rev 28*
3.2	Pages 1-11	Pages 1-11
3.2	Table 3.2-1, page 1 of 1	Table 3.2-1, page 1 of 1
3.2	Figure 3.2-1, pages 1 of 3	Figure 3.2-1, pages 1 of 4
3.4	Pages 7,8,16-38	Pages 7,8,16-38
3.6	Page 5	Page 5
3.7	Pages 1-11	Pages 1-12
3.7	Table 3.7.1 page 1 of 1	Table 3.7.1 page 1 of 1
3.8	Pages 1-7	Pages 1-8
3.9	Pages 1-3	Pages 1-3

*Text without revision bars was reformatted only.

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

SECTION 2

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

LIST OF EFFECTIVE PAGES

VOLUME 1VOLUME 1**VOLUME 1**VOLUME 1**VOLUME 1**

SECTION 1

INTRODUCTION AND SUMMARY

TABLE OF CONTENTS

SECTION 1

INTRODUCTION AND SUMMARY

TABLE OF CONTENTS

SECTION 1

INTRODUCTION AND SUMMARY

TABLE OF CONTENTS

SECTION 1

INTRODUCTION AND SUMMARY

TABLE OF CONTENTS

SECTION 1

INTRODUCTION AND SUMMARY

TABLE OF CONTENTS

SECTION 1

LIST OF TABLES

SECTION 1

LIST OF FIGURES

SECTION 2

STATION SITE AND ENVIRONS

TABLE OF CONTENTS

TABLE OF CONTENTS (CONT)

SECTION 2

LIST OF TABLES

LIST OF TABLES (Cont)

SECTION 2

LIST OF FIGURES

LIST OF FIGURES (Cont)

SECTION 3

REACTOR

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

SECTION 3

LIST OF TABLES

SECTION 3

LIST OF FIGURES

LIST OF FIGURES (Cont)

3.2 FUEL MECHANICAL DESIGN

The fuel assembly is to provide substantial fission product retention capability during all potential operational modes and sufficient structural integrity to prevent operational impairment of any reactor safety equipment. The fuel assembly and its components are designed to withstand:

a. the predicted thermal, pressure, and mechanical interaction loadings occurring during startup testing, normal operation, and abnormal operational transients without impairment of operational capability;

b. loading predicted to occur during handling without impairment of operational capability;

c. in-core loading predicted to occur from an operating basis earthquake (OBE) occurring during normal operating conditions, without impairment of operational capability;

and are evaluated for their capability to withstand:

a. in-core loading predicted to occur from a Safe Shutdown Earthquake (SSE) when occurring during normal operation;

b. control rod drop, pipe breaks inside and outside containment, fuel handling and one recirculation pump seizure accidents.

Further discussion on the functional design requirements of the fuel assembly is provided in Reference 1. Specific criteria are referenced below.

3.2.1 Fuel System Damage

This subsection applies to normal operation and anticipated operational occurrences except for Subsections 3.2.1.3, 3.2.1.6 and 3.2.1.7, which apply to normal operation only.

3.2.1.1 Stress/Strain

Bases

The fuel assembly components are evaluated to ensure that the fuel will not fail due to stresses or strains exceeding the fuel assembly component mechanical capability.

Limits

The stress/strain limits are discussed in Section 2.2.1.1.2 of Reference 1.

Evaluations

Thermal and mechanical evaluations have been performed for all fuel designs described in Reference 4 and it has been determined that the design limit is met. These evaluations are described in Section 2.2.1.1.3 of Reference 1.

The other fuel assembly stress/strain evaluations are described in References 2, 5 and 8. The model and types of evaluations performed for these events are described in detail in these reports.

3.2.1.2 Fatigue

Bases

The fuel assembly and the fuel rod cladding are evaluated to ensure that strains due to cyclic loadings will not exceed the fatigue capability.

Limits

The design limit for fatigue cycling used to ensure that the design basis is met is discussed in Section 2.2.1.2.2 of Reference 1.

Evaluations

The fatigue evaluations of the fuel assembly and fuel rod cladding have been performed for all fuel designs described in Reference 4 and it has been determined that the design limit is met. These evaluations are discussed in Section 2.2.1.2.3 of Reference 1.

The other fuel assembly fatigue evaluations are described in Reference 2. These reports describe in detail the models used and types of evaluations performed.

3.2.1.3 Fretting Wear

Bases

The fuel assembly is evaluated to ensure that fuel will not fail due to fretting wear of the assembly components.

Limits

To achieve the design basis, the design is evaluated for its potential for fretting wear based on testing and experience with the same or similar designs in operation. A separate limit on fretting wear is not used in design.

Evaluations

One area of the fuel assembly which could be susceptible to fretting wear is the spacer to fuel-rod contact point. Through both in and out-of-reactor testing with spacers, it was determined that the use of an active spring force by the spacer on the fuel rod eliminates the potential for any significant fretting wear. Thus, current spacer designs, including those for all fuel designs documented in Reference 4 are based on the concept of an active spring force.

Significant operating experience with these spacer designs has since shown fretting wear to be essentially eliminated (Reference 6).

3.2.1.4 Oxidation, Hydriding, and Corrosion Products

3.2.1.4.1 Oxidation and Corrosion Products

Bases

The fuel rod is evaluated to ensure that the effects of cladding oxidation and the buildup of corrosion products do not result in fuel rod failure. The bases is stated in Section 2.2.1.4.1.1 of Reference 1.

Limits

To assure that the design bases are satisfied, the expected amount of oxidation and corrosion product buildup on the fuel rod are considered in the fuel rod design analyses. The limits are defined in Section 2.2.1.4.1.2 of Reference 1.

Evaluations

As an integral part of fuel rod thermal-mechanical design evaluations, the effects of cladding oxidation and corrosion product buildup on the fuel rod surface are included. For all fuel designs documented in Reference 4, the effects of cladding oxidation and corrosion product buildup indicate all limits are met.

3.2.1.4.2 Hydriding

Bases

The fuel rod is evaluated to ensure that failure will not occur due to internal clad hydriding.

Limits

The hydriding limit is given in Section 2.2.1.4.2.2 of Reference 1.

Evaluations

The evaluation of hydriding of the fuel rod cladding for all fuel designs documented in Reference 4 is based on the substantial operating experience with fuel designs which employ the same limit. This operating experience has been documented in Reference 6. The experience shows that hydriding is not an active failure mechanism for current fuel designs.

3.2.1.5 Dimensional Changes

Bases

The fuel rod is evaluated to ensure that fuel rod bowing does not result in fuel failure due to boiling transition.

Limits

The limits on dimensional change are given in Section 2.2.1.5.2 of Reference 1.

Evaluations

The operational fuel rod deflection evaluation is described in Section 2.2.1.5.3 of Reference 1. The results of this evaluation indicate that the deflection limits are met for all fuel designs documented in Reference 4.

3.2.1.6 Internal Gas Pressure

Bases

The fuel rod is evaluated to ensure that the effects of fuel rod internal pressure during normal steady-state operation will not result in fuel failure due to excessive clad pressure loading.

Limits

To achieve this objective, the fuel rod internal pressure is limited. This limit is discussed in Section 2.2.1.6.2 of Reference 1.

Evaluations

The limiting fuel rods are evaluated as discussed in Section 2.2.1.6.3 of Reference 1. The results of this evaluation for all fuel designs documented in Reference 4 indicate that the applicable criteria are met.

3.2.1.7 Hydraulic Loads

Bases

The fuel assembly is evaluated to ensure that interference sufficient to prevent control blade insertion will not occur.

Limits

This limit is discussed in Section 2.2.1.7.2 of Reference 1.

Evaluations

These evaluations are described in Section 2.2.1.7.3 of Reference 1. The results of these evaluations, applicable to all fuel designs documented in Reference 4 are reported in Reference 11 for BWR/2, 3 and 4. These results demonstrate that the fuel assemblies satisfy the applicable criteria for all anticipated plant operating conditions.

Two separate aspects of channel box deflection are considered: channel bulge and channel bow. Channel bulge is addressed in Reference 2. In response to an NRC question on initial cores, Reference 12 provides supplementary information to Reference 2. Channel bow affects on thermal margins are discussed in Reference 14. These references apply only to GE channels. The channels supplied by other vendors have been evaluated and are predicted to behave in a similar fashion as GE supplied channels.

3.2.1.8 Control Rod Reactivity

See Sections 3.4 and 3.6.

3.2.2 Fuel Rod Failure

Subsections 3.2.2.1 through 3.2.2.3 apply to normal operation; Subsections 3.2.2.4, 3.2.2.5 and 3.2.2.7 apply to anticipated operational occurrences; and Subsections 3.2.2.6, 3.2.2.8 and 3.2.2.9 apply to postulated accidents.

3.2.2.1 Hydriding

Hydriding is discussed in Subsection 3.2.1.4.2 of this document.

3.2.2.2 Cladding Collapse

Bases

The fuel rod is evaluated to ensure that fuel rod failure due to cladding collapse into a fuel column axial gap will not occur.

Limits

To satisfy this design basis, the fuel rod is evaluated to ensure that cladding structural instability will not occur during normal operation. This limit is discussed in Section 2.2.2.2.2 of Reference 1.

Evaluations

This evaluation is described in Section 2.2.2.2.3 of Reference 1. The results of this evaluation for all fuel designs documented in Reference 4 indicate that cladding creep collapse is not expected to occur.

3.2.2.3 Fretting Wear

Fretting wear is discussed in Subsection 3.2.1.3.

3.2.2.4 Overheating of Cladding

The MCPR fuel cladding integrity safety limit assures over heating of the cladding does not occur. This limit is dependent on the fuel types loaded in the reactor core. The current MCPR safety limit is given in the Technical Specifications.

Overheating of the cladding is addressed in detail in Subsection 4.3.1 of Reference 1.

3.2.2.5 Overheating of Pellets

Bases

The fuel rod is evaluated to ensure that fuel rod failure due to melting will not occur.

Limits

These limits are stated in Section 2.2.2.5.2 of Reference 1.

Evaluations

The limiting fuel rods are evaluated for all fuel designs documented in Reference 4. The results of this evaluation indicate that overheating of the pellets is not expected to occur. These results are presented in Section 2.2.2.5.3 of Reference 1.

3.2.2.6 Excessive Fuel Enthalpy

Excessive fuel enthalpy is discussed in the country-specific supplement to Reference 1.

3.2.2.7 Pellet-Cladding Interaction

Bases

The bases for this evaluation is discussed in Section 2.2.2.7.1 of Reference 1.

Limits

The limits are given in Section 2.2.2.7.2 of Reference 1.

Evaluations

The limiting fuel rods are evaluated for all fuel designs documented in Reference 4. These evaluations are discussed in Section 2.2.2.7.3 of Reference 1. The results of this evaluation show all the limits are satisfied.

3.2.2.8 Bursting

Bursting is addressed in detail in the country-specific supplement to Reference 1.

3.2.2.9 Mechanical Fracturing

Bases

The fuel assembly is evaluated under Safe Shutdown Earthquake and Loss-of-Coolant Accident loading conditions to ensure that loss of fuel assembly coolability, and interference to the degree that control blade insertion is prevented, will not occur.

Limits

The limits used for this evaluation are described in Section 2.2.2.9.2 of Reference 1.

Evaluations

Evaluations of the effect of combined LOCA and seismic loads upon the components of the fuel assembly for all fuel designs documented in Reference 4 are described in Section 2.2.2.9.3 of Reference 1. The results of these evaluations show all limits are satisfied.

3.2.3 Fuel Coolability

This subsection applies to postulated accidents.

3.2.3.1 Cladding Embrittlement

Cladding embrittlement is addressed in the country-specific supplement to Reference 1.

3.2.3.2 Violent Expulsion of Fuel

The radically averaged enthalpy shall not exceed 280 cal/gm during a severe reactivity-initiated accident (such as a control rod drop).

Violent expulsion of fuel is addressed in detail in the country-specific supplement to Reference 1.

3.2.3.3 Generalized Cladding Melting

Generalized cladding melting is bounded by the cladding embrittlement criteria of subsection 3.2.3.1.

3.2.3.4 Fuel Rod Ballooning

Fuel rod ballooning is addressed in the country-specific supplement to Reference 1.

3.2.3.5 Structural Deformation

Structural deformation is addressed in Subsection 3.2.2.9.

3.2.4 Description and Design Drawings

A core cell is defined as a control rod and the four fuel assemblies which immediately surround it. See Figure 3.2-1. Each core cell is associated with a four-lobed fuel support piece. Around the outer edge of the core, certain fuel assemblies are not immediately adjacent to a control rod and are supported by individual peripheral fuel support pieces.

The fuel assembly shown in Figure 3.3-3 consists of a fuel bundle and a channel. With Reload 17 two bundle designs are in use at Pilgrim: GE14 and GNF2. The GE14 and GNF2 fuel types are based on a 10x10 lattice design with part length rods, two large central water rods, an interactive channel, an offset lower tie-plate, advanced high-performance spacers and tie-plates, and axial zoning of both enrichment and gadolinia. Design specifications for the bundle types are presented in Table 3.2-1. The fuel bundle enrichments and reference core loading pattern are documented in Appendix Q.

The GE14 and GNF2 fuel bundles contain 92 fuel rods. Fourteen of these rods are partial length rods. The rods of the GE14 and GNF2 bundle type are spaced and supported in a 10x10 array. The lower tie-plate has a nose piece which has the function of supporting the fuel assembly in the reactor. The upper tie-plate has a handle for transferring the fuel bundle from one location to another. The identifying assembly serial number is engraved on the top of the handle. No two assemblies bear the same serial number. A boss projects from one side of the handle to aid in ensuring proper fuel assembly orientation. Both upper and lower tie-plates are fabricated from Type 304 stainless steel. Zircaloy fuel rod spacers equipped with Alloy X-750 springs are employed to maintain rod-to-rod spacing. For GNF2, Alloy X-750 spacers with integral springs are employed. For GE14 finger springs located between the lower tie-plate and the channel are utilized to control the bypass flow through that flow path. For GNF2 the full thickness channel at the bottom end acts to control the bypass flow without the use of finger springs.

The GE14 fuel bundle is assembled with a debris filter lower tie-plate as standard equipment. Over the many years of nuclear power plant operation, some fuel failures have occurred due to small amounts of debris (wires, springs, drill turnings, etc.) that accumulates in the lower plenum and can be swept into the fuel assembly where it may become lodged in the assembly structure. Once lodged in the fuel assembly, flow induced vibration of the debris can cause fretting wear on fuel rods and may eventually lead to rod failure. The debris filter lower tie-plate prevents this failure mechanism by limiting the size of the debris that can enter the fuel assembly. Reload 16, Cycle 17 fuel and GNF2 fuel are equipped with DEFENDER lower tie plates that offer a tortuous inlet flow path to prevent passage of wires.

Each fuel rod consists of high density ceramic uranium dioxide fuel pellets stacked within Zircaloy cladding that is evacuated, backfilled with helium and sealed with Zircaloy end plugs welded in each end. The fuel pellets are manufactured by compacting and sintering uranium dioxide powder into right cylindrical pellets with flat ends and chamfered edges. Ceramic uranium dioxide is chemically inert to the cladding at operating temperatures and is resistant to attack by water. Several U-235 enrichments are used in the fuel assemblies to reduce the local peak-to-average fuel rod power ratios. Selected fuel rods within each reload bundle also incorporate small amounts of gadolinium as burnable poison. Gd_2O_3 is uniformly distributed in the UO_2 pellet and forms a solid solution.

The fuel rod cladding thickness is adequate to be essentially free-standing under the 1000 psia BWR environment. Adequate free volume is provided within each fuel rod in the form of a pellet-to-cladding gap and a plenum region at the top of the fuel rod to accommodate thermal and irradiation expansion of the UO_2 and the internal pressures resulting from the helium fill gas, impurities, and gaseous fission products liberated over the design life of the fuel. A plenum spring, or retainer, is provided in the plenum space to minimize movement of the fuel column inside the fuel rod during fuel shipping and handling. A hydrogen getter is also provided in the plenum space of GE11 fuel as assurance against chemical attack from the inadvertent admission of moisture or hydrogenous impurities into a fuel rod during manufacturing. Improvements in the manufacturing have allowed the elimination of the hydrogen getter from GE14 and GNF2 fuel.

All fuel rods in GE14 fuel have a six inch natural uranium blanket in the bottom, and 12″ natural uranium at the top of the non-Gd containing full-length fuel rods. Gd containing rods have 6″ natural uranium blankets born at the top and bottom of the fuel rod. Part length rods are 96″ long and have a 12″ plenum at the top. All fuel rods in GNF2 fuel have a 6 inch natural uranium blanket in the bottom and a 6 or 12 inch natural uranium blanket in the top of the full-length fuel rods. Part-length rods are 59 inches and 111 inches long and have 4.6 inch and 8 inch plenums at the top, respectively.

Three types of fuel rods are used in all the fuel bundle designs: tie rods, part-length rods, and standard rods. The tie rods in each bundle have lower end plugs which thread into the lower tie plate and threaded upper end plugs which extend through the upper tie plate. A stainless steel hexagonal nut and locking tab are installed on the upper end plug to hold the fuel bundle together. These tie rods support the weight of the bundle only during fuel handling operations when the assembly hangs by the handle. During operation, the fuel assembly is supported by the lower tie plate. Part length rods are threaded into the lower tie plate and extend up through the fifth spacer for GE14 design. For GNF2, part length rods extend to the third and sixth spacers. All of the standard fuel rods are full length rods. The end plugs of the standard rods have shanks which fit into bosses in the tie plates. An expansion spring is located over the upper end plug shank of each rod in the assembly to keep the rods seated in the lower tie plate while allowing independent axial expansion by sliding within the holes of the upper tie plate.

The GE14 and GNF2 fuel bundles include two large water rods that displace eight fuel rod positions. Details of the water rod construction and integration in the bundle design are provided in Reference 4.

3.2.4.1 Control Rods

See Section 3.4.

3.2.4.2 Velocity Limiter

See Section 3.4.

3.2.5 Testing, Inspection, and Surveillance Plans

Rigid quality control requirements are enforced at every stage of fuel rod manufacturing to ensure that the design specifications are met. Written manufacturing procedures and quality control plans define the steps in the manufacturing process. Fuel cladding is subjected to 100% dimensional inspection and ultrasonic testing to reveal defects in the cladding wall. Destructive tests are performed on representative samples from each lot of tubing, including chemical analysis, tensile, and burst tests. Integrity of end plug welds is controlled by standardization of weld processes based on radiographic and metallographic inspection of welds. Sample tests are performed for qualification of weld stations, weld parameters and weld operators prior to application. Production samples are tested as a check on the process and process controls.

UO_2 powder characteristics and pellet densities, composition, and surface finish are controlled by regular sampling inspections. UO_2 weights are recorded at every stage in manufacturing. Each separate pellet group is characterized by a single stamp. Because individual rods may contain segments of different fuel compositions, physical and administrative controls are utilized during fuel rod assembly. These controls are over checked during fuel rod inspection (e.g., scanning to verify pellet enrichment and proper assembly). Fuel rods are individually serialized prior to fuel loading: (1) to identify which pellet group(s) are to be loaded in each fuel rod; (2) to identify which position in the fuel assembly each fuel rod is to be loaded; and (3) to facilitate total fuel material accountability. Each finished fuel rod is gamma scanned to detect any enrichment or rod pellet loading deviation which exceeds design specification.

Each bundle is given a complete dimensional inspection prior to shipment. Dimensional measurements and visual inspections of critical areas are verified before shipment and again at the reactor site on a planned basis.

Further discussion on the fuel surveillance program can be found in Reference 1.

3.2.6 References

1. "General Electric Standard Application for Reactor Fuel", NEDE-24011-P-A, Revision Number Listed in Latest Supplemental Reload Submittal in Appendix Q.

2. "BWR Fuel Channel Mechanical Design and Deflection", NEDE-21354-P (Proprietary) and NEDO-21354, September 1976.

3. "Creep Collapse Analysis of BWR Fuel Using SAFE-COLAPS Model", NEDE-20606-PA (Proprietary) and NEDO-20606-A, August 1976.

4. "General Electric Fuel Bundle Designs", NEDE-31152P, Revision Number Listed in Latest Supplemental Reload Submittal in Appendix Q.

5. "Fuel Assembly Evaluation of Combined Safe Shutdown Earthquake (SSE) and Loss-of-Coolant Accident (LOCA) Loadings (Amendment 3)", NEDE-21175-3-P-A (Proprietary) and NEDO-21175-3-A, October 1984.

6. Letter from J.S. Charnely (GE) to M.S. Dunenfeld (NRC), "1984 Fuel Experience Report", October 14, 1985.

7. "American National Standard for Light Water Reactors Fuel Assembly Mechanical Design and Evaluation", American Nuclear Society Standards Committee Working Group ANS 57.5, ANSI/ANS-57.5-1981.

8. "Final Assembly Evaluation of Shipping and Handling Loadings", NEDE-23542-P (Proprietary), March 1977.

9. K.W. Hill, et. al., "Effect of a Rod Bowed to Contact on Critical Heat Flux in Pressurized Water Reactor Rod Bundles", American Society of Mechanical Engineers Publication 75-WA/HT-77.

10. E.S. Markowski, et. al., "Effect of Rod Bowing on CHF in PWR Fuel Assemblies", American Society of Mechanical Engineers Publication 77-HT-91.

11. Letter, R.R. Gridley (GE) to D.G. Eisenhut (NRC), "Evaluation of Potential Fuel Bundle Lift at Operating Reactors", July 11, 1977.

12. Letter, G.G. Sherwood (GE) to D.G. Eisenhut (NRC), "In the Matter of 238 Nuclear Island General Electric Standby Safety Analysis Report (GESSAR II) Docket No. 50-557", February 2, 1983.

13. Memo, L.S. Rubenstein (NRC) to R.L. Tedesco (NRC), "SER Input for WNP-2", February 24, 1982.

14. Letter, J.S. Charnley (GE) to R.C. Jones, Jr. (NRC), "Fuel Channel Bow Assessment", MFN086-89, November 15, 1989.

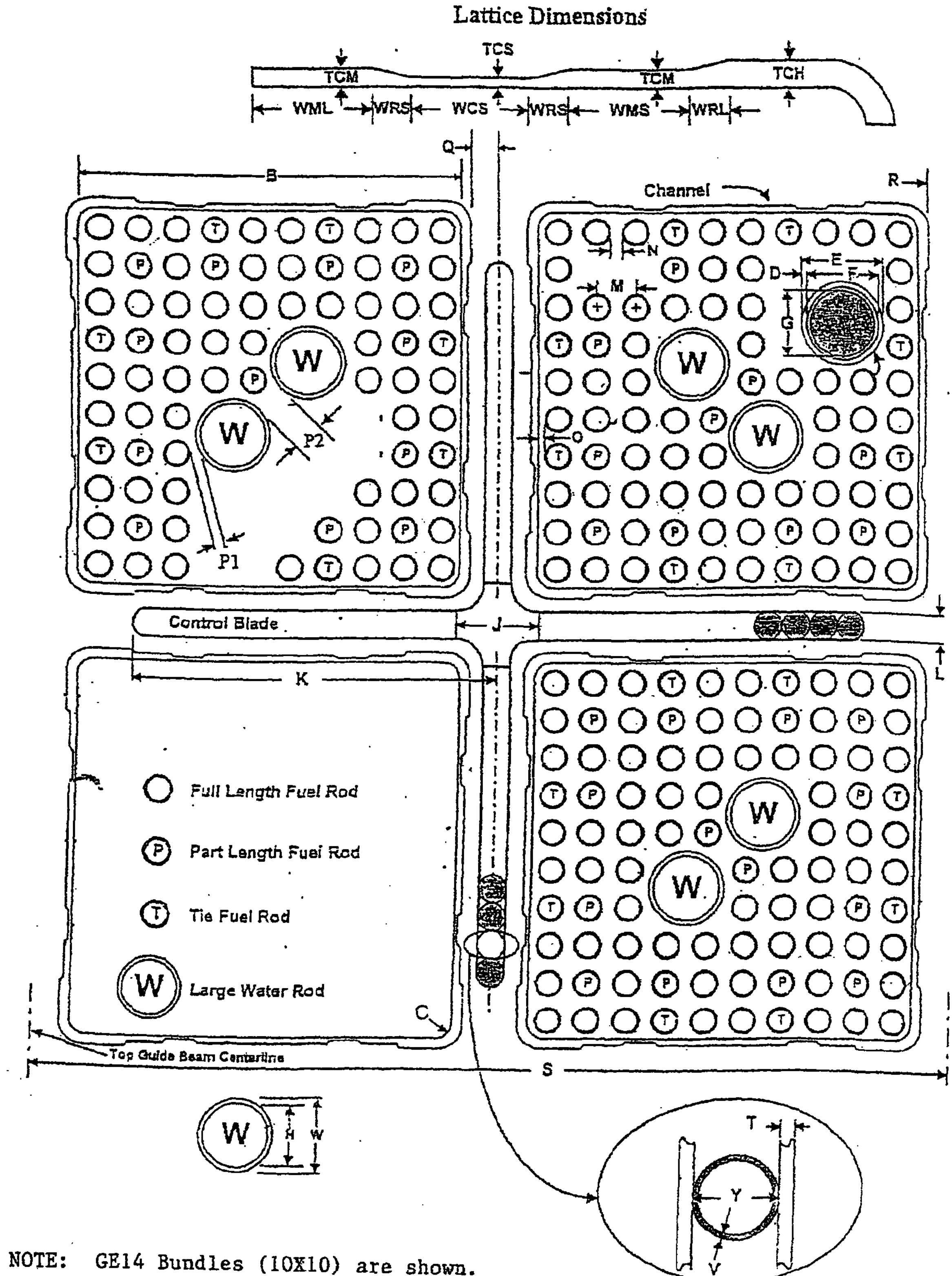
Table 3.2-1

FUEL DATA
GE11 AND GE14 FUEL DESIGNS

	GE11 *	GE14	GNF2
Fuel Assembly			
Geometry	9x9	10x10	10x10
Rod Pitch (in.)	0.566	0.510	0.510
Active Fuel Length (in.)	141.24	145.24	145.24
Heat Transfer Area (ft^2)	95.5	109	110
Debris Filter	No	Yes	Yes
Fuel Rods			
Fill Gas	helium	helium	helium
Fill Pressure (atm)	10	10	10
Getter	yes	No	No
Number of Fuel Rods	74	92	92
Fuel			
Material	sintered UO_2	sintered UO_2	sintered UO_2
Pellet Diameter (in.)	0.376	0.345	0.3496
Pellet Length (in.)	0.380	0.350	0.375
Pellet Immersion Density (%TD)	96.5	97	97
Cladding			
Material	Zr-2+ Zirconium	Zr-2+ Zirconium	Zr-2+ Zirconium
Outside Diameter (in.)	0.440	0.404	0.4039
Total Thickness (in.)	0.028	0.026	0.0236
Barrier Thickness (in.)	0.0035	0.0035	0.0035
Water Rod			
Material	Zr-2	Zr-2	Zr-2
Outside Diameter (in.)	0.980	0.980	0.980
Thickness (in.)	0.030	0.030	0.030
Number of Water Rods	2	2	2
Number of Fuel Rods Displaced	7	8	8
Spacers			
Material	Zr-2 with Alloy X-750 Springs	Zr-2 with Alloy X-750 Springs	Alloy-X-750
Number per Bundle	7	8	8
Fuel Channel			
Material	Zr-2	Zr-2	ZRY-2/ZRY-4
Inside Dimension (in.)	5.278	5.278	5.283
Equivalent** Wall Thickness (in.)	0.0745	0.0745	
Flow Trippers	Yes	No	No

* In cycle 17 core, there is no GE11 fuel. The information in this table is maintained as legacy information as GE11 fuel is in the spent fuel pool.

** Based on cross-sectional area.



NOTE: GE14 Bundles (10X10) are shown.
GE11 has 9X9 lattice with 2 water rods.

Figure 3.2-1
Typical Core Cell

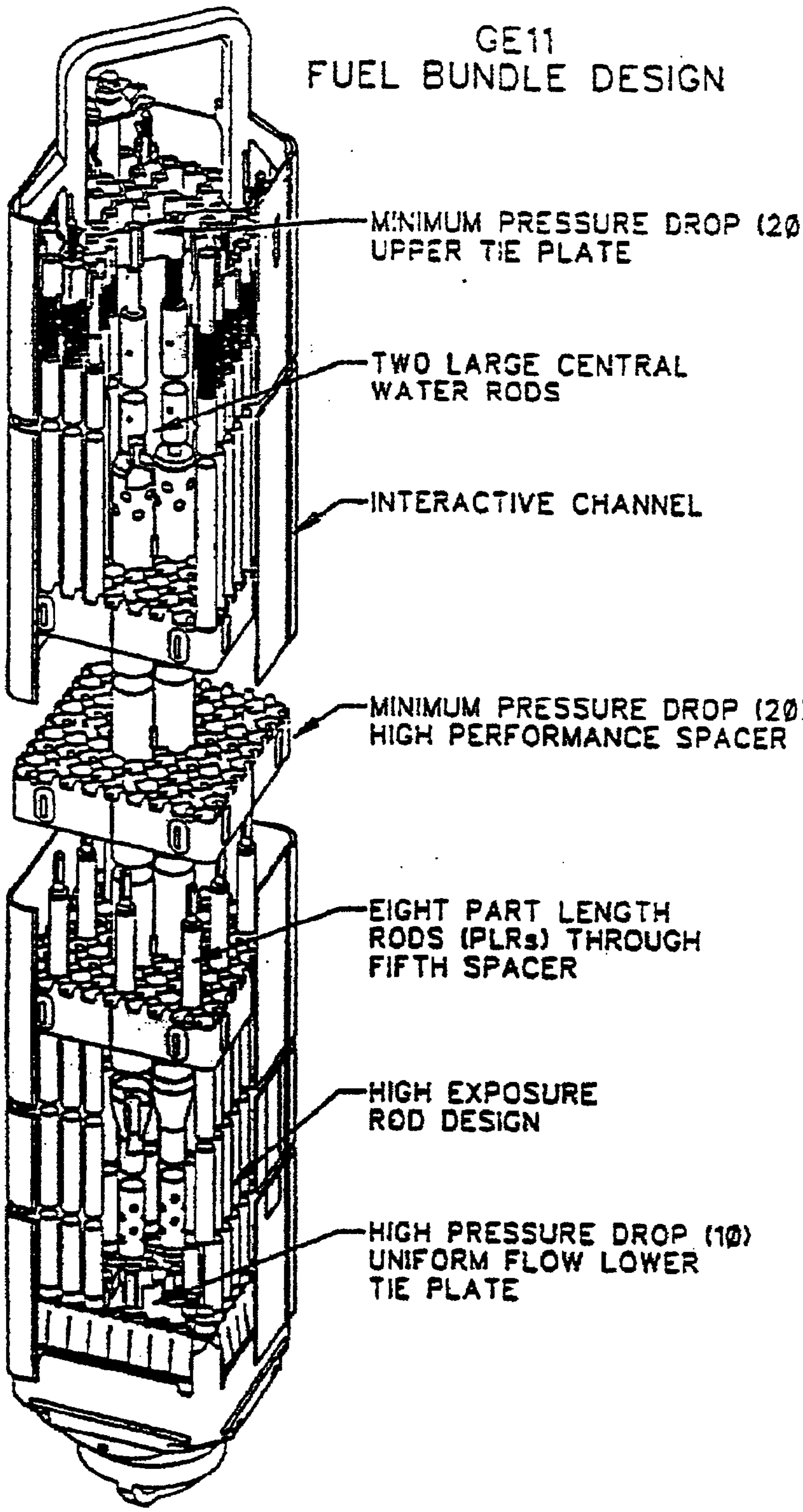


FIGURE 3.2-2
Typical GE11 Fuel Bundle Design

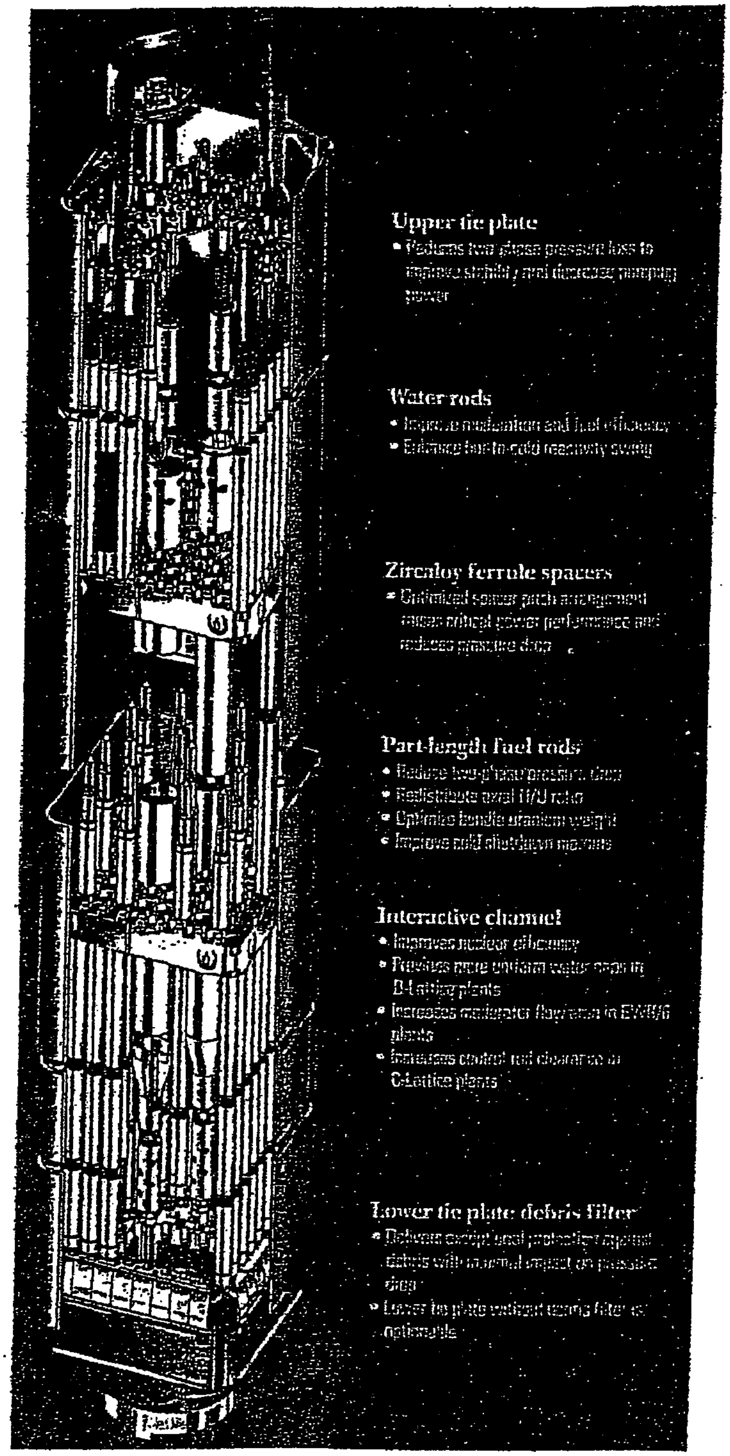


Figure 3.2-3
Typical GE14 Fuel Assembly

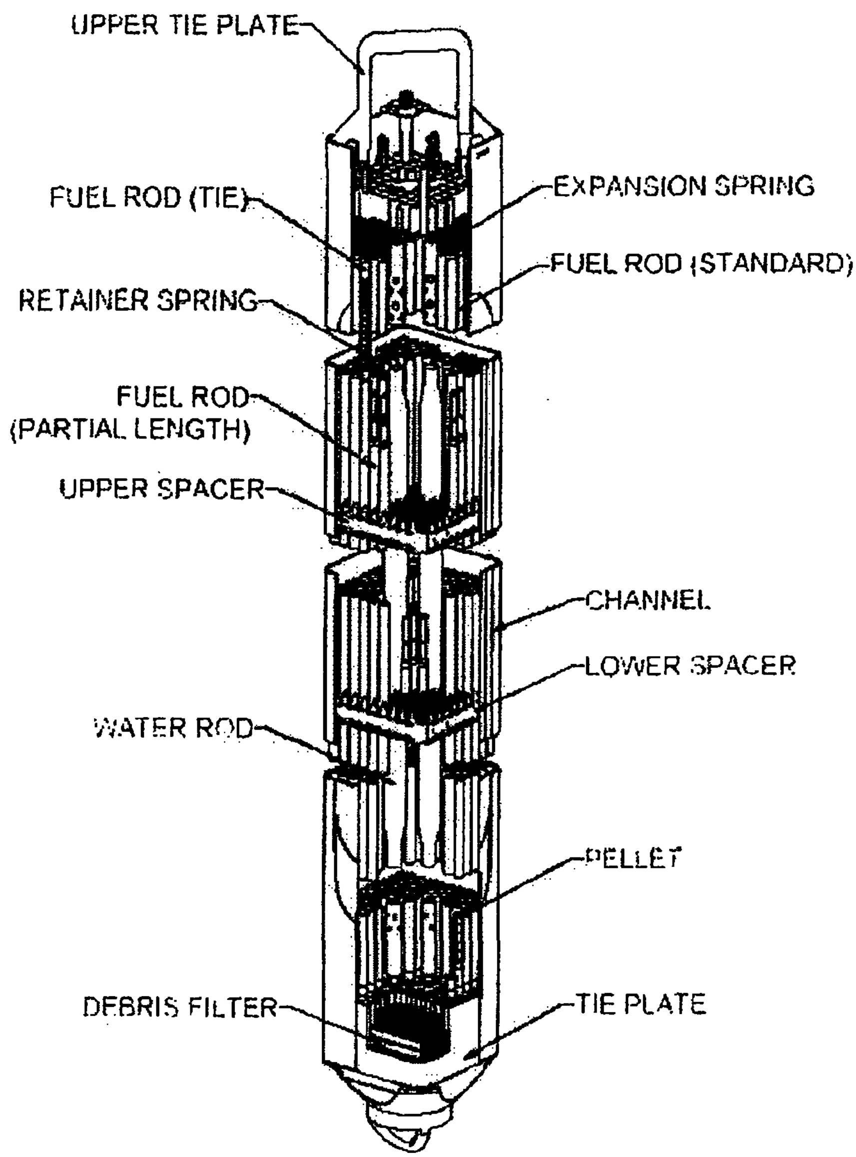


Figure 3.2-4: Typical GNF2 Fuel Assembly

of the absorber tube and sheath arrangement with an array of square absorber tubes, which results in reduced weight and increased absorber volume. The absorber tubes are welded together lengthwise to form the four wings of the control rod. Empty absorber tubes may be used near the tie rods to obtain the desired reactivity worth. The square tubes are circular inside and are or may be loaded with empty capsules, or capsules containing boron carbide or hafnium. Empty capsules are used to provide a plenum for helium released during boron carbide burnup. The boron carbide is contained in separate stainless capsules to prevent its migration. The capsules securely contain the boron carbide while allowing the helium to migrate through the absorber tube.

The reactivity worth is approximately identical (within $\pm$ 5%) to the original equipment control rods and can be used interchangeably without affecting lattice physics, core reload analyses or core monitoring software.

Operational lifetime of the Marathon control rod is determined by the same set of nuclear and mechanical design constraints as with the standard control rod. GE Hitachi Inc. has substituted Marathon D with M7 control rods, which are essentially identical to Marathon D, except that they have spacer pads instead of pins and rollers to avoid cracking/corrosion problems with pin-holes.

The Marathon D control blade meets the requirements of Safety Design Basis 1.a. (Reference 11).

3.4.5.1.2 Control Rod Velocity Limiter

The control rod velocity limiter is an integral part of the bottom assembly of each control rod. This Engineered Safeguard protects against a high reactivity insertion rate by limiting the control rod velocity in the event of a control rod drop accident. It is a one way device in that the control rod scram velocity is not significantly affected, but the control rod dropout velocity is reduced to a permissible limit. See Figures 3.4-3 and 3.4-4.

The velocity limiter is in the form of two nearly mated conical elements that act as a large clearance piston and baffle inside the control rod guide tube over the length of the control rod stroke.

The hydraulic drag forces on a control rod are approximately proportional to the square of the rod velocity and are negligible during normal rod withdrawal or rod insertion. However, during the scram stroke the rod reaches high velocity and the drag forces could become appreciable.

To limit control rod velocity during dropout but not during scram, the velocity limiter is provided with a streamlined profile in the scram (upward) direction. Thus, when the control rod is scrammed, the velocity limiter assembly offers little resistance to the flow of water over the smooth surface of the upper conical element into the annulus between the guide tube and the limiter. In the dropout direction, however, water is trapped by the lower conical element and discharged through the annulus between the two conical sections.

Because this water is jetted in a partially reversed direction into water flowing upward in the annulus, a severe turbulence is created,thereby slowing the descent of the control rod assembly to less than 5 ft/sec at 70°F.

3.4.5.2 Control Rod Drive Mechanisms

The CRD mechanism (drive), used for positioning the control rod in the reactor core, is a double acting, mechanically latched, hydraulic cylinder using water from the Condensate and Demineralized Water Storage Transfer System as its operating fluid. The demineralizer system is the preferred source because of reduced conductivity and oxygen content. See Sections 11.7 and 11.9. The individual drives are mounted on the bottom head of the reactor pressure vessel. Each drive is an integral unit contained in a housing extending below the reactor vessel. The lower end of each drive housing terminates in a flange to which the drive is bolted. The drives do not interfere with refueling and are operative even when the head is removed from the reactor vessel. The drives are accessible for inspection and servicing. The bottom location makes maximum utilization of the water in the reactor as a neutron shield giving the least possible neutron exposure to the drive components. The use of condensate or demineralizer water as the operating fluid eliminates the need for special hydraulic fluid. Drives are able to utilize simple piston seals since the leakage does not contaminate the reactor vessel and helps cool the drive mechanisms. See Figures 3.4-3, 3.4-5, 3.4-6, and 3.4-7.

The drives are capable of inserting or withdrawing a control rod at a slow controlled rate for reactor power level adjustment, as well as providing rapid insertion when required. A locking mechanism on the drive allows the control rod to be locked at every 6 in of stroke over the 12 ft length of the core.

A coupling at the top end of the drive index tube (piston rod) engages and locks into a mating socket at the base of the control rod

The weight of the control rod is sufficient to engage and lock this coupling. Once locked, the drive and rod form an integral unit which must be manually unlocked by specific procedures before a drive and its rod can be separated; this prevents accidental separation of a control rod from its drive.

Each drive positions its control rod in 6 in increments of stroke, and holds it in these distinct latch positions until actuated by the hydraulic system for movement to a new position. Indication is provided for each rod that shows when the insert travel limit or withdraw travel limit is reached. An alarm annunciates when the withdraw overtravel limit on the drive is reached. Normally, the control rod seating at the lower end of its stroke prevents the drive withdraw overtravel limit from being reached. If the drive can reach the withdrawal overtravel limit, it indicates that the control rod is uncoupled from its drive. The over travel limit alarm allows the coupling to be checked.

pressure and flows required for the operation of the control rod drive mechanisms. These hydraulic requirements identified by the function they perform are as follows. See Figures 3.4-9 (Drawing M250), 3.4-10 (Drawing M1D12-4), and 3.4-11 (Drawing M1D12-4).

1. Accumulator charging pressure normal range is 1,380 psig to 1,510 psig. Flow is required only during scram reset or during system startup. Charging water pressures outside of the normal range may occur as drive water pump performance change during its service life.

2. Drive pressure of about 250 psi above reactor vessel pressure is required at a flow rate of approximately 4 gal/min to insert a control rod and 2 gal/min to withdraw a control rod during normal operation.

3. Cooling water to the drives is required at approximately 10 psig above reactor vessel pressure, and at a flow rate of 0.20 to 0.34 gal/min per drive unit. Cooling water may be interrupted for short periods without drive damage.

4. The exhaust water header is maintained at a pressure approximately 15 psi above vessel pressure to receive the flow of the water displaced during normal control operation of the drives.

5. A scram discharge instrument volume of approximately 1.1 gallon per drive to receive the water displaced from the drives during a scram is required. The scram discharge instrument volume is required to contain air at atmospheric pressure, except during scram when it is filled with water until the scram signal is cleared and the system reset. The scram discharge instrument volume will reach reactor pressure following a scram.

6. General Electric (GE) supplied 1-in. pressure equalizing valves are installed between the CRD cooling water header and the exhaust water header. The pressure equalizing valves are self-actuated, and will perform the functions of (a) preventing continuous flow to the normal exhaust water header and coincident reverse flow through the directional control solenoid valve V-121, (b) preventing flow from the carbon steel piping in the normal exhaust water header to the drive cooling water header, and (c) repressurizing the exhaust header following a scram and preventing excessive high CRD operating differential pressure during subsequent operation of a selected CRD.

The CRD hydraulic supply and discharge systems provide the required functions with the pumps, filters, valves, instrumentation, and piping shown on Figure 3.4-9 and described in the following paragraphs.

Duplicate components are included, where necessary, to assure continuous system operation if an inservice component requires maintenance.

Pumps

One supply pump is provided to pressurize the system with water downstream of the condensate demineralizer or the condensate storage tank. One spare pump is on standby. Each pump is installed with a suction strainer and a discharge check valve to prevent bypassing flow backwards through the nonoperating pump.

A minimum flow bypass connection between the discharge of the pump and the condensate storage tank prevents overheating of the pump in the event that the pump discharge is inadvertently closed.

Filters

The filter removes foreign material larger than 50 microns absolute (25 microns nominal) from the hydraulic supply subsystem water. A differential pressure indicator and alarm monitor the filter element as it collects foreign material. A strainer in the filter discharge line guards the hydraulic system in the event of filter element failure.

Accumulator Charging Pressure

The accumulator charging pressure is maintained automatically by a flow sensing element, controller, and an air operated flow control valve. During normal operation, the accumulator charging pressure is established upstream from the flow control valve by the restriction of the flow control valve. During scram, the flow sensing system upstream of the accumulator charging header detects high flow in the charging header and partly closes the flow control valve. The flow control valve is closed enough so that the proper flow to recharge the accumulators is diverted from the hydraulic supply header to the accumulator charging header.

The pressure in the charging header is monitored in the control room with a pressure indicator and low pressure alarm.

During normal operation, the constant flow established through the flow control valves is the sum of the maximum water required to cool all the drives.

Drive Water Pressure

The drive water pressure control valve, which is manually adjusted from the control room, maintains the required pressure in the drive water header.

A flow rate of approximately 6 gpm (the sum of the flow rates required to insert and to withdraw a control rod) normally passes from the drive water pressure header through two solenoid operated stabilizing valves (arranged in parallel) and, then to the cooling water supply header down steam of the drive water pressure control valve. One stabilizing valve passes flow equal to the drive insert flow. The other passes flow equal to the drive withdrawal flow. The appropriate stabilizing valve is closed when operating a drive to divert the required flow to the drive. Thus, the flow through the drive pressure control valve is always constant.

Flow indicators are provided in the drive water header and in the line down stream from the stabilizing valves, so that flow rate through the stabilizing valves can be adjusted. Differential pressure between the reactor vessel and the drive water pressure header is indicated in the control room.

Cooling Water Pressure

The water not required for drive movement passes through the drive water control valve through the cooling water header and then to the reactor vessel.

The flow through the drive water control valve is constant. Therefore, the drive water pressure control valve can maintain the required cooling water pressure with minimum adjustments independent of reactor pressure. Changes in the setting of the pressure control valve is required only to adjust for changes in the cooling requirements of the drives, as their seal characteristics change with time. The cooling water flow is monitored by a flow indicator in the control room. A differential pressure indicator in the control room indicates the difference between reactor vessel pressure and the drive cooling water pressure. Although the drives can function without cooling water, the life of their seals is shortened by exposure to reactor temperatures.

Exhaust Water Header

The exhaust water header takes water during a normal control rod positioning operation, and returns it to the reactor vessel by backflow through the 121 valve of other CRD's. Two equalizing valves are provided between the cooling water line and the exhaust header to repressurize the exhaust header following a scram. This prevents excessively high operation of a selected CRD.

Scram Discharge Volume

The scram discharge volume is used to limit the loss of and contain the reactor vessel water from all the drives during a scram. The volume consists of two separate scram discharge headers and their associated scram discharge instrument volumes (SDIV). During normal plant operation, the discharge volume is empty with two drain valves on each SDIV and two vent valves on each header open. Upon receipt of a scram signal, the drain and vent valves close. Position indicator switches on the drain and vent valves indicate valve position by lights in the main control room.

During a scram, the scram discharge volume partly fills with water which is discharged from above the drive pistons. While scrammed, the CRD seal leakage continues to flow to the discharge volume until the discharge volume pressure equals reactor vessel pressure. There is a check valve in each HCU which prevents reverse flow from the scram discharge header to the drive. When the initial scram signal is cleared from the Reactor Protection System (RPS) the scram discharge volume scram signal is overridden with the key lock override switch and the scram discharge volume is drained.

Two test pilot valves allow the discharge volume valves to be tested without disturbing the RPS. Closing the vent and drain valves allow the outlet scram valve seats to be leak tested by timing the accumulation of leakage inside the scram discharge volume. The test pilot valves also provide for the reset of the air dump system. See Figure 3.9-4.

Three level switches and two level transmitters with analog trip units on each scram discharge instrument volume (SDIV), set at three different water levels, guard against operation of the reactor without sufficient free volume present to receive the scram discharge water in the event of a scram. At the first (lowest) level, each of two analog trip units off of two level transmitters on each SDIV initiate an alarm for operator action. Also, they send signals to the plant computer. At the second level, one level switch on each SDIV initiates a rod withdrawal block to prevent further withdrawal of any control rod. At the third (highest) level, the two level switches and two analog trip units off of two level transmitters on each SDIV (one of each type of instrument for each RPS trip system for each SDIV) initiate a scram to shut down the reactor while sufficient free volume is still present to receive the scram discharge. After a scram, these same level switches must be cleared by draining the scram discharge volume and the air dump system must be reset before reactor operation can be resumed.

Weldolet couplings and socket welded caps are provided on both CRD scram discharge headers to facilitate flushing and decontamination of the headers. Four instrument standpipes are connected to each SDIV. Connections are also provided on instrument standpipes to facilitate flushing and test/calibration of level instruments during reactor power operations.

The piping and equipment pressure parts in the CRD hydraulic supply and discharge subsystems are in accordance with Appendix A.

3.4.5.3.2 Hydraulic Control Units

Each HCU controls a single drive unit. The basic components in each HCU are manual, pneumatic, and electrically operated valves, an accumulator, filters, related piping, and electrical connections. See Figures 3.4-9 and 3.4-13.

Each HCU furnishes pressurized water upon signal to a CRD. The drive then positions its control rod as required. Operation of the electrical system which supplies scram and normal control rod positioning signals to the HCU is described in Section 7.7, Reactor Manual Control System.

The basic components contained in each HCU and their functions are as follows:

Insert Drive Valve

The insert drive valve is a solenoid operated valve which opens on an insert signal to supply drive water to the bottom side of the main drive piston.

Insert Exhaust Valve

The insert exhaust valve is a solenoid operated valve which opens on an insert signal to discharge water from above the drive piston to the exhaust header.

Withdrawal Drive Valve

The withdrawal drive valve is a solenoid operated valve which opens on a withdrawal signal to supply drive water to the top side of the drive piston.

Withdrawal Exhaust Valve

The withdrawal exhaust valve is a solenoid operated valve which opens on a withdrawal signal to discharge water from below the main drive piston to the exhaust header.

Speed Control Valves

The speed control valves, which regulate the control rod insertion and withdrawal rates during normal operation, are manually adjustable flow control valves used to regulate the water flow to and from the volume beneath the main drive piston. Once a speed control valve is properly adjusted, it is not necessary to adjust the valve except to compensate for changes in piston seal leakage.

Scram Pilot Valves

The scram pilot valve are operated from the RPS trip system. Two scram pilot valves control both the scram inlet valve and the scram exhaust valve. The scram pilot valves are identical, three way, solenoid operated, normally energized valves. On loss of electrical signal to the pilot valves, the inlet ports are closed and the exhaust ports are opened on both pilot valves. The pilot valves are arranged as shown on Figures 3.4-9 and 3.4-10 so that the trip system signal must be removed from both valves before air pressure is discharged from the scram valve operators.

Scram Inlet Valve

The scram inlet valve is opened to supply scram water pressure to the bottom of the drive piston. The scram inlet valve is a globe valve which is opened by the force of an internal spring and system pressure, and closed by air pressure applied to the top of its diaphragm operator. The opening force of the spring is approximately 700 lb. The valve opening time is approximately 0.1 sec from start to full open.

The scram inlet valve has a position indicator switch which energizes a light in the control room as soon as the valve starts to open.

Scram Exhaust Valve

The scram exhaust valve opens slightly before the scram inlet valve, exhausting water from above the drive piston during a scram. Quicker opening times are achieved because of a larger spring in the valve operator. Otherwise this valve is similar to the scram inlet valve.

Scram Accumulator

The scram accumulator stores sufficient energy to insert a control rod to the fully inserted position during a scram independent of any other source of energy. The accumulator consists of a water volume pressurized by a volume of nitrogen. The accumulator has a piston separating the water on top from the nitrogen below. A check valve in the charging line to each accumulator retains the water in the accumulator in the event supply pressure is lost.

During normal plant operation, the accumulator piston operates with a pressure drop across it of approximately 280 psid to 410 psid nominal range (depending on drive water pump performance). The piston contacts the accumulator lower end cap. Loss of nitrogen causes a decrease in the nitrogen pressure which actuates the pressure switch, and sounds an alarm in the control room.

Also, to ensure that the accumulator is always capable of producing a scram, it is continuously monitored for water leakage. A float type level switch actuates an alarm if water leaks past the barrier, and collects in the accumulator instrumentation block. The accumulator instrumentation block is located below the accumulator (nitrogen side) in such a way that it will receive any water which leaks past the accumulator piston.

The scram accumulator thus meets the requirements of safety design basis 3.d.

3.4.5.4 Control Rod Drive System Operation

The CRD System performs three operational functions: rod insertion, rod withdrawal, and scram. The functions are described below.

Rod Insertion

Rod insertion is initiated by a signal from the operator to the insert valve solenoids which open both insert valves. The insert drive valve applies reactor pressure plus approximately 90 psig to the bottom of the drive piston. The insert exhaust valve allows water from above the drive piston to discharge to the exhaust header.

As illustrated on Figure 3.4-6, the locking mechanism is a ratchet type device and does not interfere with rod insertion. The speed at which the drive moves is determined by the pressure drop through the insert speed control valve, which is set for about 4 gal/min for a shim speed (nonscram operation) of 3 in/sec. During normal insertion, the pressure on the downstream side of the speed control valve is 90 to 100 psi above reactor vessel pressure. However, if the drive slows down for any reason, the flow through and pressure drop across the insert speed control valve will decrease, and the full 250 psi differential pressure will be available to cause continued insertion. With 250 psi differential pressure acting on the drive piston, the piston exerts an upward force of 1,000 lb.

Rod Withdrawal

Drive withdrawal is, by design, more involved. First, the collet fingers (latch) must be raised to reach the unlocked position as in Figure 3.4-5. The notches in the index tube and the collet fingers are shaped so that the downward force on the index tube holds the collet fingers in place. The index tube must be lifted before the collet fingers can be released. This is done by opening the drive insert valves (in the manner described in the preceding paragraph) for approximately 1 sec. The withdraw valves are then opened, applying driving pressure above the drive piston and opening the area below the piston to the exhaust header. Pressure is simultaneously applied to the collet piston. As the collet piston raises, the collet fingers are cammed outward, away from the index tube, by the guide cap.

The pressure required to release the latch is set and maintained high enough to overcome the force of the latch return spring, plus the force of reactor pressure opposing movement of the collet piston. When this occurs, the index tube is unlatched and free to move in the withdrawal direction. Water displaced by the drive piston flows out through the withdrawal speed control valve which is set to give the control rod a shim withdrawal of 3 in/sec. The entire valving sequence is automatically controlled, and is initiated by a single operation of the rod withdraw switch.

Rod Scram

During a scram the scram pilot valves and scram valves are operated as previously described. With the scram valves open, accumulator pressure is admitted under the drive piston and the area over the drive piston is vented to the scram discharge volume.

The large differential pressure (initially about 1,400 psi and always several hundred psi depending on reactor vessel pressure), produces a large upward force on the index tube and control rod, giving the rod a high initial acceleration and providing a large margin of force to overcome any possible friction. The characteristics of the hydraulic system are such that, after the initial acceleration is achieved, the drive continues at a fairly constant velocity. This characteristic provides a high initial rod insertion rate. As the drive piston nears the top of its stroke, the piston seals close off the large passage in the stop piston tube and the drive slows down.

Each drive requires about 2.5 gal of water during the scram stroke. There is adequate water capacity in each drive's accumulator to complete a scram in the required time at low reactor vessel pressure. At higher reactor vessel pressures, the accumulator is assisted on the upper end of the stroke by reactor vessel pressure acting on the drive via the ball check (shuttle) valve. As water is forced from the accumulator, the accumulator discharge pressure falls below reactor vessel pressure. This causes the check valve to shift its position to admit reactor pressure under the drive piston. Thus, reactor vessel pressure furnishes the force needed to complete the scram stroke at higher reactor vessel pressures. When the reactor vessel is up to full operating pressure, the accumulator is actually not needed to meet scram time requirements. With the reactor at 1,000 psig and the scram discharge volume at atmospheric pressure, the scram force without an accumulator is over 1,000 lb.

The average scram performance requirements of the CRD System are provided in the current station Technical Specifications referenced in Appendix B.

3.4.6 Safety Evaluation

3.4.6.1 Evaluation of Control Rods

It is apparent from the description that the control rods meet the design basis requirements. The description also indicates how the control rod to drive coupling unit meets design basis requirements.

3.4.6.2 Evaluation of Control Rod Velocity Limiter

The control rod velocity limiter limits the free fall velocity of the control rod to a value which cannot result in nuclear system process barrier damage,[5] as required by safety design basis 1.c. This velocity is evaluated by the rod drop accident analysis in Section 14, Station Safety Analysis.

The following sequence of events is necessary to postulate an accident in which the control rod velocity limiter is required:

1. The rod to drive coupling fails.

2. The control rod sticks near the top of the core.

3. The drive is withdrawn and the control rod does not follow.

4. The operator fails to notice the lack of response as the control rod drive is withdrawn.

5. The control rod later becomes loose and falls freely to the withdrawn position.

3.4.6.3 Evaluation of Scram Time

The rod scram function of the CRD System provides the negative reactivity insertion which is required by safety design basis 2. The scram time shown in Section 3.4.5 is adequate as shown by the transient analyses of Section 14, Station Safety Analysis.

3.4.6.4 Analysis of Malfunctions Relating to Rod Withdrawal

There is no known single malfunction which could cause even a single rod to withdraw. The following malfunctions have been postulated and the results analyzed:

1. Drive Housing Fails At Attachment Weld

   The bottom head of the reactor vessel has a penetration with an internal nozzle for each control rod drive location. A drive housing is raised into position inside each penetration and fastened to the top of the internal nozzle with a J-weld. The drive is raised into the drive housing and bolted to a flange at the bottom of the housing. The basic failure considered is a complete circumferential crack through the housing wall at an elevation just below the J-weld. The housing material is seamless Type 304 stainless steel pipe with a minimum tensile strength of 75,000 psi.

Static loads on the housing wall include the weight of the drive and the control rod, the weight of the housing below the attachment weld to the vessel nozzle, and reactor pressure acting on the 6 in diameter cross sectional area of the housing and the drive. Dynamic loading is due to the reaction force during drive operation.

If the housing were to fail, as described above, the following sequence of events is foreseen. The housing would separate from the vessel and the control rod, the drive and the housing would be blown downward against the support structure by reactor pressure acting on the cross sectional area of the housing, and the drive. The amount of downward motion of the drive and associated parts would be determined by the gap between the bottom of the drive and the support structure, and by the amount the support structure deflects under load. In the current design, maximum deflection is approximately 3 in. If the collet were to remain latched, no further control rod ejection would occur.[6] The housing would not drop far enough to clear the vessel penetration. Reactor water would leak through the 0.06 in diametral clearance between the housing od and the vessel penetration id at a rate of approximately 440 gal/min.

If the basic housing failure were to occur at the same time the control rod is being withdrawn (this is a small fraction of the total drive operating time), and if the collet were to stay unlatched, the housing would separate from the vessel, the drive and housing would be blown downward against the CRD housing support, and calculations indicate that the steady state rod withdrawal velocity would be 0.3 ft/sec. During withdraw, pressure under the collet piston would be approximately 250 psi greater than the pressure over it. Therefore, the collet would be held in the unlatched position until driving pressure is removed from the pressure over port.

2. Rupture of Either or Both Hydraulic Lines to A Drive Housing Flange

   (a) Pressure Under Line Breaks

   In this case, a partial or complete circumferential opening is postulated at or near the point where the line enters the housing flange. Failure is more likely to occur after another basic failure wherein the drive housing, or housing flange, separates from the reactor vessel. Failure of the housing, however, does not necessarily lead directly to failure of the hydraulic lines.

If the pressure under line were to fail, and if the collet were latched, no control rod withdrawal would occur. There would be no pressure differential across the collet piston in this case, and therefore no tendency to unlatch the collet. Consequently, it would not be possible to either insert or withdraw the control rod involved

If reactor pressure were to shift the drive ball check valve against its upper seat, the broken pressure under line would be sealed off. If the ball check valve were to be prevented from seating, reactor water would leak to the atmosphere. Cooling water could not be supplied to the drive involved because of the broken line. Loss of cooling water would cause no immediate damage to the drive. However, prolonged drive exposure to temperatures at or near reactor temperature could lead to deterioration of material in the seals. High temperature would be indicated to the operator by the thermocouple in the position indicator probe.

If the basic line failure were to occur at the same time the control rod is being withdrawn, and if the collet were to remain open, calculations indicate that the steady state control rod withdrawal velocity would be 2 ft/sec. In this case, however, there would not be sufficient hydraulic force to hold the collet open and spring force would normally cause the collet to latch, stopping rod withdrawal.

(b) Pressure Over Line Breaks

The failure considered is complete breakage of the pressure over line at or near the point where the line enters the housing flange. If the line were to break, pressure over the drive piston would drop from reactor pressure to atmospheric pressure. If there were any significant reactor pressure, approximately 500 psig or greater, it would act on the bottom of the drive piston, and the drive would insert to the fully inserted position. Drive insertion would occur regardless of the operational mode at the time of the failure. After full insertion, reactor water would leak past the stop piston seals, the contracting seals on the drive piston, and the collet piston seals. This leakage would exhaust to atmosphere through the broken pressure over line. In an experiment to simulate this failure, a leakage rate of 80 gal/min has been measured with reactor pressure at 1,000 psi. If the reactor were hot, drive temperature would increase. The reactor operator would be apprised of the situation by indication of the fully inserted drive, by high drive temperature alarmed and recorded in the control room, and by operation of the drywell sump pump

(c) Coincident Breakage of Both Pressure Over and Pressure Under Lines

This failure would require simultaneous occurrence of the failures described above. Pressures above and below the drive piston would drop to zero and the ball check valve would shift to close off the broken pressure under line. Reactor water would flow from the annulus outside of the drive through the vessel ports to the space below the drive piston. As in the pressure over line break case, the drive would then insert at a speed dependent on reactor pressure. Full insertion would occur regardless of the operational mode at the time of failure. Reactor water would leak past the drive seals and out of the broken pressure over line to the atmosphere as described above. Drive temperature would increase. The reactor operator would be apprised of the situation by indication of the fully inserted drive, high drive temperature printed out by a recorder and alarmed in the control room, and by operation of the drywell sump pump.

3. All Drive Flange Bolts Fail in Tension

Each CRD is bolted to a flange at the bottom of a drive housing which is welded to the reactor vessel using eight bolts and slotted washers.

In the event that progressive or simultaneous failure of all of the bolts were to occur, the drive would separate from the housing, and the control rod and the drive would be blown downward against the support structure due to reactor pressure acting on the cross sectional area of the drive. Impact velocity and support structure loading would be slightly less than in drive housing failure, since reactor pressure would act on the drive cross sectional area only and the housing would remain attached to the reactor vessel. The drive would be isolated from the cooling water supply. Reactor water would flow downward past the velocity limiter piston and through the large drive filter into the annular space between the thermal sleeve and the drive. For worst case leakage calculations, it is assumed that the large filter would be deformed or swept out of the way so that it would offer no significant flow restriction. At a point near the top of the annulus, where pressure has dropped to 350 psi, the water would flash to steam and choke flow conditions would exist. Steam would flow down the annulus and out the space between the housing and the drive flanges to the atmosphere. Steam formation would limit the leakage rate to approximately 840 gal/min.

If the collet were latched, control rod ejection would be limited to the distance the drive can drop before coming to rest on the support structure. Since pressure below the collet piston would drop to zero, there would be no tendency for the collet to unlatch.

Pressure forces, in fact, exert 1,435 lb to hold the collet in the latched position.

If the bolt failure were to occur while the control rod is being withdrawn, pressure below the collet piston would drop to zero and the collet, with 1,650 lb return force, would latch, stopping rod withdrawal.

4. Weld Joining Flange to Housing Fails in Tension

The failure considered is a crack in or near the weld joining the flange to the housing that extends through the wall, and completely around the circumference of the housing so that the flange can separate from the housing. The flange material is forged Type 304 stainless steel with a minimum tensile strength of 75,000 psi. The housing material is seamless Type 304 stainless steel pipe with a minimum tensile strength of 75,000 psi. A conventional full penetration weld of Type 308 stainless steel is used to join the flange to the housing. Minimum tensile strength is approximately the same as the parent metal. The design pressure is 1,250 psig and the design temperature is 575°F. A combination of reactor pressure acting downward on the cross sectional area of the drive; the weight of the control rod, drive, and flange; and the dynamic reaction force during drive operation result in a maximum tensile stress at the weld of approximately 6,000 psi.

In the event that the basic failure described above were to occur, the flange and the attached drive would be blown downward against the support structure. The support structure loading would be slightly less severe than in drive housing failure, since reactor pressure would act only on the drive cross sectional area. Since there would be no differential pressure across the collet piston, the collet would remain latched and control rod motion would be limited to approximately 3 in. Downward drive movement would be small; therefore, most of the drive would remain inside the housing. The pressure under and pressure over lines are flexible enough to withstand the small downward displacement, and remain attached to the flange. Reactor water would follow the same leakage path described in malfunction No. 3 above, except that the exit to the atmosphere would be through the gap between the lower end of the housing, and the top of the flange. Water would flash to steam in the annulus surrounding the drive. The leakage rate would be approximately 840 gal/min.

If the basic flange to housing joint failure were to occur at the same time the control rod is being withdrawn, a small fraction of the total operating time, and if the collet were held unlatched, the flange would separate from the housing, the drive and flange would be blown downward against the support structure, and the calculated steady state rod withdrawal velocity would be 0.13 ft/sec. Since the pressure under and pressure over lines remain intact, driving water pressure would continue to be supplied to the drive and the normal exhaust line restriction would exist. The pressure below the velocity limiter piston would decrease below normal due to leakage out of the gap between the housing and the flange to the atmosphere. This differential pressure across the velocity limiter piston would result in a net downward force of approximately 70 lb. However, leakage out of the housing would greatly reduce the pressure in the annulus surrounding the drive, so that the net downward force on the drive piston would be less than normal. The overall effect would be a reduction of rod withdrawal speed to a value approximately one half of normal speed. The collet would remain unlatched with a 560 psi differential across the collet piston, but should relatch as soon as the drive signal is removed.

5. Housing Wall Ruptures

The failure considered in this case is a vertical split in the drive housing wall just below the bottom head of the reactor vessel. The hole was considered to have a flow area equivalent to the annular area between the drive and the thermal sleeve so that flow through this annular area, rather than flow through the hole in the housing, would govern leakage flow. The housing is made from Type 304 stainless steel seamless pipe having a minimum tensile strength of 75,000 psi. The maximum hoop stress of 11,900 psi is due primarily to reactor design pressure of 1,250 psig acting on the inside of the housing.

If the housing wall rupture described above were to occur, reactor water would flash to steam and leak to the atmosphere at approximately 1,030 gal/min through the hole in the housing. Choke flow conditions described in malfunction No. 3 above would exist. In this case, however, the leakage flow would be greater because the flow resistance is less; that is, the leaking water and steam would not have to flow down the length of the housing to reach the atmosphere. Critical pressure at which the water would flash to steam is 350 psi.

There would be no pressure differential across the collet piston tending to cause collet unlatching, but the drive would insert due to loss of pressure in the drive housing, and therefore, in the space above the drive piston.

If the basic housing wall failure were to occur at the same time the control rod is being withdrawn (a small fraction of the total operating time), the drive would stop withdrawing, but the collet would remain unlatched. The drive stoppage would be caused by a reduction in the net downward force acting on the drive line. This would occur when the leakage flow of 1,030 gal/min reduces the pressure in the annulus outside the drive to approximately 540 psig, and therefore reduces the pressure acting on the top of the drive piston to this value. There would be a pressure differential of approximately 710 psi across the collet piston, holding the collet unlatched as long as the operator held the withdraw signal.

6. Flange Plug Blows Out

A 3/4 in diameter hole is drilled in the drive flange to connect the vessel ports with the bottom of the ball check valve. The outer end of this hole is sealed with an 0.812 in diameter plug, 0.250 in thick. The plug is held in place with a full penetration weld of Type 308 stainless steel. The failure considered is a full circumferential crack in this weld and subsequent blow out of the plug.

If the weld were to fail and the plug were to blow out, there would be no control rod motion provided the collet were latched. There would be no pressure differential across the collet piston tending to cause collet unlatching. Reactor water would leak past the velocity limiter piston, down the annulus between the drive and the thermal sleeve through the vessel ports and drilled passage, and out the open plug hole to the atmosphere at approximately 320 gal/min. This leakage calculation is based on liquid only exhausting from the flange as a worst case. Actually, hot reactor water would flash to steam, and choke flow conditions would exist, so that the expected leakage rate would be lower than the calculated value. Drive temperature would rise, and the alarm would signal the operator.

If the basic plug weld failure were to occur at the same time the control rod is being withdrawn (a small percentage of the total operating time), and if the collet were to stay unlatched, calculations indicate that control rod withdrawal speed would be approximately 0.24 ft/sec. Leakage out of the open plug hole in the flange would cause reactor water to flow downward past the velocity limiter piston. The small differential pressure across the piston would result in an insignificant driving force of approximately 10 lb tending to increase withdraw velocity.

The collet would be held unlatched by a 295 psi pressure differential across the collet piston as long as the driving signal was maintained.

The exhaust path from the drive would have normal flow resistance since the ball check valve would be seated at the lower end of its travel by pressure under the drive piston.

7. Pressure Regulator and Bypass Valves Fail Closed (Reactor Pressure 0 psig)

Pressure in the drive water header supplying all drives is controlled by regulating the amount of water from the supply pump that is bypassed back to the reactor. This is accomplished primarily with the drive water control valves, and secondarily with the pressure stabilizing valves. There are two drive water control valves arranged in parallel. One is a motor operated valve that can be adjusted from the control room. This valve is normally in service and is partially open to maintain a pressure of reactor pressure plus 250 psig in the header just upstream from the valve. The other is a hand operated valve that is normally closed but that can be valved in and operated locally whenever the motor operated valve is out of service.

The pressure stabilizing valves are solenoid operated and have built in needle valves for adjusting flow. The two valves are arranged in parallel between the drive water header and the return line to the reactor. One valve is set to bypass 2 gal/min, and closes when any drive is given a withdraw signal, so that flow is diverted to the drive being operated rather than back to the reactor. Relatively constant header pressure is thus maintained. Similarly, the other valve is set to bypass 4 gal/min, and closes when any drive is given an insert signal.

The failure considered is when all of these valves are closed so that maximum supply pump head of 1,700 psi builds up in the drive water header. The major portion of the bypass flow normally passes through the motor operated valve; therefore, closure of this valve is most critical.

Since lowest exhaust line pressure exists when reactor pressure is zero, this reactor condition is also assumed.

If the valve closure failure described above were to occur at the same time the control rod is being withdrawn, calculations indicate that steady state withdrawal speed would be approximately 0.5 ft/sec or twice normal velocity. The collet would be held unlatched by a 1,670 psi pressure differential across the collet piston. Flow would be upward past the velocity limiter piston, but retarding force would be negligible.

8. Ball Check Valve Fails to Close Off Passage to Vessel Ports

The failure considered in this case depends upon the following sequence of events. If the ball check valve were to seal off the passage to the vessel ports during the "up" signal portion of the jog withdraw cycle, the collet would be unlatched. This is the normal withdrawal sequence. Then if the ball were to move up and become jammed in the ball cage by foreign material, or prevented from reseating at the bottom by foreign material, that settles out on the seat surface, water from below the drive piston would return to the reactor through the vessel ports, and the annulus between the drive and the housing. Since this return path would have lower than normal flow resistance, the calculated withdrawal speed would be 2 ft/sec. During withdrawal, there would be a differential pressure across the collet piston of approximately 40 psi. Therefore, the collet would tend to latch and would have to stick open before continuous withdrawal at 2 ft/sec could occur. Water would flow upward past the velocity limiter piston and a small retarding force would be generated (approximately 120 lb).

9. Hydraulic Control Unit Valve Failures

Various failures of the valves in the HCU can be postulated, but none are capable of producing differential pressures which approach those described in the preceding paragraphs, and none are capable alone of producing a high velocity withdrawal. Leakage through either or both of the scram valves produces a pressure which tends to insert the control rod rather than withdraw it. If the pressure in the scram discharge volume should exceed reactor pressure following a scram, a check valve in the line to the scram discharge header prevents this pressure from operating the drive mechanisms.

10. Failure of the Collet Fingers to Latch

The drive continues to withdraw, after removal of the signal, at a fraction of its normal withdrawal speed. There is no known means for the collet fingers to become unlocked without some initiating signal. Failure of the withdrawal drive valve to close, following a rod withdrawal has the same effect as failure of the collet fingers to latch in the index tube, and is immediately apparent to the operator. Accidental opening of the withdrawal drive valve normally does not unlock the collet fingers because of the characteristic of the collet fingers to remain locked until unloaded.

11. Withdrawal Speed Control Valve Failure

Normal withdrawal speed is determined by differential pressures at the drive and set for a nominal value at 3 in/sec. The characteristics of the pressure regulating system are such that withdrawal speed is maintained independent of reactor vessel pressure. Tests have determined that accidental opening of the speed control valve to the full open position produces a velocity of approximately 6 in/sec.

The CRD System prevents rod withdrawal as required by safety design basis 3.a. It is shown above that only multiple failures in a drive unit and its control unit could cause an unplanned rod withdrawal.

3.4.6.5 Scram Reliability

High scram reliability is the result of a number of features of the CRD system, such as the following:

1. There are two sources of scram energy to insert each control rod when the reactor is operating: Accumulator pressure and reactor vessel pressure
2. Each drive mechanism has its own scram and pilot valves so that only one drive can be affected by failure of a scram valve to open. Two pilot valves are provided for each drive. Both pilot valves must be vented to
3. The RPS and HCUs are designed so that the scram signal and mode of operation override all others
4. The collet assembly and index tube are designed so that they will not restrain or prevent control rod insertion during scram
5. The scram discharge volume is monitored for accumulated water and will scram the reactor before the volume is filled to a point that could interfere with a scram

The scram reliability meets the requirements of safety design basis 3.b and 3.c.

3.4.6.6 Control Rod Support and Operation

As shown in the description, each control rod is independently supported and controlled as required by safety design basis 3.

3.4.7 Inspection and Testing

3.4.7.1 Development Tests

The development drive (one prototype) testing included over 5,000 scrams and approximately 100,000 latching cycles during 5,000 hr of exposure to simulated operating conditions. These tests have demonstrated the following:

1. That the drive withstands the forces, pressures, and temperatures imposed without difficulty

2. That wear, abrasion, and corrosion of the nitrided Type 304 stainless parts are negligible. That mechanical performance of the nitrided surface is superior to materials used in earlier operating reactors

3. That the basic scram speed of the drive has a satisfactory margin above minimum plant requirements at any reactor vessel pressure
4. That usable seal lifetimes greater than 1,000 scrams cycles may be expected

3.4.7.2 Factory Quality Control Tests

Quality control of welding, heat treatment, dimensional tolerances, material verification, etc., is maintained throughout the manufacturing process to assure reliable performance of the mechanical reactivity control components. Some of the quality control tests on the control rods, CRD mechanisms, and HCUs are as follows:

<u>Control Rod Absorber Tube Tests</u>

1. The tubing and end plug material integrity is verified by ultrasonic inspection

2. Boron content of the Boron-10 fraction of each lot of boron carbide is verified
3. The weld integrity of the finished absorber tubes is verified by helium leak testing

CRD Mechanism Tests

1. Hydrostatic testing of the drives to check pressure holds is in accordance with ASME codes

2. Electrical components are checked for electrical continuity and resistance to ground

3. All drive parts which cannot be visually inspected for dirt are flushed with filtered water at high velocity. No significant foreign material is permissible in effluent water

4. Seal leakage tests are performed to demonstrate proper seal operation

5. Each drive is tested for shim motion, latching, and control rod position indicating

6. Each drive is subjected to cold scram tests at various reactor pressures to verify proper scram performance

Hydraulic Control Unit Tests

Each HCU receives the following tests:

1. All hydraulic systems are hydrostatically tested in accordance with USAS B-31.1.0

2. All electrical components and systems are tested for electrical continuity and resistance to ground

3. The correct operation of the accumulator pressure and level switches is verified

4. The unit's ability to perform its part of a scram is demonstrated

5. Proper operation and adjustment of the insert and withdrawal valves is demonstrated

3.4.7.3 Operational Tests

After installation, all rods, HCUs and drive mechanisms are tested through their full travel range for operability.

