7.2.3.13 Wiring

Criteria for wiring and cables in the RPS instrumentation are outlined in Section 8.4.

7.2.4 Safety Evaluation

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. It is the objective of Section 14, Station Safety Analysis, to identify and evaluate events that challenge the fuel barrier and nuclear system process barrier. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are sought and identified, are presented in that section.

Design procedure has been to select tentative scram trip settings that are far enough above or below normal operating levels that spurious scrams and operating inconvenience are avoided. It is then verified by analysis that the reactor fuel and nuclear system process barriers are protected as required by the basic objective. In all cases, the specific scram trip point selected is not the only value of the trip point which results in acceptable results relative to the fuel or nuclear system process barrier. Trip setting selection is based on operating experience and constrained by the safety design basis. The scrams initiated by Neutron Monitoring System variables, nuclear system high pressure, turbine stop valve closure, turbine control valve fast closure, and reactor vessel low water level are sufficient to prevent excessive fuel damage following abnormal operational transients.

Section 14, Station Safety Analysis, identifies and evaluates the threats to fuel integrity posed by abnormal operational events. In no case does excessive fuel damage result from abnormal operational transients. The RPS meets the timeliness and precision requirements of safety design basis 1.

The evaluation of the scram function provided by the Neutron Monitoring System is presented in Section 7.5 as well as in Section 14.

The scram initiated by nuclear system high pressure, in conjunction with the Pressure Relief System, is sufficient to prevent damage to the nuclear system process barrier as a result of internal pressure. For turbine generator trips, the turbine stop valve closure scram and turbine control valve fast closure scram provide a greater margin to the maximum allowed nuclear system pressure than would the high pressure scram alone. Section 14, Station Safety Analysis, identifies and evaluates accidents and abnormal operational events that result in nuclear system pressure increases. In no case does pressure exceed the maximum allowed nuclear system pressure. The RPS meets the timeliness and precision requirements of safety design basis 2.

The scrams initiated by the Neutron Monitoring System, main steam isolation valve closure, and reactor vessel low water level, satisfactorily limit the radiological consequences of gross failure of the fuel or nuclear system process barriers. Section 14, Station Safety Analysis evaluates gross failures of the fuel and nuclear system process barriers. In no case does the release of radioactive material to the environs exceed the guideline values of published regulations. The RPS meets the precision requirements of safety design basis 3.

Because the RPS meets the timeliness and precision requirements of safety design bases 1, 2, and 3 and the monitored variables are true direct measures of operational conditions, it is concluded that safety design basis 4 is met.

Because the RPS meets the precision requirements of safety design bases 1, 2, and 3, by using instruments with the characteristics described on Table 7.2-1, it is concluded that safety design basis 5 is met.

Neutron flux is the only essential variable of significant spatial dependence that provides inputs to the RPS. The basis for the number and locations of neutron flux detectors is discussed in Section 7.5, Neutron Monitoring System. Because the precision requirements of safety design bases 1, 2, and 3 are met using the Neutron Monitoring System as described, it is concluded that the number of sensors for spatially dependent variables satisfies safety design basis 6.

The items of safety design basis 7 specify the requirements that must be fulfilled for the RPS to meet the reliability requirements of safety design bases 1, 2, and 3. It has already been shown in the description of the RPS that safety design basis 7f has been met. The other requirements are fulfilled through the combination of logic arrangement, channel redundancy, wiring scheme, physical isolation, power supply redundancy, and component environmental capabilities. The following discussion evaluates these subjects.

In terms of protection system nomenclature, the RPS is a one-out-of-two taken twice system (1 of 2 x 2). Theoretically, its reliability is slightly higher than a two out of three system and slightly lower than a one-out-of-two system. However, since the differences are slight, they can, in a practical sense, be neglected. The advantage of the dual trip system arrangement is that it can be tested thoroughly during reactor operation without causing a scram. This capability for a thorough testing program, which contributes significantly to increased reliability, is not possible for a one-out-of-two system.

The use of independent channels allows the system to sustain any channel failure without preventing other sensors monitoring the same variable from initiating a scram. A single sensor or channel failure will cause a single trip system to trip and actuate alarms that identify the trip. The failure of two or more sensors or channels would cause either a single trip system to trip, if the

failures were confined to one trip system, or a reactor scram, if the failures occurred in different trip systems. Any intentional bypass, maintenance operation, calibration operation, or test, will cause a single trip system to trip. This leaves at least two channels, per monitored variable, capable of initiating a scram by causing a trip of the remaining trip system. The resistance to spurious scrams contributes to station safety, because unnecessary cycling of the reactor through its operating modes would increase the probability of error or actual failure. It is concluded from the preceding paragraphs evaluating the logic, redundancy, and failure characteristics of the RPS, that the system satisfies the reliability requirement stated in safety design bases 7a and 7b.

A condition in which an essential monitored variable exceeds its scram trip point is sensed by at least two independent channels in each trip system. Because only one channel must trip in each trip system to initiate a scram, the arrangement of two channels per monitored variable in each trip system provides assurance that scram will occur.

Each control rod is controlled as an individual unit. A failure of the controls for one rod will not affect the operation of other rods. The backup scram valves provide a second method of venting the air pressure from the scram valves, even if either scram pilot valve solenoid for any control rod fails to deenergize when a scram is required. It is concluded from the evaluations in the above paragraphs that the RPS meets safety design basis 7c.

Sensors, channels, and logics of the RPS are not used directly for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce failure of any portion of the protection system. This meets safety design basis 7d.

Failure of either RPS motor generator set would result, at worst, in a single trip system trip. Alternate power is available to the RPS buses. A complete, sustained loss of electrical power to both motor generator sets would result in a scram, delayed by the motor generator set flywheel inertia, in about 3 sec. In addition, Electrical Protection Assemblies (EPA's) are installed on the power sources for the RPS to disconnect the power source on over voltage, under voltage or under frequency conditions. This protects the RPS components and auxiliaries from damage due to sustained abnormal voltage/frequency conditions. This meets safety design basis 7e.

The environmental conditions in which the instruments and equipment of the RPS must operate were enveloped by the Environmental Qualification Program. 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.

The environmental capabilities of the RPS components, combined with the previously described physical and electrical isolation of sensors, and channels, satisfy safety design basis 7g.

Safe shutdown of the reactor during earthquake ground motion is assured by the design of the system as a Class I system (see Appendix C) and the failsafe characteristics of the system. The system only fails in a direction that causes the reactor to scram when subjected to the extremes of vibration and shock. This meets safety design basis 7h.

Calibration and test controls for the Neutron Monitoring System are located in the control room, and are because of their physical location, under the direct physical control of the control room operator. Calibration and test controls for pressure and level switches, transmitters, analog trip units, and valve position switches are located on the devices themselves. These devices are located in the Turbine Building, Reactor Building, and primary containment. To gain access to the setting controls on each switch, transmitter or trip unit, a cover plate or sealing device must be removed. The control room operator is responsible for granting access to the setting controls to properly qualified station personnel for the purpose of testing or calibration adjustment. This meets safety design basis 8a.

It has been shown in the description of the RPS that safety design bases 8b, 9, 10a, and 10b are satisfied.

7.2.5 System Inspection and Testing

The RPS can be tested during reactor operation by six separate tests. The first of these is the manual trip actuator test. By depressing the manual scram button for one trip system; the manual logic actuators are deenergized, opening contacts in the actuator logics. After resetting the first trip system, the second trip system is tripped with the other manual scram button. The total test verifies the ability to deenergize all 8 groups of scram pilot valve solenoids by using the manual scram push button switches. Scram group indicator lights verify that the actuator contacts have opened.

The second test is the automatic actuator test which is accomplished by operating, one at a time, the keylocked test switches for each automatic logic. The switch deenergizes the actuators for that logic, causing the associated actuator contacts to open. The test verifies the ability of each logic to deenergize the actuator logics associated with the parent trip system. The actuator and contact action can be verified by observing the physical position of these devices.

The third test includes calibration of Neutron Monitoring System by means of simulated inputs from calibration signal units. These calibrations are discussed in Section 7.2.3.12 above and in Section 7.5, Neutron Monitoring System.

The fourth test is the single rod scram test which verifies capability of each rod to scram. It is accomplished by operation of toggle switches on the protection system operations panel. Timing traces can be made for each rod scrammed. Prior to the test, a physics review must be conducted to assure that the rod pattern during scram testing does not create a rod of excessive reactivity worth.

The fifth test involves the application of a test signal to each RPS channel in turn and observing that a logic trip results. This test also verifies the electrical independence of the channel circuitry. The test signals can be applied to the process type sensing instruments (pressure and differential pressure) through calibration taps or via the analog trip unit. Generic test procedures are discussed below; additional procedures unique to specific scram channels are discussed in Section 7.2.3.12.

The sixth test involves the application of a test signal to a RPS channel under test similar to the fifth test except a scram inhibit test device will bypass the scram logic relay contact while the relay is under test. The scram inhibit test device will monitor logic relay contact status while maintaining the circuit path preventing the scram relay from initiating half a scram.

1. An instrument technician, following instruction of authorized personnel, either shuts off the instrument line, or removes the channel from service at the Analog Trip Cabinet.

2. The instrument is isolated using the instrument valve (or instrument manifold valve) and a calibration set is attached to the instrument calibration taps which are arranged to avoid spilling of water (if the instruments are normally filled). If isolation is performed via an electrical switch at the Analog Trip System, all that is required to calibrate is injection of an electrical test signal.

3. A calibration signal sufficient to actuate the sensor contacts is applied while reading the value of the applied signal.

4. The trip points and reset point are compared to the required setpoint and the value is logged.

5. Adjustments are made to the trip setting if necessary; adjustments are logged.

6. Communication with the control room is maintained during the test to verify the trip point as registered on control room instruments. The trip value is logged.

7. Proper protective relay operation is also verified by observation.

8. Upon completion of calibration, all test equipment is then removed, and the channel is restored to service.

9. The final state of the system valving (if required) and indication is verified by reactor operations or instrument personnel, and the test is logged as complete.

RPS response times are first verified during preoperational testing and may be verified thereafter by similar tests. The elapsed times from sensor trip to each of the following events is measured:

1. Channel relay deenergized
2. Actuators deenergized

The alarm typewriter provided with the process computer verifies the proper operation of many sensors during plant startups and shutdowns. The verification provided by the alarm typewriter is not considered in the selection of test and calibration frequencies and is not required for plant safety.

The provisions for functionally testing and calibrating the RPS meet the requirements of safety design basis 11.

7.2.6 Nuclear Safety Requirements for Plant Operation

Table 7.2-4 presents the nuclear safety requirements for the RPS for each BWR operating state. The entries on Table 7.2-4 represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the RPS.

The following referenced portions of the safety analysis report provide important information justifying the entries on Table 7.2-4:

Reference	Information Provided
1. Preceding parts of Section 7.2	Description of RPS hardware; RPS sensor setpoints
2. Station Safety Analysis, Section 14	Analyses verifying response of RPS to transients and accidents
3. Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which reactor protection system 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 and surveillance requirements for protection systems

Each detailed requirement on Table 7.2-4 is referenced, where possible, 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 references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns of Table 7.2-4 and are coded as follows:

Example of Matrix Reference:

```
F21-71
| |  |
--+--+--- F = BWR operating state F
  ---+--   21 = Event (row No. 21)
     ----     71 = RPS (column No. 71)
```

Most of the operational requirements on Table 7.2-4 are obvious in consideration of the information of Appendix G and the information of Section 7.2 describing the RPS in detail. An explanation of several of the less obvious requirements from Table 7.2-4 follows:

System Action 7.2.2 - Neutron Monitoring System Scram Initiation

The requirements for the Neutron Monitoring System logics refer only to that circuitry considered part of the Reactor Protection System, as shown on Figure 7.2-18. The requirements for the individual channels of the Neutron Monitoring System are developed in Section 7.5. Three IRM logics per operable trip system are required to assure that the IRM capability is sufficient to monitor the total core volume. Because the APRMs are themselves arranged to monitor average power throughout the entire core, only one APRM logic is needed in each operable RPS logic.

System Action 7.2.12 - Refueling Restrictions

The reactor mode switch is required to be in the REFUEL position whenever core alterations are being carried out. This requirement assures that the refueling interlocks are in service during such alterations. Although this requirement is not associated at all with any scram action, it is listed here because the reactor mode switch itself is considered a part of the RPS.

Because the point at which the reactor becomes less than one rod subcritical (not shutdown) is not easily recognized during station startup, requirements for RPS channels are shown for operating States A, C, and E. These requirements are selected to anticipate the need for protection should the one rod subcritical point be passed.

7.2.6.1 Surveillance Requirements for Plant Operation

The minimum functional testing frequencies for the components of the RPS are based on an analysis using two GE topical reports NEDC-30844 (Reference 3), which analyzed a representative BWR plant and provided a technical basis for ensuring that the current RPS on-line test intervals meet the recommendations of Generic Letter 83-28, Item 4.5.3, and NEDC-30851P (Reference 4), which used the base case results from NEDC-30844 to establish a basis for extending the current RPS on-line test intervals and allowable out-of-service times (AOTs). These reports used reliability analyses with fault tree modeling to estimate RPS failure frequency. Sensitivity analyses were used to vary the factors that represented the five areas of concern delineated in Item 4.5.3 so that their impact was considered appropriately.

To apply generic plant analyses to specific plants, GE collected necessary information on the RPS for each BWR, determined the differences for each plant, and analyzed the effect of each identified difference on the RPS failure frequency. The analysis evaluated the RPS using the RPS failure frequency as the risk measure.

The calculations of RPS failure frequency depend on two sets of parameters. The first set consists of initiating events that eventually lead to actuation of the RPS. The second set consists of "RPS unavailabilities," which are the probabilities that the RPS is unavailable given the demands for RPS actuation. Depending on each initiating event, the number of sensors that could actuate the RPS would vary. Therefore, the RPS unavailability for one initiating event may differ from that for another.

For each initiating event, a fault tree was developed to quantify RPS unavailability per demand. The fault tree models the logical relationship of the faults that may contribute to RPS unavailability. The logical representation of the fault tree was used with the computer code WAMCUT (Reference 5) to obtain the dominant cutsets which are the combinations of faults that cause the RPS to be unavailable. The dominant cutsets, together with information on testing and repairing the RPS, was then used with the computer code FRANTIC III, (Reference 6) which calculated the unavailability of RPS per demand.

A sensitivity analyses was performed to determine the sensitivity of RPS unavailability to uncertainties in component failure rates. The component failure rates were multiplied with an error factor, which is the ratio of the upper uncertainty bound and the median value. The results indicated that uncertainties in the component failure rates have a negligible impact on RPS unavailability. Therefore, it is concluded that the RPS unavailability is not sensitive to the uncertainties in component failure rates.

It was determined that the common cause failure rates of the scram contactors do contribute significantly to the RPS unavailability for each of the initiating events, however even when these common cause failure rates are considered, the results are still lower than other published results.

The analysis indicated that among the components in the RPS, the scram contactors are de-energized whenever an individual sensor and its associated relay are tested. Because 11 different types of sensors are tested while the reactor is at full power, the scram contactors would be challenged more often than other components in the RPS. For this reason, the effect of scram contactor wear out caused by testing was examined. The analysis indicated that the scram contactor wear created by the number of tests required does not cause any significant increase in RPS failure frequency.

The impact of reduced system redundancy during testing on the RPS unavailabilities by comparing two cases was examined. In the first case, a sensor channel is "jumpered" during a test and is unable to provide an RPS signal upon actual demand. In the second case, a sensor channel is placed in trip during a test and thus does provide an RPS signal.

The RPS unavailability for the first case is higher than that for the second case. However, the difference between these two RPS unavailabilities was found to be small and indicates that reduced redundancy during testing has no significant impact on RPS unavailability.

The analysis considered two types of human errors during a test: an operator disabling components randomly during a test and an operator causing a common cause failure of all similar components during a test. The analysis determined that the first type of operator error does not have significant impact on RPS failure frequency, but the second type of operator error does.

The analysis determined that operator error disabling all scram contactors was the biggest contributor to the RPS failure frequency. The operators perform channel functional testing of the manual scram on a weekly basis by actuating the channel manual scram/test switches in the control room.

RPS failure frequency was calculated by varying the surveillance testing intervals of the average power range monitor (APRM) and other sensors from monthly to quarterly. The results showed a small change in RPS failure frequency.

The original Technical Specifications (TSs) for the relay RPS allowed AOTs of 1 hour for repairing and 2 hours for testing a single sensor channel without placing the channel in a tripped state. The short times allowed by the original TS could cause an operator error as a result of stress during repair and testing. Placing an individual channel in a tripped condition when repairs

and tests cannot be completed within the allowable outage time could increase the likelihood of an inadvertent scram. Therefore, it was proposed to extend the AOTs for repair and for testing. The present AOTs, which are based on the average times needed to complete tests and repairs, include sufficient time margins so that the operators would not be placed under undue stress. To support these above changes, sensitivity analyses were performed and concluded the changing of the AOTs had a negligible impact on RPS failure frequency.

7.2.7 Current Technical Specifications

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

7.2.8 References

1. US Nuclear Regulatory Commission, "Generic Implications of the ATWS Events at the Salem Nuclear Power Plants", Vols. 1 and 2, NUREG-1000, April, 1983.

2. Eisenhut, D.G., NRC letter to All Licensees of Operating Reactors, Applicants for Operating License, and Holders of Construction Permits, "Required Actions Based on Generic Implications of Salem ATWS Events" (Generic Letter 83-28), July 8, 1983.

3. S. Visweswaren, et al., "BWR Owners' Group Response to NRC Generic Letter 83-28, Item 4.5.3," General Electric Company, NEDC-30844, January 1985.

4. W.P. Sullivan et al., "Technical Specification Improvement Analyses for BWR Reactor Protection Systems," General Electric Company, NEDC-30851P, May 1985.

5. R.C. Erdmann, F.L. Leverenz, and H. Kirch, "WAMCUT; A Computer Code for Fault Tree Evaluations," EPRI NP-803, Science Applications, Inc., June 1978.

6. T. Ginzburg et al., "FRANTIC III; A Computer Code for Time-Dependent Reliability Analysis," Broken National Laboratory and Science Applications, Inc., April 1984.

7. B. Collins et al., "A Review of the BWR Owners Group Technical Specification Improvement Analyses for the BWR Reactor Protection System", EGG-EA-7105, corporate publisher, January 1986.

8. D.M. Rasmusen et al., "COMCAN III; Use of COMCAN III in System Design and Reliability Analysis," EGG-2187, corporate publisher, October 1982.

9. A.S. McClymont et al., "ATWS: A Reappraisal, Part 3: Frequency of Anticipated, Transients," EPRI NP-2230, Science Applications, Inc., January 1982.

10. M. McCann et al., "Probabilistic Safety Analysis Procedures Guide," NUREG/CR-2815, Vol. 1, Rev. 1, August 1985.

11. D.P. Mackowiak et al., "Development of Transient Initiating Event Frequencies For Use in Probabilistic Risk Assessment" NUREG/CR-3862 (Draft), June 1984.

12. NRC - Letter dated March 25, 1993 (BECo Letter 1.93.057).

Table 7.2-1

REACTOR PROTECTION SYSTEM
FOR CURRENT PLANT SAFETY ANALYSIS
INSTRUMENT SPECIFICATIONS

SCRAM FUNCTION	INSTRUMENT	TRIP SETTING	DESIGN BASIS REFERENCE
Neutron Monitoring System Scram	IRM Ch. A,B,C, D,E,F,G,H APRM Ch. A,B,C, D,E,F	See Section 7.5 Neutron Monitoring	
Nuclear System High Pressure	PT263-51A,B,C,D PIS263-51A,B,C,D	1,100 psia	BECo Calc. I-N1-94 (See note 2)
Reactor Vessel Low Water Level	LT263-57A,B & -58A,B LIS263-57A,B & -58A,B LS263-57A-1, B-1 & -58A-1, B-1	483.5 in above vessel zero	BECo Calc. I-N1-102 (See note 2)
Turbine Stop Valve Closure	SVOS-1,-2,-3,-4,-1A, -2A,-3A,-4A	Before 10% Valve Closure	
Turbine Control Valve Fast Closure	PS-37,-38,-39,-40	-110 psig, Note 1	BECo Calc. I-N1-39 (See note 2)

Note: 1. This signal is derived from the same acceleration relay which causes fast closure of the control valve.
2. The setpoint for this parameter was analyzed in accordance with R.G. 1.105. The trip setting identified is the design basis analytical limit.

Table 7.2-1 (Cont)

REACTOR PROTECTION SYSTEM
FOR CURRENT PLANT SAFETY ANALYSIS
INSTRUMENT SPECIFICATIONS

SCRAM FUNCTION	INSTRUMENT	TRIP SETTING	DESIGN BASIS REFERENCE
Main Steam Line Isolation Valve Closure	ZS203-1A,B,C,D ZS203-2A,B,C,D	Before 10% Valve Closure	
Scram Discharge Instrument Volume High Water Level	LT302-82A,B & -83C,D LIS302-82A,B & -83C,D LE302-82C,D & -83A,B LS302-82C,D & -83A,B	62.835 gallons	BECo Calc. I-N1-105 and I-N1-106 (See note 2)
Primary Containment High Pressure	PT512A,B,C,D PIS512A,B,C,D	2.5 psig	BECo Calc. I-N1-132 (See note 2)

Note: 1. This signal is derived from the same acceleration relay which causes fast closure of the control valve.
2. The setpoint for this parameter was analyzed in accordance with R.G. 1.105. The trip setting identified is the design basis analytical limit.

TABLE 7.2-2

DELETED

TABLE 7.2-3

LRM CONTROL AND INDICATORS

Reference Designation	Position or Indicator	Functions
Electroluminescent Display	"ON"	Access "Operate" mode display. Display remains "on" for trips or uncleared trip alarms.
	"OFF"	Automatic "Off" 15 minutes after last key pressed, or after power has been applied, whichever is later. For manual "Off", press "Display Off" soft key.
Keylock Mode	"Operate"	Display shows measured radiation level (1 to 10^6), trip settings and status, polarizing voltage, self-test status, and "Help" messages. Accepts clearing of trip alarms upon request.
	INOP	Display shows OPERATE items and accepts 4-key password to allow changes to trip and polarizing voltage settings as well as calibration. These items are available on request.
4 Softkeys for "MENU"	Pressed	Selects instrument functions to be performed. Functions vary as display changes. Correct function of each key is labeled on display.
4 Softkeys for Cursor	Pressed	Keys for horizontal or vertical motion of display cursor, as requested.
16 Softkeys for Data	Pressed	Digits 0 thru 9, 1 key for clearing entry and 1 key for accepting entry, addition, subtraction, decimal point, exponential notation.
4 Softkeys for Menu	Pressed	Reset
"Hi-Hi"	Upscale	Manual Indicator, Auto Contact

TABLE 7.2-3 (con't.)

LRM CONTROL AND INDICATORS

Reference Designation	Position or Indicator	Functions
"Lo"	Downscale	Manual Indicator, Auto Contact
"INOP"	Inop	Auto Indicator, Auto Contact
Audible Buzzer	"ON"	Indicates valid key press

NOTES

The self-test feature of each unit is used to ensure that the LRM is operating properly. The instrument turns on through the application of 115 VAC, 60 Hz primary power at J8. When the LRM is placed in the operate mode, an automatic test of the following parameters is performed each 30 minutes: zero check, range check, downscale trip, trip point verification, alarm test/reset, and various other parameters.

At any stage in the operation of the LRM the self-test feature may be used to show that the LRM is functioning properly and is ready for operational use.

TABLE 7.2-4

REACTOR PROTECTION SYSTEM REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.1 Reactor Protection System (scram) Trip	Trip Systems	2	A	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State B apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State B
			B	1 system operable 1 system tripped

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.1 Reactor Protection System (scram) Trip (Cont)			C	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State D apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State D
			D	1 system operable 1 system tripped
			E	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State F apply in this State whenever more than one rod is withdrawn in order to anticipate the protection requirements of State F

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.1 Reactor Protection System (scram) Trip (Cont)			F	1 system operable 1 system tripped
	Reactor protection system logic (for automatic scrams)	2 logics per trip system	A	None
			B	1 logic operable per trip system
			C,D,E	None
			F	1 logic operable per operable trip system
	Motor-generator Sets	2	A	None
			B	1 set operating
			C	None
			D	1 set operating
			E	None
			F	1 set operating
	Reactor Protection system ac supply breakers	1 breaker per trip system	A	None
			B	1 breaker operable per operable trip system (B44-71)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.1 Reactor Protection System (scram) Trip (Cont)			C	None
			D	1 breaker operable per operable trip system (D44-71)
			E	None
			F	1 breaker operable per operable trip system (F44-71)
7.2.2 Neutron Monitoring System Scram Initiation	Neutron monitoring system logics-IRM portion	4 logics per trip system	A	None
			B	1 logic operable per operable trip system (B38-71)
			C	None
			D	1 logic operable per operable trip system (D38-71)
			E	None
			F	1 logic operable per operable trip system (F38-71)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.2 Neutron Monitoring System Scram Initiation (Cont)	Neutron monitoring system logics-APRM portion	4 logics per trip system	A	None
			B,C,D	None
			E	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State F apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State F
			F	1 logic operable per operable trip system (F38-71)
7.2.3 Nuclear System High Pressure Scram Initiation	Nuclear system high pressure channels	2 channels per trip system	A, B	None

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.3 Nuclear System High Pressure Scram Initiation			C	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State D apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State D
			D	1 channel operable per operable trip system
			E	None
			F	1 channel operable per operable trip system

* Minimum Required for Action is the minimum number of applicable components nece y to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.4 Reactor Vessel Low Water Level Scram Initiation	Reactor vessel low water level channels	2 channels per trip system	A	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State B apply in this State whenever more than one rod is withdrawn in order to anticipate the protection requirements of State B
			B	1 channel operable per trip system (B28-71)
			C	None
			D	1 channel operable per operable trip system (D39-71)
			E	None
			F	1 channel operable per operable trip system (F39-71)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.5 Turbine Stop Valve Closure Scram Initiation	Turbine control valve fast closure channels	2 channels per trip system	A,B,C,D	None
			E	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State F apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State F
			F	When turbine first stage pressure is above 176 psig a selected set of 4 of the 6 channels associated with any combination of 3 valves must be operable (F28-71)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.6 Turbine Control Valve Fast Closure (scram) Scram Initiation	Turbine control valve fast closure channels	2 channels per trip system	A,B,C, D,E	None
			F	1 operable channel per operable trip system when turbine first stage pressure is above 176 psig (F12-71)
7.2.7 Main Steam Line Isolation Scram Initiation	Main steam line isolation channels	2 channels per main steam line	A,B	None
			C	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State D apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State D

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.7 Main Steam Line Isolation Scram Initiation (Cont)			D	When nuclear system pressure is greater than 600 psig or when the mode switch is in RUN a selected set of 4 of the 6 channels associated with any combination of 3 steam lines must be operable (D14-71)
			E	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State F apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State F

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.7 Main Steam Line Isolation Scram Initiation (Cont)			F	When mode switch is in RUN, a selected set of 4 of the 6 channels associated with any combination of 3 steam lines must be operable (F14-71)
7.2.8 Scram Dis-Charge Volume High Water Level Scram Initiation	Scram dis-charge volume high water chan-nels (east and west)	2 channels per trip system	A	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State B apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State B
			B	1 operable channel per operable trip system
			C	None

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.8 Scram Discharge Volume High Water Level Scram Initiation (Cont)			D	1 operable channel per operable trip system
			E	None
			F	1 operable channel per operable trip system
7.2.9 Primary Containment High Pressure Scram Initiation	Primary containment high pressure channels	2 channels per trip system	A,B	None
			C	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State D apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State D

* Minimum Required for Action is the minimum number of applicable components nece. ·y to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
7.2.9 Primary Containment High Pressure Scram Initiation			D	1 operable channel per operable trip system (D39-71)
			E	Since the point at which the reactor becomes less than one rod subcritical is not easily recognized, the requirements of State F apply in this state whenever more than one rod is withdrawn in order to anticipate the protection requirements of State F
			F	1 operable channel per operable trip system (F39-71)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.2-4 (Cont)

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action*
7.2.12 Refueling Restrictions	Reactor mode switch	1 mode switch	A	Switch in REFUEL during core alterations (A1-72)
			B,C,D,E,F	None

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

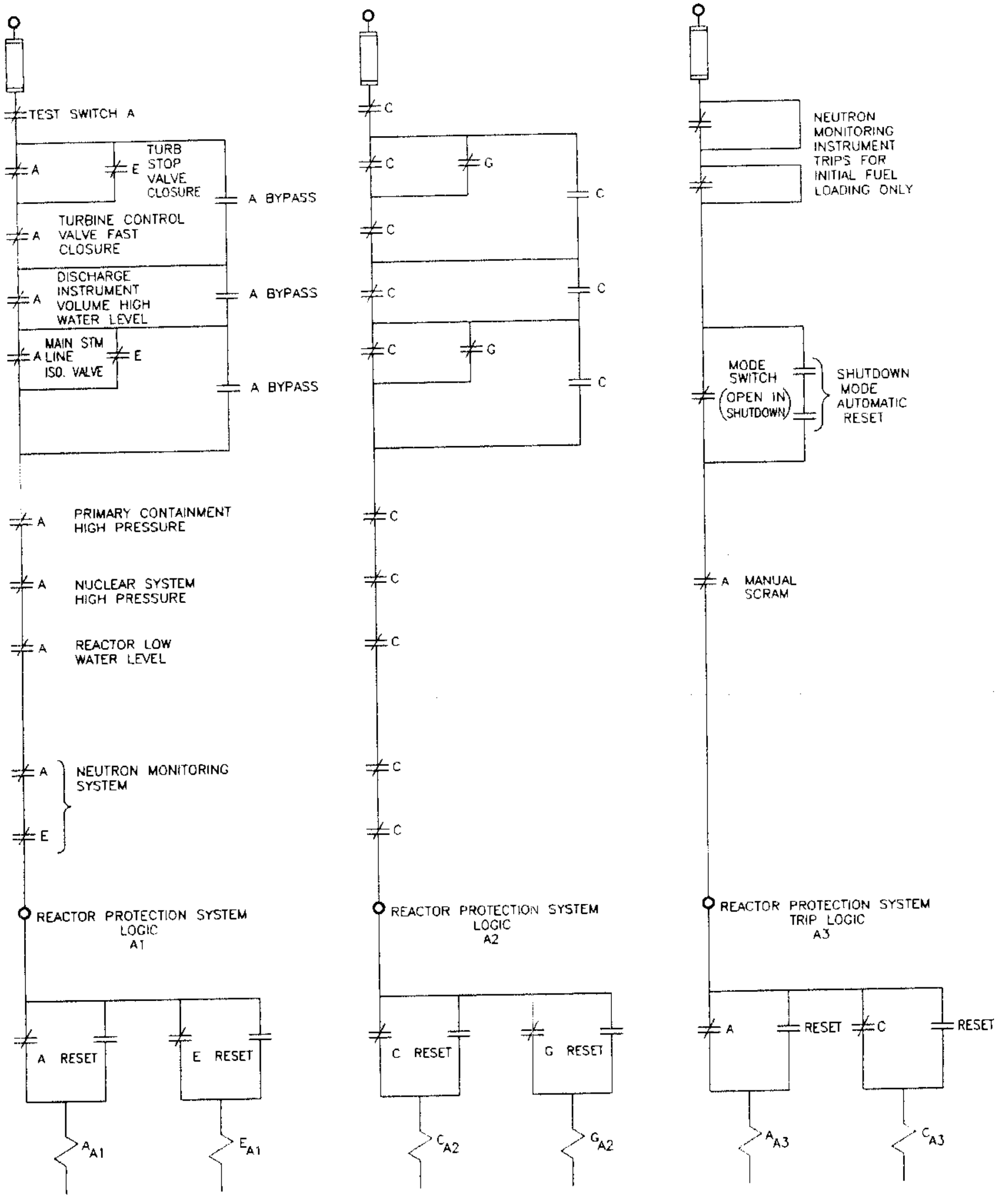
TABLE 7.2-5

SUMMARY OF SURVEILLANCES FOR PLANT OPERATION

RPS Channel or Logic	Functional Testing: Test	Functional Testing: Frequency	Calibration: Minimum Method	Calibration: Frequency	Minimum Remarks
Scram discharge volume high water level channels	Trip channel, observe alarm	3 months	Water level	Every refueling	
Main steam line isolation channels	Trip channel, observe alarm	3 months	Valve Position	Every refueling	
Turbine stop valve closure channels	Trip channel, observe alarm	3 months	Valve position	Every refueling	
Turbine control valve fast closure channels	Trip channel, observe alarm	3 months	Pressure standard	3 months	
Reactor vessel low water level channels	Trip channel, observe alarm	3 months	Water level	Every refueling	
APRM-IRM logics	APRM-trip APRM output re ays IRM-trip channel, observe alarm	APRM-1 week IRM-prior to each Startup	Heat balance	APRM-3 days IRM-1 week	See Section 7.5
Primary containment high pressure channels	Trip channel, observe alarm	3 months	Pressure standard	Every refueling	
Reactor vessel high pressure channels	Trip channel, observe alarm	3 months	Pressure standard	Every refueling	

Figures 7.2-1 and 7.2-2 have been removed.

Please refer to BECo Controlled Drawings M1P 5-5 and M1P 6-6.



NOTE: CONTACTS SHOWN IN NORMAL CONDITION

FIGURE 7.2-3

SCHEMATIC DIAGRAM OF LOGIC IN ONE TRIP SYSTEM

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 19 – June 1996

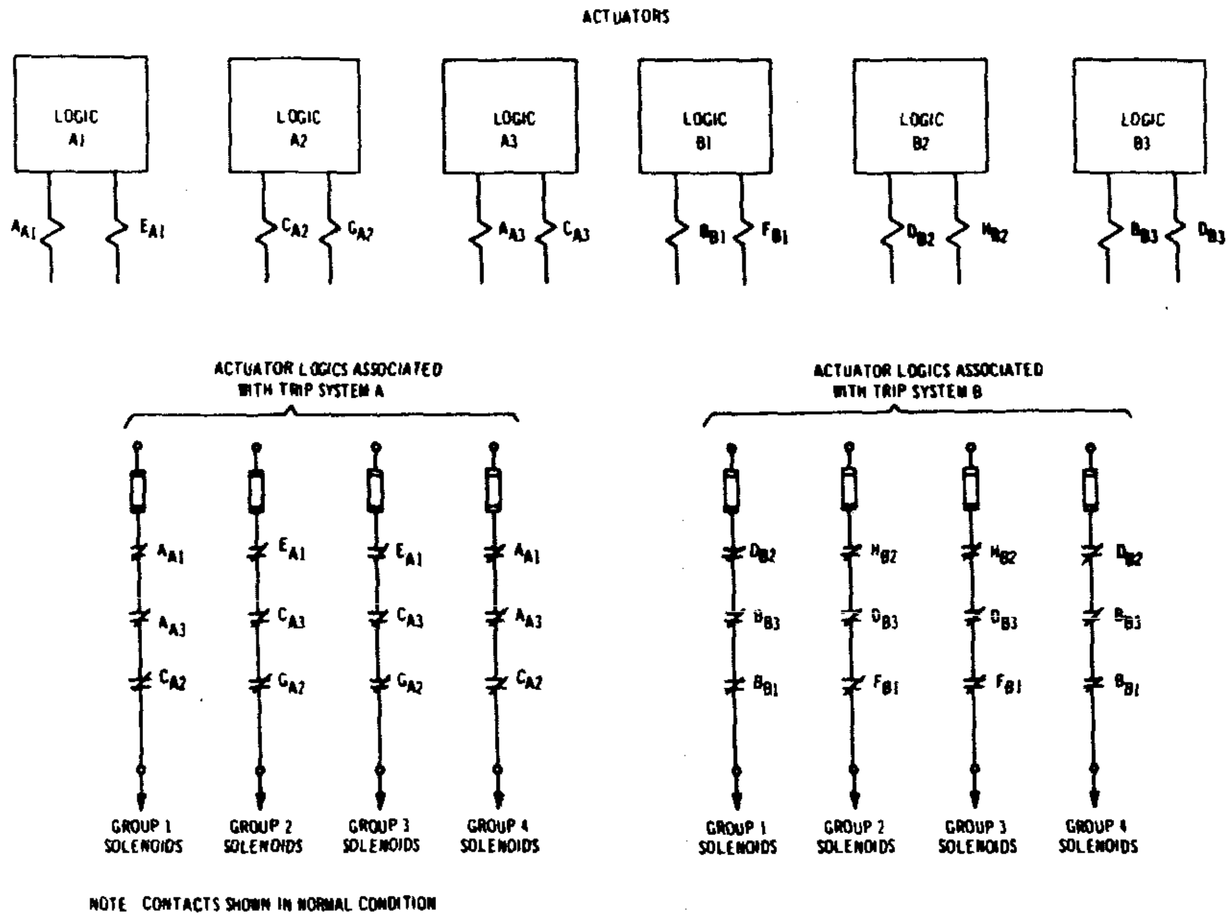
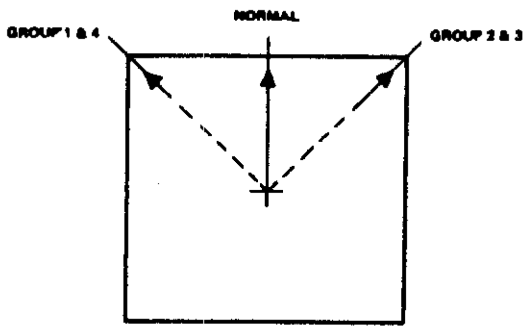


FIGURE 7.2-4
SCHEMATIC DIAGRAM OF ACTUATORS AND ACTUATOR-LOGICS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



G.E. TYPE SBM
PISTOL GRIP HANDLE
WITH SPRING
RETURN TO
NORMAL POSITION

CONTACTS HANDLE END		POSITION		
		GP 2 & 3	NORMAL	GP 1 & 4
1 — 1T 2T — 2	1	x		
	2	x		
3 — 3T 4T — 4	3			x
	4			x

FIGURE 7.2-5
SCRAM RESET SWITCH
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

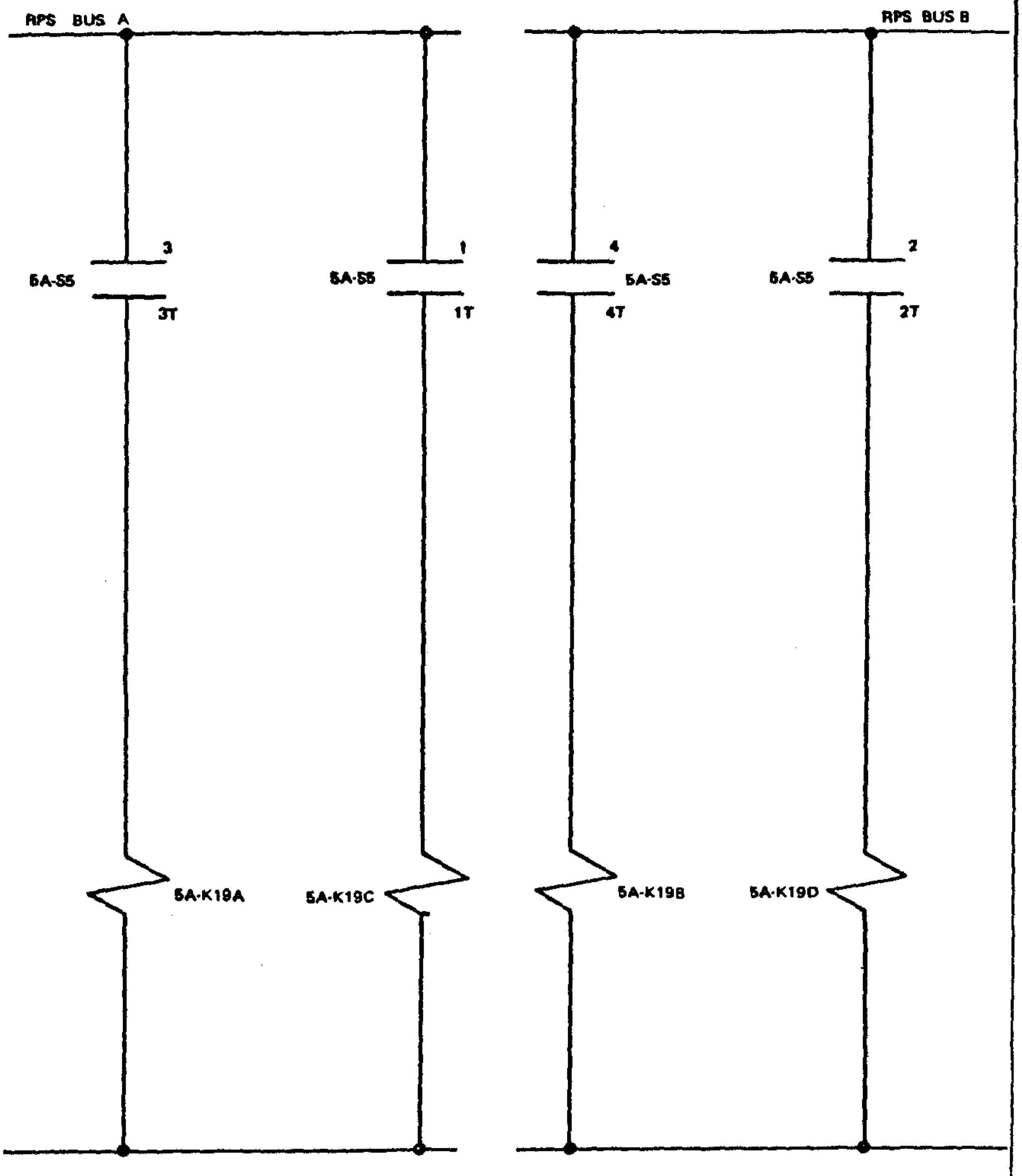


FIGURE 7.2-6
RPS RESET SWITCH CHANNELS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

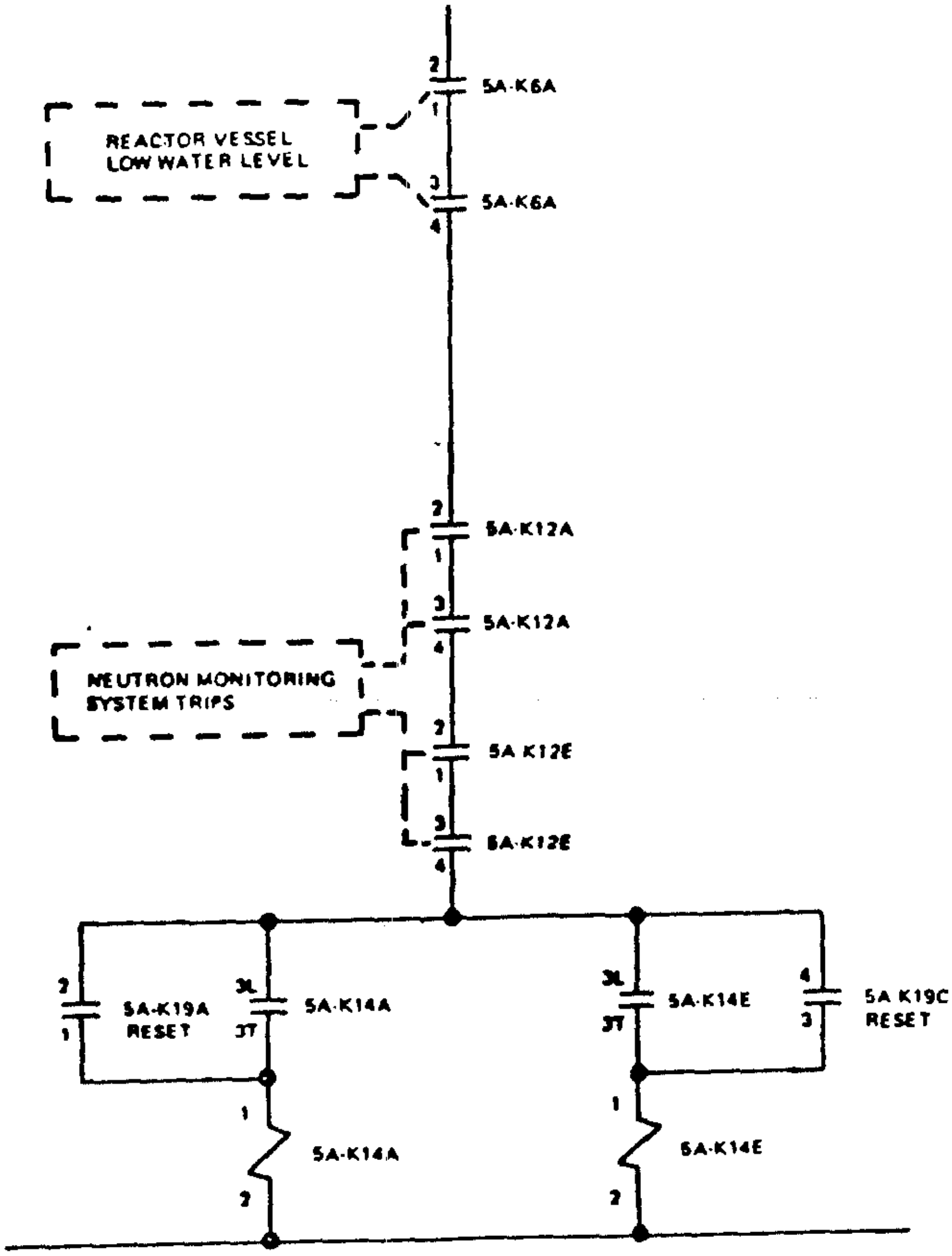


FIGURE 7.2-7
TRIP LOGIC A I FOR RPS SWITCH
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 19 - June 1996

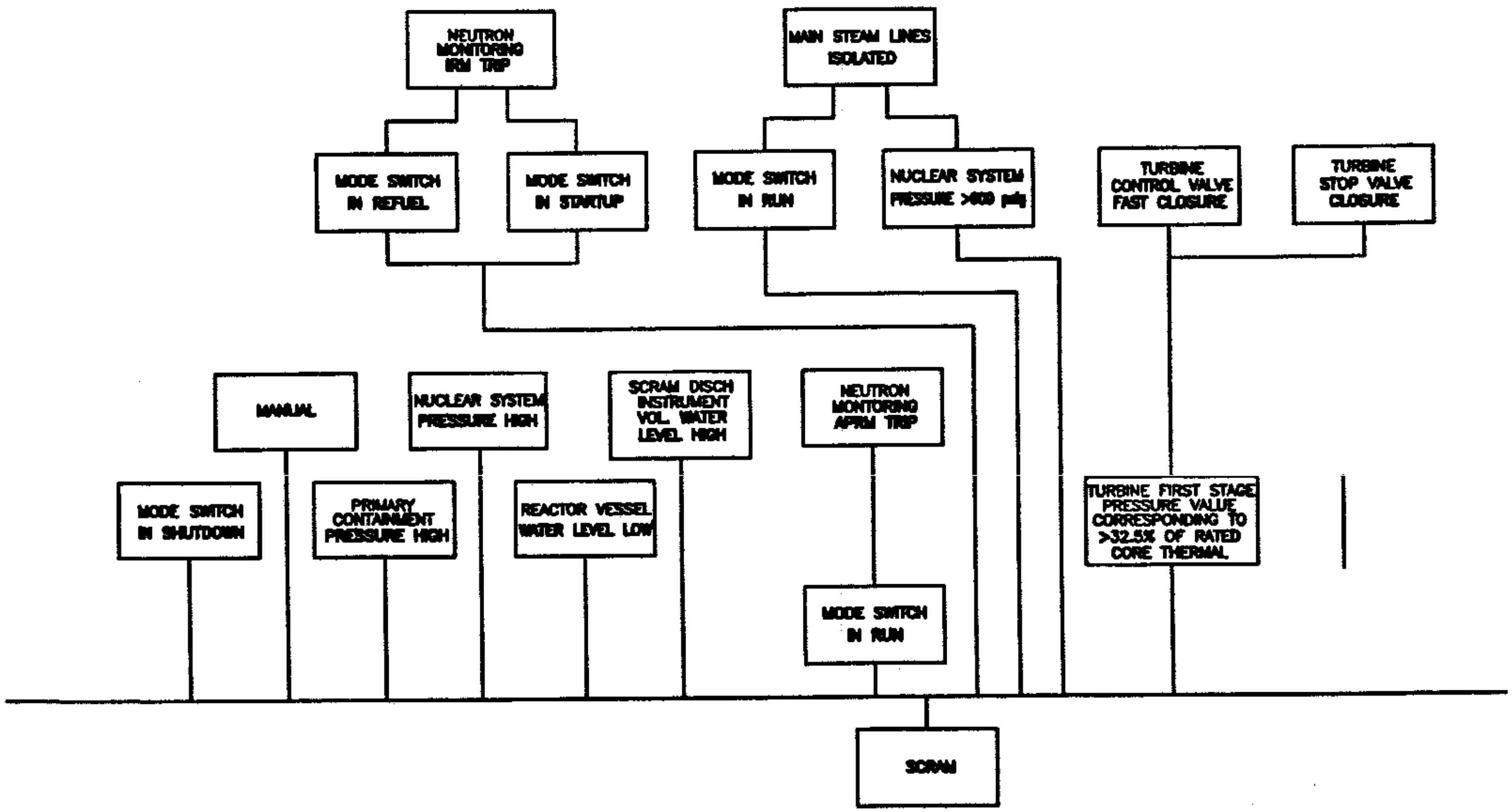


FIGURE 7.2-8

REACTOR PROTECTION SYSTEM SCRAM FUNCTIONS

PILGRIM NUCLEAR POWER STATION FINAL SAFETY ANALYSIS REPORT

Revision 25 – October 2005

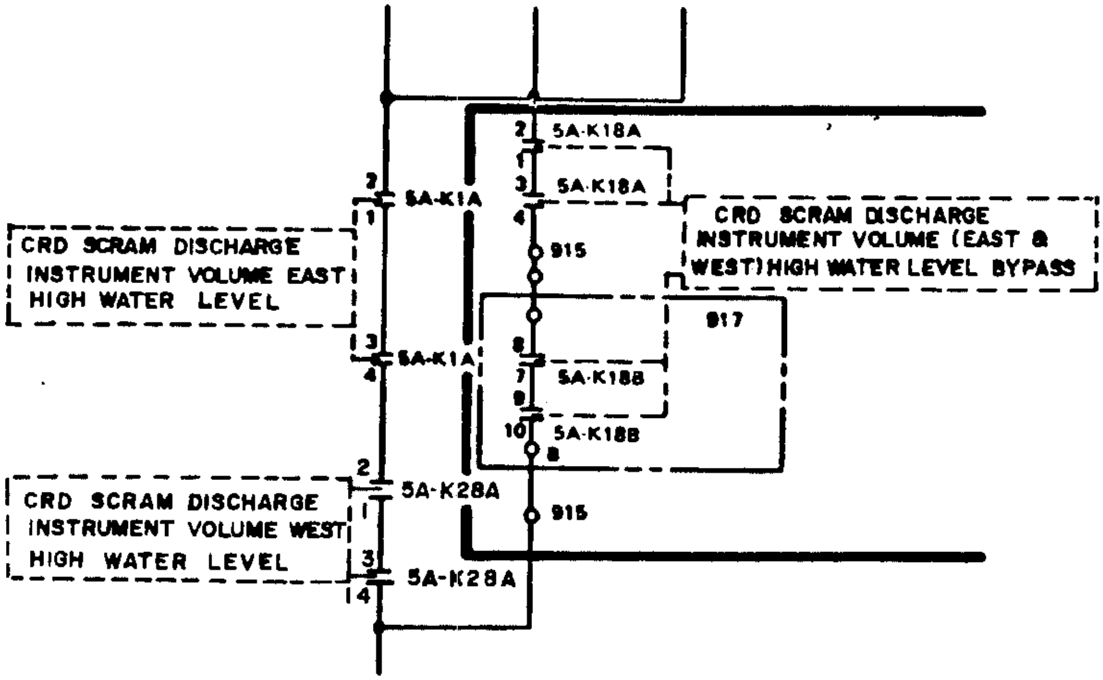


FIGURE 7.2-9
TRIP LOGIC A1 FOR CRD SCRAM DISCHARGE VOLUME HIGH WATER LEVEL BYPASS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REV. 6 JULY 1986

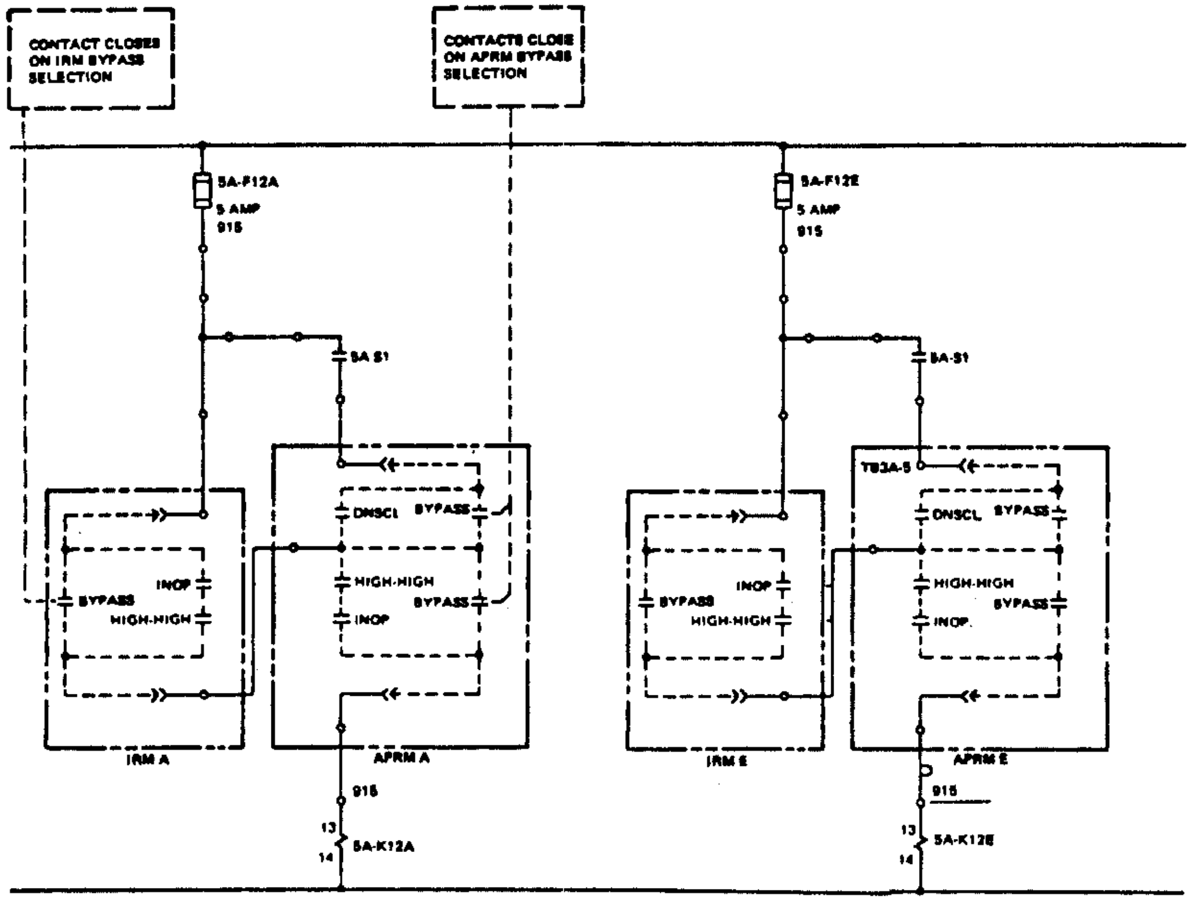


FIGURE 7.2-10
TRIP LOGIC FOR NEUTRON
MONITORING SYSTEM TRIP BYPASS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

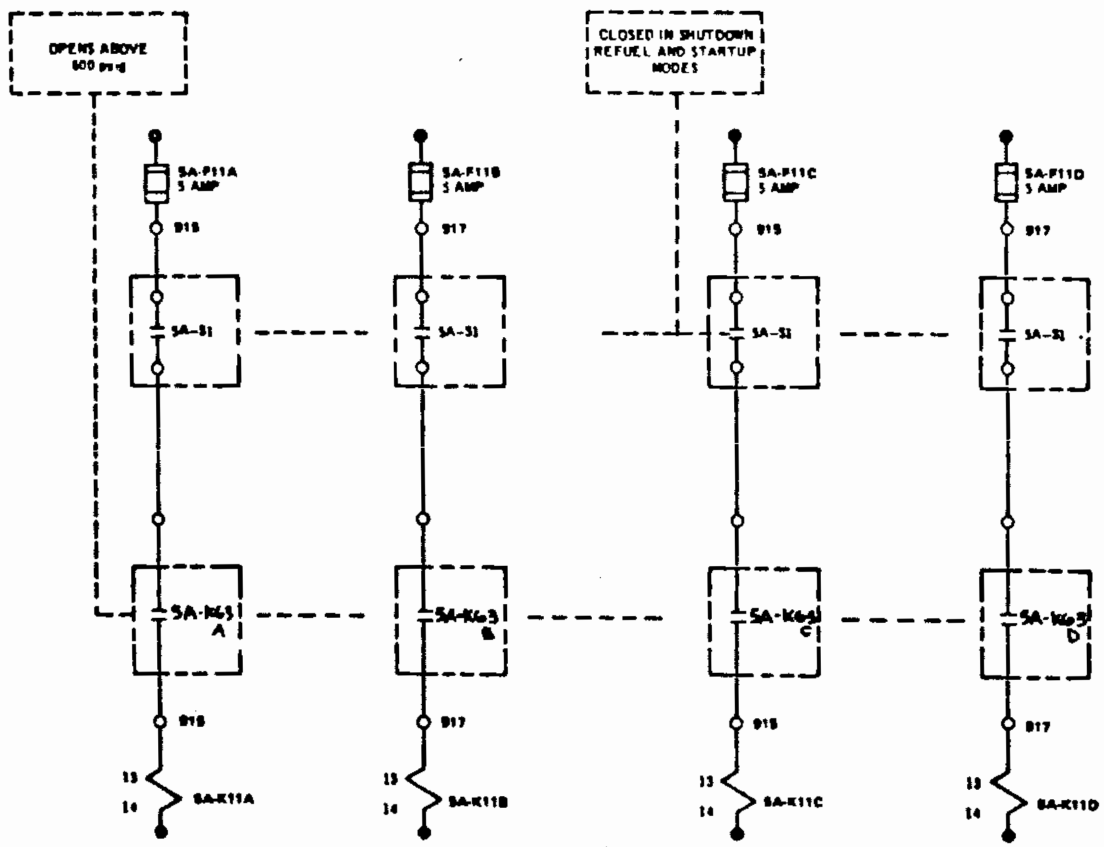


FIGURE 7.2-11
MAIN STEAM LINE
ISOLATION VALVE CLOSURE
TRIP BYPASS CHANNELS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 12– JANUARY 1991

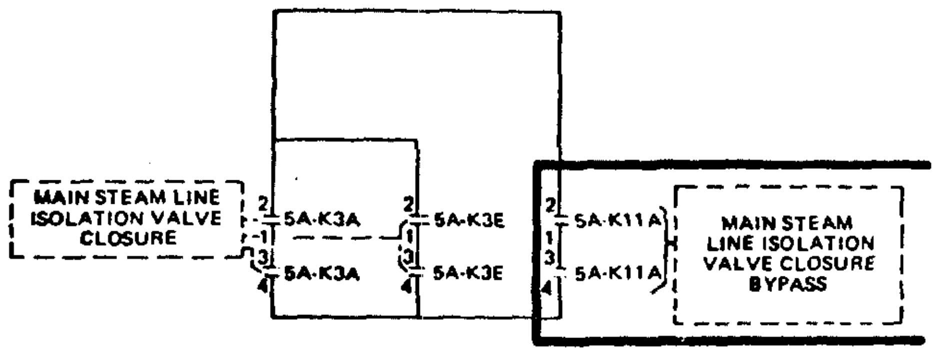


FIGURE 7. 2-12
TRIP LOGIC A1 FOR MAIN STEAM LINE ISOLATION VALVE CLOSURE BYPASS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

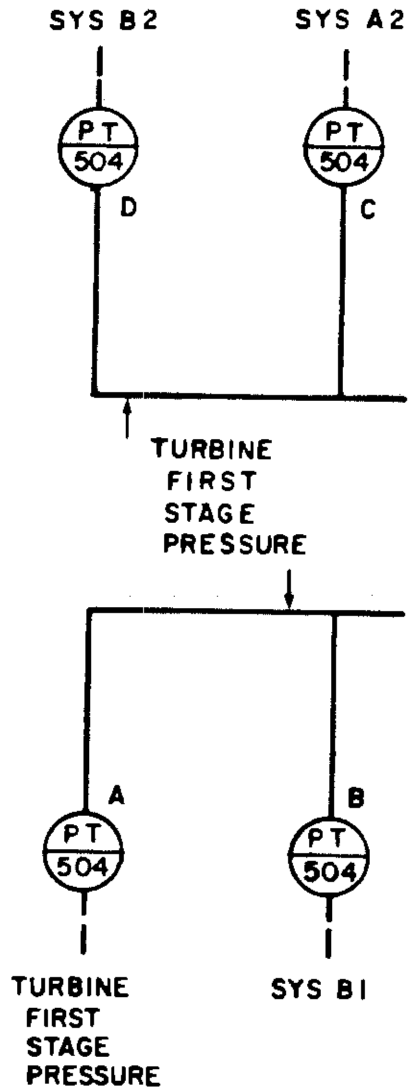


FIGURE 7.2-13
TURBINE FIRST STAGE
PRESSURE SENSORS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 12- JANUARY 1991

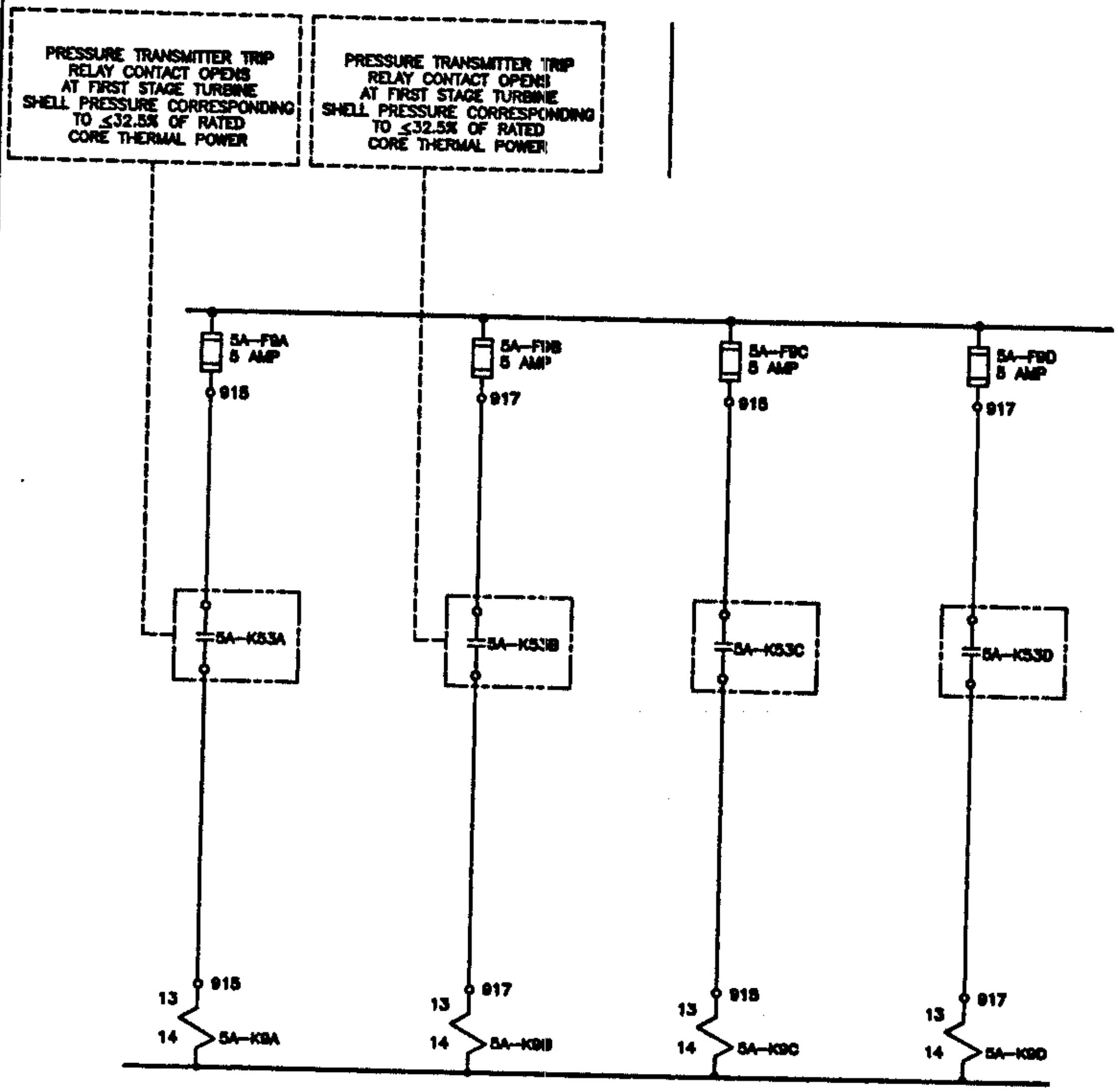


FIGURE 7.2-14

TRIP BYPASS CHANNELS FOR TURBINE STOP VALVE AND CONTROL VALVE FAST CLOSURE TRIP BYPASS

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT

Revision 25 – October 2005

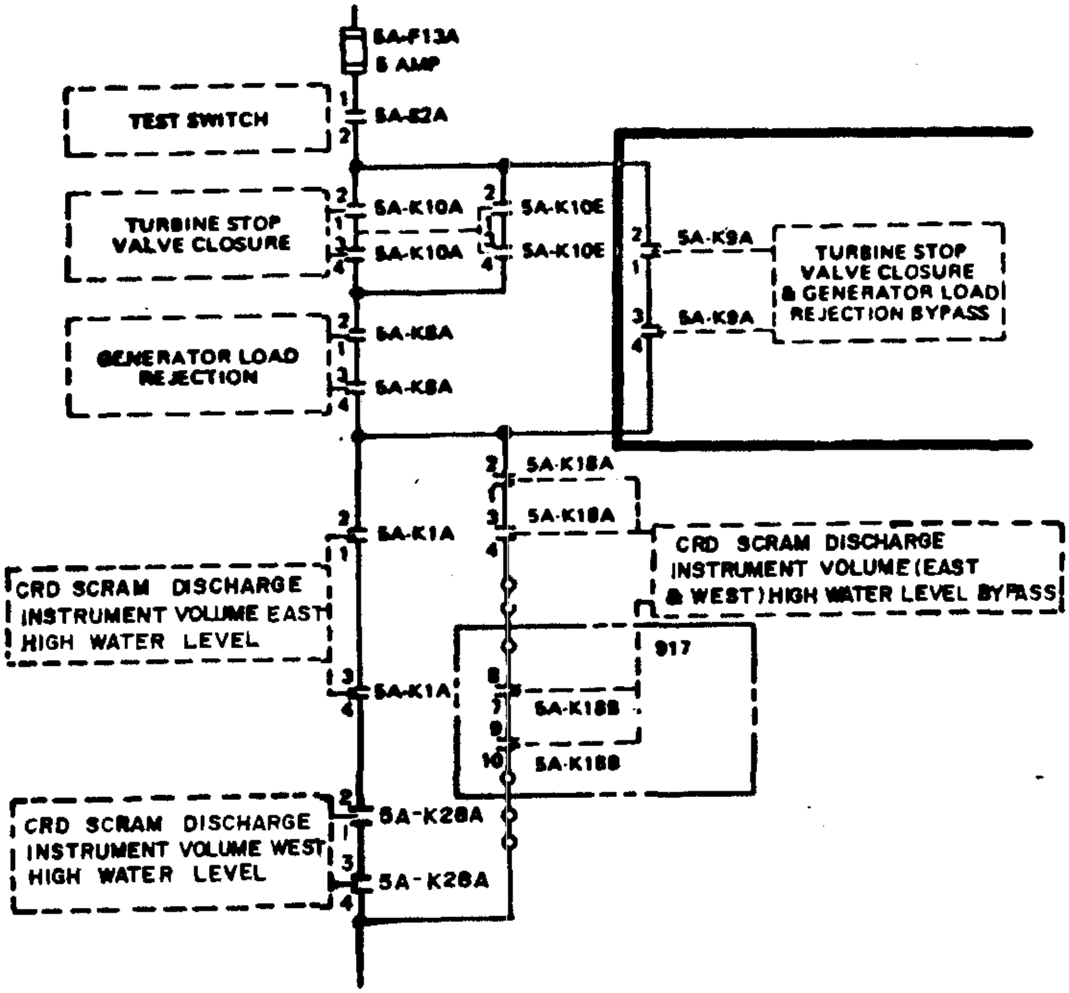


FIGURE 7.2-15
TRIP LOGIC A 1 FOR TURBINE STOP VALVE AND CONTROL VALVE FAST CLOSURE TRIP BYPASS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REV. 6 JULY 1986

Figure 7.2-16 has been removed.

Please refer to BECo Controlled Drawing M1P 7-5.

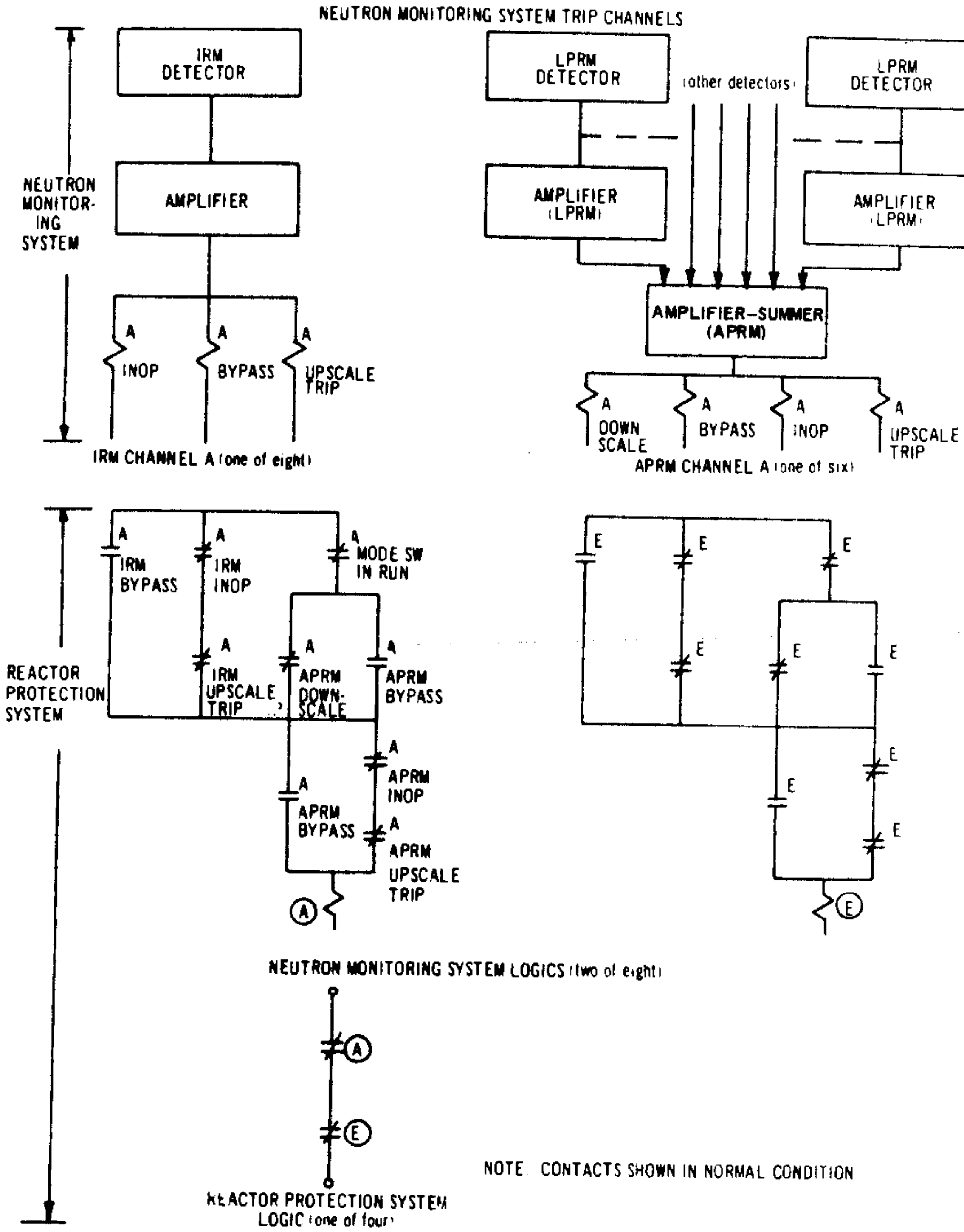


FIGURE 7.2-17
RELATIONSHIP BETWEEN NEUTRON MONITORING SYSTEM AND REACTOR PROTECTION SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

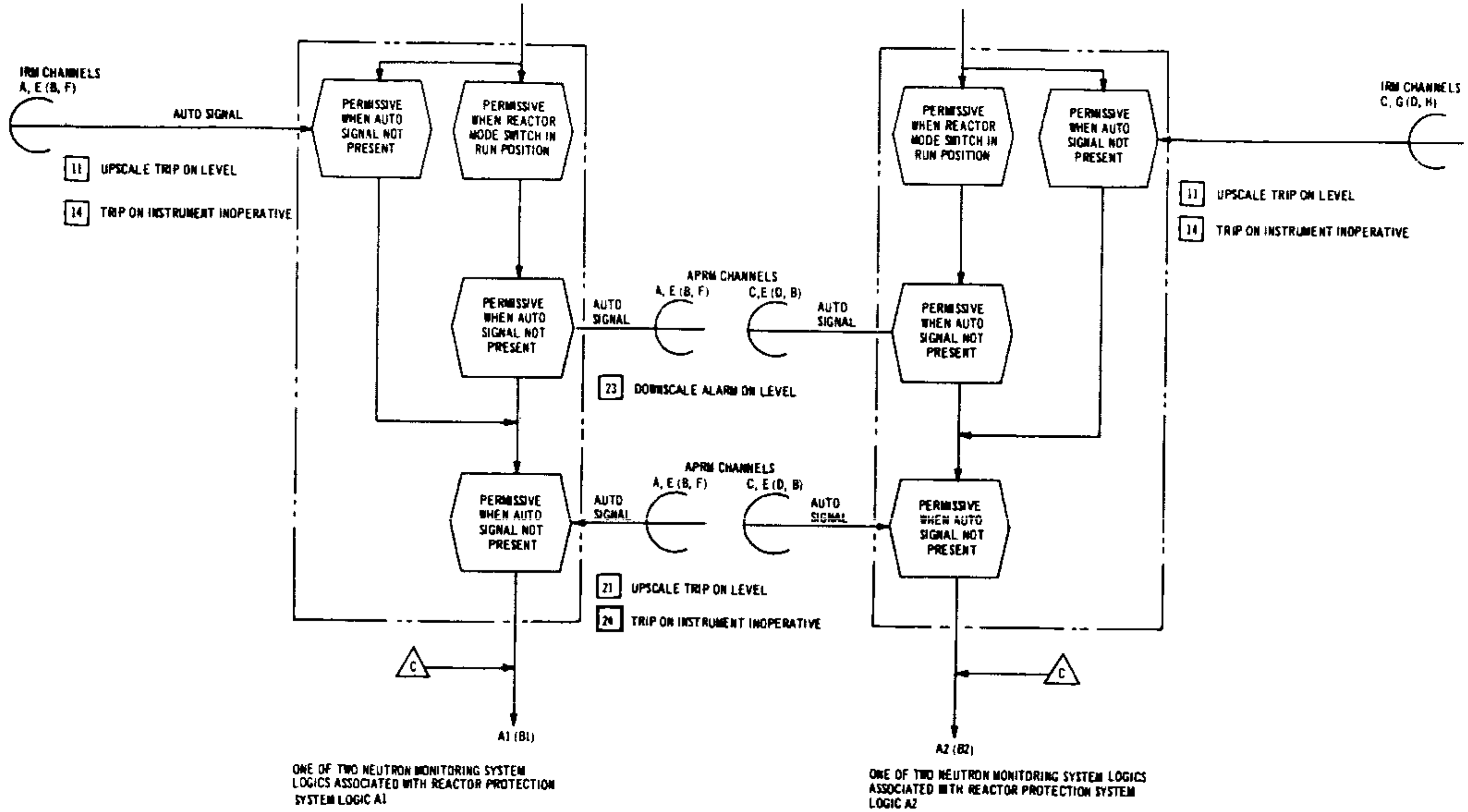
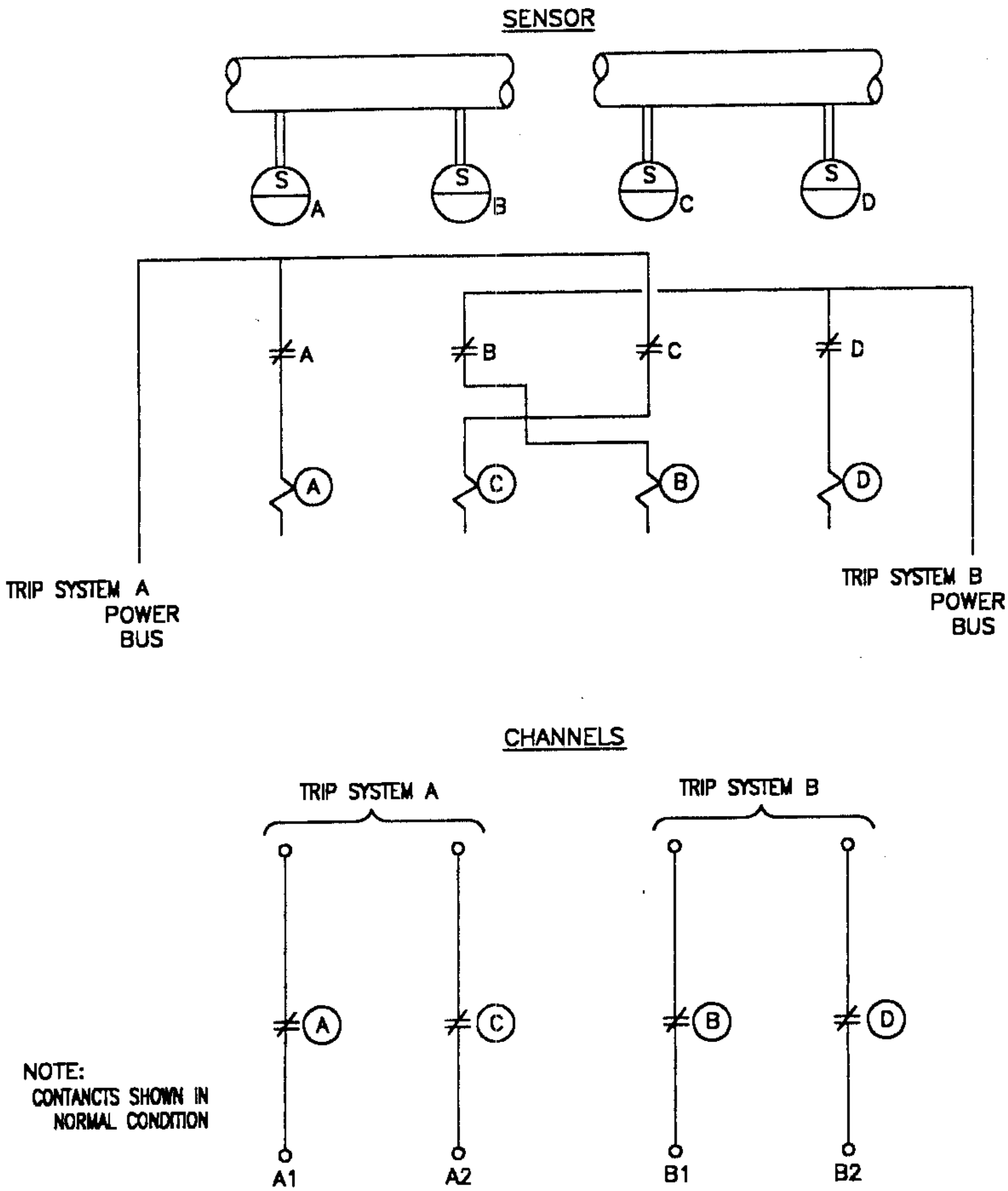


FIGURE 7.2-18
FUNCTIONAL CONTROL DIAGRAM FOR NEUTRON MONITORING SYSTEM LOGICS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



REACTOR PROTECTION SYSTEM LOGICS

TYPICAL CONFIGURATION FOR
SCRAM DISCHARGE INSTRUMENT VOLUME
HIGH WATER LEVEL (EAST & WEST)
TURBINE–CONTROL VALVE FAST CLOSURE
REACTOR VESSEL LOW WATER LEVEL

MAIN STEAM LINE HIGH RADIATION
PRIMARY CONTAINMENT HIGH PRESSURE
NUCLEAR SYSTEM HIGH PRESSURE

FIGURE 7.2–19
TYPICAL ARRANGEMENT OF CHANNELS AND LOGICS

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 17 – June 1995

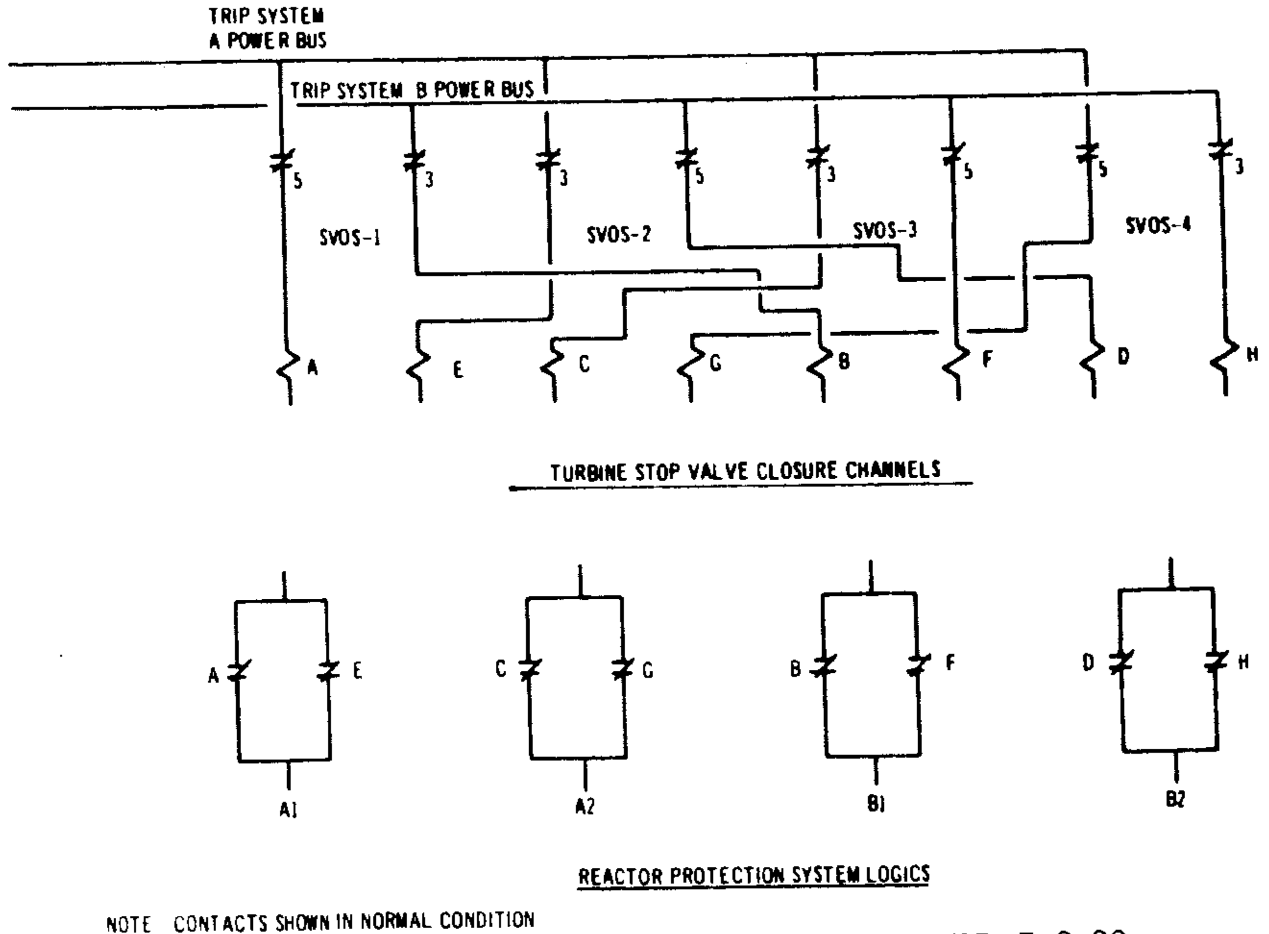
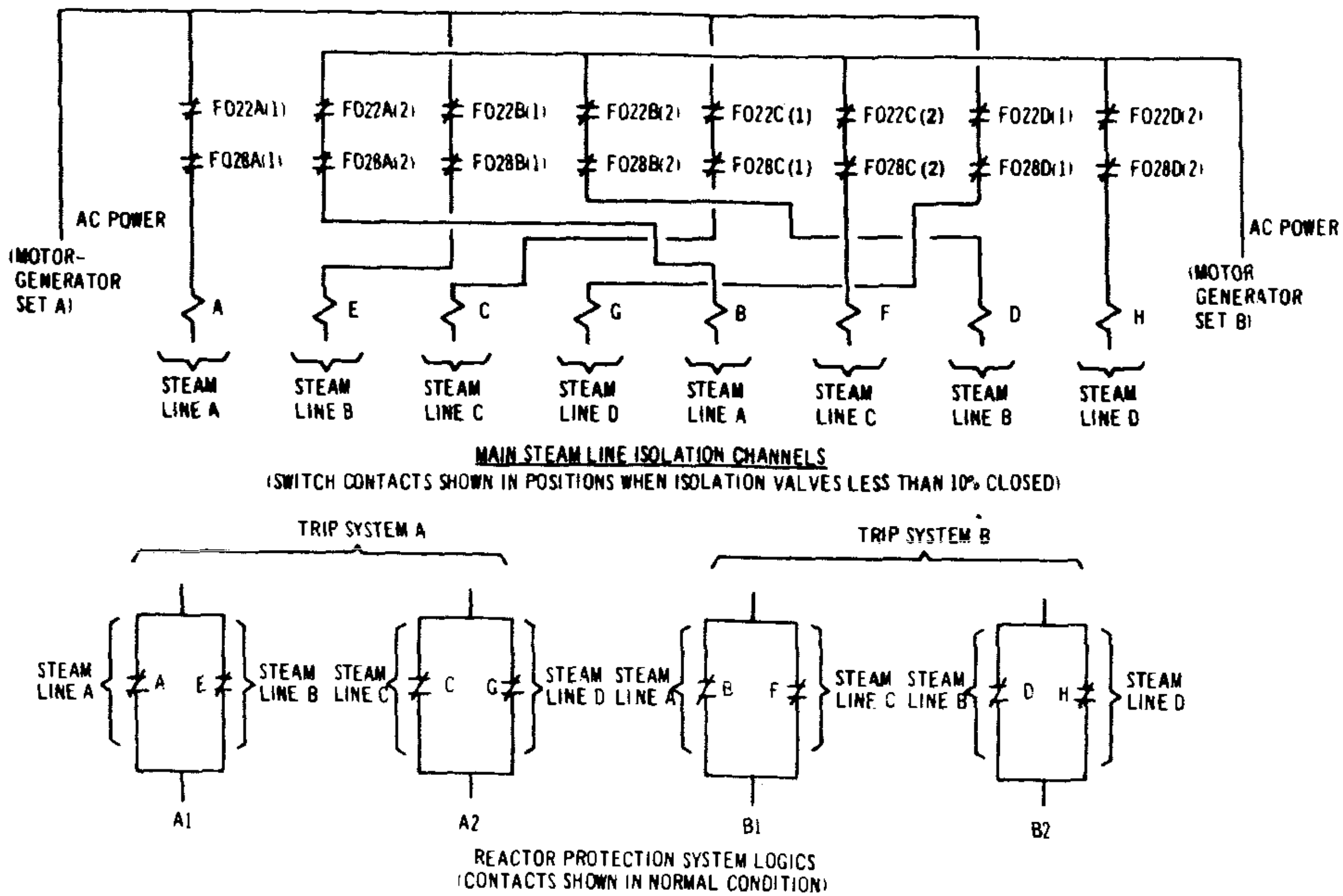


FIGURE 7. 2-20
TYPICAL CONFIGURATION FOR
TURBINE STOP VALVE
CLOSURE SCRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



KEY: F022A - STEAM LINE A, INBOARD VALVE
F028A - STEAM LINE A, OUTBOARD VALVE
F022B - STEAM LINE B, INBOARD VALVE
F028B - STEAM LINE B, OUTBOARD VALVE
F022C - STEAM LINE C, INBOARD VALVE
F028C - STEAM LINE C, OUTBOARD VALVE
F022D - STEAM LINE D, INBOARD VALVE
F028D - STEAM LINE D, OUTBOARD VALVE

FIGURE 7.2-21
TYPICAL CONFIGURATION FOR MAIN STEAMLINE ISOLATION SCRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 7.2-22 has been deleted.

Figure 7.2-23 has been deleted.

Figure 7.2-24 has been deleted.

Figure 7.2-25 has been deleted.

7.3 PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM

7.3.1 Safety Objective

To provide timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barrier, the Primary Containment and Reactor Vessel Isolation Control System initiates automatic isolation of appropriate pipelines which penetrate the primary containment whenever monitored variables exceed preselected operational limits.

A gross failure of the fuel barrier would allow the escape of fission products from the fuel. A gross failure of the nuclear system process barrier could allow the escape of gross amounts of reactor coolant. The loss of coolant could lead to overheating and failure of the fuel. For a gross failure of the fuel, the Primary Containment and Reactor Vessel Isolation Control System initiates isolation of the reactor vessel to contain released fission products. For a gross breach in the nuclear system process barrier outside the primary containment, the Isolation Control System acts to interpose additional barriers (isolation valve closure) between the reactor and the breach, thus stopping the release of radioactive materials and conserving reactor coolant. For gross breaches in the nuclear system process barrier inside the primary containment, the Primary Containment and Reactor Vessel Isolation Control System acts to close off release routes through the primary containment barrier, thus trapping the radioactive material coming through the breach inside the primary containment.

7.3.2 Definitions

See FSAR Section 5.2.3.5.1 for the primary containment isolation valve classes.

7.3.3 Safety Design Bases

1. To limit the uncontrolled release of radioactive materials to the environs, the Primary Containment and Reactor Vessel Isolation Control System shall, with precision and reliability, initiate timely isolation of penetrations through the primary containment structure which could otherwise allow the uncontrolled release of radioactive materials whenever the values of monitored variables exceed preselected operational limits.

2. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design basis 1, the Primary Containment and Reactor Vessel Isolation Control Systems shall respond correctly to the sensed variables over the expected range of magnitudes and rates of change.

3. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design basis 1, an adequate number of sensors shall be

provided for monitoring essential variables that have spatial dependence.

4. To provide assurance that conditions indicative of a gross failure of the nuclear system process barrier are detected with sufficient timeliness and precision to fulfill safety design basis 1, the Primary Containment and Reactor Vessel Isolation Control System inputs shall be derived, to the extent feasible and practical, from variables that are true, direct measures of operational conditions.

5. The time required for closure of the main steam line isolation valves shall be short, so that the release of radioactive material and the loss of coolant as a result of a breach of a steam line outside the primary containment are minimal.

6. The time required for closure of the main steam isolation valves shall not be so short that inadvertent isolation of steam lines causes excessive fuel damage or excessive nuclear system pressure. This basis ensures that the main steam isolation valve closure speed is compatible with the ability of the Reactor Protection System (RPS), and Pressure Relief System to protect the fuel and nuclear system process barrier.

7. To provide assurance that closure of Class A and Class B automatic isolation valves is initiated, when required, with sufficient reliability to fulfill safety design basis 1, the following safety design bases shall be specified for the systems controlling Class A and Class B automatic isolation valves:

    a. No single failure within the Isolation Control System shall prevent isolation action when required to satisfy safety design basis 1

    b. Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability shall not impair the functional ability of the Isolation Control System to respond correctly to essential monitored variables

    c. The system shall be designed for a high probability that, when any essential monitored variable exceeds the isolation setpoint, the event shall either result in automatic isolation or shall not impair the ability of the system to respond correctly as other monitored variables exceed their trip points

    d. Where a plant condition that requires isolation can be brought on by a failure or malfunction of a control or regulating system, and the same failure or malfunction prevents action by one or more Isolation Control System channels designed to provide protection against the unsafe condition, the remaining portions of the Isolation Control

System shall meet the requirements of safety design bases 1, 2, 3, and 7a

e. The power supplies for the Primary Containment and Reactor Vessel Isolation Control System shall be arranged so that loss of one supply cannot prevent automatic isolation when required

f. The system shall be designed so that, once initiated, automatic isolation action goes to completion. Return to normal operation after isolation action shall require deliberate operator action

g. There shall be sufficient electrical and physical separation between trip channels monitoring the same essential variable to prevent environmental factors, electrical faults, and physical events from impairing the ability of the system to respond correctly

h. Earthquake ground motions shall not impair the ability of the Primary Containment and Reactor Vessel Isolation Control System to initiate automatic isolation. See Section 7.1.6

8. To assure that the timely isolation of main steam lines is accomplished, when required, with extraordinary reliability, the following safety design bases are specified:

   a. The motive force for achieving valve closure for one of the two tandem mounted isolation valves in an individual steam line shall be derived from a different energy source than that for the other valve

   b. At least one of the isolation valves in each of the steam lines shall not rely on continuity of any variety of electrical power for the motive force to achieve closure

9. To reduce the probability that the operational reliability and precision of the Primary Containment and Reactor Vessel Isolation Control System will be degraded by operator error, the following safety design bases are specified for Class A and Class B automatic isolation valves:

   a. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables shall be under the control of the control room operator or other supervisory personnel

   b. The means for bypassing channels, logics, or system components shall be under the control of

the control room operator. If the ability to trip some essential part of the system has been bypassed, this fact will be continuously indicated in the control room

10. To provide the operator with means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier, it shall be possible for the control room operator to manually initiate isolation of the primary containment and reactor vessel.

11. To provide the operator with the means to assess the condition of the primary containment and Reactor Vessel Isolation Control System, and to identify conditions indicative of a gross failure of the nuclear system process barrier, the following bases shall be specified:

    a. The Primary Containment and Reactor Vessel Isolation Control System shall be designed to provide the operator with information pertinent to the status of the system

    b. Means shall be provided for prompt identification of channel and trip system responses

12. It shall be possible to check the operational availability of each essential channel, logic, and trip system during reactor operation.

7.3.4 Description

7.3.4.1 Identification

The primary containment and reactor vessel isolation control system includes the sensors, channels, switches, and remotely activated valve closing mechanisms associated with the valves, which, when closed, effect isolation of the primary containment or reactor vessel, or both. It should be noted that the control systems for those Class A and B isolation valves which close by automatic action pursuant to the safety design bases are the main subjects of this section. However, Class C remotely operated isolation valves are included because they add to the operator's ability to effect manual isolation. Testable check valves are also included because they provide the operator with an ability to check that the valve disk can respond to reverse flow. The primary containment and reactor vessel isolation control system is designed to comply with the intent of IEEE-279 and the Commission's Proposed General Design Criteria. Refer to Appendix F and Appendix J for additional details.

7.3.4.2 Power Supply

The power for the channels and logics of the isolation control system is supplied from the RPS motor generator sets, the station batteries and the unit preferred power system. Isolation valves

receive power from standby power sources. Power for the operation of two valves in a pipeline is fed from different sources. In most cases one valve is powered from an ac bus of appropriate voltage, and the other valve is powered by dc from the station batteries. The main steam isolation valves, described in detail later, use ac, dc, and pneumatic pressure in the control scheme. Table 5.2-4 lists the power supply for each isolation valve.

7.3.4.3 Physical Arrangement

Table 5.2-4 lists the pipelines that penetrate the primary containment and indicates the types and locations of the isolation valves installed in each pipeline. Figure 4.3-2 (BECo M252) identifies some of these pipelines. Pipelines which penetrate the primary containment and directly communicate with the reactor vessel generally have two Class A isolation valves, one inside the primary containment and one outside the primary containment. Pipelines which penetrate the primary containment and which communicate with the primary containment free space, but which do not communicate directly with the reactor vessel, generally have two Class B isolation valves located outside the primary containment. Class A and Class B automatic isolation valves are considered essential for protection against the gross release of radioactive material in the event of a breach in the nuclear system process barrier. Process pipelines that penetrate the primary containment, but do not communicate directly with the reactor vessel, the primary containment free space, or the environs, have at least one Class C isolation valve located outside the primary containment which may close either by process action (reverse flow) or by remote manual operation. Table 5.2-4 presents information about all piping penetrations in the primary containment. Only the controls for the automatic isolation valves are discussed in this part of the safety analysis report. The valves, which are the subject of this text, are specifically identified in the detailed descriptions which follow.

Power cables are run in conduits or trays from appropriate electrical sources to the motor or solenoid involved in the operation of each isolation valve. The control arrangement for the main steam line isolation valves includes pneumatic piping and an accumulator for those valves for which air is considered the emergency source of motive power for closing. Pressure and water level sensors are mounted on instrument racks in either the reactor building or the turbine building. Valve position switches are mounted on the valve for which position is to be indicated. Switches are enclosed in cases to protect them from environmental conditions. Cables from each sensor are routed in conduits and cable trays to the control room. All signals transmitted to the control room are electrical; no pipe from the nuclear system or the primary containment penetrates the control room. Pipes used to transmit level information from the reactor vessel to sensing instruments terminate inside the secondary containment (reactor building). The sensor cables and power supply cables are routed to cabinets in the cable spreading room and control room where the logic arrangement of the system is formed.

To ensure continued protection against the uncontrolled release of radioactive material during and after earthquake ground motions, the control systems required for the automatic closure of Class A and Class B valves are designed as Class 1 equipment as described in Section 12 and Appendix C. This meets safety design basis 7h.

7.3.4.4 Logic

The basic logic arrangement for essential trip functions is one in which an automatic isolation valve is controlled by two trip systems. Where many isolation valves close on the same signal, two trip systems control the entire group. Where just one or two valves must close in response to a special signal, two trip systems may be formed from the instruments provided to sense the special condition. Valves that respond to the signals from common trip systems are identified in the detailed descriptions of isolation functions.

Each trip system has a pair of logics. Each logic receives input signals from at least one channel for each monitored variable. Thus, two channels are required for each essential monitored variable to provide independent inputs to the logic of one trip system. A total of four channels for each essential monitored variable is required for the logics of both trip systems. This description is not applicable to the HPCI and RCIC steam supply low pressure isolation logics. These logics provide an operational interlock and are not intended to perform a primary containment isolation function. Figures 7.3-2 and 7.3-3 illustrate typical isolation control arrangements for motor-operated valves and for the main steam line isolation valves.

The actuators associated with one logic pair provide inputs into each of the actuator logics for that trip system. Thus, either of the two logics associated with one trip system can produce a trip system trip. The logic is a 1-out-of-m arrangement, where m may be 2 or more.

To initiate valve closure, the actuator logics of both trip systems must be tripped. The overall logic of the system could be termed one-out-of-two taken twice.

The basic logic arrangement just described does not apply to Class C isolation valves and testable check valves. Exceptions to the basic logic arrangement are made in several instances for certain Class A and Class B isolation valves as described below.

7.3.4.5 Operation

During normal operation of the station, when isolation is not required, sensor and trip contacts essential to safety are closed; channels, and trip logics are normally energized. Whenever a channel sensor contact opens, its auxiliary relay deenergizes, causing contacts in the trip logic to open. The opening of contacts in the logic deenergizes its actuator. When deenergized, the actuator trip relay opens a contact in an actuator logic. If a trip then occurs in either of the logic pairs of the other trip system, another actuator logic is deenergized. With both trip systems

tripped, appropriate contacts open or close in valve control circuitry to actuate the valve closing mechanism. Automatic isolation valves that are normally closed receive the isolation signal as well as those valves that are open. This fail safe logic is not applicable to the HPCI and RCIC systems since these systems may be required to perform a safety function during a loss of AC power. HPCI and RCIC isolation logics are therefore DC powered and energize to actuate. Additionally, RHR isolation (Group III) is not entirely fail-safe since it must perform its safety function during a loss of AC power and therefore isolation logic is DC powered and energize to actuate. The control system for each Class A isolation valve is designed to provide closure of the valve in time to prevent uncovering the fuel as a result of a break in the pipeline which the valve isolates. The control systems for Class A and Class B isolation valves are designed to provide closure of the valves with sufficient rapidity to restrict the release of radioactive material to the environs below the guideline values of applicable regulations.

All automatic Class A and Class B valves and remotely operable Class C valves can be closed by manipulating switches in the control room, thus providing the operator with means independent of the automatic isolation functions to take action in the event of a failure of the nuclear system process barrier. This meets safety design basis 10.

Once isolation is initiated, the valve continues to close, even if the condition that caused isolation is restored to normal. The operator must manually operate switches in the control room to reopen a valve which has been automatically closed. Unless manual override features are provided in the manual control circuitry, the operator cannot reopen the valve until the conditions which initiated isolation have cleared. This is the equivalent of a manual reset and meets safety design basis 7f.

A trip of an isolation trip system channel is annunciated in the control room so that the operator is immediately informed of the condition. The response of isolation valves is indicated by "open-closed" lights. All motor-operated Class A and Class B isolation valves whose primary function is to isolate, have two sets of "open-closed" lights. One set is located near the manual control switches for controlling each valve from the control room panel. A second set is located in a separate central isolation valve position display in the control room. The positions of air-operated isolation valves are displayed in the same manner as motor-operated valves.

Inputs to annunciators, indicators, and the computer are arranged so that no malfunction of the annunciating, indicating, or computing equipment can functionally disable the system. Signals directly from the isolation control system sensors are not used as inputs to annunciating or data logging equipment. Isolation is provided between the primary signal and the information output. The arrangement of indications pertinent to the status and response of the primary containment and reactor vessel isolation control system satisfies safety design bases 11a and 11b.

The control room indication provided to assess the condition of the isolation control system satisfies IEEE-279 paragraphs 4.19 and 4.20 in the following manner:

1. Identification of Protection Actions (IEEE-279 paragraph 4.19)

Protective actions (here interpreted to mean dropout of a single sensor relay) are directly indicated and identified by action of the sensor relay. The relay has an identification tag and a clear glass front window that permits convenient visible verification of the relay position. Any one of the sensor relays also actuates an annunciator, so that no single channel "trip" (relay dropout) will go unnoticed. Either of these indications (annunciation and visible verification relay actuation) fulfills the requirements of this criterion

2. Information Readout (IEEE-279 paragraph 4.20)

The information presented to the operator by the primary containment and reactor vessel isolation control system are:

a. Annunciation of each process variable which has reached a trip point

b. Relay position for trips on main steam line tunnel temperature or main steam line excess flow

c. Control power failure annunciation on each channel

d. Annunciation of steam leaks in each of the five systems monitored, i.e., main steam, reactor water cleanup, residual heat removal (RHR), high pressure coolant injection (HPCI), and reactor core isolation coolant (RCIC)

e. Open and closed position lights for each isolation valve

f. Drywell pressure and temperature indicators

g. Torus water temperature

h. Torus water level

Additional information is available to the operator for monitoring reactor vessel pressure, reactor vessel water level, neutron flux, and control rod positions

7.3.4.6 Isolation Valve Closing Devices and Circuits

Table 7.3-1 itemizes the type of closing device provided for each isolation valve intended for use in automatic or remote manual isolation of the primary containment or reactor vessel. To meet the requirement that automatic Class A valves be fully closed in time to prevent the reactor vessel water level from falling below the top of the active fuel as a result of a break of the pipeline which the valve isolates, the valve closing mechanisms are designed to give

the closing rates specified on Table 7.3-1. In many cases a "standard" closing rate is adequate to meet isolation requirements. Because of the relatively long time required for fission products to reach the containment atmosphere following a break in the nuclear system process barrier inside the primary containment, a "standard" closure rate is adequate for the automatic closing devices on Class B isolation valves.

Motor operators for Class A and Class B isolation valves are selected with capabilities suitable to the physical and environmental requirements of service. The required valve closing rates were considered in designing motor operators. Appropriate torque and limit switches are used to ensure proper valve seating. Handwheels, which are automatically disengaged from the motor operator when the motor is energized, are provided for local manual operation.

Direct solenoid operated isolation valves and solenoid air pilot valves are chosen with electrical and mechanical characteristics which make them suitable for the service for which they are intended. Appropriate watertight or weathertight housings are used to ensure proper operation under accident conditions.

Closure of the isolation valve in the pneumatic supply line to the drywell is annunciated to alert the operator as to the loss of air condition.

The main steam isolation valves are spring closing, pneumatic, piston operated valves designed to close upon loss of pneumatic pressure to the valve operator. This is a fail safe design. The control arrangement is shown on Figures 7.3-3 and 7.3-4. Closure time for the valves is adjusted between 3 and 5 sec. Each valve is piloted by two, three-way, packless, direct acting, solenoid-operated pilot valves: one powered by AC, the other by DC. An accumulator is located close to each isolation valve to provide pneumatic pressure for valve operation to preclude challenges to ECCS due to inadvertent air loss during operation.

The valve pilot system and the pneumatic pipe lines are arranged so that, when one or both solenoid-operated pilot valves are energized, normal air supply provides pneumatic pressure to the air-operated pilot valve to direct air pressure to the main valve pneumatic operator. This overcomes the closing force exerted by the spring. When both pilots are deenergized, as would be the result of both trip systems tripping or placing the manual switch in the closed position, the path through which air pressure acts is switched so that the opposite side of the valve operator is pressurized, thus assisting the spring in closing the valve. In the event of air supply failure, the loss of air pressure will cause the air operated pilot valve to move by spring force to the position resulting in main valve closure. Main valve closure is then effected by means of the air stored in the accumulator and by the spring.

Air pressure, acting alone, and the force exerted by the spring, acting alone, are each capable of independently closing the valve. The isolation valves inside the primary containment (inboard) are

designed to close under either pneumatic pressure or spring force with the vented side of the piston operator at the containment peak accident pressure. The outboard valve is exactly the same design, although it will be subjected only to atmospheric pressures. The accumulator volume was chosen to provide enough pressure to close the valve when the pneumatic supply to the accumulator has failed. The supply line to the accumulator is large enough to make up pressure to the accumulator at a rate faster than the valve operation bleeds pressure from the accumulator during valve opening or closing.

A separate, single, solenoid-operated pilot valve with an independent test switch is included to allow manual testing of each isolation valve from the control room. The testing arrangement is designed to give a slow closure of the isolation valve being tested to avoid rapid changes in steam flow and nuclear system pressure. Slow closure of a valve during testing requires 50 to 60 seconds. The valve mechanical design is discussed further in Section 4.6, Main Steam Line Isolation Valves (MSIVs).

Four additional keylock switches (one for each logic channel) are provided to facilitate testing of the MSIV pilot valve logic circuits.

7.3.4.7 Isolation Functions and Settings

The isolation allowable setpoints of the Primary Containment and Reactor Vessel Isolation Control System are listed on Table 7.3-2. The functions that initiate automatic isolation are itemized on Table 7.3-1 in terms of the pipelines that penetrate the primary containment. This latter table includes all pipelines of concern for isolation purposes. Although this section is concerned with the electrical control systems that initiate isolation to prevent direct release of radioactive material from the primary containment or nuclear system process barrier, the additional information given on Table 7.3-1 can be used to assess the overall (electrical and mechanical) isolation effectiveness of each system having pipelines which penetrate the primary containment. Isolation functions and trip settings used for the electrical control of isolation valves in fulfillment of the previously stated safety design bases are discussed in the following paragraphs. The role each isolation function plays in initiating isolation of barrier valves or groups of valves is illustrated in the functional control diagrams on Figures 7.3-5 and 7.3-6.

1. Reactor Vessel Low Water Level

   A low water level in the reactor vessel could indicate that either reactor coolant is being lost through a breach in the nuclear system process barrier, or that the normal supply of reactor feedwater has been lost and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes. Reactor vessel low water level initiates closure of various Class A and Class B valves. The closure of Class A valves is intended to either isolate a breach in any of the

pipelines in which valves are closed or conserve reactor coolant by closing off process lines. The closure of Class B valves is intended to prevent the escape of radioactive materials from the primary containment through process lines which are in communication with the primary containment free space.

Two reactor vessel low water level isolation trip settings are used to complete the isolation of the primary containment and the reactor vessel. See Table 7.3-1, Signals A and B. The first reactor vessel low water level isolation trip setting, which occurs at a higher water level than the second setting, initiates closure of all Class A and Class B valves in major process pipelines except the main steam lines. The main steam lines are left open to allow the removal of heat from the reactor core. The second and lower reactor vessel low water level isolation trip setting completes the isolation of the primary containment and reactor vessel by initiating closure of the main steam isolation valves, and any other Class A or Class B valves that must be shut to isolate minor process lines.

The first low water level setting, which is coincidentally the same as the reactor vessel low water level scram setting, was selected to initiate isolation at the earliest indication of a possible breach in the nuclear system process barrier, yet far enough below normal operational levels to avoid spurious isolation. Isolation of the following pipelines is initiated when reactor vessel low water level falls to this first setting.

Torus Vacuum Breakers

Traversing incore probe

RHR reactor shutdown cooling suction

Reactor water sample lines

Drywell equipment drain sump discharge

Drywell floor drain sump discharge

Reactor water cleanup

Drywell purge inlet and makeup gas*, **

Drywell main exhaust

Suppression chamber exhaust valve bypass*, **

Suppression chamber purge inlet and makeup gas*, **

Suppression chamber main exhaust

Drywell exhaust valve bypass*, **

RHR-LPCI supply

RHR to Radwaste

Containment atmosphere sampling lines

* Containment makeup and ventilation valves are also provided for use following an accident condition. These are remote manual operated. Refer to Section 5.4.3.

** The reactor water low level isolation signal can be bypassed. These valves may be opened anytime provided the low-low water level signal is not present.

The second and lower of the reactor vessel low water level isolation settings was selected low enough to allow the removal of heat from the reactor for a predetermined time following the scram, and high enough to complete isolation in time for the operation of CSCS in the event of a large break in the nuclear system process barrier. This second low water level setting is low enough that partial losses of feedwater supply would not unnecessarily initiate full isolation of the reactor, thereby disrupting normal shutdown or recovery procedures. Isolation of the following pipelines is initiated when the reactor vessel water level falls into this second setting.

All four main steam lines:

Main steam line drain

Reactor water sample line

A high water level in the reactor vessel indicates that the reactor is overfilled and the steam lines are in danger of being flooded with water. The high water level isolation signal is to protect against rapid depressurization due to a malfunction of the pressure regulator system during start-up when pressure is below 782 psig. This high water level isolation is not functional when the mode switch is in the run position. The reactor high water level initiates isolation of:

All four main steam lines:

Main steam line drain

Reactor water sample line

Reactor vessel high water level also shuts down the RCIC and HPCI turbines. Refer to Sections 4.7 and 7.4, respectively.

2. Deleted

3. Main Steam Line Space High Temperature

High temperature in the space in which the main steam lines are located outside of the primary containment could indicate a breach in a main steam line. The automatic closure of various Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperatures occur in the main steam line space, the following pipelines are isolated. (See Table 7.3-1, Signal D):

All four main steam lines

Main steam line drain

Reactor water sample line

The main steam line space high temperature trip is set far enough above the temperature expected during operations at rated power to avoid spurious isolation, yet low enough to provide early indication of a steam line break.

4. Main Steam Line High Flow

Main steam line high flow could indicate a break in a main steam line. The automatic closure of various Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. Upon detection of main steam line high flow, the following pipelines are isolated:

All four main steam lines

Main steam line drain

Reactor water sample line

The main steam line high flow trip setting is selected high enough to permit the isolation of one main steam line for test at rated power without causing an automatic isolation of the rest of the steam lines, yet low enough to permit early detection of a steam line break. See Table 7.3-1, Signal D.

5. Low Steam Presssure at Turbine Inlet

Low steam pressure at the turbine inlet while the reactor is operating could indicate a malfunction of the nuclear system pressure regulator in which the turbine control valves or turbine bypass valves open fully. See Table 7.3-1, Signal P.