During normal operation, each time a control rod is withdrawn a notch, the operator can observe the incore monitor indications to verify that the control rod is following the drive mechanism. All control rods that are partially withdrawn from the core can be tested for rod following by inserting or withdrawing the rod one notch and returning it to its original position, while the operator observes the incore monitor indications.

To make a positive test of control rod to CRD coupling integrity, the operator can withdraw a control rod to the end of its travel and then attempt to withdraw the drive to the overtravel position. Failure of the drive to overtravel demonstrates rod to drive coupling integrity.

Hydraulic supply subsystem pressures can be observed from instrumentation in the control room. Scram accumulator pressures can be observed on the nitrogen pressure gages.

3.4.8 Deleted

3.4.9 Operational Nuclear Safety Requirements

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

3.4.10 References

1. NEDO-24226, Evaluation of Control Blade Lifetime Evaluations Accounting for Potential Loss of B_4C, December 1979.

2. NEDO-24232, Control Blade Lifetime Evaluation Accounting for Potential Loss of B_4C, January 1980.

3. Boron Loss from BWR Control Blades, IE Bulletin No. 79-26, Rev. 1, August 29, 1980, USNRC Office of Inspection and Enforcement, Washington.

4. NEDO 24325, Control Blade Examination Results and Response to Item 4 of IE Bulletin 79-26, March 1981.

5. Control Rod Velocity Limiter. General Electric Co., Atomic Power Equipment Department, APED-5446, March 1967.

6. Benecki, J.E. Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A. General Electric Co., Atomic Power Equipment Department, APED-5555, November 1967.

7. NEDE-22290-A, Safety Evaluation of the General Electric Hybrid Control Rod Assembly, September 1983.

8. General Electric, "Safety Evaluation of the General Electric Duralife 230 Control Rod Assembly," NEDE-22290-P-A, May 1988.

9. General Electric, "GE BWR Control Rod Lifetime," NEDE 30931-X-P. (X represents current revision number)

10. General Electric, "Safety Evaluation of the General Electric Advanced Life Control Rod Assembly," NEDE-22290-B, August 1985.

11. General Electric, "Safety Evaluation of the GE Marathon Control Rod Assembly," NEDE - 31758P-A, October 1991. (SUDDSRF 03-041)

3.6.2.4 Control Requirements

The nuclear design in conjunction with the reactivity control system provides an inherently stable system for BWRs.

The control rod system is designed to provide adequate control of the maximum excess reactivity anticipated during the equilibrium cycle operation. The safety design basis requires that the core, in its maximum reactivity condition, be subcritical with the control rod of the highest worth fully withdrawn and all others fully inserted. Therefore, the shutdown capability is evaluated at the most reactive moderator temperature in a xenon-free condition.

3.6.2.4.1 Shutdown Reactivity

To assure that the safety design basis for shutdown is satisfied, an additional design margin is adopted: k-effective is calculated to be less than or equal to 0.99 with the control rod of highest worth fully withdrawn.

The cold shutdown margin for the reference core loading pattern is given in the supplemental reload licensing report in Appendix Q.

3.6.2.4.2 Reactivity Variations

The excess reactivity designed into the core is controlled by the control rod system supplemented by gadolinia-urania fuel rods. Enrichment distributions for those rods are given in Reference 1.

Control rods are used during the cycle partly to compensate for burnup and partly to flatten the power distribution.

Reactivity balances are not used in describing BWR behavior because of the strong interdependence of the individual constituents of reactivity. Therefore, the design process does not produce components of a reactivity balance at the conditions of interest. Instead, it gives the k_{eff} (contained in the supplemental reload licensing report) representing all effects combined. Further, any listing of components of a reactivity balance is quite ambiguous unless the sequence of the changes is clearly defined.

3.6.2.5 Control Rod Patterns and Reactivity Worths

Typical control rod patterns and the associated power distributions are calculated with the BWR Core Simulator. Qualification for this model can be found in Reference 1.

Scram reactivity is calculated as described in Reference 1.

3.6.2.6 Criticality of Reactor During Refueling

The maximum allowable value of k_{eff} is <1.000 at any time. Cycle specific analyses are performed as described in Reference 1.

3.7 THERMAL AND HYDRAULIC DESIGN

3.7.1 Design Basis

3.7.1.1 Safety Design Bases

Thermal-hydraulic design of the core shall establish:

(1) Actuation limits for the devices of the nuclear safety systems such that no fuel damage occurs as a result of moderate frequency transient events.

(2) The thermal-hydraulic safety limits for use in evaluating the safety margin relating the consequences of fuel barrier failure to public safety.

(3) That the nuclear system exhibits no inherent tendency toward divergent or limit cycle oscillations which would compromise the integrity of the fuel or nuclear system process barrier.

3.7.1.2 Power Generation Design Bases

The thermal-hydraulic design of the core shall provide the following operational characteristics:

(1) The ability to achieve rated core power output throughout the design life of the fuel without sustaining premature fuel failure.

(2) Flexibility to adjust core output over the range of plant load and load maneuvering requirements in a stable, predictable manner without sustaining fuel damage.

3.7.1.3 Requirements for Steady-State Conditions

For purposes of maintaining adequate thermal margin during normal steady-state operation, the MCPR must not be less than the required MCPR operating limit, and the LHGR must be maintained below the maximum LHGR for the fuel type. This does not specify the operating power nor does it specify peaking factors. These parameters are determined subject to a number of constraints including the thermal limits given previously. The core and fuel design basis for steady-state operation (i.e., MCPR and LHGR limits) have been defined to provide margin between the steady-state operating conditions and any fuel damage condition to accommodate uncertainties and to assure that no fuel damage results even during the worst anticipated transient condition at any time in life. During SLO the MCPR thermal limit is adjusted to account for increased uncertainties (Reference 5).

The design steady-state MCPR operating limit and the peak LHGR are referenced in Table 3.7-1.

3.7.1.4 Requirements for Transient Conditions

The transient thermal limits are established such that no safety limit is expected to be exceeded during the most severe moderate frequency transient event as defined in Reference 1.

3.7.1.5 Summary of Design Bases

In summary, the steady-state operating limits have been established to assure that the design basis is satisfied for the most severe moderate frequency transient event. There is no steady-state design overpower basis. An overpower which occurs during an incident of a moderate frequency transient event must meet the plant transient MCPR limit. Demonstration that the transient limits are not exceeded is sufficient to conclude that the design basis is satisfied.

3.7.2 Description of Thermal-Hydraulic Design of the Reactor Core

3.7.2.1 Summary Comparison

An evaluation of plant performance from a thermal and hydraulic standpoint is provided in Subsection 3.7.3.

A tabulation of core parameters used in the thermal and hydraulic calculation is provided in Table 3.7-1.

3.7.2.2 Critical Power Ratio

The critical power ratio is defined as the ratio of the critical power (bundle power at which some point within the assembly experiences onset of boiling transition) to the operating bundle power. The minimum critical power ratio (MCPR) ensures that fuel damage resulting from severe overheating of the fuel rod cladding caused by inadequate cooling is avoided. The minimum critical power ratio corresponds to the most limiting fuel assembly in the core.

Further description of the critical power ratio and model used to calculate this ratio is provided in Reference 1.

3.7.2.3 Linear Heat Generation Rate (LHGR)

A value of 1% plastic strain of the Zircaloy cladding has been established as the safety limit below which fuel damage due to overstraining of the fuel cladding is not expected to occur. The linear heat generation rate required to cause this amount of cladding strain is given in Reference 1. The models used to calculate this transient LHGR safety limit are also described in this reference.

3.7.2.4 Void Fraction Distribution

The void fraction distribution is calculated using the core average axial power distribution.

3.7.2.5 Core Coolant Flow Distribution and Orificing Pattern

Correct distribution of core coolant flow among the fuel assemblies is accomplished by the use of an accurately calibrated fixed orifice at the inlet of each fuel assembly. The orifice is located in the fuel support piece. The orifices serve to control the flow distribution and, hence, the coolant conditions within prescribed bounds throughout the design range of core operation.

The core is divided into two orificed flow zones. The outer zone is a narrow, reduced power region around the periphery of the core; the inner zone consists of the core center region. No other control of flow and steam distribution, other than that incidentally supplied adjustment of the power distribution with the control rod is employed or needed. The orifices can be removed for changes during refueling operations if necessary.

The sizing and design of the orifices ensures that the flow in each fuel assembly is stable during all phases of operation at normal operating conditions. Hydraulic models including core coolant flow distribution and bypass, are included in Reference 1.

3.7.2.6 Core Pressure Drop and Hydraulic Loads

The flow distribution to the fuel assemblies and bypass flow paths is calculated on the assumption that the pressure drop across all fuel assemblies and bypass flow paths is the same. This assumption has been confirmed by measuring the flow distribution in boiling water reactors. The components of bundle pressure drop considered are friction, local, elevation, and acceleration.

Models for pressure drop across the core are given in Reference 1.

3.7.2.7 Correlation and Physical Data

General Electric has obtained substantial amounts of physical data in support of the pressure drop and thermal-hydraulic loads. This information is provided in Reference 1.

3.7.2.8 Thermal Effects of Operational Transients

The evaluation of the core's capability to withstand the thermal effects resulting from anticipated operational transients is covered in Section 14.

3.7.2.9 Uncertainties in Estimates

Uncertainties in thermal-hydraulic parameters are considered in the statistical analysis which is performed to establish the fuel cladding integrity safety limit documented in Reference 1.

3.7.2.10 Flux Tilt Considerations

For flux tilt considerations, refer to Subsection 3.6.2.2.4.

3.7.3 Description of the Thermal and Hydraulic Design of the Reactor Coolant System

The thermal and hydraulic design of the reactor coolant system is described in this section.

3.7.3.1 Plant Configuration Data

Reactor coolant system geometric data is provided in Section 4.

3.7.3.2 Operating Restrictions on Pumps

Recirculation pump operational requirements are discussed in Subsection 7.9, Recirculation Flow Control System.

3.7.3.3 Power-Flow Operating Map

A BWR must operate with certain restrictions because of pump net positive suction head (NPSH) requirements, overall plant control characteristics, core thermal power limits, core thermal-hydraulic stability considerations, etc. The power-flow operating map for PNPS is shown in Figure 3.7-1. Constraints imposed by equipment, alarms or reactor scrams initiated by protective instrumentation, and operator actions based upon written operating procedures maintain operations within the embolded boundary lines shown on this map for normal operating conditions.

The current operating map depicted in Figure 3.7-1 evolved from an original region that has both expanded and contracted over several iterations. References 2 through 6, and 11 through 13 provide the bases for each change. The original operating region was enclosed by the natural circulation line, the "100% load line", and a constant recirculation pump speed line which intersects 100% rated core power at 100% rated core flow (not shown on Figure 3.7-1). Normal reactor operation would also effectively be restricted to the minimum pump speed (approximately 26%) line. An interlock prevents low power, high recirculation flow combinations which may create recirculation NPSH problems as depicted by the "minimum power line".

The analyses in references 2 through 6, and 11 through 13 altered the operating region boundaries as summarized below:

Core power cannot exceed 100% rated core power or 2028 megawatts thermal. The maximum core flow at 100% rated power is 107.5% of rated core flow (69 mlb/hr). Below 100% core power, the core flow limit increases linearly to 112.5% of rated core flow at 78.8% rated core power. Between 78.8% and 49.3% rated core power, the maximum core flow allowed is 112.5% of rated core flow. Below 49.3% rated core power, the maximum allowed core flow drops to 100% rated core flow. See References 3, 4 and 13.

100% rated core power continues as the maximum core power limit as core flow decreases from 107.5% to 76.7% rated core flow. Below 76.7% rated core flow, the maximum allowed core power decreases along the 119.3% load line toward its intersection with the natural circulation line at approximately 56.9% rated core power. See Reference 6. There are 2 regions of the operating domain where administrative controls are enforced to provide defense-in-depth protection for the occurrence of thermal hydraulic instability. The Exclusion Region is part of the Option 1-D Stability Solution. It is annotated as a shaded section. The flow range is from natural circulation to a cycle dependent core flow value. The boundary is non linear based on the calculation of core decay ratio intercept values on the natural circulation and MELLLA rod lines in Reference 11. The Buffer Zone is defined as a region in the operating domain with a parallel boundary to the Exclusion Region. The intercept point on the natural circulation line is 5% lower in power that the Exclusion Region intercept. The Buffer Zone intercept on the high rod line is 5% greater in flow than the Exclusion Region. These regions are validated for each fuel cycle and included in the COLR.

Cycle 18 ATWS Analysis required imposing a P-F map boundary different from MELLLA boundary from 0 to 5000 MWD/ST in order to limit the peak reactor pressure to 1500 psig. Power-Flow Map will show this boundary as documented in Appendix H to Supplemental Reload Licensing Report (Reference 17, Appendix Q). This boundary changes the minimum core flow to 78.5% at 100% power and has a different slope than the MELLLA line. It intersects the MELLLA line at 94.7% power, 70.6% flow. This boundary is specific to Cycle 18 and was selected to maximize the operating domain. After 5000 MWD/ST there is no restriction due to ATWS and Power-Flow Map reverts back to using MELLLA boundary.

Cycle 18 stability analysis requires use of the flow clamp from 0 to 2000 MWD/ST cycle exposure in order to prove that core wide mode is the dominant mode of oscillations, as required to use Stability Option 1-D. For cycle exposure greater than 2000 MWD/ST, flow clamp is not required (Reference 17, Appendix Q).

These regions are illustrated on Figures 3.7-1. See also the discussion in Section 3.7.4.6 and References 8 through 12.

During Single Loop Operation the acceptable boundaries of reactor operation are reduced from normal two-loop operation. Core flow is limited to 52% of rated and core power is limited to 65% of rated. The administrative controls of the stability regions are also enforced in SLO (Reference 5).

3.7.3.4 Temperature-Power Operating Map (PWR)

Not applicable.

3.7.3.5 Load-Following Characteristics

The following simple description of BWR operation with recirculation flow control summarizes the principal modes of normal power range operation. Assuming the plant to be initially hot with the reactor critical, full power operation can be approached following the sequence shown as points 1 to 7 in Figure 3.7-1. The first part of the sequence (1 to 3) is achieved with control rod withdrawal and manual, individual recirculation pump control. Individual pump startup procedures are provided that achieve 26% of full pump speed in each loop. Power, steam flow, and feedwater flow are increased as control rods are manually withdrawn until the feedwater flow has reached approximately 20%. An interlock prevents low power-high recirculation flow combinations that create recirculation pump and jet pump NPSH problems.

Control rods are withdrawn causing reactor thermal power and core flow to increase along the pump minimum speed line. Once the feedwater interlock is cleared, the operator can manually increase recirculation flow in each loop until the operating state reaches point 3.

Thermal output can then be increased by either control rod withdrawal or recirculation flow increase. For example, the operator can reach 50% power in the ways indicated by points 4 or 5. With a slight rod withdrawal and an increase of recirculation flow to rated flow, point 4 can be achieved. If, however, it is desired to maintain lowest recirculation flow, 50% power can be reached by withdrawing control rods until point 5 is reached.

The curve labeled "100% load line" represents a typical steady-state power flow characteristic for a fixed rod pattern. It is slightly affected by xenon, core leakage flow assumptions, and reactor vessel pressure variations; however, for this example, these effects have been neglected.

To optimize load following capabilities, power range operation should be near or below the "100% load line." If load following response is desired in either direction, plant operation near 90% power provides the most capability. If maximum load pickup capability is desired, the nuclear system can be operated near point 6, with load response available all the way up to point 7, rated power.

The large negative operating coefficients, which are inherent in the BWR, provide important advantages as follows:

1. Good load following with well damped behavior and little undershoot or overshoot in the heat transfer response.

2. Load following with recirculation flow control.

3. Strong damping of spatial power disturbances.

Design of this single cycle BWR plant includes the ability to follow load demand over a reasonable range without requiring operator action.

Load following is accomplished by varying the recirculation flow to the reactor. This method of power level control takes advantage of the reactor negative void coefficient. To increase reactor power, it is necessary only to increase the recirculation flow rate which sweeps some of the voids from the moderator, causing an increase in core reactivity. As the reactor power increases, more steam is formed and the reactor stabilizes at a new power level with the transient excess reactivity balanced by the new void formation. No control rods are moved to accomplish this power level change. Conversely, when a power reduction is required, it is necessary only to reduce the recirculation flow rate. When this is done, more voids are formed in the moderator, and the reactor power output automatically decreases to a new power level commensurate with the new recirculation flow rate. No control rods are moved to accomplish the power reduction.

Load following through the use of variations in the recirculation flow rate (flow control) is advantageous relative to load following by control rod positioning. Flow variations perturb the reactor uniformly in the horizontal planes, and thus allow operation with flatter power distribution and reduced transient allowances. As the flow is varied, the power and void distributions remain approximately constant at the steady state and points for a wide range of flow variations. These constant distributions provide the important advantage that the operator can adjust the power distribution at a reduced power, and flow by movement of control rods and then bring the reactor to full power conditions by increasing flow, with the assurance that the power distributions will remain approximately constant. Section 7.9, Recirculation Flow Control System, describes the means by which recirculation flow is varied.

3.7.3.6 Thermal and Hydraulic Characteristics Summary Table

The thermal-hydraulic characteristics are provided in Table 3.7-1 for the core and Section 4.0 for other portions of the reactor coolant system.

3.7.4 Evaluation

The design basis employed for the thermal and hydraulic characteristics incorporated in the core design, in conjunction with the plant equipment characteristics, nuclear instrumentation, and the reactor protection system, is given in Reference 1.

3.7.4.1 Critical Power

The GEXL-Plus critical power correlation utilized in thermal-hydraulic evaluations is discussed in Reference 1.

3.7.4.2 Core Hydraulics

Core hydraulic models and correlations are discussed in Reference 1.

3.7.4.3 Influence of Power Distributions

The influence of power distributions on the thermal-hydraulic design is discussed in Reference 1. The local, radial, and axial peaking factors used in the analysis are listed in the supplemental reload licensing report found in Appendix Q.

3.7.4.4 Core Thermal Response

The thermal response of the core for accidents and expected transient conditions is discussed in Section 14.

3.7.4.5 Analytical Methods

The analytical methods, thermodynamic data, and hydrodynamic data used in determining the thermal and hydraulic characteristics of the core are documented in Reference 1.

3.7.4.6 Thermal-Hydraulic Stability Analysis

Light water reactors, including boiling water reactors, inherently include a stabilizing negative moderator density reactivity coefficient. Fuel power increases are limited by corresponding coolant density decreases that constrain further moderation of the thermal neutron flux and subsequent power production. This feedback mechanism between the fuel and core coolant is reversible. Perturbations of fuel power by control rod motion or the core coolant density by compression/rarefaction waves passing through the vapor phase are characterized by damped oscillations of the neutron flux density. At normal power operating conditions, the reactor core coolant is the recipient of a continuous bombardment of internally and externally generated small perturbations, manifested in the electronic signal data representing neutron flux density as mid-range frequency (≈0.5 to ≈2 Hz) components of the total signal "noise".

At low reactor coolant flow conditions, the effectiveness of the feedback between fuel power production and coolant moderation to dampen neutron flux density oscillations will degrade. Moderator density changes originating in the lower elevations of the fuel assembly coolant channel are reflected later in the upper elevations of the fuel assembly coolant, the time lag determined by the velocity of the coolant flow. Reactor coolant velocities associated with forced convection flow near rated conditions incur a very short time lag, assuring that the fuel power feedback to core coolant density changes (and the reverse effect) are nearly "in phase" and result in the highly dampened oscillatory behavior response of both variables desired. The "decay ratio" of the response is much less than 1.0, i.e., the ratio of the offset from average of the variables (e.g., neutron flux density) peak value to the offset from average of the preceding peak value of that variable. However, at much lower coolant velocities near and below 40% rated core flow rate, the time lag increases; and the power feedback to the coolant from the fuel in the upper elevation of the fuel assembly associated with a coolant density change will increase or decrease partially "out of phase" with the coolant density increase or decrease that occurred earlier upstream in the fuel channel. The oscillations become less damped, and, if the time lag increases significantly, even undamped. Undamped, growing oscillations have a "decay ratio" greater than 1.0. This is known as a "dynamic density-wave" instability.

Higher core void fractions associated with increased core power can aggravate the marginal stability or instability associated with low coolant flow rate alone. As power increases in the bottom of the core, the onset of boiling moves further upstream, and the "boiling length" increases, further increasing the magnitude of the time lag that a coolant density compression/rarefaction wave can experience traveling up the fuel channel flow path. As power increases overall, both the coolant void fractions and fuel power density increase in the upper elevations of the fuel assembly channels, adding greater potential for "out-of-phase" thermal-hydraulic feedback to accelerate the effects of destabilizing low coolant flow. Therefore, while core instability may occur over a wide range of core power at low flow condition, it is at the upper portion of that range where decay ratios are expected to be significantly greater than 1.0.

While the increased delay in void propagation up a fuel channel at low reactor coolant flow conditions is the most common cause for instability in BWRs, it is but one of several reactor and fuel characteristics that may interact to lead to unstable conditions of the same or different types. One characteristic that has changed significantly since early BWR designs is a decrease in fuel pin diameter. This results in less lag between power production changes in the smaller fuel pin and the consequential thermal heat changes to the surrounding coolant/moderator. This has reduced the margin to instability previously available in the larger fuel pin designs under conditions of reduced coolant flow. The various phenomena of thermo hydraulic instability are described in NUREG/CR-6003 (Reference 7).

Thermo hydraulic density-wave instabilities do not pose a significant threat to nuclear fuel or clad failure in most cases. When the reactor core remains thermo hydraulically and neutronically coupled, core thermal-hydraulic instability quickly results in reactor scram on high neutron flux via the APRMs input to the Reactor Protection System. This is due to the essentially "in phase" response of all LPRMs feeding in to a common APRM. Even if crediting only the 120% of rated power trip setpoint to terminate reactor operation, unstable operation would incur only mild thermal cycling of the fuel before a reactor scram. However, reactor conditions may favor a neutronically and thermo hydraulically uncoupled response, resulting in "out-of-phase" LPRM neutron flux indications. Their summations in their associated APRM could "mask" the severity of local power oscillations by partially canceling out each others' oscillatory extremes. If uncoupled power oscillations were to persist without intervention, local fuel cladding may experience cycling periods of departure from nucleate boiling conditions. In the rarely experienced or expected case of single channel thermo hydraulic instability, detection is also made difficult by the APRMs representation of global, rather than local, core power.

General Design Criterion 10 of Appendix A, 10 CFR 50 precludes normal operation or anticipated transients that would lead to departure of nucleate boiling conditions, a fuel design limit. General Design Criterion 12 requires that undamped power oscillations either be automatically detected and suppressed, or that either the design or automatic actions preclude the possibility of operation at the conditions which create core power oscillations. While core thermo hydraulic instabilities have never been experienced at PNPS their possibility cannot be precluded based upon the design of the reactor core and fuel. The option of "detecting and suppressing" power oscillations was selected for PNPS beginning in Cycle 16 (Reference 11).

The PNPS Long Term Stability Solution is known as Option 1-D. PNPS has a relatively small core and small inlet orifice diameter compared to other BWR plants. These design features result in a 95% confidence that if unstable oscillations occur at PNPS, they will be global or core wide. Based on cycle dependent stability analysis the APRM scram setpoint is positioned to prevent operation in regions of the power-flow map where a 95% confidence or core wide oscillation is not ensured by the small core and small inlet orifice diameter. For core wide oscillations the LPRM's will respond in phase, which means the APRM signals will be indicative of core power conditions. The flow biased APRM scram setpoint can be used to detect and suppress the undamped oscillations. The APRM flow biased scram is the license basis feature that protects the SLMCPR limit.

The cycle specific flow biased APRM setpoint may be exposure dependent and is documented in the supplemental reload licensing report found in Appendix Q. However, there are defense-in-depth restrictions that are part of Option 1-D to provide prevention against onset of a thermal-hydraulic instability event. Option 1-D is an NRC approved methodology (References 8 through 12).

EXCLUSION REGION
The implementation of Option 1-D identified the Exclusion Region. This is an area within the operating domain where the possibility exists for the occurrence of thermal-hydraulic oscillations. See References 10 and 11. The Exclusion Region is validated for each core and cycle design. Normal operation is prohibited within the Exclusion Region. If the region is entered as a result of a transient, then immediate exit is required. Cycle 18 stability analysis requires use of the flow clamp from 0 to 2000 MWD/S cycle exposure in order to prove that core wide is the dominant mode of oscillations as required to use stability Option 1-D. For cycle exposure greater than 2000 MWD/S flow clamp is not required (Reference 17, Appendix Q). Hence, for the first 2000 MWD/S cycle exposure the APRM flow biased scram setpoint is inside the operating domain. Normally, the APRM flow biased scram setpoint is closer to the operating domain above this region to provide protection for the MCPR in case of the occurrence of an unstable oscillation. The APRM flow biased rod block is positioned parallel to the APRM scram and lower by 5% of rated power. It provides a warning prior to reaching the APRM Scram setpoint.

BUFFER ZONE
A Buffer Zone, which is parallel to the Exclusion Region, adds additional margin to prevent occurrence of thermal hydraulic instabilities. Normal and transient operation in the Buffer Zone is permitted with availability of on-line stability monitoring. The primary means of performing on-line stability monitoring is the SOLOMON program, which is part of the process computer. This feature is described in Section 7.16. The alternate means of on-line stability monitoring is the Period Based Detection System (PBDS). This feature is described in Section 7.5.

The required Stability Option 1-D limits are defined in the core operating limits report (COLR).

3.7.5 Testing and Verification

The reload core startup physics and core verification programs are contained in the Technical Specifications.

3.7.6 Instrumentation Requirements

The reactor vessel instrumentation monitors the key reactor vessel operating parameters, during planned operations. This ensures sufficient control of the parameters. The reactor vessel sensors are discussed in Subsection 7.8, Reactor Vessel Instrumentation.

3.7.7 References

1. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A, Revision Number Listed in Latest Supplemental Reload License Submittal in Appendix Q.

2. "General Electric Boiling Water Reactor Extended Load Line Limit Analysis for Pilgrim Nuclear Power Station Unit 1 Cycle 6," NEDO-22198, September 1982.

3. "Safety Review of Pilgrim Nuclear Power Station, Unit No. 1 at Core Flow Conditions Above Rated Flow Throughout Cycle 6," NEDO-30242, August 1983.

4. "Safety Review of Pilgrim Nuclear Power Station, Unit No. 1 at Core Flow Conditions Above Rated Flow For End-of-Cycle 6," NEDO-30242, Supplement 1, September 1983.

5. GE-NE-0000-0027-5301-R2-P, April 2006, Pilgrim Nuclear Power Station Single Loop Operation.

6. "Maximum Extended Load Line Limit Analyses for Pilgrim Nuclear Power Station Reload 9 Cycle 10," NEDC-32306P, March 1994 (SUDDS/RF94-042).

7. "Density-Wave Instabilities in Boiling Water Reactors," NUREG/CR-6003, prepared by J. Marche-Leuba, ORNL, September 1992.

8. NEDO 31960A, "BWR Owner's Group Long-Term Stability Solutions Licensing Methodology," November 1995.

9. NEDO 31960A, Supplement 1, "BWR Owner's Group Long-Term Stability Solutions Licensing Methodology," March 1992.

10. NEDO 32465A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

11. NEDC-33155P, "Application of Stability Long-Term Solution Option 1-D to Pilgrim Nuclear Power Station," Revision 0, October 2004.

12. General Electric Report GE-NE-GENE-0000-0033-6871-01, "Pilgrim Option 1-D APRM Flow Biased Setpoints."

13. "Safety Analysis Report for Pilgrim Nuclear Power Station Thermal Power Optimization", NEDC-33050P, GE Nuclear Energy, July 2002.

14. NRC Letter to PNPS dated April 12, 2006 (PNPS Ltr 1.06.042), Issuance of Amendment 219, SER Single Recirculation Loop Operation.

Table 3.7-1

THERMAL AND HYDRAULIC ANALYSIS PARAMETERS
FROM RELOAD LICENSING ANALYSIS

Parameter	Analysis Value
Thermal power, MWt	2028
Dome pressure, psig	1035
Steam flow, Mlb/hr	8.13
Turbine pressure, psig	972.7
Core flow (107.5%), Mlb/hr	74.2
Reactor pressure, psia**	1066.5
Inlet enthalpy, BTU/lb	528.2
Non-fuel power fraction	0.036
No. of Safety/Relief Valves	4
Lowest setpoint, psig	1190 (1155 psig ± 3%)
No. of Spring Safety Valves	2
Lowest setpoint, psig	1318 (1280 psig ± 3%)
Maximum Linear Heat Generation Rate, kW/ft	Fuel Bundle Information Report (Cycle Specific Supplement to the Supplemental Reload Licensing Report
Design Operating Minimum Critical Power Ratio	Supplemental Reload Licensing Report*
Peaking Factors:	
Local	Supplemental Reload Licensing Report
Radial	Supplemental Reload Licensing Report
Axial	Supplemental Reload Licensing Report

*See Appendix Q, Supplemental Reload Licensing Report
** Calculated Pressure at Reactor Core Mid-Plane

3.8 STANDBY LIQUID CONTROL SYSTEM

3.8.1 Safety Objective

The safety objective of the Standby Liquid Control System (SLCS) is to provide a backup method, which is independent of the control rods, to maintain the reactor subcritical as the nuclear system cools in the event that not enough of the control rods can be inserted to counteract the positive reactivity effects of a colder moderator. It also provides a method to mitigate the effects of Anticipated Transients without Scram (ATWS).

3.8.2 Safety Design Basis

1. Backup capability for reactivity control shall be provided, independent of normal reactivity control provisions in the nuclear reactor, to be able to shut down the reactor if the normal control ever becomes inoperative.

2. The backup system shall have the capacity for controlling the reactivity difference between the steady state rated operating condition of the reactor with voids and the cold shutdown condition, including shutdown margin, to assure complete shutdown from the most reactive condition, at any time in the core life.

3. The time required for actuation and effectiveness of the backup control shall be consistent with the nuclear reactivity rate of change predicted between rated operating and cold shutdown conditions and with the requirements of 10CFR50.62 for mitigation of ATWS events. A fast scram of the reactor or operational control of fast reactivity transients is not specified to be accomplished by this system.

4. Means shall be provided by which the functional performance capability of the backup control system components can be verified periodically under conditions approaching actual use requirements. A substitute solution, rather than the actual neutron absorber solution, may be injected into the reactor to test the operation of all components of the Redundant Control System.

5. The neutron absorber shall be dispersed within the reactor core in sufficient quantity to provide a reasonable margin for imperfect mixing or leakage.

6. The system shall be reliable to a degree consistent with its role as a special safety system; the possibility of unintentional or accidental shutdown of the reactor by this system shall be minimized.

3.8.3 Description

The piping and instrumentation for the SLCS is shown on Figure 3.8-1. Figure 3.8-2 is a process diagram for the system. The SLCS is manually initiated from the main control room to pump a boron neutron absorber solution into the reactor if the operator believes the reactor cannot be shut down or kept shut down with the control rods. However, insertion of control rods is expected to always assure prompt shutdown of the reactor should it be required. The boron absorbs thermal neutrons and thereby terminates the nuclear fission chain reaction in the uranium fuel.

The SLCS is needed in the improbable event that not enough control rods can be inserted in the reactor core to accomplish shutdown and cooldown in the normal manner. The SLCS therefore is sized to shut the reactor down at a steady rate within the capacity of the Shutdown Cooling Systems, and keep the reactor from going critical again as it cools. The SLCS also has the control capacity to meet the requirements of 10CFR50.62 for mitigation of ATWS.

The boron solution tank, the test water tank, the two positive displacement pumps, the two explosive valves, and associated local valves and controls are mounted in the Reactor Building outside the primary containment. The liquid is piped into the reactor vessel and discharged near the bottom of the core shroud so that it mixes with the cooling water rising through the core. See Section 3.3, Reactor Vessel Internals Mechanical Design, and Section 4.2, Reactor Vessel and Appurtenances Mechanical Design.

The specified neutron absorber solution is a 54.5 percent enriched sodium pentaborate solution. The use of 54.5 percent enriched sodium pentaborate solution requires the fraction of boron-10 isotope in the boron be enriched to a minimum 54.5 atom percent. It is prepared by dissolving enriched sodium pentaborate in demineralized water. An air sparger is provided in the tank for mixing. To prevent system plugging, the tank outlet is raised above the bottom of the tank and is fitted with a strainer.

At all times when it is possible to make the reactor core critical, the SLCS shall be able to deliver at least 2068 gal of the 8.82 percent concentration, 54.5 percent enriched sodium pentaborate solution or equivalent into the reactor. The SLCS storage tank shall have the design capacity to deliver at least 3,960 gal. of 8.82 percent concentration, 54.5 percent enriched sodium pentaborate solution or equivalent into the reactor. The shutdown margin provided by the additional capacity is equivalent to a 1599 ppm concentration of natural boron in the reactor. This additional capacity is realized by placing 3364 lbs of 54.5 percent enriched sodium pentaborate in the standby liquid tank and filling with demineralized water to at least the low level alarm volume.

The maximum saturation temperature of the specified solution is 38°F so the equipment containing the solution is installed in a room in which the air temperature is to be controlled to exceed 48°F at all times. An electric immersion heater in the tank and a temperature controller may be used to maintain the solution above saturation temperature. The heater is used to elevate the temperature and assure that the boron dissolves when first added to the water. High or low temperature, or high or low liquid level, causes an alarm in the control room.

Each positive displacement pump is sized to inject the solution into the reactor in 50 to 125 min, for any acceptable solution level in the tank, at all reactor operating pressures. The pump and system design pressure is 1,500 psig. The two relief valves are set to exceed the reactor lower plenum pressure at the time of system initiation by a sufficient margin to avoid valve leakage. The relief valves are installed with the discharge flooded to prevent evaporation and precipitation within the valve. To prevent bypass flow from one pump in case of relief valve failure in the line from the other pump, a check valve is installed downstream of each relief valve line in each pump discharge line.

The two explosive actuated injection valves provide high assurance of opening when needed and ensure that boron will not leak into the reactor even when the pumps are being tested. The valves have a firing reliability in excess of 99.99 percent. Each explosive valve is closed by a plug in the inlet chamber. The plug is circumscribed with a deep groove so the end will readily shear off when pushed by the valve plunger. This action opens the inlet hole through the plug. The sheared end is pushed out of the way in the chamber, and is shaped so it will not block the ports after release.

The shearing plunger is actuated by an explosive charge with dual ignition primers, inserted in the side chamber of the valve. Ignition circuit continuity is monitored by a trickle current, and an alarm occurs in the control room if either circuit opens. Indicator lights show which channel primer circuit opened. To service a valve after firing, a 6 in length pipe (spool piece) must be removed immediately upstream of the valve to gain access to the shear plug.

The SLCS is actuated by a three position keylock switch on the control room console. This assures that switching from the "off" position is a deliberate act. Switching to either side starts one injection pump, opens an explosive valve, and closes the Reactor Cleanup System isolation valves to prevent loss or dilution of the boron.

A green light in the control room indicates that power is available to the pump motor contactor, but that the contactor is open (pump not running). A red light indicates that the contactor is closed (pump running).

Liquid flow is confirmed by a decrease in reactivity, storage tank drawdown and pump running indication. A red light beside the keylock switch turns on when valve 1101-1, downstream of the explosive valves is open. If the pump lights or explosive valve light indicates that the liquid may not be flowing, the operator can immediately turn the keylock switch to the other side; this switch actuates the alternate equipment. Crosspiping and check valves assure a flow path through either pump and either explosive valve. The chosen pump will start even though its local switch at the pump is in the "stop" position for test or maintenance. Pump discharge pressure indication is also provided in the control room.

Equipment drains and tank overflows are not piped to the Waste System but to separate containers (such as 55 gal drums) to prevent any trace of boron from inadvertently reaching the reactor. These drums can be removed and disposed of independently, or can be held until the contents can be returned to the storage tank by means of a suitable transfer system.

Instrumentation is provided locally at the standby liquid control tank and consists of solution temperature indication and control, tank level, and heater status. Instrumentation and control logic is presented on Figure 3.8-4.

3.8.4 Safety Evaluation

The SLCS, although not necessary for plant operation, is required to be operable when in the startup or run mode where more than one control rod can be withdrawn. The system is expected never to be needed for plant safety because of the large number of independent control rods available to shut down the reactor. The SLCS requires one explosive valve and one pump to operate. To assure system availability, two explosive valves and two pumps are provided in parallel.

The system is designed to inject a quantity of boron that produces a minimum concentration equivalent to 675 ppm of natural boron in the reactor core. The 675 ppm equivalent concentration in the reactor is sufficient to bring the reactor from full power to cold subcritical condition, with adequate shutdown margin, and with the control rods fully withdrawn. The required shutdown margin is recalculated for each reload to ensure that the actual shutdown margin provided by the SLC system exceeds the shutdown margin required by the fuel type and analysis method. It includes the reactivity gains due to complete decay of the xenon inventory. It also includes the positive reactivity effects from eliminating steam voids, changing water density from hot to cold, reduced Doppler effect in uranium, reduction of neutron leakage from boiling to cold, and decreasing control rod worth as the moderator cools.

The specified minimum average concentration of natural boron in the reactor, to provide the specified shutdown margin after operation of the SLCS, is 675 ppm. The minimum quantity of natural boron sodium pentaborate to be injected into the reactor is calculated based on the required 675 ppm average concentration in the reactor coolant, and the quantity of reactor coolant in the reactor vessel and recirculation loops at the high water level alarm setting and 70°F, and the weight of water in the RHR shutdown cooling subsystem at 70°F. The result is increased by 25 percent to allow for imperfect mixing, leakage, and volume in other small piping connected to the reactor. Figure 3.8-6 shows the sodium pentaborate solution concentration and the SLCS tank volume. With the use of enriched boron, the required boron concentration is reduced in inverse proportion to the enrichment ratio:

$$\frac{\text{minimum B10 isotope atom percent for enriched boron}}{\text{B10 isotope atom percent for natural boron}} = \frac{54.5}{19.8} \quad (3.8.4\text{-}1)$$

Cooldown of the Nuclear System will take several hours as a minimum, to remove the thermal energy stored in the reactor, cooling water, and associated equipment and to remove most of the radioactive decay heat. The controlled limit for the reactor vessel cooldown is 100ºF/hr, and normal operating temperature is about 550ºF. Usually, shutting down the plant with the main condenser and various shutdown cooling systems will take 10 to 24 hr before the reactor vessel is opened, and much longer to reach room temperature (70ºF).

The solution injection rate is limited to the range of 39 to 79 gal/min. The lower rate assures that the boron gets into the reactor in about 1 1/2 hr, considerably quicker than the cooldown rate. The upper limit injection rate assures that there is sufficient mixing so the boron does not recirculate through the core in uneven concentrations which could possibly cause the nuclear power to rise and fall cyclically.

The SLCS is also required to meet 10CFR50.62 (Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants). The SLCS must have the equivalent control capacity (injection rate) of 86 gpm at 13 percent by weight natural sodium pentaborate for a 251" diameter reactor pressure vessel in order to satisfy 10CFR50.62 requirements. This equivalency requirement is fulfilled by a combination of concentration, B10 enrichment and flow rate of sodium pentaborate solution. A minimum 8.42% concentration and 54.5% enrichment of B10 isotope at a 39 GPM pump flow rate satisfies the ATWS Rule (10CFR50.62) equivalency requirement (Reference 2).

The SLCS is designed as a Class I seismic system. The system piping and equipment are designed, installed, and tested in accordance with USAS B31.1.0 Section I and Appendix A. Nonprocess equipment such as the test tank is designed as Class II.

The SLCS is required to be operable in the event of a station power failure, so the pumps, valves, and controls are powered from the standby ac power supply in the absence of normal power. The pumps and valves are powered and controlled from separate buses and circuits so that a single failure will not prevent system operation. The essential instruments and lights are powered from the 120 V ac instrument power supply.

The SLCS and pumps have sufficient pressure margin, up to the system relief valve setting over the range of approximately 1425 to 1490 psig, to assure solution injection into the reactor above a pressure of 1212 psig in the lower plenum of the reactor (Reference 3). The nuclear system relief and safety valves begin to relieve pressure above about 1155 psig; therefore, the SLCS positive displacement pumps cannot overpressurize the Nuclear System.

The system is designed to provide a minimum concentration of boron in the reactor equivalent to 675 ppm of natural boron. The shutdown margin from this concentration can be found in Pilgrim's Supplemental Reload License Submittal in Appendix Q. The analysis and models for the reload core are described in the GE Standard Application for Reactor Fuel (Reference 1).

3.8.5 Inspection and Testing

Operational testing of the SLCS is performed in at least two parts to avoid inadvertently injecting boron into the reactor. By opening two closed valves (one locked closed) to the solution tank, the boron solution may be recirculated by turning on either pump with its local switch. With the valves to and from the solution tank closed and the three valves (two locked closed) opened to and from the test tank, the demineralized water in the test tank can be recirculated by turning on either pump locally. The pumps and pipes should have the boron solution flushed out before conducting these tests. Functional testing of the injection portion of the system is accomplished by closing the locked open valve from the solution tank, opening the locked closed valve from the test tank, and actuating the keylock switch in the control room to either the A or B circuit. This starts the pump and blows open the injection valve in that circuit. The lights and alarms in the control room indicate that the system is operating.

By closing a local locked open valve to the reactor in the containment, leakage through the injection valves can be detected at a test connection in the line between the containment isolation check valves. (Position indicator lights in the control room indicate that the local valve is closed for tests, or open and ready for operation.) Leakage from the reactor through the first check valve can be detected by opening the same test connection whenever the reactor is pressurized.
After the functional tests, the injection valves and explosive charges must be replaced and all valves returned to their normal positions, as indicated on Figure 3.8-1.

The test tank contains demineralized water for about three min of pump operation. Demineralized water from the makeup or condensate storage system is available at 30 gal/min for refilling or flushing the system.

Should the boron solution ever be injected into the reactor, either intentionally or inadvertently, then, after making certain that the normal reactivity controls will keep the reactor subcritical, the boron is removed from the Reactor Coolant System by flushing for gross dilution followed by operation of the Reactor Cleanup System. There is practically no effect on reactor operations when the natural boron concentration has been reduced below approximately 50 ppm.

The concentration of the sodium pentaborate in the solution tank is determined by chemical analysis periodically. The enrichment of the sodium pentaborate in the solution is determined periodically by tests.

The gas pressure in the two accumulators is measured periodically to detect leakage. A pressure gage and portable nitrogen supply are required to test and recharge the accumulators.

3.8.6 Compliance with 10CFR50.62

Compliance with 10CFR50.62, has been demonstrated by means of the equivalent control capacity concept using the plant-specific minimum parameters. (Reference 2)

3.8.7 Current Operational Nuclear Safety Requirements

The current limiting condition for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

3.8.8 References

1. NEDE-24011-P-A, General Electrical Standard Application for Reactor Fuel (See Appendix Q for the applicable revision.)

2. Standby Liquid Control System Control Capacity Equivalence Report, General Electric, Dated January 29, 1987

3. NEDC-33532P, Pilgrim Nuclear Power Station Safety Valve Setpoint Increase, Revision 2, January 2011

3.9 RECIRCULATION PUMP TRIP, ALTERNATE ROD INSERTION, AND FEEDWATER PUMP TRIP SYSTEMS

3.9.1 Design Objective

The design objective of the Recirculation Pump Trip (RPT) and Alternate Rod Insertion (ARI) Systems is to provide a back-up method for introducing negative reactivity to the Reactor in the unlikely event of a failure of the Reactor to scram from power during an anticipated transient (such as loss of feedwater, loss of condenser vacuum, or loss of offsite power). These design features have been incorporated to comply with 10CFR50.62. The feedwater pump trip is to aid in the assurance that vessel peak pressure and suppression pool temperature and pressure limits are not exceeded (Reference 6).

3.9.2 Design Basis

The design basis for the RPT, ARI and FPT Systems is as follows:

1. RPT, ARI and FPT shall provide the means to help mitigate the consequences of a failure of the Reactor to scram.

2. RPT, ARI and FPT shall supplement the functional performance of the existing Reactor Protection System (RPS) as well as provide redundancy, diversity, and independence from the RPS. (Reference Section 7.2)

3. Means shall be provided by which functional performance capability of the RPT, ARI and FPT control system components can be verified periodically under conditions approaching actual use requirements.

4. These systems, although classified as non-safety, shall be designed and operated to provide a degree of reliability consistent with its functions.

5. The possibility of unintentional or accidental shutdown of the Reactor by these systems shall be minimized.

6. ARI shall be diverse, to the extent practical, from the RPS.

7. ARI initiated scram shall start within 15 seconds. Once initiated, control rods shall be fully inserted within 60 seconds and prior to filling the Scram Discharge Volume (SDV).

8. The ARI function shall be electrically independent from the RPS.

3.9.3 Description

3.9.3.1 Recirculation Pump Trip System

The RPT system causes a "trip" of the Recirculation Pump MG Set field breakers and drive motor breakers upon detection of either high reactor pressure or low reactor water level conditions. (Reference Sections 4.3, 7.9)

The mechanism for RPT consists of redundant shunt trip devices (trip coils) installed in each Recirculation MG Set generator field and drive motor breaker. These trip coils are normally de-energized. When RPT logic is satisfied the trip coils are energized to trip the Recirculation MG set field breakers and drive motor breakers and thus effect a trip of the Recirculation Pumps (See Figure 3.9-3).

3.9.3.2 Alternate Rod Insertion System

Instrumentation and relay logic is also provided to scram the reactor through the ARI system. The ARI system serves as a diverse electrical logic to the RPS scram. The mechanism for ARI consists of two solenoid valves (A and B) installed in the instrument air header of the Control Rod Drive - Hydraulic Control Units. These additional valves are redundant to the existing RPS backup scram valves (Refer to Figure 3.9-4). When either valve is energized, the scram valve air supply header is vented to atmosphere to initiate insertion of all control rods. (Refer to Section 3.4 and 7.2)

3.9.3.3 Feedwater Pump Trip System

The feedwater pump trip system consists of analog trip slave units that receive signals from the same pressure transmitters as the MG set field breaker trip units. The slave units cause a trip of the reactor feed pump breakers upon detection of high-high reactor pressure.

3.9.3.4 System Trip Logic

The RPT, ARI and FPT system trip logic (Division 1 and Division 2), although non-safety related, are powered from the A and B batteries respectively. (See Figure 3.9-1) The RPT and ARI systems are initiated through coincident receipt of low water level and/or high pressure signals from the reactor pressure vessel (RPV). The FPT system is initiated through coincident receipt of high high pressure signals from the RPV. Electronic Transmitters provide RPV level and pressure signals to Analog Trip Units that are adjusted to energize auxiliary relays. The trip channels are arranged in a two-out-of-two-once logic. (Refer to Figure 3.9-2) Division I Logic consists of channels A and C instruments combining in a two-out-of-two logic to trip Feedwater pumps A, B, and C and Recirculating Pumps A and B (Refer to Figure 7.9-2) and energize the A solenoid of the ARI function. Likewise, Division II Logic consists of channels B and D combining in a two-out-of-two logic to trip Feedwater pumps A, B, and C and Recirculating Pumps A and B and energize the B Solenoid of the ARI function.

3.9.4 References

1. Deleted.

2. General Electric, evaluation of ATWS NEDC-31425 at Pilgrim Nuclear Power Station.

3. General Electric GE-NE-187-69-129, New Analytical Limit for Low Low Water Level for Pilgrim Nuclear Power Station, December 1991.

4. 10CFR50.62 Reduction of Risk From Anticipated Transients Without Scram (ATWS) Events for Light Water-Cooled Nuclear Power Plants.

5. General Electric Company, "Maximum Extended Load Line Limit Analyses for Pilgrim Nuclear Power Station Reload 9 Cycle 10" Section 7.1, NEDC032306P, March 1994 (SUDDS/RF94-042)

6. GE Hitachi Nuclear Energy, "Pilgrim Nuclear Power Station Safety Valve Setpoint Increase", NEDC-33532P Revision 2, January 2011

Filing Instructions

PNPS-FSAR

Revision 28 – October 2011

Volume 2

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP2 – Rev 27	EP2 – Rev 28
Section 4 TOC	Entire Section 4 TOC	Section 4 TOC – Rev 28*
4.2	Pages 1-24	Pages 1-21
4.4	Pages 1-9	Pages 1-10
4.4	Table 4.4-1	Table 4.4-1
4.4	Figure 4.4-1	Figure 4.4-1 page 1 of 2
4.4	Figure 4.4-2	Figure 4.4-2 page 2 of 2
4.7	Pages 1-6	Pages 1-7
4.10	Pages 1-7	Pages 1-8
Section 5 TOC	Entire Section 5 TOC	Section 5 TOC – Rev 28*
5.2	Page 8	Page 8
5.2	Table 5.2-4 page 6 of 15	Table 5.2-4 page 6 of 15
5.2	Table 5.2-4 page 11 of 15	Table 5.2-4 page 11 of 15
5.2	Table 5.2-4 page 12 of 15	Table 5.2-4 page 12 of 15
Section 6 TOC	Entire Section 6 TOC	Section 6 TOC – Rev 28*
6.3	Table 6.3-1 page 1 of 1	Table 6.3-1 page 1 of 1
6.4	Pages 1-8	Pages 1-9
6.5	Pages 1-11	Pages 1-13
6.6	Pages 1-3	Pages 1-4

*Text without revision bars was reformatted only.

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 2VOLUME 2**VOLUME 2**VOLUME 2**VOLUME 2**

Page, Table (T), or Figure (F)	Revision Number

VOLUME 2

SECTION 4

LIST OF EFFECTIVE PAGES

VOLUME 2VOLUME 2**VOLUME 2**VOLUME 2**VOLUME 2**

LIST OF EFFECTIVE PAGES

VOLUME 2VOLUME 2**VOLUME 2**VOLUME 2**VOLUME 2**

LIST OF EFFECTIVE PAGES

VOLUME 2VOLUME 2**VOLUME 2**VOLUME 2**VOLUME 2**

LIST OF EFFECTIVE PAGES

VOLUME 2VOLUME 2**VOLUME 2**VOLUME 2**VOLUME 2**

LIST OF EFFECTIVE PAGES

VOLUME 2VOLUME 2**VOLUME 2**VOLUME 2**VOLUME 2**

SECTION 4

REACTOR COOLANT SYSTEM

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

SECTION 4

LIST OF TABLES

SECTION 4

LIST OF FIGURES

LIST OF FIGURES (Cont)

4.2 REACTOR VESSEL AND APPURTENANCES MECHANICAL DESIGN

4.2.1 Safety Objective

The safety objective of the reactor vessel and appurtenances, in conjunction with other safety systems, is to provide a barrier to the release of radioactive materials when operated within the range of conditions considered by the Station Safety Analysis.

4.2.2 Safety Design Basis

1. The reactor vessel and appurtenances shall be designed to withstand combinations of loadings and forces resulting from operation under abnormal and accident conditions.

2. To minimize the possibility of brittle fracture failure of the nuclear system process barrier, the following shall be required: (a) the initial ductile brittle transition temperature of materials used in the reactor vessel shall be known by reference or established empirically; (b) expected shifts in transition temperature during design service life due to environmental conditions, such as neutron flux, shall be determined and employed in the reactor vessel design; and (c) operation margins to be observed with regard to the transition temperature shall be designated for each mode of operation.

3. The reactor vessel and appurtenances shall be designed so that failure of piping integrity does not compromise the ability to provide a refloodable volume.

4.2.3 Power Generation Objective

The reactor vessel design objective is to provide a volume in which the core can be submerged in coolant, thereby allowing power operation of the fuel. The reactor vessel appurtenances design provides the means for the attachment of pipelines to the reactor vessel and the means for the proper installation of vessel internal components.

4.2.4 Power Generation Design Basis

1. The location and design of the external and internal supports provided as an integral part of the reactor vessel shall be such that stresses in the reactor vessel and supports due to reactions at these supports are within ASME Code limits.

2. The reactor vessel design lifetime shall be 40 yr.

3. The design of the reactor vessel and appurtenances shall allow for the accomplishment of a suitable program of periodic inspection and surveillance.

4.2.5 Description

4.2.5.1 Reactor Vessel

The reactor vessel is a vertical cylindrical pressure vessel with hemispherical heads of welded construction. The reactor vessel is designed and fabricated for a useful life of 40 yr based upon the specified design and operating conditions. The vessel is designed, fabricated, inspected, tested, and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III (1965 Edition and January 1966 addenda), its interpretations, and applicable requirements for Class A Vessels as defined therein. The reactor vessel and its supports are designed in accordance with the loading criteria of Appendix C. The materials used in the design and fabrication of the reactor pressure vessel are shown on Table 4.2-1. Reactor vessel data is shown on Table 4.2-2.

The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated of low alloy steel plate which is clad on the interior with stainless steel weld overlay. The plates and forgings are ultrasonically tested and magnetic particle tested over 100 percent of their surfaces after forming and heat treatment. Preheat of vessel plate and forgings is maintained during welding until the weld joints are post weld heat treated. Full penetration welds are used at all joints including nozzles throughout the vessel except for nozzles of less than 3 in nominal size and control rod drive stub tubes.

Although little corrosion of plain carbon or low alloy steels occurs at temperatures of 500°F to 600F, higher corrosion rates occur at temperatures around 140°F. The stainless steel cladding provides the necessary corrosion resistance during reactor shutdown and also helps maintain water clarity during refueling operations. Exterior exposed ferritic surfaces of pressure containing parts have a minimum corrosion allowance of 1/16 in. All carbon and low alloy steel nozzles exposed to the reactor coolant have a corrosion allowance of 1/16 in. The vessel is designed to limit coolant retention pockets and crevices.

The nil-ductility transition temperature (NDTT) is defined as the temperature below which ferritic steel fractures in a brittle rather than a ductile manner. The NDTT increases as a function of neutron fluxes at integrated neutron fluxes greater than about 1 x 10^{17} nvt with neutrons of energies in excess of 1 MeV. The material NDTT dictates the minimum operating temperature at which the reactor vessel can be pressurized. One way to control the material NDTT is by selecting fine grained steels and by using advanced fabrication techniques to minimize radiation effects. The as fabricated initial NDTT for all carbon and low alloy steel used in the main closure flanges and the shell and head materials connecting to these flanges is limited to a maximum of 10°F as determined by ASTM E208. For all other carbon and low alloy steel pressure containing materials and the vessel support skirt material, the as fabricated initial NDTT is no higher than 40°F. A grain size of 5 or finer, as determined by the method in ASTM E112, is the objective of the fabrication technique.

Another way of minimizing any changes (elevating) to the NDTT is by reducing the integrated neutron exposure at the inner surface of the reactor vessel. The maximum neutron fluents for this reactor is calculated to be 2.5 x 1018 nvt. This number is calculated based on the assumption of operational design power for 40 yr at 100 percent availability for neutron energies greater than 1 MeV.

The vessel top head is secured to the reactor vessel by studs and nuts which are designed to be tightened with a stud tensioner. The vessel flanges are sealed by two concentric Inconel seal rings designed for no detectable leakage through the inner or outer seal at any operating condition, including cold hydrostatic pressure test at the full design pressure, and heating to operating pressure and temperature at a maximum rate of 100°F/hr. To detect lack of seal integrity, a vent tap is provided in the area between the two seal rings and a monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal. A tap is also provided in the area outside the outer seal ring for use in monitoring leakage.

The head and vessel flanges are low alloy steel forgings. The reactor vessel head, flange sealing surfaces, and shell flange sealing surfaces are weld overlay clad with austenitic stainless steel similar to the vessel which consists of a minimum of two layers and a minimum of 0.25 in total thickness after all machining, including the area under the seal grooves.

The first layer is deposited with a composition equivalent to ASTM A371, Type ER309, and the second layer has a composition equivalent to ASTM A371, Type ER308, except that the carbon content does not exceed 0.08 percent.

The vessel nozzles, as shown on Figure 4.2-2, are low alloy steel forgings made in accordance with ASTM A508. Nozzles of 3 in nominal size or larger are full penetration welded to the vessel. Nozzles of less than 3 in nominal size may be partial penetration welded as permitted by ASME Code, Section III.

The vessel top head nozzles are provided with flanges with small groove facing. The drain nozzle is of the full penetration weld design. The recirculation inlet nozzles, located as shown on Figure 4.2-2, feedwater inlet nozzles and core spray inlet nozzles have thermal sleeves similar to those shown in the detail on Figure 4.2-1.

Nozzles connecting to stainless steel piping have "safe ends" of stainless steel of types which are compatible with the material of the mating pipe. Nozzles for connecting carbon steel piping (except the top head nozzles which are unclad) are clad through at least the thickness of the vessel wall or 1/2 the diameter of the nozzle bore, whichever is less.

The nozzle for the core differential pressure and standby liquid control pipe is designed with a transition so that the stainless steel outer pipe of the differential pressure and liquid control line (see Section 3.3, Reactor Vessel Internals Mechanical Design) can be socket welded to the inner end of the nozzle and so that the inner pipe passes through the nozzle. This design provides an annular region between the nozzle and the inner liquid control line to minimize thermal shock effects on the reactor vessel in the event that use of the Standby Liquid Control System is required.

Nozzle safe ends for austenitic stainless steel pipe are ASME SA 182 Grade F304, with the exception of the core spray safe ends which are SA 182 Grade F316 and the Recirc. inlet/outlet nozzle safe ends which are replaced during the 1984 Piping Replacement Program, along with the Recirc. Piping, to SA182, Grade F316NG; stainless steel safe ends were not exposed to furnace sensitization or other prolonged heating at temperatures exceeding 800F. Where stainless steel safe ends were field welded to the vessel, the weld preparation of both the safe end and the nozzle were weld built up with Inconel; weld interpass temperature for deposition of weld metal on stainless steel did not exceed 350°F. Nozzle safe ends for carbon steel piping are ASME SA 508 Class I.

Thermocouple pads are located on the exterior of the vessel. See Table 4.2-3. At each thermocouple location, two pads are provided an end pad to hold the end of a thermocouple and a clamp pad equipped with a set screw to secure the thermocouple.

A complete reactor pressure vessel design and fabrication report is included in Appendix M. It was decided at an early manufacturing stage that the Pilgrim reactor vessel would not use furnace sensitized stainless steel and therefore, to avoid any sensitization that could have occurred during heat treatment of the vessel, it was agreed that the original safe ends would be removed from the vessel in the shop and new unsensitized safe ends would be welded to the vessel in the field. See Figure 4.2-3 for a typical detail.

In order to achieve adequate quality control and material requirements, welding tests and procedures were established in advance by Bechtel Corporation, approved by General Electric Company, and reviewed by Boston Edison Company.

Early in 1970, favorable welding tests were carried out at the Bechtel Metallurgical Laboratory in San Francisco, initially to demonstrate feasibility of field welding of safe ends by open butt methods with mockup nozzles in horizontal position simulating the pressure vessel in a vertical position. Welding laboratory tests were satisfactorily carried out to ensure that the base metal peak temperature (1/8 in from the weld and 30 sec after the arc had passed that point) could be held below 800°F using normal specified welding techniques.

Welders were qualified in accordance with the ASME Code, Section IX. Welders were qualified on ASTM A106, grade B pipe that was overlayed with Inconel bar filler metal conforming to ASTM-B304, ERNiCr-3, then weld ends were remachined and finally welded with Inconel covered electrodes conforming to ASTM-B295 E NiCrFe-3.

The original safe ends were welded to the low alloy steel nozzles with Inconel. After removal of these safe ends, weld preparations were made so as to leave a minimum of 1/8 in of the Inconel weld material on the nozzles, and the reactor vessel was then shipped to the field. New safe ends with a minimum of 1/8 in Inconel buttering were also shipped to the field. During the actual welding of the safe ends, only 13 of the qualified welders had to be used. The welding of safe ends was supervised by the field reactor welding inspector, the senior field welding engineer, the reactor QC engineer, and the reactor installation superintendent to ensure control of weld quality.

Welding was performed on the fifteen safe ends to Bechtel procedures P12, P8, At-Ag (F43) Rev. 1, and Addenda dated 5-28-70 which are qualified in accordance with ASME Code Section IX and ANSI Code for Pressure Piping B31.1.0 and B31.7 using open butt method. The first three weld passes were made using the gas tungsten arc (GTAW) process with the addition of bare filler rod conforming to ASTM B304 ERNiCr-3 (no consumable inserts). All remaining passes being made with the shielded metal arc process (SMAW) with electrodes conforming to ASTM B295 E NiCrFe-3. An argon internal purge was used for the first three weld layers.

All welds except control rod drive hydraulic return line (the control rod drive), which was radiographed after the third layer, were examined where practical by liquid penetrant methods on exposed internal and external surfaces after the third GTAW weld pass. All finished welds were liquid penetrant and radiographically examined. (Liquid penetrant procedure PT-SR-1,2 and radiography procedure RT-XG-2 which conform to ASME Code Requirements). The control rod drive hydraulic return line was liquid penetrant and radiographically examined on the outside only since a preinstalled thermal sleeve prevented internal liquid penetrant examination. This line has subsequently been cut and capped at the nozzle and tested in accordance with the operable nil-ductility transition (NDT) of ASME Section XI.

During inspection, two slag inclusions were found and various minor surface defects which were removed by grinding or chipping. Before welding was resumed, liquid penetrant inspection was used to determine that the indications had been totally removed.

During the October 2003 outage, the CRD return nozzle (N10) to cap weld was weld overlay repaired in accordance with code cases N-504-2 and N-638 and ASME XI to repair a thru wall leak.

In the two regions of the vessel where field welds are made attaching structural members to furnace sensitized cladding material, weld overlay has been done to isolate the attachment pad from the reactor coolant. These two areas are the jet pump riser brace attachment pads and the recirculation inlet thermal sleeve attachment pads. The riser brace pads were weld overlayed with a minimum of 1/16 in, Type 308L stainless steel. The exposed portion of the thermal sleeve attachment pads were welded likewise.

The core $P/liquid control nozzle socket weld fitting on the inside of the vessel was removed and replaced with a new piece. This was done not because the fitting was furnace sensitized, but because it was welded with stock electrode, thus possibly entrapping flux in the socket crevis. Therefore, the fitting was removed, the pipe abrasively cleaned to remove the entrapped flux, and a new fitting welded on using a GTAW process.

4.2.5.2 Shroud Support

The reactor vessel shroud is a cylindrical shell that surrounds the core assembly and provides a barrier to separate the upward core flow from the downward annulus flow. The shroud support is a flange plate welded to the inner vessel wall and the shroud. The shroud support is designed to carry the weight of the shroud, the jet pumps, and the steam separators and dryers. Stresses due to reactions at the shroud support are within ASME Code, Section III requirements.

The design pressure differential across the core shroud support is 100 psi (higher pressure under the support) occurring at the vessel design temperature. The design of the shroud support also takes into account the restraining effect of the components attached to the support and weight and earthquake loadings. The vessel shroud support and other internal attachments (jet pump riser support pads, guide rod brackets, steam dryer support brackets, dryer holddown brackets, feedwater sparger brackets, and core spray brackets) are shown on Table 4.2-3.

4.2.5.3 Reactor Vessel Support Assembly

The reactor vessel is laterally and vertically supported and braced to make it as rigid as possible without impairing the movements required for thermal expansion. Where thermal requirements prohibit the use of rigid supports, spring anchors or hydraulic snubbers are employed to resist earthquake forces while allowing sufficient flexibility for thermal expansion.

The reactor vessel support assembly consists of a ring girder and the various bolts, shims, and set screws necessary to position and secure the assembly between the reactor vessel support skirt and the support pedestal. The concrete and steel support pedestal is constructed integrally with the building foundation. Steel anchor bolts are set in the concrete with the threads extending above the surface. The anchor bolts extend through the ring girder bottom flange. High strength bolts are used to bolt the flange of the reactor vessel support skirt to the top flange of the ring girder. The ring girder is fabricated of ASTM A36 structural steel according to AISC Specifications.

4.2.5.4 Vessel Stabilizers

Eight vessel stabilizers are connected between the reactor vessel and the top of the shield wall surrounding the vessel to provide lateral stability for the upper part of the vessel. Four stabilizer brackets are attached by full penetration welds to the reactor vessel at evenly spaced locations around the vessel below the flange. Each vessel stabilizer consists of a stabilizer rod, threaded at the ends, springs, washers, nut, a plate, and a bumper bracket with tapered shims. The stabilizers are attached to each bracket and apply tension in opposite directions. The stabilizers are evenly preloaded with tensioners to the values of the residual loads. The stabilizers are designed to permit radial and axial vessel expansion, to limit horizontal vibration, and to resist seismic and jet reaction forces.

4.2.5.5 Refueling Bellows

The refueling bellows forms a seal between the reactor vessel and the surrounding primary containment drywell to permit flooding of the space (reactor well) above the vessel during refueling operations. The refueling bellows assembly, as shown on Figure 4.2-2, consists of a bellows, a backing plate, a spring seal, and a removable guard ring. The backing plate surrounds the outer circumference of the bellows to protect it and is equipped with a tap for testing and for monitoring leakage. The self energizing spring seal is located in the area between the bellows and the backing plate and is designed to limit water loss in the event of a bellows rupture by yielding to make a tight fit to the backing plate when subjected to full hydrostatic pressure. The guard ring attaches to the assembly and protects the inner circumference of the bellows. The guard ring can be removed from above to inspect the bellows. The assembly is welded to the reactor bellows support skirt and the reactor well seal bulkhead plate. The reactor refueling bellows assembly is welded to the reactor vessel shell flange, and the reactor well seal bulkhead plate bridges the distance to the primary containment drywell wall. Watertight hinged covers are bolted in place for normal refueling operation. For normal operation, these covers are opened to permit circulation of ventilation air in the region above the reactor well seal.

4.2.5.6 Control Rod Drive Housing

The control rod drive housings are inserted through the control rod drive penetrations in the reactor vessel bottom head and are welded to the Inconel stub tubes extending into the reactor vessel[1]. See Figure 4.2-1. Each housing transmits a number of loads to the bottom head of the reactor. These loads include the weight of a control rod and control rod drive, which are bolted to the housing from below, the weight of a control rod guide tube, one four lobed fuel support piece, and the four fuel assemblies which rest on the top of the fuel support piece. See Section 3.4, Reactivity Control Mechanical Design, and Section 3.3, Reactor Vessel Internal Mechanical Design. The housings are fabricated of type 304 austenitic stainless steel.

4.2.5.7 Control Rod Drive Housing Supports

The control rod drive housing support is designed to prevent a nuclear transient in the unlikely event that there is a control rod drive housing failure. This device consists of a grid structure located below the reactor vessel from which housing supports are suspended. The supports allow only slight movement of the control rod drive or housing in the event of failure. The control rod drive housing support is treated in detail in Section 3.5, Control Rod Drive Housing Supports.

4.2.5.8 Incore Flux Monitor Housings

The incore neutron flux monitor housings are inserted up through the incore penetrations in the bottom head of the reactor vessel and are welded to the inner surface of the bottom head. See Figure 4.2-1. An incore flux monitor guide tube is welded to the top of each housing, and either a source range monitor/intermediate range monitor (SRM/IRM) drive unit, or a local power range monitor (LPRM) is bolted to the seal ring flange at the bottom of the housing. See Sections 3.3 and 7.5.

4.2.5.9 Reactor Vessel Insulation

The reactor vessel insulation is of the reflective metallic and soft figerglass type. It has an average heat transfer rate of less than 80 Btu/hr-ft^2 at the vessel operating condition of 545°F and ambient drywell air temperature of 135°F. Insulation thicknesses are 4 in for the upper head, 3 1/2 in for the cylindrical shell, 3 in for the bottom head, and 3 in around nozzles N1A, N1B, N2A, N2B, N2C, N2D, N2E, N2F, N2G, N2H, N2J, N2K; N3A, N3B, N3C, N3D; N4A, N4B, N4C, N4D; N6A, N6B; which are of the soft fiberglass pad type.

The top head insulation can be removed in one piece. The insulation on the vessel shell, nozzles, and support skirt can be removed in panel sections over those areas selected for inservice inspection. The shell insulation is supported by a frame at the bottom, and by two other support rings which are permanently welded to the vessel at intermediate positions. The bottom head insulation has a self supporting frame which bears on the leg of the support skirt. Refer to Figure 4.2-4.

4.2.6 Safety Evaluation

The reactor vessel design pressure of 1,250 psig is determined by an analysis of margins required to provide a reasonable range for maneuvering during operation, with additional allowances to accommodate transients above the operating pressure (1,000 psig at the level of the top head flange) without causing operation of the safety valves. The 575°F design temperature for the reactor vessel is based on the saturation temperature of water corresponding to the design pressure.

To withstand external and internal loadings while maintaining a high degree of corrosion resistance, a high strength carbon alloy steel is used as the base metal with an internal cladding of stainless steel applied by weld overlay. Adherence to the ASME Code, Section III, Class A, pressure vessel code design criteria provides assurance that a vessel designed, built, and operated within its design limits has an extremely low probability of failure due to any known failure mechanism.

Stress analysis and load combinations for the reactor vessel have been evaluated for the cycles expected throughout the 40 yr life, with the conclusion that ASME Code limits are satisfied. The details of assumed loading combinations are described in Appendix C for Class I equipment.

The reactor vessel is designed for a 40 yr life and will not be exposed to more than 1 x 10^{19} nvt of neutrons with energies exceeding 1 MeV. Extensive tests have established the magnitude of changes in the NDTT as a function of the integrated neutron dosage. Figure 4.2-5 presents pertinent test data for SA302B steel and plots the change in ductile to brittle transition temperature as a function of integrated neutron flux (nvt). Because SA533 is the same as 302B, all test data on SA302B is applicable to SA533 used in the vessel. The 30 ft lb refers to the energy absorbed by the Charpy V-Notch sample at the test (transition) temperature. The upper two curves apply to thick walled pressure vessels and the lower curve is for the wall thickness range representative of this reactor vessel. The SA302B steel with the fabrication procedures specified for the reactor vessel is relatively insensitive to neutron irradiation.

TransWare Report, No ENT-FLU-001-R-001, Revision 0, provides Pilgrim reactor vessel fluence values using the NRC-approved RAMA methodology and a power level of 2028 MW_t. The Pilgrim fluence calculation results show the reactor vessel will experience peak ID (at the clad/base metal interface) fluence at 34 EFPY of 7.53×10^{17} n/cm^2 at the Lower Intermediate Weld 1-338A/C locations, and 8.42×10^{17} n/cm^2 at the lower intermediate Shell Plates, respectively. Even though the peak fluence occurs in the Lower Intermediate Shell Plates, Lower Shell Plate 337-01C has a higher ART due to material chemistry effects (peak fluence - 6.96×10^{17} n/cm^2 at 34 EFPY). In addition, the N2 nozzle peak fluence at 34 EFPY was calculated to be $1.90 \times 10^{17} n/cm^2$, and the N16A/B instrument ("drill-hole" style) nozzle fluence at 34 EFPY was calculated to be 3.52×10^{15} n/cm^2. Both nozzles were evaluated for their impact on the Pilgrim P-T curves, and the limits presented the PTLR incorporate any effects of these nozzles accordingly. All fluence values at 34 EFPY are linearly interpolated from the data in TransWare Report, No. ENT -ENT -FLU-001-R-001.

34 EFPY P-T Limit Curves based on the extrapolated fluence from TransWare Report, No. ENT-FLU-001-R-001 and Calculations M1282, M1283 and M1284 were developed. For Core Not Critical (Curve B) and Core Critical (Curve C) conditions, the P-T curves specify a coolant heatup and cooldown temperature rate of ≤100°F/hr for which the curves are applicable. For Hydrostatic Pressure and Leak Test (Curve A) conditions, a coolant heatup and cooldown temperature rate of ≤25°F/hr must be maintained. The P-T limits and corresponding limits of either Curves A or B may be applied, if necessary, while achieving or recovering from test conditions. So, although Curve A applies during pressure test conditions, the limits of Curve B may be conservatively used during pressure testing if the pressure test heatup and cooldown rate limits cannot be maintained. Adjusted reference temperature (ART) and reference temperature shift (ΔRT_{NDT}) values for Pilgrim Nuclear Power Station (PNPS) reactor pressure vessel (RPV) plates and welds exposed to fluences greater than 1.0×10^{17} n/cm^2 were developed in accordance with Nuclear Regulatory Commission (NRC) Regulatory Guide 1.99, Revision 2 (RG1.99).

The reactor assembly is designed such that the average annular distance from the outermost fuel assemblies to the inner surface of the reactor vessel is approximately 80 cm. This annular volume, which contains the core shroud, the jet pump assemblies, and reactor coolant, serves to attenuate the fast flux incident upon the reactor vessel wall. For plant operation at 1,998 MWt, 80 percent station availability, and 40 yr station life, the neutron fluence at the inner surface of the vessel was calculated to be 1.5 x 10^{18} nvt for neutrons having energies greater than 1 MeV. Initially the "worst case" curve from Figure 4.2-5 would produce a NDTT shift of less than 50°F. This figure is retained for historical purposes. With an initial NDTT in the vessel plate material of 40°F, the resulting maximum NDTT of the vessel wall at the end of 40 yr would be less than 90°F. This end of life NDTT provides a substantial margin for brittle fracture prevention, since the vessel cannot be pressurized until coolant temperatures in excess of 212°F are reached.

A stress of between 5,000 and 8,000 psi is considered necessary to produce brittle fracture at or below the NDTT. Therefore, during operation when pressure is dependent upon temperature, brittle failure of the vessel is not considered possible until the integrated neutron flux of the reactor vessel reaches a value on the order of 10^{20} nvt. This value is a factor of more than 100 times greater than the maximum neutron flux conservatively calculated during the lifetime of this station.

In addition to the minimum requirements of the ASME Boiler and Pressure Vessel Code, the following precautions are taken and tests made either to assure that the initial NDTT of the reactor vessel material is low or to reduce the sensitivity of the material to irradiation effects:

1. The material is selected and fabrication procedures are controlled to produce as fine a grain size as practical. It is an objective in fabrication to maintain a grain size of five or finer.

2. Drop weight impact tests are performed on each heat and heat treatment charge of all low alloy steel plate material in its "as fabricated" condition.

3. Drop weight impact tests are made on the weld metal, the heat affected zone of the base metal, and the base metal of the weld test plates simulating seams. If different welding procedures are used for nozzle welds, drop weight tests of similarly prepared coupons are made. The NDTT test criteria for the weld and heat affected zone of the base material are the same as for the unaffected base metal.

4. The actual NDTT of the plates opposite the center of the reactor core is determined. In other areas it is sufficient to demonstrate that the two drop weight test specimens do not break 10°F above the design NDTT. The area of the vessel located opposite the core is fabricated entirely of plate welded material and is not penetrated by nozzles, nor are there any other structural discontinuities in this area which would act as stress risers.

Quality control methods are used during the fabrication and assembly of the reactor vessel and appurtenances to assure that the design specifications are met.

The fabrication test program is carried out by the reactor vessel vendor on material representative of the formed, heat treated, and fully fabricated vessel. Tests of base metal and welded joint are performed and the results are reported during the early stages of vessel construction. Tensile specimens (0.505 inch in dia) from the shell plate material are prepared for various thickness levels of the plate material. These specimens are tested at various temperatures per ASTM Specifications E8 and E21 to determine tensile strength, yield strength, elongation, and reduction of area. Tensile specimens whose gage diameter is at least 80 percent of the reactor vessel wall thickness are prepared from base metal and weld material. These specimens are tested at room temperature per ASTM Specification E8 to provide stress strain curves, tensile strength, yield strength, elongation, reduction of area, and macrophotographs of the breaks. Charpy V-Notch impact specimens are prepared from base metal and tested per ASTM Specification E23, Type A, to establish curves for determining the transition temperature at which 30 ft lb of absorbed energy result in ductile fracture for various thickness levels of the plate material. Table 4.2-4 summarizes the results of Charpy V-Notch and drop weight tests for the reactor vessel plates and forgings. The Charpy V-Notch test results have been subsequently adjusted to account for rolling direction in accordance with USNRC Branch Technical Position MTEB 5-2.

Data available from the heavy section steel technology (HSST) program show that there is no true size effect on the NDTT in the temperature regime where $K_{I_C} / \sigma_y.5 \geq 1$ regardless of whether it is defined by the drop weight test or the dynamic tear test, where:

K_{I_C} = Critical stress intensity required to initiate a brittle crack

$\sigma_y.5$ = Material yield stress

The matter of upper shelf energy for transverse specimens is specifically treated in USNRC Branch Technical Position MTEB 5-2 and the Charpy V-Notch impact test results have been adjusted accordingly. Provisions for brittle fracture control in ferritic materials which are part of the primary coolant pressure boundary meet the impact test requirements of Section III for Class A vessels, with Appendix 1 of B31.7 for piping, and with Appendix E of the Nuclear Pump and Valve Code for pumps and valves, although these codes do not apply to the piping, pumps, and valves in other respects. The use of the un-adjusted Charpy V Notch fixed energy values for each material, and an acceptance test temperature of 60°F below the lowest service metal temperature, had been the standard practice adopted by the codes.

Evaluation of the results of the HSST program and the Pressure Vessel Research Committee (PVRC) program, and successful experience with the materials employed in this plant support the adequacy of the impact test requirements of these codes.

The Reactor Coolant System is cleaned and flushed before fuel is loaded initially. During the preoperational test program, the reactor vessel and Reactor Coolant System are given a hydrostatic test in accordance with code requirements at 125 percent of design pressure. The vessel temperature is maintained at a minimum of 60°F above the NDTT prior to pressurizing the vessel for a hydrostatic test. A hydrostatic test at a pressure not to exceed system operating pressure is made following each removal and replacement of the reactor vessel head. Other preoperational tests include calibrating and testing the reactor vessel flange seal ring leakage detection instrumentation, adjusting reactor vessel stabilizers, checking all vessel thermocouples, and checking the operation of the vessel flange stud tensioner.

During the startup test program, the reactor vessel temperatures were monitored during vessel heatup and cooldown to assure that thermal stress on the reactor vessel was not excessive during startup and shutdown. Temperatures obtained during the startup test program are presented in detail in the Core Standby Cooling System (CSCS) document filed with the AEC as a GE Topical Report.[4] This satisfies safety design basis 3.

4.2.7 Inspection and Testing

Inservice inspection is considered during the design to assure adequate working space and access for inspection of selected reactor vessel components and locations. Direct visual examination is proposed whenever possible because it is sensitive, fast, and positive.

Insulation panels or portions of panels outside the vessel support are removable to permit inspection of the vessel and vessel support surfaces. Insulation panels on the inside of the vessel support are provided with inspection openings with hinged or sliding closures. All nozzles (except those nozzles inside the vessel support such as the control rod drive, incore instrument, and drain nozzles in the bottom head) have insulation designed so that it may be removed to expose the entire exterior of the nozzle and the vessel shell.

The surveillance test program provides for the preparation of a series of Charpy V-Notch impact specimens adjusted to account for rolling direction and tensile specimens from the base metal of the reactor vessel, weld heat affected zone metal, and weld metal from a reactor steel joint which simulates a welded joint in the reactor vessel. The specimens and neutron monitor wires are placed near core mid-height adjacent to the reactor vessel wall where the neutron exposure is similar to that of the vessel wall. The specimens are installed at startup or just prior to full power operation. Selected groups of specimens are being removed at intervals over the lifetime of the reactor and are tested to compare mechanical properties with the properties of control specimens which are not irradiated.

4.2.8 Proposed Nuclear Safety Requirements for Initial Plant Operation

4.2.8.1 General

The nuclear safety operational analysis in Appendix G, Table G.5-3, shows that the reactor vessel is the cause for a number of unique safety actions in every operational state, depending on the event being performed. Operating limits are imposed on certain parameters or safety actions. These limits are indicated in the reactor vessel column of the matrix by the letter "I" following the identification number of the applicable safety action.

For example, the most significant planned events with regard to the reactor vessel in state F are "power operation" and "heatup". These events are matrix blocks F3-54 and F4-54, respectively, where:

F = BWR operating state F
3 and 4 = Heatup and power operation, respectively
54 = Reactor vessel

The limits are placed on:

8I Reactor vessel pressure
9I Nuclear system temperature
10I Nuclear system water quality
11I Nuclear system leakage

4.2.8.2 Safety Limit

Two sets of limits must be considered with regard to operating parameters: (1) limits necessary to satisfy the restrictions of the ASME Code, and (2) limits necessary to remain within the envelope of conditions considered by plant safety analysis. The parameter limit which must be observed to satisfy the pressure limits of the ASME Code as applied to the reactor vessel and coolant piping is designated a safety limit. This designation is given because the Code represents the true and most significant safety requirement which must be satisfied.

The pressure safety limit of 1,375 psig, most significant for "instantaneous loss of vacuum", was derived from the design pressures of the reactor vessel and coolant piping. The Safety Limit of 1325 psig, as measured by the reactor steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Section III 1980, Edition with 1981 Addenda for the reactor recirculation piping, which permits a maximum pressure transient of 120% of design pressures of 1148 psig at 562°F for suction piping and 1241 psig at 562°F for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the applicable codes. The design pressures are 1,250 psig at 575°F for the reactor vessel, 1,148 psig for the recirculation suction line, and 1,241 psig for the discharge line at 562°F. The pressure safety limit was determined in accordance with the ASME Boiler and Pressure Vessel Code, Section III. The ASME Code permits pressure transients up to 10 percent over the design pressure (110 percent x 1,250 = 1,375 psig). The design basis for the reactor vessel makes evident the substantial margin of protection against failure at the safety pressure limit of 1,375 psig, the lowest transient overpressure allowed by the codes.

4.2.8.3 Proposed Limiting Conditions for Initial Plant Operation

The envelope limits result in limiting conditions for operation on pressure, temperature, water quality, and nuclear system leakage. These limits must be observed to remain inside the envelope of initial conditions considered by station safety analyses.

Because operating state F covers the complete range of heatup through full power operation, this state is the most demanding with respect to reactor vessel integrity. States A through E may or may not have the same limits; however, in no state will these operating limits exceed those derived from matrix blocks F3-54 and F4-54. The proposed limiting conditions for operation of the reactor vessel follow:

1. The reactor vessel head bolting studs shall not be under tension unless the temperatures of the vessel head flange and the head are at least 70°F.

   The reactor vessel head flange and the vessel flange in combination with the double "O" ring type seal are designed to provide a leaktight seal when bolted together. When the vessel head is placed on the reactor vessel, only that portion of the flange nears the inside of the vessel rests on the vessel flange. As the head bolts are replaced and tensioned, the vessel head is flexed slightly to bring together the entire contact surfaces adjacent to the "O" rings of the head and vessel flange. Both the head and the head flange have an NDTT of 10°F, and they are not subject to any appreciable neutron radiation exposure. There, the initial minimum vessel head and head flange temperature at which the studs can be placed in tension is established as 10°F + 60°F, or 70°F.

2. Reactor coolant leakage into the primary containment from unidentified sources shall not exceed 15 gal/min; the total leakage into the containment, identified and unidentified, shall not exceed 63 gal/min.

   Allowable leakage rates from the Reactor Coolant System have been based on the predicted and experimentally determined behavior of cracks in pipes, and on the ability to make up Coolant System leakage in the event of loss of offsite ac power. Earthquake and normal vibration stresses are considered in the determination of the critical crack size. The unidentified leakage rate is established at 15 gal/min, a value which is well below the calculated minimum liquid leakage from a crack large enough to propagate rapidly. See Section 4.10. This limit allows sufficient time for corrective action to be taken before the process barrier is significantly compromised. The criterion for establishing the total leakage rate limit (unidentified, plus identified leakage) is based on the makeup capacity of the Control Rod Drive System. See Section 4.10. This total leakage rate limit is established at 63 gallons/minute.

3. The average rate of reactor coolant temperature change during normal heatup and cooldown shall not exceed 100°F in any 1 hour period.

Detailed stress analyses have been made on the reactor vessel for both steady state and transient conditions with respect to material fatigue. The results of these analyses are compared to allowable stress limits. The specific conditions analyzed included numerous cycles of normal startup and shutdown with a heating and cooling rate of 100°F/hr applied continuously over a temperature range of 100°F to 546°F. The expected number of normal heatup and cooldown cycles to which the vessel will be subjected is listed in the "Reactor Thermal Cycles" document (Figure C.3-1, MIA12-2).

4. The reactor vessel shall be vented and depressurized unless the reactor vessel temperature equals or exceeds that indicated by the upper curve on Figure 4.2-6.

   The NDTT is defined as the temperature below which ferritic steel breaks in a brittle rather than a ductile manner. Radiation exposure from fast neutrons (>1 MeV) above about 1017 nvt may increase the NDTT of the vessel base metal. Extensive tests have established the magnitude of changes in the NDTT as a function of integrated neutron exposure. The initial maximum NDTT of the reactor vessel is not greater than 40°F. The design life of the reactor vessel is 40 years and the maximum fast neutron fluence for 40 years is calculated to be 2.5×10^{18} nvt.

   The NDTT limit upper curve on Figure 4.2-6 is based on the more conservative thick walled pressure vessel data. This curve also incorporates a 60°F factor of safety which is based on the requirements of the ASME Code and the considerations that resulted in these requirements. The estimated inservice transition temperature shift is not based on data related to control of residual elements.

   The lowest pressurization temperature of 100°F (40°F + 60°F) is determined by the 40°F NDTT material in the vessel. As part of the surveillance program, removable neutron flux monitors are installed in the reactor vessel. Results of this program will confirm and, if necessary, adjust the calculation of integrated flux used to determine NDT shift. It is understood that the NRC pressurization temperature limit of 180°F applies only above 250 psig with fuel in the reactor vessel and not to head bolt down discussed in item 1. Also, investigations may support the conservatism of the100°F temperature limit. Should this be the case, a request will be made to revise the higher temperature.

5. The reactor water quality shall be within the following limits when operating at rated pressure:

Conductivity, µmhos/cm @ 25°C	1.0
Chloride, ppm	0.2

When conductivity and chlorides are at these values, the pH will be between 5.6 and 8.6 when measured at 25°C. When water quality approaches or exceeds these values during plant operation at rated pressure, corrective action shall be taken.

Reactor water quality may exceed the above limits only for the time limits specified below. Exceeding these time limits or exceeding the following maximum quality limits shall be cause for shutdown and cooldown to ambient temperatures until the water is within the limits specified above:

Conductivity, µmhos/cm @25°C	10 maximum
Time above 1.0 mho/cm	2 weeks/yr
Chloride, ppm	1.0 maximum
Time above 0.2 ppm	2 weeks/yr

If these quality limits are reached, it is possible for the pH to be as low as 4 or as high as 10, depending on the impurities present. When operating at a conductivity greater than 1.0 mho/cm, pH shall be measured and shall be brought within the 5.6 to 8.6 range within 24 hr. If the pH cannot be corrected or exceeds the 4 to 10 range, the plant shall be shut down and cooled down. When the reactor is not pressurized, reactor water shall be maintained within the following limits:

Conductivity, µmhos/cm @ 25°C	10
Chloride, ppm	0.5
pH @ 25°C	6.0 to 8.5

Prior to startup, the limits of being pressurized will be observed, that is:

Conductivity, µmhos/cm @ 25°C	1.0
Chloride, ppm	0.2

Materials in the primary system are primarily stainless steel and zircaloy fuel cladding. The reactor water chemistry limits are placed upon conductivity and chloride concentration since conductivity is measured continuously, and gives an indication of abnormal conditions or the presence of unusual materials in the coolant, while chloride limits are specified to prevent stress corrosion cracking of stainless steel.

Air saturated water is pumped into the reactor as a result of operation of the Control Rod Drive System. Therefore, the oxygen level in the reactor water can be higher during startups or during periods of hot standby when the reactor is not steaming at significant powers. A more stringent limit of chloride ion content has been established for these periods to insure that the combination of chloride and oxygen will always be well below stress corrosion failure limits.

In the case of BWRs where no additives are used in the primary coolant, and where neutral pH is maintained, conductivity provides a very good measure of the quality of the reactor water. When the conductivity is within its proper normal range; pH, chloride, and other impurities affecting conductivity and water quality must also be within their normal ranges. Significant changes in conductivity provide the operator with a warning mechanism so that he can investigate and remedy the conditions causing the change.

Measurements of pH, chloride, and other chemical parameters are made to determine the cause of the unusual conductivity. Corrective action can be taken before limiting conditions, with respect to variables affecting the boundaries of the reactor coolant, are exceeded. Several techniques are available to correct off standard reactor water quality conditions including removal of impurities by the Reactor Water Cleanup System, reduction of the input of impurities causing off standard conditions by reducing power and, hence, feedwater flow, and placement of the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature dependent corrosion rates and thereby provide time for the Cleanup System to reestablish proper water quality.

6. The reactor vessel dome pressure shall remain below 1,035 psig during planned operation.

   Observation of this limit assures that the operator remains within the envelope of conditions considered by the station safety analysis.

4.2.8.4 Proposed Surveillance Requirements for Initial Plant Operation

The following surveillance requirements are given to determine the condition of the reactor vessel and that of the safety devices related to it.

1. Neutron flux wires and specimen samples of the vessel material shall be installed in the reactor vessel to experimentally verify the calculated values of integrated neutron flux that are used to determine the NDTT from Figure 4.2-6 and to monitor the affect of neutron exposure on these materials.

   The integrated neutron flux at the vessel wall is calculated from core physics data and is measured using flux wires. The measurements of the neutron flux at the vessel wall are used to check and, if necessary, correct the calculated data to determine an accurate flux. A conservative prediction of the NDTT shift can then be made well in advance of any potential changes in properties.

   The samples shall include both tensile and Charpy V-Notch impact specimens representing base metal, heat affected zone, and weld metal. The samples will be located as close as practicable to the vessel wall; correlation data is available to relate this to actual vessel wall conditions. These samples will provide further assurance that the shift in NDTT is conservative.

   It is not planned that any vessel material, other than that already in the surveillance program described above, will be retained for preparing Charpy V-Notch test specimens for the purpose of additional irradiation monitoring of vessel material, or the monitoring of thermal annealing treatments if required to recover fracture toughness in the later years of vessel service. Refer to the discussion of neutron fluents expected during the reactor vessel's 40 yr life in Sections 4.2.5.1 and 4.2.6.

2. Nondestructive examinations of the pressure vessel shall be made in accordance with the intent of the requirements of draft Code for Inservice Inspection of Nuclear Reactor Coolant Systems.

3. A visual examination for leaks shall be made with the Reactor Coolant System at pressure during each scheduled refueling outage or after major repairs have been made to the Reactor Coolant System.

   The visual examination for leaks is based on the observed rate of growth of defects from fatigue studies sponsored by the NRC. These studies show that it requires thousands of stress cycles, at stresses beyond any conceived in a reactor system, to propagate a crack; thus, it is concluded that the frequency is adequate.

4. A sample of reactor coolant shall be analyzed at least every 72 hr to determine the conductivity and chloride ion content.

   Past experience indicates that a check with conductivity instrumentation at least every 72 hr is adequate to ensure accurate readings. The sampling frequency of chloride ion is also adequate because the chloride ion content will not change rapidly over a period of several days.

4.2.9 Current Operational Nuclear Safety Requirements

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

4.9.10 References

1. Kobsa, I.R. and Wetzel, V.R. Design and Analysis of Control Rod Drive Reactor Vessel Penetrations. General Electric Company Atomic Power Equipment Department, APED-5703, November 1968.

2. South West Research Report 02-5951.

3. NED Memo No. 82-41, RPV Startup Pressure/Temperature limits, SWRI Vessel Surveillance Report 02-5951.

4. Ianni, P.W. Core Standby Cooling Systems for Boiling Water Reactors. General Electric Company, Atomic Power Equipment Department, APED-5458, March 1968.

5. NED (BECo) Calculation No. M-256, "Determine RPV Neutron Fluence Values vs. Fuel Cycle", dated January 23, 1986.

6. Burns, C.S., "Pilgrim Nuclear Power Station Reactor Pressure Vessel Fast Neutron Flux as a Function of Fuel Cycle", General Electric Report MDE-277-1285, dated November 27, 1985.

7. Tsacoyeanes, J., "Pilgrim Nuclear Power Station Reactor Pressure Vessel Pressure Temperature Limits", Teledyne Engineering Services Technical Report, TR-6052B-1, Revision 1, dated June 26, 1986.

8. NRC Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials", dated May, 1988 (Enclosure to Generic Letter 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operations", dated Jul 12, 1988.)

9. Tsacoyeanes, J., "Pilgrim RPV Pressure Temperature Limits", Teledyne Engineering Services Technical Report, TR-7487, dated April 16, 1991.

4.4 NUCLEAR SYSTEM PRESSURE RELIEF SYSTEM

4.4.1 Safety Objective

The safety objective of the nuclear system Pressure Relief System is to prevent over pressurization of the nuclear system. In addition, the automatic depressurization feature of the nuclear system Pressure Relief System operates to reduce the nuclear system pressure so that the Low Pressure Core Cooling Systems can reflood the core following certain postulated transients or accidents.

4.4.2 Safety Design Basis

1. The nuclear system Pressure Relief System shall prevent over pressurization of the nuclear system in order to prevent failure of the nuclear system process barrier due to pressure.

2. The nuclear system Pressure Relief System shall provide automatic nuclear system depressurization for small breaks in the nuclear system so that the Low Pressure Coolant Injection (LPCI) and the Core Spray Systems can operate to protect the fuel barrier.

3. The relief valve discharge piping shall be designed to accommodate forces resulting from relief action, and shall be supported for reactions due to flow at maximum relief valve discharge capacity so that system integrity is maintained.

4. The nuclear system Pressure Relief System shall be designed for testing prior to nuclear system operation and for periodic verification of the operability of the nuclear system Pressure Relief System.

5. The capacity of the relief and safety valves shall be sufficient to prevent reactor pressure from exceeding the allowable overpressure of ASME Code, Section III, during a main steam isolation valve closure with indirect scram.

6. The nuclear system Pressure Relief System shall be designed to be capable of providing a manually initiated nuclear system depressurization for postulated transients and accidents in which the main heat sink is unavailable.

4.4.3 Power Generation Objective

The power generation objective of the nuclear system Pressure Relief System is to sufficiently relieve normal overpressure transients following load rejections so that safety valve actuation is not required.

4.4.4 Power Generation Design Basis

1. The nuclear system relief valves shall be sized to prevent opening of the safety valves during load rejections.

2. The nuclear system relief valves shall discharge to the pressure suppression pool.

3. The relief valves shall properly reclose following a load rejection so that normal operation can be resumed as soon as possible.

4.4.5 Description

The nuclear system Pressure Relief System includes two safety and four relief valves, all of which are located on the main steam lines within the drywell between the reactor vessel and the flow restrictor. The safety valves provide protection against overpressure of the nuclear system and discharge directly to the interior space of the drywell.

The relief valves, which discharge to the suppression pool, provide three main protection functions:

1. Overpressure relief operation. The valves are opened (self-actuated) to limit the pressure rise and prevent spring safety valve opening

2. Overpressure safety operation. The valves augment the safety valves by opening in order to prevent nuclear system over pressurization

3. Depressurization operation. The valves are opened automatically or manually by indirectly operated devices, as part of the Core Standby Cooling System (CSCS), for small breaks in the nuclear system process barrier

The safety valves are spring loaded valves which are designed, constructed, and marked with data in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Article 9, and in accordance with USAS B31.1.0 and B16.5. Popping point tolerance (pressure at which valve "pops" wide open) is in accordance with ASME Section I, Paragraph PG-72(c). The material on the pressure side of the valve disc, in contact with the steam, is stainless steel. The valves are designed for operation with saturated steam containing less than 1 percent moisture and are designed to have an opening response time equal to or less than 0.3 sec.

The relief valves are designed, constructed, and marked with data in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Article 9, and in accordance with USAS B31.1.0 and B16.5. Popping point tolerance (pressure at which valve "pops" wide open) is in accordance with ASME Section I, Paragraph PG-72(c). Each valve is self actuating at the set relieving pressure, but may also be actuated by indirectly operated devices to permit remote manual or automatic opening at lower pressures. For depressurization operation, each relief valve is provided with a power actuated device capable of opening the valve at any steam pressure above 100 psig, and capable of holding the valve open until the steam pressure decreases to about 50 psig. The control system for the actuator is described in Section 7.4, Core Standby Cooling Systems Control and Instrumentation. Pressure containing parts of the valve body are fabricated of ASME SA-105 Carbon Steel and SB-564 Inconel 600. The relief valve is designed for operation with saturated steam containing less than 1 percent moisture. The relieving pressures for overpressure relief and safety modes are adjustable between 1100 and 1200 psig with a maximum back pressure of 40 percent of the set pressure. The delay time (maximum elapsed time between overpressure signal and actual valve motion) and the response time (maximum valve stroke time) are each equal to or less than 0.1 sec. The delay time (maximum elapsed time between overpressure signal and actual valve motion) assumed in the transient analysis for relief valve and safety valves are 0.400 and 0.000 seconds respectively. The opening time (maximum valves stroke time) assumed in the transient analysis for the relief valves and the safety valves are 0.150 and 0.300 seconds respectively.

Each of the three stage SRVs consists of three principal assembly stages: two pilot stages and one main stage. The modular pilot assembly houses the primary pilot controlled by a sensing bellows and is the primary control element for the safety function of the valve. The second stage pilot provides an exhaust path for the pressure above the piston in the main to open the valve. Figures 4.4-1 and 4.4-2 are schematic illustrations of the three stage valve in closed and open positions.

During assembly, the pilot bellows is mechanically extended a slight amount to provide a preload force on the pilot disc which seals the disc tightly and prevents reverse leakage at low system pressures.

In operation, as pressure increases, the bellows preload force is reduced to zero. From this point, the pilot disc is held closed by reactor pressure acting over the pilot valve seat area. This hydraulic seating force increases with increasing system pressure and prevents leakage, or simmering at system pressures near the set pressure. The three-stage pilot disc is submerged in condensate, which provides protection from the corrosive non-condensable that may collect in the valve.

As system pressure further increases, bellows expansion reduces the abutment gap between the stem and disc yoke. When the stem abuts against the yoke, further pressure increases reduce the net pilot seating force to zero. Once the pilot stage starts to open, the hydraulic seating force is reduced, resulting in a net increase in the force tending to extend the bellows. This increase in net force produces a popping action during the pilot stage opening.

In its normally closed position, the main valve disc is tightly seated by the combined forces exerted by reactor pressure acting over the area of the main valve disc and the main valve preload spring.

When system pressure increases to the pilot stage set pressure, the pilot and second stage of the pilot valve assembly will open, thereby venting the chamber over the main valve piston to the downstream side of the valve. This venting action creates a differential pressure across the main valve piston in a direction tending to open the valve. The main valve piston is sized such that the resultant opening force is greater than the combined spring preload and hydraulic seating force.

As is the case for the pilot stage, once the main valve disc starts to open, the hydraulic seating force is reduced, causing a significant increase in opening force and the characteristic full opening or popping action.

When the reactor pressure has been reduced sufficiently, the pilot stage reseats, the second stage reseats after depressurization of the second stage piston chamber accomplished by leakage past the piston rings and piston orifice. Leakage of system fluid past the main valve piston then repressurizes the chamber over the piston, canceling the hydraulic opening force and permitting the main spring and flow forces to close the main stage. Once closed the additional hydraulic seating force due to system pressure acting on the main valve seats the valve tightly and prevents leakage.

The SRV pilots are fitted with air operators to provide selected remote manual or automatic actuation of the valve at other than set pressure. The air operator is a diaphragm type air operator which is energized to open the valve. It is actuated by means of a solenoid control valve which admits nitrogen to the operator piston chamber and strokes the plunger, in turn stroking the second stage disc. The main valve then opens as described above. De-energizing the solenoid vents the air operator and permits the second stage disc to close. The main valve then reseats as described above.

The relief valves are installed so that each valve discharge is piped through its own uniform diameter discharge line to a point below the minimum water level in the primary containment suppression pool to permit the steam to condense in the pool. Water in the line above suppression pool water level would cause excessive pressure at the relief valve discharge when the valve again opened. For this reason, vacuum relief valves are provided on each relief valve discharge line to prevent drawing water up into the line due to steam condensation following termination of relief valve operation. The relief valves are located on the main steam line piping, rather than on the reactor vessel top head, primarily to simplify the discharge piping to the pool and to avoid the necessity for removing sections of this piping when the reactor head is removed for refueling. In addition, the relief valves, as well as the safety valves, are more accessible during a quick shutdown to correct possible valve malfunctions when located on the steam lines.

Each of the four relief valves is equipped with an air/nitrogen accumulator and check valve arrangement. These accumulators are provided to assure that the valves can be held open following failure of the air or nitrogen supply to the accumulators, and are sized to contain sufficient air for a minimum of 20 valve operations. Bottled gas can be used to manually recharge the accumulators associated with two safety relief valves. This capability was installed to address a potential loss of normal nitrogen supply to the accumulators which was identified during USI-A46 seismic reviews.

The automatic depressurization feature of the nuclear system Pressure Relief System serves as a backup to the High Pressure Coolant Injection (HPCI) System under loss of coolant accident conditions. If the HPCI System does not operate and one of the LPCI or core spray pumps is available, the nuclear system is depressurized sufficiently to permit the LPCI and Core Spray Systems to operate to protect the fuel barrier. Depressurization is accomplished through automatic opening of the relief valves to vent steam to the suppression pool. For small line breaks when the HPCI System fails, the nuclear system is depressurized in sufficient time to allow the Core Spray and LPCI Systems to provide core cooling to prevent any fuel clad melting.

For large breaks, the vessel depressurizes rapidly through the break without assistance. The signal for the relief valves to open and remain open is based upon simultaneous signals from: (1) drywell high pressure unless bypassed by a preset time delay relay, (2) reactor vessel low-low water level, (3) adequate discharge pressure on one of the LPCI or core spray pumps, and (4) 120 sec delay timer completes timing cycle. Further descriptions of the operation of the automatic depressurization feature are found in Section 6, Core Standby Cooling Systems, and Section 7.4, Core Standby Cooling System Control and Instrumentation. The Automatic Depressurization System is designed as Class I equipment in accordance with Appendix C.

A manual depressurization of the nuclear system can be effected in the event the main condenser is not available as a heat sink after reactor shutdown. The steam generated by nuclear system sensible and core decay heat is discharged to the suppression pool. The core is reflooded by the low pressure CSCS. The relief valves are individually operated by remote manual controls from the main control room to control nuclear system pressure.

Section 7.4.3.3.4 describes instrumentation associated with relief and safety valves that provides leakage monitoring capability and position status.

The number, set pressures, and rated capacities of the relief valves and safety valves are shown on Table 4.4-1.

4.4.6 Safety Evaluation

The ASME Boiler and Pressure Vessel Code require that each vessel designed to meet Section III be protected from pressure in excess of the vessel design pressure. A peak allowable pressure for upset conditions of 110 percent of the vessel design pressure is allowed by the code. The code specification for safety valves requires that, (1) the lowest safety valve be set at or below vessel design pressure, and (2) the highest safety valve be set to open at or below 105 percent of vessel design pressure.

The relief valves are set during testing to open by self actuation (overpressure safety mode) at 1155 ± 1% psig and the safety valves are set to operate at 1280 ± 1% psig. This satisfies the ASME Code specifications for safety and relief valves since the relief valves open below the 1,250 psig nuclear system design pressure and below 1,313 psig (105 percent of nuclear system design pressure).

Safety and relief valve capacity is determined by analyzing the pressure rise accompanying the main steam flow stoppage resulting from an MSIV closure with the reactor initially operating at 2,028 MWt +2% to account for uncertainty in the initial power level. The analysis hypothetically assumes the reactor is shut down by an indirect flux scram. Reference 1 describes the reasons for choosing this event, the conservatism of applying upset condition limits to the event analysis, and models and methodology used in the evaluation of this event. The sequence of events assumed in this analysis is investigated to meet ASME code requirements and for Pressure Relief System evaluation. Comprehensive supporting analysis for the current relief and safety valve capacities, set pressures, and set pressure tolerance specified in Table 4.4-4 is documented in Reference 2.

Rated power operation is permitted at PNPS over a core flow range indicated on the power flow map described in FSAR Section 3.7. Evaluation of maximum vessel pressure resulting from the limiting transients is performed at the core flow included in the PNPS licensed operating domain that results in the highest vessel pressure. This analysis for maximum vessel pressure and verification of the adequacy of overpressure protection is repeated for each reload cycle and the results are provided in the supplemental reload licensing submittal in Appendix Q. The analysis typically indicates that the design capacities of the safety valves and relief valves are capable of maintaining adequate margin, approximately 30 and 35 psi below the peak ASME Code allowable pressure in the nuclear system (1,375 psig).

System malfunctions which pose threats to the radioactive material containment barriers are presented in Section 14, Station Safety Analysis. Evaluation of the most severe abnormal operational transient resulting in a nuclear system pressure rise shows that the relief valves open fully to limit the pressure rise, and that the peak pressure at the vessel dome is much below that given by the hypothetical event of MSIV closure with indirect scram.

Evaluations of the automatic depressurization capability of the nuclear system Pressure Relief System are presented in Section 6, Core Standby Cooling Systems, and Section 7.4, Core Standby Cooling System Controls and Instrumentation.

The piping attached to the relief valve discharges is designed, installed, and tested in accordance with USAS B31.1.0 plus the additional requirements outlined in Appendix A.

It is concluded that the safety design bases are satisfied.

4.4.7 Power Generation Evaluation

Although this is not a safety concern, an analysis is performed for each reload to show that the relief valves have the capacity to hold reactor vessel pressure below the safety valve set point of 1280 psig in the event of an abnormal operational transient.

4.4.8 Inspection and Testing

The safety and relief valves are tested in accordance with the manufacturer's quality control procedures to detect defects and prove operability prior to installation. The following final tests were performed:

1. Hydrostatic test.

2. Seat leakage test.

3. Steam test: valve pressurized with saturated steam with the pressure rising to the valve set pressure, the specified set point is verified when the valve opens (capacity and blowdown not tested with steam).

The safety and relief valves are installed as received from the factory. The set points are adjusted, verified, and indicated on the valves by the vendor. Proper manual and automatic actuation of the relief valves is verified during the preoperational test program.

It is recognized that it is not feasible to test the safety and relief valve set points while the valves are in place or during normal station operation. The valves are mounted on 6 in dia, 1,500 lb primary service rating flanges so that they may be removed for maintenance or bench checks, and reinstalled during normal station shutdowns. The internal surface of the relief valves and safety valves are 100 percent visually inspected when the valves are removed for maintenance or bench checks.

Based on a comparison of analyses of safety relief bypass capability made for plants in the GE 1965 Product Line, the original design with three relief valves has been modified to four relief valves to ensure adequate protection.

4.4.9 Operational Nuclear Safety Requirements for Plant Operation

Table 4.4-2 represents the nuclear safety requirements for the nuclear system Pressure Relief System for each BWR operating state. Table 4.4-2 represents an extension of the plant wide BWR systems analysis of Appendix G to the components of the nuclear system Pressure Relief System. The following references provide important information justifying the entries on Table 4.4-2:

Reference	Information Provided
1. Earlier parts of Section 4.4	Description of the nuclear system Pressure Relief System hardware; Pressure Relief System relief capacity, and relief set-points.
2. ASME Boiler and Pressure Vessel Code, Section III, Article 9, Protection Against Overpressure	Assumptions required for the relief and safety valve sizing transients.
3. Plant Safety Analysis, Section 14	Analysis verifying the response of the nuclear systems Pressure Relief System to transients and accidents.
4. Plant Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which the nuclear system Pressure Relief System is required.

Each detailed requirement on Table 4.4-2 is referenced to the most significant plant condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block in the "minimum required for action" columns on Table 4.4-2 and are coded as follows:

Example of Matrix Reference:

```
F13 - 64
|  |    |
'--|----|------ F = BWR operating state F
   '----|------13 = Event (row #13)
        '----- 64 = Nuclear System Pressure Relief System
                    (column #64)
```

All relief valves in the nuclear system Pressure Relief System function as a part of the Automatic Depressurization System. The operational nuclear safety requirements placed on these valves, due to their function in the Automatic Depressurization System, are discussed in Section 6.7.

In the states where the reactor head is on (States C through F), the potential to pressurize exists and overpressure protection is required. The minimum number of relief and safety valves actually required for an abnormal operational transient is variable and dependent on factors such as initial stored energy, initial pressure, energy produced during pressurization, scram setpoint, scram speed, and scram reactivity. Both the closure of all main steam isolation valves and a turbine trip with bypass failure produce severe pressure transients. Evaluation of transient behavior has shown that the most severe pressurization event is the main steam isolation valve closure when credit is taken only for the indirectly derived scrams.

The main steam isolation valve closure with neutron flux scram is utilized for relief and safety valve sizing for the following reasons. The ASME Boiler and Pressure Vessel Code, Section III requires that protection systems directly related to the abnormal operational transient in question cannot be credited with action in determining relief or safety valve capacity. Therefore, the main steam isolation valve closure with neutron flux scram is used in relief and safety valve sizing. Credit for the valve position scram is not taken because it is directly related to the main steam isolation valve closure.

The main steam isolation valve closure with flux scram is evaluated for each reload and the results are reported in the Supplemental Reload Licensing Report (Appendix Q). The cycle specific analysis of the main steam isolation closure is performed at the core thermal power (including measurement uncertainty) and core flow conditions that result in the highest overpressure condition. This analysis indicates that four relief valves and two safety valves operate. Analysis is not performed to demonstrate adequate protection from less than four relief and two safety valves. Therefore, the Technical Specifications do not contain any allowance for relief or safety valve inoperability.

The method of testing the operability of a relief or safety valve at rated conditions is to remove it from the reactor and perform a bench test. Thus, when operating, there is little definite knowledge of the actual number of operable relief and safety valves, and adequate redundancy must be assured by providing additional valves. As a result, the limiting condition for operation is more conservatively stated, i.e., the reactor may remain in operation and pressurized only if none of the relief or safety valves are known to be inoperable.

Experience in safety valve operation shows that a testing of 50 percent of the safety and relief valves per cycle is adequate to detect failures or deterioration. The bench tests shall be used to verify that the set points are within the 1 percent tolerance of the design pressure, as specified in Section III of the ASME Boiler and Pressure Vessel Code. An analysis has been performed which shows that with all safety and relief valves set at values given in Table 4.4-1, the reactor vessel code transient overpressure limit of 1,375 psig is not exceeded. The relief valves are exercised once per operating cycle at reduced system pressure to assure that they will open and pass steam.

4.4.10 Current Technical Specifications

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the current Station Technical Specifications referenced in Appendix B.

Safety and relief valve leakage monitoring requirements formerly located in the Technical Specifications are located in FSAR Appendix B.

4.4.11 References

1. NEDE-24011-P-A, General Electric Standard Application for Reactor Fuel, applicable revision.

2. NEDC-33532P, Pilgrim Nuclear Power Station Safety Valve Setpoint Increase Revision 2, January 2011

TABLE 4.4-1

NUCLEAR SYSTEM SAFETY AND RELIEF VALVES

	Number of valves	Set Pressure (Note 1) (psig)	Capacity at 103 Percent Reference Pressure (Note 2) (lb/hr each)	Reference pressure (psig)
Relief Valves	4	1155 ± 1%	921,235	1155
Safety Valves	2	1280 ± 1%	1,162,115	1280

Notes:

(1) Following lift testing, setpoint shall be set within a ± 1% tolerance. Analytical setpoint and as-found lift testing allowable tolerance is ± 3%.

(2) These capacities are rated capacities at 103% reference pressure for the installed throat diameters.

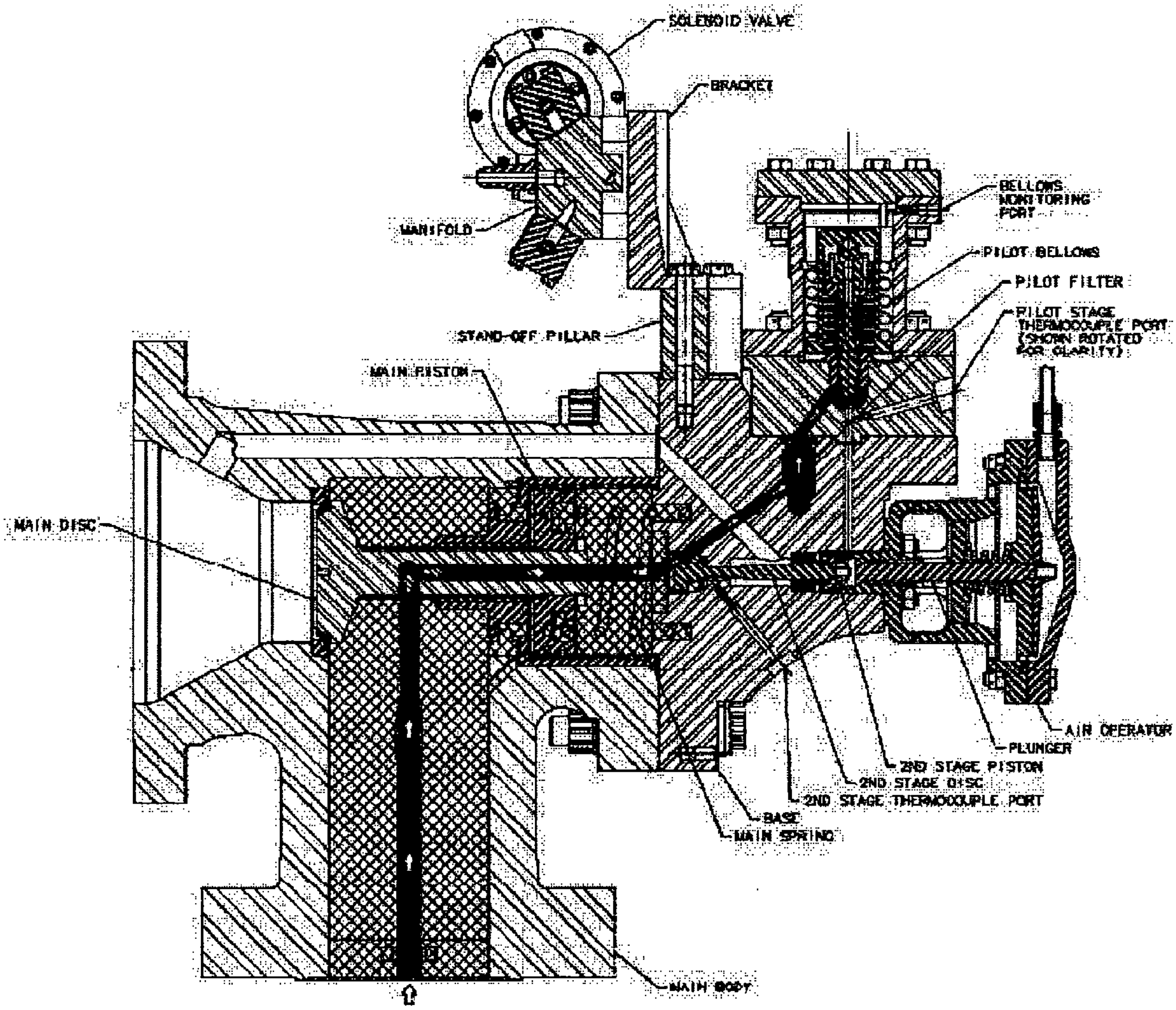


FIGURE 4.4-1
NUCLEAR SYSTEM RELIEF VALVE
THREE-STAGE – CLOSED POSITION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

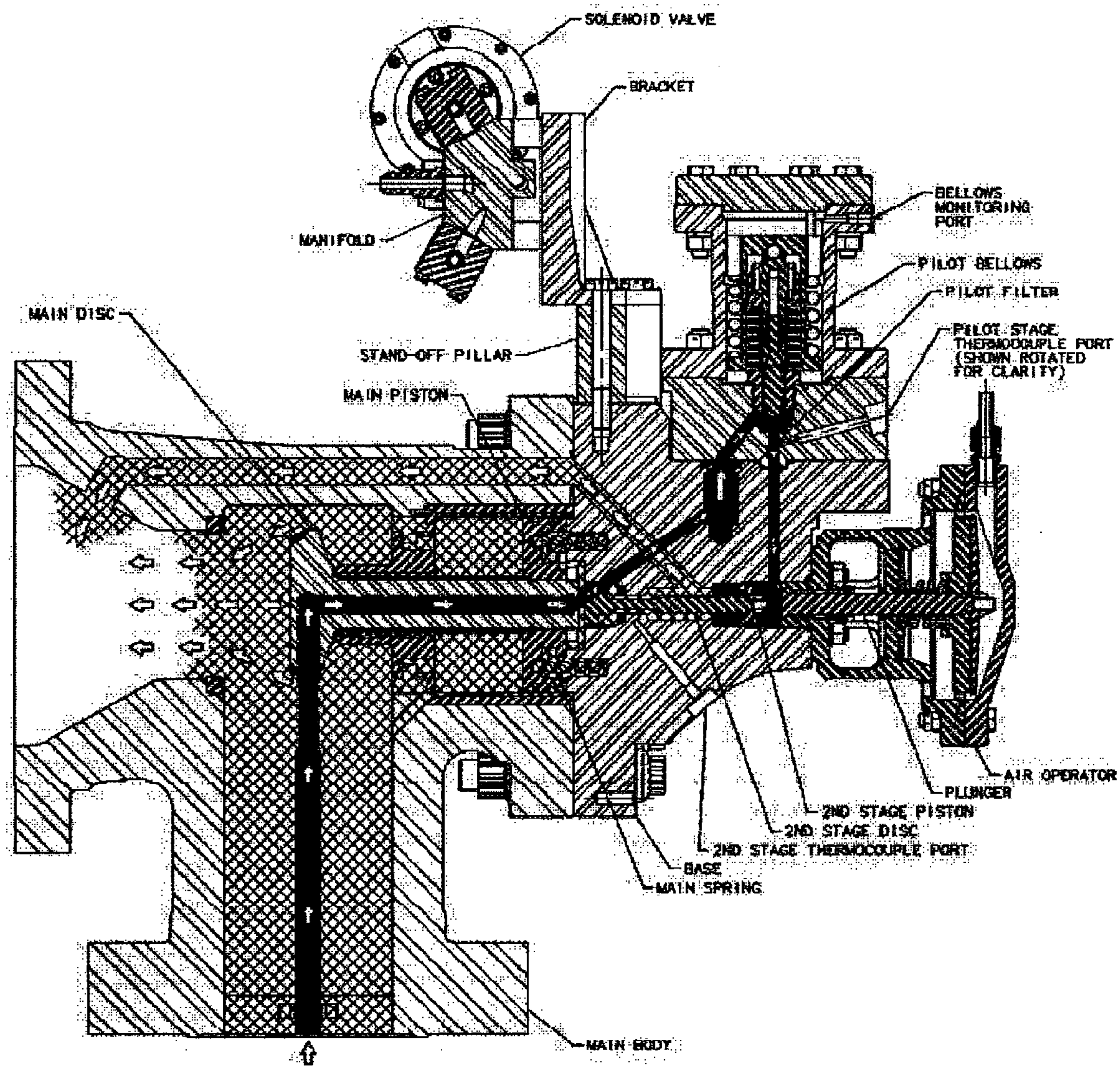


FIGURE 4.4-2
NUCLEAR SYSTEM RELIEF VALVE
THREE-STAGE – OPEN POSITION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

4.7 REACTOR CORE ISOLATION COOLING SYSTEM

4.7.1 Safety Objective

The reactor core isolation cooling system (RCIC) provides makeup water to the reactor vessel following reactor vessel isolation in order to prevent the release of radioactive materials to the environs as a result of inadequate core cooling.

4.7.2 Safety Design Basis

1. The system shall operate automatically to maintain sufficient coolant in the reactor vessel so that the integrity of the radioactive material barrier is not compromised.

2. Piping and equipment, including support structures, shall be designed to withstand the effects of an earthquake without a failure which could lead to a release of radioactivity in excess of the guideline values in published regulations.

4.7.3 Power Generation Objective

RCIC provides makeup water to the reactor vessel during shutdown and isolation to supplement or replace the normal makeup sources.

4.7.4 Power Generation Design Basis

1. The system shall operate automatically.

2. Provision shall be made for remote manual initiation of the system from the main control room. RCIC controls are arranged to allow for remote manual startup in two different ways:

   a. Manual initiation via a single pushbutton switch located on panel C904. Depressing the switch initiates a timed sequence which starts and runs the system in the full-flow injection mode.

   b. Manual startup by manipulation of individual control switches on panel C904 which actuate the various pumps and valves required to start and run the system. This method requires the operator to actuate each component in a prescribed sequence.

   Controls are also provided on panel C904 to allow plant operators to operate and shutdown the system.

3. To provide a high degree of assurance that the system shall operate when necessary, provision shall be made so that periodic testing can be performed during plant operation.

4.7.5 Description

RCIC consists of a steam driven turbine-pump unit and associated valve and piping capable of delivering makeup water to the reactor vessel. A summary of the design requirements of the turbine-pump unit is shown on Table 4.7-1. Schematic system diagrams are shown on Figures 4.7-1, 4.7-2, and 4.7-3 (Drawings M245, M246, and M1G1-2).

The steam supply to the turbine comes from the reactor vessel. The steam exhaust from the turbine dumps to the suppression pool. The pump normally takes suction from the demineralized water in the condensate storage tank. This supply is backed up by a supply line from the suppression pool. The pump discharges either to the feedwater line or to a full flow return test line to the condensate storage tank. A minimum flow bypass line to the suppression pool is provided. The makeup water is delivered into the reactor vessel through a connection to the feedwater line, and is distributed within the reactor vessel through the feedwater sparger. Cooling water for the RCIC turbine lube oil cooler and gland seal condenser is supplied from the discharge of the pump.

Following any reactor shutdown, steam generation continues due to heat produced by the radioactive decay of fission products. Initially the rate of steam generation can be as much as approximately 6 percent of rated flow and is augmented during the first few seconds by delayed neutrons and some of the residual energy stored in the fuel. The steam normally flows to the main condenser through the turbine bypass or, if the condenser is isolated, through the relief valves to the suppression pool. The fluid removed from the reactor vessel can be entirely made up by the feedwater pumps or partially made up from the control rod drive system which is supplied by the control rod drive feed pumps. If makeup water is required to supplement these primary sources of water, the RCIC turbine-pump unit either starts automatically upon receipt of a reactor vessel low-low water level signal (see Figure 4.7-4, Drawing M1G 2-5), or is started by the operator from the control room by remote manual controls. RCIC is assumed in safety analyses to deliver its design flow within 75 seconds after activation accounting for worst environmental and voltage conditions and process delays. Normal system response is significantly less. The reactor vessel low-low water level condition also actuates the closure of the main steam isolation valves to limit the amount of fluid leaving the reactor vessel, and actuates the high pressure coolant injection system (HPCI) as another source of makeup water.

RCIC has a makeup capacity sufficient to prevent the reactor vessel water level from decreasing to the level where the core would be uncovered without the use of core standby cooling systems. See Section 14, Station Safety Analysis. The pump suction is normally lined up to both condensate storage tanks. Each condensate storage tank is designed to provide a reserve of approximately 75,000 gallons for HPCI and RCIC use. The other condensate tank service demands are physically isolated by use of suction lines raised to an elevation above this reserve. Because the volume of water that is usable by HPCI or RCIC within the reserve is reduced to maintain adequate suction nozzle submergence, an additional amount of volume in the CST is administratively controlled to ensure adequate inventory is available for HPCI and RCIC to support an 8 hour station blackout duration.

The backup supply of cooling water for the RCIC is the suppression pool. The turbine pump assembly is located below the level of the condensate storage tank and below the minimum water level in the suppression pool to assure positive suction head to the pump.

Components necessary for initiating operation of the RCIC require only dc power from the station battery to operate the valves and controls. The power source for the turbine-pump unit is the steam generated in the reactor pressure vessel by the decay heat in the core. The steam is piped directly to the turbine and the turbine exhaust is piped to the suppression pool. The RCIC compartment is normally cooled by equipment area coolers supplied by the reactor building closed cooling water system.

If for any reason the reactor vessel is isolated from the main condenser, pressure in the reactor vessel increases but is limited by actuation of the relief valves. Relief valve discharge is piped to the suppression pool. Throughout the period of RCIC operation, the exhaust from the RCIC turbine and relief valve discharge being condensed in the suppression pool result in a temperature rise in the pool. During this period, Residual Heat Removal System (RHR) heat exchangers are used to maintain pool water temperature within acceptable limits.

After a loss of feedwater and vessel isolation event, with the safety relief valve setpoint at the upper analytical value of 1190 psig, 320 gpm makeup from the RCIC system is sufficient to maintain reactor water level above the top of active fuel (Reference 1 and Reference 2). The RCIC system is capable of delivering 400 gpm to the reactor vessel over a range of reactor pressures from 150 psig to 1190 psig.

The RCIC turbine-pump unit is located in a shielded area to assure that personnel access to other areas is not restricted during RCIC operation. The turbine controls (see Figures 4.7-4 through 4.7-6; Drawings M1G2-5, M1G4-5, and M1G3-4) provide for automatic shutdown of the RCIC turbine upon receipt of the following signals:

1. Reactor vessel high water level - indicating that core cooling requirements are satisfied (See Note)

2. Turbine overspeed - to prevent damage to the turbine and turbine casing

3. Pump low suction pressure - to prevent damage to the turbine-pump unit due to loss of cooling water

4. Turbine high exhaust pressure - indicating turbine or turbine control malfunction

NOTE: On receipt of a reactor vessel high water level signal, the turbine is shut down by closure of the turbine steam supply valve. This valve is motor operated and allows the RCIC turbine to restart automatically upon receipt of a subsequent low-low water level signal. Trip signal numbers 2, 3, and 4 shut down the turbine through closure of the turbine trip and throttle valve. Manual reset of this valve and manual restart of the turbine are required following shutdown by these trip signals.

Since the steam supply line to the RCIC turbine is a primary containment boundary, certain signals automatically isolate this line and shutdown the RCIC turbine through closure of the turbine trip and throttle valve. Automatic shutdown of the steam supply (see Figure 4.7-4) is described in Section 7.3, Primary Containment and Reactor Vessel Isolation Control System. Operating logic for all other valves is shown on Figures 4.7-5 (Drawing M1G4-5) and 4.7-6 (Drawing M1G3-4). The maximum closure time for the RCIC AC isolation steam line valve is 20 seconds and for the DC isolation valve is 29 seconds.

The RCIC turbine is designed to accommodate dry and saturated steam. The casing is designed accounting for corrosion, erosion, and material fatigue. Condensate and moisture carryover are prevented from accumulating by a drain pot and steam traps located immediately upstream of the turbine inlet valve. When the turbine is shut down, the inlet is kept at elevated temperature and the condensate is continuously drained.

Tests on a production unit of the HPCI turbine (which is of similar design) have been completed to verify the capability of the turbine to take low quality steam. Results confirm that the pressure integrity of the turbine housing is maintained during two-phase flow conditions at the turbine inlet.

The turbine flow control system shall be positioned by the demand signal from a flow controller located in the main control room or by a controller located at a remote panel in the Reactor Building and shall position the turbine governor valve as required to maintain constant pump discharge flow over the range of system operation. The maximum operating speed of the turbine pump is limited to a nominal value of 125% above the rated speed of 4500 rpm as controlled by the overspeed trip system. The over speed trip system is independent from the flow control system.

The RCIC piping within the drywell up to and including the outer isolation valve is designed in accordance with the USA Standard Code for Pressure Piping USAS B31.1.0, plus ASME Boiler and Pressure Code Section I. Piping and equipment, including support structures, are designed to seismic Class I specifications. See Appendix C. All piping and valves are also designed to meet the requirements outlined in Appendix A.

4.7.6 Safety Evaluation

To provide a high degree of assurance that the RCIC shall operate when necessary and in time to prevent inadequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during station operation. Evaluation of the reliability of the instrumentation for the RCIC shows that no failure of a single initiating sensor either prevents or falsely starts the system. Safety Design Basis 1 is therefore satisfied. Safety Design Basis 2 is satisfied by design of the RCIC to Class I specifications. See Appendix C.

RCIC suction valves do not automatically transfer pump suction from the condensate storage tanks (CST) to the torus on low CST level. Although automatic transfer would reduce the potential for operator error, adequate time exists for manual transfer of the suction valves. The NRC concurred that additional hardware would introduce a new failure mechanism and that a cost benefit analysis would not support this modification (reference NRC Letter 1.85.270).

4.7.7 Inspection and Testing

A design flow functional test of the RCIC is performed during station operation by taking suction from the demineralized water in the condensate storage tank and discharging through the full flow test return line back to the condensate storage tank. This test may only be performed if condensate storage tank level is above the administrative limit of 20 feet from the bottom of the tank. This limit is necessary to prevent return flow from causing air entrainment into the pump suction. The discharge valve MO1301-49 to the feedwater line remains closed during the test and reactor operation is undisturbed. The RCIC system test line includes a restricting orifice which partially simulates the resistance that the pump is required to overcome while delivering the required flow rate to the reactor vessel. During testing, the remainder of the system resistance is introduced via a remote manual throttle valve located on the test line. This restricting orifice reduces the throttling duty of the test line globe valve, reducing degradation of the valve.

Control system design provides automatic return from test to operating mode if system initiation is required during testing. The design of MO1301-48 has been changed such that it only serves as a maintenance isolation valve and it must be open at any time RCIC is required to be operable. Although M01301-48 receives an automatic signal to open on RCIC initiation, the opening stroke time is not evaluated for RCIC operability requirements with this valve initially closed. The valve must therefore be open and has no active safety function. The RCIC test return isolation valve is opened for testing and will automatically operate in the closed direction while a system initiation signal remains present. The closing cycle of the RCIC test return isolation valve is terminated either if the system initiation signal clears or the test return isolation valve reaches the full closed position. Periodic inspection and maintenance of the turbine-pump unit is carried out in accordance with manufacturers' instructions. Valve position indication as well as instrumentation alarms are displayed in the control room. See Figure 4.7-6 (Drawing M1G3-4). The instrument specifications for control of the RCIC for current plant operation are defined on Table 4.7-2. The pump discharge injection valve is tested in accordance with Technical Specification 3.13.

4.7.8 Operational Nuclear Safety Requirements for Plant Operation

Table 4.7-3 presents the nuclear safety requirements for the RCIC for each operating state. The entries on this table represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the RCIC. The following referenced portions of the Safety Analysis Report provide important information justifying the entries on Table 4.7-3.

	Reference	Information Provided
1.	Preceding parts of Section 4.7	Description of RCIC hardware and operation.
2.	Station Safety Analysis, Section 14	Analyses verifying response of RCIC to transients.
3.	Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which RCIC action is required.

Each detailed requirement on Table 4.7-3 is referenced, if possible, to the most significant plant condition originating the need for the requirement by identifying a matrix block on Table G.3-5. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns on Table 4.7-3 and are coded as follows:

<u>Example of Matrix Reference:</u>

```
F27-60
| | |
|-|-|------F = BWR operating State F
  |-|------27 = Event (row #27)
    |------60 = RCIC (column #60)
```

The matrix analyses in Appendix G show several events for which operation of the RCIC or HPCI is required. The most significant event is the transient resulting from a complete loss of feedwater flow to the reactor vessel. The need for the RCIC evolves from the criteria in Appendix G which require certain safety actions to be performed, the absence of which could lead to an unacceptable safety result.

Table 4.7-3 shows a breakdown of RCIC component requirements in all operating states. Since the reactor vessel head is off in states A and B, there are no operational requirements for RCIC. However, in states C through F the RCIC must be available to perform two specific system actions; reactor vessel water level control and automatic initiation. Core cooling is the one unique safety action for which the RCIC is required to safely accommodate certain transients.

As indicated on the matrix in Appendix G, core cooling is to be performed by the RCIC in conjunction with the HPCI. See block F27-60 for example.

4.7.9 Current Technical Specifications

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

4.7.10 References

1. NEDO-22159, "GE BWR Increased Safety/Relief Valve Simmer Margin Analysis for PNPS Unit 1", June 1982.

2. NEDC-33532P, "Pilgrim Nuclear Power Station Safety Valve Setpoint Increase", Rev. 2 January 2011

4.10 NUCLEAR SYSTEM LEAKAGE RATE LIMITS

4.10.1 Safety Objective

Nuclear system leakage rate limits are established so that appropriate action can be taken before the integrity of the nuclear system process barrier is unduly compromised.

4.10.2 Safety Design Basis

The safety design basis for nuclear system leakage rate limits is as follows:

1. The nuclear system leakage rate limits shall be set so that corrective action can be taken:

    a. before the nuclear system process barrier is threatened with significant compromise

    b. before the rate of leakage exceeds the coolant makeup capability

    c. before the total leakage rate within the drywell exceeds the capability for leakage removal from the drywell

2. Means shall be provided for the detection of leakage rates so that corrective action can be taken before the integrity of the nuclear system process barrier is unduly compromised

4.10.3 Description

The leakage considered in this section is limited to that water and steam released from the nuclear system process barrier inside the primary containment. This released water and steam, after condensation, is collected in the drywell floor drain and/or equipment drain sumps. Nuclear system leakage inside the drywell is treated separately from leakage elsewhere in the station because it can not be investigated locally or isolated from the reactor vessel during power operation.

Figure 10.19-1 (BECo Drawing M239) and 4.10-2 are diagrams of the reactor pressure boundary leak detection system and of the drywell sumps, respectively. As shown on the figures, there are two drywell sumps. One sump, the drywell equipment drain sump, receives drainage from pump seal leakoffs, reactor vessel head flange seal leakoff, selected valve stem leakoff including recirculation loop and main steam isolation valves, and other equipment drains through directly connected drain lines. The second sump, the floor drain collector sump, receives leakage from the drywell coolers, control rod drives, other valve stems and flanges, floor drains, and closed cooling water system drains. Collection of leakage in excess of normal background amounts is potentially indicative of a reactor coolant leak. The discharge lines from the equipment drain sump and floor drain sump to the radwaste system are provided with flow meters, pressure indicators, and sample points outside of the primary containment.

The drywell equipment and drywell floor sump each consist of two separate sumps: (1) a drain sump, and (2) a pump sump (Reference Figure 4.10-2). Both the floor and equipment drain sumps are located in the under vessel compartment. The cover of each drain sump is positioned flush with the surrounding concrete slab. The floor drain sump is covered by a grating to permit floor drainage to enter. The equipment drain sump is covered by a solid checker plate that is gasketed and secured to a steel frame. The equipment drain sump is sealed to prevent floor drainage from intermixing with equipment drainage.

Each drain sump is connected to its pump sump by two eight inch diameter drain lines. The pump sump covers are mounted on a six inch curb. Level instrumentation and pumps are mounted and penetrate through the pump sump covers. Each pump sump includes an elevated vent. The six inch curb and elevated vent prevents floor drain leakage from entering the pump sump.

Total leakage rate consists of all leakage, identified and unidentified, which flows to the drywell floor drain and equipment drain sumps.

The criterion for establishing the total leakage rate limit is based on the ability to provide makeup to the coolant system during a loss of offsite AC power.

Additionally, the total leakage rate is set low enough to prevent overflow of the drywell sumps. The equipment drain sump and floor drain sump which collect all leakage each have a total operating volume of 1250 gallons (total capacity of 1600 gallons). The sumps are each drained by two 50 gal/min pumps. The total leakage rate limit is therefore below the removal capacity of the two pumps in each sump. Further, it is unlikely that the total leakage would all collect in one sump. The total leakage rate is given in the Technical Specifications.

Each drywell sump has an alarm system which annunciates when either a low level or high level condition occurs in the sump. Periodically, the pumps for each sump are started to discharge the collected water leakage to the radwaste system. "On-Off" lights indicate the operational status of each pump.

At any time, each pump can be manually started by taking the pump control switch to the "MAN" position. The pump will continue to run until the switch is taken to the "OFF" position. When started in "AUTO" the pump will stop automatically when either the level in the sump reaches a pre-set level above the "low level" alarm setpoint or a timer in the pump control circuit times out.

By observing the sump discharge flow metering instrumentation, a high level alarm can be ascribed to either failure of one or both pumps or to excessive leakage into the sump.

As the water which has been collected in the sumps is pumped out, the discharge flow from each sump is individually metered by flow integrators. Total leakage rate is routinely calculated from these flow integrators and a record is maintained and reviewed to detect increases in total leakage rate.

4.10.3.1 Identified Leakage Rate

The identified leakage rate is the sum of all component leakage collected from identified sources. These sources drain to the drywell equipment drain sump. Leakage from the reactor vessel head flange gasket is piped to a collection chamber and then to the equipment drain sump. The chamber filling time is periodically timed during station operation and the flange gasket leakage rate can be calculated. A more detailed discussion of this instrumentation is in Section 7.8, Reactor Vessel Instrumentation. Most valves and recirculation pumps in the nuclear system inside the drywell are equipped with double seals. Leakage from these seals is piped to the equipment drain sump. The recirculation pump seals are instrumented as shown in Section 4.3, Reactor Recirculation System. Main steam relief valve leakage is identified by temperature sensors in the valve discharge piping. Such leakage would collect in the suppression pool as steam leakage is condensed.

Drywell cooler flow alarm switches annunciate in the main control room. These switches are set at 2 gal/min or less to detect possible rupture of the cooling water lines and also to detect high condensate flows. Annunciation from individual drywell coolers indicate unusual conditions and identify suspected leak areas. Operating experience with these flow alarm switches has determined their utility as part of the overall primary boundary leakage monitoring capability.

4.10.3.2 Unidentified Leakage Rate

The unidentified leakage rate is the sum of all leakage collected from unidentified sources. These sources drain to the drywell floor drain sump.

A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a crack which is large enough to propagate rapidly. The unidentified leakage rate is limited because of the possibility that most of the unidentified leakage rate might be emitted from a single crack in the nuclear system process barrier.

Primary containment atmospheric temperature, humidity, and pressure instrumentation are available as an aid to detecting leakage. Primary containment atmosphere temperature sensors are dual element resistance temperature detectors (RTD). Sensors are at several locations inside the drywell and the suppression chamber. One set of RTDs is recorded on a multipoint strip chart recorder having a range of 30°F to 200°F. The other set of RTDs is utilized as input to the computer.

Primary containment humidity sensors (dewcells) are at several locations in the drywell and the suppression chamber. The dewcell element operates by automatically maintaining a saturated solution of hygroscopic salt at a temperature at which it is in vapor pressure equilibrium with the measured atmosphere. This element is basically a temperature detector which measures the dew point temperature of the atmosphere. The output from each sensor is recorded on a multipoint strip chart recorder having a dew point temperature range of 40°F to 135°F and is also available as an input to the computer.

Containment pressure for leakage monitoring is sensed by a precision pressure gage utilizing a fused quartz pressure sensitive element with optical coupling between the pressure sensor and readout. This absolute pressure instrument provides a local digital indication of pressure and also provides a digital input to the computer. This instrument has a range of 0 to 100 psia. Assuming a constant containment volume, this combination of temperature, humidity, and absolute pressure sensors, when read out on the computer, permits an evaluation of the time varying behavior of the mass of gas and water vapor within the drywell.

The sensitivity for detecting low leak rates by monitoring containment parameters is dependent on the masking effect of water vapor condensation on surfaces within the drywell. After temperature equilibrium is established within the drywell, the principal location for condensation is expected to be the drywell coolers. Calculations indicate that leaks equivalent to several gal/min from the primary system should be detectable using the combined temperature, pressure, and humidity instrumentation being provided. The response time for detection of a small leak is dependent upon the possible masking effects of the drywell coolers and any other condensation locations.

The study of primary containment temperature, pressure, and humidity as a function of leak size and quality has demonstrated that measurable containment atmospheric parameters will not necessarily react to a specific size and type of leak in a unique manner. Initial conditions of temperature, pressure, humidity, drywell cooler efficiency, and other heat rejection mechanisms contribute to the creation of a relatively complex thermodynamic system. Because of the number of assumptions required and the uncertainties involved, the observation of containment temperature, pressure, or humidity parameters individually will not provide a reliable measure of the absolute value of the leakage rate.

Leakage from the reactor pressure boundary inside the primary containment is measured by monitoring floor and equipment drain sumps. Although these methods are capable of detecting leakage matter of approximately 5 gal/min, a more sensitive technique is desirable.

Leakage from the reactor pressure boundary will contain varying amounts of radioactive material. Depending on the age of the reactor plant and the amount of fuel leakage, the radioactivity will be in the form of activation and noble gases, corrosion products, and halogens. Some portion of the release radioactivity will remain airborne in the containment atmosphere. Because the containment atmosphere is a closed volume, the concentration of airborne radioactivity will steadily increase to easily detectable levels even from extremely small leaks. Factors which would reduce the amount of radioactivity available for detection include radioactive decay, plateout of halogens and particulates, and removal by vapor condensation in drywell coolers.

4.10.3.3 Reactor Pressure Boundary Leak Detection System

The monitoring of airborne radioactivity levels in the containment atmosphere permits operators to evaluate leakage relative to the probable source. For example, an abundance of iodine in the containment atmosphere would indicate water leakage, whereas an abundance of gaseous activity would indicate steam leakage.

Such monitoring is accomplished by means of a reactor pressure boundary leak detection system. This system consists of two permanently installed panels, C-19A and C-19B and is capable of monitoring the two recirculation pumps inside the primary containment for particulate and gaseous radioactivity in the atmosphere as a result of leaks. See Figure 10.19-1 (BECo Drawing M239).

The system takes suction from the H_2/O_2 analyzer system sampling lines downstream of the existing H_2/O_2 analyzer system containment isolation valves. The H_2/O_2 analyzer sample supply lines are heat traced to prevent condensation of the sample before it reaches the analyzer. The sample lines are maintained at approximately 250°F except for the sample lines from penetrations X-106A-b and X-50A-d which are maintained at approximately 160°F. The two lines which are maintained at a lower temperature are also used as sample supply lines to the reactor pressure boundary leak detection panel (C-19). The leak detection system cannot operate at the higher temperatures.

If an unusual increase above background levels on any channel (as would be expected from a reactor pressure boundary leak) should occur, an alarm will sound in the control room. Daily equilibrium activity levels are taken from panel C-19 which are compared to previous equilibrium levels to detect possible background level changes or instrument malfunction. Alarm settings are established at or below 10^6 cpm. The unidentified leakage limit is 5 gpm and past experience has shown that the 10^6 cpm alarm point has always been reached well below the 5 gpm limit (typical levels are between 2 and 3 gpm).

Alarm settings are established at or below 10^6 cpm. The unidentified leakage limit is 5 gpm and past experience has shown that the 10^6 cpm alarm point has always been reached well below the 5 gpm limit (typical levels are between 2 and 3 gpm).

An air particulate sensitivity of 10^{-10} microcuries/cm^3 and gaseous sensitivity of 10^{-6} microcuries/cm^3, is employed. Relating instrumentation sensitivities to response times and leak rates requires information such as the amount of fuel failure, plateout, and air flow characteristics. These parameters are not necessarily constant, thus it is not possible to establish a unique value to leak detection sensitivity. Even though a quantification of leak rates is not feasible with the system, it does respond to increases of radioactivity in the primary containment atmosphere. The rate of change on the monitoring channels over a known period of time can give a relative idea of the magnitude of a leak. In addition, the particulate and halogen filters are examined for radioisotopic content. This data is also utilized in evaluating reactor pressure boundary leakage.

A leakage rate of 150 gal/min has been conservatively calculated to be the minimum liquid leakage from a crack large enough to propagate rapidly. An allowance for reasonable leakage which does not compromise barrier integrity and is not identifiable is made for normal operation.

The unidentified leakage rate limit is established at 5 gal/min which is far enough below the 150 gal/min leakage rate to allow time for corrective action to be taken before the process barrier is significantly compromised.

Condensation from the drywell atmosphere occurs as the atmosphere is circulated through the drywell coolers. This condensation is collected and piped to the drywell floor drain sump. Fluid leakage from the primary pressure boundary will result in increased cooling loads on the drywell air coolers which will result in abnormal temperature measurements on the cooling units. The condensation on the coolers will increase and abnormally high condensate flows to the floor drain sump will result. Condensation on the drywell walls and structures within the primary containment will also collect in the floor drain sump. The integrated floor drain sump flow, the drywell atmosphere pressure and temperature, the drywell atmosphere humidity, and the drywell air cooler temperatures are all employed as indicators of potential leakage from the primary pressure boundary.

4.10.4 Safety Evaluation

The unidentified leakage rate limit is based, with an adequate margin for contingencies, on the calculated leakage from a crack large enough to propagate rapidly. The established limit is sufficiently low so that even if the entire unidentified leakage rate were coming from a single crack in the nuclear system process barrier, corrective action could be taken before the integrity of the barrier is threatened with significant compromise.

The limit on total leakage rate is established so that in the absence of offsite AC power and feedwater, and without using the core spray cooling system, the leakage loss from the nuclear system could be replaced. Either one of the two control rod drive pumps can furnish the required makeup flow rate. The limit on total leakage also allows a reasonable margin below the discharge capability of either the floor drain or equipment drain sump pumps. Thus, the established total leakage rate allows sufficient time for corrective action to be taken before either the nuclear system coolant makeup or the drywell sump removal capabilities are exceeded.

Provided in the description is a discussion of the leakage detection instrumentation. With this information it is shown that means are provided for the detection of leakage so that corrective action can be taken before the integrity of the nuclear system process barrier is unduly compromised. It is concluded that the safety design basis is met.

4.10.5 Inspection and Testing

Because the sump pumps are periodically started and their operation is verified by the alarms and discharge flow instrumentation, no special inspection or testing during power operation of the station is necessary. The pumps and controls are inspected and tested during each refueling cycle.

4.10.6 Proposed Nuclear Safety Requirements for Initial Plant Operation

Table G.5-3 shows a requirement for nuclear system leakage rate indications in states C, D, E, and F during planned operation. Matrix entry 11 under system 51 shows that the leakage indications must be continuously operable in each state. The actual limits observed within the primary containment and the methods of indication are discussed in the preceding descriptive section.

4.10.7 Current Operational Nuclear Safety Requirements

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

SECTION 5

CONTAINMENT

TABLE OF CONTENTS

SECTION 5

CONTAINMENT

TABLE OF CONTENTS

SECTION 5

CONTAINMENT

TABLE OF CONTENTS

SECTION 5

LIST OF TABLES

SECTION 5

LIST OF FIGURES

1,300°F or higher, and thus the temperatures to which the seals would be exposed during a LOCA would have no adverse effect on their leak tightness characteristics.

The electrical penetrations used for low voltage power, control, and instrumentation cable and for coaxial cable utilize a bonding resin to maintain the leak tight integrity of the containment penetrating sleeves. A prototype of the penetration assembly has been tested by exposing the interior face of the penetration assembly to the following environmental conditions: 352°F, 124 psig for 30 min. and then reduced to 309°F for 23.5 hours. The assembly was then submerged in water at 135°F, 62 psig for 3 hours. The pressure retaining capability of the penetration assembly was maintained throughout the duration of the tests.

Additional tests were conducted to certify the pressure retaining capability of those penetrations utilizing bonding resin. The electrical penetration assembly was exposed to a design basis accident environment as described below and maintained its containment and electrical circuit integrity (the environment and loading conditions shall not produce a helium leak rate greater than 1E-6 cc/sec through the entire penetration assembly) during a postulated LOCA accident. The 2 AWG and 6 AWG wires were energized with derated current of 70 amps and 40 amps, respectively. These wires were energized for a period of 30 minutes during 340 at 340°F ambient.

The LOCA environmental condition:

Temperature:	340°F for 4 hrs, 325°F for 3 hrs, and then 260°F for 10 days
Pressure:	103 psig for 4 hrs, 81 psig for 3 hrs, and then 23 psig for 10 days
Humidity:	100% for entire test duration (10 days and 7 hrs)

The post-LOCA leak rate was 8E-07 cc/sec at 15 psig and 72°F. These values satisfied the acceptance criteria of the leak rate of 1E-06 cc/sec and, therefore, demonstrated its integrity.

A prototype of the penetrations using a polysulfone seal has been qualified to the following environmental conditions: 360 degrees F and 73 psig reached in 6 minutes: at least 350 degrees F and 62 psig maintained for 3 hours and 54 minutes; at least 324 degrees F and 62 psig maintained for 71 hours; at least 310 degrees F and 61 psig maintained for 150 hours; and at least 315 degrees F and 31 psig maintained for 100 hours. The penetration leak rate was 8.6E-5 sec/sec helium at 66 psig.

5.2.3.4.4 Traversing Incore Probe Penetrations

Traversing incore probe (TIP) guide tubes pass from the Reactor Building through the primary containment. Penetration of the guide tubes through the primary containment are sealed by means of brazing which meets the requirements of the ASME Boiler and Pressure Vessel Code, Section VIII.

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE. # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5065-20B	H2/O2 Analyzer Supply	X-50Ad;OPC	2.0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	18
MO-1001-28A	RHR Injection "A" Loop	X-51A;OPC	30.0	A-X	Globe	AC	AC	Open	-- --	E,T,RM	
MO-1001-29A	RHR Injection "A" Loop	X-51A;OPC	30.0	A-X	Gate	AC	AC	Closed	3 Closed	A,E,F,U,T,RM	11,17
1001-68A	RHR Injection A	X-51A;IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev. Flow	
MO-1001-28B	RHR Injection "B" Loop	X-51B;OPC	30.0	A-X	Globe	AC	AC	Open	-- --	E,T,RM	
MO-1001-29B	RHR Injection "B" Loop	X-51B;OPC	30.0	A-X	Gate	AC	AC	Closed	3 Closed	A,E,F,U,T,RM	11,17
1001-68B	RHR Injection B	X-51B;IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev. Flow	
M0-2301-4	HPCI Steam to Turbine	X-52;IPC	25.0	A-X	Gate	AC	AC	Open	4 Closed	L,RM,AA	13
MO-2301-5	HPCI Steam to Turbine	X-52;OPC	34.0	A-X	Gate	DC	DC	Open	4 Closed	L,RM.AA	13
MO-1301-16	RCIC Steam to Turbine	X-53;IPC	20.0	A-X	Gate	AC	AC	Open	5 Closed	K,RM,AA	10
MO-1301-17	RCIC Steam to Turbine	X-53;OPC	29.0	A-X	Gate	DC	DC	Open	5 Closed	K,RM,AA	10
SV-5065-14A	$H_2/0_2$ Analyzer Supply	X-106Ab;OPC	2.0	B	Globe	AC	Spring	Open	2 Closed	A,F,RM	18
SV-5065-21A	$H_2/0_2$ Analyzer Supply	X-106Ab;OPC	2.0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	18
9-CK-341	Torus Makeup	X-205;OPC	--	B	Check	--	Process	Closed	-- --	Rev. Flow	9
AO-5033B	Drywell/Torus Purge	X-205;OPC	10.0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	9,21,27
AO-5033C	Torus Makeup	X-205;OPC	10.0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,27.30
AO-5036A	Torus Purge Inlet	X-205;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27,35
AO-5036B	Torus Purge Inlet	X-205;OPC	5.0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27,35
SV-5087A	Post Accident Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5087B	Post Accident Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

ISOLATION SIGNAL CODES FOR TABLE 5.2-4

Signal	Description
A*	Reactor vessel low water level - scram and close isolation valves except main steam lines.
B*	Reactor vessel low low water level - initiate RCIC, HPCI and close main steam line isolation and drain valves.
C	Deleted
D*	Line break - main steam line (steam line high space temperature or high steam flow).
E	Reactor low low level or high drywell pressure - select LPCI and close other loop valves.
F*	High drywell pressure - close RHR/shutdown cooling and head spray, the RHR to radwaste valves, and Torus Vacuum Breaker.
G	Reactor vessel low low water level and low pressure; or high drywell pressure - initiate Core Spray and RHR systems.
J*	Line break in cleanup system - high space temperature, or high flow.
K*	Line break in RCIC system steam line to turbine (high steam line space temperature or high steam flow) or low steam line pressure.
L*	Line break in HPCI system steam line to turbine (high steam line space temperature or high steam flow).
M*	Line break in RHR shutdown and head cooling (high space temperature; alarm only; no auto closure).
N*	High Drywell pressure and Low reactor vessel pressure - close HPCI vacuum breakers.
P*	Low main steam line pressure at inlet to main turbine (RUN mode only).
Q*	Reactor high water level - isolate main steam line (except in run mode).
RM*	Remote manual switch from control room.
Rx	This valve is a Reactor Vessel Isolation Valve only (not a Primary Containment Isolation Valve).
S	Low drywell pressure - close containment spray valves.
T	Low reactor pressure permissive to open core spray and RHR-LPCI valves.
U	High reactor vessel pressure - close RHR shutdown cooling valves and head cooling valves.
W	High temperature at outlet of cleanup system nonregenerative heat exchanger.

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

ISOLATION SIGNAL CODES FOR TABLE 5.2-4

Y	Standby liquid control system actuated.
Z	Refuel floor high radiation. This signal is part of the Reactor Building Isolation Control System. See Section 7.18.
AA*	Low reactor pressure - closure of HPCI and RCIC steam to turbine isolation valves.
*	These are the isolation functions of the primary containment and reactor vessel isolation control system; other functions are given for information only.