The termal stresses associated with excessive depressurization could result in a significant increase in the nuclear system process barrier's lifetime fatigue usage factor. Also, excessive depressurization would permit sufficient level swell to trap water in the main steamline between the in-board MSIVs and the SRVs, requiring SRVs to discharge either liquid or

two-phase flow. SRVs are only designed for saturated steam with less than 1% moisture.

A rapid depressurization of the reactor vessel while the reactor is near full power could also result in undesirable differential pressures across the channel around some fuel bundles of sufficient magnitude to cause mechanical deformation of channel walls. Such depressurizations, without adequate preventative action, could require thorough vessel analysis or core inspection prior to returning the reactor to power operation. To avoid excessive depressurization, the steam pressure at the turbine inlet is monitored and upon falling below a preselected value with the reactor in the RUN mode initiates isolation of the following pipelines:

All four main steam lines

Main steam drain line

Reactor water sample line

The low steam pressure isolation setting is selected far enough below normal turbine inlet pressures to avoid spurious isolation yet high enough to provide timely detection of a pressure regulator malfunction. Although this isolation function is not required to satisfy any of the safety design bases for this system, this discussion is included here to make the listing of isolation functions complete.

An evaluation that demonstrates the adequacy of the isolation setting of 750 psig is included in Reference 1. The actual analytical limit is calculated to be 782 psig.

6. Primary Containment (drywell) High Pressure

High pressure in the drywell could indicate a breach of the nuclear system process barrier inside the drywell. The automatic closure of various Class B valves prevents the release of significant amounts of radioactive material from the primary containment. Upon detection of a high drywell pressure, the following pipelines are isolated. See Table 7.3-1, Signal F.

Torus Vacuum Breakers

Traversing incore probe

RHR shutdown cooling suction

Reactor water sample lines

Drywell equipment drain sump discharge

Drywell floor drain sump discharge

Drywell purge inlet and makeup gas*, **

Drywell main exhaust

Suppression chamber exhaust valve bypass*, **

Suppression chamber purge inlet and makeup gas*, **

Suppression chamber main exhaust

Drywell exhaust valve bypass*, **

RHR-LPCI supply

RHR to Radwaste

Containment atmosphere sampling lines

The primary containment high pressure isolation setting is selected to be as low as possible without inducing spurious isolation trips. See Table 7.3-1, Signal F.

* Containment makeup and ventilation valves are also provided for use following an accident condition. These are remote manual operated. Refer to Section 5.4.3.

** The reactor water low level isolation signal can be by-passed. These valves may be opened anytime provided the low-low water level signal is not present.

7. RCIC System Equipment Space High Temperature

High temperature in the vicinity of the RCIC System equipment could indicate a break in the RCIC steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperature occurs near the RCIC System equipment, the RCIC turbine steam line is isolated. The high temperature isolation setting is selected far enough above anticipated normal RCIC system operational levels to avoid spurious operation but low enough to provide timely detection of a RCIC turbine steam line break. See Table 7.3-1, Signal K.

8. RCIC Turbine High Steam Flow

RCIC turbine high steam flow could indicate a break in the RCIC turbine steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant, and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of RCIC system turbine high steam flow, the RCIC system turbine steam line is isolated. The high steam flow trip setting is selected high enough to avoid spurious isolation yet low enough to provide timely detection of a RCIC turbine steam line break. See Table 7.3-1, Signal K.

The logic arrangement used for this function is shown on Figure 7.3-7 and is an exception to the usual logic requirement because high steam flow is the second method of detecting a RCIC turbine steam line break.

9. RCIC Turbine Steam Line Low Pressure

   RCIC turbine steam line low pressure is used to automatically close the two isolation valves in the RCIC turbine steam line, so that steam and radioactive gases will not escape from the RCIC turbine shaft seals into the reactor building after steam pressure has decreased to such a low value that the turbine cannot be operated. The isolation setpoint is chosen at a pressure below that at which the RCIC turbine can operate effectively. This isolation is an operational interlock not required for safety. See Table 5.2-4, Signal K.

10. HPCI System Equipment Space High Temperature

   High temperature in the vicinity of the HPCI system equipment could indicate a break in the HPCI system turbine steam line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperature occurs near the HPCI system equipment, the HPCI system turbine steam supply line is isolated. The high temperature isolation setting is selected far enough above anticipated normal HPCI system operational levels to avoid spurious isolation, but low enough to provide timely detection of a HPCI turbine steam line break. See Table 5.2-4, Signal L.

11. HPCI Turbine High Steam Flow

   HPCI turbine high steam flow could indicate a break in the HPCI turbine steam line. The automatic closure of certain class A valves prevents the excessive loss of reactor coolant, and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of HPCI turbine high steam flow the HPCI turbine steam line is isolated. The high steam flow trip setting is selected high enough to avoid spurious isolation, yet low enough to provide timely detection of a HPCI turbine steam line break. See Table 5.2-4, Signal L.

   The logic arrangement used for this function, shown on Figure 7.3-7, is an exception to the usual logic requirement, because high steam flow is the second method of detecting a HPCI turbine steam line break.

12. Low Reactor Vessel Pressure

   Low reactor vessel pressure is used to automatically close the two isolation valves in the HPCI turbine steam line, so that steam and radioactive gases will not escape from the HPCI

turbine shaft seals into the reactor building after steam pressure has decreased to such a low value that the turbine cannot be operated. The isolation setpoint is chosen at a pressure below that where the HPCI turbine can operate efficiently. This isolation is an operational interlock not required for safety. See Table 5.2-4, Signal AA.

13. Reactor Water Cleanup System Space High Temperature

High temperature in the vicinity of the reactor water cleanup (RWCU) equipment and piping could indicate a break in a RWCU line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. When high temperature occurs near the RWCU equipment, the RWCU system is isolated. The high temperature isolation setting is selected far enough above anticipated normal system operational levels to avoid spurious isolation, yet low enough to provide timely detection of a line break. See Table 5.2-4, Signal J.

14. Reactor Water Cleanup System High Flow

RWCU high flow could indicate a break in a RWCU line. The automatic closure of certain Class A valves prevents the excessive loss of reactor coolant, and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of RWCU high flow, the RWCU line is isolated. The high flow trip setting and time delay setting were selected high enough to avoid spurious isolation, yet low enough to provide timely detection of line break. See Table 5.2-4, Signal J.

15. High Reactor Vessel Pressure

High reactor vessel pressure is used to automatically close the two isolation valves in the RHR pumps' shutdown cooling suction piping and the two isolation valves in the shutdown cooling head spray line so that the RHR low pressure piping will not be threatened by overpressurization. The isolation setpoint is chosen at a pressure below where the RHR piping could be overpressurized and the maximum differential pressure associated with the suction isolation valves is not exceeded. The RHR inboard injection valve control circuit uses the negation of this signal as a permissive for the shutdown cooling mode. See Table 5.2-4, Signal U.

16. Low Reactor Vessel Pressure AND High Drywell Pressure

Low reactor vessel pressure AND high drywell pressure are used to automatically close the two isolation valves in the HPCI turbine exhaust vacuum breaker line. The low reactor vessel pressure isolation setpoint was chosen to coincide with the pressure at which the HPCI system would trip. See Table 5.2-4, Signal N.

7.3.4.8 Instrumentation

Sensors providing inputs to the Primary Containment and Reactor Vessel Isolation Control System are not used for the automatic control of process systems, thus separating the functional control of protection systems and process systems. Channels are physically and electrically separated to assure that a single physical event cannot prevent isolation. Channels for one monitored variable that are grouped near to each other provide inputs to different isolation trip systems. Figures 7.3-2, 7.3-3, and 7.3-7 through 7.3-12 illustrate typical arrangements of channels, logics, and valve closing mechanism circuitry for Isolation Control Systems. Figures 7.3-5 and 7.3-6 illustrate in detail the functional arrangement of channels used to initiate isolation of various groups of valves. Table 7.3-2 lists instrument characteristics. Figures 7.3-14 through 7.3-24 illustrate how the many different channels and logics are typically combined to form the Isolation Control System. On Figures 7.3-14 through 7.3-24, the key contacts and relays have been consistently identified so that tracing the action of the isolation control circuitry from sensor through valve control is possible. Not all isolation valve controls are illustrated on Figures 7.3-14 through 7.3-24; however, sufficient illustration of typical controls is given that the general arrangement for any isolation valve control circuit is included.

1. Reactor vessel low water level signals are initiated from four differential pressure transmitters which sense the difference between the pressure due to a constant reference column of water, and the pressure due to the actual water level in the vessel. An analog trip unit actuated by each of the four transmitters is used to indicate that water level has decreased to the first and higher low water level isolation setting; another analog trip unit actuated by each of the four transmitters is used to indicate that water level has decreased to the second and lower of the two low water level isolation settings. Reactor vessel high water level signals are initiated from analog trip units activated from the same transmitters. The four transmitters and respective trip units for each level setting are arranged in pairs; each transmitter/trip unit in a pair provides a signal to a different trip system. Two pipelines, attached to taps above and below the water level on 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 in the Reactor Building; they are physically separated from each other and tap off the reactor vessel at widely separated points. The reactor vessel low water level transmitters sense level from these pipes. This arrangement assures that no single physical event can prevent isolation when required. Cables from the level sensors are routed to the analog trip cabinets in the Cable Spreading Room. Level instrumentation sensing lines inside the drywell have been designed with a minimum vertical drop to reduce error due to high drywell temperature.

2. Deleted.

3. High temperature in the vicinity of the main steam lines is detected by bimetallic temperature switches located in the main steam line tunnel ventilation exhaust duct and in the turbine basement area. The detectors are located or shielded so that they are sensitive to air temperature and not the radiated heat from hot equipment. An additional temperature sensor is located near each set of four detectors for remote temperature readout and alarm. The temperature sensors activate an alarm at high temperature and upon loss of power, operate to give the alarm condition. The main steam line space temperature detection system is designed to detect leakage greater than 10 gal/min in the main steam tunnel and 150 gal/min in the condenser compartment. Figure 7.3-8 illustrates in general terms the instruments used to detect high temperatures in the main steam line space. Figure 7.3-9 illustrates how temperature switches are combined to form a typical single channel. A total of four main steam line space high temperature channels are provided. Each main steam line isolation logic receives an input signal from one main steam line space high temperature channel. See Section 7.3.4.8.1.

4. High flow in each main steam line is sensed by four differential pressure transmitters which sense the pressure difference across the flow restrictor in that line. Figure 7.3-10 illustrates the general arrangement of instruments used to sense the flow in a single main steam line. Figure 7.3-11 illustrates how the 16 differential pressure transmitters and respective trip units are combined to form four channels. Each main steam line isolation logic receives an input signal from one main steam line high flow channel.

5. Main steam line low pressure is sensed by four pressure transmitters which sense pressure downstream of the outboard main steam isolation valves. The sensing point is located at the header that connects the four steam lines upstream to the turbine stop valves. Each transmitter and respective trip unit is part of an independent channel. Each channel provides a signal to one isolation logic.

6. Primary containment pressure is monitored by four non-indicating pressure transmitters which are mounted on instrument racks outside the drywell. Pipes that terminate in the reactor building connect the transmitters with the drywell interior. Cables are routed from the transmitter to the analog trip cabinets. The transmitters and respective trip units are grouped in pairs, physically separated, and electrically connected to the isolation control system so that no single event will prevent isolation due to primary containment high pressure.

7. High temperature in the vicinity of the RCIC equipment is sensed by two sets of four bimetallic temperature switches. Each set is arranged as two trip systems. Figure 7.3-7 illustrates how temperature switches are combined to form a typical temperature channel. Each trip system receives input

signals from two temperature trip channels. Both trip channels in either one of two trip systems must trip to initiate isolation. An additional temperature sensor is located near each set of four detectors for remote temperature read out and alarm. Figure 7.3-8 illustrates in general terms the instruments used to detect high RCIC area temperatures. See Section 7.3.4.8.1.

8. High flow in the RCIC turbine steam line is sensed by two differential pressure switches which monitor the differential pressure across an elbow installed in the RCIC turbine steam supply pipeline. The arrangement is illustrated on Figure 7.3-12. The tripping of either trip channel initiates isolation of the RCIC turbine steam line. This exception to the usual channel arrangement is because high steam flow is the second method of detecting a steam line break, high RCIC equipment space temperature being the first.

9. Low pressure in the RCIC turbine steam line is sensed by four pressure switches from the RCIC turbine steam line upstream of the isolation valves. The four switches are arranged in a one-out-of-two taken twice logic in a single trip system. This trip is not considered a PCIS function. The logic is one-out-of-two taken twice to preclude inadvertent system isolation due to instrument failure, and to insure isolation even if a single instrument fails.

10. High temperature in the vicinity of the HPCI equipment is sensed by two sets of four bimetallic temperature switches. Each set is arranged as two trip systems. Figure 7.3-7 illustrates how temperature switches are combined to form a typical temperature channel. Each trip system receives input signals from two temperature trip channels. Both trip channels in either one of two trip systems must trip to initiate isolation. An additional temperature sensor is located near each set of four detectors for remote temperature read out and alarm. Figure 7.3-8 illustrates in general terms the instruments used to detect high HPCI area temperature. See Section 7.3.4.8.1.

11. High flow in the HPCI turbine steam line is sensed by two differential pressure switches which monitor the differential pressure across an elbow installed in the HPCI turbine steam pipeline. The arrangement is illustrated on Figure 7.3-12. The tripping of either switch initiates isolation of the HPCI turbine steam line. This exception to the usual sensor arrangement is because high steam flow is the second method of detecting a steam line break, high HPCI equipment space temperature being the first.

12. High temperature in the spaces occupied by the RHR (shutdown cooling) and piping outside the primary containment is sensed by temperature detectors that provide readout and activate alarms only, indicating possible pipe breaks.

A typical arrangement is shown on Figure 7.3-8. Automatic isolation on high temperature is not required since the reactor vessel low water level isolation function is adequate in preventing the release of significant amounts of radioactive material in the event that either of these two systems suffers a breach.

13. High temperature in the vicinity of the RWCU system is sensed by four sets of two bimetallic temperature switches. A set of two temperature switches is installed in each of the four areas to be monitored; each set is a one-out-of-two trip system and capable of initiating isolation.

14. High flow in the RWCU system supply line is sensed by two differential pressure switches which monitor the pressure difference across an elbow installed in the RWCU system supply line. The arrangement of the differential pressure switches is similar to that shown on Figure 7.3-12. The tripping of either switch initiates isolation of the RWCU system.

15. Reactor high pressure is sensed by two pressure transmitters which monitor reactor pressure at the steam portion of the reactor vessel. These transmitters provide analog signals to the rosemount analog trip units which are used to automatically isolate the shutdown cooling. These switches are also used as a permissive in the Group III isolation of the RHR injection inboard valves.

16. Low reactor pressure is sensed by four pressure transmitters which are mounted on instrument racks outside the drywell. The transmitters provide electrical signals to analog trip units located in the cable spreading room. The tripping of either the "A" or "B" division of these trip units will initiate isolation of the HPCI steam line, HPCI pump suction line, and turbine exhaust drain pot line. When in conjunction with the high drywell pressure, the HPCI turbine exhaust vacuum breaker line will also isolate.

Channel and logic relays are high reliability relays equal to type GP and EGP relays made by Agastat and HFA and CR120A relays made by the General Electric Company. The relays are selected so that the continuous load will not exceed 50 percent of the continuous duty rating.

7.3.4.8.1 High Temperature Sensors

The location, spatial independence, and resistance to spurious tripping of the high temperature sensors in the main steamline, HPCI turbine steamline and RCIC turbine steamline are detailed in this section.

Table 7.3-3 lists the areas outside the primary containment where main steam, HPCI, and RCIC steam lines are routed. This table also lists the leak detection sensors, summarizes the physical separation of sensors, and specifies the set points at which isolation of the respecting steam line would be initiated.

Potential leak sources and rates which would initiate isolation are as follows:

Main Steam Tunnel

This area contains feedwater, cleanup, and main steam piping. Isolation of the main steam lines will be initiated at ventilation exhaust temperatures from the main steam tunnel of 160°F to 170°F, which would result from steam leaks equivalent to 10 gal/min and greater. The feedwater and cleanup systems normally operate at approximately 1,000 psig with 400°F water. Leakage of about 40 gal/min from either of these water systems would cause an area temperature increase and initiation of main steam isolation. If ventilation exhaust temperatures did not decrease following main steam line isolation, then the presence of leakage from another system would be suspected and further actions taken to identify the source of the suspected leak.

Condenser Compartment Leak

This area contains main steam piping, extraction steam piping, and feedwater piping. Temperature sensors are provided in the main ventilation exhaust from this area to isolate the main steam lines at temperatures of 140°F to 150°F. This would correspond to steam leaks of approximately 150 gal/min or greater.

HPCI Turbine Area

This area contains only HPCI system components. Isolation of the HPCI steam line will be initiated at ventilation exhaust temperatures of 160°F to 170°F. This would result from a steam leak equivalent to approximately 10 gal/min or greater.

HPCI Valve Station Area

This area contains both HPCI and RHR system piping. Isolation of the HPCI steam line will be initiated at ventilation exhaust temperatures of 160°F to 170°F. This would result from a steam leak equivalent to approximately 10 gal/min or greater. The RHR system piping contains water sufficiently hot to flash and increase ventilation exhaust temperatures to the leak detection setpoint only when operating in the shutdown cooling mode. Therefore, RHR Leakage would not cause isolation of the HPCI system when it is required to be operable. The shutdown cooling mode of RHR operation does not operate above a reactor pressure of about 75 psig, while the HPCI system does not operate below a pressure of about 50 psig.

RCIC Turbine Area

This area contains RCIC system components only. Isolation of the RCIC steam line will be initiated at space temperatures of 160°F to 170°F, which would result from a steam leak equivalent to approximately 10 gal/min or greater.

RCIC Valve Station Area

This area contains RCIC piping and various cold water lines associated with other systems. Isolation of the RCIC steam line

will be initiated at a space temperature of 190°F to 200°F, which would result from a steam leak of approximately 10 gal/min. A leak from the other piping in this area would be cold water and would not cause an area temperature increase and spurious isolation of the RCIC steam line.

Torus Compartment Area

This area contains both HPCI and RCIC steam lines in addition to the "cold" water lines associated with other systems. The HPCI and RCIC steam lines are separated by a minimum distance of approximately 65 ft.

Protection against the continued spurious isolation of either the HPCI or RCIC steam supply line due to leakage in the torus compartment is provided by establishing a temperature differential between the initiation setpoints of the temperature switches in the torus compartment ventilation exhaust ducts in combination with operating procedures.

Analytical limits are listed in Table 7.3-2 for the sensors associated with the RCIC steam line and trip settings of 190°F to 200°F are specified for those associated with the HPCI steam line. This difference in trip settings allows preferential isolation of the RCIC steam line in the event of a small leak, and permits the HPCI system to remain operable.

Isolation of the RCIC system due to steam line leakage:

a. If the leak occurs in the RCIC system piping, the RCIC steam line temperature would decrease and thus prevent HPCI system Isolation at the higher exhaust duct temperature

b. If the leak occurs in the HPCI system piping, the HPCI steam line temperature would continue to increase and isolate the HPCI system. The operator would subsequently return the RCIC system to service

Simultaneous isolation of HPCI and RCIC system steam supply lines could be postulated to occur as a result of a large RCIC system leak in the immediate vicinity of the exhaust plenum from the torus compartment, resulting in a rapid temperature increase to the HPCI analytical limit before the RCIC system steam line isolation valves were completely closed. However, analysis indicates that high RCIC steam flow would isolate the RCIC steam line before the HPCI temperature setpoint was reached.

Distinguishing between an RCIC and an HPCI steam line leak, assuming both lines were simultaneously isolated, would be possible by opening each line in succession and observing the temperature effect on the local sensors. The nonleaking system could then be returned to service. The temporary isolation of both the RCIC and HPCI steam supply lines as a result of a steam leak within the torus compartment is acceptable since neither system would be required to perform its function of providing coolant makeup to the reactor

vessel. The isolation of the leaking steam line would limit coolant losses from the reactor vessel without disrupting normal plant operation. The specified settings will initiate RCIC isolation upon steam leaks of approximately 40 gal/min and greater.

7.3.4.9 Environmental Capabilities

The physical and electrical arrangement of the Primary Containment and Reactor Vessel Isolation Control System was selected so that no single physical event will prevent isolation. The location of Class A and Class B valves inside and outside the primary containment provides assurance that the control system for at least one valve on any pipeline penetrating the primary containment will remain capable of automatic isolation. Electrical cables for isolation valves in the same pipeline are routed separately. Motor operators for valves inside the primary containment are of the totally enclosed type; those outside the primary containment have weatherproof type enclosures. Solenoid valves, whether used for direct valve isolation or as an air pilot, are provided with watertight enclosures. All cables and operators are capable of operation in the most unfavorable ambient conditions anticipated for normal operations. Temperature, pressure, humidity, and radiation are considered in the selection of equipment for the system. Cables used in high radiation areas have radiation resistant insulation. Shielded cables are used where necessary to eliminate interference from electromagnetic fields.

Special consideration has been given to isolation requirements during a loss of coolant accident inside the drywell. Components of the Primary Containment and Reactor Vessel Isolation Control System that are located inside the primary containment and that must operate during a loss of coolant accident are the cables, control mechanisms, and valve operators of isolation valves inside the drywell. These isolation components are required to be functional in a loss of coolant accident environment.

Electrical cables are selected with insulation designed for this service. Closing mechanisms and valve operators are considered satisfactory for use in the Isolation Control System only after completion of environmental testing under loss of coolant accident conditions or submission of evidence from the manufacturer describing the results of suitable prior tests.

Verification that the isolation equipment has been designed, built, and installed in conformance to the specified criteria is accomplished through quality control and performance tests in the vendor's shop or after installation at the station before startup, during startup, and thereafter during the service life of the equipment.

Control is also exercised through review of equipment design during bid review and by approval of vendor's drawings during the fabrication stage. Purchase specifications require extensive control of materials and of the fabrication procedure.

7.3.5 Safety Evaluation

The Primary Containment and Reactor Vessel Isolation Control System, in conjunction with other protection systems, is designed to provide timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barriers. It is the objective of Section 14, Station Safety Analysis, to identify and evaluate postulated events resulting in gross failure of the fuel barrier and the nuclear systems process barrier. The consequences of such gross failures are described and evaluated in that section.

Tentative trip settings are selected that are far enough above or below normal operating levels that spurious isolation and operating inconvenience are avoided. It is then verified by analysis that the release of radioactive material following postulated gross failures of the fuel and nuclear system process barrier is kept within acceptable bounds by those trip settings. Trip setting selection is based on operating experience and constrained by the safety design basis and the safety analyses.

Section 14 shows that the actions initiated by the Primary Containment and Reactor Vessel Isolation Control System, in conjunction with other safety systems, are sufficient to prevent releases of radioactive material from exceeding the guide values of published regulations. Because the actions of the system are effective in restricting the uncontrolled release of radioactive materials under accident situations, the Primary Containment and Reactor Vessel Isolation Control System meets the precision and timeliness requirements of safety design basis 1.

Because the Primary Containment and Reactor Vessel Isolation Control System met the precision and timeliness requirements of safety design basis 1 using instruments with the characteristics described on Table 7.3-2, it is concluded that safety design basis 2 was met.

Temperatures in the spaces occupied by various steam lines outside the primary containment are the only essential variables of significant spatial dependence that provide inputs to the primary containment and reactor vessel isolation control system. The large number of temperature sensors and their dispersed arrangement near the steam lines requiring this type of break protection provide assurance that a significant break will be detected rapidly and accurately. One of the two groups of four temperature switches is located in the ventilation exhaust from the steam line tunnel between the drywell and the secondary containment ventilation barrier and the other group of four temperature switches is located in the ventilation exhaust from the turbine basement area. This assures that abnormal air temperature increases are detected regardless of leak location in that space. It is concluded that the number of sensors provided for steam line break detection satisfies safety design basis 3.

Because the Primary Containment and Reactor Vessel Isolation Control System meets the timeliness and precision requirements of safety design basis 1 by monitoring variables that are true, direct

measures of operational conditions, it is concluded that safety design basis 4 is satisfied.

Section 14 evaluates a gross breach in a main steam line outside the primary containment during operation at full power. The evaluation shows that the main steam lines are automatically isolated in time to prevent a release of radioactive material in excess of the guide values of published regulations and to prevent the loss of coolant from being great enough to allow uncovering of the core. These results are true even if the longest closing time of the valve is assumed. The time required for automatic closure of the main steam isolation valves meets the requirements of safety design basis 5.

The shortest closure time of which the main steam valves are capable is 3 sec. The transient resulting from a simultaneous closure of all main steam isolation valves in 3 sec during reactor operation at full power is considerably less severe than the transient resulting from inadvertent closure of the turbine stop valves (which occurs in a small fraction of 1 sec) coincident with failure of the turbine bypass system.

The RPS is capable of accommodating the transient resulting from the inadvertent closure of the main steam line isolation valve. This conclusion is substantiated by Section 14. This meets safety design basis 6.

The items of safety design bases 7, 8, and 9 must be fulfilled for the Primary Containment and Reactor Vessel Isolation Control System to meet the design reliability requirements of safety design basis 1. It has already been shown that safety design bases 7f and 7h have been met. The remainder of the reliability requirement is met by a combination of logic arrangement, sensor redundancy, wiring scheme, physical isolation, power supply arrangement, and environmental capabilities. These subjects are discussed in the following paragraphs.

Because essential variables are monitored by four channels arranged for physical and electrical independence, and because a dual trip system arrangement is used to initiate closure of automatic isolation valves, no single failure, maintenance operation, calibration operation, or test can prevent the system from achieving isolation. An analysis of the Isolation Control System shows that the system does not fail to respond to essential variables as a result of single electrical failures such as short circuits, ground, and open circuits. A single trip system trip is the result of these failures. Isolation is initiated upon a trip of the remaining trip system. For some of the exceptions to the usual logic arrangement, a single failure could result in inadvertent isolation of a pipeline. With respect to the release of radioactive material from the nuclear system process barrier, such inadvertent valve closures are in the safe direction and do not pose any safety problems. HPCI, RCIC, and RHR primary containment isolation logics are single failure proof with an energize to actuate design. Any single failure can only affect closure of one of two containment isolation valves. This meets Safety Design Bases 7a and 7b.

The redundancy of channels provided for all essential variables provides a high probability that whenever an essential variable exceeds the isolation setting, the system initiates isolation. In the unlikely event that all channels for one essential variable in one trip system fail in such a way that a system trip does not occur, the system could still respond properly as other monitored variables exceed their isolation settings. This meets Safety Design Basis 7c.

The sensors, circuitry, and logics used in the primary containment and reactor vessel isolation control system are not used in the control of any process system. Thus, malfunction and failures in the controls of process systems have no direct effect on the isolation control system. This meets Safety Design Basis 7d.

The various power supplies used for the isolation system logic circuitry and for valve operation provide assurance that the required isolation can be effected in spite of power failures. If AC for valves inside the primary containment is lost, DC is available for operation of valves outside the primary containment. The main steam isolation valve control arrangement is resistant to both AC and DC power failures. Because both solenoid-operated pilot valves must be deenergized, loss of a single power supply will neither cause inadvertent isolation nor prevent isolation if required.

The logic circuitry for each channel is powered from the separate sources available from the reactor protection system buses, the uninterruptible AC power supply, or the 125V DC buses (for HPCI, RCIC, and RHR). A loss of power here results in a single trip system trip. In no case does a loss of a single power supply prevent isolation when required. This meets Safety Design Basis 7e.

All instruments, valve closing mechanisms, and cables of the isolation control system can operate under the most unfavorable environmental conditions associated with normal operation. The discussion of the effects of rapid nuclear system depressurization on level measurement given in Section 7.2, Reactor Protection System, is equally applicable to the reactor vessel low water level transmitters used in the primary containment and reactor vessel isolation control system. The temperature, pressure, differential pressure, and level switches, transmitters, trip units, cables, and valve closing mechanisms used were selected with ratings that make them suitable for use in the environment in which they must operate.

The special considerations (treated in the description portion of this section) made for the environmental conditions resulting from a loss of coolant accident inside the drywell are adequate to ensure operability of essential isolation components located inside the drywell.

The wall of the primary containment effectively separates adverse environmental conditions which might otherwise affect both isolation valves in a pipeline. The location of isolation valves on either side of the wall decouples the effects of environmental factors with respect to the ability to isolate any given pipeline. The

previously discussed electrical isolation of control circuitry prevents failures in one part of the control system from propagating to another part. Electrical transients have no significant effect on the functioning of the isolation control system. It is concluded that safety design basis 7g is satisfied.

The design of the main steam isolation valves meets the requirement of safety design basis 8a in that the motive force for closing each main steam line isolation valve is derived from both a source of pneumatic pressure and the energy stored in a spring. Either energy source is capable, alone, of closing the valve. None of the valves relies on continuity of any sort of electrical power to achieve closure in response to essential safety signals. Total loss of the power used to control the valves would result in closure. This meets safety design basis 8b.

Calibration and test controls for pressure and temperature switches, transmitter and analog trip units are located on the devices themselves. These devices are located in the turbine building and reactor building. To gain access to the setting controls on each device, a cover plate, access plug, or sealing device must be removed by operations personnel before any adjustment in trip settings can be effected. The location of calibration and test controls in areas under the control of the control room operator or other supervisory personnel reduces the probability that operational reliability will be degraded by operator error. This meets safety design basis 9a. Because no manual bypasses are provided in the isolation control system, safety design basis 9b is met.

Because safety design bases 7, 8, and 9 have been met, it can be concluded that the Primary Containment and Reactor Vessel Isolation Control System satisfies the reliability requirement of safety design bases 10, 11a, and 11b as shown in the description of the system. The following section on inspection and testing of the system demonstrates that safety design basis 12 is satisfied.

It is concluded that all safety design bases are met.

7.3.6 Inspection and Testing

All essential parts of the primary containment and reactor vessel isolation control system are testable during reactor operation. Isolation valves can be tested to assure that they are capable of closing by operating manual switches in the control room and observing the position lights and any associated process effects. Testing of the main steam line isolation valves is discussed in Section 4.6, Main Steam Line Isolation Valves.

7.3.7 Nuclear Safety Requirements for Plant Operation

Table 7.3-4 presents the operational nuclear safety requirements for the primary containment and reactor vessel isolation control system for boiling water reactor (BWR) operating states C, D, E, and F as proposed for initial plant operation.

The entries on Table 7.3-4 represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the Primary Containment and Reactor Vessel Isolation Control System. The following referenced portions of this safety analysis report provide important information justifying the entries on Table 7.3-4:

Reference	Information Provided
1. Preceding parts of Section 7.3	Description of primary containment and reactor vessel isolation control system hardware; isolation control system sensor setpoints
2. Station Safety Analysis, Section 14	Analysis verifying response of isolation control system to transients and accidents
3. Station Nuclear Safety Operational analysis, Appendix G	Identifies conditions and events for which isolation control system action is required
4. Jacobs, I.M., Guidelines for Determining Safe Test Intervals and Repair Times for Engineering Safeguards, General Electric Company, Atomic Power Equipment Department, April 1969, (APED-5736)	Describes methods used to establish allowable repair times

Each detailed requirement on Table 7.3-4 is referenced, where possible, to the most significant condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references, given in parentheses beneath the detailed requirements in the "minimum required for action" columns on Table 7.3-4 are coded as follows:

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

```
F21-73
|
|--------- F - BWR operating state F
  |--|---- 21 - Event (row 21)
     |--- 73 - Isolation Control System
                  (column 73)
```

In most cases, the basis for an operational nuclear safety requirement is clear from the information provided by the previously noted references. The Isolation Control System requirements in operating states C, D, E, and F result from considerations for the main steam line break accident, the loss of coolant accident, or lesser cases of these two design basis accidents. In general, the requirements for the isolation functions are applicable only when the nuclear system is pressurized, because only under this condition are pipe breaks postulated. In addition, operability of the various

isolation components is necessary only when the associated lines are unisolated. The following paragraphs give additional information about some of the less obvious operational nuclear safety requirements.

The requirements of items 7.3.1, 7.3.2, and 7.3.4 of Table 7.3-4 are applicable only when any of the affected lines are unisolated. The requirement for the main steam line low pressure isolation function, item 7.3.6 on Table 7.3-4, is applicable only in operating State F and only when the mode switch is in RUN. If the mode switch is not in RUN, this isolation function is bypassed; operating State F is the only state in which the RUN position is utilized as part of planned operation.

The surveillance test and calibration frequencies for the instrumentation of the Primary Containment and Reactor Vessel Isolation Control System are selected on the same basis as for the Reactor Protection System. See Section 7.2.6. The Radiation Monitoring Systems are treated in Section 7.12.

The surveillance test frequencies for the automatic isolation valves of the Primary Containment and Reactor Vessel Isolation Control System are contained in the Technical Specifications referenced in Appendix B. The frequencies are based upon the need to prevent the uncovering of the core following pipe breaks outside the primary containment, the need to contain released fission products following pipe breaks inside the primary containment, the reliability of the valves, and the potential service experience of the valves. The valves of the system are highly reliable and have low service requirements; many of the valves are normally closed. Successful passing of the surveillance tests for the valves essential to reactor vessel isolation requires that they close within specified closure times.

The full system test at each refueling outage (state A) requires that each initiating function for isolation be tested to demonstrate that all the automatic valves associated with an initiating function actually close upon receipt of the isolation signal.

7.3.8 Current Technical Specifications

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

7.3.9 References

1. NEDO-31296, "Safety Evaluation of MSIV Low Turbine Inlet Pressure Isolation Setpoint Change for Pilgrim Nuclear Power Station," General Electric Company, May 1986.

Table 7.3-1 has been deleted.

Please refer to Table 5.2-4

Table 7.3-2

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM
FOR CURRENT PLANT SAFETY ANALYSIS
INSTRUMENT SPECIFICATIONS

ISOLATION FUNCTION	INSTRUMENT	TRIP SETTING	DESIGN BASIS REFERENCE
Reactor Vessel High Water Level	LT263-57A,B & -58A,B LIS263-57A,B & -58A,B LS263-57A-2,B-2 & -58A-2,B-2	542.5 in above vessel zero	Calc. I-N1-103 (See Note 1)
Reactor Vessel Low Water Level (Group 2, 3 and 6)	LT263-57A,B & -58A,B LIS263-57A,B & -58A,B LS263-57A-1, B-1 & -58A-1, B-1	483.5 in above vessel zero	Calc. I-N1-102 (See Note 1)
Reactor Vessel Low Water Level (Group 1)	LT263-57A,B & -58A,B LIS263-57A,B & -58A,B	425.6 in above vessel zero	Calc. I-N1-101 (See Note 1)
Main Steam Line Space High Temperature	TS261-15A,B,C,D TS261-16A,B,C,D	178°F 158°F	I-N1-113 I-N1-114 (See Note 1)
Main Steam Line High Flow	DPT261-2A,B,C,D,E,F,G H,J,K,L,M,N,P,R,S DPI261-2A,B,C,D,E,F,G H,J,K,L,M,N,P,R,S	147.6% rated flow	BECo Calc. I-N1-127 (See Note 1)
Reactor Vessel High Pressure	PT263-50A,B PS263-50A-4, 50B-4	80>P>50 psig	

NOTE: 1. The setpoint for this parameter was analyzed in accordance with R.G. 1.105. The trip setting identified is the design basis analytical limit.

Table 7.3-2(Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM FOR CURRENT PLANT SAFETY ANALYSISINSTRUMENT SPECIFICATIONS

ISOLATION FUNCTION	INSTRUMENT	TRIP SETTING	DESIGN BASIS REFERENCE
Reactor Vessel Low Pressure	PT263-50A,B PIS263-50A,B PS263-50A-3, B-3 PT263-52A,B PIS263-52A,B PS263-52A-2,B-2	150>p>50 psig	Calc. I-N1-150 and I-N1-153 (See Note 1)
Main Steam Line Low Pressure	PT261-30A,B,C,D PIS261-30A,B,C,D	782 psig	Calc I-N1-93 (See Note 1)
Primary Containment High Pressure (Group 2 and 3)	PT512A,B,C,D PIS512A,B,C,D	2.5 psig	Calc. I-N1-132 (See Note 1)
RCIC Turbine Steam Line Space High Temperature	TS1360-14C,D & -16C,D TS1360-15A,B & -17A,B TS1360-15C,D & -17C,D	200°F 170°F 150°F	I-N1-122 I-N1-123 I-N1-124 (See Note 1)
RCIC Turbine Steam Line High Flow	DPIS1360-1A,B	300% rated flow	Calc. I-N1-189 (See Note 1)
RCIC Turbine Steam Line Low Pressure	PS1360-9A,B,C,D,	100>p>50 psig	I-N1-195 (See Note 1)
RWCU Inlet High Flow	DPIS1243 DPIS1244	350% rated flow	Calc. I-N1-182 (See Note 1)
Primary Containment Pressure (Group 7)	PT1001-89A,B,C,D PIS1001-89A,B,C,D PS1001-89A-3,B-3,C-3,D-3	2.5 psig	Calc. I-N1-137 (See Note 1)

NOTE: 1. The setpoint for this parameter was analyzed in accordance with R.G. 1.105. The trip setting identified is the design basis analytical limit.

Table 7.3-2 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM
FOR CURRENT PLANT SAFETY ANALYSIS
INSTRUMENT SPECIFICATIONS

ISOLATION FUNCTION	INSTRUMENT	TRIP SETTING	DESIGN BASIS REFERENCE
HPCI Turbine Steam Line Space High Temperature	TS2370C, D, TS2371A,B TS2372C,D, TS2373A,B TS2371C,D, TS2373C,D TS2371A,B, TS2373A,B	170°F 170°F 200°F	I-N1-119 I-N1-119 I-N1-211 I-N1-120
HPCI Turbine Steam Line High Flow	DPIS2352 DPIS2353	≤300%	I-N1-198 (See Note 1)
Reactor Water Cleanup System Space High Temperature	TS1291-14C,D,E,F,G,H,J,K	150°F	I-N1-115
Alarms Only RHR Shutdown Cooling Space High Temperature	TS1040-16	140°F	

Table 7.3-3

STEAM LEAK TEMPERATURE SENSORS

System	Monitored Area	Sensors	Location	Analytical Limit
Main Steam	Steam Tunnel above elevation 23 ft south of Reactor	TS-261-15A TS-261-15C TS-261-15B TS-261-15D	Sensors 15A and 15B are located on one side and sensors 15C and 15D are located on the opposite side of the 20 in x 20 in rectangular exhaust duct external to the main steam tunnel.	See Note 1
Main Steam	Turbine Basement below elevation 51 ft	TS-261-16A TS-261-16B TS-261-16C TS-261-16D	Sensors are located on each side of the exhaust duct at Building Elevation 79 ft 0 in (above the turbine floor). Sensors A and B are separated from sensors C and D by at least 3 ft horizontal distance.	See Note 1
HPCI	Pump/Turbine Room Area below elevation 23 ft NW of Reactor	TS-2371A TS-2371A TS-2371B TS-2373B	Sensors 71A and 73A are in one exhaust duct external to the HPCI compartment. Sensors 71B and 73B are located similarly in the other exhaust duct with approximately 3 ft separation between ducts.	See Note 1
RCIC	Pump/Turbine Room Area below elevation 23 ft NW of Reactor	TS-1360-15A TS-1360-17A TS-1360-15B TS-1360-17B	Sensors 15A and 17A are located in one corner of the mezzanine stairwell to the RCIC compartment. Sensors 15B and 17B are located on the opposite side of the stairwell at least 3 ft away from the A sensors.	See Note 1
HPCI	Valve station above elevation 23 ft	TS-2370C TS-2372C TS-2370D TS-2372D	Sensors 70C and 72C are located in the exhaust external to the valve station. Sensors 70D and 72D are located at least 3 ft horizontally away from the A sensors.	See Note 1
RCIC	Valve station above elevation 23 ft SW of Reactor	TS-1360-14C TS-1360-16C TS-1360-14D TS-1360-16D	Sensors 14C and 16C are wall mounted and located in the valve station area. Sensors 14D and 16D are located at least 3 ft horizontally away from the C sensors.	See Note 1
HPCI	Torus Compartment above elevation (-) 17 ft 6 in	TS-2371C TS-2371C TS-2371D TS-2373D	Sensors 71C and 73C are located in the vertical exhaust duct at elevation 25 ft external to the torus compartment. Sensors 71D and 73D are located in the other side of the duct (at the same elevation) a distance of 40 in horizontally from the C sensors.	See Note 1
RCIC	Torus Compartment above elevation (-) 17 ft 6 in	TS-1360-15C TS-1360-17C TS-1360-15D TS-1360-17D	Sensors 15C and 17C are located in the vertical exhaust duct at elevation 30 ft external to the torus compartment. Sensors 15D and 17D are located in the other side of the duct (at the same elevation) a distance of 40 in horizontally from the C sensors.	See Note 1

Table 7.3-3 (Cont)

System	Monitored Area	Sensors	Location	Isolation Set Point °F
RHR	Pump Room Area below elevation 23 ft NW of Reactor Building	TE1001-92A	Wall Mounted	Alarm Only
RHR	Pump Room Area below elevation 23 ft SE of Reactor Building	TE1001-92B	Wall Mounted	Alarm Only
RHR	RHR Piping Room elevation 23 ft SE of Reactor Building	TE1001-92F	Wall Mounted	Alarm Only
RHR	Pipeway, elevation 23 ft SE of Reactor Building	TE1001-92G	Wall Mounted	Alarm Only
RHR	Fuel Pool Heat Exchanger Room elevation 80 ft NE of Reactor Building	TE1001-92H	Wall Mounted	Alarm Only
RWCU	Open area east half elevation 51 ft	TS1291-14C & F D	Located in HV duct from backwash Receiver Tank Room	See Note 1
RWCU	Open area east half of elevation 51 ft	TS1291-14 E & F	Located in HV duct from RWCU heat Exchanger Room	See Note 1
RWCU	RHR Piping Room elevation 23 ft	TS1291-14G & H	Wall Mounted	See Note 1
RWCU	CRD Modules area east half, elevation	TS1291-14J & K	Located in HV duct from RHR valve room "A"	See Note 1

Note 1: See Table 7.3-2 for Analytical Limit

Table 7.3-4

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION •	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION •	MINIMUM REQ'D FOR ACTION *
7.3.1 Isolation Control System Trip	1. Trip System	2 trip systems			With any affected line unisolated: 1 trip system operable 1 trip system inoperable	With any affected line unisolated: 1 trip system operable 1 trip system inoperable	With any affected line unisolated: 1 trip system operable 1 trip system inoperable	With any affected line unisolated: 1 trip system operable 1 trip system inoperable
	2. Trip system logics	2 pairs of logics per trip system (each pair includes the input for each isolation function, RCIC isolation, and HPCI isolation)			With any affected line unisolated and with the nuclear system pressurized: 1 pair of logics operable per operable trip system	With any affected line unisolated and with the nuclear system pressurized : 1 pair of logics operable per operable trip system	With any affected line unisolated: 1 pair of logics operable per operable trip system	With any affected line unisolated: 1 pair of logics operable per operable trip system

• Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *
7.3.2 Reactor Vessel low water level isolation initiation	1. Reactor vessel low water level channels (first setting)	2 channels per trip system			With nuclear system pressurized and any affected line unisolated: 1 channel operable per operable trip system (C39-73)	With nuclear system pressurized and any affected line unisolated: 1 channel operable per operable trip system (D39-73)	With any affected line unisolated: 1 channel operable per operable trip system (E39-73)	With any affected line unisolated: 1 channel operable per operable trip system (F39-73)
	2. Reactor vessel low water level channels (second setting)	2 channels per trip system			With nuclear system pressurized and any affected line unisolated: 1 channel operable per operable trip system (C39-73)	With nuclear system pressurized and any affected line unisolated: 1 channel operable per operable trip system (D39-73)	With any affected line unisolated: 1 channel operable per operable trip system (E39-73)	With any affected line unisolated: 1 channel operable per operable trip system (F39-73)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *
7.3.3 Primary Containment high pressure isolation initiation	Primary containment high pressure channels	2 channels per trip system			With nuclear system pressurized and any affected line unisolated: 1 channel operable per operable trip system (C39-73)	With nuclear system pressurized and any affected line unisolated: 1 channel operable per operable trip system (D39-73)	With any affected line unisolated: 1 channel operable per operable trip system (E39-73)	With any affected line unisolated: 1 channel operable per operable trip system (F39-73) See section 7.12 (F38-73)
7.3.5 Main steam line break isolation initiation	1 Main steam line flow channels	2 channels per trip system			With nuclear system pressurized and any main steam line unisolated: 1 channel operable per operable trip system (C41-73)	With nuclear system pressurized and any main steam line unisolated: 1 channel operable per operable trip system (D41-73)	With any main steam line unisolated: 1 channel operable per operable trip system (E41-73)	With any main steam line unisolated: 1 channel operable per operable trip system (F41-73)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.5 Main steam line break isolation initiation (Cont)	2. Main steam line space high temperature channels	2 channels per trip system			With nuclear system pressurized and any main steam line unisolated: 1 channel operable per operable trip system (C41-73)	With nuclear system pressurized and any main steam line unisolated: 1 channel operable per operable trip system (D41-73)	With any main steam line unisolated: 1 channel operable per operable trip system (E41-73)	With any main steam line unisolated: 1 channel operable per operable trip system (F41-73)
7.3.6 Main steam line low pressure isolation initiation	Main steam line low pressure channels	2 channels per trip system						With any main steam line unisolated and mode switch in RUN: 1 channel operable per operable trip system F25-73)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.7 RCIC steam line break isolation initiation	1. RCIC steam line space high temperature channels	2 channels per RCIC isolation trip system			With nuclear system pressurized and RCIC steam line unisolated: 1 channel operable per operable RCIC isolation trip system (C41-73)	With nuclear system pressurized and RCIC steam line unisolated: 1 channel operable per operable RCIC isolation trip system (D41-73)	With the RCIC steam line unisolated: 1 channel operable per operable RCIC isolation trip system (E41-73)	With the RCIC steam line unisolated: 1 channel operable per operable RCIC isolation trip system (F41-73)
	2. RCIC steam line high flow channels	2 channels			With nuclear system pressurized and RCIC steam line unisolated: I channel operable (C41-73)	With nuclear system pressurized and RCIC steam line unisolated: I channel operable (D41-73)	With RCIC steam line unisolated: 1 channel operable (E41-73)	With RCIC steam line unisolated: 1 channel operable (F41-73)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.8 HPCI steam line break isolation initiation	1. HPCI steam line spacc high temperature channels	2 channels per HPCI isolation trip system			With nuclear system pressurized and HPCI steam line unisolated: 1 channel operable per operable HPCI isolation trip system (C41-73)	With nuclear system pressurized and HPCI steam line unisolated: 1 channel operable per operable HPCI isolation trip system (D41-73)	With the HPCI steam line unisolated: 1 channel operable per operable HPCI isolation trip system (E41-73)	With the HPCI steam linc unisolated: 1 channel operable per operable HPCI isolation trip system (F41-73)
	2. HPCI steam line high flow channels	2 channels			With nuclear system pressurized and HPCI steam line unisolated: I channel operable (C41-73)	With nuclear system pressurized and HPCI steam line unisolated: 1 channel operable (D41-73)	With HPCI steam line unisolated: 1 channel operable (E41-73)	With HPCI steam line unisolated: 1 channel operable (F41-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal	1. Automatic isolation valve in steam and water lines directly connected to reactor							
	1a. Main steam line isolation valves	2 valves per main steam line			See Section 4.6	See Section 4.6	See Section 4.6	See Section 4.6
	1b. Main steam line drain isolation valves	2 valves			With nuclear system pres- surized: 1 valve oper- able per unisolated line (C41-73)	With nuclear system pressurized: 1 valve operable per unisolated line (D41-73)	1 valve operable per unisolated line (E41-73)	1 valve operable per unisolated line (F41-73)
	1c. RCIC steam line isolation valves	2 valves						
	1d. HPCI steam line isolation valves	2 valves						
	1e. RHR shutdown cooling system isolation valves	2 valves per line			With nuclear system pres- surized: 1 valve oper- able per unisolated line(C39-73)	With nuclear system pres- surized: 1 valve oper- able per unisolated line(D39-73)	1 valve operable per unisolated line (E39-73)	1 valve operable per unisolated line (F39-73)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal (Cont)	1f. Reactor vessel head isolation valves	2 valves			With nuclear system pressurized: 1 valve operable per unisolated line (C41-73)	With nuclear system pressurized: 1 valve operable per unisolated line (D41-73)	1 valve operable per unisolated line (E41-73)	1 valve operable per unisolated line (F41-73)
	1g. Reactor water cleanup system supply isolation valves	2 valves			With nuclear system pressurized: 1 valve operable per unisolated line (C39-73)	With nuclear system pressurized: 1 valve operable per unisolated line (D39-73)	1 valve operable per unisolated line (E39-73)	1 valve operable per unisolated line (F39-73)
	1h. Reactor water cleanup system return isolation valves	1 valve			With nuclear system pressurized: 1 valve operable when reactor water clean-up system return line unisolated (C39-73)	With nuclear system pressurized: 1 valve operable when reactor water clean-up system return line unisolated (D39-73)	1 valve operable when reactor water clean-up system return line unisolated (E39-73)	1 valve operable when reactor water clean-up system return line unisolated (F39-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal (Cont)	1i. Reactor water sample line isolation valves	2 valves			With nuclear system pres-surized: 1 valve operable per unisolated line (C39-73)	With nuclear system pres-surize: 1 valve operable per unisolated line (D39-73)	1 valve operable per unisolated line (E39-73)	1 valve operable per unisolated line (F39-73)
	2 Automatic isolation valves in water lines not directly connected to reactor							
	2a. Drywell equipment drain sump discharge isolation valves	2 valves			With nuclear system pres-surize: 1 valve oper-able per unisolated line (C39-73)	With nuclear system pres-surize: 1 valve oper-able per unisolated line (D39-73)	1 valve operable per unisolated line (E39-73)	1 valve operable per unisolated line (F39-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal (Cont)	2b. Drywell floor drain sump discharge isolation valves	2 valves			With nuclear system pres-surize: 1 valve operable per unisolated line (C39-73)	With nuclear system pres-surize: 1 valve operable per unisolated line (D39-73)	1 valve operable per unisolated line (E39-73)	1 valve operable per unisolated line (F39-73)
	3. Automatic isolation valves in air and gas lines 3a. Drywell purge inlet isolation valves	2 valves			With nuclear system pres-surize: Either dry-well purge inlet out-board valve operable or both drywell purge inlet inboard valve and suppression chamber purge inlet valve (item 3.d) operable (C39-73)	With nuclear system pres-surize: Either dry-well purge inlet out-board valve operable or both drywell purge inlet inboard valve and suppression chamber purge inlet valve (item 3.d) operable (D39-73)	Either dry-well purge inlet out-board valve operable or both drywell purge inlet outboard valve and suppression chamber purge inlet valve (item 3.d) operable (E39-73)	Either dry-well purge inlet out-board valve operable or both drywell purge inlet outboard valve and suppression chamber purge inlet valve (item 3.d) operable (F39-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal (Cont)	3b. Drywell main exhaust isolation valves	2 valves			With nuclear system pressurized: 1 valve operable per unisolated line (C39-73)	With nuclear system pressurized: 1 valve operable per unisolated line (D39-73)	1 valve operable per unisolated line (E39-73)	1 valve operable per unisolated line (F39-73)
	3c. Drywell exhaust valve bypass isolation valve	1 valve			With nuclear system pressurized: Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (C39-73)	With nuclear system pressurized: Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (D39-73)	Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (E39-73)	Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (F39-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal (Cont)	3d. Suppression chamber purge inlet isolation valve	1 valve			With nuclear system pressurized: Either suppression chamber purge inlet valve operable or drywell purge inlet outboard valve (item 3.a) operable (C39-73)	With nuclear system pressurized: Either suppression chamber purge inlet valve operable or drywell purge inlet outboard valve (item 3.a) operable (D39-73)	Either suppression chamber purge inlet valve operable or drywell purge inlet outboard valve (item 3.a) operable (E39-73)	Either suppression chamber purge inlet valve operable or drywell purge inlet outboard valve (item 3.a) operable (F39-73)
	3e. Suppression chamber main exhaust isolation valves	2 valves			With nuclear system pressurized: 1 valve operable per unisolated line (C39-73)	With nuclear system pressurized: 1 valve operable per unisolated line (D39-73)	1 valve operable per unisolated line (E39-73)	1 valve operable per unisolated line (F39-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 (Cont)

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal (Cont)	3f. Suppression chamber exhaust valve bypass isolation valve	1 valve			With nuclear system pressurized: Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (C39-73)	With nuclear system pressurized: Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (D39-73)	Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (E39-73)	Either exhaust valve bypass valve operable or exhaust valve to standby gas treatment operable (F39-73)
	3g. Purge exhaust valve to standby gas treatment	1 valve			With nuclear system pressurized: Either exhaust valve to standby gas treatment operable or both exhaust valve bypass valves (items 3.c and 3.f) operable (C39-73)	With nuclear system pressurized: either exhaust valve to standby gas treatment operable or both exhaust valve bypass valves (items 3.c and 3.f) operable (D39-73)	Either exhaust valve to standby gas treatment operable or both exhaust valve bypass valves (items 3.c and 3.f) operable (E39-73)	Either exhaust valve to standby gas treatment operable or both exhaust valve bypass valves (items 3.c and 3.f) operable (F39-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.3-4 *(Cont)*

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.3.9 Physical isolation of lines on automatic signal (Cont)	4. TIP guide tube automatic isolation valves	1 valve per TIP guide tube			With nuclear system pressurized: 1 valve operable per unisolated TIP guide tube (C39-73)	With nuclear system pressurized: 1 valve operable per unisolated TIP guide tube (D39-73)	1 valve operable per unisolated TIP guide tube (E39-73)	1 valve operable per unisolated TIP guide tube (F39-73)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Figure 7.3—1 has been deleted.

Please refer to Figure 4.3—2.

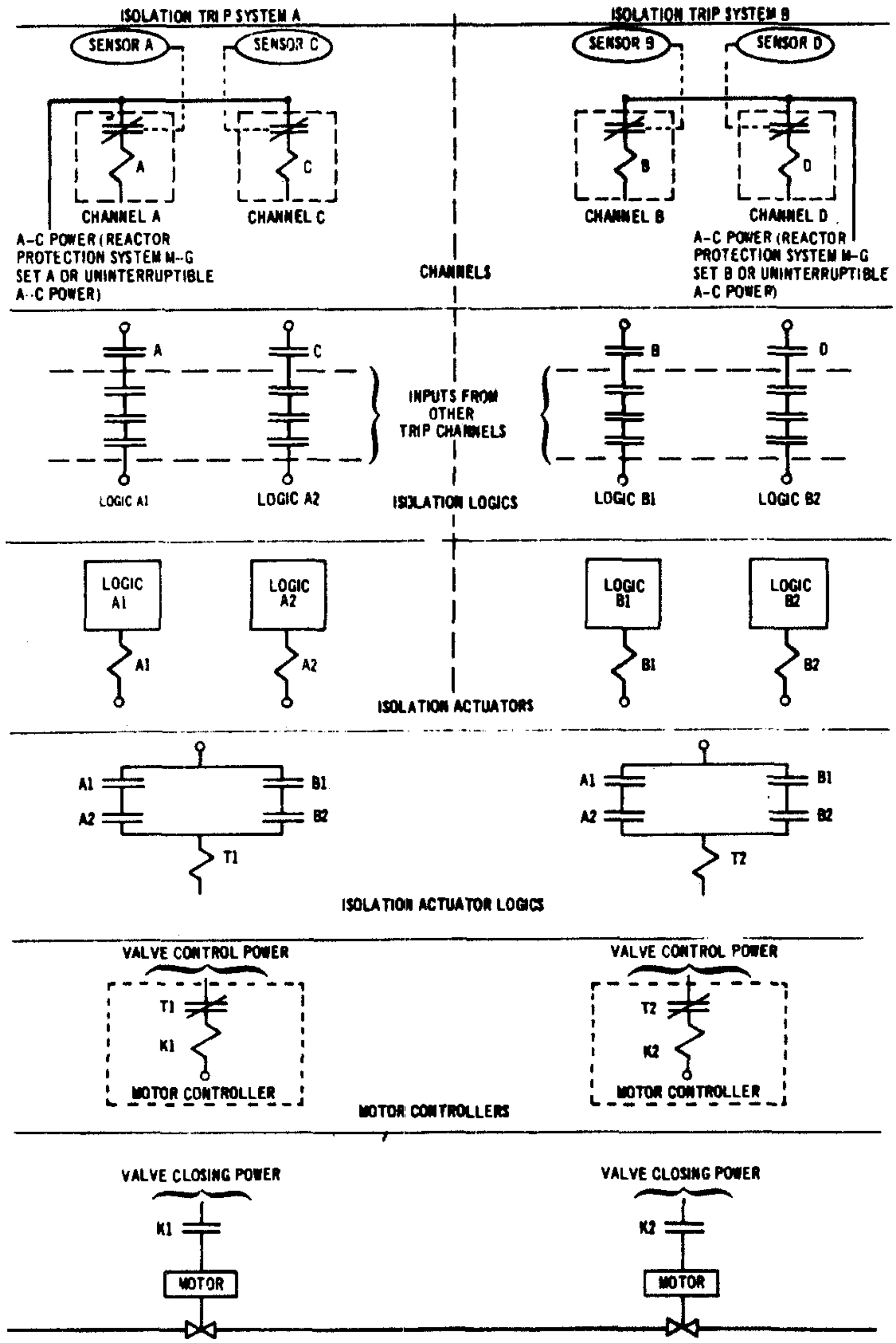


FIGURE 7.3-2
TYPICAL ISOLATION CONTROL SYSTEM USING MOTOR OPERATED VALVES
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

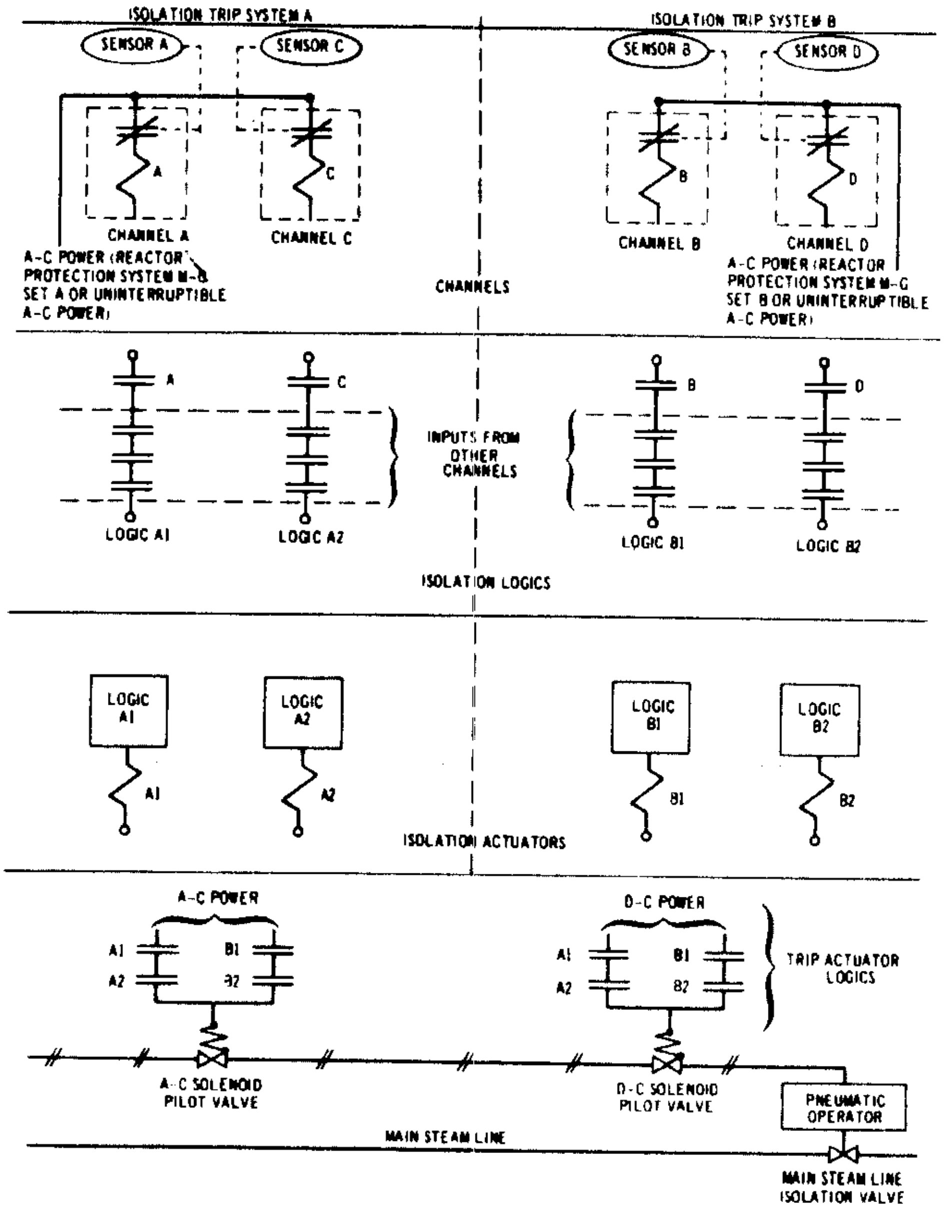


FIGURE 7.3-3
TYPICAL ISOLATION CONTROL SYSTEM FOR MAIN STEAMLINE ISOLATION VALVES

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

LEGEND

1 - 4 WAY VALVE
2 - 4 WAY VALVE
3 - AIR STORAGE TANK
4 - 3 WAY VALVE
5 - 3 WAY VALVE
6 - 3 WAY VALVE
7 - SPEED CONTROL VALVE
8 - HYDRAULIC CYLINDER
9 - SWING CHECK VALVE

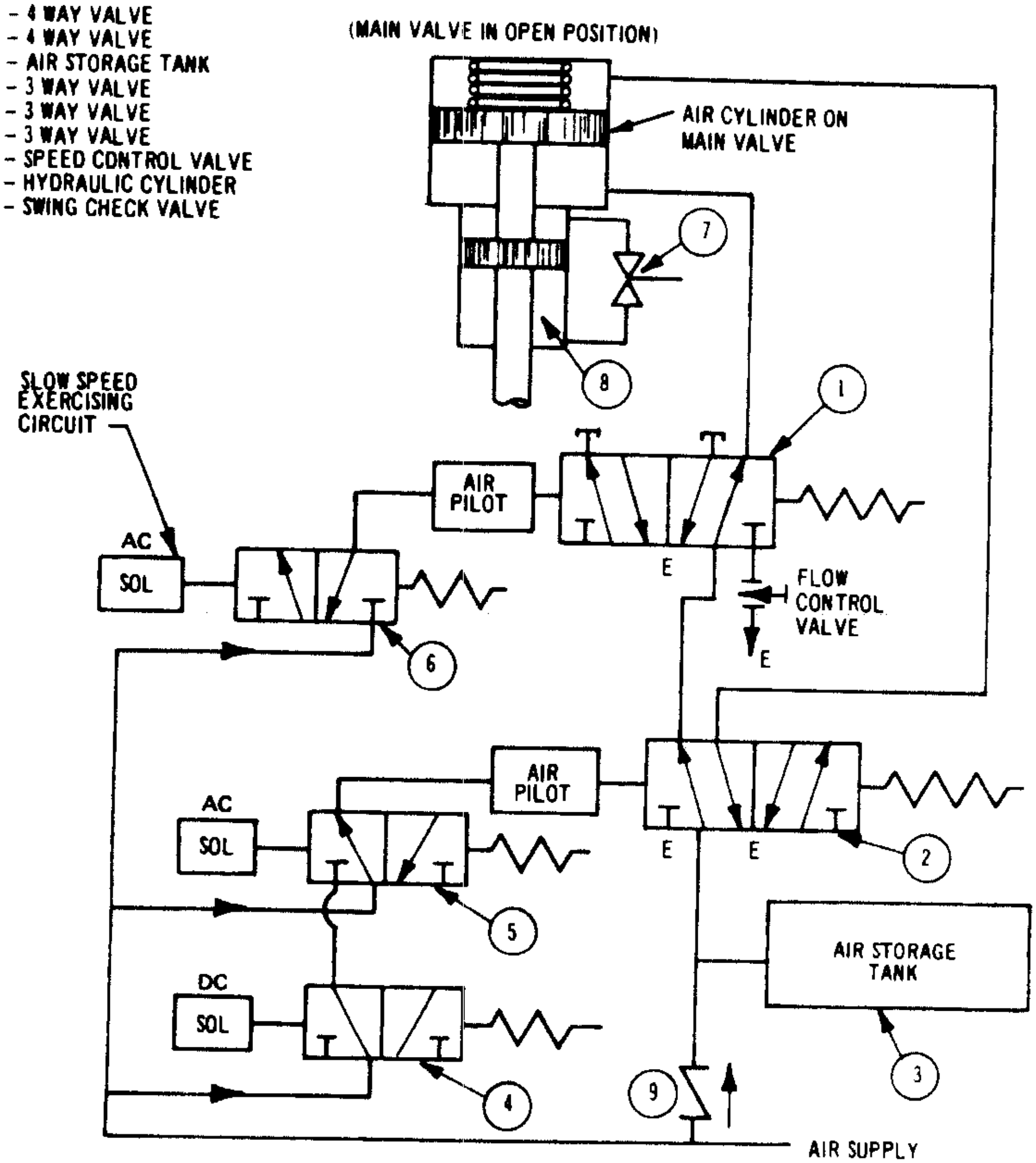


FIGURE 7.3-4
MAIN STEAMLINE ISOLATION VALVE SCHEMATIC CONTROL DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figures 7.3-5 and 7.3-6 have been removed.

Please refer to BECo Controlled Drawings M1A16-5 and M1A15-7.

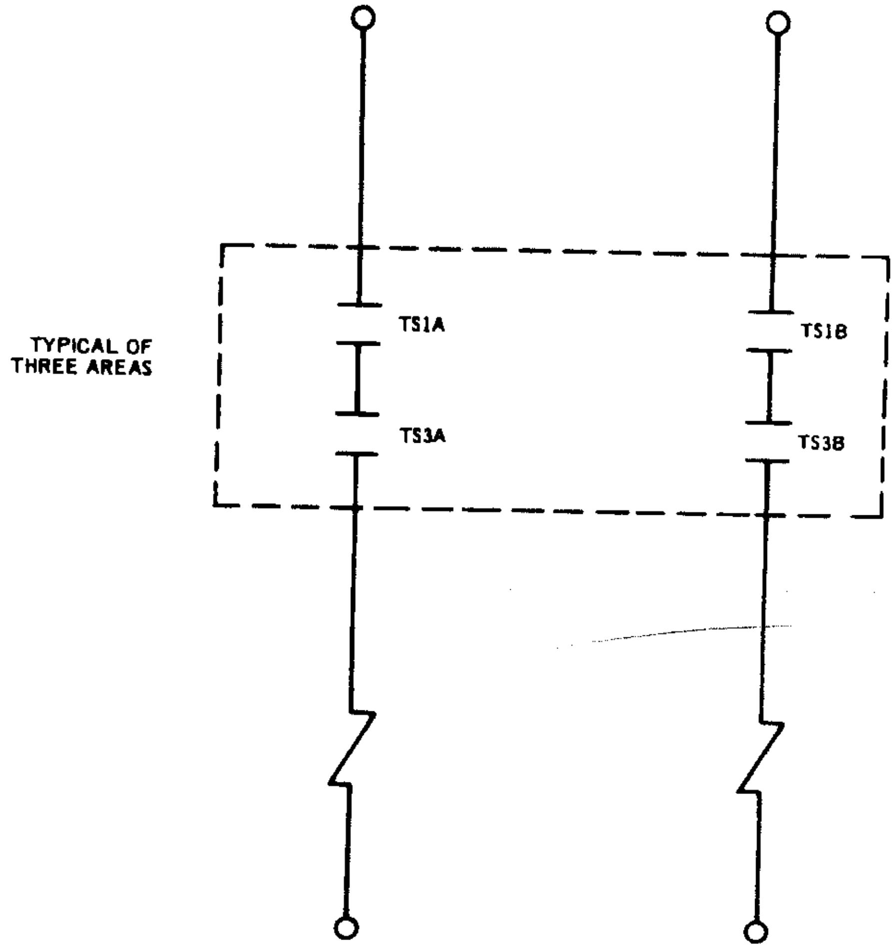


FIGURE 7.3-7
HPCI/RCIC HIGH
TEMPERATURE CHANNEL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

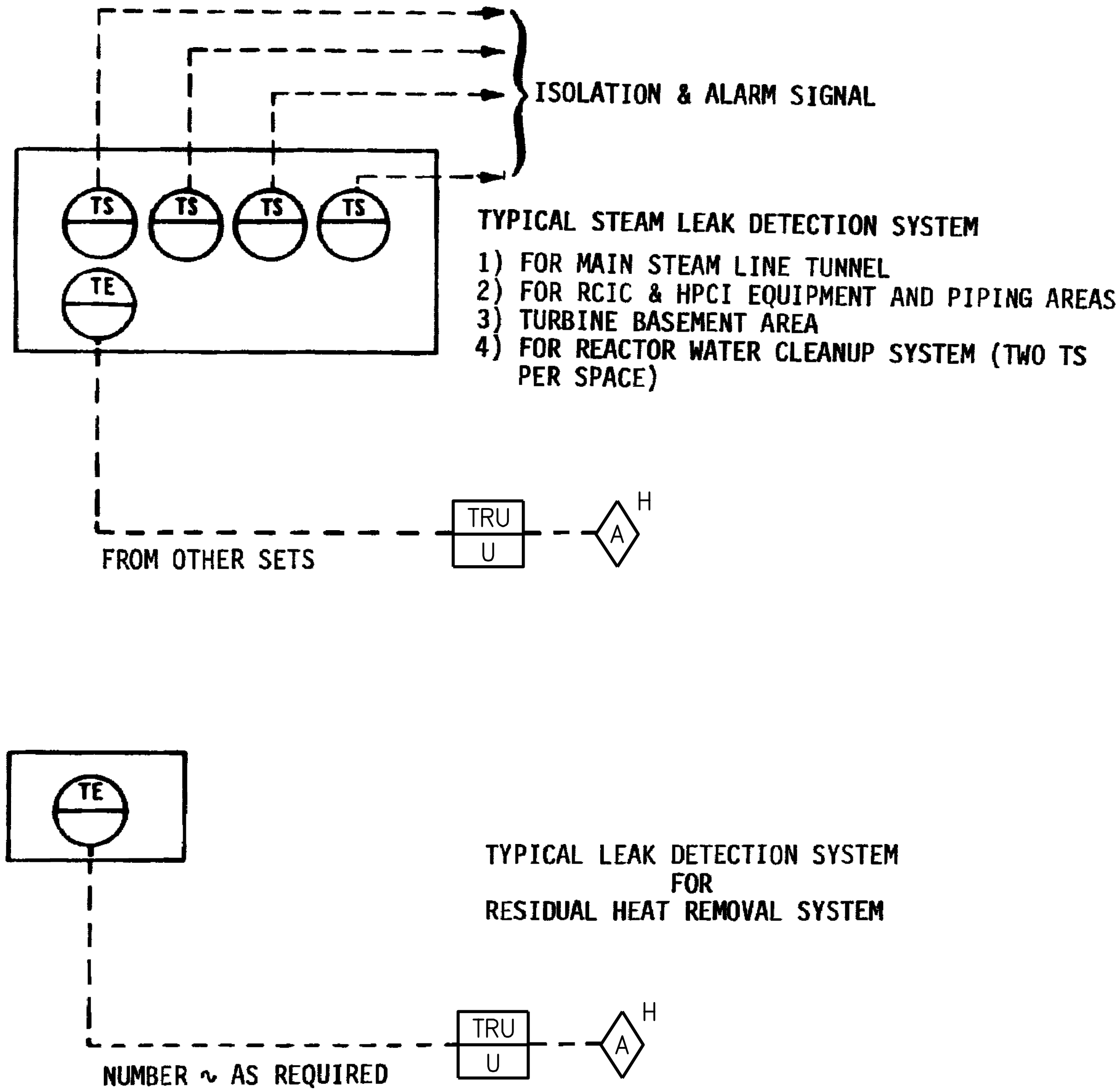


FIGURE 7.3-8
AREA AND COMPARTMENT LEAKAGE DETECTION BY TEMPERATURE MEASUREMENT
PILGRIM NUCLEAR POWER STATION FINAL SAFETY ANALYSIS REPORT

Revision 30 – November 2015

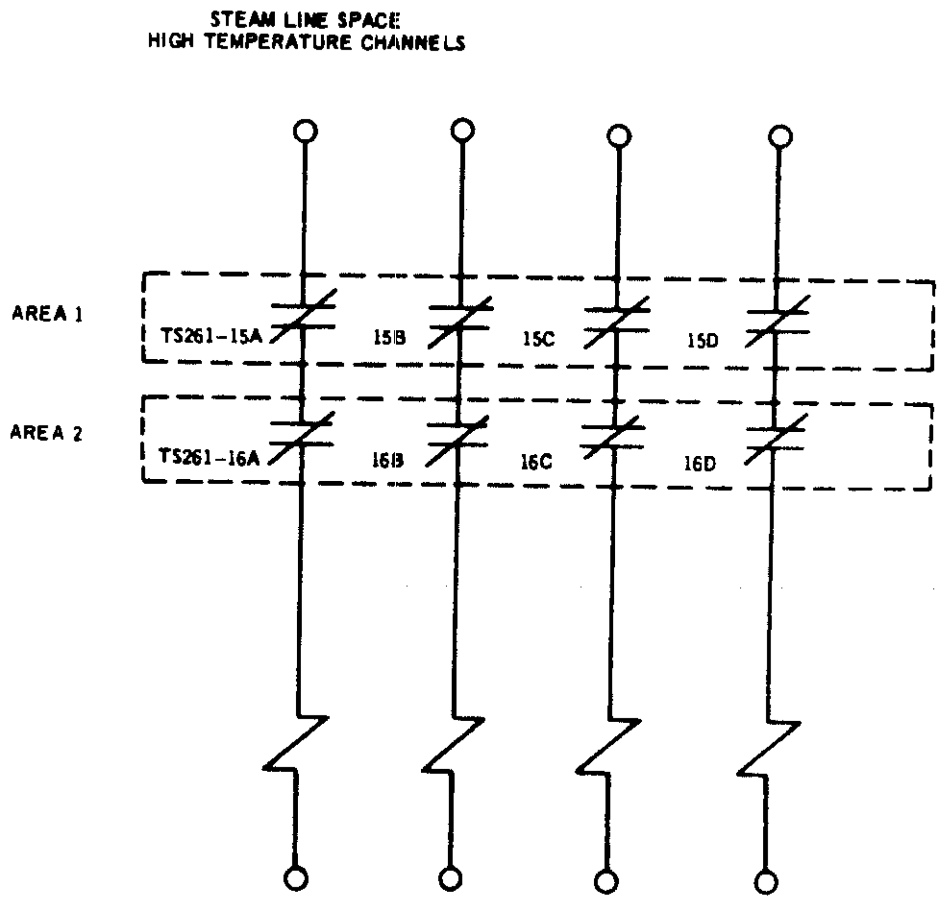


FIGURE 7.3-9
MAIN STEAMLINE SPACE
HIGH TEMPERATURE CHANNEL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

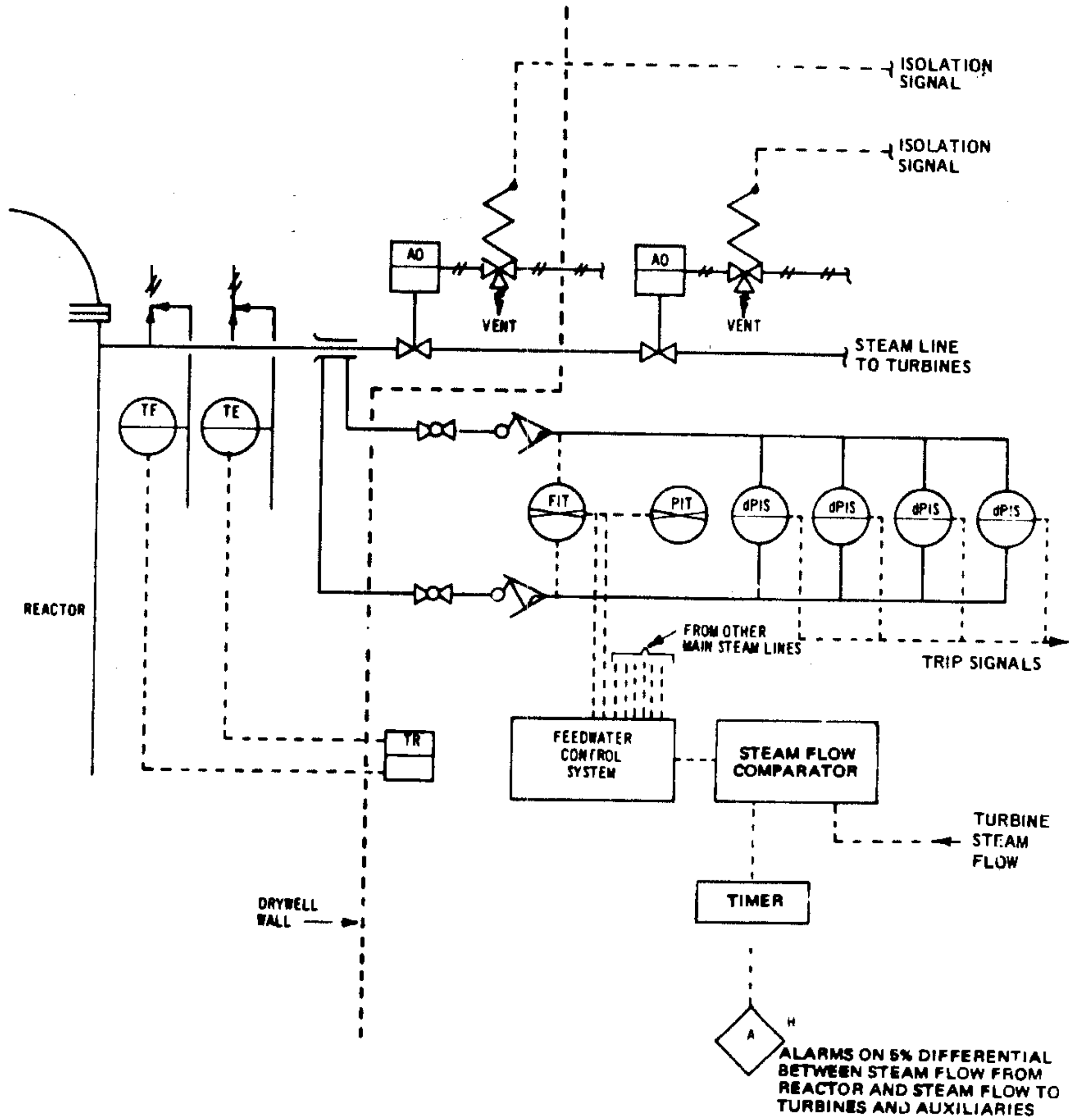


FIGURE 7.3-10
TYPICAL ARRANGEMENT FOR MAIN STEAMLINE LEAK DETECTION BY FLOW MEASUREMENT
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

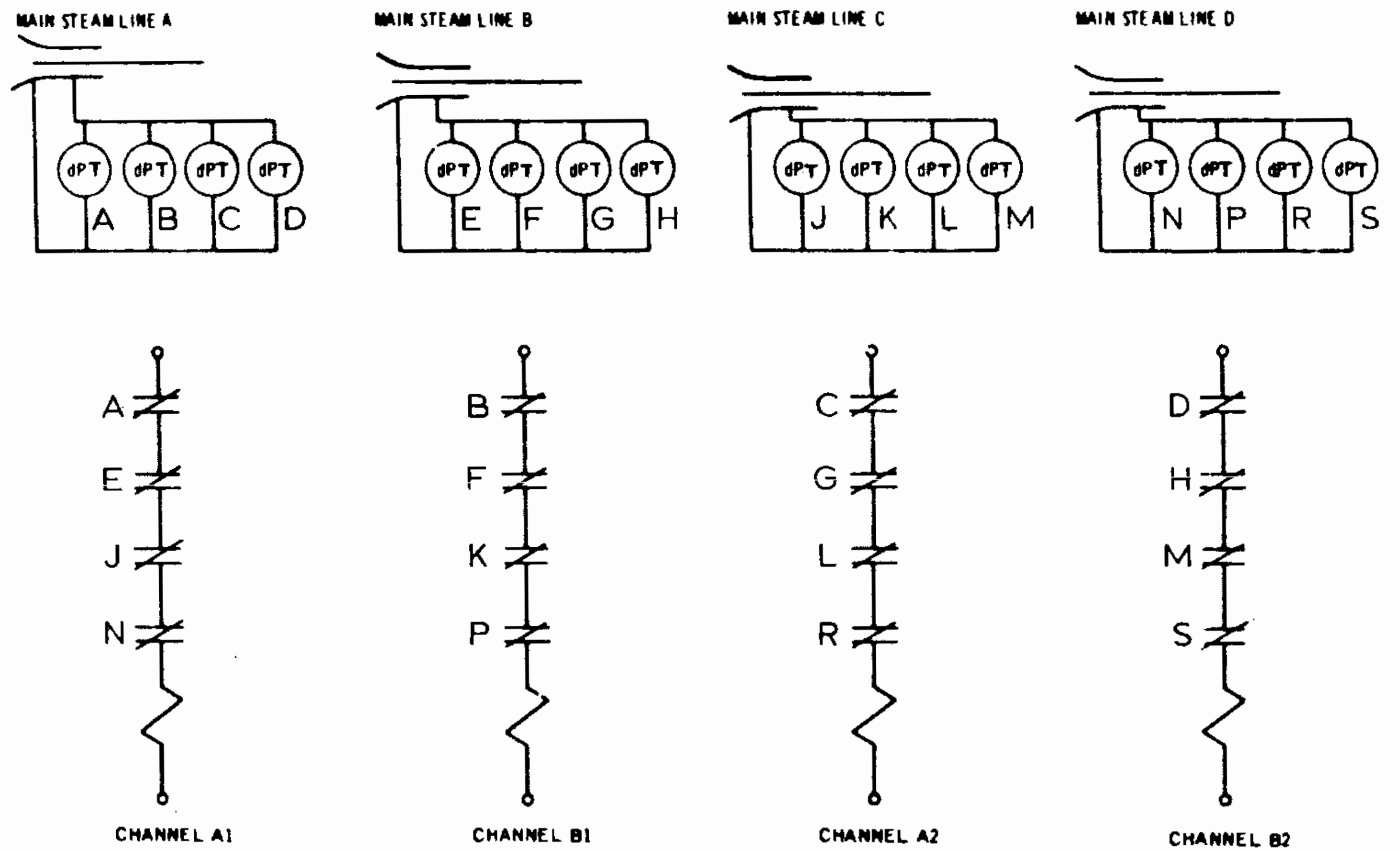
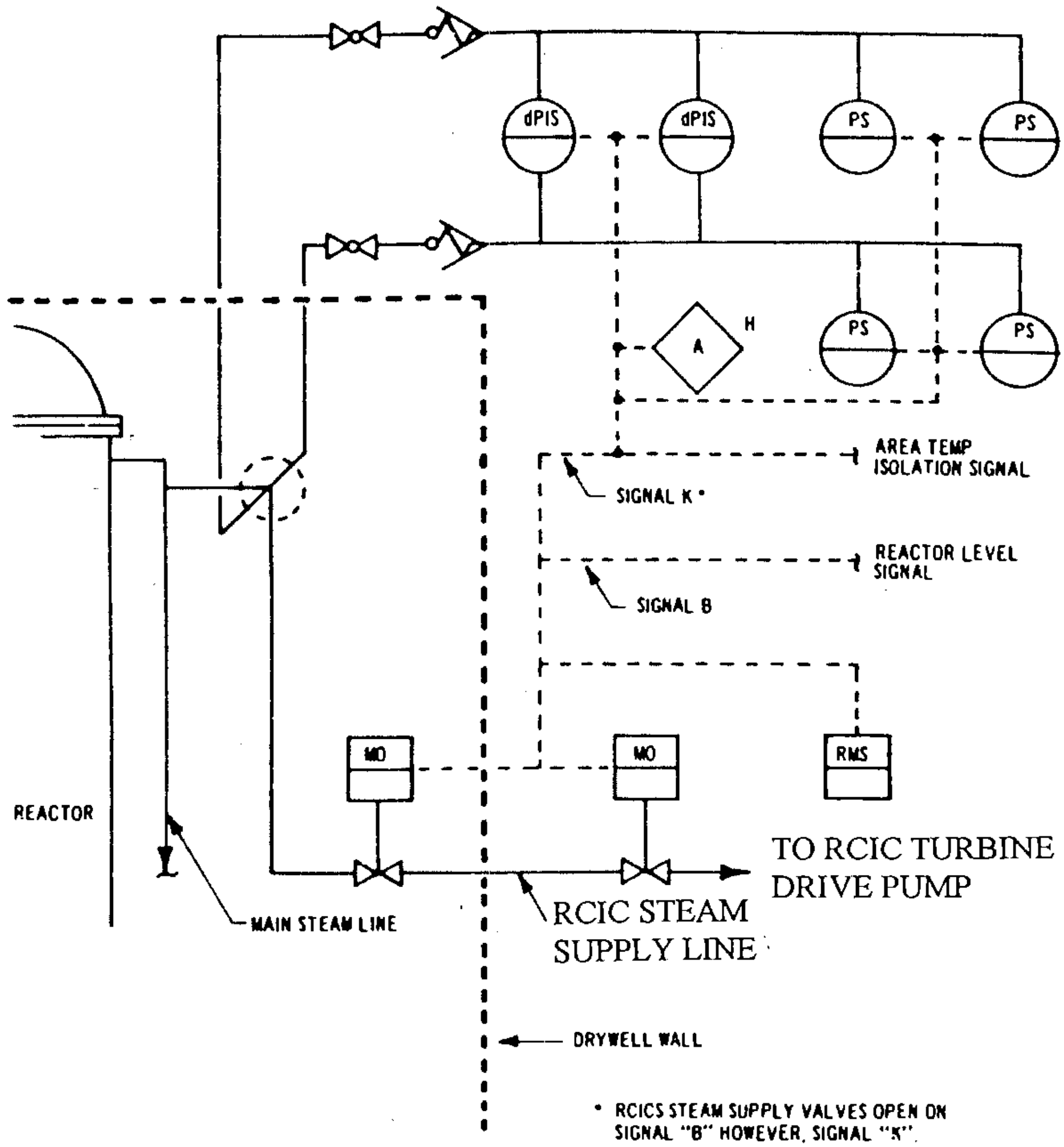


FIGURE 7.3-11
MAIN STEAMLINE
HIGH FLOW CHANNELS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 12- JANUARY 1991



* RCICS STEAM SUPPLY VALVES OPEN ON SIGNAL "B" HOWEVER, SIGNAL "K", RESULTING FROM RCICS LINE BREAK, OVERIDES SIGNAL "B" & CLOSES RCIC STM SUPPLY VALVES

FIGURE 7.3-12
RCIC ELBOW TAP ARRANGEMENT
FOR GROSS LEAK DETECTION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 21 OCTOBER 1997

This page intentionally left blank

Figure 7.3-13
NOT USED

Figures 7.3-14, 7.3-15 and 7.3-16 have been removed.

Please refer to BECo Controlled Drawings M1N33-10, M1N34-9 and M1N36-7.

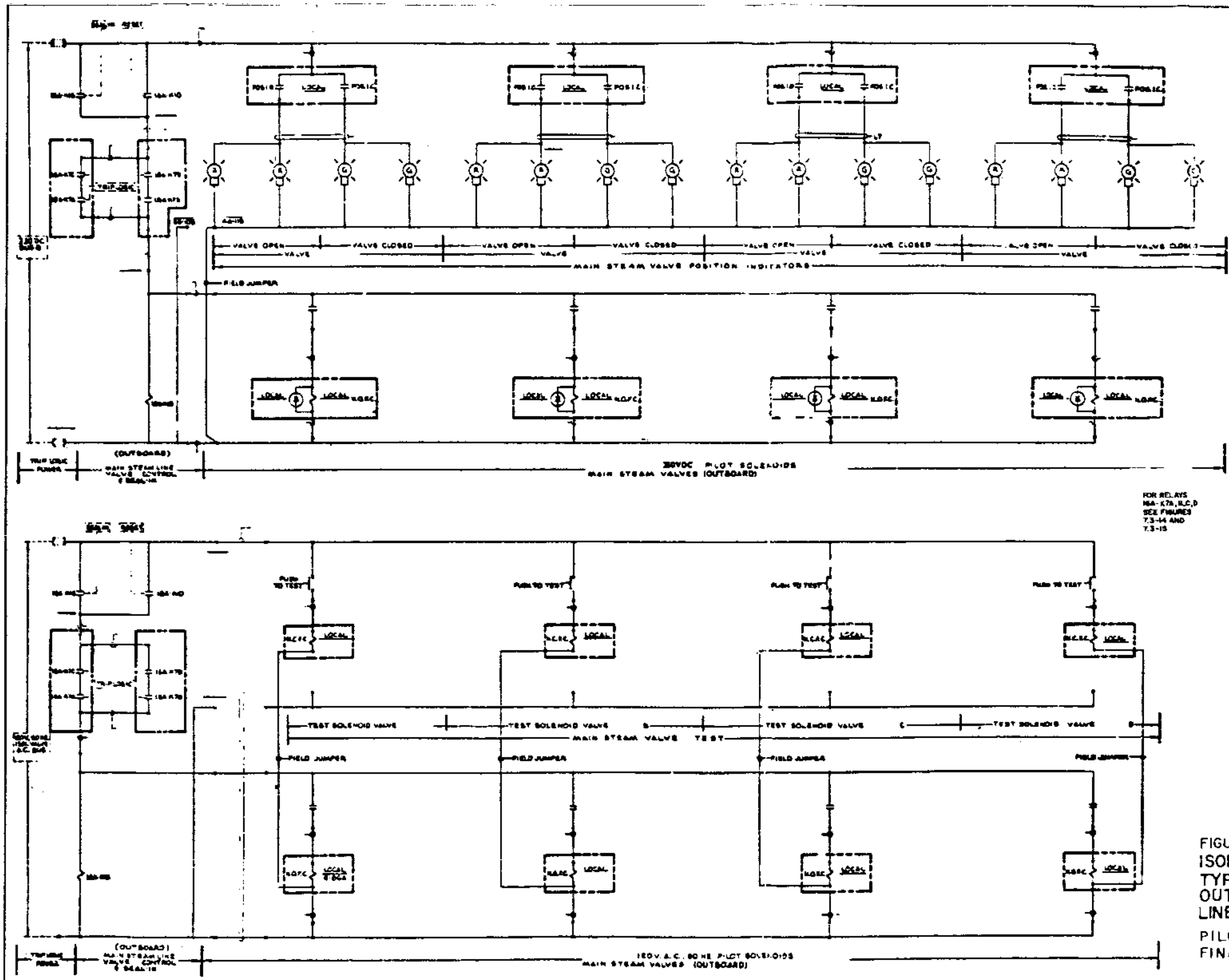


FIGURE 7.3-17
ISOLATION CONTROL SYSTEM
TYPICAL CONTROLS FOR
OUTBOARD MAIN STEAM
LINE ISOLATION VALVES

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 1 - OCTOBER 1982

Figures 7.3-18, 7.3-19 and 7.3-20 have been removed.

Please refer to BECo Controlled Drawings M1N39-13, M1N60 and M1N40-12.

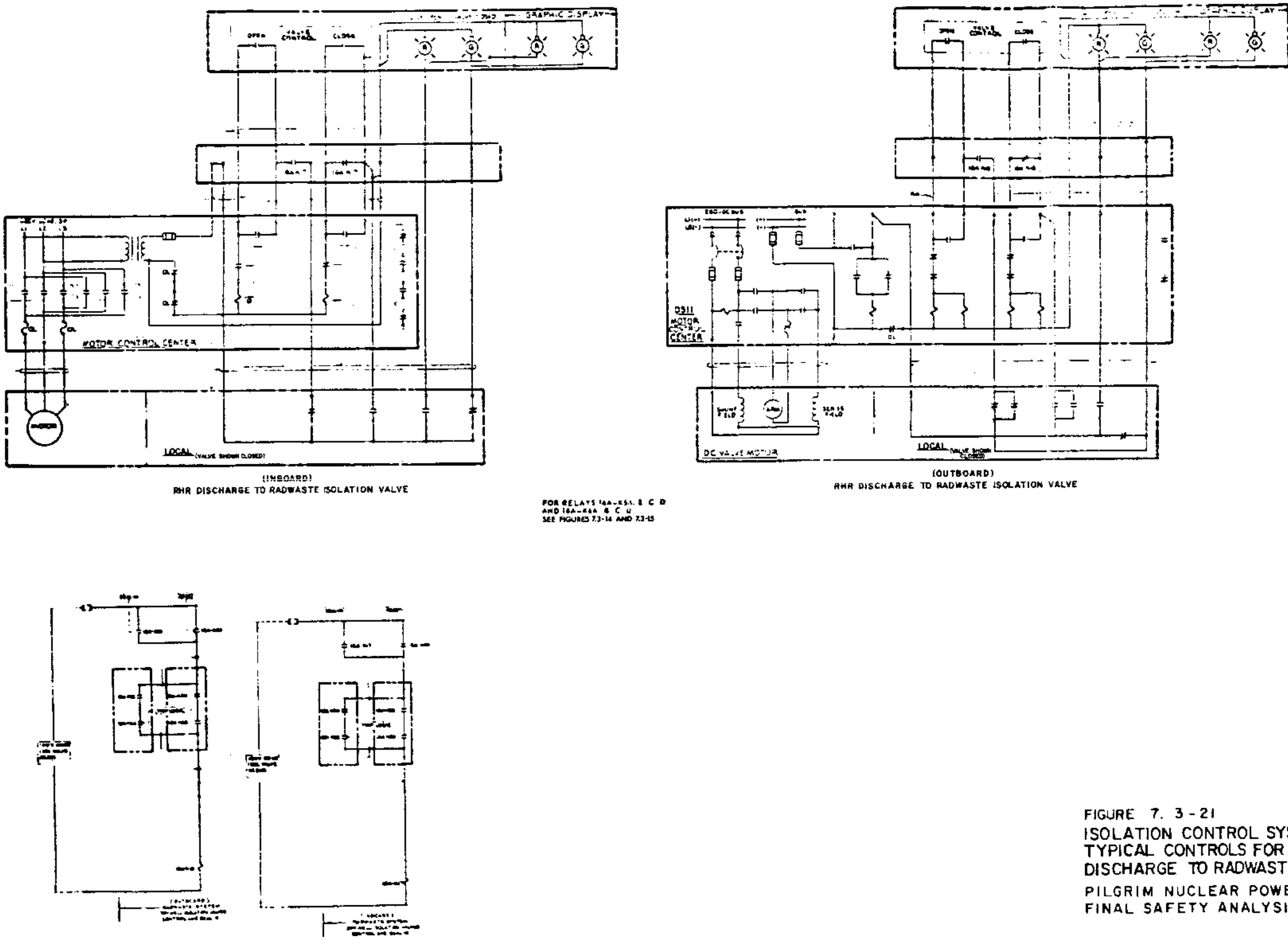
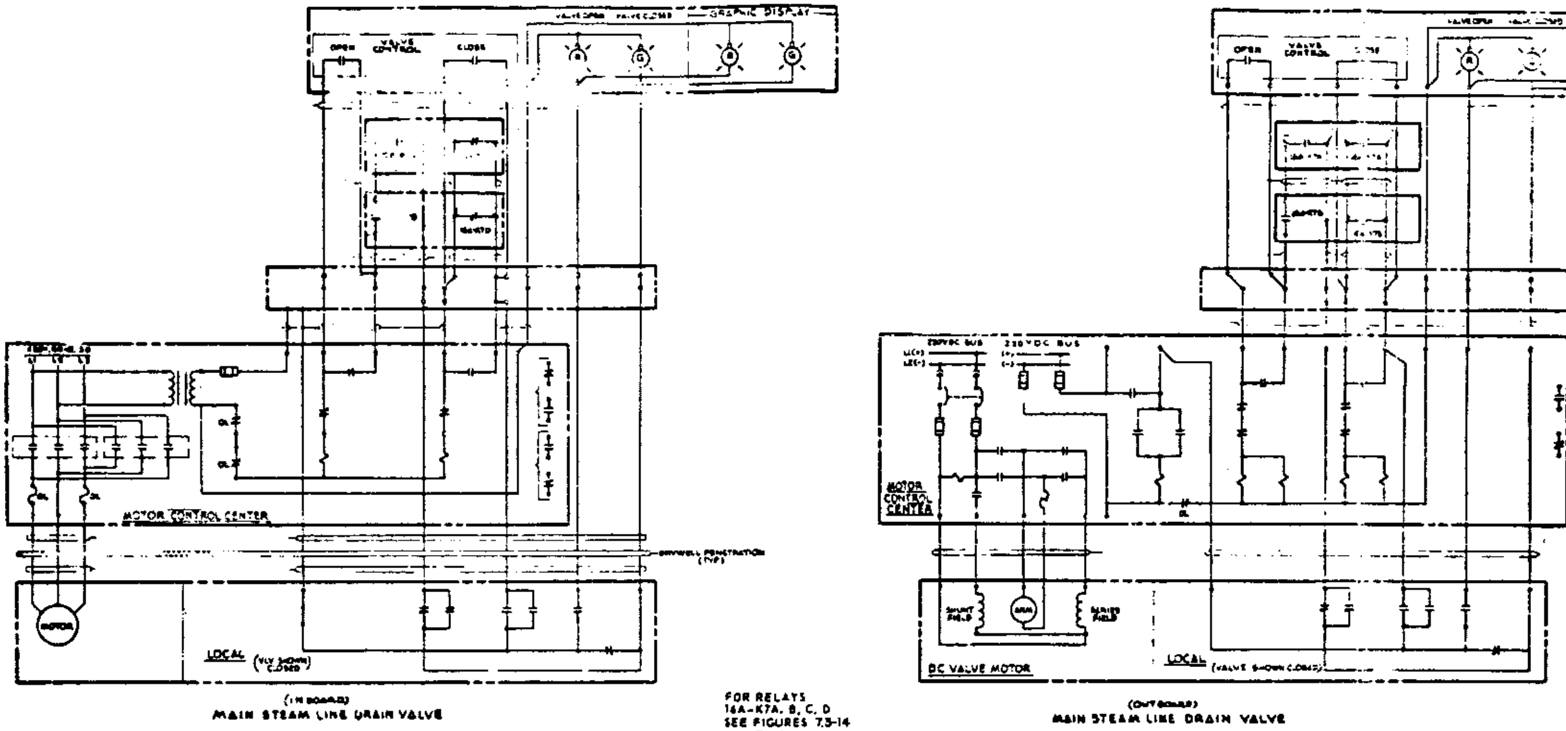


FIGURE 7. 3-21
ISOLATION CONTROL SYSTEM
TYPICAL CONTROLS FOR RHRS
DISCHARGE TO RADWASTE VALVES
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

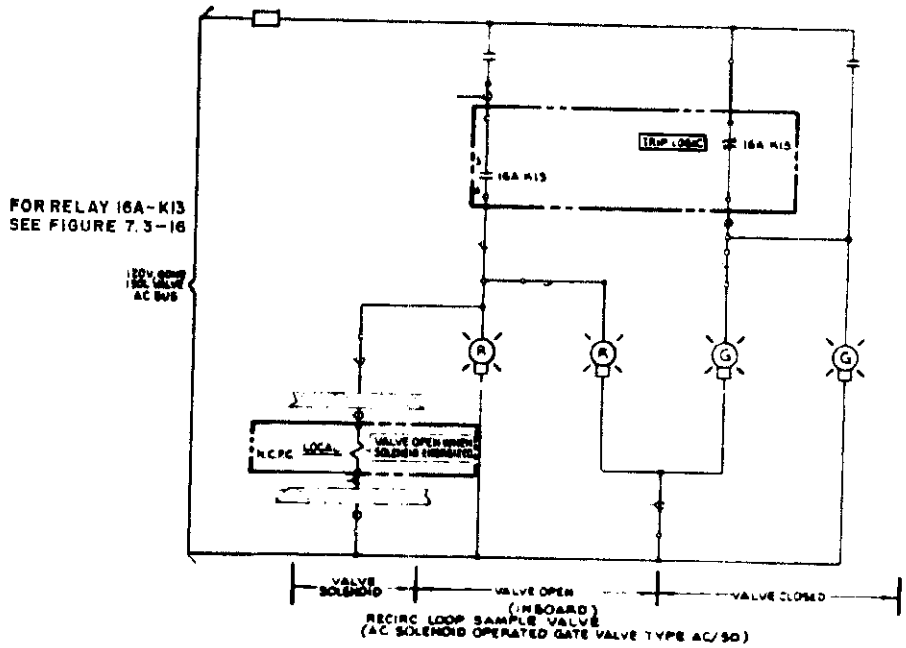
REVISION 1-OCTOBER 1982



FOR RELAYS
16A-K7A, B, C, D
SEE FIGURES 7.3-14
AND 7.3-15

FIGURE 7. 3 - 22
ISOLATION CONTROL SYSTEM
TYPICAL CONTROLS FOR MAIN
STEAM LINE DRAIN VALVES
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 1-OCTOBER 1982



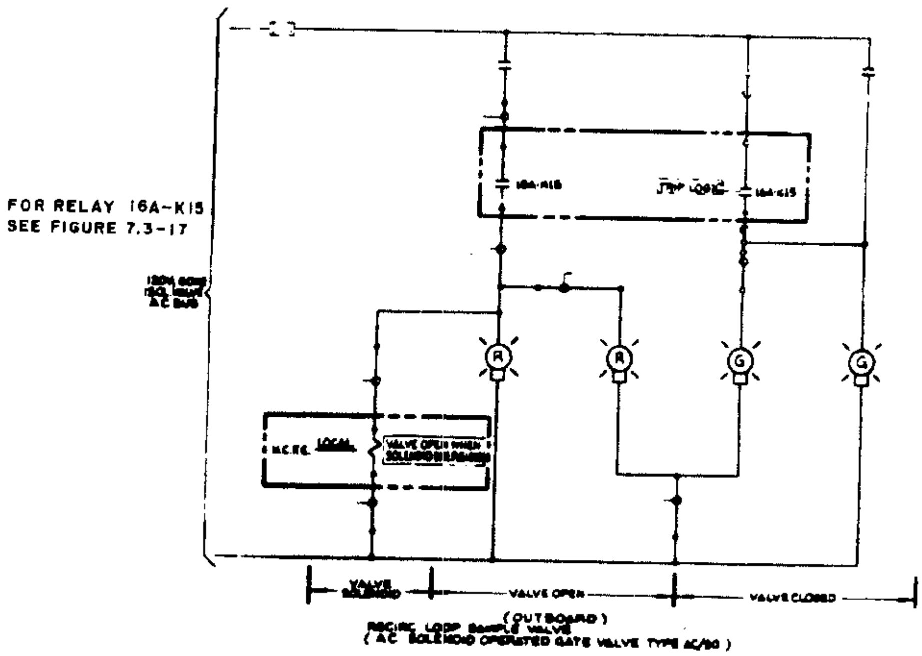


FIGURE 7.3-23

ISOLATION CONTROL SYSTEM TYPICAL CONTROLS FOR RECIRCULATION LOOP SAMPLE VALVES

PILGRIM NUCLEAR POWER STATION FINAL SAFETY ANALYSIS REPORT

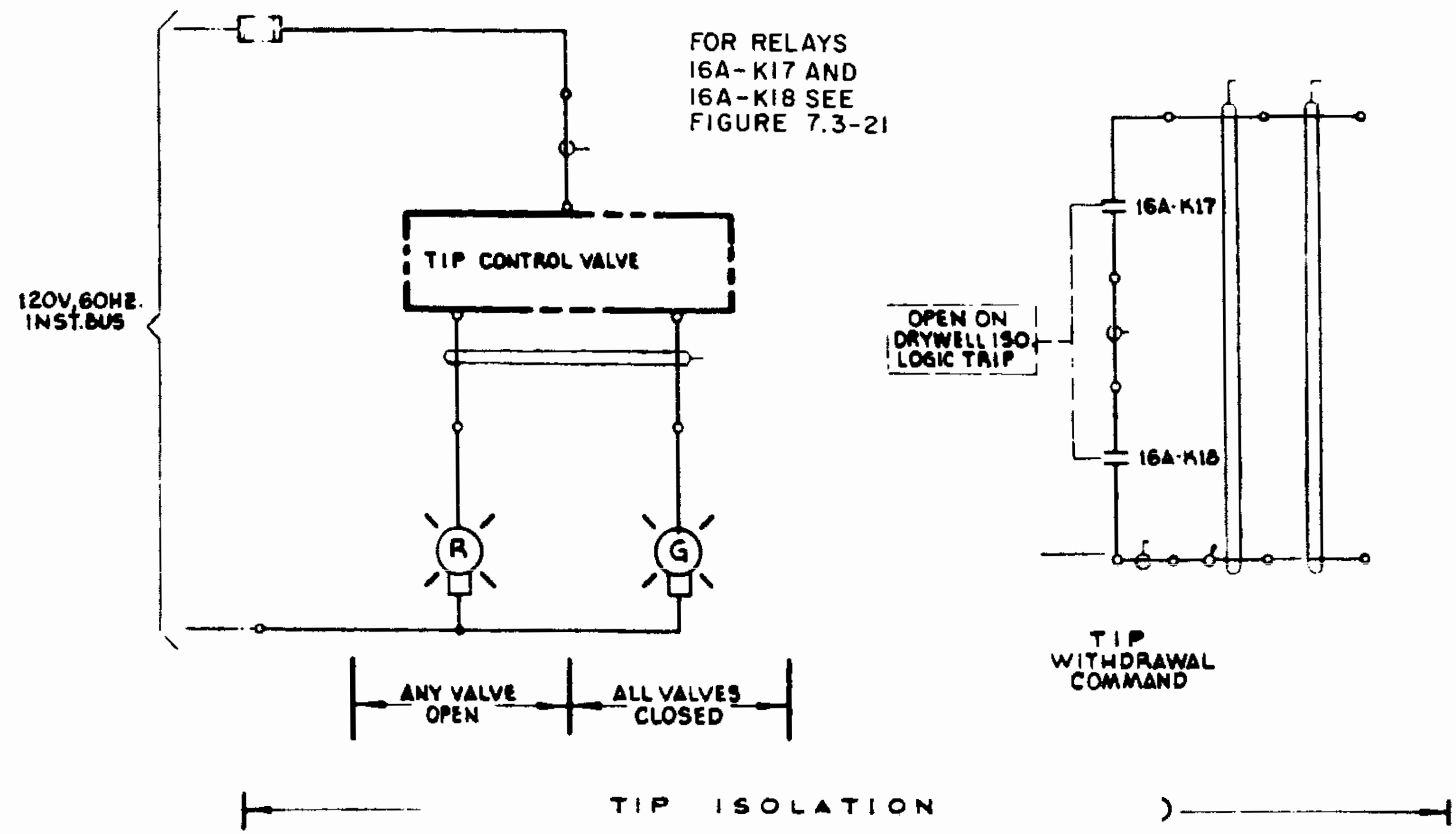


FIGURE 7.3-24
ISOLATION CONTROL
SYSTEM TYPICAL
CONTROLS FOR TIP SYSTEM

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

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. Similarly, this temperature element is used to detect pilot or main stage leakage from a two-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-stage SRVs only)

(3) valve body internal thermowell in proximity to the second stage pilot seat, (3-stage SRVs only)

(4) mounted external to pilot assembly to detect bellows assembly leakage. (3-stage SRVs only)

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. The bellows temperature detector and alarm are applicable only to 3-Stage SRVs and not required for 2-Stage SRVs.

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.

Table 7.4-2

AUTOMATIC DEPRESSURIZATION SYSTEM FOR CURRENT PLANT SAFETY ANALYSIS
INSTRUMENT SPECIFICATIONS

SYSTEM FUNCTION	INSTRUMENT	RANGE	TRIP SETTING	DESIGN BASIS REFERENCE
Reactor Vessel Low Water Level (See Note 1)	LT263-72A,B,C,D LIS263-72A,B,C,D	-50 to +50 in (See Note 2)	425.6 in above vessel zero	BECo Calc. I-N1-96 (See Note 3)
Primary Containment (drywell) High Pressure (See Note 1)	PT1001-89A,B,C,D PIS1001-89A,B,C,D	0 to 5 psig	2.5 psig	BECo Calc. I-N1-134 (See Note 3)
Relief Valve Leakage	TR260-20	0-600°F	200°F	
LPCI Pump Discharge Pressure Interlock	PS1001-93A,B,C,D PS1001-104A,B,C,D	0 to 600 psig	100 psig	
Core Spray Pump Discharge Pressure Interlock	PS1451A,B PS1464A,B	0 to 600 psig	100 psig	

NOTES:
1. Incident Detection circuitry instrumentation
2. Referenced to instrument zero (482½ 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.

Table 7.4-3

CORE SPRAY SYSTEM FOR CURRENT PLANT SAFETY ANALYSIS
INSTRUMENT SPECIFICATIONS

CORE SPRAY FUNCTION	INSTRUMENT	RANGE	TRIP SETTING	DESIGN BASIS REFERENCE
Reactor Vessel Low Water Level (Pump start signal) (See Note 1)	LT263-72A,B,C,D LIS263-72A,B,C,D	-50 to +50 in (See Note 3)	425.6 in above vessel zero	BECo Calc. I-N1-96 (See Note 4)
Primary Containment (drywell) High Pressure (Pump start signal) (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	BECo Calc. I-N1-137 (See Note 4)
Reactor Vessel Low Pressure (Pump Start Permissive)	PT263-50A,B PIS263-50A,B PS263-50A-1,B-1	0 to 1,200 psig	290 psia	BECo Calc. I-N1-148 (See Note 4)
Core Spray Sparger High Differential	DPIS1459A, B	-10 to 0 to 15 psid	-1 psid (± 1.5 psid)	
Discharge Header Pressure	PS1400-42A,B	0-500 psig	400 psid (See Note 2)	
Reactor Vessel Low Pressure (Valve Opening Permissive)	PT263-52A,B PIS263-52A,B PS263-52A-1,B-1	0 to 1,200 psig	450 psig> P>290 psia	BECo Calc. I-N1-152 (See Note 4)

NOTES:
1. Incident Detection circuitry instrumentation
2. Alarm point to signal leakage from nuclear system into core spray outside primary containment
3. Referenced to instrument zero (482½ inches above vessel zero)
4. The setpoint for this parameter was analyzed in accordance with R.G. 1.105. The trip setting identified is the design basis analytical limit.