SECTION 6

CORE STANDBY COOLING SYSTEMS

TABLE OF CONTENTS

SECTION 6

LIST OF TABLES

SECTION 6

LIST OF FIGURES

TABLE 6.3-1

CORE STANDBY COOLING SYSTEMS EQUIPMENT DESIGN DATA SUMMARY

Function	Number Installed	Design Flow (each) Flow	psid*	Pressure Range	AC Power Required for Initiation	Source of Water	Backup Systems
HPCI	1	4,250 gal/min	@ 1,120-150****	1,120 to 150 psig	None	Condensate Storage Tank and suppression pool	Auto Depress. + Core Spray + LPCI (RHR)
Automatic Depressurizing Valves	4	800,000 lb/hr	@ 1,095**	1,120 to 50 psig	None	None	HPCI
Core Spray Systems	2	3,600 gal/min	@ 104***	204 to 0 psid	Normal Aux. or Standby Diesel Generator	Suppression Pool	LPCI (RHR) Redundant Core Spray System
LPCI (RHR)	4	4,800 gal/min	@ 20	237 to 0 psid	Normal Aux. or Standby Diesel Generator	Suppression Pool	Core Spray Systems

NOTE:

* psid-pounds per in^2 differential between reactor vessel and primary containment

** Minimum required flow is 800,000 lb/hr @ 1095 psig

*** Minimum required flow is 3240 gpm @ 104 psig reactor pressure

**** Periodic pump testing demonstrates the HPCI system is capable of delivering 3000 gpm to the reactor vessel for a system head corresponding to a reactor pressure of 1126 psig, the highest analytical setpoint of the safety relief valves.

6.4 DESCRIPTION

6.4.1 High Pressure Coolant Injection System (HPCIS)

The HPCIS consists of a steam turbine assembly driving a constant flow pump assembly and system piping, valves, controls, and instrumentation. The HPCIS is shown schematically on Figure 6.4-1 (Drawing M1J6-4).

The principal HPCIS equipment is installed in the Reactor Building. The turbine-pump assembly is located in a shielded area to assure that personnel access to adjacent areas is not restricted during operation of the HPCIS. Suction piping comes from the condensate storage tank and the suppression pool. Injection water is piped to the reactor feedwater pipe at a T-connection. Steam supply for the turbine is piped from a main steam header in the primary containment. This piping is provided with an isolation valve on each side of the drywell barrier. Remote controls for valve and turbine operation are provided in the station main control room. The controls and instrumentation of the HPCIS are described, illustrated, and evaluated in detail in Section 7.4, Core Standby Cooling Controls and Instrumentation.

The HPCIS is provided to ensure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the nuclear system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCIS permits the reactor to be shut down while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized, the pressure at which Low Pressure Coolant Injection (LPCI) operation or Core Spray System operation maintain core cooling.

If a loss of coolant accident occurs, the reactor scrams upon receipt of a low water level signal or a high drywell pressure signal. The HPCIS starts when the water level reaches a preselected height above the core, or if high pressure exists in the primary containment. The HPCIS automatically stops when a high water level in the reactor vessel is signaled.

The HPCIS is designed to pump water into the reactor vessel over a wide range of pressures in the reactor vessel, from 150 psig to 1120 psig (Reference Table 6.3-1). Accident safety analysis requires the HPCIS deliver 4250 gpm to the reactor vessel over a range of reactor pressures from 150 psig to 1000 psig, which is well within the design capability of the HPCIS.

The HPCIS also serves as a backup for the RCIC system during loss of feedwater transients (i.e., no pipe break), and similar to RCIC the nominal HPCIS injection flowrate at the upper analytical SRV setpoint of 1190 psig is 400 gpm. Analysis performed to increase the SRV setpoint to 1115 $\pm$ 11 psig demonstrated that 320 gpm was sufficient to prevent core uncovery with margin of approximately 4 feet above top of active fuel (TAF)(Ref. 4.7.10.1).

The analysis described in reference 4.7.10.1 remains valid for the current SRV upper analytical setpoint of 1190 psig (1155 ± 3%), because the change in total inventory lost from the vessel at the higher SRV setpoint is negligible because the inventory loss is primarily dependent on decay heat which is unaffected by the setpoint increase (Reference 4.7.10.2).

Because, the HPCIS minimum flow valve automatically opens on low flow, the HPCIS flowrate with reactor pressure at the upper analytical SRV setpoint must remain above the low flow setpoint to avoid diversion of injection flow to the torus. Periodic testing is performed that verifies the HPCIS can provide a flow rate of 3000 gpm at a system head corresponding to the upper analytical SRV setpoint of 1190 psig. This test requirement demonstrates a HPCIS performance substantially greater than required for reactor isolation events.

Two sources of water are available. Initially, demineralized water from the condensate storage tank is used instead of injecting from the suppression pool into the reactor. This provides reactor grade water to the reactor vessel for the case where the need for the HPCI is rapidly satisfied. Water from either source is pumped into the reactor vessel via the feedwater line. Flow is distributed within the reactor vessel through the feedwater spargers to obtain mixing with the hot water or steam in the reactor pressure vessel.

The pump assembly is located below the level of the condensate storage tank and below the water level in the suppression pool to assure positive suction head to the pumps.

The HPCIS turbine-pump assembly and piping are located to be protected from the physical effects of design basis accidents, such as pipe whip, and high temperatures; the equipment is located outside the primary containment. This arrangement satisfies safety design basis 9.

The HPCIS turbine is driven by steam from the reactor which is generated by decay heat and residual heat. The steam is extracted from a main steam header upstream of the main steam line isolation valves. The two HPCIS isolation valves in the steam line to the HPCIS turbine are normally open to keep the piping to the turbine at elevated temperatures to permit rapid startup of the HPCIS. Signals from the HPCIS control system open or close the turbine stop valve.

A condensate drain pot is provided upstream of the turbine stop valve to prevent the HPCIS steam supply line from filling with water. The drain pot normally routes the condensate to the main condenser, but upon receipt of an HPCIS initiation signal or a loss of control air pressure, isolation valves on the condensate line automatically shut.

The turbine has two devices for controlling power; a speed governor which limits turbine speed to its maximum operating level and a control governor with automatic speed set point control which is positioned by a demand signal from a flow controller to maintain constant flow over the pressure range of HPCIS operation. Manual operation of the governor is possible when in the test mode, but it is automatically repositioned by the demand signal from the flow controller if system initiation is required.

As reactor steam pressure decreases, the HPCIS turbine throttle valves open further to pass the steam flow required to provide the necessary pump flow. The capacity of the system is selected to provide sufficient core cooling to limit clad temperature while the pressure in the reactor vessel is above the pressure at which core spray and LPCI become effective.

Exhaust steam from the HPCIS turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects moisture present in the steam. Collected moisture is discharged through a trap to the suppression pool or bypassed to the gland seal condenser if the trap fails.

The HPCIS turbine exhaust line has two separate vacuum relief mechanisms which prevent significant vacuum from developing. Vacuum relief prevents water from being drawn into the turbine exhaust line from the torus and aids draining of condensed steam. The relief mechanisms include a pipe (including vacuum relief check valves and containment isolation valves) from the torus atmosphere to the HPCIS turbine exhaust line downstream of the double check valve arrangement and a nitrogen purge system (not safety related) which can be used to pressurize the HPCIS turbine exhaust line after a turbine trip.

The HPCIS turbine gland seals are vented to the gland seal condenser and part of the water from the HPCIS pump is routed through the condenser for cooling purposes. Noncondensible gases from the gland seal condenser are pumped to the Standby Gas Treatment System when the Reactor Building is isolated.

The system piping is designed to USASI B31.1.0 and the additional requirements of Appendix A. The pump is designed to ASME Section III, Class C and is also designed and tested in accordance with the Standards of the Hydraulic Institute.

The HPCIS turbine exhaust vacuum breaker line from the torus to the HPCIS exhaust line is designed to ASME Section III Subsection NC.

The HPCIS equipment, piping, and support structures are designed as Class I equipment. See Section 12 and Appendix C. This satisfies design basis 10.

The system is designed for a service life of 40 yr, accounting for corrosion, erosion, and material fatigue.

Startup of the HPCIS is completely independent of ac power. Only dc power from the station batteries and steam extracted from the Nuclear System are necessary. This satisfies safety design basis 5.

The various operations of the HPCIS components are summarized as follows:

The HPCIS controls automatically start the system and bring it to design flow rate within 90 sec from receipt of a reactor vessel low water level signal, or a primary containment (drywell) high pressure signal.

The HPCIS turbine is shut down automatically by any of the following signals:

1. Turbine overspeed - This prevents damage to the turbine and turbine casing.

2. Reactor vessel high water level - This indicates that core cooling requirements are satisfied.

3. HPCIS pump low suction pressure - This prevents damage to the pump due to loss of flow.

4. HPCIS turbine exhaust high pressure - This indicates a turbine or turbine control malfunction.

5. Automatic HPCIS isolation signal - If an initiation signal is received after the turbine is shut down, the system is capable of automatic restart if no shutdown signals exist.

Because the steam supply line to the HPCIS turbine is part of the Nuclear System process barrier, certain signals automatically isolate this line, causing shutdown of the HPCIS turbine. Automatic shutoff of the steam supply is described in Section 7.3, Primary Containment and Reactor Vessel Isolation Control System. However, automatic depressurization and the low pressure systems of the CSCS act as backup, and automatic shutoff of the steam supply does not negate the ability of the CSCS to satisfy the safety objective.

In addition to the automatic operational features of the system, provisions are included for remote manual startup, operation, and shutdown (provided initiation or shutdown signals do not exist).

HPCIS initiation automatically actuates the following valves:

HPCIS pump discharge test bypass valves
HPCIS pump suction shutoff valve
HPCIS pump discharge shutoff valve
HPCIS steam supply shutoff valves
HPCIS turbine stop valves
HPCIS turbine control valves
HPCIS steam supply line drain isolation valves

Startup of the hydraulic oil pump and proper functioning of the Hydraulic Control System is required to open the turbine valves. Operation of the gland seal condenser components is required to prevent outleakage from the turbine shaft seals. Startup of the equipment is automatic. Prior to startup, the control governor may be anywhere between its high speed and low speed stop positions. Upon receipt of an initiating signal, the flow control signal automatically runs the control governor toward its high speed stop (maximum demand signal from flow controller). The same initiating signal automatically starts the hydraulic oil pump and when sufficient oil pressure is developed, both the turbine stop valve and the control valves open simultaneously and the turbine accelerates toward the rpm of either the control governor or the speed governor, whichever is lower. When rated flow is established, the flow controller signal adjusts the setting of the control governor so that rated flow is maintained as Nuclear System pressure decreases.

A minimum flow bypass is provided for pump protection. The bypass valve automatically opens on a low flow signal, and automatically closes on an increasing flow signal. When the bypass is open, flow is directed to the suppression pool. There are shutoff valves in the line used for system testing. These valves are sequenced to close by the signal which actuates system operation, and are interlocked closed when either suction valve from the suppression pool is open. All automatically operated valves are equipped with a remote manual functional test feature.

The HPCIS initially injects water from the condensate storage tank. When the water level in the tank falls below a predetermined level or on high level in the suppression pool, the pump suction is automatically transferred to the suppression pool. This transfer may also be made from the control room using remote controls. This establishes a closed loop for recirculation of water escaping from a break.

6.4.2 Automatic Depressurization System

In case the capability of the Feedwater System, the control rod drive water pumps, Reactor Core Isolation Cooling System (RCICS), and HPCIS is not sufficient to maintain the reactor water level, the Automatic Depressurization System functions to reduce the reactor pressure so that flow from LPCI and the core spray system enters the reactor vessel in time to cool the core and limit fuel clad temperature.

The automatic depressurization system utilizes the four nuclear system pressure relief valves to relieve the high pressure steam to the suppression pool. The design, description, and evaluation of the pressure relief valves are discussed in detail in Section 4.4, Nuclear System Pressure Relief System and it is shown that Safety Design Bases 5, 9, and 10 are satisfied.

The pressure relief valves automatically open upon coincident signals of reactor vessel low-low water level, primary containment (drywell) high pressure, and discharge pressure indication of any low pressure cooling system (LPCI or core spray), but only after a time delay. The time delay provides time for the high pressure systems to restore reactor water level and for the operator to cancel the automatic depressurization signal if main control room information indicates the signal is false or is not needed.

6.4.3 Core Spray System

Two independent loops are provided as a part of the core spray system. Each loop consists of a core spray pump, a sparger ring, a spray nozzle, and the necessary piping, valves, and instrumentation. Figure 6.4-2 (Drawing M1K 2-4) shows a schematic process diagram of the core spray system.

In case of low water level in the reactor vessel or high pressure in the drywell, the core spray system, when reactor vessel pressure is low enough, automatically sprays water onto the top of the fuel assemblies in time and at a sufficient flow rate to cool the core and limit fuel clad temperature (The LPCI System starts from the same signals and operates independently to achieve the same objective by flooding the reactor vessel).

The core spray system provides protection of the core for the large break in the nuclear system when the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are unable to maintain reactor vessel water level.

The protection provided by the core spray system also extends to a small break (see Figure 6.3-1) in which the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are all unable to maintain the reactor vessel water level and the automatic depressurization system has operated to lower the reactor vessel pressure so LPCI and the core spray system can provide core cooling.

The core spray pumps receive power from the station 4,160V auxiliary buses. Each core spray pump motor and the associated automatic motor valves receive AC power from different buses. Similarly, control power for each loop of the core spray system comes from different DC buses. This arrangement satisfies Design Basis 5.

The core spray pumps and all automatic valves can be operated individually by manual switches in the main control room. Operating information is provided in the main control room with pressure indicators, flow meters, and indicator lights.

The major equipment for one loop is described in the following paragraphs.

When the system is actuated, water is taken from the suppression pool. Flow then passes through a normally open butterfly valve and a motor operated valve which can be closed by a remote manual switch from the main control room. This motor operated valve is normally open. The butterfly valve is located in the core spray pump suction line as close to the suppression pool as practical. This valve is equipped with an extension operator to permit manual closure of the valve from the floor above the suppression chamber.

The core spray pumps are located in the reactor building below the water level in the suppression pool to assure positive pump suction. The pump, piping, controls, and instrumentation of each loop are separated and protected so that any single physical event, or missiles generated by rupture of any pipe in any system within the containment drywell, cannot make both core spray loops inoperable. The switchgear for each loop is in a separate cabinet for the same reason. This arrangement satisfies safety design basis 9.

The effects on available NPSH for the core spray pumps due to a postulated accumulation of LOCA generated debris on the suction strainers in the suppression pool were evaluated in accordance with Regulatory Guide 1.82 Rev. 2. The RHR and core spray suction strainers in each loop were replaced with a large capacity (670 ft^2) stacked disk strainer spanning the width of one torus bay and connected to the three pumps. The debris analysis determined the maximum volume of shredded fiberglass, sludge, dirt/dust, rust flakes, and paint chips generated from the bounding line break inside primary containment. Based on a bounding analysis for debris generation, transport, and accumulation, the increase in suction strainer head loss is within the margin for NPSH available to the core spray pumps following the design basis LOCA. Refer to Section 14.5.3 for the NPSH evaluation.

A shaft seal drain line is provided from the pump casings which drains to the radwaste system.

A low flow bypass line is provided from the pump discharge to below the surface of the suppression pool. The bypass flow is required to prevent the pump from overheating when pumping against a closed discharge valve. An orifice limits the bypass flow. A manual valve, normally locked open, is used to close the bypass line for maintenance.

A relief valve, set for 500 psig, protects the low pressure core spray system upstream of the outboard shutoff valve from reactor pressure. The relief valve discharges to the radwaste system.

A full flow test line permits circulating water to the suppression pool for testing the system during planned operations. A normally closed, motor operated valve in the line is controlled by a remote manual switch in the main control room. Partial opening of the valve combined with an orifice in the test line permits test operation at rated core spray flow at a pressure drop equivalent to discharging into the reactor vessel. A flow indicator is provided in the main control room to monitor core spray system flow rate.

Two motor operated valves are provided to isolate the core spray system from the nuclear system when the core spray pump is not running. These valves admit core spray water to the reactor when signaled to open. Both valves are installed outside the drywell to facilitate operation and maintenance, but as close as practical to the drywell to limit the length of line exposed to reactor pressure. The valve nearer the containment is normally closed to back up the inside check valve for containment purposes. The outboard valve is normally open, to limit the equipment needed to operate in an accident condition. A drain line is provided between the two shutoff valves to measure leakage through the inside check valve or the inboard shutoff valve. A drain line is normally closed with two valves and a pipe cap to assure containment.

A check valve is provided in each core spray pipeline just inside the primary containment, to prevent loss of reactor coolant outside containment in case the core spray line breaks. A normally locked open manual valve is provided downstream of the inside check valve to shut off the core spray system from the reactor during shutdown conditions for maintenance of the upstream valves. The two core spray system pipes enter the reactor vessel through nozzles 120 deg apart. Each internal pipe then divides into a semicircular header with a downcomer at each end which turns through the shroud near the top. A semicircular sparger is attached to each of the four outlets to make two practically complete circles, one above the other. Short elbow nozzles are spaced around the spargers to spray the water radially into the tops of the fuel assemblies.

Core spray piping upstream of the outboard shutoff valve is designed for the lower pressure and temperature of the core spray pump discharge. The outboard valve and piping downstream are designed for reactor vessel pressure and temperature. The system is designed in accordance with Appendix A. The core piping and support structures are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. The core spray system is assumed filled with water for seismic analysis. It is concluded that Safety Design Basis 10 is satisfied.

Upon signals of reactor low-low water level and low vessel pressure or drywell high pressure, the automatic controls turn on the core spray pumps and restore other valves to the spray mode. When reactor pressure decreases, the core spray shutoff valves are signaled to open. Flow to the sparger begins when the pressure differential opens the inside check valve. Section 7.4, Core Standby Cooling System Controls and Instrumentation, contains further details and evaluation.

6.4.4 Low Pressure Coolant Injection

In case of low-low water level in the reactor and low vessel pressure or high pressure in the containment drywell, LPCI mode of operation of the residual heat removal (RHR) system pumps water into the reactor vessel in time to flood the core to limit fuel clad temperature.

(The core spray system starts from the same signals and operates independently to achieve the same objective.)

LPCI operation provides protection to the core for the case of a large break in the nuclear system when the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are unable to maintain reactor vessel water level.

Protection provided by LPCI also extends to a small break (see Figure 6.3-1) in which the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are all unable to maintain the reactor vessel water level and the automatic depressurization system has operated to lower the reactor vessel pressure so LPCI and the core spray system start to provide core cooling.

Figure 6.4-3 shows a schematic process diagram of LPCI. LPCI operation consists of using at least three of the four ac motor driven centrifugal pumps taking water from the suppression pool and pumping it into one or the other recirculation loop. The water enters the reactor through the jet pumps to restore the water level in the reactor vessel. LPCI operation includes using associated valves, controls, instrumentation, and pump accessories. The LPCI pump motors receive power from the station 4,160V auxiliary busses. The LPCI pump motors and the associated automatic motor valves within each loop receive ac power from the same bus. This arrangement satisfies safety design basis 5.

LPCI pumps and piping equipment are described in detail in Section 4.8, Residual Heat Removal System, which also describes the other functions served by the same pumps if not needed for the LPCI function. The portions of the RHR System required for accident protection are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. It is concluded that safety design basis 10 is satisfied.

6.5 SAFETY EVALUATION

The safety design basis for the Core Standby Cooling System (CSCS) for limiting peak clad temperature is to demonstrate compliance with the acceptance criteria of 10 CFR 50.46. The safety analysis models and methodology used to demonstrate conformance with the criteria of 10 CFR 50.46 are in compliance with the requirements of 10 CRF 50, Appendix K.

6.5.1 Summary

In order to satisfy the safety design basis, four (4) means for core standby cooling are provided:

High Pressure Coolant Injection (HPCI)
Automatic Depressurization System (ADS)
Core Spray System (CSS)
Low Pressure Coolant Injection (LPCI)

These are in addition to the other systems which supply core coolant: Feedwater, Control Rod Drive, and Reactor Core Isolation Cooling (RCIC).

For reliability, each Standby Cooling System uses equipment with as few components required to actuate as feasible, and makes provisions for testing during normal operation. To provide diversity, two different cooling methods are provided - spraying and flooding.

Evaluation of the reliability and redundancy of the controls and instrumentation for the CSCS shows that no failure of a single initiating sensor either prevents or falsely starts the initiation of these cooling systems. No single control failure prevents the combined cooling systems from providing the core with adequate cooling. The controls and instrumentation can be calibrated and tested to assure proper response to conditions representative of accident situations.

As stated in the safety objective and in safety design basis 2, the CSCS removes the residual and decay heat from the reactor core so that fuel clad melting is prevented. The design basis used is that the fuel clad will not reach 2200°F.

All of the safety design bases for the CSCS are shown to be met by the previous descriptions, the referenced descriptions and evaluations in other sections, and by the following safety evaluations of the individual and combined CSCS.

Peak clad temperatures are determined in accordance with the models described in Reference 20.

Evaluation of the cooling performance of the CSCS is calculated by an analytical model and digital computer program to cover the spectrum of conditions in detail, and assure that core cooling is adequate across the entire spectrum of break sizes.

6.5.2 Performance Analysis

The manner in which the CSCS operates to protect the core is a function of the rate at which coolant is lost from the break in the nuclear system process barrier. The High Pressure Coolant Injection System (HPCIS) is designed to operate while the nuclear system is at high pressure. The Core Spray and Low Pressure Coolant Injection (LPCI) Systems are designed for operation at low pressures. If the break in the nuclear system boundary is of such a size that the loss of coolant exceeds the capacity of the HPCIS, nuclear system pressure drops at a rate fast enough for the Core Spray System and LPCI to commence coolant addition to the reactor vessel in time to cool the core.

Automatic depressurization is provided to automatically reduce nuclear system pressure if a break has occurred and vessel water level is not maintained by the HPCIS and the other water addition systems. Rapid depressurization of the nuclear system is desirable to permit flow from the Core Spray System and LPCI to enter the vessel, so that the temperature rise in the core is limited.

If, for a given size break, the HPCIS has the capacity to make up for all the coolant loss from the nuclear system, flow from the low pressure portion of the CSCS is not required for core protection until nuclear system pressure has decreased below LPCI pump shutoff head. This pressure is above the value at which the HPCIS turbine steam stop valve shuts due to low steam supply pressure. (See Section 7.3 Primary Containment Reactor Vessel Isolation Control)

The redundant features of the CSCS are shown on Figure 6.3-1 in bar chart form. Capability for cooling exists over the entire spectrum of break sizes even with concurrent loss of offsite auxiliary power. To provide clarification of the action taken by each system of the CSCS during a LOCA, the results of the analysis as applied to an individual system of the CSCS is presented in the form of graphs of coolant level and pressure in the reactor vessel versus time for a typical size break in the nuclear system process barrier. In addition, these graphs show peak clad temperature versus break area for integrated CSCS operation.

6.5.2.1 Analysis Model

References 1-6 describe the analysis model used for LOCA analysis up to 1990. References 17-21 describe an updated analytical model currently used for analysis of LOCA for PNPS. A detailed description of the model is found in Reference 20. References 7-16 which supported the original LOCA analysis are listed in Section 6.5.6 for continuity.

6.5.2.2 Plant Specific Application

The plant specific analysis for PNPS for the entire spectrum of LOCA events is described in detail in Reference 17. The analysis in Reference 17 covers particular fuel types in use when the analysis was prepared. Additional LOCA analysis has been performed for each fuel type in use at PNPS (Reference 27). The reload license submittal documented in Appendix Q provides both the analysis results for each fuel type and pertinent references. This analysis has its foundations built upon a licensing methodology and BWR 3/4 generic analysis described in Reference 19. The methodology is generally referred to as SAFER/GESTR-LOCA and uses both best estimate and limiting calculations of LOCA consequences to demonstrate that the fuel clad boundary is not breached following a LOCA event. Uncertainties in the outcome of LOCA are specifically accounted for in the calculations of peak fuel clad temperature.

6.5.2.3 High Pressure Coolant Injection System (HPCIS)

The HPCIS is designed to provide adequate reactor core cooling for small breaks by maintaining vessel water level or by depressurizing the reactor primary system such that the LPCI and Core Spray System can be initiated. A detailed discussion of the performance of the HPCIS in conjunction with the LPCI and Core Spray System is given in Section 6.5.3.

The plant specific analysis for PNPS for the entire spectrum of LOCA events in Reference 17 includes an assumption that the HPCIS is unavailable for large break sizes and for small break sizes the HPCIS was considered a single failure. Therefore, the plant specific analysis in Reference 17 does not evaluate HPCIS capability.

The small break analysis in Reference 17 assumes ADS is used to lower reactor pressure to allow low pressure LPCI and Core Spray systems to provide makeup. Reactor depressurization by ADS involves core uncovery and the resulting clad temperature changes are evaluated in Reference 17. However, for small break sizes that lie within the range of HPCI, the reactor depressurization that accompanies HPCIS operation allows low pressure LPCI and Core Spray systems to provide makeup and the core never uncovers. Therefore, for small breaks within the range of HPCI, the core is continuously cooled throughout the accident so that no core damage of any kind occurs.

FSAR Figure 6.3-1 shows that the HPCIS range can be divided into two categories: (1) the half width bars show break sizes for which HPCI requires assistance by low pressure systems within 1000 seconds to prevent core uncovery, and (2) the full width bars show break sizes for which HPCI can alone maintain reactor water level above top of active fuel (TAF) for at least 1000 seconds. The 1000 seconds is included in the definition because the HPCIS requires a minimum vessel pressure to sustain the operation of the turbine.

The upper limit of the HPCIS unassisted capability (0.1 ft2 for liquid breaks and point 0.7 ft2 for steam breaks on Figure 6.3-1) is defined as the largest break size for which the HPCIS can protect the core for a period of at least 1000 seconds without assistance from any other Core Standby Cooling System. Since the decay heat generation continually decreases with time a point will eventually be reached where the energy additions from decay heat will no longer be sufficient to maintain the required operating pressure for the HPCIS turbine. However, this point is well below the pressure at which either the Core Spray System or the LPCI System is sufficient to keep the core cool after the HPCIS shuts off. Analysis of this break size is illustrated on Figure 6.5-1 which shows that the HPCIS delivers enough water into the reactor vessel before shutdown because of low reactor pressure, that reactor level does not reach TAF until 1000 seconds. As indicated on Figure 6.5-1, reactor pressure remains below 1000 psia throughout the period of the HPCIS operation. This analysis for the upper limit of the HPCIS unassisted capability (0.1 ft2 liquid line break) defines HPCI pump performance requirements at a flowrate of 4250 gpm.

The HPCIS turbine is designed to accommodate dry and saturated steam. The design objective for the turbine casing has a useful life of 40 years accounting for corrosion, erosion, and material fatigue. Condensate and moisture carryover are prevented from accumulating by a drain pot and steam traps located immediately upstream of the turbine inlet valve. When the turbine is shutdown, the inlet line is kept at an elevated temperature and the condensate is continuously drained.

An analysis has been made to determine if any carryover occurs in the steam supply to the HPCIS turbine which could have a detrimental effect on turbine operation. In the case of a break in a liquid line, when the HPCIS is energized, the level in the reactor vessel is low enough to prevent carryover in the steam which leaves the reactor vessel. In the case of a small break in the reactor steam region simultaneously with a loss of offsite power, reactor scram, recirculation pump coastdown, and loss of feedwater, analysis shows that the initial decrease of pressure in the reactor results in no significant level swell and no carryover of water into the steam supply to the HPCIS turbine. The HPCIS cold water quenches any steam formation in the downcomer region. After the HPCIS has been operating, and as the level rises in the reactor vessel, natural circulation within the vessel becomes established and steam to the HPCIS turbine passes through the steam separators and dryers eliminating any moisture carryover. It is concluded that a mechanism to cause bypassing of the steam separators, by the swelling steam water mixture, is not available. Therefore, gross moisture carryover to the HPCIS turbine should not occur over the range of steam line breaks of interest in this system.

The HPCIS turbine has been designed for high reliability under its design requirements of quick starting. Moreover, the turbine has adequate capacity to accept the small losses in efficiency due to any credible moisture carryover, and HPCIS turbine efficiency is not of paramount importance.

Tests on a production unit of the HPCIS turbine have been completed to verify the capability of the turbine to take low quality steam. Preliminary results confirm that the pressure integrity of the turbine housing is maintained during two-phase mixture conditions at the turbine inlet. This testing did not compromise the turbine housing pressure boundary. The closure time for the HPCIS system AC steamline isolation valve is 25 seconds and for the DC isolation valve is 34 seconds.

The feedwater spargers are utilized in the reactor for HPCIS injection. Each sparger is mounted to the inside of the reactor vessel surface. The thermal sleeve is attached to the sparger midpoint; however, the sleeve is not welded to the vessel nozzle. Therefore, the feedwater sparger is removable. The spargers are mounted in the vessel at one elevation to distribute the feedwater in a symmetric pattern about the vessel axis. Each sparger is supported by the thermal sleeve and a bracket mounted to each end of the sparger. Provision is made for the differential expansion between the stainless steel sparger and carbon steel vessel. Radial differential expansion is taken up by the slip fit of the thermal sleeve into the vessel nozzle. Tangential differential expansion is taken up by tangential slots cut in the bracket mounted to each end of the feedwater sparger bracket. The sparger is analyzed assuming the thermal sleeve is welded into the nozzle. Additionally, pressure differentials, jet reactions, and earthquake loadings are all added; these stresses within the sparger are all within ASME Code Section III for Class A Vessels.

The resultant bracket loads are sized to meet the loading criteria (see Appendix C). It is concluded that Design Basis 8 is satisfied.

6.5.2.4 Automatic Depressurization System

When the Automatic Depressurization System is actuated, the flow of steam through the valves provides a maximum energy removal rate while minimizing the corresponding fluid mass loss from the reactor vessel. Thus, the specific internal energy of the saturated fluid in the reactor vessel is rapidly decreased causing pressure reduction. The system provides the backup for the HPCIS.

Actuation of the automatic depressurization function does not require any source of offsite power. The relief valves require DC power from the station batteries for control and air power from accumulators for operation. This satisfies Safety Design Basis 5.

The accumulators and the nuclear system relief valves are within the primary containment and this satisfies the containment isolation requirements of safety design basis 6.

6.5.2.5 Core Spray System

The Core Spray System is designed to maintain continuity of reactor core cooling for a large spectrum of LOCA. The integrated performance of the Core Spray System in conjunction with other CSCS is given in Section 6.5.3.

Performance analyses of the reactor Core Spray System are based on an analytic prediction of the reactor vessel pressure and mass inventory as a function of time following a postulated rupture of the coolant system piping. In all cases, the analyses are begun with the coolant system liquid inventory at low level scram and the reactor operating at design power. For all loss of coolant analyses, the break is assumed to occur instantaneously and simultaneous with the loss of offsite auxiliary power.

There exists a break size below which the Core Spray System alone cannot protect the core. This is because vessel pressure does not drop rapidly enough to allow sufficient core spray injection before the clad hot spot reaches excessively high temperature. Below this break size either the HPCIS or the Automatic Depressurization System extend the range of the Core Spray System to breaks of insignificant magnitude.

To assure continuity of core cooling, signals to isolate the primary or secondary containments do not operate any Core Spray System valves. This arrangement satisfies safety design basis 6.

The discharge check valve is the only core spray equipment in the primary containment required to actuate during a loss of coolant accident which requires consideration for the high temperature and humidity environment in the containment from the accident. The selected valve actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor accident environment in the containment affects the operability of the core spray equipment for the accident. It is concluded that safety design basis 9 is satisfied.

Taking the core spray water from the suppression pool establishes a closed loop for recirculation of the spray water escaping from the break.

The core spray spargers and piping are designed as Class I (see Section 12 and Appendix C) so that they meet design basis 8.

6.5.2.6 Low Pressure Coolant Injection

LPCI is provided to automatically reflood the reactor core after a nuclear system LOCA when the reactor vessel pressure is below the shutoff head of the pumps. LPCI provides cooling by flooding which differs from the Core Spray System which provides cooling by spraying.

The LPCI pumping system is designed with both adequate head and adequate coolant flow capacity to meet flooding requirements for the entire break spectrum, when operating in conjunction with either the HPCIS or the Automatic Depressurization System.

The maximum vessel pressure against which the LPCI pumps must deliver some flow is determined by the required overlap with HPCI which has a low pressure cutoff for the HPCIS turbine at about 100 psig.

LPCI cooling capability is analyzed by the computerized method summarized previously, based on the mass and energy flows to and from the reactor. The break in the nuclear system process barrier is assumed to occur instantaneously and simultaneously with loss of offsite auxiliary AC power.

The analysis begins at reactor scram from design power because of a reactor vessel low water level signal.

The LPCI control system senses if the break is in a recirculation loop, closes the recirculation pump discharge valve in the unbroken loop, and opens the LPCI valve to the unbroken loop. When the nuclear system pressure decreases to the pumping head of LPCI, the check valve in the injection line opens and LPCI water is pumped into the reactor vessel to reflood the core.

These actions provide an integral flow path for the injection of the LPCI flow into the bottom plenum of the reactor vessel. As the LPCI flow accumulates, the level rises inside the shroud. When the level reaches the top of the jet pumps, spillover occurs for a time raising the level outside the shroud. As the subcooled LPCI flow begins spilling into the region outside the shroud, the depressurization effect of the break is reduced since the subcooled water is now flowing out the break. As the pressure begins to rise, the LPCI flow is reduced until a quasi-equilibrium pressure is reached. At this point, the break is partially covered by subcooled water which has spilled over the top of the jet pumps and the equivalent area of the break available for steam blowdown is thus reduced. The size of the break available for steam blowdown is maintained at the required equilibrium value by the LPCI spillage. If pressure were to rise the LPCI flow would be reduced, the equivalent break size for steam blowdown would increase, and pressure would drop. Complete equilibrium will be reached when the rate of saturating the LPCI water becomes equal to the boiloff rate.

It is noted that this condition will not actually be attained because of the HPCIS and Automatic Depressurization System effects on the transient. Although HPCI flow will be lost when pressure is reduced sufficiently, the auto depressurization valves would also be open.

To assure continuity of core cooling, signals to isolate the primary or secondary containments do not operate any LPCI valves. This arrangement satisfies safety design basis 6.

The two discharge check valves are the only LPCI equipment in the primary containment required to actuate during a LOCA which require consideration for the high temperature and humidity environment in the containment from the accident. The type of valve chosen actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor accident environment in the containment affects the operability of the LPCI equipment for the accident. It is concluded that safety design basis 9 is satisfied.

Using the suppression pool as the source of water for LPCI establishes a closed loop for recirculation of LPCI water escaping from the break.

The LPCI and appropriate portions of the recirculation loops are designed as Class I. See Section 12 and Appendix C so that they meet design basis 8.

6.5.3 Integrated Operation of the Core Standby Cooling Systems

The previous discussion has described the performance and operation of each of the CSCS individually. This discussion is directed toward the integrated performance of the CSCS, i.e., how the CSCS operate together to provide core cooling for the entire spectrum of LOCA. The discussion is subdivided based on the two types of loss of coolant accidents; recirculation line breaks and non-recirculation line breaks. The primary emphasis of the discussion is placed on the recirculation line break since the consequences of a break in a recirculation line are more severe than for a break in a non-recirculation line.

It is demonstrated that at least two different and independent core cooling systems are provided to limit fuel clad temperature over the entire spectrum of postulated reactor primary system breaks. Such cooling capability is available assuming the loss of all offsite ac power.

6.5.4 Recirculation Line Breaks

6.5.4.1 Model Applicability and BWR 3/4 Generic Analysis

The Generic analysis for BWR 3/4's in Reference 19 determined the limiting LOCA event as the double-ended recirculation suction line break coincident with a failure of a train of stand-by batteries. The licensing methodology was applied on this basis to show that margin existed between calculated peak fuel clad temperature and clad temperature limits established as acceptance criteria. PNPS specific analysis showed the same limiting LOCA event scenario for nominal (non-Appendix K) conditions as was shown in the generic analysis. However, for the Appendix K input assumptions, analysis results indicate the single failure associated with the highest peak clad temperature is failure of the LPCI injection valve. Plant specific uncertainties were generated consistent with the licensing methodology. Adequate margin between calculated fuel clad temperatures and the established clad temperature limits exists for PNPS. Reference 17 details these results. The analysis in Reference 17 covers particular fuel types in use when the analysis was prepared. Additional LOCA analysis will be performed for each fuel type in use at PNPS (Reference 27). The reload license submittal documented in Appendix Q provides both the analysis results for each fuel type and pertinent references.

6.5.4.2 Recirculation Break Spectrum Analysis

The LOCA analysis for recirculation line breaks, based on the use of the above models, is performed using the procedures outlined in Reference 17. The total LOCA analysis is generally provided for each plant independent of the reload license submittal. However, when new fuels are introduced, the reload license submittal will contain the MAPLHGR and PCT as a function of exposure for fuel not previously licensed to operate at PNPS. MAPLHGR and PCT as a function of exposure for fuel bundles licensed for use by PNPS are provided in the PNPS Technical Specifications. MAPLHGR and PCT are documented in Reference 17. Significant input parameters to the LOCA analysis are provided in Table 6.5-1.

A number of break sizes and single failure combinations were analyzed with nominal inputs to the PNPS-specific SAFER/GESTR-LOCA model. Further calculations with Appendix K (10 CFR 50) input assumptions provide limiting peak fuel clad temperatures for the range of recirculation line break sizes. Several fuel types were considered. The results of this analysis are detailed in Reference 17. The most limiting break (highest fuel clad temperature) was a 4.21 square foot suction line break that includes the area of the bottom head drain.

All peak fuel clad temperatures were below the limits established in Reference 26 by the NRC. Also, other criteria which insures fuel cladding integrity were met as discussed in Reference 17.

6.5.4.3 Conclusions of Recirculation Line Break Analysis

LOCA analyses have been performed for PNPS utilizing an NRC approved methodology. With ECCS performance characteristics assumed to be below the capacities and response times actually measured and maintained at PNPS, the analyses demonstrated adequate margin to the safety limits required via conformance to 10 CFR 50.46 and Appendix K. These analyses establish the current licensing basis for PNPS. (References 17 through 21 and 26 support this basis)

Further, these analyses accounted for alternate modes of plant operation to include ARTS/ELLA, increased core recirculation flow, single recirculation loop operation, and maximum extended load line limit region operation. These modes of operation are described in References 17 and 22 through 25.

With the explicit verification of the licensing PCT for PNPS being greater than the 95th percentile PCT, the level of safety and conservatism of this analysis meets the NRC approved criteria. Therefore, the requirements of Appendix K are satisfied.

The single failure evaluation showing the remaining ECCS following an assumed failure is shown in Table 6.5-2.

6.5.5 Non-Recirculation Line Breaks

The analyses of LOCA for PNPS included postulated non-recirculation line breaks such as LPCS line, feedwater line, and steamlines. The results of PNPS specific calculations are reported in Reference 17. The calculated peak clad temperature is significantly lower than that calculated for postulated recirculation line breaks. Non-recirculation line break analysis is not performed for new fuel types in use at PNPS because of the non-limiting nature of these break types as documented in Reference 17.

6.5.6 References

1. "Analytical Model for Loss-of-Coolant Analyses in Accordance With 10CFR50 Appendix K", NEDE-20566-P and NEDO-20566, January 1976.

2. "Fuel Rod Pressurization - Amendment 1", NEDE-23786-1-P, May 1978.

3. Letter, T. A. Ippolito (NRC) to R. L. Gridley (GE), "Generic Reload Fuel Application - NEDE-24011-P-A", April 16, 1979.

4. Letter, A. J. Levine (GE) to D. F. Ross (NRC), "General Electric (GE) Loss-of-Coolant (LOCA) Analysis Model Revisions--Core Heatup Code CHASTE05", January 27, 1977.

5. "Emergency Core Cooling Tests of an Internally Pressurized, Zircaloy-Clad, 8x8 Simulated BWR Fuel Bundle", NEDO-20231, December 1973.

6. Letter, H. Bernard (NRC) to G.G. Sherwood (GE), "Supplementary Acceptance of Licensing Topical Report NEDE-20566A(P)", May 11, 1982.

7. Letter, G. L. Gyorey (GE) to V. Stello, Jr. (NRC), "Compliance With Acceptance Criteria of 10CFR50.46", May 12, 1975.

8. Letter, L. Liu (IEL&P) to E. G. Case (NRC), Letter No. IE-77-1453, dated July 29, 1977.

9. "Loss of Coolant Accident Analysis Report for Duane Arnold Energy Center (Lead Plant)", NEDO-21082-02-1A, July 1977.

10. "Loss of Coolant Accident Analysis Report for Pilgrim Nuclear Power Station", NEDO-21696, August 1977.

11. Letter, D. G. Eisenhut (NRC) to E. D. Fuller (GE), "Documentation of the Reanalysis Results for the Loss-of-Coolant Accident (LOCA) of Lead and Non-Lead Plants", June 30, 1977.

12. Letter, T. J. Galligan, Jr., (BECO) to Director, Division of Reactor Licensing (NRC), "10CFR50 Appendix K and Proposed Technical Specifications for Pilgrim Nuclear Power Station, Unit 1", July 9, 1975.

13. Letter, R. E. Engel (GE) to P.S. Check (NRC), "DC Power Source Failure For BWR/3 and 4", November 1, 1978.

14. BECO Letter 80-223 to NRC Staff, "Effect of a DC Power Supply Failure on ECCS Performance", September 1980.

15. "Pilgrim Nuclear Power Station Loss of Coolant Accident (LOCA) Analysis Update", NEDO-30767, September 1984.

16. "Safety Evaluation for Interim Operation of Pilgrim Nuclear Power Station with Reduced Core Spray System Flow Rate," EAS-55-0889, DRF A00-03585, August, 1989.

17. "Safer/ GESTR-LOCA Loss-of-Coolant Accident for Pilgrim Nuclear Power Station", NEDC-31852P, Rev. 4. January, 2008.

18. Letter, C. O. Thomas (NRC) to J. F. Quirk (GE), "Acceptance for Referencing of Licensing Topical Report NEDE-23785, Revision 1, Volume III (P), 'The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident'," June 1, 1984.

19. "The GESTR-LOCA and SAFER models for the evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," NEDE-23785-1-PA, General Electric Company, Revision 1, October 1984.

20. "General Electric Standard Application for Reactor Fuel (U.S. Supplement)", NEDE-24011-P-A, General Electric Company, September 1988. Revision number listed in the latest Supplemental Reload License Submittal in Appendix Q.

21. "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K", NEDO-20566A, General Electric Company, September 1986.

22. "ARTS Improvement Program Analysis for Pilgrim Nuclear Power Stations," NEDO-31312P, General Electric Company, September 1987.

23. "Safety Review of Pilgrim Nuclear Power Station Unit No. 1 at Core Flow Conditions Above Rated Flow Throughout Cycle 6," NEDO-30242, General Electric Company, August 1983.

24. "Pilgrim Nuclear Power Station Single-Loop Operation," NEDO-24268, General Electric Company, June 1980.

25. "Maximum Extended Load Line Limit Analyses for Pilgrim Nuclear Power Station Reload 9 Cycle 10," NEDC-32306P, General Electric Company, March 1994, (SUDDS/RF94-042).

26. "GESTR-LOCA and SAFER Models for Evaluation of Loss-of-Coolant Accident, Volume III, Supplement 1, Additional Information for Upper Bound PCT Calculation," NEDE-23785P-A, Supplement 1, Revision 1, March 2002.

27. Pilgrim Nuclear Power Station GNF2 FLCCS-LOCA Evaluation, 0000-0095-4071-RO, February 2009.

6.6 INSPECTION AND TESTING

Each active component of the core standby cooling systems (CSCS) provided to operate in a design basis accident is designed to be operable for test purposes during normal operation of the nuclear system.

The high pressure coolant injection system (HPCIS), automatic depressurization, and core spray systems have no normal process uses and, therefore, are tested periodically to provide assurance that the CSCS will operate to effectively cool the reactor core in an accident. The four low pressure coolant injection (LPCI) pumps may be placed in use as part of the residual heat removal system, and if so, their status is known from normal process uses. However, the LPCI pumps are tested no less frequently than the rest of the CSCS. Other parts of LPCI, such as the two discharge check valves inside the primary containment drywell and the four shutoff valves outside the drywell, are intended for use only in an accident, so they are also tested periodically.

Preoperational tests of the CSCS were conducted during the final stages of construction prior to initial startup. Testing of the HPCI turbine could not be completed until steam was available during nuclear system heatup. See Section 13, Conduct of Operations. These tests assured the proper functioning of all controls and instrumentation pumps, piping, and valves. System reference characteristics such as pressure differentials and flow rates were documented during the preoperational tests and are used as base points for measurements obtained in the subsequent operational tests.

During normal operation, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the reactor vessel is open, for refueling or other purposes, the spargers and other internals can be inspected.

When the system is tested, the operation of most of the components is indicated in the main control room. There are exceptions which require local observation at the component and may require special tests for which there are special provisions and methods.

Pressure operated relief valves may leak after operation and it is not advisable to over pressurize the system for test, so relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments. Bench tests of the automatic depressurization valves are discussed in Section 4.4, Nuclear System Pressure Relief System.

Flow operated check valves for reverse flow or excess flow are tested periodically in place by isolating that portion of the system and simulating the function conditions, either with the system pump or through test connections provided for this purpose.

The proper position of manual valves for the accident mode is indicated by flow and pressure instrumentation during the periodic system tests and after maintenance.

Test lines are provided between pairs of containment isolation valves in the CSCS to measure leakage when the containment is pressurized for tests. The test line is also used to pressurize between the closed valves to identify which one is leaking.

Pumps for the CSCS are equipped with face type mechanical shaft seals. Normal leakage for these seals is small at operating conditions.

A design flow functional test of the HPCIS up to the normally closed pump discharge valve is performed during normal operation by pumping water from the condensate storage tank and back through the full flow test return line to the reservoir. The HPCIS turbine pump is driven at its rated output by steam from the reactor. The suction valves from the suppression pool and discharge valve MO2301-8 to the reactor feedwater line remain closed. The design of MO2301-9 has been changed such that it only serves as a maintenance isolation valve and it must be open at any time the HPCIS is required to be operable. Although MO2301-9 receives an automatic signal to open on HPCI initiation, the opening stroke time is not evaluated for the HPCIS operability requirements with this valve initially closed. The valve must therefore be open and has no active safety function.

The HPCIS test conditions are tabulated on the HPCIS process flow diagram, Figure 6.4-1 (Drawing M1J6-4). The HPCI pump is tested during normal operation at two different operating points: (1) 4250 gpm for a system head that corresponds to the reactor pressure during the test per Technical Specification 4.5.C, and (2) 3000 gpm for a system head that corresponds to a reactor pressure of 1190 psig. For further discussion of these pump requirements, refer to sections 6.4 and 6.5. These operating points exceed the required capability of the HPCIS in the accident and transient analysis. If an initiation signal occurs while the HPCIS is being tested, the system returns to the automatic startup mode. The HPCIS test return isolation valves are opened for testing and will automatically close if a system initiation signal occurs. The control scheme for one HPCIS test return isolation valve uses seal-in contacts in the opening and closing circuit. The upstream HPCIS test return isolation valve is a throttle valve used for system control during testing and will automatically operate in the closed direction while a system initiation signal remains present. The automatic closing cycle of this HPCIS test return isolation valve is terminated if either the system initiation signal clears or the test return isolation valve reaches the full closed position.

The HPCIS may be tested at full flow with condensate at any time except when the reactor vessel water level is low, drywell pressure is high, the valves from the suppression pool to the pump are open, or if the water level in the condensate storage tank is less than 20 feet above the tank bottom. These restrictions are automatic, except for the condensate storage tank level limit. The condensate storage tank level is controlled administratively in order to prevent return flow from causing air entrainment into the pump suction.

To conduct the full flow test, the minimum flow bypass valve is initially opened. Initially, the pump delivers bypass flow to the suppression pool until the minimum flow bypass valve automatically closes after pump flow reaches a predetermined level.

The HPCIS test line includes a manual adjustable orifice which partially simulates the resistance that the pump is required to overcome while delivering the required flow rate to the reactor vessel. During pump testing, the remainder of the system resistance is introduced via a remote manual throttle valve located on the test line. This manual adjustable orifice reduces the throttling duty of the test line globe valve, reducing the degradation of the valve.

The HPCIS is not capable of achieving rated flow at 150 psig reactor pressure when the test line manual adjustable orifice is positioned for the high pressure test that is conducted quarterly at normal reactor operating pressure. Therefore, the manual adjustable orifice valve must be repositioned at or near full open for conduct of the pump test at less than or equal to 150 psig reactor pressure.

The pump discharge valve is tested in accordance with Technical Specification 3.13. The pump discharge check valve in the steam tunnel may be tested by manually actuating the disk using the square nut located on the valve.

Each loop of the Core Spray System may be tested during reactor operation. The test conditions are tabulated on the Core Spray System process diagram, Figure 6.4-2 (Drawing M1K2-4). The normal system test can not inject cold water into the reactor because the discharge check valve is held closed by the reactor pressure which is higher than core spray pump pressure. The injection isolation valves are also interlocked to maintain at least one valve closed whenever reactor pressure exceeds the preset interlock value. To test the reactor injection portion of the system, using demineralized water, the reactor must be shut down and depressurized. This prevents unnecessary thermal stresses.

To test the core spray pumps at rated flow, the full flow test bypass valve is opened to the suppression pool, the pump suction valve from the suppression pool is opened, and the pumps are started using the remote manual switches in the main control room. Proper operation is determined by observing the instruments in the control room. The Core Spray System outside the drywell is checked for leaks periodically.

The injection valves are tested in accordance with Technical Specification 3.13.

If an initiation signal occurs during the test, the Core Spray System is signaled to start and the system returns to the automatic startup mode.

Similarly, LPCI pumps and valves are tested periodically during reactor operations. With the injection valves closed and the return line open to the suppression pool, full flow pumping capability is demonstrated. The injection valves are tested in accordance with Technical Specification 3.13. The system test conditions during reactor shutdown are shown on the Residual Heat Removal System (LPCIS) process diagram, Figure 6.4-3 (see Figure 4.8-2). The portion of the LPCI outside the drywell is inspected for leaks periodically during tests. Controls and instrumentation are tested as described in Section 7.4, Core Standby Cooling Systems Control and Instrumentation.

Upon receipt of an LPCI initiation signal during tests, the valves in the test bypass lines and in the shutdown cooling system are closed automatically to ensure that the LPCI pump discharge is routed properly to the reactor vessel.

It is concluded that Safety Design Basis 7 is satisfied.

Filing Instructions

PNPS-FSAR

Revision 28 – October 2011

Volume 3

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C – Rev 28
LOEP	EP3 – Rev 27	EP3 – Rev 28
Section 7 TOC	Entire Section 7 TOC	Section 7 TOC – Rev 28
7.4	Pages 1-28	Pages 1-31
7.4	Table 7.4-1 page 1 of 1	Table 7.4-1 page 1 of 1
7.14	Page 1	Page 1

*Text without revision bars was reformatted only.

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

LIST OF EFFECTIVE PAGES

VOLUME 3VOLUME 3**VOLUME 3**VOLUME 3**VOLUME 3**

SECTION 7

CONTROL AND INSTRUMENTATION

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

SECTION 7

LIST OF TABLES

LIST OF TABLES (Cont)

SECTION 7

LIST OF FIGURES

LIST OF FIGURES (Cont)

LIST OF FIGURES (Cont)

LIST OF FIGURES (Cont)

LIST OF FIGURES (Cont)

LIST OF FIGURES (Cont)

LIST OF FIGURES (Cont)

7.4 CORE STANDBY COOLING SYSTEMS CONTROL AND INSTRUMENTATION

7.4.1 Safety Objective

The controls and instrumentation for the Core Standby Cooling Systems (CSCS) initiate appropriate responses from the various cooling systems so that the fuel is adequately cooled under abnormal or accident conditions. The cooling provided by the systems restricts the release of radioactive materials from the fuel by limiting the extent of fuel damage following situations in which reactor coolant is lost from the nuclear system.

Even after the reactor is shut down from power operation by the full insertion of all control rods, heat continues to be generated in the fuel as radioactive fission products decay. An excessive loss of reactor coolant would allow the fuel temperature to rise, cladding to melt, and fission products in the fuel to be released. If the temperatures in the reactor rose to a sufficiently high value, a metal (zirconium)-water reaction could occur this would release energy. Such a reaction would increase the pressure inside the nuclear system and the primary containment. This could threaten the integrity of the barriers which are relied upon to prevent the uncontrolled release of radioactive materials. The controls and instrumentation for CSCS prevent such a sequence of events by actuating core cooling systems in time to limit fuel temperatures to acceptable levels.

7.4.2 Safety Design Bases

1. With precision and reliability, controls and instrumentation shall automatically initiate and control the CSCS to allow removal of heat from the reactor core in time to prevent fuel clad melting, so that fuel and core deformation do not limit effective cooling of the core.

2. With precision and reliability, controls and instrumentation shall initiate and control the CSCS with sufficient timeliness to prevent more than a small fraction of the core from heating to a temperature at which a gross release of fission products could occur.

3. To meet the precision requirements of safety design bases 1 and 2, the controls and instrumentation for the CSCS shall respond to conditions that indicate the potential inadequacy of core cooling, regardless of the physical location of the defect causing the inadequacy.

4. To place limits on the degree to which safety is dependent on operator judgement in time of stress, the following safety design bases are specified:

a. Appropriate responses of the CSCS shall be initiated automatically by control systems when positive precise action is immediately required so that no decision or manipulation of controls beyond the capacity of operations personnel is demanded

b. Readout of the responses of the CSCS shall be provided to the operator by control room instrumentation so that faults in the actuation of safety equipment can be diagnosed

c. Facilities for manual actuation of the CSCS shall be provided in the control room so that operator action is possible, yet reserved for the remedy of a deficiency in the automatic actuation of the safety equipment, or for control over the long term effects of an abnormal or accident condition

5. To meet the reliability requirements of safety design bases 1 and 2, the following safety design bases are specified:

   a. No single failure, maintenance, calibration, or test operation shall prevent the integrated operations of the CSCS from providing adequate core cooling

   b. No equipment protective device which causes interruption of performance or availability of the CSCS shall be automatic, unless there is a high probability that continued use would make complete failure imminent. Instead, such protective devices shall indicate off standard conditions for operator decision and action

   c. The power supplies for the controls and instrumentation for the CSCS shall be chosen so that core cooling can be accomplished concurrently with a loss of offsite ac power

   d. The physical events that accompany a loss of coolant accident shall not interfere with the ability of the CSCS controls and instrumentation to function properly

   e. Earthquake loading shall not impair the ability of essential CSCS controls and instrumentation to function properly. See Section 7.1.6

6. To provide the operator with the means to verify the availability of the CSCS, it is possible to test the responses of the controls and instrumentation to conditions representative of transient or accident situations.

7.4.3 Description

7.4.3.1 Identification

The controls and instrumentation for the CSCS are identified as that equipment required for the initiation and control of the following:

High Pressure Coolant Injection System (HPCI)
Automatic Depressurization System (ADS)
Core Spray System
Low Pressure Coolant Injection (LPCI), an operating mode of the Residual Heat Removal System

The equipment involved in the control of these systems includes automatic injection valves, turbine driven pump controls, electric motor driven pump controls, relief valve controls, and the sensors, trip units, contacts, and relays that make up sensory logic channels. Testable check valves and certain automatic isolation valves are described in Section 7.3.

To assure the functional capabilities of the CSCS during and after earthquake loading, the controls and instrumentation for each of the systems are designed as Class I seismic design equipment as described in Appendix C. This satisfies safety design basis 5e.

The CSCS initiations and control instrumentations can be conveniently divided into two parts, the Incident Detections Circuitry (IDC) and the control instrumentation. The IDC includes those channels which detect a need for CSCS operation and the corresponding trip systems which initiate the proper response of CSCS. The control instrumentation includes the balance of CSCS instrumentation which is utilized in control and testing.

The CSCS is designed to comply with intent of IEEE-279 and the Commission's proposed General Design Criteria. Appendices F and J give additional details.

7.4.3.2 High Pressure Coolant Injection System Control and Instrumentation

7.4.3.2.1 Identification and Physical Arrangement

When actuated, the HPCI pumps water from either the condensate storage tank or the suppression chamber to the reactor vessel via the feedwater pipelines. The HPCI includes one turbine, one turbine- driven pump, one dc motor driven auxiliary oil pump, one gland seal condenser, one dc condensate pump, one gland seal condenser dc blower, automatic valves, control devices for this equipment, sensors, and logic circuitry. The arrangement of equipment and control devices is shown on Figures 7.4-1 and 7.4-2.

Pressure and level switches/transmitters used in the HPCI are located on racks in the reactor building. The only operating component for the HPCI that is located inside the primary containment is one of the two HPCI turbine steam supply pipeline isolation valves. The rest of the HPCI control and instrumentation components are located outside the primary containment. Cables connect the sensors to control circuitry in the control room. Although the system is arranged to allow a full flow functional test of the system during normal reactor power operation, the test controls are arranged so that the system can operate automatically to fulfill its safety function regardless of the test being conducted. Some testing may temporarily disable the automatic realignment feature, during which periods HPCI would not be available as a CSCS.

7.4.3.2.2 HPCI Initiation Signals and Logic

Either reactor vessel low-low water level or primary containment (drywell) high pressure can automatically start the HPCI as indicated on Figures 7.4-3, 7.4-4, and 7.4-5 (see Drawings M1J22-5, M1J23-4, and M1J24-4). Reactor vessel low water level is an indication that reactor coolant is being lost and that the fuel is in danger of being overheated. Primary containment high pressure is an indication that a breach of the nuclear system process barrier has occurred inside the drywell.

The logic scheme used for initiating the HPCI system is a single trip system containing two decision making logic circuits as shown on Figure 7.4-6. Each decision making logic is made up of two series parallel paths. One decision making logic actuates upon receipt of a low-low water level signal. The other actuates upon receipt of a high drywell pressure signal. Either decision making logic can start the HPCI. The HPCI trip system is dc powered.

Instrument analytical limit trip settings used in the plant safety analysis are listed on Table 7.4-1. The actual plant setting is determined in the referenced design basis calculation and has adequate margin to account for the total instrument uncertainty. The reactor vessel low water level setting for HPCI initiation is conservatively selected above the active fuel to start the HPCI in time to prevent fuel damage during abnormal operational transients. The water level setting is far enough below normal levels that spurious HPCI startups are avoided. The primary containment high pressure setting is selected to be as low as possible without inducing spurious HPCI startup.

7.4.3.2.3 HPCI Initiating Instrumentation

Reactor vessel low-low water level is monitored by four analog transmitters that sense the difference between the pressure due to a constant reference column of water and the pressure due to the actual height of water in the vessel. Two pipelines, attached to taps above and below the water level in the reactor vessel, are required for the differential pressure measurement for each pair of transmitters. The two pairs of pipelines terminate outside the primary containment and inside the reactor building; they are physically separated from each other and tap off the reactor vessel at widely separated points. These same pipelines are also used for pressure and water level instruments for other systems. The level transmitters for HPCI are arranged in pairs, each pair sensing level from one pair of pipelines. Either pair sensing low-low water level can initiate the HPCI system. This arrangement assures that no single event can prevent HPCI initiation from reactor vessel low-low water level. Minimizing the vertical drop of the reference legs inside the drywell optimized the accuracy of level measurements.

Primary containment pressure is monitored by four pressure transmitters which are mounted on instrument racks outside the drywell but inside the reactor building. Pipes that terminate in the reactor building allow the transmitters to communicate with the drywell interior. The transmitters are grouped in pairs similar to the level sensors and electrically connected so that no single event can prevent the initiation of HPCI due to primary containment high pressure.

7.4.3.2.4 HPCI Turbine and Turbine Auxiliaries Control

The HPCI controls automatically start HPCI upon receipt of an initiation signal and bring the system to its design flow rate within 90 sec. The controls then function to provide design makeup water flow to the reactor vessel until vessel water level is restored to high level or until reactor pressure falls below the HPCI operating range. HPCI will automatically restart if vessel level decreases to the low vessel level setpoint with reactor pressure within the HPCI operating range. If HPCI trips on low reactor pressure, the system will not automatically restart unless the trip is reset using the remote manual reset switches. HPCI controls are arranged to allow for remote manual startup in two different ways:

1. Manual initiation via a single pushbutton switch located on panel C903. Depressing the switch initiates a timed sequence which starts and runs the system in the full-flow injection mode.

2. Manual startup by manipulation of individual control switches on panel C903 actuates the various pumps and valves required to start and run the system. This method requires the operator to actuate each component in a prescribed sequence.

Controls are also provided on panel C903 to allow plant operators to operate and shutdown the system.

The HPCI turbine is functionally controlled as shown on Figure 7.4-5. A control governor receives a HPCI flow signal and adjusts the turbine steam control valve so that design HPCI pump discharge flow rate is obtained. Manual control of the governor is possible in the test mode, but the governor automatically returns to automatic control upon receipt of a HPCI initiation signal. Figure 7.4-5 shows the various modes of turbine control. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the HPCI pump discharge pipeline. The governor controls the pressure applied to the hydraulic operator of the turbine control valve which, in turn, controls the steam flow to the turbine. Hydraulic pressure is supplied for both the turbine control valve and the turbine stop valve by the dc powered oil pump during startup, and then by the shaft driven hydraulic oil pump when the turbine speed is adequate.

Upon receipt of an initiation signal, the auxiliary oil pump starts, providing hydraulic pressure for the turbine stop valve and turbine control valve hydraulic operator. Because there is no flow in HPCI, the flow signal will run the control governor to high speed. The turbine governor system is equipped with a ramp generator which, upon initiation of the turbine start, will control the acceleration rate up to a speed relative to the flow controller output signal. Turbine speed is limited to the maximum output of the flow controller (50 Ma) and is equivalent to the maximum turbine speed required to maintain design flow. As hydraulic oil pressure is developed, the turbine stop valve and the turbine control valve open simultaneously, and the turbine accelerates toward the speed setting of the control governor. As HPCI flow increases, the flow signal adjusts the control governor setting so that design flow is maintained.

The turbine is automatically shut down by tripping the turbine stop valve closed if any of the following conditions are detected:

Turbine overspeed
High turbine exhaust pressure
Low pump suction pressure
Reactor vessel high water level
HPCI automatic isolation signal

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the exhaust pipeline. Low pump suction pressure warns that cavitation and lack of cooling can cause damage to the pump which could place it out of service. A turbine trip is initiated for these conditions so that if the cause(s) of the abnormal conditions can be found and corrected, the system can be quickly restored to service. The trip settings are selected far enough from normal values so that a spurious turbine trip is unlikely, but not so far that damage occurs before the turbine is shut down. Turbine overspeed is detected by a standard turbine overspeed mechanical-hydraulic device. Two pressure switches are used to detect high turbine exhaust pressure; either switch can initiate turbine shutdown. One pressure switch is used to detect low HPCI pump suction pressure.

High water level in the reactor vessel indicates that HPCI has performed satisfactorily in providing makeup water to the reactor vessel. The reactor vessel high water level setting which trips the turbine is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the turbine. Two level transmitters that sense differential pressure are arranged to require that their respective trip units trip (coincidence) to initiate a turbine shutdown. A single failure in either level transmitter/trip unit would prevent automatic shutdown of the HPCI turbine upon reaching high water level in the vessel. However, prior to reaching reactor vessel high water level, alarms would alert operating personnel to the approaching high level condition. Operator action could then be taken to manually control flow rate, and/or shut down the systems prior to flooding the steam lines. HPCI automatic isolation signals are described in Section 7.3.

The control scheme for the turbine auxiliary oil pump is shown on Figure 7.4-4 (BECo M1J 23-4). The controls are arranged for automatic or manual control. Upon receipt of a HPCI initiation signal, the auxiliary oil pump starts and provides hydraulic pressure to open the turbine stop valve and the turbine control valve. As the turbine gains speed, the shaft driven oil pump begins to supply hydraulic pressure. After about 1/2 min during an automatic turbine startup, the pressure supplied by the shaft driven oil pump is sufficient, and the auxiliary oil pump automatically stops upon receipt of a high oil pressure signal. Should the shaft driven oil pump malfunction, causing oil pressure to drop, the auxiliary oil pump restarts.

Operation of the gland seal condenser components - gland seal condenser condensate pump (DC), gland seal condenser blower (DC), and gland seal condenser water level instrumentation - prevents outleakage from the turbine shaft seals. Startup of this equipment is automatic, as shown on Figures 7.4-4 and 7.4-5.

7.4.3.2.5 HPCI Valve Control

All automatic valves in the HPCI system are equipped with remote manual test capability, so that the entire system can be operated from the main control room. Motor operated valves are provided with appropriate limit or torque switches to turn off the motors when the full open or full closed positions are reached. Valves that are automatically closed on isolation or turbine trip signals are equipped with manual reset devices, so that they cannot be reopened without operator action. The reset devices are located in the main control room. All essential components of the HPCI control operate from DC power sources.

To assure that the HPCI can be brought to design flow rate within 90 seconds from the receipt of the initiation signal, the following design operating times against full reactor pressure for essential HPCI valves are provided by the valve operation mechanisms:

HPCI turbine steam admission (MO2301-3)	90 sec
HPCI pump discharge valve (MO2301-8)	40 sec
HPCI pump minimum flow bypass valve	20 sec

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice versa. Because the two HPCI steam supply line isolation valves (MO-2301-4,5) are normally open, and because they are intended to isolate the HPCI steam line in the event of a break in that line, the operating time requirements for them are based on isolation specifications. These are described in Section 7.3. A normally closed dc motor-operated isolation valve is located in the turbine steam supply pipeline just upstream of the turbine stop valve. The control scheme for this valve is shown on Figure 7.4-4. Upon receipt of a HPCI initiation signal this valve opens and remains open until closed by operator action from the main control room.

Two normally open isolation valves are provided in the steam supply line to the turbine. The valve inside the drywell is controlled by an AC motor. The valve outside the drywell is controlled by a DC motor. The control diagram is shown on Figure 7.4-3. Although they are normally open, a HPCI initiating signal opens them if they are closed. The inboard isolation valve has the capability of being jogged open to allow controlled pressurization of the HPCI steam line. These isolation valves automatically close upon receipt of a HPCI turbine steam line high flow signal, or low reactor pressure signal, or high steam line space temperature. To ensure proper isolation of the HPCI turbine, the turbine exhaust line drain pot isolation valves (CV-9068 A & B) are also closed upon receipt of either of these signals. The instrumentation for isolation is described in Section 7.3.

Two normally open isolation valves are provided in the turbine exhaust vacuum breaker line. These valves are controlled by AC motors. The control design is shown on Figure 7.4-3. These isolation valves automatically close upon receipt of a high drywell pressure signal coincident with low reactor pressure. A keylock switch provides the capability to bypass the automatic isolation signals which will permit manual operation of the valves via their control switches.

Three pump suction valves are provided in the HPCI. One valve lines up pump suction from the condensate storage tank, the other two from the suppression pool. The condensate storage tank is the preferred source. All three valves are operated by DC motors. The control arrangement is shown on Figure 7.4-5. Although the condensate storage tank suction valve is normally open, a HPCI initiation signal opens it if it is closed. If the water level in the condensate storage tank falls below the minimum level, the suppression pool suction valves automatically open after a time delay. When the suppression pool valves are both fully open, the condensate storage tank suction valve automatically closes. Two pressure switches are used to detect the condensate storage tank low water level condition. Either switch can cause the suppression pool suction valves to open. The suppression pool suction valves also automatically open and the condensate storage tank suction valve closes if a high water level is detected in the suppression pool. Two level switches monitor the suppression pool water level. Either switch can initiate opening of the suppression pool suction valves. Time delay is introduced into the suppression pool suction valve opening circuits to prevent false/transient signals from initiating suction transfer. If open, the suppression pool suction valves automatically close upon receipt of the signals that initiate HPCI steam line isolation.

The consequences of a single failure in the circuitry, which automatically transfers suction from the condensate storage tanks to the suppression pool, are as follows: The HPCI system is not required by design to be single failure proof. The HPCI circuitry automatically initiates transfer of the HPCI suction from the condensate storage tank to the suppression pool as a result of either a condensate tank low level condition or a suppression pool high level condition. Two sensors monitor the condensate low level condition and two sensors monitor the suppression pool high level condition. The proper operation of any one of these sensors initiates transfer of HPCI suction to the pool.

Loss of power to the transfer circuitry also opens the HPCI suction valves to the suppression pool. Premature transfer of the HPCI suction from the condensate tank to the suppression pool due to single failures such as described above do not interfere with the ability of the HPCI system to perform its intended function.

Two DC motor-operated HPCI pump discharge valves in the pump discharge pipeline are provided. The control schemes for these two valves are shown on Figure 7.4-3 (Drawing M1J22-5) and 7.4-4 (Drawing M1J23-4). Both valves are arranged to open upon receipt of the HPCI initiation signal. The valves remain open upon receipt of a turbine trip signal until closed by operator action in the main control room. Discharge valve MO2301-9 must be open for HPCI to be considered operable. See Section 6.6.

To prevent the turbine pump from being damaged by overheating at reduced HPCI pump discharge flow, a pump discharge minimum flow bypass is provided to route the water discharged from the pump back to the suppression pool. The bypass is controlled by an automatic, DC motor-operated valve whose control scheme is shown on Figure 7.4-3 (Drawing M1J22-5). At HPCI high flow, the valve is closed; at low flow, the valve is opened. Flow switches that measure the pressure difference across a flow element in the HPCI pump discharge pipeline provide the signals used for flow indication. There is also an interlock provided to shut the minimum flow bypass whenever the turbine is tripped or isolation occurs. This prevents draining the condensate storage tank into the suppression pool.

To prevent the HPCI steam supply pipeline from filling up with water and cooling, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain pipeline arrangement just upstream of the turbine supply valve. The control scheme is shown on Figure 7.4-4. The controls position valves so that during normal operation, steam line drainage is routed to the main condenser. Upon receipt of a HPCI initiation signal, the drainage path is isolated. The water level in the steam line drain condensate pot is controlled by a level switch and an air operated valve which opens to allow condensate to flow out of the pot.

During test operation, the HPCI pump discharge is routed to the condensate storage tank. Two DC motor-operated valves are installed in the pump discharge to the condensate storage tank. The piping arrangement is shown on Figure 7.4-1 (Drawing M243). The control scheme for the two valves is shown on Figure 7.4-3 (Drawing M1J22-5). Upon receipt of an HPCI initiation signal, the valves close and remain closed. Some testing may temporarily disable the automatic realignment feature, during which periods HPCI would not be available as a CSCS. The control scheme for one HPCI test return isolation valve uses seal-in contacts in the opening and closing circuit. The upstream HPCI test return isolation valve is a throttle valve used for system control during testing and will automatically operate in the closed direction while a system initiation signal remains present. The automatic closing cycle of this HPCI test return isolation valve is terminated if either the system initiation signal clears or the test return isolation valve reaches the full closed position. The valves are interlocked closed if either of the suppression pool suction valves are open. As designed, the HPCI test return isolation valves meet the requirements and intent of IEEE 279 regarding completion of protective actions once an initiation signal is received. Numerous indications pertinent to the operation and condition of the HPCI are available to the main control room operator. Figures 7.4-1, 7.4-2, and 7.4-4 (Drawings M243, M244, and M1J23-4) show the various indications provided.

7.4.3.2.6 HPCI Environmental Considerations

The only HPCI control component located inside the primary containment that must remain functional in the environment resulting from a loss of coolant accident (LOCA) is the control mechanism for the inboard isolation valve on the HPCI turbine steam line. The environmental capabilities of this valve are discussed in Section 7.3. The HPCI control and instrumentation equipment located outside the primary containment is selected in consideration of the normal and accident environments in which it must operate.

7.4.3.3 Automatic Depressurization System Control and Instrumentation

7.4.3.3.1 Identification and Physical Arrangement

Four automatically controlled relief valves are installed on the main steam lines inside the primary containment. The valves are dual purpose in that they relieve pressure by inherent mechanical (overpressure) action or by action of an electric pneumatic control system. The relief by mechanical action is initiated inherently by an overpressure condition in the nuclear system. The depressurization by automatic action of the control system is employed to reduce nuclear system pressure so that the core spray and LPCI systems can inject water into the reactor vessel during a LOCA when the HPCI is inoperable. The automatic control and instrumentation equipment for the automatic depressurization mode of relief valve operation is described in this section.

The control system, which is functionally illustrated on Figure 7.3-6 (Drawing M1A 15-7), consists physically of pressure and water level sensors arranged in trip systems that control a solenoid operated pilot valve. The solenoid operated pilot valve controls the pneumatic pressure applied to a diaphragm actuator which controls the relief valve directly. An accumulator is included with the control equipment for each relief valve to store pneumatic energy for relief valve operation. The accumulators are sized to provide sufficient air/nitrogen for a minimum of twenty pilot actuations following failure of the normal air/nitrogen supply to the accumulator. Cables from the sensors lead to the control room where the logic arrangements are formed in cabinets. The electrical control circuitry is powered by DC in the following manner: the equipment of ADS Logic A is placed on Battery A without automatic transfer. The equipment of ADS Logic B is on Battery B with an automatic transfer to Battery A upon loss of Battery B. Therefore, loss of any battery affects only one 120 second timing circuit. Electrical elements in the control system energize to cause opening of the relief valve. Each solenoid operated pilot valve is powered by DC from either station battery through sensing relays.

7.4.3.3.2 Automatic Depressurization System Initiating Signals and Logic

Two initiation signals are used for the Automatic Depressurization System:

1. Reactor vessel low-low water level

2. Primary containment (drywell) high pressure

When low-low water level is sensed, a high drywell pressure bypass timer (0 to 30 minute adjustable) is initiated. If drywell high pressure is not sensed before the selected time has elapsed, and if the low-low water level signal is still present, the ADS valves will be signaled to open without high drywell pressure (See Figure 7.3-6, Drawing M1R 4-10). After these conditions are satisfied, there is a 120 second time delay to permit the HPCI to restore water level before the relief valves are actuated. Reactor vessel low water level indicates that the fuel is in danger of becoming overheated. This low water level condition would normally not be sustained unless the HPCI failed. Primary containment high pressure indicates that a breach in the nuclear system process barrier may have occurred inside the drywell.

The bypass arrangement increases the range of events over which ADS will respond. Events such as a break external to the drywell or a stuck open SRV do not necessarily cause a High Drywell Pressure Signal.

After receipt of both initiation signals, and after an approximate 2 min delay provided by timers, the solenoid operated pilot air valve for each ADS valve is energized provided that at least one LPCI or core spray pump is affirmed to be running at rated speed. An interlock is provided in each trip system in order to give reassurance that low pressure core coolant is available before the ADS actually permits depressurization of the reactor vessel. These pressure permissive interlocks are designed to meet the requirements of single failure and separation. Two pressure switches on the discharge of each core spray and each LPCI pump (12 total) are connected through relays in redundant groups so that each ADS trip system is blocked from actuating unless at least one low pressure pump shows verified discharge pressure. These pressure switch relay circuits are monitored continuously during normal station operation so that if any pressure switch circuit gives a false signal of the presence of pressure in the low pressure systems, an annunciator immediately alerts the operator so that the malfunction can be corrected. Once the blowdown has started, seal in contacts around the low pressure pump permissive continues the blowdown, even if all low pressure pumps are lost.

Keylocked switches have been added to permit plant operators to disable the automatic logic. This manual action will be displayed on the control panels by indicating lights and it will be annunciated. These switches allow the operator to inhibit ADS per the instructions in the Emergency Operating Procedures.

Energization of the solenoid operated pilot valves allows pneumatic pressure from the accumulator to act on the diaphragm actuator. The diaphragm actuator is an integral part of the relief valve and expands to hold the relief valve open. Lights in the main control room inform the main control room operator whenever the solenoid operated pilot valve is energized, indicating that the relief valve is open or being opened.

A two position switch is provided in the main control room for the remote control of each relief valve. The two positions are "open" and "auto". In the "open" position the switch energizes the solenoid-operated pilot valve, which allows pneumatic pressure to be applied to the diaphragm actuator of the relief valve. This allows the main control room operator to take manual action independent of the automatic system. Appropriate numbers of relief valves can be manually opened in this manner to provide a controlled nuclear system cooldown under conditions where the normal heat sink is not available. In "auto" position, the valve is controlled by the ADS logic.

Manual reset circuits are provided for the reactor vessel low-low water level and drywell high pressure initiating signals. By manually resetting these signals both the delay and the high drywell pressure bypass timers are recycled. The operator can use the reset switches to delay or prevent automatic opening of the relief valves, or he can use the ADS inhibit keylock switches to prevent relief valve opening if such delay or prevention is prudent. Manual actuation on one ADS "Reset" button recycles both the display the timer and bypass timer for one of the two trip systems. The second "Reset" button resets the second set of timers and the delay timers must be reset in order for the operator to delay automatic activation of these valves.

The logic scheme used for initiating the ADS system is a single trip system containing two trip system logics as shown on Figure 7.4-6. Each trip system logic can initiate automatic depressurizations when the logic in that trip system is satisfied. Each trip system logic includes a timer that delays the opening of the relief valves. This allows time for the HPCI to restore water level before the relief valves are actuated. Each logic channel also contains a bypass timer, which allows automatic depressurization with low-low water level only, after a predetermined time has passed. An annunciator indicates that the bypass timer is running and that a low-low water level signal is present. The ADS trip system is dc powered.

A manual "inhibit" switch in each of the two trip system logics allows the operator to prevent automatic depressurization. This switch is key-locked in the "normal" position to prevent inadvertent operation. An indicator light for each switch is illuminated when the switch is in the "inhibit" position. An annunciator in the control room alarms when either switch is in the "inhibit" position. The inhibit switch does not break the seal-in logic and will not terminate an ADS blowdown once it has begun.

Instrument specifications and allowable trip settings used in the plant safety analysis are listed on Table 7.4-2. The wiring for the trip systems is routed in separate conduits to reduce the probability that a single event will prevent automatic opening of a relief valve. Pump discharge pressure switches are used to sense that the core spray and LPCI pumps are running.

The reactor vessel low-low water level initiation setting for the automatic depressurization system is selected to open the relief valves to depressurize the reactor vessel in time to allow adequate cooling of the fuel by the core spray and LPCI systems following a LOCA in which the other makeup systems, Feedwater, RCIC, HPCI fail to maintain vessel water level. The primary containment high pressure setting is selected to be as low as possible without inducing spurious initiation of the ADS.

7.4.3.3.3 Automatic Depressurization System Initiating Instrumentation

The pressure and level analog trip units used to initiate the ADS are common to each relief valve control circuitry. Reactor vessel low water level is detected by four transmitters that measure differential pressure. Primary containment high pressure is detected by four pressure transmitters.

Two timers, one for each of the two trip system logics, (See Figure 7.4-6), are used in the control circuitry for each relief valve. The delay time setting before the ADS is actuated is chosen to be long enough so that the HPCI has time to start, yet not so long that the core spray system and LPCI are unable to adequately cool the fuel if the HPCI fails to start. An alarm in the main control room is annunciated every time either of the timers is timing. Resetting the ADS initiating trips - reactor vessel low-low water level and primary containment high pressure - recycles the timers.

Four additional timers (0 to 30 minutes adjustable), one for each channel of the two dual-channel trip system logics, provide bypasses of the high drywell pressure system initiation signal. These bypasses permit automatic system initiation without high drywell pressure. The delay-time setting can be chosen to be long enough to prevent blowdown on temporary reductions in water level but not so long as to permit the water level to become dangerously low. An alarm in the control room annunciates when any one of the high drywell pressure bypass timers is timing. The timers are reset automatically whenever the water level rises above the low-low setpoint. The bypass timers are also reset manually whenever the reset pushbuttons, one in each of the two trip system logics, are depressed.

7.4.3.3.4 Automatic Depressurization System Alarms

A dual temperature element is installed in the relief valve discharge piping approximately 4.5 to 6 feet from the valve body. This temperature element located near the valve discharge provides a means to detect relatively small amounts of steam leakage from either the first and second stage pilot valves or main stage in the three-stage safety relief valve. This discharge piping temperature element is connected to a multipoint recorder in the main control room to provide a means of detecting and monitoring relief valve discharge temperature during station operation. When the temperature in any relief valve discharge pipeline exceeds a preset value, an alarm is sounded in the main control room. The alarm setting is selected far enough above normal rated power temperatures to avoid spurious alarms, yet low enough to give early indication of relief valve leakage.

Additional dual temperature elements are installed in the following locations:

(1) discharge piping thermowell approximately 16 to 22 ft from the valve body,

(2) valve body internal thermowell in proximity to the first stage pilot seat,

(3) valve body internal thermowell in proximity to the second stage pilot seat,

(4) mounted external to pilot assembly to detect bellows assembly leakage.

The additional temperature elements in the discharge piping and valve body are connected to the plant computer and a local recorder and are used to diagnose and evaluate leakage from the associated safety relief valve. The dual temperature element installed to detect bellows assembly leakage is connected to the plant computer and when the temperature exceeds a preset value, an alarm is sounded in the main control room.

Safety relief valve leakage monitoring requirements are specified in FSAR Appendix B.

Additionally available are individual valve displays (acoustic monitors) located in the control room. These displays provide a means of determining the status of each of the four relief valves, RV-203-3A, B, C, and D, and also the status of the safety valves RV-203-4A and B. The open/close indication is made possible by the installation of acoustic transducers on the discharge piping of the relief valves RV-203-3A, B, C, and D, and on the bodies of the code safety valves RV-203-4A and B. When the valves are open, indication is provided by means of indicating lights on the safety and relief valve monitors. An audible alarm will also sound if any of the valves open. There are 10 indicating lights for each relief valve, which illuminate sequentially to give an indication of valve opening as indicated by noise and vibration induced by the steam flow through the valve.

Panels, located outside the control room, are also available to remotely operate the relief valves.

7.4.3.3.5 Automatic Depressurization System Environmental Considerations

The signal cables, solenoid valves, and relief valve operators are the only items of the control and instrumentation equipment of the ADS that are located inside the primary containment and must remain functional in the environment resulting from a LOCA. These items are selected with capabilities that permit proper operation in the most severe environment resulting from a design basis LOCA. Gamma and neutron radiation is also considered in the selection of these items. Other equipment, located outside the drywell, is selected in consideration of the normal and accident environments in which it must operate.

7.4.3.4 Core Spray System Control and Instrumentation

7.4.3.4.1 Identification and Physical Arrangement

The core spray systems consist of two independent spray loops as illustrated on Figure 7.4-8. Each loop is capable of supplying sufficient cooling water to the reactor vessel to cool the core adequately following a design basis LOCA. The two spray loops are physically and electrically separated so that no single physical event makes both loops inoperable. Each loop includes one ac motor driven pump, appropriate valves, and the piping to route water from the suppression pool to the reactor vessel. The controls and instrumentation for the core spray systems include the sensors, relays, wiring, and valve operating mechanisms used to start, operate, and test each system. Except for the check valves 9A and 9B in each spray loop, which is inside the primary containment, the sensors and valve closing mechanisms for the core spray systems are located in the Reactor Building. Cables from the sensors are routed to the main control room where the control circuitry is assembled in electrical panels. Each core spray pump is powered from a different ac bus which is capable of receiving standby power. The power supply for automatic valves in each loop is from the same source as that used for the core spray pump in that loop. Control power for each of the core spray loops comes from separate dc buses. The electrical equipment in the main control room for one core spray loop is located in a separate cabinet from that used for the electrical equipment for the other loop.

Two initiating functions are used for the core spray system: reactor vessel low-low water level coincident with reactor low pressure and primary containment (drywell) high pressure. Either initiation signal can start the systems.

7.4.3.4.2 Core Spray System Initiating Signals and Logic

The control scheme for the core spray system is illustrated on Figure 7.4-9. Allowable trip settings used in the current plant safety analysis are given on Table 7.4-3. The overall operation of a system following the receipt of an initiating signal is as follows:

1. Test bypass valves are closed and interlocked to prevent opening

2. The core spray pump in both spray loops starts 1/3 sec after power becomes available to the pump

3. When reactor vessel pressure drops to a preselected value, valves open in the pump discharge lines allowing water to be sprayed over the core

Two initiating functions are used for the core spray system: reactor vessel low-low water level coincident with reactor low pressure and primary containment (drywell) high pressure. Either initiation signal can start the systems.

Reactor vessel low-low water level indicates that the core is in danger of being overheated due to the loss of coolant. Drywell high pressure indicates that a breach of the nuclear system process barrier has occurred inside the drywell. The reactor vessel low-low water level and primary containment high pressure settings and the instruments that provide the initiating signals are selected and arranged so as to assure proper system operation without inducing spurious system startups.

The core spray system can be initiated by low-low water level alone, without reactor low pressure or high drywell pressure, after a selected time delay (0 to 30 minutes adjustable). The timing function starts when the low-low water level setpoint is reached. The timers are reset automatically if the water level rises above the setpoint before the selected time has elapsed. The timers are also reset manually when the ADS reset pushbuttons, one in each of the two ADS trip systems, are depressed.

Keylocked switches have been installed to permit blockage of the drywell high pressure initiation signal. These switches are primarily for use under post-LOCA conditions to permit shutdown of the applicable core spray pump motor without affecting the reactor vessel low water level initiation signal.

The scheme used for initiating each core spray system is a trip system containing decision making logic circuits. A typical core spray system trip actuation logic is shown on Figure 7.4-6. The decision making logic in a trip system can initiate core spray equipment in one core spray loop. The trip systems are powered by reliable independent dc buses.

7.4.3.4.3 Core Spray System Pump Control

The control arrangements for the core spray pumps are shown on Figure 7.4-9. Each pump can be manually controlled by a main control room remote switch or the automatic control system. A pressure transmitter on the discharge pipeline from each core spray pump provides a signal in the main control room to indicate the successful startup of a pump. If a core spray initiation signal is received the core spray pumps start 1/3 sec after the bus is energized. The core spray pump motors are provided with overload protection. Overload relays are applied so as to maintain power as long as possible without immediate damage to the motors or emergency power system.

Loss of voltage trips are provided with time delays sufficient to permit automatic transfer from the unit auxiliary transformer source to the startup transformer source (preferred offsite) without tripping the pump power supply breaker open.

Calibration and testing of the overload trip relays provided for these motors is accomplished by passing a test current through these protective devices to verify set points and relay actuation. This test current is measured with field standard ammeters. Current or voltage is measured with field standard ammeters and voltmeters.

The motors are protected by long time induction overcurrent relay elements and by low-set and high-set instantaneous overcurrent elements for overload and phase faults and by ground sensor relays for ground faults.

The long time, high-set and ground sensor elements are set in general accordance with recommendations in the IEEE Induction Motor Protection Guide No. 288, November 1968. The setting of the low-set element is not covered in the Guide.

The long time element is set at 115 percent to 125 percent of rated motor current with a time delay set about twice rated motor starting time. The long time element is used for overcurrent annunciation and in series with the low-set instantaneous element, set at about twice rated motor current, it is used to trip the motor circuit breaker for overload protection. This design permits continued motor operation under emergency loading conditions while alerting the operator to a nominal overload condition.

The high-set instantaneous element provides short circuit protection and is set at about ten times rated motor current which is compatible with system minimum phase fault current capacity. This set point is higher than rated locked rotor current with a margin for inrush current and current asymmetry.

The ground sensor relays are instantaneous relays operating from ground sensor current transformers. The relay setting typically provides a 30 to 1 margin of maximum ground fault current to relay pickup when operating from any of the station service transformer sources. This setting is high enough to prevent relay pickup for ground faults when operating on the diesel generator source.

Flow measuring instrumentation is provided in each of the core spray pump discharge lines. The instrumentation provides flow indication in the main control room.

7.4.3.4.4 Core Spray System Valve Control

Except where specified otherwise, the remainder of the description of the core spray refers to one spray system. The second core spray system is identical. The control arrangements for the various automatic valves in the core spray system are indicated on Figure 7.4-9 (BECo M1K1-8). All motor-operated valves are equipped with limit and torque switches to turn off the valve motor when the valve reaches the limits of movement. Each automatic valve can be operated from the main control room.

Upon receipt of an initiation signal the test bypass valve is interlocked shut. The core spray pump discharge valves are automatically opened when nuclear system pressure drops to a preselected value; the setting is selected low enough so that the low pressure portions of the core spray system are not overpressurized, yet high enough to open the valves in time to provide adequate cooling for the fuel. Two pressure transmitters are used to monitor nuclear system pressure. The trip unit associated with either of these transmitters can initiate opening of the discharge valves. The full stroke design time of the pump discharge valves is selected to be rapid enough to assure proper delivery of water to the reactor vessel in a design basis accident. The full stroke design operating times are as follows:

Test bypass valve	16 sec
Pump suction valve	120 sec
Pump discharge valves	22 sec

7.4.3.4.5 Core Spray System Alarms and Indications

Core spray system pressure between the two pump discharge valves is monitored by a pressure switch to permit detection of leakage from the nuclear system into the core spray system outside the primary containment. A detection system is also provided to continuously confirm the integrity of the core spray piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the top of the core support plate and the inside of the core spray sparger pipe just outside the reactor vessel. If the core spray sparger piping is sound, this pressure difference will be the small drop across the core resulting from inter-channel leakage. If integrity is lost, this pressure drop will also include the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the main control room. Pressure in each core spray pump suction and discharge is monitored by a pressure indicator which permits determination of suction head and pump performance.

7.4.3.4.6 Core Spray System Environmental Considerations

There are no control and instrumentation components for the core spray system that are located inside the primary containment and that must operate in the environment resulting from a LOCA. All components of the core spray system that are required for system operation are outside the drywell and are selected in consideration of the normal and accident environments in which they must operate.

7.4.3.5 Low Pressure Coolant Injection Control and Instrumentation

7.4.3.5.1 Identification and Physical Arrangement

Low pressure coolant injection (LPCI) is an operating mode of the residual heat removal system (RHR). Because the LPCI system is designed to provide cooling water to the reactor vessel following the design basis LOCA, the controls and instrumentation for it are discussed here. Section 4.8 describes the RHR in detail.

Figure 7.4-10 shows the entire RHR system including the equipment used for LPCI operation. The following list of equipment itemizes essential components for which control or instrumentation is required to operate in the LPCI mode:

Four RHR pumps
Pump suction valves (from suppression pool)
LPCI-to-recirculation loop injection valves
Recirculation loop valves

The instrumentation for LPCI operation provides inputs to the control circuitry for other valves in the RHR System. This is necessary to ensure that the water pumped from the suppression pool by the pumps is routed directly to a reactor recirculation loop. These interlocking features are described in this section. The actions of the reactor recirculation loop valves are described in this section because these actions are accomplished to facilitate LPCI operation.

LPCI operation uses two identical pump subsystems, each subsystem with two pumps in parallel. The two subsystems are arranged to discharge water into different reactor recirculation loops. A cross connection exists between the pump discharge lines of each subsystem. Figure 7.4-10 (BECo M241) shows the locations of instruments, control equipment, and LPCI components relative to the primary containment. Except for the LPCI check valves 1001-68A, 1001-68B and the reactor recirculation loop pumps and valves, the components pertinent to LPCI operation are located outside the primary containment.

The power for the RHR system pumps is supplied from ac buses that can receive standby ac power. Each pair of pumps in each subsystem receives its power from a different bus. Motive power for the injection valves on both sides used during LPCI operation comes from a common bus which can be automatically connected to either of two alternate standby power sources. Control power for the LPCI components comes from the dc buses. Redundant trip systems are powered from different dc busses. The use of common buses for some of the LPCI components is acceptable because the core spray systems and LPCI operation are arranged independently to accomplish the same objective: provide adequate cooling for the fuel at low nuclear system pressure following a design basis accident.

LPCI is arranged for both automatic operation and remote manual operation from the main control room. The equipment provided for manual operation of the system allows the operator to take action independent of the automatic controls in the event of a LOCA.

7.4.3.5.2 LPCI Initiating Signals and Logic

The overall operating sequence for LPCI following the receipt of an initiation signal is as follows:

1. If the preferred (offsite) ac power is available, one pump in each subsystem starts after an approximate 5 sec delay. The second pump in each subsystem starts after an approximate 10 sec time delay, taking suction from the suppression pool. The valves in the suction paths to the suppression pool are maintained open so that no automatic action is required to line up suction

2. If the preferred source of ac power is not available, one pump in each subsystem starts after an approximate 5 sec delay after the standby power source is operating. The second pump in each subsystem starts after an approximate 10 sec time delay

3. If the accident has not resulted from rupture of a reactor recirculation line, the LPCI instrumentation selects loop B for water injection

4. If the accident has resulted from rupture of one of the reactor recirculation lines, the LPCI instrumentation identifies the damaged loop

5. The recirculation pump discharge valve in the undamaged reactor recirculation loop automatically closes and recirculation pumps are tripped

6. Valves in the LPCI system respond automatically so that the water pumped from the suppression chamber is routed to the undamaged loop

7. When nuclear system pressure has dropped to a predetermined value, the LPCI injection valves to the undamaged recirculation loop automatically open, allowing the LPCI pumps to inject water into the pressure vessel

8. The LPCI system then delivers water to the reactor vessel via that recirculation loop to restore water level and provide core cooling

Figure 7.4-10 shows the locations of sensors. Figures 7.4-11, 7.4-12, and 7.4-13 show the functional use of each sensor in the control circuitry for the various LPCI components. Instrument analytical limit settings used in the current plant safety analysis are given on Table 7.4-4. The actual plant setting is determined in the referenced design basis calculation and has adequate margin to account for the total instrument uncertainty.

Two automatic initiation functions are provided for the LPCI: reactor vessel low-low water level coincident with low reactor pressure and primary containment (drywell) high pressure. Reactor vessel low water level indicates that the fuel is in danger of being overheated because of an insufficient coolant inventory. Primary containment high pressure is indicative of a break of the nuclear system process barrier inside the drywell.

LPCI can be initiated by low-low water level alone, without reactor low pressure or high drywell pressure after a selected time delay (0 to 30 minutes adjustable). The timing functions start when the low-low water level is reached. The timers are reset automatically if the water level rises above the setpoint before the selected time delay has elapsed. The timers are also reset manually when the ADS reset pushbuttons, one in each of the two ADS trip systems, are depressed.

The instruments used to detect reactor vessel low-low water level coincident with low reactor pressure and primary containment high pressure are the same ones used to initiate the other CSCS. Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset. The seal-in feature is shown on Figure 7.4-11.

Keylocked control switches have been installed to permit blockage of the drywell high pressure initiation signal. These switches are primarily for use under post-LOCA conditions to permit shutdown of the applicable RHR pump motors without affecting the reactor vessel low water level initiation signal.

The scheme used for initiating the LPCI system and the recirculation loop selection logic is a trip system containing two decision making logics. A typical LPCI trip system is shown on Figure 7.4-6. Either of the two decision making logics can initiate the LPCI. The trip system is powered by dc buses.

7.4.3.5.3 LPCI Pump Control

The functional control arrangement for the pumps is shown on Figure 7.4-11. If the preferred offsite AC source is available, the four main system pumps start in the timed sequence described above. If the preferred (offsite) ac source is not available, the four main system pumps automatically start in a timed sequence (described above) when the standby ac power source becomes available.

Only three of the four RHR pumps are required to provide adequate flow to restore reactor vessel water level for the design basis LOCA. The time delays are provided by timers which are set as given in the Technical Specifications referenced in Appendix B.

Pressure indicators installed in the pump discharge pipelines upstream of the pump discharge check valves; provide indication of proper pump operation following an initiation signal. A low pressure in a pump discharge pipeline indicates pump failure. The locations of the pressure indicators relative to the discharge check valves prevent the discharge pressure from an operating pump from concealing a pump failure.

To prevent RHR pump damage due to overheating at no flow, the control circuitry prevents a pump from starting unless a suction path is lined up. Limit switches on suction valves provide indications that a suction lineup is in effect. If suction valves change from their fully open position during RHR pump operation, the limit switches trip the pump power supply breaker open.

The RHR pump motors are provided with overload protection. The overload relays are applied so as to maintain power on the motor as long as possible without harm to the motor or immediate damage to the ac power system. Loss of voltage trips are provided with time delays sufficient to permit automatic transfer from the unit auxiliary source to the preferred source without tripping the pump power supply breaker open. See Section 7.4.3.4.3 for a description of calibration and testing.

The reactor recirculation pumps are tripped automatically upon a LOCA. If only one of the two recirculation pumps is running, it is tripped by the LPCI initiation logic. Both pumps are automatically tripped by the low reactor water level. When a recirculation pump trip signal is initiated, the power supply breaker for the drive motors of the recirculation pump motor generators sets is tripped open.

7.4.3.5.4 LPCI Valve Control

The automatic valves controlled by the LPCI control circuitry are equipped with limit and torque switches which stop the valve operating mechanisms whenever the valves reach the limits of travel. Seal-in and interlock features are provided to prevent improper valve positioning during automatic LPCI operation. The operating mechanisms for the valves are selected to meet times required by the LPCI operational objectives. The design time required for the valves pertinent to LPCI operation to travel from the fully closed to the fully open positions, or vice versa, is as follows:

LPCI injection valves	30 sec
Reactor recirculation loop valves	35 sec
Containment spray valves*	45 sec
Residual heat removal system test line isolation valves*	30 sec

*Normally closed

The pump suction valves to the suppression pool are normally open. Two separate operator actions are required in the main control room to shut these valves. Upon receipt of an LPCI initiation signal, RHR shutdown cooling mode valves and the RHR test line valves automatically close. By closing these valves, the pump suction and discharge is properly routed. Also included in this set of valves are the valves which, if not closed, would permit the pumps to take suction from the reactor recirculation system, a lineup that is used during normal shutdown cooling system operation. All valve motors are protected by overload alarms.

The LPCI is designed for automatic operation following a break in one of the reactor recirculation loops. The LPCI logic is required to open the injection valve to the unbroken recirculation loop and close the recirculation pump discharge valve in the unbroken recirculation loop. The control scheme for the LPCI-to-recirculation loop injection valves is shown on Figure 7.4-11 (Drawing M1H1-70BC).

The purpose of the injection valve control circuitry is to identify and direct LPCI flow to the undamaged recirculation loop. This is done by comparing the absolute pressure of the two recirculation loops. The broken loop is indicated by a lower pressure than the unbroken loop. The loop with the higher pressure is then used for LPCI injection. Four indicating type differential pressure switches are used in the control circuitry for the injection valves. The differential pressure switches detect the pressure difference between corresponding risers supplying the jet pumps from each recirculation loop. The switches are connected in such a way that a one-out-of-two taken twice logic is used to positively identify a broken recirculation loop. The differential pressure switch setting is selected to give the earliest valid indication of a break in a recirculation loop.

Upon receipt of either a reactor low-low level or a high drywell pressure signal the LPCI logic senses the recirculation pump operation by means of differential pressure between the suction and discharge of each pump. Four differential pressure switches are provided across each recirculation pump. The four sensors in each loop are arranged in a one-out-of-two taken twice logic. A time delay relay provides 1/2 second for the logic to detect if one recirculation pump is running. If the logic senses that one pump is not running, the operating pump is tripped off. Stopping this pump is necessary to eliminate the possibility of breaks being masked by the operating recirculation pump pressure. If pump stoppage is initiated, there is next a requirement that reactor vessel pressure drop to a specified value before the logic will continue. This adjusts the selection time to optimize sensitivity and still ensure that the LPCI action is not unnecessarily delayed. There are four separate reactor pressure sensors arranged in a one-out-of-two taken twice logic. After satisfaction of this pressure requirement, or if both recirculation pumps were initially running, a time delay of about 2 seconds is provided to remove initial perturbations and allow momentum effects to stabilize. Loop selection is then initiated by means of the differential pressure switches between the corresponding recirculation loop risers. See Figure 7.4-15. If, after approximately a half second delay, the pressure in Loop A is not indicating greater than Loop B, the circuit provides a signal to shut the Loop B recirculation pump discharge valve and opens the LPCI injection valve to Loop B. If recirculation Loop A pressure indicates higher than Loop B, the recirculation pump discharge valve in Loop A is ordered shut and the LPCI injection valve to Loop A is signaled open. The injection valves do not open however, until reactor vessel pressure decreases to a value which approximates the discharge head of the LPCI system.LPCI flow then enters the vessel when the check valve opens due to LPCI pressure being higher than reactor pressure. The sensing circuit for break detection and valve selection is arranged so that failure of a single device will not prevent correct selection of the loop for injection.

A timer cancels the LPCI signals to the injection valves after a delay time long enough to permit satisfactory operation of the LPCI system. The cancellation of the signals allows the operator to divert the water for other post-accident purposes. Cancellation of the signals does not cause the injection valves to move.

The manual controls in the main control room allow the operator to open an LPCI injection valve only if either nuclear system pressure is low or the other injection valve in the same pipeline is closed. These restrictions prevent overpressurization of the RHR piping. The same pressure transmitter/trip unit combination used for the automatic opening of the valves is used in the manual circuit. Limit switches on both injection valves in each side provide valve position signals.

To protect the pumps from overheating at low flow rates, a minimum flow bypass pipeline, which routes water from the pump discharge to the suppression pool, is provided for each pair of pumps. A single motor-operated valve controls the condition of each bypass pipeline. The minimum flow bypass valve automatically opens upon sensing low flow in both injection lines. Figure 7.4-10 shows the location of the two flow indicating differential pressure switches on the LPCI injection flow elements.

Figures 7.9-2,3,4 shows the control arrangement for the recirculation loop valves. If a recirculation loop has been damaged, the recirculation pump discharge valve in the undamaged recirculation loop automatically closes upon the receipt of an LPCI injection signal. The valves in the damaged recirculation loop are left open to allow continued depressurization of the nuclear system so that the LPCI and core spray systems can inject water into the reactor vessel as soon as possible.

The same arrangement of differential pressure switches that is used in the LPCI injection valve circuitry to identify a damaged recirculation loop is used in the recirculation loop valve control circuitry. The manual control circuitry for the recirculation loop valves is interlocked to prevent valve opening whenever an LPCI initiation signal is present.

The valves that allow the diversion of water for containment spray cooling are automatically closed upon receipt of an LPCI initiation signal. The manual controls for these valves are interlocked so that opening the valves by manual action is not possible unless both primary containment (drywell) pressure is high, which indicates the need for containment spray cooling, and reactor vessel water level inside the core shroud is above the level equivalent to 2/3 the core height. Four transmitters are used to monitor drywell pressure for the set of valves in each subsystem. The trip setting is selected to be as low as possible yet provide indication of abnormally high drywell pressure. The drywell pressure trip units associated with these transmitters are arranged in a one-out-of-two taken twice logic arrangement. A single level transmitter/trip unit combination is used to monitor water level inside the core shroud for the set of valves in each subsystem. A keylock switch in the main control room allows a manual override of the 2/3 core height permissive contact for the containment cooling valves.

Sufficient temperature, flow, pressure, and valve position indications are available in the main control room for the operator to accurately assess the LPCI operation. Valves have indications of full open and full closed positions. Pumps have indications for pump running and pump stopped. Alarm and indication devices are shown on Figures 7.4-10 and 7.4-13.

7.4.3.5.5 LPCI Environmental Considerations

The only control components pertinent to LPCI operation that are located inside the primary containment and that must remain functional in the environment resulting from a LOCA are the cables and valve closing mechanisms for the recirculation loop valves. The cables and valve operators are selected with environmental capabilities that assure valve closure under the environmental conditions resulting from a design basis LOCA. Gamma and neutron radiation is also considered in the selection of this equipment. Other equipment, located outside the drywell, is selected in consideration of the normal and accident environments in which it must operate.

7.4.4 Safety Evaluation

In Section 14, Station Safety Analysis, and Section 6, Core Standby Cooling Systems, the individual and combined capabilities of the standby cooling systems are evaluated. The control equipment characteristics and trip settings described in these sections were considered in the analysis of CSCS performance. For the entire range of nuclear process system break sizes the cooling systems are effective both in preventing fuel clad melting and in preventing more than a small fraction of the reactor core from reaching the temperature at which a gross release of fission products can occur. This conclusion is valid even with significant failures in individual cooling systems because of the overlapping capabilities of the CSCS. The controls and instrumentation for the CSCS satisfy the precision and timeliness requirements of safety design bases 1 and 2.

Safety design basis 3 requires that instrumentation for the CSCS responds to the potential inadequacy of core cooling regardless of the location of a breach in the nuclear system process barrier. The reactor vessel low water level initiating function, which alone can actuate HPCI, LPCI, and core spray, meets this safety design basis because a breach in the nuclear system process barrier inside or outside the primary containment is sensed by the low water level detectors.

Because of the isolation responses of the Primary Containment and Reactor Vessel Isolation Control system to a breach of the nuclear system outside the primary containment, the use of the reactor vessel low water level signal as the only Standby Cooling System initiating function that is completely independent of breach location is satisfactory. The other major initiating function, primary containment high pressure, is provided because the Primary Containment and Reactor Vessel Isolation Control system may not be able to isolate all nuclear system breaches inside the primary containment. The primary containment high pressure initiating signal for the CSCS provides a second reliable method for sensing losses of coolant that cannot necessarily be stopped by isolation valve action. This second initiating function is independent of the physical location of the breach within the drywell. The method used to initiate the ADS, which employs reactor vessel low water level and primary containment high pressure in coincidence, requires that the nuclear system breach be inside the drywell because of the required primary containment high pressure signal. This control arrangement is satisfactory in view of the automatic isolation of the reactor vessel by the Primary Containment and Reactor Vessel Isolation Control System for breaches outside the primary containment and because the ADS is required only if the HPCI fails. Thus, safety design basis 3 is satisfied.

An evaluation of CSCS controls shows that no operator action beyond the reasonable capability of the operator is required to initiate the correct responses of the CSCS. The alarms and indications provided to the operator in the main control room allow interpretation of any situation requiring CSCS operations and verify the response of each system. Manual controls are illustrated on functional control diagrams. The main control room operator can manually initiate every essential operation of the CSCS. The degree to which safety is dependent on operator judgement and response has been appropriately limited by the design of CSCS control equipment and safety design bases 4a, 4b, and 4c are therefore satisfied.

The redundancy provided in the design of the control equipment for the CSCS is consistent with the redundancy of the cooling systems themselves. The arrangement of the initiating signals for the CSCS is similar to that provided by the dual trip system arrangement of the RPS. No failure of a single initiating sensor can prevent the start of the cooling systems. The numbers of control components provided in the design for individual cooling system components is consistent with the need for the controlled equipment. An evaluation of the control schemes for each CSCS component shows that no single control failure can prevent the combined cooling systems from providing the core with adequate cooling. In performing this evaluation the redundancy of components and cooling systems was considered. The functional control diagrams provided with the descriptions of cooling systems controls were used in assessing the functional effects of instrumentation failures. In the course of the evaluation, protection devices which can interrupt the planned operation of cooling system components were investigated for the results of their normal protective action as well as malfunction on core cooling effectiveness. The only protection devices that can act to interrupt planned CSCS operation are those that must act to prevent complete failure of the component or system.

Examples of such devices are the HPCI turbine overspeed trip, HPCI steam line break isolation trip, pump trips on low suction pressure, and automatically controlled minimum flow bypass valves for pumps. In every case the action of a protective device cannot prevent other redundant cooling systems from providing adequate cooling to the core.

The locations of controls where operation of CSCS components can be adjusted or interrupted have been surveyed. Controls are located in areas under the surveillance of operations personnel. Local control switches are of the keylock type and main control room override of local switches is provided. Other controls are located in the main control room and are under the supervision of control room personnel.

The environmental capabilities of instrumentation for the CSCS are discussed in the descriptions of the individual systems. Components which are located inside the primary containment and which are essential to standby cooling system performance are designed to operate in the environment resulting from a LOCA.

Special consideration has been given to the performance of reactor vessel water level, pressure sensors, reference legs, and condensing chambers during rapid depressurization of the nuclear system. The discussion of this consideration is included in Section 7.2, Reactor Protection System, and is equally applicable to the instrumentation for the CSCS.

Indication of reactor water is provided by redundant mechanical indicators mounted on local instrument racks.

It is concluded from the previous paragraphs and the description of control equipment that safety design bases 5a through 5d are satisfied. The testing capabilities of the CSCS, which are discussed in Section 7.4.5, satisfy safety design basis 6.

7.4.5 Inspection and Testing

Components required for HPCI, LPCI, and core spray are designed to allow functional testing during normal power operation. Overall testing of these systems is described in Section 6. During overall functional tests the operability of the valves, pumps, turbines, and their control instrumentation can be checked. The relief valves are tested during shutdown periods.

Logic circuitry used in the controls for the CSCS can be individually checked by applying test or calibration signals to the sensors and observing trip system responses. Valve and pump operation from manual switches verifies the ability of breakers and valve closing mechanisms to operate. The automatic control circuitry for the CSCS is arranged to restore each of the cooling systems to normal operation if a LOCA occurs during a test operation.

7.4.6 Nuclear Safety Requirements for Plant Operation

The CSCS initiation and control instrumentation has been broken down into the incident detection circuitry (IDC) and control instrumentation. The CSCS control instrumentation is not critical for the initiation of the CSCS, only for operational control of those systems. Since the control instrumentation for the CSCS is checked each time the mechanical operation of the CSCS is functionally checked, (see Section 6), only the initiation circuitry, IDC, will be examined for operational requirements in this section.

Table 7.4-5 presents the nuclear safety requirements for the incident detection circuitry for each BWR operating state. The entries on Table 7.4-5 represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the incident detection circuitry. The following referenced portions of the safety analysis report provide important information justifying the entries on Table 7.4-5:

	Reference	Information Provided
1.	Section 7.4	Description of incident detection circuitry hardware; incident detection system sensor setpoints
2.	Station Safety Analysis, Section 14	Analysis verifying performance of the incident detection circuitry in transients and accidents
3.	Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which incident detection circuitry action is required
4.	Jacobs, I.M. Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards General Electric Company, Atomic Power Equipment Department, APED-5736, April 1969	Describes methods used to establish allowable repair times for protection systems

Each detailed requirement on Table 7.4-5 is referenced, where possible, to the most significant condition originating the need for the requirements by identifying a matrix block on one of the six matrices 3 of Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns of Table 7.4-5 and are coded as follows:

Example of Matrix Reference:

Example of Matrix Reference:

```
F39-92
|  |  |
-------- F - BWR operating state F,
   ----- 39 - Event (Row 39)
      ---- 92 - Incident Detection Circuitry
                 (Column 92)
```

In most cases, the basis for an operational nuclear safety requirement is clear from the information provided by the previously noted references. The incident detection circuitry (IDC) requirements in states C, D, E, and F result from considerations for the LOCA or lesser cases of this design basis accident. There are no requirements on the IDC in states A and B. Manual start is shown on Table 7.4-5 to indicate the need for the CSCS in these states, but none of the IDC components are required to assure the manual start capability.

There is one HPCI trip system and one ADS trip system. These two systems function as a pair to satisfy the single failure criterion whenever the nuclear system is pressurized above 150 psig. The safety analysis takes no credit for operation of the HPCI below 150 psig vessel pressure. Even if the HPCI is inoperable when reactor pressure is above 104 psig and below 150 psig, reactor pressure can be brought in to the shutdown cooling range by turbine bypass to the condenser or by limited use of safety relief valves which are required to be operable above 104 psig. It should be noted that the core spray and LPCI systems are capable of providing substantial flow to the reactor vessel at vessel pressure of 150 psig and above. The vessel pressure for incipient flow to the vessel is in excess of 200 psig for both the Core Spray and LPCI systems. Below 104 psig, the low pressure CSCS can deliver 100 percent of design flow and no requirements are made upon the HPCI and ADS trip systems.

There are two LPCI trip systems and two core spray trip systems. These trip systems must be operable anytime the nuclear system is pressurized. They must be operable above 104 psig, because they would be required any time the ADS system was actuated.

The operable LPCI and CSS pump discharge pressure channels required in the ADS trip system must be in operable low pressure pump cooling paths. A low pressure pump cooling path includes an RHR or CSS pump and the corresponding piping and equipment required to complete a core cooling path.

7.4.7 Current Technical Specifications

The current limiting conditions for operation, surveillance requirements, and their bases are contained in the Technical Specifications referenced in Appendix B.

Table 7.4-1

HIGH PRESSURE COOLANT INJECTION SYSTEM FOR CURRENT PLANT SAFETY ANALYSIS INSTRUMENT SPECIFICATIONS

HPCI FUNCTION	INSTRUMENT	RANGE	TRIP SETTING	DESIGN BASIS REFERENCE CALCULATION
Reactor Vessel High Water Level Turbine Trip	LT263-72A, B LIS263-72A,B LS263-72A-2, B-2	-50 to + 50 in (See Note 2)	542.5 in above vessel zero	I-N1-98 (See Note 3)
Turbine Exhaust High Pressure	PS2368A,B	0 to 200 psig	150 psig	
HPCI Pump Low Suction Pressure	PS2360-1	30 in Hg VAC to 0.5 psig	16.69 in Hg VAC	I-N1-57 (See Note 3)
Reactor Vessel Low Water Level (See Note 1)	LT263-72A,B,C,D LIS263-72A,B,C,D LS263-72A-1, B-1, C-1, D-1	-50 to + 50 in (See Note 2)	425.6 in above vessel zero	I-N1-97 (See Note 3)
Primary Containment (Drywell) High Pressure (See Note 1)	PT1001-89A,B,C,D PIS1001-89A,B,C,D PS1001-89A-3, B-3, C-3,D-3	0 to 5 psig	2.5 psig	I-N1-137 (See Note 3)
HPCI System Flow (for discharge bypass)	FS2354	NA	Low 450 GPM	I-N1-203 (see note 3)
Suppression Pool High Water Level	LS2351A,B	-2 to +2 H_2O	1 ft 9-1/2 in below torus center line	I-N1-59 (See Note 3)
Condensate Storage Tank Level	PS2390A,B	0 to 25 psig	43" from bottom of tank	I-N1-245 (See Note 3)

NOTE:
1. Incident Detection circuitry instrumentation
2. Referenced to instrument zero (482 1/2 inches above vessel zero)
3. The setpoint for this parameter was analyzed in accordance with R. G. 1.105. The trip setting identified is the design basis analytical limit.

7.14 ENVIRONS RADIATION MONITORS

7.14.1 General

As reported in Section 2.6, Environs Radiation Surveillance Program, the Applicant has been measuring radiation levels in the site environs since August 1969. The following sections describe the monitoring equipment presently being used in the program.

7.14.2 Air Sampling

Air sampling is performed through the use of continuous low volume vacuum pump samplers. A flow rate of approximately 1 ft3/min is measured by a dry gas meter.

Particulates are collected on glass fiber filters. Gaseous iodine is collected on charcoal filters which are inserted behind the glass fiber filters in the filter holders.

Each sampler is housed in a shelter to protect it from the weather. Ambient air enters the sampling system through the filter holder which is located several feet above the ground, to lessen the buildup of ground dust on the filter.

7.14.3 External Gamma Radiation

Both onsite and offsite gamma radiation levels are being determined through the use of thermoluminescent dosimeters.

A permanent record of each reading is provided by the laboratory readout system.

Prior to the initial field distribution the laboratory calibrates all dosimeters in a known field of radiation. Periodic checks are made to ensure proper operation throughout the survey.

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 4

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C – Rev 28
LOEP	EP4 – Rev 27	EP4 – Rev 28
Section 8 TOC	Entire Section 8 TOC	Section 8 TOC – Rev 28
8.2	Pages 1-8	Pages 1-9
8.3	Pages 1-4	Pages 1-4
8.8	Pages 1-4	Pages 1-5
8.9	Pages 1-7	Pages 1-8
Section 9 TOC	Entire Section 9 TOC	Section 9 TOC – Rev 28
Section 10 TOC	Entire Section 10 TOC	Section 10 TOC – Rev 28
10.3	Pages 1-9	Pages 1-10
10.8	Pages 1-14	Pages 1-16
Section 11 TOC	Entire Section 11 TOC	Section 11 TOC – Rev. 28*
11.9	Page 1	Page 1
Section 12 TOC	Entire Section 12 TOC	Section 12 TOC – Rev 28*
12.4	Pages 1-6	Pages 1-7

*Text without revision bars was reformatted only.

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

SECTION 8

ELECTRICAL POWER SYSTEM

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

SECTION 8

LIST OF TABLES

SECTION 8

LIST OF FIGURES

8.2 UNIT AND PREFERRED AC POWER SOURCES

8.2.1 Unit AC Power Source

8.2.1.1 Power Generation Objective

The station main generator, while supplying power to the 345 kV transmission system through the main transformer, also supplies through the unit auxiliary transformer, the unit source of AC power necessary for all station auxiliaries during power operation.

The main and unit auxiliary transformers can provide alternate access to the 345 kV supply following loss of the startup transformer.

8.2.1.2 Not used.

8.2.1.3 Power Generation Design Basis

1. The unit AC power source is capable of supplying all loads during power operation.
2. The main transformer is capable of transmitting the station output to the 345 kV switchyard.

8.2.1.4 Description

The station main generator provides power through the isolated phase bus at 24 kV to both the main transformer and the unit auxiliary transformer. The generator voltage is stepped up through the main transformer to 345 kV and power flows into the ring bus in the switchyard to the New England power grid over the two 345 kV transmission lines connected to the ring bus. The generator voltage is reduced through the unit auxiliary transformer to 4,160 V, and power flows into the auxiliary power distribution system as described in Section 8.4.

Table 8.2-1 provides detailed electrical ratings of equipment discussed in Section 8.2. Figure 8.2-1 (Drawing E1 SH1) illustrates the power flow and connection from the main generator to the 345 kV switchyard and station service system.

The main generator stator core and the rotor conductors are hydrogen cooled. Excitation is from a self-excited, shaft-driven alternator with stationary rectifier banks to accomplish the AC to DC conversion. The generator is grounded through a grounding transformer with a secondary resistor. See Figure 8.2-2 (Drawing E6 SH1) for details of the excitation and protective relay systems for the generator. Bolted flexible connectors located at the main transformer and main generator are included to isolate the main generator from the main transformer and unit auxiliary transformer with sufficient clearance to permit operation of the main transformer and unit transformer from the 345 kV system with the generator disconnected. Special provisions have been included for personnel access and rapid removal of the connections to facilitate energization of the station auxiliary busses using this alternate access to the 345 kV source.

The main transformer 345 kV high voltage winding is connected in grounded wye to the 345 kV ring bus in the switchyard. The low voltage 22.8 kV winding is connected in delta.

The unit auxiliary transformer 23 kV high voltage winding is connected in delta. The two 4.16 kV low voltage windings, X and Y, are each connected in resistance grounded wye. The X winding feeds four 250 MVA switchgear buses and the Y winding feeds two 350 MVA switchgear buses. These buses are in the auxiliary power distribution system and are described in Section 8.4.

8.2.1.5 Inspection and Testing

Inspection and testing at vendor factories and initial system tests were conducted to insure that all components were operational within their design capability.

8.2.2 Preferred AC Power Source

8.2.2.1 Power Generation Objective

The preferred AC power source provides a source of offsite AC power to the entire Auxiliary Power Distribution System adequate for the startup, operation, or shutdown of the station.

8.2.2.2 Safety Design Basis

1. The preferred AC power source is capable of supplying all emergency loads of the auxiliary power distribution system necessary for the safe shutdown of the reactor, as a result of anticipated operational occurrences or postulated accidents.
2. The availability of the preferred AC power source is continuously monitored and indication of the operational status is provided in the main control room.
3. The preferred AC power source is automatically connected to the emergency service buses in the event that the unit power source is lost.
4. The preferred and unit AC power sources are as independent as possible within the constraints of the transmission system development.
5. The preferred AC power source is not synchronized with the secondary AC power source.
6. The preferred AC power source is designed to be available following a loss of all onsite AC power supplies and secondary AC power source, to assure that fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded.

8.2.2.3 Power Generation Design Basis

1. The preferred AC power source is capable of supplying all loads during normal station startup.
2. The preferred AC power source is capable of supplying all loads during normal station shutdown.
3. The preferred AC power source is capable of supplying all loads during normal station operation.

8.2.2.4 Description

The station is connected to the New England power grid through a 345 kV ring bus located in a switchyard adjacent to the station.

Refer to Figure 8.1-1. The 345 kV ring bus is connected to the following:

1. Station main transformer, described in Section 8.2.1
2. One 345 kV transmission line to the Canal Station ring bus of the Canal Generating Company of NSTAR, Sandwich, Massachusetts, and to the Auburn Street Station of National Grid
3. Station startup transformer (preferred AC power source)
4. One 345 kV transmission line to the breaker and half scheme Carver Station of NSTAR Company, Carver, Massachusetts

The Canal, Auburn Street, and Carver Stations are in turn connected to the New England power grid and the NSTAR system by separate 345 kV lines.

Offsite AC power for station startup and shutdown is obtained from the 345 kV ring bus through the startup transformer to the station auxiliary power distribution system. The two 345 kV transmission lines are individually or jointly capable of supplying power to the startup transformer.

The startup transformer supplies power to the station auxiliary power distribution system whenever the main generator is offline. After the main generator has been synchronized to the 345 kV system and has been partially loaded, the auxiliary power distribution system is manually transferred from the startup transformer to the unit AC power source (unit auxiliary transformer).

Automatic fast transfer capability is provided in the design to restore the preferred AC power source (startup transformer) to the auxiliary power distribution system in the event that the unit AC power source is lost for any reason. The diesel generator load shedding logic will also be actuated (See Section 8.5.4), immediately upon the fast transfer of the safety related buses A5 and A6 to the Startup Transformer, in the presence of a LOCA signal, when the startup transformer secondary voltage is below the degraded voltage alarm reset setpoint.

Should power be interrupted to the preferred AC power source (startup transformer) due to a double 345 kV line fault, it will be automatically restored when the line breakers reclose after the fault is cleared and the lines are re-energized. This automatic reclosure is designed to prevent both 345 kV breakers from reclosing at the same time.

The breaker controls for the preferred AC power source are interlocked to prevent interconnection with the secondary AC power source. The preferred AC power source may be synchronized and interconnected with the unit AC power source to permit live source transfer following synchronization of the main generator. Procedural restrictions back up the breaker interlocks and assure that interconnection of the preferred AC power and unit AC power sources occur only for a short period of time.

The transmission system is protected in accordance with normal utility practice using carrier relaying on the lines and high speed differential protection on the transformers. The 345 kV switchyard breakers will be controlled directly from the main control room. Breaker position, 345 kV transmission line voltages and other parameters are monitored in the main control room.

The startup transformer 345 kV high voltage winding is connected in grounded wye. The tertiary winding is connected in delta. The two 4.16 kV low voltage windings, X and Y, are connected in resistance grounded wye. The X winding feeds four 250 MVA switchgear buses through 2,000 amp breakers and the Y winding feeds two 350 MVA switchgear buses through 3,000 amp breakers. These buses are in the auxiliary power distribution system and are described in Section 8.4.

The four circuit breakers are SF6 type and each rated at 345 kV, 2,000 amp, three-phase, 40,000 amp interrupting rating, and are installed in the ring bus to separate the four connections to the bus. Disconnect switches are provided on each side of each circuit breaker, for each transmission line, and for each transformer.

The two 345 kV lines, as well as those with which they interconnect, are designed to equal or exceed the requirements for heavy loading districts, Grade B construction, consisting of 4 lb/ft2 wind on 1/2 in radial ice on cable, and 6.4 lb/ft2 wind on 1.5 faces of the tower and with the National Electrical Safety Code overload factors. The two transmission lines are designed to equal or exceed the requirement for traverse hurricane wind of 25 lb/ft2 on bare cable at 60°F and 40 lb/ft2 on 1.5 faces of the tower with an overload factor of 1.25. The lightning performance design goal for the lines is to achieve no more than one outage per 100 mi-yr.

The transmission lines run adjacent to each other for a distance of approximately 8 mi and then diverge at the Snake Hill Road Tap. A tap from one line (342) is made at approximately 5 mi from Pilgrim switchyard (Jordan Road Tap) that runs northwesterly approximately 26 mi to the Auburn Street Station of National Grid.

At Snake Hill Road Tap the two lines diverge, one line (342) running southerly approximately 13 mi to Canal Station; the other line (355) running westerly and northwesterly approximately 13.5 mi to the Carver Station of NSTAR.

The height of the towers supporting the two 345 kV transmission lines varies from 110 ft. to 160 ft. The separation provided between the two nearest conductors on these common towers is 23 ft.

Commercial communication antennas are mounted on some transmission towers slightly raising the overall height of these towers above what is described herein.

The tower structures are analyzed and acceptable to the applicable state and federal structural codes and standards.

The largest dimension of the antennas is well below adjacent conductors' spacing of 23 ft. and therefore, their structural failure will not contact two conductors and provide a shorting out of transmission.

8.2.2.5. Deleted

8.2.2.6 Safety Evaluation

8.2.2.6.1 General

The 345 kV transmission and ring bus are arranged so that failure of either line will not result in the loss of the main generator, the other 345 kV line, or the startup transformer. Either transmission line will be capable of carrying the full station output and of supplying the startup transformer. The startup transformer rating is large enough that the emergency service loads are simultaneously connected and started under accident conditions.

A high degree of reliability in the transmission system is provided so that the station output is available to the New England power grid and so that a power source is available to the startup transformer. To provide maximum security in the switching station, a ring bus design is used with the generator transformer, transmission line, startup transformer, and the second transmission line alternating around the ring, in that order. Therefore, both the generator and startup transformers have direct connections to both transmission lines. The failure of any single breaker will not cause the loss of both 345 kV transmission lines.

8.2.2.6.2 Analytical Studies

The transmission system is analytically studied to determine its behavior when various system components are assumed to be low or out of service and the design provides protection against single contingency type of failures. This is a continuing procedure which takes place as the system is modified and expanded to meet load growth requirements.

The following analytical studies were performed to substantiate that the loss of Pilgrim Station or any other generating unit in the system would not affect the offsite power.

1.	Load Flow	Digital computer analysis of transmission loading for both normal and contingency operation
2.	Unit Stability	Stability studies of Pilgrim and other units in the interconnected New England System
3.	Transient Network trans-Analysis switching	Transient network analysis of mission line over voltage surges
4.	Relaying	An analytical study to select the proper type, speed, and application as dictated by 1, 2, and 3 above

Load Flow

Studies performed by the New England Pool Transmission Task Force established the firm transmission requirements for Pilgrim Nuclear Power Station and the Canal Units. Normal and contingency cases were studied at light and heavy load conditions and these studies concluded that the transmission network was adequate to carry the combined output of both Canal and Pilgrim generators after the loss of the Pilgrim-Carver intertie. The studies also concluded that the loss of the Pilgrim Nuclear Power Station or any other generating unit in the system would not affect the availability of offsite power to the Pilgrim Nuclear Power Station.

In the event of the loss of both 345 kV lines out of the Pilgrim Nuclear Power Station, the station output would be lost to New England. However, analysis indicates that this loss would not cascade so as to involve any other generating unit in New England.

Unit Stability

Stability studies of the Pilgrim Nuclear Power Station were completed in 1968. Under the auspices of the New England Pool Planning Committee Stability Task Force, stability studies are updated every two years. The Pilgrim Nuclear Power Station along with all other major units in the interconnected New England System were included in all of these studies. These studies concluded that there was no close in three-phase fault or phase to ground fault that would lead to the instability of the Pilgrim Nuclear Power Station.

Transient Network Analysis

A transient network analysis of the transmission system associated with the Pilgrim Nuclear Power Station and the Canal Units was completed in 1968. From these tests, the magnitude of switching surge over voltages was determined. These data were used to coordinate the lightning arresters and BIL, of the various transformers connected to this transmission system.

Relaying

In the event of a phase to phase or phase to ground fault on one of the 345 kV transmission lines, the two adjacent air circuit breakers in the ring bus would open to disconnect the affected line. The main generator and the startup transformer would be unaffected and station operation would therefore be unaffected.

In the event of a phase to phase or phase to ground fault on one of the 345 kV transmission lines, combined with the failure of a single air circuit breaker in the ring bus, the two air circuit breakers adjacent to the failed circuit breaker would open to disconnect both the affected line and the failed breaker from the remaining ring bus. Failure at either of two locations is possible and both are described as follows:

Either Breaker Adjacent to Main Transformer Tap Failure to Open

In this event, the automatic opening of the adjacent circuit breakers in the ring bus would disconnect the affected transmission line, the failed breaker, and the main transformer. The main generator is disconnected from the system in this event and any station auxiliary buses connected to the unit power source are automatically transferred to the preferred power source, the startup transformer.

The startup transformer provides adequate capacity to power the entire auxiliary distribution system, including the emergency service portions.

Either Breaker Adjacent to Startup Transformer Tap Failure to Open

In this event, the automatic opening of the adjacent circuit breakers in the ring bus would disconnect the affected transmission line, the failed breaker, and the startup transformer.

If the main generator was offline prior to this event, the loss of the preferred power source (startup transformer) would automatically initiate the standby power source, described in Section 8.5. The preferred power source would be restored to service as soon as practical, by opening the two 345 kV disconnects to isolate the failed breaker and the de-energized transmission line, and then manually transferring the startup transformer back to the operating transmission line.

8.2.2.6.3 Single Failure Analysis

Consequences of Single Failures in the Preferred AC Power Source to Protective Relaying and Breaker Controls

The preferred ac power source (startup transformer) protective relaying in the 345 kV switchyard consists of three protection systems: primary, backup, and inoperative breaker relays. Each relay system and 345 kV circuit breaker has a separate control source from the dc distribution panel to the controlled equipment. Each control source has cable fault protection. The dc distribution panel is supplied by a 60 cell, 180 amp hr (3 hr rating) battery. The battery charger can supply control power to the primary, backup, or inoperative breaker protection if the battery is not available. The battery charger is supplied from two sources of ac power including the diesel generators. The charger is provided with current limiting protection.

In the event of a failure involving the preferred ac power source or the 345 kV bus, the primary relays will operate to clear the fault. If the fault fails to clear (due to the loss of control source dc power, for example) the backup relay system will operate to clear the fault.

If a failure in the dc control power source to a 345 kV circuit breaker adjacent to the preferred ac power source transformer causes a forced outage, the inoperative breaker relay system will operate to open the two circuit breakers adjacent to the failed circuit breaker and disconnect both the transformer and failed circuit breaker from the remaining ring bus.

Loss of dc power to the startup transformer (preferred source) lockout relay circuit would remove protection against ac system faults. Since ac system faults are totally independent of the loss of dc power, this is acceptable for a limited time period. The power supply is monitored in the main control room via the relay house general alarm.

A single failure in one of the protective relay inputs to the lockout relay could provide a spurious trip signal which would isolate the preferred source by tripping and locking out the appropriate switchyard breakers and alarming in the main control room. This would be an acceptable result with the standby ac power source and the secondary ac power source automatically ready to provide emergency service power if required.

8.2.2.6.4 Conclusions

It is concluded from the analysis of the transmission system, switchyard arrangement, and relay protection that the safety design bases for the preferred ac power source are met.

8.2.2.7 Inspection and Testing

Inspection and testing at Vendor factories and initial system tests were conducted to insure that all components are operational within their design capability. Periodic tests of the equipment and the system are conducted to detect the deterioration of equipment in the system toward an unacceptable condition.

8.2.2.8 Proposed Operational Nuclear Safety Requirements for Initial Plant Operation

The general entries in this section represent the proposed nuclear safety requirements for the preferred ac power source for station startup. The preferred ac power source operating limitations are related to the operability status of the standby ac power sources and are described in Section 8.5.6. The following referenced portion of the safety analysis report provides important information justifying the entries in that section.

Reference	Information Provided
1. Earlier parts of Section 8.2	Description of the preferred(offsite) ac power source

System Action

To provide a source of ac power to station systems for startup.

Number Provided by Design

One startup transformer connected to two 345 kV transmission lines through a 345 kV ring bus.

Surveillance

The preferred AC power source will be tested periodically to detect any deterioration of equipment toward an unacceptable condition.

NOTE: The components of the preferred source are normally energized.

Conclusion

The preferred AC power supply is one of the two physically independent circuits designed to provide power to the 4.16 kV auxiliary power distribution system. It is designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the secondary AC power supply power circuit, to assure that fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. Additionally, it is designed to be available following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained. Therefore, it can be concluded that the startup transformer and associated 345kV transmission lines satisfies the offsite preferred power source requirement of GDC 17.

8.3 SECONDARY AC POWER SOURCE (SHUTDOWN TRANSFORMER)

8.3.1 Power Generation Objective

The secondary AC power source provides an alternate source of offsite power to the emergency service portion of the auxiliary power distribution system to permit portions of the 345 kV system to be removed from service for inspection, testing, and maintenance.

8.3.2 Safety Design Basis

1. The secondary source is capable of supplying the loads on the emergency service portion of the auxiliary power distribution system in the time required for safe shutdown of the reactor as a result of anticipated operational occurrences.

2. Provisions shall be included to minimize the probability of losing electric power from the remaining sources as a result of, or coincident with the loss of power generated by the unit, loss of power from the transmission network, or loss of power from the onsite electric power supplies.

3. The secondary AC power supply is not synchronized to the preferred AC power source.

4. The secondary source is designed to be available following a loss of all onsite AC power supplies and the preferred AC power source, to assure that fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded.

5. The secondary AC power source is capable of supplying all required loads of one emergency AC 4.16 kV bus for the safe shutdown of the reactor for postulated accidents.

8.3.3 Description

The secondary AC power source is connected to a 23 kV line No. 72, which is supplied from the Manomet Substation of NSTAR. The Manomet Substation is supplied by 12.1 mi, 115 kV line from the Horse Pond Switching Station of the New England power grid as shown on Figure 8.1-1 (Drawing E1SH3).

The point where the 23 kV line passes under the 345 kV line is placed underground to insure that no possible 345 kV tower failure can result in interruption of the 23 kV supply to the site.

The voltage is reduced from 23 kV to 4,160 V by the shutdown transformer which can be connected to the emergency service auxiliary buses through 1,200 amp breakers.

The shutdown transformer is rated at 5/5.6 MVA, 55°C/65°C, self-cooled, three-phase 60 Hz, with a 22,900V high voltage winding and a 4,160V low voltage winding.

Voltage unbalances on the 23 kV secondary (offsite) AC power source are detected by a negative sequence relay connected to a potential transformer that is connected to the bus between the normal closed breaker on the shutdown transformer secondary side, and the normally open breakers of buses A5 and A6. The relay will alarm instantaneously with a 30 sec delay trip. This time delay will allow the operator additional time to analyze the condition of the 23 kV system prior to an automatic trip. A voltmeter and phase selector switch are available for this analysis. Should plant condition dictate the continued operation of this power source, in spite of the voltage unbalance, a trip bypass switch is available to enable a manual removal of the negative relay trip function.

The breaker controls for the secondary AC power source are interlocked to prevent interconnection with either the unit AC power source, the preferred AC power source, or the standby AC power source. These interlocks are backed up by procedural restrictions.

8.3.4 Safety Evaluation

The following analysis demonstrates the adequacy of the 23 kV line as a redundant source of offsite power.

1. Capacity - Availability - Normal Operating Mode

The source for the 23 kV line is the Manomet Substation of NSTAR. This substation has sufficient capacity to supply the area load and, in addition, that load required by the shutdown transformer to supply the two 4,160 V emergency buses at Pilgrim Station. The 23 kV line is conducted overhead with one 336 KC mil ACSR cable per phase.

The 23 kV line and the shutdown transformer are normally energized with power supplied from the Manomet Substation. Breakers 152-600 and 152-802 are operated normally closed, and breakers 152-801, 152-501 and 152-601 are operated normally open. Breaker A802 controls power from the shutdown transformer. Breaker A801 controls power from the blackout diesel generator (see section 8.9) which is a back-up source of power to the shutdown transformer. Refer to Figure 8.4-1 (Drawing E7 for breaker arrangement. The shutdown transformer and diesel generators supply power to the two 4,160 V emergency service buses (A or B). The A bus is separated from the B bus by a concrete floor. The 4,160 V cables from the shutdown transformer are run in an underground duct bank into the Turbine Building, and then in rigid steel conduit to the south end of emergency service buses A and B. Each diesel generator's power leads are run in a separate conduit and cable tray to the north end of each bus (A or B). Since the leads approach each bus from opposite directions, maximum possible separation is achieved.

2. Single Failure Analysis

The shutdown transformer and diesel generator power supplies to each emergency service bus are electrically independent as far as possible without compromising the independence of the safeguard A and B buses. For example, the DC supply to bus A controls are from battery A, hence both shutdown transformer and diesel generator supply breakers have a common control power source. The control power source for bus B is independent from bus A; however, control devices for each bus are separated from each other in the control board and their cables are routed separately to their respective switchgear buses.

The controls for the 23 kV transmission line feeding the shutdown transformer are located on the vertical section of the control board. The controls for the emergency diesel generators are located in the bench board section of the control board. This provides adequate separation. The controls for the shutdown transformer supply breaker to one 4,160 V bus are not separated from the controls for the diesel generator supply breaker to the same bus. The controls for the A and B buses are separated, however, to satisfy the design intent for separation of the two emergency service buses. DC control power is individually supplied to each switchgear bus, maintaining separate routing from separate batteries. Each diesel generator is individually supplied with DC control power, maintaining separate routing from separate batteries. The shutdown transformer protective relays receive dc power from 125 V DC panel C which may be supplied from either battery.

A single failure in the controls or interlocks in the standby AC power (diesel generator) supply breakers, or in the secondary AC power (shutdown transformer) supply breakers, would not permit simultaneous electrical interconnection of both diesel generators with the shutdown transformer. Therefore, the required independence of the standby AC power source and the secondary AC power source is maintained.

3. Separation 23kV-345kV lines

The 23 kV line crosses under the 345 kV lines at one location adjacent to Pilgrim Station. The 23 kV line is installed underground at the location where it crosses underneath the 345 kV transmission lines. The 23 kV line from the station is constructed on wood poles which run parallel to public streets for approximately 1.1 miles and which run parallel to the private access road to the station for 0.9 miles. The remainder of the 23 kV line is routed on a private right of way to the Manomet Substation.

The station design conforms to the intent of IEEE-308 1971, Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations. The 345 kV transmission supplies the preferred power supply. The 23 kV line supplies the secondary power supply. Additional access to the 345 kV supply is available within 8 hr following station shutdown by removal of the main generator disconnect link, and subsequent energization of the main and unit auxiliary transformers. Special provisions have been included in the station design for personnel access and rapid removal of the disconnect link to facilitate energization of the station auxiliary buses using this alternate access to the 345 kV source.

4. Conclusion

It can be concluded that the secondary AC offsite power source meets the offsite secondary power source requirement of GDC-17 and provides a reliable backup for one of the standby AC power supplies.

8.3.5 Inspection and Testing

Inspection and testing at vendor factories and initial system tests were conducted to insure that all components are operational within their design ratings.

The secondary AC power source functions as one of several available AC power sources. Operating limitations are related to the operability status of the standby AC power system as described in Section 8.5.6.

A test of the secondary shutdown transformer to supply buses A5 and A6 will be conducted each refueling outage. This sequential load test will ascertain the ability of NSTAR Company to supply the required load through the 5/5.6 MVA Shutdown Transformer upon demand with the addition of NSTAR expanded 23kV distribution.

8.8 120 VOLT AC POWER SYSTEM

8.8.1 Safety Objective

The 120V AC safeguard control power subsystem distributes the 120v AC power required to safely shutdown the reactor, maintain the shutdown condition and operate all instrumentation and control circuits necessary for safe shutdown.

8.8.2 Power Generation Objective

1. The 120V AC instrument subsystem supplies power to non-safeguard instruments, control to non-safeguard systems, and power to non-safeguard auxiliaries.

2. The 120/240V AC vital services subsystem provides power for vital services for which power interruption should be avoided. These vital services are necessary for the operation of the station but are not vital to station safety.

3. The 120V ac reactor protection subsystem shall provide power to the reactor protection system (RPS) logic monitors.

8.8.3 Safety Design Basis

1. The 120V AC safeguard control power subsystem distributes power to the 120V AC instrumentation and control loads which are essential to plant safety.

2. The 120V AC safeguard control power subsystem has adequate capacity to supply all loads required for normal and accident conditions, including the H2O2 Analyzer portion of the PASS System.

3. The 120V AC safeguard control subsystem is supplied from the emergency portion of the APDS, which is supplied from both off-site and on-site ac power sources.

4. The 120V AC safeguard control power subsystem is designed and installed to Seismic Class 1 Criteria.

5. The 120V AC safeguard control power subsystem is designed and installed in accordance with IEEE 308, Standard Criteria for Nuclear Power Generating Stations

6. The 120V AC power system, normal and safeguard portion, is arranged so that a single failure will not prevent or impair the operation of the essential station safety functions.

8.8.4 Power Generation Design Basis

1. The instrument subsystem distributes adequate power to the main control room instruments, the 24V dc battery chargers (described in Section 8.7), and to all other loads as shown on Figure 8.7-1 (BECo E14). The subsystem receives power from either of two ac sources.

2. The vital service subsystem has adequate capacity to power all loads shown on panel Y2 on Figure 8.7-1. Power is supplied from: (1) a motor-driven generator which may be powered from either an ac or a dc source, or (2) a second ac source. The motor-driven generator maintains the output voltage while the input is being changed from the ac to the dc source.

3. The reactor protection subsystem contains two ac motor-driven generators, each with adequate capacity to power the logic monitors of one trip channel. Alternate power is provided to both trip channels from a second ac source, powering either bus A or bus B, but not both.

8.8.5 Description

The 120V ac Power System consists of four subsystems: the instrument subsystem, the vital services subsystem, the reactor protection subsystem and the safeguard control power subsystem. See Figure 8.7-1 for all subsystems.

The instrument subsystem receives power from the Auxiliary Power Distribution System (APDS) described in Section 8.4. Power is normally supplied from 480V common emergency service bus B6 and automatically transferred to 480V emergency service bus B1 upon loss of power at the instrument bus. The instrument bus distributes power to all the conventional instrumentation and non-critical monitors and controls.

The instrument power supply transformer is rated at 37.5 KVA, 480-120/240V, single phase, three wire, 60 Hz. The standby instrument and vital services transformer is rated at 50 KVA, 480-120/240V, single phase, three wire, 60 Hz.

The instrument 120V ac power supply panel is a NEMA Type I, dead front, surface mounted panel with single pole manually operated circuit breakers.

The vital services subsystem receives power from the APDS described in Section 8.4, or from the 250V DC power system described in Section 8.6. Normally, power is distributed through a motor-generator set driven by an ac motor receiving power from 480V common emergency service bus B6. Upon loss of power to the ac drive motor, vital services power will continue to be supplied via a dc drive motor on the same shaft as the ac motor and vital services MG set. The dc drive motor is supplied from the 250V dc power bus. Return of ac power will cause an automatic transfer back to the ac drive motor.

A large flywheel maintains the output voltage level of the generator during each transfer. Upon loss of the motor generator set, ac power is automatically supplied through 480 V ac emergency service bus B1 and through the same path as the alternate supply to the instrument subsystem. Manual transfer is required to supply the vital service bus from the motor-generator set when it returns to service. The motor generator set as the normal power source provides 120/240 V ac power free of electrical noise and transient voltage dips.

The vital services motor-generator set is rated at 31.2KVA, 0.8 power factor, 120/240V, single phase, three wire, 60 Hz.

The standby transformer is common to the instrument subsystem described in Section 8.8.2.

The vital services 120/240 V ac power supply panel is a NEMA Type I, dead front, surface mounted panel with manually operated circuit breakers.

The reactor protection subsystem receives power from the APDS, described in 8.4. Power is normally supplied from 480V normal service buses B3 and B4 through two motor driven generators to two reactor protection logic monitor buses. Alternately, power may be supplied to either of the buses through 480V common emergency service bus B6.

The reactor protection motor-generator sets are each rated 18.75 KVA, 0.8 power factor, 120V, single phase, two wire, 60 Hz.

The two motor generator sets and the alternate power supply for the Reactor Protection System have class IE electrical protection assemblies installed. There are two protection assemblies, in series, for each RPS 120V, 60 Hz supply. A random, or seismically-induced abnormal voltage or frequency condition on the outputs of an MG set, or the alternate supply, would trip one or both of the two protective assemblies installed between a power supply and its respective RPS bus. This protects the RPS components and auxiliaries from damage due to sustained abnormal voltage conditions (over and undervoltage and underfrequency).

The reactor protection 120V AC power supply buses are in a NEMA Type I panel in isolated compartments with manually operated circuit breakers. See Section 7.2 for details.

The safeguard control power subsystem receives power from the APDS described in section 8.4. Power is supplied from 480V emergency service buses B17, B17a, B18, B18a, and B20 through stepdown transformers. The 208/120V ac safeguard subsystem supplies control power to the PCIS, PASS and PAM control panels. It also supplies control power to various other valves and control panels. The panels are NEMA class I, Type B wiring panels. The step down transformers supplying power to the panels are 15KVA, 480-120V, single phase, two wire, 60 Hz for panels Y4 and Y41; 10KVA, 480-120V, single phase, two wire, 60 Hz for panels Y3 and Y31, 25KVA, 480 122/244V, single phase, two wire, 60 Hz for panels Y13 and Y14; and 15KVA, 480-208/120V, 3 phase, 4 wire, 60 Hz for panels Y6, Y7 and Y8.

The 10KVA stepdown transformer for distribution panels Y3 and Y31 is voltage regulating type maintaining output voltage at 120VAC ± 4% for voltage inputs of 480VAC + 10% / -25% for panels Y3 and Y31 . The 25KVA step down transformers which supply power to distribution panels Y13 and Y14 are voltage regulating type maintaining output voltage at 122VAC ± 4% for voltage inputs of 480VAC ± 20%. During undervoltage transients below 480VAC -25% for panels Y3 and Y31 and below 480V -20% for panels Y13 and Y14, the regulating transformers will select the highest transformer tap to maximize the output voltage as close to 120V AC as possible. During overvoltage transients above 480VAC +10% for panels Y3 and Y31 and above +20% for panels Y13 and Y14, the regulating transformer will select the lowest tap to limit the output voltage as close to 120VAC as possible.

The 15KVA stepdown transformer which supplies panels Y4 and Y41 is voltage regulating type but operated in "BYPASS" mode with fixed tap voltage of 480VAC:122.1VAC.

The RPS components which are located inside the primary containment, and which must function in the environment resulting from a break of the nuclear system process barrier inside the primary containment, are the condensing chambers and associated variable and reference leg piping. Special precautions are taken to ensure satisfactory operability after the accident.

8.8.6 Inspection and Testing

Inspection and testing at vendor factories and initial system tests were conducted to insure that all components are operational within their design ratings.

Periodic tests of the equipment and system will be as follows:

Operation Test	*
Mechanical Inspection	2 Years
Overhaul	When Required
Breaker Overcurrent Trip Test	*
RPS Electrical Protection Assemblies:	
Instrument Functional Test	Every 18 months
Instrument Calibration	Once per 18 months
Circuit Breaker Testing	Once per 18 months

* When operation of generating station permits

8.9 CABLE INSTALLATION CRITERIA

8.9.1 General Design Criteria

This section defines the criteria for safety and non-safety systems that are applicable through the plant unless the more stringent criteria in Section 8.9.3 apply.

Installation by Cable Function

Medium voltage cables (4,160 V) shall be installed in covered cable trays or conduits separate from other cables.

Low voltage power (480 V and below) and control (120V ac or 125V dc) cables shall be installed in cable trays or conduit separate from other cables. A metal barrier strip shall be used to separate power from control wiring in the same cable tray. Power and control cables are permitted in the same conduit only to motors 15 hp and smaller. For allowable intermixing, see Cable Intermixing in Section 8.9.2

Low level signal cables shall be installed in cable trays or conduits separate from other cables. The cable trays shall have covers when directly below a low voltage power and control cable tray or below a medium voltage cable tray. For allowable intermixing, see Cable Intermixing in Section 8.9.2

Exceptions to the above criteria will be approved by the Electrical Engineering Department. Any cables which are installed without conduit or a cable tray shall be nonsafety related for communication, computer and monitoring systems. Temporary modification can also install cable without a conduit or cable tray. The Plant Design Change, Field Revision Notice or temporary modification shall ensure the design intent of this section of the FSAR is not compromised. The cables shall be flame retardant and supported properly.

Where practical, the following sequence from top to bottom shall be used when stacking trays:

1. Medium voltage power
2. Low voltage power and control
3. Low level signal
4. Computer

The minimum vertical distance (tray bottom to tray top) is 12 in between trays containing power cables (ventilated). The minimum is 10 in when the tray below does not contain power cables (non-ventilated). Less than minimum spacing, as defined in this section, may be permitted if a review is made to assure that overheating will not occur.

8.9.2 Specific System Wiring Criteria

Reactor Protection System

The Reactor Protection System (RPS) consists of two independent trip systems (A and B) and two independent trip logics (A1, A2 for trip system A; B1, B2 for trip system B). The four input channels to the logic (A1, A2, B1, B2) are routed in four separate conduits or enclosed gutters to maintain channel independence.

Wiring and cables for RPS instrumentation are selected to avoid excessive deterioration due to temperature and humidity during the design life of the plant. Cables and connectors used inside the primary containment are designed for continuous operation at an ambient temperature of 150°F and a relative humidity of 99 percent.

The wires from duplicate sensors on a common process tap are run in separate conduits. Low level signal and power circuits are each run in separate rigid metallic conduits. Wires for sensors of different variables in the same RPS logic run in the same conduit.

The scram pilot valve solenoids are powered from eight actuator logic circuits; four circuits from trip system A and four from trip system B. The four circuits associated with any one trip system are run in separate conduits. One actuator logic circuit from each trip system runs in the same conduit; wiring for the two solenoids associated with any one control rod runs in the same conduit.

The neutron monitoring cables beneath the reactor vessel are an exception to the general rule. They are not routed in conduit because of space limitations and need for flexibility of cables. However, these cables are grouped and separated to obtain effective channel independence. Cables through the primary containment penetrations are not in separate conduit but are grouped so that failure of all cabling in a single penetration cannot prevent a scram.

Electrical panels and components of the RPS are prominently identified by nameplate. Each cable is uniquely marked at each termination as part of the RPS.

Engineered Safeguard Systems

The Engineered Safeguard Systems (ESS) include the Core Standby Cooling Systems (CSCS), the Reactor Building Isolation and Control System (RBICS), and required auxiliary systems. The ESS are separated into two principal divisions identified as SA and SB. A third division, SX, consists of components which may be transferred between the SA and SB divisions. When cables in the three divisions are routed in cable trays, the following minimum separation requirements apply.

1. Horizontal separation of 3 ft. or a vertical fire barrier shall exist between independent safety system cable trays.

2. Vertical separation of 5 ft plus a horizontal fire barrier shall exist between independent safety system open top cable trays which are stacked vertically one above the other, regardless of the intervening trays. The fire barrier shall be installed directly beneath the uppermost safety system tray.

3. Crossovers of independent safety system cable trays (including a safety system cable tray crossing an independent safety system) shall have 5 ft vertical separation or a horizontal fire barrier shall be installed.

4. When a non-safety system cable tray crosses over or under two independent safety system cable trays in one room or compartment, either a horizontal fire barrier shall be installed or a fire stop shall be installed in the non-safety system cable tray.

One of the following installation criteria must apply to redundant cables and associated non-safety circuits of the three safety divisions whose functions are necessary to achieve and maintain cold shutdown conditions:

(a) Separation of redundant cables and equipment and associated circuits by a fire boundary having a 3 hour fire rating; or

(b) Separation of redundant cables and equipment and associated circuits by a horizontal distance of more than 20 feet with no intervening combustibles or fire hazards. In addition, fire detectors and an automatic fire suppression system are installed in the fire area; or

(c) Enclosure of one train of redundant cables and equipment and associated circuits by a fire barrier having a one-hour fire rating. In addition, fire detectors and an automatic fire suppression systems are installed in the fire area; or

(d) Alternate or dedicated shutdown capability provided for one train of redundant cables and equipment and associated circuits. The alternate or dedicated shutdown capability is not affected by a fire in the fire zone that alternate or dedicated shutdown capability is provided for.

Primary Containment Isolation System

The cables associated with input sub channels to the Primary Containment Isolation System (PCIS) are treated in the same manner as the input sub channels to the RPS as described in Reactor Protection System in Section 8.9.2. The cables associated with operation of actuated devices are treated in the same manner as the ESS cables as described in Section 8.9.2, Engineered Safeguard System.

Cable Intermixing

The RPS cables and input to the PCIS may be routed together but no other cables are permitted in the same raceways.

Nonsafety-related cables may be routed in raceways with ESS cables of only one independent division. For example, a nonsafety system cable may mix with SA cables but this same nonsafety cable may not also mix in SB or SX cable raceways.

Nonsafety-related low voltage power and control cables, although normally separated from each other per Section 8.9.1, Installation by Cable Function, are permitted to mix in the same cable tray.

Low level signal cables may be permitted to mix with control cables if a review is made to assure that any spurious signals due to electrical noise will have no effect of safety significance.

8.9.3 Physical Separation and Protection Design Criteria

This section defines the criteria for physical separation and protection against concurrent failure of functionally independent safety systems by a single credible event external to the systems. The safety systems and required functional independence are described in Appendix G. The portions of safety systems considered are those components (sensors, sensing lines, process lines, and electrical cables) required to initiate and control a system to meet its design Safety function. The single events considered are those credible events that could cause safety systems failure coincident with a need for the affected system function to keep the plant in a safe condition. These events are defined below together with the criteria for physical separation and protection of independent safety systems necessary to accomplish the required degree of single failure independence. These criteria are considered minimum requirements and design guidelines for use in the absence of a confirming design review to support less stringent requirements.

Mechanical Damage (Missile) Area

Arrangement and/or protective barriers shall be such that no locally generated missile can prevent independent safety system components from performing their design safety function.