Table 7.4-4

LOW PRESSURE COOLANT INJECTION SYSTEM FOR CURRENT PLANT SAFETY ANALYSIS INSTRUMENT SPECIFICATIONS

LPCI FUNCTION	INSTRUMENT	RANGE	SETPOINT ANALYTICAL LIMIT	DESIGN BASIS REFERENCE CALCULATION
Reactor Vessel Low Water Level (LPCI Pump Start Signal) (See Note 1)	LT263-72A,B,C,D LIS263-72A,B,C,D LS263-72A-1, B-1, C-1, D-1	-50 to +5 in (See Note 5)	425.6 in above vessel zero	I-N1-97
Primary Containment (Drywell) High Pressure (LPCI Initiation) (See Note 1)	PT1001-89A,B,C,D PIS1001-89A,B,C,D PS1001-89A-2, B-2 C-2,D-2	0 to 5 psig	2.5 psig	I-N1-136
Reactor Vessel Low Water Level (Inside Shroud)	LT263-73A,B LIS263-73A,B	-277.5 to +22.5 in (See Note 5)	307 in above vessel zero (approx. 2/3 core height level)	I-N1-133
Reactor Vessel Low Pressure (Pump Start Permissive)	PT263-50A,B PIS263-50A,B PS263-50A-2,B-2	0 to 1,200 psig	290 psia	I-N1-149
Recirculation Loop Break Detection	DPIS261-12A,B,C,D	0 - 10 psid	4.9 psid trip on upscale (See Note 2)	I-N1-194
Reactor Vessel Low Pressure (valve opening permissive)	PT263-52A,B PIS263-52A,B	0 to 1,200 psig	450 psig >P >290 psia	I-N1-151

NOTES:
1. Incident Detection circuitry instrumentation.
2. Return from over-range of 200 psi to 0 psi in 100 milliseconds maximum.
3. Return from over-range of 200 psi to 0 psi in 100 milliseconds maximum.
4. Flow point for opening pump minimum flow bypass valves
5. Referenced to instrument zero (482½ inches above vessel zero)

Table 7.4-4 (Cont)

LOW PRESSURE COOLANT INJECTION SYSTEM FOR CURRENT PLANT SAFETY ANALYSIS INSTRUMENT SPECIFICATIONS

LPCI FUNCTION	INSTRUMENT	RANGE	SETPOINT ANALYTICAL LIMIT	DESIGN BASIS REFERENCE CALCULATION
Containment Spray Valve Manual Control Interlock High Drywell Pressure	PT1001-89A,B,C,D PIS1001-89A,B,C,D PS1001-89A-1,B-1, C-1,D-1	0 to 5 psig	2 psig >P>1 psig	I-N1-135
LPCI Pump Low Flow	DPIS-1001-79A,B	0-5,000 GPM	2,500 GPM (See Note 4)	I-N1-199
Reactor Vessel Pressure Permissive	PT263-49A,B PIS263-49A,B PT263-50A,B PIS263-50A,B	0-1,500 psig	935 psig >P>800 psia	I-N1-146 and I-N1-147
Recirculation Pumps Differential Pressure Switch	DPIS261-36A,B DPIS261-37A,B DPIS261-38A,B DPIS261-39A,B	0 to 10 psid	4.9 psid Trip on Downscale (See Note 3)	I-N1-201

NOTES: 1. Incident Detection circuitry instrumentation.
2. Return from over-range of 200 psi to 0 psi in 100 milliseconds maximum.
3. Return from over-range of 200 psi to 0 psi in 100 milliseconds maximum.
4. Flow point for opening pump minimum flow bypass valves
5. Referenced to instrument zero (482½ inches above vessel zero)

Table 7.4-5

CORE STANDBY COOLING SYSTEMS (LOGIC) OPERATIONAL REQUIREMENTS FOR PLANT SAFETY ANALYSIS

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *
7.4.1 Incident Detection and CSCS Initiation	1. Trip Systems	HPCI-1 ADS-1 LPCI-2 CSS-2	Manual start system operable.	Manual start system operable.	1. Above 104 psig, the HPCI trip system operable or ADS trip system operable. 2. 1 LPCI trip system operable. 3. 1 CSS trip system operable. (C39-92)	1. Above 104 psig, the HPCI trip system operable or ADS trip system operable. 2. 1 LPCI trip system operable. 3. 1 CSS trip system operable. (D39-92)	1. The HPCI trip system operable or ADS trip system operable. 2. 1 LPCI trip system operable. 3. 1 CSS trip system operable. (E39-92)	1. The HPCI trip system operable or ADS trip system operable. 2. 1 LPCI trip system operable. 3. 1 CSS trip system operable. (F39-92)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.4-5 (Cont)

CORE STANDBY COOLING SYSTEMS (LOGIC) OPERATIONAL REQUIREMENTS FOR PLANT SAFETY ANALYSIS

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.4.1 Incident Detection and CSCS Initiation (Con't)	2. Trip system logics	2 Trip system logics per trip system except LPCI which has 3 trip system logics per trip system			1 trip system logic operable per operable trip system except for LPCI where the loop selection trip system logic must be operable and 1 of the 2 remaining trip system logics must be operable. (C39-92)	1 trip system logic operable per operable trip system except for LPCI where the loop selection trip system logic must be operable and 1 of the 2 remaining trip system logics must be operable. (D39-92)	1 trip system logic operable per operable trip system except for LPCI where the loop selection trip system logic must be operable and 1 of the 2 remaining trip system logics must be operable. (E39-92)	1 trip system logic operable per operable trip system except for LPCI where the loop selection trip system logic must be operable and 1 of the 2 remaining trip system logics must be operable. (F39-92)
	3. Parallel Logic Pairs	2 Parallel logic pairs per trip system logic in the HPCI, LPCI, and CSS trip systems.			1 parallel logic pair operable per operable trip system logic and 1 parallel logic pair inoperable and tripped. (C39-92)	1 parallel logic pair operable per operable trip system logic and 1 parallel logic pair inoperable and tripped. (039-92)	1 parallel logic pair operable per operable trip system logic and 1 parallel logic pair inoperable and tripped. (E39-92)	1 parallel logic pair operable per operable trip system logic and 1 parallel logic pair inoperable and tripped. (F39-92)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.4-5 (Cont)

CORE STANDBY COOLING SYSTEMS (LOGIC) OPERATIONAL REQUIREMENTS FOR PLANT SAFETY ANALYSIS

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.4.1 Incident Detection and CSCS Initiation (Cont)	4. Power Supply to Control circuits	2 125 V dc busses			1 125 V dc bus (C39-92)	1 125 V dc bus (D39-92)	1 125 V dc bus (E39-93)	1 125 V dc bus (F39-92)
Detect Accident Condition and Initiate HPCI Operation	1. Reactor vessel low water level channels. 2. Primary containment high pressure channels.	4 channels in 1 trip system logic. 4 channels in the other trip system logic.			Above 150 psig, 1 channel operable in each of the 2 parallel logic pairs in each trip system logic (C39-65)	Above 150 psig, 1 channel operable in each of the 2 parallel logic pairs in each trip system logic (D39-65)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic (E39-65)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic F39-65)
7.4.3 Initiate Auto Depressurization Valves	1. Reactor vessel low water level channels. 2. Primary containment high pressure channels	2 channels in each trip system logic 2 channels in each trip system logic			Above 104 psig, 2 channels operable in 1 series logic pair and 1 channel tripped in the other series logic pair, in each trip system logic (C39-66)	Above 104 psig, 2 channels operable in 1 series logic pair and 1 channel tripped in the other series logic pair, in each trip system logic (D39-66)	2 channels operable in 1 series logic pair and 1 channel tripped in the other series logic pair, in each trip system logic (E39-66)	2 channels operable in 1 series logic pair and 1 channel tripped in the other series logic pair, in each trip system logic (F39-66)

*Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.4-5 (Cont)

CORE STANDBY COOLING SYSTEMS (LOGIC) OPERATIONAL REQUIREMENTS FOR PLANT SAFETY ANALYSIS

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.4.2 Initiate Auto Depressurization Valves (Cont)	3. Automatic depressurization delay timer (permissive after 120 sec.)	1 timer in each trip system logic.			Above 104 psig, 1 timer operable in each trip system logic. (C39-66)	Above 104 psig, 1 timer operable in each trip system logic. (D39-66)	1 timer operable in each trip system logic (E39-66)	1 timer operable in each trip system logic (F39-66)
	4a. LPCI pump discharge pressure channel (permissive when at 150 psig.)	1 channel in the ADS trip system.			Above 104 psig, 1 operable channel in an operable low pressure pump cooling path. (C39-66)	Above 104 psig, 1 operable channel in an operable low pressure pump cooling path. (D39-66)	1 operable channel in an operable low pressure pump cooling path. (E39-66)	1 operable channel an operable low pressure pump cooling path. (F39-66)
	4b. Core spray pump discharge pressure channel (permissive when at 150 psig.)	2 channels in the ADS trip system.						
7.4.4 Detect Accident Condition and Initiate LPCI Mode Operation of RHR	1. Reactor vessel low water level channels (for recirculation loop selection)	4 channels per trip system logic			1 channel operable in each of the 2 parallel logic pairs in each trip system logic (C39-62)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic (D39-62)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic (E39-67)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic (F39-67)
	2. Primary containment high pressure channels.	4 channels per trip system logic						

**Minimum Required for Action* is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.4-5 (Cont)

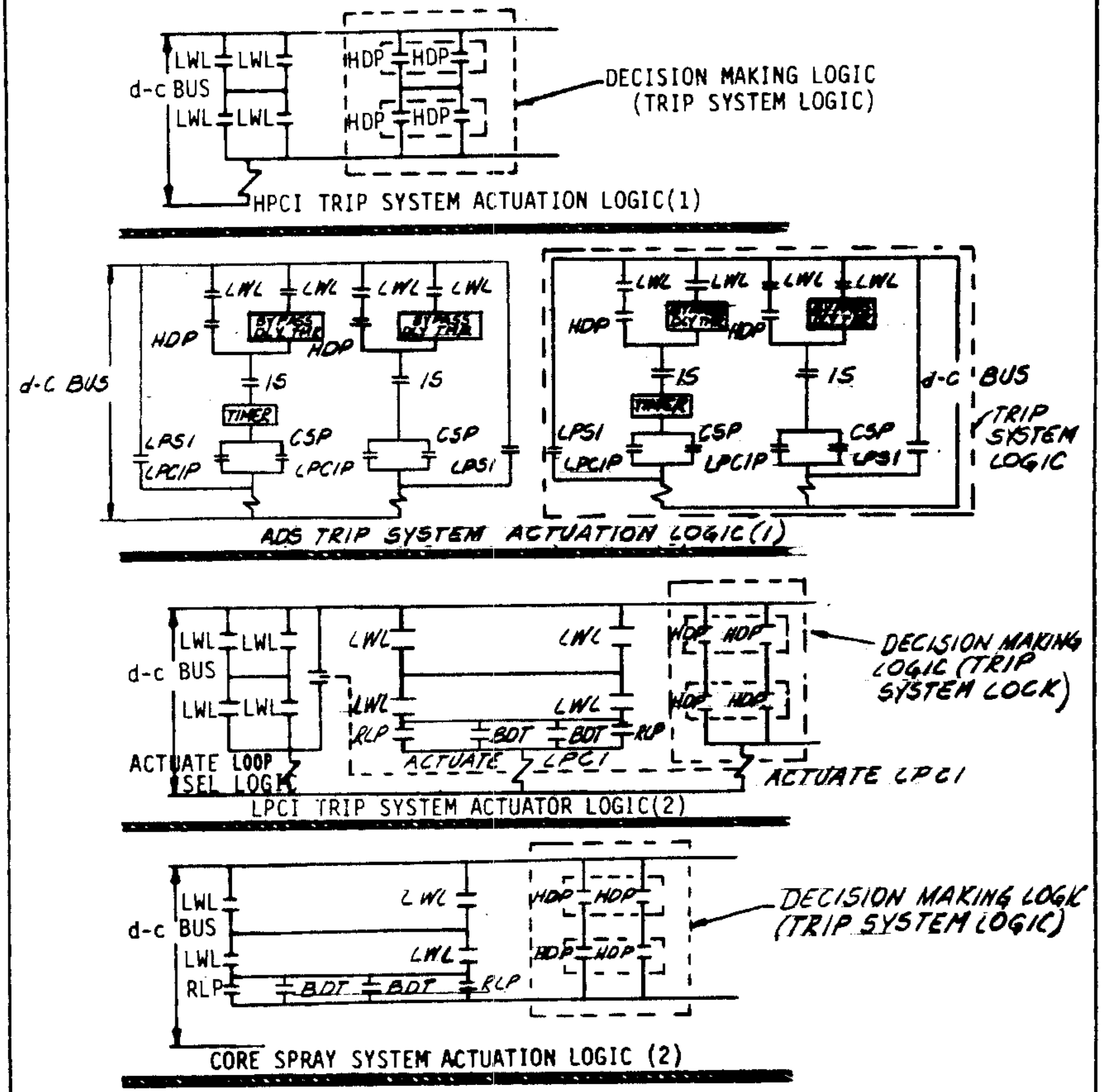
CORE STANDBY COOLING SYSTEMS (LOGIC) OPERATIONAL REQUIREMENTS FOR PLANT SAFETY ANALYSIS

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.4.5 Detect Accident Condition and Initiate Core Spray Operation	1. Reactor vessel low water level channels 2. Primary containment high pressure channels	4 channels per trip system logic 4 channels per trip system logic			1 channel operable in each of the 2 parallel logic pairs in each trip system logic (C39-67)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic (D39-67)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic (E39-67)	1 channel operable in each of the 2 parallel logic pairs in each trip system logic (F39-67)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

The following FSAR figures have been removed from the FSAR. Please refer to the corresponding BECo controlled drawing.

FSAR FIGURE	**BECO CONTROLLED DRAWING**
7.4-1	M243
7.4-2	M244
7.4-3	M1J22-5
7.4-4	M1J23-4
7.4-5	M1J24-4



LEGEND:

LWL-LOW WATER LEVEL
HDP-HIGH DRYWELL PRESSURE
ADS-AUTOMATIC DEPRESSURIZATION SYSTEM
CSP-ONE CORE SPRAY PUMP RUNNING
LPCIP-ONE LPCI PUMP RUNNING
RLP-REACTOR LOW PRESSURE

IS-INHIBIT SWITCH
LPSI-LOW PRESS. PUMP SEAL-IN
BDT-BYPASS DELAY TIMER

FIGURE 7.4-6
TYPICAL CORE STANDBY COOLING SYSTEMS TRIP SYSTEMS ACTUATION LOGIC
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 10 - JULY 89

Figure 7.4-7 has been deleted.

Please refer to Figure 7.3-6.

Figure 7.4-8 and 7.4-9 have been deleted.

Please refer to BECo Controlled Drawings M242 and M1K1-8.

Figure 7.4-10 has been deleted

Please refer to figure 4.8-1(BECo M241)

Figure 7.4-11, 7.4-12, and 7.4-13 have been deleted.

Please refer to BECo Controlled Drawings M1H1-7BC, M1H2-6, and M1H3-6.

Figure 7.4-14 has been deleted.

See Figures 7.9-2, 7.9-3 and 7.9-4 for the Functional Control Diagram of the Recirculation Flow Control System

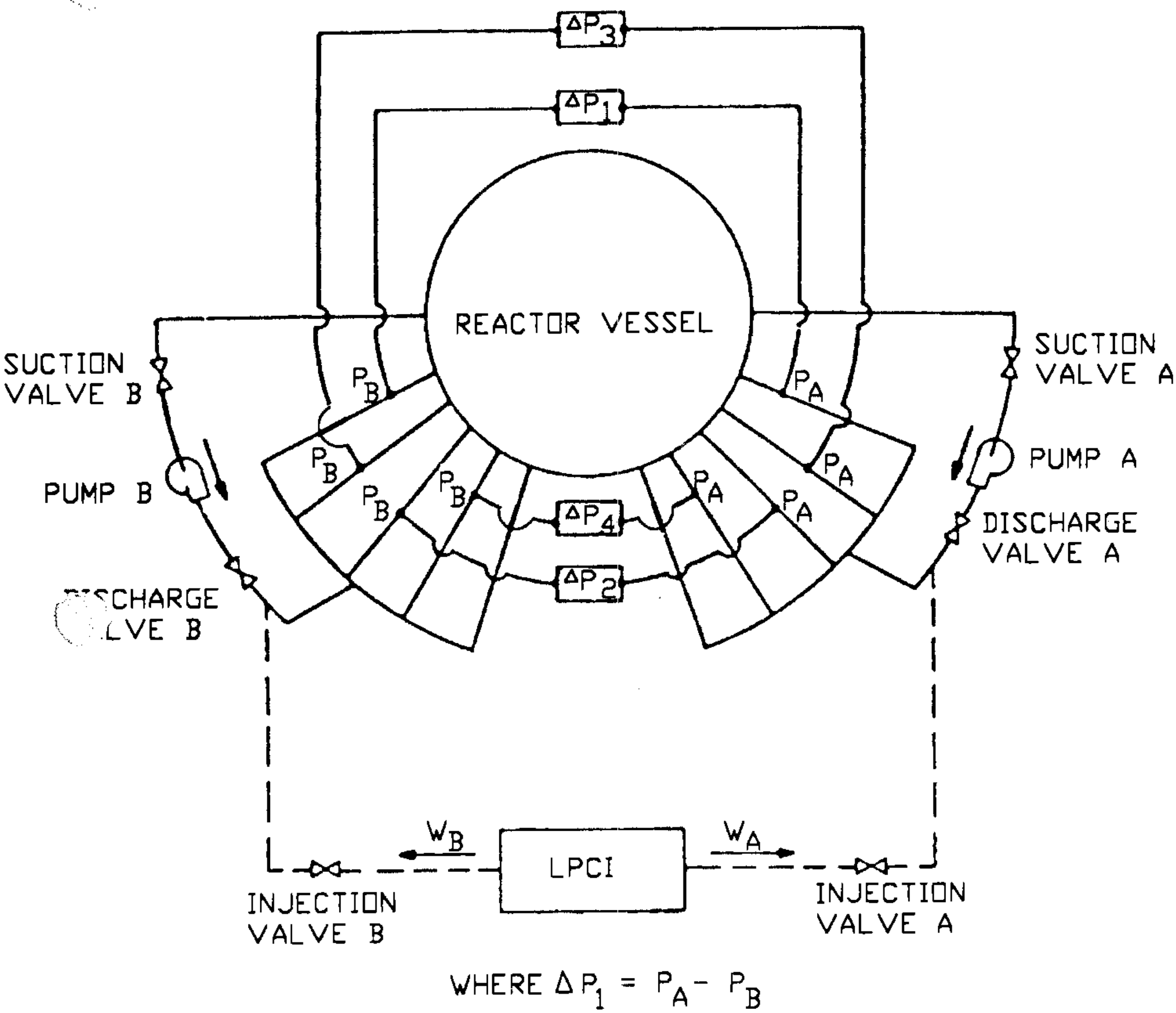


FIGURE 7.4-15
LPCI LOOP SELECTION
LOGIC COMPONENT ARRANGEMENT
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

7.5 NEUTRON MONITORING SYSTEM

7.5.1 Safety Objective

The safety objective of the Neutron Monitoring System is to detect conditions in the core that threaten the overall integrity of the fuel barrier due to excessive power generation, and provide signals to the Reactor Protection System (RPS), so that the release of radioactive material from the fuel barrier is limited.

7.5.2 Power Generation Objective

The power generation objective of the Neutron Monitoring System is to provide information for the efficient, expedient operation and control of the reactor. Two specific power generation objectives of the Neutron Monitoring System are to detect conditions that could lead to local fuel damage and to provide signals that can be used to prevent such damage, so that station availability is not reduced.

7.5.3 Identification

The Neutron Monitoring System has seven major subsystems:

Source Range Monitor Subsystem (SRMS)

Intermediate Range Monitor Subsystem (IRMS)

Local Power Range Monitor Subsystem (LPRMS)

Average Power Range Monitor Subsystem (APRMS)

Rod Block Monitor Subsystem (RBMS)

Traversing Incore Probe Subsystem (TIPS)

Each subsystem above is designed to comply with the intent of IEEE-279 and the July 1967 draft proposed 70 General Design Criteria issued by the Atomic Energy Commission. Appendix F and Appendix J contain additional details.

The seventh subsystem is the Period Based Detection Subsystem (PBDS). The PBDS is a back up feature to monitor the core for adverse trends toward decreasing thermal-hydraulic stability.

7.5.4 Source Range Monitor Subsystem

7.5.4.1 Power Generation Design Basis

1. Neutron sources and neutron detectors shall be provided for the initial startup. See Section 3.3.4.11, Startup Neutron Sources. In the following cycles only neutron detectors shall be provided. These detectors shall have a signal count to signal noise count level of no less than 2 to 1 and a count rate of no less than 3 cps with all control rods fully inserted prior to power operation.

2. The SRMS shall be designed to indicate a measurable increase in output signal from at least one detecting channel before the reactor period is less than 20 sec during the worst possible startup rod withdrawal conditions.

3. The SRMS shall be designed to indicate substantial increases in output signals with the maximum permitted number of SRM channels out of service during normal reactor startup operations.

4. The SRMS shall be designed so that SRM channels are on scale when the IRMS first indicates neutron flux during a reactor startup.

5. The SRMS shall provide a measure of the time rate of change of the neutron flux (reactor period) for operational convenience.

6. The SRMS shall be capable of generating a trip signal to block control rod withdrawal if the count rate exceeds a preset value or falls below a preset limit (if the IRMs are not above the second range) or if certain electronic failures occur.

7.5.4.2 Description

7.5.4.2.1 Identification

The SRMS provides neutron flux information during reactor startup and low flux level operations. There are four SRM channels, each of which includes one detector that can be remotely positioned in the core from the control room. The detectors are inserted into the core for a reactor startup and may be withdrawn if the indicated count rate is between preset limits or if the IRMS is on the third range or above.

7.5.4.2.2 Power Supply

The power for the monitors is supplied from the two separate 24 V dc buses, two monitors on one bus and two monitors on the other. See Section 8.7, 24 V DC Power System.

7.5.4.2.3 Physical Arrangement

Each detector assembly consists of a miniature fission chamber operated in the pulse counting mode and attached to a low loss quartz fiber insulated transmission cable. See Figure 7.5-1. The sensitivity of the detector is 1.2×10^{-3} cps/nv nominal, 5.0×10^{-4} cps/nv minimum and 2.5×10^{-3} cps/nv maximum. The detector cable is connected underneath the reactor vessel to a triple shielded coaxial cable. This shielded cable carries the pulses formed to a pulse current preamplifier located outside the primary containment.[1] The detector and cable are located inside the reactor vessel in a dry tube sealed against reactor vessel pressure. A remote controlled detector drive system can move the detector along the length of the

dry tube allowing vertical positioning of the chamber at any point from 1 1/2 ft above the reactor (fuel) centerline to 2 ft below the reactor fuel region, as shown on Figure 7.5-1. The detector can be stopped at any location between the limits of travel, but only the end points of travel are indicated. When a detector arrives at a travel end point, the detector motion is automatically stopped. A slip clutch is used to prevent overloads from damaging the flexible shaft portion of the drive system. See Figure 7.5-2. SRM/IRM drive control logic is presented on Figure 7.5-3. The electronics for the SRMs, their trips, and their bypasses are all located in one cabinet. Source range signal conditioning equipment is designed so that it may be used for open core experiments.

7.5.4.2.4 Signal Conditioning

A current pulse preamplifier provides amplification and impedance matching to allow signal transmission to the signal conditioning electronics. See Figure 7.5-4.

The signal conditioning equipment is designed to receive a series of input current pulses, convert the current pulse series to analog dc currents corresponding to the logarithm of the count rate (LCR), to derive the period, to display the outputs on front panel meters, and to provide outputs for remote meters and recorders. The LCR meter displays the rate of the occurrence of the input current pulses, and the period meter displays the time in seconds for the count rate to change by a factor of 2.72. The equipment also contains integral test and calibration circuits, trip circuits, power supplies, and selector circuits.

A high voltage power supply supplies a polarizing potential for the fission counter detectors. The potential is introduced to the detector through a filter network to minimize noise coupling.

The pulses from the pulse preamplifier have various heights. In general, the pulses produced by neutrons are larger than pulses due to gamma and noise. To count only neutrons, the pulse height discriminator (PHD) is set to reject the small pulses and to accept only the large pulses, the threshold being adjustable. One output of the PHD has two stable states represented by full voltage and zero voltage. Each time an input pulse exceeds the threshold, the output of the PHD reverses state and holds that state until the next pulse causes another reversal. The PHD provides the pulse train input required by the log integrator. The PHD also has a scaler output which produces an output pulse for each input pulse crossing the threshold. The various signals are shown in the block diagram outlined by circles on Figure 7.5-4. At (A), the current pulses are shown as four different amplitudes to illustrate the output of the fission chamber. At (B), the absolute amplitudes are increased, but the relative amplitudes remain proportional. A dashed line representing the threshold level is indicated. At (C), there is an output pulse for every input pulse exceeding the threshold, which shows the action of the discriminator. This pulse is shaped to be compatible with the scaler input requirements. At (D), the PHD cuts off the second pulse because it did not attain the threshold level.

The log integrator is a network arranged to synthesize an output response which is a logarithmic function of the input counting rate. The log integrater has a time constant which varies with the counting rate. Thus, at low counting rates, the time constant is large to provide an adequate smoothing effect on the reading. At high counting rates, the time constant is small to provide for a faster overall response time.

The output of the log integrator is a current output requiring amplification. Operational Amplifier No. 1 converts the current output from the log integrator to the standard signal used to drive the indicator recorders, trip circuits, and Operational Amplifier No. 2. Operational Amplifier No. 2 is a differentiator with a resistor feedback and a capacitor input which drives the period indicator. The gain of the amplifier is scaled to produce a full scale period reading of +10 sec.

Calibration features are included to enable the accuracy of all measuring circuits to be verified and the trip level of the trip circuits to be set and checked. A signal generator provides two discrete frequencies for use in verifying the calibration of the log integrator and provides an operational check on the PHD.

7.5.4.2.5 Trip Functions

The trip outputs of the SRMS are all designed to operate in the fail- safe mode; the loss of power to the trip auxiliaries causes the associated trips to function. See Figure 7.5-5.

The SRMS provides SRM upscale, downscale, detector improper position, and inoperative signals to the Reactor Manual Control System to block rod withdrawal under certain conditions. Any one SRM channel can initiate a rod block. These rod blocking functions are discussed in Section 7.7 Reactor Manual Control System. Appropriate lights and annunciators are actuated to indicate the existence of these same conditions. See Table 7.5-1. The trip actions are bypassed when the reactor mode switch is in the RUN position. Any one of the four SRM channels can be bypassed by the operation of a switch on the operator's console.

7.5.4.3 Power Generation Evaluation

The locations and sensitivities of the SRM detectors are designed to provide a count rate of 3 cps when the reactor is first assembled. Sources are preirradiated at a suitable time prior to startup to allow for decay before appreciable flux becomes available in the core to sustain minimum count rate. Operation at power maintains the radioactivity of antimony (neutron, gamma interaction) to a level above the original design activation. The design activation is specified using experimental data provided by measurement of the neutron strengths of test sources, observation of design sources in operating reactors, [1] and calculational techniques. The arrangement of the sources and SRM detectors in the reactor is shown on Figure 7.5-6. This arrangement produces at least 3 cps in the SRMS using the sensitivity noted in Section 7.5.4.2.3 and the design source strength at initial reactor startup. If the discriminator setting

is adjusted to produce the specified sensitivity, the signal to noise count ratio is well above the 2 to 1 design basis for cold startup.

Design calculations show that if the multiplication of one section of the core is increased to the extent necessary to put that section of the reactor on a 20 sec period, the nearest SRM chamber shows an increase in count rate; in general, at least one detector indicates the change in multiplication. These calculations use the design source intensity and neutron diffusion through the surrounding subcritical core.

During the initial startup, one of the four control rods adjacent to each SRM chamber and one control rod adjacent to each neutron source is withdrawn before the reactor is critical. This procedure reduces source and detector shadowing and assures increases in the detector signals as the core average neutron multiplication increases.

Following the initial fuel cycle, the Antimony-Beryllium neutron sources are removed. Removal of these sources should have no effect on normal outages (≤120 days) when fuel with greater than 5,000 MWD/T average exposure is left in the core. However, for cases in which the fuel is fully unloaded, there will not be a source of neutrons to satisfy the Technical Specification requirements of ≥3 counts/sec on the startup range monitors during initial fuel reloading, nor during the final steps of future full core unloadings. However, changes outlined in Technical Specification 3.10.B.2 will allow necessary full core discharge and reloading provided the fuel is moved in a spiral pattern.

Clarification

A spiral unloading pattern is one by which the fuel in the outermost cells (four fuel bundles surrounding a control blade) is removed first. Unloading continues by removing the remaining outermost fuel, cell by cell. The center cells will be the last removed. A spiral loading program is one by which fuel is loaded on the periphery of the previously loaded fueled region beginning around a single SRM. Spiral unloading and reloading will generally preclude the creation of flux traps (moderator filled cavities surrounded on all sides by fuel). However, prior to initiating spiral unloading, selected cells may be unloaded provided the remaining fuel portion of the core is contiguous and connected to all four SRMs. Fuel bundles are considered contiguous when loaded face adjacent. The total number of cells unloaded shall not exceed five.

During spiral unloading, the SRMs shall have an initial count rate of ≥3 cps with all rods fully inserted. The count rate will diminish during fuel removal. Under the special condition of complete spiral core unloading, it is expected that the count rate of the SRMs will drop below 3 cps before all of the fuel is unloaded.

Since there will be no reactivity additions, a lower number of counts will not present a hazard. When all of the fuel has been

removed to the spent fuel storage pool, the SRMs will no longer be required. Requiring the SRMs to be operable prior to fuel removal assures that the SRMs are operable and can be relied on even when the count rate may go below 3 cps.

During spiral reload, SRM operability will be verified by using a portable external source every 12 hr until the required amount of fuel is loaded to maintain 3 cps. As an alternative to the above, up to two fuel assemblies will be loaded in different cells containing control blades around each SRM to obtain the required 3 counts/sec. Until these two assemblies have been loaded, the 3 counts/sec requirement is not necessary.

Safety Considerations

The technical specifications allow spiral unloading of the full core and subsequent spiral reloading with less than 3 cps on the SRM when only a few assemblies are in the core. The minimum count rate requirement in the Technical Specifications accomplishes three safety functions:

1. It assures the presence of some neutrons in the core.

2. It provides assurance the analog portion of the SRM channels is operable.

3. It provides assurance the SRM detectors are close enough to the array of the fuel assemblies to monitor core flux levels.

Unloading and reloading of the entire core leads to some difficulty with this minimum count rate requirement. When only a small number of assemblies are present within the core, the SRM count rate will drop below the minimum due to the small number of neutrons being produced, and due to attenuation of these neutrons in the water and control blades separating the fuel from the SRM detectors.

Past practice has been to connect temporary "dunking" chambers to the SRM channels in place of the normal detectors, and to locate these detectors near the fuel. Besides being operationally inconvenient, dunking chambers suffer from signal variations due to their lack of fixed geometry. Moreover, the use of dunking chambers increases the risk of loose objects being dropped into the vessel.

Spiral unloading and reloading allows the SRM count rate to drop below the minimum count rate requirement without the operational inconvenience of dunking chambers. The impact of spiral unloading and reloading on the three safety functions of the minimum count rate requirement are discussed below:

Minimum Flux in Core

A multiplying medium with no neutrons present forms the basis for an accident scenario in which reactivity is gradually but inadvertently added until the medium is highly supercritical. No neutron flux

will be evident since there are no neutrons present to be multiplied. The introduction of some neutrons at this point would cause the core to undergo a sudden power burst, rather a gradual startup, with no warning from the nuclear instrumentation.

This scenario is of great concern when loading fresh fuel, but is of lesser concern for exposed fuel. Exposed fuel continuously produces neutrons by spontaneous fission of certain plutonium isotopes, photofission and photodisintegration of deuterium in the moderator. This neutron production in exposed fuel is normally great enough to meet the 3 cps minimum for a full core after a refueling outage with lumped neutron sources removed.

Thus there is assurance a minimum flux level will be present as long as some exposed fuel is present. Specifically, each control cell shall have one assembly with a minimum exposure of 1000 MWD/ST.

SRM Operability

A functional check of SRM channels, including a check of neutron response, is required prior to making any alteration to the core. Neutron response must be checked daily thereafter when not spiral unloading or spiral reloading. The more extensive fuel handling involved with spiral reloading and spiral unloading implies a greater probability of SRM failure. Accordingly, the frequency at which neutron response must be checked is increased to once every 12 hours when spiral unloading or spiral reloading is underway.

Flux Attenuation

The four SRM detectors are located, one per quadrant, roughly half a core radius from the center. Although these are incore detectors and thus very sensitive when the reactor is fully loaded, they loose some of their effectiveness when the reactor is partially defueled and the detectors are located some distance from the array of remaining fuel.

Spent fuel pool studies have shown that 16 or more fuel assemblies (four or more control cells) must be loaded together before criticality is possible. In spiral unloading sequences in the Pilgrim core, an array containing four or more control cells will be at most two control cells away from an SRM detector. The sensitivity loss associated with such a configuration is at most one decade. This magnitude of sensitivity loss remains acceptable. In spiral loading sequences, loading proceeds around an SRM, minimizing the sensitivity loss associated with spiral loading.

Normal startup procedures, after the neutron sources are removed, require specific rod withdrawal patterns that ensure that the withdrawn control rods are distributed about the core so that the multiplication in no one section of the core exceeds the average by a large amount; hence, each SRM chamber can respond to some degree as the initial rod withdrawal is accomplished. Current design indicates that a scattered rod withdrawal of approximately one quarter of all control rods is required to reach criticality.

Examination of the sensitivity of the SRM detectors (Section 7.5.4.2.3) and their operating ranges of 10^6 cps indicates that the IRMS is on scale before the SRM reaches full scale. See Figure 7.5-7. Further overlap is provided by retraction of the SRM chambers to any position between full in and full out. SRM detector retraction is permitted without rod block only if the indicated SRM count rate remains above the rod block trip level (10^2 cps), or if the IRM has been ranged to the third or any less sensitive (higher) IRM range.

7.5.4.4 Inspection and Testing

Each SRM channel is tested and calibrated using approved station procedures and the SRM instruction manual. Inspection and testing are performed as required on the SRM detector drive mechanism; the mechanism can be checked for full insertion and retraction capability. The various combinations of SRM trips can be introduced to ensure the operability of the rod blocking functions.

7.5.5 Intermediate Range Monitor Subsystem

7.5.5.1 Safety Design Basis

1. The IRMS shall be capable of generating a trip signal that can be used to prevent fuel damage resulting from abnormal operational transients that occur while operating in the intermediate power range.

2. The independence and redundancy incorporated in the design of the IRMS shall be consistent with the safety design basis of the RPS.

7.5.5.2 Power Generation Design Basis

1. The IRMS shall be capable of generating a trip signal to block rod withdrawal if the IRMS reading exceeds a preset value or if the IRMS is not operating properly.

2. The IRMS shall be designed so that overlapping neutron flux indications exist with the SRMS and Power Range Monitoring Subsystems.

7.5.5.3 Description

7.5.5.3.1 Identification

The IRMS monitors neutron flux from the upper portion of the SRM range to the lower portion of the Power Range Monitoring Subsystems. The IRM subsystem has eight IRM channels each of which includes one detector that can be physically positioned in the core by remote control. The detectors are inserted into the core for a reactor startup and are withdrawn after the reactor mode selector switch is turned to RUN.

7.5.5.3.2 Power Supply

Power is supplied separately from two 24 V dc sources. See Section 8.7, 24 V DC Power System. The supplies are split according to their use so that loss of a power supply will result in loss of power to channels associated with only one trip system of the RPS.

7.5.5.3.3 Physical Arrangement

Each detector assembly consists of a miniature fission chamber attached to a low loss, quartz fiber insulated transmission cable. When coupled to the signal conditioning equipment, the detector produces approximately a 30 percent reading on the most sensitive range with a neutron flux of 108 nv. The detector cable is connected underneath the reactor vessel to a triple shielded cable which carries the pulses generated in the fission chamber through the primary containment to the preamplifier. The detector and cable are located in the drywell, are movable in the same manner as the SRM detectors, and use the same type of mechanical arrangement.[1]

7.5.5.3.4 Signal Conditioning

A voltage preamplifier unit located outside the primary containment serves as a preamplifier. This unit is designed to accept superimposed current pulses from the fission chamber, remove the dc component, convert the current pulses to voltage pulses, amplify the voltage pulses, establish the bandpass characteristics for the system, and provide a low impedance output suitable for driving a terminated cable. The gain of the low range of the preamplifier is fixed, but the gain of the high range is variable over a limited range to permit tracking between low and high ranges. The preamplifier output signal is coupled by a cable to the IRM signal conditioning electronics. See Figure 7.5-8.

The signal conditioning equipment for each IRM channel contains an input signal attenuator, additional stages of amplification, an inverter, a mean square analog unit, a calibration and diode logic unit, a range switch, power supplies, trip circuits, and integral test and calibration circuits. Each IRM channel receives its input signal from the preamplifier and operates upon it with various combinations of preamplification gain and amplifier attenuation ratios. The amplification and attenuation ratios of the IRM and preamplifier are selected by a remote range switch which provides 10 ranges of increasing attenuation, the first six called low range and the last four called high range, acting upon the signal from the fission chamber. As the neutron flux of the reactor core increases from 1 x 108 nv to 1.5 x 1013 nv, the signal from the fission chamber becomes larger. The signal from the fission chamber is attenuated to keep the input signal to the inverter in the same range. The output current is proportional to the power contained in the pulses received from the fission chamber. This output signal, which is proportional to neutron flux at the detector, is amplified and supplied to a locally mounted meter and an indicator/recorder on the main control board. The meter and indicator/recorder have two linear scales on a single face. The appropriate range being used is indicated by the range switch position. There is in the amplifier a potentiometer with a gain effect of 1 to 1.85, which provides an adjustment greater than one range position (approximately a factor

of 3 in flux) in the output signal. The calibration and diode logic unit include a circuit to develop a triangular wave shape signal of adjustable amplitude to provide a means of full scale calibration of the power meter. Calibration settings of 40 percent and 125 percent on a 125 percent scale are possible.

The high voltage supply associated with IRM supplies the polarizing potential for the fission chamber detector through a filter network to minimize noise coupling.

7.5.5.3.5 Trip Functions

The IRMS is divided into two groups of IRM channels arranged in the core as shown on Figure 7.5-9. IRM Channels A, C, E, and G are associated with Trip System A of the RPS. IRM Channels B, D, F, and H are associated with Trip System B of the RPS. Two IRM channels and their trip auxiliaries from each group are installed in one bay of a cabinet; the remaining channels are installed in a separate bay of the cabinet. Full length side covers on the cabinet bays isolate the two bays. The arrangement of IRM channels allows one IRM channel in each group to be bypassed without compromising intermediate range neutron monitoring capability.

Each IRM channel includes four trip circuits. One trip circuit is used as an instrument trouble trip. It operates whenever the high voltage drops below a preset level, whenever one of the modules is not plugged in, or whenever the mode switch is not in the OPERATE position. Each of the other trip circuits can be chosen to operate whenever preset downscale or upscale levels are reached. A simplified circuit arrangement of the IRM trips is shown on Figure 7.5-10.

The trip functions actuated by the IRM trips are indicated on Table 7.5-2. The reactor mode switch determines whether IRM trips are effective in initiating a rod block and a reactor scram. Section 7.7, Reactor Manual Control System, describes the IRM rod block trips.

7.5.5.4 Safety Evaluation

The safety evaluation in Section 7.2, Reactor Protection System, evaluates the arrangement of redundant input signals to the RPS. The Neutron Monitoring System trip input to the RPS and the trip channels used in actuating a Neutron Monitoring System trip are of equivalent independence and redundancy to other RPS inputs.

The number and locations of the IRM detectors have been analytically and experimentally determined to provide sufficient intermediate range flux level information under the worst permitted bypass or detector failure conditions. For verification of this, a range of rod withdrawal accidents were analyzed for the initial core. The most severe case assumes that the reactor is just subcritical with one-fourth of the control rods plus one more rod removed in the normal operating sequence. This configuration is illustrated on Figure 7.5-11. The error or malfunction is the removal of the control rod adjacent to the last rod withdrawal. The location of

this rod has been chosen to maximize the distance to the second nearest IRM detector assigned to each RPS Trip System. It is assumed that the nearest detector in each RPS Trip System is bypassed. A scram signal is initiated when one IRM detector in each RPS Trip System reaches its scram trip level. The neutron flux vs distance resulting from this withdrawal is shown on Figure 7.5-12. Note that the second nearest detector in Trip System B is farther away than the second nearest detector in Trip System A. The ratio of the neutron flux at this point to the peak flux is 1 to 4,100. This detector reaches its high scram trip setting of 120 on a 125 percent full scale at a local flux approximately 3.3×10^{8} nv. At this time the peak flux in the core is 1.35×10^{12} nv or 2.7 percent rated average flux. The core average power is 0.07 percent when scram occurs. For this scram point to be valid, the IRM must be on the correct range. To assure that each IRM is on the correct range, a rod block trip is initiated any time the IRM is both downscale and not on the most sensitive (lowest) scale. A rod block is initiated if the IRM detectors are not fully inserted in the core and the reactor mode switch is not in the RUN position. The IRM scram trips are automatically bypassed when the reactor mode switch is in the RUN position and the APRMs are on scale. The IRM rod block trips are automatically bypassed when the reactor mode switch is in the RUN position.

The IRM detectors and electronics have been tested under operating conditions and verified to have the operational characteristics given in the description and as such provide the level of precision and reliability required by the RPS safety design basis.

The eight intermediate range channels are grouped four to a trip system: channels A, C, E, and G to Trip System A, and channels B, D, F, and H to Trip System B. Bypass of one channel from each trip system is permitted for calibration, and the equipment is arranged to prevent a single failure from disabling more than two channels in any one trip system, resulting at least one operative channel on each trip system at all times.

When a channel is bypassed, the trip signal (a circuit discontinuity caused by relays deenergizing and their contacts opening) is bypassed by contact closures from the energizing of 24 V dc relays mounted in each instrument channel in the startup range neutron monitoring panel (Panel 936). These relays are controlled by two bypass switches on the main control board (Panel 905), one for each trip system. Thus, the trip system wiring is not routed to Panel 905 for bypassing, but remains within the bays of Panel 936.

The wiring between 936 and 905 is shielded and separated to prevent short-induced bypassing of more than two channels on a trip system. This would require the application of 24 V dc line to the relay coil leads in more than two channels, without also shorting to ground. This would be an obvious detectable failure, since individual channel bypass indicators are centrally located on Panel 905, and also displayed on Panel 936.

The wiring within Panel 905 is a continuation of shielded cables, with the shields carried as close as possible to the terminal boards

and switch terminals. Cables from the three channels run from separated terminal boards to one joystick for each trip system. This switch mechanically prevents the making of more than one circuit in any position and is constructed such that barriers between circuits make inadvertent short circuits between any switch terminal and another terminal highly improbable.

Two modes of switch failure must be considered; one, where the switch permits normal manual bypass of one channel, and through damage, bypasses two more channels; and two, where the switch bypasses three channels. For either mode, the switch must be damaged through physical destruction or heat/fire such that conductors from three shielded cables are connected together and to the live side of a 24 V dc power source without making contact with any ground surface or ground wiring. The improbability of this type of damage coupled with the limited accessibility to abuse (under the benchboard surface) and the improbability of an undiscovered fire beneath the central benchboard surface keep this from being considered a serious problem.

7.5.5.5 Power Generation Evaluation

The IRMS is the primary source of information on the approach of the reactor to the power range. Its linear, approximate half decade steps with the rod blocking features on both high flux level and low flux levels require that the operator keep all the IRMs on the correct range to increase core reactivity by rod motion. The SRM overlaps the IRM as shown on Figure 7.5-7. The sensitivity of the IRM is such that the IRMS is on scale on the least sensitive (highest) range with the reactor power about 15 percent.

7.5.5.6 Inspection and Testing

Each IRM channel is tested and calibrated using approved station procedures and the IRM instruction manual. The IRM detector drive mechanisms and the IRM rod blocking functions are checked in the same manner as for the SRM channels. Each of the various IRM channels can be checked to ensure that the IRM high flux scram function is operable.

7.5.6 Local Power Range Monitor Subsystem

7.5.6.1 Power Generation Design Basis

1. The LPRMs shall provide signals proportional to the local neutron flux at various locations within the reactor core to the APRMs, so that accurate measurements of average reactor power can be made.

2. The LPRMs shall supply signals to the RBMs, so that measurement of changes in local relative neutron flux can be made during the movement of control rods.

3. The LPRMs shall be capable of alarming under conditions of high or low local neutron flux indication.

4. The LPRMs shall supply signals proportional to the local neutron flux to the process computer to be used in power distribution calculations, local heat flux calculations, minimum critical heat flux calculations, and fuel burnup calculations.

5. The LPRMs shall supply signals proportional to the local neutron flux to drive indicating meters and auxiliary devices to be used for operator evaluation of the power distribution, local heat flux, minimum critical heat flux, and fuel burnup.

6. The LPRMs shall supply selected signals to the PBDS. The signals are analyzed by the PBDS to monitor changes in reactor core stability.

7.5.6.2 Description

7.5.6.2.1 Identification

The LPRMs consist of the fission chamber detectors, the signal conditioning equipment, and trip functions. The LPRM signals are also used in the APRMs, RBMs, and process computer.

7.5.6.2.2 Power Supply

Power for the LPRMs is supplied by the two 120V AC RPS buses; approximately one half of the LPRMs are supplied from each bus. See Section 8.8, 120V AC Power Supply and Distribution. Associated with each LPRM amplifier is a separate power supply in the control room which furnishes the detector polarizing potential.

This power supply is adjustable from 50V to 200V DC with a maximum current output of 3 milliamps, which ensures that the chambers can be operated in the saturated region at the maximum specified neutron fluxes. For maximum variation in the input voltage or line frequency, and over extended ranges of temperature and humidity, the output voltage varies no more than 2V. Each "page" of amplifiers is supplied an operating voltage from a separate low voltage power supply.

7.5.6.2.3 Physical Arrangement

The LPRMs include LPRM detectors located throughout the core at different axial heights. Figure 7.5-13 illustrates the LPRM detector

radial layout scheme which provides a power range detector assembly at every fourth intersection of the narrower of the water channels around the fuel bundles (narrow-narrow water gap). Thus, every narrow-narrow water gap has either an actual detector assembly or a symmetrically equivalent assembly in some other quadrant.

The 30 power range detector assemblies, each containing four LPRM detectors, are distributed to monitor four horizontal planes throughout the core. The detector assemblies (Figure 7.5-14, Drawing M1U75-4)) are inserted into the core in spaces between the fuel assemblies through thimbles which are mounted permanently at the bottom of the core lattice and which penetrate the bottom of the reactor vessel. These thimbles are welded to the reactor vessel at the penetration point. They extend down into the access area below the reactor vessel where they terminate in a flange which mates to the mounting flange on the power range detector assembly. The detector assemblies are locked at the top end to the top fuel guide by means of a spring loaded plunger. This type of assembly is referred to as top entry-bottom connect, since the assembly is inserted through the top of the core and penetrates the bottom of the reactor vessel. Special water sealing caps are placed over the connection end of the assembly and over the penetration at the bottom of the vessel during installation or removal of an assembly. This prevents the loss of reactor coolant water upon removal of an assembly and also prevents the connection end of the assembly from being immersed in the water during installation or removal.

The power range detector assembly contains four miniature fission chambers with an associated solid sheath cable. Each fission chamber produces a current which, when coupled with the LPRM signal conditioning equipment, provides the desired scale deflection throughout the design lifetime of the chamber. Each chamber of the assembly is a moistureproof, pressure sealed unit. Each assembly also contains a calibration tube for a Traversing Incore Probe (TIP). The enclosing tube around the entire assembly contains holes evenly spaced along its length. These holes allow circulation of the reactor coolant water to cool the fission chambers. Numerous tests have been performed on the chamber assemblies including tests of linearity, lifetime, gamma sensitivity, and cable effects.[1] These tests and experience in operating reactors provide confidence in the ability of the LPRMS to monitor neutron flux to the design accuracy throughout the design lifetime.

The four miniature fission chambers used on each assembly are designed to operate up to a temperature of 599°F and a pressure of 1,250 psig. The LPRM chambers are vertically spaced in the power range detector assemblies in such a manner as to give adequate axial coverage of the core, complementing the radial coverage given by the horizontal arrangement of the LPRM detector assemblies. Each miniature chamber consists of two concentric cylinders, which act as electrodes. The inner cylinder, the collector, is mounted on insulators and is separated from the outer cylinder by a small air gap. The gas between the electrodes is ionized by the charged particles produced as a result of neutron fissioning of the uranium coated outer electrode. The chamber has at the beginning of operation a sensitivity of approximately 4.86 x 10^{-18} amps/nV for

LPRM GE Model No. NA200 or 7.29 x 10^{-18} amps/nV for LPRM GE Model No. NA300 and is operated at a polarizing potential of approximately 100 V. The negative ions produced in the gas are accelerated to the collector by the potential difference maintained between the electrodes. In a given neutron flux, all the ions produced in the ion chamber can be collected if the polarizing voltage is high enough. When this situation exists, the ion chamber is considered to be saturated. Output current is then independent of operating voltage.

7.5.6.2.4 Signal Conditioning

The current signals from the LPRM detectors are transmitted to the LPRM amplifiers in the control room. Each amplifier is a modular plug-in element which is mounted in a hinged vertical assembly designated a "page". The current signal from a chamber is transmitted directly to its amplifier through coaxial cable. The amplifier is a linear current amplifier whose voltage output is proportional to the current input and therefore is proportional to the magnitude of the neutron flux. The output of the amplifier ranges from 0 to 10 V dc for 0 to 125 percent indication. Additional low level output signals provided are suitable as an input to the computer, recorders, and the like. The outputs of each LPRM amplifier are isolated to prevent interference of the signal by inadvertent grounding or application of a stray voltage at the signal terminal point.

The LPRM amplifier signals can be read by the operator on the reactor console. When a central control rod is selected for movement, the output signals from the amplifiers associated with the nearest sixteen LPRM detectors are displayed on console meters. The four LPRM detector signals from each of the four LPRM assemblies are displayed on a stacked set of 16 meters. The operator can readily obtain the readings of all the LPRM amplifiers by selecting the control rods in the proper order. Section 7.7, Reactor Manual Control System, describes in greater detail the indications on the reactor console.

7.5.6.2.5 Trip Functions

The trip circuits for the LPRMS provide trip signals to activate lights, instrument inoperative signals, and annunciators. These trip circuits use the dc power supply and are set to trip on loss of power; they also trip when power is not available for the LPRM amplifiers. Table 7.5-3 indicates the trips.

The trip levels can be adjusted to within 0.5 percent of full scale deflection and are accurate to $\pm$1 percent of full scale deflection in the normal operating environment.

7.5.6.3 Power Generation Evaluation

The LPRMS, as calibrated by the TIPS, provides detailed information about the neutron flux throughout the reactor core. The total of 30 LPRM assemblies and their distribution is determined by extensive calculational and experimental procedures. The division of the LPRMS

into various groups for dc power supply allows operation with one dc power supply failed or being serviced without limiting reactor operation. Individual failed chambers can be bypassed, and neutron flux information for a failed chamber location can be interpolated from nearby chambers. A substitute reading for a failed chamber can be derived from an octantsymetric chamber, or an actual flux indication can be obtained by insertion of a TIP to the failed chamber position.

The LPRM outputs provide for the functions required in the LPRM power generation design basis. Each output is electrically isolated so that an event, grounding the signal or applying a stray voltage, on the reception end does not destroy the validity of the LPRM signal. Tests and experience[1] attest to the ability of the detector to respond proportionally to the local neutron flux changes.

7.5.6.4 Inspection and Testing

LPRM channels are calibrated using data from previous full power runs and TIP data and are tested by procedures in the applicable instruction manual.

7.5.7 Average Power Range Monitor Subsystem

7.5.7.1 Safety Design Basis

1. The design of the APRMS shall be such that for the worst permitted input LPRM bypass conditions, the APRMS shall be capable of generating a scram trip signal in response to average neutron flux increases resulting from abnormal operational transients in time to prevent fuel damage.

2. The flow-biased scram setpoint function shall provide detect and suppress protection for unstable thermal-hydraulic oscillations of the Exclusion Region for the Option 1-D Long Term Stability Solution (Reference 3, 4, and 5).

3. The design of the APRMS shall be consistent with the requirements of the safety design basis of the RPS.

7.5.7.2 Power Generation Design Basis

1. The APRMS shall provide a continuous indication of average reactor power from a few percent to 125 percent of rated reactor power.

2. The APRMS shall be capable of providing trip signals for blocking rod withdrawal when the average reactor power exceeds pre-established limits set to prevent scram actuation.

3. The APRMS shall provide a reference power level for use in the RBMS.

7.5.7.3 Description

7.5.7.3.1 Identification

The APRMS has six APRM channels, each of which uses input signals from a number of LPRM channels. Three APRM channels are associated with each of the trip systems of the RPS.

7.5.7.3.2 Power Supply

The APRM channels receive power from the 120 V AC supplies used for the RPS power. See Section 8.8, 120 V AC Power Supply and Distribution.

Power for each APRM trip unit is supplied from the same power supply as the APRM which it services.

7.5.7.3.3 Signal Conditioning

The APRMS uses electronic equipment which averages the output signals from a selected set of LPRMs, trip units which actuate automatic devices, and signal readout equipment. Each APRM channel can average the output signals from up to 24 LPRMs. Assignment of LPRMs to an APRM is made using the pattern illustrated on Figure 7.5-15. The letters at the detector locations on Figure 7.5-15 refer to the axial positions of the detectors in the LPRM detector assembly. Position A is the bottom position, Positions B and C are above Position A, and Position D is the topmost LPRM detector position. APRM Channels A, C, and E are powered from the same ac bus used for Trip System A of the RPS; APRM Channels B, D, and F are powered from the ac bus used for Trip System B. The 120 V ac bus used for a given APRM channel is the same as that used for the LPRMs providing inputs to that APRM. The pattern on Figure 7.5-15 is for the APRMs associated with Trip System A of the RPS. Assignments of LPRMs to APRMs associated with Trip System B of the RPS are given on Figure 7.5-16. APRM Channels A, C, and E average the output signals from 16 LPRMs. Channels B, D, and F average the output from 14 LPRMs.

The APRM amplifier gain can be adjusted to allow calibration to power as determined by a heat balance. The averaging circuit automatically corrects for the number of unbypassed LPRM amplifiers providing inputs to the APRM.

7.5.7.3.4 Trip Function

The trip units for the APRMs supply trip signals to the RPS and the Reactor Manual Control System. Table 7.5-4 itemizes the APRM trip functions used in the plant safety analysis. Any one APRM can initiate a rod block, depending upon the position of the reactor mode switch. Section 7.7, Reactor Manual Control System, describes in detail the APRM rod block functions. The APRM upscale rod block trip setpoint is varied as a function of reactor recirculation flow. The slope of the upscale rod block trip response curve with recirculation flow is adjustable to allow tracking of the required trip setpoint with recirculation flow changes. This provides an

effective rod block if core average power is increased above the power vs flow specification at any flow rate. An APRM upscale or inoperative trip actuates one trip system in the RPS. Since only the trip system associated with the APRM is affected, at least one APRM channel in each trip system of the RPS must be actuated to cause a scram. See Figure 7.5-5.

Because each trip is actuated by removing voltage to a relay coil, loss of power results in actuating the trips. The trips from one APRM in each trip system of the RPS can be bypassed by operator action in the main control room. A simplified APRM circuit arrangement is shown on Figure 7.5-17.

When the mode switch is not in RUN position the APRM trip point is set down to eliminate operational problems encountered in the IRM/APRM overlap region between an APRM downscale block and an IRM high rod block.

7.5.7.4 Safety Evaluation

Each APRM derives its signal from information obtained from the LPRMs. The assignment, power separation, cabinet separation, and LPRM signal isolation are in accord with the safety design basis of the RPS. There are six APRM channels, three for each RPS trip system, to allow one bypass and one undetected failure in each trip system and still satisfy the RPS safety design basis.

Figure 7.5-18 illustrates the ability of the APRMs to track initial core power vs coolant flow starting at 100 percent power and 100 percent flow to below the 65 percent flow point. Figure 7.5-19 illustrates (for the initial core) the ability of the APRM to respond to control rod motion. The conditions for this are selected from the most restrictive case. This figure illustrates a full withdrawal of a control rod from limiting conditions at rated power. Normal control rod manipulation results in good agreement (less than 5 percent deviation on the worst APRM) through a wide range of power levels.

The adequacy of the APRM scram analytical setpoint (123 percent of rated power) is demonstrated to be adequate in preventing fuel damage as a result of abnormal operational transients by the analyses in Section 14, Station Safety Analysis.

The adequacy of the APRM scram flow biased setpoint function is demonstrated to detect and suppress the occurrence of a core power thermal-hydraulic instability in the Exclusion Region by the Stability Solution Option 1D methodology. (See References 4, 5 and 6)

These setpoint functions are a function of recirculation drive flow and accommodate various operational conditions. The APRM flow biased setpoint function is above the operating domain and has 3 sections. The flow range for each section is determined by the requirements for each region. The Stability Option 1-D Exclusion Region requires that the APRM flow biased setpoints provide detect and suppress protection for unstable thermal-hydraulic oscillations.

The setpoint function above the operating domain for the flow range greater than the Exclusion Region and below rated power is not credited for mitigating the consequences of any accident discussed in Chapter 14. PNPS is licensed for continuous Single Loop Operation beginning in Cycle 16 (Reference 8). In this mode of operation, the relationship between recirculation drive flow and core flow is different than operation with both recirculation pumps in service. A correction factor is determined based on the methodology in Reference 7. The APRM flow biased setpoints are adjusted to based on the correction factor (Reference 6 and 7).

The Neutron Monitoring System supplies trip signals to the RPS from channels in the intermediate and power ranges of operation.

The six power range channels are grouped three to a trip system; Channels A, C, and E to Trip System A and Channels B, D, and F to Trip System B. Bypass of one channel from each trip system is permitted for calibration, and the equipment is arranged to prevent a single failure from disabling more than one channel in one trip system, resulting in at least one operative channel on each trip system at all times.

When a channel is bypassed, the trip signal (a circuit discontinuity caused by relays deenergizing and their contacts opening) is bypassed by contact closures from the energizing of relays mounted in each instrument channel in the power range neutron monitoring panel (Panel 937). These relays are controlled by two bypass switches on the main control board (Panel 905), one for each trip system. Thus, the trip system wiring is not routed to Panel 905 for bypassing, but remains within the bays of Panel 937.

The wiring between 937 and 905 is shielded and separated to prevent short induced bypassing of more than two channels on a trip system. This would require the application of 120 V AC line to the relay coil leads in more than two channels, without also shorting to ground. This would be an obvious detectable failure, since individual channel

bypass indicators are centrally located on Panel 905, and also displayed on Panel 937.

The wiring within Panel 905 is a continuation of shielded cables, with the shields carried as close as possible to the terminal boards and switch terminals. Cables from the three channels run from separated terminal boards to one joystick for each trip system. This switch mechanically prevents the making of more than one circuit in any position and is barriered such that inadvertent shorting of several circuits terminals is considered highly improbable.

Two modes of switch failure must be considered; one, where the switch permits normal manual bypass of one channel, and through damage, bypasses two more channels; and two, where the switch bypasses three channels. For either mode, the switch must be damaged through physical destruction or heat/fire such that conductors from three shielded cables are connected together and to the live side of a 120 V ac power source without making contact with any ground

surface or ground wiring. The improbability of this type of damage coupled with the limited accessibility to abuse (under the benchboard surface) and the improbability of an undiscovered fire beneath the central benchboard surface keep this from being considered a serious problem.

7.5.7.5 Power Generation Evaluation

The APRMs provides the operator with six continuous recordings of the average reactor power. The rod blocking function prevents operation above the region defined by the design power response to recirculation flow control. The flow signal used to vary the rod block level is supplied from the recirculation system flow instrumentation. Two flow comparators monitor the two flow signals and initiate a rod block if the two flow signals are not in agreement within predetermined limits. Because any one of the APRMs can initiate a rod block, this function has a high level of redundancy and satisfies the power generation design basis. One APRM channel in each RPS trip system may be bypassed. In addition a minimum of 11 LPRM inputs is required for each APRM channel to be operative. If the number is less than this, an automatic APRM inoperative trip is generated.

7.5.7.6 Inspection and Testing

APRM channels are calibrated using data from previous full power runs and are tested by approved station procedures and the applicable instruction manual. Each APRM channel can be individually tested for the operability of the APRM scram and rod blocking functions by introducing test signals.

7.5.8 Rod Block Monitor Subsystem

7.5.8.1 Power Generation Design Basis

1. The RBMS shall be designed to assist the operator in preventing local fuel damage as a result of a single rod withdrawal error under the worst permitted condition of RBM bypass.

2. The RBMS shall provide a signal to permit operator evaluation of the change in the local relative power level during control rod movement.

7.5.8.2 Description

7.5.8.2.1 Identification

The RBMS has two RBM channels each of which uses input signals from a number of LPRM channels. A trip signal from either RBM channel can initiate a rod block. One RBM channel may be bypassed without loss of subsystem function. The minimum number of LPRM inputs required for each RBM channel to prevent an instrument inoperative alarm is four when using eight LPRM assemblies, three when using six LPRM assemblies, and two when using four LPRM assemblies. See Figure 7.5-20.

7.5.8.2.2 Power Supply

The RBMS power is received from the 120 V ac supplies used for the RPS, see Section 8.8, 120 V AC Power Supply and Distribution.

7.5.8.2.3 Signal Conditioning

The RBM signals for channels A and B are generated by averaging a subset of the LPRMs displayed to the operator upon rod selection. For an interior control rod surrounded by four LPRM strings, the subsets for each of the two RBM channels consist of two B-level, two D-level and four C-level LPRMs. Each of the RBM channels receive input signals from a different pair of B and D-level LPRMs. Both RBM channels receive input signals from the same four C-level LPRMs. The four A-level LPRMs are not used in the RBM averaging electronics, although they are displayed for the operator's information. This assignment scheme is illustrated in Figure 7.5-21. Rods near the core periphery are surrounded by fewer than four LRPM strings. For such rods, as shown in Figure 7.5-20, the RBM averages the input from two or three LPRMs, depending on the particular control rod selected. The RBM is automatically bypassed for rods on the core periphery.

The RBM automatically accounts for inoperative LPRMs by comparing the input signal from each LPRM with a predetermined reference signal. If the LPRM input signal is less than the reference signal, the LPRM is automatically bypassed in the RBM averaging electronics. A count of the active LRPMs providing input to the RBM averaging electronics is made and the rod withdrawal permissive removed if more than half the LRPMs are bypassed.

The RBM signal is filtered to reduce signal noise. Further conditioning is delayed until the filtered signal nears equilibrium. After the delay, a gain is applied to normalize the RBM signal to a reference source signal. The rod withdrawal permissive is not present during the normalization sequence. Once the gain adjustment is accomplished, the gain setting is maintained until a new rod is selected.

7.5.8.2.4 Trip Functions

The RBM supplies a trip signal to the Reactor Manual Control System to inhibit control rod withdrawal. The trip is initiated whenever the RBM output exceeds a variable set point. One of the two RBMs can

be bypassed at any time for maintenance or testing. Either RBM can inhibit control rod withdrawal. See Figure 7.5-5.

The RBM setpoint is a function of power as shown in Figure 7.5-29, where:

LPSP = Low-power setpoint
IPSP = Intermediate-power setpoint
HPSP = High-power setpoint
LTSP = Low trip setpoint
ITSP = Intermediate trip setpoint
HTSP = High trip setpoint
DTSP = Downscale trip setpoint

The RBM uses an APRM signal to determine core thermal power and the appropriate rod block setpoint. The power dependence of these setpoints reflects the greater margin to the MCPR safety limit which must be preserved at lower powers to protect against core-wide transients. The increased margin at low powers permits the accommodation of more severe rod withdrawal errors. Hence, the low-power RBM setpoints are greater than the high-power RBM setpoints and low-power restrictions on control rod movement are reduced. Below the low-power setpoint, LPSP, the RBM is not required to protect the MCPR safety limit in the event of a rod withdrawal error and RBM trips are automatically bypassed. The downscale trip setpoint, DTSP, is defined to prevent control rod movement when RBM signal levels are abnormally low, indicating a RBM system malfunction.

7.5.8.3 Power Generation Evaluation

Motion of a control rod causes the LPRMs adjacent to the control rod to respond strongly to the change in power in the region of the rod in motion. Figure 7.5-22 illustrates the typical response of the RBM to the full withdrawal of a selected control rod.

The rod block setpoint halts rod motion before local fuel damage can occur even with one RBM channel bypassed and up to half the LPRMs failed in the operable RBM channel.

7.5.8.4 Inspection and Testing

The rod block monitor channels are tested and calibrated by approved station procedures and the applicable instruction manuals. The RBMs are functionally tested by introducing test signals into the RBM channels.

7.5.9 Traversing Incore Probe Subsystem

7.5.9.1 Power Generation Design Basis

1. The TIPS shall be capable of providing a signal proportional to the axial neutron flux distribution at selected small axial intervals over the regions of the core where power range detector assemblies are located.

This signal shall be of high precision to allow reliable calibration of LPRM gains.

2. The TIPS shall provide accurate indication of the position of the flux measurement of the axial neutron flux distribution.

7.5.9.2 Description

7.5.9.2.1 Identification

The TIPS includes four traversing incore probe (TIP) channels each of which has the following components:

1 Traversing Incore Probe

1 drive mechanism

1 indexing mechanism

Up to 10 incore guide tubes

1 chamber shield

The subsystem allows calibration of LPRM signals by correlating TIP signals to LPRM signals as the TIP is positioned in various radial and axial locations in the core. The guide tubes inside the reactor are divided into groups. Each group has its own associated TIP channel. The assignment of LPRM strings to the four TIP channels is shown on Figure 7.5-23.

7.5.9.2.2 Physical Arrangement

A TIP drive mechanism uses a fission chamber attached to a flexible drive cable, which is driven from outside the primary containment by a gear box assembly. The flexible cable is contained by guide tubes that continue into the reactor core. The guide tubes are part of the power range detector assembly and are specially prepared to provide a durable low friction surface. The indexing mechanism allows the use of a single detector in any one of ten different tube paths. The tenth tube is used for TIP cross calibration with the other TIP channels. The control system provides both manual and semiautomatic operation. The TIP signal is amplified and displayed on a meter. Core position vs neutron flux is recorded in the main control room on an X-Y recorder. A block diagram of the drive system is shown on Figure 7.5-24.

The heart of each TIP channel is the TIP probe, consisting of a detector and the associated signal drive cable. See Figure 7.5-25. The detector is a fission chamber 0.180 inch in diameter and 1.0 inch in active length. The body of the fission chamber is made of titanium with a neutron sensitive inner coating of U-235. Sensitivity of the chamber is approximately 7×10^{-18} amps/nv. The chamber can operate in a neutron flux level of greater than 10^{14} nv. The saturation voltage is approximately 150 V dc[1].

The signal current from the detector is transmitted from the TIP to amplifiers and readout equipment by means of a triaxial signal cable which is an integral part of the mechanical drive cable. The outer sheath of the drive cable is constructed of carbon steel in a helix array. The cable drive mechanism engages this helix to effect movement in and out of the guide tubes. The inner surface of the guide tubing between the reactor vessel and the drive mechanism is coated with a ceramic bonded lubricant to reduce friction. Within the reactor vessel the guide tubing inner surface is nitrided.

The drive mechanism inserts and withdraws the TIP and its cable from the reactor and provides detector position indication signals. The drive mechanism consists of a motor and drive gear box which drives the cable in the manner of a rack and pinion. The motor is an adjustable speed 230 vdc, 1/2 hp motor. Motor speed varies depending on TIP position and location. Speed will vary between 7.5 ft/min. and 90 ft/min. Three redundant stops are incorporated to prevent inadvertent TIP withdrawals. See Figures 7.5-26 (BECo M1Q1-5) and 7.5-27 (BECo M1Q2-6).

A takeup reel is included in the cable drive mechanism to coil the drive cable as it is withdrawn from the reactor. This reel makes it possible to connect the TIP and its cable to the amplifier through a connector rather than slip rings which reduces possible noise and maintenance problems.

The encoding system consists of a transducer and an encoder. The transducer is mechanically linked through a gear train to the drive wheel and produces 400 Hz range analog signals that are proportional to the angular position of the drive wheel. These signals are transmitted from the drive mechanism to the encoder (encoder electronics in the TIP control unit). One revolution of the transducer represents approximately 20 in (51 cm) of linear cable movement. The transducer has the capacity to provide a full count of 100 revolutions which means that the cable can travel approximately 167 ft (51m) and still be within the range of the transducer. Each revolution produces 100 counts so the readout range is 10^5. When the system is not in use, the detector probe can be completely withdrawn to a position in the center of the chamber shield.

A circular transfer machine with 10 indexing points functions as an indexing mechanism. Nine of these locations are for the guide tubes associated only with that particular TIP machine. The tenth location is for the guide tube common to all the TIP machines. Indexing to a particular tube location is accomplished manually at the control panel by means of a position selector switch which energizes the electrically actuated rotating mechanism.

Electrical interlocks prevent the indexing mechanism from changing positions until the probe cable has been completely retracted beyond the transfer point. Additional electrical interlocks prevent the cable drive motor from moving the cable until the transfer mechanism has indexed to the preselected guide tube location. See Figure 7.5-28.

A valve system is provided with a valve on each guide tube entering the primary containment. These valves are closed except when the TIPS is in operation. A ball valve and a cable shearing valve are mounted in the guide tubing just outside of the primary containment. They prevent the loss of reactor coolant in the event a guide tube ruptures inside the reactor vessel. A valve is also provided for a gas purge line to the indexing mechanisms. A guide tube ball valve opens only when the TIP is being inserted. The shear valve is used only if a leak occurs when the TIP is beyond the ball valve and power to the TIPS fails. The shear valve, which is controlled by a manually operated protected switch, an cut the cable and close off the guide tube. The shear valves are actuated by detonation squibs. The continuity of the squib circuits is monitored by front panel indicator lights in the control room.

A guide tube ball valve is normally de-energized and in the closed position. When the TIP starts forward the valve is energized and opens. As it opens, it actuates a set of contacts which gives a signal light indication at the TIPS control panel and bypasses an inhibit limit switch which automatically stops TIP motion if the ball valve does not open on command. See Figure 7.5-28 (Drawing M1U110-1).

7.5.9.2.3 Signal Conditioning

The readout instruments and electrical controls for the TIP machines are mounted in a cabinet in the control room. Since there are several groups of guide tubes, each with an associated TIP machine, there are also several groups of readout equipment controls mounted in the cabinet. Each set of readout equipment consists of a dc amplifier and a dc power supply for the TIP polarizing voltage. A common X-Y recorder records the flux variations of each scan. An X-Y output is provided for use by the process computer. The TIP output is linear to within about ±2 percent from a flux of 2.1×10^{13} to 2.1×10^{14} nv. The probe and cable leakages contribute less than one percent of indicated reading. For normal operating conditions the flux amplifier is linear to within ±0.8 percent of full scale and drifts less than 0.8 percent of full scale during a 700 hr period at design operating conditions. Actual operating experience has shown the system to reproduce within 1.0 percent of full scale in a sequence of tests(1).

7.5.9.3 Power Generation Evaluation

An adequate number of TIP channels are supplied to assure that each LPRM assembly can be probed by a TIP, and one LPRM assembly (the central one) can be probed by every TIP to allow intercalibration. Typical TIPs have been tested to prove linearity(1). The system has been field tested in an operating reactor to assure reproducibility or repetitive measurement, and the mechanical equipment has undergone life testing under simulated operating conditions to assure that all specifications can be met. The system design allows semiautomatic operation for LPRM calibration and process computer use. The TIP machines can be operated manually to allow pointwise flux mapping.

7.5.9.4 Inspection and Testing

The TIPS equipment is tested and calibrated using heat balance data and approved station procedures and the applicable instruction manuals.

7.5.10 Period Based Detection Subsystem (PBDS)

7.5.10.1 Functional Design Basis

1. The PBDS is a back-up system for SOLOMON (see Section 7.16) to provide operators with on-line stability indications. PBDS monitors, multiple selected LPRM signals from LPRM Group A and LPRM Group B pages to determine if reactor core oscillations indicative of unacceptable reactor stability (or excessive HI decay ratio) are present.

2. The PBDS shall supply INOP and HI Decay Ratio alarm signals to Control Room Panel C905 for personnel use in monitoring PBDS system and reactor stability conditions.

3. Each PBDS channel has an analog indicating device available for monitoring reactor stability conditions. They can be used to validate the HI alarms, but are not required for channel operability.

7.5.10.2 Description

7.5.10.2.1 Identification

The PBDS has two separate and independent channels. The PBDS has two separate microprocessor circuit board cards containing the Period Based Algorithm. This algorithm analyzes LPRM signals to determine if the reactor is in a state of unacceptable high decay ratio. The cards generate alarms and analog outputs to control room instrumentation. Each PBDS card has associated alarms for INOP and HI Decay Ratio conditions. Each card generates two analog outputs from the Period Based Algorithm. These signals are the highest and second highest decay ratio confirmation counts of all input LPRM signals to the PBDS circuit card. The analog outputs of each PBDS card are displayed on a separate indicating device. The analog indicating device may be used to validate a HI alarm, but is not required for PBDS channel operability.

7.5.10.2.2 Power Supplies

Each PBDS card uses ±15V DC power supplies from the associated LPRM page. The annunciator relays associated with each PBDS card use 20V DC power supplies of the NMS in Panel C937. The annunciator power supply is 125V DC. The control room indicating device uses the 120V AC instrument power supply.

7.5.10.2.3 Physical Arrangement

The PBDS cards are the same size as the LPRM cards. They are mounted in the associated LPRM pages in the same manner as the LPRM cards in Panel C937. PBDS Channel A card is located in LPRM Group A page, and PBDS Channel B card is located in LPRM Group B page. The associated alarm relays are mounted in the same manner as other alarm relays of the NMS. The alarms are located on Panel C905 Left. The indicating devices are located on the vertical board section of Panel C905 below the alarms.

7.5.10.2.4 Signal Conditioning

Each analog LPRM signal is processed through an anti-aliasing filter to attenuate signals that have a frequency greater than one-half of the sample frequency. This prevents undesirable out of band signals from appearing at frequencies within the signal band pass. There is also a conditioning filter that reduces the band width to the minimum necessary for proper performance. This corner frequency filter is adjustable over a range by switches on the PBDS circuit cards. The LPRM signals are validated for excessive high or low conditions. Any LPRM signal that does not meet the criterion is excluded from evaluation by the PBA.

7.5.10.2.5 Operations

The PBDS is a backup system to detect unacceptable conditions of high core decay ratio and generate appropriate alarms. The basis for PBDS to monitor degrading core stability is documented in Reference 2. The primary system to monitor core stability is the SOLOMON program, which is part of the plant process computer. These two independent systems for monitoring stability ensure monitoring capability for personnel. Stability monitoring is required in the Buffer Zone of the operating domain as discussed in FSAR Section 3.7.

The PBDS cards are in accordance with IEEE-279 design requirement 4.19. The analog indicating devices are also assigned to separate PBDS channels. They may be used to validate a HI alarm from the associated PBDS channel because they are located on Panel C905 and are

readily available to personnel. However, they are not required for PBDS Channel operability, and the required actions are taken on the annunciators if the analog indicating devices are not available. The alarm functions are listed in Table 7.5-6. The alarms and analog displays are located on Panel C905. The PBDS provides accurate, complete, and timely information to personnel on the status and trend of the core decay ratio conditions. In cases where the core conditions degrade to excessive high decay ratio or channel unavailability, the associated channel alarms will immediately alert personnel.

The logic and redundancy of the PBDS assure spurious alarms do not occur. Each card has independent power supplies and wiring in conduits between Panel C937 and Panel C905. The analog displays on Panel C905 provide independent means of monitoring core decay ratio conditions.

The HI alarm logic requires 2 LPRMs from the same PBDS circuit card to be at the setpoint for actuation. The microprocessor selects the highest two confirmation counts from algorithm results of all LPRMs that provide input into the PBDS card. These outputs of the card are provided for analog display. If the associated analog display is operable, it provides immediate validation of the HI alarm. However, the analog indicating device is not required for the associated PBDS Channel to be available, and actions are initiated solely on the annunciator if the associated channel analog indicating device is not operable.

The PBDS is required to be operable when operating in the Buffer Zone and SOLOMON is not operable. Any inoperable condition causes a channel specific alarm on Panel C905. Personnel can clear this alarm by placing the bypass toggle switch to the bypass condition. Inoperable conditions are due to software self-test failures and an inadequate number of valid LPRM inputs. At least 6 LPRMs are required to be valid. Only one PBDS channel is required to meet the system operability requirements. If the PBDS is not operable and the reactor is in the Buffer Zone, immediate exit is required. The PBDS operability requirements are listed in Table 7.5-7.

7.5.10.2.6 Inspection and Testing

Table 7.5-8 lists the PBDS Surveillance Requirements. While operating in the Buffer Zone with SOLOMON inoperable, a channel check is required to be performed every hour.

Every 24 months a channel function test is performed. There is an internal surveillance program of the PBDS circuit cards to verify operability.

After each refueling, the PBDS card response is verified to be appropriate by performing a tuning procedure. The tuning criterion is based on the Period Confirmation Count Model described in Section 5.3.3.1 of Reference 2. This procedure verifies the card confirmation counts are neither too high nor low for the expected low core decay ratio conditions.

7.5.11 Nuclear Safety Requirements for Plant Operation

Table 7.5-5 presents the nuclear safety requirements for the neutron monitoring system for each BWR operating state. The entries on Table 7.5-5 represent an extension of the station wide BWR systems analysis of Appendix G to the components of the Neutron Monitoring System. The following referenced portions of the safety analysis report provide important information justifying the entries on Table 7.5-5:

Reference	Information Provided
1. Preceding parts of Section 7.5	Describes neutron monitoring system components signal conditioning, and trip functions
2. Station Safety Analysis, Section 14	Analyses verifying response of Neutron Monitoring System to transients and accidents
3. Station Nuclear Safety Operational Analyses, Appendix G	Identifies conditions and events for which neutron Monitoring System action is required
4. Jacobs, I.M., Guidelines for Determining Safe Test 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
5. Morgan, W. R., Incore Neutron Monitoring System for General Electric Boiling Water Company, Atomic Power Equipment Department, APED-5706, November 1968, revised April 1969	Describes Neutron Monitoring System components signal conditioning, trip and alarm functions, redundancy of system equipment

Each detailed requirement on Table 7.5-5 is referenced, where possible, to the most significant plant condition originating the need for the requirement by identification of a matrix block on 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 7.5-5 and are coded as follows:

Example of Matrix Reference:

```
F38-74
| | |
-|-|----- F  - BWR operating state F
  -|----- 38 - Event (Row 38)
   |----- 74 - Neutron Monitoring System (Column 74)
```

The basis for an operational nuclear safety requirement is generally clear from the information provided by the previously noted references. There are no Neutron Monitoring System operational requirements in Operating states A, C, and E because, with the reactor shut down (more than one rod sub-critical) in each of these states, there is no function of the system necessary to avoid any of the unacceptable results defined in Appendix G. Requirements imposed on the system for Operating states B, D, and F result from consideration of:

1. The minimum degree of core power level indication necessary prior to placing the mode selector switch in the startup position, and withdrawing control rods for an approach to criticality to ensure adequate core power level control within the envelope of operating conditions encompassed by station safety analyses.

2. The design basis control rod drop accident, lesser cases thereof, and abnormal operational transients.

3. The minimum degree of core flux distribution indication necessary for adequate flux distribution control to ensure operation of the reactor within the envelope of operating conditions encompassed by station safety analysis (state F only).

No requirements result from the consideration of the third factor above because the requirements imposed on the LPRM detectors by necessary operability of APRM channels (for provision of a neutron flux signal to the RPS) are more limiting and, therefore, ensure more than adequate flux distribution indication. The following paragraphs give specific bases for the operational nuclear safety requirements cited on Table 7.5-5 and technical specifications developed there from.

The SRMS performs no automatic safety function but provides the operator with a visual indication of neutron level which is required for a controlled reactor startup from low neutron levels. The results of reactivity accidents are functions of the initial neutron flux level. The requirement of an observable count rate of at least 3 cps prior to withdrawing control rods for an approach to

criticality assures that any ensuing transient begins at or above the initial value of 10^{-8} percent rated power used in the analyses of transients and accidents from cold conditions. One operable SRM channel would be adequate to monitor an approach to criticality using homogeneous patterns of scattered control rods. A minimum of three operational SRM channels is required as an added conservatism.

There is no requirement for LPRM-APRM availability to provide a neutron flux signal to the RPS in Operating states B and D due to the fact that it would take multiple operator errors or equipment malfunctions to render the IRM scram function inoperative. There is a requirement for both IRM and APRM scram protection in Operating State F due to the applicability of both the startup and run modes in this state.

Analytical studies of APRM channel response to power level changes with varying numbers of LPRM inputs inoperative, as well as experimental data obtained from operating BWRs[1], have demonstrated that errors encountered in tracking power level changes are acceptable with as many as half of the available inputs to a channel inoperative. A number of 11 (more than 50 percent) operable LPRM inputs has been selected as the minimum for which an APRM channel is considered operable. This required number of operable LPRM channels, which is quadrupled by the requirement that there be two operable APRM channels per Reactor Protection Trip System, also ensures more than an adequate number of operable LPRM channels to provide the necessary degree of core flux distribution indication.

One APRM channel of the three associated with each Reactor Protection Trip System may be bypassed without tripping the trip system. Core protection, through provision of an adequate scram function, is maintained by the remaining two operable APRMs in each trip system, as only one channel in each trip system is required to provide independent inputs to the trip system trip logics.

One IRM channel of the four associated with each of the two reactor protection trip systems may be bypassed without undermining the effectiveness of the system. In a low power low flow condition, uniform control rod withdrawal is the most probable cause of significant power rise. This power rise would be very slow since the flux distribution associated with such a withdrawal would not involve high local power peaks and because several rods would have to be moved. In an assumed uniform rod withdrawal to the scram level, the rate of power rise is no more than 5 percent rated per min, and three operable IRM channels in each trip system would be more than adequate to assure scram before power could exceed the acceptable levels.

The general considerations pertinent to the surveillance of equipment essential to the scram safety action are discussed in Section 7.2.6. An APRM channel is considered functionally as a device utilizing an analog sensor followed by an amplifier and a bistable trip circuit. Thus, a once per week functional test (trip output relays, observe alarms) is established through the calculations presented in Section 7.2.6. An IRM channel is considered functionally as a device which is needed only under some

restricted or infrequent mode of operation (startup and shutdown). The only tests which are meaningful are those performed just prior to startup or shutdown, i.e., the tests performed just prior to the need for the instrument. Thus, the IRM channel functional test (trip channel, observe alarm) must be performed prior to each startup. Should the reactor be operated for an extended period in the IRM range, the IRM channels should be considered analogous to the APRM channels in the power range; a functional test once per week is appropriate to the mode of operation.

The APRM, LPRM, and IRM channels are detecting devices which drift and lose sensitivity. A heat balance is used to correlate through calibration the APRM indications to the actual power level. Consideration of the drift characteristics, power distribution changes, and loss in LPRM detector sensitivity dictates a calibration of the APRM channels through a heat balance once each week. Operating experience with the LPRM subsystem indicates that calibration of the LPRM channels by the TIPS is sufficient to maintain adequate LPRM performance. Because the SRMS is required only as an indicator for planned operation, surveillance in accordance with the equipment manual is satisfactory.

Surveillance requirements have been developed from considerations discussed in reference 4 (under Section 7.5.10) for those devices which are not continually operating and whose purpose is to provide a certain function on a given operating condition. Calibration should be done in accordance with applicable manufacturer's equipment manuals. Past practice has indicated that a calibration of LPRMs by the TIPS once every 6 weeks has been satisfactory, and nothing has developed to indicate that this frequency should be changed.

Because the point at which the reactor becomes less than one rod subcritical (not shutdown) is not easily recognizable by the operator during plant startup, IRM protection requirements are selected to anticipate the need for protection should the one rod subcritical point be passed. IRM protection is required in state A when the mode switch is in the refuel position because of the possibility of going to state B from state A without recognizing the transition; for states C, D, E, and F scram functions are required to assure that placing the mode switch in the refuel position does not diminish reactor protection. See Section 7.2.

In recognition of the possibility of frequent switching between REFUEL and STARTUP in Operating states A and B, the true requirement for the SRMs is stepped back to include the REFUEL position of the mode switch.

7.5.12 Current Technical Specifications

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

7.5.13 References

1. Morgan, W.R. Incore Neutron Monitoring System for General Electric Boiling Water Reactors. APED-5706, November 1968, revised April 1969.

2. NEDO-32339 Licensing Topical Report Reactor Stability Long-Term Solution: Enhanced Option I-A.

3. NEDO 31960A, BWR Owner's Group Long-Term Stability Solutions Licensing Methodology, June 1991.

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

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

6. General Electric Report GE-NE-GENE-0000-0033-6871-01, "Pilgrim Option 1-D APRM Flow Biased Setpoints", Oct 2004.

7. General Electric Report GE-NE-0000-0027-5301-R2-P, Pilgrim Nuclear Power Station Single Loop Operation, April 2006.

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

TABLE 7.5-1

SRM TRIPS

Back Panel	Front Panel	Trip Function	Trip Action
Upscale Hi Hi	Light (Scram when shorting links removed)	SRM upscale or inoperative	Rod Block, Annunciator, amber light
Upscale Hi	Light, Alarm, Rod block	Detector Retraction Permissive (SRM downscale)	Bypass detector limit switch, annunciator, white light, rod block
Downscale	Light, Alarm, Rod block	SRM downscale	Annunciator, white light, rod block
Inoperable	Light (when out)	SRM period	Annunciator, white light
Retract Permissive Period	Light, Alarm	SRM retraction permissive	Display, white light
Bypass	Light	SRM bypassed	Display, white light

TABLE 7.5-2

IRM TRIPS

Back Panel	Front Panel	Trip Function	Trip Action
Downscale	light, alarm, red block	IRM upscale or inoperative	Scram, Annunciator, red light
Upscale Hi	light, alarm, red block	IRM upscale	Rod block, Annunciator, amber light
Upscale Hi Hi	light, scram	IRM downscale	Rod block (exception on most sensitive scale), Annunciator, white light
Inoperable	light, alarm, scram	IRM bypassed	White light
Bypassed	light		

TABLE 7.5-3

LPRM TRIPS

Trip Function	Trip Range	Trip Setpoint	Trip Action
LPRM downscale	2% to full scale	3%	Light and annunciator
LPRM upscale	2% to full scale	100%	Light and annunciator
LPRM bypass	Manual Switch	-	Light, annunciator, and APRM Averag-ing compensation

Table 7.5-4

APRM TRIPS

BACK PANEL (C937	FRONT PANEL (C905)	TRIP FUNCTION	TRIP POINT RANGE	TRIP SETTING	ACTION
APRM Downscale	Light, Alarm, Rod Block	APRM Downscale	2% to full scale	2%	Rod Block, Annunciator, White Light, IRM Scram Interlock
APRM Upscale (HI)	Light, Alarm, Rod Block	APRM Upscale (HI)	Varied linear functions with recirc flow and clamp value at rated power	Latest values (including SLO) in COLR	Rod Block, Annunciator, Amber Light
APRM Upscale (HI-HI)	Light, Scram	APRM Upscale (HI-HI)	Varied linear functions with recirc flow and clamp value at rated power	Latest values (including SLO) in COLR	Scram, Annunciator, Red Light
APRM Inoperative	Light, Rod Block, Scram	APRM Inoperable	Calibrate Switch, or too few inputs	Not in operate mode or less than 11 LPRM inputs	Rod Block, Scram, Annunciator, Red Light

Table 7.5-5

NEUTRON MONITORING SYSTEM OPERATIONS REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.5.5.1 Provide core power level indication	1. SRM sub-system	4 channels	Since the point which the reactor becomes less than one rod subcritical is not easily recognized the requirements of State B apply whenever more than one rod is withdrawn in State A to anticipate the protection requirements of State B.	With Mode Switch in Startup, 1 operable channel (B02-46) (B02-74)	Same as for State D whenever more than one control rod is withdrawn in this state.	With Mode Switch in STARTUP: 1 operable channel (D02-46) (D02-74)	Same as for State F whenever more than one control rod is withdrawn in this state.	With Mode Switch in STARTUP: 1 operable channel (F02-46) (F02-74)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.5-5 (cont)

NEUTRON MONITORING SYSTEM OPERATIONS REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*	MINIMUM REQ'D FOR ACTION*
7.5.5.2 Provide neutron flux signal to the reactor protection system	1. LPRM sub-system	30 LPRM detector assembles, 120 detectors 16 detectors for APRM channels A, C, E 14 detectors for APRM channels B, D, F						11 operable detectors per operable APRM channel (F38-74)
	2. APRM sub-system (channels + logic)	6 channels (3 per RPS trip system)					Same as State F whenever more than one control rod is withdrawn	With mode switch in RUN: 1 channel per operable RPS trip system (F38-74)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.5-5 (cont)

NEUTRON MONITORING SYSTEM OPERATIONS REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	A MINIMUM REQ'D FOR ACTION*	B MINIMUM REQ'D FOR ACTION*	C MINIMUM REQ'D FOR ACTION*	D MINIMUM REQ'D FOR ACTION*	E MINIMUM REQ'D FOR ACTION*	F MINIMUM REQ'D FOR ACTION*
7.5.5.2 Provide neutron flux signal to the reactor protection system (Cont)	3. IRM sub-system (channels + logic)	8 channels (4 per RPS trip system)	Since the point at which the reactor becomes less than one rod subcritical, is not easily recognized, the requirements of State B apply whenever more than one rod is withdrawn in State A in order to anticipate the protection requirements of State B	With Mode Switch in STARTUP: 1 channel per operable RPS trip system (B38-74)	Same as State A	With Mode switch in STARTUP: 1 channel per operable RPS trip system.	Same as State A	With Mode Switch in STARTUP: 1 channel per operable RPS trip system. (F38-74)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.5-6

Period Based Detection Subsystem Trip Functions

Front Panel C905	Trip Function Status	Trip Point Range	Setpoint
Alarm	HI	All LPRMs above 3%	2 LPRMs at 7 confirmation counts
Alarm	INOP	Self-test INOP signal generated. Less than required number of valid LPRMs	self-test signals - various minimum valid LPRMs: 6

Table 7.5-7

Period Based Detection Subsystem Actions (1)

Available Channels	Minimum Required	Applicability	Condition	Required Action	Completion Time
2	1	Thermal Power and Core Flow in the Buffer Zone	Any operable PBDS channel indicating HI Decay Ratio Alarm and alarm is validated (2)	Exit the Buffer Zone	15 minutes
2	1	Inadvertent entry and operation of Thermal Power and Core Flow in the Buffer Zone	Any operable PBDS channel indicating HI Decay Ratio Alarm and alarm is validated. (2) OR Required PBDS channel not operable (2)	Exit the Buffer Zone	15 minutes
2	1	Thermal Power and Core Flow in the Buffer Zone	Required PBDS channel not operable (3)	Initiate action to exit the Buffer Zone	15 minutes

(1) The requirement only applies if PBDS is being used as an on-line stability monitor.

(2) Validation shall be comparing analog indicating device on C905 for HI conditions. If the analog indicating is not operable, then the actions shall be initiated from alarm actuation only.

(3) The PBDS channel shall be defined as the PBDS cards in C937 and the annunciators (INOP and HI) on C905. The status of any other components do not affect the PBDS availability.

Table 7.5-8

Period Based Detection System Surveillance Requirements (1)

Surveillance	Frequency	Basis
1. Verify each channel of PBDS not in HI Decay Ratio Alarm	Immediately after transient entry into the Buffer Zone OR Prior to planned entry into the Buffer Zone AND Every hour while operating in the Buffer Zone.	During operation in the Buffer Zone the HI Decay Ratio Alarm is relied upon to indicate conditions consistent with the reactor trending toward neutron/thermal hydraulic instability. Verification provides assurance of the proper indication of the alarm.
2. Perform Channel Function Test	Every refueling	This surveillance ensures the entire system will perform the intended function. The test includes manual initiation of an internal test sequence and verification of appropriate alarm and inoperable conditions. The alarm circuit is designed to operate for over 24 months with sufficient accuracy of signal amplitude and considering environment and initial calibration.
3. Perform Channel Tuning for each channel of PBDS	After refueling	This surveillance ensures the response of the card is sensitive to adequately respond to conditions of increasing core decay ratio.

(1) Only applies if the PBDS is being used as an on-line stability monitor.

Figure 7.5-1 has been removed.

Please refer to BECo Controlled Drawing M1U103-4.

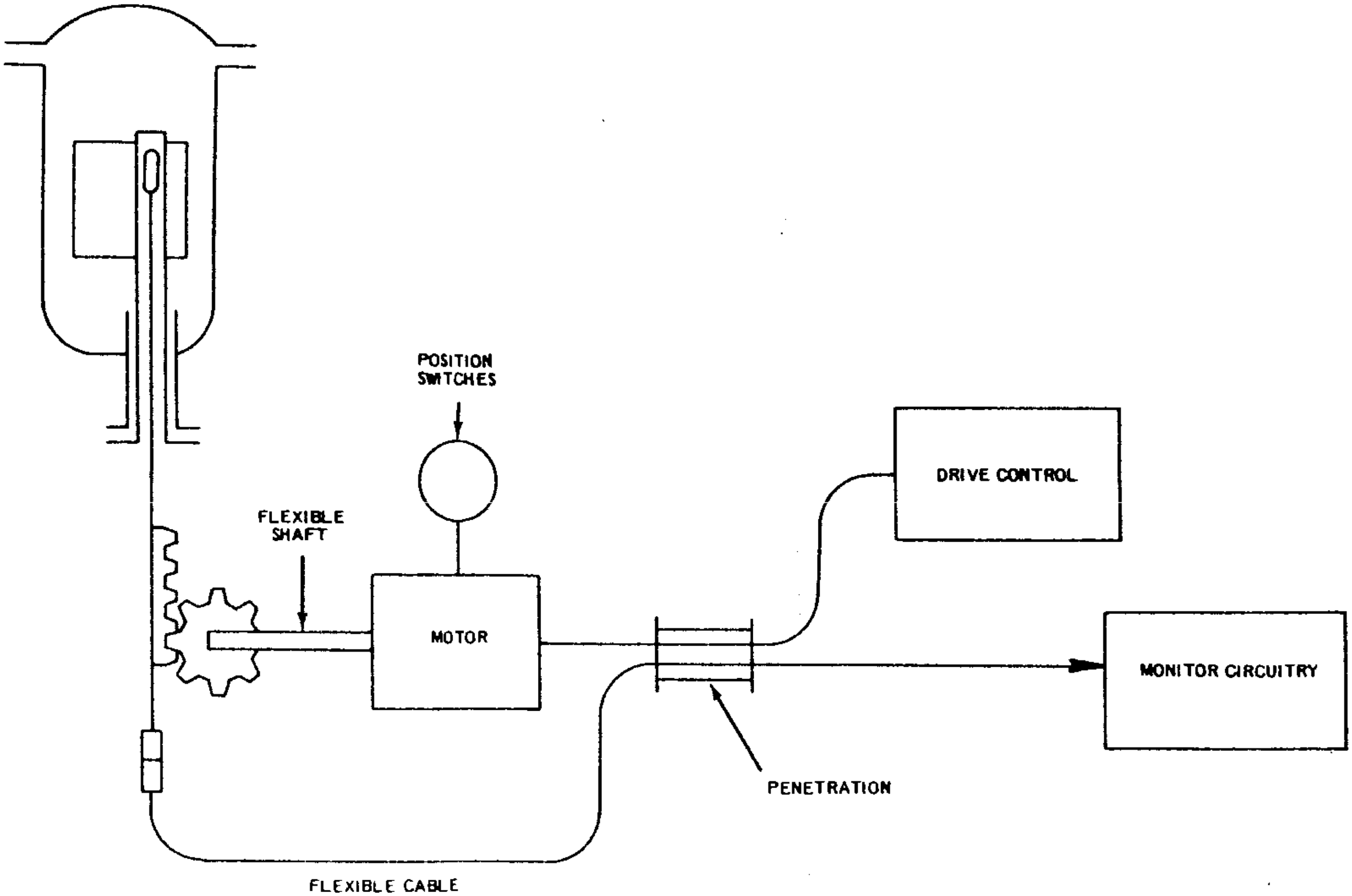


FIGURE 7.5-2
DETECTOR DRIVE SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 7.5-3 has been removed.

Please refer to BECo Controlled Drawing M1U109-2.

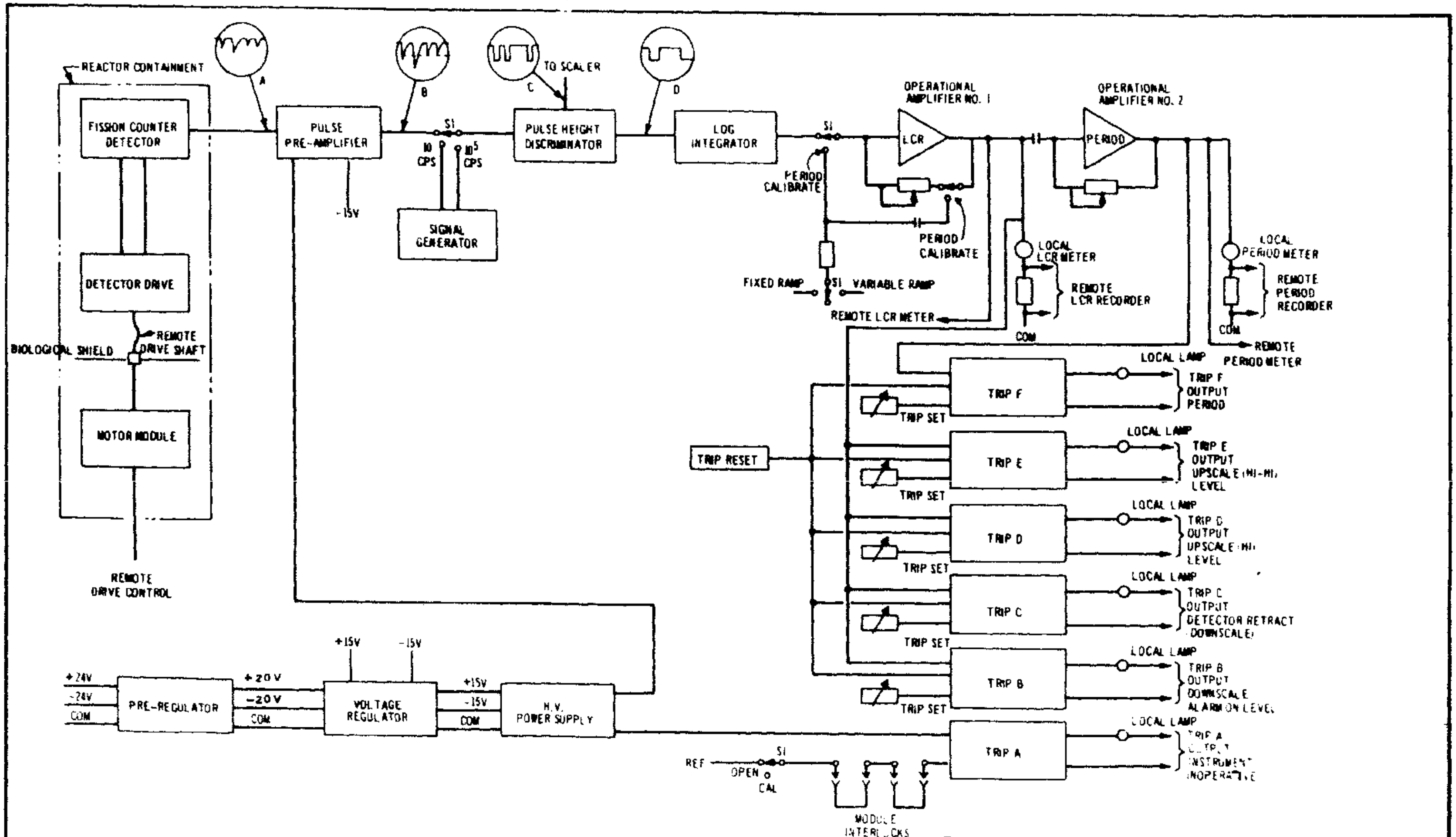


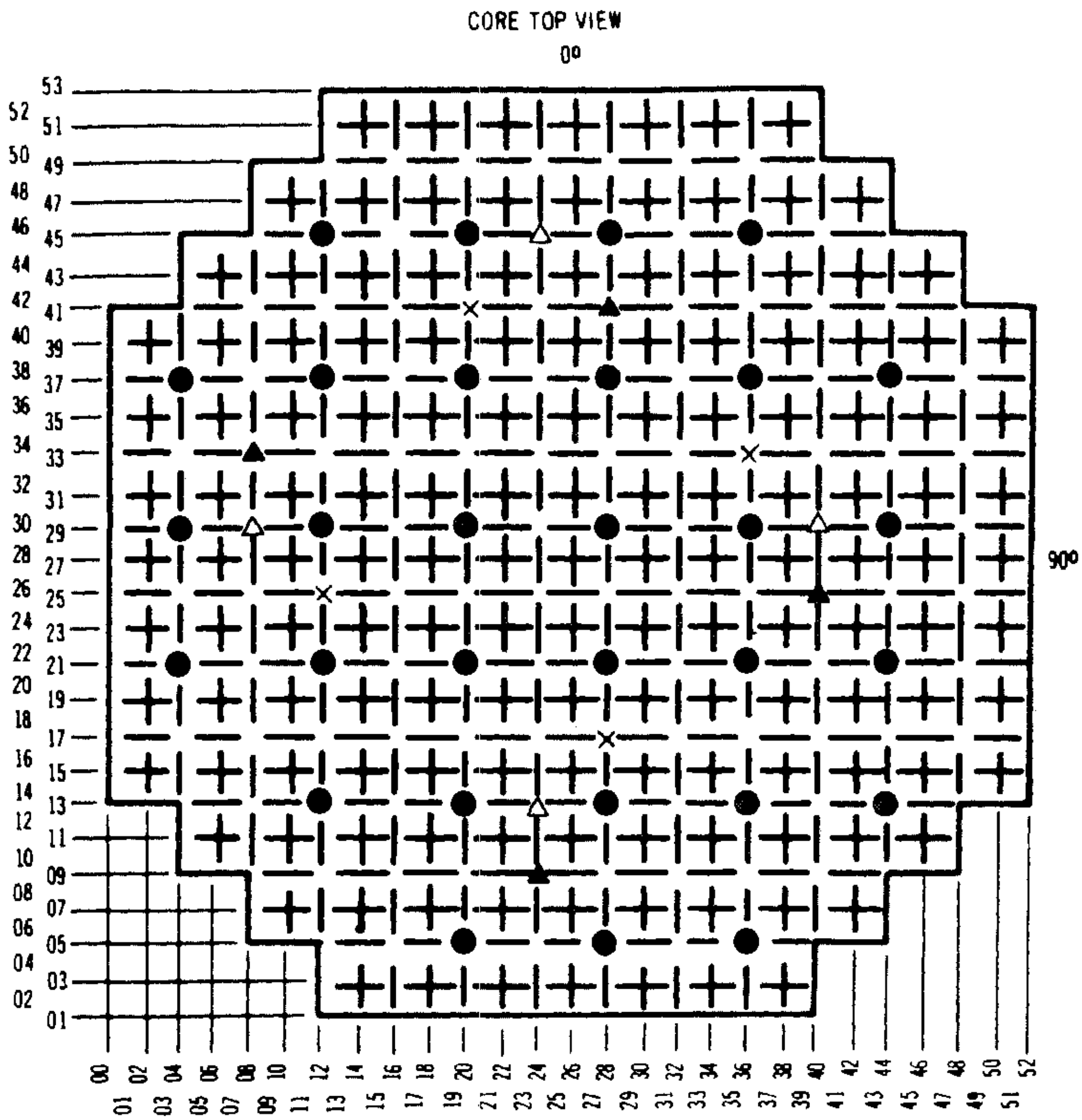
FIGURE 7.5-4

FUNCTIONAL BLOCK DIAGRAM OF SRM CHANNEL

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 7.5-5 has been removed.

Please refer to BECo Controlled Drawing M1U104-2.



× NEUTRON MONITORING SYSTEM DETECTOR LOCATIONS – 4

▲ DESIGN NEUTRON SOURCE LOCATIONS – 5

△ SPARE NEUTRON SOURCE LOCATIONS – 4

FIGURE 7.5-6
SOURCE RANGE MONITORING
SYSTEM CORE LOCATIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

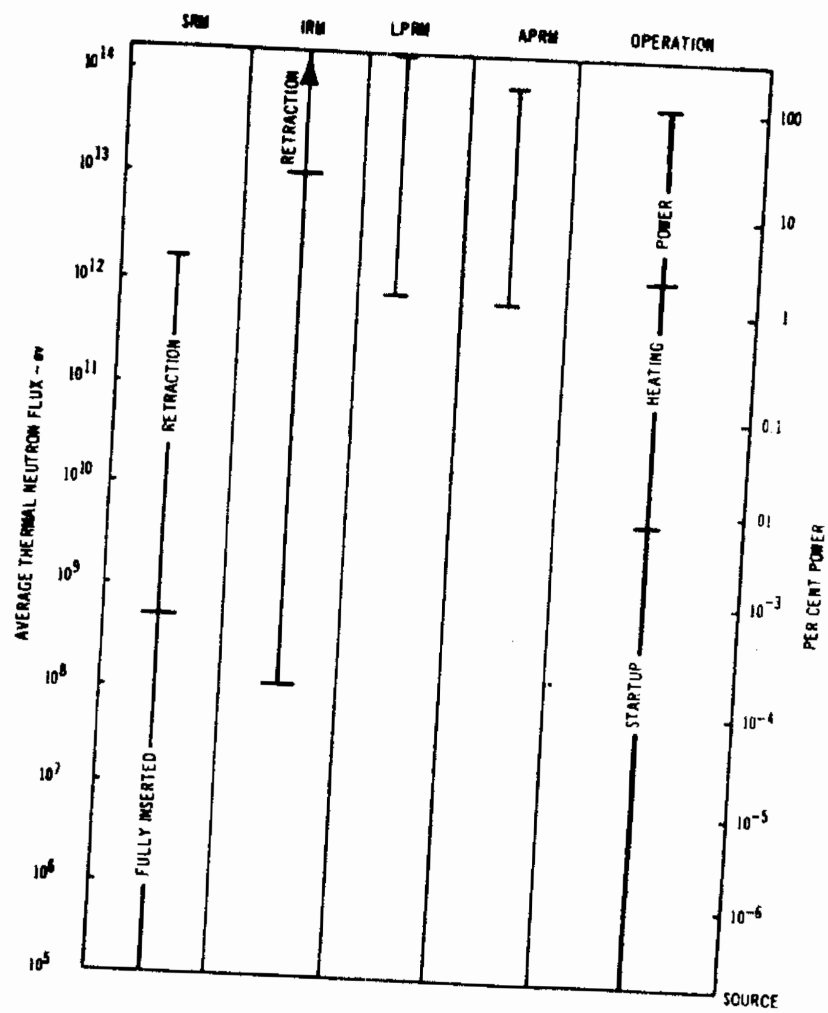


FIGURE 7.5-7
RANGES OF NEUTRON
MONITORING SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

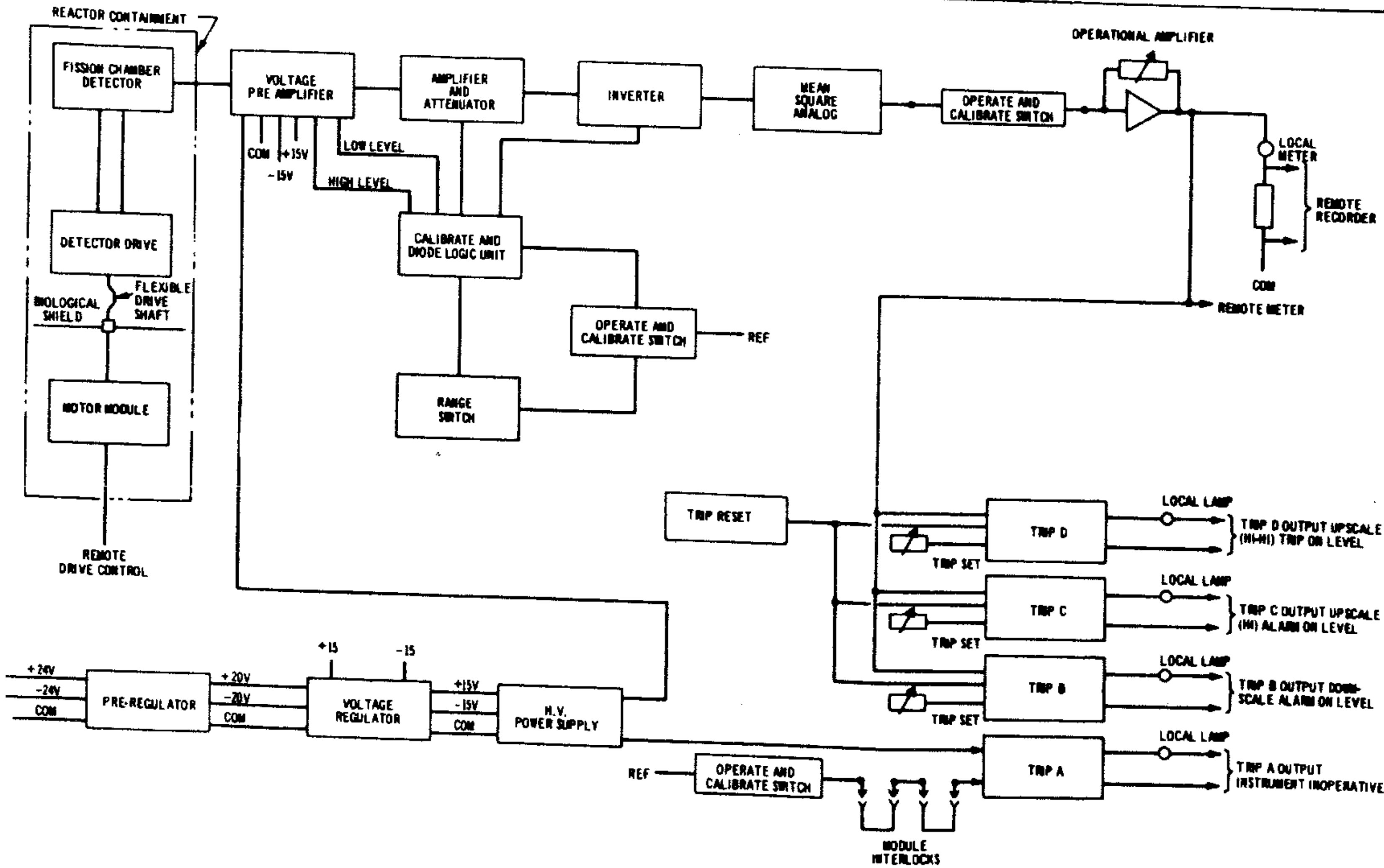
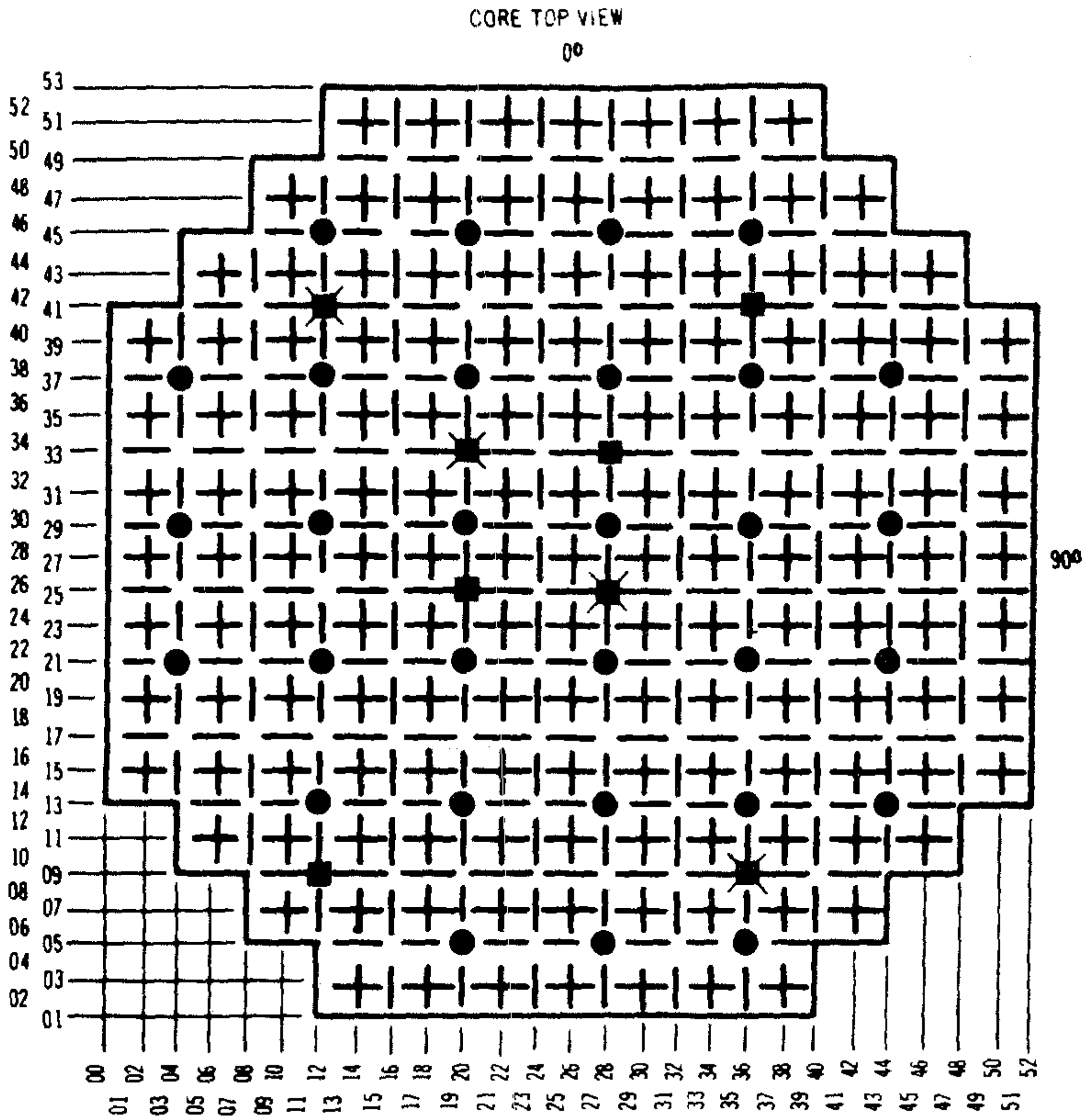


FIGURE 7.5-8
FUNCTIONAL BLOCK DIAGRAM OF IRM CHANNEL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

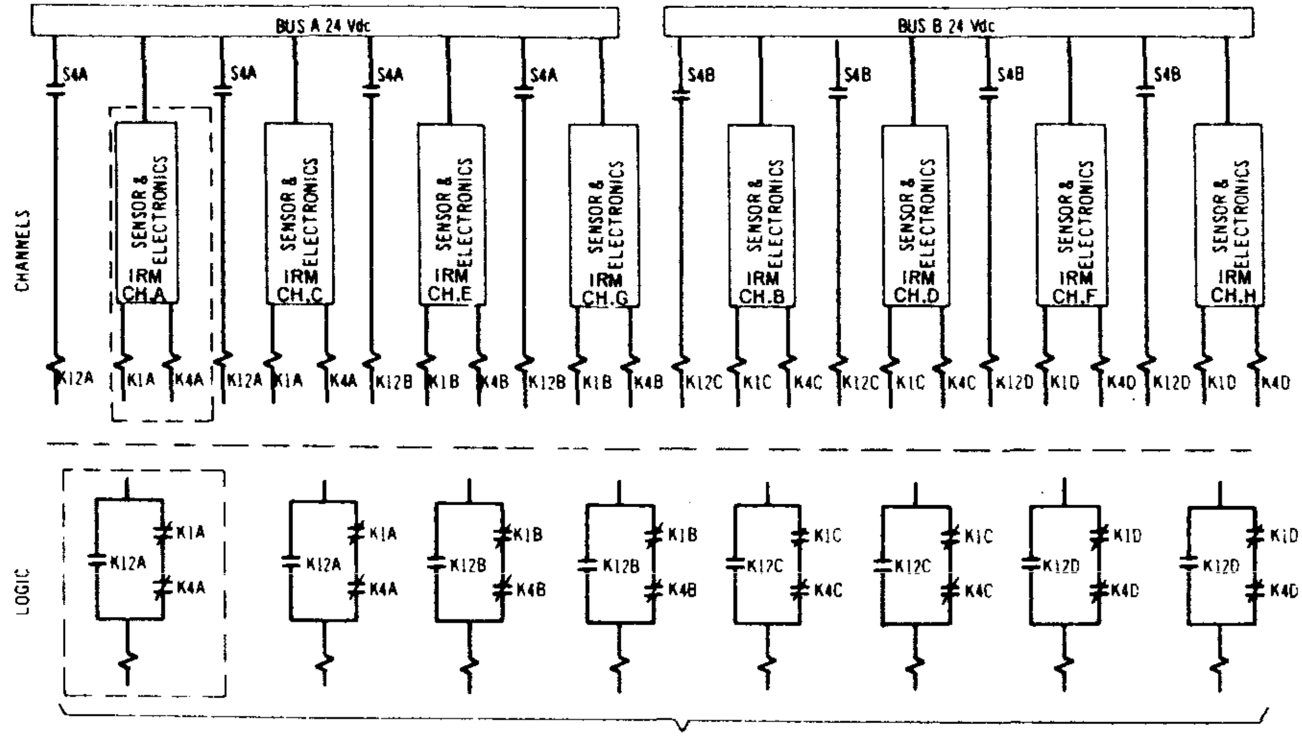


INTERMEDIATE RANGE MONITORING CHANNELS -4
REACTOR PROTECTION SYSTEM TRIP SYSTEM A

INTERMEDIATE RANGE MONITORING CHANNELS -4
REACTOR PROTECTION SYSTEM TRIP SYSTEM B

TOTAL IRM CHANNELS -8

FIGURE 7.5-9
IRM LOCATIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



LEGEND: K1A, B, C, D – INOPERATIVE TRIP
K4A, B, C, D – UPSCALE TRIP
S4A, B – BYPASS SWITCH

NOTE: TRIP CONTACTS ARE SHOWN IN NORMAL OPERATION POSITION, BYPASS SWITCH CONTACTS ARE SHOWN IN UNBYPASSED POSITION.

FIGURE 7.5-10
TYPICAL IRM CIRCUIT ARRANGEMENT FOR REACTOR PROTECTION SYSTEM INPUT
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

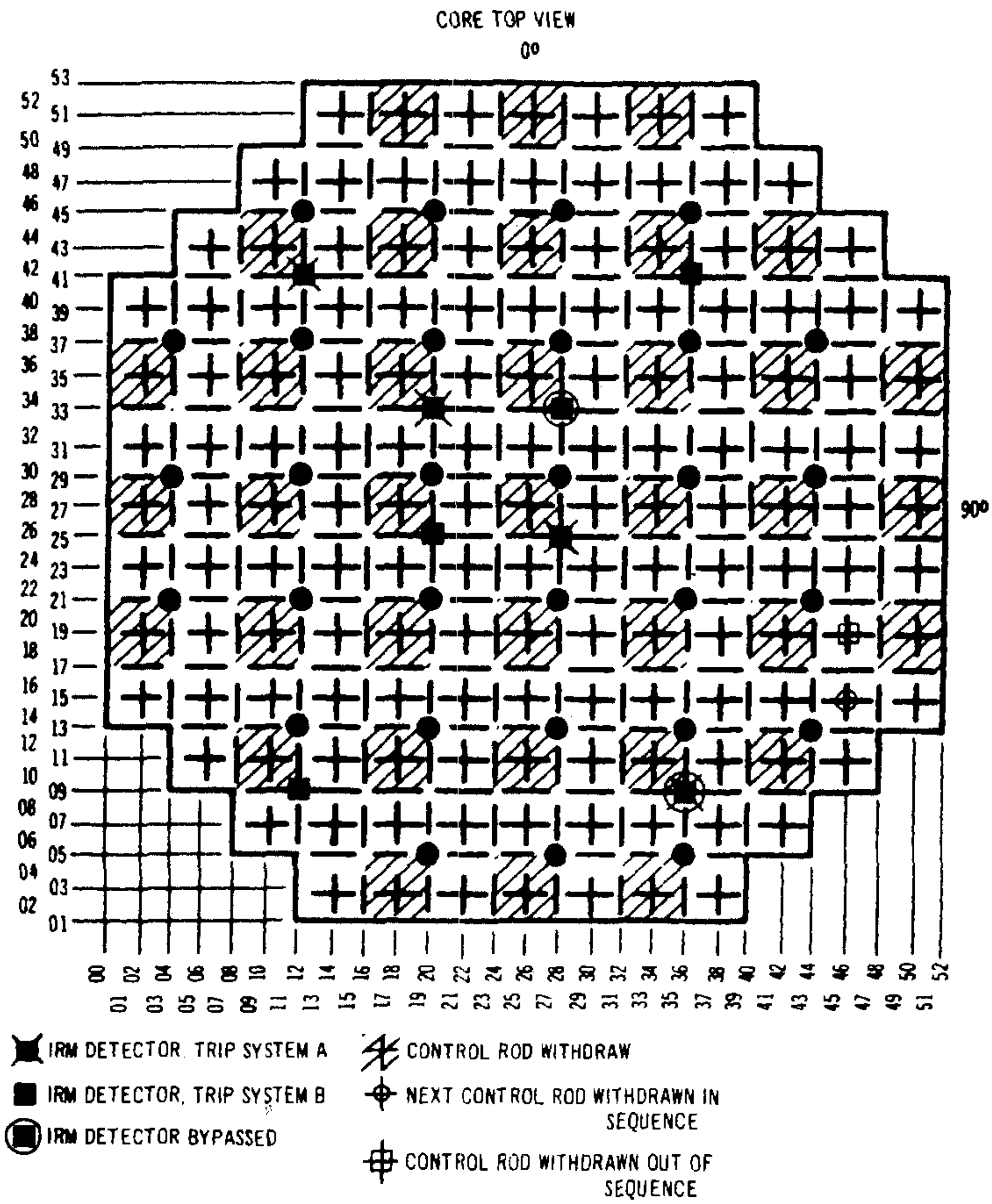


FIGURE 7.5-11
INITIAL CORE
CONTROL ROD WITHDRAWAL ERROR
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

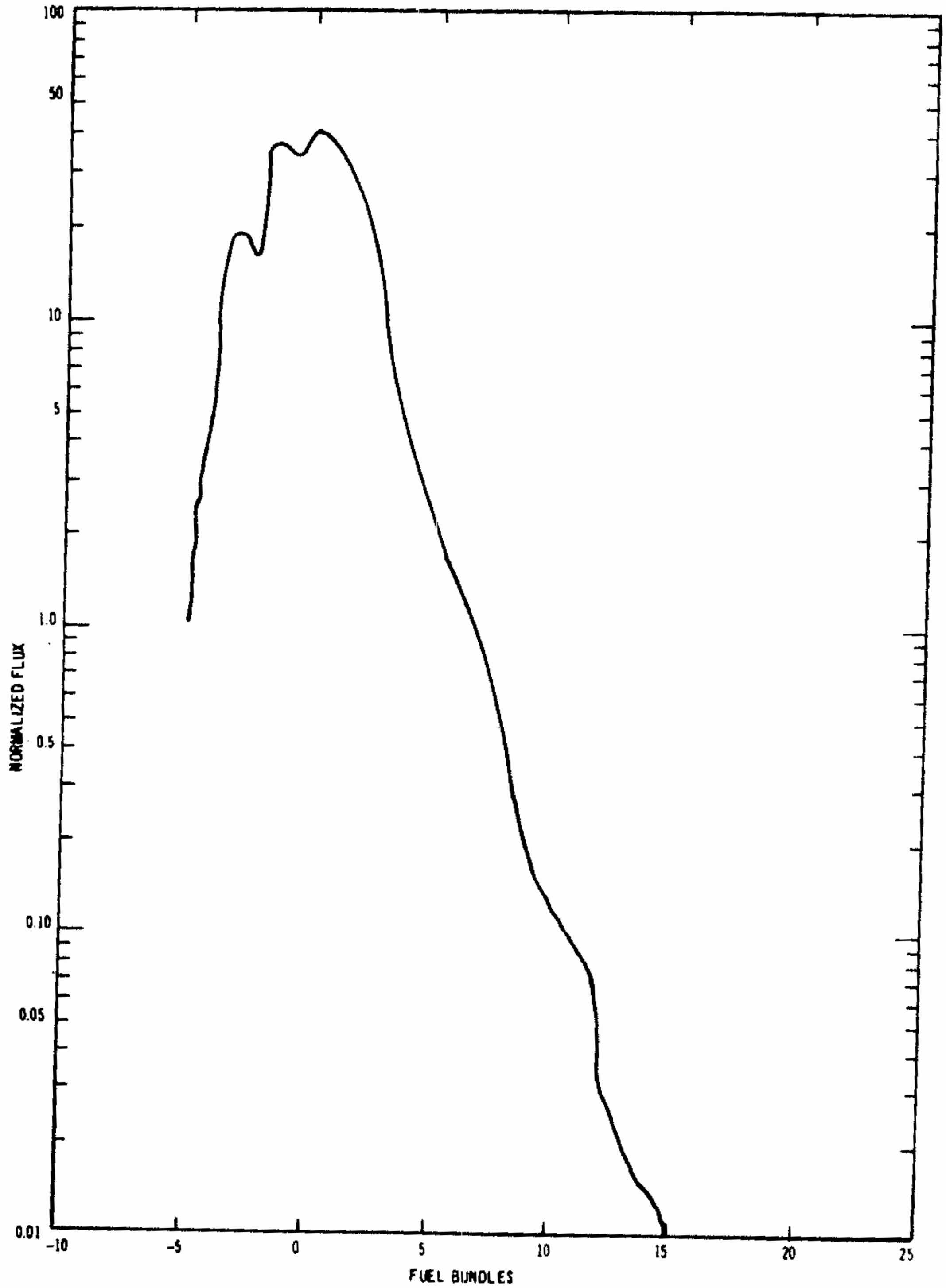


FIGURE 7.5-12
INITIAL CORE
NORMALIZED FLUX DISTRIBUTION
FOR ROD WITHDRAWAL ERROR
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

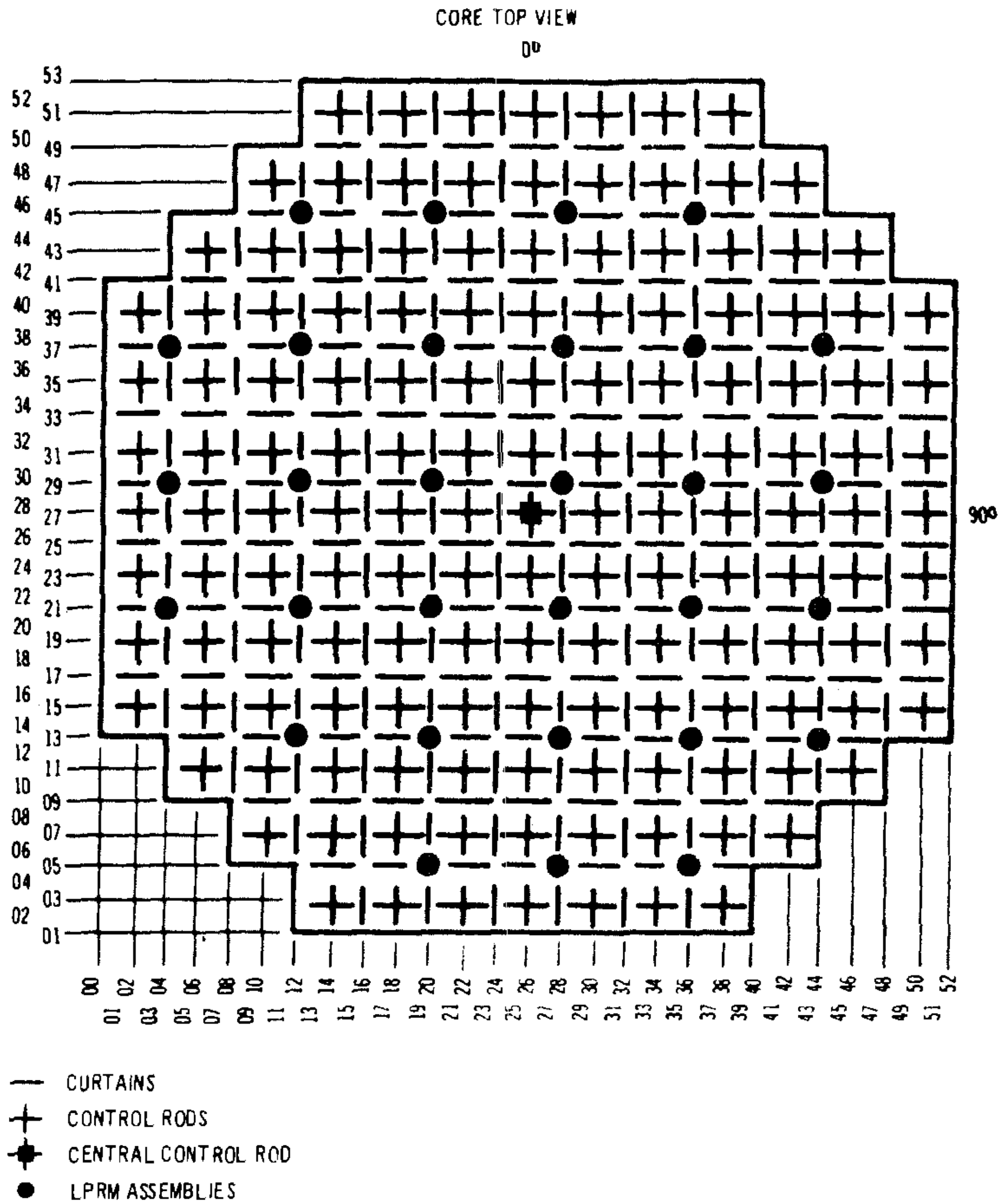
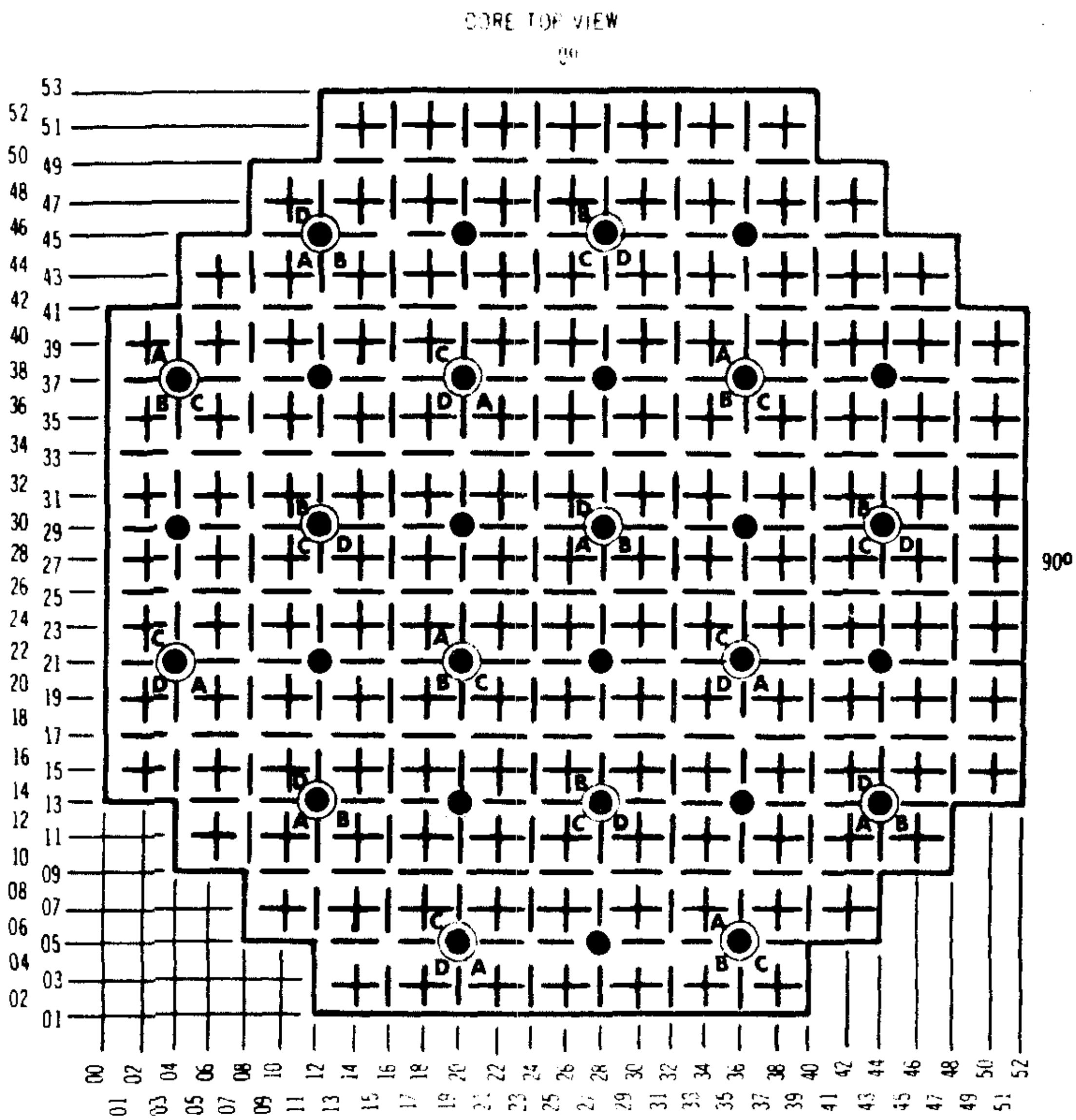


FIGURE 7.5-13
LPRM LOCATIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 7.5-14 has been removed.

Please refer to BECo Controlled Drawing M1U 75-4.



POWER RANGE DETECTOR ASSEMBLIES WITH LPRM's PROVIDING INPUT TO APRM CHANNELS A,C,E

UPPER LEFT LETTER IS LPRM CHAMBER ASSIGNED TO APRM A } FOR REACTOR PROTECTION

LOWER LEFT LETTER IS LPRM CHAMBER ASSIGNED TO APRM C } SYSTEM TRIP

LOWER RIGHT LETTER IS LPRM CHAMBER ASSIGNED TO APRM E } SYSTEM A

LEGEND

D - TOP LPRM DETECTOR POSITION

C - UPPER MIDDLE LPRM DETECTOR POSITION

B - LOWER MIDDLE LPRM DETECTOR POSITION

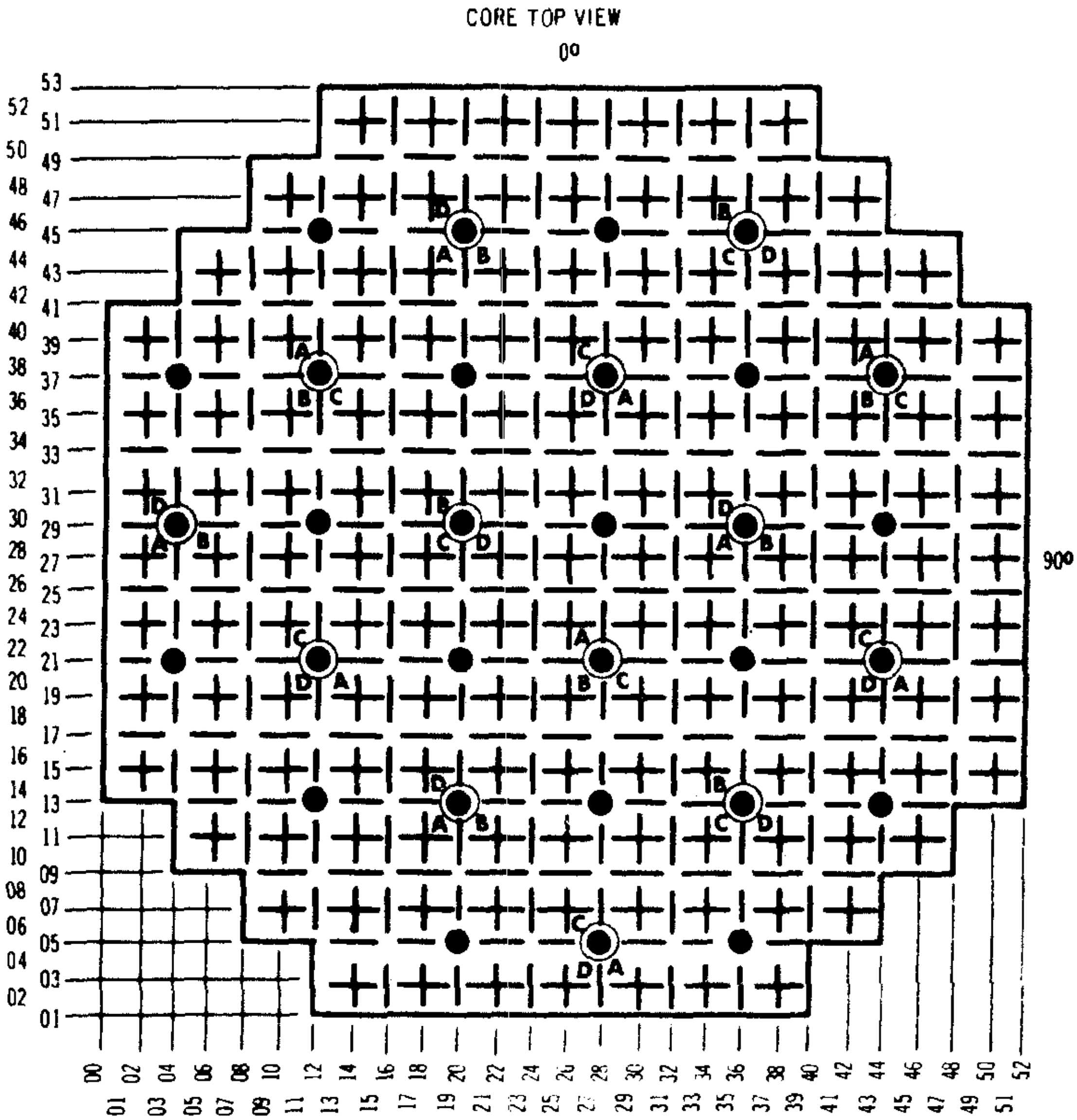
A - BOTTOM LPRM DETECTOR POSITION

FIGURE 7.5-15

LPRM TO APRM ASSIGNMENT SCHEME (TRIP SYSTEM A)

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT



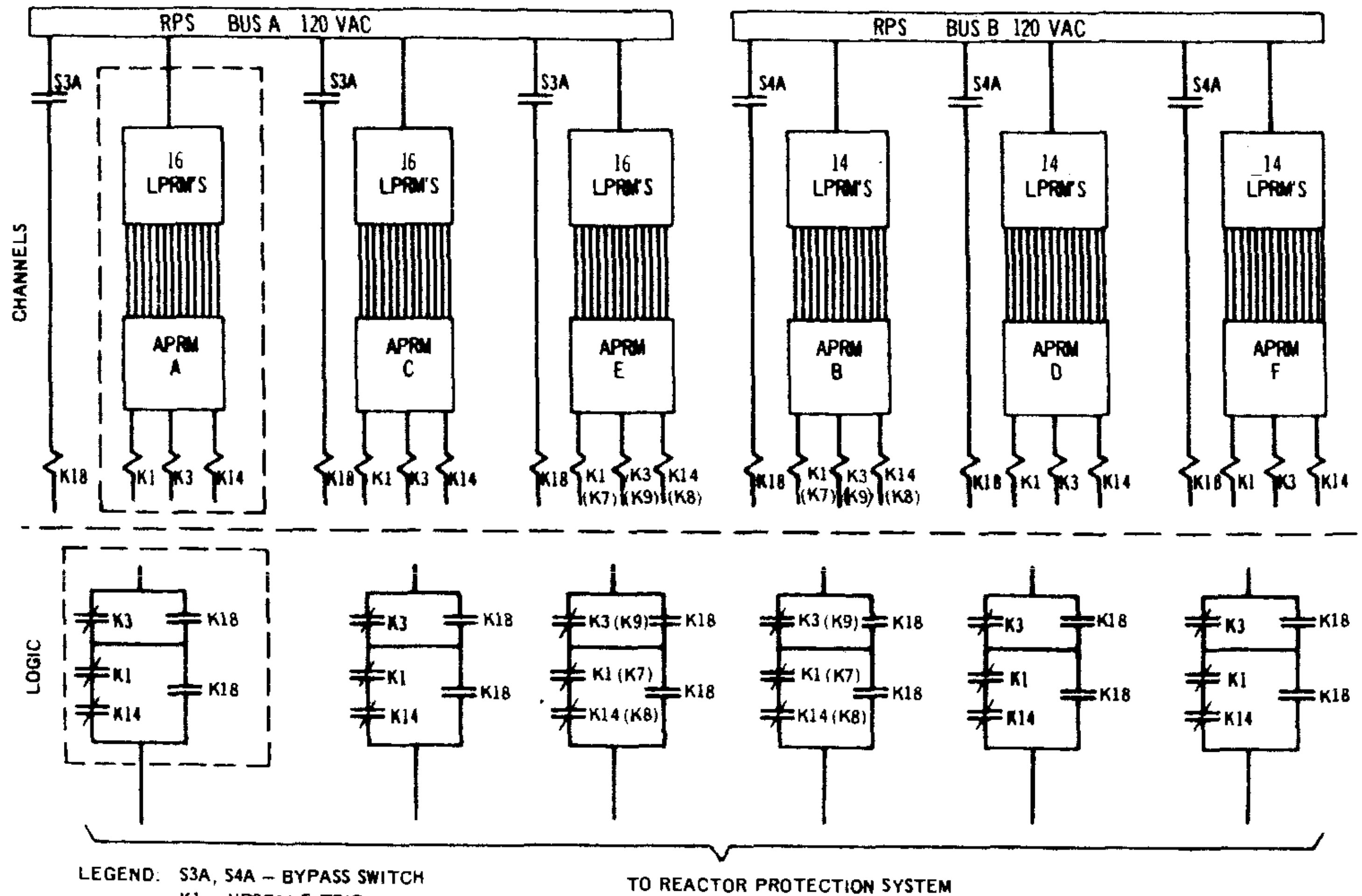
POWER RANGE DETECTOR ASSEMBLIES WITH LPRM's PROVIDING INPUT TO APRM CHANNELS B, D, F

UPPER LEFT LETTER IS LPRM CHAMBER ASSIGNED TO APRM B } FOR REACTOR PROTECTION
LOWER LEFT LETTER IS LPRM CHAMBER ASSIGNED TO APRM D } SYSTEM TRIP
LOWER RIGHT LETTER IS LPRM CHAMBER ASSIGNED TO APRM F } SYSTEM B

LEGEND

D – TOP LPRM DETECTOR POSITION
C – UPPER MIDDLE LPRM DETECTOR POSITION
B – LOWER MIDDLE LPRM DETECTOR POSITION
A – BOTTOM LPRM DETECTOR POSITION

FIGURE 7.5-16
LPRM TO APRM ASSIGNMENT SCHEME (TRIP SYSTEM B)
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



LEGEND: S3A, S4A – BYPASS SWITCH
K1 – UPSCALE TRIP
K3 – DOWNSCALE TRIP
K14 – INOPERATIVE TRIP

NOTE: TRIP CONTACTS ARE SHOWN IN NORMAL OPERATION POSITION. BYPASS SWITCH CONTACTS ARE SHOWN IN UNPASSED POSITION. RELAYS SHOWN (KX) ARE USED IN TRIP SUBSYSTEM A2 AND B2 FOR APRM'S E AND B, RESPECTIVELY.

FIGURE 7.5-17
TYPICAL APRM CIRCUIT ARRANGEMENT FOR REACTOR PROTECTION SYSTEM INPUT
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

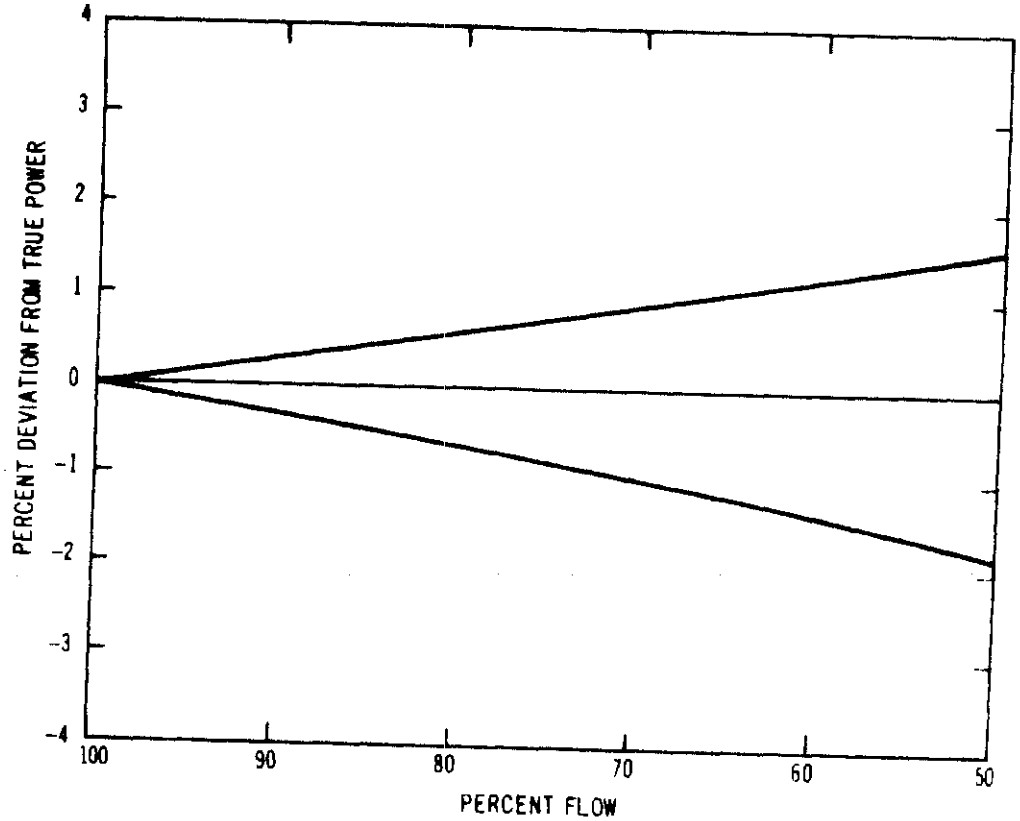


FIGURE 7.5-18
INITIAL CORE
ENVELOPE OF MAXIMUM APRM
DEVIATION, REDUCTION IN POWER
BY FLOW CONTROL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

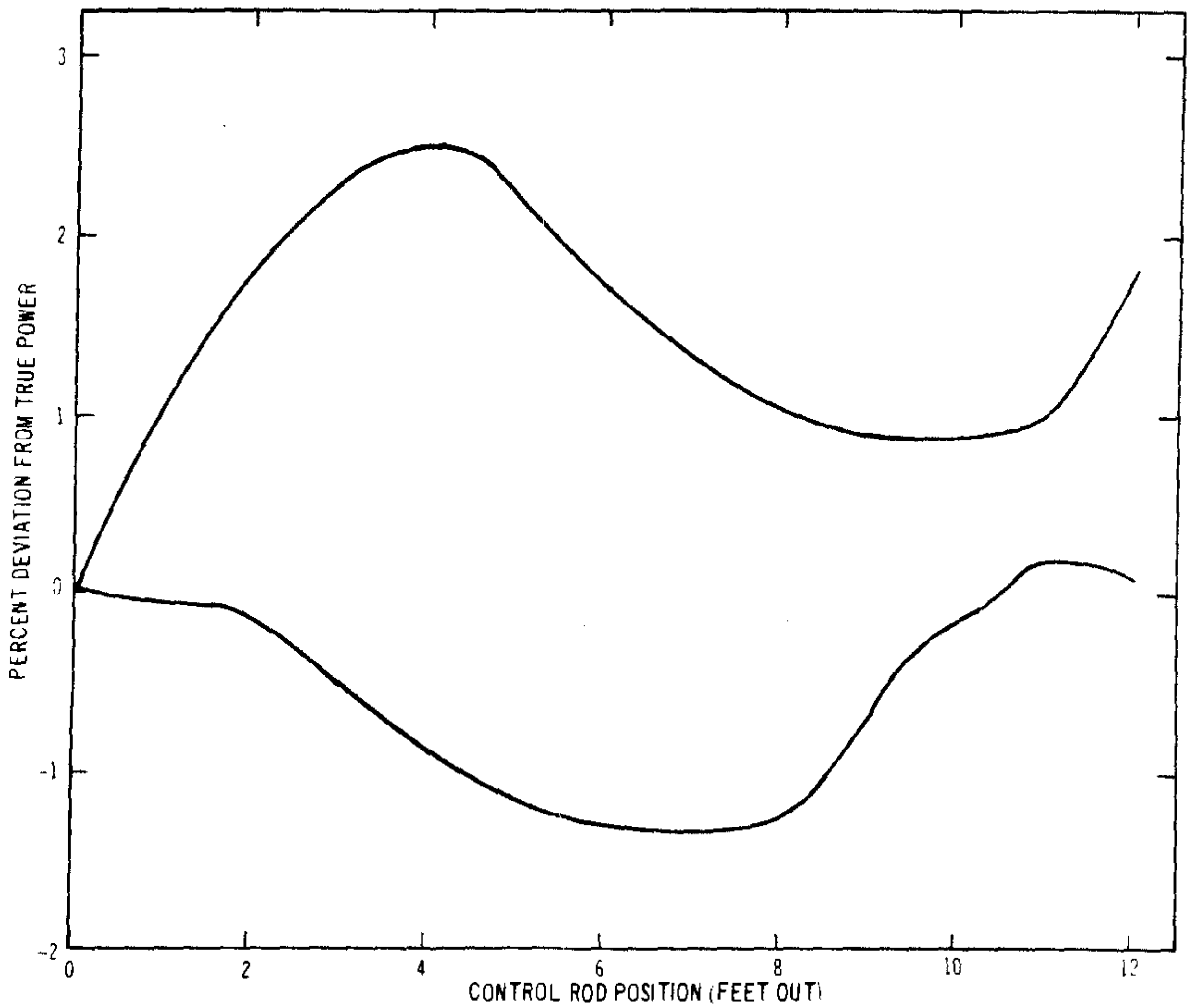
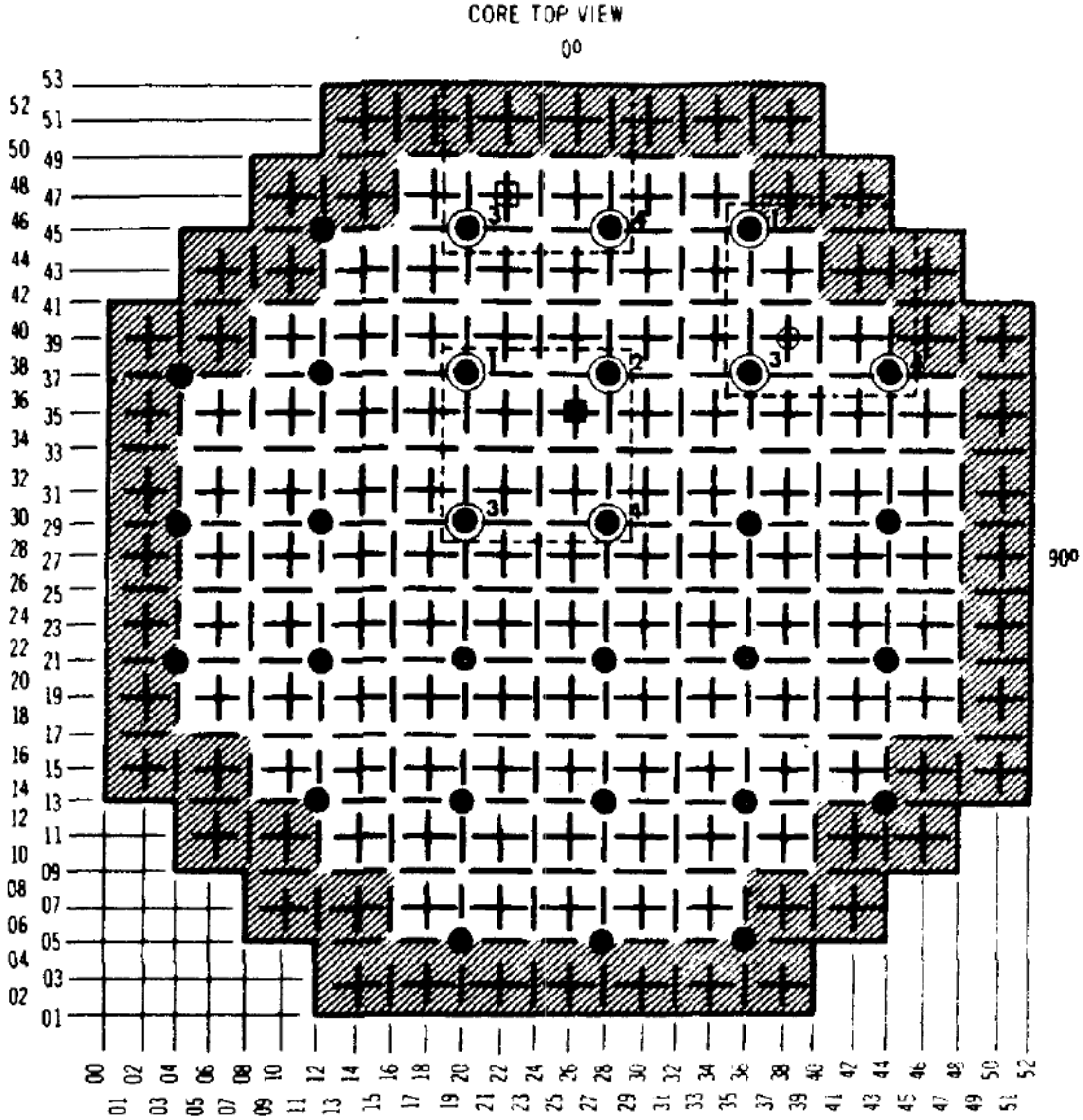


FIGURE 7.5-19
INITIAL CORE
ENVELOPE OF MAXIMUM DEVIATION
APRM TRACKING WITH ON-LIMITS
CONTROL ROD WITHDRAWAL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



▨ RBM AUTOMATICALLY BYPASSED (READING ZEROED)

☐ TYPICAL ROD YIELDING FOUR LPRM's AS INPUT (2 POWER RANGE DETECTOR ASSEMBLIES)

○ TYPICAL ROD YIELDING SIX LPRM's AS INPUT (3 POWER RANGE DETECTOR ASSEMBLIES)

● TYPICAL ROD YIELDING EIGHT LPRM's AS INPUT (4 POWER RANGE DETECTOR ASSEMBLIES)

NOTE: ASSIGNMENT IS AUTOMATICALLY INITIATED UPON ROD SELECTION.

FIGURE 7.5-20
ASSIGNMENT OF POWER RANGE DETECTOR ASSEMBLIES TO RBM'S
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

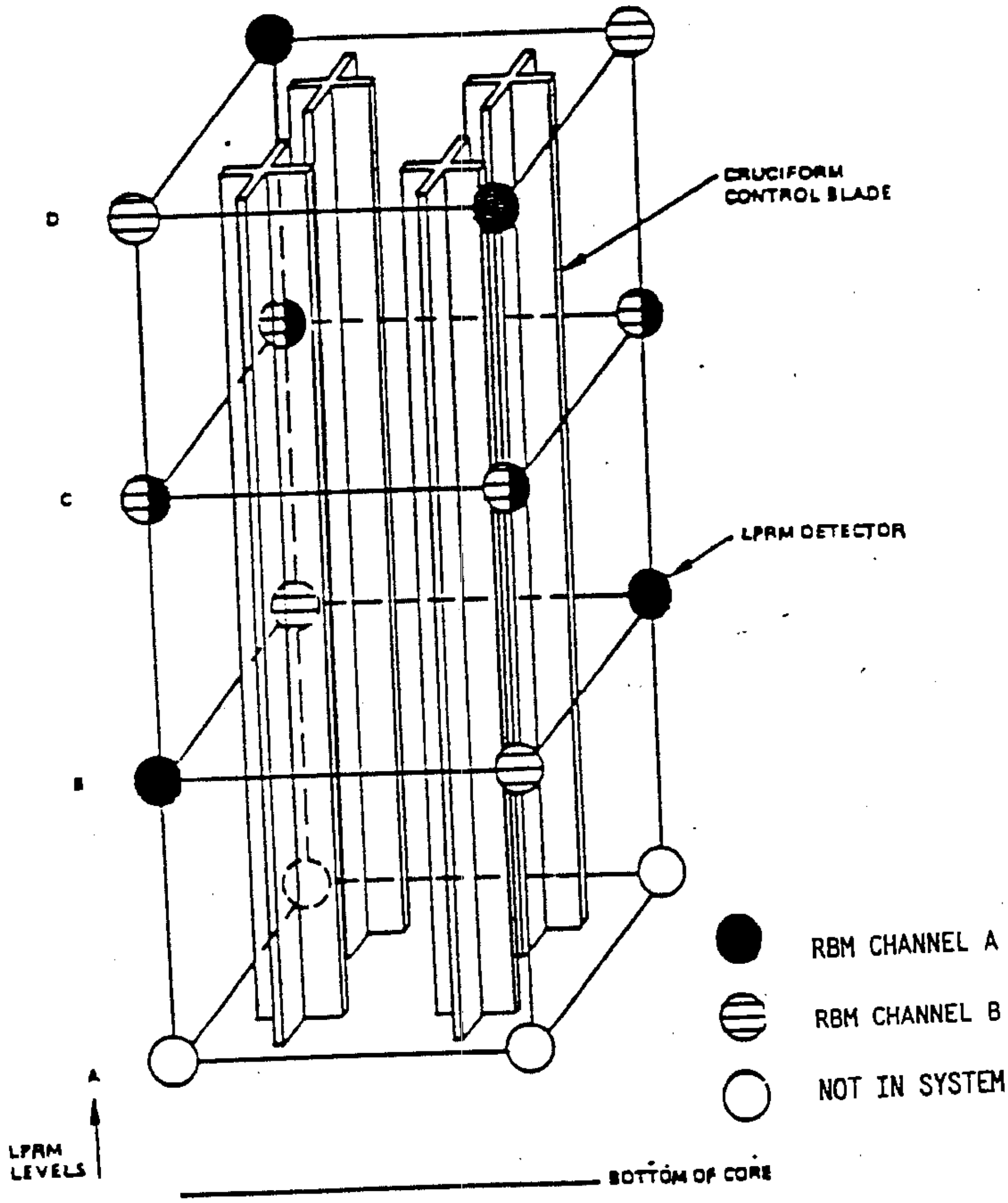


FIGURE 7.5-21 LPRM ASSIGNMENT TO RBM FOR INTERIOR ROD SURROUNDED BY FOUR LPRM STRINGS

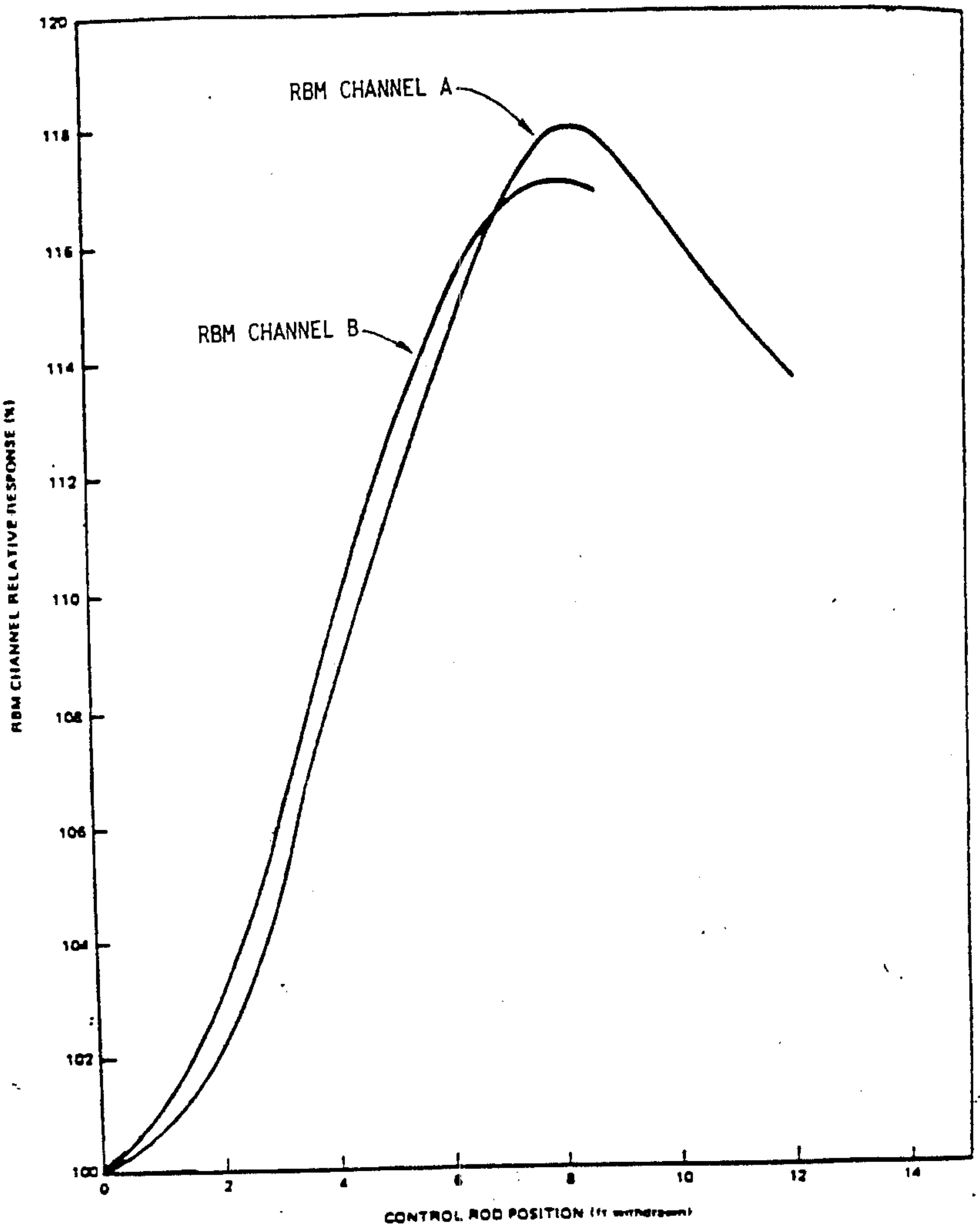


FIGURE 7.5-22

TYPICAL RMB CHANNEL RESPONSES
(NO FAILED LPRM's)

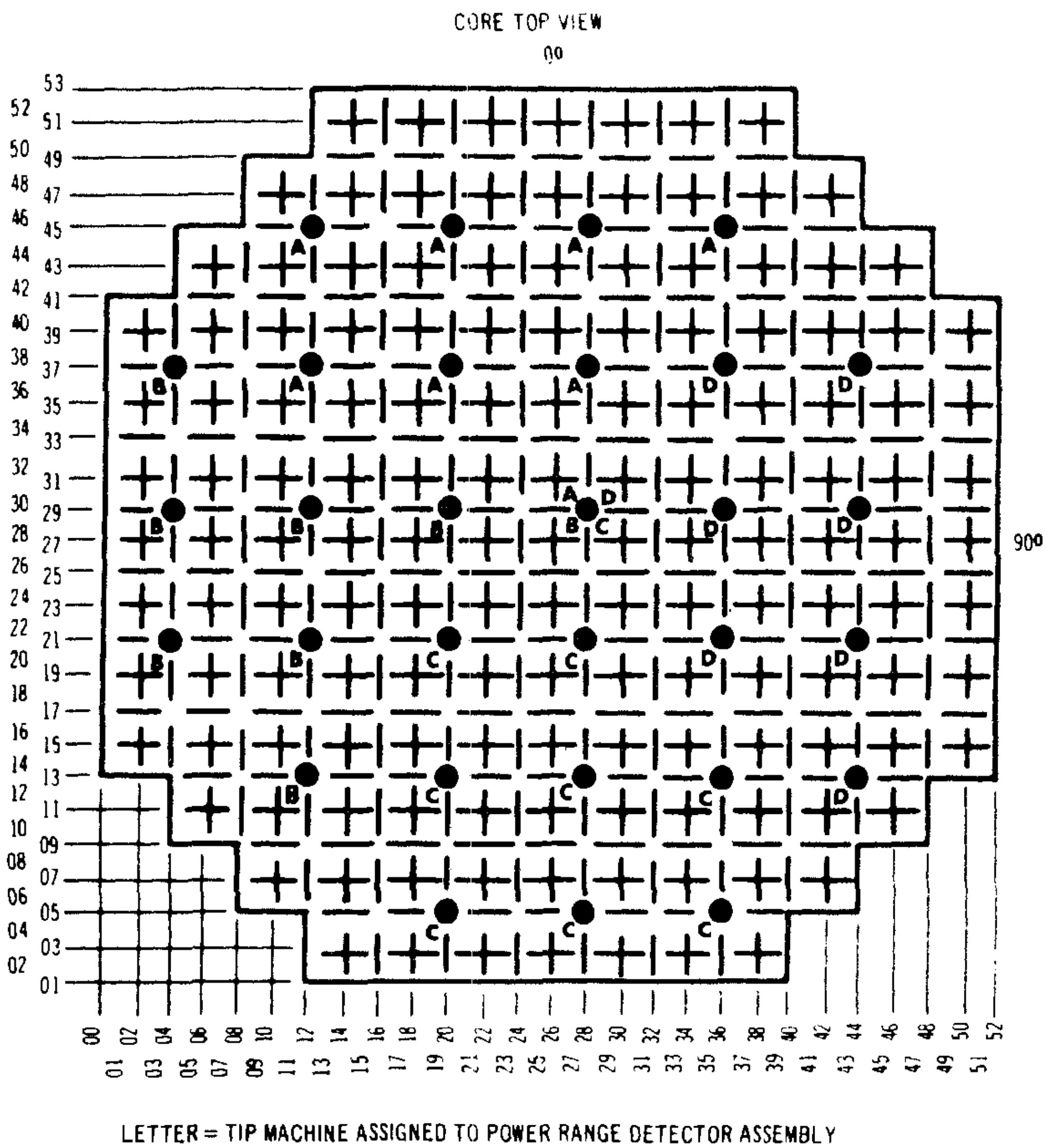


FIGURE 7.5-23
ASSIGNMENT OF LPRM STRINGS TO TIP MACHINES
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

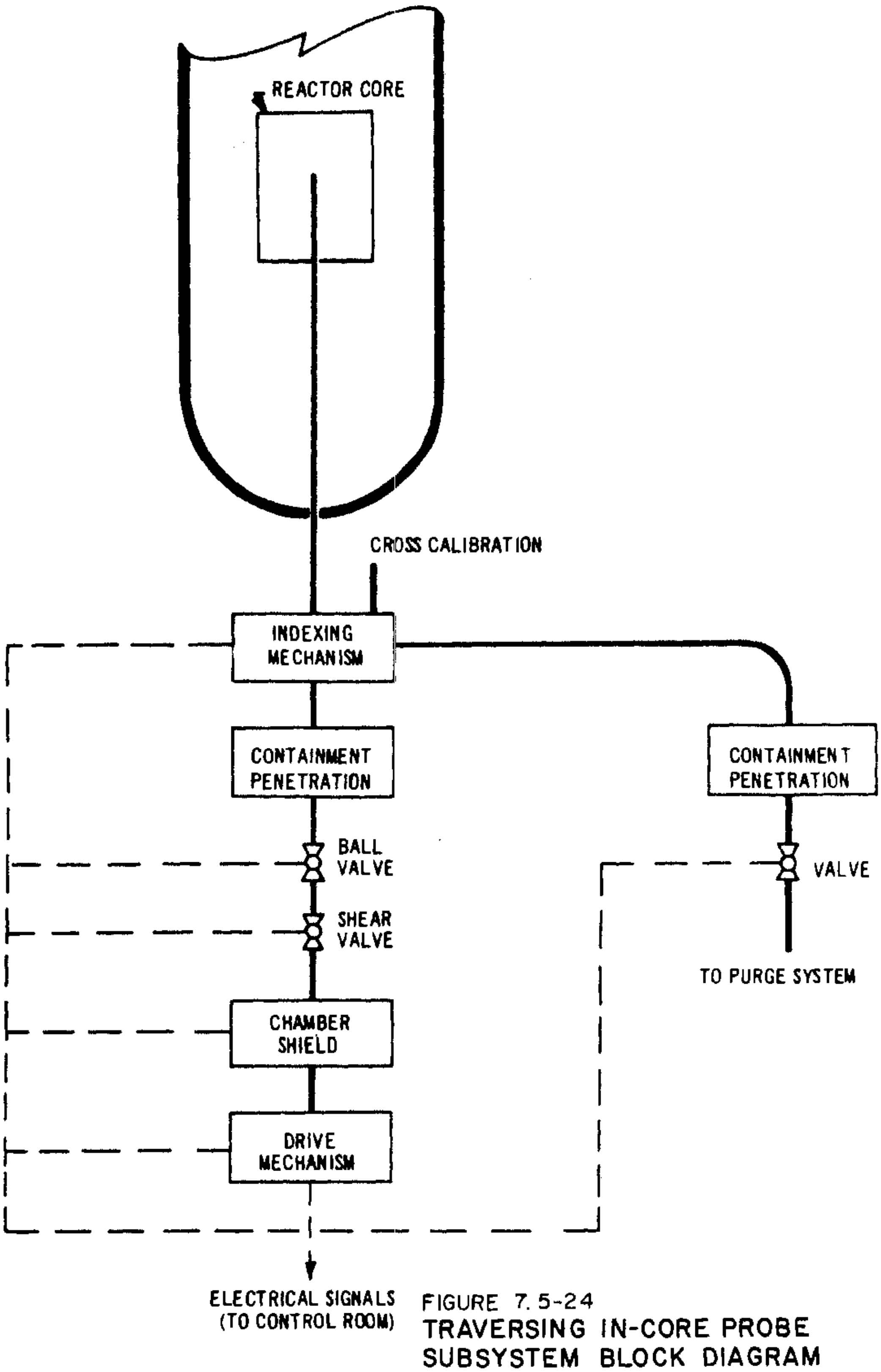


FIGURE 7.5-24
TRAVERSING IN-CORE PROBE SUBSYSTEM BLOCK DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

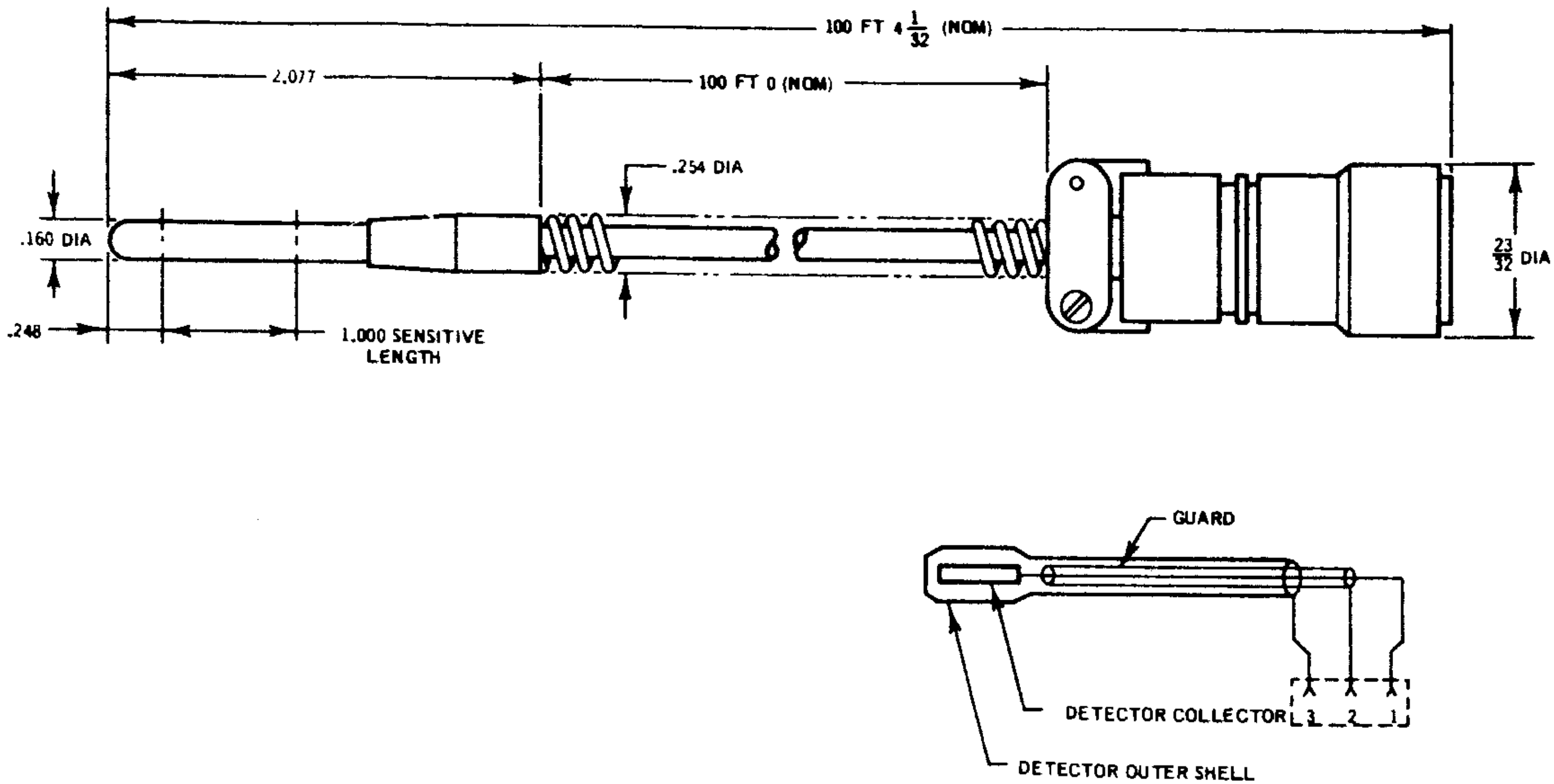


FIGURE 7.5-25
TRAVERSING IN-CORE
PROBE ASSEMBLY
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figures 7.5-26, 7.5-27 and 7.5-28 have been removed.

Please refer to BECo Controlled Drawings M1Q 1-5, M1Q 2-6, M1U110-1.

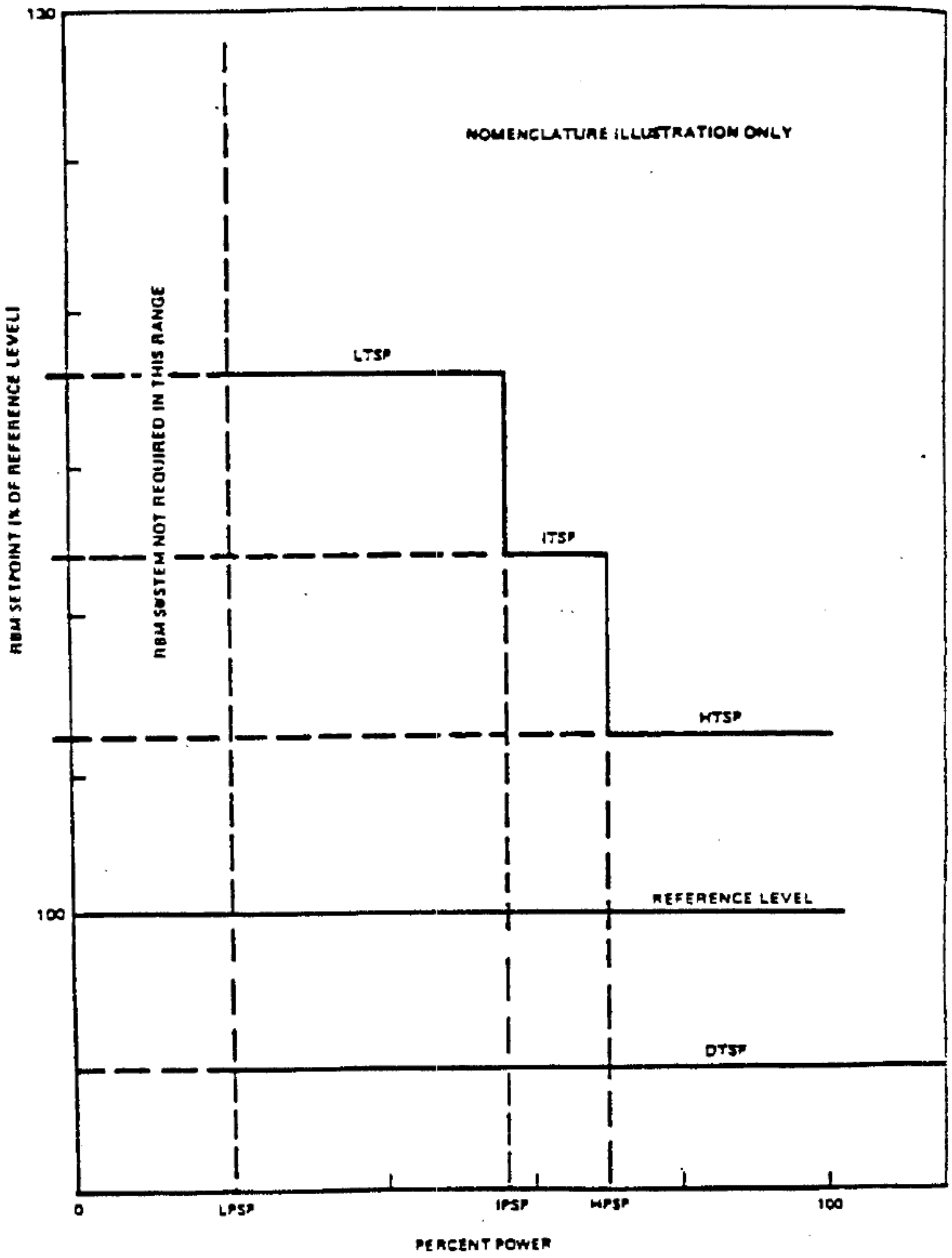


FIGURE 7.6-29
POWER DEPENDENT RBM
TRIP NOMENCLATURE

7.6 REFUELING INTERLOCKS

7.6.1 Safety Objective

The refueling interlocks are designed to back up procedural core reactivity controls during refueling operations. Specifically, the interlocks prevent an inadvertent criticality during refueling operations.

7.6.2 Safety Design Basis

1. During fuel movements in or over the reactor core, all control rods shall be in their fully inserted positions.

2. No more than one control rod shall be withdrawn from its fully inserted position at any time when the reactor is in the refuel mode.

7.6.3 Description

During a refueling operation, the reactor vessel head is removed, allowing direct access to the core. Refueling operations include the removal of reactor vessel upper internals and the movement of spent and fresh fuel assemblies between the core and the fuel storage pool. The service platform (retired), refueling platform, and the equipment handling hoists on the platforms are used to accomplish the refueling task. The refueling interlocks reinforce operational procedures that prohibit taking the reactor critical under certain situations encountered during refueling operations by restricting the movement of control rods and operation of refueling equipment.

The refueling interlocks include circuitry which senses the condition of the refueling equipment and the control rods. Depending on the sensed condition, interlocks are actuated which prevent the movement of the refueling equipment or withdrawal of control rods (rod block).

Circuitry is provided which senses the following conditions:

1. All rods inserted

2. Refueling platform positioned near or over the core

3. Refueling platform hoists are fuel loaded (fuel grapple, frame mounted hoist, monorail mounted hoist)

4. Fuel grapple not fully up

5. Service platform hoist fuel loaded
   (The service platform has been retired.)

6. One rod withdrawn

A two channel DC circuit indicates that all rods are in. The rod in condition for each rod is established by the closure of a magnetically operated reed switch in the rod position indicator

probe. The rod in switch must be closed for each rod before the "all rods in" signal is generated; two channels carry the signal. Both channels must register the "all rods in" signal in order for the refueling interlock circuitry to indicate the "all rods in" condition.

The refueling platform is provided with two mechanical switches attached to the platform which are tripped open by a long, stationary ramp mounted adjacent to the platform rail. The switches open before the platform or any of its hoists are physically located over the reactor vessel, thereby providing indication of the approach of the platform toward the core or its position over the core.

In addition, the refuel bridge platform has a keylock switch installed within its control circuitry. A two-position switch labeled "NORMAL-BYPASS" is used for this application. The utilization of the keylock switch in the "BYPASS" position will allow the refuel bridge platform to be moved over the reactor cavity when the refueling interlocks are not required by the PNPS Technical Specifications. The keylock switch is mounted in the main control room within Panel C928.

The three hoists on the refueling platform and hoist on the service platform are provided with switches which open when the hoists are fuel loaded. The switches are set to open at a load weight which is lighter than the weight of a single fuel assembly, thus providing positive indication whenever fuel is loaded on any hoist.

Additional features (not refueling interlocks) have been implemented to enhance bridge operation.

Load cell readout is provided for all hoists with indicators which display given hoist load directly to the operator. Load sensing is accomplished by use of load cells. Associated interlock and load functions are performed by devises which sense the signal generated by the load cells.

A key locked switch is mounted in the operator's cab that disengages the main hoist "raise" power if the hoist senses a loaded condition with either the grapple "not closed", or the key is not in place. The key is maintained in the Control Room or in the custody of licensed personnel. This provides positive administrative control of the refueling mast.

The grapple hooks (multiple) fail closed on loss of electrical supply and fail as-is on loss of air supply.

The hooks are mechanically load-locking and cannot be opened electrically or mechanically with load on the hooks. If the grapple switch is set to the RELEASE position with the grapple loaded, a continuous Sonalert alarm will activate. The hoist has two limit switches to cut off "raise" power at a jam load of 1200 lbs; the monorail and frame mounted hoists also have the jam feature. Sensors that monitor the hoist's submergence will disable "raise" power at a level that provides shielding for irradiated loads (this is adjustable) and has override capability to allow tool changing or cask loading.

Positive indication is provided to the operator, by grapple head switches, when the fuel bundle is properly engaged in the grapple receptacle and the grapple hook is fully closed.

A Bridge travel interlock system senses Bridge location and will stop travel at pre-programmed limits to protect equipment.

A "Rigid Pole System" is mounted on the bridge, available for in-vessel servicing and not used for fuel handling.

Refueling interlock conditions are combined in logic circuits to satisfy all restrictions on refueling equipment operation and control rod movement, as described on Figures 7.6-1 and 7.6-2, and in the following:

1. Refueling platform travel toward the core is stopped when the following three conditions exist concurrently:

   a. Any refueling platform hoist is loaded or the fuel grapple is not in its full up position

   b. Not all rods are in

   c. Refueling platform position is such that the position switch is open (platform near or over the core)

2. With the mode switch in "Startup", refueling platform travel toward the core is prevented when the refueling platform position switch is open (platform near or over the core)

3. With the mode switch in "Refuel", refueling platform travel towards the core is prevented when the following two conditions exist concurrently:

   a. More than one rod withdrawn

   b. The refueling platform position switch is open (platform near or over the core)

4. The refueling platform frame mounted hoist "LIFT" electrical circuit is open when the following three conditions exist concurrently:

   a. Frame mounted hoist fuel loaded

   b. Not all rods in

   c. Refueling platform near or over the core

5. The refueling platform monorail mounted hoist "LIFT" electrical circuit is open when the following three conditions exist concurrently:

   a. Monorail mounted hoist fuel loaded

   b. Not all rods in

   c. Refueling platform near or over the core

6. Operation of the telescoping fuel grapple is prevented when the following two conditions exist concurrently:

   a. Not all rods in

   b. Refueling platform near or over the core

7. Operation of the service platform hoist (retired) is prevented when the following two conditions exist concurrently:

   a. Not all rods in

   b. Service platform hoist fuel loaded
      (The service platform has been retired.)

8. With the mode switch in "Refuel", either of the following condition prevents a control rod withdrawal:

   a. Refueling platform over the core with a load on any refueling platform hoist or the fuel grapple not fully up

9. With the mode switch in "Startup", any one of the following conditions prevents a control rod withdrawal:

   a. Refueling platform over the core

   b. Service platform hoist fuel loaded
      (The service platform has been retired.)

The prevention of a control rod withdrawal is accomplished by opening contacts at two different points in the rod block circuitry; prevention of refueling equipment operation is accomplished by interrupting the power supply to the equipment.

During refueling operations no more than one control rod may be withdrawn; this is enforced by a redundant logic circuit which uses the "all rods in" signal and a rod selection to prevent the selection of a second rod for movement with any other rod not fully inserted. The simultaneous selection of two control rods is prevented by the interconnection arrangement of the select push buttons. With the mode switch in "Refuel", the circuitry prevents the withdrawal of more than one control rod and the movement of the loaded refueling platform over the core with any control rod withdrawn.

A bypass for the service platform hoist (retired) load interlock is provided. When the service platform (retired) is no longer needed, its power plug is removed, deenergizing the power supply to the hoist; the platform can then be moved to a location away from the core. Deenergizing the hoist power supply opens the hoist load switches, giving a false indication that the hoist is loaded; this indication prevents control rod withdrawal with the mode switch in "Startup" or "Refuel". A bypass plug is provided to allow control rod movement in this situation. The bypass plug is physically arranged to prevent the connection of the service platform power plug (retired) unless the bypass plug is removed. The service platform has been retired; however, the circuitry and bypass remain in place.

7.6.4 Safety Evaluation

The nuclear characteristics of the core assure that the reactor is subcritical even when the highest worth control rod is fully withdrawn. Refueling procedures are written to avoid situations in which inadvertent criticality is possible.

The refueling interlocks are designed to prevent criticality during refueling operations. The interlock systems accomplish this by:

a. Preventing operation of the fuel loaded refueling equipment over the core whenever any control rod is withdrawn

b. Preventing control rod withdrawal whenever fuel loading equipment is over the core

c. Preventing withdrawal of more than one control rod when the mode switch is in the refuel position

The rod block interlocks and refueling platform interlocks provide two independent levels of interlock action. The interlocks which restrict operation of the platform hoist and grapple provide a third level of interlock action since they would be required only after a failure of a rod block and refueling platform interlock. Strict procedural control exercised during refueling operation provides a fourth level of backup.

The refueling interlocks have been carefully designed utilizing redundancy of sensors and circuitry to provide a high level of reliability and assurance that the stated design bases will be met. Single failure criterion is satisfied, considering the multiple levels of interlocks available.

Table 7.6-1 illustrates the effectiveness of the refueling interlocks. This table considers various operational situations involving rod movement, hoist load conditions, refueling platform movement and position, and mode switch manipulation. The initial conditions in situations 4 and 5 appear to be in contradiction to the action of refueling interlocks, because the initial conditions indicate that more than one control rod is withdrawn, yet the mode switch is in REFUEL. Such initial conditions are possible if the rods are withdrawn when the mode switch is in STARTUP, and then the mode switch is turned to REFUEL. In all cases, proper operation of the refueling interlocks is successful in preventing either the operation of loaded refueling equipment over the core whenever any control rod is withdrawn or the withdrawal of any control rod when fuel loaded refueling equipment is operating over the core. In addition, when the mode switch is in REFUEL, only one rod can be withdrawn; selection of a second rod initiates a rod block. Thus, safety design bases 1 and 2 are satisfied.

7.6.5 Inspection and Testing

Complete functional testing of all refueling interlocks before any refueling outage will provide indication that the interlocks operate in the situations for which they were designed. Prior to any fuel handling with the head off the reactor vessel the refueling interlocks will be functionally tested by conducting both a logic functional test and an operations function test as follows. Where redundancy is provided in the logic circuitry, a logic functional test can be performed to assure that each redundant logic element can independently perform its function. By loading each hoist with a weight equal to the fuel assembly, positioning at the refueling platform, and withdrawing control rods the interlocks can be subjected to a valid operations functional test. Following initial completion of both the logic functional test and operational functional test, the interlocks will be tested at weekly intervals thereafter by repeating the operations functional test described above.

7.6.6 Nuclear Safety Requirements for Plant Operation

The nuclear safety requirements for the refueling interlocks and the operation of the refueling equipment are as follows:

1. The mode switch is required to be locked in the REFUEL position during core alterations when fuel is in the reactor vessel because the REFUEL position places the refueling interlocks in operation. Refueling interlocks prevent core alterations unless all control rods are fully inserted. If all control rods are fully inserted during core alterations, no single error in the manipulation of fuel assemblies, control rod curtains, or control rods can produce criticality.

2. The refueling interlocks shall be tested prior to any fuel handling within the reactor vessel.

   During refueling operations, the reactivity potential of the core is being altered. It is necessary to require certain interlocks and restrict certain refueling operations such that there is assurance that the operations remain within the envelope of conditions considered by the station safety analysis. Addition of excessive amounts of reactivity to the core is prevented by operating procedures, which are in turn backed up by refueling interlocks on rod withdrawal and movement of the refueling equipment. These limiting conditions for operation are derived from various blocks of Matrix 3A and B of Appendix G. (Blocks A1-75, A1-87, B1-75, B1-87)

   The test surveillance frequency is based upon engineering judgment, and past experience. Complete functional testing of all refueling interlocks before any refueling outage will provide positive indication that the interlocks operate in the situations for which they were designed. Prior to any fuel handling with the head off the reactor vessel the refueling interlocks will be functionally tested by conducting both a logic functional test and an operations function test as follows. Where redundancy is provided in the logic circuitry, a logic functional test can be performed to assure that each redundant logic element can independently perform its function. By loading each hoist with a weight equal to the fuel assembly, positioning the refueling platform, and withdrawing control rods the interlocks can be subjected to a valid operations functional test. Following initial completion of both the logic functional test and operational functional test, the interlocks will be tested at weekly intervals thereafter by repeating the operations functional test described above.

7.6.7 Current Technical Specifications

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

TABLE 7.6-1

REFUELING INTERLOCK EFFECTIVENESS

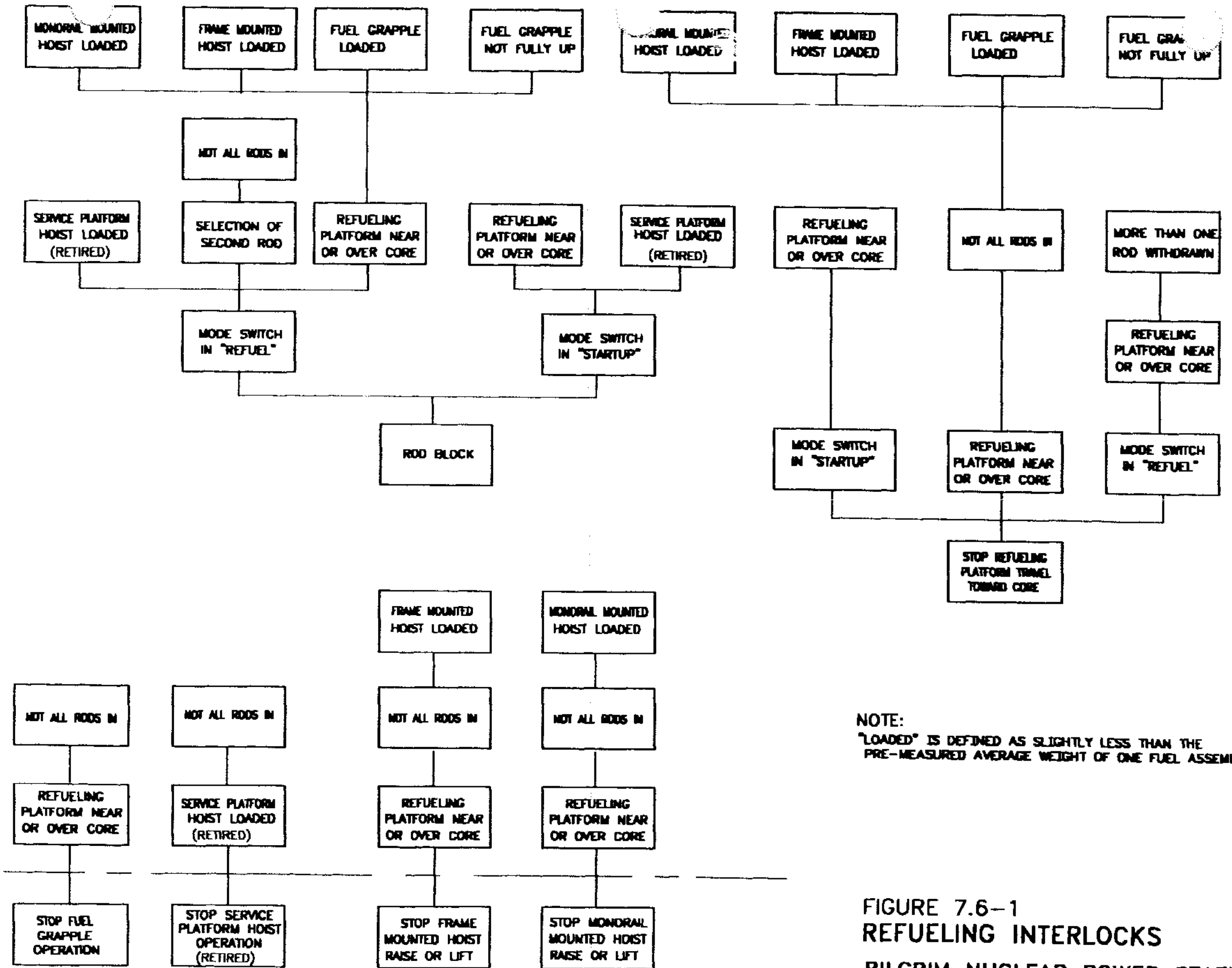
Situation	Refueling Platform Position	Refueling Platform Hoists MMH*	FMH*	FG*	Service Platform Hoist**	Control Rods	Mode Switch	Attempt	Result
1.	Not near core	UL*	UL*	UL*	UL*	All rods in	Refuel	Move refueling platform over core	No restrictions
2.	Not near core	UL	UL	UL	UL	All rods in	Refuel	Withdraw rod	Cannot withdraw more than one rod
3.	Not near core	UL	UL	UL	UL	One rod withdrawn	Refuel	Move refueling platform over core	No restrictions
4.	Not near core	Any hoist loaded or not fully up		FG	UL	One or more rods withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
5.	Not near core	UL	UL	UL	UL	More than one rod withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
6.	Over core	UL	UL	UL	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
7.	Over core	Any hoist loaded or not fully up		FG	UL	All rods in	Refuel	Withdraw rods	Rod block
8.	Not near core	UL	UL	UL	L*	All rods in	Refuel	Withdraw rods	Rod block
9.	Not near core	UL	UL	UL	L	All rods in	Refuel	Operate service platform hoist	No restrictions
10.	Not near core	UL	UL	UL	L	One rod withdrawn	Refuel	Operate service platform hoist	Hoist operation prevented
11.	Not near core	UL	UL	UL	UL	All rods in	Startup	Move refueling platform over core	Platform stopped before over core
12.	Not near core	UL	UL	UL	L	All rods in	Startup	Operate service platform hoist	No restrictions
13.	Not near core	UL	UL	UL	L	One rod withdrawn	Startup	Operate service platform hoist	Hoist operation prevented

TABLE 7.6-1 (Cont)

Situa-tion	Refueling Platform Position	Refueling Platform Hoists MMH*	FMH*	FG*	Service Platform Hoist**	Control Rods	Mode Switch	Attempt	Result
14.	Not near core	UL	UL	UL	L	All rods in	Startup	Withdraw rods	Rod block
15.	Not near core	UL	UL	UL	UL	All rods in	Startup	Withdraw rods	No restrictions
16.	Over core	UL	UL	UL	UL	All rods in	Startup	Withdraw rods	Rod block
17.	Over core	Any hoist loaded or FG not fully up			UL	One rod withdrawn	Refuel	Operate loaded hoist	Hoist operation prevented

NOTE:

*LEGEND
MMH - Monorail Mounted Hoist   FMH - Frame Mounted Hoist   FG - Fuel Grapple   UL- Unloaded   L - Fuel-loaded
**The service platform has been retired.



NOTE:
"LOADED" IS DEFINED AS SLIGHTLY LESS THAN THE PRE-MEASURED AVERAGE WEIGHT OF ONE FUEL ASSEMBLY.

FIGURE 7.6-1
REFUELING INTERLOCKS

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REV 22– OCT 1999

Figure 7.6-2 has been removed.

Please refer to BECo Controlled Drawings M1D20-2, M1D21-2.

7.7 REACTOR MANUAL CONTROL SYSTEM

7.7.1 Power Generation Objective

The objective of the Reactor Manual Control System is to provide the operator with the means to make changes in nuclear reactivity so that reactor power level and power distribution can be controlled. The system allows the operator to manipulate control rods.

7.7.2 Power Generation Design Basis

1. The Reactor Manual Control System shall be designed to inhibit control rod withdrawal following erroneous control rod manipulations so that RPS action (scram) is not required.

2. The Reactor Manual Control System shall be designed to inhibit control rod withdrawal in time to prevent local fuel damage as a result of erroneous control rod manipulation.

3. The Reactor Manual Control System shall be designed to inhibit rod movement whenever such movement would result in operationally undesirable core reactivity conditions or whenever instrumentation (due to failure) is incapable of monitoring the core response to rod movement.

4. To limit the potential for inadvertent rod withdrawals leading to RPS action, the Reactor Manual Control System shall be designed in such a way that deliberate operator action is required to effect a continuous rod withdrawal.

5. To provide the operator with the means to achieve prescribed control rod patterns, information pertinent to the position and motion of the control rods shall be available in the control room.

7.7.3 Safety Design Basis

1. The circuitry provided for the manipulation of control rods shall be designed so that no single failure can negate the effectiveness of a reactor scram.

2. Repair, replacement, or adjustment of any failed or malfunctioning component shall not require that any element needed for reactor scram be bypassed unless a bypass is normally allowed.

7.7.4 Description

7.7.4.1 Identification

The Reactor Manual Control System consists of the electrical circuitry, switches, indicators, and alarm devices provided for operational manipulation of the control rods and the

surveillance of associated equipment. This system includes the interlocks that

inhibit rod movement (rod block) under certain conditions. The Reactor Manual Control System does not include any of the circuitry or devices used to automatically or manually scram the reactor; these devices are discussed in Section 7.2, Reactor Protection System. Neither are the mechanical devices of the control rod drives and the Control Rod Drive Hydraulic System included in the Reactor Manual Control System. These mechanical components are described in Section 3.4, Reactivity Control Mechanical Design.

7.7.4.2 Operation

7.7.4.2.1 General

Figures 7.7-1 and 7.6-2 show the functional arrangement of devices for the control of components in the Control Rod Drive Hydraulic System. Although the figures also show the arrangement of scram devices, these devices are not part of the Reactor Manual Control System.

Control rod movement is accomplished by admitting water under pressure from a control rod drive water pump into the appropriate end of the double-acting control rod drive cylinder. The pressurized water forces the piston, which is attached by a connecting rod to the control rod, to move. Three modes of control rod operation are used: insert, withdraw, and settle. Four solenoid operated valves are associated with each control rod to accomplish the actions required for the various operational modes. The valves control the path that the control rod drive water takes to the cylinder. The Reactor Manual Control System controls the valves.

Two of the four solenoid operated valves for a control rod are electrically connected to the insert bus. When the insert bus is energized and when a control rod has been selected for movement, the two insert valves for the selected rod open, allowing the control rod drive water to take the path that results in control rod insertion. Of the two remaining solenoid operated valves for a control rod, one is electrically connected to the withdraw bus, and the other is connected to the settle bus. The withdraw valve that connects the insert drive water supply to the exhaust water header is the one that is connected to the settle bus. The remaining withdraw valve is connected to the withdraw bus. When both the withdraw bus and the settle bus are energized and when a control rod has been selected for movement, both withdraw valves for the selected rod open, allowing control rod drive water to take the path that results in control rod withdrawal.

The settle mode is provided to insure that the control rod drive index tube is engaged promptly by the collet fingers after the completion of either an insert or withdraw cycle. During the settle mode, the withdraw valve connected to the settle bus is opened or remains open while the other three solenoid operated valves are closed. During an insert cycle, the settle action vents the pressure from the bottom of the drive piston to the exhaust header, thus gradually reducing the differential pressure across the drive piston

of the selected rod. During a withdraw cycle, the settle action again vents the bottom of the drive piston to the exhaust header while the withdraw drive water supply is shut off. This also allows a gradual reduction in the differential pressure across the control rod drive piston. After the control rod has slowed down, the collet fingers engage the index tube and lock the rod in position. See Figure 7.7-1 for valve sequence and timing.

The arrangement of control rod selection pushbuttons circuitry permits the selection of only one control rod at a time for movement. A rod is selected for movement by depressing a button for the desired rod on the reactor control benchboard in the control room. The direction in which the selected rod moves is determined by the position of a switch, called the "rod movement" switch, which is also located on the reactor control benchboard. This switch has "rod-in" and "rod-out-notch" and "off" positions. The rod selection circuitry is arranged so that a rod selection is sustained until either another rod is selected or separate action is taken to revert the selection circuitry to a no-rod-selected condition. Initiating movement of the selected rod prevents the selection of any other rod until the movement cycle of the selected rod has been completed. Reversion to the no-rod-selected condition is not possible (except for loss of control circuit power) until any moving rod has completed the movement cycle.

7.7.4.2.2 Insert Cycle

The following is a description of the detailed operation of the Reactor Manual Control System during an insert cycle. The cycle is described in terms of the insert, withdraw, and settle busses. The response of a selected rod when the various busses are energized has been explained previously. Figure 7.7-1 can be used to follow the sequence of an insert cycle.

A three position rod movement switch is provided on the reactor control benchboard. The switch has a "rod-in" position, a "rod-out- notch" position, and an "off" position. The switch returns by spring action to the "off" position. With a control rod selected for movement, placing the rod movement switch in the "rod-in" position and then releasing the switch energizes the insert bus for a limited amount of time. Just before the insert bus is deenergized, the settle bus is automatically energized and remains energized for a limited period of time after the insert bus is deenergized. The insert bus timer setting and the rate of drive water flow provided by the Control Rod Drive Hydraulic System determine the distance traveled by a rod. The timer setting results in a one-notch (6 in) insertion of the selected rod for each momentary application of a rod-in signal from the rod movement switch. Continuous insertion of a selected control rod is possible by holding the rod movement switch in the "rod-in" position.

A second switch is available to initiate insertion of a selected control rod. This switch is the "rod-out-notch override" switch and is called the RONOR switch. The RONOR switch has three positions:

"emergency in," "notch override," and "off". By holding the RONOR switch in the "emergency in" position, the insert bus is continuously energized, causing a continuous insertion of the selected control rod. The switch returns to the "off" position by spring action.

7.7.4.2.3 Withdraw Cycle

The following is a description of the detailed operation of the Reactor Manual Control System during a withdraw cycle. The cycle is described in terms of the insert, withdraw, and settle busses. The response of a selected rod when the various busses are energized has been explained previously. Figure 7.7-1 can be used to follow the sequence of the withdraw cycle.

With a control rod selected for movement, placing the rod movement switch in the "rod-out-notch" position energizes the insert bus for a short period of time. Energizing the insert bus at the beginning of the withdrawal cycle is necessary to allow the collet fingers to disengage the index tube. When the insert bus is deenergized, the withdraw and settle busses are energized for a controlled period of time. The withdraw bus is deenergized prior to the settle bus, which, when deenergized, completes the withdraw cycle. This withdraw cycle is the same whether the rod movement switch is held continuously in the "rod-out-notch" position or released. The timers that control the withdraw cycle are set so that the rod travels one notch (6 in) per cycle. An interlock is provided in the withdraw circuitry to deenergize the control circuit and prevent rod withdrawal if the withdraw bus timer fails to deenergize the withdraw bus after the specified time period. A selected control rod can be continuously withdrawn if the rod movement switch is held in the "rod-out-notch" position at the same time that the RONOR switch is held in the "notch-override" position. With both switches held in these positions, the withdraw bus is continuously energized. Both switches return to the "off" position by spring action.

7.7.4.2.4 Control Rod Drive Hydraulic System Control

Two motor operated pressure control valves, one air operated flow control valve, and two solenoid operated stabilizing valves are included in the control rod drive hydraulic system to maintain smooth and regulated system operation. See Section 3.4, Reactivity Control Mechanical Design. The motor operated pressure control valves are positioned by manipulating switches in the control room. The switches for these valves are located close to the pressure indicators that respond to the pressure changes caused by the movements of the valves. The air operated flow control valve is automatically positioned in response to signals from an upstream flow measuring device. The stabilizing valves are automatically controlled by the action of the energized insert and withdraw busses. The control scheme is shown on Figure 7.7-1. The two drive water pumps are controlled by switches in the control room. Each pump automatically stops upon indication of low suction pressure.

7.7.4.3 Rod Block Interlocks

7.7.4.3.1 General

Figures 7.7-1 and 7.6-2 show the rod block interlocks used in the Reactor Manual Control System. Figure 7.7-1 shows the general functional arrangement of the interlocks, and Figure 7.6-2 shows the rod blocking functions that originate in the Neutron Monitoring System in greater detail.

To achieve an operationally desirable performance objective where most failures of individual components would be easily detectable or do not disable the rod movement inhibiting functions, the rod block logic circuitry is arranged as two similar logic circuits. Most common connection points that would, after failure, allow rod withdrawal under rod block conditions are eliminated. The two circuits are energized when control rod movement is allowed. Rod block contacts are normally closed and rod block relays are normally energized. Each of the two similar circuits receive input trip signals from a number of trip channels. There are a total of three rod withdrawal block signals associated with the two rod block circuits.

Either of the two circuits can provide a rod block signal to the rod control circuitry. The individual signal from each circuit, when tripped, sounds a horn or buzzer in the control room to indicate the block signal. The third rod block signal is obtained by combining the outputs of the two similar logic circuits, the rod worth minimizer output, and the rod block monitor outputs. See Section 7.16. When tripping occurs from this signal, the condition is indicated in the control room by a light indicator and a horn or buzzer. The rod worth minimizer and the rod block monitor output are used independently. All of the rod block control circuitry must be in the permissive state for control rod withdrawal to be possible. A failure of any one of the rod block controls cannot prevent the remaining parts of the rod block circuitry initiating a rod block. When in the tripped state, the rod block control prevents withdrawal of the selected rod by opening the rod control circuit used to energize the withdraw bus.

The rod block circuitry is effective in preventing rod withdrawal, if required, during both normal (notch) withdrawal and continuous withdrawal. If a rod block signal is received during a rod withdrawal, the control rod is automatically stopped at the next notch position, even if a continuous rod withdrawal is in progress.

The components used to initiate rod blocks in combination with refueling operations provide rod block trip signals to these same rod block circuits. These refueling rod blocks are described in Section 7.6, Refueling Interlocks.

7.7.4.3.2 Rod Block Functions

The following discussion describes the various rod block functions and explains the intent of each function. The instruments used to sense the conditions for which a rod block is provided are discussed later. Figure 7.6-2 shows all the rod block functions; the rod block functions provided specifically for refueling situations are described in Section 7.6, Refueling Interlocks.

With the mode switch in SHUTDOWN, no control rod can be withdrawn. This enforces compliance with the intent of the SHUTDOWN mode.

The circuitry is arranged to initiate a rod block regardless of the position of the mode switch for the following conditions:

1. Any average power range monitor (APRM) upscale rod block alarm. The purpose of this rod block function is to avoid conditions that would require RPS action if allowed to proceed. The APRM upscale rod block alarm setting is selected to initiate a rod block before the APRM high neutron flux scram setting is reached

2. Any APRM inoperative alarm. This assures that no control rod is withdrawn unless the average power range neutron monitoring channels are either in service or properly bypassed

3. Either rod block monitor (RBM) upscale alarm. This function is provided to stop the erroneous withdrawal of a control rod so that local fuel damage does not result. Although local fuel damage poses no significant threat in terms of radioactive material released from the nuclear system, the trip setting is selected so that no local fuel damage results from a single control rod withdrawal error during power range operation

4. Either RBM inoperative alarm. This assures that no control rod is withdrawn unless the RBM channels are in service or properly bypassed

5. Either recirculation flow converter upscale or inoperative alarm. This assures that no control rod is withdrawn unless the recirculation flow converters are operable. Recirculation flow is used to bias the APRM upscale rod block trip

6. Recirculation flow converter comparator alarm or inoperative. This assures that no control rod is withdrawn unless the difference between the outputs of the flow converters is within limits and the comparator is in service

7. Scram discharge instrument volume high water level. This assures that no control rod is withdrawn unless enough capacity is available in the scram discharge volume to

accommodate a scram. The setting is selected to initiate a rod block well in advance of that level which produces a scram

8. Scram discharge instrument volume high water level scram trip bypassed. This assures that no control rod is withdrawn while the scram discharge instrument volume high water level scram function is out of service

9. The rod worth minimizer (RWM) function of the Process Computer System can initiate a rod insert block, a rod withdrawal block, and a rod select block. The purpose of this function is to reinforce procedural controls that limit the reactivity worth of control rods under low power conditions. The rod block trip settings are based on the allowable control rod worth limits established for the design basis rod drop accident. Adherence to prescribed control rod patterns is the normal method by which this reactivity restriction is observed. Additional information on the rod worth minimizer function is available in Section 7.16, Process Computer System

10. Rod Position Information System malfunction. This assures that no control rod can be withdrawn unless the Rod Position Information System is in service

11. Rod movement timer switch malfunction during withdrawal. This assures that no control rod can be withdrawn unless the timer is in service

With the mode switch in RUN, the following additional conditions initiate a rod block:

1. Any APRM downscale alarm. This assures that no control rod is withdrawn during power range operation unless the average power range neutron monitoring channels are operating properly or are correctly bypassed. All unbypassed APRMs must be onscale during reactor operations in the RUN mode

2. Either RBM downscale alarm. This assures that no control rod is withdrawn during power range operation unless the RBM channels are operating properly or are correctly bypassed. Unbypassed RBMs must be onscale during reactor operations in the RUN mode. RBMs automatically bypass for reactor power less than 30 percent

With the mode switch in STARTUP or REFUEL the following additional conditions initiate a rod block:

1. Any source range monitor (SRM) detector not fully inserted into the core when the SRM count level is below the retract permit level and the associated IRM range switches are on either of the two lowest ranges. This assures that no control rod is withdrawn unless all SRM detectors are

properly inserted when they must be relied upon to provide the operator with neutron flux level information

2. Any SRM upscale level alarm. This assures that no control rod is withdrawn unless the SRM detectors are properly retracted and a RETRACT permissive is available during a reactor startup. The rod block setting is selected at the upper end of the range over which the SRM is designed to detect and measure neutron flux

3. Any SRM downscale alarm and any IRM range switch on any of the three lowest ranges. This assures that no control rod is withdrawn unless the SRM count rate is above the minimum prescribed for low neutron flux level monitoring

4. Any SRM inoperative alarm. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all SRM channels are in service or properly bypassed

5. Any intermediate range monitor (IRM) detector not fully inserted into the core. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all IRM detectors are properly located

6. Any IRM upscale alarm. This assures that no control rod is withdrawn unless the intermediate range neutron monitoring equipment is properly upranged during a reactor startup. This rod block also provides a means to stop rod withdrawal in time to avoid conditions requiring RPS action (scram) in the event that a rod withdrawal error is made during low neutron flux level operations

7. Any IRM downscale alarm except when range switch is on the lowest range. This assures that no control rod is withdrawn during low neutron flux level operations unless the neutron flux is being properly monitored. This rod block prevents the continuation of a reactor startup if the operator upranges the IRM too far for the existing flux level; thus, the rod block ensures that the intermediate range monitor is onscale if control rods are to be withdrawn

8. Any IRM inoperative alarm. This assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available in that all IRM channels are in service or properly bypassed

7.7.4.3.3 Rod Block Bypasses

To permit continued power operation during the repair or calibration of equipment for selected functions which provide rod block interlocks, a limited number of manual bypasses are permitted as follows:

One SRM Channel

Two IRM Channels

Two APRM Channels

One RBM Channel

The permissible IRM and APRM bypasses are not arranged in the same way as in the RPS. The IRMs are arranged as two groups of equal numbers of channels. One manual bypass is allowed in each group. The groups are chosen so that adequate monitoring of the core is maintained with one channel bypassed in each group. The same type of grouping and bypass arrangement is used for the APRMs. The arrangement allows the bypassing of up to two IRM and up to two APRM in each rod block logic circuit.

These bypasses are effected by positioning switches in the control room. A light in the control room indicates the bypassed condition.

An automatic bypass of the SRM detector position rod block is effected as the neutron flux increases beyond a preset low level on the SRM instrumentation. The bypass allows the detectors to be partially or completely withdrawn as a reactor startup is continued.

An automatic bypass of the RBM rod block occurs whenever the power level is below a preselected level or whenever a peripheral control rod is selected. Either of these two conditions indicates that local fuel damage is not threatened and that RBM action is not required.

The RWM rod block function is automatically bypassed when reactor power increases above a preselected value in the power range. It may be manually bypassed for maintenance at any time.

7.7.4.3.4 Arrangement of Rod Block Trip Channels

One half of the total numbers of APRMs, IRMs, SRMs, and RBMs provides inputs to one of the rod block logic circuits, and the remaining half provides inputs to the other logic circuit. One recirculation flow converter provides a rod block signal to one logic circuit; the remaining converter provides an input to the other logic circuit. The flow converter comparator provides trip signals to each flow converter trip circuit. In addition to the arrangement just described, both RBM trip channels provide input signals into a separate circuit for the rod block control. Scram discharge volume high water level signals are provided as inputs into one of the two rod block logic circuits. Both rod block logic circuits sense when the high water level scram trip for the scram discharge volume is bypassed. The rod withdrawal block from the RWM trip affects a separate circuit that trips the "non-annunciating rod block control". The rod insert block from the

RWM function prevents energizing the insert bus for both notch insertion and continuous insertion.

The APRM rod block settings are varied as a function of recirculation flow, as shown on Figure 7.7-2.

Analyses show that the settings selected are sufficient to avoid both RPS action and local fuel damage as a result of a single control rod withdrawal error. Mechanical switches in the SRM and IRM Detector Drive Systems provide the position signals used to indicate that a detector is not fully inserted. Additional detail on all the Neutron Monitoring System trip channels is available in Section 7.5, Neutron Monitoring System. The rod block from scram discharge volume high water level utilizes a non-indicating heated RTD sensor installed on the scram discharge volume.

7.7.4.4 Instrumentation

Table 7.7-1 gives instrument information for the Reactor Manual Control System. A large rod information display is presented on the vertical portion of the reactor control benchboard. This large display is patterned after a top view of the reactor core and is designed to allow the operator to acquire information rapidly by scanning. The use of colored windows provides an overall indication of rod pattern and allows the operator to quickly identify an abnormal indication. The following information for each control rod is presented in this large display:

Rod fully inserted (green)

Rod fully withdrawn (red)

Rod identification (coordinate position, white)

Accumulator trouble (amber)

Rod scram (blue)

Rod drift (red)

Also dispersed throughout the display in locations representative of the physical location of local power range monitor (LPRM) strings in the core are LPRM lights as follows:

LPRM low flux level (white)

LPRM high flux level (amber)

A separate, smaller display is located just below the large display on the vertical part of the benchboard. This display presents the positions of the control rod selected for movement and the other rods in the rod group. For display purposes the control rods are considered in groups of four adjacent rods centered around a common core volume monitored by four LPRM strings. Rod groups at the periphery of the core may have less than four rods. The small rod display shows the positions in digital form of the rods in the group to which the selected rod belongs. A white light indicates which of

the four rods is the one selected for movement. On either side of the four-rod position display are indicated the readings of the 16 LPRM channels (4 LPRM strings) surrounding the core volume common to the four rods of the group.

The four-rod display allows the operator to easily focus his attention on the core volume of concern during rod movements. This arrangement eliminates the problems inherent in larger, full core displays where the operator must concentrate his attention on a small portion of a large display. The four-rod display also allows the operator to quickly investigate any volume of the core by simply selecting a control rod located in that volume.

The position signals of selected control rods together with a rod identification signal are provided as inputs to the online process computer. The acquisition of the rod position signal does not interrupt the rod position indicating signal in the control room. The computer can, on demand, provide a full core printout of control rod positions.

Control rod position information is obtained from reed switches in the control rod drive that open or close a magnet attached to the rod drive piston passes during rod movement. Reed switches are provided at each 3 in increment of piston travel. Since a notch is 6 in, indication is available for each half notch of rod travel. The reed switches located at the half notch positions for each rod are used to indicate rod drift. Both a rod selected for movement and the rods not selected for movement are monitored for drift. A drifting rod is indicated by an alarm and red light in the control room. The rod drift condition is also monitored by the process computer.

Reed switches are also provided at locations that are beyond the limits of normal rod movement. If the rod drive piston moves to these overtravel positions, an alarm is sounded in the control room. The overtravel alarm provides a means to verify that the drive-to-rod coupling is intact, because with the coupling in its normal condition, the drive cannot be physically withdrawn to the overtravel position. Coupling integrity can be checked by attempting to withdraw the drive to the overtravel position.

The following control room lights are provided to allow the operator to know the conditions of the Control Rod Drive Hydraulic System and the control circuitry: (Figure 7.7-1)

Stabilizer valve selector switch position
Insert bus energized
Withdraw bus energized
Settle bus energized
Withdrawal not permissive
Notch override
Pressure control valve position
Flow control valve position
Drive water pump low suction pressure (alarm only)

Drive water pump low suction pressure (alarm only)
Drive water filter high differential pressure (alarm only)
Charging water (to accumulator) low pressure (alarm only)
Control rod drive temperature
Scram discharge instrument volume not drained (alarm and computer point only)
Scram valve pilot air header low pressure (alarm only)

Additional instrumentation provided for the Reactor Manual Control System is presented in Table 7.7-1. Many of these Reactor Manual Control System indications are displayed on the reactor control benchboard.

7.7.5 Safety Evaluation

The circuitry described for the reactor manual control system is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. The scram circuitry is discussed in Section 7.2, Reactor Protection System. Because each control rod is controlled as an individual unit, a failure that results in the energizing of any of the insert or withdraw solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunctioning of any one control rod. It can be concluded that no single failure in the Reactor Manual Control System can result in the prevention of a reactor scram and that repair, adjustment, or maintenance of Reactor Manual Control System components does not affect the scram circuitry. This meets safety design bases 1 and 2.

7.7.6 Inspection and Testing

The Reactor Manual Control System can be routinely checked for proper operation by manipulating control rods using the various methods of control. Detailed testing and calibration can be performed by using standard test and calibration procedures for the various components of the reactor manual control circuitry.

7.7.7 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.

TABLE 7.7-1

REACTOR MANUAL CONTROL SYSTEM INSTRUMENT SPECIFICATIONS

Measured Variable	Instrument Type	Normal Range	Nominal Accuracy	Alarm Setting
Pump Suction Pressure	Pressure Indicator	-15 to +250 psig	±2% Full Scale	--
Pump Suction Pressure Alarm	Pressure Switch	0-30 in. Hg Abs.	±5% Full Scale	--
Pump Discharge Pressure	Pressure Indicator	1,400 to 1,650 psig	±2% Full Scale	--
Filter Pressure Drop	dP Indicator	5 to 25 psid	±2% Full Scale	--
System Flow Indicator and Controller	Flow Indicator	0 to 80 gpm	±5% Set Point	62 gpm
Accum Charge HDR Press Alarm	Pressure Indicator	1,400 to 1,510 psig	±2% Full Scale	--
Drive HDR Flow	Flow Indicator	0, 2, 4 gpm	±2% Full Scale	--
Drive HDR Pressure	Pressure Indicator	250 to 1,250 psig	±1% Full Scale	--
Drive HDR Pressure Drop	dP Indicator	0 - 1000 psid	±2% Full Scale	--
Cooling HDR Flow	Flow Indicator	32 to 49 gpm	±2% Full Scale	--
Cooling Pressure	Pressure Indicator	20 to 1,040 psig	±1% Full Scale	--
Cooling HDR Pressure Drop	dP Indicator	20 to 40 psid	±2% Full Scale	--
Stabilizing Flow	Flow Indicator	6 to 7 gpm	±5% Full Scale	--
Exhaust Pressure	Pressure Indicator	0 to 1,015 psig	±1/2% Full Scale	--
Return Pressure	Pressure Indicator	0 to 1,005 psig	±1/2% Full Scale	--

TABLE 7.7-1

REACTOR MANUAL CONTROL SYSTEM INSTRUMENT SPECIFICATIONS

Measured Variable	Instrument Type	Normal Range	Nominal Accuracy	Alarm Setting
Scram Discharge Instrument Volume Level	Level Element/Switch	N/A	±0.20% Full Scale	--
	Level Transmitter/ Indicating Switch	9.5 to 85.5 in H_2O	±0.13% Full Scale	--
Drive Temperature	Local multiplexer with control room alarm and printout	50 to 500°F	±1% Full Scale	250°F
Instrument Air Supply Pressure	Pressure Indicator	0 to 50 psig	±2% Full Scale	--
FC Station Air Pressure	Pressure Indicator	0 to 15 psig	±2% Full Scale	--
Scram Pilot Air HDR Press	Pressure Indicator	70 to 100 psig	±2% Full Scale	--
Scram Pilot Air HDR Pressure	Pressure Switch	70 to 100 psig	±2% Full Scale	--
Accum N_2 Charge Pressure	Pressure Indicator	800 psig	±2% Full Scale	--
FCV Electro/Pneumatic Converter	Pressure/Current	3 to 15 psig/ 10 to 50 ma	--	--
Reactor Pressure	Pressure Indicator	0 to 1,000 psig	±2%	--
Upstream Return Press	Pressure Indicator	0 to 1,010 psig	±2%	--

TABLE 7.7-1 (Cont)

Measured Variable	Instrument Type	Normal Range	Nominal Accuracy	Alarm Setting
Control Rod Drive Overtravel (withdraw direction)	Reed Switches	2 in beyond full withdrawal position	±2%	--
Control Rod Drive Overtravel (insert direction)	Reed Switches	1-9/16 in beyond full insert position	±1-1/2 in	2 in beyond full withdrawal position
Control Rod Position (normal range)	Reed Switches	Full in to full out every 3 in	±1-1/2 in	--
Rod Block-Neutron Monitoring System Trip Channels		See NEUTRON MONITORING SYSTEM		
Rod Block-Rod Worth Minimizer		See PROCESS COMPUTER SYSTEM		
Rod Block-flow Converter and Comparator Trip Channels		See NEUTRON MONITORING SYSTEM		

Figure 7.7-1 has been removed.

Please refer to BECo Controlled Drawings M1D16-3, M1D17-3, M1D18-2, M1D19-2.