Potential missiles considered shall be limited to valve stems and thermowells that could originate from a process system which is normally pressurized to reactor pressure. Trajectory cones of 20 deg divergence shall be used to define the missile hazard areas. Minimum separation of independent safety system components shall be taken normal to the trajectory cone in accordance with Table 8.9-1.

An exception to this is that valve stems are not considered potential missiles if at least one feature in addition to the stem threads is included in their design to prevent ejection. Valves with backseats are prevented from becoming missiles by this feature. In addition, air or motor operated valve stems are effectively restrained by their operators.

In areas where large rotating equipment will be operating, a minimum separation of 20 ft between independent safety system components or the equivalent of a 6 in thick reinforced concrete wall shall separate either (1) the independent safety system components from each other or (2) the hazard from one of the components.

In any area containing an operating crane, independent safety system components shall be horizontally separated by 20 ft or the equivalent of a 6 in thick reinforced concrete wall.

Fire Hazard Area

Arrangement and/or protective barriers shall be such that a fire cannot prevent both independent safety system components from performing their design safety functions. Only components which are susceptible to fire shall be considered.

Locating components of independent safety systems in areas where there is the potential for accumulation of a significant quantity of flammable materials shall be avoided. Where unavoidable, mechanical components shall be separated and protected by fire resistant materials and/or automatically actuated Fire Protection Systems. Electrical and instrumentation components of only one independent safety system shall be permitted in a fire hazard area and where necessary they shall be protected by fire barriers.

In areas containing both independent safety system electrical and instrumentation components, piping containing flammable liquids or vapors shall be separated from the nearest safety system component by 20 ft or by fire barriers.

Flooding Hazard Area

Arrangement and/or protective barriers shall be such that a pipe rupture and flooding cannot prevent independent safety system components from performing their design safety functions. Only components which are susceptible to water damage shall be considered.

Locating components of independent safety systems in areas where there is the potential for flooding shall be avoided. Where unavoidable, the components shall be separated by water tight doors or located above the maximum possible flood level, and where necessary, protected by splash proof enclosures or shields.

Cable Spreading Room

Where cables of independent safety systems approach each other entering panels or room penetrations with less than 3 feet horizontal or 5 feet vertical separation, at least one of the cables shall be run in rigid or flexible conduit until this separation exists.

Control and Relay Panels

When two panels containing independent safety system components are less than 3 feet apart, there shall be a steel barrier between the two panels. Panel ends closed by steel end plates are acceptable when cables and components are at least one inch from the end plate.

When one panel contains both independent safety system components, either:

1. A minimum separation of 3 feet must exist between cables and components of the two divisions

2. The cables and components of the two divisions must be separated by a fire barrier

3. A minimum of one safety system's set of cables must be enclosed in rigid or flexible conduit

4. None of the above if a design review is performed to ascertain that the apparent deviation from the separation criteria does not compromise plant safety. The acceptable deviations shall be denoted by a secondary color coding

As stated in Item 2, penetration of the fire barriers for wiring is permitted, provided that such penetrations are sealed or otherwise treated to provide a fire stop to maintain the required functional independence.

8.9.4 Installation Evaluation

An evaluation of the plant installation shall be performed to ascertain that the installation has complied with the intent of the criteria described above.

8.9.5 Cable Protection and Process Instrumentation Location Criteria

Drywell electrical penetrations are physically grouped at four locations separated at approximately right angles around the drywell. Figure 8.9-1 illustrates the grouping and assignment of drywell electrical penetrations.

The total cable cross sectional area is generally limited to 30 percent of tray cross sectional area. Tray fill greater than 30 percent is approved by engineering only after review to ensure that cable damage, either mechanical or thermal, will not take place. With the large diameter power cables, fill may exceed 30 percent when limited to a single cable layer.

The protective and safety system power and control cable insulation was selected, considering electrical service requirement, voltage level, to provide additional protection against the propagation of fire and capability to withstand the environmental conditions.

Power cables are derated according to Insulated Power Cable Engineers Association (IPCEA) procedures depending on the type of raceway, ambient temperature, spacing, etc.; however, voltage drop and fault current may be the governing factors of sizing the cable.

Overload protection is provided by the proper selection and setting of relays, circuit breakers, heaters, and fuses.

Fire stops are provided where cable trays pass through wall or floor blockouts. Openings around cables from the cable spreading room up into the control room are sealed with fire resistant materials. Openings around cables penetrating fire barriers which separate two ESS divisions are sealed with fire resistant materials.

Fire detection systems are located in strategic areas throughout the plant. In the cable spreading room, fire protection is provided by a gaseous fire suppression system automatically actuated by fire detectors. Smoke detection is used in the cable spreading and computer rooms, the safety systems switchgear areas, and both diesel generator areas to provide early warning of potential fire hazard.

Each protection and safeguard system cable is identified with a cable marker indicating "from" and "to" locations and the "scheme cable number." Safeguard system cable markers have a prefix designating the safeguard division.

RPS cable markers have a prefix identifying each division. The safeguard system cables and raceways are marked with distinctive colors for easy identification.

The design engineering staff is responsible for ensuring that the design meets the above criteria. Control and assurance that the cable is installed in accordance with the design instructions are provided by the Quality Control and Quality Assurance Programs. Construction forces are only permitted to route cables as designated by design engineering.

Deviations are permitted only with the approval of design engineering. Field inspection verifies proper installation workmanship and compliance with design instructions; including cable type, identification, routing, and connections; and raceway type, identification, and routing.

Spatial separation and the natural protection afforded by the biological shield are used to preserve the independence of redundant sensors and sensing lines considering the requirements for safety functions.

The temperature equalizing columns and condensing chambers for reactor vessel sensors are located on opposite sides of the drywell and the sensing lines are routed to widely separated penetrations.

The principal safety related sensors inside the primary containment are the main steam isolation valve limit switches. Cables between these sensors and electrical penetrations are protected by rigid steel conduit or enclosed metallic gutter.

SECTION 9

RADIOACTIVE WASTE SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

SECTION 9

LIST OF TABLES

SECTION 9

LIST OF FIGURES

SECTION 10

AUXILIARY SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

SECTION 10

LIST OF TABLES

SECTION 10

LIST OF FIGURES

SECTION 10

LIST OF FIGURES

10.3 SPENT FUEL STORAGE

10.3.1 Power Generation Objective

The power generation objective of the spent fuel storage racks and the spent fuel storage pool is to provide specially designed underwater storage space for the spent fuel assemblies which require shielding during storage and handling.

10.3.2 Power Generation Design Basis

1. Spent fuel storage racks are supplied for the storage of a maximum number of fuel assemblies.

2. The spent fuel storage racks and the spent fuel storage pool are designed to allow efficient handling of the fuel assemblies during refueling operations.

10.3.3 Safety Design Basis

1. The spent fuel storage racks are designed to maintain, when fully loaded with fuel assemblies, a subcritical configuration having a k_{eff} <0.95 for normal and abnormal conditions, as defined in Section 10.3.4.

2. The storage pool and concrete structures provide a sufficient depth of water and sufficient concrete thicknesses to adequately shield station personnel from radiation emitted by a full load of spent fuel assemblies.

3. The fully loaded spent fuel storage racks, supports, and pool concrete structures are designed to Class I standards.

10.3.4 Description

10.3.4.1 General

The spent fuel storage racks provide storage at the bottom of the fuel pool for the spent fuel received from the reactor vessel. See Figure 10.3-1. The racks are full length, top entry, and designed to maintain the spent fuel in a space geometry which precludes the possibility of criticality under normal and abnormal conditions. Normal conditions exist when the spent fuel is stored at the bottom of the fuel pool in the design storage position. Abnormal conditions may result from:

- Increased temperature
- Boiling
- Reduced moderation density
- Fuel assembly positioning (rack bending)
- Assembly placed outside rack
- Dropped fuel assembly
- Lost/Missing absorber plate

The standard spent fuel racks, shown on Figure 10.3-1, are a modular design of varying sizes. Each rack has the capacity to store an average of 260 spent fuel assemblies. The fuel pool has a licensed capacity of 3859 fuel assemblies. With the present inventory of fuel racks in the pool, PNPS only has the capacity to store 3404 fuel assemblies. The racks are free standing.

Nine racks are made up of welded stainless steel assemblies in the shape of cruciforms, angles, and tees. Sheets of Boraflex poison material are sandwiched between the stainless steel sheets creating a welded assembly. The rack assembly is shown on Figure 10.3-1.

The remainder of the racks are made up of welded stainless steel boxes. Sheets of Boral or Metamic poison material have been sandwiched between the box walls and a stainless steel sheath welded to the box walls for the purposes of holding the poison in position. Refer to Figures 10.3-4, 10.3-5 and 10.3-6.

The pool configuration for the existing and new racks plus the future expansion racks are shown in Figure 10.3-7.

The racks are designed to withstand a pull-up force equal to 4,000 lb acting on the rack corner (necessary in the event that a fuel assembly or grappling device acting on the rack corner binds during removal). The maximum allowable stress on the members required to maintain the subcritical condition will not exceed 75 percent of the material yield strength or 75 percent of that stress at which local buckling occurs.

No spaces exist between normal fuel storage positions so that it is not possible to insert a fuel assembly, either deliberately or by accidental drop, in any position not intended as a fuel storage position, except as analyzed. See Section 10.3.5.

Each fully loaded spent fuel storage rack is designed as a Class I structure. The spent fuel racks are designed such that the stresses in a fully loaded rack do not exceed applicable American Institute of Steel Construction or American Society of Civil Engineers specification requirements when subjected to the seismic loads resulting from the Safe Shutdown Earthquake. Both the horizontal and vertical forces due to the earthquakes are considered to act simultaneously. Acceleration time-histories resulting at the spent fuel pool floor during the Safe Shutdown Earthquake are used as input to the dynamic analysis of the racks.

The storage rack structure is designed to absorb the vertical impact force imposed by a fuel assembly dropped from a height of 36 in above a rack onto any location on the rack. Under this impact force, those members, whose function is to physically maintain the normal design subcritical spacing to assure $k_{eff} \leq 0.95$, will remain intact.

All materials used in the construction of the rack are specified in accordance with the latest issue of applicable ASTM specifications, and all welds are in accordance with AWS standards or ASME Section IX for materials used. Materials selected are corrosion resistant or treated to provide the necessary corrosion resistance.

Special brackets have been designed to hang control rod blades from the spent fuel pool curb. Design calculations and administrative controls have been established to identify acceptable radiological limits for storing material in the spent fuel pool. Hanging control rod blades from the spent fuel pool curb is within the plant shielding design as specified in Sections 12.3.1.1 and 12.3.3.2.

The spent fuel storage pool has been designed to withstand earthquake loading as a Class I structure. It is a reinforced concrete structure, completely lined with seam-welded stainless steel plates welded to reinforcing members (channels, I-beams, etc) embedded in concrete. Interconnected drainage monitoring channels are provided behind the liner welds. These channels are designed to (1) prevent pressure buildup behind the liner plate, (2) prevent the uncontrolled loss of contaminated pool water to other relatively cleaner locations within the secondary containment, and (3) provide necessary detection and measurement of liner leaks. These drainage channels are formed in the concrete behind the liner and are designed to permit free gravity drainage to the floor drainage sump. The passage between the spent fuel storage pool and the refueling cavity above the reactor vessel is provided with two double sealed gates with a monitored drain between the gates. This arrangement permits monitoring of leaks and facilitates repair of a gate or seal, if necessary.

To avoid unintentional draining of the pool, there are no penetrations that would permit the pool to be drained below a safe storage level (approximately 10 ft above the top of the fuel). Lines extending below this level are equipped with siphon breakers to prevent siphon backflow. Two epoxy phenolic-lined carbon steel skimmer surge tanks are sized to take into account the placement of large items such as the spent fuel cask into the pool.

Makeup water to the fuel pool is transferred from the condensate storage tanks directly to the skimmer surge tanks to make up for normal fuel pool losses. The available methods of providing makeup water to the spent fuel pool include the following:

1. Condensate transfer system with either of the two condensate transfer pumps operating can provide water through two paths:

   a. 3-inch piping directly to the fuel pool skimmer surge tanks with a maximum flow rate of 200 GPM.

   b. 10-inch piping to the spent fuel pool cooling system (SFPCS) discharging directly to the fuel pool or to the filter-demineralizer train with a flow rate of approximately 1100 GPM.

2. Demineralized water transfer system 4-inch piping to the spent fuel pool, reactor basin, and dryer separator pool service boxes. Either of the two demineralized water transfer pumps can provide 100 GPM to the service boxes which may be connected to discharge to the fuel pool.

3. The fire protection system (FPS) has two hose stations on the refuel floor (Elev. 117 ft). The FPS can be fed from the electric motor driven fire pump or the diesel engine driven fire pump, each rate at 2000 GPM, drawing water from either of the two fire water storage tanks. Each hose station is rated to discharge 150 GPM.

4. After the reactor has been brought to the cold shutdown condition, the RHR/SFPCS intertie may be used to add makeup water to the fuel pool if the other methods described above are not available. The fire protection system is connected to the RHR loop cross-tie to which the RHR/SFPCS intertie is also connected thus delivering water from the FPS directly to the fuel pool. One loop of RHR using one pump may also be used to deliver water from the torus to the fuel pool while the other RHR loop maintains shutdown cooling of the reactor.

The condensate and demineralized water transfer systems include three alternate storage tanks, four pumps, and three separate flow paths to the SFPS. The FPS is configured with a ring header arrangement that provides two independent flow paths to each hose station. During a loss of off-site power, the FPS diesel fire pumps and mobile fire engines, if needed, would be available.

10.3.4.2 Fuel Pool Level Indicators

Low water level alarms are provided locally and in the main control room in the event of water loss from either rupture of the fuel pool wall liner, or the rupture of the reactor basin refueling bellows. (The alarm from the reactor basin is isolated during station operation.) As a backup, flow alarms are provided in the drain lines of the reactor vessel to drywell seal, drywell to concrete seal, and fuel pool gate to detect leakage. See Section 10.4.

10.3.5 Safety Evaluation

The design of the spent fuel storage provides for a $k_{eff} \leq 0.95$ for both normal and abnormal storage conditions. Normal conditions exist when the fuel storage racks are located at the bottom of the pool covered with a normal depth of water (about 25 ft above the stored fuel) and with fuel assemblies in their design storage positions. Abnormal conditions may result from abnormal location of a fuel assembly adjacent to the fuel storage racks, eccentric positioning of a fuel assembly within a fuel storage cell, zirconium fuel channel distortion, a dropped fuel assembly, or fuel rack lateral movement.

Analysis of the reactivity effects has been completed twice, first for the existing high density racks by Southern Science (Reference 3) and second by Holtec International (References 4 and 10) for the new racks. The Holtec Analysis bounds the existing analysis and, hence, provides acceptance criteria for storage of reactor fuel equally applicable for both the old and new spent fuel racks.

These analyses of the reactivity effects were performed with both the CASMO-3 computer code (a two-dimensional multi-group theory code) and the KENO-5a code (a Monte Carlo code), using the 27 energy group SCALE neutron cross section library. CASMO-3 was used as the primary method of analysis as well as the means of evaluating small reactivity increments associated with manufacturing tolerances. Burn up calculations were also performed with CASMO-3. KENO-5a was used to perform an independent verification of the CASMO-3 results as well as to assess the reactivity consequence of eccentric fuel positioning and abnormal locations of fuel assemblies. Both codes are widely used for the analysis of fuel storage rack reactivity and have been benchmarked against results from numerous critical experiments.

An assessment of the reactivity has also been performed using TGBLA06 in place of CASMO-3 and MCNP-05P in place of KENO-5a. This analysis concluded that acceptance criteria established by the Holtec analysis are also appropriate for use with GNF 10 x 10 fuel.

To ensure that true reactivity will always be less than the calculated reactivity, the following conservative assumptions were made:

1. The racks contain the most reactive fuel authorized to be stored in the facility without any controls or any uncontained burnable poison, and with the fuel at the burn up corresponding to the highest reactivity during its burn up history.

2. Moderator is pure, unborated water at a temperature within the design-basis range corresponding to the highest reactivity.

3. Criticality safety analyses are based on the infinite multiplication factor ($K\infty$); that is, lattice of storage racks is infinite in all directions, except in the assessment of certain abnormal/accident conditions where neutron leakage is inherent.

4. Neutron absorption effects of minor structural material are neglected.

For the design basis reactivity calculations, uncertainties due to tolerances in the following were accounted for: boron loading, Boral thickness, cell lattice spacing, stainless steel cell wall thickness, and fuel enrichment and density. These uncertainties were statistically combined at the 95 percent probability, 95 percent confidence (95/95 probability/confidence) level. In addition, a calculation bias of 0.01 Δk was added to account for possible differences between fuel vendor calculations and those performed here.

The resulting conservative criteria for acceptable storage of fuel in the spent fuel storage racks at Pilgrim Station are:

1) Fuel must have lattice-average enrichment of 4.6% or less.

2) The K_∞ in the standard core geometry, calculated at the burn up of maximum bundle reactivity, must be 1.32 or less.

Together these criteria satisfy the USNRC criteria that K_{eff} of fuel storage racks be maintained less than or equal to 0.95.

The reactivity effects during abnormal and accident conditions due to the effects of temperature and water density, abnormal location of a fuel assembly, eccentric fuel assembly positioning, fuel rack lateral movement or the dropping of a fuel assembly on top of the storage rack were considered. None of the credible conditions resulted in exceeding the limiting reactivity criterion of K_{eff} no greater than 0.95.

Reactivity calculations discussed above assume that the neutron absorbing material incorporated in the design of the fuel storage racks maintains its installed configuration and material properties. However, the older design employs Boraflex, a polymer which has demonstrated shrinkage under irradiated conditions including exposure to gamma fluxes from stored spent fuel. When further exposed to water, the polymer erodes and washes out of the racks. Initial in-situ examinations of highly exposed Boraflex material in the PNPS spent fuel racks has confirmed the expected shrinkage, but did not indicate erosion. The test results are reported in reference 11. Reactivity calculations, as previously described, were repeated to allow evaluation of potential future changes in the condition of various Boraflex parameters to determine the extent of further degradation that may be acceptable. The results are reported in reference 12. For the same fuel criteria discussed above, the K_{eff} remains less than 0.95.

Fuel in the spent fuel storage pool is covered with sufficient water for radiation shielding. Low water level alarms are provided locally and in the main control room in the event of water loss from either rupture of the fuel pool wall liner or the rupture of the reactor basin refueling bellows. As a backup, flow alarms are provided in the drain lines to detect reactor vessel to drywell seal, drywell to concrete seal, and fuel pool gate leakages. An adequate fuel pool water level is maintained even in the unlikely event of a pipe break between the skimmer surge tanks and the fuel pool cooling system pumps, since fuel pool discharge to the skimmer surge tanks is by overflow only. Thus, a pipe break would drain the skimmer surge tank but not reduce the fuel pool level. Siphon-breakers prevent siphon backflow through the fuel pool cooling system discharge pipes.

Criticality monitoring shall be in accordance with the requirements of 10 CFR 50.68(b).

10.3.6 Consequences of a Dropped Fuel Cask

The spent fuel pool is designed as a Class I structure using the design criteria described in Appendix C and Section 12. The loading combinations considered do not include the forces generated by a heavy falling object such as a spent fuel handling cask, and it must be conservatively assumed therefore that such an event could potentially result in localized damage to the spent fuel pool floor and liner.

To preclude a cask handling accident six shop tests were performed:

1. Main Hook: Load tested to 200 percent capacity followed by magnetic particle and ultrasonic testing. Dimensional checks conducted prior and subsequent to load testing.

2. Rope Tests: Sample pieces from each rope end piece receive destructive breaking strength tests prior to final splicing.

3. Girder Welds: Three test samples of girder cover plate to web plate automatic welds are radiographed.

4. Trolley Welds: Visual inspection with weld size gage.

5. Gear and pinion blanks, shafts, couplings and brakes for hoist drive are examined by magnetic particle or ultrasonic methods.

6. Swivels, load block frames, and hook trunnions are examined by ultrasonic or magnaflux methods.

<u>Field Tests</u>

1. No-load tests: A no-load operational test was conducted to verify proper operation of all controls, brakes, limiting devices, and lifting speeds.

2. Load test: The crane was loaded to 105 percent of rated load (100 tons). The load was raised from the 23 ft elevation to the 117 ft elevation and moved to center span where deflection measurements were taken. The load was moved through the full range of bridge and trolley limits. During the loaded test, a complete operational checkout was repeated.

In addition to the use of conservatively designed hoisting equipment, load testing, and examination prior to cask handling to verify sound equipment and minimize the possibility of a dropped cask (see Section 10.3.7), an energy absorbing system is provided on the floor of the fuel pool in the cask handling area in order to minimize pool damage in the event of a dropped cask. The energy absorbing system consists of approximately 3 ft of aluminum "Hexcel" honeycomb and a high strength steel load distribution plate. The energy of the falling cask would be transmitted to the "Hexcel" honeycomb core which has an available crushing distance of approximately 70 percent of the core thickness. Analysis has demonstrated that with the energy absorber in place, damage to the floor will not result in a leakage rate greater than the pool makeup capability.

In order to maintain its energy absorbing function and fuel pool water quality, the "Hexcel" core is enclosed in a watertight stainless steel box. The energy absorber is designed so that it can be lifted out of the fuel pool, and is to be provided with connections which will permit periodic testing for leak tightness.

In the unlikely event of a fuel cask drop through the equipment hatch during cask handling operations, the cask would fall back onto the transport vehicle which could absorb, dissipate, and distribute over a wide area most of the kinetic energy of the cask. Under the most severe postulated conditions, which assume the transport vehicle and the reactor building floor at el 23 ft do not stop the cask, the cask could land in the torus compartment at el -17 ft 6 in and could strike and damage the torus.

Regardless of the degree of penetration of the cask or the location at which it ultimately stops, the ability to safely achieve plant shutdown, cool down, and depressurization is not jeopardized. The reactor would be immediately shut down. Cool down and depressurization would be initiated using the turbine bypass to the condenser and feedwater system. At the appropriate time the shutdown cooling mode of the residual heat removal system (RHR) would be initiated using the RHR and reactor building closed cooling water systems (RBCCW) unaffected by the cask drop.

10.3.7 Inspection and Testing

Leak detection channels are provided on the concrete side of the spent fuel storage pool liner. Surveillance of flow from these leak channels will permit early determination and localization of any leakage.

The spent fuel racks require no special inspection and testing for nuclear safety purposes. A commitment was made in response to Generic Letter 96-04, Boraflex Degradation of Spent Fuel Pools, to a periodic material surveillance of the Boraflex material cell panels installed on spent fuel pool racks. A separate commitment was made to an accelerated surveillance program for Boral test coupons installed in the spent fuel rack area as part of License Amendment 155 (increased spent fuel storage capacity). A similar surveillance program will be used for Metamic poison material.

Prior to cask handling operations a visual inspection of cables, sheaves, hook, yoke, and cask lifting trunnions is made. Following these inspections no-load mechanical and electrical tests are conducted to verify proper operation of crane controls, brakes, and lifting speeds. A load test is then conducted by lifting the empty cask approximately 1 ft off its transport vehicle. Once again all critical elements, controls, and lifting speeds are examined and tested in the loaded condition. Additionally, this test is used to verify that no significant movement occurs after an interval in the loaded condition.

After confirmation of the operational acceptability of the crane, the fuel cask is hoisted to the refueling floor and moved over a prescribed path to its position in the fuel storage pool. Travel over the spent fuel storage pool with the refueling cask is limited to that small area provided for cask use.

Preventive maintenance procedures include inspection and testing of crane controls, brakes, and rigging. Hooks are examined by nondestructive testing methods.

The proper application of prescribed industrial specifications in the design of the reactor building crane provides an adequate safety margin over the designed lifting capacity. Inspection, maintenance, and operating procedures as described in the preceding paragraphs will assure that an adequate safety margin is maintained throughout the lifetime of the plant.

10.3.8 References

1. American National Standard, "Design Objectives for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations", ANS-57.2, ANSI N210-1976.

2. US Nuclear Regulatory Commission "Standard Review Plan", Office of Nuclear Reactor Regulation, NUREG-0800.

3. Southern Science Co., "Criticality Safety Analysis of the High Density Spent Fuel Storage Racks for the Pilgrim Nuclear Power Station", SSA-159 (SUDDS/RF 85-40, March 1985).

4. GE Letter ELH: 85-079, from E. L. Heinlein to R. G. Clough, "Transmittal of K-infinity Calculations", September 23, 1985.

5. Holtec International "PNPS Spent Fuel Storage Capacity Expansion" Licensing Report #HI-92925, (SUDDS/RF 93-01)

6. Holtec International "Single Rack Analysis" Report #HI-92927 (SUDDS/RF 94-23)

7. Holtec International "Spent Fuel Pool Slab Analysis" Report #HI-92952 (SUDDS/RF 94-24)

8. Holtec International "Whole Pool Multi Rack Analysis" Report #HI-92929 (SUDDS/RF 94-27)

9. Holtec International "Thermal Hydraulic Analysis" Report #HI-92936 (SUDDS/RF 94-28)

10. Holtec International "Criticality Safety Analysis" Report #HI-92939 (SUDDS/RF 94-29)

11. Holtec International "Blackness Testing of Boraflex in Selected Cells of the Pilgrim Station Spent Fuel Storage Racks", Report #HI-60935 (SUDDS/RF96-57).

12. Holtec International "Criticality Safety Analyses of the Pilgrim Spent Fuel Storage Racks with Degradation of the Boraflex Neutron Absorber", Report #HI-91709 (SUDDS/RF97-43).

13. Holtec International "In-Situ Neutron Absorber Surveillance Program", HSP-10

10.8 FIRE PROTECTION SYSTEM

10.8.1 Power Generation Objective

The power generation objective of the fire protection system is to provide adequate fire protection capability in all areas of the station and to ensure safe shutdown in the event of a fire in any area of the plant.

10.8.2 Power Generation Design Basis

The fire protection system is designed to furnish water, halon, carbon dioxide, and/or dry chemicals as necessary for fire extinguishment in the station. The fire protection system is designed to provide the following:

1. A reliable supply of fresh water for fire fighting

2. A reliable system for delivery of water to potential fire locations

3. Automatic fire detection in selected areas

4. Fire extinguishment or control by fixed equipment activated either automatically or manually for areas with a high fire risk

5. Manually operated fire extinguishing equipment for use by operating personnel at selected points throughout the station

In addition, an alternate shutdown system has been installed to ensure that the station's safe shutdown capability is not adversely affected by a fire (Reference 6).

The requirements contained in the Entergy Quality Assurance Program Manual (QAPM) are applied to those activities affecting fire protection systems and equipment required to limit fire damage to safety-related structures, systems, and components so that the capability to safely shut down the plant is ensured.

10.8.3 Description

The fire protection system, piping and instrumentation diagram is shown on Figure 10.8-1 (BECo M218).

10.8.3.1 Fire Water System

The site fire water supply is taken from two 250,000 gal, lined carbon steel water tanks which are devoted exclusively to fire protection. The fire water system may also use water from a city water main.

The water supply is delivered by either an electric motor-driven pump (rated at 2,000 gal/min) or a diesel engine driven pump (rated at 2,500 gal/min). The diesel engine driven pump is used for standby and emergency use on loss of ac power. A hydro turbine driven by diesel fire pump P-140 drives the backup diesel fuel transfer pump (P-181). This pump takes suction from the emergency diesel generator fuel oil storage tanks, bypasses diesel transfer pump P141-A and discharges to day tank T-123. The purpose of this hydro turbine driven pump is to provide a redundant (non-electric power dependent) diesel fuel oil transfer pump for the diesel fire pump P-140. This redundant pump will allow extended operation of the diesel fire pump as a water source for the RHR system during extended station blackout and severe accident scenarios beyond design basis. A small jockey pump (rated at 50 gal/min) is provided to maintain a constant pressure for the water system. If the system pressure drops substantially, the motor-driven fire pump will start automatically, and if pressure continues to drop, the diesel-driven pump will also start automatically.

The pumps feed outdoor fire hydrants, interior hose stations, sprinkler systems, and deluge systems for the station.

As part of the Safety Enhancement Program (SEP), a piping connection is provided from the Fire Protection System to the RHR System. This connection will allow water from the Fire Protection System fire pumps to flow to the upper containment spray header, torus spray header, and/or LPCI injection lines during a severe accident or station blackout.

The interconnection of the Fire Protection System and the RHR is manually initiated. Inadvertent admission of fire water to the RHR and or RHR contamination of the FPS is prevented by requiring the operator to install a removable pipe section with couplings and to open two locked closed valves. The removable pipe section is not installed during normal operation.

There are four types of sprinkler or water spray systems used at PNPS: (1) deluge, (2) pre-action, (3) wet pipe, and (4) dry pipe systems.

Deluge and pre-action systems have empty pipes. In these systems, the water is controlled (i.e., held out) by a separate heat detection system. Deluge systems have "open" sprinkler heads or water spray nozzles and pre-action have "closed" automatic heads or nozzles.

Wet pipe systems have pressurized water in their pipes and "closed" sprinkler heads. Dry pipe systems have pressurized air in their pipes and automatic "closed" sprinkler heads.

Deluge systems protect the exterior surface of the following equipment:

1. Main Transformer
2. Auxiliary Transformer
3. Shutdown Transformer
4. Startup Transformer

Wet pipe sprinkler systems protect the following areas:

1. Turbine basement area (west of shield wall)
2. Turbine lube oil reservoir room
3. Turbine lube oil conditioning room
4. Contaminated tool storage area
5. Recirculation motor generator sets room
6. Station heating boiler room
7. Old Machine shop
8. Offices at 37′ elevation radwaste bldg.
9. Diesel fire pump and day tank rooms
10. Offgas Retention Building - charcoal filter room
11. Radwaste hydraulic press (baler) area
12. Access control area and radiological offices
13. Condenser Retubing Building
14. Reactor Building (20 ft wide sprinkler systems only on El. 23'0" and 51'-0")
15. Reactor Auxiliary Building - Water Treatment Room
16. Safety enhancement program (SEP) Pump Building.
17. Redline building (RCA ingress/egress area and trash and laundry area).
18. Trash Compaction Facility

There are pre-action systems provided for the following areas:

1. Hydrogen seal supply oil area (sprinklers)

2. Diesel generator and day tank rooms (sprinklers)

3. Deleted

4. Turbine lube oil reservoir (water spray)

5. Turbine generator bearings (water spray) and oil hazards below the turbine lagging (sprinklers)

There is a dry pipe sprinkler system in the radwaste trucklock and condenser retubing building trucklock areas.

10.8.3.2 Other Extinguishing Systems

Total flooding, automatically actuated Halon 1301 fire suppression systems protect the following areas:

1. Cable spreading room

2. Plant computer room

3. O&M building record storage vault

4. Station blackout (SBO) diesel generator building

Dry chemical wheeled cart fire extinguishers will be provided in the following areas:

1. Diesel generator building

2. HPCI pump and turbine areas

3. Recirculation pump motor generator set room

4. Reactor feedpump area

Portable CO_2 hand extinguishers are provided in the control room and computer room. Portable dry chemical and pressurized water hand extinguishes are provided throughout the plant, as indicated in the Fire Protection System Evaluation and as modified by the Safety Evaluation Reports (References 1, 2, and 3).

10.8.3.3 Other Fire Protection Features

Fire detection systems which alarm in the control room are located in the following areas:

1. Diesel generator building

2. Reactor feed pump area

3. Computer room

4. Recirculation pump motor generator set room

5. Control room air recirculation fan inlet duct

6. Control room cabinets and consoles required for safe shutdown

7. Vital motor generator set room

8. Safety pump rooms (HPCI, RCIC, RHR)

9. CRD modules and MCC areas - east and west elevation 23 ft

10. Switchgear rooms and battery rooms

11. Radwaste trucklock area

12. Reactor Building areas at elevations 51 ft, 74 ft 3 in, 91 ft 3 in, and 117 ft and other areas housing safe shutdown equipment, panels, cable trays, and instrumentation

13. Reactor Building closed cooling water pump rooms A and B

14. Offgas Retention Building

15. The cable spreading room

Fire Detection Systems which do not alarm in the Control Room are located in the following areas:

1. Operation & Maintenance Building

2. EPIC Computer Room

10.8.3.4 Fire Barriers

Three hour rated fire walls, and some that are less than three hour rated in accordance with PNPS Safety Evaluation Report (Reference 4), are identified in the Fire Protection Evaluation Report (Reference 1). Doors, dampers, pipe penetrations, and cable penetrations through these fire walls are also rated 3 hour fire resistant, unless an evaluation demonstrates a fire rating of less than 3 hours is acceptable.

These fire walls separate fire areas containing safety related equipment for safe shutdown of the station in accordance with PNPS Safety Evaluation Reports (References 2, 3, and 4).

Fire exits in the turbine auxiliary building (i.e., access area and time tunnel) are separated by smoke control doors.

Noncombustible shields are installed between the feedwater pumps (i.e., turbine building) to prevent oil from one pump from spraying on the other(s).

The diesel generator day tank room(s) are designed to prevent diesel fuel oil from entering the diesel generator room(s).

Curbs have been installed in the Generator Auxiliaries Area of the Turbine Building to contain potential oil spills and prevent them from spreading into the Lower Switchgear Room. These curbs, in conjunction with the sprinkler system in the area, provide a reasonable means of fire control should an oil fire occur.

10.8.3.5 Alternate Shutdown System

The alternate shutdown system, independent of cabling and equipment in the cable spreading room (CSR) and Control Room, is provided to effect safe shutdown of Pilgrim in the event of a fire in the CSR or the Control Room. This is accomplished by installing isolation switches for safety-related equipment that will provide the capability for the plant operators to reach a safe shutdown condition. These switches will isolate their associated equipment from the CSR cables, thus transferring control from the Control Room to the local emergency shutdown stations outside of the CSR and Control Room. These isolation switches are located in alternate shutdown panels and are located as close as practical to the equipment or switchgear they serve.

Alternate shutdown panels are provided for the following systems:

a. Core Spray
b. RHR
c. RBCCW
d. Salt Service Water
e. HPCI
f. RCIC
g. Automatic Depressurization System
h. Diesel Generators

An Emergency Lighting System has been installed to provide sufficient illumination for the access routes to each alternate shutdown panel and for operation of the safety related equipment from these panels (References 2, 3, & 4).

10.8.4 Inspection, Testing and Technical Requirements for Fire Protection Equipment

The following provides surveillance frequencies, acceptance criteria and degraded equipment requirements for equipment associated with fire protection. This section reflects the guidance provided in Generic Letters 86-10 and 88-12.

10.8.4.1 Fire Detection Instrumentation

10.8.4.1.1 Fire Detection Instrumentation Technical Requirements

The minimum fire detection instrumentation for each fire detection zone shown in Table 10.8-1 shall be operable at all times when equipment in that fire detection zone is required to be operable.

ACTION: With the number of minimum operable fire detection instruments less than required by Table 10.8-1:

a. Within 1 hour, establish a fire watch patrol to inspect the zone with the inoperable instrument(s) at least once per hour; and

b. Restore the inoperable instrument(s) to operable status within 14 days to assure the minimum operable detectors for each detection zone, or determine the cause of the malfunction and develop plans for restoring the instrument(s) to operable status.

c. For inoperable fire detectors controlling fire suppression systems, see the respective fire suppression system section (i.e., Section 10.8.4.3 for water suppression systems or 10.8.4.4 for gaseous suppression systems).

10.8.4.1.2 Fire Detection Instrumentation Surveillance Requirements

As a minimum, the number of fire detectors noted in Table 10.8-1 shall be demonstrated operable in accordance with NFPA 72 Fire Code by a functional test at least once per year.

EXCEPTION; The detectors in the charcoal vault in the augmented offgas building need to be functionally tested once per refueling outage.

10.8.4.2 Fire Water Supply System

10.8.4.2.1 Fire Water Supply System Technical Requirements

At all times when any safety related equipment is required to be operable, the fire water supply system shall be operable with:

1. Two 2000 gpm, 119 psig (95% of the 125 psi rated output), fire pumps which are arranged to start automatically.

2. Two water supplies with a minimum storage quantity of 240,000 gallons of water in each.

3. Two independent water flow paths from 1 and 2 above to each fire water suppression system. (10.8.4.3 and 10.8.4.5)

ACTION: With less than the above required equipment:

a. Restore the inoperable equipment to operable status within 7 days or implement the plans and procedures to be used to provide for the loss of redundancy in this system.

b. With no Fire Water Supply System flow path operable, establish the Backup Fire Water Supply System within 24 hours (in accordance with station procedures) or an orderly shutdown of the reactor shall be initiated and the reactor shall be in the cold shutdown condition within 24 hours.

10.8.4.2.2 Fire Water Supply System Surveillance Requirements

The fire water supply system shall be tested and verified to be operable:

a. by checking the volume of water in each fire water tank at least once every 7 days.

b. by automatically starting each fire pump at least once every month and running the diesel engine driven pump for thirty minutes and the motor driven pump for at least 10 minutes at that time.

c. by visually checking every shutoff valve on the fire water supply system at least once every month for proper position. (Exception - once per cycle for those in Locked High Radiation Areas)

d. by cycling each fire water supply system shutoff valve through its full operation at least once per cycle.

e. by verifying at least once per cycle that each pump starts and delivers at least 2000 gpm while maintaining a system pressure of at least 119 psig (95% of the 125 psi rated output).

f. by performing a water flow test on the fire water yard loop at least once every year.

g. by verifying at least once every month that the diesel fire pump fuel storage tank contains a minimum of 175 gallons of fuel oil.

h. at least once per operating cycle by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with the manufacturer's recommendations for the class of service.

i. by verifying at least once per 3 months that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM D4057-81 or D4177-82, is within the acceptable limits specified in Table 1 of ASTM D975-81 with respect to viscosity, water content, and sediment.

j. by demonstrating that the diesel starting 24-volt battery bank and charger are operable as follows:

   1. at least once per week by verifying that the electrolyte level of each battery is above the plates and battery voltage is at least 24 volts.

   2. at least once per 3 months by verifying that the specific gravity is appropriate for continued service of the battery.

   3. at least once per operating cycle by verifying that the batteries and battery racks show no visual indication of physical damage or abnormal deterioration and the battery-to-battery and terminal connections are clean, tight, free of corrosion, and coated with anti-corrosion material.

10.8.4.3 Spray and/or Sprinkler Systems

10.8.4.3.1 Spray and/or Sprinkler Systems Technical Requirements

The spray and/or sprinkler systems located in the following areas shall be operable at all times when equipment in the spray/sprinkler protected area is required to be operable:

1. Diesel generator room preaction sprinkler systems (including detectors).

2. Diesel fire pump fuel oil storage room wet pipe sprinkler system.

3. Auxiliary boiler room wet pipe sprinkler system.

4. Recirculation pump MG set room wet pipe sprinkler system.

5. Hydrogen seal oil supply unit preaction sprinkler system (including detectors).

6. Turbine basement addition wet pipe sprinkler system.

7. Reactor building elevation 23'-0", north side wet pipe sprinkler system.

8. Reactor building Elevation 51'-0", north and south side wet pipe sprinkler systems.

9. Reactor auxiliary building, water treatment area, wet pipe sprinkler system.

10. Health physics access area wet pipe sprinkler system.

ACTION: From and after the date that a spray and/or sprinkler system is made or found to be inoperable:

a. Within one hour establish a continuous fire watch with backup suppression, except as specified in 10.8.4.3.1, actions c, d, e, f, and g.

b. Restore the system to operable status within 14 days or determine the cause of inoperability and develop plans for restoring the system to operable status.

c. If the Spray or Sprinkler System is not operable because no Fire Water Supply System flow path is operable, complete actions identified in Section 10.8.4.2.1.

d. If the suppression system of the diesel generator room preaction sprinkler systems (including detectors but excluding the Pilotex portion of the system), is inoperable, establish an hourly fire watch patrol with backup suppression provided that the detection system in that fire area and the detection and suppression system for the redundant fire area is operable.

e. If two or more detectors of the diesel generator room preaction sprinkler system are found or made to be inoperable, within one hour charge that sprinkler system piping with water.

f. If the wet pipe sprinkler system for the reactor recirculation pump MG set room, reactor building auxiliary building water treatment room, auxiliary boiler room, reactor building elevations 23′ & 51′ north side, or reactor building elevation 51′ south side is inoperable, establish an hourly fire watch patrol with backup suppression provided that the detection system in the area is operable. Additional administrative controls will be implemented to further reduce any potential fire hazards while the automatic suppression systems are inoperable.

g. When the entire fire area protected by a spray and /or sprinkler system is designated, "HIGH RADIATION AREA/AIRBORNE RADIOACTIVITY AREA", an hourly fire watch patrol may be established (e.g., for ALARA considerations in lieu of a continuous fire watch). If a zone of the fire area is so designated, one of the following shall apply: (1) If the zone is adequately inspectable from a non-High Radiation Area, the continuous fire watch shall be located in the non-High Radiation Area, or (2) If (1) cannot be accomplished, a fire watch patrol shall enter the High Radiation Area once every eight hours.

It is not necessary to enter areas designate designated as "Locked High Radiation Area".

10.8.4.3.2 Spray and/or Sprinkler Systems Surveillance Requirements

The spray and/or sprinkler systems shall be demonstrated to be operable according to the following:

1. Each sprinkler system and water spray system alarm shall be tested at least once every year by opening the alarm bypass or inspector test valve. Alarms in high radiation areas are to be tested once per cycle.

2. Deleted.

3. Each preaction sprinkler system shall be trip tested at least once per cycle.

4. Each water spray system shall be trip tested automatically by simulated actuation of the heat detectors at least once per cycle.

10.8.4.4 Halon System

10.8.4.4.1 Halon System Technical Requirements

The halon system for the cable spreading room shall be operable with each of the five storage tanks charged to at least 95% of the minimum quantity of halon (217 lbs. per tank) necessary to extinguish a fire, and minus or plus 10% of the pressure stamped on the data plate on the tank corresponding to an ambient temperature of 70°F. Detectors associated with the automatic initiation of the halon system shall be operable, except that an individual detector may be inoperable if the other detector in the same bay is operable and both detectors in all adjacent bays are operable.

The halon system shall be operable at all times when the safety related equipment in the cable spreading room is required to be operable.

ACTION:

a. Within one hour from and after the time that the system is found to be inoperable, establish a continuous fire watch with backup suppression equipment.

10.8.4.4.2 Halon System Surveillance Requirements

The halon system shall be demonstrated operable:

1. At least once per month by verifying the halon storage tank pressure and that the control panel is in the automatic mode.

2. At least once per 6 months by verifying the quantity of halon in the storage tank(s).

3. a. At least once per operating cycle by verifying that the system and associated devices actuate upon receipt of a simulated actuation signal, and

   b. Performance of an inspection to assure the nozzles are unobstructed.

10.8.4.5 Fire Hose Stations

10.8.4.5.1 Fire Hose Stations Technical Requirements

The interior fire hose stations shown in Table 10.8-2 shall be operable at all times when the equipment in the area protected by the fire hose station is required to be operable.

ACTION:

a. With a hose station inoperable, provide an additional equivalent capacity hose for the unprotected area at/from an operable hose station within 1 hour, except as specified in 10.8.4.5.1. Action b.

b. If a fire hose station is not operable because no fire water supply system flow path is operable, complete actions specified in section 10.8.4.2.1.

10.8.4.5.2 Fire Hose Stations Surveillance Requirements

Each interior fire hose station shall be verified to be operable:

1. At least once per month by visual inspection of the station to assure that the hose and nozzle are properly installed. (Exception - Once per cycle for those in Locked High Radiation Areas).

2. At least once per cycle by removing the hose for inspection, replacing any degraded coupling gaskets, and reracking.

3. At least once per two fuel cycles (approximately 4 years) by partially opening each hose station valve to verify valve operability and no obstruction. (Partial flow test).

4. By conducting a hydrostatic test of each hose every three years.

    a. at a pressure 50 psig greater than the maximum available pressure at that hose station, or

    b. at the applicable service test pressure as listed in Table 8-3 of the "Standard for Care, Maintenance of Fire Hose Including Connection and Nozzles." NFPA No. 1962-1979, or

    c. by replacing each nontested hose with a new or used hose which has been hydrostatically tested in accordance with the pressures specified in a or b above.

10.8.4.6 Fire Barrier System

10.8.4.6.1 Fire Barrier System Technical Requirements

All fire barrier systems providing separation of redundant safe shutdown systems shall be functional at all times when the safe shutdown systems are required to be operable.

ACTION: With one or more of the required fire barrier systems nonfunctional:

a. Within one hour either establish a continuous fire watch on one side of the affected barrier or verify the OPERABILITY of an automatic fire detection or suppression system on at least one side of the nonfunctional fire barrier and establish an hourly fire watch patrol, except as identified in 10.8.4.6.1 actions b and c.

b: When the fire areas on both sides of the affected fire barrier are designated "HIGH RADIATION AREAS/AIRBORNE RADIOACTIVITY AREA", an hourly fire watch patrol may be established (e.g. for ALARA considerations) in lieu of a continuous fire watch.

c Certain fire barrier components may be degraded without adversely affecting the fire barrier function of preventing fire damage to redundant trains of safe shutdown equipment. Fire Protection may perform an evaluation to document that no fire watch is necessary or to allow hourly fire watches for circumstances where degraded barriers are still capable of performing their fire protection function.

10.8.4.6.2 Fire Barrier System Surveillance Requirements

Surveillance requirements for penetrations in fire barriers are as follows:

1. Fire Barrier Penetration Seals: At least 20% of the fire barrier penetration seals shall be visually inspected once per cycle. The sampling shall ensure that 100% of the seals are inspected within a 10 year period or 5 fuel cycles. If any seal is found to be inoperable, then an additional 10% of the seals shall be inspected. Sampling and inspection shall continue until all of the seals in a sample are found to be operable or until 100% of the seals are inspected.

2. Fire Doors: Each fire door shall be tested once per cycle for operability of closure and latching mechanisms and for integrity.

3. Fire Dampers: Each fire damper shall be tested once per every 2 cycles for operability and integrity. In certain circumstances Fire Protection may determine that it is not necessary to test a damper and may recommend an inspection only. An evaluation will be prepared to document the basis for such determinations.

10.8.4.7 Fire Brigade

A fire brigade of 5 members including a fire brigade leader shall be maintained on site at all times. This minimum excludes 3 members of the minimum shift crew necessary for safe shutdown and any personnel required for other essential functions during a fire emergency.

The fire brigade training shall be in accordance with Pilgrim Station's Fire Protection Training Program. The fire protection training of fire brigade members shall be held quarterly.

10.8.4.8 Alternate Shutdown Panels

The operability and surveillance requirements for the alternate shutdown system are in Section 3/4.12 of Pilgrim Station's Technical Specifications. The emergency lighting system for the alternate shutdown system is within the scope of the Maintenance Rule at PNPS. Performance requirements are established and monitored accordingly.

10.8.5 References

1. Pilgrim Station 600, Unit 1, Boston Edison Company, Fire Protection System Evaluation, March 1, 1977.

2. Safety Evaluation Report by the Office of Nuclear Reactor Regulation (Amendment 35 to License No. DPR-35) for Pilgrim Nuclear Power Station-1, December 21, 1978.

3. Safety Evaluation Report (additional Fire Protection Information Review) for Pilgrim Nuclear Power Station-1, October 7, 1980.

4. Safety Evaluation Report by the Office of Nuclear Reactor Regulation Related to Amendment No. 123 to Facility Operating License No. DPR-35, dated October 13, 1988.

5. Report 89XM-1-ER-Q Updated Fire Hazards Analysis.

6. Power System Calculation No. 32, "Appendix R, Safe Shutdown Analysis for PNPS".

7. License Amendment 143 resulting from Generic Letters 86-10 and 88-12.

SECTION 11

POWER CONVERSION SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

SECTION 11

LIST OF FIGURES

11.9 CONDENSATE STORAGE SYSTEM

11.9.1 Power Generation Objective

The power generation objective is to provide condensate for system makeup needs, and to take system "reject" surges.

11.9.2 Power Generation Design Basis

The Condensate Storage System shall provide station system makeup, receive system reject flow, and provide condensate for any continuous service needs and intermittent batch type services. The total stored design quantity shall be based on the demand requirements during refueling for filling the dryer separator pool and the reactor well.

Two tanks shall be used for reasons of operational flexibility so that a plant shutdown will not be required when one tank is being maintained.

11.9.3 Description

The two 275,000 gal condensate storage tanks supply the various station requirements as shown on Figure 11.9-1. The tanks are of coated carbon steel with all inlet and outlet lines, overflows, vents, and instrument lines located at the tank bottom or toward the tank center to prevent freezing problems. The condensate storage system also consists of the two condensate transfer pumps, a jockey pump, and associated piping and valves.

The condensate tanks provide the preferred supply to the HPCI and RCIC systems. The torus water storage provides the backup emergency HPCI and RCIC systems supply. Each condensate storage tank is designed to provide a reserve of approximately 75,000 gallons for HPCI and RCIC use. The other condensate tank service demands are physically isolated by use of suction lines raised to an elevation above this reserve. Because the volume of water that is usable by HPCI or RCIC within the reserve is reduced to maintain adequate suction nozzle submergence, an additional amount of volume in the CST is administratively controlled to ensure adequate inventory is available for HPCI and RCIC to support an 8 hour station blackout duration.

SECTION 12

STRUCTURES AND SHIELDING

TABLE OF CONTENTS

SECTION 12 (Cont)

SECTION 12 (Cont)

SECTION 12

LIST OF TABLES

SECTION 12

LIST OF FIGURES

LIST OF FIGURES (Cont)

LIST OF FIGURES (Cont)

12.4 RADIOACTIVE MATERIALS SAFETY

12.4.1 Materials Safety Program

Use, Handling, and Storage of Licensed Radioactive Sources

When not in use, all licensed radioactive sources shall be stored in a locked container, cabinet, or room. The sources will normally be stored in the radiochemistry lab and the radiation protection lab.

Other controls for the storage, possession, and use of these sources are presented in PNPS Radiation Protection Operating Procedures and are as follows:

1. Each source and/or source container shall be labeled with a radiation sign and a control number. For each source there will be a Radioactive Source Record Sheet with the following information:

   (a) source control number

   (b) source type

   (c) quantity

   (d) date quantity measurement was made

2. Sources will be controlled by the Radiation Protection Manager (or designee) and will be in a locked container, cabinet, or room when not in use.

3. Sign out logs on which to record the removal of various sources from the assigned storage area and to authorize such removals are provided to the radiation protection lab and radiochemistry lab. The user's signature is required on this record.

4. Sources are to be used, transported, and stored in such a way as to minimize personnel exposure to them. Shielded sources shall be kept in their shielded containers except when they are in use.

5. Each sealed source containing radioactive material either in excess of 100 micro curies of beta and/or gamma emitting material or 5 micro curies of alpha emitting material shall be free of > 0.005 micro curies of removable contamination at all times.

   Each sealed source with removable contamination in excess of the above limit shall be immediately withdrawn from use and:

A. Either decontaminated and repaired, or

B. Disposed of in accordance with Commission Regulations.

6. Each sealed source shall be tested for leakage and/or contamination by:

A. The licensee, or

B. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 micro curies per test sample.

7. Each category of sealed sources, excluding startup sources and fission detectors previously subjected to core flux, shall be tested at the frequency described below.

A. Sources in use - At least once per six months for all sealed sources containing radioactive material:

1. With a half-life greater than 30 days, excluding Hydrogen 3, and

2. In any form other than gas.

B. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

C. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

NOTE - If a vendor or source supplier furnishes a certificate indicating that a test has been made within 6 months, the source need not be tested for 6 months and may be made available for immediate use.

The Radiation Protection Department shall assure compliance with provisions of 10CFR20, 10CFR30 and applicable conditions of the Facility Operating License.

A complete inventory of radioactive materials in possession shall be maintained current at all times by the Radiation Protection Department. All such sources shall be inventoried at intervals not

to exceed 6 months. Reactor Engineering shall maintain a complete inventory of all special nuclear material maintained on site. A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of $\geq$0.005 micro curies of removable contamination.

Records will be kept of all receipts, transfers, disposal, leak test, and other information pertinent to by-product licensed material.

Records required to be maintained for two years:

A. Test results, in units of micro curies, for leak test performed pursuant to Section 12.4.1

B. Record of annual physical inventory verifying accountability of sources on record.

Unsealed sources will be stored in a locked location in the radiochemistry lab.

Liquid sources will be used in accordance with the PNPS radiation protection procedures and general rules of good practice in radioactive material handling when they are unsealed.

Use, Handling and Storage of Nuclear Fuel

The new and used fuel storage facilities are described in FSAR Sections 10.2 and 10.3. The multiplication constants for fuel in both the new and spent fuel racks are specified in the Pilgrim I Technical Specifications.

The new fuel storage vault, the spent fuel storage pool, and other locations on the refueling floor where fuel assemblies will be handled or stored are monitored by a Radiation Monitoring System complying with the requirements of 10 CFR 70.24.

All spent fuel handling shall be with cranes and hoists designed specifically for that purpose. These consist of the 5 ton auxiliary hook of the Reactor Building crane, the refueling platform grapple, the refueling platform auxiliary hoists, and the socket mounted jib cranes.

The probability of fire in the inspection and preparation area will be minimized by restricting the allowable quantities of flammable materials in the area. Solvents, such as acetone, are required for cleaning and will be handled in small quantities.

Access to the refueling floor and to the overhead bridge crane shall be permitted only to authorized personnel. Fuel loading and unloading operations will be performed by qualified personnel (including contractors) under the direct supervision of a licensed Senior Reactor Operator or Senior Reactor Operator restricted to fuel handling. "Qualified" within the context of the training rule (10 CFR 50.120) means training in, and testing of, site specific refueling procedures to include demonstration of equipment operation (reference NRC Information Notice 94-13).

New fuel inspection shall be performed by Pilgrim Station or contractor personnel. Entry to the refueling floor will be restricted by locked gates or doors any time that full time surveillance by guards or authorized personnel is not in effect and fuel handling operations are in progress.

Fuel shall be brought to the refueling floor in metal criticality proof shipping containers. Only one metal container will be opened and placed in an upright position at any one time.

A minimum of nine assemblies in a flooded square arrangement is necessary for a minimum critical array. Therefore, handling only two assemblies and inspecting no more than two additional assemblies at any one time precludes the possibility of criticality during the handling and inspection sequence.

12.4.2 Facilities and Equipment

Laboratory instruments will be provided for measuring alpha, beta, and gamma radiation, and for the analysis of radioactive gaseous, liquid, and solid samples. These will include an instrument for gross beta gamma counting of smear samples used for contamination control, and a multi-channel gamma analyzer for gaseous and liquid samples used for effluent release control.

Portable radiation survey instruments will be available as required for measurement of alpha, beta, gamma, and neutron radiation expected during normal operation, and in emergencies.

12.4.2.1 Method, Frequency, and Standards Used in Calibrating Instruments

All beta-gamma instruments will be calibrated in accordance with PNPS Radiation Protection Procedures. These calibrations will employ a calibration unit with an appropriate calibration source.

Alpha instruments will be calibrated in accordance with PNPS Radiation Protection Procedures using an appropriate alpha source set.

The neutron instruments will be calibrated in accordance with PNPS Radiation Protection Procedures using an appropriate calibration source. In addition, neutron instruments are response checked prior to use.

12.4.2.2 Dosimeters and Bio-Assay Procedures Used

Personal monitoring devices, i.e., TLDs, OSLDs, electronic dosimeters, and pocket dosimeters, will be furnished to and worn by personnel who require radiation dose monitoring in accordance with PNPS station procedures.

Bio-Assay: Whole body counting is normally done onsite by the Licensee. A licensed off-site facility is available for contingency in whole body counting or analysis of in vitro bio-essay materials.

12.4.3 Personnel and Procedures

The Reactor Engineering Superintendent is the custodian of special nuclear materials received, possessed, used, or transferred under authorization of Operating License DPR-35.

The Radiation Protection Manager is the custodian of by-product and source materials received, possessed, used, or transferred under the authorization of Operating License DPR-35 and NRC Materials License 20-07626-04, and Commonwealth of Massachusetts Materials License 07-6262. The health physics aspects of the handling, storage, and use of these materials will be administered by the Radiation Protection Manager as defined by ANSI N18.1, 1971.

Radiation protection procedures assure compliance with applicable regulations and appropriate sections of the Operating License, Technical Specifications, and FSAR.

12.4.4 Required Materials

The Licensee is authorized to receive, possess, use, and transfer materials as required for operation of the facility by License No. DPR-35.

12.4.5 Offsite Materials Safety Program

All radioactive materials fixed or contained within reactor system components and shipped to temporary field locations such as vendor facilities will remain in the custody of PNPS, and will be under direct supervision of a qualified PNPS representative normally on the Radiation Protection staff.

Radiation protection activities shall be conducted at the temporary field locations in order to assure that all Pilgrim radioactive reactor components are appropriately packaged, surveyed, and labeled in accordance with applicable NRC/Massachusetts DOT regulations and PNPS radiation protection procedures.

PNPS shall assume responsibility for all radiation protection activities incident to inspection, repair, and testing of Pilgrim equipment containing radioactive material while such equipment is at temporary field locations. These activities shall be conducted in accordance with the requirements of 105 CMR 120, Massachusetts Regulations for the Control of Radiation, at temporary field locations within the borders of Massachusetts, or the requirements of 10 CFR 20, Standards for Protection Against Radiation for temporary field locations outside the borders of Massachusetts but within the borders of the continental United States, as applicable. Radiation monitoring instrumentation and personnel monitoring devices such as those used at Pilgrim Station will be utilized at the offsite location.

The maximum total activity of mixed corrosion products contained within and/or fixed upon the surface of the reactor system components shipped to temporary field locations within the borders of Massachusetts shall be limited to the values indicated in Massachusetts Materials License No. 07-6262 or temporary field locations outside the borders of Massachusetts but within the borders of the continental United States shall be limited to the values indicated in U.S. NRC Materials License No. 20-07626-04, as applicable.

All handling of Pilgrim equipment containing radioactive material at vendor's facilities shall be conducted in such a manner as to preclude the onsite release or disposal of any radioactive materials. All radioactive waste from temporary field stations shall be appropriately packaged, surveyed, and labeled and either returned to Pilgrim Station for ultimate disposal through a licensed contractor, or directly transferred to a licensed waste disposal contractor at the field location.

All vendor company employees shall receive radiation protection orientation prior to their assignment of work on radioactive reactor components in any area controlled by PNPS. The orientation will cover all pertinent radiation protection practices, and procedures to the degree sufficient to allow an employee to perform his assignment without incurring unnecessary radiation exposure.

PNPS shall maintain records of all licensed activities conducted at temporary field locations including records showing the transfer of radioactive materials to and from the location, records of radiation surveys, and records of personnel radiation exposure. A report showing individual radiation exposures shall be furnished to the vendor company upon the completion of licensed activities at the temporary location.

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 5

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP5 – Rev 27	EP5 – Rev 28
Section 13 TOC	Entire Section 13 TOC	Section 13 TOC – Rev 28
13.2	Pages 1-10	Pages 1-9
Section 14 TOC	Entire Section 14 TOC	Section 14 TOC – Rev 28
14.4	Pages 1-8	Pages 1-9
14.5	Pages 1-32	Pages 1-34
14.5	Table 14.5-4 page 1 of 1	Table 14.5-4 page 1 of 1
14.5		Table 14.5-4A page 1 of 1
14.5	Table 14.5-5 page 1 of 1	Table 14.5-5 page 1 of 1
14.7	Page 2	Page 2
Appendix A TOC	Entire Appendix A TOC	Appendix A TOC – Rev 28*
Appendix A.1	Pages 1-3	Pages 1-7
Appendix B TOC	Entire Appendix B TOC	Appendix B TOC – Rev 28*
Appendix B.1	Pages 1-22	Pages 1-26

*Text without revision bars was reformatted only.

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

APPENDIX A

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

LIST OF EFFECTIVE PAGES

VOLUME 5VOLUME 5**VOLUME 5**VOLUME 5**VOLUME 5**

SECTION 13

CONDUCT OF OPERATIONS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

SECTION 13

LIST OF FIGURES

13.2 ORGANIZATION AND RESPONSIBILITIES

The Boston Edison Company (BECo) Nuclear Division was originally responsible for the engineering, maintenance, and operation of Pilgrim Nuclear Power Station (Pilgrim Station).

BECo established a project type organization to direct all activities of Pilgrim Station. The organization for operation of the Pilgrim Station was shown on Figure 13.2-1 (deleted). The nuclear division was responsible for the quality assurance, engineering, maintenance, and operations activities. This organization directed the activities of all Boston Edison personnel who worked on the Pilgrim effort and was also responsible for coordinating and supervising the activities of Boston Edison's principal contractors for Pilgrim Station. This organization was responsible for coordinating the testing programs and for approval of test results and acceptance of station operating performance.

The quality assurance function reported to the responsible BECo executive. The nuclear engineering services and regulatory relations organizations reported to the general manager - technical. The plant, nuclear training & management services, and nuclear services organizations reported to the station director. The operation review committee reported to the station director. The nuclear safety review and audit committee reported to the senior vice president - nuclear.

On July 13, 1999, the ownership and authority for the operation of Pilgrim Station was transferred from BECo to the Entergy Nuclear Generation Company (ENGC). On May 5, 2002, the authority for the operation of Pilgrim Station was transferred from ENGC to Entergy Nuclear Operations, Inc. (ENO), with ENGC remaining the owner of Pilgrim Station.

The following are the plant specific titles for personnel fulfilling responsibilities of positions delineated in Technical Specifications.

a. The specified corporate officer at Pilgrim responsible for overall plant nuclear safety is the Site Vice President.

b. The plant manager is the General Manager, Plant Operations.

c. The operations manager is the Manager, Operations.

d. The assistant operations manager is the Assistant Manager, Operations.

e. The control room supervisor is the Control Room Supervisor.

f. The qualified individual that provides advisory technical support to the unit operations shift crew in the areas of engineering and accident analysis is the Shift Control Room Engineer.

g. The radiation protection manager is the Manager, Radiation Protection.

13.2.1 EXECUTIVE MANAGEMENT

Refer to the Quality Assurance Program Manual (QAPM) for discussion of the Entergy Nuclear Operations Incorporated (ENO) Management Structure.

13.2.1.1 Deleted

13.2.1.2 Site Vice President

The Pilgrim Station site vice president reports to the Senior Vice President of Entergy Nuclear Operations.

13.2.1.3 Deleted

13.2.2 MANAGEMENT (GENERAL)

General management is achieved by directors, senior managers, and managers.

13.2.2.1 Directors

Directors head functional areas and report to the site vice president or the executive responsible for the functional area.

13.2.2.2 Deleted

13.2.2.3 Managers

Managers of functional areas report to the director or executive responsible for the functional area.

13.2.2.4 Assistant or Deputy Managers

As necessary, an assistant or deputy manager is assigned to assist the manager.

13.2.2.5 Deleted

13.2.2.6 Senior Management Staff Position

A person selected or appointed for a specific task or range of tasks typically fulfills this function.

13.2.3 PLANT ORGANIZATION

13.2.3.1 Plant Organization

For administrative purposes, the plant organization consists of operations, maintenance, chemistry, and radiation protection. These functions report to the general manager of plant operations.

13.2.3.1.1 General Manager of Plant Operations

The general manager functions as a single point of responsibility for achieving standards of performance for overall plant operation.

13.2.3.1.2 Operations

The operations function is responsible for operating Pilgrim Station, manipulating all process systems, identification of system performance problems, and technical diagnosis of plant events.

The Pilgrim Station licensed operators and non-licensed operators are part of the operations function.

13.2.3.1.3 Shift Manning

The minimum shift crew composition will be as defined in Pilgrim Station Technical Specifications and in accordance with 10 CFR 50.54 (k),(l) and (m).

13.2.3.1.4 Deleted

13.2.3.1.5 Maintenance

The maintenance function is responsible for the management of maintenance activities including corrective maintenance, planned maintenance, and surveillance testing. This function supports safe and reliable plant operations.

The principal responsibilities include:

- Performing plant maintenance activities in a safe and quality manner, ensuring plant safety in accordance with the applicable local, state, and federal regulations and requirements, and in conformance with good Industry practices and the applicable corporate requirements.

- Enforcing radiological controls in accordance with the radiological control program ensuring radiation exposures at a level as-low-as-reasonably-achievable (ALARA).

- Coordinating activities to implement modifications and construction projects.

13.2.3.1.6 Outage

The outage function is responsible for outage administration and planning.

13.2.3.1.7 Instrumentation and Control

The instrumentation and control function is part of the maintenance function and is responsible for the management and coordination of all instrumentation and control activities for the station. This function implements programs which provide administrative and technical controls for the maintenance of the station.

The principle responsibilities of this function are to implement on-line and off-line instrumentation and control activities in a safe manner ensuring plant safety in accordance with the applicable local, state and federal regulations and in accordance with good industry practices.

13.2.3.1.8 Work Control

The work control function is part of the maintenance function and is responsible for all on-line and outage maintenance activities. Implementation of the work control function occurs when the unit is on-line, during planned outages and forced outages that require a progression of events to restore electrical generation in a timely fashion including planning and scheduling of corrective maintenance, preventive maintenance, modifications, surveillances and post work testing.

This function primarily interfaces with the operations and other maintenance organizations in allocating manpower, task prioritization, obtaining necessary support resources and assessing schedule progress to achieve outage milestones or on-line goals.

13.2.3.2 Deleted

13.2.3.2.1 Chemistry

The chemistry function is responsible for the chemistry programs and assuring compliance with applicable regulatory requirements, station operational requirements, and corporate policy.

The chemistry function plans, develops, coordinates and directs:

- a plant chemistry program for surveillances, required by the operating license, monitoring chemical parameters or plant process streams;

- technical guidance to ensure systems are operated efficiently to prevent unnecessary system degradation;

- operational chemical engineering services to develop and operate systems and components with plant chemistry impact such as the hydrogen water chemistry system; and

- all onsite chemical programs to insure compliance with federal, state, and industry standards to include chemical surveillance testing, chemical control, and the chemical preventive maintenance and quality assurance programs.

13.2.3.2.2 Radiation Protection

The radiation protection function deals with all aspects of the control and monitoring of radioactive material and monitoring, documenting, and control of personnel radiation dose.

The radiation protection department manager, is responsible for effective management of all radiological programs at Pilgrim Station.

The radiation protection manager approves, directs, and oversees the development and implementation of policies for:

- management of the Pilgrim Station Radiological Program, including implementation of the ALARA Program.

- input to facility design and operational planning.

- data collection and trend analysis in radiation work performance of station personnel, contamination and dose control, and job doses.

- initiation of action to correct adverse radiological trends.

- investigation of incidents associated with radiation protection controls, and assignment and follow-up of corrective actions.

The radiation protection manager is the senior advisor to management for radiological affairs concerning both the plant work force and the general public affected by the site. As such, the manager has direct access to the site vice president, when required, to ensure timely action on matters of significant radiological consequence.

The radiation protection manager interfaces with managers on a routine basis for the provision of support services, including aid in goal setting to control radiation dose to the work force and the general population.

This position acts as the spokesperson for Radiation Protection. The manager or designee fulfills requirements for radiation protection manager as specified in Regulatory Guide 1.8. In this regard, the incumbent exercises the authority to initiate and lift "Stop Work" orders imposed for inadequate radiation protection practices.

The Radioactive Material Control function is part of the radiation protection function and is responsible for:

- those activities associated with the generation, collection, transfer, packaging, shipment, storage, and disposal of low level radioactive waste at Pilgrim Station;
- maintaining compliance with applicable federal and state regulations and licenses on all radwaste shipments.

13.2.3.2.3 Protective Services

The protective services function directs onsite security activities in support of the safe operation of Pilgrim Station and ensures that provisions of the Site Security Plan, Contingency Plan, Training and Qualification Plan, and applicable regulations are met.

The Manager Security provides a single point of responsibility for standards, development, performance, and needs of security personnel. The manager ensures personnel are in a state of readiness to allow prompt and effective response to security incidents.

This function ensures security personnel interface effectively with the General Employee Training, Health Physics Records and Medical, plus local and state law enforcement agencies and other utility security groups.

13.2.3.2.4 Facilities

The facilities function is part of the maintenance function and performs general housekeeping and related activities including site painting, maintenance and cleaning.

13.2.3.3 Training

The training function is responsible for the Pilgrim Station training program. The training function develops and implements training programs to support line management including operations, technical and professional staff, and simulator training.

13.2.3.4 Quality Assurance

The quality assurance function is responsible for:

- assuring the implementation of the Quality Assurance Program.
- providing feedback to responsible management on compliance to and effectiveness of the Quality Assurance Program
- ensuring the establishment, maintenance, and implementation of an effective quality control function. This may be performed by other organizations, but remains the responsibility of the quality assurance function.

- assuring that all operational phase activities falling within the scope of the Quality Assurance Program are prescribed by and implemented according to approved procedures, and that these procedures provide effective management controls.

In order to implement the quality assurance functional responsibilities, this function is provided with "Stop Work" authority whereby the manager can suspend any quality related activity or process, which may adversely affect the safe operation of Pilgrim Station.

13.2.4 Deleted

13.2.4.1 Nuclear Engineering

The nuclear engineering function is responsible for the following:

- establishing plant design requirements.
- design engineering for design changes and plant modifications and selective maintenance.
- design verification and evaluation of changes to the base configuration of Pilgrim Station, which could affect the design and licensing basis.
- design configuration control, including establishment and maintenance of a system to incorporate approved design changes into engineering documents.
- engineering review of the current design in response to requests from the other members of the Nuclear Organization.
- preparation and review of 10 CFR 50.59 evaluations for plant modifications and design changes.
- systems engineering review and analysis of performance data to determine potential changes to improve plant safety and operations reliability.
- make component design changes to support plant operations, including design changes required to support procurement of equivalent replacement items.
- fire protection
- ASME Section XI Pump and Valve Program
- 10 CFR 50 Appendix J Test Program
- ASME Section XI Inservice Inspection Program

13.2.4.2 Nuclear Assessment

The nuclear assessment function manages the interface between Pilgrim Station and federal, state, and local regulating agencies and insurers. The principal interface is between Pilgrim Station and the U. S. Nuclear Regulatory Commission (NRC) and includes the Office of Nuclear Reactor Regulation and Region I.

This function has the continuing responsibility for the following:

- preparing and processing changes to the Facility Operating License and Updated Final Safety Analysis Report.
- preparing reports to the NRC, FEMA and other agencies on emergency preparedness matters,
- technical evaluations and management of regulatory requirements and licensing issues.
- reporting requirements under 10 CFR 50.73.
- coordinating inspections and responses.
- environmental permits and monitoring programs.
- maintaining the Emergency Preparedness Program.
- maintaining the Pilgrim Station and Corporate Radiological Emergency Plan and implementing procedures in accordance with applicable regulations and industry standards.
- assuring adequate support is provided to ensure the maintenance of offsite emergency response plans and procedures for the Commonwealth of Massachusetts and the local communities involved in a response to an incident at Pilgrim Station.
- the Emergency Response Organization training program conducted to ensure the existence of an adequate level of knowledge, and that adequate records are maintained to track individual qualifications.
- the training program for offsite response personnel.
- preparing for and conducting the drill and exercise program.
- assuring that Emergency Response Facilities (onsite and offsite) are maintained in a constant state of readiness.
- developing and implementing the Emergency Preparedness public information program.

13.2.4.3 Purchasing, Materials and Contracts

The purchasing, materials and contracts function provides procurement and related tasks such as planning, requisitioning, purchasing, inspecting, expediting, manufacturing oversight, commercial grade item evaluation, logistics management, and warehousing in support of Pilgrim Station.

13.2.5 QUALIFICATIONS AND TRAINING

The operations manager, operations shift managers, and operations shift supervisors shall hold a Senior Reactor Operator License. The licensed nuclear plant reactor operators shall hold a Reactor Operator License.

13.2.5.1 Unit Staff Qualifications

The qualifications with regard to educational and experience backgrounds of the unit staff at the time of appointment to the active position shall meet the minimum requirements as described in the American National Standards Institute N18.1-1971, "Selection and Training of Personnel for Nuclear Power Plants." In addition, the individual performing the function of radiation protection manager shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

13.2.5.2 Training Program

A retraining and replacement training program for the unit staff is maintained under the direction of the training function.
The training programs for the licensed personnel shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and 10 CFR Part 55.

The training programs for the Fire Brigade shall meet or exceed the requirements of NFPA Standard No. 27-1975 "Private Fire Brigade."

For further information regarding Pilgrim Station Training Programs, see FSAR Section 13.3.

SECTION 14

STATION SAFETY ANALYSIS

TABLE OF CONTENTS

TABLE OF CONTENTS

SECTION 14

LIST OF TABLES

SECTION 14

LIST OF FIGURES

14.4 ABNORMAL OPERATIONAL TRANSIENTS

The transients corresponding to the event categories in Section 14.3.3 are shown in Table 14.4-1. However, only a few of these transients would result in a significant reduction in MCPR or increase in LHGR.

To determine the limiting transient events, the relative dependency of CPR upon various thermal-hydraulic parameters was examined. A sensitivity study was performed to determine the effect of changes in bundle power, bundle flow, sub cooling, R-factor, and pressure on CPR for fuel designs. The R-factor is a weighted peaking factor used to characterize the local peaking pattern in the vicinity of the rod.

From this study it was determined that CPR is most responsive to fluctuations in the R-factor and bundle power. A slight sensitivity to pressure and flow changes and relative independence to changes in inlet sub cooling was also shown. The R-factor is a function of bundle geometry and local power distribution and is assumed to be constant throughout a transient. Therefore, transients which would be limiting because of MCPR would primarily involve significant changes in power. Based on this, the transients most likely to limit operation because of MCPR considerations are:

1. Generator load rejection without bypass or turbine trip without bypass

2. Loss of feedwater heating or inadvertent HPCI startup.

3. Feedwater controller failure (maximum demand).

4. Control rod withdrawal error.

Subsequent transient analyses verified the results of the above sensitivity study. Descriptions of the above limiting events are given below.

For reloads, the potentially limiting events are evaluated to determine the required operating limits. The analytical results for the limiting transients and the required operating limits are provided in the supplemental reload licensing report (Appendix Q).

14.4.1 Margin Improvement Options

The cycle specific transient analyses may be performed with the following margin improvement options:

1. ODYN Option B scram times and

2. Exposure dependent limits.

The ODYN Option B scram time improvement option uses generic, measured scram times that are more realistic than Technical Specification scram times to analyze core-wide pressurization transients. To use this option it must be demonstrated that the actual plant scram time distribution is consistent with the generic, measured scram time distribution. This is accomplished through an approved Technical Specification which consists of testing at the 5% significance level and allows adjustment of the MCPR operating limit if the actual scram speed distribution is outside the assumed distribution.

Exposure dependent limits may be established by repeating the transient analyses for selected mid-cycle exposures. The severity of any plant transient is typically worst at the end of the cycle primarily because the EOC all-rods-out scram curve gives the worst possible scram response. By analyzing the transients at other interim points in the cycle, a lower OLMCPR will be calculated and the plant may operate at these lower limits up until the analyzed exposure limit is reached. The plant then operates at the OLMCPR limit calculated for the next analyzed point. The transients which are most affected by the scram response are the increase in reactor pressure events and feedwater controller failure (maximum demand).

14.4.2 Operating Flexibility Options

The following operating flexibility options may be reflected in the cycle specific transient analyses:

1. Maximum Extended Operating Domain

2. ARTS

3. Feedwater Temperature Reduction.

4. Single Loop Operation (SLO)

The modified operating envelope termed Maximum Extended Operating Domain (MEOD) permits extension of operation into additional power/flow area, provides improved power ascension capability to full power and additional flow range at rated power, and includes an increased flow region to compensate for reactivity reduction due to exposure during an operating cycle. Overall, MEOD can be utilized to increase operating flexibility and plant capacity factor.

The extended load line region boundary of MEOD is typically limited to 75% of original core flow at 100% of original licensed thermal power and the corresponding power/flow constant rod line. The increased core flow region is limited by plant recirculation system capability, acceptable flow-induced vibration, fuel lift considerations, and force impact on the vessel internal components.

Evaluations performed for MEOD include normal and transient conditions, LOCA analysis, containment responses, stability, flow-induced vibration, and the effects of increased flow-induced loads on reactor internal components and fuel channels. The results of these analyses must be re-evaluated each cycle.

The ARTS improvement program is a comprehensive project involving the Average Power Range Monitor (APRM), the Rod Block Monitor (RBM), and Technical Specifications.

Implementing the ARTS improvement program provides for the following improvements which enhance the flexibility of the BWR during power level monitoring:

1. The APRM trip setdown requirement is replaced by a power-dependent MCPR operating limit similar to that used in the BWR6, and a flow-dependent MCPR operating limit to reduce the need for manual setpoint adjustments. Another set of LHGR power and flow dependent limits will be specified for more rigorous fuel thermal protection during postulated transients at off-rated conditions. In addition, another set of MAPLHGR power and flow dependent limits will be specified to provide protection of the fuel during postulated loss-of-coolant accidents at off-rated conditions. These power and flow dependent limits were verified for plant specific application during the initial ARTS licensing implementation and are applicable to subsequent cycles provided that there are no changes to the plant configuration as assumed in the licensing analyses. The power and flow correction factors applicable to the current spent fuel cycle are specified in the supplemental reload licensing report (Appendix Q.)