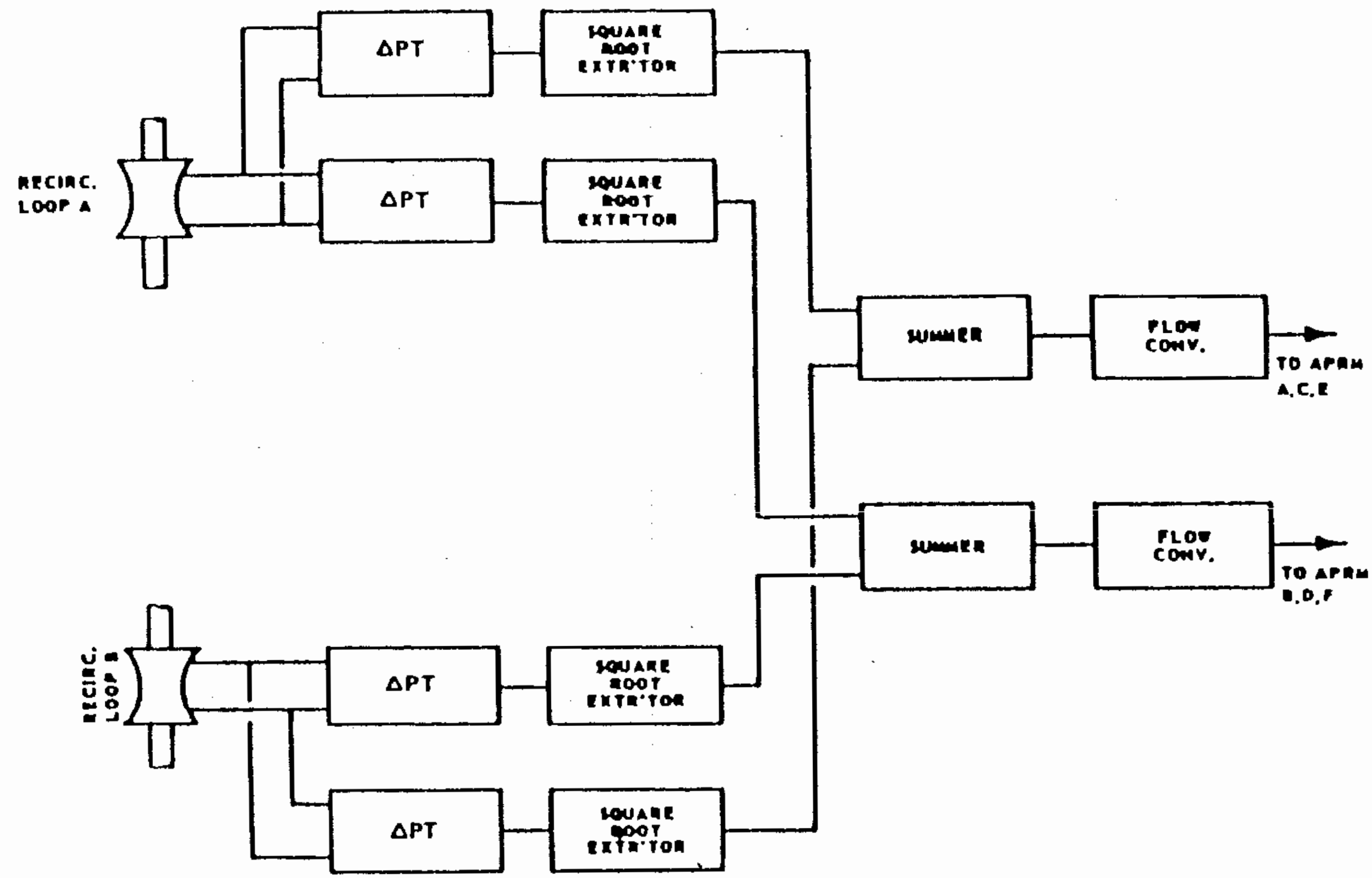
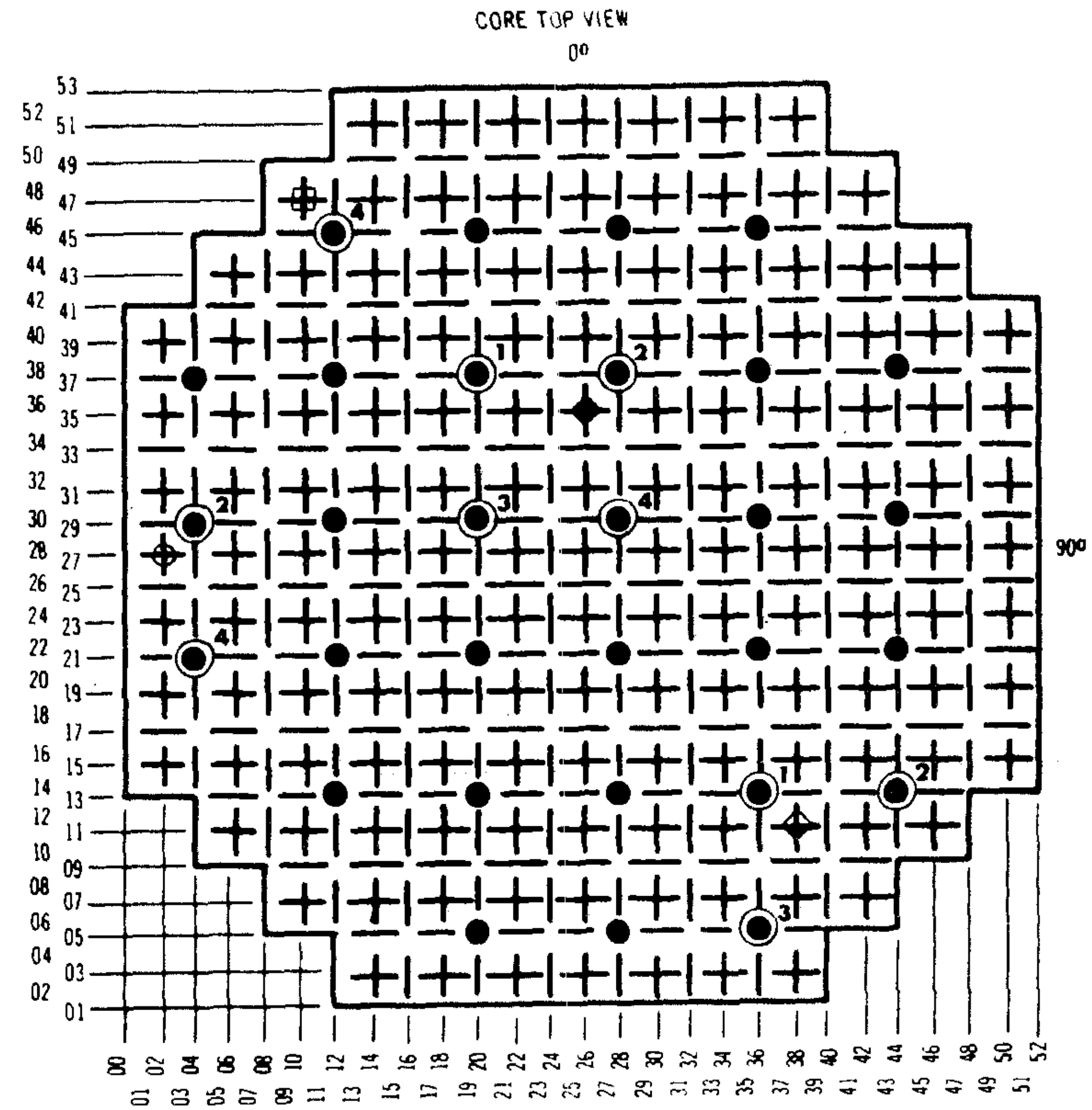


FIGURE 7.7-2

RECIRCULATION FLOW RATE
CIRCUIT, SCHEMATIC



LPRM INPUT UPON ROD SELECTION
TYPICAL ROD YIELDING FOUR STRING INPUT
TYPICAL ROD YIELDING THREE STRING INPUT
TYPICAL ROD YIELDING TWO STRING INPUT
TYPICAL ROD YIELDING ONE STRING INPUT

METER STACKS

1	2
3	4

FIGURE 7.7-3
INPUT SIGNALS TO
FOUR ROD DISPLAY
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

51				XX	XX	XX	XX	XX	XX	XX			
47			XX	XX	XX	XX	XX	XX	XX	XX	XX		
43		XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	
39	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX
35	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX
31	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX
27	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX
23	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX
19	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX
15	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX
11		XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	XX	
07			XX	XX	XX	XX	XX	XX	XX	XX	XX		
03				XX	XX	XX	XX	XX	XX	XX			
	02	06	10	14	18	22	26	30	34	38	42	46	50

FIGURE 7.7-4
TYPICAL PROCESS
COMPUTER PRINTOUT
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

7.8 REACTOR VESSEL INSTRUMENTATION

7.8.1 Safety Objective

The safety design objective of the reactor vessel instrumentation is to monitor and transmit information concerning key reactor vessel operating parameters during planned operations to ensure that sufficient indication of these parameters is possible.

7.8.2 Power Generation Objective

The power generation objective of the reactor vessel instrumentation is to monitor and transmit reactor vessel parameter information such that the convenient, efficient, and economical operation of the plant is facilitated.

7.8.3 Safety Design Bases

Reactor vessel instrumentation shall be designed to:

1. Provide the operator with sufficient indication of reactor core flow rate during planned operations to avoid operating conditions not considered by plant safety analyses

2. Provide the operator with sufficient indication of reactor vessel water level during planned operations to determine that the core is adequately covered by the coolant inventory inside the reactor vessel to avoid the release of radioactive materials to the environs such that the limits of 10CFR20 are exceeded, and to avoid operating conditions not considered by plant safety analyses

3. Provide the operator with sufficient indication of reactor vessel pressure during planned operations to avoid nuclear system stress in excess of those allowed by applicable industry codes

4. Provide the operator with sufficient indication of reactor vessel top head flange leakage during planned operations to avoid nuclear system stress in excess of that allowed by applicable industry codes and the release of radioactive material to the environs such that the limits of 10CFR20 are exceeded

7.8.4 Power Generation Design Basis

Reactor vessel instrumentation shall be designed to monitor and transmit sufficient reactor vessel parameter information to the operator such that he is continually able to operate the plant conveniently, efficiently, and economically.

7.8.5 Description

Figures 7.8-1 and 7.8-2 show the numbers, location, and arrangements of the sensors, switches, and sensing equipment used to monitor reactor vessel conditions. The reactor vessel sensors used for safety systems and engineered safeguards have been

described and evaluated in other portions of the Safety Analysis Report.

7.8.5.1 Reactor Vessel Surface Temperature

Reactor vessel temperature is determined on the basis of reactor coolant temperature. Temperatures which are needed for operation and for compliance with the technical specification operating limits are obtained from one of several sources depending upon the operating condition. During normal operation, either reactor pressure and/or the inlet temperature of the coolant in the recirculation loops may be used to determine the vessel temperature. Below the operating span of the resistance temperature detectors in the recirculation loop the vessel pressure is used for determining the temperature. Below 212°F the vessel coolant, and thus the vessel temperature, is reasonably well shown by the reactor water cleanup inlet temperature indicator. These three sources of input are most conveniently available from the process computer. Refer to Section 7.16 for details of callup methods for this information. During normal operation, vessel thermal transients are limited via operational constraints on parameters other than temperature. See Section 7.2, Reactor Protection System.

Reactor vessel thermocouples are provided as a means of observing vessel metal surface temperature behavior in response to vessel coolant temperature changes during startup and power operation testing. Indications based upon the thermocouples can be used for controlling the rate of heating or cooling or limiting the vessel thermal stresses. Selected temperatures are recorded on a multipoint recorder. Thermocouple and temperature recorder specifications are listed on Table 7.8-1.

7.8.5.2 Reactor Vessel Water Level

Reactor vessel water level indication is detected by comparing the pressure exerted by the actual height of water inside the vessel to the pressure exerted by a constant reference column of water. Pipelines which are connected to widely separated nozzles in the reactor vessel lead from the vessel to locations outside the primary containment where they terminate at instrument racks in the Reactor Building. Level measuring instruments are attached to the appropriate sensor pipelines so that the proper differential pressure is applied to the level instruments. A condensing chamber is installed in each of the pipelines used to provide a reference column of water for level measurements. The redundant level instruments used with the safety related systems (See Section 7.2) receive the reactor level signal from reference columns which are predominately located outside of the primary containment which improves the accuracy of level measurement and minimizes flashing of the reference column on depressurization.

High containment temperatures combined with depressurization of the reactor can cause boiling or flashing of the portion of the reference column that is located inside the drywell and lead to inaccurate water level

indications. Although the reactor water level indication becomes inaccurate, the indication will still allow monitoring of the reactor level to ensure adequate coolant inventory to cool the fuel. Each of the instrument pipelines is fitted with one manual isolation valve and one excess flow check valve both of which are located directly outside the drywell in the Reactor Building. The instrument pipelines slope down a minimum of 1/2 in/ft in the direction of the instruments so that no air traps are formed. Pressure and differential pressure measuring instruments also use these same instrument lines, as indicated on Figure 7.8-2.

The reactor water level instruments were found to be susceptible to level indication anomalies described as "notching" during reactor depressurizations after long periods of full power operation. The cause of "notching" is non-condensable gases coming out of solution in the level measurement reference leg during depressurization of the reactor. To solve this problem, PNPS installed a reference leg backfill system in 1993 to supply a continuous flow of water from the Control Rod Drive (CRD) hydraulic system charging water header that was fed into the reference legs at a very low flow rate. There were subsequent events during reactor depressurizations where problems with the backfill system occurred that adversely affected the operation of the reactor normal range water level instruments. As a result of these level indication anomalies, a modification was installed to vent the condensing chambers and eliminate the need for either continuous or intermittent backfilling of the reference legs during reactor operation.

Condensing chambers 12A, 12B, 13A and 13B were modified to a vented configuration during refueling outage #14 in 2003. The vent line connects to the chamber steam space and runs entirely within the drywell to the active leg of the water level sensing piping at a point upstream (inboard) of the sensing line restriction orifices. The vent to the active leg removes non-condensable gases from the condensing chambers by maintaining a constant flow of steam through the chamber and into the vent line where condensation occurs. The non-condensable gases are then dissolved into the condensate and returned to the reactor vessel via the active leg sensing piping. The venting process thereby prevents the significant accumulation of non-condensable gases in the condensing chambers and the reference legs.

There is indication of reactor vessel water level in the Reactor Building. The level measuring instruments, LI263-59A&B indicate locally, as shown on Figure 7.8-2.

There are nine separate reactor vessel water level indications provided in the control room. These are continuously displayed on various benchboards and the PAM Panel (see Section 7.8.10). Two of the control room normal range level indications are derived from an auxiliary signal from the analog trip system reactor water level monitors, two more normal range level indications come from the level transmitters provided for the feedwater control system, four accident level indications come from the instruments used to measure the water level inside the core shroud, and one indicator uses a separate reference column of water located so that water level indication is possible all the way to the top of the vessel. A level recorder that receives level signals from level transmitters in the feedwater control system provides a continuous record of reactor vessel water level. This same recorder provides high and low

level alarms. A second recorder connected to another level transmitter which measures water level inside the core shroud provides a continuous monitor of vessel level in the cold shutdown condition. Additional level recordings are provided on the PAM panel (see Table 7.8-3). Table 7.8-1 lists the specifications for level instruments not previously described with other systems.

Figure 7.8-2 is a chart indicating water levels at which various automatic alarms and safety actions are initiated. Each of the actions listed is described and evaluated in the section of the Safety Analysis Report where the system involved is described. The following list tells where various level measuring components and their setpoints are discussed.

Level Instrumentation	Section in Which Discussed
Level instrumentation for initiating scram	Reactor Protection System (7.2)
Level instrumentation for initiating primary containment or reactor vessel isolation	Primary Containment and Reactor Vessel Isolation Control System (7.3)
Level instrumentation used for HPCI, LPCI, core spray, Automatic Depressurization System, recirculation pump trip, or recirculation loop valve closure	Core Standby Cooling Systems Controls and Instrumentation (7.4)
Level instrumentation used to measure water level inside core shroud	Core Standby Cooling Systems Controls and Instrumentation (7.4)
Level transmitters and recorders used for feedwater control	Feedwater Control System (7.10)
Level instrumentation used to trip main turbine, RCIC turbine, and HPCI turbine	Core Standby Cooling Systems Controls and Instrumentation (7.4)
Level instrumentation used to initiate the RCIC	Reactor Core Isolation Cooling System (4.7)

The large number of reactor vessel water level indications provide the operator with sufficient information to determine the adequacy of the coolant inventory to cool the fuel. In addition, by verifying that reactor vessel water level is not rising to an abnormally high level, the operator is assured that turbines are not endangered by the possibility of water carried into the steam lines. The approach of abnormal conditions is brought to the operator's attention by audible and visual alarms (Figure 7.8-2).

7.8.5.3 Reactor Vessel Coolant Flow Rates and Differential Pressures

Figure 7.8-2 shows the flow instruments, differential pressure instruments, and recorders provided so that the core coolant flow rates and the hydraulic performance of reactor vessel internals can be determined. Core flow instrumentation includes the following:

1. Control room readout of the total core flow rate and the total discharge flow from each group of jet pumps which is driven by an individual drive loop. Measurement of diffuser entrance to core supply plenum pressure differentials is indicated in the control room for each double tapped jet pump unit

2. Control room readout of fluid temperature in the recirculation pump suction and feedwater lines (event recall log from computer)

3. Control room readout of the total feedwater flow rate and cleanup flow rate

4. Control room readout of flow in each jet pump drive loop (recirculation loop) using the flow nozzles provided

5. Control room readout of the discharge flow from four specially calibrated jet pumps. The diffusers on these jet pump units contain special pressure taps for calibration using prototype test performance maps.

6. Locally accessible transducers, and pressure sensing taps for making detailed performance measurements and calibrations during reactor operation for the preceding control room readout equipment.

7. The local differential pressure indicators, which are connected to each jet pump branch supply line and to the vessel annulus, may be used to obtain relative supply branch pressure differentials.

This arrangement of flow measuring instrumentation accomplishes the following: Total core flow rate can be determined by three methods from the control room. The first method is direct readout of Item 1. The second method involves computer calculation of core flow rate using Items 2 and 3 and applying an energy and mass balance to the reactor downcomer region. The third method is to establish a correlation (during startup tests) between drive loop flow rate and core flow rate with reactor power as a parameter. The correlation is then used to convert the readout of Item 4 to core flow rate. The correlation should be updated periodically. During operation, results of the three methods can be cross checked to ensure validity.

Calibration of the flow summers (included in Item 1) is dependent upon deriving the relationship between the two differential pressure readouts (Items 1 and 5) on the specially instrumented jet pumps as a function of jet pump flow. This relationship is obtained under reactor environmental conditions using jet pump prototype performance maps as the calibration basis.

7.8.5.4 Reactor Vessel Internal Pressure

Reactor vessel internal pressure is detected by pressure switches, indicators, and transmitters from the same instrument pipelines used for reactor vessel water level measurements. Two pressure indicators that sense pressure from different separated instrument pipelines provide pressure indications in the Reactor Building. Two reactor vessel pressure indications are provided in the main control room. These come from the two pressure transmitters used in the Feedwater Control System. Reactor vessel pressure is continuously recorded in the main control room on two recorders. Each recorder receives a pressure signal from one of the Feedwater Control System pressure transmitters.

The following list shows where reactor vessel pressure measuring instruments used for the automatic control of equipment or systems are discussed:

Pressure Instrumentation	Section in Which Discussed
Pressure instruments used to initiate a scram	Reactor Protection System (7.2)
Pressure instruments used to bypass main steam line isolation valve closure scram	Reactor Protection System (7.2)
Pressure instruments used for Core Spray System and LPCI	Core Standby Cooling Systems Controls and Instrumentation (7.4)
Pressure transmitters and recorders used for feedwater control	Feedwater Control System (7.10)
Differential pressure switches measuring differential pressure between reactor vessel and jet pump riser pipes	Core Standby Cooling Systems Controls and Instrumentation (7.4)
Differential pressure switches measuring differential pressure between inside of core spray sparger pipes and core inlet above the core support assembly	Core Standby Cooling Systems Controls and Instrumentation (7.4)

7.8.5.5 Reactor Vessel Top Head Flange Leak Detection

A connection of the reactor vessel flange is provided into the annulus between the two metallic seal rings used to seal the reactor vessel and top head flanges. This connection permits detection of leakage from the inside of the reactor vessel past the inner seal ring. The connection is piped to a collection chamber installed between two air operated valves. The arrangement is shown on Figure 7.8-1. The upsteam valve is normally open, the

downstream valve normally closed. A level switch is provided to detect the accumulation of water in the collection chamber. This level switch actuates an alarm in the main control room. A pressure switch is also provided to actuate the alarm in the main control room as pressure in the leakage collection piping becomes abnormally high. A pressure indicator is provided to indicate the pressure inside the piping arrangement. The level switch is located inside the primary containment, and the pressure instruments are located outside the drywell but inside the Reactor Building. The instrument pipeline for the pressure instruments is provided with one manual isolation valve. The specifications for the level and pressure instruments are given on Table 7.8-1. The two air operated valves are controlled by a switch in the main control room. The positions of the valves are indicated by lights. If leakage past the inner seal ring is indicated, the upstream valve can be closed and the downstream valve can be opened by remote manual operation from the main control room. This action routes the accumulated leakage to the drywell equipment drain sump. After the collection chamber is drained, the air operated valves can be returned to their normal positions. The leakage rate can be determined by timing the period until the level alarm is reactivated. See Section 4.10, Nuclear System Leakage Rate Limits.

A connection is provided on the reactor vessel beyond the outer metallic head seal. This connection is piped to a point in the drywell accessible during reactor shutdown and is capped. (Note: In the event that difficulty is encountered in obtaining a pressure tight seal on the inner metallic seal, it may be desirable to operate on the outer metallic seal only. It shall be possible to install a low pressure seal beyond the outer metallic seal and monitor the space between for outer metallic seal leakage by use of this piped connection.)

7.8.6 Safety Evaluation

The reactor vessel instrumentation is designed to provide sufficient continuous indication of key reactor vessel operating parameters during planned operations such that the operator can efficiently monitor these parameters and anticipate any approach to operating conditions which could lead to any of the unacceptable safety results discussed in the Safety Design Bases (Section 7.8.4) and the Operational Nuclear Safety Requirements (Section 7.8.8). The redundancy of all indicators provided assures that the possibility that all instrumentation could be lost simultaneously is so remote as to be negligible. In addition, sensors providing safety signals to the RPS and engineered safeguards systems for scram and isolation functions are separate from these indicator sensors such that loss of indication does not directly obviate protection against accidents and transients. It is therefore concluded that the safety design bases are satisfied.

7.8.7 Inspection and Testing

The large number of spare thermocouples provided on the reactor vessel and its attachments permit cross checking to verify proper

thermocouple response. Pressure, differential pressure, water level, and flow instruments are located in the Reactor Building and are piped so that calibration and test signals can be applied during reactor operation, if desired.

7.8.8 Nuclear Safety Requirements for Plant Operation

Table 7.8-2 presents the nuclear safety requirements for reactor vessel instrumentation for each BWR operating state. The entries on Table 7.8-2 represent an extension of the station wide BWR systems analysis of Appendix G to the applicable reactor vessel instrumentation. The following referenced portions of the Safety Analysis Report provide information justifying entries on Table 7.8-2:

Reference	Information Provided
1. Preceding parts of Section 7.8	Description of reactor vessel instrumentation components and indication functions.
2. Station Nuclear Safety Operational Analyses, Appendix G	Identifies conditions and events for which reactor vessel instrumentation is required.

Each detailed requirement on Table 7.8-2 is referenced to the most significant station condition originating the need for the requirement by identification of a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the requirements in the "minimum required for action" columns of Table 7.8-2 and are coded as follows:

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

```
D03-50
|  |  |
|--|--|--D - BWR operating state D
   |--|--03 - Event (Row 3)
      |---50 - Reactor Vessel Water Temperature
                    indications (Column 50)
```

The basis for an operational nuclear safety requirement is generally clear from the information provided by the previously noted references.

<u>Reactor core flow rate indications</u>

There are no operational nuclear safety requirements for flow rate indication in any operating state except F, which is the only state in which power operation is planned. However, it should be noted that the flow rate measurement, associated with the jet pumps, will actually be available at any time that recirculation flow is established.

Reactor vessel water level indications

There are operational nuclear safety requirements imposed on reactor vessel water level indications in all operating states. These result from consideration of necessity of level indication to the operator from the standpoint of ensuring that the fuel is covered with coolant to avoid both release of radioactive material to the environs such that the limits of 10CFR20 are exceeded and the existence of operating conditions not considered by station safety analyses.

Reactor vessel pressure indications

There are no operational nuclear safety requirements imposed on reactor vessel pressure indications in operating States A and B because with the head off in these two states, the reactor vessel pressure is at atmospheric. The operational nuclear safety requirements imposed in states C through F result from consideration of vessel pressure indication necessary to the operator to assure the degree of pressure control required to avoid both nuclear system stress in excess of that allowed for planned operations by applicable industry codes and the existence of station conditions not considered by station safety analysis. In states C through F, the reactor vessel pressure indication due to operation of a BWR at saturation conditions.

Reactor vessel water temperature indications

There are operational nuclear safety requirements imposed on reactor vessel water temperature indications in all operating states. These result from consideration of the degree of water temperature indication necessary to ensure adequate nuclear system temperature control to avoid nuclear system stress in excess of those allowed for planned operations by applicable industry codes. Available indicators associated with other systems or parameters are utilized to give the operator water temperature information rather than using the installed reactor vessel surface temperature thermocouples, as direct indication and control of water temperature is considered preferable from a stress anticipation standpoint. These surface temperature indications are nonetheless available to check metal temperature response.

Nuclear system leakage indications

There are operational nuclear safety requirements imposed on nuclear system leakage indications in all operating states. These result from consideration of leakage detection necessary for adequate leakage control to avoid (1) nuclear system stress in excess of those allowed for station operation by applicable industry codes (in states C through F only), and (2) the release of radioactive materials to the environs such that limits of 10CFR20 are exceeded (states D, E, and F only).

7.8.9 Current Technical Specifications

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

7.8.10 Post Accident Monitoring (PAM)

Following the accident at Three Mile Island Unit No. 2 (TMI-2) on March 28, 1979, the Nuclear Regulatory Commission (NRC) staff developed a number of proposed requirements to be implemented on operating reactors and on plants under construction. These requirements (originally outlined in NUREG-0578,:TMI-2 Lessons Learned-Task Force Status Report and Short Term Recommendations" and subsequently set forth in NUREG-0737, "Clarifications of TMI Action Plan Requirements", included the installation of additional instruments that would enable operators to follow, and more closely evaluate, the course of an accident (see Table 7.8-3).

These instruments are installed on dedicated PAM control panels located in the main control room. They have been furnished in accordance with the requirements stated in Regulatory Guide 1.97 Rev. 2 - "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following An Accident."

Table 7.8-1

REACTOR VESSEL INSTRUMENTATION
INSTRUMENT SPECIFICATIONS*

MEASURED VARIABLE	INSTRUMENT TYPE	NORMAL RANGE	ACCURACY	TRIP SETTING
Reactor Vessel Surface Temperature	Thermocouple	0-600°F	ASA C96.1	—
Reactor Vessel Top Head Surface Temperature	Thermocouple	0-600°F	ASA C96.1	—
Reactor Vessel Top Head Flange Surface Temperature	Thermocouple	0-600°F	ASA C96.1	—
Reactor Vessel Surface Temperature	Temperature recorder	0-600°F	+ 1%	—
Reactor Vessel Water Level	Level indicator (local)	-50 to +50 inches	±X% of full scale	—
Reactor Vessel Water Level	Level indicator LI263-100A & B LI640-29A & B	 -50 to +50 inches 0 to +60 inches	 ± 1% ± 2%	See Fig. 7.8-2
Specially Calibrated Jet Pump Flow Rate	Flow transmitter FT263-63A FT263-63B FT263-63C FT263-63D	 0-15.45 psid 0-14.30 psid 0-15.24 psid 0-15.70 psid	± 1/4% typical	—
Jet Pump Flow Rate	Flow transmitter	-.42 - 14.43 psid	± X%	—
Specially Calibrated Jet Pump Flow Rate	Flow indicator	$0-4 \times 10^6$ lb/hr	± 2%	—
Jet Pump Flow Rate	Flow indicator	$0-40 \times 10^6$ lb/hr	± 2%	—
Specially Calibrated Jet Pump Flow Rate	Square root	-	± X%	—
Recirculation Loop Flow Rate	Flow summer	-	± X%	—
Recirculation Loop Flow Rate	Flow indicator	0-70,000 gpm	± 2%	—
Core Total Flow	Flow summer	-	± X%	—

TABLE 7.8-1 (Cont)

Measured Variable	Instrument Type	Normal Range	Accuracy	Trip Setting
Reactor vessel annulus to core inlet plenum differential pressure	Differential pressure transmitter	0-50 psid	±1%	-
Reactor vessel annulus to core inlet plenum differential pressure	Differential pressure indicator	0-50 psid	±2%	-
Differential pressure across the core support assembly	Differential pressure transmitter	0-25 psid	±1%	-
Reactor vessel pressure	Pressure indicators	0-1,500 psig	±2%	-
Reactor vessel flange leakage collection chamber level	Level switch	-	-	-
Reactor vessel flange leak detection piping internal pressure	Pressure switch	0-1,500 psig	±2%	600 psig
Reactor vessel flange leak detection piping internal pressure	Pressure indicator	0-1,500 psig	±2%	-

NOTE:

*Other instruments measuring reactor vessel variables are discussed in sections of the Safety Analysis Report where the systems using the instruments are described.

Table 7.8-2

REACTOR VESSEL INSTRUMENTATION REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *
7.8.2.1 Provide core coolant flow rate indication	1. Jet pump pressure taps. 2. Differential pressure transmitter and indicator (core annulus/inlet plenum). 3. Differential pressure transmitter (core inlet plenum/ core support assy).	1. Two per jet pump (total 40) 2. One 3. One						2 pressure taps associated with any jet pump (F04-45)
7.8.2.2 Provide reactor vessel water level indication.	1. Level indicator.	Eight (two temperature compensated).	1 operable level indicator (A01-48)	1 operable level indicator (B01-48)	1 operable level indicator (C06-48)	1 operable level indicator (D03-48)	1 operable level indicator (E06-48)	1 operable level indicator (F04-48)
7.8.2.3 Provide reactor vessel pressure indication.	1. Pressure indicators 2. Pressure transmitters	1. Two 2. Two			1 operable pressure indicator (C06-49)	1 operable pressure indicator (D03-49)	1 operable pressure indicator (E06-49)	1 operable pressure indicator (F04-49)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.8-2 (Cont)

REACTOR VESSEL INSTRUMENTATION REQUIREMENTS FOR PLANT OPERATION

			BWR OPERATING STATES					
			A	B	C	D	E	F
SYSTEM ACTIONS	COMPONENTS	NUMBER PROVIDED BY DESIGN	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *	MINIMUM REQ'D FOR ACTION *
7.8.2.4 Provide reactor vessel water temperature indication.	1. States A and B: a. Cleanup system inlet temperature. b. RHR heat exchanger inlet temperature. 2. States C,D,E,F a. Recirc pump inlet temperature. b. Cleanup system inlet temperature. c. Reactor vessel pressure indicators.	States A & B a. One b. One a. Two b. One c. Four (see 7.8.2.3)	1 operable temperature indicator. (A06-50)	1 operable temperature indicator. (B01-50)	1 operable temperature or pressure indicator. (C06-50)	1 operable temperature or pressure indicator. (D03-50)	1 operable temperature or pressure indicator. (E06-50)	1 operable temperature or pressure indicator. (F03-50) (F04-50)
7.8.2.5 Provide nuclear system leakage indication.	Pressure switch with pressure indicator, level switch monitoring leak detection piping and drywell drain sump (arrangement hereinafter referred to as "system").	One system			1 operable system. (C02-51)	1 operable system. (D03-51)	1 operable system. (E02-51)	1 operable system. (F04-51)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.8-3

POST ACCIDENT MONITORING INSTRUMENT* SPECIFICATIONS

MEASURED VARIABLE	MONITOR TYPE	QUANTITY	RANGE	IDENTIFICATION
Reactor Pressure	Indicator	2	0-1500 psig	PI-263-49A, 49B
Containment Pressure - High	Indicator	2	0-225 psig	PI-1001-600A, 600B
Containment Pressure - Low	Indicator	2	-5 to +5 psig	PI-1001-601A, 601B
Containment Pressure - High/Low	Recorder	2	0-225 ±5 psig	PR-1001-600A, 600B
Reactor Pressure	Recorder	2	0-1500 psig	PR-1001-600A, 600B
Torus Water Level	Indicator	2	0-300" H_2O	LI-1001-604A, 604B
Reactor Water Level	Indicator	2	-277.5 to +22.5"	LI-1001-650A, 650B
Torus Water Level	Recorder	2	0-300" H_2O	LR-1001-604A, 604B
Reactor Water Level	Recorder	2	-50" - +50" H_2O	LR-1001-604A, 604B
Reactor Water Level	Recorder	2	-277.5 to +22.5"	LR-1001-604A, 604B
Drywell Radiation	Indicating Transmitter	2	1 to 10^7 Rad/hr	RIT-1001-606A, 606B
Torus Radiation	Indicating Transmitter	2	1 to 10^7 Rad/hr	RIT-1001-607A, 607B
Containment Radiation	Recorder	2	1 to 10^7 Rad/hr	RR-1001-606A, 606B
Station Noble Gas Effluent Radiation	Recorder	1	10^{-1} to 10^4 Rad/hr	RR-1001-608
Reactor Bldg Effluent	Indicator	1	10^{-1} to 10^4 Rad/hr	RI-1001-609
Turbine Bldg Effluent	Indicator	1	10^{-1} to 10^4 Rad/hr	RI-1001-610
Stack Effluent	Indicator	1	10^{-1} to 10^4 Rad/hr	RI-1001-608
Containment Oxygen/Hydrogen	Recorder	2	0-20% O_2/0-10% H_2	AR-1001-612A, 612B

NOTES:

* In addition to these instruments the PAM panels also contain:

1. The manually operated control switches used to control the containment atmosphere following an accident. See Section 5.4.3.

2. The safety/relief valve monitors that provide indication of the status of two safety valves and four relief valves in the reactor coolant system.

Figure 7.8-1 has been deleted.

Please refer to Figure 4.3-2.

Figures 7.8-2 and 7.8-3 have been removed.

Please refer to BECo Controlled Drawings M 253 and M1A7-4.

7.9 RECIRCULATION FLOW CONTROL SYSTEM

7.9.1 Power Generation Objective

The objective of the recirculation flow control system is to control reactor power level over a limited range by controlling the flow rate of the reactor recirculating water.

7.9.2 Power Generation Design Basis

The recirculation flow control system is designed to allow manual control of reactor power by adjusting the flow rate of the recirculation water.

7.9.3 Safety Design Basis

The recirculation flow control system shall function so that no operational transient resulting from a malfunction in the recirculation flow control system can result in fuel damage or in a violation of the nuclear system pressure limit.

7.9.4 Description

7.9.4.1 General

The recirculation flow control system adjusts the flow rate of the recirculation pumps by adjusting the frequency supplied to the pump motors thereby affecting changes in reactor power level.

An increase in recirculation flow temporarily reduces the void content of the moderator by increasing the flow of coolant through the core. Due to the higher moderator density, the core reactivity, and thus power level, is increased. At this higher power level (higher heat flux) the steam volume in the core increases with a subsequent decrease in core reactivity. A new steam void equilibrium is subsequently attained at the higher recirculation flow rate which establishes a new steady state power level. When the recirculation flow is reduced, the power level is reduced in the reverse manner.

Figure 7.9-1 illustrates how the recirculation flow control operates.

7.9.4.2 Motor Generator Set

Each motor generator (MG) set supplies power to its associated recirculating pump motor. Each of the two MG sets and its controls are identical; therefore, only one description is given. Figure 7.9-5 (BECo M1E8-7) shows the general arrangement and rating of the MG set. The MG set can continuously supply power to the pump motor at any frequency between approximately 19 and 96 percent of MG set drive motor synchronous frequency. The MG set is capable of starting the pump, and, accelerating it from standstill to the desired operating speed when the pump motor thrust bearing is fully loaded by reactor pressure acting on the pump shaft after the pump has been sitting idle in a hot pressurized loop during a shutdown period. Contacts are provided that trip the recirculation pump MG drive motor breaker on low reactor water level (see Figure 7.9-2, BECo M1E6-6).

Means are also provided to trip the MG set field breakers and drive motor breakers through the recirculation pump trip (RPT) system in the unlikely event that the RPS fails to accomplish a reactor scram from power. (Refer to Section 3.9 and Figure 7.9-2, BECo M1E6-6).

The main components of the MG set are a drive motor, a generator, and a variable speed converter with an actuation device to adjust the output speed.

Drive Motor

The drive motor is an ac induction motor which drives the input shaft of the variable speed converter. The motor can operate under electrical supply variations of ± 5 percent of rated frequency or ± 10 percent of rated voltage. The ac power for each drive motor is supplied from a different auxiliary bus.

Generator

The variable frequency generator is driven by the output shaft of the variable speed converter. During normal operation, the generator is self excited. The generator is excited from an external source during pump startup.

Variable Speed Converter and Actuation Device

The variable speed converter transfers power from the drive motor to the generator. The variable speed converter actuator automatically adjusts the slip between the converter input shaft and output shaft as a function of the signal from the speed controller. If the speed controller signal is lost, the actuator is locked to cause the speed converter slip to remain "as is." Manual reset of the actuation device is required to return the speed converter to normal operation.

7.9.4.3 Speed Control Components

The speed control system (Figure 7.9-6, Drawing M1E14-5) controls the variable speed converters of both MG sets. The MG sets are controlled individually. The control system functions for each MG set are the following: a manual/automatic control station, a rate limiter, a function generator, failure alarms, startup signal generator, and speed limiters.

Pump Speed Controllers

The pump speed controller (1 for each loop) is a programmable digital control system whose output signal (representing recirculation pump speed demand) is fed to the variable speed converter actuation device. Speed demand signals are generated within the speed control system based on control settings set by the plant operators and automatic responses based on certain external conditions (such as number of feedwater pumps operating). Pump speed is continuously monitored (and displayed to the operators) by the control system; speed feedback is utilized in an automatic speed control mode which is available for selection within the system.

The pump speed controller for each loop operates independently of the other except for various external interlocks.

The following functions are programmed into each pump speed controller. Programming of functions and selection of major parameters, such as maximum pump speed rate-of-change, are not under the control of plant operators.

Three-Mode Manual/Automatic Controller

This is the major internal functional device of each control system. Based on the setpoint inserted by the plant operators, the controller develops the speed demand signal when manual control is selected. If in automatic, the controller utilizes the feedback signal, the setpoint, and the three control modes (proportional, integral, and derivative) to develop a speed demand signal which varies as pump speed approaches the setpoint. Range of the setpoint is 20-100 percent speed. Operators control the setpoint value.

Rate Limiter

This function acts to limit the rate-of-change of the speed demand signal to certain programmed maximum values either increasing or decreasing. This function can not be controlled by the plant operators.

Startup Generator

This function supplies a fixed setpoint signal to the control system during MG Set startup. This sets the MG Set variable speed converter actuation device to a position equivalent to approximately 53 percent speed. This signal is automatically removed during the startup sequence.

Speed Limiters (2 for each MG Set)

Speed limiter No. 1 automatically limits the recirculation pump speed to 26 percent of rated speed if the recirculation pump main discharge valve is not fully open or the total feedwater flow is less than 20 percent of rated flow. Without this speed limiter, the recirculation pump could overheat if the recirculation pump discharge valve is partly closed. This speed limiter also prevents cavitation in the recirculation or jet pumps if the feedwater flow drops below 20 percent of rated flow.

Speed limiter No. 2 automatically limits the recirculation pump speed to 44 percent of rated speed if one of the three feedwater pumps is tripped off and coincidentally the reactor water level is below the low level alarm set point. This reduction of the recirculation pump speed reduces the reactor power to a level within the capacity of the remaining feedwater flow, thus making a low water level scram unnecessary.

Function Generator

The function generator compensates for any inherent system nonlinearity by suitably characterizing the speed demand output to the MG set variable speed actuation device.

Alarm Functions

The digital control system is capable of monitoring system operation and will generate alarms when the following anomalies occur:

Speed Demand Signal Failure/Power Failure

If the speed demand signal is reduced to below the minimum value or if control system power fails, an alarm signal will be generated.

Speed Rate-of-Change High

If the pump speed input signal indicates that speed rate-of-change exceeds a maximum value, an alarm signal will occur.

Speed Deviation Abnormal

Pump speed and speed demand are continuously compared. If speed and speed demand differ by a set amount for greater than a set time, an alarm signal will occur.

Self-Diagnostic Alarm

The control system periodically checks itself for programming/ operational faults. If such a fault is detected, the system will generate an alarm.

7.9.4.4 System Operation

7.9.4.4.1 Recirculation Loop Starting Sequence

Each recirculation loop is independently put into operation by operating the controls as follows:

1. The starting sequence is manually initiated by placing the drive motor control switch for one MG set in the start position. The drive motor breaker closes provided that:

a. The drive motor bus is near rated voltage

b. The recirculation loop suction valve is fully open

c. The recirculation loop discharge valve is fully closed

d. The generator field breaker is open

2. The manual/automatic transfer station will have been previously switched to manual control and its output signal adjusted to give the desired generator speed (typically 20 percent of rated speed) after the pump has started.

3. When the drive motor breaker is closed and once the variable speed converter has achieved its startup position the following events occur:

a. The external source of field excitation is engaged

b. The generator field breaker is closed after a time delay

4. After recirculation pump start is sensed by a differential pressure switch, the generator is automatically transferred to self-excitation.

5. The recirculation loop discharge valve is now manually opened.

6. Recirculation flow is increased during startup by manually increasing recirculation pump speed.

Refer to Section 7.9.7, Operational Requirements.

7.9.5 Safety Evaluation

The recirculation flow control system is designed so that coupling is maintained between an MG set drive motor and its generator even if the ac power or a speed control circuit signal fails. This assures that the drive motor inertia contributes to power supplied to the recirculation pump during the coastdown of the MG set after loss of ac power and that the generator continues to be driven if the speed control circuit signal is lost.

Transient analyses described in Appendix R, show that no malfunction in the recirculation flow control system can cause a transient sufficient to damage the fuel barrier or exceed the nuclear system pressure limits, as required by the safety design basis.

7.9.6 Inspection and Testing

The MG set and speed control circuit are functioning during normal power operation. Any abnormal operation of these components can be detected during operation. The components which do not continually function during normal operation can be tested and inspected during scheduled shutdowns.

7.9.7 Operational Requirements

A restriction is imposed to prevent starting an idle recirculation pump until the coolant in the idle recirculation loop is within 50°F of the reactor coolant temperature.

Since both recirculation pumps are manually started, a two pen recorder and individual indicators are provided in the main control room to allow operator monitoring of the temperature in the two recirculation loops.

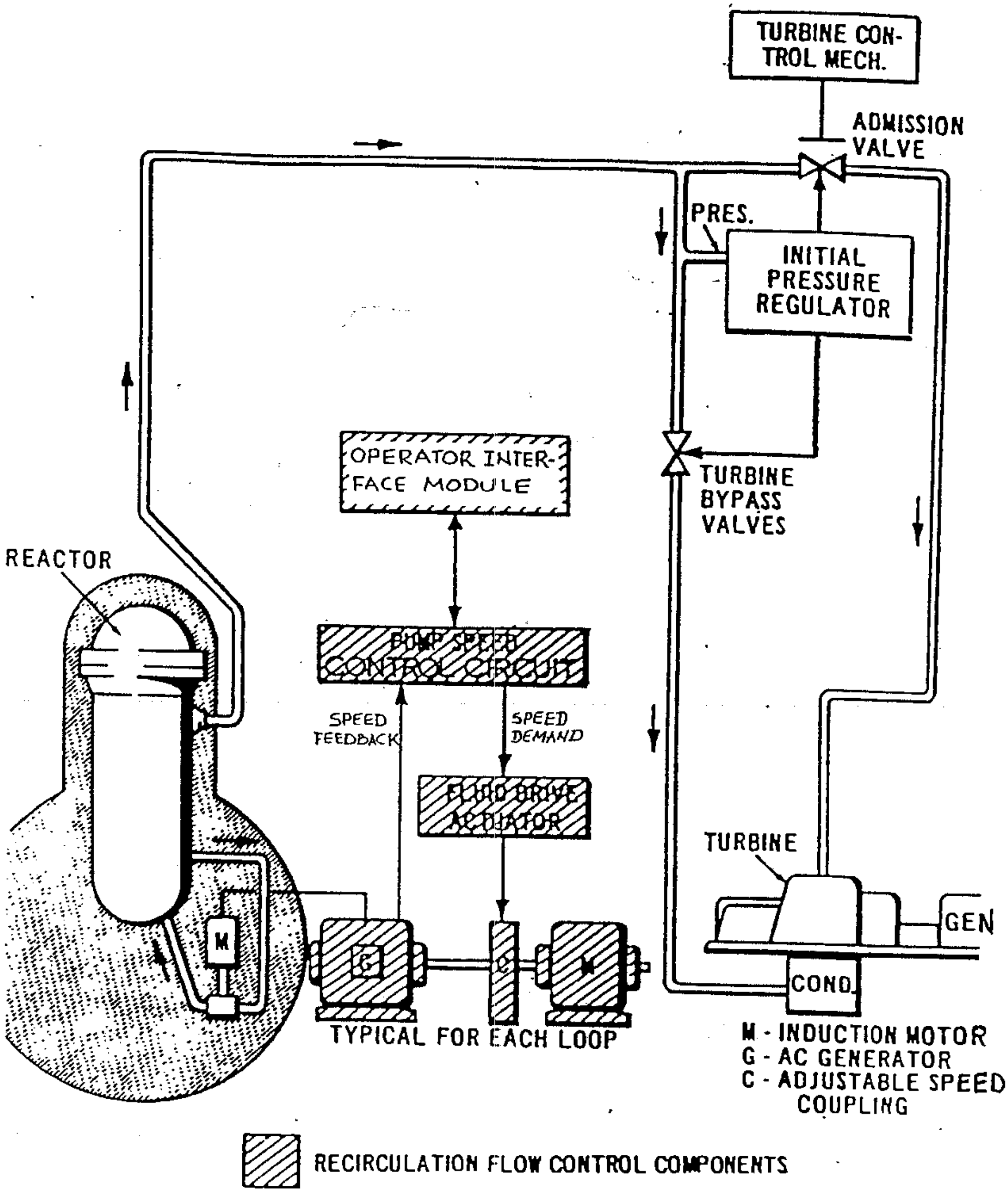


FIGURE 7.9-1

TITLE : RECIRCULATION FLOW CONTROL,
ILLUSTRATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 21 OCTOBER 1997

The following figures have been removed from the FSAR. Please refer to the corresponding BECo controlled drawing.

FSAR FIGURE	**BECO CONTROLLED DRAWING**
7.9-2	M1E 6-6
7.9-3	M1E 7-5
7.9-4	M1E 13-3
7.9-5	M1E 8-7
7.9-6	M1E 14-5

7.10 FEEDWATER CONTROL SYSTEM

7.10.1 Power Generation Objective

The objective of the Feedwater Control System is to maintain a preestablished water level in the reactor vessel during planned operation.

7.10.2 Power Generation Design Bases

The Feedwater Control System shall regulate the feedwater flow so that the proper water level in the reactor vessel is maintained according to the requirements of the steam separators over the entire operating range of the reactor.

The feedwater flow shall also provide sufficient subcooled water to the reactor vessel during power operation to maintain normal operating temperatures.

7.10.3 Description

The feedwater control system, during planned operation, automatically regulates feedwater flow into the reactor vessel. The system is capable of being manually operated.

The feedwater flow control instrumentation measures the water level in the reactor vessel, the feedwater flow rate into the reactor vessel, and the steam flow rate from the reactor vessel. During automatic operation, these three measurements are used for controlling feedwater flow.

The optimum reactor vessel water level is determined by the requirements of the steam separators which limit the water carryover with the steam going to the turbines and limit the steam carryunder with the water returning to the core. For optimum limitation of carryover and carryunder, the steam separators require a decrease in reactor vessel water level as a function of an increase in reactor power level. The water level in the reactor vessel is maintained within %2 in of the optimum level. This control capability is achieved during plant load changes by balancing the mass flow rate of feedwater to the reactor vessel with the steam flow from the reactor vessel. The feedwater flow regulation is achieved by adjusting the feedwater control valves to deliver the required feedwater flow to the reactor vessel (see Figure 7.10-1, Drawing M1P 2-7).

7.10.3.1 Reactor Vessel Water Level Measurement

Reactor vessel water level is measured by two identical, independent sensing systems. A differential pressure transmitter senses the difference between the pressure due to a constant reference column of water and the pressure due to the variable height of water in the reactor vessel. This differential pressure transmitter is installed on differential pressure taps that serve other systems (see Section 7.8, Reactor Vessel Instrumentation). The differential pressure signal is fed into a proportional amplifier which converts the level signal from 4-20MA to 10-50MA for indication and control. The

reactor vessel water level and pressure from each sensing system are indicated in the main control room. The level signal from either sensing system can be selected by the operator as the signal to be used for feedwater flow control. The water level and the reactor vessel pressure are continually recorded in the main control room.

Each level sensing analog instrumentation system is equipped with a bistable device that provides a signal to trip the feedwater pumps and alarm at the main control room when extreme high water level is detected. A coincident detection of both systems is required for initiation of the automatic backup trip protection of the feedwater pumps. A bypass of this function is provided.

7.10.3.2 Steam Flow Measurement

The steam flow is measured across each main steam line flow restrictor by a differential pressure transmitter. A pressure transmitter, multiplier/divider, and proportional amplifier correct the steam flow signal for density to produce an accurate steam flow signal.

The corrected steam flow rate from each main steam line is indicated in the main control room. The steam flow signals are added by a summer to produce a total steam flow signal for indication and feedwater flow control. The total steam flow is recorded in the main control room.

7.10.3.3 Feedwater Flow Measurement

Feedwater flow is measured in each feedwater line on the reactor side of the control valves. A flow element in each feedwater line is provided for flow measurement. The pressure difference across the flow element is sensed by a differential pressure transmitter. Corrections to the feedwater signal are made for water density variations due to temperature changes. These corrections are made by an input from a temperature element through a millivolt/current transmitter and multiplier/divider. The feedwater signal is then linearized by a square root extractor to produce a mass flow rate signal.

A summer is used to add the flow signals from the feedwater lines. The output from the summer is the total corrected feedwater mass flow rate signal. This signal is used for indication and feedwater flow control. The total feedwater flow is recorded in the main control room.

7.10.3.4 Feedwater Control Signal

The feedwater control signal adjusts the feedwater control valves. The components which are manually operated or automatically function to produce the feedwater control signal are the following:

Level Controller

During automatic operation of the feedwater control system, the level controller output is the feedwater control signal. During manual operation the level controller output signal is blocked.

The level controller automatically establishes its setpoint, proportional to the total steam flow signals, at the optimum reactor vessel water level. The level controller receives a three-element control input signal (described in paragraph 7.10.3.4.1) which represents reactor vessel water level. The output from the level controller, resulting from comparison of the setpoint to the signal representing reactor vessel water level, regulates the feedwater flow so that the reactor vessel water level meets the setpoint requirement.

Manual/Automatic Transfer Station
(one for each feedwater control valve)

The manual/automatic transfer station is a manual controller with a transfer switch. While the feedwater control valves are being controlled by the level controller, the transfer switch is positioned so that the manual controller potentiometer is bypassed and the level controller signal goes through the manual/automatic transfer station to a feedwater control valve. During startup or when manual control may be desirable, the level controller signal is blocked by the transfer switch and the feedwater control signal is transmitted and controlled at the manual/automatic transfer station by the operator.

7.10.3.4.1 Automatic Operation

The ability of the Feedwater Control System to maintain reactor vessel water level within a small margin of optimum water level during plant load changes is accomplished by the three element control signal. The three element control signal is the signal fed to the level controller representing reactor vessel water level. Operations determine the optimum water level to be maintained. This is accomplished by adjusting the level controller setpoint.

The three element control signal is obtained as follows: The total steam flow signal and the total feedwater flow signal are fed into a proportional amplifier. The output from this amplifier reflects the mismatch between its input signals and is designated as the steam flow/feedwater flow error signal. If steam flow is greater than feedwater flow, the amplifier output is increased from its normal value until steam and feedwater flows are equal. The reverse is also true. This amplifier output is fed to a second proportional amplifier which also receives the reactor vessel water level signal.

The addition of the reactor vessel water level signal to the steam flow/feedwater flow error signal results in the three element control signal which is fed to the level controller. A lead lag network is provided to improve system response. Its output is fed to the level controller during three element control.

The feedwater control signal is adjusted by the level controller according to the requirements of the three element control signal

and the total steam flow signal so that the required reactor vessel water level is maintained.

7.10.3.4.2 Optional Operating Modes

Optional methods of Feedwater Control System operation are available, and are used during ascension to power. A one element signal (reactor vessel water level) is used to replace the three element control signal to the level controller. At high power level when steam flow and feedwater flow signals are large, anticipatory action is effective. At low loads (0-40 percent), single element control is recommended since steam flow measurement signal-to-noise ratio is prohibitive and it has no useful anticipatory action. Manual/automatic transfer stations can be individually operated to transmit feedwater control signals to each of the feedwater control valves.

7.10.3.5 Feedwater Valve Control

During normal power operation feedwater is delivered to the reactor vessel through two feedwater valves arranged in parallel. Another valve, the low flow valve, is used exclusively for plant startup and is manually controlled at the manual loading station. The feedwater pumps are powered by constant speed AC motors. The feedwater valves are air operated.

The feedwater control signal is fed to both Feedwater Regulating Valve (FRV) Electronic Positioner/Controllers. For each FRV, an electronic module installed outside of the Condenser Bay provides a signal to a stepper motor/encoder driving a high capacity pneumatic module that directly controls the air supply to the double-acting piston type pneumatic actuator. A displacement sensor mounted on the actuator provides the valve stem position feedback to the electronic module. The FRV is a stacked disk type throttle valve with a characterized trim that optimizes the control of the feed flow over the full operating range.

Protection is provided against overfilling the vessel when in the flow control mode by separate contacts on reactor water level alarm units. These can be set anywhere throughout the control normal reactor water level range. High water level is annunciated by alarm contacts on the reactor level recorder, and reactor feed pump trip alarm units. Siince the high level trip uses 2 out of 2 taken once logic, failure of onee channel to indicate high, does not cause the reactor feed pump trrip. For this reason, this trip is not used in transient analysis begginning with Cycle 21.

The level controller and its associated manual/balance/auto switching that provide for normal manual or automatic control are located in the control room. The manual/auto stations for the valves are also located in the control room.

Each feedwater regulating valve will pneumatically lock-up in the “as-is” position in the event of a control signal failure, instrument air supply failure, or electronic controller fault condition when in the normal operating mode.

7.10.3.6 Feedwater Pump Trip

The reactor feedwater pump breakers will be tripped on high-high reactor pressure for events that are indicative of an ATWS event. The trip occurs from the feedwater pump trip logic in the ATWS panels as described in 3.9.3.3

7.10.4 Inspection and Testing

All Feedwater Flow Control System components can be tested and inspected according to manufacturers' recommendations. This can be done prior to plant operation and during scheduled shutdowns. Reactor vessel water level indications from the two water level sensing systems can be compared during normal operations to detect instrument malfunctions. Steam mass flow rate and feedwater mass flow rate can be compared during constant load operation to detect inconsistencies in their signals. The level controller can be tested while the feedwater control system is being controlled by the manual/automatic transfer stations.

Figure 7.10-1 has been removed.

Please refer to BECo Controlled Drawing M1P 2-7.

7.11 TURBINE GENERATOR CONTROL SYSTEM

7.11.1 Power Generation Objective

The power generation objectives are: (a) to maintain the nuclear steam at an essentially constant pressure so that pressure induced core reactivity changes are controlled; (b) to provide turbine generator speed load controls for startup and operation of turbine generator unit; and (c) to limit turbine overspeed.

7.11.2 Power Generation Design Basis

The power generation design basis of the turbine-generator control systems is to generate coordinated positioning signals for the control, intercept, and bypass valves to control reactor pressure and turbine load (or speed during startup, shutdown, and emergency conditions).

7.11.3 Description

7.11.3.1 General

The reactor steam is admitted to the high pressure turbine section through four sets of main stop and control valves. After expansion through the high pressure turbine section, steam flows to moisture separators and returns to the low pressure turbine section by passing through four sets of combined intermediate valves, intercept and intermediate stop valves combined into one assembly. After expansion through the low pressure turbine section, the steam is discharged into the condenser.

A bypass system allows reactor steam to be bypassed to the condenser whenever the turbine cannot absorb all the generated steam.

The principal turbine generator control systems include:

1. The Pressure Regulator System (pressure control unit)
2. The Steam Flow and Speed Governing System (speed control unit)
3. The Emergency Tripping System

The Pressure Regulator and the Steam Flow/Speed Governing Systems use a compound control mechanism to coordinate the operation of the control valves and bypass valves. The pressure regulator system maintains the desired reactor pressure and the Steam Flow/Speed Governing System provides the capability to control and limit turbine overspeed. The Emergency Tripping System operates independently to protect the turbine and limit overspeed conditions. See Figure 7.11-1.

7.11.3.2 Compound Control Mechanism

A compound control mechanism operates the control valves and bypass valves in proper coordination to control reactor pressure and turbine load, (or speed during startup) to set values for a given reactor control rod configuration.

The normal input signals to this control mechanism are:

1. Reactor pressure setpoint (established by setpoint adjustment of pressure regulator)

2. Load or speed setpoint (established by speed/load changer)

3. Turbine speed

4. Reactor pressure

The output signals are:

1. Position of control valve relay

2. Position of bypass relay

Special or overriding input signals are:

1. Main load limit

2. Reactor flow limit

3. Bypass valve opening jack

4. Control valve limit

The entity of the compound control mechanism has the following functional units:

1. Pressure control unit

2. Speed control unit

3. Control valve relay control unit

4. Bypass relay control unit

Figure 7.11-1 shows a block diagram of the entire turbine control equipment. The principal control intelligence for normal turbine reactor control is performed by the control valve relay unit. The inputs to this unit are (1) the desired total steam flow into the turbine as represented by the speed relay lift which, is designated the S-1 signal, and (2) the available generation of reactor steam as represented by the output of the pressure control unit which, is designated the P-1 signal. The output signals generated by the

control valve relay unit are (1) the desired control valve position as represented by the V-1 signal, and (2) the desired bypass control valve position as represented by the V-3 signal.

If, as will be the case during a startup, the amount of available steam (P-1 signal) is greater than the amount of steam required by the turbine (S-1 signal), then the surplus of steam must be discharged into the condenser through the bypass valves. Then, the bypass valves, as represented by the V-3 output, only need to open whenever the magnitude of P-1 signal is greater than the magnitude of S-1 signal. The corresponding magnitude of the control valve opening, as represented by the V-1 output signal, will correspond to the magnitude of the S-1 input signal.

Conversely, as will be the case at some elevated load, if the amount of desired steam (S-1 signal) to produce a certain turbine power output is greater than the amount of steam available from the reactor (P-1 signal), then the V-3 signal is zero and the corresponding magnitude of control valve opening, as represented by the V-1 output signal, will correspond to the magnitude of the P-1 input.

The normal control signals to and from the control valve relay may be overridden as described below.

The main load limit may override the speed governor and call for a lower steam flow into the turbine. In such a case, the S-1 signal will be determined by the load limit setting.

There is no overriding mechanism associated with the bypass relay proper. Thus, the output of the bypass relay will always be equivalent to the signal V-3 produced by the control valve relay. There is, however, an overriding device, the so called bypass opening jack, associated with the pressure relay unit with which the bypass valves can be opened beyond the amount called for by the pressure regulators. Thus, the P-1 travel will either be determined by the controlling pressure regulator or by the bypass opening jack, whichever calls for the greater travel.

The control valve lift limit will limit the output V-1 of the control valve relay directly.

The reactor flow limit will limit the output P-1 signal of the pressure control unit, thus, limiting the maximum opening of the combined control and/or bypass valves and thereby limiting the total reactor steam flow.

The speed and pressure control units, the control valve, and bypass relay units are part of the compound control system controlling turbine load and reactor pressure in proper coordination.

Figure 7.11-1 also shows the many ways in which the various turbine valves may be closed by trip action. While the diagram should be self explanatory, note that any turbine trip action either caused by the emergency trip valve (in front standard) or vacuum trip No. 1

does not trip the bypass valves. The only trip device that automatically closes the bypass valves is vacuum trip No. 2, which is only actuated at an extremely poor condenser vacuum of 7 in Hg. As long as the condenser vacuum is at all acceptable, the bypass valves are retained in service during any turbine trip in order to dispose of the steam which the reactor generates following a turbine trip.

Description of the principal components of the turbine control systems and their operation and design function follows.

7.11.3.2.1 Pressure Control Unit

The pressure control unit has two independent pressure regulators: the bypass valve opening jack and the reactor flow limit. One of the pressure regulators is of the hydraulic mechanical design and one of the electrohydraulic design.

Each regulator is capable of overriding the other. The regulator which calls for the greatest combined opening of the control and bypass valves is the actual controlling regulator. Expressed differently, whichever regulator is adjusted for the lower set pressure is in actual control.

Should for some reason, the operating pressure regulator become ineffective so as to permit a pressure increase, then the second regulator would take over control of the reactor pressure at its own setpoint.

Both the mechanical and the electrical regulators sense pressure of the main steam lines (reactor to the turbine) from the Pressure Averaging Manifold located ahead of the main stop valves.

The two pressure regulators and the bypass valve opening jack operate a common torque shaft, as shown on Figure 7.11-2 and whichever of these devices calls for the greatest signal magnitude will be positioning the torque shaft. This torque shaft represents the P-1 signal in the compound control mechanism. If one assumes that the bypass valve opening jack is not in control, the P-1 signal represents a measure of the steam flow generated by the reactor.

The bypass valve opening jack can override the pressure regulators and open the bypass valves further than the operating pressure regulator calls for. The bypass valve opening jack may be used to control the bypass flow manually during startup as long as the pressure in the reactor is too low to be controlled by any of the pressure regulators. This device can be operated locally at the front standard by a handwheel mechanism or by remote operation of the bypass valve opening jack motor.

The reactor flow limit is a mechanical stop in the control linkage that serves to limit the combined opening of control and bypass valves to a preset maximum value. This device, by acting on the common output torque shaft of the pressure regulators, will override

the signal from the controlling pressure regulator to avoid exceeding a preset total reactor steam flow condition.

Detailed description of the mechanical pressure regulator and the electrohydraulic pressure regulator follows.

7.11.3.2.2 Mechanical Pressure Regulator

The mechanical pressure regulator is a wide range, high precision pressure regulator. It operates a pilot control of an integrated control mechanism to regulate a steam pressure within very close limits to the setpoint. Its response characteristic can be adjusted within an extremely wide range to match the requirements of the overall control system. The hydraulic mechanical regulator has a setpoint adjustment range of 150 to 1,050 psig. The possibility of setting a low setpoint pressure makes this regulator suitable for use during a reactor startup, when the reactor pressure must be raised slowly. The pressure setting can be changed manually at the regulator or remote electrically from the control room.

This is a force restored regulator on which the forces produced by the steam pressure sensitive element are counterbalanced by the forces produced by the reference pressure setpoint device under steady state conditions. When these forces are unbalanced, the regulator produces an output through a servomotor to the torque shaft which, in turn, connects to the control valve relay linkage. Feedback to the regulator during transients is provided from the movement of the regulator servomotor and also from movement of the control valve secondary speed relay.

An increase in steam pressure above the reference pressure setpoint results in an unbalanced force condition on the regulator control beam which, in turn, results in an output to the torque shaft. The torque shaft produces an input to the control valve relay linkage, which represents a demand for valve opening and increased steam flow.

Once steam flow has been adjusted and steam pressure restored to the reference pressure, the regulator control beam is restored to a balanced force condition and no longer affect the torque shaft.

7.11.3.2.3 Electrohydraulic Pressure Regulator

The electrohydraulic pressure regulator is a reliable, fast acting pressure regulator designed for boiling water nuclear reactors.

The electrohydraulic regulator is composed of three electrically connected devices:

1. A sensing unit located near the area of the main steam lines where the steam pressure is to be measured

2. An electronic hardware unit in the control or cable spreading room area

3. A hydraulic output unit in the turbine front standard.

The sensing unit converts steam pressure into an electrical signal. The electronic hardware unit contains the necessary control intelligence hardware and produces a sufficient dc output signal to drive the servo valve in the hydraulic output unit. In this latter unit the servo valve, through control of hydraulic oil flow, positions the output piston which acts on the torque shaft that is common to all regulators and the bypass valve opening jack. The positions of the output piston, as well as the control valve servo and bypass relay, are measured by additional LVDTs and fed back into the electronic hardware unit.

Figure 7.11-2 is a simplified schematic of the overall control system. Both mechanical and electrical regulators are used in an arrangement so that the regulator calling for the lower pressure is in control and the other is in standby operation ready to take over in case the controlling regulator fails. If the turbine load limit is set so that the turbine will not accept the required steam flow, an overriding device actuates a bypass valve which dumps steam directly into the condenser.

Figure 7.11-3 is a simplified block diagram. Reactor steam pressure is converted into mechanical displacement by the pressure sensor, and the displacement converted to a dc electrical signal.

The pressure signal and position signals from both the control and bypass valves are summed with the setpoint signal in the PLC. The valve signals produce a system with 3 percent regulation. Pressure drops 3 percent for a 100 percent decrease in steam flow.

Output of the PLC is the input reference for the flow control loop whose forward elements consist of an amplifier, an electrohydraulic valve, and hydraulic cylinder. A differential transformer and demodulator are used for feedback elements.

A number of fail-safe features are incorporated. The circuit design causes an increase in pressure if any differential transformer signal is lost. A mechanical bias in the electrohydraulic valve is normally offset by an electrical input. Upon loss of the electrical input, the mechanical bias produces an oil flow to position the hydraulic cyclinder in the minimum flow or maximum pressure position. Alarm and trip relays are provided to protect against loss of power. Each of these failures will result in an increase in pressure causing the standby regulator to take over at a higher pressure which depends upon its setpoint adjustment.

7.11.3.2.4 Speed Control Unit

The speed control unit controls the speed of the turbine during starting and synchronizing, as long as the generator is not connected to the system. When the generator is connected to the line, it will control the load of the unit. The inputs to the speed control unit are:

1. The shaft speed which is transmitted to the speed control unit by means of a worm gear driving the speed governor

2. The reference speed setting expressed in the position of the synchronizing device

3. The load limit position controlled by remote or local operation of the load limit device

The output of the speed control unit is the piston stroke of the speed relay, point S-1 on Figure 7.11-1.

The speed control unit consists of the speed governor, the synchronizing device, the load limit device, and the speed relay.

7.11.3.2.5 Speed Governor

The speed governor is of the flyball type, positioning a rotating pilot valve. The speed relay is a servomotor of the oil-opened, spring-closed design.

Through a mechanical linkage system, the speed relay is either controlled by the rotating pilot valve positioned by the speed governor or the auxiliary pilot valve positioned by the load limit. This dual control feature is obtained by feeding the oil to the speed relay in series first through the auxiliary pilot valve and then through the rotating pilot valve. Depending on whether the speed governor or the load limit calls for the lower speed relay position (or control valve position), the rotating pilot valve or the auxiliary pilot valve will be in control of the speed relay.

When the turbine is at rest or at some low speed, the flyball weights are at their inner position and the rotating pilot valve is at the top of its stroke, leaving the top port wide open for oil flow between the auxiliary pilot valve and the speed relay. Under these conditions, the speed governor is out of range and would permit the speed relay to go fully open. However, the load limit, by means of the auxiliary pilot valve, may limit the speed relay to a lower position anywhere within the entire speed relay operating range. The load limit device is therefore used for controlling the control valve opening when coming up to speed.

As the turbine approaches normal speed, the governor weights move outward, lowering the rotating pilot valve. When reaching some speed between 89 to 95 percent (depending on the position of the synchronizing device), the rotating pilot valve reaches the on port

position and takes over control of the speed relay. In order to establish a steady state speed, the speed relay will likely be lowered which, in turn, will move the load limit pilot valve slightly above port, leaving controls entirely to the rotating pilot valve or, in other words, to the speed governor. Once the speed governor is in control of the speed relay, the load limit may be moved out of the way and used as a steam flow or load limiting device.

When the turbine speed is controlled by the speed governor, the steady state speed may be varied by changing the position of the synchronizing device. This device may be manually operated at the turbine front standard or remotely from the control room by electrical controls.

When the unit is synchronized to the line, the speed relay position is determined by the position or setting of the synchronizing device. Since speed relay position is representative of steam flow, the synchronizing device now becomes a load adjuster.

Either the speed governor or the load limit override the other toward a lower position of the speed relay and, eventually, the control valves.

The speed relay position is representative of the desired steam flow to be admitted to the turbine. It is designated as the S-1 signal in the compound control mechanism scheme, as shown on Figure 7.11-1.

7.11.3.2.6 Acceleration Relay

To keep the overspeed of the turbine as low as possible following loss of full generator load, an acceleration relay is provided to cause the control valves to close sooner than they would if controlled only by the normal governing system. The acceleration device and relay consist of a dashpot, a pilot valve mechanism, and a piston element which acts to control the motion of the linkage between the speed relay and the control valve relay upon load rejection. The dashpot is connected to an intermediate point and the pilot valve is connected to the end point of the operating lever of the acceleration device and relay. The other end of the operating lever is connected to the speed relay output linkage. The dashpot is capable of following slow, normal movements of the speed relay. Here, the pilot valve acts as the fulcrum of the operating lever.

If an abnormally fast turbine acceleration occurs (as would happen on rejection of full load), the operating lever moves faster than the dashpot piston is capable of moving. Now the pilot valve moves up and the dashpot becomes the fulcrum. Upon upward movement of the acceleration pilot valve, oil is dumped from beneath the piston element causing it to move down and override the normal control inputs from the speed relay to the control valve relay. This action causes oil in the control valve relay to dump, quickly closing the control valve. Since the input from the pressure regulator unit will stay approximately fixed during the short time interval which has elapsed, the compound control mechanism will open the bypass relay

and the bypass valves in turn. The action of the compound control mechanism results in closure of the control valves and opening of the bypass valves at a fast rate and in a synchronized manner.

The oil supply to the acceleration relay is from the emergency trip oil system. Therefore, the loss of emergency oil pressure automatically results in actuation of the acceleration relay and fast closure of the control valves.

7.11.3.2.7 Main Load Limit Device

This device is operated either by a handwheel or by a motor through a slip friction clutch. The position of the load limit mechanism is indicated in the control room and at the turbine front standard. The handwheel and motor operate a lead screw, through a latching mechanism, which positions the load limit pilot valve and thereby limits the output from the speed relay. The load limit trip piston controls the latching mechanism. The trip piston is spring loaded and held in position normally by emergency trip oil pressure. Whenever emergency trip oil is dumped, the load limit trip piston will open and unlatch the load limit mechanism. This will result in a sudden change in speed relay output and fast closure of the control valves.

7.11.3.2.8 Control Valve Relay Unit

This is a spring-closed hydraulic relay whose output piston positions the secondary control valve relay. The lift of the control valve relay is representative of the required control valve flow. There are three pilot valves, designated as V-2, V-3, and L, that control the piston position of the control valve relay unit. All three pilot valves are arranged in series in the oil feed to the piston chamber. The pilot valve calling for the lower lift of the control valve relay is in control of the oil supply and, as a result, in control of the relay piston proper.

The input end of the V-2 pilot valve floating lever is operated by the speed relay (S-1 signal) and the input of the V-3 pilot valve floating lever by the output torque shaft (P-1 signal) of the pressure control unit. The input end of the L pilot valve floating lever is operated by the control valve limit handwheel.

In the event the V-2 pilot valve has control over the control valve relay, then the control valve relay lift (V-1 signal on Figure 7.11-1) is proportional to the speed relay lift, and the V-3 pilot valve is some amount above port; the amount of its overtravel (V-3 signal on Figure 7.11-1) representing the amount of reactor steam that is not absorbed by the control valves and, as a result, must be passed through the bypass valves. A linkage system is connected to the V-3 pilot valve directly to transmit its position to the bypass relay unit.

Conversely, if the V-3 pilot valve has control over the control valve relay, then the V-2 pilot valve is some amount above port. Any

amount of overtravel of this pilot valve is significant of the fact that the permitted opening of the control valves does not pass sufficient flow to carry the turbine load called for by the speed relay. As a result, the turbine will not be on governor control.

The lift of the control valve relay piston may be limited by the L pilot valve if it is desired to limit the opening of the control valves for special purposes. This limits the V-1 output of the control valve relay. This L pilot valve can be operated by a handwheel mechanism, the control valve limit, which is accessible at the turbine front standard. Since this means of control will only be used very seldom, no means of remote control of the control valve limit is provided. The control valve secondary relay amplifies the V-1 output from the control valve relay and increases the force sufficiently to operate the control valve camshaft.

7.11.3.2.9 Bypass Valve Relay Unit

The bypass valve relay amplifies the V-3 output from the control valve relay and increases the force sufficiently to operate the camshaft at the bypass valves.

The bypass relay is located in the turbine front standard. The relay is oil-opened and spring-closed, with the oil supply coming from vacuum trip No. 2. Thus, tripping of vacuum trip No. 2 closes the bypass relay. The bypass relay is a pilot valve controlled and spring-closed hydraulic relay which positions the bypass valves. The lift of this relay is representative of the desired bypass flow.

The bypass valves are to be opened when, due to limited turbine output, the steam flow into the turbine is held at a smaller magnitude than the steam generated by the reactor.

As described for the control valve relay, the position of the V-3 pilot valve of the control valve relay unit serves as an input signal to the bypass relay through a suitable linkage system. As long as the V-3 primary relay pilot valve is on port, the bypass relay is held at some minimum lift close to the point where the No. 1 bypass valve begins to open. As soon as the V-3 pilot valve moves into the open-end overtravel range, the bypass relay piston is lifted which, in turn, opens the bypass valves in sequence.

Under steady state conditions, the output of the bypass relay always conforms to the V-3 signal generated by the V-3 pilot valve of the control valve relay unit.

In the event of the turbine-generator load rejection, the bypass relay has to open fast, requiring a substantial flow of hydraulic fluid which is in excess of what the turbine shaft pump can supply. The accumulator of the spring-loaded piston type supplements the oil supply during rapid opening of the bypass relay.

7.11.3.2.10 Intercept Valve Control

If the signal from the pressure control unit is not controlling the control valve relay by the V-3 pilot valve, and the control valve limit stop is not controlling the control valve relay by the L pilot valve, then the speed governor positions both the turbine control and intercept valves, where steamflow control (and thereby turbine speed and load control) is always maintained by the control valves. To do this, the speed governing operating mechanism must initially open the intercept valves (approximately 30 percent open) before the first control valve is opened, and thereafter keep the intercept valves well ahead in valve opening as the control valves are positioned for speed or load control.

Under normal governor action, the intercept valves reach full stroke at about 10 percent rated load and remain fully open for the remainder of the load range. In addition, the intercept valves must close as rapidly as possible under pre-emergency conditions of overspeeding of the turbine, then reopen ahead of the control valves. They must remain at a greater valve opening as deceleration occurs so that speed control is regained by the control valves.

Under governor action, the valve opening and positioning requirements for the intercept valves, in relation to the control valves, are accomplished by means of the hydraulic positioning transmitter and receiver, and dashpot linkage which fulfills the following basic functions:

1. Converts the governor speed relay signal (i.e., position) to a pressure signal, then converts this pressure signal to a piston position at the intercept valves

2. Provides the proper nonlinear valve opening characteristic with relation to the control valves, which can be adjusted to initiate an intercept valve cracking point ahead of the control valves

3. Hastens closure of the intercept valves in case an instantaneous turbine speed acceleration occurs

7.11.3.2.11 Control Valves

There are four individual and identical control valves located side by side and physically interconnected through the upstream stop valve casings.

The control valve is of the angle body casing and balanced disk design. The disk balancing feature, which reduces significantly the force required to open the valve against the prevailing steam pressure, is obtained by use of a balance chamber subjected to below seat steam pressure.

The steam discharges vertically down into individual steam leads and the valve is operated through a vertical stem, crosshead and spring

arrangement located on top of the valve. All the control valves will be operated in parallel, except for the No. 1 valve, which may open slightly ahead of all other valves in order to provide single valve steam admission for synchronizing the unit to the line.

Each control valve has its own servomotor to operate the valve stem through a suitable lever and rod system. The four servomotors are arranged in a separate oil tight housing located on the side of the valve arrangement. A camshaft operates the pilot valves of all hydraulic servos in proper relationship. This camshaft is positioned by the secondary control valve relay located in the same housing.

This relay, in turn, is controlled by the control valve relay located in the front standard through a linkage system.

7.11.3.2.12 Combined Intermediate Valves

There are four individual combined intermediate valves located in the crossover lines close to the low pressure turbine inlets. A combined intermediate valve is a combination intercept and intermediate stop valve in one casing. The intercept valve disk is of a balanced sleeve type while the intermediate stop valve disk is of the globe type. Both valves share a common seat, the seating circle of the intermediate stop valve being of a smaller diameter than the seating circle of the intercept valve. The intermediate stop valve disk which is arranged in the interior space of the intercept valve is operated by a stem entering through the bottom of the casing. The intercept valve is operated by a stem entering through the top of the casing. With this design, each valve can move through full stroke regardless of the position of the other.

The servomotors for both valves are combined into one assembly fastened to the bottom side of the valve body through a yoke type of construction. The intermediate stop valve servo piston is directly coupled to the intermediate stop valve stem at the bottom, while the intercept valve servo operates the intercept valve stem by means of a horizontal lever on top of the valve assembly, and a vertical operating rod connecting this lever with the servo piston.

The intercept valve servomotor is a pilot valve operated and positioned restored hydraulic cylinder, oil opened and spring closed. The pilot valve is controlled by the S-1 output of the speed relay.

The intermediate stop valve servomotor is an oil-opened and spring-closed hydraulic cylinder under control of both the relay dump valve and a test pilot valve. These two devices are arranged such that either can override the other to close the servo and the valve. When the relay dump valve is reset and the test pilot valve is in the "open" position, hydraulic oil is admitted to the servo piston and the servo piston goes open and stays open. When either the relay dump valve is tripped or the test pilot valve is in the "closed" position, then the servo piston goes closed and stays closed.

The relay dump valve is under control of the emergency trip oil system and consists of a large disk serving as a removable floor to the servo piston chamber. When reset, it is held tight against the servo piston chamber by emergency oil acting on the bottom side of the disk. In this condition, it can withstand full hydraulic pressure in the servo piston chamber. When the emergency oil pressure is lost by action of either the emergency trip valve or the No. 1 vacuum trip valve, the pressure in the servo piston chamber forces the dump valve to move downwards, thereby opening up a large area for the discharge of the servomotor oil and facilitating fast closure of the servo piston.

The test pilot valve is operated by an air piston. In turn, it is actuated by an air solenoid valve which is used for test operation of the valve. The test pilot valve is also moved to the closed position whenever emergency trip oil pressure is lost.

7.11.3.2.13 Bypass Valves

A bypass valve chest containing three valves is provided. The chest is piped to the main steam lines from the reactor. The steam discharge is piped into the condenser. The bypass valve has its servomotor arranged underneath the valve chest and fastened to the valve chest by a yoke type structure. The servomotor is of the oil opened and spring closed type and controlled for continuous positioning by a hydraulic pilot valve. The positioning signal for the servomotor is obtained from the bypass relay through a suitable linkage system.

7.11.3.2.14 Main Stop Valves

There are four stop valves of conventional design with vertically moving globe valves provided. The main stop valve servo is mounted underneath the stop valve body by a yoke structure and directly coupled to the valve stem. The stop valve servo is under control of both there relay dump valve and a test pilot valve. These two control devices are arranged such that either can override the other to close the servomotor and, in turn, the main stop valve. When the relay dump valve is reset and the test pilot valve is in the open position, hydraulic oil is admitted to the servo piston and the servo piston goes open and stays open. When either the relay dump valve is tripped or the test pilot valve is in the closed position, the servo piston, goes closed and stays closed.

The relay dump valve consists of a large disk serving as a "removable floor" to the servo piston chamber and is under control of the emergency trip oil system. When reset, it is held tight against the servomotor cylinder by emergency oil acting on the bottom side of the disk. In this condition, it can withstand full hydraulic pressure in the servo piston chamber. When the emergency oil pressure is lost by action of either the emergency trip valve or the No. 1 vacuum trip valve, the pressure in the servo piston chamber forces the dump valve to move downwards, thereby opening up a large area for the discharge

of the servomotor oil and facilitating the fast closure of the servo piston.

The test pilot valve is used for test operation of the valve. In addition, on main stop valve No. 2, this pilot valve is also used for positioning control of the small bypass valve built into the main disk which is used during turbine warmup. The testing mechanism consists of a solenoid air valve actuating an air operated piston which, in turn, moves the above mentioned pilot valve into the "closing position", discharging oil from the servomotor piston into the drain. The test pilot valve is also moved to the close position whenever emergency trip oil pressure is lost.

7.11.3.3 Emergency Tripping System

The turbine trip system basically controls those turbine components which constitute the second line of defense against overspeed. In this function, it permits shutting off the steam flow into the turbine quickly. The following are the principal trip devices of the emergency trip system:

No. 1 vacuum trip

Emergency overspeed trip

Backup overspeed trip

Each of the listed trip devices contains a three-way trip or dump valve. When in the reset position, the downstream port is connected with the upstream port. When in the tripped position, the downstream port is shut off and the upstream port opened to drain. They control the following turbine components:

Main stop valves

Intermediate stop valves

Load limit device

Acceleration relay

The emergency tripping system is schematically illustrated on Figure 7.11-4.

Hydraulic oil is fed to the No. 1 vacuum trip first. When this trip is reset, it admits hydraulic oil to the emergency trip; when this latter valve is reset, it in turn feeds hydraulic oil to the stop valve bypass handwheel trip piston, the load limit trip piston, the relay dump valves at the main stop and intermediate stop valve hydraulic cylinders, and the acceleration relay. Thus, these devices are only reset provided both the No. 1 vacuum and the emergency trip valve are reset. If one or both of these trip valves are tripped, the stop valves, the load limit and the acceleration relay will be tripped and all turbine steam admission valves will close.

7.11.3.3.1 No. 1 Vacuum Trip

The No. 1 vacuum trip consists of a three-way dump valve which is either held in the reset position by a mechanical latch or in the tripped position by a spring. In the reset position, it admits hydraulic oil to the line leading to the emergency trip valve. Assuming that the emergency trip is reset, then the entire hydraulic turbine trip system is pressurized, thus holding the relay dump valves reset and permitting the main and intermediate stop valves and the load limit to be opened and the acceleration relay and extraction relay dump valve to be reset. Should the vacuum trip be in the tripped position, regardless of the status of the emergency trip, then all the stop valves as well as the load limit and acceleration relay will be tripped closed.

The trip valve is reset by a solenoid actuated air piston. It may be tripped by a variety of devices as listed below:

1. The vacuum sensing mechanism

2. A trip piston actuated by the backup overspeed trip

3. A solenoid

The vacuum sensing mechanism converts vacuum pressure into a position of a servo piston. This servo piston will trip the dump valve when the vacuum in the condenser drops below 20 in Hg. The backup overspeed actuates an individual hydraulic piston which separately trips the dump valve. When energized, the solenoid will also trip the dump valve. It may be energized by either the operator pushing the trip button or the generator protective circuits through the generator lockout relay.

7.11.3.3.2 Emergency Overspeed Trip

The emergency trip contains a double-line three-way emergency trip valve which is arranged inside a lockout sleeve. The trip valve is held in the reset position by an extension rod shouldering against the ledge of the trip finger. Whenever the trip finger is actuated, the trip valve snaps to the tripped position by spring action. The following actions can trip the dump valve through action of the trip finger:

1. Overspeed of the turbine will cause the overspeed emergency governor ring to snap out of center and trip the trip finger and the trip valve

2. Manual operation of the master trip handle by means of an intermediate pilot valve will drain oil from a master trip cylinder, enabling its piston to strike the trip finger by spring force and trip the trip valve

3. Manual operation of the oil trip handle by means of a pilot valve will admit oil into a pocket of the emergency governor

ring, causing it o go eccentric at rated speed, striking the trip finger and in turn tripping the trip valve

Actions 2 and 3 can also be initiated remotely through solenoids that actuate the handle-operated pilot valves mentioned above.

A unique feature of the hydraulic tripping system is the design of the lockout valve. This operates in conjunction with the emergency trip piston so as to permit testing of the emergency governor while the unit carries load, without shutting down the turbine. The design is described as follows:

Oil feeding through the (reset) emergency trip valve enters the side of the valve casing at the forward end, flows through a port in the lockout sleeve, leaves through a second port in the sleeve, and out the opposite end of the casing. The lockout sleeve is hydraulically operated by a handle arranged in the same area on the front standard as the trip and reset handles or remotely by a solenoid which actuates the handle-operated pilot valve. This handle operates a small oil pilot valve which feed operating oil to a chamber at the front end of the lockout sleeve (independent of trip oil space). Admission of oil displaces the lockout sleeve toward the emergency governor to its test position (i.e., the lockout sleeve will be shifted so that its inlet and outlet ports will now be at the extreme opposite end in relationship to the larger ports of the valve casing). This permits the emergency governor and emergency trip piston to be tested without dumping oil from the outlet header. When the emergency governor or master trip is actuated with the lockout in TEST, the trip piston is moved to its tripped position. This action however, has no effect on the trip oil circuit because with the lockout sleeve in the test position, the limited motion of the emergency trip valve to the tripped position is not sufficient to change the porting between these two elements. Specifically, the trip line from the vacuum trip remains connected to the output header of the emergency trip and the drain port will not be opened up.

The overspeed emergency governor is located on the turbine shaft between the No. 1 bearing and the governor bracket. It consists of an unbalanced ring which is actuated by centrifugal force against the force of a spring when the turbine overspeeds. The movement puts the ring in an eccentric position so that it strikes the trip finger of the emergency trip valve which closes all turbine valves, thus shutting the turbine down immediately.

The emergency governor may be tested by tripping it at normal speed by the application of oil through a nozzle.

The design of the emergency governor consists of a supporting sleeve bolted to the turbine shaft which is encircled by a hollow steel ring. The ring runs concentric with the shaft but is unbalanced; that is, the center of gravity of the moving parts lies offcenter from the center of rotation. The centrifugal force of the overspeed emergency governor due to this unbalance is counteracted by the force of a compressed helical spring. When the shaft speed increases to

about 10 percent above normal the centrifugal force of the ring overcomes the force of the spring. The ring moves outward striking the trip finger of the emergency trip valve and thereby dumping emergency oil and closing all steam admission valves to the turbine.

7.11.3.3.3 Backup Overspeed Trip

The backup overspeed trip is essentially an additional pilot valve provided as an integral part on the upper end of the main governor rotating pilot valve, which is positioned by the flyweights of the speed governor (speed-sensitive) rotating weight assembly. As long as speed is below 112 percent, the rotating pilot valve feeds hydraulic oil to a trip piston mounted at the No. 1 vacuum trip. When the speed rises over 112 percent, the rotating pilot valve cuts off the oil supply and drains oil from the trip piston at the vacuum trip. This trip piston immediately actuates the vacuum trip, which dumps emergency oil and thereby closes all turbine steam admission valves.

Provisions have been made to permit reduction of the setpoint of the backup overspeed trip from 112 percent to about 109 percent. This is accomplished by lifting the pilot valve sleeve upwards a preset amount which is equivalent to a three percent change in speed. The sleeve may be lifted manually or remotely from the control room by means of a solenoid air valve. Two electrical switches are provided to indicate the position of the pilot valve sleeve. One electrical switch indicates when the pilot valve sleeve is in the 112 percent trip position. The other electrical switch indicates when the pilot valve sleeve is in the 109 percent trip position.

Raising the sleeve reduces the overspeed trip setpoint but does not interfere with the backup overspeed tripping protection or the ability to actuate the No. 1 vacuum trip. Since no normal manipulation on the turbine can cut the backup overspeed trip out (note that the lockout valve described previously bypasses only the emergency overspeed trip but not the backup overspeed trip) this device is used as a backup to protect the turbine against overspeed while the emergency trip is temporarily locked out for testing purposes.

7.11.3.3.4 No. 2 Vacuum Trip

This vacuum trip is of a similar design to vacuum trip No. 1. It has the same trip valve, reset and vacuum sensing mechanisms. This vacuum trip will act on the bypass valves only, and trip this system closed whenever the condenser vacuum falls below approximately 7 in Hg (relative to atmosphere).

The No. 2 vacuum trip is not connected into the turbine emergency trip system and has no emergency function other than to close the bypass valves when condenser vacuum is lost. Multiple controls or protection devices are provided to limit turbine overspeeds. The greatest potential for a turbine overspeed condition exists following a generator full load rejection.

In the event of a generator trip and full load rejection, the generator lockout relay actuates the electrical trip solenoid of vacuum trip No. 1, which in turn dumps the emergency oil and trips the main stop valves and the intermediate stop valves closed. Dumping the emergency oil will also trip the load limit trip piston and the acceleration relay. This will limit turbine overspeed in the transient to a few percent above rated speed.

Acting independently following a generator load rejection, the main speed governor through the speed relay would initiate closure of the control and intercept valves. If turbine speed increased sufficiently, the acceleration relay would function and dump control oil pressure which results in fast closure of the control and intercept valves. These speed controls are designed to independently limit the turbine overspeed to about 109.8 percent of rated speed assuming that the solenoid trip vacuum trip No. 1 from the generator lock-out relay was not actuated.

If the turbine speed reaches 110 percent of rated, the emergency governor (main overspeed trip device) will be actuated. The emergency governor is an unbalanced ring which is normally held concentric with the turbine shaft by a spring. When the turbine shaft reaches the overspeed trip setting, the centrifugal force of the ring overcomes the force of the spring and the ring snaps to an eccentric position. In so doing, it strikes the trip finger and thereby operates the emergency trip valve which dumps emergency oil pressure and in turn closes the main stop valves and the intermediate stop valves. The loss of emergency oil pressure also actuates the load limit trip piston and the acceleration relay which in turn initiates fast closure of the control and intercept valves.

The backup overspeed trip operates normally as 112 percent of rated speed. The backup overspeed trip device is built into the main governor speed control unit. The backup overspeed trip device consists mainly of an additional pilot valve, rotating in a special bushing and connected to the top of the main speed governor rotating pilot governor rotating pilot valve. As soon as the speed increases to the overspeed setpoint, this pilot valve will dump hydraulic oil from the trip piston mounted on the No. 1 vacuum trip device, thereby tripping the No. 1 vacuum trip which in turn dumps emergency oil pressure (completely independent of the emergency trip valve), and thereby closes all turbine steam admission valves.

The Pilgrim Nuclear Power Station turbine control system is functionally equivalent to the turbine control system of the Millstone Unit No. 1 with the exception of certain features at Millstone associated with that station's high steam bypass capability. The maximum turbine bypass steam flow at the Pilgrim Nuclear Power Station is 25 percent of the full load steam flow.

7.11.3.3.5 Overspeed Protection Component Tests

The operability of the turbine-generator main overspeed protection devices is confirmed in the control room while the turbine-generator

unit is in operation. This can be done by selective individual testing of components used in overspeed protection actions.

The emergency governor (main overspeed trip device) can be tested when the turbine is in operation by means of a lockout sleeve associated with the emergency trip valve. The movement of the lockout sleeve to the lockout position can be accomplished from the main control room by a solenoid actuator. Provisions are available in the main control room also to simulate turbine overspeed by injecting oil into the unbalanced ring of the emergency governor when the turbine is operating at normal speed. The oil injected into the emergency governor increases the rotational inertia of the ring, overcomes the spring force which holds the ring concentric and causes the ring to snap to the eccentric position. This movement causes the ring to strike the trip finger simulating the overspeed trip actions. Confirmation that the emergency trip oil feature is locked out, that the emergency trip has occurred and that reset has been accomplished are obtained from indicating lights in the control room. During this period of time, turbine overspeed protection is provided by the backup overspeed trip device.

The test is accomplished remotely from the main control room by sending an electrical signal to a solenoid valve which admits air to an air-oil relay which allows oil to be injected into the concentric emergency trip ring. The air supply to this air-oil relay is required to function only during testing of the emergency governor. The air system has no tripping function during actual overspeed conditions. This test of the emergency governor is conducted as a miminum on a quarterly basis. In addition to the operational test of the emergency governor previously described, the ability of the emergency governor to trip the turbine under actual overspeed conditions will be verified during startup after refueling outages while the turbine is operating at no load conditions.

The main stop and control valves and the intermediate stop and intercept valves can be individually exercised from the control room. The closed and open positions of these valves are indicated by lights in the control room. These valves should be sequentially exercised normally once each week during sustained power operation.

The ability of the backup overspeed device to trip the turbine under an actual overspeed condition will be verified during startup after refueling outages while the turbine is operating at no-load conditions. This test is normally conducted with the backup overspeed pilot valve sleeve shimmed upward such that turbine trip occurs at 109 percent of rated turbine speed rather than at the normal 112 percent setpoint.

Provisions have been included to permit the backup overspeed trip setpoint to be reduced from the normal 112 percent setpoint to 109 percent. The setpoint can be reduced from the main control room by actuating a solenoid air valve which uses air pressure to raise the pilot valve sleeve a distance equivalent to three percent speed, and thereby decreasing the tip setpoint from 112 percent to

109 percent. The air pressure does not interfere with the overspeed tripping action and is not required for overspeed trip protection.

7.11.3.3.6 Turbine Shaft High Vibration Trip

The turbine shaft high vibration trip is provided to trip the main turbine when turbine shaft vibration exceeds a preset limit of 12 mils on the trip board.

Turbine shaft vibration is one of the variables monitored by the PNPS turbine supervisory instrument system. For turbine shaft vibration the supervisory instrument system consists of ten vibration channels which include ten velocity-type detectors on the turbine, ten dual-alarm boards, one trip board, and associated recorder and annunciator.

The trip signal output from the supervisory trip board picks up an interposing relay and one normally open contact of the relay will pick-up the main trip solenoid to trip the turbine. Another normally open contact of the relay will annunciate the turbine trip in the main control room (See Figure 7.11-1).

Because the turbine vibration trip system is a "one out of ten" logic scheme, the failure of any one vibration probe could cause a spurious turbine trip. Consequently, the vibration trip function may be bypassed during normal steady state operation. During steady state operation with the vibration trip function bypassed, the vibration alarm remains functional and operating procedures direct the operator response to turbine vibration alarms.

7.11.4 Power Generation Evaluation

The turbine-generator control system design is such that it provides a stable control response to normal load fluctuations.

The main turbine bypass valves are capable of responding to the maximum closure rate of the turbine admission valves such that reactor steam flow is not significantly affected until the magnitude of the load rejection exceeds the capacity of the bypass valves (25 percent of full load flow). Load rejections in excess of bypass valve capacity can cause the reactor to scram due to high pressure. Any condition causing the turbine stop valves to close will directly initiate a scram before reactor pressure or neutron flux has risen to the trip level.

The turbine-generator control system can fail in such a manner as to cause the control and bypass valves to fail either open or closed. Refer to Section 14, Station Safety Analysis, for the transient analysis.

Redundant pressure regulators above 950 psig reduce the probability that pressure regulator malfunctions will cause operational problems.

7.11.5 Inspection and Testing

7.11.5.1 Turbine Generator Supervisory Instruments

Although the turbine is not readily accessible during operation, the turbine supervisory instrumentation is sufficient to detect any potential maloperation. The turbine supervisory instrumentation includes monitoring of the following variables:

Vibration and eccentricity

Thrust bearing wear

Exhaust hood temperature and spray pressure

Oil system pressures, levels, and temperatures

Bearing metal and drain temperatures

Shell temperatures

Valve positions

Shell and rotor differential expansion

Shaft speed, electrical load, and control valve inlet pressure indication

Load current/cooling water flow comparison

Hydrogen temperature, pressure, and purity

Stator coolant temperature and conductivity

Stator winding temperature

Generator core temperatures

Alternator air coolant temperatures

Steam seal pressure

Steam packing exhauster vacuum

Steam chest pressure

Seal oil pressure

7.11.5.2 Testing Provisions

Provisions are made for testing each of the following devices while the unit is operating.

Main stop and control valves

Bypass valves

Intermediate stop and control valves

Overspeed governor

Bleeder trip valves

Thrust bearing wear detector

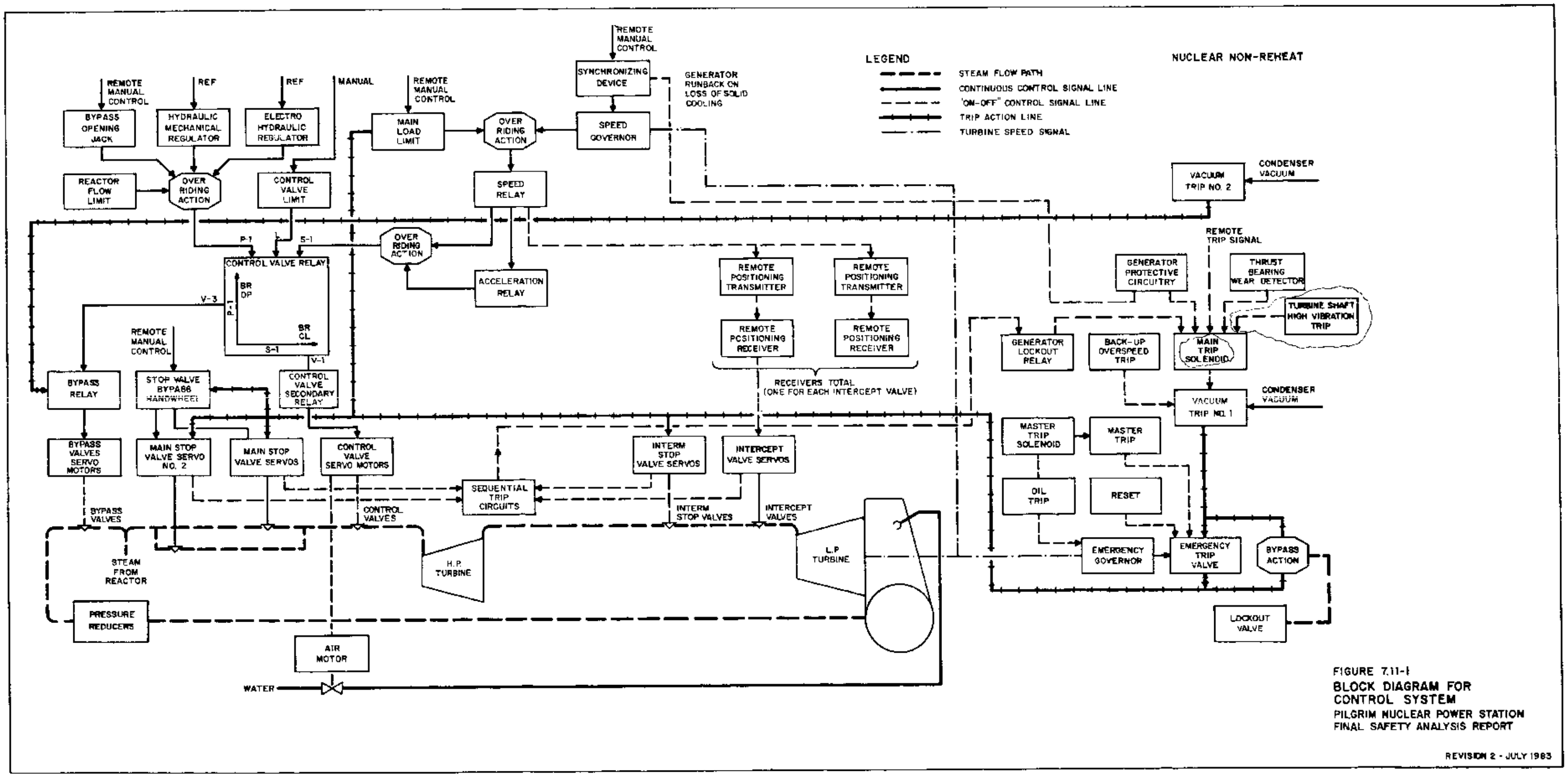


FIGURE 7.11-1
BLOCK DIAGRAM FOR CONTROL SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 2 - JULY 1983

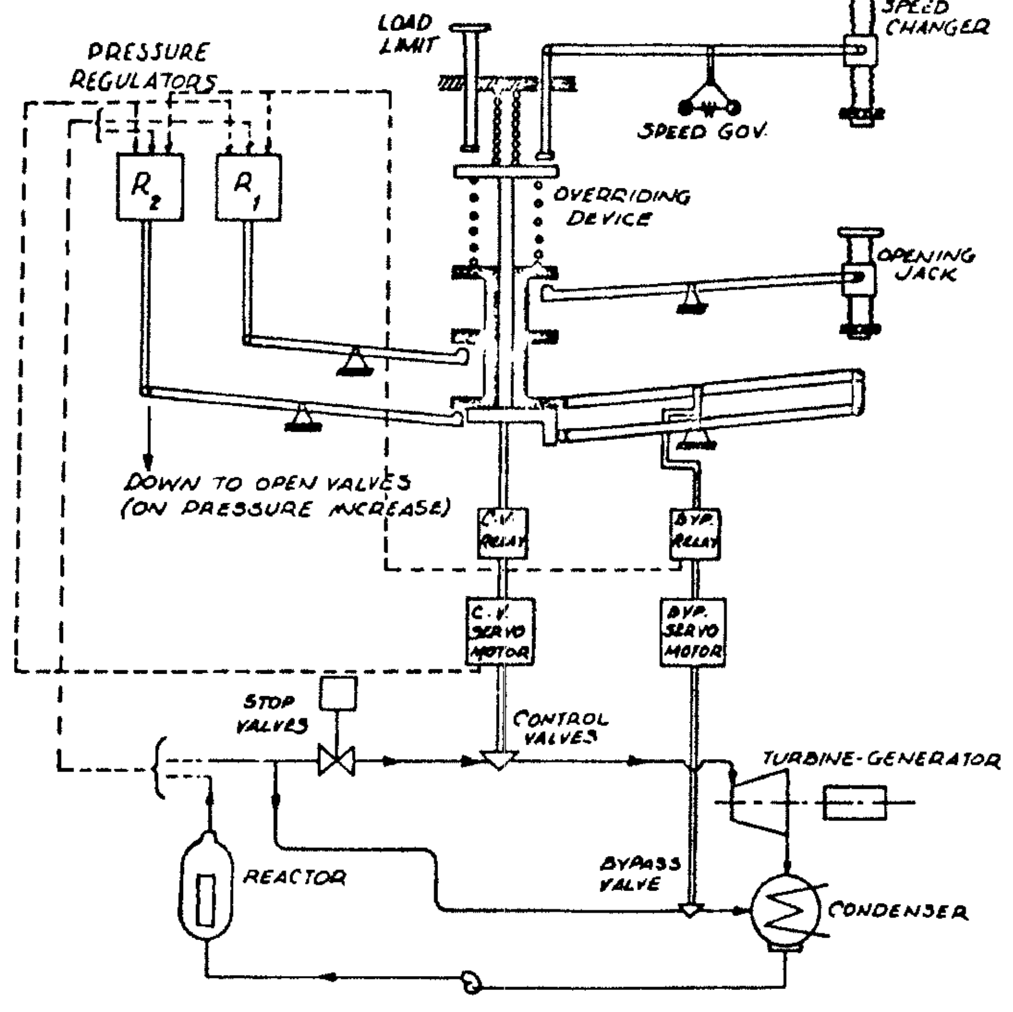


FIGURE 7.11-2
SIMPLIFIED SCHEMATIC
OF THE OVERALL SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

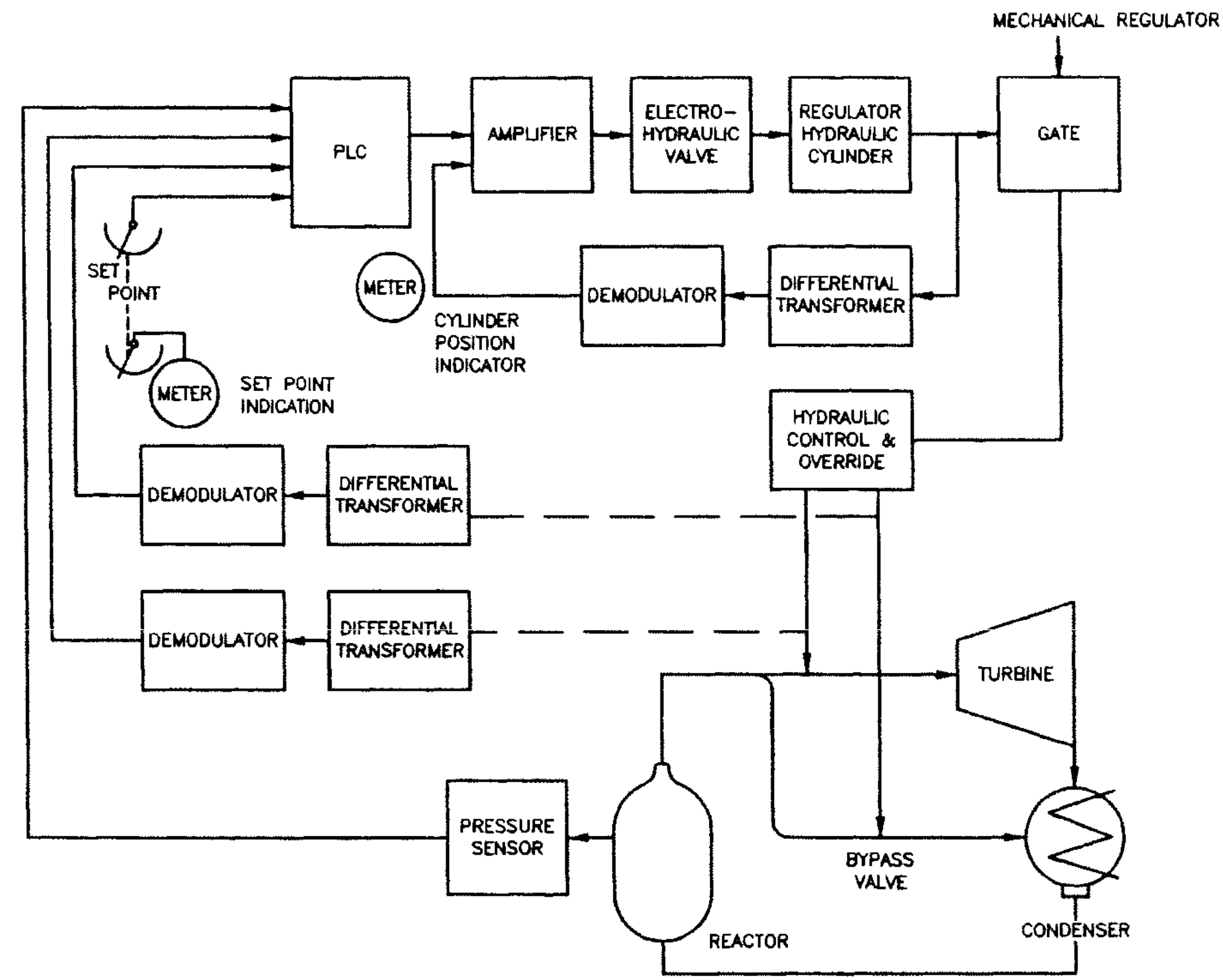


FIGURE 7.11-3
SIMPLIFIED BLOCK DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 27 – October 2009

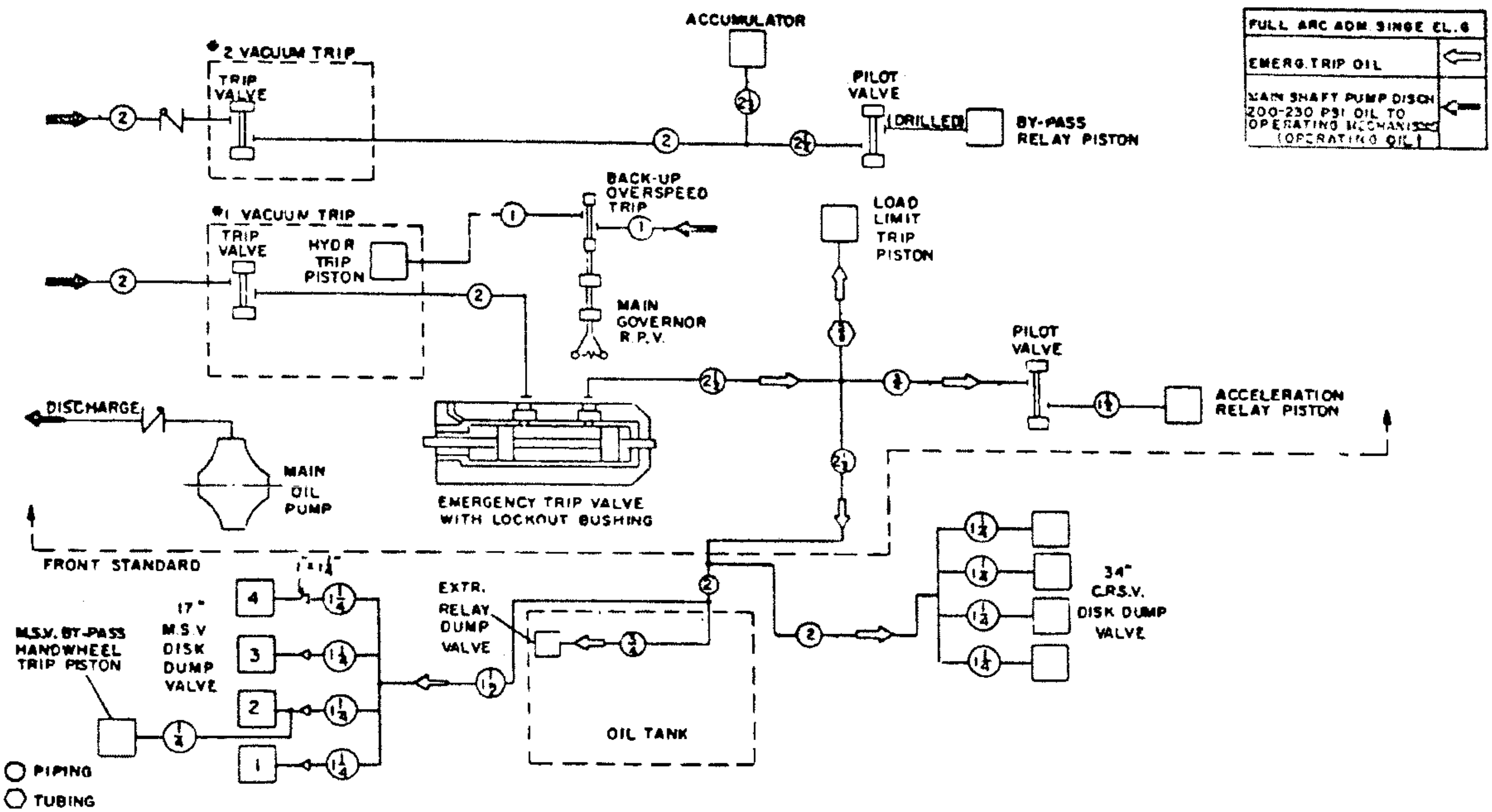


FIGURE 7.11-4
EMERGENCY TRIP CIRCUIT DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

7.12 PROCESS RADIATION MONITORING

Process Radiation Monitoring Systems include the following:

1. Main Steam Line Radiation Monitoring System
2. Air Ejector Offgas Radiation Monitoring System
3. Post-Treatment Radiation Monitoring System
4. Main Stack Radiation Monitoring System
5. Main Stack High Range Radiation Monitoring System
6. Refueling Ventilation Exhaust Radiation Monitoring System
7. Reactor Building Exhaust Vent Radiation Monitoring System
8. Reactor Building Exhaust Vent High Range Radiation Monitoring System
9. Turbine Building Effluent Radiation Monitoring System
10. Turbine Building Roof Exhaust Vent High Range Radiation Monitoring System
11. Standby Gas Treatment Exhaust Radiation Monitoring System
12. Control Room Ventilation Intake Radiation Monitoring System
13. Torus Atmospheric High Range Radiation Monitoring System
14. Drywell Atmospheric High Range Radiation Monitoring System
15. Radwaste Liquid Discharge Radiation Monitoring System
16. Reactor Building Closed Cooling Water System (RBCCW) Liquid Radiation Monitoring System

Process Radiation Monitoring Systems are incorporated into the station design for one or more of the following functions:

1. Monitor and record radioactivity levels of station effluents released to the environs during planned operations

In general, these Radiation Monitoring Systems provide information to evaluate compliance with annual average, or other long term, site release limitations. In these applications, the design specifies manual actuation of control to regulate releases to permit operator evaluation of conditions and selection of preferred control action. Radiation Monitoring Systems which perform this function include the Main Stack Radiation Monitoring System, Reactor Building Exhaust Vent Radiation Monitoring System, and Radwaste Liquid Discharge Radiation Monitoring System

2. Monitor radioactivity levels in process systems to provide selected information on system status to the operator

   In general, these Radiation Monitoring Systems provide information for trending relatively slow changes in system behavior. Manual initiation of control action following operator evaluation of system conditions is considered adequate. Certain process systems operate continuously and release radioactivity to the environs during planned operations. In these applications, the design may provide a capability to initiate automatic actuation of source controls, after an appropriate time delay to permit operator evaluation and possible alternate control action to avoid unnecessary shutdown. The Air Ejector Offgas Radiation Monitoring and Main Steam Line Radiation Monitoring Systems perform this function. Note that source control for intermittent or batch operated process systems is, in general, achieved by sampling and laboratory analysis of radioactivity levels prior to release

3. Monitor and initiate automatic actuation of controls to contain accidental releases of radioactivity in accordance with design basis accident analyses

   These Radiation Monitoring Systems provide information on accidental gross releases of radioactivity and are designed to immediately initiate appropriate control actuation. For example, the Main Steam Line Radiation Monitoring System is provided to monitor for a gross release of radioactive material from the fuel during operation, and to initiate a trip signal to the mechanical vacuum pump to contain the gross release of radioactive material. Similarly, the Refueling Ventilation Exhaust Radiation Monitoring System is provided to monitor for a gross release of radioactive material from the fuel during fuel handling, and to initiate action to contain the gross release of radioactive material

These systems are described individually in the following sections.

7.12.1 Main Steam Line Radiation Monitoring System

7.12.1.1 Safety Objective

The objective of the Main Steam Line Radiation Monitoring System is to monitor for the gross release of fission products from the fuel and, upon indication of such failure, to initiate appropriate action to limit fuel damage and contain the released fission products.

7.12.1.2 Safety Design Basis

1. The Main Steam Line Radiation Monitoring System shall be designed to provide prompt indication of a gross release of fission products from the fuel.

2. The Main Steam Line Radiation Monitoring System shall be capable of detecting a gross release of fission products from the fuel under any anticipated operating combination of main steam lines.

3. Upon detection of a gross release of fission products from the fuel, the Main Steam Line Radiation Monitoring System shall initiate a trip signal to the mechanical vacuum pump to contain the fission products released from the fuel.

7.12.1.3 Description

Four gamma sensitive instrumentation channels monitor the gross gamma radiation from the main steam lines. The detectors are physically located near the main steam lines downstream of the outboard main steam line isolation valves. The detectors are geometrically arranged so that the system is capable of detecting significant increases in radiation level for all main steam lines in operation. Their location along the main steam lines allows the earliest practical detection of a gross fuel failure. This meets Safety Design Bases 1 and 2. Two of the channels are powered from one Reactor Protection System (RPS) bus, and the other two channels are powered from the other RPS bus.

Upon receipt of the high radiation trip signals the mechanical vacuum pump is shutdown, if running, and the mechanical vacuum pump discharge valve is closed. This meets Safety Design Bases 3.

The radiation trip setting is selected so that a high radiation trip results from the fission products released in the design basis rod drop accident. The setting so selected is enough above the background radiation level in the vicinity of the main steam lines that spurious trips are avoided at rated power. Yet, the setting is low enough that the monitors can respond to the fission products released during the design basis rod drop accident.

Four instrumentation channels are used to minimize the possibility of inadvertent trip of the mechanical vacuum pump as a result of instrumentation malfunctions. The output trip signals of each monitoring channel are combined in such a way that at least two channels must signal high radiation to initiate a trip signal to the

mechanical vacuum pump. Thus, failure of any one monitoring channel does not result in inadvertent action. The four channel arrangement also assures that failure of any one monitoring channel will not prevent trip action when required.

Each monitoring channel consists of a gamma sensitive ion chamber and a log radiation monitor, as shown on Figure 7.12-1. Capabilities of the monitoring channel are listed on Table 7.12-1. Each log radiation monitor has two trip circuits. One trip circuit is an upscale trip that is used to initiate a trip signal to the mechanical vacuum pump. The other trip circuit is a downscale trip that actuates an instrument trouble alarm in the main control room. The output from each log radiation monitor is displayed on an electroluminescent display in the main control room.

A two-pen recorder is used to record the outputs from two of the four monitoring channels. Manual selector switches allow the outputs of any two of the four channels to be recorded. The recorder has one upscale alarm circuit. The alarm setting is lower than the log radiation monitor upscale trip setting, so that an alarm is received in the main control room before the trip signal to the mechanical vacuum occurs.

The trip circuits for each monitoring channel operate normally energized, so that failures in which power to monitoring components is interrupted result in a trip signal. The environmental capabilities of the components of each monitoring channel are selected in consideration of the locations in which the components are to be placed.

7.12.1.4 Safety Evaluation

The description of the main steam line radiation monitors indicates how the safety design bases are satisfied. The system is capable of initiating safety action at the level of fuel damage resulting from the design basis rod drop accident. In Section 14, Station Safety Analysis, it is shown that the amount of fuel damage and fission product release involved in this accident is relatively small. In addition this system is designed to comply with the intent of IEEE-279 and the NRC's General Design Criteria. Refer to Appendix F and Appendix J for additional details. It is concluded that for any situation involving gross fission product release, the Main Steam Line Radiation Monitoring System is capable of providing prompt safety action.

7.12.1.5 Inspection and Testing

A built-in, self-test circuit is provided for test purposes with each log radiation monitor. Routine verification of the operability of each monitoring channel can be made by comparing the outputs of the channels during power operation.

7.12.1.6 Nuclear Safety Requirements for Plant Operation

Table 7.12-2 presents the nuclear safety requirements for the Main Steam Line Radiation Monitoring System for each BWR operating state. The entries on Table 7.12-2 represent an extension of the station wide BWR systems analysis of Appendix G to the components of the Main Steam Line Radiation Monitoring System. The following referenced portions of the safety analysis report provide important information justifying the entries on Table 7.12-2:

Reference	Information Provided
1. Preceding parts of Section 7.12.1	Description of Main Steam Line Radiation Monitoring System hardware; monitoring system sensor setpoints
2. Station Safety Analysis, Section 14	Analyses verifying performance of the radiation monitoring system for accidents
3. Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which system action is required
4. Jacobs, I.M. Guidelines for Determining Safe Test Intervals and Repair Times for Engineering Safeguards. General Electric Company, Atomic Power Equipment Department, (APED-5736) April 1969	Describes methods used to establish allowable repair times per protection systems

Each detailed requirement on Table 7.12-2 is referenced, where possible, to the most significant condition originating the need for the requirement by identifying a matrix block on 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 7.12-2 and are coded as follows:

Example of Matrix Reference:

F38-80

F = BWR operating State F
38 = Event (Row 38)
80 = Main Steam Line Radiation Monitoring System (Column 80)

The Main Steam Line Radiation Monitoring System must be operable only in operating states D and F because it is only in these states that the rod drop accident can result in a situation requiring the response of the monitoring system. In operating states C and E a rod drop accident cannot produce criticality. Because the control rods must be withdrawn to set up a condition in which a significant rod drop accident could potentially occur, the main steam line radiation monitors are needed only when the mode switch is in "REFUEL", "STARTUP" or "RUN". Only the "STARTUP" and "REFUEL" positions must be considered in operating state D, because placing the mode switch in "RUN" in this state causes an automatic scram due to downscale neutron flux indications.

The monitors need be operable only if a main steam line is unisolated with steam flowing. If the main steam lines are isolated, the monitors could not detect high radiation due to the monitor's location downstream of the main steam line isolation valves. The full system test for isolation required at each refueling outage is needed to demonstrate that the main steam line radiation initiating signal for isolation is successful in isolating the mechanical vacuum pump.

A main steam line radiation monitoring channel is classified as an analog detector device coupled to an amplifier and a bistable trip circuit. The calibration of the main steam line radiation monitors can be compared on a continuing basis by checking the indications of the several channels. Once every 24 months calibration with a standard current source is sufficient to counteract the effects of electronic drift.

7.12.1.7 Current Technical Specifications

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

7.12.2 Air Ejector Offgas Radiation Monitoring System

7.12.2.1 Power Generation Objective

The objectives of the Air Ejector Offgas Radiation Monitoring System are to indicate when limits for the release of radioactive material to the environs are approached and to effect appropriate control of the offgas so that the limits are not exceeded during planned operation.

7.12.2.2 Design Basis

1. The Air Ejector Offgas Radiation Monitoring System shall initiate appropriate action in time to prevent exceeding short-term limits on the release of radioactive materials to the environs as a result of releasing the radioactivity contained in the air ejector offgas line.

2. The Air Ejector Offgas Radiation Monitoring System shall provide a record of the radioactivity level of the air ejector offgas line.

3. The Air Ejector Offgas Radiation Monitoring System shall provide an alarm to operations personnel whenever the radioactivity level of the air ejector offgas reaches short-term limits.

7.12.2.3 Description

The Air Ejector Offgas Radiation Monitoring System takes a continuous sample from the offgas line just after the offgas system condenser as shown on Figure 7.12-1. The specifications are given on Table 7.12-1. The system has two instrumentation channels. Each channel consists of a gamma sensitive detector and logarithmic radiation monitor that includes a power supply and an electroluminescent display. Both channels are recorded on a two-pen recorder located in the control room. Each logarithmic radiation monitor is powered from a different bus of the RPS.

The two gamma sensitive ion chambers are positioned adjacent to a vertical sample chamber which is internally polished to minimize plateout. A sample is drawn from the offgas line through the sample chamber by the main condenser suction. The sample system is arranged to give at least a 2-minute time delay before the sample is monitored. The time delay allows nitrogen 16 and oxygen 19 activity to decay. This reduces the background radiation that the detector would otherwise measure.

Small changes in the offgas gross fission product concentration can be detected by the continuous use of the linear radiation monitor. The linear radiation monitor is not a process monitor such as the channels described above but is utilized as an expanded scale device as an aid in locating ruptured or failed fuel elements. The detector is a gamma sensitive ionization chamber which monitors the same sample as the air ejector offgas detectors. The system uses a linear readout with a range switch instead of a logarithmic readout. The output from the monitor is recorded on a one pen recorder. The channel is connected to the 24V DC power bus. See Section 8.7, 24 Volt DC Power System.

Each monitor has an upscale trip and a downscale trip. An upscale trip indicates high radiation, and a downscale trip indicates instrument trouble. Any one trip will give an alarm in the control room. Any two trips will actuate, through a keylock switch, a time delay switch which in turn closes drain valves and an outlet valve in the air ejector offgas line. The time delay switch is adjustable from 0 to 15 minutes.

The time delay is permitted because of the length of time the gas takes to travel from the sample point to the outlet valve. The time delay allows the operator to reduce power or to correct for a spurious trip condition before the outlet valve is closed (See Figure 11.4-1). Subsequent operator action is required to reopen this valve. This will ensure positive control of releases to the environment.

The environmental and power supply design conditions are given on Table 7.12-4.

7.12.2.4 Evaluation

The air ejector offgas radiation monitors have been selected with monitoring characteristics sufficient to provide station operations personnel with accurate indication of radioactivity in the air ejector offgas line. The system thus provides the operator with enough information to limit the activity release rate during planned operations. Sufficient redundancy is provided to allow maintenance and testing of the Radiation Monitoring System.

7.12.2.5 Inspection and Testing

The requirements for testing and verifying operability of the air ejector offgas monitors are:

1. Daily instrument check.

2. Quarterly instrument functional test.

3. 24-Month calibration.

The front panel test procedure is described in the Log Radiation Monitor Instruction Manual. These tests will verify the operability of the log radiation monitors, the log radiation monitor trip logic, and the timer in the "Auto" closure mode. Operability in the "Close" mode is made by manually switching to "CLOSE" and verifying that a signal is sent to close the offgas outlet valve and the drain valve. In addition, routine verification of operability can be observed during power operation. Trip circuits can be tested using test signals or by instrument self-test.

7.12.3 *Post-Treatment Radiation Monitoring System*

7.12.3.1 Objective

The objectives of the Post-Treatment Radiation Monitoring System are to indicate when limits for the release of radioactive material to the environs are approached and to effect appropriate control of the offgas so that the limits are not exceeded during planned operation.

7.12.3.2 Design Basis

1. The Post-Treatment Radiation Monitoring System shall initiate appropriate action in time to prevent exceeding short-term limits on the release of radioactive materials to the environs as a result of releasing the radioactivity contained in the air ejector offgas line.

2. The Post-Treatment Radiation Monitoring System shall provide a record of the radioactivity level of the augmented offgas line.

3. The Post-Treatment Radiation Monitoring System shall provide an alarm to operations personnel whenever the radioactivity level of the augmented offgas reaches short-term limits.

7.12.3.3 Description

The Post-Treatment Radiation Monitoring System takes a continuous sample from the outlet of the Augmented Offgas Treatment System, as shown on Figure 7.12-3. This system has two instrumentation channels. Each channel consists of a gamma sensitive detector, a pulse preamplifier, a logarithmic radiation monitor with a power supply and an electroluminescent display. Both channels are recorded on a two-pen recorder located in the main control room. Each logarithmic radiation monitor is powered from a different bus of the 24 Volt DC System. See Section 8.7, 24 Volt DC Power System.

The two scintillation detectors are mounted in two shielded sample chambers. The sample is drawn from the offgas line through the sample chamber by the sample pump.

Each monitor has two upscale trips and a downscale trip. Any one upscale high radiation trip of the post-treatment monitor closes the carbon bed filter bypass valve, if open, and opens the offgas line to the carbon bed, if closed, in the augmented Offgas System. This upscale high radiation trip also provides an annunciator alarm in the control room.

Any combination of two high-high upscale radiation trips, one high-high upscale trip and one downscale trip, or two downscale trips of each monitor will actuate a time delay switch through a keylock selector switch. This is the same 0-15 minute time delay switch located by the Air Ejector Offgas Radiation Monitor which closes the drain valve and the outlet valve in the offgas discharge line.

7.12.3.4 Evaluation

The post-treatment offgas radiation monitors have been selected with monitoring characteristics sufficient to provide station operations personnel with accurate indication of radioactivity in the Post-Treatment offgas line. The system thus provides the operator with enough information to limit the activity release rate during planned operations. Sufficient redundancy is provided to allow maintenance and testing of the Post-Treatment Radiation Monitoring System.

7.12.3.5 Inspection and Testing

The requirements for testing and verifying operability of the post-treatment offgas monitors are:

1. Daily instrument check.

2. Quarterly instrument functional test.

3. 24-Month calibration.

The front panel test procedure is described in the Log Radiation Monitor Instruction Manual. These tests will verify the operability of the log radiation monitors, the log radiation monitor trip logic, and the timer in the "Auto" closure mode. Operability in the "Close" mode is made by manually switching to "CLOSE" and verifying that a signal is sent to close the offgas outlet valve and the drain valve. In addition, routine verification of operability can be observed during power operation. Trip circuits can be tested using test signals or by instrument self-test.

7.12.4 Main Stack Radiation Monitoring System

7.12.4.1 Objective

The objectives of the Main Stack Radiation Monitoring System are to indicate the rate of radioactive material release from the main stack during planned operation, and to alarm whenever limits on the release of radioactive material to the environs are reached or exceeded.

7.12.4.2 Design Basis

1. The Main Stack Radiation Monitoring System shall record the rate of release of radioactive material to the environs, so that determination of the total amounts of activity released is possible.

2. The Main Stack Radiation Monitoring System shall provide an alarm to operations personnel whenever 10CFR20 limits on the release of radioactive material to the environs are reached or exceeded.

3. The Main Stack Radiation Monitoring System shall indicate the rate of release of radioactive material ranging from values normally encountered during high power operation to values above release rate limits.

7.12.4.3 Description

The Main Stack Radiation Monitoring System is shown on Figure 7.12-2 (BECo M1U 101-7), and specifications are given on Table 7.12-1. The system consists of two individual channels. Each channel consists of a gamma sensitive scintillation detector and a log count rate monitor that includes a power supply and an electroluminescent display.

Both channels are recorded on a two-pen recorder located in the main control room. Both channels are connected to the 24V DC power bus. See Section 8.7, 24V DC Power System.

Each monitor has two upscale trips and one downscale trip. Each trip initiates an alarm in the main control room, but no control action is provided. The upscale alarms indicate high radiation, and the downscale alarm indicates instrument trouble.

To monitor the main stack gas effluent, a sample is drawn through an isokinetic probe which is located in the stream to assure representative sampling. The sample passes through two shielded chambers where the radiation level of the stack gas is measured by two scintillation detectors, one located in each shielded chamber.

As shown on Figure 7.12-1 (BECo M1U1-8), the system also provides for monitoring iodine and particulates by the use of one of three parallel filters in the gas sample monitoring stream. Each filter is installed in a lead shielded cask. The filters are routinely analyzed in the laboratory. The environmental and power supply design conditions are given on Table 7.12-4.

The radiation monitors relative location in the stack and the instrumentation provided to monitor and record the main stack gas flow are shown in Figure 11.4-1 (BECo M210).

In the event the Main Stack Radiation Monitoring System becomes inoperable and/or requires maintenance/repair, auxiliary sample equipment (as described in station procedures and Technical Specifications) shall be installed and utilized until no longer necessary.

7.12.4.4 Evaluation

The main stack radiation monitors have been selected with monitoring characteristics sufficient to provide station operating personnel with accurate indication of radioactivity being released to the environs via the main stack. The system thus enables the operator to limit the activity release to the environs during planned operation. Because the system is not essential to any transients or accidents, no redundancy is required, although sufficient redundancy is provided to allow maintenance on one channel without losing the indication provided by the system. The first alarm setpoint is based on the average annual release limit and the second alarm setpoint is based on the short-term maximum release rate.

7.12.4.5 Inspection and Testing

Each individual channel includes a built-in check source and a N_2 purge line to purge the stack gas from the sampling chamber. Both the purge valve and the check source are operated from the main control room. Each channel is calibrated by circulating isotopically analyzed offgas samples through the radiation monitor sample chambers. Alarm trip circuits can be tested using a test source.

7.12.4.6 Nuclear Safety Requirements for Plant Operation

Table 7.12-5 presents the nuclear safety requirements for the Main Stack Radiation Monitoring System.

The entries on Table 7.12-5 represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the Main Stack Radiation Monitoring System. The following referenced portions of the safety analysis report provide important information justifying the entries on Table 7.12-5:

Reference	Information Provided
1. Preceding parts of Section 7.12	Description of the Main Stack Radiation Monitoring System hardware
2. Station Nuclear Safety Analysis, Appendix G	Identifies conditions and events for which system action is required

Each detailed requirement on Table 7.12-5 is referenced, where possible, to the most significant condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns on Table 7.12-5 and are coded as follows:

Example of Matrix Reference:

C 6-77

C - BWR operating state C
6 - Event (Row 6)
77 - Main Stack Radiation Monitoring System (Column 77)

The requirements given on Table 7.12-5 are the result of a consideration for the need for indication of the activity release rate via the main stack. The indications thus provided allow operator control of the radioactivity released via the main stack.

7.12.4.7 Current Technical Specifications

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

7.12.5 Main Stack High Range Radiation Monitoring System

7.12.5.1 Objective

The objective of the Main Stack High Range Radiation Monitoring System is to indicate the rate of radioactive material release from the main stack during accident conditions when normal PRMs might be off scale. The stack high range monitor will alarm whenever limits on the release of radioactive material to the environs are reached or exceeded.

7.12.5.2 Design Basis

1. The Main Stack High Range Radiation Monitoring System shall record the rate of release of radioactive material to the environs, so that determination of the total amounts of activity released is possible.

2. The Main Stack High Range Radiation Monitoring System shall provide an alarm to operations personnel whenever 10 CFR 20 limits on the release of radioactive material to the environs are reached or exceeded.

3. The Main Stack High Range Radiation Monitoring System shall indicate the rate of release of radioactive material ranging from values above normal high power operation to values possibly released under accident conditions.

7.12.5.3 Description

The Main Stack High Range Radiation Monitoring System is shown on BECo drawing E550 Sh 14. The system is one channel consisting of a gamma sensitive ion chamber detector, a log count rate monitor that includes a power supply, and a local alarm/display station. The channel is recorded on a three-pen recorder located in the main control room on the post accident monitoring panel C170.

The monitor has two upscale trips which are both set at the same setpoint. The upscale trips initiate an alarm light at the monitor and provide local alarm (bell and light) at the main stack. The monitor output is also displayed and recorded at the post accident monitoring panel C170 in the main control room.

7.12.5.4 Evaluation

The main stack high range radiation monitor has been selected with monitoring characteristics sufficient to provide station operating personnel with accurate indication of radioactivity being released to the environs via the main stack. The detector used is a gamma sensitive ion chamber capable of measuring from 10^{-1} to 10^{4} R/hour. This covers a radiation level range possible during and after an accident condition when normal stack monitors would be offscale high.

7.12.5.5 Inspection and Testing

The main stack high range radiation monitor includes a built-in electronic check current signal which can be used to functionally verify monitor operation and test alarm trip circuits.

The channel is calibrated using a highly radioactive source and compared to instrumentation traceable to the National Institute of Standards and Technology.

7.12.6 Refueling Ventilation Exhaust Radiation Monitoring System

7.12.6.1 Safety Objective

The objective of the Refueling Ventilation Exhaust Radiation Monitoring System is to indicate whenever abnormally high amounts of radioactive material exist in the refueling floor area of the Reactor Building, to initiate isolation of the normal Reactor Building Ventilation Systems and to start the Standby Gas Treatment System.

7.12.6.2 Safety Design Basis

1. The Refueling Ventilation Exhaust Radiation Monitoring System shall be designed to provide prompt indication of a gross release of fission products from the spent fuel in the refueling floor area of the Reactor Building.

2. Upon detection of gross release of fission products from the spent fuel, the Refueling Ventilation Exhaust Radiation Monitoring System shall initiate prompt action to effect secondary containment.

3. The response time of the Refueling Ventilation Exhaust Radiation Monitoring System to effect a trip condition shall permit isolation of reactor building ventilation prior to the transport of gross quantities of fission products from the refueling area to the normal building exhaust location.

4. The system must meet the requirements of IEEE-279.

7.12.6.3 Description

The Refueling Ventilation Exhaust Radiation Monitoring System is shown on Figure 7.12-2 and specifications are given on Table 7.12-1. Four gamma sensitive instrumentation channels monitor the radiation from the refueling area ventilation exhaust ducts. The physical location of the detectors allows the earliest practical detection of gross fission product release from spent fuel in the refueling area of the reactor building. Two of the detectors are located on the refueling floor exhaust header above elevation 117 feet, and two are located below elevation 117 feet. All refueling floor exhaust ducts enter upstream of the detector location. One detector is powered from RPS bus "A", one detector is powered from RPS bus "B" and the other two detectors are powered from vital bus Y-2. This meets safety design basis 1.

When a significant increase in the refueling ventilation exhaust duct radiation level is detected, trip signals are transmitted to the Reactor Building Isolation and Control System. Upon receipt of the high radiation trip signals, the Reactor Building Isolation and Control System initiates shutdown of Reactor Building ventilation supply and exhaust fans, closure of Reactor Building ventilation isolation dampers, and startup of the Standby Gas Treatment System (SGTS). This meets safety design basis 2.

The radiation trip setting is selected so that a high radiation trip results from the fission products released in the design basis refueling (fuel handling) accident. The setting so selected is sufficiently above background radiation levels during planned operation that spurious trips are avoided.

Four instrumentation channels are used to minimize the possibility of inadvertent trip and actuation of the Reactor Building Isolation and Control System as a result of instrumentation malfunctions. The output trip signals of each monitoring channel are combined in such a way that at least two channels must signal high radiation to initiate reactor building isolation. Thus failure of any one monitoring channel does not result in inadvertent action. The four-channel arrangement also assures that failure of any one monitoring channel will not prevent trip action when required. This meets safety design basis 4.

Each monitoring channel consists of a gamma sensitive Geiger-Muller type detector and a combined log radiation indicator and trip unit. Capabilities of the monitoring channel are listed on Table 7.12-1. Each log radiation monitor has two trip circuits. One trip circuit is a one-out-of-two taken twice upscale trip that is used to initiate reactor building isolation. The other trip circuit is a two-out-of-two taken twice downscale trip and it also initiates a reactor building isolation. The output from each log radiation monitor is displayed in the main control room.

A two-pen recorder is used to record the output from two of the four monitoring channels. Manual selector switches allow the outputs of any two of the four channels to be recorded.

The trip circuits for each monitoring channel operate normally energized, so that failures in which power to monitoring components is interrupted result in a trip signal.

The environmental and power supply design conditions are given on Table 7.12-4.

7.12.6.4 Safety Evaluation

The description of the refueling ventilation exhaust monitors indicates how the safety design bases are satisfied. The system will initiate the high radiation level trip signals at the level of fission product release resulting from the design basis refueling (fuel handling) accident which is described in Section 14, Station Safety Analysis. The capability of the station design to effect Reactor Building isolation after receipt of the high radiation trip signals and thereby to limit the radiological consequences of gross fission product release in the refueling area is described in Section 5.3.4.2. Safety design basis 3 is met.

In addition this system is designed to comply with the intent of IEEE-279 and the NRC's General Design Criteria. Refer to Appendix F and Appendix J for additional details.

7.12.6.5 Inspection and Testing

A built-in, adjustable test signal is provided for test purposes with each log radiation monitor. Verification of the operability of each channel can be made by comparing the outputs of the channels during power operation. The operability can be verified at other times using a portable gamma source.

7.12.6.6 Nuclear Safety Requirements for Plant Operation

Table 7.12-6 presents the nuclear safety requirements for the Refueling Ventilation Exhaust Radiation Monitoring System.

The entries on Table 7.12-6 represent an extension of the Stationwide BWR Systems analysis of Appendix G to the components of the Refueling Ventilation Exhaust Radiation Monitoring System. The following referenced portions of the safety analysis report provide important information justifying the entries on Table 7.12-6:

Reference	Information Provided
1. Preceding parts of Section 7.12	Description of the Refueling Ventilation Exhaust Radiation Monitoring System hardware
2. Station Safety Analysis, Section 14	Analyses verifying response of the system to accidents
3. Station Nuclear Safety Analysis, Appendix G	Identifies conditions and events for which system action is required
4. Jacobs, I.M., Guidelines for Determining Safe Test Intervals and Repairing 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 7.12-6 is referenced, where possible, to the most significant condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns on Table 7.12-6 and are coded as follows:

Example of Matrix Reference:

A40-79

A - BWR operating state A

40 - Event (Row 40)

79 - Refueling Ventilation Exhaust Radiation Monitoring System (Column 79)

The entries on Table 7.12-6 are the results of considering the objectives of the Radiation Monitoring System. In all operating states, all the monitors provide isolation for any abnormal release of radioactivity during the planned operations.

Table 7.12-6 summarizes the operational nuclear safety requirements for the Refueling Ventilation Exhaust Radiation Monitoring System.

7.12.6.7 Current Technical Specifications

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

7.12.7 Reactor Building Exhaust Vent Radiation Monitoring System

7.12.7.1 Objective

The objectives of the Reactor Building Exhaust Vent Radiation Monitoring System are to indicate the rate of radioactive material release from the reactor building vent to the environs during planned operations and to alarm whenever abnormally high amounts of radioactive material exist in the building vent effluent.

7.12.7.2 Design Basis

1. The Reactor Building Exhaust Vent Radiation Monitoring System shall record the rate of release of radioactive material to the environs, so that determination of the total amounts of activity released is possible.

2. The Reactor Building Exhaust Vent Radiation Monitoring System shall provide an alarm to operations personnel whenever abnormally high amounts of radioactive material exist in the building vent effluent.

3. The Reactor Building Exhaust Vent Radiation Monitoring System in conjunction with operating procedures shall control building vent releases within radioactive material release limits during planned operations.

7.12.7.3 Description

The Reactor Building Exhaust Vent Radiation Monitoring System is shown on Figure 7.12-2 (BECo M1U 101-7) and specifications are given on Table 7.12-1. The system consists of two individual channels. Each channel consists of a gamma sensitive detector and a log count rate monitor that includes a power supply and an electroluminescent display. Both channels are recorded on a two-pen recorder located in the main control room. Both channels are connected to the 24V DC power bus. See Section 8.7, 24V DC Power System.

Each monitor has two upscale trips and one downscale trip. Each trip initiates an alarm in the main control room but no control action is provided. The upscale alarms indicate high radiation, and the downscale alarm indicates instrument trouble.

To monitor the building exhaust vent gas effluent, a sample is drawn through an isokinetic probe that is located to assure representative sampling. The sample passes through two shielded chambers where the radiation level of the gas is measured by two scintillation detectors, one located in each shielded chamber.

As shown on Figure 7.12-2 (BECo M1U 101-7), the system also provides for monitoring iodine and particulates by the use of one of three parallel filters in the gas sample monitoring stream. Each filter is installed in a lead-shielded cask. The filters are routinely analyzed in the laboratory. The environmental and power supply design conditions are given on Table 7.12-4.

In the event the Reactor Building Exhaust Vent Radiation Monitoring System becomes inoperable and/or requires maintenance/repair, auxiliary sample equipment (as described in station procedures and Technical Specifications) shall be installed and utilized until no longer necessary.

7.12.7.4 Evaluation

The reactor building exhaust vent radiation monitors have been selected with monitoring characteristics to provide station operating personnel with a high sensitivity indication of radioactivity levels being released to the environs via the building vent. This indication in conjunction with periodic laboratory analyses of the iodine and particulate filters provided in the system enable the operator to limit the activity release to the environs during planned operations. Because the system is not essential to any transients or accidents, no redundancy is required, although sufficient redundancy is provided to allow maintenance on one channel without losing the indication provided by the system.

7.12.7.5 Inspection and Testing

Each individual channel includes a built-in check source and a N_2 purge line to purge the gas from the sampling chamber. Both the purge valve and the check source are operable from the main control room. Each channel is calibrated by circulating isotopically analyzed offgas grab samples through the radiation monitor sample chamber. Alarm trip circuits are tested using test signals.

7.12.8 Reactor Building Exhaust Vent High Range Radiation Monitoring System

7.12.8.1 Objective

The objective of the Reactor Building Exhaust Vent High Range Radiation Monitoring System is to indicate the rate of radioactive material release from the reactor building exhaust vent during accident conditions when normal PRMs might be offscale. The reactor building exhaust vent high range monitor will alarm whenever limits on the release of radioactive material to the environs are reached or exceeded.

7.12.8.2 Design Basis

1. The Reactor Building Exhaust Vent High Range Radiation Monitoring System shall record the rate of release of radioactive material to the environs, so that determination of the total amounts of activity released is possible.

2. The Reactor Building Exhaust Vent High Range Radiation Monitoring System shall provide an alarm to operations personnel whenever 10 CFR 20 limits on the release of the radioactive material to the environs are reached or exceeded.

3. The Reactor Building Exhaust Vent High Range Radiation Monitoring System shall indicate the rate of release of radioactive material ranging from values above normal high power operation to values possible released under accident conditions.

7.12.8.3 Description

The Reactor Building Exhaust Vent High Range Radiation Monitoring System is shown on BECo drawing E550 Sh 14. The system is one channel consisting of a gamma sensitive ion chamber detector, a log count rate monitor that includes a power supply, and a local alarm/display station. The channel is recorded on a three-pen recorder located in the main control room on the post accident monitoring panel C170.

The monitor has two upscale trips which are both set at the same setpoint. The upscale trips initiate an alarm light at the monitor and provide local alarm (bell and light) at the reactor building vent access area on elevation 51 foot, turbine building. The monitor output is also displayed and recorded at the post accident monitoring panel C170 in the main control room.

7.12.8.4 Evaluation

The reactor building exhaust vent high range radiation monitor has been selected with monitoring characteristics sufficient to provide station operating personnel with accurate indication of radioactivity being released to the environs via the reactor building vent. The detector used is a gamma sensitive ion chamber capable of measuring from 10^{-1} to 10^{4} R/hour. This covers a radiation level range possible during and after an accident condition when normal exhaust vent monitors would be offscale high.

7.12.8.5 Inspection and Testing

The reactor building exhaust vent high range radiation monitor includes a built-in electronic check current signal which can be used to functionally verify monitor operation and test alarm trip circuits. The channel is calibrated using a highly radioactive source and compared to instrumentation traceable to the National Institute of Standards and Technology.

7.12.9 Turbine Building Effluent Radiation Monitoring System

7.12.9.1 Objective

The objectives of the Turbine Building Effluent Radiation Monitoring System are to indicate the rate of radioactive material release from the turbine hall and reactor feed pump bay during normal plant operation, and to alarm whenever limits on the release of radioactive material to the environs are reached or exceeded.

7.12.9.2 Description

The Turbine Building Effluent Radiation Monitoring System consists of two individual channels. Each channel includes a beta sensitive scintillation type detector, preamplifier and log count ratemeter mounted on a local skid. The skid also includes a sampling pump, and a control valve with particulate and iodine filters.

Each monitor has two upscale alarms and one instrument failure alarm. All three alarms are displayed locally at the skid, but no control action is provided.

To monitor the turbine hall area, a representative sample is drawn through one of two probes located in the stream of two of the eight turbine hall roof exhauster fans. The sample passes through particulate and iodine filters and enters a shielded chamber where the radiation level of the turbine hall effluent is measured by a beta sensitive scintillation detector.

To monitor the feed pump bay, a sample is drawn through an isokinetic probe which is located in an exhaust duct common to all three feed pump area roof exhauster fans. The sample passes through particulate and iodine filters and enters a shielded chamber where radiation levels of the feed pump bay effluent are measured by a beta sensitive scintillation detector.

7.12.9.3 Inspection and Testing

A built-in check source is provided for functional testing.

7.12.10 Turbine Building Roof Exhaust Vent High Range Radiation Monitoring System

7.12.10.1 Objective

The objective of the Turbine Building Roof Exhaust Vent High Range Radiation Monitoring System is to indicate the rate of radioactive material release from the turbine building roof exhaust vent during accident conditions when normal PRMs might be off scale. The stack high range monitor will alarm whenever limits on the release of radioactive material to the environs are reached or exceeded.

7.12.10.2 Design Basis

1. The Turbine Building Roof Exhaust Vent High Range Radiation Monitoring System shall record the rate of release of radioactive material to the environs, so that determination of the total amounts of activity released is possible.

2. The Turbine Building Roof Exhaust Vent High Range Radiation Monitoring System shall provide an alarm to operations personnel whenever 10 CFR 20 limits on the release of radioactive material to the environs are reached or exceeded.

3. The Turbine Building Roof Exhaust Vent High Range Radiation Monitoring System shall indicate the rate of release of radioactive material ranging from values above normal high power operation to values possible released under accident conditions.

7.12.10.3 Description

The Turbine Building Roof Exhaust Vent High Range Radiation Monitoring System is shown on BECo drawing E550 Sh 14. The system is one channel consisting of a gamma sensitive ion chamber detector, a log count rate monitor that includes a power supply, and a local alarm/display station. The channel is recorded on a three-pen recorder located in the main control room on the post accident monitoring panel C170.

The monitor has two upscale trips which are both set at the same setpoint. The upscale trips initiate an alarm light at the monitor and provide local alarm (bell and light) at elevation 51 foot turbine floor. The monitor output is also displayed and recorded at the post accident monitoring panel C170 in the main control room.

7.12.10.4 Evaluation

The turbine building roof exhaust vent high range radiation monitor has been selected with monitoring characteristics sufficient to provide station operating personnel with accurate indication of radioactivity being released to the environs. The detector used is a gamma sensitive ion chamber capable of measuring from 10^{-1} to 10^4 R/hour. This covers a radiation level range possible during and after an accident condition when normal turbine floor roof monitors would be offscale high.

7.12.10.5 Inspection and Testing

The turbine building roof exhaust vent high range radiation monitor includes a built-in electronic check current signal which can be used to functionally verify monitor operation and test alarm trip circuits. The channel is calibrated using a highly radioactive source and compared to instrumentation traceable to the National Institute of Standards and Technology.

7.12.11 Standby Gas Treatment Exhaust Radiation Monitoring System

7.12.11.1 Objective

The objective of the Standby Gas Treatment Exhaust Radiation Monitoring System is to provide an indication to operations personnel of abnormally high radioactivity in the standby gas treatment exhaust during planned operations.

7.12.11.2 Description

The Standby Gas Treatment Exhaust Radiation Monitoring System is shown on Figure 7.12-2 and specifications are given on Table 7.12-1. One channel is provided which is located in the common discharge from the two standby gas treatment units.

The Standby Gas Treatment System is operated during planned operations to process the purge exhaust from the primary containment prior to refueling if the radiation levels are high. During these planned operations the standby gas treatment exhaust radiation monitor provides additional information to the operator regarding possible sources of radioactivity to the main stack.

The channel utilizes a gamma sensitive Geiger-Muller type detector and a combined log radiation indicator and trip unit. The unit has two trip circuits. One trip circuit is an upscale trip that activates an alarm in the main control room on high radiation. The other trip circuit is a downscale trip that actuates an instrument trouble alarm in the main control room. The output from the log radiation monitor is displayed in the main control room.

The environmental and power supply design conditions are given on Table 7.12-4.

7.12.11.3 Inspection and Testing

The alarm trip circuit can be tested using test signals and the channel response can be verified by background readings. Calibration is performed using a portable gamma source.

7.12.12 Control Room Ventilation Intake Radiation Monitoring System

7.12.12.1 Objective

The objective of the Control Room Ventilation Intake Radiation Monitoring System is to provide an indication to operations personnel of abnormal radioactivity in the normal ventilation air intake supplying the main control room.

7.12.12.2 Description

The Control Room Ventilation Intake Radiation Monitoring System is shown on Figure 7.12-2 (BECo M1U101-7)and specifications are given on Table 7.12-1. One channel is provided. The detector is located in the normal ventilation air intake supplying the main control room.

The channel utilizes a gamma sensitive Geiger-Muller type detector and a combined log radiation indicator and trip unit. The unit has two trip circuits. One trip circuit is an upscale trip that actuates an alarm in the main control room on high radiation. The other trip circuit is a downscale trip that actuates an instrument trouble alarm in the main control room. The output from the log radiation monitor is displayed in the main control room.

The environmental and power supply design conditions are given on Table 7.12-4.

7.12.12.3 Inspection and Testing

The alarm trip circuit can be tested using test signals and the channel calibration can be performed using a portable gamma source.

7.12.13 Torus Atmospheric High Range Radiation Monitoring System

7.12.13.1 Objective

The objectives of the Torus Atmospheric High Range Radiation Monitoring System are to measure post accident rates of gross release of radioactive materials into the Torus area, and to alarm whenever limits on the release of radioactive material to the Torus area are reached or exceeded.

7.12.13.2 Description

The Torus Atmospheric High Range Radiation Monitoring System is one portion of the overall PNPS Containment High Radiation Monitoring System (CHRMS). The other portion consists of the drywell area monitors. The torus area monitors have two channels; each channel consisting of a gamma sensitive ion chamber detector and a log count rate monitor. The two detectors are mounted on the Torus room wall at selected locations to ensure adequate response to post accident airborne radiation sources and to allow for maintenance repairs/replacement of the detectors while the plant is operational.

The log count rate radiation monitors and recorders are located on the post accident panels in the main control room. The log rad monitors provide four trip circuits; two upscale, one downscale and one inoperative/trouble trip. The trips do not provide any control function, but are used for alarms only.

7.12.13.3 Evaluation

The torus area high range radiation monitors were selected with monitoring characteristics sufficient to provide station operating personnel with accurate indication of radioactivity being released into the Torus area. The detectors used are gamma sensitive ion chamber capable of measuring levels from 1 to 10^7 R/hour. This covers a radiation rate possible during and after an accident condition.

7.12.13.4 Inspection and Testing

The torus area high range radiation monitors have a built-in adjustable current source which is used to functionally verify the monitor's operation and test its alarm trip circuits. The detector and monitor are calibrated using a highly radioactive source and compared to instrumentation traceable to the National Bureau of Standards and Technology. The detectors are located such that inspections and maintenance repairs can be performed on-line without entering the Torus.

7.12.14 Drywell Atmospheric High Range Radiation Monitoring System

7.12.14.1 Objective

The objectives of the Drywell Atmospheric High Range Radiation Monitoring System are to measure post accident rates of gross release of radioactive materials inside the Drywell area, and to alarm whenever limits on the release of radioactive material in the drywell area are reached or exceeded.

7.12.14.2 Description

The Drywell Atmospheric High Range Radiation Monitoring System is one portion of the overall PNPS Containment High Radiation Monitoring System (CHRMS). The other portion consists of the torus area monitors. The drywell area monitors have two channels; each channel consisting of a gamma sensitive ion chamber detector and a log count rate monitor. The two detectors are mounted in drywell penetrations at selected locations to ensure adequate response to post accident airborne radiation sources and to allow for maintenance repairs/replacement of the detectors while the plant is operational.

The log count rate radiation monitors and recorders are located on the post accident panels in the main control room. The log rad monitors provide four trip circuits; two upscale, one downscale and one inoperative/trouble trip. The trips do not provide any control function, but are used for alarms only.

7.12.14.3 Evaluation

The drywell area high range radiation monitors were selected with monitoring characteristics sufficient to provide station operating personnel with accurate indication of radioactivity being released inside the drywell area. The detectors used are gamma sensitive ion chambers capable of measuring levels from 1 to 10^7 R/hour. This covers a radiation rate possible during and after an accident condition.

7.12.14.4 Inspection and Testing

The drywell area high range radiation monitors have a built-in adjustable current source which is used to functionally verify the monitor's operation and test its alarm trip circuits. The detector and monitor are calibrated using a highly radioactive source and compared to instrumentation traceable to the National Bureau of Standards and Technology. The detectors are located such that inspections and maintenance repairs can be performed on-line without entering the drywell.

7.12.15 Radwaste Liquid Discharge Radiation Monitoring System

7.12.15.1 Objective

The objectives of the Radwaste Liquid Discharge Radiation Monitoring System are to indicate the radioactivity level of material released through the liquid radwaste discharge header during planned operations and to alarm whenever abnormally high amounts of radioactive material are detected in the liquid radwaste discharge header.

7.12.15.2 Design Basis

1. The Radwaste Liquid Discharge Radioactive Monitoring System shall record the radioactivity level of liquids released to the environs from the radwaste system.

2. The Radwaste Liquid Discharge Radioactive Monitoring System shall provide an alarm to operations personnel whenever abnormally high amounts of radioactive material are detected in the liquid radwaste discharge header.

7.12.15.3 Description

The Radwaste Liquid Discharge Radiation Monitoring System is shown on Figure 7.12-1 (BECo M1U1-8) and specifications are given on Table 7.12-1. One channel is provided which is connected to the 24V DC power bus.

The channel includes a scintillation detector, a pulse preamplifier, a radiation monitor, and is recorded on a strip chart recorder. The detector is located in a shielded sampler that is located in a section of the radwaste liquid discharge header to minimize background radiation. The monitor is located in the main control room, while its recorder is located in the Radwaste control room.

The channel has an upscale trip to indicate high radiation level and a downscale trip to indicate instrument trouble. The upscale trip alarms in the main control room, and the Radwaste control room, trips the monitor tank pumps, and terminate the discharge. The downscale trip alarms in the main control room.

The environmental and power supply design conditions are given on Table 7.12-4.

7.12.15.4 Evaluation

The radwaste liquid discharge radiation monitor has been selected with monitoring characteristics to provide station operating personnel with adequate indication and recording of radioactivity levels of the liquids released from the Radwaste System through the liquid radwaste discharge header to the environs. This indication serves as an adjunct to procedural controls which require each batch of liquid radwaste to be sampled and analyzed in the laboratory for radioactive content. The laboratory analysis serves as an independent record of radioactive liquid discharges and is the

principal control method used to maintain the radwaste liquid effluent within the allowable liquid radioactive release limitations for the site.

The high radioactivity alarm on the radwaste liquid discharge radiation monitor serves as an additional check to identify potential misoperation of the liquid radwaste system. The batch process utilized in the liquid radwaste system provides the principal control method used to limit the radiological consequences of misoperation of the Liquid Radwaste System. Refer to Section 9.2, Liquid Radwaste System.

7.12.15.5 Inspection and Testing

Alarm trip circuits can be tested using test signals. The channel is calibrated by laboratory analysis of a grab sample from the liquid radwaste system.

7.12.15.6 Nuclear Safety Requirements for Plant Operation

The Radwaste Liquid Discharge Radiation Monitor System is used during planned operation to monitor potential release paths for radioactivity to the environs. The radwaste liquid discharge monitor is backed up by sampling, analyses, and release rate calculations.

7.12.16 Reactor Building Closed Cooling Water System Liquid Radiation Monitoring System

7.12.16.1 Objective

The objective of the RBCCW Liquid Radiation Monitoring System is to provide an indication to operations personnel of potential process system malfunctions by detecting an increase of radioactive material in the closed cooling water loops.

7.12.16.2 Description

The RBCCW Liquid Radiation Monitors are shown on Figure 7.12-1 and specifications are given on Table 7.12-1. One channel is provided on each Reactor Building closed cooling water loop. All channels are connected to the 24V DC power bus.

Each channel has a scintillation detector, pulse preamplifier, and a radiation monitor and is recorded on a strip chart recorder in the main control room. Each detector is located in a shielded sampler that is located in a section of the loop piping to minimize background radiation.

Each channel has an upscale trip to indicate high radiation level and one downscale trip to indicate instrument trouble. The trips give an alarm but no control action.

7.12.16.3 Evaluation

The RBCCW is utilized to provide cooling for potentially contaminated areas such as the residual heat removal system, the drywell atmosphere cooling coils, nonregenerative heat exchanger, recirculation pumps and various sample coolers. The system normally contains only low levels of radioactivity due to activation of added corrosion inhibitors. Changes in the normal radiation level in the closed loop could indicate leaks of radioactive water into the system.

The environmental and power supply design conditions are given on Table 7.12-4.

7.12.16.4 Inspection and Testing

All alarm trip circuits can be tested using test signals and the channel response can be verified using a portable gamma source.

TABLE 7.12-1

PROCESS RADIATION MONITORING
SYSTEMS CHARACTERISTICS

Monitoring System	Instrument Range (1)	Instrument Scale	Upscale Trips Per Channel	Downscale Trips Per Channel	Number of Channels
Main Steam Line	1 to 10^6 mR/hr	6 Decade Log	1	1	4
Main Condenser Air Ejector Offgas	1 to 10^6 mR/hr	6 Decade Log	1/3	1/1	2/2
Main Condenser Air Ejector Offgas	1 to 10^6 mR/hr with range switch	6 Decade linear	-	1	1
Main Stack	10^{-1} to 10^6 CPS (2)	7 Decade Log	2	1	2
Refueling Ventialtion Exhaust	0.1 mR/hr to 1 R/hr	4 Decade Log	1	1	4
Reactor Building Exhaust Vent	10^{-1} to 10^6 CPS (2)	7 Decade Log	2	1	2
Standby Gas Treatment Exhaust	1 to 10^4 mR/hr	4 Decade Log	1	1	1
Control Room Intake	0.01 to 100 mR/hr	4 Decade Log	1	1	1
Liquid Radwaste Discharge Header	10^{-1} to 10^6 CPS (2)	7 Decade Log	1	1	1
RBCCW Loop Liquid	10^{-1} to 10^6 CPS (2)	7 Decade Log	1	1	1

NOTE:

(1)Range of measurements is dependent on items such as the source geometry, background radiation, shielding, energy levels, and method of sampling.

(2)Readout is dependent upon the pulse height discriminator setting.

TABLE 7.12-2

MAIN STEAM LINE RADIATION MONITORING
SYSTEM REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Main steam line high radiation mechanical vacuum pump trip and discharge valve isolation	Main steam line high radiation channels	2 trip systems - 2 channels per trip system	A	Surveillance At least once during each operating cycle verify automatic securing and isolation of the mechanical vacuum pump.
			D	With any main steam line unisolated and the mode switch in STARTUP: 1 channel operable per operable trip system (D38-80)
			F	With any main steam line unisolated: 1 channel operable per operable trip system (F38-80)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Table 7.12-3 Deleted

TABLE 7.12-4

PROCESS RADIATION MONITORING
SYSTEM ENVIRONMENTAL AND POWER
SUPPLY DESIGN CONDITIONS

	Sensor Location		Main Control Room	
Parameter	Design Center	Range	Design Center	Range
Temperature	25°C	0° to + 60°C	25°C	5° to +50°C
Relative Humidity	50%	20 to 98%	50%	20 to 90%
Power, ac	115 V 60 cps	±10% ±5%	115 V 60 cps	±10% ±5%
Power, dc	+24 V dc -24 V dc	+22 to +29 V dc -22 to -29 V dc	+24 V dc -24 V dc	+22 to +29 V dc -22 to -29 V dc

TABLE 7.12-5

MAIN STACK RADIATION MONITORING SYSTEM REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Indicate whenever operational limits on the release of radioactive material to the environs are reached or exceeded and indicate the rate of radioactive material release during normal operation	Main Stack Radiation Monitoring System	2 monitoring channels	A	1 operable channel when gases are routed to the offgas vent (A1-77)
			B	1 operable channel when gases are routed to the offgas vent (B1-77)
			C	1 operable channel when gases are routed to the offgas vent (C3-77)
			D	1 operable channel when gases are routed to the offgas vent (D3-77)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.12-5 (Cont)

MAIN STACK RADIATION MONITORING SYSTEM REQUIREMENTS
FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Indicate whenever operational limits on the release of radioactive material to the environs are reached or exceeded and indicate the rate of radioactive			E	1 operable channel when gases are routed to the offgas vent (E6-77)
material release during normal operation (Cont)			F	1 operable channel when gases are routed to the offgas vent (F4-77)

* Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.12-6

REFUELING VENTILATION EXHAUST RADIATION MONITORING SYSTEM REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action ***
Initiate isolation of secondary containment and start standby gas treatment system.	Refueling ventilation exhaust radiation channels.	2 trip systems - 2 channels per trip system	A**	1 channel operable per trip system (A1-79) (A40-79)
			B**	1 channel operable per trip system (B1-79) (B40-79)
			C*	1 channel operable per trip system (C6-79)
			D*	1 channel operable per trip system (D3-79)
			E*	1 channel operable per trip system (E6-79)

NOTE: * Requirements apply in these states only when handling fuel over the spent fuel pool.

** Requirements apply in these states when handling fuel over the spent fuel pool or core.

*** Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

TABLE 7.12-6 (Cont)

REFUELING VENTILATION EXHAUST RADIATION MONITORING
SYSTEM REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action ***
Initiate isolation of secondary containment and start standby gas treatment system. (Cont)			F*	1 channel operable per trip system (F4-79)

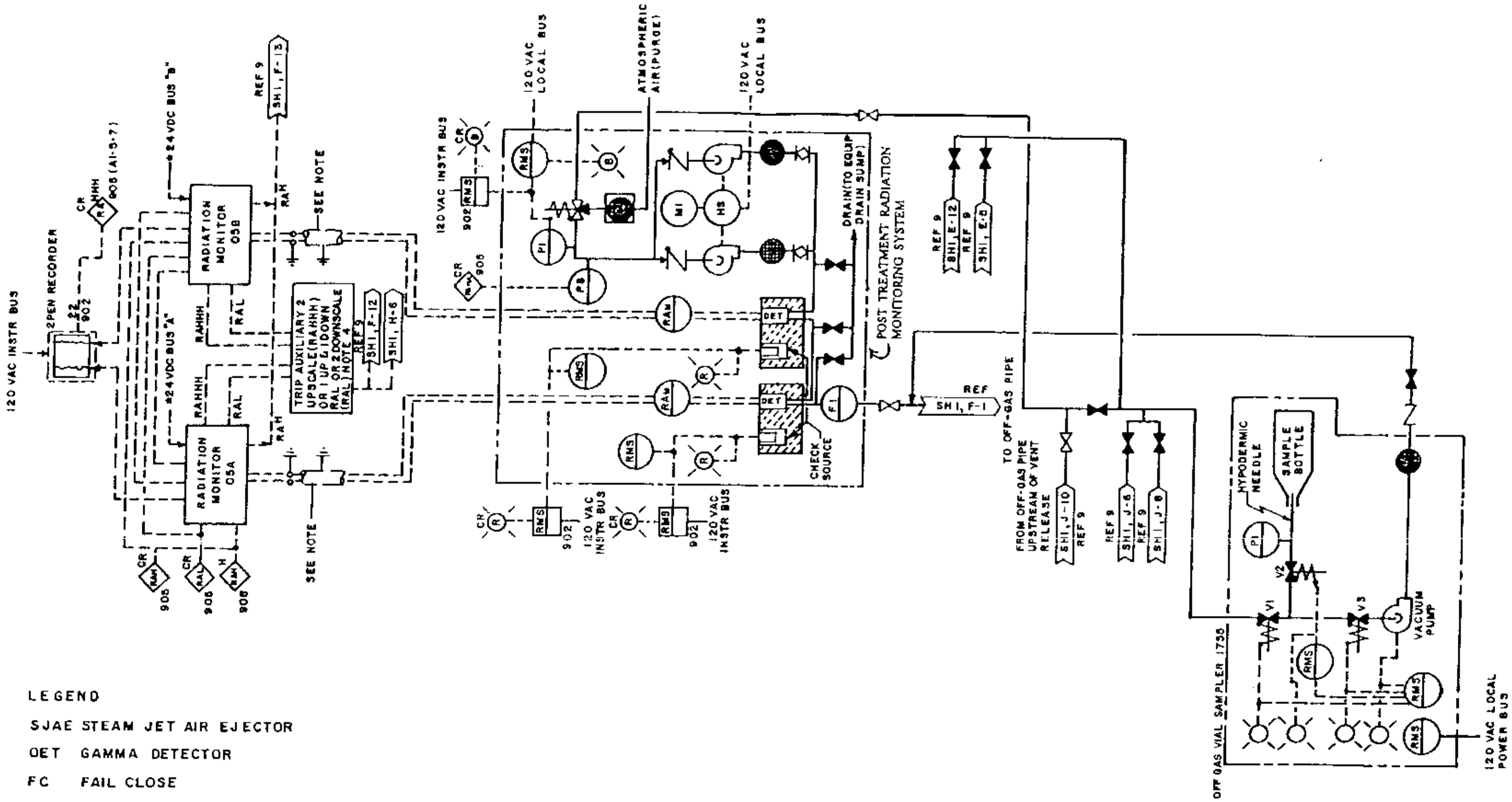
NOTE: * Requirements apply in these states only when handling fuel over the spent fuel pool.

** Requirements apply in these states when handling fuel over the spent fuel pool or core.

*** Minimum Required for Action is the minimum number of applicable components necessary to complete the associated Safety Action. Limiting Conditions for Operation may be different and are contained in the Technical Specifications referenced in Appendix B.

Figures 7.12-1 and 7.12-2 have been removed.

Please refer to BECo Controlled Drawings M1U 1-8 and M1U 101-7.



LEGEND

SJAE STEAM JET AIR EJECTOR

DET GAMMA DETECTOR

FC FAIL CLOSE

RAH RADIATION ALARM HIGH

RAL INSTRUMENT TROUBLE ALARM

RAHH RADIATION ALARM HIGH HIGH

UNLESS OTHERWISE NOTED WHERE THE DEVICE DESIGNATION IS SHOWN AS A TWO OR THREE DIGIT NO. WITH OR WITHOUT SUFFIX LETTER (02A). IT IS AN ABBREVIATION OF THE COMPLETE DEVICE DESIGNATION WHICH IS $\frac{902}{1706\text{-}02A}$

NOTE:
ALL CABLE SHALL COMPLY WITH G.E. ENGR. SPEC. REF. A

FIGURE 7.12-3
POST-TREATMENT RADIATION MONITORING SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 21 OCTOBER 1997

7.13 AREA RADIATION MONITORING SYSTEM

7.13.1 Power Generation Objective

The objective of the area radiation monitoring system is to warn of abnormal gamma radiation levels in areas where radioactive material may be handled or inadvertently introduced.

7.13.2 Power Generation Design Bases

1. The area radiation monitoring system shall provide operating personnel with a record, and an indication in the main control room of gamma radiation levels at selected locations within the various station buildings.

2. The area radiation monitoring system shall provide local alarms where it is necessary to warn personnel of substantial immediate changes in gamma radiation levels.

7.13.3 Description

7.13.3.1 Monitors

The area radiation monitoring system is shown as a functional block diagram on Figure 7.13-1. A typical channel consists of a combined sensor and converter unit, a combined indicator and trip unit, a shared power supply, and a shared multipoint recorder. In addition, some channels have a local audio alarm auxiliary unit. Each monitor has an upscale trip that indicated high radiation and a downscale trip that may indicate instrument trouble. These trips sound alarms but cause no control action. The system is powered from the 120 V ac instrument bus. The trip circuits are set so that loss of power causes an alarm. The environmental and power supply design conditions are given on Table 7.13-1.

7.13.3.2 Locations

Work areas where monitors will be located are tabulated on Table 7.13-2. Annunciation and indication are provided in the main control room.

7.13.4 Inspection and Testing

An internal trip test circuit, adjustable over the full range of the trip circuit is provided. The test signal is fed into the indicator and trip unit input so that a meter reading is provided in addition to a real trip. All trip circuits are of the latching type and must be manually reset at the front panel.

7.13.5 Local Readout Monitors

Certain areas of the plant, where the process changes can affect area radiation levels, are only provided with local readout radiation monitors. These monitors allow operators to observe conditions prior to entering and during the time spent working in these areas.

Criticality monitoring shall be in accordance with the requirements of 10CFR50.68(b).

TABLE 7.13-1

AREA MONITORING SYSTEM
ENVIRONMENTAL AND POWER SUPPLY
DESIGN CONDITIONS

	Sensor Location		Control Room	
Parameter	Design Center	Range	Design Center	Range
Temperature	25°C	0° to 60°C	25°C	5° to +50°C
Relative Humidity	50%	20 to 100%	50%	20 to 90%
Power	120V	±10%	120V	±10%
	60 cps	±5%	60 cps	±5%

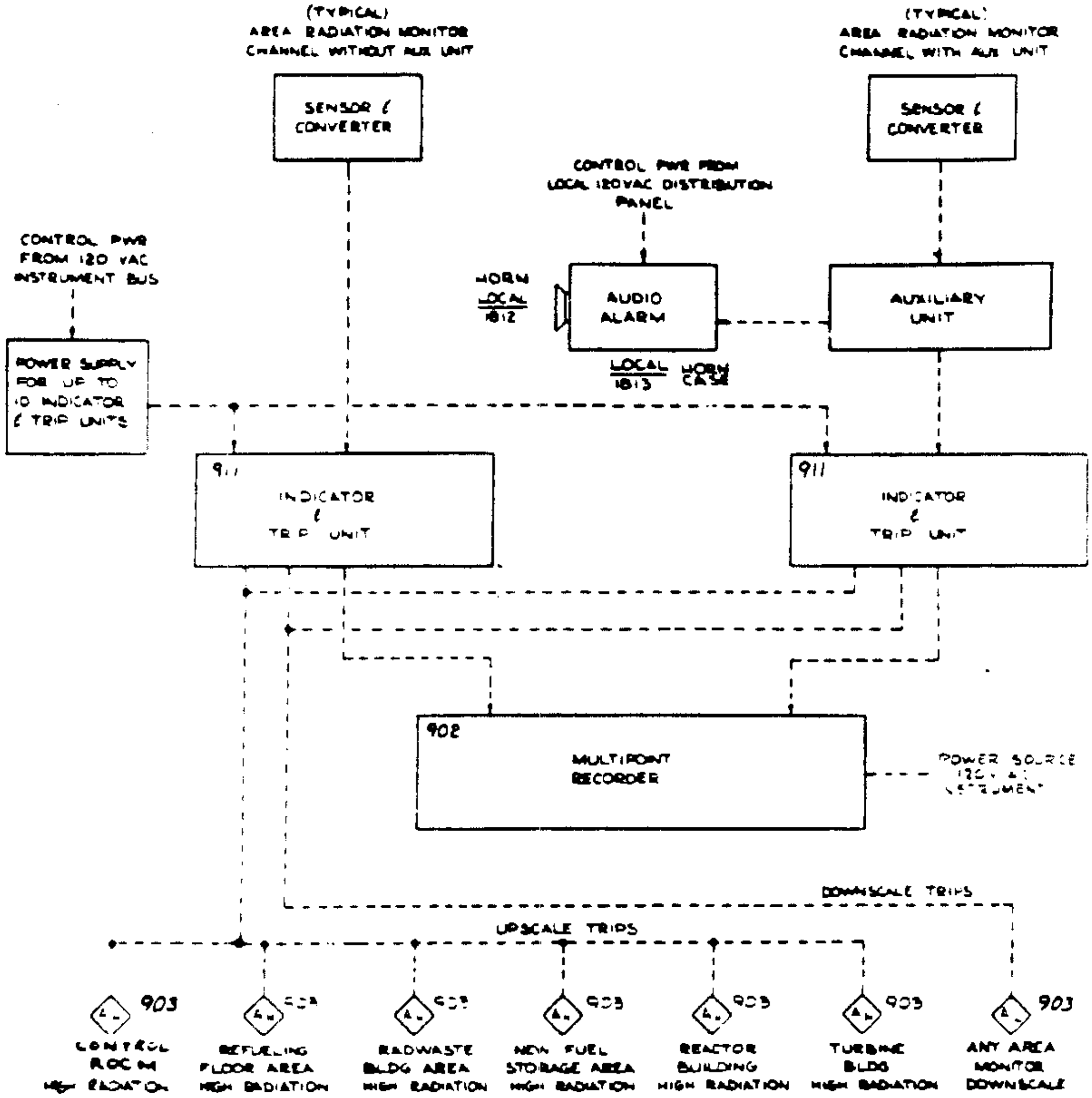
This table does not apply to Local Readout Monitors.

TABLE 7.13-2

LOCATIONS OF FIXED AREA
RADIATION MONITORS

Control Room Equip I/D	Range mR/hr	Detector Location
RIS-1815-3A	0.1 - 1,000	Condensate Pumps (stairway)
RIS-1815-8A	1.0 - 10,000	Feedwater Heaters (stairway)
RIS-1815-2A	0.01 - 100	Main Control Room
RIS-1815-8B	1.0 - 10,000	Turbine - Front Standard
RIS-1815-3B	0.1 - 1,000	Radwaste - Corridor
RIS-1815-8C	1.0 - 10,000	Radwaste - Sump Area
RIS-1815-8D	1.0 - 10,000	Chem. Waste RCVR TK, Inlet
RIS-1815-2B	0.01 - 100 Room	Reactor Building - Outside Tip
RIS-1815-2C	0.01 - 100	Radwaste Shipping Lock
RIS-1815-2D	0.01 - 100	Reactor Building (S.E.)
RIS-1815-3C	0.1 - 1,000	New Fuel Racks
RIS-1815-3D	0.1 - 1,000	New Fuel Storage Vault
RIS-1815-3E	0.1 - 1,000	Shield Plug Area
RIS-1815-3F	0.1 - 1,000	Spent Fuel Pool
RIS-1705-60	0.1 - 1,000	Charcoal Vault Area
--- *	1.0 - 10,000	Condensate Demineralizer Regeneration Room

* Local Readout Monitors, no Control Room indication/alarm.



THIS DIAGRAM DOES NOT APPLY TO LOCAL READOUT MONITORS

FIGURE 7.13-1
AREA RADIATION MONITORING SYSTEM, FUNCTIONAL BLOCK DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 11 - JULY 1990

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.

7.15 HEALTH PHYSICS AND LABORATORY ANALYSIS RADIATION MONITORS

Health Physics and laboratory radiation monitors are described in Section 12.4.2.

7.16 PROCESS COMPUTER SYSTEM

The Replacement Process Computer System (PCS) has contractually been designated the "Emergency and Plant Information Computer" (EPIC).

7.16.1 Power Generation Objective

The objectives of the Process Computer System are to provide a quick and accurate determination of core thermal performance, to improve data reduction, accounting, and logging functions; and to supplement procedural requirements for control rod manipulation during reactor startup and shutdown.

7.16.2 Safety Design Basis

The Process Computer System shall provide inputs to the rod block circuitry to supplement and aid in the enforcement of procedural restrictions on control rod manipulation, so that rod worth is limited to the values assumed in plant safety analyses.

7.16.3 Power Generation Design Basis

1. The Process Computer System shall be designed to periodically determine the three dimensional power density distribution for the reactor core, and provide printed logs which permit accurate assessment of core thermal performance.

2. The Process Computer System shall provide continuous monitoring of the core operating level, and appropriate alarms based on established core operating limits to aid the operator in assuring that the core is operating within acceptable limits at all times, including periods of maneuvering.

7.16.4 EPIC SYSTEM DESCRIPTION

7.16.4.1 GENERAL

The Pilgrim Nuclear Power Station (PNPS) Emergency and Plant Information Computer (EPIC) is a centralized, integrated system which performs the process monitoring and calculations defined as being necessary for the effective evaluation of normal and emergency power plant operation. The EPIC acquires and records process data including temperatures, pressure, flows, and status indicators. This data is then processed by the EPIC to produce meaningful displays, logs, and plots of current or historical plant performance and presented to plant personnel in the plant main control room or other user definable locations.

The EPIC can be functionally divided into major functional groupings which perform definable functions. These functional groupings are:

a. Main Processing Functions - performs functions entailing basic data manipulations and preprocessing.

b. Man-Machine Interface - performs the function of interfacing the human with the EPIC system.

c. Data Acquisition Functions - performs data acquisition and plant process instrumentation interface.

d. Performance Monitoring Functions - performs all functions necessary to evaluate the performance of the Nuclear Steam Supply System and Balance of Plant.

e. Transient, and Recording and Analysis Functions - performs analysis logging, plotting and recording functions.

f. Real-Time Analysis and Display Functions - performs all functions required to produce displays including display building and dynamic display processing functions.

A brief description of each major function is provided below.

7.16.4.1.1 MAIN PROCESSING FUNCTIONS

Main processing functions are those functions which are generic in nature and perform basic data preparation functions. Included in these functions are conversions, evaluation, alarming and data definition functions. This function of the EPIC performs any generic calculations and processing of data for display or further analysis. These functions include point compositions (generation of a point from 2 or more other points), limit checking, complex algorithm processing, and engineering unit conversions. In addition; many system level functions such as database building and security control (password, key lock, etc.) are a part of this EPIC function.

7.16.4.1.2 MAN-MACHINE INTERFACE

The Man-Machine Interface (MMI) performs the function of interfacing the EPIC with plant personnel. Using the interface, the user can place demands on the system or acknowledge information received by the system. The interface also presents the results of monitoring, calculations, and control actions taken to the user. MMI hardware consists of keyboards, function keys, CRT's, printers and types.

7.16.4.1.3 DATA ACQUISITION (DA)

The Data Acquisition functions perform the function of interfacing the EPIC with process variable instrumentation. This interface function is able to acquire real-time analog, digital, and pulse data simultaneously from the process instrumentation and make that data available to the EPIC. The Data Acquisition function has the ability to gather data at specified rates and is capable of accommodating user specific requirements for the gathering and transmitting of that process data.

The Data Acquisition function is provided by a modular set of solid state components. The data acquisition function samples the plant signals at rates of up to 250 samples/second for analog signals and 500 samples/second for digital signals. The data acquisition portion of the EPIC has provisions for checking, signal loop calibration, signal conditioning and self-testing. In addition, incoming data is provided with "time tags" in order to provide Sequence of Events determination. The data is interfaced with plant sensors via Input/Output modules (IOMs) and transmitted by fiber optic cable in order to provide a means to isolate the EPIC from existing plant equipment. Transmission via wire cable is also provided where isolation is not required.

7.16.4.1.4 PERFORMANCE MONITORING (PM)

The Performance Monitoring (PM) functions provide monitoring of total plant performance. The PM, in addition to being an evaluation tool, also aids in providing efficiency of plant operation. Evaluations are performed including, but not limited to, thermal power distribution, thermal limit margins, core and hot channel decay ratio, energy summaries, exposure accumulations, enthalpies, data summaries, calibration and diagnostics for analysis of the nuclear steam supply. In addition, provisions are available to include Balance of Plant performance calculation capabilities for turbine cycle, condenser, electrical, and feedwater heater performance analysis.

7.16.4.1.5 TRANSIENT RECORDING AND ANALYSIS (TRA)

The Transient Recording and Analysis (TRA) functions provide a real-time and historical perspective for the operation of the power plant. The purpose of the TRA functions is to provide high resolution recording capabilities for various plant parameters and means for event monitoring, data archival, plotting, trending, analyses, automatic and on-demand logging.

The TRA portion of the EPIC provides a means of data recording, archiving and analysis in order to support the determination and analysis of plant transients. Data recording and archiving capabilities can record changing plant parameters for up to 2-hours of pre-event data and 12-hours of post-event data. Data is then available for various outputs such as alarm logs, sequence of events report, trending, post trip logs, significant change reporting and plotting. In addition, analysis routines are available to provide statistical evaluation (such as means minimums, maximums, standard deviations) and time series analysis.

7.16.4.1.6 REAL-TIME ANALYSIS AND DISPLAY (RTAD)

The Real-Time Analysis and Display (RTAD) functions provide automatic reporting and display updating of plant parameters for current user requests. The RTAD shows critical plant parameters such as water levels, temperatures, pressures, flows, and status of pumps, valves, and other equipment. The RTAD is also capable of showing plant operational parameters.

The Real-Time Analysis and Display (RTAD) function of the EPIC provides real-time color graphic displays to provide a medium for the SPDS requirements of NUREG 0737, Supplement 1. The Real-Time Analysis and Display function provides the capability to display sampled data, status indications, synthesized data and trends. Displays on the RTAD hardware are updated at least every 2 seconds. Trend information can also be provided for up to 60 minutes of data. In addition to display capability, the RTAD function provides display creation functions.

Table 7.16-1 provides an instrumentation input summary of some of the nuclear system variables monitored by the process computer system (PCS).

Table 7.16-2 provides an instrumentation output summary of some of the signal requirements from the PCS to plant instrumentation.

7.16.4.2 Reactor Core Performance Function

7.16.4.2.1 Power Distribution Evaluation

The local power density for a specified axial segment of every fuel assembly is calculated, using plant inputs of pressure, temperature, flow, Local Power Range Monitor (LPRM) levels, control rod positions, and the calculated fuel exposure. Total core thermal power is calculated from a reactor heat balance. Iterative computational methods are used to establish a compatible relationship between the core coolant flow and core power distribution. The results are subsequently interpreted as local power at specified axial segments for each fuel bundle in the core.

After calculating the power distribution within the core, the computer uses appropriate reactor operating limit criteria to establish alarm trip settings (ATS) for each LPRM channel. The ATSs are expressed as maximum acceptable LPRM values to which the actual scanned LPRM readings are compared. These then assist the operator in maintaining core operation within permissible thermal limits established by prescribed maximum fuel rod power density and minimum critical power flux ratio criteria.

The core evaluation analytical sequence is completed periodically and on demand. Subsequent to executing the program, the computer prints a periodic log for record purposes.

7.16.4.2.2 LPRM Calibration

Flux level and position data from the traversing incore probe (TIP) equipment are read into the computer. The computer evaluates the data and determines gain adjustment factors by which the LPRM amplifier, gains can be altered to compensate for exposure-induced sensitivity loss. The LPRM amplifier gains are not to be physically altered except immediately prior to a whole core calibration using the TIP system. The gain adjustment factor computations help to indicate to the operator when such a calibration procedures is necessary.

7.16.4.2.3 Fuel Exposure

Using the power distribution data, a distribution of fuel exposure increments from the time of a previous power distribution calculation is determined and is used to update the distribution of cumulative fuel exposure. Each fuel bundle is identified by batch and location, and its exposure is stored for each of the axial segments used in the power distribution calculation. These data are printed out on demand by the operator.

7.16.4.2.4 Control Rod Exposure

Exposure increments are determined periodically for each one-quarter length section of each control rod. The corresponding cumulative exposure totals are periodically updated and printed out on demand by the operator.

7.16.4.2.5 LPRM Exposure

The exposure increment of each LPRM is determined periodically, and is used to update both the cumulative ion chamber exposures, and the correction factors for exposure dependent LPRM sensitivity loss, and can be printed out on demand by the operator.

7.16.4.2.6 Isotopic Composition of Exposed Fuel

The computer provides on-line capability to determine monthly and on demand the isotopic composition of each fuel bundle in the core. This evaluation consists of computing the weight of three uranium and five plutonium isotopes as well as the total uranium and total plutonium content. The isotopic composition is calculated for each one-quarter length of the fuel bundle and summed accordingly by bundles and batches. The method of analysis consists of relating the computed fuel exposure, and the exposure weighted void fraction for the given fuel segments to computer stored isotopic characteristic applicable to the specific fuel type. The output is to data files which can be obtained for future use and for additional data processing.

7.16.4.2.7 PNPS's Core Thermal Power Evaluation

CTP = Qfw + Qcr + Qcu + Qrad + Qp
where:

CTP = 100% License Core Thermal Power = 2028 MWt
Qfw = Power transferred to Feedwater Flow
Qcr = Power transferred to Control Rod Drive Flow
Qcu = Power loss in Cleanup Demineralizer System
Qrad = Radiative Power Loss
Qp = Power added by Recirculation Pumps

Station design documents and control calculations identify instrument loops and account for uncertainties to ensure licensed power level is not exceeded with a confidence of 95%.

7.16.4.2.8 Feedwater Correction Factor

Feedwater flow is the major component of the core thermal power evaluation. A correction factor within the computer provides a bias to account for feedwater flow element fouling and erosion.

7.16.4.2.9 SOLOMON

Core and Hot Channel Decay Ratio are required to be monitored during operation in the Buffer Zone. These parameters are calculated in the SOLOMON program from other process computer inputs, and printed out automatically or at operator request. These outputs provide the primary means of performing on-line stability monitoring. These actions are required during SLO, as well as dual recirculation loop operation. Section 3.7 provides discussion on the applicable operating conditions when SOLOMON is being used as the on-line stability monitor. Operator actions are required based on SOLOMON outputs and operating conditions as given in the table below:

Applicability	Condition	Require Action
Prior to planned entry into the Buffer Zone	SOLOMON results for predicted entry shall indicate Core decay ratio < 0.6 AND Hot channel decay ratio < 0.55	If not met, Entry prohibited
Prior to increasing power when operating in the Buffer Zone	SOLOMON results for predicted entry shall indicate Core decay ratio < 0.7 AND Hot channel decay ratio < 0.55	If not met, Power increase is prohibited.
During continued operation with thermal Power and Core Flow in the Buffer Zone	Every hour SOLOMON case shall indicate the following: Core decay ratio < 0.7 AND Hot channel decay ratio < 0.55	If not met, Immediately exit the Buffer Zone
Upon entry into the Buffer Zone due to a transient	SOLOMON results shall indicate: Core decay ratio < 0.7 AND Hot channel decay ratio < 0.55	If not met, Immediately exit the Buffer Zone

7.16.4.3 Rod Worth Minimizer Function

The rod worth minimizer (RWM) function assists and supplements the operator with an effective backup control rod monitoring routine that enforces adherence to established startup, shutdown, and low power level control rod procedures. The computer prevents the operator from establishing control rod patterns that are not consistent with prestored RWM sequences by initiating appropriate rod select block, rod withdrawal block, and rod insert block interlock signals to the reactor manual control systems rod block circuitry. The RWM sequences stored in the computer memory are based on control rod withdrawal procedures designed to limit and, thereby, minimize individual control rod worths to acceptable levels as determined by the design basis rod drop accident.

The RWM function does not interfere with normal reactor operation, and in the event of a failure does not itself cause rod patterns to be established which would violate the above objective. The RWM function may be bypassed and its rod block function disabled only by specific procedural control initiated by the operator.

The enforcement of the pre-stored RWM sequences is on a Rod-by-Rod basis. Multiple rod movements are grouped in to a "step", and the sequence of rod movements within each step must be followed. The enforcement software will issue interlock signals to ensure compliance with the pre-stored RWM sequences. The following operator and sensor inputs are utilized by the RWM:

7.16.4.3.1 RWM Inputs

1. Sequence

The operator can select either one of two permissible sequences to be enforced by the computer.

The operator is permitted to switch from sequence A to sequence B or vice versa at shutdown, and whenever the reactor is operating above the low power level set point.

2. Shutdown Margin Test Sequence

By selecting this input option, the operator is permitted to withdraw and re-insert any two control rods in the core while all other control rods are maintained in the fully inserted position.

3. Normal/Bypass Mode

A key lock switch is provided to permit the operator to apply permissives to RWM rod block functions at any time during plant operation.

4. System Start/Reset

This input is initiated by the operator to start or restart the RWM programs and system at any time during plant operation.

5. Control Rod Selected

The RWM recognizes the binary coded identification of the control rod selected by the operator.

6. Control Rod Position

The RWM recognizes the binary coded identification of the control rod position.

7. Control Rod Drive Selected and Driving

The RWM utilizes this input as a logic diagnostic verification of the integrity of the rod select input data.

8. Control Rod Drift

The RWM recognizes a position change of any control rod using the control rod drift indication. This information is used to evaluate permissible withdrawal or insertion of subsequently selected rods.

9. Reactor Power Level

Feedwater flow and steam flow signals are used to implement two digital inputs to permit program control of the RWM function. These two inputs, the low power setpoint and the low power alarm setpoint, are used to disable the RWM blocking function at power levels above the intended service range of the RWM function. The low power setpoint is initially set at 20 percent rated power. The low power alarm setpoint is initially set at 25 percent rated power.

10. Permissive Echoes

Rod select, rod withdraw, and rod insert permissive echo inputs are utilized by the RWM as a verification "echo" feedback to the system hardware to assure proper response of a RWM output.

11. Diagnostic Inputs

The RWM utilizes selected diagnostic inputs, such as parity error and stall alarm, to verify the integrity and performance of the processor.

7.16.4.3.2 RWM Outputs

The RWM provides isolated contact outputs to plant instrumentation as follows:

1. Blocks

The RWM is interlocked with the reactor manual control system to permit or inhibit selection, withdrawal, or insertion of a control rod. These actions do not affect any normal instrumentation displays associated with the selection of a control rod.

2. Scan Mode

This RWM output is used to synchronize acquisition of control rod position data during the scan mode.

7.16.4.3.3 RWM Indications

The RWM control panel provides the following indications:

1. Insert Error

Control rod coordinate identification for up to two insert errors.

2. Withdrawal Error

Control rod coordinate identification for one withdrawal error.

3. Latched Group

Identification of the RWM sequence group number currently enforced by the computer.

4. Sequence Select

Indication of the RWM sequence last selected by the operator.

5. Latched Sequence

Indication of the RWM sequence currently being enforced by the computer.

6. RWM Bypass

Indication that the RWM is manually bypassed.

7. Select Error

Indication of a control rod selection error.

8. Blocks

Indication that a selection block, withdrawal block, or insertion block is in effect for all control rods.

9. Low Power-Out of Sequence

Indication that the actual control rod pattern is out of sequence with the RWM sequence currently being monitored while the reactor is operating above the low power setpoint but below the low power alarm setpoint.

10. RWM Off Line

Indication that the RWM is unable to operate properly.

7.16.4.4 Monitor Alarm and Logging Functions

1. General

The processor is capable of checking each analog input variable against two types of limits for alarming purposes: (a) process alarm limits as determined by the computer during computation or as pre-programmed at some fixed value by the operator, and (b) a reasonableness limit of the analog input signal level as determined and programmed by the operator.

The alarming sequence consists of an audible high pitch tone, a console indication, and a typewriter message for the variables exceeding process alarm limits. An acknowledge pushbutton is provided to reset the high pitch tone and console indication to normal. A variable that is returning to normal is signified by an audible low pitch tone and typewritten message.

The processor provides the capability to alarm the system in the event of abnormal PCS operation. Abnormal conditions for alarm include but are not limited to over temperature, and selected program driven PCS contacts.

2. Event Recall Logging

The processor measures and stores the values of analog and/or digital variables at preset intervals to provide a history of nuclear system data. Select balance of station variables are measured at preset intervals to provide a history of balance of station data. An on demand request permits the operator to initiate typing of this data and to subsequently terminate the log printout.

The processor automatically prints the values of these analog and/or digital variables for the period immediately preceding and the period following a reactor scram. A scram is indicated by a digital signal internal to the processor.

3. Trend Logging

A trend capability is provided for logging the values of operator-selected analog and/or digital inputs and calculated variables. The periodicity of the log is limited to a nominal selection of intervals, which can be adjusted as desired by program control.

7.16.4.4.2 Digital Monitor and Alarm

1. Sequence Annunciator Recording

Selected digital inputs are implemented to provide for logging the sequence of contact closure or opening on the alarm output device. Input alarms received are sequentially differentiated and chronologically printed. The printout includes point description and time of occurrence to the nearest 1/60th of a sec.

2. Status Alarm

The status alarm function scans digital inputs at least once each second and provides a printed record of system alarms. The record includes point description and time of occurrence.

7.16.4.4.3 Alarm Logging

The alarm logs required by the associated process programs are typed by the alarm typewriter located in the control room. Alarm printouts are used to inform the operator of computer system malfunctions, system operation exceeding acceptable limits, and potentially unreasonable, off-normal, or failed input sensors.

7.16.5 Safety Evaluation

As described in the Station Safety Analysis (Section 14) for the initial core treatment of the control rod drop accident, the maximum rod worth below 20 percent power assumed was 0.025 k. The rod worth minimizer operates to maintain the maximum rod worth below 0.01 k. At levels above 20 percent of rated power, the maximum rod worth possible was assumed in the control rod drop accident cases; thus, no rod worth control is required above 20 percent of rated power. Should the rod worth minimizer program be inoperative for any reason, the reactor operator can maintain acceptable rod worth by simply adhering to prescribed control rod patterns and sequences when below 20 percent of rated power.

For the reload core, the rod worth assumed in the analysis of the control rod drop accident in the station safety analysis is referenced in Section 14.

7.16.6 Inspection and Testing

The process computer system is self checking. It performs diagnostic checks to determine the operability of certain portions of the system hardware, and it performs internal programming checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.

Table 7.16-1

INSTRUMENTATION INPUT SUMMARY

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
		NEUTRON MONITORING SYSTEM		
LPRM Level (Flux)	Analog	% PWR	Core Performance	1 sec scan class
APRM Level (Flux) (Channel A, C)	Analog	% PWR	Core Performance Event Recall Log	1 sec scan class
APRM Level (Flux) (Channel B,D,E,F)	Analog	% PWR	Core Performance	1 sec scan class
APRM Channel Bypass	Digital	Status	Status Alarm Log	1 sec scan class
APRM Trip on Level (Flux Chnl A,B,C,D,E,F)	Digital	Status	Sequence Annunciator Log	1 sec scan class
APRM Upscale Alarm on Level (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
APRM Downscale Alarm on Level (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
APRM Alarm on Instrument Inoperative (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
Flow Converter Upscale Trip/Alarm on Level/ Instrument Inoperative	Digital	Status	Status Alarm Log	1 sec scan class
Alarm on Flow Converter Comparator	Digital	Status	Status Alarm Log	1 sec scan class

Table 7.16-1

INSTRUMENTATION INPUT SUMMARY

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
NEUTRON MONITORING SYSTEM				
TIP Level (Flux) (System A,B,C,D)	Analog	% PWR	Core Performance	1 sec scan class
TIP Guide Tube Address (4 inputs per machine (Machine A,B,C,D)	Digital code Group	Selected Tube Location	Core Performance	1 sec scan class
TIP Probe at Top of Core	Digital	Status	Core Performance	1 sec scan class
TIP Probe Position	Digital	Status	Core Performance	1 sec scan class
TIP Machine Ready (System A,B,C,D)	Digital	Status	Core Performance	1 sec scan class
Reactor Neutron Monitor System Trip (A,B,C,D)	Digital	Status	Sequence Annunciator	1 sec scan class
SRM Detector Not in "Start-Up Position" (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
SRM Upscale Alarm on Level (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
SRM Alarm on Instrument Inoperative (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
SRM Bypassed (Any Channel)	Digital	Status	Status Alarm Log	1 sec scan class

Table 7.16-1 (Cont)

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
IRM Upscale Trip on Level (Chnl A,B,C,D,E,F,G,H)	Digital	Status*	Sequence Annunciator Log	1 sec scan class
IRM Detector Not in "Full In Position" (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
IRM Upscale Alarm on Level (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
IRM Downscale Alarm on Level (Any Channel)	Digital	Status	Status Alarm Log	1 sec scan class
IRM Alarm on Instrument Inoperative (Any Channel)	Digital	Status*	Status Alarm Log	1 sec scan class
IRM Bypassed (Any Channel)	Digital	Status	Status Alarm Log	1 sec scan class
RBM Level (Flux) (Channel A,B)	Analog	% PWR	Variable Alarm Log	1 sec scan class
RBM Trip on Level (Either Channel)	Digital	Status	Status Alarm Log	1 sec scan class
RBM Downscale Alarm on Level (Either Channel)	Digital	Status	Status Alarm Log	1 sec scan class
RBM Alarm on Instrument Inoperative (Either Channel)	Digital	Status	Status Alarm Log	1 sec scan class
RBM Bypass (Either or Both Channels)	Digital	Status	Status Alarm Log	1 sec scan class
REACTOR MANUAL CONTROL SYSTEM				
Control Rod Drive System Flow	Analog	GPM	Core Performance	1 sec scan class

Table 7.16-1 (Cont)

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
Control Rod Selected; Control Rod Pos., Tens; Control Rod Pos. Units; Rod Drift Alarm; Rod Selected and Driving	Digital Code Group	Rod Number, Notch Pos.	Core Performance and Rod Worth Minimizer	1 sec scan class
Control Rod Withdraw	Digital	Status	Core Performance	1 sec scan class
Discharge Vol. High Water Level Scram Trip (A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Refuel Interlock	Digital	Status	Status Alarm Log	1 sec scan class
Control Rod Timer Malfunction	Digital	Status	Status Alarm Log	1 sec scan class
Rod Pattern Sequence (A,B) Select	Digital	Status	Rod Worth Minimizer Status Alarm Log	1 sec scan class
Shutdown Margin Select	Digital	Status	Rod Worth Minimizer Status Alarm Log	1 sec scan class
RWM Rod Insert Permissive Echo	Digital	Status	Rod Worth Minimizer Status Alarm Log	1 sec scan class
RWM Rod Select Permissive Echo	Digital	Status	Rod Worth Minimizer Status Alarm Log	1 sec scan class
RWM Block	Digital	Status	Status Alarm Log	1 sec scan class
Rod Out Block	Digital	Status	Status Alarm Log	1 sec scan class
Discharge Volume High Water Level Rod Block	Digital	Status	Status Alarm Log	1 sec scan class

Table 7.16-1 (Cont)

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
RWM Rod Withdraw Permissive Echo	Digital	Status	Rod Worth Minimizer Status Alarm Log	1 sec scan class
RPIS Malfunction	Digital	Status	Status Alarm Log	1 sec scan class
		FEEDWATER CONTROL SYSTEM		
Reactor Feedwater Inlet Flow (A,B)	Analog	10^6 lb/hr	Core Performance Event Recall Log	1 sec scan class
Reactor Pressure	Analog	psig	Core Performance Event Recall Log	1 sec scan class
Reactor Water Level	Analog	In of Water	Core Performance Event Recall Log	1 sec scan class
Total Steam Flow	Analog	10^6 lb/hr	Event Recall Log	1 sec scan class
Low Power Level Alarm	Digital	Status	Rod Worth Minimizer	1 sec scan class
Low Power Level Interlock	Digital	Status	Rod Worth Minimizer	1 sec scan class
Reactor Feedwater Inlet Temperature (A1,A2,B1,B2)	Analog	°F	Core Performance Event Recall Log	1 sec scan class

Table 7.16-1 (Cont)

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
		REACTOR VESSEL INSTRUMENTATION		
Reactor Core Pressure Drop	Analog	psi	Core Performance Event Recall Log	1 sec scan class
Total Reactor Jet-Pump Flow (Core Flow)	Analog	10^6 lb/hr	Core Performance Event Recall Log	1 sec scan class
Total Recirculation Drive Flow (A1,A2,B1,B2)	Analog	KGPM	Core Performance	1 sec scan class
Recirculation Pump Motor Power (A,B)	Analog	10^6 Watts	Core Performance	1 sec scan class
Reactor Water Level (Channel A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Main Steam Line Isolation Valve Closure (A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Main Steam Line Leak Detection (A,B,C,D)	Digital	Status	Status Alarm	1 sec scan class
Reactor High Pressure (A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Main Steam Line High Flow (A,B,C,D)	Digital	Status	Status Alarm Log	1 sec scan class
Recirculation Loop Inlet Temperature (A1,A2,B1,B2)	Analog	°F	Core Performance	1 sec scan class

Table 7.16-1 (Cont)

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
		REACTOR PROTECTION SYSTEM		
Primary Containment High Pressure (A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Scram Discharge Volume Not Drained	Digital	Status	Status Alarm Log	1 Sec Scan Class
Manual Scram (Channel A,B)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Reactor Scram (Channel A,B)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Turbine Control Valve Fast Closure (A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
Turbine Stop Valve Closure (A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
		PROCESS RADIATION MONITORING SYSTEMS		
Main Steamline High Radiation (A,B,C,D)	Digital	Status	Sequence Annunciator Log	1 sec scan class
		REACTOR WATER CLEANUP SYSTEM		
Cleanup System Inlet Temperature	Analog	°F	Core Performance	1 sec scan class
Cleanup System Outlet Temperature	Analog	°F	Core Performance	1 sec scan class

Table 7.16-1 (Cont)

Primary Variable	Type of Input	Engr Units	Data Utilization	Data Acquisition Mode**
Cleanup System Flow (Channel A,B)	Analog	GPM	Core Performance	1 sec scan class
OTHER SYSTEMS				
Gross Generator Power	Analog	10^6 Watts	Core Performance	1 sec scan class
Gross Generator Energy	Pulse	KWH/Pulse	Core Performance	1 sec scan class

* Assume that no respective channel bypass is applied.

NOTE: TIP = Traversing Incore Probe

APRM = Average Power Range Monitor

LPRM = Local Power Range Monitor
SRM = Source Range Monitor

IRM = Intermediate Range Monitor
RBM = Rod Block Monitor

NOTE: ** The Process Computer (EPIC) signals are set at a 1 sec scan rate class as a minimum. A faster scan rate is used for selected input signals.

TABLE 7.16-2

INSTRUMENTATION OUTPUT SUMMARY
SIGNAL OUTPUT DESCRIPTION

TIP Position Enable
TIP Core Top Enable
RPIS Scan Mode
RPIS Next Rod

Figure 7.16-1 has been deleted.

7.17 NUCLEAR SYSTEM STABILITY ANALYSIS FOR INITIAL CORE

7.17.1 Power Generation Objective

The objective of the nuclear system stability analysis is to demonstrate that in the event of small disturbances, the reactor will always return to its normal operational state and remain within acceptable operational limits.

7.17.2 Safety Design Basis

To ensure that radioactive material barriers are not in danger of compromise, the nuclear system shall exhibit no inherent tendency toward divergent or limit cycle oscillations for all attainable operating conditions.

7.17.3 Power Generation Design Basis

To facilitate normal maneuvering and control, the nuclear system shall exhibit at least a specified minimum calculated amount of damping of its responses over all normally expected operating conditions.

7.17.4 Initial Core Description and Performance Analysis

7.17.4.1 Introduction

A boiling water reactor (BWR) consists of many interacting dynamic processes and associated control systems. A dynamic process may be defined as one in which the interrelated variables are time varying, e.g., the boiling of water in the reactor core. The process may be self regulating in that it exhibits a negative feedback effect. In a BWR, when a control rod is withdrawn, core power increases due to the reactivity insertion. This causes increased boiling. The increased boiling increases the steam volume in the core resulting in decreased neutron moderation. This is equivalent to removing reactivity to counteract the reactivity addition of the withdrawn control rod. Thus, a rise incore power is limited by the negative feedback effect of the increased steam volume. This inherent negative feedback effect present in BWRs serves as a self regulating mechanism upon core dynamics. A secondary inherent negative feedback effect, Doppler reactivity, also occurs as the fuel temperature varies with power. Whenever there is a negative feedback in a system, whether it be inherently self regulated in the process or added to the process by a control system, the stability characteristics must be considered. There are many definitions of stability, but for feedback processes and control systems, the following definitions may be used: a system is stable if, following a disturbance, the transient settles to a steady, noncyclic state. A system may also be acceptably safe even if oscillatory, provided the limit cycle of the oscillations is less than a prescribed magnitude. Instability, then, is a continuous departure from a final steady state value or it may be a greater-than-prescribed limit cycle about the final steady state value.

It is possible for an unstable process to be stabilized by the addition of a control system. In general, however, it is preferable that a process with inherent feedback be designed to be stable by itself before it is combined with other processes and control systems. The design of the BWR is based on this premise that individual system components are stable.

In the design of BWR systems, three types of stability are considered:

1. Channel hydrodynamic stability
2. Reactor core (reactivity) stability
3. Total system stability

Items 1 and 2 are concerned with the reactor core dynamics. In the design of the core, two types of stability are examined utilizing a linearized analytical model. First is the hydrodynamic channel stability of one or more types of channels operating in parallel with other channels in the core. This is considered because flow oscillations may impede heat transfer to the moderator and/or drive the reactor into power oscillations. Second is the reactivity feedback instability of the entire reactor core which could drive the reactor into power oscillations. Criteria have been established to ensure that the channels are hydrodynamically stable, and that reactivity feedback stability of the core is realized.

Item 3 is concerned with the total system dynamics. The dynamics of the control systems combined with those of the basic process determine the dynamics of the entire reactor system. A time domain analysis, compatible with the frequency domain model, is applied to evaluate the total system stability. A stable system is analytically demonstrated if no inherent limit cycle or divergent oscillation develops within the system as a result of calculated step disturbances of any critical variable, such as steam flow, pressure, neutron flux, and recirculation flow.

The criteria to be considered are stated in terms of two compatible parameters. First the decay ratio X_2/X_0 is defined as the ratio of the magnitudes of the second overshoot to the first overshoot resulting from a step perturbation. This is a graphic representation of the physical responsiveness of the system, which is readily evaluated in a time domain analysis. Second, the damping coefficient ζ_n is defined corresponding to the pole pair closest to the $j\omega$ axis in the s plane for the system closed loop transfer function. This parameter is also applicable to the frequency domain interpretation and is directly related to the decay ratio. This relationship is illustrated on Figure 7.17-1.

7.17.4.2 Reactor Core and Channel Hydrodynamic Stability Model Description

The mathematical model representing the core examines the linearized reactivity response of a reactor system with density dependent reactivity feedback due to boiling. In addition, the hydrodynamics of various hydraulically coupled reactor channels or regions are examined separately on an axially multinoded basis by grouping various channels which are thermodynamically and/or hydraulically similar. This interchannel hydrodynamic interaction or coupling exists through pressure variations in the inlet plenum, such as can be caused by disturbances in the flow distribution between the various regions or channels. This approach provides a reasonably accurate three dimensional representation of the reactor's hydrodynamics.

The model, which is shown in block diagram form on Figure 7.17-2, solves the dynamic equations which represent the reactor core in the frequency domain. From the solution of these dynamic equations, the reactivity and individual channel hydrodynamic stability of the BWR is determined for a given reactor flow rate, power distribution, and total power. This gives the most basic understanding of the inherent core behavior (and hence the system behavior), and is the principal consideration in evaluating the stable performance of the reactor. As new experimental or reactor operating data are obtained, refinements are made to the model to improve the capability and accuracy of the model.

On Figure 7.17-3, the competence of the core stability model is demonstrated and the inherent conservatism of the model is illustrated. The relationship of the calculated damping coefficient from the reactor core dynamic analytical code is related to measured results from 14 control rod oscillator tests performed at large operating BWR plants by the General Electric Company. The correlated most probable values are presented, based on a least squares determination, and the line below which there is 97.5 percent confidence that the actual values will fall is also presented on Figure 7.17-3.

The results show the analytical method to be an effective and useful design tool, with significant conservatism in its application to boiling water reactor core evaluation. Neal and Zivi[1] further confirm the effective application of essentially the same model to channel and core analyses.

7.17.4.3 Total System Analytical Stability Model Description

The plant model considers the entire reactor system, neutronics, heat transfer, hydraulics, and the basic processes, as well as associated control systems such as the flow controller, pressure regulator, feedwater controller, etc. Although the control systems may be stable when analyzed individually, final control system settings must be made in conjunction with the operating reactor so that the entire system is stable. The model yields results which are essentially

equivalent to those achieved with the core model and allows the addition of the controllers, which have adjustable features permitting the attainment of the desired performance of the system within the inherent capabilities of the channel and core behavior.

The model solves the dynamic equations which represent BWR system in the time domain. The various variables such as steam flow, pressure, etc, are represented as a function of time. The extensiveness of this model is shown in block diagram form on Figure 7.17-4. Many of the blocks are extensive systems in themselves.

7.17.5 Initial Core Ultimate Performance Limit Criteria and Conformance

7.17.5.1 Criteria Definition

The criteria that is to be observed is based on avoiding an inherent instability of total or component systems, whether manifest as a divergent oscillation or a limit cycle oscillation. The pertinent systems are analytically evaluated for compliance with the ultimate performance criteria.

The assurance that the total station is stable, and, therefore, has significant safety margin, shall be demonstrated analytically when the decay ratio X_2/X_0 is less than 1.0, or equivalently when the damping coefficient =h greater than zero for each type of stability discussed. Special attention is given to differentiate between inherent system limit cycles and small, acceptable, limit cycles which are always present, even in the most stable reactors. The latter are caused by physical nonlinearities (deadband, striction, etc.) in real control systems and are not representative of inherent hydrodynamic or reactivity instabilities in the reactor. On Table 7.17-1 these limits are summarized.

These criteria shall be satisfied for the station for all attainable and unusual operating conditions that may be encountered in the course of plant operation. For stability purposes, the most severe combination of conditions occur with end-of-life power peaking and natural circulation flow at a power corresponding to the rod block power limit condition.

7.17.5.2 Channel Hydrodynamic Conformance to the Ultimate Performance Criteria

The channel hydrodynamic performance evaluation is made at the most limiting condition which occurs at the end-of-core life. The calculations yield decay ratios as presented below:

Channel Hydrodynamic Performance	Natural Circulation Maximum Power
Decay Ratio, X_2/X_0	<0.46
Resonant Frequency, Hz:	0.334

At this most responsive attainable mode, rod block power at natural circulation with end-of-life power peaking, the most responsive channel is in conformance with the ultimate performance criteria of $\leq$1.0 decay ratio. In this reactor, the channel performance over the entire range of attainable operation is well below the threshold of instability.

7.17.5.3 Reactor Core Conformance to Ultimate Performance Criteria

The most limiting condition is that condition corresponding to natural circulation flow and a power level corresponding to the rod block power at the flow condition, with end-of-life power peaking. This represents the most responsive operating condition attainable, i.e., the condition having the least stability margin.

Reactor Core Stability	Natural Circulation Maximum Power
Decay Ratio, X_2/X_0	0.92
Resonant Frequency, Hz	0.371

The calculated values show the reactor to be in compliance with the ultimate performance criteria.

7.17.5.4 Total System Conformance to the Ultimate Performance Criteria

Conformance to the ultimate performance criteria is tested by assuming that the reactor is initially operating at the most sensitive condition, corresponding to natural circulation flow and a power level at the rod-block limit. The nuclear system is then subjected to step disturbances from control rods (about $0.10 worth), pressure regulator setpoint (10 psi), and level controller (6 in). These time responses, shown on Figures 7.17-5, 7.17-6, and 17.7-7, indicate that no limit cycle is present and that the decay ratio is less than 1.0 in conformance with the ultimate performance limit criteria.

7.17.6 Initial Operational Design Guide and Conformance

7.17.6.1 Design Guide Limit Definition

A decay ratio of 1/4 shall be observed for reactor core and total system conformance, and is based on accepted performance standards of the control industry for most process systems.[2] Although the absolute stability of the plant and reactor is assured as described in Section 7.17.5, it is the practice to design to a level of operational excellence that will allow normal maneuvering and control

with no undesirable, highly underdamped response. Therefore, after meeting the ultimate performance limit criteria for stability considering all attainable operating conditions, the station and reactor is then analyzed to conform with the operational design guide limits over all normally expected operating conditions. The operational design guide analysis for transient performance is conducted for the total system, the reactor core, and the channel hydrodynamics, utilizing the same analytical methods described in Section 7.17.4 for investigating stability.

The assurance that the plant has the desirable operational dynamic characteristics within the limits specified for the decay ratio X_2/X_0 or the damping coefficient ζ_n is demonstrated analytically under the heading "Acceptable Operational Design Guide Limits for Initial Core" on Table 7.17-2. The design performance is analyzed to bound any normal operating condition to be experienced, and compliance will be determined based on results of the analytical study.

These limits are satisfied for all expected power and flow conditions to be encountered in normal operation. The expected most limiting condition corresponds to that attained starting from 1998 MWt conditions and reducing flow, potentially to natural circulation, with a corresponding power reduction. The power and flow condition at which the above limits are analytically attained are recognized as the operational boundary for normal manual or automatic control. The total system stability analysis evaluates the relative stability of the total system, from time responses generated by applying step changes to the input variables to the total system stability model.

The channel hydrodynamic operational design guide limit is presented on Table 7.17-2 such as to allow locally more responsive operation than is allowed for the complete core or the total system. This is justified for a stable channel by the fact that the response of an individual component can be less damped than the total system as long as total performance is uncompromised, and local transients are not harmful. These can both be satisfied in the presence of a highly responsive, but stable, channel. Because of the short period of natural resonance relative to the slow response of heat transfer, the local channel transients will not be manifested as significant local heat flux transients.

7.17.6.2 Channel Hydrodynamic Conformance to the Operational Design Guide

The channel hydrodynamic performance calculation yields the decay ratio to be encountered at rated operating conditions and at natural circulation and the corresponding nominal power.

Channel Hydrodynamic Performance	Rated Conditions	Natural Circulation
Decay Ratio, X_2/X_0	<0.01	0.28
Frequency Hz	0.538	0.342

The most responsive channel is therefore in conformance with the operational design guide of ≤ 0.5 decay ratio.

7.17.6.3 Reactor Core Conformance to the Operational Design Guide

The calculated decay ratio, X_2/X_0 varies along the rated power-flow control line from 0.01 at rated power and flow to 0.59 at that power level corresponding to natural circulation, See Figure 7.17-8. It can be seen that the flow control range from design power and flow to that point on the flow control line corresponding to 65 percent power does not violate the Operational Design Guide limits of decay ratio equal to 0.25. Thus, the flow control operating range to be covered during normal operation is to be limited to 35 percent of 1998 MWt, although it is indicated that the system will perform satisfactorily beyond this stated limit.

7.17.6.4 Total System Conformance to the Operational Design Guide

For expected normal operating modes, the time response of each of the primary response variables of the reactor system to small step disturbances can be underdamped, but must analytically show a decay ratio of less than 1/4 in order to satisfy the Operational Design Guide limit. Each of the following disturbances are analytically imposed, one at a time, using the model previously described for time domain analysis:

1. A pressure regulator setpoint change of 10 psi

2. A control rod position change equivalent to a 10-cent reactivity change

3. A recirculation flow decrease and increase equivalent to a turbine steam flow change of 10 percent near full power

4. A reactor water level setpoint change of 6 in

The calculated responses of the primary variables to the reactivity step change, to the pressure setpoint change, to the level setpoint change, and to the load demand perturbation are shown on Figures 7.17-9, 7.17-10, 7.17-11, 7.17-12 and 7.17-13, respectively, for 1998 MWt operating conditions. Figures 7.17-14, 7.17-15, 7.17-16, and 7.17-17, respectively, give the responses at the nominal power corresponding to the analytically acceptable lower end of the power-flow control path, 65 percent power and 50 percent flow. In all cases, the decay ratio of each of the primary response variables is less than 1/4, thus good dynamic damping is indicated for expected normal operating conditions in conformance with the Operational Design Guide. The total system response does not in this case constrain the operating range. The reactor core performance analysis has therefore provided the only limiting constraint on normal operating range, as indicated in the previous section.

7.17.7 Initial Core Summary

The stability of the station, including the basic process, associated equipment, and control systems have been evaluated by an extensive plant analytical simulation model. Selected near-step perturbations were introduced into the station during startup testing to demonstrate the acceptable time response behavior of the reactor system at various conditions of operation. Compliance with the ultimate performance limit criteria was demonstrated at the attainable operational extremes, and as was evidenced by the absence of divergent oscillations or limit cycle oscillations, excluding those minor fluctuations induced by the controller deadband characteristics.

Compliance with the Operational Design Guide at selected normal operating conditions was approximately assessed insofar as the near- step perturbation obtainable approximates the analytical step disturbance. This assured desirable control and acceptable operating characteristics in all modes to be encountered.

7.17.8 Reload Case

For the reload core, channel hydrodynamic and core stability can be significantly affected by the selection of reload fuel type, and the reload core configuration. The reload core is reanalyzed using the models and methods described in GE, Standard Application for Reactor Fuel.(3) The applicable evaluation criteria are also identified.(3) The results of the reload analysis are documented in Supplemental Reload License Submittal for Pilgrim Station, in Appendix Q.

7.17.9 References

1. Neal, L.G. and Zivi, S.M., The Stability of *Boiling Water Reactors and Loops*, *Nuclear Science* Engineering, 30 25 (1967).

2. Process Instruments and Controls Handbook, Considine, McGraw Hill, 1957.

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

Table 7.17-1

ACCEPTABLE ULTIMATE PERFORMANCE LIMITS

Type of Dynamic Performance	Ultimate Performance Limit Criteria
Channel Hydrodynamic	x_2/x_0 <1
Stability	ζ_η >0
Reactor Core (Reactivity)	x_2/x_0 <1
Stability	ζ_η >0
Total System	x_2/x_0 <1
Stability	ζ_η >0

Where x_2/x_0 is the decay ratio and ζ_η is the damping coefficient

Table 7.17-2

ACCEPTABLE OPERATIONAL DESIGN LIMITS
FOR INITIAL CORE

Type of Dynamic Performance	Operational Design Guide Limits
Channel Hydrodynamic Performance	$x_2/x_0 \leq 0.5$ $\zeta_\eta \geq 0.11$
Reactor Core (Reactivity) Performance	$x_2/x_0 \leq 0.25$ $\zeta_\eta \geq 0.22$
Total System Performance	$x_2/x_0 \leq 0.25$ $\zeta_\eta \geq 0.22$

where x_2/x_0 is the decay ratio and ζ_η is the damping coefficient.