2. The RBM system is modified from flow-biased to power-dependent trips to allow the use of a new generic non-limiting analysis for the rod withdrawal error and to improve response predictability to reduce the frequency of nonessential alarms. The applicability of the RWE analysis for subsequent cycles must be verified as part of the general reload core design analysis.

The resulting improvements in the flexibility of the BWR provided by ARTS are designed to significantly minimize the time to achieve full power from startup conditions.

Analyses are performed in order to justify operations at a reduced feedwater temperature at rated thermal power. Usually, the analyses are performed for end-of-cycle operation with the last stage feedwater heaters out of service. However, throughout cycle operation, an appropriate feedwater temperature reduction can be justified by analyses at the appropriate operating conditions.

The limiting transients are reanalyzed for operation at a reduced feedwater temperature. In addition, the loss-of-coolant (LOCA), fuel loading error, rod drop accident, and rod withdrawal error are also re-evaluated for operation at a reduced feedwater temperature.

The increase in the feedwater nozzle fatigue usage factor must also be considered.

PNPS was licensed for continuous Single Loop Operation (SLO) beginning in Cycle 16 (Ref 19). The capability of operating at reduced power with a single recirculation loop is highly desirable in the event that maintenance of a recirculation pump or other components renders one loop inoperable. This operating flexibility offers a significant increase in plant availability. The SLO analysis evaluates the plant for continuous operation at a maximum expected power output during SLO, which is lower than that which is attainable for two-pump operation.

To justify SLO, safety analyses have to be reviewed for one-pump operation. The MCPR fuel cladding integrity safety limit. AOO analyses, operating limit MCPR, and non-LOCA accidents are evaluated. Increased uncertainties in the total core flow and TIP readings result in a small increase in the fuel cladding integrity safety limit MCPR.

SLO can also result in changes to plant response during a LOCA. These changes are accommodated by the application of reduction factors to the two-loop operation MPLHGR limit, MAPLHGR reductions factors are evaluated on a plant and fuel type dependent basis. In each subsequent reload, reduction factors are checked for validity and, if new fuel types are added, new reduction factors may be needed in order to maintain the validity of the SLO analysis. (Ref 20)

14.4.3 Generator Load Rejection without Bypass

Fast closure of the turbine control valves is initiated whenever electrical grid disturbances occur which result in significant loss of load on the generator. The turbine control valves are required to close as rapidly as possible to prevent overspeed of the turbine generator rotor. The closing causes a sudden reduction of steam flow which results in a nuclear system pressure increase. The reactor is scrammed by the fast closure of the turbine control valves.

14.4.3.1 Starting Conditions and Assumptions

The following plant operating conditions and assumptions form the principle bases for which reactor behavior are analyzed during a load rejection:

1. The reactor and turbine generator are initially operating at full power when the load rejection occurs.

2. All of the plant control systems continue normal operation.

3. Auxiliary power is continually supplied at rated frequency.

4. The reactor is operating in the manual flow control mode when load rejection occurs, although the results do not differ significantly for operation in the automatic flow control mode.

5. The turbine bypass valve system is failed in the closed position.

14.4.3.2 Event Description

Complete loss of the generator load produces the following sequence of events:

1. The power load unbalance device steps the load reference signal to zero and closes the turbine control valves at the earliest possible time. The turbine accelerates at a maximum rate until the valves start to close.

2. Reactor scram is initiated upon sensing control valve fast closure.

3. If the pressure rises to the safety/relief valve setpoint, these valves open and discharge to the suppression pool.

4. If pressure rises to approximately 1210 psig, the MG set drive motor breakers and generator field breakers trip.

5. If pressure rises to the spring safety valve setpoint, these valves open and discharge to the drywell.

14.4.4 Turbine Trip Without Bypass

A variety of turbine or nuclear system malfunctions will initiate a turbine trip. Some examples are: moisture separator and heater drain tank high levels, large vibrations, loss of control fluid pressure, low condenser vacuum and reactor high water level. The turbine stop valve closes causing a sudden reduction in steam flow which results in a nuclear system pressure increase and the shutdown of the reactor.

14.4.4.1 Starting Conditions and Assumptions

The plant operating conditions and assumptions are identical to those of the generator load rejection in Section 14.4.3.1.

14.4.4.2 Event Description

The sequence of events for a turbine trip is similar to those for a generator load rejection. Stop valve closure occurs over a period of 0.10 second.

Position switches at the stop valves sense the turbine trip and initiate reactor scram. If the pressure rises to the pressure relief setpoints, the relief function of the safety/relief valves open discharging steam to the suppression pool.

14.4.5 Loss of Feedwater Heating

Loss of feedwater heating results in a core power increase due to the increase in core inlet sub cooling.

14.4.5.1 Starting Conditions and Assumptions

The following plant operating conditions and assumptions form the principal basis for which reactor behavior is analyzed during the loss of feedwater heating transient:

1. The plant is operating at full power.

2. The plant is operating in the manual flow control mode. The transient is moderated by the runback in core flow if operation is in the automatic flow control mode.

14.4.5.2 Event Description

Feedwater heating can be lost in at least two ways:

1. Steam extraction line to heater is closed.

2. Feedwater is bypassed around heater.

The first case produces a gradual cooling of the feedwater. In the second case, the feedwater bypasses the heater and no heating of the feedwater is generated. In either case the reactor vessel receives cooler feedwater. The maximum number of feedwater heaters which can be tripped or bypassed by a single event represents the most severe transient for analysis considerations. The feedwater heaters are assumed to trip instantaneously. This event causes an increase in core inlet sub cooling, collapsing core coolant voids which increases core power due to the negative void reactivity coefficient. In automatic control some compensation of core power is realized by modulation of core flow.

In either case, power would increase at a very moderate rate. If power exceeded the normal full power flow control line, the operator would be expected to insert control rods to return the power and flow to their normal range. If this were not done, the neutron flux could exceed the scram set point where a scram would occur.

14.4.6 Inadvertent Start of HPCI Pump

The inadvertent HPCI startup event description was revised in the analysis of the Cycle to include the possibility that the Feedwater Control System would not respond to the effective increase in Feedwater flow (and reactor vessel level) associated with a HPCI startup prior to reaching the high level turbine trip set point.

Instead of a relatively simple power increase driven by the coldwater injection, the inadvertent HPCI startup is a power increase followed by a level turbine trip. Above bypass the turbine trip initiates a reactor scram.

This changes the HPCI event from a cold water injection to a more severe form of a Feedwater Controller Failure (FWCF) event. More severe because HPCI injection water is colder than excess Feedwater modeled in the FWCF resulting in a larger power excursion before the turbine trip. See App. Q for reference to the current analysis. This event established the Operating Limit MCPR.

14.4.6.1 Starting Conditions and Assumptions

The HPCI system starts due to a malfunction or operator error. The Feedwater Control System does not respond sufficiently; resulting in rising water level in the reactor vessel.

14.4.6.2 Event Description

The relatively cold HPCI flow caused a slow rise in neutron flux and thermal power, as well as a slow rise in reactor vessel level. The power and level increases continue until the reactor vessel high level trip set point is reached causing a turbine trip. Above bypass, the turbine trip initiates a scram. The event is similar to the Feedwater Controller Failure - Maximum Demand.

14.4.7 Feedwater Controller Failure - Maximum Demand

This event is postulated on the basis of a single failure of a control device, specifically one which can directly cause an increase in coolant inventory by increasing the Feedwater flow. The most severe applicable event is a Feedwater controller failure during maximum flow demand. The Feedwater controller is forced to its upper limit at the beginning of the event.

14.4.7.1 Starting Conditions and Assumptions

The starting conditions and assumptions considered in this analysis are as follows:

1. Feedwater controller fails during maximum flow demand.

2. Maximum feedwater pump run out is assumed.

3. The reactor is operating in a manual flow control mode which provides for the most severe transient.

14.4.7.2 Event Description

A feedwater controller failure during maximum demand produces the following sequence of events:

1. The reactor vessel receives an excess of feedwater flow.

2. This excess flow results in an increase in core sub cooling, which reduces the void fraction and thus induces an increase in reactor power and in the reactor vessel water level.

3. The rise in the reactor vessel water level eventually leads to a high water level turbine trip and reactor scram trip.

4. If the pressure rises to the safety/relief valve setpoint, these valves open and discharge to the suppression pool

5. If pressure rises to approximately 1210 psig, the MG set drive motor breakers and generator field breakers trip.

6. If pressure rises to the spring safety valve setpoint, these valves open and discharge to the drywell.

14.4.8 Rod Withdrawal Error

Rod withdrawal error results in a core power increase due to positive reactivity insertion. The results reported in the plant supplemental reload submittal are either plant/cycle specific or from the generic rod withdrawal error analyses described in Reference 1. If the generic analysis value is reported, it will be designated as generic in the plant supplemental reload submittal.

14.4.8.1 Starting Conditions and Assumptions

The reactor is operating at a power level above 75% of rated power at the time the control rod withdrawal error occurs. The reactor operator has followed procedures and up to the point of the withdrawal error is in a normal mode of operation (i.e., the control rod pattern, flow set points, etc., are all within normal operating limits). For these conditions, it is assumed that the withdrawal error occurs with the maximum worth control rod. Therefore, the maximum positive reactivity insertion will occur.

14.4.8.2 Event Description

While operating in the power range in a normal mode of operation, the reactor operator makes a procedural error and withdraws the maximum worth control rod to its fully withdrawn position. Due to the positive reactivity insertion, the core average power and local power increase causing a LPRM alarm. The event ends with a rod block by the RBM.

14.5 POSTULATED DESIGN BASIS ACCIDENTS

The abnormal operating transients documented in Section 14.4 are evaluated to determine the normal plant operating MCPR limit and compliance with the LHGR 1% plastic strain limit. In addition to these analyses, evaluations of less frequent postulated events are made to assure an even greater depth of safety. Accidents are events which have a projected frequency of occurrence of less than once in every one hundred years for every operating BWR. The broad spectrum of postulated accidents is covered by four categories of design basis events. These events are as follows:

1. Decrease in Reactor System Flow Rate - Recirculation Pump Seizure,

2. Reactivity and Power Distribution Anomalies - Control Rod Drop Accident and Loading Error Accident,

3. Decrease in Reactor Coolant Inventory - Steam Line Break and Loss of Coolant Accident, and

4. Radioactive Release from Subsystem or Component - Fuel Handling Accident.

The recirculation pump seizure and misplaced fuel bundle events were analyzed as abnormal operating transients in the initial core evaluation. Since that time, these events have been recategorized as accidents.

As documented in Reference 1, only some of the above accidents are reanalyzed for each reload cycle. These include control rod drop accident and misoriented fuel bundle. The loss of coolant accident analysis is performed only when a new bundle enrichment or new fuel is placed in the core. These three events, the steam line break accident, and the fuel handling accident are addressed below.

14.5.1 Control Rod Drop Accident

There are many ways of inserting reactivity into a boiling water reactor; however, most of them result in a relatively slow rate of reactivity insertion and therefore pose no threat to the system. It is possible, although unlikely, that a rapid removal of a high worth control rod could result in a potentially significant excursion. Therefore, the accident which encompasses the consequences of a reactivity excursion is the control rod drop accident.

The drop of the control rod results in a high local reactivity in a small region of the core and for large, loosely coupled cores like PNPS, significant shifts in the spatial power generation during the course of the excursion. Therefore, the method of analysis must be capable of accounting for any possible effects of the power distribution shifts.

Analysis of this accident is performed at various reactor operating states; the key reactivity feedback mechanism affecting the termination of the initial prompt power burst is the Doppler Reactivity Coefficient. Final shutdown is achieved by scramming all but the dropped rod. The methods utilized to evaluate the rod drop accident are documented in Reference 1. The limit for this event is 280 cal/gm.

14.5.1.1 Sequence of Events

For this accident, the reactor is assumed to be at a control rod pattern corresponding to the maximum incremental rod worth. The rod worth minimizer or operators are functioning within the constraints of the Banked Position Withdrawal Sequences (BPWS). The control rod that will result in the maximum incremental reactivity worth addition at any time in core life, under any operating condition while employing the BPWS, becomes decoupled from the control rod drive.

The operator selects and withdraws the drive of the decoupled rod along with the other control rods assigned to the Banked-Position group such that the proper core geometry for the maximum incremental rod worth exists. The decoupled control rod sticks in the fully inserted position.

The control rod then becomes unstuck and drops at the maximum velocity determined from experimental data (3.11 fps). The reactor goes on a positive period and the initial power burst is terminated by the Doppler Reactivity Feedback. The APRM 120% power signal scrams the reactor. The MSIV's, Steam Line Drain Isolation Valves, and Reactor Water Sample Valves remain open. The Mechanical Vacuum Pump receives an auto trip signal.

14.5.1.2 Analytical Methods and Results

Techniques and models used to analyze the control rod drop accident (CRDA) are documented in Reference 1. Analytical results from BPWS plants like PNPS have been statistically analyzed. The results of this statistical analysis show that, in all cases, the peak fuel enthalpy in a CRDA would be much less than the 280 cal/gm event limit even with a maximum incremental rod worth corresponding to 95% probability at the 95% confidence level. The details of this analysis are given in Reference 1.

14.5.1.3 Radiological Consequences

The analysis for removing the MSIV isolation function was performed by General Electric in NEDO-31400A, Safety Evaluation for Eliminating the Boiling Water Reactor Main Steam Line Isolation Valve Closure Function and Scram function of the Main Steam Line Radiation Monitor. Input values were collected from all participating utilities (includes PNPS) to consider the most bounding case of the effects of removing the MSIV isolation function. The analysis considered the offsite dose consequences for 2 release scenarios.

1) A CRDA where the source term is not reduced, even though the MSIVs close, and the radionuclides enter the condenser at atmospheric pressure to leak directly to the environment.

2) A CRDA where the MSIVs do not close and the activity is processed through the AOG and released via the main stack.

The consequences for the CRDA at PNPS were evaluated using PNPS-specific assumptions and parameter values. The source term is based on the failure of 1200 rods for GE14 fuel. Conservatively, the maximum radial peaking factor that is expected during the operating fuel cycle was applied to all affected rods. The approach is as used in NEDO 31400 and as outlined in Standard Review Plan (SRP) 15.4.9 "Spectrum of Rod Drop Accidents (BWR)."

For the first scenario in which the radioactivity leaks directly from the condenser to the environment, the estimated consequences are 3.7 rem to the thyroid and 0.03 rem to the whole body.

In the event of the second scenario, in which the MSIVs do not close, the offgas pre-treatment or post-treatment monitors would automatically isolate the main stack prior to any release. The off-gas monitors are required by Technical Specifications and the Offsite Dose Calculation Manual to be in continuous operation to isolate the main stack in the event of a noble gas release rate greater than the setpoint value used for normal plant effluent releases. In the event of a CRDA the activity release rate would be significantly greater than that allowed during normal plant operation. The monitors would, therefore, isolate the main stack. The accident activity released from the fuel would be contained in the condenser and the consequences would be as determined for the condenser release scenario.

The CRDA activity release via the AOG system and main stack is highly unlikely at PNPS. However, since the off-gas monitors are not safety-related, a conservative evaluation assuming such a scenario was performed. It was assumed that the AOG system is in service but that the monitors fail to isolate the main stack. Conservatively, the AOG charcoal delay bed hold-up times for noble gases was assumed to be zero. A conservative AOG system flow rate was also used. For this scenario the estimated consequences are still well below the limits established in SRP 15.4.9, which were used in the safety evaluation report as the bases for accepting NEDO 31400. Therefore, the AOG system is not required to mitigate the consequences of a CRDA.

NEDO-31400A recognized that early vintage BWRs like Pilgrim operate at power levels above the mechanical vacuum pump capability while AOG is bypassed. NEDO-31400A states that this operating mode is acceptable because the pretreatment radiation monitors' set points are established to automatically isolate the effluent pathway before Technical Specification dose rate limits are exceeded. If a CRDA occurred while operating in the AOG bypass mode, the resulting offsite dose is expected to be similar to the condenser leakage scenario discussed in this section (i.e., that dose would be a small fraction of 10 CFR 100 dose limits).

The NEDO-31400A safety evaluation did not address removing any other trip functions from the Main Steam Line Radiation Monitors. The other possible trip functions from the Main Steam Radiation monitoring are as follows:

1) Trip the Mechanical Vacuum Pump.
2) Close the Main Steam Line Drain Isolation Valves
3) Close the Reactor Sample Isolation Valves

The Mechanical Vacuum Pump trip function is operable at PNPS. The other trip functions are not operable at PNPS as explained below.

There is no effect on the off-site dose as a result of the main steam line drain valves remaining open during a CRDA since the piping is also routed to the condenser. The source term in the condenser is unaffected because no plate out or condensation of the source term from the reactor to the condenser is assumed in the NEDO-31400A analysis. The occurrence of these phenomena in the drain lines would tend to diminish the condenser source term.

The reactor water sample enters the Reactor Building as a 1-inch line in the Reactor Water Cleanup Heat Exchanger Room. The line splits off to a 1/2-inch line to the Crack Arrest Verification System (CAVS) and 1/2-inch line to the Reactor Water Sample Panel (C121). There is a 1/2-inch line from the CAVS that goes to a sample panel (C136) and drains to the Reactor Water sample panel drain.

The conservative assumptions used in calculating the dose contribution from the open reactor water sample valves are as follows:

1. The valves are assumed to be open for 2 hours before action is taken by the operator.

2. The same fraction of halogens get vented to the atmosphere from the sample line as from the condenser. This assumes no condensation occurs. However, the process stream that goes to the drain first goes to a sample panel cooler and has an outlet temperature of approximately 77°F. Therefore, the actual fraction of halogens that get vented to the atmosphere will be very small.

The estimated contributing doses from this drain are 20.1 rem thyroid and 7.0 E-03 rem whole body.

Another contribution to offsite dose during a CRDA is from the Turbine Gland Seal Condenser Exhausters. This source draws steam from the steam chest of the Main Steam System and supplies it to the gland seals of the turbine. There is a separate condenser for this steam that is mixed with air and then exhausted to the same effluent path as the mechanical vacuum pump. The amount of steam existing through this path depends on the clearances of the packing on the turbine seals. The maximum seal clearance was assumed when considering the offsite dose contribution during a CRDA. Also, no condensation of the steam is assumed after it leaves the exhausters and is released to the environment. The actual process flow is through piping that contains 2 loop seals to collect condensation before being released to the stack. The estimated dose contribution from this source was 0.64 Rem thyroid and 1.3E-02 Rem whole body.

The offsite dose from all sources during a CRDA is totaled below (reference 14.7.11):

Source	Thyroid	WB
Condenser	3.7	3.0E-02
RX Sample Line	20.1	7.0E-03
Gland Seals	0.64	1.3E-02
TOTAL	24.4	5.0E-02

At PNPS, the worst case CRDA most probably would occur during mechanical vacuum pump operation. The mechanical vacuum pump would trip and the radionuclides would be trapped in the condenser. Therefore the condenser leakage scenario is bounding for PNPS.

The CRDA whole body dose for PNPS is less than the NEDO-31400A of 0.31 Rem. The PNPS CRDA thyroid dose is greater than the NEDO-31400A value of 4.3 Rem because of the PNPS site specific added contributions from the reactor sample line and gland seals. However, the total offsite dose for a CRDA is less than the SRP 15.4.9 limits of 75 Rem thyroid and 6 Rem whole body.

NEDO-31400A considered the failure of 850 fuel rods of the 8x8 configuration. For 9x9 fuel, approximately 1000 fuel rods are expected to fail at the same level of deposited energy due to the postulated accident. However, the radiological consequences for the 9x9 fuel designs are the same as for 8x8 fuel designs due to an offsetting lower plenum activity (per rod).

14.5.2 Loading Error Accident

One of the events which is evaluated each cycle is the fuel bundle loading error. The probability of a significant fuel assembly loading error is much less than once in a plant lifetime and requires multiple operator errors to occur. A loading error in the core configuration is defined as one of the following:

1. A fuel bundle is inserted in an improper location (mislocated bundle accident); or

2. A fuel bundle is loaded in an improper orientation, i.e., rotated 90 or 180 degrees (misoriented bundle accident).

The results of this accident must not exceed the Fuel Cladding Integrity MCPR Safety Limit; therefore, there are no radiological consequences.

14.5.2.1 Mislocated Bundle Accident

Mislocated bundle analyses are not performed for reload cores because, based on an analysis of data available from past reloads, the probability that a mislocated fuel bundle loading error will result in a CPR less than the safety limit is sufficiently small that plant/cycle specific analyses are not necessary. Details of this analysis are provided in Reference 1.

14.5.2.2 Misoriented Bundle Accident

Proper orientation of fuel assemblies in the reactor core is readily verified by visual observation and assured by verification procedures during core loading. Five separate visual indications of proper fuel assembly orientation exist:

1. The channel fastener assemblies, including the spring and guard used to maintain clearances between channels, are located at one corner of each fuel assembly adjacent to the center of the control rod.

2. The identification boss on the fuel assembly handle points toward the adjacent control rod.

3. The channel spacing buttons are adjacent to the control rod passage area.

4. The assembly identification numbers which are located on the fuel assembly handles are all readable from the direction of the center of the cell.

5. There is cell-to-cell replication.

Experience has demonstrated that these design features are clearly visible so that any misoriented fuel assembly would be readily identifiable during core loading verification.

Analysis methods for the misoriented fuel assembly are given in Reference 1. A penalty of 0.02 CPR to account for tilting of the misoriented bundle is added to the calculated CPR used in determining the operating limit MCPR. The misoriented bundle accident is evaluated on a cycle specific basis.

14.5.3 Loss of Coolant Accident

Break of a large recirculation pipe represents the limiting pipe break inside the containment. This event has been analyzed quantitatively in Section 6.5. The following is a discussion of the containment analysis and radiological consequences. Assumptions used in these analyses are given in Appendix R.6 and below.

Two ultimate heat sink (UHS) temperatures (65°F and 75°F) are presented in Loss-of-Coolant-Accident, Primary Containment and ECCS Pump NPSH analysis contained Section 14.5.3. The 65°F analysis represents the original design and licensing value. The 65°F analysis information was retained in the FSAR for its historical value and because it was the original basis for the sizing and selection of the containment heat removal systems.

By license amendment (Ref. 12 & 13), the design and licensing basis maximum UHS temperature was raised from 65°F to 75°F. The current operational limit in the Technical Specifications is 75°F. Therefore, the design and licensing value for the maximum UHS temperature is defined at 75°F, to ensure plant operation is not limited below 75°F and that all safety functions directly or indirectly dependent on UHS temperature can be satisfied up to 75°F.

14.5.3.1 Primary Containment Response

14.5.3.1.1 Initial Conditions and Assumptions

The following assumptions and initial conditions were used in the calculation of the effects of a LOCA on the primary containment. The plant response to the accident can be separated into two distinct phases: the short term response and the long-term recirculation phase. The short-term response includes that period of time in the accident up to 600 seconds when initiation of containment cooling is assumed. The peak drywell and wetwell airspace temperatures occur in this period of time and are not influenced by the performance of containment cooling. The long-term recirculation phase of the accident response is defined to begin at 600 seconds with the initiation of containment cooling and continue past the peak suppression pool temperature to the point of minimum NPSH margin.

Historically, the primary containment response has been established using the design value of 65°F for the SSW inlet temperature to the RBCCW heat exchanger. The following discussion of containment response includes analysis performed for the DBA LOCA using a site maximum SSW injection temperature of 75°F. In the following discussion the analysis that used a 75°F SSW injection temperature is referred to as the 75°F SSW Case, likewise the analysis based on 65°F SSW injection temperature is referred to as the 65°F SSW Case.

1. The reactor is operating at full power with all valves in the recirculation system open. Initial power for the 75°F SSW Case was increased to 102% consistent with the current standard based on the requirements of Regulatory Guide 1.49.

65°F SSW Case	75°F SSW Case
1998 MWt	2038 MWt

2. The reactor is assumed to go subcritical at the time of accident initiation due to void formation in the core region. Scram also occurs in less than 1 sec from receipt of the high drywell pressure signal, but the difference in shut down time between 0 and 1 sec is negligible.

3. The sensible heat released in cooling the fuel to 545°F (the normal primary system operating temperature) and the core decay heat were included in the reactor vessel depressurization calculation. The rate of energy release was calculated using a conservatively high heat transfer coefficient throughout the depressurization. Because of this assumed high energy release rate, the vessel is maintained at near rated pressure for almost 6 sec. The high vessel pressure increases the calculated flow rates out of the break; this is conservative for containment analysis purposes. With the vessel fluid temperature remaining near 545°F, however, the release of sensible energy stored below 545°F is negligible during the first 6 sec. The later release of this sensible energy does not affect the peak drywell pressure. The small effect of this energy on the end of transient suppression pool temperature is included in the calculations.

4. The main steam line isolation valves were assumed to start closing at 0.5 sec after the accident, and the valves were assumed to be fully closed in the shortest possible time of 3 sec following closure initiation. Actually, the closures of the main steam line isolation valves are expected to be the result of reactor low-low water level, so these valves may not receive a signal to close for over 4 sec, and the closing time could be as high as 10 sec. By assuming rapid closure of these valves, the reactor vessel is maintained at a high pressure, which maximizes the discharge of high energy steam and water into the primary containment, which in turn maximizes the loading on the containment.

5. For both the short and long-term analysis in the 65°F SSW Case, the feedwater flow was assumed to stop instantaneously at time zero. This conservatism is used because the relatively cold feedwater flow, if considered to continue, tends to depressurize the reactor vessel, thereby reducing the discharge of steam and water into the primary containment.

   Short-term containment response in the 75°F SSW Case is consistent with the 65°F SSW Case. For the 75°F SSW Case long-term analysis, feedwater flow into the RPV continues until the high-energy feedwater (above feedwater enthalpy of 201 BTU/lbm) is injected into the reactor vessel. This assumption is conservative for the long-term suppression pool temperature analysis because additional energy is added to the reactor vessel and containment.

6. The vessel depressurization flow rates were calculated using Moody's critical flow model[2] assuming "liquid only" outflow because this maximizes the energy release to the containment. "Liquid only" outflow means that all vapor formed in the vessel due to bulk flashing rises to the surface rather than being entrained in the exiting flow. Some entrainment of the vapor would occur and would significantly reduce the reactor vessel discharge flow rates. Moody's critical flow model, which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximized slip ratio, accurately predicts vessel outflows through small diameter orifices. However, actual flow rates through larger flow areas are less than the model indicates due to the effects of a near homogeneous two phase flow pattern and phase nonequilibrium. These effects are in addition to the reduction due to vapor entrainment discussed above.

   For the 75°F SSW Case, the vessel depressurization rates were calculated using the homogeneous equilibrium critical flow model described in NEDO-21052, "Maximum Discharge of Liquid-Vapor Mixtures from Vessels." (Reference 6).

7. The pressure response of the containment is calculated assuming:

   a. Thermodynamic equilibrium in the drywell and suppression chamber. Because complete mixing is nearly achieved, the error introduced by assuming complete mixing is negligible and in the conservative direction.

   b. The constituents of the fluid flowing in the drywell to suppression chamber vents are based on a homogeneous mixture of the fluid in the drywell. The consequences of this assumption result in complete liquid carryover into the drywell vents. Actually, some of the liquid will remain behind in a pool on the drywell floor so that the calculated drywell pressure is conservatively high.

c. The flow in the drywell suppression pool vents is compressible except for the liquid phase. In the development of the drywell flow model, it is noted that the mass fraction of liquid in the drywell is on the order of 0.60, while the volumetric fraction is only about 0.005. This fact resulted in the following interpretation of the flow pattern. The liquid is in the form of a fine mist that is carried along by the predominately steam air flow and does not affect the flow except to add inertia to the flowing fluid. Except for the corrections to account for the liquid inertia, flow is treated as compressible flow of an ideal gas in a duct with friction. The loss coefficients of the Vent/Header/Downcomer System are lumped as an equivalent length of pipe.

The accuracy of this interpretation of the effects of liquid carryover is supported primarily by a series of tests performed as part of the Humboldt Bay series of pressure suppression tests.(3) In this series of tests, changes in the drywell geometry resulted in variation in the amount of liquid carryover achieved. The liquid remaining in the drywell at the end of the test was measured and recorded. These tests were performed with a relatively small diameter orifice in the reactor vessel so that the reactor vessel outflow can be calculated accurately using Moody's critical flow model.(2) On Figure 14.5-1 the calculated and measured pressure responses for these tests are shown. Note that with 100 percent carryover the agreement is excellent. In this test, the drywell was preheated to 184°F before the steam water mixture was introduced to the drywell; the preheating prevented any condensation on the drywell walls. A calculated response assuming condensation but no carryover is also shown on Figure 14.5-1, and the agreement with the measured response with no carryover is excellent.

d. No heat loss from the gases inside the primary containment is assumed. The model is compared against the Bodega Bay test data for two of the smaller orifices tested on Figures 14.5-2 and 14.5-3. As can be seen in the figures, the reactor vessel depressurization model accurately predicted the results of these tests. However, the predicted drywell pressure response is slightly higher than the test results. The over prediction is believed to be due to a combination of:

No condensation assumed in calculated response,

Slight over prediction of reactor vessel discharge flow rates, and

Incomplete liquid carryover into the drywell vents.

As the chosen size of the vessel orifice increases, the vessel depressurization rate is over-predicted and the over prediction of drywell pressure increases. This trend is illustrated on Figure 14.5-4, where calculated and measured drywell peak pressure is compared. In no case did the model underpredict the test data.

14.5.3.1.2 Containment Response

<u>65°F SSW Case</u>

The calculated pressure and temperature responses of the containment are shown on Figures 14.5-5, 14.5-6, and 14.5-7. Figure 4.5-5 shows that the calculated drywell peak pressure is 45 psig, which is well below the maximum allowable pressure of 62 psig. After the discharge of the primary coolant from the reactor vessel into the drywell, the temperature of the suppression chamber water approaches 130°F (Figure 14.5-7), and the primary containment pressure stabilizes at about 27 psig, as shown on Figure 14.5-5. Most of the noncondensible gases are forced into the suppression chamber during the vessel depressurization phase. However, the noncondensibles soon redistribute between the drywell and the suppression chamber via the vacuum-breaker system as the drywell pressure decreases due to steam condensation.

The core spray system removes decay heat and stored heat from the core, thereby controlling core heatup and limiting metal water reaction to less than 0.1 percent. The core spray water transports the core heat out of the reactor vessel through the broken recirculation line in the form of hot water. This hot water flows into the suppression chamber via the drywell to suppression chamber vent pipes. Steam flow is negligible. The energy transported to the suppression chamber water is then removed from the primary containment system by the residual heat removal system (RHR) heat exchangers.

Prior to activation of the RHR containment cooling mode (arbitrarily assumed at 600 sec after the accident), the RHR pumps (low pressure coolant injection (LPCI) mode) have been adding liquid to the reactor vessel along with the core spray. After the reactor vessel is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow, in addition to cooling the fuel, offers considerable cooling to the drywell and causes a depressurization of the containment as the steam in the drywell is condensed. At 600 sec, the RHR pumps are assumed to be switched from the LPCI mode to the containment cooling mode. The containment spray would normally not be activated at all and the changeover to the containment cooling mode need not be made for several hours. There is considerable time available to place the containment cooling system in operation because about 8 hr will pass before the containment design pressure is reached, assuming no containment cooling.

To access the primary containment long term response after the accident, an analysis was made of the effects of various containment spray and containment cooling combinations. For all cases, one of the core spray loops is assumed to be in operation. The long term pressure and temperature response of the primary containment was analyzed for the following containment spray and cooling conditions:

Case A - Operation of both RHR cooling loops with two residual heat removal (RHR) pumps and two RHR heat exchangers in suppression pool cooling mode. No containment spray.

Case B - Operation of one RHR cooling loop with one RHR pump and one RHR heat exchanger in suppression pool cooling mode. No containment spray.

Case C - Operation of one RHR cooling loop with one RHR pump and one RHR heat exchanger in containment spray mode.

The initial pressure response of the containment (the first 30 sec after break) is the same for each of the conditions. During the long term containment response (after depressurization of the reactor vessel is complete) the suppression pool is assumed to be the heat sink in the containment system. The effects of decay energy, stored energy, and energy from the metal water reaction on the suppression pool temperature are considered.

Case A

This case assumes that both RHR loops are operating at design heat removal capacity. This includes two RHR heat exchangers, two RHR pumps, and design values of cooling water flow to both RHR loops operating in the suppression pool cooling mode. The RHR pumps draw suction from the suppression pool and pump water through the RHR heat exchangers and back into the suppression pool. This forms a closed cooling loop with the suppression pool. This suppression pool cooling condition is arbitrarily assumed to start at 600 sec after the accident. Prior to this time the RHR pumps are used to flood the core (LPCI mode).

The containment pressure response to this set of conditions is shown as curve "a" on Figure 14.5-5. The corresponding drywell and suppression pool temperature responses are shown as curves "a" on Figures 14.5-6 and 14.5-7. After the initial rapid depressurization, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment. When the energy removal rate of the RHR exceeds the energy addition rate from the decay heat, the containment pressure and temperature begin to decrease. Table 14.5-1 summarizes the peak containment pressure following the initial blowdown peak, the peak suppression pool temperature, and a summary of the equipment capability assumed in the analysis.

Case B

This case assumes that one RHR loop is operating at design heat removal capacity (one RHR heat exchanger, one RHR pump, and design value of cooling water flow to one RHR loop operating in the suppression pool cooling mode). As in the previous case, there is no containment spray operation and the suppression pool cooling mode is assumed to be activated at 600 sec after the accident. The containment pressure response to this set of conditions is shown as curve "b" on Figure 14.5-5. The corresponding drywell and suppression pool temperature responses are shown as curves "b" on Figures 14.5-6 and 14.5-7. A summary of this case is shown on Table 14.5-1, including a summary of the equipment capability assumed in the analysis.

Case C

This original case assumes the same equipment operability as Case B except that the entire discharge from the RHR heat exchanger is routed to the containment spray headers in the drywell and wetwell. It assumed that the containment spray is established at 600 sec after the accident.

The containment response to this set of conditions is shown as curve "c" on Figure 14.5-5. The corresponding drywell and suppression pool temperatures are shown as curves "c" on Figures 14.5-6 and 14.5-7. A summary of this case is shown on Table 14.5-1, including a summary of the equipment capability assumed in the analysis.

Comparing the "containment spray" Case C with the "no spray" Case B, it is seen that the suppression pool temperature response is the same because the same amount of energy is removed from the pool via the RHR heat exchanger. The total flow rate through the RHR heat exchanger is the same for Case B & C. However, the post blowdown containment pressure is higher for the "no spray" case, as shown by Figure 14.5-5. This, however, is of no consequence since the pressure is still much less than the containment design pressure of 56 psig. Figure 14.5-8 illustrates the slight effect on calculated containment leakage rate, due to the higher pressure.

The containment spray flowrate used in the original FSAR containment analysis (based on a 65°F SSW inlet temperature) was substantially reduced from its design value of 5,000 gpm down to 1,100 gpm by capping the majority of the drywell spray nozzles. The Case C, containment pressure and temperature response curves shown on Figure 14.5-5 and Figure 14.5-6 were not recalculated using the current containment spray flow rate of approximately 1,100 gpm. The spray reduction will increase the drywell temperature and pressure between 600 seconds when spray is initiated and 1×10^6 seconds, the time at which the analysis is terminated. Although, drywell temperature and pressure increase, that increase is bounded by the results for Case B which is based on one loop of RHR in the suppression pool cooling mode and no spray.

To assure the suppression pool temperature response is the same as that shown on Figure 14.5-7, the RHR heat exchanger flowrate must be maintained consistent with values in Table 14.5-1. Operating procedures require that a portion of the discharge from the RHR heat exchanger be routed to the containment spray headers and the remaining portion return to the suppression pool via the suppression pool bypass line.

75°F SSW Case

For the 75°F SSW Case, the calculated pressure and temperature responses of the containment are shown on Figures 14.5-16, and 14.5-17. The short-term response of the drywell, wetwell, and suppression pool is the same as for the Case B from the 65°F SSW Case. The containment response prior to 600 seconds is unaffected by containment cooling and remains the same for both cases. The 65°F SSW Case provides an additional description of the short-term response.

Prior to the activation of containment cooling, the LPCI and core spray pumps have been adding liquid to the reactor vessel. After the vessel is flooded to the height of the jet pump nozzles, the excess flow discharges through the break into the drywell. This flow cools the fuel and flushes sensible heat from the reactor vessel into the drywell. The flow of sub cooled liquid into the drywell causes depressurization of the containment as the steam in the drywell is condensed.

For the 75°F SSW Case, the long-term analysis assumes one RHR loop is available for containment cooling. At 600 seconds, the necessary valves are opened admitting cooling water flow to the RHR heat exchanger. The RHR heat exchanger bypass valve is assumed to remain in its full open normal position and the RHR system is assumed to remain in the LPCI mode with containment cooling by heat rejection through the RHR heat exchanger. No disruption of LPCI flow is required to enter this mode of cooling. This configuration will provide maximum core cooling, but does not provide rated heat removal because more than half of the two pump LPCI flow rate goes through the heat exchanger bypass line and not the heat exchanger.

At two hours after the start of the accident, a transition is made from the two pump LPCI with Heat Rejection mode to the one pump LPCI with Heat Rejection mode to maximize the heat removal function of the RHR System. Rated heat removal from the containment is obtained using the LPCI with Heat Rejection mode by removal of one RHR pump from LPCI service and closure of the RHR heat exchanger bypass valve while maintaining maximum LPCI injection flow from the single RHR pump. One pump LPCI with Heat Rejection mode is assumed to run continuously throughout the remainder of the accident response.

For the design basis LOCA analysis, it is assumed that there is only one loop of containment heat removal (RHR, RBCCW, and SSW) operable. The containment heat removal assumed in the design basis LOCA analysis is that which can be obtained with one loop of the RHR, RBCCW, and SSW Systems operating at the limiting conditions for pump and heat exchanger performance. Suppression pool temperature will continue increasing from the transfer of sensible and decay heat from the reactor core to the suppression pool until reaching the peak approximately 5 to 6 hours after the accident. The design peak suppression pool temperature for the DBA-LOCA is 185°F, which is well below the primary containment design temperature of 281°F. Subsequently, the decreasing decay heat results in a steady cooldown and depressurization of primary containment. The RHR heat transfer parameters at the peak suppression pool temperature are given in Table 14.5-6 and the resulting containment and suppression pool temperature profiles are given in Figure 14.5-17.

14.5.3.1.3 Core Standby Cooling System Pump Net Positive Suction Head

To assure proper operation of the CSCS pumps following a design basis LOCA, the Primary Containment and CSCS system design is such that Net Positive Suction Head (NPSH) margin is available to the pumps at all times.

The NPSH available (NPSHA) at the suction to the CSCS pumps is equal to the total absolute pressure minus the vapor pressure of water at the suppression pool temperature. The NPSH required at the pump suction (NPSHR) is the minimum pressure over and above the vapor pressure that must be present in order to prevent pump cavitation.

NPSH design margin is based on calculations that include the effect from the increase in wetwell vapor pressure and air/nitrogen partial pressure in equilibrium with increasing suppression pool temperature with an accounting for containment initial conditions and leakage.

The design margin for NPSH available to the RHR and core spray pumps is determined using the following assumptions:

1. The primary containment is assumed to contain the minimum credible mass of noncondensible gas (air/nitrogen) prior to the design basis LOCA. The drywell initial condition is 150°F, 80% RH, 1.3 psig, and the wetwell is 85°F, 100% RH, 0 psig.

2. The water vapor pressure in containment increases to be in equilibrium with the suppression pool temperature.

3. The partial pressure of the containment air/nitrogen increases with the pool temperature per the ideal gas laws after the initial mixing of the drywell and wetwell air has occurred.

4. Where stated on the figures, containment leakage has been calculated based on a leak rate of 1% per day for design basis conditions and 5% per day to demonstrate conservative design margin with impaired containment integrity.
   The leakage values represent percent mass per day at a reference pressure of 45 psig using the mass leakage formulation described in Appendix R.5.4.2 "Long Term Containment Response."

5. The suppression pool temperature profile is based on minimum primary containment system cooling, i.e., one RHR loop in containment cooling is assumed, with an initial suppression pool temperature of 85°F and a salt service water heat sink temperature of 75°F.

6. Minimum initial water volume in the suppression pool is assumed (84,000 ft^3).

7. Drywell free volume temperature is equal to wetwell temperature following the accident. This is based on the redistribution of noncondensible gases between the drywell and wetwell via the vacuum-breaker system following the vessel depressurization phase.

8. Maximum flow rates are used for the CSCS pumps to maximize the suction line losses and NPSH required by the pumps. The NPSHR is 27 ft at 5670 gpm for the RHR pumps and 29 ft at 4950 gpm for the core spray pumps.

Based on the above conservative assumptions, the margin for NPSH available was evaluated for the limiting accident event which is the design basis LOCA. The NPSH available and NPSH margin for the RHR and core spray pumps were evaluated for both a 75°F SSW injection temperature and 65°F SSW injection temperature. In the following discussion the analysis that used a 75°F SSW injection temperature is referred to as the 75°F SSW Case, likewise the analysis based on a 65°F SSW injection temperature is referred to as the 65°F SSW Case.

The 65°F SSW Case is based on the suppression pool temperature profile in Figure 14.5-7 from the original design basis LOCA analysis as described earlier in this section. The assumed flow rates, head losses, initial containment mass of nitrogen, and NPSH required for the RHR and core spray pumps have been revised from the original 65°F NPSH analysis so that the same values are used for both the original 65°F and updated 75°F NPSH analyses presented in this Section. The 75°F SSW Case uses the suppression pool temperature profile from Figure 14.5-17 that is from the updated design basis LOCA analysis described earlier.

Figure 14.5-9 shows the NPSH available as a function of pool temperature with zero containment leakage which makes this curve independent of time. Since no leakage effect is included, Figure 14.5-9 represents the highest NPSH margin that can be obtained using the above assumptions and as can be seen, a large margin exists for all pool temperatures. NPSH margin for the 65°F SSW Case, with leakage effects included, is present in a different format on Figure 14.5-10 and Figure 14.5-13. Here, the suppression pool temperature and containment pressure are shown as a function of time. Also shown is the primary containment pressure required to provide the required NPSH to the RHR and core spray pumps at their maximum required flow rates. As can be seen, substantial margin exists throughout the duration of the event. Therefore, it can be concluded that adequate NPSH will be available at all times following a design basis LOCA for the 65°F SSW Case.

NPSH margin for the 75°F SSW Case, with leakage effects included, is presented on Figure 14.5-18 and Figure 14.5-19. Here, the suppression pool temperature and containment pressure are shown as a function of time. Also shown is the primary containment pressure required to provide the required NPSH to the RHR and core spray pumps at their maximum required flow rates. As can be seen, substantial margin exists throughout the duration of the event. Therefore, it can be concluded that adequate NPSH will be available at all times following a design basis LOCA for the 75°F SSW Case.

The RHR and Core Spray System design analysis shows that substantial NPSH margin is available at all times following the bounding design basis LOCA. The design margin for NPSH available is that which exists between the minimum containment pressure that provides the required NPSH and the containment pressure that exists due to equilibrium conditions for the gas/vapor mixture with an accounting for containment initial conditions and leakage. This method of analysis for determining NPSH margin is in accordance with the original design basis for Pilgrim and other similar BWRs. The NRC has chosen to impose limits on the amount of containment pressure that may be included in the NPSH margin for CSCS pump suction strainer evaluations. These time-dependent containment pressure limits were selected based on NRC review of plant-specific accident analysis and are considerably less than the calculated equilibrium pressure.

In accordance with the NRC Safety Evaluation Report for License Amendment 185, the amount of containment positive pressure that may be included in a CSCS pump NPSH analysis has been limited to the following:

Time After Accident (sec)	(hour)	Containment Pressure (psig)	(psia)
0 to 1,200	0.00 to 0.33	0.0	14.7
1,200 to 1,800	0.33 to 0.50	1.9	16.6
1,800 to 3,600	0.50 to 1.0	3.0	17.7
3,600 to 57,600	1.0 to 16.0	5.0	19.7
57,600 to 108,000	16.0 to 30.0	2.5	17.2
108,000 to 172,800	30.0 to 48.0	1.0	15.7
172,800 to 864,000	48.0 to 240.0	0.0	14.7

These limits on containment pressure are included in the evaluation of LOCA debris head losses for the RHR and core spray pumps and the resulting NPSH available for long-term containment heat removal. There remains sufficient NPSH margin within these containment pressure limits to accommodate the postulated LOCA debris without affecting pump performance. The limits listed above are included in Figure 14.5-18 along with the calculated amount of containment pressure available. Figure 14.5-18 also includes a curve showing the amount of containment pressure required to provide adequate NPSH to the most limiting core spray pump operating with the maximum suction strainer head loss from the bounding analysis for strainer debris described in Section 6.4.3.

Evaluations of NPSH for reactor isolation events are bounded by the design basis LOCA. Analysis for isolation scenarios such as a fire event, where the high pressure makeup systems are assumed unavailable, are included in the updated containment analysis with a 75°F SSW heat sink. It is assumed that reactor depressurization occurs at 1450 seconds (24 minutes) due to low reactor water level and there is no suppression pool cooling for two hours. The peak pool temperature is less than 185°F while the equilibrium mechanism for containment pressure and NPSH available are the same as for the LOCA. The resulting NPSH available exceeds that for the design basis LOCA due to the lower pool temperature.

During Reactor Core Isolation Cooling System (RCIC) operation, the drywell free air volume cooler will normally remain operational. Due to the reduced heat load on the air coolers caused by the shutdown of the two reactor coolant recirculation system pumps, the drywell temperature could actually be less than the normal operating value in spite of the fact that some of the air cooler capacity may also be shut down. The lower drywell temperature would tend to reduce the primary containment pressure which would reduce the NPSH available. In order to arrive at a conservative lower bound on the total NPSH available, the following model was assumed:

1. No leakage from the primary containment (even at 5 percent free volume per day, leakage would be negligible during the short time period being considered).

2. Drywell and wetwell pressure equal (maintained equal by the vacuum breakers between the wetwell and drywell).

3. Torus air temperature equal to pool water temperature.

4. Drywell temperature during reactor core isolation cooling equal to 110°F, 20 percent rh (very conservative estimates).

5. Initial drywell conditions: 150°F, 0 psig, 100 percent rh

Actually, Assumption 4 and 5 are contradictory. If the heat load during normal operation is large enough to cause a drywell temperature of 150°F and a relative humidity of 100 percent, the air coolers would not be capable of reducing the drywell temperature to 110°F during RCIC operation. Such a heat load implies a small steam leak from the primary system.

This RCIC NPSH evaluation is based on very conservative assumptions for drywell and wetwell conditions during RCIC operation. The drywell atmosphere is assumed to be cooled and dehumidified down to 110°F at 20% rh by operation of the drywell coolers. The wetwell is in thermal equilibrium with the suppression pool, but the drywell and wetwell pressures are equalized due to the drywell vacuum breakers. The reactor is assumed to be scrammed at a suppression pool temperature of 110°F and depressurized when the pool reaches 120°F per the Technical Specifications. Due to the fixed drywell temperature at low humidity and the pressure equalization between the drywell and wetwell, the resulting containment pressure is minimized to a level only slightly above atmospheric pressure.

Figure 14.5-11 plots the NPSH available versus suppression pool temperature and show that there is NPSH margin at pool temperatures up to at least 175°F. The RCIC System is specified for continuous operation up to a suppression pool temperature of 140°F; however, short term operation at up to 170°F is also considered for system design since this represents the temperature at the end of a reactor depressurization that begins at 120°F. Figure 14.5-12 plots the containment pressure and a suppression pool temperature profile for a postulated controlled cooldown and depressurization of the reactor. The peak suppression pool temperature at the end of the reactor depressurization is 163°F, which is well within the range for which sufficient NPSH is available.

Assumptions regarding initial pool temperature, heat sink temperature, and decay heat have a minor effect on this peak pool temperature. The predominant effect on pool temperature is the fixed assumptions of reactor shutdown at 110°F and depressurization at 120°F which ensure the suppression pool temperature will not exceed 170°F during the depressurization.

The conservative assumption that pump NPSH required is 28 feet makes this RCIC analysis bounding for both the RCIC and HPCI pumps for operation through vessel depressurization to less than 200 psig.

Vessel depressurization to 200 psig allows the LPCI and/or Core Spray System to maintain core cooling. The NPSH evaluations for RCIC operation is inherently more limiting than for HPCI since during RCIC operation, there is no assumption of a steam leak to heatup and pressurize the drywell. As can be seen in Figure 14.5-11, there is significantly more NPSH available than required for suppression pool temperatures up to 170°F. Therefore, it can be concluded that adequate NPSH will be available during RCIC and HPCI operation.

14.5.3.1.4 Metal Water Reaction Effects on the Primary Containment

If Zircaloy in the reactor core is heated to temperatures above 2,000°F in the presence of steam, a chemical reaction occurs in which zirconium oxide and hydrogen are formed. This is accompanied by an energy release of about 2,800 Btu/lb of zirconium reacted. The energy produced is accommodated in the suppression chamber pool. The hydrogen formed, however, will result in an increased drywell pressure due simply to the added volume of gas in the fixed containment volume. Although very small quantities of hydrogen are produced during the accident, the containment has the inherent ability to accommodate a much larger amount as discussed.

The basic approach to evaluating the capability of a Containment System with a given Containment System spray design is to assume that the energy and gas are liberated from the reactor vessel over some time period. The rate of energy release over the entire duration of the release is arbitrarily taken as uniform, since the capability curve serves as a capability index only, and is not based on any given set of accident conditions as an accident performance evaluation might be.

It is conservatively assumed that the suppression pool is the only body in the system which is capable of storing energy. The considerable amount of energy storage which would take place in the various structures of the containment is neglected. Hence, as energy is released from the core region, it is absorbed by the suppression pool. Energy is removed from the pool by heat exchangers which reject heat to the station cooling systems. Because the energy release is taken as uniform and the service water temperature and system flow rates are constant, the temperature responses of the pool can be determined. It is assumed that the suppression chamber gases are at the suppression chamber water temperature.

The metal water reaction during core heatup is calculated by the core heatup model described in Appendix R.5. The extent of the metal water reaction thus calculated is less than 0.1 percent of all the zirconium in the core. As an index of the containment's ability to tolerate postulated metal water reactions, the concept of "Containment Capability" is used. Since this capability depends on the time domain, the duration over which the metal water reaction is postulated to occur is one of the parameters used.

Containment capability is defined as the maximum percent of fuel channels and fuel cladding material which can enter into a metal water reaction during a specified duration without exceeding the maximum allowable pressure of the containment. To evaluate the containment capability, various percentages of metal-water reaction are assumed to take place over certain time periods. This analysis presents a method of measuring system capability without requiring prediction of the detailed events in a particular accident condition.

Since the percent metal water reaction capability varies with the duration of the uniform energy and gas release, the percent metal water reaction capability is plotted against the duration of release. This constitutes the containment capability curves as shown on Figure 14.5-14. All points below the curves represent a given metal water reaction and a given duration which will result in a containment peak pressure which is below the maximum allowable pressure. The calculations are made at the end of the energy release duration because the number of moles of gases in the system is then at a maximum, and the suppression pool temperature is higher at this time than at any other time during the energy release.

It should be noted that the curves are actually derived from separate calculations of two conditions: the steaming and the non-steaming situations. The minimum amount of metal water reaction which the containment can tolerate for a given duration is given to the condition where all of the noncondensible gases are stored in the suppression chamber. This condition assumes that steaming from the drywell to the suppression chamber results in washing all of the noncondensible gases into the suppression chamber. This is shown as the flat portion of the containment capability characteristic curve. Activation of containment sprays condense the drywell steam so that no steaming occurs, thus allowing noncondensibles to also be stored in the drywell. This is denoted by the rising spray curve. The intersection between the no spray curve and the spray curve represents the duration and metal water reaction energy release which just raises all the spray water to the saturation temperature at the maximum allowable containment pressures.

For durations to the left of the intersection some steam is generated and all the gases are stored in the suppression chamber. For durations to the right of the intersection, the spray flow is subcooled as it exits from the drywell by increasing amounts as the duration is increased.

The energy release rate to the containment is calculated as follows:

$$qin = \frac{Qo + Qmw + Qs}{T_D}$$

Where:

qin = Arbitrary energy release rate to the containment, Btu/sec

Qo = Integral of decay power over selected duration of energy gas release, Btu

Qmw = Total chemical energy released exothermically from selected metal-water reaction, Btu

Qs = Initial internal sensible energy of core fuel and cladding, Btu

T_D = Selected duration of energy and gas release, sec

The total chemical energy released from the metal water reaction is proportional to the percent metal water reaction. The initial internal sensible energy of the core is taken as the difference between the energy in the core after the blowdown and the energy in the core at a datum temperature of 250°F.

The temperature of the drywell gas is found by considering an energy balance on the spray flows through the drywell as described in Appendix R.5.

Based upon the drywell gas temperature, suppression chamber gas temperature, and the total number of moles in the system, as calculated above, the containment pressure is determined. The containment capability curves on Figure 14.5-14 present the results of the parametric investigation.

14.5.3.2 Radiological Consequences

14.5.3.2.1 Loss of Coolant Accident Assumption

1. The reactor has operated for an extended period at 1,998 MWt. To account for power measurement uncertainty, a 2% allowance was added.

2. One hundred percent of the noble gases and 25 percent of the iodine in the core instantaneously become available for leakage from the primary containment.

3. The primary containment leak rate is a constant 1.25 percent/day for 30 days.

4. For radiological dose considerations, release to the atmosphere was assumed to occur via drywell leakage, main steam isolation valve (MSIV) leakage, and emergency core cooling system (ECCS) leakage. Drywell and ECCS Leakage, flows through the Standby Gas Treatment System without the inherent benefit of mixing in the Secondary Containment Building, and is released to the environment via the Main Stack. Main steam isolation valve leakage is a ground level, unfiltered release through the condenser and high pressure turbine.

5. Ninety-nine percent of the iodine entering the Standby Gas Treatment System is retained by the charcoal filters.

6. Atmosphere dispersion factors were based on Regulatory Guide 1.145 models.

7. The breathing rate is 347 cm^3/sec for the first 8 hr, 175 cm^3/sec for the next 16 hr, and 232 cm^3/sec thereafter.

14.5.3.2.2 Analytical Results

Radiological consequences for the loss of coolant accident based on the above assumptions are given in Table 14.5-2.

14.5.4 Main Steam Line Break Accident

The analysis of the main steam line break accident depends on the operating thermal-hydraulic parameters of the overall reactor (such as pressure) and overall factors affecting the consequences (such as primary coolant activity). Insertion of reload fuel does not change any of these parameters. Therefore the analyses presented for the initial core remains applicable. The results of this analysis based on the initial core thermal-hydraulic basis are given in Appendix R.3.5. The results of the coolant loss and radiological consequences are given below. The loss of coolant due to a main steam line break accident evaluation was not performed for the Pilgrim 10 CFR 50 Appendix K power uprate (1.5% of 1,998 MWt at constant pressure). All safety and operational aspects of MSIV and steam flow restrictors performance are within pre-power uprate evaluations.

14.5.4.1 Coolant Loss Analysis

The steam flow rate through the upstream side of the break increases from the initial value of 550 lb/sec in the line to 1,100 lb/sec (about 200 percent of rated flow for one steam line) with critical flow initially occurring at the flow restrictor. The steam flow rate was calculated using an ideal nozzle model. That the flow model predicts the behavior of the flow limiter has been substantiated by tests conducted on a scale model over a variety of pressure, temperature, and moisture conditions.

The steam flow rate through the downstream side of the break consists of equal flow components from each of the unbroken lines. In each of the unbroken lines, the steam flow rate increases from an initial value of 550 lb/sec to 1,100 lb/sec. Critical flow would be occurring at the flow limiters in these lines.

The total steam flow rate leaving the vessel is thus approximately 4,500 lb/sec, which is in excess of the steam generation rate of 2,200 lb/sec. The steam flow steam generation mismatch causes an initial depressurization of the reactor vessel at a rate of 45 psi/sec. The formation of bubbles in the reactor vessel water causes a rapid rise in the water level. The analytical model used to calculate level rise predicts a rate of rise of about 6 ft/sec. Thus, the water level reaches the vessel steam nozzles at 2 to 3 sec after the break. From that time on a two phase mixture is discharged from the break as shown on Figure 14.5-15. The two phase flow rates are determined by vessel pressure and mixture enthalpy.[4] The vessel depressurization is calculated using a digital computer model in which the reactor vessel is divided into nine major nodes. The model includes the flow resistance between nodes, as well as heat addition from the core.

As shown on Figure 14.5-15, two phase flow is discharged through the break at an almost constant rate until late in the transient. This is the result of not taking credit for the effect of valve closure on flow rate until isolation valves are far enough closed to establish critical flow at the valve locations. The linear decrease in discharge flow rate at the end of the transient is the result of the assumption regarding the effect of valve closure on flow rate after critical flow is established at the valve location.

The following total masses of steam and liquid are discharged through the break prior to isolation valve closure:

Steam	25,000 lb
Liquid	60,000 lb

14.5.4.2 Radiological Consequences

14.5.4.2.1 Steam Line Break Accident Assumptions (Ground Level Release)

1. The reactor has operated for an extended period at 1,998 MWt. To account for power measurement uncertainty, a 2% allowance was added.

2. The concentrations of radionuclides in the reactor water are those corresponding to the maximum reactor coolant iodine concentration permitted by plant Technical Specifications.

3. The total mass of steam and water released from the steam line contains concentrations of radionuclides identical with those in the reactor water.

4. All of the radionuclides contained in the steam and water mass released from the steam line are released to the atmosphere from the top of the Turbine Building. All the radioactivity was assumed to be released to the environment as a puff release.

5. It is assumed that there is no thermal rise of the steam cloud.

6. Atmospheric relative concentration values were based on Regulatory Guide 1.145 models.

7. The breathing rate is 347 cm^3/sec.

14.5.4.2.2 Analytical Results

Radiological consequences for the steam line break accident based on the above assumptions are given in Table 14.5-2.

14.5.5 Fuel Handling Accident

Accidents that result in the release of radioactive materials directly to the containment can occur when the drywell is open. A survey of the various conditions that could exist when the drywell is open reveals that the greatest potential for the release of radioactive material occurs when the drywell head and reactor vessel head have been removed. In this case, radioactive material released as a result of fuel failure is available for transport directly to the containment.

Various mechanisms for fuel failure under this condition have been investigated. With the current fuel design the refueling interlocks, which impose restrictions on the movement of refueling equipment and control rods, prevent an inadvertent criticality during refueling operations. In addition, the reactor protection system can initiate a reactor scram in time to prevent fuel damage for errors or malfunctions occurring during planned criticality tests with the reactor vessel head off. It is concluded that the only accident that could result in the release of significant quantities of fission products to the containment during this mode of operation is one resulting from the accidental dropping of a fuel bundle onto the top of the core.

This event occurs under non-operating conditions for the fuel. The key assumption of this postulated occurrence is the inadvertent mechanical damage to the fuel rod cladding as a consequence of the fuel bundle being dropped on the core in the cold condition. Therefore, fuel densification considerations do not enter into or affect the accident results.

14.5.5.1 Sequence of Events

The assumptions and analyses applicable to this type of fuel handling accident are described below.

(1) The fuel assembly is dropped from 32.95 feet (the maximum height allowed by the fuel handling equipment).

(2) The entire amount of potential energy, including the energy of the entire assemblage falling to its side from a vertical position (referenced to the top of the reactor core), is available for application to the fuel assemblies involved in the accident. This assumption neglects the dissipation of some of the mechanical energy of the falling fuel assembly in the water above the core and requires that the grapple cable break, allowing the grapple head and three sections of the telescoping mast to remain attached to the falling assembly.

(3) None of the energy associated with the dropped fuel assembly is absorbed by the fuel material (uranium dioxide).

(4) All fuel rods, including tie rods, were assumed to fail by 1% strain in compression, the same mode as ordinary fuel rods. For the fuel designs considered here, there is no propensity for preferential failure of tie rods.

14.5.5.2 Fuel Damage

Because of the complex nature of the impact and the resulting damage to fuel assembly components, a rigorous prediction of the number of failed rods is not possible. For this reason, a simplified energy approach was taken and numerous conservative assumptions were made to assure a conservative estimate of the number of failed rods.

The number of failed fuel rods was determined by balancing the energy of the dropped assemblage against the energy required to fail a rod. The wet weight of the dropped bundle is 617 pounds and the wet weight of the grapple component is 350 pounds. The drop distance is 32.95 feet. The total energy to be dissipated by the first impact is

$$E = (617 + 350)\ (32.95) = 31{,}870 \text{ ft-lb}$$

One half of the energy was considered to be absorbed by the falling assembly and one half by the four impacted assemblies.

No energy was considered to be absorbed by the fuel pellets (i.e., the energy was absorbed entirely by the non-fuel components of the assemblies). The energy available for clad deformation was considered to be proportional to the mass ratio:

$$\frac{\text{mass of cladding}}{(\text{mass of assembly - mass of fuel pellets})}$$

and is equal to a maximum of 0.519 for the fuel designs considered here.

The energy absorbed by the cladding of the four impacted assemblies is

$$(15{,}935 \text{ ft-lb})\ (0.519) = 8270 \text{ ft-lb}$$

Each rod that fails is expected to absorb approximately 250 ft-lb before cladding failure, based on uniform 1% plastic deformation of the cladding.

The number of rods failed in the impacted assemblies is

$$N_F = \frac{(8270 \text{ ft-lb})}{(250 \text{ ft-lb})} = 33 \text{ rods}$$

The dropped assembly was considered to impact at a small angle, subjecting all the fuel rods in the dropped assembly to bending moments. The fuel rods are expected to absorb little energy prior to failure as a result of bending. For this reason, it was assumed that all the rods in the dropped assembly fail. The total number of failed rods on initial impact was 62 + 33 = 95.

The assembly was assumed to tip over and impact horizontally on the top of the core. The remaining available energy was used to predict the number of additional rod failures. The available energy was calculated by assuming a linear weight distribution in the assembly with a point load at the top of the assembly to represent the fuel grapple weight.

$$E = W_G H_G + \int_0^{H_B} \frac{W_B}{H_B} y \, dy = W_G H_G + \frac{1}{2} W_B H_B$$

$$= (350 \text{ lb}) \frac{160}{12} + \frac{1}{2} (617) \frac{160}{12} = 8780 \text{ ft-lb}$$

As before, the energy was considered to be absorbed equally by the falling assembly and the impacted assemblies. The fraction available for clad deformation was 0.519. The energy available to deform clad in the impacted assemblies was

$$E_c = (0.50)\ (8780 \text{ ft-lb})\ (0.519) = 2278 \text{ ft-lb}$$

and the number of failures in the impacted assemblies was

$$N_F = \frac{(2278 \text{ ft-lb})}{(250 \text{ ft-lb})} = 9 \text{ rods}$$

Since the rods in the dropped assembly were considered to have failed in the initial impact, the total failed rods in both impacts are 95 + 9 = 104.

Both the GE8x8EB and the GE8x8NB fuel designs contain 2 fewer fuel rods than the 62 fuel rods assumed in the preceding analysis. Hence, this analysis is conservatively bounding for these fuel types.

For GE11, 123 rods are calculated to fail using the conservative energy balance approach described above for the 8x8 design. For GE 14, 151 rods are calculated to fail or 1.641 equivalent bundles. For GNF2 fuel, 150 rods are calculated to fail, or 1.75 equivalent bundles. However, a maximum core radial peaking factor of 2.1 was assumed for GE14 FHA analysis as compared to a core radial peaking factor of 1.7 for GNF2 fuel. By rationing the ruptured bundles and radial peaking factors, it can be shown that the radiological consequences of a FHA with GE14 fuel presented in the following sections, bounds GNF2 fuel.

14.5.5.3 Radiological Consequences

The Fuel Handling Accident (FHA) could occur inside the open reactor vessel or, inside the spent fuel pool, both of which are located inside the reactor building, during shutdown refueling operations.

Of the two possible FHA's, it is the FHA occurring inside the open reactor vessel that would be expected to release more radioactive gaseous material from the gap spaces of fuel bundles containing damaged cladding of spent fuel rods.

14.5.5.3.1 Method and Assumptions

The DBA FHA analysis uses the AST guidelines outlined in NUREG-1465 (Reference 21), Regulatory Guide 1.183 (Reference 22), and Regulatory Guide 1.194 (Reference 23).

The following assumptions and initial conditions are used in calculating the fission product release to the environment:

(a) The accident is assumed to occur 24 hours after shutdown.

(b) The FHA results in 151 rods failing, and the release to the environment from the refueling floor occurs within 2 hours.

(c) A decontamination factor (DF) of 200 was assumed for the scrubbing effects of water on halogen activity release. The DF was based on a minimum of 23 feet of water over the dropped assembly. No DF was applied to noble gases and the DF for other radionuclides were assumed to be infinite.

(d) The core inventory was based on a thermal power level of 2028 MW_t, plus a measurement uncertainty of 0.5% (2038 MW_t). A radial peaking factor of 2.1 was used. The bounding core and FHA inventories are given in Table 14.5-4.

(e) All activity within the gaps of the failed fuel rods is released to the refueling cavity water. The released activity corresponds to 8% of the entire inventory of I-131 in the rods, 10% of the Kr-85, 5% of the remaining halogens and noble gases, and 12% of the alkalis (Cs and Rb).

(f) The reactor building is assumed to be open during the refueling operations, with the normal ventilation on, such that all releases to the environment would be via the reactor building vent.

(g) 5 years of hourly meteorological data was used for atmospheric dispersion factors as shown in Table 14.5-4A.

(h) The control room ventilation system was assumed to remain in the normal operating mode during the entire exposure interval (30 days).

(i) Breathing rates, and control room occupancy factors are as given in Reg. Guide 1.183.

(j) The control room air intake rate was assumed to be 1000 cfm (a low value), and 9000 cfm (a high value).

14.5.5.3.2 Results

The dose evaluations of the postulated fuel handling accident are summarized in Table 14.5-5 and demonstrate that the calculated TEDE values to the control room, EAB, and LPZ are less than the limits set forth in 10CFR50.67 and Reg. Guide 1.183.

14.5.6 Radwaste System Accidents

The reactor building, the radwaste building, and the turbine building contain systems which have significant amounts of radioactive materials. The reactor building, the radwaste building, and the turbine building, where they house or support Class I equipment, are Class I. The condenser hotwell, the offgas system piping, the monitor tanks, the treated water holdup tanks, and the condensate storage tanks contain significant amounts of liquid or gaseous radioactivity not enclosed in a Class I structure. This response analyzes the effects, which would result from the failure of the condenser hotwell, of the offgas system piping (rupture disk failure), or of any radwaste system tank.

14.5.6.1 Assumptions

The following assumptions are made in evaluating the potential effects resulting from condenser hotwell or Radwaste System tank failures inside the Radwaste and Turbine building. This analysis is not based on TID-14844 source terms.

1. The maximum activity concentrations in the reactor water and in the radwaste tanks are those expected, assuming offgas stack release rate of 100,000 microcuries/sec after 30 min holdup and, for the Radwaste System, normal daily liquid volume.

2. The activity concentrations in the condenser hotwell are based upon a reactor water steam separation factor of 10^{+4}.

3. The iodine activity concentration in a Radwaste System tank is equal to the ratio of the iodine activity concentration to total reactor water activity concentration after 8 hr decay, multiplied by the maximum activity concentration in the inlet stream to the particular tank.

4. The partition coefficient, the ratio of the iodine concentration in the liquid phase to the iodine concentration in the gas phase at equilibrium, equals $4.43 \times 10^{+5}$ based upon a pH of 7.0, a temperature of 25°C and a total iodine concentration of less than 1×10^{-9} moles /1.[5] Expected iodine concentrations are at least two orders of magnitude less.

5. The partition coefficient is constant and does not increase with decreasing concentration of iodine in the liquid phase.

6. Instantaneous dynamic equilibrium is maintained between the gaseous and liquid phases. The equilibrium exists between the release liquid and the net free volume of the Radwaste Turbine Building basement area; or between the condenser hotwell condensate and condenser compartment net free volume.

7. The area ventilation fans continue exhausting through the Reactor Building vent at full capacity, resulting in one air change every 6.5 min from the Radwaste Turbine Building basement area and one air change every 10 min from the condenser compartment.

8. An airborne iodine reduction factor of 2 results due to plateout of iodine in the gaseous phase.

9. All releases except from offgas piping failure occur during the following meteorological conditions:

   a. For the first 8 hr, Pasquill Type F, 1 m/s, nonvarying wind direction and a volumetric building wake correction factor of c = 1/2 used with the cross sectional area of the structure with a maximum building wake reduction factor of 1/3

   b. From 8 to 24 hr, Pasquill Type F, 1 m/s with plume meander in a 22 1/2 degree sector

   c. From 1 to 4 days, Pasquill Type F and 2 m/s with a frequency of 60 percent, Pasquill Type D 3 m/s with a frequency of 40 percent with a meander in the same 22 1/2 degree sector

   d. From 4 to 30 days, Pasquill Types C, D, and F each occurring 33 1/3 percent of the time with wind speeds of 3 m/s, 3 m/s, and 2 m/s, respectively, with meander in the same 22 1/2 degree sector 33 1/3 percent of the time

10. A breathing rate of 3.47×10^{-4} m3/s for the first 8 hr, $1.75 \times 10^{-4} m^3/s$ from 8 to 24 hr and $2.32 \times 10^{-4} m^3/s$ thereafter is assumed.

11. The effective release height is 30 m with downwash occurring.

12. No credit is taken for radioactive decay in the environment.

14.5.6.2 Radiological Effects

The above assumptions have been chosen to maximize the initial activities, and overestimate the release rates, total releases, and total doses.

Consider first the failure of the condenser hotwell, or a Radwaste System tank. Each set of tanks is surrounded by waterproof shield walls designed to contain the spillage from the failure of one tank in the immediate vicinity until the liquid can be pumped into another tank. The floors in the Radwaste Turbine Building basement area are sloped such that gross tankage failure in that area, if assumed, would result in fluid flow in direction of the Radwaste Building and the Class I portions of the Turbine Building. Thus, all released liquid from tank failure in that area could be assumed to be contained and enclosed by a Class I structure. Also, the release of radioactivity from the condenser hotwell or a tank failure directly into the environment through the ground water is precluded by the PVC, watertight membrane which encloses and forms a continuous seal around the Turbine Building, Reactor Building and Radwaste Building footings below grade and by the hydrostatic head exerted on the foundations by the ground water. The only possible release of radionuclides to the environment would be due to the release of gaseous iodine in chemical equilibrium with iodine in the liquid phase of the spillage.

During normal operation, Radwaste System tanks containing high activity liquids are vented directly into the Radwaste Exhaust system and tanks containing low activity liquids, such as the monitor tanks and the treated water holdup tanks are vented directly into their immediate areas which are vented into the Radwaste Ventilation Exhaust System. All Radwaste Building Ventilation System air passes through one of two parallel sets of high efficiency particulate air (HEPA) filter trains and is released through the Reactor Building exhaust vent stack.

The iodine activity released to the Ventilation Exhaust System during normal station operation or from spillage following an assumed tank or condenser hotwell failure is a function of the partition coefficient which is the ratio of the iodine concentration in the liquid phase to the iodine concentration in the gas phase at equilibrium. Because iodine undergoes a series of hydrolysis reactions, the partition coefficient is a function of solution temperature, pH, and concentration. The partition coefficient is not a function of the container, thus the coefficient existing prior to the hypothetical tank failure would continue to be appropriate after the failure.

The calculation model developed to determine the release of iodine from spillage to the air above after postulated tank failure assumes that an instantaneous equilibrium exists between the iodine in the liquid and gaseous phases. Solution of the simultaneous coupled differential equations resulting from the differential activity balances across the liquid gas interface, and between the Radwaste Turbine Building basement air and the environment, yields the total iodine activity released to the environment as a function of time.

Solutions to the differential equations show that the release rate to the environment increases with increasing activity and/or volume of the gaseous phase, and decreases with increasing liquid volume, and with time. Thus the maximum release rate results from the failure of one tank containing a maximum activity in a minimum liquid volume. Application of the assumption that an iodine equilibrium condition exists between the released liquid and the total free volume of the Radwaste Turbine Building basement area yields extremely conservative releases, since the released liquid would normally be contained by the waterproof shield walls, and thus would not have the large surface area with which to communicate and establish equilibrium with the total net free volume of the area.

The resulting maximum iodine release rates, total release, and total doses are shown on Table 14.5-3 for various tank failures and the condenser hotwell failures. The maximum iodine release rate is within the Technical Specification limits for releases from the building exhaust vent.

The dose consequences for the failure of the offgas piping is no more than 2.5 REM total body applied over a 2 hour period at the Exclusion Area Boundary. This limit was endorsed by the NRC in their acceptance of Pilgrim's limit of 500,000 micro curies per second (referenced to a 30 minute hold-up) of noble gases at the steam jet air ejector contained in the Amendment 89 (Reference 15).

The Safety Evaluation Report contained in Reference 15 endorsed Pilgrim's use of the NRC guidance contained in NUREG-0133 to meet the intent of NUREG-0473. In Pilgrim's analysis (Reference 18) an air ejector discharge line break is assumed to release the discharge from the air ejectors for one hour, and from the hold up line and process piping downstream of the break for 2 hours.

The other source of low level activity not enclosed in a Class I structure is the water in the condensate storage tanks. As a worst case, simultaneous nonmechanistic failure of both condensate storage tanks was assumed. Station yard layout and design dictates that the direction of unrestrained surface flow will be towards the intake canal, through the armor stone, and onto the surface of the salt water in the intake canal. The rate and extent of vertical dilution is a function of the relative temperatures and densities of sea water and condensate storage water. The total volume of sea water into which the condensate storage tank would be diluted is a function of: 1) the prevailing wind direction and speed; 2) the wave action inside the intake canal; 3) the tidal cycle; 4) whether or not the circulating water pumps are operating; and 5), the relative temperatures of the ambient air, the sea water, and the condensate storage tank water. Calculations were performed to determine the whole body dose resulting from 30.5 cm, 7.63 cm, and 1 cm, layers of undiluted condensate storage tank water supported by a thermocline between it and the colder salt water below. The estimated doses at the surface of the water were 2.4 x 10^{-2} mrem/hr, 1.4 x 10^{-2} mrem/hr, and 0.3 x 10^{-2} mrem/hr, respectively. These dose rates would be reduced as mixing and dilution occur in the intake channel due to the effects noted previously.

Table 14.5-4

BOUNDING CORE AND FHA INVENTORIES

Radionuclide	Undecayed Inventory (CI)		Fuel Rod Gap Fraction	FHA Undecayed Source Term (CI)
	Full Core	Peak Assembly		
BR 82	6.872E+05	2.488E+03	0.05	2.042E+02
BR 82M	2.656E+05	9.617E+02	0.05	7.892E+01
BR 83	8.640E+06	3.128E+04	0.05	2.567E+03
BR 84	1.593E+07	5.768E+04	0.05	4.733E+03
BR 84M	4.468E+05	1.618E+03	0.05	1.328E+02
BR 85	1.957E+07	7.086E+04	0.05	5.815E+03
BR 86	1.466E+07	5.308E+04	0.05	4.356E+03
BR 87	3.339E+07	1.209E+05	0.05	9.921E+03
BR 88	3.803E+07	1.377E+05	0.05	1.130E+04
I128	1.919E+06	6.948E+03	0.05	5.702E+02
I129	6.033E+00	2.184E-02	0.05	1.793E-03
I130	4.655E+06	1.685E+04	0.05	1.383E+03
I130M	1.818E+06	6.582E+03	0.05	5.402E+02
I131	5.716E+07	2.070E+05	0.08	2.717E+04
I132	8.113E+07	2.937E+05	0.05	2.411E+04
I133	1.150E+08	4.164E+05	0.05	3.417+04
I134	1.284E+08	4.649E+05	0.05	3.815E+04
I134M	1.371E+07	4.964E+04	0.05	4.074E+03
I135	1.071E+08	3.878E+05	0.05	3.182E+04
I136	5.198E+07	1.882E+05	0.05	1.544E+04
I136M	3.179E+07	1.151E+05	0.05	9.446E+03
KR 83M	8.638E+06	3.128E+04	0.05	2.567E+03
KR 85	1.439E+06	5.210E+03	0.1	8.551E+02
KR 85M	1.979E+07	7.165E+04	0.05	5.880E+03
KR 87	3.956E+07	1.432E+05	0.05	1.175E+04
KR 88	5.592E+07	2.025E+05	0.05	1.662E+04
KR 89	7.054E+07	2.554E+05	0.05	2.096E+04
KR 90	7.004E+07	2.536E+05	0.05	2.081E+04
XE131M	6.4123+05	2.322E+03	0.05	1.905E+02
XE133	1.150E+08	4.164E+05	0.05	3.417E+04
XE133M	3.541E+06	1.282E+04	0.05	1.052E+03
XE135	5.869E+07	2.125E+05	0.05	1.744E+04
XE135M	2.297E+07	8.317E+04	0.05	6.825E+03
XE137	1.012E+08	3.664E+05	0.05	3.007E+04
XE138	1.022E+08	3.700E+05	0.05	3.037E+04
XE139	8.237E+07	2.982E+05	0.05	2.447E+04

Table 14.5-4A

Atmospheric Dispersion Factors (X/Q's)
For Control Room, EAB and LPZ

No	Release Point	Receptor Point	Interval	Concentration (χ/Q) (sec/m^3)	Gamma (χ/Q) (sec/m^3)
1	Reactor Building Vent	EAB (actual)[a]	0-2 hrs	7.479E-04	3.199E-04
2		LPZ(4.25 miles)	0-2 hrs	3.692E-05	3.551E-05
			2-8 hrs	1.915E-05	1.782E-05
			8-24 hrs	1.066E-05	9.627E-05
			24-96 hrs	4.339E-06	3.745E-05
			96-720 hrs	1.194E-06	9.656E-07
		Control Room Fresh Air Intake	0-2 hrs	1.76E-03	N/A
			2-8 hrs	1.25E-03	
3			8-24 hrs	4.26E-04	
			24-96 hrs	3.67E-04	
			96-720 hrs	3.15E-04	
4	Truck Lock Door	EAB (actual)	0-2 hrs	See RB vent[b]	
5		LPZ (4.25 miles)	0-720 hrS		
6		Control Room Fresh Air Intake	0-2 hrs	9.72E-04	N/A
			2-8 hrs	7.52E-04	
			8-24 hrs	2.80E-04	
			24-96 hrs	1.93E-04	
			96-720 hrs	1.61E-04	

(a) The EAB distances employed in the atmospheric dispersion analysis are from the closest point of the reactor building; as such, they conservatively apply to releases via the RB vent, which is a the plant SW corner. The critical receptor is in the true NE sector, at a distance of 486 m (at the over-water exclusion zone).