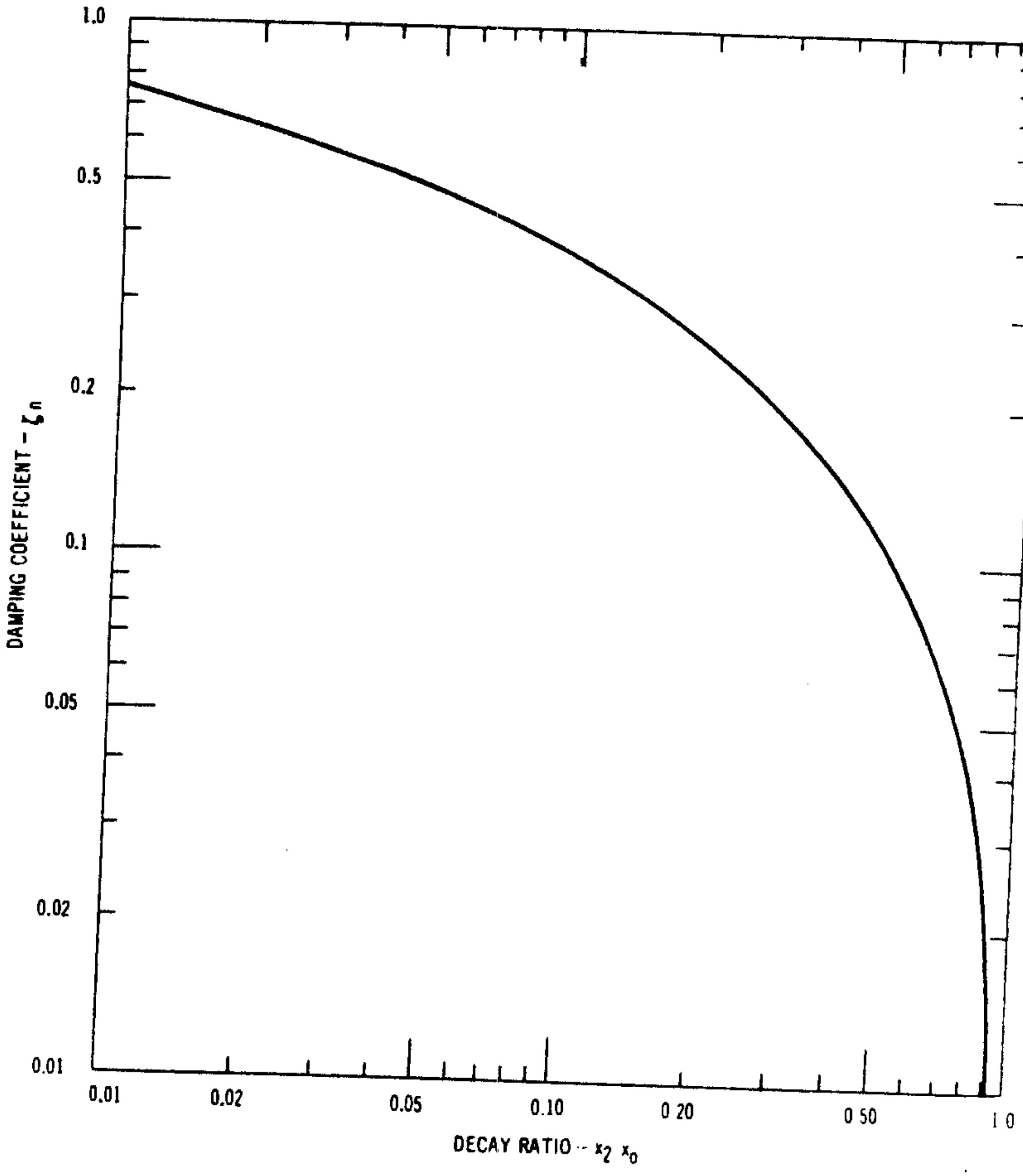


FIGURE 7. 17-1
DAMPING COEFFICIENT
VERSUS DECAY RATIO
(SECOND ORDER SYSTEMS)
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

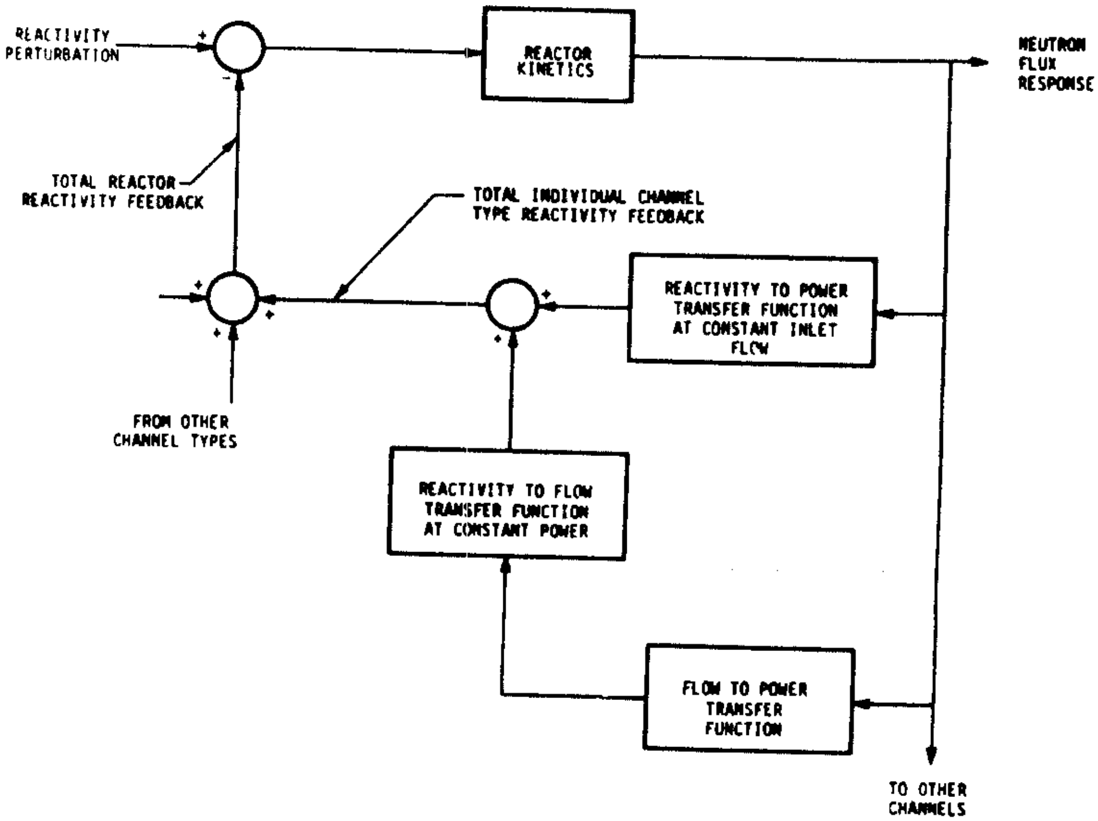


FIGURE 7.17-2
HYDRODYNAMIC AND CORE STABILITY MODEL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

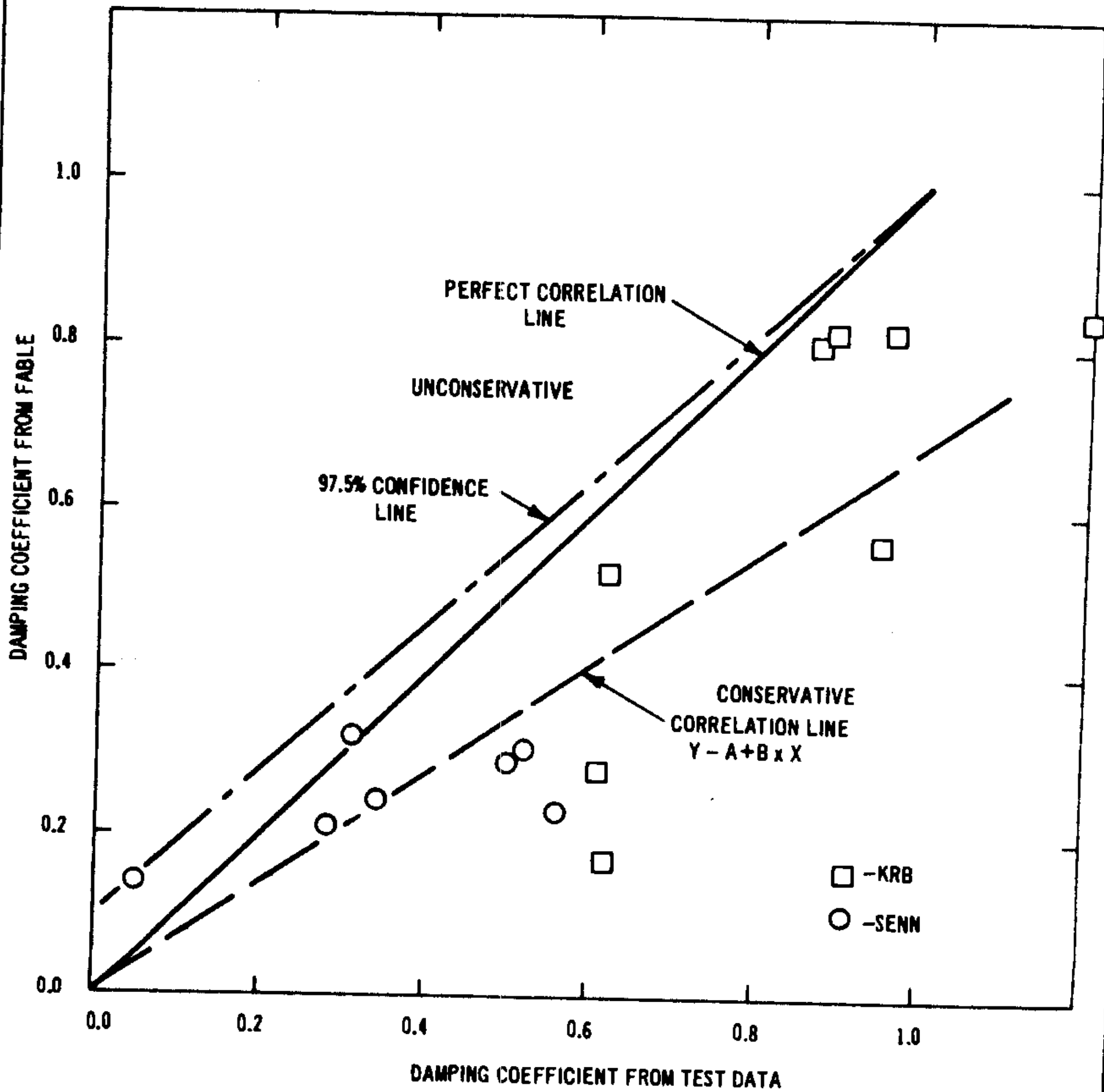
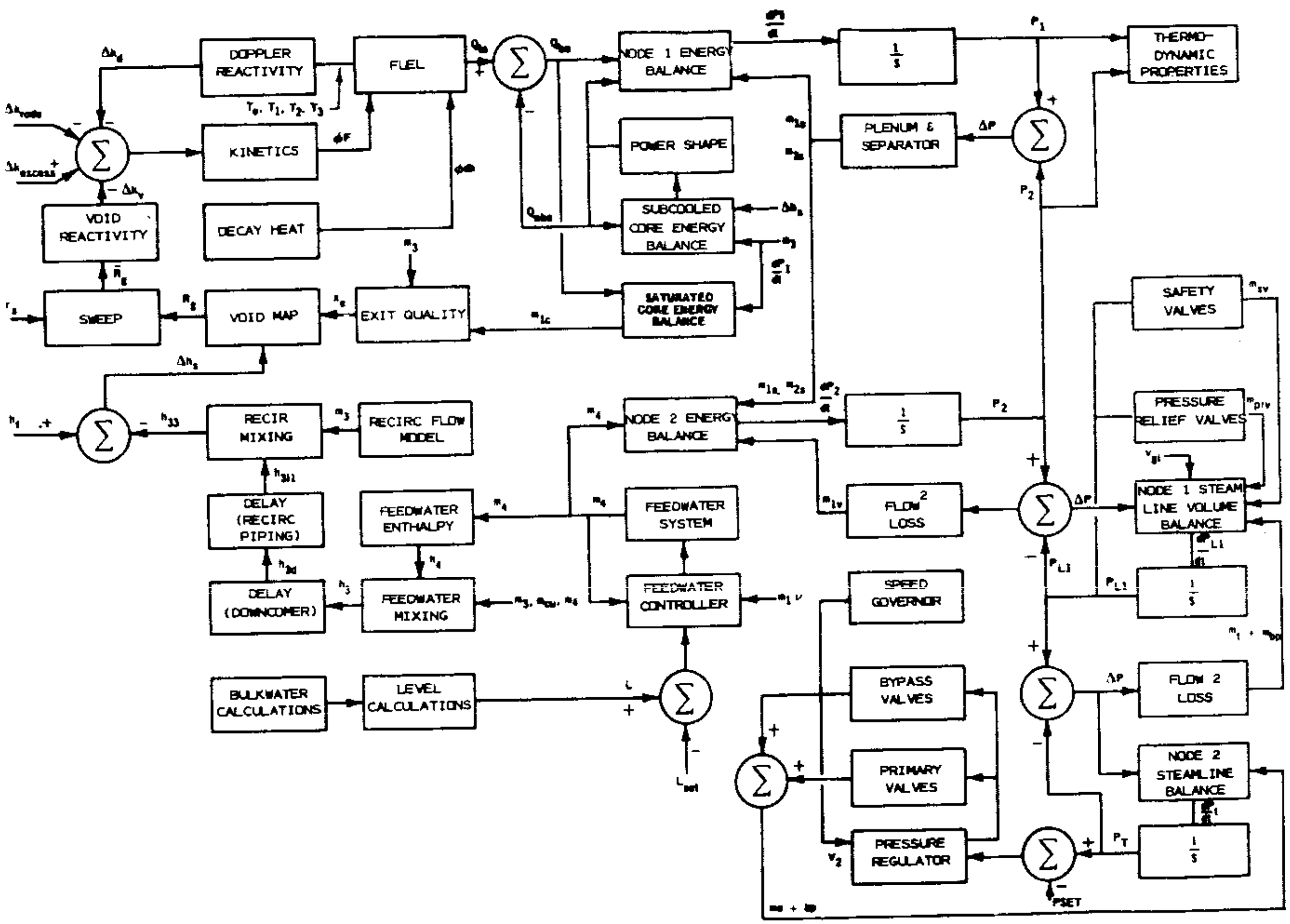


FIGURE 7.17-3
COMPARISON OF TEST RESULTS WITH REACTOR CORE ANALYSIS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



- h_f = SATURATED ENTHALPY
- h_{3d} = ENTHALPY OF DOWNCOMER FLUID
- h_4 = FEEDWATER ENTHALPY
- h_{33} = CORE INLET ENTHALPY
- h_{3d} = DELAYED ENTHALPY—ENTHALPY OF FLUID AT ENTRANCE TO RECIRCULATION LOOPS
- h_{3l1} = ENTHALPY OF FLUID IN 4th RECIRCULATION LOOP
- L = REACTOR VESSEL WATER LEVEL
- L_{set} = LEVEL SET POINT
- m_3 = RECIRCULATION MASS FLOW RATE
- m_4 = FEEDWATER MASS FLOW RATE
- m_{1c} = CORE EXIT-STEAM MASS FLOW RATE
- m_{1s} = SEPARATOR STEAM FLOW RATE
- m_{1v} = VESSEL STEAM FLOW
- m_{2s} = SEPARATOR SATURATED WATER MASS FLOW RATE
- $m_t + bp$ = STEAM FLOW TO THE TURBINE AND BYPASS
- m_{cu} = SATURATED VAPOR MASS FLOW RATE OUT OF NOTE 2 (DOME)
- m_{prv} = PRESSURE RELIEF VALVE MASS FLOW RATE
- m_{sv} = SAFETY VALVE MASS FLOW RATE
- P_1 = PRESSURE—NOTE 1 (CORE)
- P_2 = PRESSURE—NOTE (DOME)
- P_{L1} = PRESSURE—STREAMLINE NODE 1
- P_T = TURBINE PRESSURE
- P_{set} = PRESSURE SET POINT
- Q_{ba} = BOILING ACTIVE HEAT (HEAT TO SATURATED REGION OF THE CORE)
- Q_{nba} = NONBOILING ACTIVE HEAT (HEAT TO SUBCOOLED REGION OF THE CORE)
- Q_{ta} = TOTAL ACTIVE CORE HEAT
- R_g = CORE AVERAGE VOID FRACTION
- T_0 = FUEL TEMPERATURE—CENTER OF FUEL ROD
- T_1 = FUEL TEMPERATURE—RADIUS r_1 OF FUEL ROD
- T_2 = FUEL TEMPERATURE—RADIUS r_2 OF FUEL ROD
- T_3 = FUEL TEMPERATURE—RADIUS r_3 OF FUEL ROD
- V_2 = SPEED GOVERNOR DEMAND SIGNAL
- v_{g1} = SPECIFIC VOLUME—NODE 1 STEAMLINE
- Δhs = REACTOR SUBCOOLING
- Δk_d = DOPPLER REACTIVITY
- Δk_{excess} = FUEL EXCESS REACTIVITY
- Δk_{rods} = CONTROL ROD REACTIVITY
- Δk_{scram} = SCRAM REACTIVITY
- Δk_v = VOID REACTIVITY
- ϕ_{dh} = DECAY HEAT
- ϕ_f = NEUTRON FLUX WHICH PRODUCES HEAT IN THE FUEL
- τ_s = SWEEP TIME CONSTANT

FIGURE 7.17-4
TOTAL SYSTEM STABILITY MODEL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

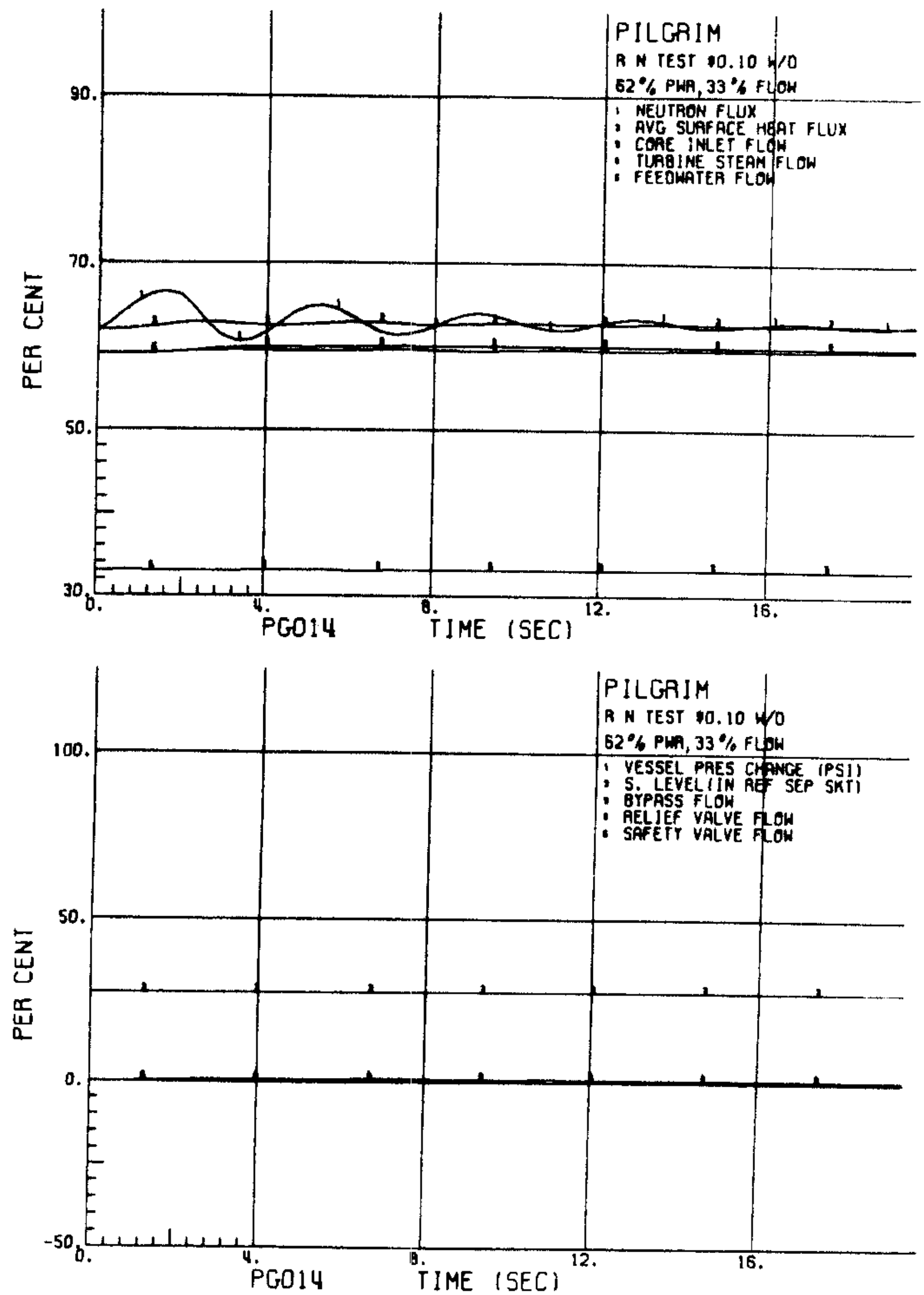
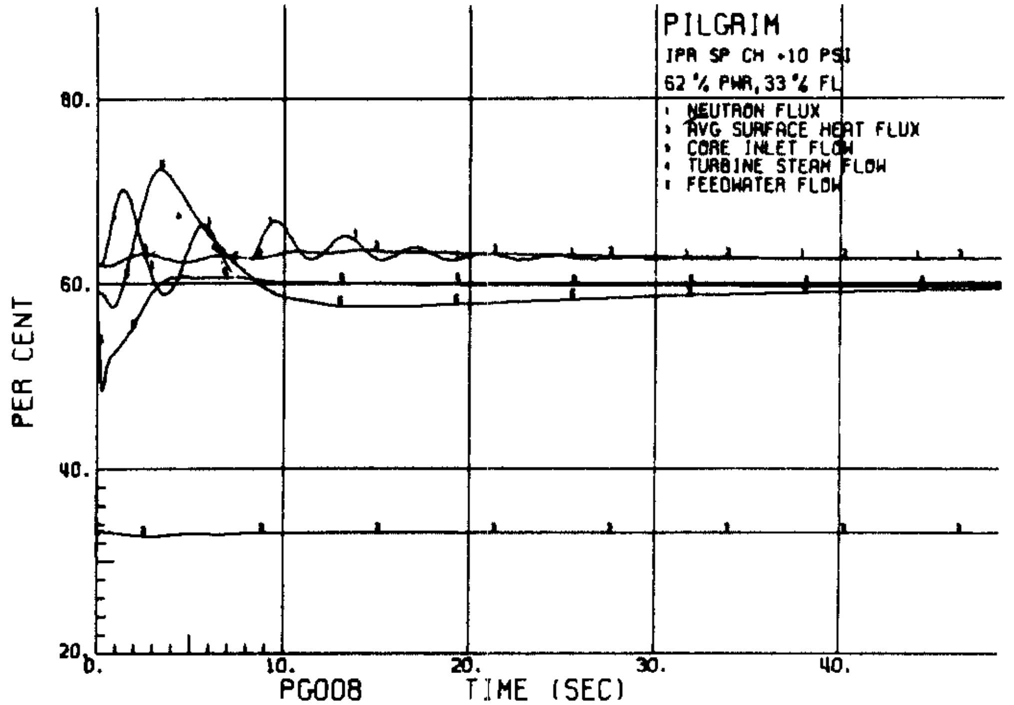


FIGURE 7.17-5
INITIAL CORE
10-CENT ROD REACTIVITY STEP
AT ROD BLOCK POWER
AND NATURAL CIRCULATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



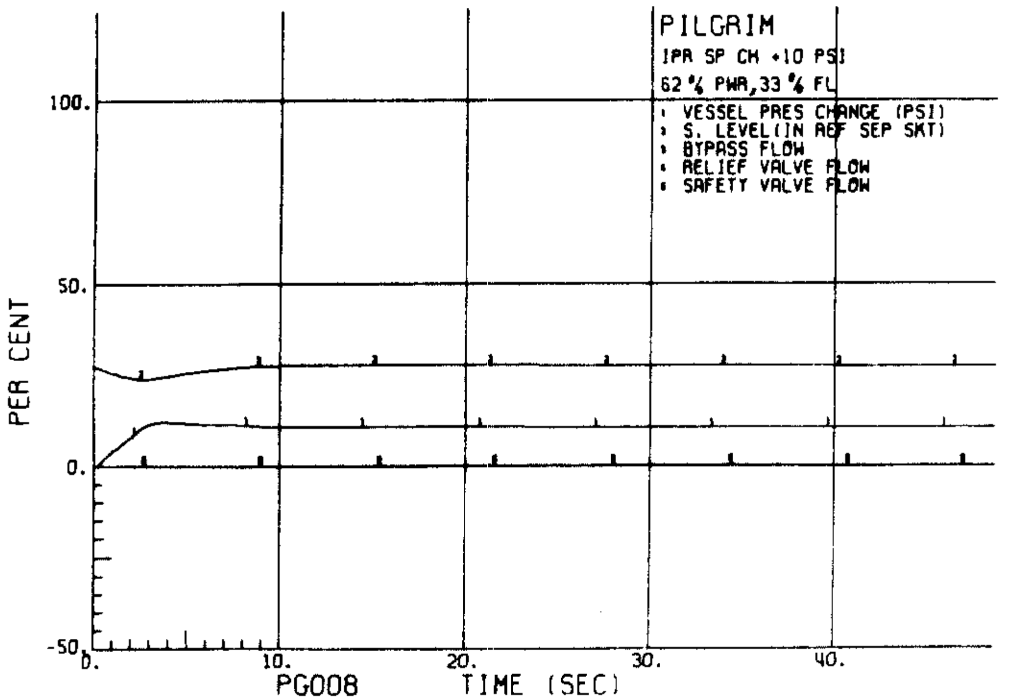
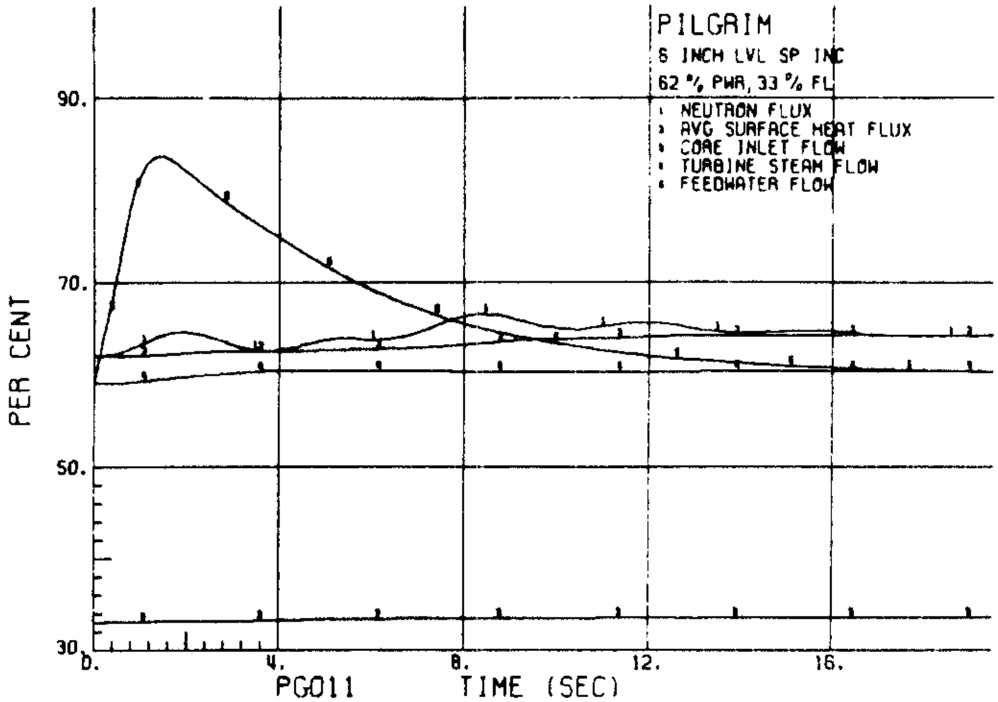


FIGURE 7.17-6
INITIAL CORE
10 PSI PRESSURE REGULATOR
SETPOINT STEP AT ROD-BLOCK
POWER AND NATURAL CIRCULATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



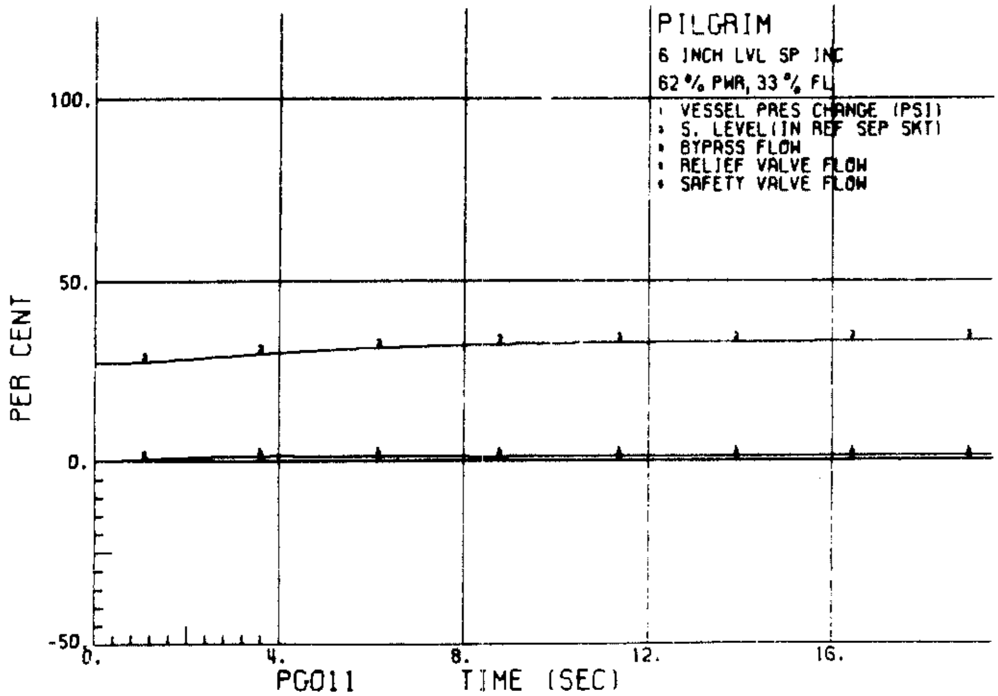


FIGURE 7.17-7
INITIAL CORE
6-INCH WATER LEVEL SETPOINT
STEP AT ROD-BLOCK POWER
AND NATURAL CIRCULATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

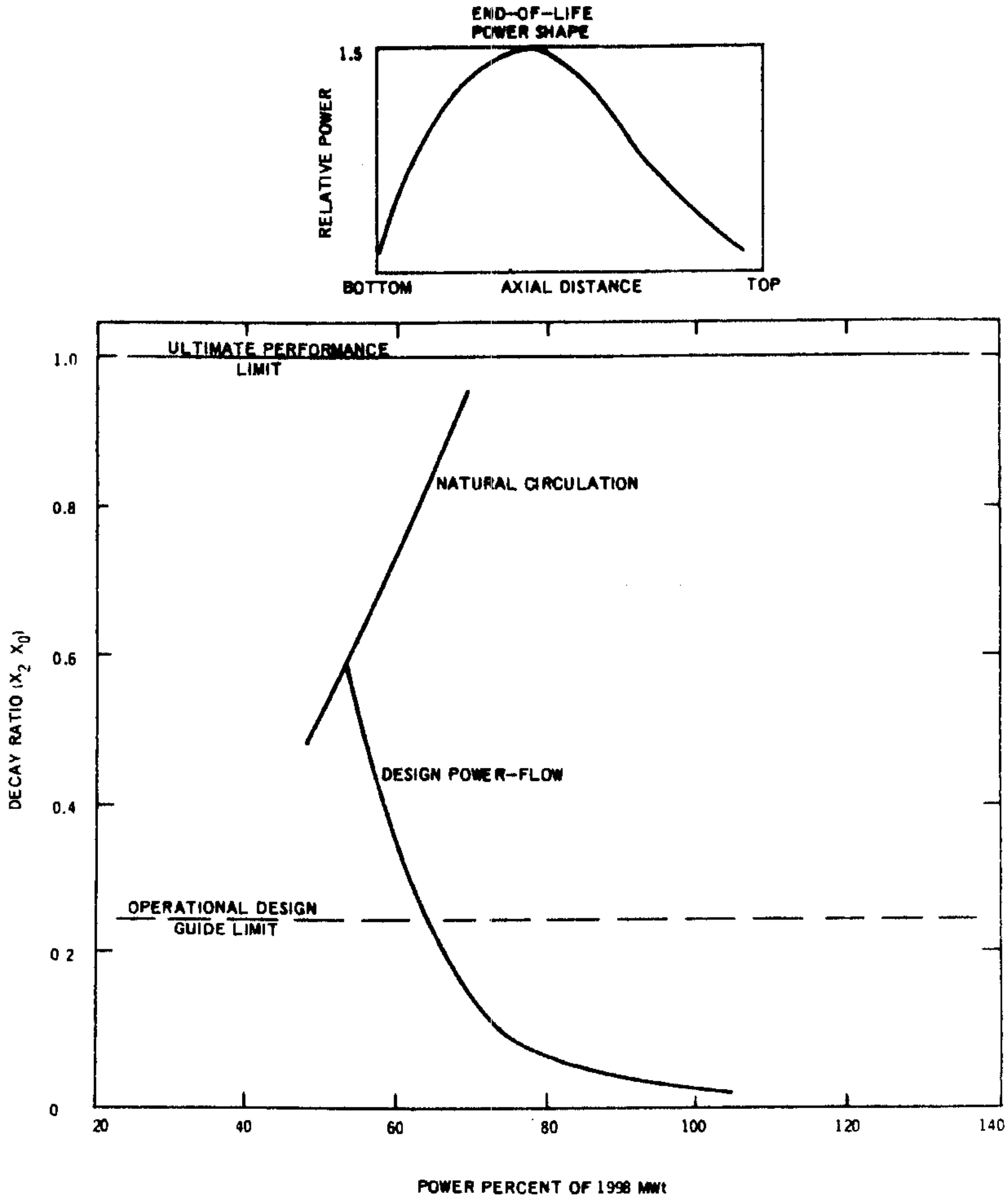


FIGURE 7.17-8
INITIAL CORE
DECAY RATIO END-OF-LIFE
POWER PEAKING
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

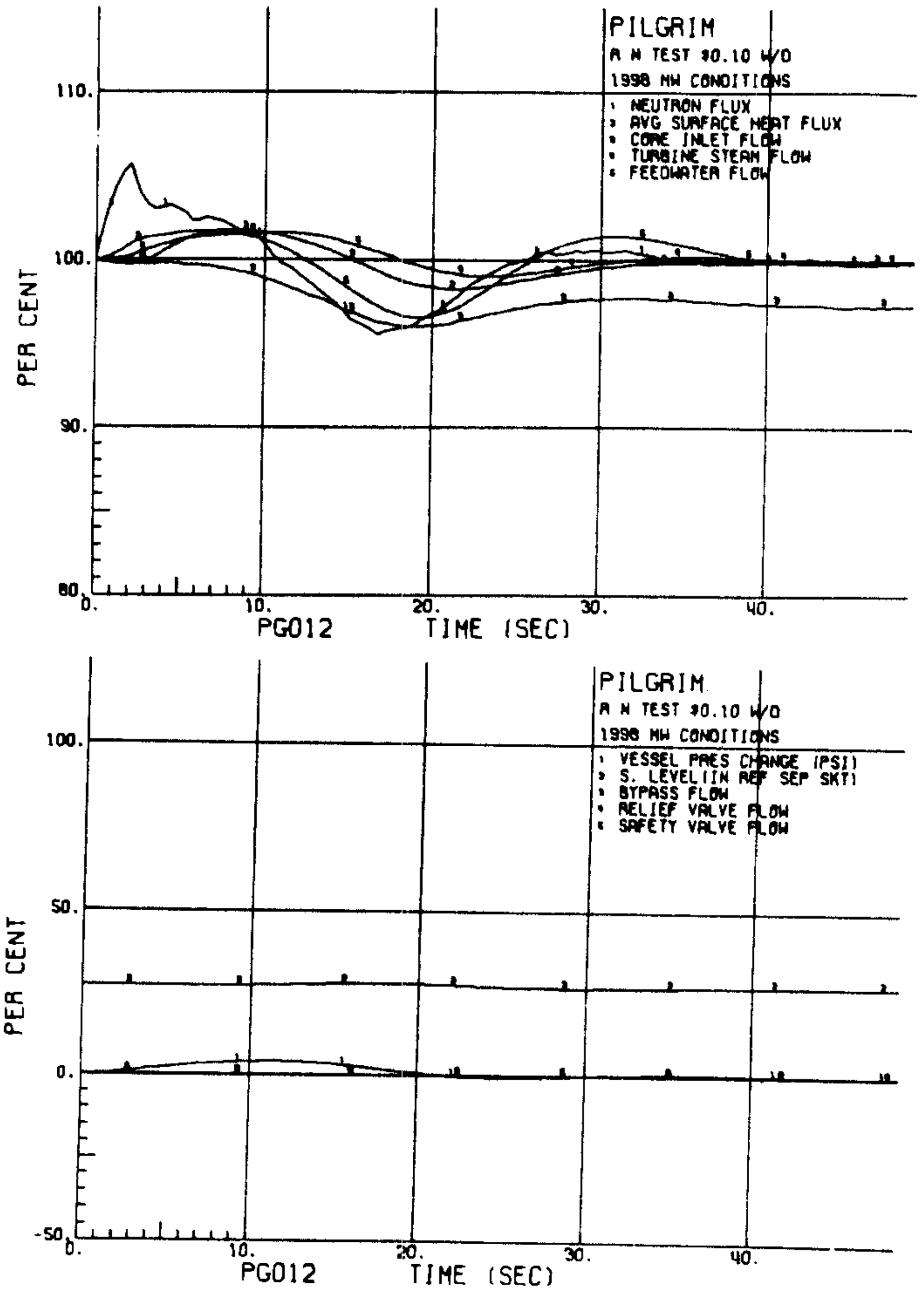
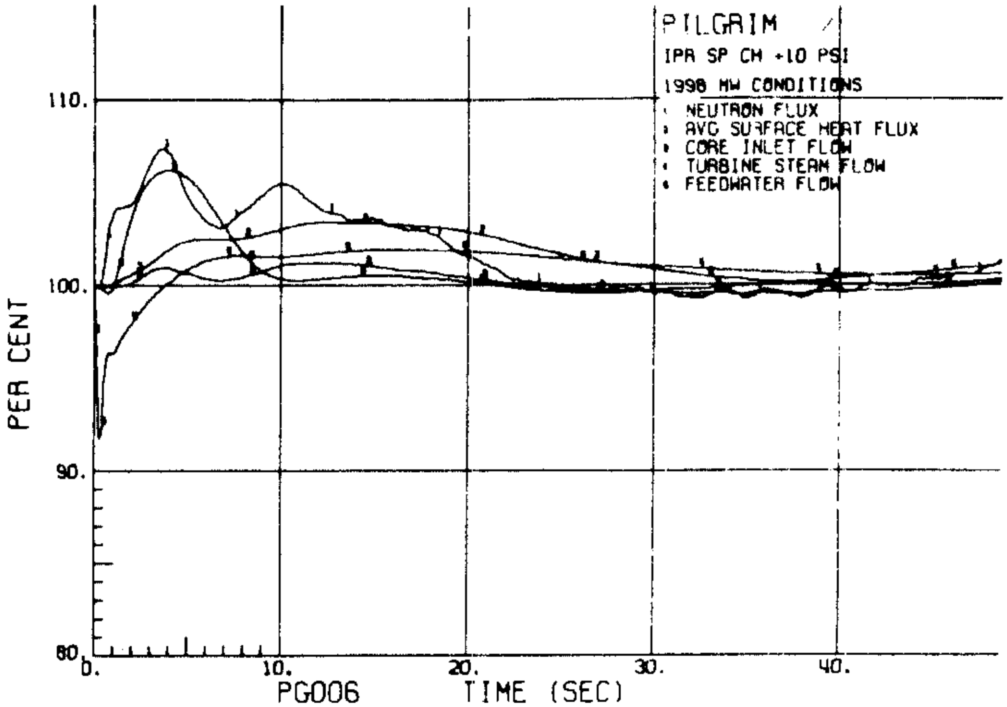


FIGURE 7.17-9
INITIAL CORE
10-CENT ROD REACTIVITY STEP
AT 1998 MWt CONDITIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



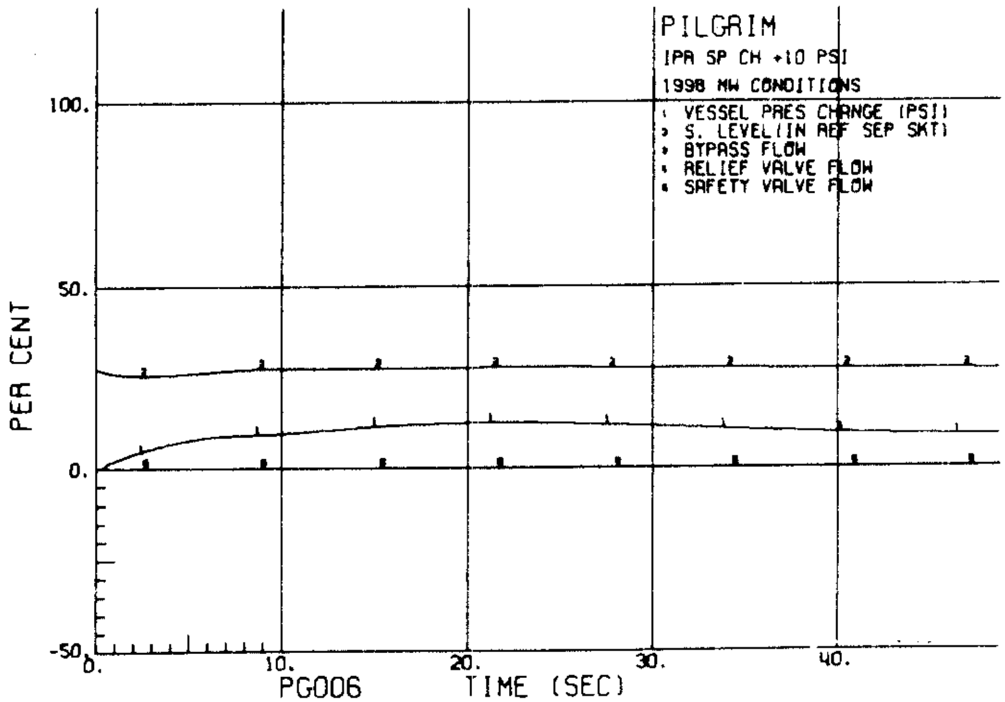


FIGURE 7.17-10
INITIAL CORE 10 PSI
PRESSURE REGULATOR SETPOINT
STEP AT 1998 MWt CONDITIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

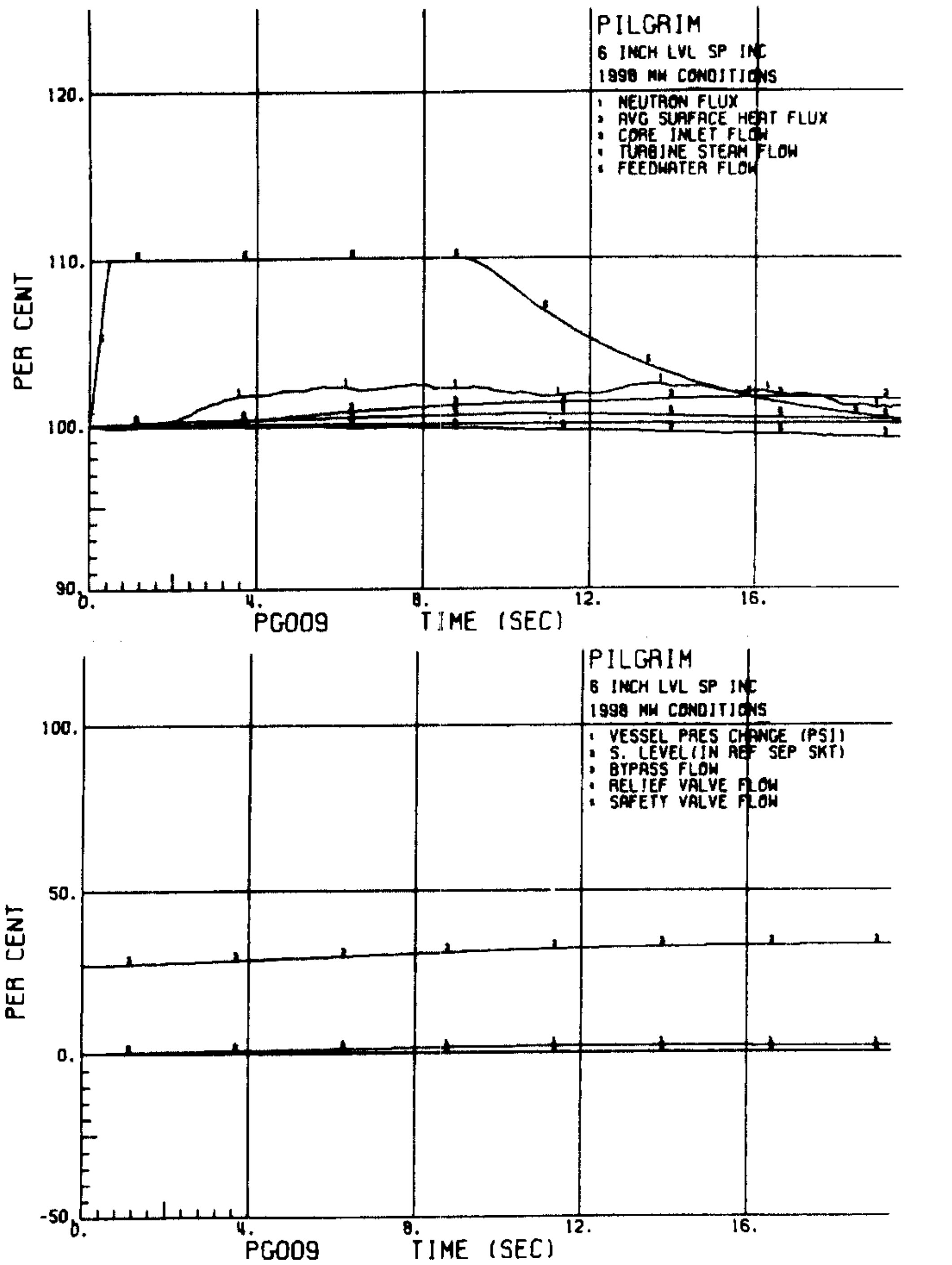


FIGURE 7.17-11
INITIAL CORE
6-INCH WATER LEVEL SETPOINT
STEP AT 1998 MWt CONDITIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

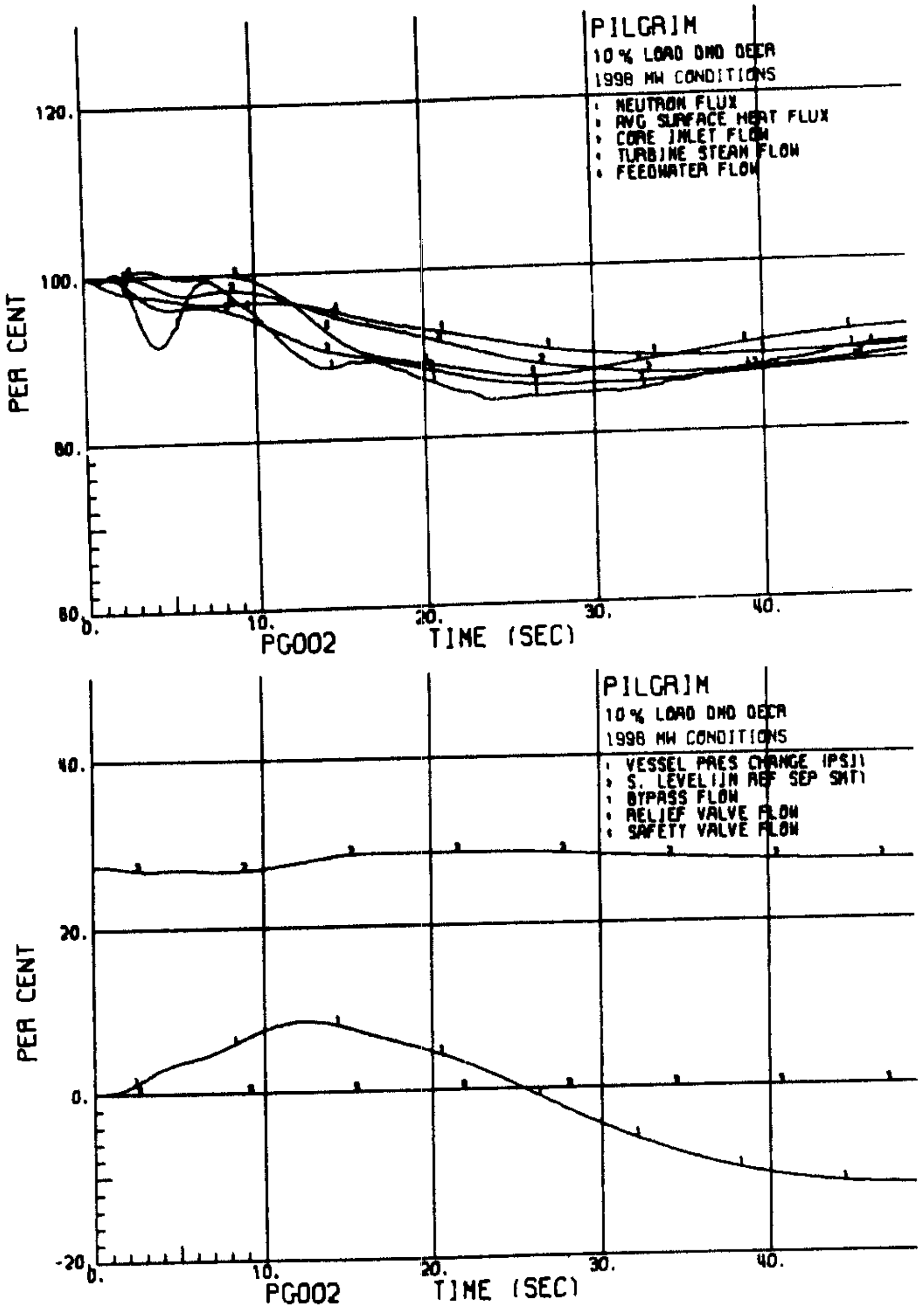


FIGURE 7.17-12
INITIAL CORE
10% LOAD DEMAND DECREASE
FROM 1998 MWt CONDITIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

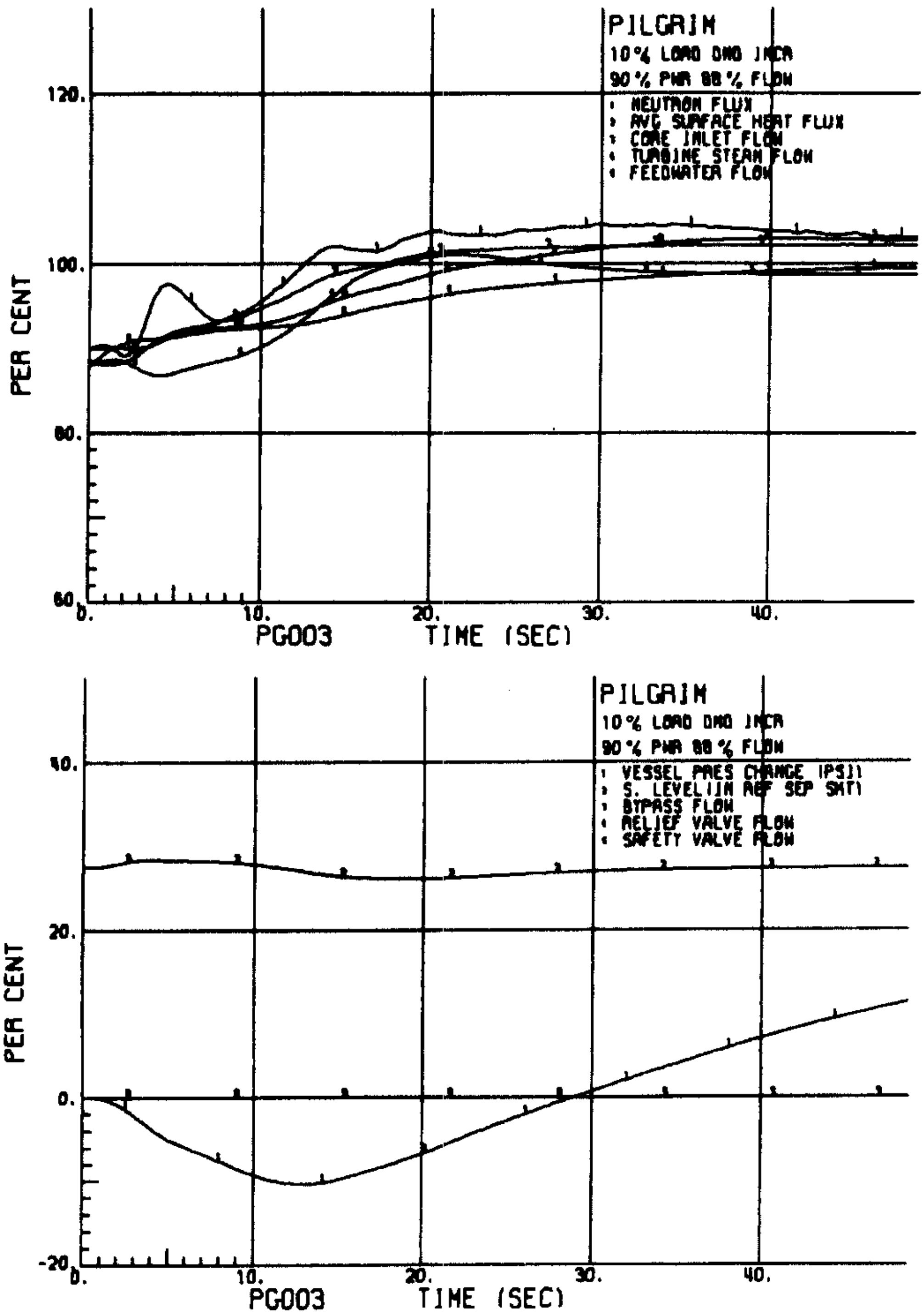


FIGURE 7.17-13
INITIAL CORE
10% LOAD DEMAND
INCREASE TO 1998 MWt
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

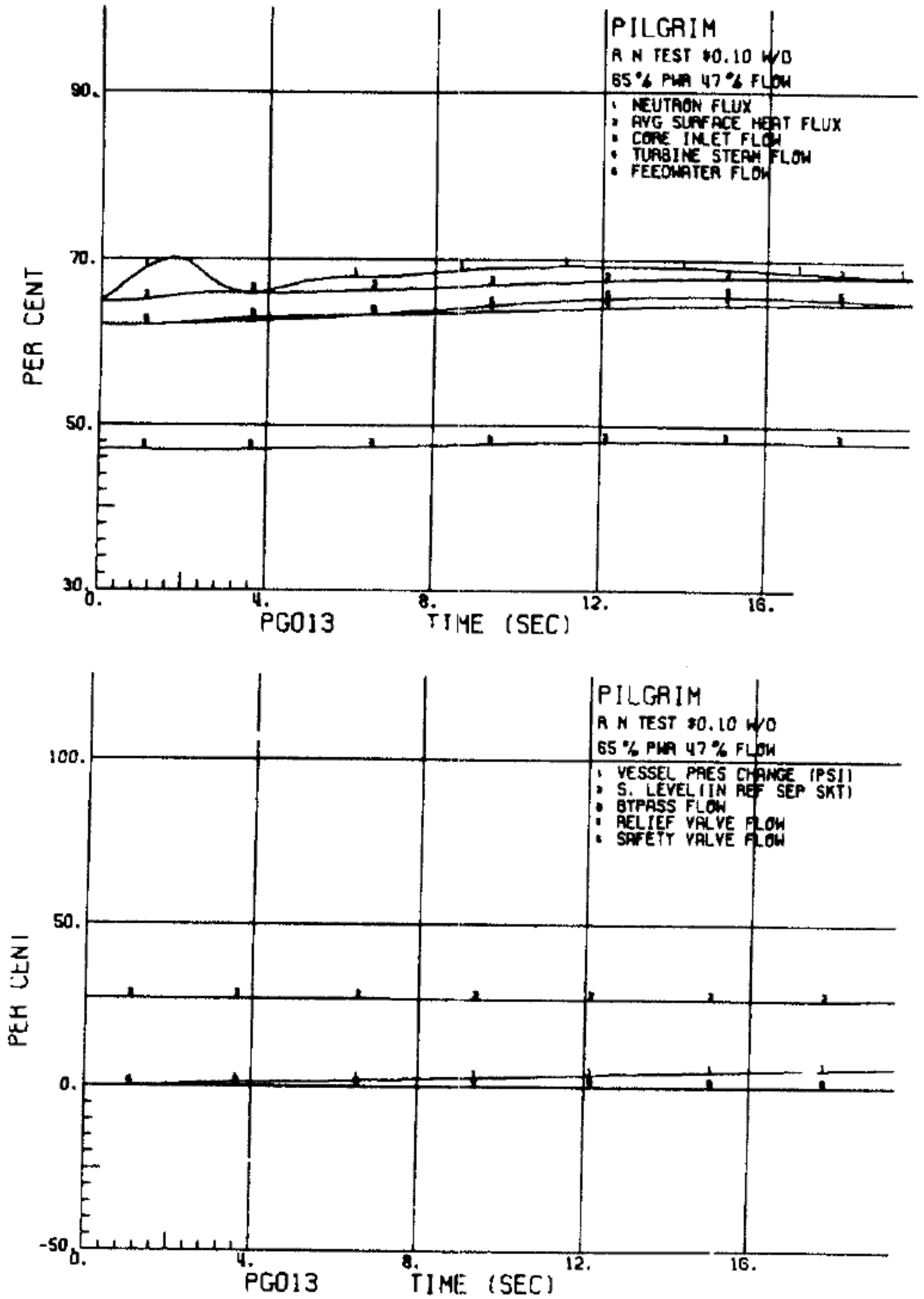


FIGURE 7.17-14
INITIAL CORE
10-CENT ROD REACTIVITY STEP
FROM ANALYTICAL LOWER LIMIT
OF AUTOMATIC FLOW CONTROL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

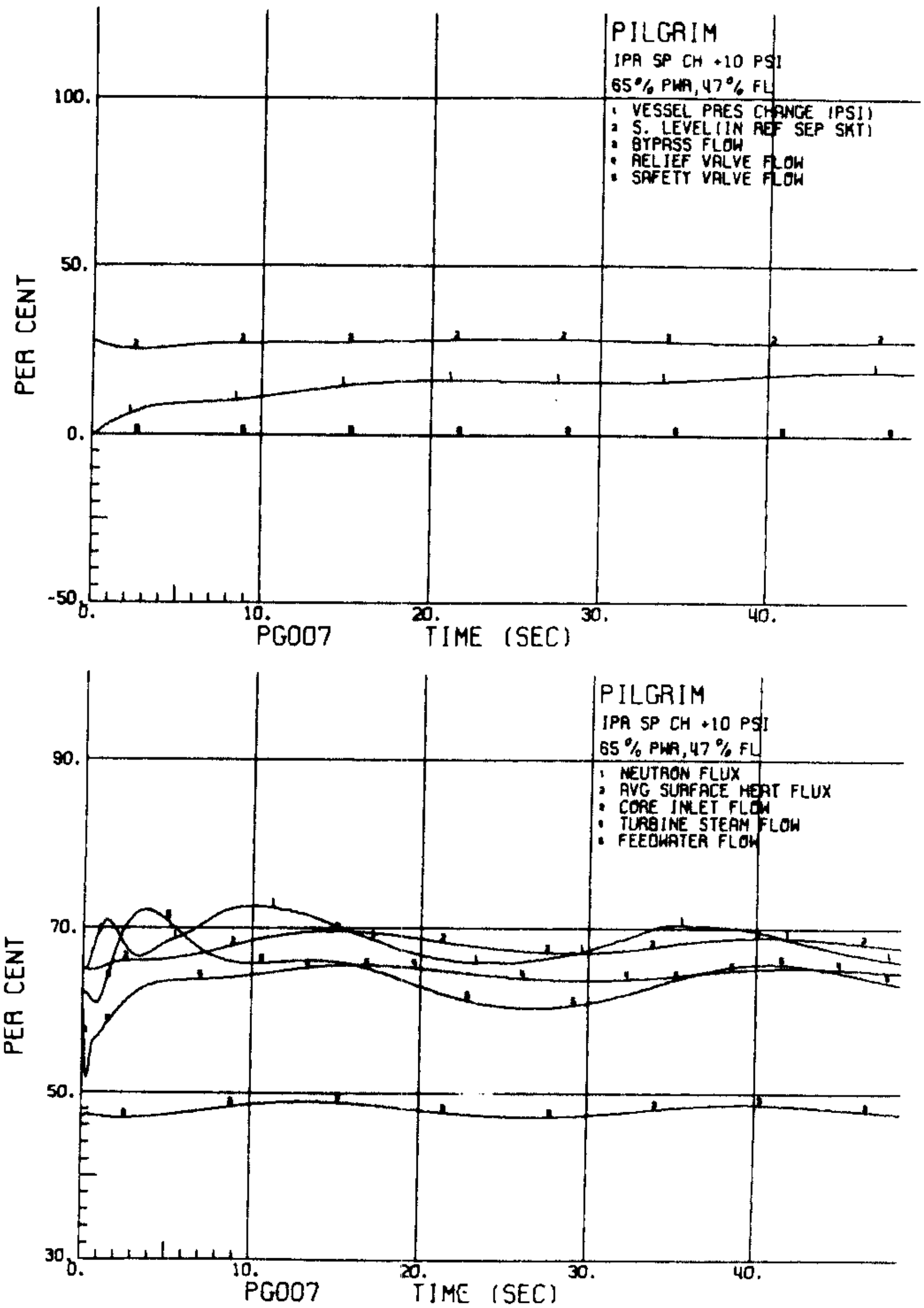
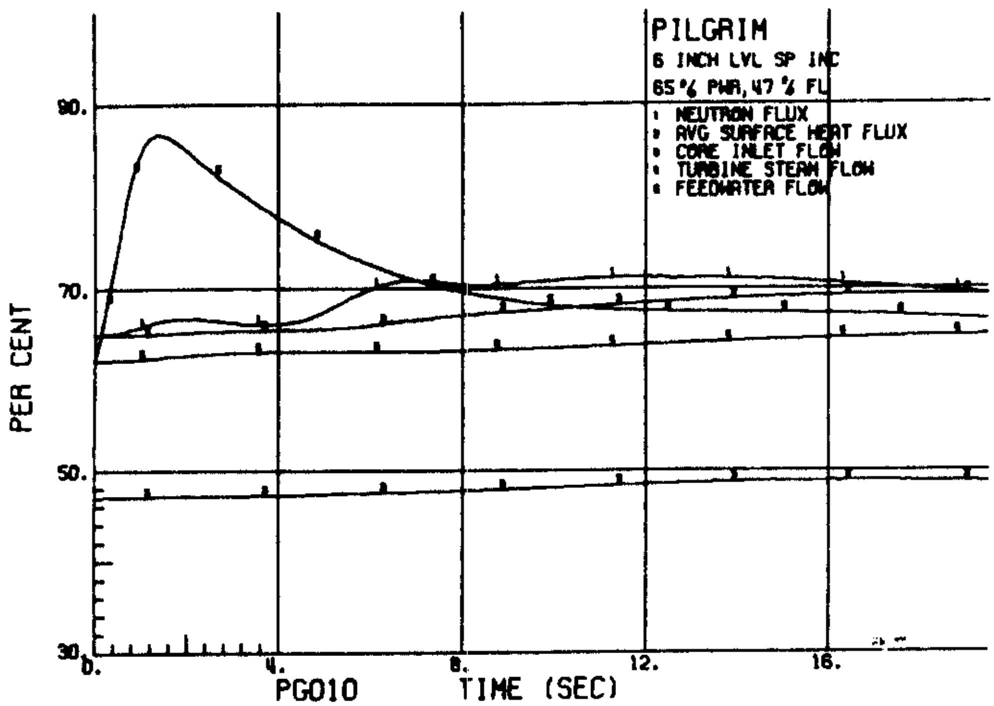


FIGURE 7.17-15
INITIAL CORE
10 PSI PRESSURE REGULATOR
SETPOINT STEP AT ANALYTICAL
LOWER LIMIT OF AUTOMATIC
FLOW CONTROL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



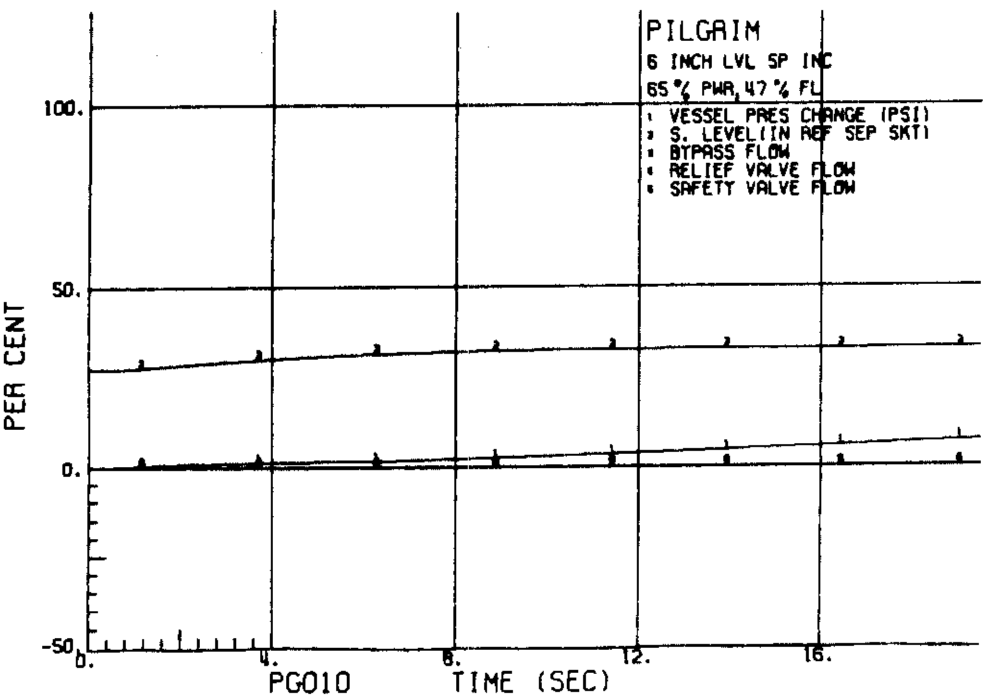


FIGURE 7.17-16
INITIAL CORE
6-INCH WATER LEVEL SETPOINT
STEP AT ANALYTICAL LOWER
LIMIT OF AUTOMATIC FLOW CONTROL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

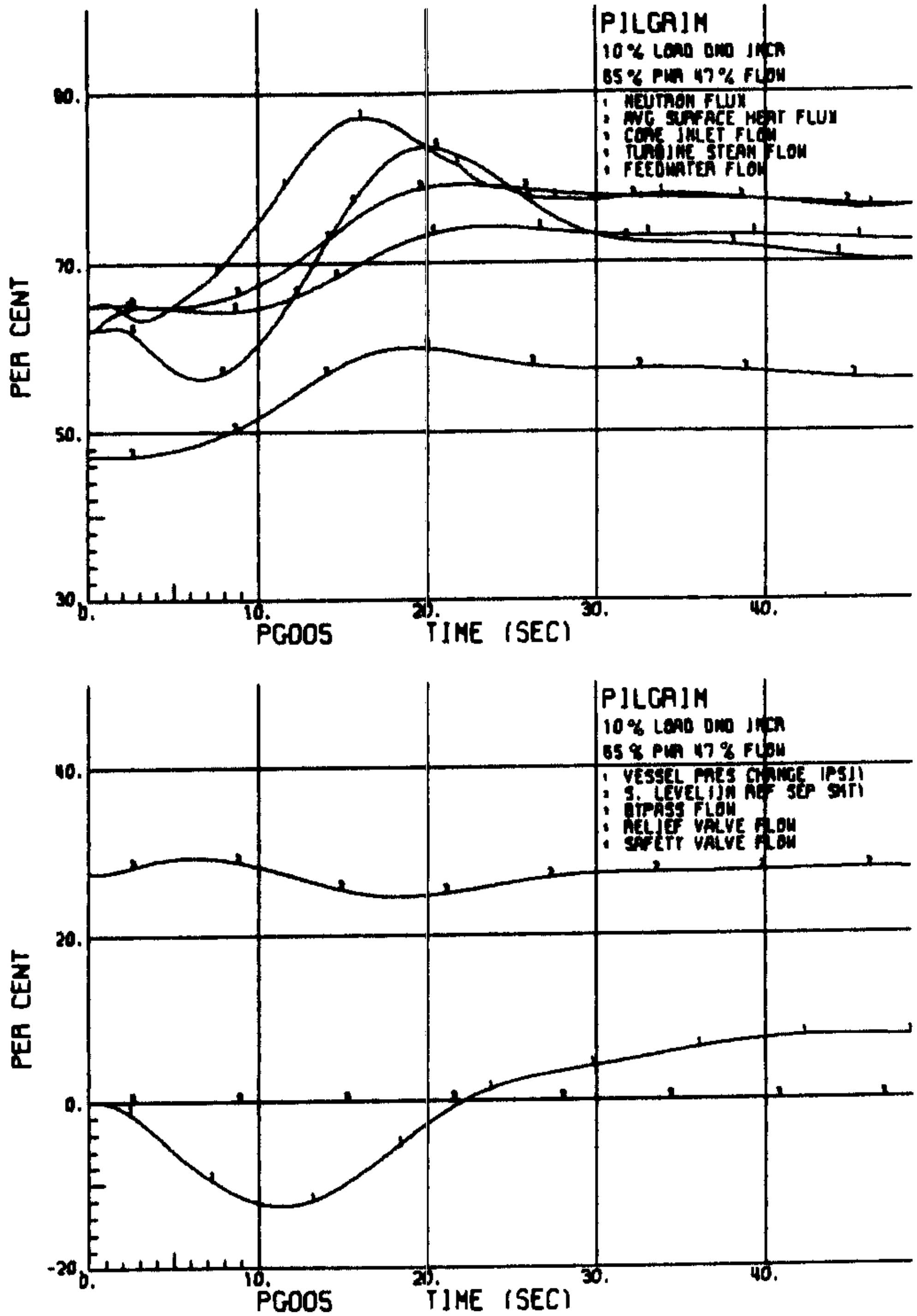


FIGURE 7.17-17
INITIAL CORE
10% LOAD DEMAND INCREASE
FROM ANALYTICAL LOWER LIMIT
OF AUTOMATIC FLOW CONTROL
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

7.18 REACTOR BUILDING ISOLATION AND CONTROL SYSTEM

7.18.1 Safety Objective

To limit the release to the environs of radioactive material so that offsite doses from a postulated design basis accident will be below the guideline values stated in 10CFR100. The Reactor Building Isolation and Control System (RBICS) shall trip the Reactor Building supply and exhaust fans, isolate the normal ventilation system, and provide the initiation signals for the Standby Gas Treatment System (SGTS) in the event of the Postulated Loss of Coolant Accident (LOCA) in the drywell or the postulated fuel handling accident in the Reactor Building.

7.18.2 Safety Design Basis

1. The RBICS shall isolate the Reactor Building sufficiently fast to prevent fission products from the postulated fuel handling accident from being released to the environs through the normal discharge path.

2. The RBICS shall have sufficient redundancy so that no single active component failure would prevent the system from achieving its safety objective.

3. The power supplies for the RBICS shall be arranged so that loss of one power supply will not prevent automatic isolation when required.

4. The RBICS shall be designed so that, once initiated, automatic isolation action goes to completion. Return to normal operation after isolation action shall require deliberate operator action.

5. The RBICS shall be designed in accordance with Class I design criteria.

6. The RBICS shall be designed so as to provide the control room personnel with the capability for manual initiation of the RBICS.

7. The RBICS shall be provided with means to conduct periodic tests to verify system performance.

7.18.3 Description

7.18.3.1 General

The RBICS, shown on Figures 7.18-1 and 7.18-2, includes the sensors, channels, switches, and remotely activated mechanisms which, when operated, effect isolation of the Reactor Building and initiate the Standby Gas Treatment System (SGTS).

The RBICS serves to trip the Reactor Building supply and exhaust fans, isolate the normal ventilation system and provide the

starting signals for the SGTS in the event of the postulated LOCA inside the drywell or the postulated fuel handling accident in the Reactor Building. Either of two signals will initiate the RBICS. The signals which indicate a LOCA inside the drywell are high drywell pressure or low reactor water level. In addition, radiation monitors in the operating (refueling) floor ventilation exhaust duct, which indicate a fuel handling accident, can initiate the RBICS. Isolation can also be initiated manually from the control room.

The RBICS "seals in" upon initiation. Clearing of initiation signals will not reset the RBICS to its pre-initiation condition. The system must be manually reset from the control room.

Normally open, fail closed, isolation dampers are provided on the discharge side of the Reactor Building, and operating floor supply fans. Normally open, fail closed, isolation dampers are provided on the intakes to the operating floor ventilation exhaust fans, the clean area exhaust fans, the contaminated area exhaust fans (upstream of the filter assemblies), and the control rod drive maintenance room exhaust fan. See Figure 7.18-1. Two dampers in series are provided throughout the isolation system to provide the required redundancy. The isolation dampers are piston operated, and are designed to close within 3 sec after receipt of the isolation signal.

The SGTS consisted of two parallel filter trains drawing reactor building exhaust air via blowers, powered by redundant power services, in each train from an inlet plenum and discharging the effluent up a ventilation exhaust stack. Dampers/valves upstream of the filter trains' inlet plenum are designed to fail in positions which provide an open flow path from all reactor building areas to the plenum. The dampers/valves are arranged such that loss of instrument air, dc control power and/or a logic channel will not prevent alignment of an area with the parallel filter trains inlet plenum.

The plenum exhaust and fan discharge (isolation) valves of both filter trains are serviced by a common dedicated air source. This dedicated air system provides a reliable motive force to align the reference piston operated valves, as required by the associated fan's mode of operation. The isolation valves for the "A" train fail open and the "B" train fail close on loss of instrument air and/or dc control power. The "A" train isolation valves open when the associated fan is started and the corresponding control switches are in the AUTO position. The "B" train containment isolation signal coincident with the "B" train control switch being in either the MAINTENANCE or the STANDBY positions and the suction damper control switch is in the AUTO position. The valve remains open, in the STANDBY mode, for a predetermined finite interval, set by a time delay relay, unless the initiating signal is removed. The "B" train fan discharge valve opens when the associated fan is started and the corresponding control switch is in the AUTO position. The isolation valves for both filter trains may also be opened

manually to facilitate maintenance and testing by placing the corresponding control switches in the RUN position.

The mode of operation for each standby gas treatment filter train is selected by placement of this three position mode switch, in the control room, in the required position. The "A" filter train is designated as the READY train and its mode switch is normally placed in the AUTO position during plant operation. The AUTO position is unique to the "A" train's mode switch. The "B" filter train is designated as the BACKUP train and its mode switch is normally placed in the STANDBY position during plant operation. The STANDBY position is unique to the "B" train's mode switch. Mode switches for both filter trains also have RUN and OFF positions; these positions are to facilitate manual operation as well as maintenance and testing of a train.

The reference switch positions allow the corresponding fan to operate as follows:

OFF: This position prevents the corresponding fan from operation.

RUN: This position allows direct operation and testing of the corresponding filter train and associated fan.

AUTO: This position is unique to and the normal position for the "A" train mode switch. In this position the "A" train blower will automatically startup upon receipt of the "A" train containment isolation signal and continue to run until removal of the initiating signal or the mode switch is placed in the OFF position, notwithstanding associated blower component postulated failures.

STANDBY: This position is unique to the normal position for the "B" train mode switch. IN this position the "B" train fan will automatically startup whenever its associated suction damper is open and continues to run until the damper is closed, notwithstanding associated fan component postulated failures.

MAINTENANCE: This position is unique to the "B" train mode switch. In this position, the "B" train fan will automatically startup upon receipt of the "B" train containment isolation signal and continue to run until removal of the initiating signal or the control switch is placed in the OFF position, not withstanding associated blower component postulated failures. This position is to be selected when the "A" train is down for maintenance.

Both the "A" and "B" train fans will be tripped on associated motor overloads and/or after a preset time delay, following the

detection of low current in one or more of the associated heater phases.

7.18.3.2 Power Supply

The power for the initiation signals is supplied from the RPS motor generator sets. Control and logic of the RBICS is supplied from 125 V dc sources. Power for the operation of the two valves in a ventilation line is fed from different batteries. One valve is powered from dc bus A, the other from dc bus B.

7.18.3.3 Physical Arrangement

All ducts and ventilation pipelines leading through the secondary containment have two valves or dampers installed. Each valve/damper in a ventilation line is controlled from a separate logic system. Position switches on each valve/damper provide status indication in the control room of each valve/damper.

Power and control cabling to RBICS components is routed as safeguard cabling.

7.18.3.4 Logic

The logic for initiation signal derivation is described in Section 7.3.4.4 for reactor vessel low water level and primary containment (drywell) high pressure, and in Section 7.12.4.1 for Refueling Ventilation Exhaust High Radiation. Figure 7.18-3 is the logic diagram for the RBICS. The logic is designed such that upon receipt of an initiation signal each Reactor Building normal ventilation penetration shall be isolated, and both standby gas treatment filter trains shall start. After a predetermined time, one filter train will stop and remain in a standby status. Hand switches are provided to manually initiate the RBICS from the control room. Additionally, switches are provided to manually operate individual valves, dampers, and fans.

7.18.3.5 Operation

During normal operation the isolation dampers of the Reactor Building Ventilation System are open, and the required supply and exhaust fans to the various areas are operating. The standby gas treatment dampers/valves are closed and the filter trains are not operating. In this condition, administrative procedures will ensure that the "A" standby gas treatment train is in "AUTO" and the "B" is in "STANDBY", unless maintenance requirements temporarily place one train out of service.

Upon receiving the required initiation signal (high drywell pressure, low reactor water level, any two signals from the four refueling floor ventilation exhaust duct radiation monitors, or manual initiation from the control room), the RBICS isolates all normal Reactor Building ventilation, the SGTS "A" filter train fan, set in the AUTO mode, starts directly; the "B" train suction valve, set in the AUTO mode, opens directly and in turn starts the "B" filter train fan, set in the STANDBY mode; both the "A"

train isolation valves and the "B" train isolation discharge valve, all set in the AUTO mode, open when their associated blowers start. Each blower draws air from the isolated reactor building. The "B" train suction valve is closed by a timer resulting in the associated STANDBY "B" train being tripped. The air discharge flow rate of each fan may be adjusted, when they are running, by operating personnel in the control room using the information provided by the flow indicators and associated outlet damper controls. The STANDBY "B" fan will be in readiness to run in case of the "A" train AUTO fan or associated device failure. Operation of this "A" train fan is monitored by a flow switch, which will provide the startup signal to the STANDBY fan on low flow from the AUTO fan.

In the event that the "A" train is down for maintenance, the "B" train control switch is in the MAINTENANCE position, the "B" train blower will run continuously, bypassing the timed interval and backup operation sequences, when its associated suction valve is open in its AUTO mode.

The availability of sufficient air in the dedicated air system is monitored by two pressure indicators and a pressure switch. Comparison of the two indicated pressures provides a means of checking indicator operation. The pressure switch is set to energize the "SBGTS TROUBLE" common alarm and de-energize a "SGTS DEDICATED AIR AVAILABLE" (Amber) indicating light on Panel No. C7 in the control room.

Each filter train's three phase multi-element electric heater package is energized whenever its associated fan is started, unless tripped by its corresponding thermal cutout switch. The fans of both filter trains will be tripped upon detection of low heater current in any or all phases of the corresponding heater, whenever the fan is operating. Tripping of the "A" train AUTO fan will result in the "B" train STANDBY fan automatically starting, due to low standby gas treatment system effluent flow.

In order to achieve the designed differential pressure as rapidly as possible and reduce the possibility of ex-filtration, both trains start initially. The setting of the timer, which subsequently shuts off the "STANDBY" "B" train, will be determined during the preoperational testing phase.

7.18.3.6 Isolation Functions and Settings

Section 7.3.4.7 describes in detail the reactor vessel low water level and primary containment (drywell) high pressure isolation functions and settings. Section 7.12.6 describes the Refueling Ventilation Exhaust Monitoring System isolation function and settings.

7.18.3.7 Instrumentation

Section 7.3.4.8 describes in detail the reactor vessel low water level and primary containment (drywell) high pressure instrumentation. Section 7.12.6 describes the Refueling Ventilation Exhaust Monitoring System instrumentation.

7.18.3.8 Environmental Capabilities

The physical and electrical arrangement of the RBICS was designed so that no single physical event will prevent operation. The specific environmental design conditions for instrumentation are listed on Tables 7.2-2 and 7.12-4.

7.18.4 Safety Evaluation

Refer to Section 5.3.4.

7.18.5 Inspection and Testing

The provisions for testing reactor vessel low water level and primary containment (drywell) high pressure are described in Section 7.3.6. The testing of the Refueling Ventilation Exhaust Monitoring system is described in Section 7.12.6.5. The initiation of RBICS is tested manually from the control room. Individual actuation devices are tested by hand switches. The flow switches and corresponding associated element as well as time delay relay which restart the "STANDBY" filter train are tested by manually starting and stopping the "A" train and observing the "STANDBY" "B" filter train start.

See Section 11.4 for testing of the electric heater low phase current transformers instantaneous and time delay relays.

The limit switches on the "B" filter train's inlet valve (AON-106) are manually tested by placing the train in STANDBY; the associated valve's control switch in OPEN; and observing the train's operation.

The SBGT system's dedicated air supply accumulator's pressure gauge functionality will be checked by observing the reading of the gauge during operations daily tour.

The SBGT system's dedicated air supply relief valve will be manually tested by observing the lifting lever position as the system's regulator output is adjusted from system normal operating pressure, to its setpoint, to 103 and 110 percent of its setpoint.

7.18.6 Nuclear Safety Requirements for Plant Operation

Refer to Section 5.3.6 for the requirements of the RBICS.

Figure 7.18-1 has been deleted.

Please refer to Figure 5.3-1.

Figure 7.18-2 and 7.18-3 have been removed.

Please refer to BECo Controlled Drawings M294 and M78.

7.19 RHR Service Water System (SSW, RBCCW)

The SSW System and RBCCW System objectives and descriptions are contained in Sections 10.7 and 10.5, respectively.

7.20 Equipment Area Cooling System

The Equipment Area Cooling System objectives and description is contained in Section 10.18. The effect of loss of heating, ventilation, or air conditioning on safety related equipment is described in Section 7.1.8.

7.21 METEOROLOGICAL INSTRUMENTATION

Meteorological instrumentation is summarized in Section 2.3.2.

The instrumentation is maintained in accordance with the preventive maintenance program.

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 (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

SUMMARY TABLE OF CONTENTS (Cont)

LIST OF EFFECTIVE PAGES

VOLUME 4VOLUME 4**VOLUME 4**VOLUME 4**VOLUME 4**

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

VOLUME 4

SECTION 8

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**

Page, Table (T), or Figure (F)	Revision Number
12-iv	30
12-v	30
12-vi	30
12-vii	30
12.1-1	0
F12.1-1 Refer to M11	17
F12.1-2 Refer to M12	17
F12.1-3 Refer to M13	17
F12.1-4 Refer to M14	17
F12.1-5 Refer to M15	17
F12.1-6 Refer to M16	17
F12.1-7 Refer to M17	17
F12.1-8 Refer to M18	17
F12.1-9 Refer to M19	17
F12.1-10 Refer to M20	17
F12.1-11 Refer to M21	17
F12.1-12 Refer to M22	17
F12.1-13 Refer to M23	17
F12.1-14 Refer to M24	17
F12.1-15 Refer to M25	17
F12.1-16 Refer to M26	17
12.2 Pages 1-24	30
T12.2-1 (1 of 3)	0
T12.2-1 (2 of 3)	0
T12.2-1 (3 of 3)	21
T12.2-2 (1 of 1)	21
T12.2-3 (1 of 1)	21
T12.2-4 (1 of 1)	21
T12.2-5 (1 of 1)	2
T12.2-6 (1 of 3)	0
T12.2-6 (2 of 3)	0
T12.2-6 (3 of 3)	0
F12.2-1 (deleted)	4
F12.2-2 Refer to M27	17
F12.2-3 Refer to M28	17
F12.2-4 (1 of 1)	0
F12.2-5 Refer to C4	17
F12.2-6 (1 of 1)	0
F12.2-7 (1 of 1)	0
F12.2-8 (1 of 1)	0
F12.2-9 (1 of 1)	0

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

SECTION 8

ELECTRICAL POWER SYSTEMS

8.1 SUMMARY DESCRIPTION

The station electrical power systems provide a diversity of dependable power sources which are physically separated. The station electrical power systems consist of unit and preferred AC power systems, the secondary AC power system, the station blackout AC power source, auxiliary power distribution system, standby AC power system, 125/250 V DC power system, 24 V DC power system, and the 120 V AC power system. See ANSI/IEEE Standard 260-1978 for electrical abbreviations used in Section 8.

Figure 8.1-1 illustrates the power flow and connection from the main generator to the transmission system and station service system. Electrical diagram symbols are explained on Figure 8.1-2 (BECo E1).

An onsite electric power system and an offsite power system is provided to permit functioning of structures, systems, and components important to safety.

The design of the offsite and onsite electrical power system meets the requirements of General Design Criterion 17. The offsite electrical power system consists of the preferred AC power source and the secondary AC power source. Only the preferred and secondary power sources are required to meet the offsite power requirements of GDC 17.

The unit AC power source provides AC power to all station auxiliaries and is the normal station AC power source when the main generator is operating. The unit AC power source can be backfed through the main transformer to provide an alternate means of energizing the station auxiliary power distribution system from the 345kV system when the main generator is isolated and the startup transformer is unavailable.

The station preferred (offsite) AC power source provides AC power to all station auxiliaries required for startup and shutdown and is normally in use when the unit AC power source is unavailable. See Section 8.2.

The secondary (offsite) AC power source provides AC power to essential station auxiliaries. It is used to supply essential station auxiliary loads only when the main generator is shut down and there is a failure of the preferred AC power source and failure of a standby AC power source. See Section 8.3.

The station auxiliary power distribution system distributes all AC power necessary for startup, operation, or shutdown of station loads. All portions of this distribution system receive AC power from the unit AC power source or the preferred AC power source. The emergency service portions of this distribution system also can receive AC power from the secondary AC power source, the standby AC power source, or the station blackout AC power source. See Sections 8.3, 8.5, and 8.10 respectively.

The standby AC power source provides two independent diesel generators as the onsite sources of AC power to the emergency service portions of the station Auxiliary Power Distribution System. Each onsite source provides AC power to safely shut down the reactor, maintain the safe shutdown condition, and operate all auxiliaries necessary for station safety. See Section 8.5.

The station 125/250 V DC Power System provides two independent onsite sources of dc power for startup, operation, shutdown, and all loads essential to station safety. See Section 8.6.

The station 24 V DC Power System, provides a reliable onsite source of power to some radiation monitoring instrumentation. See Section 8.7.

The station 120 V AC Power System provides a versatile distribution system to supply AC power to the station computer, instruments, and control devices requiring uninterruptable power and conventional instrumentation, and monitoring systems. See Section 8.8.

The Station Blackout AC Power Source provides an independent diesel generator as the onsite source of AC power to the emergency service portions of the Auxiliary Power Distribution System in the unlikely event of a loss of preferred and secondary offsite power sources combined with a complete failure of the Standby AC Power System. See Section 8.10.

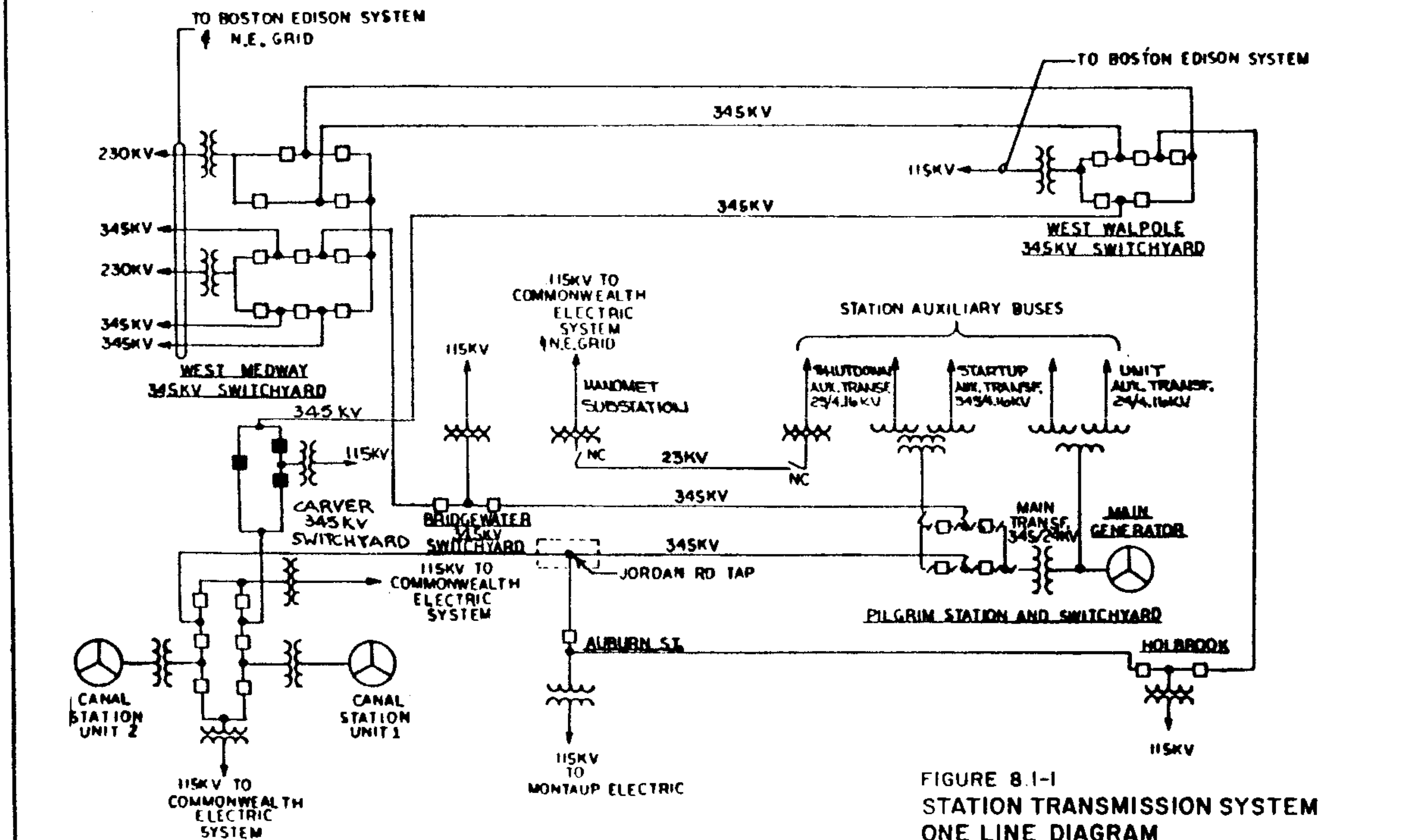


FIGURE 8.1-1
STATION TRANSMISSION SYSTEM
ONE LINE DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 11 - JULY 1990

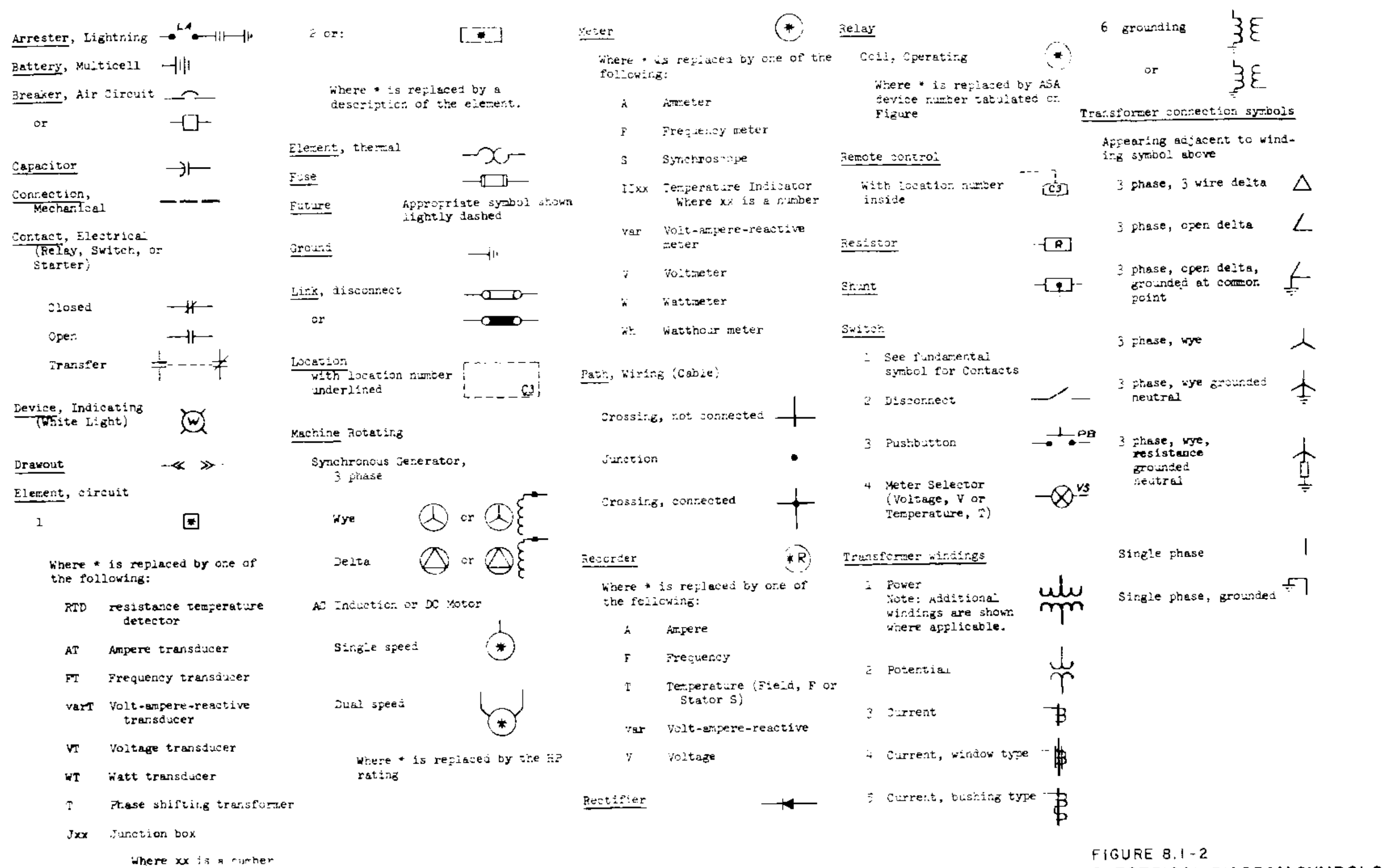


FIGURE 8.1-2
ELECTRICAL DIAGRAM SYMBOLS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

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 battery charger has a transfer switch installed between the incoming power source and the battery charger itself. This allows for the use of alternate power to be used as the incoming source during a beyond design basis event. 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.

TABLE 8.2-1

LIST OF MAJOR ELECTRICAL EQUIPMENT
UNIT AND PREFERRED AC POWER SOURCES

1. Station Main Generator	780 MVA, 24 kV,3ph,60 Hz, 0.87 pf, 0.5 SCR 60 psig H^2, 1,800 rpm
2. Transformers	
a. Main Transformer	880 MVA, FOA, 65°C, 345-22.8 kV, 3 ph, 60 Hz, High Voltage BIL 900 kV, Low Voltage BIL 150 kV
b. Unit Auxiliary Transformer	21.4/28.6/35.7 MVA, OA/FA/FOA, 55°C, 23-4.16 kV, 3 ph, 60 Hz High Voltage BIL 150 kV, Low Voltage BIL 75 kV
c. Startup Transformer	20/26.6/33.2/37.2 MVA, OA/FA/FOA, 55/65°C, 345-4.16 kV, 3 ph, 60 Hz, High Voltage BIL 900 kV, Low Voltage BIL 75 kV
3. Isolated phase Bus	
a. Main Bus	24 kV, 20,000A, 3 ph, 60 Hz asymmetrical momentary 200 kA
b. Unit Auxiliary Bus	24 kV, 850A, 3 ph, 60 Hz asymmetrical momentary 300 kA

Figures 8.2-1 and 8.2-2 have been removed.

Please refer to BECo Controlled Drawings E1 and E6.

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.

8.4 AUXILIARY POWER DISTRIBUTION SYSTEM

8.4.1 Safety Objective

The emergency service portion of the Auxiliary Power Distribution System (APDS), under all transient and accident conditions, distributes ac power required to safely shut down the reactor, maintain the shutdown condition, and operate all auxiliaries necessary for station safety.

8.4.2 Power Generation Objective

The entire APDS, normal and emergency service portions, distributes ac power to all station ac auxiliaries required for startup, operation, and shutdown of the station.

8.4.3 Safety Design Basis

1. The emergency service portion of the APDS distributes power to the station auxiliaries and all loads which are essential to plant safety.

2. The APDS, normal and emergency service portions, is arranged so that a single failure will not prevent or impair the operation of essential station safety functions.

3. The emergency service portions of the APDS are supplied from both offsite and onsite ac power sources.

4. The emergency service portion of the APDS shall be in accordance with the IEEE-308, Standard Criteria for Class IE Electrical Systems for Nuclear Power Generating Stations.

8.4.4 Power Generation Design Basis

The APDS distributes power to all the station auxiliaries necessary for normal station operation.

8.4.5 Description

8.4.5.1 Arrangement of Auxiliary Buses

There are six 4,160 V buses (A1,A2,A3,A4,A5, and A6) in the station APDS. The six buses are divided into emergency service and normal service buses. See Figures 8.2-1, 8.2-2, and 8.4-1. The two emergency service buses, A5 and A6, supply power to essential loads required during abnormal operational transients and accidents. The four normal service buses, A1,A2,A3, and A4, supply power to other station auxiliaries requiring ac power during planned operations. For description of major loads on 4,160 V buses, see Table 8.4-1.

Power is distributed to the six 4,160 V station auxiliary buses during normal operation from either the unit ac power or the preferred ac power source. The preferred power source is used to supply 4,160 V buses during normal startup and shutdown. After the main generator has been

synchronized to the 345 kV system and a minimum stable load established (approximately 20 percent of full output), the 4,160 V buses are individually transferred from the preferred power source to the unit power source. This is done by manually closing the unit power source supply breaker (after synchronization checks) to an individual 4,160 V bus while it is still energized from the preferred power source. The preferred power source supply breaker to this bus is then manually opened and the transfer is complete.

This results in the temporary interconnection of the preferred power source (startup transformer) through a single 4,160 V auxiliary bus.

These procedures are repeated until all six 4,160 V buses have been individually transferred from the preferred power source to the unit power source. Procedural restrictions and synchronization switch interlocks assure that the 4,160 V buses are individually transferred. The preferred and unit power sources are parallel through one 4,160 V bus only for the short period required to verify that the unit power source supply breaker has closed before the preferred power source supply breaker is manually opened.

Each safety-related 4,160 V bus is provided with automatic second- level undervoltage (Degraded Voltage) protection as outlined below:

(a) Two fast-acting undervoltage relays are connected to the bus's potential transformers which will alarm at an undervoltage condition below normal but above a voltage level which is considered degraded (set at approximately 95 percent of nominal.)

(b) Four similar relays are connected to the potential transformers of the preferred ac source (startup transformer) which protect safety-related equipment from damage or misoperation due to sustained degraded voltage by removing this source from the bus. Power to the affected bus is restored automatically from the standby source. These relays are connected in one-out-two taken twice coincidence logic and set at approximately 93 percent of nominal.

An appropriate time delay is provided for all the above relays to override transients such as motor starting.

Automatic fast transfer is provided to restore each 4,160 V bus to the preferred power source in the event that the unit power source is lost. The preferred source supply breaker to an individual 4,160 V bus closes automatically whenever the unit power source supply breaker to the bus opens, and fast transfer logic is operational, thus maintaining power to all station auxiliaries connected to that bus. To ensure automatic transfer of the 4,160 V emergency bus supplies during a design basis event, backup trips of the normal supply breakers to emergency buses A5 and A6 are provided through the operation of seismically qualified undervoltage relays and RPS logic relays. The fast transfers of individual

4,160 V buses from the unit power source to the preferred power source will not interfere with normal station operation. Automatic transferring is in one direction only, from the unit power source to the preferred power source. 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.

The 4,160 V emergency service buses, A5 and A6, can also be supplied from the standby ac power source or the secondary ac power source. In the event that both the unit power source and the preferred power source are lost, the standby ac power source will reenergize buses A5 and A6 within approximately 10 sec. The failure of a diesel generator to restore voltage on one of these emergency service buses would result in automatically connecting the affected bus to the secondary (offsite) ac power source after an additional approximate 2 sec time delay. The secondary (offsite) ac power source may also be manually connected to the emergency service 4,160 V buses to reduce the duration of diesel generator operation whenever both the unit power source and the preferred power source are unavailable. The secondary (offsite) ac power source is from the Commonwealth Electric Company 23 kV distribution line No. 72 discussed in Section 8.3. However, the secondary and standby source supply breakers are interlocked to prevent parallel operation. If either one or both standby AC power sources are unavailable and the secondary offsite AC power source is also unavailable, the Station Blackout Diesel Generator will be able to power either A5 or A6 bus with limited loading requirements. (Refer to Section 8.10).

The eight 480 V buses, B1, B2, B3, B4, B5, B6, B7, and B8 are also divided into normal service buses and emergency service buses. The essential 480 V auxiliaries required during abnormal operational transients and accidents are all supplied from the three emergency service buses, B1, B2, and B6. The five normal services buses, B3, B4, B5, B7, and B8 supply power to other 480 V auxiliaries required during planned operations. The 480 V emergency service buses B1 and B2 receive power from the 4,160 V emergency service buses A5 and A6 respectively. The common 480 V emergency service bus, B6, receives power from either B1 or B2 and is automatically transferred to the alternate source upon loss of voltage on the normal supply.

The 480 V buses B3 and B7 receive power from the 4,160 V bus A3, and the 480 V buses B4, B5, and B8 receive power from the 4,160 V bus A4. Provisions are included to permit normal service buses B3 and B4 to be manually transferred to emergency service buses B1 and B2 respectively in the event that bus A3 or A4 is out of service. The tie breakers are interlocked to prevent bus B3 (or B4) from being connected to both bus A3 (or A4) and B1 (or B2) simultaneously. Procedural restrictions prevent closure of the tie breakers during power operation. See Figure 8.4-2.

Power from the 4,160 V switchgear buses is fed directly to 250 hp motors and larger, and through load center transformers to the 480 V load center buses. Power from the 480 V load centers is fed directly to motors and to motor control centers (MCC). Power from the MCC is fed directly to motors, motor operators, and power panels.

Ammeters are provided for monitoring four safety-related MCC, B10, B14, B15, and B20; and two nonsafety-related MCCs, B19A and B19B. These ammeters will aid the operator to prevent overload condition during unique operating conditions and prevent tripping of the MCCs. MCCs 19A and 19B, although not safety-related, are essential inmaintaining ambient temperatures within limits to assure continuous smooth operation of the plant.

8.4.5.2 System Components

All of the 4,160V switchgear, described on Table 8.4-2, are of the metal clad indoor type with dripproof covers. The circuit breakers are electrically operated three-pole vertical lift breakers with stored energy closing mechanism operated from the 125V DC station batteries described in Section 8.6.

Seven of the 480V load centers, described on Table 8.4-2, consist of low voltage switchgear and a transformer. One load center, B6, consists of switchgear only. All of the switchgears are of the metal enclosed indoor type with dripproof covers. Two of the transformers are rated at 1000/1333 KVA AA/FA, 115°C/150°C temperature rise, three-phase, 60 Hz. Five are dry-type AA, 150°C temperature rise, three phase, 60 Hz/1000 kVA. The circuit breakers are electrically operated three-pole breakers with stored energy closing mechanisms operated from the 125V DC station batteries, described in Section 8.6.

Three of the 480V load centers (B17, B18, B20) have been provided with walk-in enclosures which assure environmental qualification of the MCCs. The exterior walls of the enclosure consist of 1/4" thick steel plate and are designed to withstand the effects of postulated seismic events (OBE and SSE), external pressure due to PBOCs (1 psid), and tornado loads. The walls of the enclosures are covered with insulating material in order to minimize heat transfer from the Reactor Building Atmosphere to the enclosure following a PBOC. Major penetrations such as conduit and pipe are installed with foam sealant.

Each enclosure also includes a non-safety related and safety related cooling system. The non-safety related cooling system consists of two, 100% capacity, split design type air conditioning units. These units are utilized during normal operation to maintain local air temperatures within the enclosures to less than or equal to 80°F. This meets the normal operating environmental qualification temperature criteria for the MCCs electrical equipment to perform their safety functions during normal and postulated accident conditions. The safety related cooling system consists of a vane axial fan and normally closed inlet and outlet dampers

(motor operated butterfly valves) which operate to force reactor building air through the enclosure when the internal enclosure air temperature increases to more than that 120°F. In the event both non-safety related cooling units fail, or are not available, following a PBOC, Reactor Building temperature will decrease below 120°F before the internal enclosure local air temperature reaches the 120°F actuation setpoint for the safety related ventilation system. This results in motor control center (MCC) enclosures' 30-day air temperature profiles following a postulated PBOC which is less severe than the profiles the MCCs' electrical equipment were qualified to perform their safety functions.

The principal design criteria are provided in Table 8.4-4.

All of the 480V motor control centers are NEMA Type I gasketed construction with dripproof covers. The circuit breakers are manually operated. Circuit breakers are provided with either magnetic or thermal magnetic short circuit protection on all poles. All motor starters are provided with thermal overload protection on all poles which will either trip the motor starter or alarm in the main control room. See Figures 8.4-2 through 8.4-5 (Drawings E9, E10, E11, and E12).

Cables have adequate flame resistant properties, and are designed to resist radiation, high temperature, and high humidity levels of the area in which they are installed. Power and control cables to safeguard equipment within the primary containment are designed to withstand the environmental conditions caused by any accident during which the equipment they are supplying is assumed to operate. The current carrying capacity of all power cables is conservatively calculated to preclude damage due to thermal overloads except where deviations are approved by design engineering as stated in Section 8.9.5. Cables used within the containment penetration sealed canisters meet additional insulation material and current carrying capacity restrictions.

Cables and components of redundant circuits are physically separated by space, fire barriers, or concrete walls and floors to assure maximum independence of redundant channels. Cables are installed in conduits or metal trays.

8.4.6 Safety Evaluation

Provisions to ensure continued availability of AC power to the emergency service portions of the auxiliary power distribution system have been made in the design. The multiplicity of offsite and onsite sources feeding these buses, the redundancy of transformers and buses within the plant, and the division of critical loads between buses yields a system that has a high degree of reliability. Also, the physical separation of buses and service components provides independence to limit or localize the consequences of electrical faults or mechanical accidents occurring at any point in the system.

480 Volt Bus B6

Independence is not compromised by the source transfer scheme which transfers ac power from one independent emergency power source to the other in the event that the first source is lost.

Since the diesel generators could be supplying emergency power, the source transfer is slowly performed to ensure their complete independence. The transfer is a slow transfer which allows the load voltage to decay before reapplying power from the second source. This eliminates the possibility of immediately transferring a motor from one diesel generator operating at one frequency to the other diesel generator operating out of phase or at another frequency. Due to the loss of voltage during transfer, loads which are not essential to station safety will be shed.

To ensure the desired degree of independence between redundant engineered safeguard systems, protective device coordination curves were developed which demonstrate adequate margin between primary and secondary protection. These protective devices both sense and isolate faulted equipment. The protective device settings are set as low as the largest engineered safeguard load would permit, while maintaining adequate margin between devices.

Considering a single breaker or bus failure criterion, overload protection was provided on both of the series connected tie breakers. Hence, a fault on emergency service bus B1 will not cause the loss of buses B2 or B6 or vice versa. A fault on bus B6 will not cause the loss of bus B1 or B2.

The 480 V buses B1, B2, and B6 are shown on Figure 8.4-2. Bus B6 normally receives power from either bus B1 or B2 through series connected circuit breakers 102 and 601 or through 202 and 602. One set of series breakers is closed and the other set is open. An automatic transfer signal (loss of normal supply voltage or a reduction of voltage to degraded levels with a time delay to override transients such as motor starting.) causes both "closed" circuit breakers to trip after a time delay The open circuit breakers are then closed by two independent closing signals provided there is adequate voltage on the alternate source. This completes the automatic transfer. Buses B1 and B2 cannot be connected together through B6 by a single failure since (a) the two circuit breakers in series are normally open and (b) their closing circuits cannot both be actuated by the single failure. Interlocks are provided to preserve independence as described below:

1. Failure of either breaker 601 or 602 to trip would prevent closure of the other

2. Failure of either breaker 102 or 202 to trip would prevent closure of the other

3. A fault on 480 V bus B6 would be isolated by either breakers 601 or 102 (or 602 or 202), one breaker located at B6 and one at the power source (B1 or B2). This isolation maintains the source voltage and prevents transfer of the faulted bus B6 to the other source. Two series connected circuit breakers at different locations must both fail for a transfer malfunction. Since the breakers are series connected, the only postulated single failure source is excessive overcurrent.

The breakers are designed to interrupt the short circuit currents available when supplied from the preferred ac power source. Since the diesel generators are incapable of supplying short circuit current of this magnitude, the simultaneous failure of both breakers 601 and 102 (or 602 and 202) to trip is not considered a single failure

4. Each 480 V load center (B1, B2, and B6) is sectionalized, providing barriers for added reliability and physical independence. The load centers are separated by a concrete wall or floor

The source transfer feature is an essential part of the overall station design for safeguard loads and provides additional, desirable operating reliability for nonsafeguard loads of importance. The existence of bus B6 is justified by the objective for each load to have access to redundant ac power supplies. To facilitate the ensuing analysis of the requirements of each load, the loads are divided into groups as follows:

1. RHR System Injection Valves and Recirculation Loop Valves

2. Containment Motor-Operated Isolation Valves

3. Station Economic Investment Loads

4. Fire System Loads

5. Loads Requiring a Backup Power Source

As shown by the above grouping, the selection of bus B6 as power source for each load is not based only on engineered safeguard load performance during postulated accidents or transients. Bus B6 was selected as the best available ac power source to loads which are critical during planned operations. AC loads, which have dc backup, are supplied from bus B6 to provide access to either ac source.

1. RHR System (LPCI) Injection Valves and Recirculation Loop Valves

   Power to the RHR injection valves and recirculation loop valves which must operate for the LPCI mode during loss of coolant accident (LOCA) conditions is supplied from bus B6. The automatic source transfer allows the operation of two RHR pumps in LPCI mode in the event that one diesel generator is not available.

   The LPCI mode of the RHR System is designed to inject water into the intact recirculation loop in the event that a recirculation line break initiates a LOCA. Power to the RHR injection valves and recirculation valves required to operate during the LOCA is supplied from bus B6.

The station as designed assumes the operability of one Core Spray System and two RHR pumps in LPCI mode in the event of the single failure of one diesel generator. Water from the two RHR pumps may not be available under this condition unless automatic source transfer is accomplished thus making power available to the selected recirculation loop valves from the operating diesel generator.

In the event of a single failure resulting in the loss of Bus B6, the station as designed assumes that both diesel generators and two Core Spray Systems remain operable.

2. Containment Motor-Operated Isolation Valves

The inboard ac valves are backed up by outboard dc valves. DC valves are powered from 125 V dc side A, 125 V dc side B, or 250 V dc side B, with all three batteries used. For additional reliability the inboard ac valves are connected to bus B6 and therefore can be supplied from either diesel generator. The inboard ac valve cables are routed as SX while the outboard dc cables are routed as both SA and SB; therefore separation is maintained.

3. Station Economic Investment Loads

These loads, such as the turbine turning gear, are vital to protect the station economic investment. Assuming only one diesel generator is running, it is desirable to operate these loads although they may be automatically blocked from operation if safeguard loads dictate the diesel generator or startup transformer loading requirements.

4. Fire System Loads

Assuming only one diesel generator is running, it is desirable to operate fire system auxiliary loads although they are automatically blocked from operation if safeguards loads dictate the diesel generator loading requirements. These loads are not required for initiation of any fire system equipment, but are required to maintain the system's readiness to function and rejuvenate after system operation.

5. Loads Requiring a Backup Power Source

Systems with <u>third</u> backup components in addition to two redundant A and B components should be capable of operating the third component upon failure of either A or B power source. For example, the 125 V dc backup battery charger would be manually energized if either A or B side battery charger is out of service.

The plant air compressor is a third component which differs from the above. The compressor will be rotationally selected as one of the two running compressors, the third on standby status. It is desirable that two compressors are available, hence the third is supplied from bus B6.

8.4.7 Inspection and Testing

Inspection and testing at vendor factories and initial system tests were conducted to ensure that all components were operational within their design capability.

Periodic tests of the equipment and system are conducted as shown on Table 8.4-3 to:

1. Detect the deterioration of equipment in the system toward an unacceptable condition

2. Demonstrate the capability of equipment which is normally deenergized to perform properly when energized

8.4.8 Proposed Nuclear Safety Requirements for Initial Plant Operation

The emergency service portions of the Auxiliary Power Distribution System are required for station startup and for operability of the standby ac power system. Operating limitations are related to the operability status of the auxiliary ac power sources and are described in Section 8.5.6.

TABLE 8.4-1

LIST OF MAJOR LOADS
AUXILIARY POWER SYSTEM

1. Loads on 4,160 V Switchgear Buses (Normal Service)

a. Bus A1

Reactor Feedwater Pump A	5,000hp
Reactor Feedwater Pump C	5,000hp
Condensate Pump B	2,000hp

b. Bus A2

Condensate Pump A	2,000hp
Condensate Pump C	2,000hp
Reactor Feedwater Pump B	5,000hp

c. Bus A3

Reactor Recirculation Pump A, MG Set	4,500hp
Condenser Circulating Water Pump A	1,250hp
Turbine Auxiliary Oil Pump A	250hp
Load Center B3 (Normal Service)	1,000 kVA
Load Center B7 (Normal Service)	1,000 kVA

d. Bus A4

Reactor Recirculation Pump B, MG Set	4,500hp
Condenser Circulating Water Pump B	1,250hp
Turbine Auxiliary Oil Pump B	250hp
Load Center B4 (Normal Service)	1,000 kVA
Load Center B5 (Normal Service)	1,000 kVA
Load Center B8 (Normal Service)	1,000 kVA

2. Loads on 4,160 V Switchgear Buses (Emergency Service)

a. Bus A5

Control Rod Drive Water Pump A	250hp
Residual Heat Removal Pump A	800hp
Residual Heat Removal Pump C	800hp
Core Spray Pump A	800hp
Load Center B1 (Emergency Service)*	1000/1333 kVA AA/FA

b. Bus A6

Control Rod Drive Water Pump B	250hp
Residual Heat Removal Pump B	800hp
Residual Heat Removal Pump D	800hp
Core Spray Pump B	800hp
Load Center B2 (Emergency Service)*	1000/1333 kVA AA/FA

*Load Center B6 (Common Emergency Service) is included with both B1 and B2 since it may be supplied power from either source.

TABLE 8.4-2

LIST OF MAJOR ELECTRICAL EQUIPMENT
AUXILIARY POWER SYSTEM

1. Switchgear

   a. 4,160 V (normal service)

Switchgear A1 and A2	350 MVA, 3,000A Main Breakers, 1,200A Feeder Breakers
Switchgear A3 and A4	250 MVA, 2,000A Main Breakers, 1,200A Feeder Breakers

   b. 4,160 V (emergency service)

Switchgear A5 and A6	250MVA, 2,000A and 1,200A Main Breakers,1,200A Feeder Breakers

2. Load Centers

a. 480 V (normal service)	Transf. 1000 kVA, AA, 4160V-480/277 V, 3ph
Load Centers B3, B4, B5,B7,and B8	1,600A Main Breaker, 600A Feeder Breakers
b. 480 V (emergency service)	Transf. 1000/1333 kVA, AA/FA, 4,160V-480/277V, 3ph
1. Load Center B1 and B2	1,600A Main and Tie Breakers, 600A and 600A Feeder Breakers
2. Load Center B6	480/277 V. 3ph, 1,600A Main Breakers, 600A Feeder Breakers

TABLE 8.4-3

PERIODIC TESTS OF SAFETY RELATED AUXILIARY POWER SYSTEMS

DESCRIPTION OF ACTIVITY	RFO YEAR 0	ON LINE YEAR 1	RFO YEAR 2	ON LINE YEAR 3	RFO YEAR 4	ON LINE YEAR 5	RFO YEAR 6	ON LINE YEAR 7	RFO YEAR 8	ON LINE YEAR 9	RFO YEAR 10	ON LINE YEAR 11	RFO YEAR 12
4160V SWITCHGEAR													
Bus and Taps - Inspect and Clean	PM								PM				
Bus - Insul Res Test, PT Drawer Check	PM/T				PM/T				PM/T				PM/T
Bkrs	OVHL				PM				PM				PM
Relays (non Tech Spec)(4)	PM/T				PM/T				PM/T				PM/T
Motor/Cable Insul Test(7)	T		T		T		T		T		T		T
480 Volt Load Centers													
Bus and Taps - Inspect and Clean	PM								PM				
Bus & Pwr xfmr Ins Res Test, PT Drawer Chk	PM/T						PM/T						PM/T
Bkrs	OVHL						PM						PM
480V AC MOTOR CONTROL CENTERS													
Bkrs/Bus Insulation Res Test (9)(8)(12)	PM/T						T		PM				T

OVHL = Complete overhaul/rebuild of the breaker (6)
PM = Clean, lube, adjust, calibrate, check operation, cycle as applicable (Preventative Maintenance)(6)
T = Test, as described.

TABLE 8.4-3

PERIODIC TESTS OF SAFETY RELATED AUXILIARY POWER SYSTEMS

Note 1. Time intervals and sequences for PMs and OVHLs apply to "inservice" breakers, only. A removable breaker will be either PM'd or OVHL'd depending on its particular maintenance history and its "next" usage. In all cases, the program intent will be met.

Note 2. All time intervals are subject to a target 25 percent grace period up to a maximum of one year. It is recognized that occasionally a specific maintenance activity may be delayed beyond the target grace period due to plant operating conditions. In such cases the activity will be performed promptly at the next available opportunity.

Note 3. The interval between RFOs is assumed to be 2 years.

Note 4. The intervals shown for PM and testing of Relays do not reflect those covered by Tech Spec.

Note 5. Deleted

Note 6. Whenever a PM or OVHL is conducted on a breaker, a PM is done on the cubicle including, as applicable, lubrication of the elevating/drawout mechanisms and a mechanical check of stops, cell switches, and interlocks. If this is not possible due to safety or operational concerns, the cubicle will be PM'd at the next scheduled RFO.

Note 7. Insulation test of 4160V Switchgear includes cable and motor insulation.

Note 8. Non Q 480V AC MCC breakers that protect cables that are routed in a raceway which contains safety related cables are considered "associated" as such preventive maintenance will be performed on the same frequency as safety related circuit breakers.

TABLE 8.4-3

PERIODIC TESTS OF SAFETY RELATED AUXILIARY POWER SYSTEMS
(continued)

Note 9. Equipment in the EQ Master List may have additional maintenance requirements as established by the PNPS Equipment Environmental Qualification Program.

Note 10. The maintenance interval for 4160V and 480V load center breakers is; overhaul every 14 years for 4Kv and 15 years for 480V, PM every 4 years.

Note 11. All breakers, both safety and non safety related, that protect cables that penetrate primary containment shall have preventive maintenance performed on a four year interval.

Note 12. Non Q 480VAC MCC breakers that affect the appendix R analysis shall have preventive maintenance performed on the same frequency as safety related circuit breakers.

TABLE 8.4-4

PRINCIPAL DESIGN CRITERIA FOR
MCC (B17, B18, B20) ENCLOSURES

1. The MCC enclosures are designed to maintain the environment around the MCCs to be less than 80°F for continuous service and less than 120°F during accident conditions (PBOC).

2. The Reactor Building Environment (surrounding the enclosures) is as follows:

   a. Normal Operating

PARAMETER	MIN.	NORM.	MAX.
Temperature	40	85	104
Pressure (PSIA)	14.65	14.7	14.7
Relative Humidity %	40	60	90

   b. Accident Conditions

   Refer to Drawing M632, Sheet 7.

   c. Radiation levels (40 year normal + LOCA + 30 days)

MCC	ZONE	GAMMA	BETA
B17	1.9	1.3E5	6.8E5
B18	1.10	7.3E4	6.8E5
B20	1.9	5.8E4	6.8E5

   d. Heat release rate per MCC (normal and accident) maximum.

   B17 1240 watts (4230 BTU/hr)
   B18 1240 watts (4230 BTU/hr)
   B20 625 watts (2133 BTU/hr)

   NOTE: The rates assume the MCC space heaters are deenergized.

3. The enclosures are designed for a 1.0 psig external pressure (pipe rupture load). This value envelopes the maximum pressure resulting from all PBOCs with an appropriate dynamic load factor applied.