(b) The atmospheric dispersion factors for releases via the Truck Lock (which is in the plant W side, near the NW corner of the building site), are conservatively bounded by releases from the reactor building proper.

Table 14.5-5

RADIOLOGICAL CONSEQUENCES OF FUEL
HANDLING DESIGN BASIS ACCIDENT (REM)

LOCATION	**Exposure interval**	**Unfiltered Outside Air Intake Rate**	**TEDE Dose (rem)**	**Regulatory Limit (rem)**	**Percent of Regulatory Limit**
Control Room	30 days	1000 cfm	2.846	5	56.9
		9000 cfm	2.863	5	57.3
EAB	2 hrs	N/A	1.439	6.3	22.8
LPZ	30 days	N/A	0.0920	6.3	1.46

15. Pilgrim License Amendment 89 for Pilgrim Nuclear Power Station, NRC Letter 1.85.287, dated August 30, 1985.

16. NUREG-0133 "Preparation of Radiological Effluent Technical Specifications for Nuclear Power Plants."

17. NUREG-0473 "Radiological Effluent Technical Specifications for Boiling Water Reactors."

18. PNPS-1-ERHS-XII.D-8 "Maximum Release Rate at Air Ejector Discharge to Produce 2.5 Rem Whole Body at Exclusion Boundary in the Event of an Air Ejector Line Break" Revision 0, dated 4/17/97.

19. NRC Letter to PNPS dated April 12, 2006, (PNPS Ltr 1.06.042), Amendment 219, SER for Single Recirculation Loop Operation.

20. GNF2 Fuel Design Cycle-Independent Analyses for Entergy Pilgrim Nuclear Power Station, GEH-0000-0085-9069-RO, February 2009.

21. NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants, "L. Soffer et al., February 1995.

22. Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accident at nuclear power Reactors," July 2000.

23. Regulatory Guide 1.194, "Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at nuclear Power Plants", June 2003.

APPENDIX A

PRESSURE INTEGRITY OF PIPING AND EQUIPMENT PRESSURE PARTS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

TABLE OF CONTENTS (Cont)

APPENDIX A

LIST OF TABLES

APPENDIX A

LIST OF FIGURES

APPENDIX A

PRESSURE INTEGRITY OF PIPING AND EQUIPMENT PRESSURE PARTS

A.1 SCOPE

This Appendix provides information pertinent to the original plant construction concerning the pressure integrity of piping and equipment parts. It is now used as a reference regarding the original requirements since, as described below, repairs, inspections and replacements are now performed using subsequently issued editions of the ASME Boiler and Pressure Vessel Code Section XI for Safety Class 1, 2 or 3 systems. The applicable ASME Code Safety Class 1, 2, or 3 designations are now selected using the In Service Inspection P&ID drawings.

The original classifications used in this Appendix (A, B, etc.) are no longer applicable for purchase and installation of code safety class material. PNPS piping specifications show the material to be in accordance with either ASTM or ASME Standards, but the examination and test requirements for purchase and installation of Safety Class 1, 2, or 3 pressure boundary piping and equipment parts has been updated and reconciled to the 1989 or later Editions of the ASME Boiler and Pressure Vessel Code Section III. These later requirements supersede the original specifications and are consistent with the ASME Code Section III & XI requirements for materials, examinations, fabrication, and testing. The design remains consistent with the original construction code except where ASME Code Section III has been explicitly adopted for replacements or new systems.

PNPS piping systems were designed and fabricated before the ASME Code Section III had issued Subsections NB, NC, and ND that covered piping and components other than the reactor vessel. The original design codes used for vessels, pumps, and piping were as follows:

The original Construction Code for the Reactor Vessel, the Reactor Recirculation Pumps, and other Primary Pressure Boundary components was:

> ASME Boiler & Pressure Vessel Code, Section III, 1965 Edition through Winter 1966 Addenda.

Where necessary, the rules of ASME Code Section VIII were applied to the materials, design, fabrication, inspection, and testing of vessel and pump pressure boundary components with supplementary welding design and inspection requirements in accordance with ASME Code Section III Paragraph N-2110 for any Category A or B welded joints.

The original Construction Code for PNPS piping was:

> USAS B31.1.0, Power Piping, 1967 Edition as supplemented by the additional requirements in Bechtel Specification M300.

This was the original Construction Code for PNPS piping systems along with supplemental requirements contained in Bechtel Specification M300 and its companion piping fabrication Specifications that included M100, M301, and M305.

The original classifications for the PNPS piping systems were based on Bechtel Specification M300. An excerpt from the original M300 shows that PNPS Class I piping is defined as follows:

> "Class I Piping: This is defined on the P.&I.D.'s only by the symbol shown on the P.&I.D. index. This is to designate the systems whose failure could cause significant release of radioactivity or which are vital to a safe shutdown of the plant and to the removal of decay and sensible heat. These systems require tornado protection and Class I seismic considerations as set forth in the general Specification 6498-G-5. A Class I system may also be a nuclear or critical system, but does not have to be either."

PNPS Class I piping was further divided into classifications as Nuclear, Critical, or Non-Critical.

PNPS Class I "Nuclear" included the Reactor Primary Pressure Boundary piping and corresponds to the later ASME Code Section III Subsection NB Class 1 piping, and also included the Primary Containment Pressure Boundary piping into the Core Standby Cooling Systems (CSCS), and the pump discharge piping from these systems, most of which corresponds to the later ASME Code Section III Subsection NC Class 2 piping.

PNPS Class I "Critical" piping included the other piping of the Core Standby Cooling Systems (CSCS), outside of the Reactor Primary Pressure Boundary, most of which corresponds to the later ASME Code Section III Subsection NC Class 2 piping. This also included the Standby Liquid Control (SLC) System, Main Steam to the Turbine & Bypass Valves, Feedwater Pump Discharge, and Off-Gas System piping.

The original Specifications referenced above implemented the requirements that are described in FSAR Appendix A, including the requirements for the design, materials, fabrication, installation, testing, and inspection for all plant piping systems. Each portions of each piping system was assigned into one of the Classes A, B, C, D, E, J, L, or M (FSAR Appendix A.2). The most rigorous requirements were in Class A with progressively less augmentation of the basic USAS B31.1.0 Power Piping Code for each succeeding Class, with Class M being in strict accordance with USAS B31.1.0 but with no supplemental requirements.

The supplementing of the basic USAS B31.1.0 Power Piping Code requirements was done to apply the most rigorous fabrication, inspection, and quality assurance methods to the Nuclear and Critical piping. These additional requirements were generally consistent with the later ASME Code Section III requirements for ASME Code Class 1, 2, and 3 piping systems.

Three "Material Schedules" M1, M2, & M3 invoked the appropriate "Brittle Fracture Control for Ferritic Steels" as supplementary requirements where needed (FSAR Appendix A.4). Fabrication and installation of piping was performed according to four "Fabrication and Erection Schedules" F1, F2, F3, & F4, (FSAR Appendix A.8) and five "Inspection and Test Schedules" T1, T2, T3, T4, & T5 (FSAR Appendix A.10).

Beginning in 1983, the original PNPS Class I systems were reviewed for the purposes of implementing the ASME Code Section XI In-Service Inspection (ISI) Program, which required that all Safety-Related Systems be categorized as ASME Section III Code Class 1, 2, or 3 piping with respect to the ongoing inspection requirements of an ASME Section XI ISI Program. The boundaries for ASME Code Class 1 Reactor Coolant Pressure Boundary (RCPB) components are defined in 10CFR50.2 and the boundaries for Class 2 and 3 components are established using the guidance in Regulatory Guide 1.26. The Code Classifications for the PNPS ISI P&IDs were prepared using Reg Guide 1.26, NUREG-0800, and NUREG-0803 (for CRD) and included only those systems which are important to safety that contain water, steam, or radioactive materials. There are some differences between the Reg Guide and PNPS classifications and these are described in the PNPS ISI Program Plan PNPS-RPT-05-001.

To distinguish between the original PNPS Class I (Roman numeral "I") and ASME Code Class 1, the terms "PNPS Safety Class 1", "ISI Class 1", or "ISI Safety Class 1" are used at PNPS. Specification M300 was subsequently revised to adopt the Safety Class 1, 2, 3 designations in addition to the Nuclear (N), Critical (C), or Non-Critical (NC) classifications that are still listed. The M300 inspection requirements were revised to include materials, fabrication, and examination requirements that are consistent with ASME Code Section III, Subsection NB, NC, & ND for Class 1, 2, & 3 piping in lieu of the original M300 requirements for Nuclear and Critical piping.

Repairs, inspections, and replacements to PNPS piping designated as PNPS Safety Class 1, 2, or 3 are performed under the controls and requirements of ASME Section XI, as stated, but Section XI is not a design or fabrication code and it directs the user to establish and define the design & fabrication code that is to be applied for any given repair or replacement. It is allowed to use the original or later editions of the original construction code, or to adopt the appropriate subsection of ASME Section III.

FSAR Appendix A identifies the PNPS piping systems, or portions thereof, that have been replaced with piping for which the materials, design, fabrication, and examination are in accordance with ASME Code Section III (i.e., piping for which ASME Section III has been adopted as the Construction Code).

The PNPS seismic design stress criteria for piping and components are given in FSAR Appendix A.3 and Bechtel Specification G505 and later PNPS Specification C114ERQE0.

The PNPS material requirements are given in FSAR Appendix A.4 and the Material Schedules in A.9. Fracture Toughness testing and material requirements were not directly included in USAS B31.1.0 such that FSAR Appendix A.4 and Specification M300 imposed applicable requirements from ASME Code Section III at the time for the "Low Temperature Carbon Steel" Pipe Classes DL, EL, GL, HL, & HM. The Pipe Class Data Sheets included Charpy Impact Test criteria, based on ASME Code Section III that was consistent with the impact testing done for low temperature pipe and weld filler metal testing at the time. Impact Test criteria has been removed from the M300 Pipe Class Data Sheets and Fracture Toughness requirements and exemptions are now imposed directly in accordance with the applicable ASME Code Section III Subsections for PNPS Safety Class 1, 2, and 3 piping, which include the applicable Charpy Impact Test criteria for piping, components, weld materials, and weld process qualifications.

The PNPS original fabrication requirements are given in FSAR Appendix A.5 and the Fabrication and Erection Schedules in A.8. These required fabrication details included such items as welding joint design, welding procedures and processes to be used, and specific welding details for groove and socket weld fabrication were included in Specifications M300 along with M100 and M301 for piping fabrication in the shop and in the field, with weld process information in the Welding Procedure Specifications as required by Specification M305. Fabrication requirements are now imposed by these Specifications in accordance with the Entergy Welding Program and its General Welding Standards and related Procedures for Preheat & Postweld Heat Treatment, Inspections, Examinations, and the compilation of Welding Procedure Specifications.

The PNPS inspection and examination requirements that were supplementary to USAS B31.1.0-1967 are given in FSAR Appendix A.6 and the Inspection and Testing Schedules in A.10. These supplementary requirements for radiography and surface examinations were included in Specifications M300 for materials and components and in M100 and M301 for piping fabrication in the shop and in the field. Inspection and examination requirements are now imposed by these Specifications in accordance with the applicable ASME Code Section III Subsections NB, NC, & ND for PNPS Safety Class 1, 2, and 3 piping. For piping that is PNPS Class I but is not Safety Class 1, 2, or 3, the examination requirements of ASME B31.1 are applicable.

For the purposes of this Appendix, the pressure boundary of the process fluid includes, but is not necessarily limited to:

branch outlet nozzles or nipples, instrument wells, reservoirs, pump casing closures, blind flanges and similar pressure closures, studs, nuts, and fasteners in flanged joints between pressure parts and bodies, and pressure parts of inline components such as traps and strainers.

Specifically excluded from the scope of this Appendix are nonpressure parts such as pump motors, shafts, seals, impellers, wear rings, valve stems, gland followers, seat rings, guides, yokes, and operators; any nonmetallic material such as packing and gaskets; fasteners not in pressure part joints such as yoke studs and gland follower studs; washers of any kind.

A.1.1 Codes and Specifications

The piping and equipment pressure parts in this station are designed, fabricated, inspected, and tested in accordance with recognized industrial codes and specifications as far as these codes and specifications can be applied. In some cases these codes and specifications are not stringent enough for nuclear systems and supplementary requirements are applied to increase safety and operational reliability. The application of the industrial codes and specifications is defined in this Appendix, as well as the application of the supplementary requirements. Where conflicts occur between the industrial codes and specifications and the supplementary requirements, the supplementary requirements take precedence.

Repairs, alterations, and inservice inspection are made to the appropriate ASME Boiler and Pressure Vessel Code, Section XI.

The codes and specifications used in the design, fabrication, inspection, and testing of the liquid radwaste system, solid radwaste system, fuel cool cooling and cleanup system, reactor building closed cooling water system, turbine building closed cooling water system, salt service water system, circulating water system, condensate demineralizer system, condensate and demineralized water storage and transfer system, and the diesel fuel oil storage and transfer system are:

a. ASME Boiler and Pressure Vessel Code, Sections I, II, III, VIII, IX, XI, and API-650 Code.

b. USAS B31.1.0 or later editions

c. ASTM Standards

d. Pipe Fabrication Institute Standards

The principal tanks and heat exchangers that are necessary for the proper functioning of the systems listed above are designed, fabricated, inspected, and tested in accordance with the codes and specifications listed on Table A.1-1.

Class I Components are designed such that the stresses in the structural portions shall not exceed the working stress levels allowed by AISC Manual of Steel Construction or other equivalent industrial codes for the Operating Basis Earthquake, and shall not exceed 150 percent of code allowable, provided that primary stresses are less than the yield stress for the Safe Shutdown Earthquake. No supplementary nondestructive testing requirements beyond those required by applicable codes have been specified for Class I tanks and heat exchangers.

The schedules of Appendix A which prescribe the allowable materials apply primarily to the systems which include reactor coolant pressure boundary, extension of containment, and engineered Safeguard Systems. Many of the listed balance of plant systems have unique process conditions requiring a much broader spectrum of allowable materials than those for which Appendix A provides. Essentially all materials needed in these applications are approved for use by USAS B31.1.0 (or later editions). The use of Alloy 20 materials in dilute acid systems such as liquid radwaste and condensate demineralizer systems is not discussed in the code. Replacement pipe materials for Recirculation, Residual Heat Removal (inside the Containment), Core Spray (inside the Containment), Reactor Water Cleanup, and new piping materials for High Pressure Coolant Injection Turbine exhaust vacuum breaker line are approved for use by the ASME Boiler and Pressure Vessel Code Section III Division 1 Appendix I, 1980 Edition through Winter 1980 Addenda. Replaced core spray pipe outside the containment is approved for use by the ASME B&PV Code Section XI, 1980 Edition through Winter 1980 Addenda.

All Torus Mark I Containment analysis and modifications per NUREG-0661 have been completed at PNPS. The criteria used to evaluate the torus structure is the ASME Boiler & Pressure Vessel Code, Section III, Division I, with addenda through Summer 1977 and Code Case N-197. The analysis of Safety Relief Valve piping and supports, Torus Attached Piping (TAP) and branch lines, and TAP and branch line supports was done in accordance with Section III of the ASME B & PV Code, 1977 Edition, including Summer 1977 addenda. Modifications were done under Section XI of the ASME B & PV Code, 1977 Edition through Winter 1980 addenda. Details are provided in Teledyne Report TR-5310-1, Rev. 2: "Mark I Containment Program, Plant Unique Analysis Report of the Suppression Chamber for Pilgrim Station - Unit 1", and TR-5310-2, Rev. 1: "Mark I Containment Program, Plant Unique Analysis Report of the Torus Attached Piping for Pilgrim Nuclear Power Station".

*All recirculation pipe was replaced; RHR inside the containment and connected to the recirculation system was replaced; RWCU inside the containment and connected to the RHR supply pipe was replaced and; Core Spray pipe inside containment between the gate valve and containment penetration was replaced. A section of Loop B RHR pipe outside the containment between the drywell penetration and the first valve was also replaced. A section of Loop B core spray pipe outside the containment upstream of valve MO-1400-25B was also replaced.

APPENDIX B

TECHNICAL SPECIFICATIONS

TABLE OF CONTENTS

B.1 TECHNICAL SPECIFICATIONS

The Technical Specifications for Pilgrim Nuclear Power Station were prepared in accordance with 10 CFR 50.36 and submitted to the AEC as part of Application Amendment 13 (2/12/1970). The Technical Specifications were subsequently issued by the AEC as part of License Amendment 1 (9/15/72). The document is entitled The Pilgrim Nuclear Power Station Technical Specifications, which is maintained in a document separate from this FSAR.

B.2 TECHNICAL SPECIFICATIONS RELOCATED TO THE FSAR

The NRC requirements related to the content of Technical Specifications is set forth in 10 CFR 50.36.

Regulation 10 CFR 50.36(c)(2)(ii) sets forth four criteria to be used in determining whether specifications and limiting condition of operations are required to be established for an item of safety significance and those which satisfy any of the criteria of 10 CFR 50.36(c)(2)(ii) must be retained in the Technical Specifications. Those specifications and LCOs that do not satisfy the 10 CFR 50.36(c)(2)(ii) criteria may be relocated to licensee controlled documents, such as FSAR, Core Operating Limits reports, Quality Assurance Manuals, etc.

Pilgrim amended the Technical Specifications by license amendments and relocated to the FSAR certain specifications, LCOs, and surveillance requirements that do not follow the four criteria in 10 CFR 50.36(c)(2)(ii). The Technical Specifications and related Bases relocated to this Appendix began with License Amendment 195.

The relocated Technical Specifications and related Bases contained in the following sections follow the same order as they had been in the Technical Specifications. The definitions and the rules of usage of the Technical Specifications and Bases apply to the relocated Technical Specifications and related Bases. Revision to the relocated Technical Specifications and related Bases may be carried out in accordance with the requirements of 10 CFR 50.59.

B.2.1 License Amendment No. 143: Relocation of Technical Specifications 3/4.12, Fire Protection.

This License Amendment relocated the following Technical Specifications (TS) to the FSAR (Rev. 13). TS 3/4.12.A, "Fire Detection Instrumentation," to FSAR section 10.8.4.1 (new); TS Table 3.12-1, "Fire Detection Instrumentation," to FSAR Table 10.8-1 (new); TS 3/4.12.B, "Fire Water Supply System," to FSAR section 10.8.4.2 (new); TS 3/4.12.C, "Spray and/or Sprinkler Systems," to FSAR section 10.8.4.3 (new); TS 3/4.12.D, "Halon System," to FSAR section 10.8.4.4 (new); TS 3.4.12.E, "Fire Hose Stations," to FSAR section 10.8.4.5 (new); TS Table 3.12-2, "Fire Hose Stations," to

FSAR Table 10.8-2 (new); and, TS 3/4.12.F, "Fire Barrier System," to FSAR section 10.8.4.6 (new).

B.2.2 License Amendment No. 195: Relocation of Technical Specification 3/4.6.I, Shock Suppressors (snubbers).

This License Amendment relocates Technical Specifications 3/4.6.I, "Shock Suppressors (snubbers)" and its related Bases to the FSAR. The affected TS contain snubber operability and surveillance requirements for all MODES of operation except cold shutdown and refuel, replacement or repair of inoperable snubbers, and the initiation of an engineering evaluation to determine whether the component by the snubber(s) is and remains capable of meeting its intended function in the specific safety system involved. The snubber inspection and surveillance program shall follow the fourth interval ISI program plan.

B.2.3 License Amendment No. 196: Relocation of Technical Specification 3/4.2, Instrumentation that Initiates Rod Block.

This License Amendment relocates certain control rod block functions from Technical Specifications 3/4.2.C, "Control Rod Block Actuation," Tables 3.2.C.1, 3.2.C-2, and 4.2.C to the FSAR. The instrumentation functions being relocated are those functions that provide information to the operators to help prevent unnecessary automatic reactor protection system actuation. They are used to monitor core reactivity, but they are not relied upon in the accident analysis to ensure specified fuel design limits are met for postulated transients or accidents. The associated Bases pages reflecting these changes are also relocated to the FSAR.

The summary of relocated requirements is as follows:

TS Table 3.2.C.1: The Average Power Range Monitor (APRM), Intermediate Range Monitor (IRM), Source Range Monitor (SRM), Scram Discharge Volume (SDV) and Recirculation Flow Converter Trip Functions that initiate control rod blocks including requirements for Minimum and available Operable Channels per Trip Function, Required Operational Conditions, and Table 3.2.C.1 Notes (1), (3), (4), and (6).

TS Table 3.2.C-2: The APRM, IRM, SRM, SDV, and Recirculation Flow Converter Control Rod Block Trip Functions Trip Setpoints (if applicable) and Note (2).

Table 4.2.C: The APRM, IRM, SRM, SDV, and Recirculation Flow Converter Instrument Channel minimum test and calibration frequency for control rod block actuation, including Table 4.2.C Note (3).

The relocated requirements are placed in the same order as they were in the Technical Specifications and the applicable Bases.

B.2.4 License Amendment No. 202: Relocation of Technical Specification 3/4.6.B, Primary System Boundary Coolant Chemistry.

This License Amendment relocates Technical Specifications 3/4.6.B, Primary System Boundary - Coolant Chemistry to the FSAR. The relocated portions involve limiting condition for operation and surveillance requirements for reactor coolant conductivity and chloride concentration. The associated bases sections are also relocated to the FSAR.

The relocated TS sections and Bases are revised to follow the latest revision to the BWR Water Chemistry Guidelines and BWRVIP Implementation Guide for primary system boundary coolant chemistry.

B.2.5 License Amendment 224: Relocation of Technical Specification 3/4.6.G Structural Integrity.

This license amendment relocated Technical Specification 3/4.6.G and its Bases to the FSAR. The relocated portions include limiting conditions for operation and surveillance requirements for structural integrity of the reactor coolant system boundary. The associated Bases section was also relocated to the FSAR.

B.2.6 License Amendment 225: Relocation of Technical Specification 3/4.6.C drywell equipment drain sump requirements.

This license amendment relocated certain portions of Technical Specification 3/4.6.C and its Bases to the FSAR. The relocated portions include limiting conditions for operation and surveillance requirements for the drywell equipment drain sump. The associated Bases were also relocated to the FSAR.

B.2.7 License Amendment No. 229: Adoption of Technical Specification Task Force (TSTF) Change TSTF-372, "The Addition of Limiting Condition for Operation (LCO) 3.0.8 on the inoperability of snubbers".

This License Amendment adds the following LCO:

When on or more required snubbers are unable to perform their associated support function(s), any affected supported LCO(s) are not required to be declared not met solely for this reason if risk is assessed and managed, and:

a. the snubbers not able to perform their associated support function(s) are associated with only one train or subsystem of a multiple train or subsystem supported system or are associated with a single train or subsystem supported system and are able to perform their associated support function within 72 hours; or

b. the snubbers not able to perform their associated support function(s) are associated with more than on train or subsystem of a multiple train or subsystem supported system and are able to perform their associated support function within 12 hours.

At the end of the specified period the required snubbers must be able to perform their associated support function(s), or the affected supported system LCO(s) shall be declared not met.

The Bases for the LCO is provided in Technical Specification Bases for LCO 3.0.8 on page B3/4.0-1.

B.2.8 License Amendment No.235: Relocation of Technical Specification 3/4.6.D Related to Safety Relief Valve Discharge Pipe Monitoring.

This License Amendment relocates certain instrumentation related to Safety Relief Valve (SRV) discharge pipe temperature monitoring requirements to the FSAR. The relocated portions include requirements related to SRV discharge pipe temperature monitoring, daily temperature logging, and calibration and functioning of discharge pipe temperature monitoring instrumentation.

B.3.0 RELOCATED TECHNICICAL SPECIFICATIONS AND RELATED BASES

B.3.2 INSTRUMENTATION THAT INITIATES ROD BLOCK

B.3.6.B PRIMARY SYSTEM BOUNDARY -COOLANT CHEMISTRY

B.3.6.C COOLANT LEAKAGE

B.3.6.D SAFETY/RELIEF VALVES TEMPERATURE MONITORING

B.3.6.G STRUCTURAL INTEGRITY

B.3.6.I SHOCK SUPPRESSORS (SNUBBERS)

TABLE 3.2.C.1

INSTRUMENTATION THAT INITIATES ROD BLOCKS

Trip Function	Operable Channels per Trip Function Minimum	Available	Required Operational Conditions	Notes
APRM Upscale (Flow Biased)	4	6	Run	(1)
APRM Upscale	4	6	Startup/Refuel	(1)(6)
APRM Inoperative	4	6	Run/Startup/Refuel	(1)(6)
APRM Downscale	4	6	Run	(1)
IRM Downscale	6	8	Startup/Refuel, except trip is bypassed when IRM is on its lowest range	(1)(6)
IRM Detector not in Startup Position	6	8	Startup/Refuel, trip is bypassed when mode switch is placed in run	(1)(6)
IRM Upscale	6	8	Startup/Refuel	(1)(6)
IRM Inoperative	6	8	Startup/Refuel	(1)(6)

TABLE 3.2.C.1 (Cont)

INSTRUMENTATION THAT INITIATES ROD BLOCKS

Trip Function	Operable Channels per Trip Function Minimum	Operable Channels per Trip Function Available	Required Operational Conditions	Notes
SRM Detector not in Startup Position	3	4	Startup/Refuel, except trip is bypassed when SRM count rate is $\geq$ 100 counts/second or IRMs on Range 3 or above	(1)(4)(6)
SRM Downscale	3	4	Startup/Refuel, except trip is bypassed when IRMs on Range 3 or above	(1)(4)(6)
SRM Upscale	3	4	Startup/Refuel, except trip is by-passed when the IRM range switches are on Range 8 or above (4)	(1)(4)(6)
SRM Inoperative	3	4	Startup/Refuel, except trip is by-passed when the IRM range switches are on Range 8 or above (4)	(1)(4)(6)
Scram Discharge Instrument Volume Water Level - High	2	2	Run/Startup/Refuel	(3)(6)
Scram Discharge Instrument Volume-Scram Trip Bypassed	1	1	Refuel/Shutdown	(3)(6)

TABLE 3.2.C.1 (Cont)

INSTRUMENTATION THAT INITIATES ROD BLOCKS

Trip Function	Operable Channels per Trip Function: Minimum	Operable Channels per Trip Function: Available	Required Operational Conditions	Notes
Recirculation Flow Converter - Upscale	2	2	Run	(1)
Recirculation Flow Converter - Inoperative	2	2	Run	(1)
Recirculation Flow Converter - Comparator Mismatch	2	2	Run	(1)

NOTES FOR TABLE 3.2.C-1

1. With the number of operable channels:

   a. One less than required by the minimum operable channels per trip function requirement, restore an inoperable channel to operable status within 7 days or place an inoperable channel in the tripped condition within the next hour.

   b. Two or more less than required by the minimum operable channels per trip function requirement, place at least one inoperable channel in the tripped condition within one hour.

2. Deleted

3. If the number of operable channels is less than required by the minimum operable channels per trip function requirement, place the inoperable channel in the tripped condition within one hour.

4. SRM operability requirements during core alterations are given in Technical Specification 3.10.

5. Deleted

6. When the reactor mode switch is in the Refuel position, the reactor vessel head is removed, and control rods are inserted in all core cells containing one or more fuel assemblies, these Rod Block functions are not required.

7. Deleted

TABLE 3.2.C-2
CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

Trip Function	Trip Setpoint
APRM Upscale	(1) (2)
APRM Inoperative	Not Applicable
APRM Downscale	$\geq$ 2.5 Indicated on Scale
IRM Downscale	$\geq$ 5/125 of Full Scale
IRM Detector not in Startup Position	Not Applicable
IRM Upscale	$\leq$ 108/125 of Full Scale
IRM Inoperative	Not Applicable
SRM Detector not in Startup Position	Not Applicable
SRM Downscale	$\geq$ 3 counts/second
SRM Upscale	$\leq 10^5$ counts/second
SRM Inoperative	Not Applicable
Scram Discharge Instrument Volume Water Level - High	$\leq$ 17 gallons
Scram Discharge Instrument Volume - Scram Trip Bypassed	Not Applicable
Recirculation Flow Converter - Upscale	$\leq$ 120/125 of Full Scale
Recirculation Flow Converter - Inoperative	Not Applicable
Recirculation Flow Converter - Comparator Mismatch	$\leq$ 8% Flow Deviation
Mode Switch in Shutdown	Not Applicable

(1) The trip level setting shall be as specified in the CORE OPERATING LIMITS REPORT.

(2) When the reactor mode switch is in the refuel or startup positions, the APRM rod block trip setpoint shall be less than or equal to 13% of rated thermal power, but always less than the APRM flux scram trip setting.

TABLE 4.2.C

MINIMUM TEST AND CALIBRATION FREQUENCY FOR CONTROL ROD BLOCKS ACTUATION

Instrument Channel	Instrument Functional Test	Calibration	Instrument Check
APRM - Downscale	Once/3 Months	Once/3 Months	Once/Day
APRM - Upscale	Once/3 Months	Once/3 Months	Once/Day
APRM - Inoperative	Once/3 Months	Not Applicable	Once/Day
IRM - Upscale	(2) (3)	Startup or Control Shutdown	(2)
IRM - Downscale	(2) (3)	Startup or Control Shutdown	(2)
IRM - Inoperative	(2) (3)	Not Applicable	(2)
SRM - Upscale	(2) (3)	Startup or Control Shutdown	(2)
SRM - Inoperative	(2) (3)	Not Applicable	(2)
SRM - Detector Not in Startup Position	(2) (3)	Not Applicable	(2)
SRM - Downscale	(2) (3)	Startup or Control Shutdown	(2)
IRM - Detector Not in Startup Position	(2) (3)	Not Applicable	(2)
Scram Discharge Instrument Volume Water Level-High	Once/3 Months Refuel	Not Applicable	
Scram Discharge Instrument Volume-Scram Trip Bypassed	Once/Operating Cycle	Not Applicable	Not Applicable
Recirculation Flow Converter	Not Applicable	Once/Operating Cycle	Once/Day
Recirculation Flow Converter-Upscale	Once/3 Months	Once/3 Months	Once/Day
Recirculation Flow Converter-Inoperative	Once/3 Months	Not Applicable	Once/Day
Recirculation Flow Converter-Comparator Off Limits	Once/3 Months	Once/3 Months	Once/Day
Recirculation Flow Process Instruments	Not Applicable	Once/Operating Cycle	Once/Day

NOTES FOR TABLE 4.2.C

1. Not Applicable

2. Functional tests, calibrations and instrument checks are not required when these instruments are not required to be operable or are tripped. Functional tests shall be performed before each startup with a required frequency not to exceed once per week. Calibrations of IRMs and SRMs shall be performed during each startup or during controlled shutdowns with a required frequency not to exceed once per week. Instrument checks shall be performed at least once per day during those periods when the instruments are required to be operable.

3. This instrumentation is excepted from the functional test definition. The functional test will consist of injecting a simulated electrical signal into the measurement channel.

4. Not Applicable

5. Not Applicable

6. Not Applicable

7. Not Applicable

BASES:

3.2 PROTECTIVE INSTRUMENTATION

The APRM system provides a control rod block to prevent rod withdrawal beyond a given point, thereby possibly avoiding an APRM Scram. The rod block setpoint is automatically reduced with recirculation flow to form the upper boundary of the Pilgrim power/flow map. The flow biased APRM rod block is not necessary to prohibit fuel damage and is not included in the analysis of anticipated transients.

The RBM rod block function provides local protection of the core, for a single rod withdrawal error from a limiting control rod pattern. The RBM bypass time delay (t_{d2}) is the delay between the time the signal is normalized to the reference signal and the time the signal is passed to the trip logic. Control rod withdrawal is unrestricted during this interval. The RBM bypass time delay is low enough to assure that control rod movement is minimized during the time RBM trips are bypassed.

The IRM rod block function provides local as well as gross core protection. The scaling arrangement is such that trip setting is less than a factor of 10 above the indicated level.

A downscale indication on an APRM, RBM or IRM is an indication the instrument has failed or the instrument is not sensitive enough. In either case the instrument will not respond to changes in control rod motion and thus, control rod motion is prevented. The downscale trips are as shown in Table 3.2.C-2.

The flow comparator and scram discharge volume high-level components have only one logic channel and are not required for safety.

The refueling interlocks also operate one logic channel, and are required for safety only when the mode switch is in the refueling position.

Control Rod Block and PCIS instrumentation common to RPS instrumentation have surveillance intervals and maintenance outage times selected in accordance with NEDC-30851P-A, Supplements 1 and 2 as approved by the NRC and documented in SERs (letters to D. N. Grace from C. E. Rossi dated September 22, 1988 and January 6, 1989).

B.3.6.B PRIMARY SYSTEM BOUNDRY - Coolant Chemistry

1. Reactor coolant chemistry control limits, associated sampling frequencies and associated actions taken when reactor coolant chemistry control limits are exceeded shall be adhered to in accordance with the latest revision of the BWR Water Chemistry Guidelines.

2. Deviations from limits, sampling frequencies and actions taken pertaining to reactor coolant chemistry control limits as specified in the latest revision to the BWR Water Chemistry Guidelines, shall be evaluated and documented in accordance with the latest revision of the BWR Vessel and Internals Project Program Implementation Guide.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage

2. Leakage Detection Systems

a. The following reactor coolant system leakage detection systems shall be Operable:

1. The drywell equipment drain sump monitoring system.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage

2. Leakage Detection Systems

The following reactor coolant leakage detection systems shall be demonstrated Operable:

a. For the drywell equipment drain sump monitoring system perform:

1. An instrument functional test at least once per 31 days, and

2. An instrument channel calibration at least once per operating cycle.

BASES:

3/4.6 PRIMARY SYSTEM BOUNDARY (Cont)

C. Coolant Leakage

Two leakage collection sumps are provided inside primary containment. Identified leakage is piped from pump seal leakoffs, reactor vessel head flange seal leakoff, selected valve stem leakoffs including recirculation loop and main steam isolation valves, and other equipment drains to the drywell equipment drain sump. The second sump, the drywell floor drain sump, receives leakage from the drywell coolers, control rod drives, other valve stems and flanges, floor drains, and closed cooling water system drains. Drainage into the drywell floor drain sump is generally considered unidentified leakage. Both sumps are equipped with level and flow monitoring equipment to alert operators if allowable leak rates are approached.

The drywell floor drain sump monitoring system, as required in 3.6.C.2, consists of one floor drain sump pump, plus associated instrumentation. The basic instrument system for the drywell floor drain sump is comprised of a flow integrator that is used to record the flow of liquid from the drywell floor drain sump. The drywell equipment drain sump is equipped similarly. A manual system whereby the time interval between sump pump starts is utilized to provide a back-up to the flow integrator if the instrumentation is found to be inoperable. This time interval determines the leakage flow using the tested capacity for the pump.

The 2 gpm limit for coolant leakage rate increase within any 24 hour period is a limit specified by the NRC in Generic Letter 88-01: "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping". This limit applies only during the RUN mode to accommodate the expected coolant leakage increase during pressurization.

The total leakage rate consists of all leakage, which flows to the drywell equipment drain sump (Identified leakage) and floor drain sump (Unidentified leakage).

FUNCTIONAL REQUIREMENTS FOR SRV/SSV TEMPERATURE MONITORING

3.6 PRIMARY SYSTEM BOUNDARY

D. Safety/ Relief Valves Temperature Monitoring

1. If the discharge pipe temperature of any safety relief valve (SRV) measured at 4.5 to 6 feet exceeds ambient temperature by ambient temperature by ambient temperature by 30°F during normal reactor power operation for a period of greater than 24 hours, an engineering evaluation shall be performed justifying continued operation for the corresponding SRV temperature increases.

2. Any SRV whose discharge pipe temperature measured under Section 3.6.D.1 exceeds ambient temperature by 30°F for 24 hours or more shall be removed at the next cold shutdown of 72 hours or more, tested in the as-found condition, and recalibrated as necessary prior to reinstallation.

3. Whenever SRVs are required to be operable, at least one of the dual thermocouples at each of the following locations shall be functional.

   a. Bellows monitoring temperature

   b. The discharge pipe temperature monitoring (Thermocouple 4.5 to 6 feet down stream from discharge point)

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY

D. Safety/ Relief Valves Temperature Monitoring

1. Whenever the safety relief valves are required to be operable, the safety relief valve discharge pipe temperature of each safety relief valve shall be logged daily.

2. Whenever the safety relief valves are required to be operable, the bellows thermocouple temperature of each safety relief valve shall be logged daily.

3. Instrumentation shall be calibrated and checked once per cycle during refueling outage.

4. First Stage Thermocouple, Second Stage Thermocouple, and safety relief valve discharge thermocouple located 16 to 22 feet down stream from discharge may be used to collect information for an engineering evaluation justifying continued plant operation for the corresponding temperature increases.

3/4.6 D TECHNCIAL BASES FOR LEAKAGE MONITORING

The purpose of monitoring Safety Relief Valve (SRV) discharge pipe temperature is to determine if the SRV is leaking so that appropriate corrective action can be taken to achieve acceptable SRV performance and compatibility with other requirements such as maintaining suppression pool temperature.

Enhanced temperature monitoring thermocouples have been installed to detect, monitor, and evaluate degraded SRV performance from leakage. In addition to the thermocouples located on the discharge pipe 4.5 to 6 feet down stream of SRV discharge and the bellows monitoring thermocouples, there are thermocouples on the SRV first stage, second stage, and 16 to 22 feet down stream of SRV discharge. The bellows monitoring thermocouple will detect a degraded condition with the bellows and any leakage. The thermocouple 4.5 to 6 feet down stream of SRV discharge will detect any valve leakage due to the first stage, second stage or main stage. The first and second stage thermocouples can determine if valve leakage is due to first stage or second stage pilot leakage or main stage leakage. The thermocouple located 4.5 to 6 feet down stream of valve discharge is a backup to the acoustic monitor. The thermocouple located 16 to 22 feet down stream of the valve discharge is used to monitor larger leakage rates. A dual thermocouple will be installed at each temperature monitoring location (first stage, second stage, 4.5 to 6 feet down stream on SRV discharge pipe, 16 to 20 feet down stream on SRV discharge pipe, and bellows monitoring). Under Section 3.6.D.3, only one of the dual thermocouples at each location is necessary to perform the leakage monitoring function for 4.5 to 6 feet down stream on SRV discharge pipe and bellows monitoring.

General Electric (GE) Service Information Letter (SIL) No. 196, Supplement 11, dated October 31, 1977, provides a recommendation to install thermocouples 4.5 to 6 feet down stream of the discharge flange to achieve good sensitivity to determine SRV leakage with an alarm point setting for all SRVs. Thermocouples installed 4.5 to 6 feet down stream of the discharge point meet this recommendation for Pilgrim. This instrumentation provides indication and an alarm in the Control Room. This instrumentation replaces the temperature indication from the 16 to 22 feet down stream of the SRV discharge.

GE SIL 196. Supplement 5, dated October 31, 1977, recommends SRV bellows integrity monitoring with a pressure switch connected to the bonnet that surrounds the bellows assembly. Pilgrim has elected to monitor bellows integrity with a dual thermocouple connected to a sensing line attached to the bonnet surrounding the bellows assembly. Bellows assembly leakage will be considered to be present if there are indications of higher than normal temperature at the bellows thermocouple in combination with an unidentified drywell leakage rate increase. The thermocouples are more sensitive than pressure switches, as recommended by SIL 196, Supplement 11. The SRV bellows monitoring thermocouple will provide temperature indication and an alarm in the Control Room. The alarm setpoint will be determined during power ascension for operating Cycle 19 (restart from Refueling Outage 18) based upon the ambient temperature profile at the thermocouple location.

The SRV discharge pipe thermocouple located 4.5 to 6 feet down stream of the SRV discharge provides an alarm in the Control Room, which would indicate SRV leakage, but would not confirm SRV inoperability. Based on this indication an engineering evaluation would be required for continued operation. The SRV first stage, second stage and the discharge pipe thermocouple located 16 to 22 feet down stream of the discharge will provide additional information to determine the condition of SRV performance and leakage, which would be used in an engineering evaluation to determine the corrective actions.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (Cont)

G. Structural Integrity

1. The structural integrity of the primary system boundary shall be maintained at the level required by the ASME Boiler and Pressure Vessel Code, Section XI "Rules for Inservice Inspection of Nuclear Power Plant Components," Articles IWA, IWB, IWC, IWD and IWF and mandatory appendices as required by 10CFR50.55a(g), except where specific relief has been granted by the NRC pursuant to 10CFR50.55a(g)(6)(i).

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY (Cont)

G. Structural Integrity

Inservice inspection of components shall be performed in accordance with the PNPS Inservice Inspection Program. The results obtained from compliance with this program will be evaluated at the completion of each ten year interval. The conclusions of this evaluation will be reviewed with the NRC

BASES:

3/4.6 PRIMARY SYSTEM BOUNDARY (Cont)

G. Structural Integrity

The Pilgrim Nuclear Power Station Inservice Inspection Program conforms to the requirements of 10CFR50.55a(g). Where practical, the inspection of ASME Section XI Class 1, 2, and 3 components conforms to the edition and addenda of Section XI of the ASME Boiler and Pressure Vessel Code required by 10CFR50.55a(g). When implementation of an ASME Code required inspection has been determined to be impractical for PNPS, a request for relief from the inspection requirement is submitted to the NRC in accordance with 10CFR50.55a(g)(5)(iii).

Requests for relief from the ASME Code inspection requirements will be submitted to the NRC prior to the beginning of each 10 year inspection interval for which the inspection requirement is known to be impractical. Requests for relief from inspection requirements which are identified to be impractical during the course of the inspection interval will be reported to the NRC on an annual basis throughout the inspection interval.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY

I. Shock Suppressors (Snubbers)

1. During all modes of operation except Cold Shutdown and Refuel, all safety-related snubbers listed in PNPS Procedures shall be operable except as noted in 3.6.I.2 through 3.6.I.3 below.

An Inoperable Snubber is a properly fabricated, installed and sized snubber that cannot pass its functional test.

Upon determination that a snubber is either improperly fabricated, installed or sized, the corrective action will be as specified for an inoperable snubber in Section 3.6.I.2.

2. Limiting Condition for Operability (LCO) 3.0.8 on the inoperability of snubbers is provided in TS LCO 3.0.8.

Further corrective action for this snubber, and all generically susceptible snubbers, shall be determined by an engineering evaluation.

The provisions of this section (3.6.I.1) are not applicable to snubbers removed from a piping system for maintenance purposes. For snubbers that are removed from service for maintenance purposes, Sections 3.6.I.1 and 3.6.I.3 apply.

SURVEILLANCE REQUIREMENTS

4.6 PRIMARY SYSTEM BOUNDARY

I. Shock Suppressors (Snubbers)

The following surveillance requirements apply to all safety-related hydraulic and mechanical snubbers listed in PNPS Procedures.

1. The snubber inspection and surveillance program shall follow the fourth interval ISI Program Plan.

2. Snubber Service Life Monitoring

A. A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designated service life is based shall be maintained.

B. This Snubber Service Life Monitoring Program shall become effective July 1, 1982.

LIMITING CONDITIONS FOR OPERATION

3.6 PRIMARY SYSTEM BOUNDARY (cont)

I. Shock Suppressors (Snubbers)

3. From and after the time a snubber is determined to be inoperable, improperly fabricated, improperly installed or improperly sized, if the requirements of Section(s) 3.6.I.1 and 3.6.I.2 cannot be met, then the affected safety system, or affected portions of that system, shall be declared inoperable, as provided by LCO 3.0.8.

4. Snubbers may be added to, or removed from, per 10 CFR 50.59, safety-related systems without prior NRC approval. The addition or deletion of snubbers shall be reported to the NRC in accordance with 10 CFR 50.59.

TABLE 4.6.I-1

(Deleted)

3/4.6.I

BASES 3/4.6 PRIMARY SYSTEM BOUNDARY

I. Shock Suppressors (Snubbers)

Snubbers are designed to prevent unrestrained pipe motion under dynamic loads as might occur during an earthquake or severe transient, while allowing normal thermal motion during startup and shutdown. The consequence of an inoperable snubber is an increase in the probability of structural damage to piping as a result of a seismic or other event initiating dynamic loads. It is therefore required that all snubbers required to protect the primary coolant system and all other safety-related systems or components be operable during reactor operation.

The visual inspection frequency is based on maintaining a constant level of snubber protection to systems. The cumulative number of inoperable snubbers detected during any inspection interval is the basis for establishment of the subsequent inspection interval and the existing inspection interval should remain in effect until its completion.

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and verified by inservice functional testing, that snubber may be exempted from being counted as inoperable.

Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, and are exposed to the same environmental conditions such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is initiated, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. Initiating this evaluation within 72 hours ensures that prompt corrective action will be afforded.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance programs.

The service life of a snubber is evaluated via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation. Due to the number and complexity of the relevant interacting factors it was necessary to develop a comprehensive Service Life Program. This program became effective July 1, 1982.

B.4 REFERENCES (DELETED)

Filing Instructions

PNPS-FSAR

Revision 28 – October 2011

Volume 6

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP6 – Rev 27	EP6 – Rev 28*

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

Page, Table (T), or Figure (F)	Revision Number
VOLUME 6	
Summ T of C-i	28
Summ T of C-ii	28
Summ T of C-iii	28
Summ T of C-iv	28
Summ T of C-v	28
Summ T of C-vi	28
Summ T of C-vii	28
Summ T of C-viii	28
List of Effective Pages Vol. 6 (1 thru 8)	28
APPENDIX F	
F-i	11
F-ii	9
F.1-1	0
F.2-1	0
F.2-2	0
F.2-3	0
F.2-4	0
F.2-5	5
F.2-6	5
F.2-6a	5
F.2-7	0
F.2-8	0
F.2-9	0
TF.2-1 (1 of 1)	22
TF.2-2 (1 of 1)	0
TF.2-3 (1 of 1)	0
TF.2-4 (1 of 1)	0
TF.2-5 (1 of 1)	0
TF.2-6 (1 of 1)	0
TF.2-7 (1 of 2)	0
TF.2-7 (2 of 2)	0
TF.2-8 (1 of 1)	0
TF.2-9 (1 of 1)	0

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

Page, Table (T), or Figure (F)	Revision Number

APPENDIX G

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

LIST OF EFFECTIVE PAGES

VOLUME 6VOLUME 6**VOLUME 6**VOLUME 6**VOLUME 6**

Filing Instructions

PNPS-FSAR

Revision 28– October 2011

Volume 7

TAB	Remove	Insert
Summary Table of Contents	Summ T of C – Rev 27	Summ T of C - Rev 28
LOEP	EP7 – Rev 27	EP7 – Rev 28
Appendix L TOC	Entire Appendix L TOC	Appendix L TOC – Rev 28*
Appendix L.3	Pages 1-12	Pages 1-13
	Table L.3-1 Page 1 of 1	Table L.3-1 Page 1 of 1
Appendix Q TOC	Entire Appendix Q TOC	Appendix Q TOC - Rev 28
Appendix Q.1	Pages 1-3	Pages 1-4

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

LIST OF EFFECTIVE PAGES

VOLUME 7VOLUME 7**VOLUME 7**VOLUME 7**VOLUME 7**

APPENDIX L

CONTAINMENT REPORT

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

APPENDIX L

CONTAINMENT REPORT

LIST OF TABLES

APPENDIX L

CONTAINMENT REPORT

LIST OF FIGURES

APPENDIX L

LIST OF FIGURES (Cont)

L.3 CONTAINMENT SYSTEM DESIGN

L.3.1 General

Chicago Bridge and Iron Company (CB&I) designed, fabricated, furnished, installed, and tested the containment vessel and connecting vent piping, including bellows, jet deflectors, penetration sleeves, vessel supports, and other appurtenances. This was accomplished in accordance with Bechtel Corporation specifications.

The information in this report pertaining to the detailed design of the Pressure Containment System was taken from CB&I's Certified Stress Report, which is on file at the Boston Edison Company, Boston, Massachusetts.

The suppression pool portion of the containment has been reanalyzed by Teledyne Engineering Services using loads generated by the GE Mark I Long Term Program.

Field painting of the drywell and suppression chamber was accomplished under Bechtel specifications.

L.3.2 Design of Drywell, Pressure Suppression Chamber, and Connecting Vent System

L.3.2.1 General Description and Dimensions

The Pressure Suppression Containment System consists of a drywell, a pressure suppression chamber which stores a large volume of water, and a connecting vent system between the drywell and the water pool.

Materials, design, fabrication, inspection, and testing are in accordance with the SAME Boiler and Pressure Vessel Code, Section III, Section B, 1967 Edition, with all applicable Addenda published to June 1967, and Code Case 1177-5 and 1330-1. See Table L.3-1.

Materials used for suppression pool modifications were in accordance with the ASME Boiler and Pressure Vessel Code Section III, 1977 Edition, with Addenda up to summer 1978, and Section II.

The material for the shell of the drywell, suppression chamber, and interconnecting vent system is ASME-SA516, Grade 70 Fire Box quality fabricated to ASTM-A300. The Charpy V-notch impact tests of the material were conducted as specified in N-330, at a maximum test temperature of 0°F. This impact test temperature is based on a lowest service metal temperature of 30°F.

The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion. The 34 ft 2 in dia bolted top closure is made with a double tongue and groove seal with test connection between which will permit periodic checks for tightness without pressurizing the entire vessel.

Jet deflectors are provided at the inlet of each vent pipe to prevent possible damage to the pipes or bellows assemblies from a jet force which might accompany a pipe break in the drywell, and to prevent overloading any single vent.

The free flow area around the periphery of the jet deflector plate is equal to 1.4 times the area of the 6 ft 9 in dia vent duct (1.4 x 5150 = 7210 sq in). The deflectors project approximately 2 ft 4 in into the drywell. The vent pipes are enclosed with sleeves and are provided with two-ply expansion bellows to accommodate differential motion between the drywell and suppression chamber.

During erection, the drywell vessel was supported on a steel skirt which was attached to the vessel at elevation 4 ft 1/2 in.

After the initial leak rate and overpressure testing, the drywell was embedded in concrete to elevation 5 ft 11 7/8 in thereby providing uniformity in the support by following the contour of the vessel. An embedment transition is provided for the shell from elevation 5 ft 11 7/8 in to elevation 9 ft 2 in. See Figure L.1-1.

The suppression chamber is a steel pressure vessel in the shape of a torus below and encircling the drywell. Inside the suppression chamber, also in the shape of a torus, is the vent system distribution header. Projecting downward from the header are 96 downcomer pipes which terminate below the water surface of the pool.* Columns extending from, and attached to, the bottom of the suppression chamber support the vent header and downcomers, and vent header deflector, and also resist the upward reaction from the downcomers during blowdown. The columns are pinned at the top and bottom to accommodate the differential horizontal movement between the header and the suppression chamber.

* The 48 vent header downcomer intersections are reinforced with two gusset plates and one tie plate to allow these components to withstand loads generated by a LOCA.

Vacuum breakers relieve pressure from the suppression chamber to the drywell to prevent a significant pressure differential between the drywell and suppression chamber. These vacuum breakers also prevent a backflow of water from the suppression pool into the vent system and prevent excessive water level oscillation within the downcomer pipes.

Access to the pressure suppression chamber from the Reactor Building is through two manholes with double-gasketed bolted covers, with a test connection between, which can be tested for leakage.

Access to the drywell is through the equipment hatch, personnel air lock, and through the double-gasketed drywell head, with a manhole, all of which have provisions for individual leak testing.

The pressure suppression chamber is supported on 16 pairs of equally spaced columns and 16 saddle-type supports. These supports transmit vertical loading to the reinforced concrete foundation slab of the Reactor Building. Lateral loads due to an earthquake are transmitted to the foundation by four symmetrically placed earthquake ties.

The dimensions of the Drywell and Pressure Suppression System are given on Table L.3-2.

The interior surface of the primary containment vessel is primed with an inorganic zinc coating (Carbonzinc 11) and finish-painted with a modified epoxy phenolic coating (Phenoline 368 inside the suppression chamber, and Phenoline 305 inside the drywell).

L.3.2.2 Applicable Codes and Regulations

The following publications, of the issues listed below, form a part of the applicable codes and regulations used in the design of the Pressure Suppression Containment System.

L.3.2.2.1 American Society of Mechanical Engineers (ASME)

Boiler and Pressure Vessel Code, Sections III, VIII, and IX, 1967 edition, and the particular requirements for Class B vessels as defined in paragraph N-132, Section III. Modifications were made using the same Code 1977 edition with Addenda up to Summer 1978 with particular requirements of Subsections NE for containment and NF for supports.

Boiler and Pressure Vessel Code, Section II, 1967 edition with all applicable addenda, for the following material specifications for original construction and Section II, 1977, with Summer 1978 Addenda for modifications.

Designation	Title
SA-194	Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service (Grade 4)
SA-240	Corrosion Resisting Chromium and Chromium Nickel-Steel Plate, and Strip for Fusion Welded Unfired Pressure Vessels
SA-312	Seamless and Welded Austenitic Stainless Steel Pipe

SA-320 Alloy-Steel Bolting Materials for Low-Temperature Service (Grade L7 or L43)

SA-333 Seamless and Welded Steel Pipe for Low-Temperature Service (Grade 1 or 6)

SA-350 Forged or Rolled Carbon and Alloy Steel Flanges, Forged Fittings, Valves and Parts for Low-Temperature Service (Grade LFI)

SA-516 Carbon Steel Plates of Intermediate Tensile Strength and Fusion Welded Pressure Vessels for Atmospheric and Lower Temperature

Service (Grade 70 Firebox Quality Aluminum Killed)

L.3.2.2.2 American Society for Testing and Materials Standards (ASTM)

Designation Title

A-36 Structural Steel

A-53 Welded and Seamless Steel Pipe (Grade B)

A-106 Seamless Carbon-Steel Pipe for High-Temperature Service

A-300 Steel Plates for Pressure Vessels for Service at Low Temperatures

L.3.2.2.3 United States Steel Publication No. ADUSS 01-1205

T-1 Low-Carbon Constructional Alloy Steel

L.3.2.2.4 American National Standards Institute (ANSI)

B31.1.0 Power Piping

L.3.2.2.5 American Institute of Steel Construction (AISC)

"Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings" adopted April 1963.

L.3.2.2.6 The Commonwealth of Massachusetts

Board of Standards Building Code

Rules and Regulations for the Prevention of Accidents in Construction Operations (Industrial Bulletin No. 12)

L.3.2.3 Design Loadings

The loadings considered in the design of the drywell, suppression chamber, and interconnecting elements are shown on Tables L.3-3 and L.3-4.

A description of the loads and the various load combinations used in the design are presented in the following paragraphs.

L.3.2.3.1 Description of Loads

L.3.2.3.1.1 Pressures and Temperatures Under Normal Operating Conditions

During reactor operation the vessels will be subjected to temperatures up to 150°F at atmospheric pressure. The suppression chamber will also be subjected to the loads associated with the 84,000 cubic ft of water distributed uniformly within the vessel.

L.3.2.3.1.2 Pressures and Temperatures Under Accident Conditions

The drywell, suppression chamber, and the Vent System are designed for a maximum internal pressure of 62 psig coincident with a drywell wall temperature of 281°F and the suppression chamber will be subjected to the increased loads associated with the storage of 94,000 cubic feet of water.

L.3.2.3.1.3 Jet Forces

The drywell and closure head are designed to withstand the jet forces listed on Table L.3-3. These listed forces do not occur simultaneously. However, the jet force was assumed to occur concurrently with the design internal pressure of 56 psig and a temperature of 150°F. The jet forces consist of steam and/or water at 300°F. The drywell is largely enclosed within the structural and shielding concrete. There is a nominal 2 in gap between the vessel and the concrete except at the closure head and top flanges. Where the drywell shell is backed up by concrete, local yielding may take place due to jet force impingement; however, rupture will not occur.

Where the shell is not backed up by concrete, the primary stresses resulting from the jet force loads do not exceed 0.9 times the yield point of the material at 300°F. However, primary plus secondary stresses permitted are three times the allowable stress values given on Table N-421 of Section III, Section B, of the ASME Boiler and Pressure Vessel Code.

The suppression chamber and vent system are designed to withstand the vessel blowdown reactions associated with the design basis loss of coolant accident. The design forces on downcomer pipe are listed on Table L.3-4. Stresses resulting from these reactions are limited to ASME Code allowable stresses.

L.3.2.3.1.4 Gravity Loads to be Applied to the Primary Containment

The gravity loads consist of weight of the shell and appurtenances, personnel lock, equipment hatch, spray headers, equipment supporting structural members, water inside the torus, water up to El 116 ft (during refueling), air (during leak rate tests), and live and dead loads on welding pads. These loads are shown on Table L.3-3.

L.3.2.3.1.5 Lateral Loads-Wind

Wind loads prior to construction of the Reactor Building are in accordance with ASCE paper 3269 "Wind Forces on Structures". The wind loads are shown on Table L.3-3.

L.3.2.3.1.6 Seismic Loads

Seismic loads for the primary containment are due to the Operational Basis Earthquake horizontal ground acceleration of 0.8g percentage acting simultaneously with vertical acceleration of 0.53g percentage.

The customary 1/3 increase in allowable stresses is not used for seismic loads.

Loads due to the Safe Shutdown Earthquake are not governing since the margins between actual stresses and allowable increased stresses would be greater than those for the Operating Basis Earthquake, because stresses due to the seismic load produced by the Safe Shutdown Earthquake will increase by approximately, 1 percent while the allowable stresses may be increased by 50 percent or up to the yield stress, whichever is smaller. The seismic loads generally are insignificant when compared with the internal accident pressure loading. See Figures L.3-1 and L.3-2 for acceleration curves for construction and final stages, respectively.

L.3.2.3.2 Load Combinations Used in the Design of the Primary Containment Vessel

Tables L.3-5 and L.3-6 show the CB&I case numbers used in the design of the drywell and the suppression chamber. The right hand columns contain and relate load symbols used on Tables L.3-7 through L.3-12 to the loads shown on Tables L.3-5 and L.3-6.

The load symbols considered in the Design Summary of the containment include the following:

D = Dead load of the structure and related equipment plus any other permanent loads contributing stress, such as soil or hydrostatic loads; live loads expected to be present when the station is operating; and the loads due to thermal expansion under normal operating conditions. This load takes into account any deviations from normal operating conditions which are reasonably expected to occur during the design lifetime of the station.

R = Loads resulting from jet forces and pressure and temperature transients associated with rupture of a single pipe within the primary containment. This load is considered as indicated in the tables.

E = Loads due to the Operating Basis Earthquake (0.08 g horizontal ground acceleration; two-thirds of horizontal ground acceleration spectrum applied simultaneously for vertical seismic acceleration).

Flood = Loads due to flooding the drywell up to El 116 ft.

= Design wind loading conditions.

The following are the load combinations and corresponding allowable stress limits, as shown on Tables L.3-7 through L.3-12.

Load Combination Limits

1. D+E Stresses remain within normal code allowable stresses (AISC for structural steel, ACI for reinforced concrete, ASME Pressure Vessel Code Section III (Class B) for the primary containment). The customary increase in design stress for earthquake loadings is not permitted.

2. D+W Maximum allowable stresses may be increased one-third above normal code allowable stresses.

3. D+R+E Stresses remain within normal code allowable stresses (AISC for structural steel, ACI for reinforced concrete, ASME Pressure Vessel Code, Section III (Class B) for the primary containment). The customary increase in design stress for earthquake loadings is not permitted. In the case of jet impingement loading on the primary containment, where it is backed up by concrete, the general primary membrane stress, plus the primary bending stress, plus the secondary membrane, plus bending stress must be less than either twice the yield stress or 90 percent of the ultimate stress, whichever is lower. For jet impingement loading on the primary containment (including containment penetration assemblies), where the primary containment is not backed up by concrete, the primary stresses must not exceed 90 percent of the yield strength of the material at 300°F.

4. D+E +Flood	Local membrane stresses in the primary containment may exceed the yield point, but must not rupture.

L.3.2.4 Design Calculations

L.3.2.4.1 Introduction

A complete set of design calculations for the drywell, suppression chamber, interconnecting elements, nozzle reinforcements, and access openings have been prepared by CB&I and Teledyne Engineering Services and will be on file at the Boston Edison Company, Boston, Massachusetts. The analyses have taken into consideration all of the design loads, and load combinations shown on Tables L.3-3, L.3-4, L.3-5, and L.3-6. The maximum stresses computed are all within the ASME Boiler and Pressure Vessel Code allowables.

L.3.2.4.2 Drywell Design-Primary Membrane Stresses

The drywell is designed by membrane theory which is based on the principle that the thin shell resists the imposed loads by direct stresses only. To resist earthquake loads, the stabilizer assembly is provided at El 81 ft 6 1/4 in to transfer the seismic load on the internal structure through the shell and into the external concrete shield wall.

The seismic load on the shell and appurtenances is resisted jointly by the shell and by the stabilizer.

The shell acts as a beam of variable cross section fixed at embedment level El 9 ft 2 in, and simply supported at stabilizer level, El 81 ft 6-1/4 in. The stabilizer assembly is designed for loads due to seismic and jet forces on the internal structure, in addition to a stay force on the drywell shell. The magnitude of the forces is shown on Table L.3-3. The deflection due to the stay force is accommodated in the gap between the male and female parts of the stabilizer assembly. The stresses induced in the shell due to the stay force are extremely small, and they do not govern the design of the shell.

L.3.2.4.3 Drywell Design-Maximum Primary Membrane Stresses in the Shell

The maximum primary general membrane stresses in the shell result from the combination of an internal pressure of 62 psig, the dead load of the shell and appurtenances, lateral and vertical seismic loads, and gravity load on welding pads, which is Case 7, Table L.3-5, the accident condition. The internal pressure load causes by far the greatest stress.

The maximum primary membrane stress, shown on Table L.3-7, of 17.448 ksi is less than the 17.500 ksi allowed by the code. It occurs in the cylindrical portion of the drywell. Other stresses computed at other points along the drywell are shown on Table L.3-7.

Case 1 shown on Table L.3-5 is for the overload test conducted at a pressure of 70 psig, which is higher than the design internal pressure of 56 psig. Since this condition and pressure were temporary, an increase in the allowable membrane stress was allowed.

In addition to maximum stresses computed for the cylindrical and spherical portions of the drywell, stresses have been computed on the elliptical top closure head of the vessel, taking into account the effect of jet forces, since this portion of the vessel is not backed up by concrete. The maximum stress on the head has been found to be 30.24 ksi and results from jet forces combined with the design internal pressure of 56 psig. The design specification allowance for this loading combination is 30.33 ksi (0.9 Fy at 300°F).

L.3.2.4.4 Drywell Design-Discontinuity Stresses

Drywell discontinuity stresses at embedment, expansion joint, and vent-to-drywell shell have been accounted for and stress values included in the CB&I certified stress report. The following gives the actual and allowable stresses at these discontinuities:

Location	Maximum Actual Stress	Allowable Stress
Drywell embedment at accident condition	22.22 ksi	3 S_m =52.50 ksi
Expansion joint	15.20 ksi	19.80 ksi @ 300°F for ASME SA-240 Type 304
Vent-to-drywell shell	15.07 ksi	1.5 S_m =26.250 ksi

L.3.2.4.5 Drywell Design-Expansion of the Drywell Containment Vessel and Jet Forces

Design pressure for the drywell permits a relatively thin-walled steel vessel. However, the vessel has relatively little capability to resist concentrated jet forces. Such loads are, however, readily accepted by the massive concrete shield which surrounds the vessel. Accordingly, the space between the steel drywell vessel and the concrete shield outside has to be sufficiently small so that, although local yielding of the steel vessel can occur under concentrated forces, yielding to the extent causing rupture will be prevented. Space has been provided to allow the drywell to expand in its stressed condition in order for it to function as a pressure vessel. In addition, the vessel is subjected to thermal expansion caused by operating or possible accident condition temperatures significantly higher than ambient. Jet impingement force stresses are summarized on Table L.3-8.

In order to ensure that a steel shell could deflect up to 3 in locally without failure as a result of a concentrated load, CB&I has conducted a series of tests on a steel plate formed to simulate a portion of the drywell vessel. The tests were satisfactory and also provided data on loading required to produce a given deflection, and the strain at various points of the shell. In performing these tests, permanent deformation was not considered as failure.

L.3.2.4.6 Drywell Design-Flooded Condition

The primary containment was analyzed for its ability to withstand loading from post accident flooding of the drywell.

Under this condition, the drywell is flooded with water to El 116 ft. Other loads, such as internal pressure, temperature, live loads, and jet forces are not combined with the hydrostatic load since these loads will not occur simultaneously with flooding. However, the vessel was analyzed for earthquake loads combined with the hydrostatic loads.

Table L.3-7 summarizes the stresses in the shell under the flooded conditions and earthquake.

L.3.2.4.7 Drywell Design-Buckling Considerations

The drywell shell must be capable of resisting the compressive stresses resulting from the external pressure, the dead load of the shell and appurtenances, the live load on the access hatch and beam loads, the gravity loads on the weld pads, plus the seismic loads. These loads produce biaxial compressive stresses of varying magnitude at different points along the drywell shell.

The worst condition for drywell buckling is during the refueling condition, Case 6, Table L.3-5, combined with stresses due to seismic loading. The maximum compressive stress occurs at the drywell embedment and it is 0.81 of the allowable stress.

L.3.2.4.8 Drywell Design-Stabilizer Shear Lugs

Eight stabilizer mechanisms are designed to transfer at El 81 ft 6-1/4 in into the building the reaction due to seismic loads or seismic plus jet loads acting on the drywell, reactor, and shield. The loads are shown on Table L.3-3.

Each stabilizer mechanism is composed of four components: (1) the connection between the reactor stabilizer and the drywell shell, (2) the male lug, (3) the female lug, and (4) the concrete shear connectors. The geometry of the stabilizer mechanism allows for radial and vertical movements due to pressure and temperature. Computed stresses in the stabilizer mechanism are compared to either the AISC or ASME Code allowables, depending upon the component being analyzed. All components and welds which are attached directly to the drywell shell satisfy the ASME Code. The stresses in the remaining components are compared to AISC allowables. The allowed and computed stresses are summarized on Table L.3-9.

L.3.2.4.9 Suppression Chamber Design-Primary Membrane Stresses

The suppression chamber is supported on 16 pairs of equally spaced columns located on the inner and outer perimeters. Although the principal stresses computed on the suppression chamber were circumferential, detailed analyses have been performed to determine the magnitude of localized stresses at the points of column and downcomer supports and vents to determine the need for and to provide additional stiffeners and reinforcing as required. The computed stresses are summarized on Tables L.3-10 and L.3-11.

Due to the complexity of the analysis involved in the determination of maximum stresses under various loads and load combinations, Teledyne Engineering Services set up a computer program for each of the major loading combinations. These combinations were the initial and final condition at ambient temperature at the time of the acceptance test, and the accident condition at 281°F. In addition, the flooded condition was analyzed. The Teledyne Engineering Services calculations for the suppression chamber, including the printout sheets for the computer program, will be included in the certified stress report.

L.3.2.4.10 Suppression Chamber Design-Accident Condition

The maximum primary membrane stresses in the shell and ring girder result from a combination of downcomer thrusts of 21,000 lb each, an internal pressure of 62 psig at 281°F or an external pressure of 2 psig, dead load of shell and appurtenances, the load of the 84,0003 ft of water in the suppression pool, lateral and vertical seismic loads, and vent thrusts of 62 psig at 281°F.

The maximum primary membrane stresses in the shell and ring girder result from a combination of loads as shown on Table L.3-6. The principal stresses are shown on Table L.3-10. The maximum actual stresses calculated in the columns due to a combination of axial compression and bending are 0.897 and 0.795 of the allowable stress for the outside and inside columns, respectively.

Stresses are determined at critical points along the girder. The maximum stresses, 13.11 ksi acting in the plane of the shell, and 16.80 ksi acting in the ring girder flange, are for the accident condition and the ASME Code allowable of 17.5 ksi.

L.3.2.4.11 Suppression Chamber Design-Flooded Condition (Ring Section and Supports)

With the water level at elevation 116 ft in the drywell for the flooded condition, a computer analysis showed that the maximum stresses in the support ring are 16.24 ksi in the plan of the shell, and 22.94 ksi in the ring girder flange which are below ASME Code allowable of 1.33 X 17.5 ksi = 23.33 ksi.

The outside and inside column stresses were investigated at three locations 90 deg apart. The maximum stress due to a combination of axial compression and bending was calculated to be 0.809 and 0.549 of the allowable stress for the outside and inside columns, respectively.

The design of rods, column connections, plates, etc., have been analyzed for the flooded condition with earthquake and the stresses are less than the code allowable stresses.

L.3.2.4.12 Suppression Chamber Design-Header, Downcomer, and Vent Pipes

These components of the suppression chamber were analyzed and adequately sized for plate thickness and reinforcements as required, and in conformance with the ASME Code.

L.3.2.4.13 Containment System Design - Summary

All possible loads, as well as their combinations, have been taken into consideration and the maximum stresses computed are all within the design specification and the ASME Boiler and Pressure Vessel Code allowable stresses.

L.3.3 Penetration Nozzle Design

CB&I designed the penetration nozzles. The shell stresses, from loads on the nozzles, at the nozzle neck to shell junction, were analyzed by the methods outlined in Welding Research Council Bulletin No. 107. A computer program was written to perform the calculations outlined in the computation forms for a spherical and a cylindrical shell.

Unit loads were run on the computer to determine the stresses for various combinations of loads. The stress report by Teledyne Engineering Services includes the computer printout sheets listing the stresses for a 1,000 lb radial load, 1,000 in-lb moment and 1,000 lb shear. Using these coefficients, stresses were determined for combined loading conditions including thermal, earthquake, dead load, and pipe rupture loads.

The size and thickness of the nozzle neck and necessary reinforcement are computed from requirements listed in Section III, Section B, of the ASME Boiler and Pressure Vessel Code. The attachments are designed to provide the strength required by the ASME Code. The computed stresses and allowable stresses are summarized on Table L.3-12.

TABLE L.3-1

MATERIALS AND STRESSES

The vessels are constructed with the following materials:

Material Code Designation	Min Ult Tensile (ksi)	Min Yield (Ambient) (ksi)	Code Tensile Allow (To 650°F) (ksi)	Notes
Plate				
ASME-SA516 Gr 70 fabricated to ASTM-A300	70	38	17.5	Yield at 300°F = 33.7 ksi
ASME-SA240 TP 304	75	30	13.75	
Pipe				
ASME-SA333 Gr 1	55	30	13.75	Yield at 300°F = 26.6 ksi
or ASME-SA333 Gr 6	60	35	15.0	Yield at 300°F = 31.0 ksi
ASME-SA312 TP 304	75	30	13.75	
Forgings				
ASME-SA350 LF1	60	30	15	
Bolting*				
ASME-SA320-L7	125	105	25	Through 2 1/2 in ϕ
or ASME-SA320-L43	125	105	25	Through 4 in ϕ
ASME-SA194 Gr 4	-	-	-	Specification Req. Proof Test
Structural				
ASTM-A36	60	36	22	Not to be used for pressure part nor within 4 in of pressure part.
ASTM-A53 Gr B	60	35	21	
ASTM-A106 Gr B	60	35	15	
USS T-1	118	105	-	

*Excludes Gibbs Manway Cover Studs

APPENDIX Q

SUPPLEMENTAL RELOAD LICENSING REPORTS

TABLE OF CONTENTS

APPENDIX Q

LIST OF TABLES

Table	Title
Not Used	

APPENDIX Q

LIST OF FIGURES

APPENDIX Q
SUPPLEMENTAL RELOAD LICENSING REPORTS

Q.1 INTRODUCTION

The latest plant supplemental reload licensing report is "Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 18/Cycle 19", 0000-0119-4309-SRLR, Revision 1, Class I, January 2011 (ECH-NE-11-00013, Revision 2). This report provides the cycle core loading pattern and the results of the cycle specific nuclear transient and vessel overpressurization analyses. This report also addresses the applicability of generic stability and accident analyses. Refer to this report for reload information. All other sections of Appendix Q have been removed from the FSAR. References for previous cycle specific reports are as follows:

RELOAD SUBMITTAL REFERENCES

Reload No.	Reference
1	"Reload 1 Licensing Submittal of Pilgrim Nuclear Power Station", NEDO-20286, Revision 1, February 1974.
2	"General Electric Boiling Water Reactor Reload No. 2 Licensing Submittal for Pilgrim Nuclear Power Station Unit 1", NEDO-20855, June 1975.
	"Reload No. 2 Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 with Bypass Flow Holes Plugged", NEDO-20855-01, September 1975.
3	"General Electric Boiling Water Reactor Reload No. 3 Licensing Submittal for Pilgrim Nuclear Power Station Unit 1", NEDO-21460-01, May 1977.
4	"Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 4", NEDO-24224, November 1979.
	"Supplement 1 to Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 4", NEDO-24224-1, Supplement 1, March 1980.
	"Supplement 2 to Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 4 (Load Line Limit Analysis Reverification)", NEDO-24224-2, April 1981.
5	Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 5", Y1003J01A28, Revision 2, February 1983.

Reload No.	Reference
6	"Supplement Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 6", 23A1694, March 1984.
7	"Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Reload 7", 23A4800, December 1986.
8	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 8, Cycle 9," 23A7101, March 1991.
	(Note: the generator load reduction without bypass analyzed in the above licensing report is updated in another analysis (BECo SUDDS 91-44). All results presented here reflect this updated analysis).
9	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 9, Cycle 10" 23A7195, February 1993.
10	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 10, Cycle 11", 24A5172, Revision 0, February 1995.
11	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 11/Cycle 12", J11-03014SRL, Revision 0), February 1997.
12	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 12/Cycle 13", J11-03474-10 SRLR, Revision 0, Class I, April 1999 (SUDDS RF99-142).
13	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 13/Cycle 14", J11-03878-10 SRLR, Revision 0, Class I, February 2001 (SUDDS/RF 00-112).
14	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 14/Cycle 15", 0000-0008-6613-SRLR, Revision 1, Class I, March 2003 (SUDDS RF0258).
15	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 15/Cycle 16", 0000-0030-7302-SRLR, Revision 0, Class I, February 2005.
16	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 16/Cycle 17", 0000-0056-6173-SRLR, Revision 0, Class I, February 2007.
17	"Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 17/Cycle 18", 0000-0083-7478-SRLR, Revision 0, Class I, February 2009.

18 "Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 18/Cycle 19", 0000-0119-4309-SRLR, Revision 1, Class I, January 2011.

Sections Q.2, Q.A, Q.B, Q.C, and Q.D have been removed.

Please refer to "Supplemental Reload Licensing Report for Pilgrim Nuclear Power Station Reload 18/Cycle 19", 0000-0119-4309-SRLR, Revision 1, Class I, January 2011 (ECH-NE-11-00013, Revision 2), and "Pilgrim Cycle GESTARII Section 3.4.3. Assessment," DRF.# 0000-0039--2731, April 28, 2005 (Letter #REK-ENN-HK1-05, April 28, 2005).