4. The enclosures are designed for the depressurization loads associated with a tornado (1 psi/sec. for 3 seconds). To achieve this, the enclosures are designed for a ½ psig internal pressure. Pressure relief devices are provided to assure this design pressure is not exceeded.

TABLE 8.4-4 (Cont)

PRINCIPAL DESIGN CRITERIA FOR
MCC (B17, B18, B20) ENCLOSURES

5. The enclosures are designed for the following seismic loads:

   A OBE (Horiz.) = 1.5g
   A OBE (Vert.) = 0.198g
   A SSE (Horiz.) = 1.65g
   A SSE (Vert.) = 0.26g

6. Allowable floor live load of 250 psf shall not be exceeded.

7. Insulation is designed to retain its insulation capability assuming the environmental conditions associated with an HELB.

The following FSAR figures have been removed from the FSAR. Please refer to the corresponding BECo controlled drawing.

FSAR FIGURE	BECO CONTROLLED DRAWING
8.4-1	E7
8.4-2	E9
8.4-3	E10
8.4-4	E11
8.4-5	E12

8.5 STANDBY AC POWER SOURCE

8.5.1 Safety Objective

The safety objective of the standby AC power source is to provide a single failure proof source of onsite AC power adequate for the safe shutdown of the reactor following abnormal operational transients and postulated accidents.

8.5.2 Safety Design Basis

1. The Standby AC Power System consists of two independent AC power sources that are self-contained within the station site and which are independent of offsite power sources.

2. Each standby generator unit is capable of providing sufficient power to its emergency bus, upon failure of all offsite power, to satisfy the load on the bus.

3. Each standby generator unit is designed in accordance with Class I criteria.

4. The generator sets are capable of automatic start at any time and capable of continued operation at rated load, voltage, and frequency until manually stopped.

5. The generator sets have the ability to pick up loads as described on Table 8.5-1 in the sequence and time period outlined on Table 8.5-2.

6. The generators are capable of being independently synchronized for parallel operation with the unit auxiliary transformer or the startup transformer (preferred AC power source). This synchronization is done manually for system performance tests. Provisions were made in the design to prevent: (a) the electrical interconnection of both generators and (b) the electrical interconnection of *either* generator with the secondary AC power source.

7. Each engine generator unit has a unit fuel storage (day tank) tank. Each day tank is supplied from its main fuel storage tank. Provisions are made to refill the EDG storage tanks from the two station blackout diesel generator storage tanks. The combined on-site diesel fuel supply provides continuous seven days operation of both EDGs at full rated capacity.

8. A manual cross connection between the EDG storage tanks is provided to transfer diesel fuel from one EDG tank to the other, when necessary.

9. 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 P-141A, 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. Each main fuel subsystem is capable of providing sufficient fuel for seven days of operation of one engine generator unit under postulated accident conditions. Each day tank provides enough fuel for a minimum of 2 hours of diesel generator operation at its two-hour overload rating (2860 kW).

10. Control power required for the startup and operation of each unit is supplied from the 125V Station DC Power System. Other auxiliaries necessary to ensure continuous operation are supplied as required from the diesel generator through the emergency service buses.

11. The units are capable of being started or stopped manually from local control stations near the engines or remotely started from the control room. The engines are normally connected to the emergency service buses from the control room. The engines start automatically upon the loss of both the preferred power source and the unit auxiliary power source or low-low reactor water level, or high drywell pressure.

12. The Standby AC Power System conforms to the applicable sections of IEEE-308, Standard Criteria for Class IE Electrical Systems for Nuclear Power Generating Stations.

13. Provisions shall be included to minimize the probability of losing 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.

8.5.3 Description

There are two normal power sources available to each 4,160V emergency bus; the unit power source and the preferred power source (startup transformer). A fourth power source is from the secondary power source discussed in Section 8.3. This source is a backup to the standby diesel generator. The breaker is interlocked to prevent synchronization or interconnected with the diesel generator, or with the normal power sources. The loss of the unit power source results in automatic fast transfer to the preferred power source. The loss of both the startup transformer source and the unit auxiliary power source to either emergency service bus results in automatic starting of the diesel generator associated with that bus. The diesel generator supply breaker will close approximately 10 seconds later, if the diesel generator has reached rated speed and voltage. The diesel generator, the third power source, now supplies power to the affected emergency bus.

The following events occur under Loss of Coolant Accident (LOCA) conditions in the order indicated:

1. The diesel generators are automatically started (independent of availability of offsite AC power)

2. If the preferred power source is available, but voltage is below the degraded voltage alarm reset setpoint, load shedding is initiated and essential auxiliaries are automatically started in a predetermined sequence.

3. If there has been a loss of power from the preferred source:

    a. The normal power source breakers at the emergency service switchgear buses are tripped open

    b. All 4,160V feeder breakers on the emergency service switchgear buses are tripped open, except the feeds to the 480V emergency service load centers

    c. The diesel generator supply breaker closing sequences are automatically started

    d. After approximately 10 seconds, the diesel generator power supply breakers will close at each emergency service bus when its diesel generator has reached rated voltage and speed

    e. When the voltage on any emergency service bus is established, essential auxiliaries are then automatically started in a predetermined sequence as shown on Table 8.5-2

4. If there has been a degraded voltage condition from the preferred source:

    a. The normal power source breakers at the emergency service buses are tripped open in a predetermined time by the 4,160V degraded voltage relays.

    b. All 4,160V feeder breakers on the emergency service switchgear buses except the feeds to the 480V emergency service load centers are tripped open via the 4,160 Loss of Voltage relays when emergency service buses are at approximately 25% of their rated voltage. The diesel generator power supply breakers will then close at each emergency service bus after a predetermined time delay provided the diesel generator has reached rated voltage and speed.

    c. When the voltage on any emergency service bus is established, essential auxiliaries are then automatically started in a predetermined sequence as shown on Table 8.5-2A.

Each diesel generator is connected to only one 4,160V emergency service bus. Interlocks and procedural restrictions assure that the two diesel generators are not interconnected.

During emergency operation the generator is tripped by the following:

1. Generator differential

2. Generator phase overcurrent

3. Engine overspeed

The overcurrent relays are set so they will not trip the generator on transient overcurrents or surges in power due to starting or tripping of large loads. The other protective relays and devices provided to annunciate abnormal generator conditions are:

1. Generator ground overvoltage

2. Blown potential transformer fuse (voltage unbalance)

These alarms are annunciated in the main control room and the operator takes appropriate corrective action.

Both generators are housed in reinforced concrete Class I structures. Each unit is completely enclosed to provide independence from the other unit. The units are connected by cables run in underground ducts, and cable trays, and in rigid steel conduits to the 4,160V emergency service metal clad switchgear. Each 4,160V switchgear is housed in a separate room within a Class I structure. The diesel generators are designed to start and attain rated voltage and frequency within 10 seconds. Closure of the diesel generator output breaker is controlled by two time delay permissive relays. One time delay relay is required to be set at approximately 10.0 seconds and the other time delay relay is required to be set at approximately 4.0 seconds for the A and B diesel generators. The time limits for the diesels is based on the assumptions made in the analyses of Pipe Breaks Outside Containment. The generator, static exciter, and voltage regulator are designed to accept load and accelerate the motors in the sequence and time requirements shown on Table 8.5-2. Voltage drop on starting of large motors has been calculated to ensure proper acceleration of the pumps under the required conditions for core cooling after a design basis LOCA. Proper control and timing relays are provided so that each load is applied automatically at the proper time in the starting sequence as indicated on Table 8.5-2. For the automatic load sequencing, refer to Section 8.5.4.

Four key locked control switches have been installed to permit blockage of the drywell high pressure initiation signals: two switches in the core spray initiation logic described under Section 7.4.3.4.2, and two switches in the LPCI initiation logic described under Section 7.4.3.5.2. These four switches are for use under post LOCA conditions to permit shutdown of idling diesel generators without affecting the reactor vessel low water level, or loss of AC power initiation signals.

Each diesel generator with its associated auxiliaries, connection to 4,160V emergency switchgear, control system, and distribution of power to the various safeguard loads, are segregated and separated

from the corresponding systems of the other diesel generator. Each unit is operated independently of the other.

Necessary information, data, and annunciation of trouble at the diesel generator is provided in the main control room. Table 8.5-3 shows diesel generator ratings.

The diesel engine is tripped on engine overspeed between 1060 and 1075 RPM (118 and 119 percent of rated speed respectively). The following abnormal conditions are alarmed in the control room under "Diesel Generator Trouble":

1. Lubricating oil, low pressure
2. Jacket water, low-high temperature
3. Cooling water expansion tank, low-high level
4. Starting air, low pressure (for each system)
5. Circulating lubrication pump, failure
6. Lubricating oil, low-high temperature
7. Overspeed trip
8. Starting sequence abnormal
9. Generator Field Ground

The following conditions are alarmed in the control room individually:

1. Day tank, low-high level
2. Oil storage tank low level
3. Loss of control bus DC supply
4. Voltage regulator on manual
5. Diesel generator starting signal blocked
6. Abnormal voltage or frequency

For increased starting reliability, two Air Starting Systems are provided for each unit with two starting motors in each Air Supply System. The engine may be started by any one system (two starting motors) or both air systems (all four starting motors). Any one of these systems is capable of starting a unit. One air compressor is available, driven by an electric motor or a gasoline engine, for each unit. Two air reservoirs are provided for each diesel engine, each capable of providing sufficient air for two normal starts. One air start receiver with a minimum pressure of 225 psig is adequate to provide two normal EDG starts. The Diesel Fuel Supply System is shown on Figure 8.5-1 (Drawing M223).

Turbo Air Assist System

The Turbo Air Assist System provides two major functions:

(a) it provides a "jet assist" to the turbo charger during engine starts to ensure the diesel generator attains rated voltage and frequency within the specified time (10 seconds).

(b) it provides "jet assists" when large load changes are sensed to ensure the diesel generator can accept load and accelerate the motors in the sequence and time requirements shown on Table 8.5-2.

The Turbo Air Assist System has one air compressor and three air reservoirs for Turbo Charger Assist in starting and loading.

A pressure drop calculation determined that any 2 out of 3 available reservoirs have sufficient air capacity to satisfy the requirements of (a) and (b) above. Capacity is dependent on pressure in the available reservoirs, and therefore the isolation of any reservoir will require that a minimum pressure be maintained in the remaining reservoirs. Procedural controls assure that adequate turbo assist configurations exist and that minimum pressures are maintained.

8.5.4 Safety Evaluation

The diesel generator units were selected on the basis of their proven reliability and independence as standby power sources. Redundancy is provided in the Air Starting System components for each unit to improve the starting reliability of the units.

Also, each diesel generator is capable of starting or sustaining the loss of the largest load at any time during the LOCA sequence up to and including loads manually added by the operator, as justified by the following:

The largest individual load which is automatically or manually applied to the diesel generator during the LOCA sequence is one CSCS pump motor. These motors are sequentially started when loaded onto the diesel generator by individual preset time delay elements contained in the starting logic for each motor.

The RHR pumps and core spray pump each develop about 800 bhp at rated flow. The core spray pump motor is the first CSCS pump motor automatically loaded on the diesel generator. An RHR pump motor is the first CSCS pump motor load manually removed from the diesel generator after the core is reflooded. The starting of the core spray pump motor or the loss of an RHR pump motor therefore represents the largest step load change required during the LOCA sequence.

The diesel generator acceptance tests included engine load changes which simulated the sequenced starting of the three CSCS pump loads. The tests also included the simulated loss of an RHR pump load and initial full load condition on the engine.

During loading transients, the diesel generator speed varies between approximately 90 and 110 percent of rated. Voltage drop to 75 percent of rated is expected, with recovery within the time to accept the succeeding sequenced loads and recovery to 100 percent at steady state conditions.

The generator voltage variations and the diesel engine speed variations did not approach these limits for all engine loadings simulated during the acceptance testing.

The load breakers on the emergency service buses do not all have the same trip characteristics. The breakers that supply motors from the 4,160V emergency service buses will trip open when a loss of bus voltage is sensed and will not re-close when the voltage is restored unless they subsequently receive a start signal. Assuming design basis LOCA conditions, the three 4,160V CSCS pump motors would be sequentially loaded on the diesel generator at 5 second intervals after the diesel generator is connected to the emergency bus. The breakers that supply the 4,160/480V transformers from the 4,160V emergency service buses do not trip during a loss of bus voltage. The 480V breakers that connect the transformer to bus B1 or B2 do not trip during a loss of bus voltage.

The loads connected to the 480V emergency buses are controlled by a set of load limiting relays or by the characteristics of the control circuit. The load limiting relays for emergency service bus A are independent from the load limiting relays for emergency service bus B.

The loads connected to the 480V emergency buses have control characteristics which are established by the requirements for the load during emergency loading conditions. The load groupings considered are as follows:

Group 1

Those loads that are intended to operate immediately following a LOCA such as containment isolation valves, Recirculation loop valves, Core Spray and LPCI valves, and Standby Gas Treatment exhaust fans are automatically supplied when required. Additional loads not required during emergency conditions but which represent negligible load on the emergency bus or which are operationally desirable (such as the battery chargers) are also permitted in this load group.

Group 2

Selected loads are tripped off or blocked during the automatic, sequential startup of the three 4,160V CSCS motors and remain blocked as long as these three CSCS pumps continue to operate or the drywell high pressure signal is still present. The four key locked control switches described in Section 8.5.3 are for use under post LOCA conditions to permit automatic reset of the Group 2 loads. In the case where the safety related buses are being supplied from the Startup Transformer, and load shedding was initiated due to degraded voltage, resetting of Group 2 or Group 4 loads is not permitted until the 4,160V bus degraded voltage alarm resets. After vessel water level is restored and one CSCS pump is manually tripped off,

these loads are permitted to reload automatically in accordance with the normal control logic requirements. Loads controlled in this manner include the heating and ventilating units that normally supply the main control room, the station air compressors, turbine-generator turning gear motor and lube oil pump, diesel generator standby auxiliaries, and turbine building closed cooling water pumps.

Group 3

Selected loads are tripped off during the automatic, sequential startup of the three 4,160V CSCS motors and are automatically restarted by time delay relays having longer delay settings than those used in the time delay relays in the starting logic of the three CSCS motors. This provides sequenced, automatic startup of essential emergency loads on the diesel generator. Essential loads that are restarted by time delay relays include Reactor Building Closed Cooling Water Pumps and Salt Service Water pumps. Other loads which are restarted for convenience by time delay relays include the vital motor generator set (which is powered from the 250V battery until reconnected to the AC supply).

Group 4

Selected loads are tripped off during the automatic sequential startup of the three 4,160V CSCS pumps and remain blocked off by latching relays. These loads cannot be restarted until the operator manually resets the latching relays. The latching relays can only be reset after the Group 2 loads have been automatically reset.

The load shedding relays (Groups 2, 3, and 4) for each diesel generator are located in separate sections (SA and SB) of an additional main control room panel which has three wiring sections (SA, SB, and SX) separated by fire barriers. Some engineered safeguard loads are affected by these relays and these circuits will be tested periodically.

Each diesel generator is capable of starting and continuously operating at full rated capacity for a period of 7 days using fuel stored onsite in underground storage tanks. The minimum quantity of fuel maintained in each EDG storage tank is sufficient to ensure continuous operation at full rated capacity of the corresponding EDG for approximately four days. The combined quantity of fuel in the two EDG and two SBODG tanks is sufficient to ensure continuous seven days operation of both EDGs at full rated capacity. A manual refilling method to transfer diesel fuel from SBODG storage tanks to the EDG storage tanks is available to provide the operating EDG with the additional fuel necessary to support continuous operation.

The starting air supply is stored in receivers and maintained at proper pressure. Independent sources of 125V DC power are used to supply electrical control power to the Air Starting System for diesel generator units. See Section 8.6.4 for a more detailed description of the 125V System. The units and all necessary auxiliaries are housed in Class I structures.

The engineered safeguard loads are divided between the two 4,160V emergency service buses so that the failure of one diesel generator or one 4,160V emergency service bus would not prevent a safe shutdown of the reactor. Each diesel generator and its associated system is separated so that failure of any one component will not affect the operation of the redundant system.

The capability of the diesel generator to start and attain rated voltage and frequency within 10 seconds, to accept the necessary engineered safeguard loads, and to start and accelerate the emergency core cooling system pumps in the required time, meets the necessary requirements for the standby AC power system.

8.5.5 Inspection and Testing

Since the diesel generators are utilized as standby units, readiness is of prime importance. Readiness can best be demonstrated by periodic testing, which insofar as practical, simulates actual emergency conditions. The testing program is designed to test the ability to start the system as well as to run under load for a period of time long enough to bring all components of the system into equilibrium conditions to assure that cooling and lubrication are adequate for extended periods of operation. Functional tests of the automatic circuitry are conducted on a periodic basis to demonstrate proper operation.

Provisions are included for manual synchronization of an individual diesel generator unit with the unit auxiliary transformer or the startup transformer to provide the capability to functionally test the diesel generator performance at full rated output.

Interlocks are provided to preclude the synchronization or interconnection of both diesel generators with each other, or of either diesel generator with the secondary AC power source.

An initial system test was performed to demonstrate that the standby AC power system could start and accept design load within the design basis time.

8.5.6 Proposed Nuclear Safety Requirements for Initial Plant Operation

General

The entries in this section represent the proposed nuclear safety requirements for initial plant operation for auxiliary AC power sources for each BWR operating state. The entries result from the station wide BWR systems analysis reported in Appendix G. The following referenced portions of the safety analysis report provide important information justifying the entries in this section.

	Reference	Information Provided
1.	Earlier parts of Section 8.2, 8.3, 8.4 and 8.5	Description of the Standby AC Power System diesel generators, the preferred offsite AC power source, and 4,160 and 480V emergency service buses; initiation control and bus loading sequences
2.	Station Nuclear Safety	Identifies conditions and events Operational Analysis, for which the auxiliary AC power Appendix G sources are required

Each detailed requirement in this section is referenced, when possible, to the most significant station condition originating the need for the requirement by identifying a matrix block shown on Matrix 3. See Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the minimum required for action section. The matrix block references identify the BWR operating state, the event number and the system number For example, F39-88, identifies BWR operating state F, Matrix 3, event row 39, and system column 88.

Standby AC power is required in all operating states to supply required engineered safeguard loads following a total loss of normal auxiliary power. The maximum requirement for standby AC power is based on a LOCA at design power with concurrent loss of normal preferred AC power. Load requirements will be less in other operating conditions.

AC power for emergency shutdown requirements and operation of engineered safeguards equipment can be provided by either of two offsite and either of two standby sources (two diesel generators) of power. The requirements of two sources of power was established to provide for maintenance and repair of equipment, and still have redundancy of power sources. The station main generator is not given credit as a source since it is not available during shutdown.

System Action

System Action includes providing emergency AC power to station nuclear safety and engineered safeguards systems and their required auxiliaries.

Number Provided by Design

Two 2,600 kW diesel generators and related emergency service buses. Two offsite AC power sources.

Minimum Required for Action

(BWR Operating States A, B, C, D, E, F)

One diesel generator and its related emergency service buses if the preferred AC power source is inoperable.

(A28-88)	(B28-88)
(C39-88)	(D39-88)
(E39-88)	(F39-88)
(A35-96)	(B35-96)
(C27-96)	(D27-96)
(E27-96)	(F27-96)

Condition Required for Continuous Operation (BWR Operating States A,B,C,D,E,F)

Proposed Limiting Conditions for Initial Plant Operation

The limiting conditions for operation are set forth in the Technical Specifications for Pilgrim Nuclear Power Station. The auxiliary AC power sources and distribution systems must be operable except that portions may be inoperable provided that the related requirements listed below are met.

1. One diesel generator may be inoperable for no longer than the allowable repair time provided that requirements a through c are met.

   a. The other diesel generator is tested and demonstrated to be operable and is then started and loaded on an increased test frequency of once each day until both diesel generators are again operable.

   b. All of the nuclear safety or engineered safeguard systems required in this operating state and powered by the Operable Standby AC Power System are operable.

   c. The appropriate DC battery is operable.

2. If the preferred AC power source becomes inoperable during power operation, repair shall be initiated immediately and the standby AC power sources shall be tested weekly. The reactor may remain in operation until repairs are completed.

3. If both diesel generators become inoperable, the reactor shall be placed in the cold shutdown condition.

4. There shall be a minimum of 19,800 gal of diesel fuel in each of the standby diesel generator fuel tanks for the diesel generators to be considered operable.

Allowable Repair Time (Diesel Generator and Emergency Bus)

The allowable repair time is 3 days, provided the increased testing frequency is observed. The limitation of allowable repair time does not apply in the cold shutdown condition.

Proposed Surveillance Requirements for Initial Plant Operation

Each diesel generator will be tested monthly. Functional performance capability tests will be performed on each diesel generator unit approximately once per operating cycle. Emergency switchgear will also be tested as per Table 8.4-3.

8.5.7 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.

TABLE 8.5-1

DIESEL GENERATOR "A" EMERGENCY LOADS [l] - STANDBY AC POWER SYSTEM

Function	Station Total Number Available	Maximum Number Available	Nameplate HP	Load KW	LOCA w/ LOOP 0-10 Min. Number Connected	LOCA w/ LOOP 0-10 Min. Operating Load	LOCA w/ LOOP 10-120 Min Number Connected	LOCA w/ LOOP 10-120 Min Operating Load	LOCA w/ LOOP >120 Min. Number Connected	LOCA w/ LOOP >120 Min. Operating Load [a]	LOOP Number Connected	LOOP Operating Load
Control Rod Drive Feed Pump	2	1	250	-	-	-	-	-	-	-	1	280 hp
Residual Heat Removal Pump	4	2	800	-	2	1600 hp	2	1600 hp	1	800 hp	1	800 hp
Core Spray Cooling Pump	2	1	800	-	1	808 hp	1	808 hp	1	808 hp	-	-
Battery Charger (125 V DC)	3	2	-	31.4	2	62.8 kw (k)	2	62.8 kw (k)	2	62.8 kw (k)	2	62.8 kw (k)
Battery Charger (250 V DC)	2	1	-	72.3	1	72.3 kw (h)	1	72.3 kw (h)	1	72.3 kw (h)	1	72.3 kw (h)
Aux Oil Pump Recirc M-G Set	2	1	30	-	-	-	-	-	-	-	1	30 hp
Standby Gas Treatment System	2	1	15	30.2	1	15 hp / 30.2 kw	1	15 hp / 30.2 kw	1	15 hp / 30.2 kw	1	15 hp/ 30.2 kw
RBCCW Pump	6	3	60	-	1	60 hp	2	110 hp	2	110 hp	2	110 hp
TBCCW Pump	2	1	100	-	-	-	-	-	1	100 hp	1	100 hp
Salt Service Water Pump	5	3	100	-	1	113 hp	2	204 hp	2	204 hp	2	204 hp
Station Instrument Air Compr. (b)	3	2	40	-	-	-	-	-	2	80 hp	2	80 hp
Drywell Unit Coolers	16	8	95	-	-	-	-	-	-	-	8	95 hp
Emergency Lighting	-	All	-	46.6	All	46.6 kw	All	46.6 kw	All	46.6 kw	All	46.6 kw
Vital MG Set (m)	-	1	75	15	1	15 kw	1	15 kw	1	15 kw	1	15 kw
Station HVAC System (b) (e)	-	-	-	-	-	36 hp	-	39 hp / 17.7 kw	-	42 hp / 17.7 kw	-	74 hp / 44 kw
Turbine Generator Auxiliaries	-	-	-	-	-	23 hp	-	23 hp	-	133 hp	-	133 hp
Miscellaneous Auxiliaries	-	-	-	-	-	6 hp / 83.6 kw	-	7 hp / 83.6 kw	-	22 hp / 184.2 kw	-	22 hp / 209.2 kw
345 KV SWYD Feed	-	-	-	75	-	-	-	-	-	-	-	75 kw
Total KW Load on "A" Continuous (g)	-	-	-	-	-	2499 kw		2641 kw	-	2372 kw	-	2321 kw
Short Time (MOV's) KW Load on D.G. "A" (c)	-	-	-	-	-	169.4 kw		69 kw	-	69 kw	-	69 kw
Total KW Load (Continuous & Short Term) (g)						2669 kw		2710 kw		2441 kw		2390 kw

TABLE 8.5-1

DIESEL GENERATOR "B" EMERGENCY LOADS [l] - STANDBY AC POWER SYSTEM

Function	Station Total Number Available	Maximum Number Available	Nameplate HP	Load KW	LOCA w/ LOOP 0-10 Min Number Connected	LOCA w/ LOOP 0-10 Min Operating Load	LOCA w/ LOOP 10-120 Min Number Connected	LOCA w/ LOOP 10-120 Min Operating Load	LOCA w/ LOOP >120 Min Number Connected	LOCA w/ LOOP >120 Min Operating Load [a]	LOOP Number Connected	LOOP Operating Load
Control Rod Drive Feed Pump	2	1	250	-	-	-		-	-	-	1	280 hp
Residual Heat Removal Pump	4	2	800	-	2	1600 hp	2	1600 hp	1	800 hp	1	800 hp
Core Spray Cooling Pump	2	1	800	-	1	808 hp	1	808 hp	1	808 hp	-	-
Battery Charger (125 V DC)	3	2	-	31.4	2	62.8 kw [f]	2	62.8 kw [f]	2	62.8 kw [f]	2	62.8 kw [f]
Battery Charger (250 V DC)	2	1	-	72.3	1	72.3 kw	1	72.3 kw	1	72.3 kw	1	72.3 kw
Standby Gas Treatment System	-	-	15	30.2	1	15 hp / 30.2 kw	1	15 hp / 30.2 kw	1	15 hp/ 30.2 kw	1	15 hp / 30.2 kw
RBCCW Pump	6	3	60	-	1	60 hp	2	110 hp	2	110 hp	2	110 hp
TBCCW Pump	2	1	100	-	-	-	-	-	1	100 hp	1	100 hp
Salt Service Water Pump	5	3	100	-	1	113 hp	2	204 hp	2	204 hp	2	204 hp
Aux Oil Pump Recirc M.G. Set	2	1	30	-	-	-	-	-	-	-	1	30 hp
Station Instrument Air Compr. [b]	3	2	40	-	-	-	-	-	2	80 hp	2	80 hp
Emergency Lighting	-	-	-	46.6	All	46.6 kw	All	46.6 kw	All	46.6 kw	All	46.6 kw
Drywell Unit Coolers	16	8	100	-	-	-	-	-	-	-	8	100 hp
Vital MG Set [m]	-	-	75	15	1	15 kw	1	15 kw	1	15 kw	1	15 kw
Station HVAC System [b] [e]	-	-	-	-	-	30.5 hp	-	33.5 hp / 17.7 kw	-	36.5 hp / 47.7 kw	-	68.5 hp / 74 kw
Turbine Generator Auxiliaries	-	-	-	113	-	23 hp	-	23 hp		133 hp	-	133 hp
Miscellaneous Loads	-	-	-	-	-	4.5 hp / 81.6 kw	-	5.5 hp / 81.6 kw	-	20.5 hp / 193.6 kw	-	20.5 hp / 218.6 kw
345 KV SWYD Feed	-	-	-	75	-	-	-	-	-	-	-	75 kw
Total KW Load on "B" Continuous [g]	-	-	-	-	-	2489 kw	-	2629 kw	-	2335 kw	-	2350 kw
Short Time (MOV's) KW Load on D.G. "B" [c]	-	-	-	-	-	149.4 kw		70 kw	-	70 kw	-	70 kw
Total KW Load (Continuous & Short Term) [g]						2639 kw		2699 kw		2405 kw	-	2420 kw

TABLE 8.5-1

DIESEL GENERATOR EMERGENCY LOADS - STANDBY AC POWER SYSTEM

a. Of these additional loads, approximately 330 KW could automatically restart when the operator manually stops any one of the three large CSCS pumps. The other load additions in this column are started manually by the operator as required when diesel load limits permit.

b. Intermittent or short term loads.

c. Isolation and essential valves. Maximum expected coincident MOV loading during the 0 10 min period of a LOCA w/LOOP; operation of the largest PNPS MOV during all other scenarios.

d. Not used.

e. Includes essential CSCS unit area coolers, battery room exhaust fan, and essential control room ventilation.

f. 31.4 KW of this loading assumes an abnormal lineup where the backup 125 V DC charger feeds the "A" battery. Battery chargers are assumed to be operating at current limit.

g. After short term MOV's operate in the first 10 minutes after an accident and with three CSCS pumps operating, the total diesel generator load remains within the 2,000 hr rating (2750 KW) with manual start of one additional SSW pump and one additional RBCCW pump to support containment cooling. This is the worst case loading under design basis loading. Under abnormal conditions, i.e. at the *maximum expected generator frequency* and voltage and the worst case single failures that could impact both EDG's, the maximum continuous load is within the 2 hr in 24 hr rating of the EDG's for the first two hours of a LOCA and within the 2000 hr rating at all other times. The peak short time load during operation of motor operated valves (< 1 minute) is below the 3000 kW, 30 minute rating of the EDG's.

h. This loading assumes an abnormal lineup where the backup charger feeds the 250 V DC battery. Battery chargers are assumed to be operating at current limit.

i. Not used.

j. Not used.

k. 31.4 KW of this loading assumes an abnormal lineup where the backup 125 V DC charger feeds the "B" battery. Battery chargers are assumed to be operating at current limit.

l. These EDG loading Tables list specific loads/specific loading categories for each PNPS EDG. The total load "continuous" and "continuous & short term" for each scenario are from load flow calculations. The total load listed includes all distribution system losses.

m. The Vital MG Set has a 75 hp AC drive motor. The actual load on this unit is less than 15 kw.

TABLE 8.5-2

STANDBY DIESEL GENERATOR SYSTEM
TYPICAL TIMING AND SEQUENTIAL LOADING OF DIESEL GENERATORS
(all times approximate)

Event	Time (sec)	Comment
Design basis loss of coolant accident starts, normal auxiliary power assumed lost.	0	
Signal diesel generator to start from drywell high pressure or vessel low water level or loss of preferred AC power source.	3	This sequence applies to one diesel and its associated loads. The other diesel has a similar sequence and load.
Diesel generator ready to load Start core spray pump. Signal selected reactor coolant recirculation system line valves to close. Connect emergency lighting and motor operated isolation valves.	13	
Core spray pump at speed. Start first RHR pump (LPCI mode).	18	
Reactor pressure decreases to 350 psig. Signal core spray and LPCI injection valves to open.	19	
First RHR pump at speed. Start second RHR pump.	23	
Second RHR pump at speed.	28	
Reactor core spray cooling system injection valve open.	29	This completes the reactor core spray cooling system start sequence.
Recirculation system valves closed and LPCI injection valves open.	43	This completes the LPCI Start sequence.
Start additional loads (e.g., cooling water pumps).		

TABLE 8.5-2A

STANDBY DIESEL GENERATOR SYSTEM
TYPICAL TIMING AND SEQUENTIAL LOADING OF DIESEL GENERATORS
(all times approximate)

Event	Time (seconds)	Comment
Design basis loss of coolant accident starts, normal auxiliary power assumed degraded.	0	
Signal diesel generator to start from drywell high pressure or vessel low water level.	3	This sequence applies to one diesel and it's associated loads. The other diesel has a similar sequence and load.
Normal auxiliary power lost due to degraded voltage relay actuation.	12	
Diesel generator ready to load. Start core spray pump. Signal selected reactor coolant recirculation system line valves to close. Connect emergency lighting and motor operated isolation valves.	18	
Reactor pressure decreases to 350 psig. Signal core spray and LPCI injection valves to open.	19	
Core spray pump at speed. Start first RHR pump (LPCI mode).	23	
First RHR pump at speed. Start second RHR pump.	28	
Reactor core spray cooling system injection valve open.	31	This completes the reactor core spray cooling system start sequence.
Second RHR pump at speed	33	
Start cooling water pumps (SSW, RBCCW).	38-48	
Recirculation system valves closed and LPCI injection valves open.	53*	This completes the LPCI Start sequence.

*Timing is approximately 56 seconds with an assumed loss of "A" EDG.

TABLE 8.5-3

STANDBY AC POWER SOURCE
EQUIPMENT LIST

Diesel Engine

Rated Speed	900 rpm
Continuous Rated Capacity*	2,600 kW
Overload Capacity*	2,750 kW for 2,000 hrs 2860 kW for 730 hrs (not to exceed 2hrs/24hrs) 3,000 kW for 30 minutes
Fuel consumption at 2860 kW	222 gallons/hour

Generator

Continuous Rated Capacity	3,250 kVA
Power Factor	0.8
Frequency	60 Hz
Voltage	4,160V
Phase (connection)	3 (wye)
Overload Capacity	3,440 KVA (2,750 kW @ 0.8 pf) for 2,000 hrs/yr 3,575 KVA (2,860 kW @ 0.8 pf) for >730 hrs/yr** 3,750 KVA (3,000 kW @ 0.8 pf) for 2 hrs/yr

Exciter

Size	21 kW

Diesel Generator Startup

Starting time to rated speed and voltage, and ready to accept load	≤10 seconds
Starting time to rated load	≤30 seconds

On-Site Fuel Oil Storage

Day Tank	greater than 600 gallons
EDG Storage Tanks	25,000 gallons (each)
SBODG Storage Tanks	20,000 gallons (each)

*See Table 8.5-4 for additional restrictions.
**Conservatively determined based on the above nameplate data.

TABLE 8.5-4

EMERGENCY DIESEL GENERATOR MAXIMUM ALLOWABLE LOADING (kW)
BETWEEN MAJOR INSPECTIONS OR OVERHAULS

Load	Time	
≤ 2600 kW	≤ 8000 hrs	or
2601 kW to 2750 kW	≤ 2000 hrs	or
2751 kW to 2860 kW	≤ 730 hrs (not to exceed 2hrs/24hrs)	or
2861 kW to 3000 kW	≤ 30 minutes	

Note:

Table 8.5-4 establishes the maximum operating time for each Emergency Diesel Generator (EDG) at varying loads between major inspections or overhauls. The Table provides the maximum operating time for each load if it is applied exclusively. Once reaching the maximum operating time for any load condition, a major inspection or overhaul of the EDG must be performed prior to being available for continued operation.

Alternately, operation of the EDG at various combinations of the above loads may continue while the following load prorating formula is satisfied:

$$\frac{N_1}{8000} + \frac{N_2}{2000} + \frac{N_3}{730} + \frac{N_4}{0.5} \leq 1.0$$

where:

N_1 = Number of hours at loads of ≤ 2600 kW
N_2 = Number of hours at loads of 2601 kW to 2750 kW
N_3 = Number of hours at loads of 2751 kW to 2860 kW
N_4 = Number of hours at loads of 2861 kW to 3000 kW

(e.g.:) $$\frac{200}{8000} + \frac{56}{2000} + \frac{55}{730} + \frac{N_4}{0.5} \leq 1.0$$

$N_4 \leq 0.435$ hrs (26 minutes) of operation at 3000 kW

Figure 8.5-1 has been removed.

Please refer to BECo Controlled Drawing M 223.

8.6 125 AND 250 VOLT DC POWER SYSTEMS

8.6.1 Safety Objective

To provide and distribute an uninterruptible source of power adequate for normal operation and for the safe shutdown of the reactor following abnormal operation transients and postulated accidents.

8.6.2 Safety Design Basis

1. Each 125 V and 250 V battery has adequate capacity to safeguard the station until ac power sources are restored.

2. Each battery charger has adequate capacity to restore its battery to full charge from a totally discharged condition while carrying the normal station steady state dc load.

3. The 125 V and 250 V DC Power Systems are arranged so that no single component failure will prevent the systems from providing power to a sufficient number of vital dc loads necessary for safe shutdown.

4. The 125 V and 250 V dc power systems are provided in accordance with the IEEE-308, Standard Criteria for Class IE Electrical Systems for Nuclear Power Generating Stations.

5. The batteries and battery racks are Class I equipment to assure continuous operation of the equipment under maximum seismic shock conditions applicable to the area and location of the equipment.

8.6.3 Description

The dc power systems (125 V for power and control and 250 V for power) supply dc power to conventional station emergency equipment and selected safeguard system loads. The dc power systems are shown on Figure 8.6-1. Table 8.6-1 lists the major electrical equipment of the dc power systems.

The battery chargers in both the 125 and 250 V dc power systems are supplied from the 480 V ac emergency service buses which are described in Section 8.4.

The 125 V dc power system supplies power and control through two control buses, A and B, two distribution panels, A and B, and a common distribution panel, C. Power feeds into control bus A from:

1. Control battery A

2. Battery charger A which is fed from 480 V ac emergency service load center B1 through a transfer switch which can allow use of alternate power in the event of loss of AC power.

3. The 125 V dc backup battery charger which is fed through 480 V ac common emergency service load center B6 through a transfer

switch which can allow use of alternate power in the event of loss of AC power.

Control bus A feeds power to distribution panel A, 125V DC motor control center No. 1 and through automatic transfer switches to distribution panel C. All connections to control bus B are the same as control bus A, except that battery charger B is fed through 480V AC emergency service load center B2. The 125V DC backup battery charger is common to both control bus A and bus B. The two 125V DC motor control centers feed power to selected safeguard system pump motors and motor operated valves.

Distribution panel C receives power through the automatic transfer switches from either control bus A or bus B. Distribution panel C feeds power to the emergency lighting distribution panel and the solenoid operated valve distribution panel.

The 250V DC power system supplies power through one bus. The bus receives power from:

1. The 250V power battery

2. The 250V normal battery charger which is fed through the 480V AC emergency service load center B2 through a transfer switch which can allow use of alternate power in the event of loss of AC power.

3. The 250V backup battery charger which is fed through 480V AC common emergency service load center B6 through a transfer switch which can allow use of alternate power in the event of loss of AC power.

The bus feeds power directly to conventional station emergency equipment, including the vital motor generator set described in Section 8.8, and through a 250V DC motor control center to selected safeguard system loads.

The 125V control batteries A and B are lead calcium type. Table 8.6-1 provides detailed information of the 125V and 250V DC power system. Each control battery is located in a separate ventilated battery room. The 250V power battery is lead calcium type. The power battery is located in the same room as the 125V control battery B.

The 125V DC battery chargers utilize silicon thyristors and diodes in a full wave rectifier circuit rated at 200 amperes (Future 300A) capable of maintaining 0.5 percent voltage regulation with supply voltage variations of $\pm$10 percent of 460V or frequency variations of $\pm$5 percent.

The 250V DC battery chargers are full wave silicon controlled rectifier type rated at 200 amp and 0.5 percent voltage regulation with AC supply variations of 10 percent in voltage and 5 percent in frequency.

The 125V DC control buses A and B (D16 and D17) are rated at 600 amp continuous current and at least 20,000 amp momentary current. All of the 125V DC panels include two pole molded case circuit breakers. The 125V DC distribution panel A (D4) has buswork and breakers with an interrupt rating of at least 20,000 amp momentary current. The buswork and breakers on 125V DC distribution panels B (D5) and C (D6) have an interrupt rating of at least 10,000 amp momentary current. The automatic transfer switches associated with distribution panel C have a continuous rating of 200 A, an interrupt rating of 3000 A and a short circuit capability of 15,000 A. The 250V DC power bus and 250V DC motor control center have main buses rated at 600 amp continuous current. The power bus (D10) is rated for at least 25,000 amp momentary current and the 250V DC motor control center (D9) is rated for at least 10,000 amp momentary current. The 250V circuit breakers are two pole manually operated. All of the breakers and fuses on the power bus (D10) are capable of interrupting at least 25,000 amp momentary current. The breakers in D9 are capable of interrupting at least 10,000 amp. All motor starters are provided with single pole thermal overload elements for alarm only in the main control room. Each motor starter in the 250V DC motor control center is monitored for loss of 250V DC power or loss of 125V DC control power. Any loss of DC power is annunciated in the control room. The 125V DC distribution panels, A, B, and C, are NEMA Type 1 construction, dead front, surface mounted panels with two pole manually operated circuit breakers.

The 125V DC motor control centers are NEMA Type I gasketed construction with drip proof covers. The main bus is rated at 600 amp. The original plant circuit breakers are two pole manually operated with magnetic short circuit protection on both poles. All motor starters are provided with single pole thermal overload elements for alarm only in the main control room. Due to spare part considerations and improved reliability, many of the magnetic only circuit breakers have been replace with thermal-magnetic breakers to provide both short circuit and long term overload protection.

Three of the DC load centers (D7, D8, and D9) have been provided with walk-in enclosures which assure environmental qualification of the MCCs. The exterior walls of the enclosure consists of 1/4" thick steel plate and are designed to withstand the effects of postulated seismic events (OBE and SSE), external pressure due to PBOCs (1 psid), and tornado loads. The walls of the enclosures are covered with insulating material in order to minimize heat transfer from the Reactor Building Atmosphere to the enclosure following a PBOC. Major penetrations such as conduit and pipe are installed with foam sealant.

Principal design criteria are provided in Table 8.6-2.

Cable installation and design criteria for the DC Power System is discussed in Section 8.4.5.2. The current carrying capacity of all power cables is conservatively calculated to preclude damage due to thermal overloads except where deviations are approved by design engineering as stated in Section 8.9.5. Provisions for loss of AC and DC power have been made in the design. The multiplicity of battery charger sources and the division of critical loads between

buses yields a system that has a high degree of reliability. Also, the physical separation of buses and service components will limit or localize the consequences of electrical faults or mechanical accidents occurring at any point in the system.

8.6.4 Safety Evaluation

Power is normally supplied to the dc systems from the AC emergency service buses of the Auxiliary Power Distribution System through three battery chargers. Loss of the ac power source to any of the three chargers causes the related battery to supply power to its dc loads. Each battery is capable of supplying adequate power to operate its loads during normal and emergency conditions. The related backup battery charger (supplied by the 480 V common emergency Bus B6) is then manually connected to the affected battery bus. The backup battery charger recharges the battery while supplying power to the loads. Each battery charger has adequate capacity to restore its battery to full charge from a totally discharged condition while carrying the normal station steady state dc load.

<u>125 Volt DC Distribution Panel C</u>

Independence is not compromised by the automatic transfer scheme which transfers dc power from one independent battery side to the other in the event that the first battery side is lost.

The 125 V DC buses A and B (D16 and D17) and panel C (D6) are shown on Figure 8.6-1. Panel C normally receives power from bus A through an automatically controlled switch in series with the normally closed portion of an automatic transfer switch. Between bus B and panel C is a normally open automatically controlled switch in series with the normally open portion of the automatic transfer switch. Buses A and B cannot be connected together through panel C by a single failure since (a) the automatically controlled switch and transfer switch connected in series are both open and (b) their closing (or transfer) circuits cannot be both actuated by a single failure.

The transfer of panel C from battery side A to B is intentionally delayed 1/2 sec after an under-voltage condition is detected on side A. Operating current for the transfer is taken from the side to which the load is being transferred. After side A has returned to normal and voltage has been maintained at least 1 min, the load will be transferred back to side A. Loss of side B during this 1 min time delay would cause instantaneous (1/3 sec) transfer back to side A.

The effect on the dc systems of the two possible fault types discussed in the following analysis is different than the same fault types on the ac systems. A single line to ground fault is the most common fault possible. Since the DC systems are ungrounded, this fault would not cause excessive over current and under voltage. However, the fault is detected and annunciated for operator action. Multiple DC grounds need not be evaluated because the first ground

would be located and removed as soon as possible after alarming in the main control room. The only type of fault causing excessive over current and under voltage is a line to line fault. If this highly improbable single failure occurs anywhere in a system it will not result in losing both A and B sides. Loss of either A or B side will not cause loss of the other side or panel C. Loss of panel C will not cause the loss of either A or B side.

Postulated loss of battery side A, while much less probable than loss of AC bus A, has generated the use of panel C for loads which do not have redundant 125 V DC sides yet require maximum reliability. To facilitate the ensuing analysis of the requirements of each DC load, the loads are divided into groups as follows:

1. Main Steam Line Isolation Valves (inboard)

2. Bus B6 Control

3. Station Economic Investment Loads and Annunciators

4. Fire System Load

5. Other Loads

As with AC bus B6, (see Section 8.4) the grouping manifests the same basis for the selection of panel C as the power source. Discussion of each load group follows:

1. Main Steam Line Isolation Valves (inboard)

   As described in Containment Motor Operated Isolating Valves, in Section 8.4.6, all inboard motor operated valves are routed as SX. Similarly, the supplies to dc solenoids are routed as SX which also ensures proper separation from the outboard valves which are routed as SB

2. Bus B6 Control

   The control power for operation of the ac SX bus circuit breakers must be separated from SA and SB wiring. Hence the DC SX bus is used as the power source.

3. Station Economic Investment Loads and Annunciator

   These are basically turbine-generator auxiliaries and are vital to protect the station economic investment. Therefore, the most reliable source of DC power has been selected; panel C. All main control room annunciators are powered from panel C to ensure their availability when one battery side is lost.

4. Fire System Load

The cable spreading room gaseous fire suppression system initiation power is supplied from panel C for maximum availability and reliability.

5. Other Loads

Emergency DC lighting of the main control room, redundant switchgear areas, diesel generator areas, and the routes between them is made available during the loss of either battery side, to ensure continued access to these critical areas

Since the vital services motor generator set power is fed from the 250 V DC battery side, its control has been taken from panel C. Hence, loss of one 125 V DC battery side will not cause the failure of the 120 V AC vital services subsystem

The analysis shows that the intent of safety design basis 4 in Section 8.4.3 is met and that a reasonable and sufficient degree of electrical and physical independence is provided in the current PNPS design

When the diesel generators are started for emergency service following loss of all normal AC power to the emergency service buses, the batteries are supplying all dc power. The batteries have adequate capacity for 8 hr operation before battery chargers need to be reenergized. The 250 V dc battery charger and the 125 V DC battery chargers will be reenergized by the standby AC power source and will now supply the DC loads. In the event of loss of the standby AC power source, the installed transfer switches allow the use of alternate power to reenergize the battery chargers. Therefore the loads receive uninterrupted DC power during AC power interruptions.

The 125 V and 250 V power systems are ungrounded with ground detectors which alarm in the main control room. Multiple grounds are not probable since the first ground would be located and removed as soon as possible after alarming in the main control room.

All batteries and battery racks are designed to Class I requirements.

Although loss of one of the three DC sources is highly improbable, loss of one source would not prevent safe shutdown of the station. It is therefore concluded that the safety design bases are met.

8.6.5 Inspection and Testing

Inspection and testing at vendor factories and an initial system test 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.

8.6.6 Proposed Nuclear Safety Requirements for Initial Plant Operation

General

The entries in this section represent the proposed nuclear safety requirements for initial plant operation for the 125 V and 250 V DC power systems for each BWR operating state which result from the station wide BWR systems analysis reported in Appendix G. The following referenced portions of the safety analysis report provide important information justifying the entries in this section:

	Reference	Information Provided
1.	Section 8.6.3	Description of the 125 V and 250 V DC power systems
2.	Station Nuclear Safety and Operational Analysis Appendix G	Identifies conditions and events for which the 125 V and 250 V DC systems are required
3.	Jacobs, I.M. Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards. General Electric Co., Atomic Power Equipment Department, APED-5736, April 1969	Describes methods used to establish allowable repair times

Each detailed requirement in this section is referenced, if possible, to the most significant station condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" section. The matrix block references identify the BWR operating state, the event number, and the system number. For example, F39-89, identifies BWR operating state F (Matrix 3), event (row) No. 39, and system (column) No. 89.

The maximum requirement on the batteries is based on a loss of coolant accident (LOCA) at design power with a concurrent loss of AC auxiliary power. Load requirements in operating states A and B will be much less.

System Action

System action includes providing emergency DC power to station nuclear safety and engineered safeguard systems and their required auxiliaries.

Number Provided by Design

Two 125 V DC batteries and one 250 V DC battery, three 125 V battery chargers and two 250 V battery chargers.

Battery Side A: one 125 V battery and one 125 V battery charger

Battery Side B: one 125 V battery and one 125 V battery charger, one 250 V battery and one 250 V battery charger

Backup: one 125 V battery charger and one 250 V battery charger

Minimum Required for Action (BWR Operating States A,B,C,D,E,F)

Below 104 psig (states A,B,C,D):

The 125 V portion of one battery side with the associated diesel generator and distribution system operable.

(A28-89) (B28-89)
(C39-89) (D39-89)

Above 104 psig (states C,D,E,F):

One battery side with the associated diesel generator and distribution system operable.

(C39-89) (D39-89)
(E39-89) (F39-89)

Condition Required for Continuous Operation (BWR Operating States A,B,C,D,E,F) - Proposed Limiting Conditions for Initial Plant Operation

Below 104 psig (states A,B,C,D), the 125 V portions of both battery sides must be operable except that one battery side may be inoperable for no longer than the allowable repair time, provided that requirements No. 1 through 3 below are met.

Above 104 psig (states C,D,E,F), battery sides "A" and "B" must be operable except that one battery side may be inoperable for no longer than the allowable repair time provided that requirements 1 through 3 below are met:

1. The diesel generator which is controlled by the operable battery must also be operable during this period

2. None of the nuclear safety or engineered safeguard systems required in this state which are powered or controlled by the operable battery side or powered by the operable diesel generator can be out of service

3. During the period that one battery side is out of service, pilot cell voltage and specific gravity, and overall battery voltage must be tested daily on the operable battery side

Allowable Repair Time

The allowable repair time is 10 days, provided the increased testing frequency of 3 is observed. The limitation of allowable repair time is not applicable in cold shutdown condition.

Proposed Surveillance Requirements for Initial Plant Operation

Item	Periodic Test Description	Test Interval
All Batteries	Liquid Level	Monthly
	Specific Gravity and Cell Voltage	Pilot cell weekly All cells quarterly
	Visual Inspection	Weekly
	Performance Discharge	1/cycle
All Battery Chargers	Visual Inspection	Weekly
DC Buses	Mechanical Inspection	2 yr
	Overhaul	When required

8.6.7 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.

TABLE 8.6-1

LIST OF MAJOR ELECTRICAL EQUIPMENT
125/250 V DC POWER SYSTEMS

Batteries	
Control: A and B	125V, 60 cell, 2,550 amp-hr @ 8 hr rate at 77°F to 1.75 V (Cell Voltage)
Power (B only)	250V, 120 cell, 2,550 amp-hr @ 8 hr rate at 77°F to 1.75 (Cell Voltage)
Battery Chargers	
Control: A, B, and Backup	125V DC, 200 amp
Power: Normal and Backup	250V DC, 200 amp
DC Buses	
Control: A and B momentary (D16 & D17)	125V DC, 600 amp, 20,000 amp
Power (B only) momentary (D10 Main Bus)	250V DC, 600 amp, at least 25,000 amp

TABLE 8.6-2

PRINCIPAL DESIGN CRITERIA FOR
MCC (D7, D8, D9) ENCLOSURES

1. The MCC enclosures are designed to maintain the environment around the MCCs to be less than or equal to 80°F (average) for continuous service, less than 100°F peak for D8 and D9 and less than 90°F peak for D7 during normal operation, and less than 130°F during accident conditions.

2. The Reactor Building Environment (surrounding the enclosures) is as follows:

   a. Normal Operating

PARAMETER	MIN.	NORM.	MAX.
Temperature	40	85	104
Pressure (PSIA)	14.65	14.7	14.7
Relative Humidity	%40	60	90

3. The enclosures are designed for a 1.0 psig external pressure (pipe rupture load). This value envelopes the maximum pressure resulting from all PBOCs with an appropriate dynamic load factor applied.

4. The enclosures are designed for the depressurization loads associated with a tornado (1 psi/sec. for 3 seconds). To achieve this, the enclosures are designed for a ½ psig internal pressure. Pressure relief devices are provided to assure this design pressure is not exceeded.

TABLE 8.6-2 (Cont)

PRINCIPAL DESIGN CRITERIA FOR
MCC (D7, D8, D9) ENCLOSURES

5. The enclosures are designed for the following seismic loads:

   A OBE (Horiz.) = 1.5g
   A OBE (Vert.) = 0.198g
   A SSE (Horiz.) = 1.65g
   A SSE (Vert.) = 0.26g

6. Allowable floor live load of 250 psf shall not be exceeded.

7. Insulation is designed to retain its insulation capability assuming the environmental conditions associated with an HELB.

Figure 8.6-1 has been removed.

Please refer to BECo Controlled Drawing E 13.

8.7 24 VOLT DC POWER SYSTEM

8.7.1 Power Generation Objective

The power generation objective of 24 V DC Power System is to provide uninterruptable dc power to neutron monitoring and process radiation monitoring instrumentation.

8.7.2 Power Generation Design Basis

1. The 24 V dc batteries have adequate capacity to power the instrument loads for 4 hr upon loss of ac power supply to the battery chargers.

2. The battery chargers have adequate capacity to automatically recharge the batteries to full charge from a totally discharged condition.

3. Undervoltage relays are provided to alarm in the main control room on low voltage conditions.

8.7.3 Description

The 24 V DC System supplies the source and intermediate range neutron monitors and their trip auxiliaries, selected process radiation monitors and the process radiation monitor trip auxiliaries.

A single line diagram of the 24 V DC Power System is shown on Figure 8.7-1. Two 24 V dc systems are provided. Each system has two 24 V batteries and two 24 V battery chargers arranged in a three wire system to provide $\pm$ 24 V dc power relative to ground. Each system is insulated from ground at all points except at the main control room where the neutral wire for each instrument is grounded.

The batteries and associated chargers in each system are operated as units.

During normal operation the load requirements and system losses are supplied from the battery chargers. Upon failure of the supply of dc power from the charger, the dc loads are supplied from the batteries until power from the charger is restored, or the battery capacity exhausted. All battery chargers are energized from the same 120 V ac instrument bus (see Section 8.8) which normally receives ac power from the common emergency service bus B6 and alternate power from the emergency service bus B1.

The loss of the 120 V ac distribution panel from a single failure would not affect the intermediate range neut ron monitors and the selected process radiation monitors because there is no worst case. Failure of the 120 V ac distribution panel which will not either cause scram immediately or will not allow power to be maintained to the dc operated systems for up to 3 hr before a loss of power initiates the scram (3 hr battery discharge). When this safety action scram is initiated, the reactor is safely shut down before

exceeding any one of the unacceptable safety results described in Appendix G. The sequence of events leading up to and including reactor shutdown results in no danger to the health and safety of the public. There are no safety related process radiation monitors powered by the 24 V DC System.

Each 24 V subsystem is provided with undervoltage and overvoltage relays that alarm in the main control room if voltage deviates from the normal range.

The batteries are lead calcium type with 12 cells each. Each battery has a minimum 60 amp hr rating based on a constant discharge rate for 4 hr with a starting voltage of 2.25 V per cell and a minimum voltage of 1.75 V per cell at the end of the 4 hr period.

The battery chargers have the following ratings:

Input:	120 V ac
Output:	25 amp, +24 V dc

The full wave silicon rectifier chargers have a built in voltmeter and an ammeter connected to the dc output. They also have reverse current protection to prevent them from loading the batteries.

The chargers are supplied from multiple sources of plant auxiliary power including the plant Standby Diesel Generator System. The aggregate system is so arranged that the probability of system failure resulting in loss of dc power is very low.

The 24 V batteries for each system are located in one of two common ventilated battery rooms separate from each other.

Loss of one of the two 24 V dc systems will not affect plant safety since redundant instrumentation will continue to be supplied by the second system.

Total loss of power from both 24 V dc systems will result in actuation of the intermediate range neutron monitor trips because of the fail-safe behavior of the Neutron Monitoring System. Refer to Section 7.5.

8.7.4 Inspection and Testing

The batteries and other equipment associated with the 24 V dc system are easily accessible for inspection and testing. Service and testing are accomplished on a routine basis in accordance with recommendations of the manufacturer.

Figure 8.7-1 has been removed.

Please refer to BECo Controlled Drawing E14

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 10KVA, 480-120V, single phase, two wire, 60 Hz for panels Y3 and Y31,and Y4 and Y41, 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.

Transfer switches have been located next to the regulating transformers which supply power to panels Y3, Y31, Y4, and Y41. Transfer switches have also been located near panels Y13 and Y14. The transfer switches provide capability to supply alternate power to these panels in the event of an extended loss of AC power by way of diesel generators.

The 10KVA step-down transformers for distribution panels Y3 and Y31 and Y4 and Y41 are 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 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.

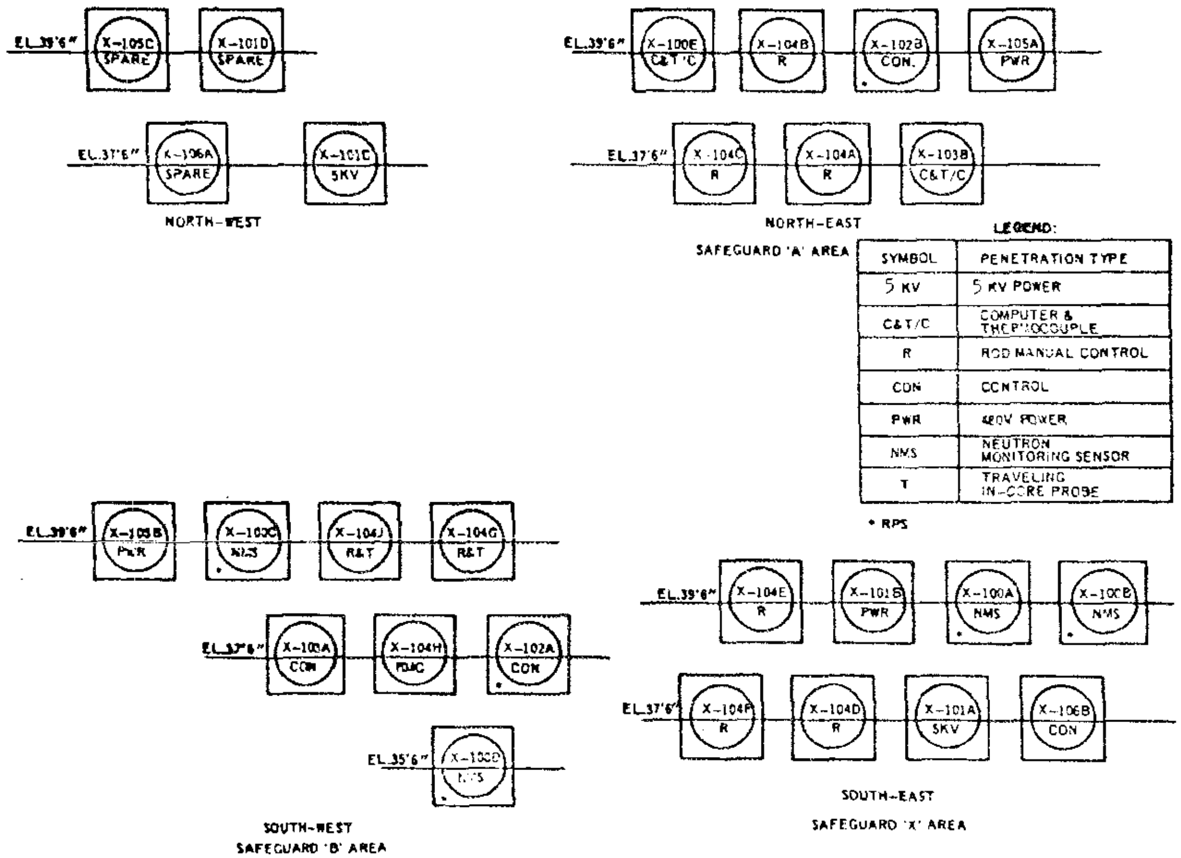
TABLE 8.9-1

CABLE SEPARATION REQUIREMENTS IN MISSILE ZONES

Pipe Diameter[1] (in)	Separation[2] (in)
1	28
6	47
10	62
18	92
24	100

NOTES:

1. Use straight line interpolation for pipe diameters not shown
2. Based on maximum dimensions of valve stem components



LEGEND:

SYMBOL	PENETRATION TYPE
5 KV	5 KV POWER
C&T/C	COMPUTER & THERMOCOUPLE
R	ROD MANUAL CONTROL
CON	CONTROL
PWR	480V POWER
NMS	NEUTRON MONITORING SENSOR
T	TRAVELING IN-CORE PROBE

FIGURE 8.9-1
DRYWELL ELECTRICAL
PENETRATION GROUPINGS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

8.10 BLACKOUT AC POWER SOURCE

8.10.1 Power Generation Objective

The Blackout AC Power Source consists of an independent diesel generator which provides a non-safety related source of onsite AC power to the 4.16kV emergency service buses through a two breaker 4.16kV bus in the event of a station blackout.

8.10.2 Power Generation Design Basis

1. The blackout diesel generator has the capacity to carry the load associated with one of three ECCS pumps on either emergency service bus A5 or A6 and all associated loads on that train required for loss of offsite power without a LOCA. Some loads associated with buses A5 or A6 (See Table 8.10-1 for ratings) are one salt service water (SSW) pump, one reactor building closed cooling water (RBCCW) pump and various electrically operated valves. Operator action is required to limit blackout diesel generator loading and automatic start of the 4kV-ECCS pumps.

2. The Blackout AC Power Source is completely self-contained, not relying on any permanent system for operation. The blackout diesel generator is mounted on a skid and housed in a pre-engineered enclosure for protection from the environment. The unit is capable of providing rated power (See Table 8.10-2) for a minimum period of one week without refueling. The blackout diesel storage tanks are used to augment the emergency diesel generator fuel capacity (i.e., the seven-day on-site fuel requirement).

3. Maintenance loads for the blackout diesel generator are provided by a 480V feed from the station during normal operations. However, upon loss of power, the unit is capable of "blackstart" automatically picking up the maintenance loads. The Blackout AC Power Source is a manual start system either from the main control room or locally from the diesel enclosure.

4. The Blackout AC Power Source will operate in parallel with the shutdown transformer during load testing of the blackout diesel.

8.10.3 Description

The Blackout AC Power Source is connected to PNPS through a two breaker 4.16 kV bus A8 with the blackout diesel generator connected to the first breaker, A801, and the shutdown transformer secondary connected to the second breaker, A802. The 4.16 kV bus A8 is connected by cable to breaker A600 of the emergency service buses. Power from the secondary ac power source (shutdown transformer or the blackout diesel generator) to the 4.16kV emergency service buses is controlled by breakers A600, A501 and A601.

The controls of circuit breakers A801 and A802 are interlocked to prevent interconnection of the diesel generator with the shutdown transformer except for testing of the diesel generator. The blackout diesel generator is interlocked, as is the shutdown transformer, to prevent operation in parallel with the unit AC power source, the preferred offsite power source, or the standby AC power source.

The diesel generator and the 4.16kV breakers of bus A8 are controlled manually either from the main control room or locally within the diesel generator enclosure. The diesel generator has sufficient fuel capacity to supply rated load for a minimum of one week. Protective relaying is provided to prevent damage to the diesel generator and the shutdown transformer. Relaying is also provided to prevent the diesel generator from supplying unacceptable power (voltage and frequency) to the emergency 4.16kV buses A5/A6, as applicable, and to the 24kV system during load testing of the diesel generator. The diesel generator on starting will pickup its auxiliary load automatically under station blackout conditions. An independent 125V DC System is provided to supply control power to the blackout diesel generator unit and associated 4.16kV switchgear A8.

The diesel generator has the capability to energize either emergency bus A5 or A6 from the control room within 10 minutes following a Station Blackout. A Station Blackout is defined as a total Loss of Offsite Power (both the preferred and secondary offsite AC power sources) and either or both standby AC power sources. This capability complies with the requirements of Station Blackout Rule 10 CFR 50.63. Once either A5 or A6 is energized, steps will be taken to proceed to a safe shutdown condition (cold shutdown or hot standby).

8.10.4 Inspection and Testing

Inspection and testing by the supplier and initial system tests were conducted to assure that all components are operational within their design rating.

The diesel generator is tested at regular intervals for its ability to start and pickup load by operating it in parallel with the secondary offsite AC power source (shutdown transformer). The diesel generator is tested during each refueling outage for connection to a 4.16kV emergency service bus (A5 or A6) and acceptance of 4.16kV loads from the selected bus.

TABLE 8.10-1

LIST OF MAJOR LOADS
BLACKOUT AC POWER SOURCE

Loads on 4160 switchgear buses (blackout service)

Bus A8

ECCS Pump	800 HP
Salt Service Water Pump	100 HP
RBCCW Pump	60 HP

Bus A8 supplies power to these loads through emergency service buses A5 or A6. The loads are manually connected as required.

TABLE 8.10-2

BLACKOUT AC POWER SOURCE
EQUIPMENT LIST

DIESEL ENGINE

Rated Speed	1,200 rpm
Continuous Rated Capacity	2,000 kW
Standby Rated Capacity	2,200 kW
Fuel Consumption at Rated Capacity	.498 lb/kW-hr

GENERATOR

Continuous Rated Capacity	2,000 kW
Power Factor	0.8
Frequency	60 Hz
Voltage	4,160 V
Phase (Connection)	3 (wye)

SWITCHGEAR

4160 V (Blackout Service), 350 MVA, 1200A Breakers, Switchgear A8

FUEL OIL STORAGE

Day Tank	275 gallon
Main Storage	40,000 gallon (2 tanks @ 20,000 gallons each)

SECTION 9

RADIOACTIVE WASTE SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

SECTION 9

LIST OF TABLES

SECTION 9

LIST OF FIGURES

SECTION 9

RADIOACTIVE WASTE SYSTEMS

9.1 SUMMARY DESCRIPTION

The Radioactive Waste Systems collect, treat, and dispose of radioactive and potentially radioactive wastes in a controlled and safe manner such that the operation and availability of the station is not limited. The Radioactive Waste Systems include equipment, instrumentation, and operating procedures which ensure that radioactive wastes may be safely processed and discharged from the station at levels which are as low as reasonably achievable.

The radioactive input to the radwaste systems is due primarily to:

a. Activation products resulting from irradiation of the reactor water and impurities therein (principally metallic corrosion products)

b. Fission products resulting from defective fuel cladding or uranium contamination within the reactor system

Radioactive wastes resulting from station operation are classified as liquid, gaseous, and solid. The following definitions apply to radioactive wastes:

1. Liquid Radioactive Wastes - Liquids directly from the reactor process and auxiliary systems or liquids which can become contaminated due to contact with these liquids from reactor process systems
2. Gaseous Radioactive Wastes - Gases or airborne particulates vented directly from reactor and turbine equipment containing radioactive material
3. Solid Radioactive Wastes - Solids from the reactor primary or auxiliary systems, solids in contact with reactor primary system liquids or gases, and solids (such as cleaning materials), used in reactor primary, turbine systems, and auxiliary systems operations

The source terms which the radioactive waste systems are designed to process and the environmental effects of releases from the systems are evaluated in the Pilgrim Station Unit 1 Appendix I Evaluation, dated April 1977.

The requirements contained in the Entergy Quality Assurance Program Manual (QAPM) are applied to activities affecting the processing, packaging, and shipping of radioactive material to ensure compliance with applicable regulations. The QAPM fulfills the quality assurance requirements specified in 10 CFR 71 and 10 CFR 20.2006. THE QAPM does not apply to the design and fabrication of shipping casks under 10 CFR 71.

9.2 LIQUID RADWASTE SYSTEM

9.2.1 Power Generation Objective

The Liquid Radwaste System collects, processes, stores, and disposes of all radioactive liquid wastes such that operation and availability of the station is not limited.

9.2.2 Power Generation Design Basis

The Liquid Radwaste System is designed to collect, process, store, and dispose of radioactive and potentially radioactive liquid wastes in a controlled and safe manner such that the operation and availability of the station is not limited.

9.2.3 Safety Design Basis

1. The Liquid Radwaste System is designed to include equipment, instrumentation, and operating procedures such that liquid radwastes can be discharged from the station at levels which are as low as reasonably achievable.

2. The system is designed to maintain safe operating conditions by minimizing radiation hazards to station personnel.

9.2.4 Description

The Liquid Radwaste System collects, processes, stores, and disposes of all radioactive liquid wastes. Equipment is selected, arranged, and shielded to permit operation, inspection, and maintenance within personnel radiation exposure limits. Sumps, pumps, valves, and instruments are located in controlled access areas. Tanks and processing equipment which may contain quantities of liquid radwastes are shielded. In addition, equipment is selected for a minimum of maintenance.

The system is divided into several subsystems so that the liquid wastes from various sources can be segregated and processed separately. Cross connections between the subsystems provide additional flexibility for processing of the wastes by alternate methods. The liquid radwastes are classified, collected, and treated in subsystems as either clean, chemical, or miscellaneous radwastes.

9.2.4.1 Clean Radwaste

"Clean" radwastes are liquids having a varying amount of radioactivity and are expected to have low conductivity.

Clean radwaste (see Figure 9.2-2, sheets 1 and 2) is collected in the following sumps:

Drywell Equipment Drain Sump

Reactor Building Equipment Drain Sump

Turbine Building Equipment Drain Sump

Radwaste Building Equipment Drain Sump

Retention Building Equipment Drain Sump

From these sumps, the wastes are transferred to the clean waste receiver tanks for processing. See Figure 9.2-3 (Drawing M233). The drywell and Turbine equipment drain sump discharge may be directed to the main condenser (see Figures 9.2-2 [Drawing M232] and 4.9-2) in order to provide operating flexibility and reduce water inventory delivered to radwaste for processing. Resin transfer water, ultrasonic resin cleaner (URC) flushwater, and drains are routed to the clean waste receiver tank. URC flush water may also be sent to the chemical waste tanks.

The Clean Radwaste System also receives liquid from the ultrasonic resin cleaner. The URC is designed to remove suspended solids from condensate demineralizer resins without requiring chemical regeneration. The major components of the URC are the cleaning column, flow adjustment panel, and control panel. Resin enters the cleaning column and falls through an ultrasonic field where the solids are removed. See Figure 9.2-5 (Drawing M217) for a detailed piping and instrumentation diagram of the URC.

A countercurrent flow of water removes the solids and resin fines and transfers them to a holding tank. The waste water containing the solids is then pumped to the Clean Radwaste System and/or Chemical Waste System. The cleaned resin is then transferred back to the Condensate Demineralizer System for reuse.

Wastes from the receiver tanks are processed through Thermex, radwaste filter/demineralizer, or radwaste demineralizer or other water processing equipment, before collection in the treated water holdup tanks. After the liquid wastes in the treated water holdup tanks have been sampled and analyzed, they are normally returned to the condensate storage tanks for reuse within the plant or sent to the main condenser hotwell. If the analysis of the sample reveals water of high contaminants or high radioactivity concentration, it may be reprocessed. Abnormally high conductivity water may either be reprocessed or be discharged at a controlled rate through the liquid radwaste discharge header to the circulating water discharge canal.

9.2.4.2 Chemical Radwaste

9.2.4.2.1 System Function

"Chemical" radwastes are liquid wastes which generally have low concentrations of radioactive impurities and rather high conductivities.

Chemical radwastes (see Figure 9.2-2, Drawings M232, M232A, M254) are collected in the following sumps:

Drywell Floor Drain Sump

Reactor Building Floor Drain Sump

Turbine Building Floor Drain Sump

Radwaste Building Floor Drain Sump

Retention Building Floor Drain Sump

The sump wastes are primarily minor equipment leakages, tank overflows, equipment drains, and floor drainage. When a sump has filled to a preset liquid level, the wastes are automatically pumped to the chemical waste receiver tank. See Figure 9.2-4 (Drawing M234). Floor drain sump wastes may also be processed through the clean radwaste system if the wastes are relatively low in conductivity.

Laboratory wastes are routed directly to the chemical waste receiving tank.

The chemical waste receiver and monitor tanks are atmospheric tanks with a capacity of 15,000 gallons and 20,000 gallons, respectively. The tanks are designed and constructed in accordance with API 650 and are internally coated with a phenolic lining for corrosion protection. The receiver tanks have level and annunciators which will be used in monitoring the waste inventory. The monitor tanks also have level indicators and annunciators. Depending on the activity level, the wastes after storage and decay may be released on a controlled basis through the liquid radwaste discharge header to the circulating water discharge canal or further processed. See Figure 9.2-4 (Drawing M234). Both the chemical waste receiver and monitor tanks are located in shielded cells to maintain safe operating conditions and minimize radiation exposure to station personnel.

The two chemical waste process and two monitor tank pumps are horizontal centrifugal pumps each rated at 100 gal/min. The pumps have 100 percent capacity each and will provide maximum system reliability.

9.2.4.2.2 System Operation

During operation it is expected that the daily flow from the floor drain sumps will be approximately 5,000 gallons. The drywell floor sump wastes will normally be transferred to the Chemical Radwaste System.

The chemical wastes can be pumped through Thermex to remove suspended solids.

9.2.4.2.3 Safety Evaluation

The activity level of the chemical wastes processed through the Chemical Waste System is generally low. Releases to the environment will be kept to a minimum.

Backup equipment has been installed wherever practicable to achieve maximum system availability. Piping has been designed to permit maximum system flexibility and system recycle capability. Table 9.2-1 provides an equipment malfunction and failure mode analysis summary.

9.2.4.2.4 System Instrumentation

The various components in the Chemical Radwaste System are instrumented to indicate the status of vital process functions. Annunciators are provided on important system controls to alert station personnel to any abnormal process deviations and allow adequate time for corrective action.

The following is a list of instruments on a system component basis:

<u>Chemical waste receiver tanks</u>

Level indicator

Level annunciation (high and low)

Low-low and high-high level switch (pump trip)

<u>Chemical waste process pumps</u>

Discharge pressure indicator

<u>Monitor tank pumps</u>

Discharge pressure indicator

<u>Monitor tanks</u>

Level indicator

Level annunciator (high-low)

9.2.4.2.5 Inspection and Testing

The Chemical Radwaste System is continuously operated during station operation thereby demonstrating system operability without special inspections or testing. Periodic testing will be done on influent wastes with the chemical waste receiver tank. Area radiation monitoring will also be done routinely.

9.2.4.3 Miscellaneous Radwastes

9.2.4.3.1 Design Basis

The Miscellaneous Waste System is designed to:

a. Collect low level radioactive liquid wastes that have potentially high detergent levels or other contaminents such as seawater that would not be desirable in Chemical or Clean radwaste systems

b. Provide processing of the miscellaneous wastes such that operation and availability of the station is not limited

c. Minimize radioactive liquid effluent releases to levels which are as low as reasonably achievable

9.2.4.3.2 System Function

Miscellaneous radwastes are those wastes which potentially have high detergent or contaminant level, but are of low radioactivity concentration.

The Miscellaneous Waste System collects equipment washdown and decontamination solution wastes, radiochemistry laboratory solution wastes, miscellaneous water waste, and personnel decontamination wastes. The Miscellaneous Waste System processes and strains these liquid wastes before discharge through the radwaste discharge header into the circulating water discharge canal or batched to floor drain to process as chemical waste. The liquid wastes are sampled and analyzed before release and continually monitored during release.

The miscellaneous waste drain tank (see Figure 9.3-1, Drawing M235) collects drainage from floor drains originating in the following areas:

Turbine washdown area

Personnel decontamination areas

Fuel cask decontamination area

Reactor head washdown area

Truck decontamination area

Machine shop wastes

Retube building decontamination area

9.2.4.3.3 System Operation

The miscellaneous waste drain tank is an atmospheric tank with a capacity of 1,000 gallons. The tank is designed and fabricated in accordance with API 650. The tank is carbon steel and divided into two sections each with a capacity of 500 gallons. The tank is located within a shielded cell. The miscellaneous waste strainer is a duplex type strainer.

During normal operation it is expected that the monthly volume of miscellaneous wastes will be approximately 1,000 gallons. The sources of miscellaneous wastes will be kept to a minimum through administrative control.

When one section of the miscellaneous waste tank is filled, the wastes are sampled and analyzed for radioactivity. The wastes are pumped through a strainer and discharged at a controlled rate through the liquid radwaste discharge header into the circulating water discharge canal or batched to floor drain to process as chemical waste. The miscellaneous waste is continuously monitored for activity as it passes through the radwaste discharge header. If necessary, miscellaneous wastes of high radioactivity concentrations and low detergent levels may be transferred to the chemical waste receiver tank for further processing.

Miscellaneous waste will often be processed using a portable reverse osmosis skid prior to draining liquid radioactive wastewater to Radwaste.

9.2.4.3.4 Safety Evaluation

The activity concentration of the miscellaneous wastes is low. Releases to the environment can be kept to a minimum by administrative control of waste generation. The Miscellaneous Waste System is operated on a batch basis allowing station personnel maximum system control.

9.2.4.3.5 Malfunction and Failure Mode Analysis

When higher than normal activity levels are experienced in the Miscellaneous Waste System, the wastes can be processed through the Chemical Radwaste System. The occurrence of high activity is not expected.

9.2.4.3.6 System Instrumentation

The following is a list of Miscellaneous Waste System instrumentation:

a. Miscellaneous Waste Drain Tank
   (1) Level indicators
   (2) Level switches (high and low, pump trip on low-low)
   (3) Level annunciators (high and low)

b. Miscellaneous Waste Drain Tank Pump
   (1) Discharge pressure indicator
   (2) Flow indicator

c. Miscellaneous Waste Strainer
   (1) Differential pressure switch with annunciator

9.2.4.3.7 Inspection and Testing

The Miscellaneous Waste System is operated during normal station operation thereby demonstrating system operability without special inspections or testing. Routine analysis for activity levels will be done on the miscellaneous wastes prior to release.

9.2.5 Estimates of Radioactive Liquid Releases During Normal Operation

Estimates of radioactive liquid releases and resultant doses during normal operation are given in the Pilgrim Station Unit 1, Appendix I Evaluation, dated April 1977.

TABLE 9.2-1

MALFUNCTION AND FAILURE MODE ANALYSIS

Equipment	Malfunction	Consequences	Design Precautions	Malfunction Correction
1. Chemical waste receiver tank	a. Tank overfilled	Tank overflows	Tank overflow is piped to the radwaste building sump. Floor drain sumps are tripped on high-high level in tank. The level instrumentation will alarm before the tank overflows	Lower tank level and process incoming wastes into the other receiver tank
	b. pH too acidic or basic	Unacceptable discharge ph	Wastes cannot be processed until pH is acceptable	Manually neutralize
	c. Tank corrosion due to possible chemical attack	Pin hole leak in tank-slight leakage onto floor	Tanks are lined with a corrosion resistant lining. Spillage will be contained within the tank cell	Locate leak and repair tank
	d. Loss of air for sparging	Chemical waste not homogeneously mixed	Tanks have mixing eductor which can be used in place of the sparger	Station switches to second low pressure air blower
	e. Floating suction becomes fixed in place	No fluid will be pumped when level of tank is below suction	The tank piping has been designed to enable the chemical waste process pump to take suction from the bottom of tank. The floating suction has a large moment about its pivot point to keep itself free	Drain tank and free the floating suction
2 Chemical waste Process Pumps	a. Pump failure	Cannot process wastes from receiver tank	The pump piping has been arranged so either pump may take suction from either tank	Replace pump and use other pump during the interim
	b. Pump cavitation due to lack of suction head	Possible pump motor failure	The pumps will be tripped out of service on low-low level of the tank. The operation will be alerted before the pump trips by the low level annunciators	Replace motor and use other pump during the interim

TABLE 9.2-1 (Cont)

Equipment	Malfunction	Consequences	Design Precautions	Malfunction Correction
	c. Pump running at shutoff head for a prolonged period	Possible pump motor failure	The pump motor has been designed with a 1.15 service factor for overload and a minimum recirculation flow is maintained by an orifice loop around the pump	Find cause of high pumping head requirements and correct. Use other pump during the interim
3. Monitor tanks	a. Tank overfilled	Tank overflows	The tank level instrumentation will alarm before the tank has reached the overflow point	Reduce level in tank by discharging wastes to circulating water discharge canal or by processing wastes through the solidification system
	b. Tank level low due to pump out	Heaters no longer used.	Level instrumentation has been installed to prevent the waste level from going below the heater level. The pumps will trip on low-low level	Add makeup water to keep tank level above the heaters
4. Monitor tank pumps	a. Pump failure	Cannot process wastes from the monitor tank	The pump piping has been arranged so either pump can take suction from any of three monitor tanks	Replace pump and use other pump during the interim
	b. Pump cavitation due to lack of suction head	Possible pump/motor failure	The pumps will be tripped on low-low level on the tank. The operator will be alerted before the pump trips by the low level annunciator	Replace motor and use other pump during the interim
	c. Pump running at shut-off head for a prolonged period	Possible pump/motor failure	The pumps will be operated with a recirculation flow back to the monitor tank	Correct cause of high pump pressure

Figure 9.2-1 has been deleted.

Please refer to Figures 9.2-2 thru Figure 9.2-5.

The following FSAR figures have been removed from the FSAR. Please refer to the corresponding BECo controlled drawings.

FSAR FIGURE	BECO CONTROLLED DRAWING
9.2-2	M 232, M232 A
9.2-3	M233
9.2-4	M234
9.2-5	M217

9.3 SOLID RADWASTE SYSTEM

9.3.1 Power Generation Objective

The power generation objective of the Solid Radwaste System is to collect, process, package, and provide temporary storage facilities for solid waste prior to shipment for offsite disposal.

9.3.2 Power Generation Design Basis

1. The system is designed to provide collection, processing, packaging, and interim storage of solid wastes resulting from normal station operations.

2. The system is designed to provide a safe and reliable means for handling solid wastes and to minimize radiation exposure to station personnel and members of the general public.

9.3.3 Safety Design Basis

1. The Solid Radwaste System is designed to include equipment, instrumentation, and operating procedures such that the solid radwastes are collected, processed, and temporarily stored for offsite shipment such that radiation exposures will be reduced to levels which are as low as reasonably achievable.

2. Packaging is provided as necessary to conform with 10 CFR 71 and 49 CFR 172-178.

3. Interim storage of solid radwaste conforms with NUREG0800, Standard Review Plan 11.4, Appendix A.

4. The low level radwaste storage facility (LLRWSF) is designed to ensure that no design basis event (i.e., fire, flood, design basis earthquake, or tornado) or credible accident scenario will result in loss of control of radioactive material; administrative procedures ensure loss of control will not result in exceeding 10% of the off-site dose limits allowed by 10 CFR 100.

9.3.4 Description

9.3.4.1 General

The solid waste processing areas are located in the radwaste building, the radwaste trucklock, and the trash compaction facility (see Section 9.5). Both wet and dry solid wastes are processed. Wet solid wastes include backwash sludge wastes from the Reactor Water Cleanup System; all spent resins and charcoal from radwaste, spent fuel pool, and condensate demineralizers; and Thermex and radwaste filter/demineralizer.

Dry solid wastes include rags, paper, small equipment parts, solid laboratory wastes, etc.

An outdoor LLRWSF is provided on-site for interim storage up to 5 years of solid radioactive waste prior to disposal off-site or for temporary storage of bulk-dewatered radwaste awaiting shipment to a processing facility for volume reduction prior to burial. The LLRWSF consists of a compacted gravel bed surrounded by a gravel or earth filled modular block shield wall. Dewatered solid wastes contained in high integrity containers are placed in cylindrical, concrete storage modules within the facility. Dry activated waste in steel containers and overpack, as well as other miscellaneous low level radioactive materials, is also stored in the LLRWSF in rectangular, concrete storage modules.

9.3.4.2 Radwaste Disposal System for Reactor Cleanup Sludge

9.3.4.2.1 System Function

The purpose of the radwaste system for cleanup sludge is to process the highly radioactive backwash waste which is discharged from the reactor water cleanup system. Refer to Figure 9.3-1 (Drawing M235).

The Reactor Water Cleanup System includes two filter-demineralizer units each of which are precoated with powdered ion exchange resin (Powdex) supported by filter aid which is in turn retained on a permanent, stainless steel septum. These filter-demineralizer units remove by filtration and ion exchange, the suspended and dissolved solids, both radioactive and stable, from the circulating reactor water. Upon exhaustion of either its filtration or ion exchange capability, the exhausted cleanup demineralizer is taken out of service, backwashed, and precoated anew. The backwash waste as discharged from a cleanup demineralizer is a relatively dilute slurry (1.1 percent by weight suspended solids) which is highly radioactive. The backwash waste slurry is accumulated in the backwash collector tank from which it is periodically transferred on a batch basis to the Radwaste Disposal System for subsequent processing.

The function of the Radwaste Disposal System is to reclaim the liquid phase for reuse within the station and to prepare the solid waste for offsite shipment with minimum exposure of the operators to radiation.

The Radwaste Disposal System has been modified. A sludge transfer and decant line has been provided for the Cleanup Sludge Storage Tanks. The transfer line is used to transfer sludge to the offsite discharge pipe in the radwaste trucklock. This arrangement bypasses the floc-recycle tank (abandoned). The sludge is dewatered in the radwaste trucklock before being stored to await shipment to a burial processor facility or for other processing. A decant line has been installed between the Sludge Transfer Pumps (P-318A, B) discharge and the Clean Waste Tanks (T-301A, B) inlet piping. The transfer

line and decant connections are shown on Figures 9.3-1 (Drawing M235), 9.2-3 (Drawing M233), and 9.2-4 (Drawing M234).

9.3.4.2.2 System Operation

The backwash discharge from the cleanup demineralizer is collected in the receiver tank which is located below the cleanup demineralizers in the reactor building. The receiver tank volume is 1,500 gallons. After two backwashes are accumulated, the batch is transferred to the radwaste disposal system for cleanup sludge which is located in the radwaste area. The transfer is made just prior to the next (third) backwash.

In the radwaste area, the waste is received by one of the two 4,500 gallon cleanup sludge storage tanks. These tanks are designed to concentrate the sludge from 1.1 weight percent solids to from 5 to 10 weight percent solids by sedimentation and decantation of the supernatant. The decant process is controlled through the alignment of manual and remotely operated valves, and remote operations of the Sludge Transfer Pumps in low radiation areas. Decanting will be initiated on tank high level and continue until the level drops to the decant discharge nozzle. The decanting process will be terminated when accumulating sludge reaches the decant discharge nozzle and small amounts of sludge begin to carry over into the decant line. The radiation instrumentation, mounted on the decant pipe, will provide an audio alarm and the Radwaste Operator will stop the pumps. The tanks are alternately used to receive the incoming waste batches. While the working tank is filling, the other previously filled tank is held isolated to allow additional decay of sludge activity.

A radwaste disposal system bypass has been installed. The bypass will allow direct processing of the reactor cleanup system sludge in the radwaste trucklock by a qualified radwaste contractor or station personnel.

The 5 percent slurry is pumped from the sludge storage tank to a Processing/Shipping Container located in the radwaste trucklock. The container contains a filter which allows the slurry to be dewatered to meet burial site or processing facility criteria.

The liquid phase after filtration is high purity water with very low radioactivity since any soluble radioactivity was retained by the Powdex ion exchange resin that was removed by filtration. However, to assure a quality suitable for reuse, the filtrate is processed through the Clean Liquid Radwaste System which ultimately discharges it to the condensate storage tank. The highly radioactive solid phase is retained within the processing/shipping container which is designed as a combination filter and shipping liner/burial container. Hence, the steps of solids separation, moisture drainage, and preparation for shipment, in accordance with Department of Transportation regulations, are accomplished in a single operation. At no time does there exist within the station an unshielded container of solid waste; consequently, exposure of operators and members of the general public to radiation is at a minimum.

9.3.4.2.3 Equipment Description

Cleanup Sludge Storage Tanks

These tanks are of all stainless steel construction and designed and fabricated in accordance with API 650 for a design pressure of 5 psig at 200°F. Each tank has a 4,500 gallon capacity.

Sludge Transfer Pump

These pumps are air driven diaphragm pumps.

High Integrity Containers

High Integrity Containers (HICs) are used for shipments to the Barnwell, S.C. Burial Site. These containers contain filters that allow waste slurry to be dewatered. Once dewatered, the HIC is sealed and stored to await shipment to a burial site or other processing facility.

9.3.4.3 Spent Resin and Miscellaneous Solid Waste System

9.3.4.3.1 System Function

The purpose of the spent resin and miscellaneous Solid Waste Systems is to process and temporarily store spent resins and miscellaneous solid waste (rags, used clothing, paper, air filters, etc.) on the site in shielded areas as required prior to offsite shipment to a licensed burial ground or other processing facility.

9.3.4.3.2 System Description

Spent Resin System

All spent resins from radwaste, spent fuel pool, Thermex, and condensate demineralizers are sluiced into a spent resin tank which provides 670 ft^3 capacity. Thermex waste water and miscellaneous waste waters may be added to the tank to utilize remaining capacity of spent resin and allow for reprocessing. This may be done to reduce solid radwaste volume and overboard discharge of contaminated waste water.

The radwaste demineralizer T-303 (Drawing M233) contains 30 ft^3 of mixed resins which are not regenerated. Expected spent resin volume is approximately 120 ft^3/yr. A vendor supplied radwaste liquid processing system (Thermex) also contains approximately 55 ft^3 of mixed resin and approximately 90 ft^3 charcoal. The expected spent resin/charcoal volume is estimated at 500 ft^3/yr.

The spent fuel pool demineralizer contains 90 ft^3 of mixed resins which are not regenerated. Expected spent resin volume is estimated at 180 ft^3/yr.

The condensate demineralizer system consists of seven mixed resin demineralizers. Each demineralizer contains 220 ft^3 of cation and anion (mixed bed) resin which are not regenerated. The expected spent resin volume is estimated at 900 ft^3/yr.

When spent resins accumulate in the spent resin tank to the amount desired for offsite shipment, the spent resins will be pumped from the tank into a processing/shipping container or HIC as required for dewatering and for shipment and offsite disposal/processing. A backflushing system for tank overflow and spent resin retention screens is provided to eliminate or reduce screen plugging with resin fines as much as possible. Sluice water is recycled back to the spent resin tank.

Backup Filter/Demineralizer

Two radwaste filter/demineralizers X-362A/B (Drawing M273) are also provided for processing liquid radwaste. The two vessels may be run in series, parallel, or independently. The vessels (35 ft^3 each) may be filled with media such as resin, charcoal, or a combination. The expected spent resin/charcoal volume is estimated at 35 ft^3/yr.

Miscellaneous Solid Waste System

The contaminated miscellaneous solid wastes such as air filters, rags, paper, small equipment parts, and solid laboratory wastes are placed in disposable containers and shipped for processing or disposal.

Compressed solid wastes in the disposable containers are stored temporarily on the site for future offsite shipment.

9.3.4.3.3 Equipment Description

Spent Resin Tank

The tank is of all stainless steel construction and designed and fabricated in accordance with ASME Code Section III, Class C, for atmospheric pressure and a temperature of 160°F. The tank has a 670 ft^3 capacity.

9.3.4.4 Clean Radwaste Solids Recovery Systems

The clean radwaste effluent is processed through various processing equipment resulting in spent resin/powdered resin (sludge) which is loaded into containers for shipment to an offsite radioactive waste minimization process facility or shipped for burial.

9.3.4.5 Low Level Radwaste Storage Facility

9.3.4.5.1 System Description

The LLRWSF consists of a compacted gravel pad with gravel or earth filled shield walls. The facility accommodates single-stacked, concrete, cylindrical storage modules (each module containing a single high integrity container (HIC) or metal liner and single-stacked, concrete, rectangular storage modules for containing dry activated waste (DAW).

A HIC processing container is loaded into a cylindrical storage module in a radwaste processing area and transported to the LLRWSF via flatbed truck or similar transport method. A crane lifts the storage module and places it in a pre-determined location within the facility.

9.3.5 Safety Evaluation

Operation of the Solid Radwaste System is by semi-remote means, and the shielding design in the system working areas minimizes radiation exposure to personnel. Uncontrolled release of liquid spillage from the Radwaste Trucklock during dewatering operations is prevented by curbs which enclose the processing area. The operating procedures, waste containment vessels, and storage facilities of the system reduce radiation exposures to levels which are as low as reasonably achievable. The storage of solid radwaste conforms to Standard Review Plan 11.4 Appendix A.

The LLRWSF is used for interim storage of solid radioactive waste or for temporary staging of bulk-dewatered radioactive waste. Apart from transporting material to and from the facility, no processing of waste is performed outdoors or in the LLRWSF. The facility and concrete storage modules are designed to reduce radiation exposures to levels which are as low as reasonably achievable.

9.3.6 Inspection and Testing

The Solid Radwaste System is used on a routine basis and therefore does not require specific testing to ensure operability.

The LLRWSF design allows for routine inspections and testing to ensure design basis radiological doses are not exceeded and to verify that the integrity of the waste containers and their associated concrete storage modules are maintained.

Figure 9.3-1 has been removed.

Please refer to BECo Controlled Drawing M 235.

9.4 GASEOUS RADWASTE SYSTEM

9.4.1 Power Generation Objective

The Gaseous Radwaste System processes gaseous radioactive wastes from the main condenser air ejectors, the startup mechanical vacuum pump, the gland seal condensers, and other minor sources, and controls their release to the atmosphere through the main stack in such a way that the operation and availability of the station is not limited.

9.4.2 Power Generation Design Basis

1. The Gaseous Radwaste System is designed so that gaseous and particulate radwastes are processed and discharged such that operation and availability of the station is not limited.

2. The Gaseous Radwaste System is designed to minimize the possible explosion hazard of the hydrogen and oxygen present.

9.4.3 Safety Design Basis

1. The Gaseous Radwaste System is designed to include equipment, instrumentation, and operating procedures such that the gaseous radwastes can be discharged from the station at levels which are as low as reasonably achievable.

2. The Gaseous Radwaste System is designed to provide isolation on high offgas radioactivity level.

3. The Gaseous Radwaste System is designed to maintain its integrity for all expected operating conditions by conservative process design.

9.4.4 Description

9.4.4.1 Air Ejector Offgas and Augmented Offgas System

9.4.4.1.1 General

The Air Ejector and Augmented Offgas System shown on Figures 11.4-1 and 9.4-1 includes the subsystems that process and/or dispose of the gases from the main condenser air ejectors, the startup mechanical vacuum pump, and the gland seal condensers. All such gases from the unit are routed to the main stack for dilution and elevated release to the atmosphere. Discharges from the air ejector, the charcoal vault, and the stack are continuously monitored by radiation monitors.

Gases routed to the main stack include air ejector and gland seal offgases, and gases from the Standby Gas Treatment System (SGTS). Dilution air input to the stack is supplied by two full capacity fans located in the filter building at the base of the main stack. The stack is designed such that prompt mixing of all gas inlet streams occurs in the base to allow location of sample points as near the base as possible. The stack drainage is routed to the liquid radwaste collection system.

The Augmented Offgas (AOG) System provides for the controlled recombination of radiolytic hydrogen and oxygen, followed by chilling of the gas mixture to strip the condensible water vapor and reduce the volume and relative humidity of the remaining noncondensibles, principally inleakage air with traces of the radioactive noble gases krypton and xenon, which are delayed by an adsorption process using activated charcoal. The offgas passes through the charcoal vessels and is then discharged to the environs via the Main Stack. The delay time created by the charcoal adsorption process allows for the continued decay of the krypton and xenon radioactivity to a point where the ultimate release of the offgas results in a site boundary gamma radiation dose that meets the definition of ALARA (As Low As Reasonably Achievable). The radioactivity of the gas mixture is monitored immediately downstream of the SJAEs, representing the inlet conditions to AOG, and at the discharge from the AOG system.

As a design basis for the system, a noble gas input equivalent to an average offgas release rate (based on 30 minute decay upstream of the charcoal adsorbers) of 100,000 microcuries/second was used. Table 9.4-1 indicates the design basis noble gas activity referenced to a 30 minute holdup time and the noble gas activity after processing through the AOG charcoal beds. Also shown on Table 9.4-1 are individual noble gas isotope activity reduction factors and the overall activity reduction factor provided by the system.

The microcurie release rates and reduction factors given in Table 9.4-1 are based on the AOG system operating with effective charcoal holdup times of 17 hours for krypton and 289 hours (12 days) for xenon isotopes. The system operating with this performance achieves an overall reduction factor of 42 for the release rate of the noble gas isotopes. This represents the nominal design basis performance for the AOG system. These holdup times are defined as the rated performance level for the AOG system.

The AOG system receives the noncondensible gases discharged from the Main Condenser Steam Jet Air Ejector (SJAE). The maximum allowable air inleakage is limited physically by the capacity of the Main Condenser Steam Jet Air Ejector and/or by the AOG Steam Jet Compressors to move the gas volume. The design capacity of the steam jet ejector/compressors is based on conveying a mixture of noncondensible gases consisting of a maximum nominal flow rate of 40 SCFM inleakage air plus a fixed flow rate of electrolytic hydrogen and oxygen as given in Table 9.4-2. The air inleakage flow originates from the main condenser. Although every effort is made to minimize condenser air inleakage there is no direct control over this parameter. The effective noble gas holdup time has an approximate inversely linear relationship to offgas flow rate. A credible lower value inleakage flow for the size of the PNPS condenser is approximately 12 SCFM. The design basis for the AOG system has been established with an air inleakage normal range of 12 to 40 SCFM with a nominal design flow rate of 20 SCFM. For a baseline, air inleakage as measured at three smaller operating boiling water reactors is given in Table 9.4-3. Actual SJAE performance and condenser vacuum will also depend on backpressure and condensate temperature. Steam jet devices typically have actual capabilities greater than their nominal design ratings and may operate satisfactorily at flow rates greater than 40 SCFM. Therefore, operation at offgas air flow rates greater than 40 SCFM may continue so long as adequate condenser vacuum is maintained.

There is no maximum allowable volumetric flow rate for the AOG system with respect to charcoal performance. The AOG system is considered to be performing adequately when its operating point is within the acceptable region of the design basis release rate versus holdup time plot described above. Therefore, the required system performance (holdup time) depends upon the actual SJAE radioactivity release rate (microcuries/second). The design maximum flow rate of 40 SCFM is based on the rated capacity for the SJAE as described above.

9.4.4.1.2 System Function

The Augmented Offgas System shown on Figure 9.4-1 uses a high temperature catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen from the Air Ejector System. Noncondensible radioactive offgas is continuously removed from the main condenser by the air ejector during plant operation. The air ejector offgas normally contains activation gases, principally N-16, 0-19, and N-13. The N-16 and 0-19 have short half lives and quickly decay. The 10 min half-life N-13 is present in small amounts which is further reduced by decay. The air ejector offgas also contains the radioactive noble gases Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87,

and Kr-88. The concentration of these noble gases depends upon the amount of tramp uranium in the coolant and on the reactor fuel cladding surfaces (usually extremely small) and the number and size of fuel cladding leaks. After hydrogen/oxygen recombination and chilling to strip the condensible to reduce the volume, the remaining noncondensibles, principally kryptons, xenons, and air, are delayed in a 30 min holdup system before reaching the adsorption bed. Radioactive particulate daughters of the noble gases are retained on the charcoal and the post-charcoal HEPA filters. The charcoal adsorption bed, operating in a constant temperature vault, selectively adsorbs and delays the xenons and kryptons from the bulk carrier gas, principally air. This delay on

the charcoal permits the Xe and Kr to decay in place. The offgas is discharged to the environs via the main stack. The activity of the gas leaving the Offgas Treatment System is continuously monitored.

The adsorption of noble gases on charcoal depends upon gas flow rate, holdup time, mass of charcoal and a gas unique coefficient known as the dynamic adsorption coefficient. The parametric inter-relationships and governing equations are well proven from three years of operation of a similar unit at KRB in Germany.

The design requirements for the equipment of the Offgas System are given on Table 9.4-4. The Augmented Offgas System is designated seismic Class II. This class includes those structures, equipment, and components which are important to reactor operation, but are not essential for preventing an accident which would endanger the public health and safety, and are not essential for the mitigation of the consequences of these accidents. A Class II designated item shall not degrade the integrity of any item designated Class I.

The front end components of the system are installed in the Turbine Building. The charcoal adsorbers and associated auxiliary equipment are installed in the Retention Building whose access doors are at elevation 23 ft. As described in Section 2.4.4.3, station structures at elevation 23 ft are not subjected to flooding.

The system is not designed to be functional during or after a tornado. The system is not essential for the prevention of accidents nor is it essential for the mitigation of the consequences of such accidents.

The Offgas System is provided with flow, temperature, and radiation instrumentation to ensure proper operation and control. Hydrogen analyzer instrumentation is also provided to ensure that hydrogen concentration is maintained below the flammable limit. Table 9.4-5 lists process system indication and their location.

The Offgas radiation monitoring is divided into two subsystems. One subsystem (pre-treatment) takes a continuous sample from the offgas line prior to the delay and adsorption treatment process, and is described in Section 7.12.2. The other subsystem (post-treatment) takes a continuous sample from the offgas line just before discharge to the main stack, and is described in Section 7.12.3.

The subsystem monitoring the Offgas System upstream of the main station stack has two instrumentation channels. Each channel consists of a gamma-sensitive detector, a pulse preamplifier, a logarithmic radiation monitor with a power supply and a meter, and a strip chart recorder point. The monitors and the two-pen recorder are located in the control room. Each logarithmic radiation monitor is powered from a different bus of the 24V DC system. The two gamma-sensitive scintillation detectors are mounted in two shielded

sample chambers. The sample is drawn from the offgas line through the sample chamber by the sample pump. Each monitor has two upscale trips and a downscale trip. An upscale trip indicates high radiation. A downscale trip indicates instrument trouble. Any one trip will give an alarm in the control room. Any one upscale high radiation trip closes the charcoal bed filter bypass valve, if open, and opens the offgas line to the charcoal bed, if closed. Two upscale high-high radiation trips, one upscale high-high radiation trip and one downscale trip or two downscale trips isolate the Offgas System outlet and drain valves (See Figure 11.4-1). Subsequent operator action is required to reopen the valves. This will ensure positive control of releases to the environment.

The Offgas System radiation monitors have monitoring characteristics sufficient to provide accurate indication of radioactivity in the air ejector offgas, and provide the operator with sufficient information to monitor the performance of the Augmented Offgas System. Sufficient redundancy is provided to allow maintenance and testing of the Radiation Monitoring System. Each channel can be calibrated by analyzing a grab sample.

Figure 9.4-2 shows the location and arrangement of the front end components of the Augmented Offgas System in the Turbine Building.
Figure 9.4-3 shows the arrangement of the charcoal adsorbers and adsorber auxiliary equipment in a building located approximately 20 ft south of the Turbine Building between column lines 3 and 8. The building is approximately 68 ft by 72 ft in plan and extends 20 ft above and below grade.

9.4.4.1.3 System Operation

Noncondensible gas removed from the main condenser, including air inleakage, is diluted with steam to less than 4 percent by volume hydrogen concentration in the steam jet compressors. See Figure 9.4-1. The diluted offgas is superheated and then passed through a catalytic recombiner to convert the hydrogen and oxygen into water. The offgas effluent from the recombiner, containing only traces of hydrogen, is passed through a condenser, cooled by condensate, to remove the bulk moisture, and then to a 30 min holdup for the decay of the N-13, N-16, O-19, krypton and xenon isotopes. Decay daughters and iodine are removed by condensation on the walls of the holdup pipe and further removal of the decay daughters is effected by filtration. The offgas is processed by a cooler-condenser to remove additional moisture and iodine, and a deentrainer to reduce the relative humidity prior to entering the charcoal adsorbers.

The charcoal adsorbers provide holdup of the xenon and krypton isotopes in the offgas for sufficient time duration to maintain the dose rate at the site boundary within acceptable limits. Two parallel trains of adsorbers are used to minimize back pressure. The charcoal vault is heated or cooled, as needed, to maintain the normal temperature within a range of

72 to 82°F. The normal temperature for the charcoal vault is derived from basic psychrometric principles together with the adsorption characteristics of activated charcoal. Adsorption of the noble gases xenon and krypton is evaluated at equilibrium conditions of gas velocity, temperature, and relative humidity at a particular moisture content (% water adsorbed) for the charcoal. Charcoal will preferentially adsorb moisture from an airstream before noble gases. The adsorbed moisture content of charcoal is an equilibrium condition determined by the relative humidity of the gas in contact with it and has a maximum value of approximately 22% by weight. When charcoal is at its maximum moisture content, it has essentially zero affinity for the noble gases. The AOG system design performance is based on the equilibrium charcoal moisture content being at 5 to 10% by continuously maintaining the inlet offgas at less than 40% relative humidity.

The Offgas Cooler-Condensers perform the final air-drying function of the offgas prior to entering the charcoal. Since the design dewpoint temperature at the cooler-condenser outlet is ≤ 45°F, the dry bulb temperature of the offgas entering the charcoal should be at or above 72°F to maintain ≤ 40% relative humidity as the offgas passes through the charcoal. It is also a characteristic of dry charcoal that the affinity for noble gases decreases as temperature goes higher such that the ideal temperature is within the normal operating band of 72°F to 82°F, which provides a suitable range for the vault HVAC unit temperature control.

On occasion, it may be necessary to operate the charcoal vault at an elevated temperature to accelerate drying of the charcoal in the event that excessive moisture has been introduced by inadvertent system operation or failure of the cooler-condenser units. The accelerated drying process is conducted with the system operating at normal inlet conditions and humidity but with higher charcoal vault temperature. There is a substantial benefit to reducing excessive charcoal moisture content by elevated temperature drying. An elevated vault temperature of up to 125°F has been evaluated as having no adverse effects on the charcoal or equipment.

The offgas effluent from the adsorbers is passed through a high efficiency filter prior to discharge to the main stack.

No dilution air is added to the offgas stream during steady state operation. The air present during operation is from air inleakage into the main condenser which operates at sub-atmospheric pressure. Oil free air is bled into the system during startup of the system. Its flow rate is 56.7 lb/hr, which is stopped after the recombiner comes up to temperature. Air is supplied during recombiner startup in order to prevent wetting of the recombiner catalyst and subsequent deterioration of the hydrogen recombiner performance.

In the event of failure of a nonredundant Augmented Offgas System component or hydrogen buildup, provisions are made to bypass the Augmented Offgas System and operate the station using the installed 30 min Offgas Holdup System until maintenance of the Augmented Offgas System can be completed.

9.4.4.1.4 Safety Evaluation

The decay time provided by the Augmented Offgas (AOG) system permits significant radioactive decay of the activation gases and fission gases that are in the main condenser offgas. The operational limit for noble gas release rates from AOG is based on a site boundary accumulated dose of 8 mrad/yr. This was reduced from the 10 mrad/yr gamma limit in the Offsite Dose Calculation Manual (ODCM) to account for that limit applying to the total radioactive noble gas release from all PNPS sources.

Figure 9.4-5 plots the maximum allowable microcuries/second at the Steam Jet Air Ejector (SJAE) monitor for a given AOG holdup time (not including the decay time in the holdup line before the charcoal adsorbers). The curves are based on calculations that determined the maximum microcuries/second release rate that results in an 8 mrad/yr gamma radiation dose at the site boundary. To show the effect of reducing the decay time in the holdup line upstream of the charcoal adsorbers, the upper curve is based on the nominal design flow of 20 SCFM and the second curve is included at a bounding maximum offgas flow rate of 80 SCFM. Also shown on this plot is the Technical Specification limit of 500,000 microcuries/second gross gamma activity release rate for noble gases measured at the Steam Jet Air Ejector pretreatment monitor station.

Since 500,000 microcuries/second is the maximum activity rate allowed at the SJAE, it is evident from the plot that the holdup time required for this release rate into AOG to be acceptable is 17 hours for krypton and 289 hours (12 days) for xenon at the nominal design offgas flow rate of 20 SCFM.

The function of the AOG system is to limit offsite releases to provide assurance that releases of radioactive gaseous effluents will be kept As Low As Reasonably Achievable (ALARA). Operation of the system with holdup times that are less than the rated performance levels will reduce the operational capability of the system but it does not result in a condition outside the analyzed bounds so long as the Technical Specification and ODCM limits on release rate are met. Therefore, the AOG system is considered to be in service and operating within ALARA principles whenever the actual point of operation (microcuries/second release rate @ SJAE for measured holdup time) is in the region of Figure 9.4-5 bounded by the 8 mrad/yr site boundary dose limit and the 500,000 microcuries/second SJAE release rate limit. Operation within the Figure 9.4-5 limits via maintenance of AOG holdup times that are adequate for the SJAE release rate inputs defines AOG system operability.

The solid daughter products of the decay of the noble gases are removed by filtration and/or are retained on the charcoal. Final filtration of the charcoal adsorber effluent precludes escape of charcoal fines. Particulate activity release is expected to be negligible.

Iodine input into the offgas system is small because of its retention in reactor water and condensate. Additional iodine removal is provided by steam condensation which occurs in the offgas condenser located downstream of the hydrogen recombiner. Minute quantities of iodine entering the charcoal adsorbers are further adsorbed.

The Augmented Offgas System radiation monitors, which are normally monitoring the release rate from the adsorber beds, can be selectively valved to monitor the release rates from the recombiner outlet, Offgas Prefilters X-349A/B, or the outlets of the first charcoal bed in in each train, all of which provide diagnostic information on the performance of the charcoal bed Holdup System. The charcoal bed adsorber radiation monitor also automatically isolates the Offgas System in the event of high-high radiation levels in order to prevent treated gas of unacceptably high activity from discharging to the atmosphere.

Shielding is provided for offgas system equipment to maintain safe radiation exposure levels for plant personnel. The equipment is principally operated from the control room.

The charcoal adsorbers operate in a massive temperature controlled vault of 77°F so that upon system shutdown, radioactive gases on the adsorbers will be subject to the same holdup time as during normal operation, even in the presence of continued air flow. The adsorbers are maintained at a constant temperature by an air conditioning system which removes the decay heat generated in the adsorbers. Failure of the Air Conditioning System will cause an alarm in the control room. In addition, a radiation monitor is provided to monitor the radiation level in the charcoal bed vault. High radiation will cause an alarm in the control room.

The hydrogen concentration of the gases from the air ejector is maintained below the flammable limit by maintaining adequate steam flow for dilution at all times. This steam flow rate is monitored and alarmed. The preheaters are steam heated rather than electrically heated in order to eliminate the presence of potential ignition sources and to limit the temperature of the gases in the event of cessation of gas flow. The recombiner temperatures are monitored and alarmed to indicate any deterioration of performance. A hydrogen analyzer downstream of the recombiners provides an additional check.

The Air Ejector Offgas System operates at a pressure of about 5 psig or less so the differential pressure which could cause leakage of radioactive gases is small. To minimize the possibility of leakage of radioactive gases, the system is welded wherever possible and bellows seal valve stems or equivalent are used.

Operational control is maintained by the use of radiation monitors to assure that the release rate is within the established limits. Environmental monitoring is used to determine resultant dose rates and to relate these to the release rates as a check on station performance. Provision is also made for sampling and periodic analysis of the influent and effluent gases for purposes of

determining their composition. This information is used in calibration of the monitors and in relating the release to environs dose. The operator is thus in full control of the system at all times.

9.4.4.1.5 Malfunction and Failure Mode Analysis

Table 9.4-6 contains a detailed malfunction and failure mode analysis indicating the consequences of failure of various components of the system and design precautions taken to prevent such failures.

9.4.4.1.6 Inspection and Testing

The requirements for testing and verifying operability of the Augumented Offgas System hydrogen monitors are:

1. Daily instrument checks when the system is operating,

2. Monthly instrument functional test, and

3. Quarterly instrument calibrations.
   (Calibrate at 2 points with standard gas samples differing by at least 1%, but not exceeding 4%.)

Calibration and maintenance of other monitoring equipment is performed on a routine basis.

Various temperatures, flow rates, and level signals are continuously monitored to detect possible system malfunctions.

Experience with boiling water reactors has shown that the calibration of the offgas and effluent monitors changes with isotopic content, isotopic leaks in the reactor, and the nature of the leaks. Because of this, the monitors are calibrated against grab samples periodically and at any time there appears to be a significant change in offgas release rate.

9.4.4.1.7 Requirements for Plant Operations

During Augmented Offgas System operation, the concentration of hydrogen in the Augmented Offgas System shall be limited to less than or equal to 2 percent by volume at the outlet of the augmented offgas recombiner.

With the concentration of hydrogen in the Augmented Offgas System greater than 2 percent by volume, but less than or equal to 4 percent by volume, restore the concentration of hydrogen to within the limit within 48 hours.

OR

Be in a cold shutdown condition within 24 hours.

The concentration of hydrogen in the Augmented Offgas System shall be determined to be within the limits by continuously monitoring the waste gases in the Augmented Offgas System with the hydrogen monitor.

Operation of the Augmented Offgas Holdup System may continue without any hydrogen monitors operable, provided grab samples are collected at least once per 24 hours, analyzed within the following 4 hours, and the proper function of the recombiner is assured by monitoring recombiner temperature.

9.4.4.2 Turbine Sealing and Mechanical Vacuum Pump Systems

9.4.4.2.1 System Function

The Gland Seal Holdup System collects and processes, by delay, the noncondensible exhaust from the main turbine gland seal condenser. During startup operation the discharge of the condenser mechanical vacuum pump is routed through the Gland Seal Holdup System. The effluent of the Gland Seal Holdup System is routed to the main station stack where it is continuously monitored by the Main Stack Radiation Monitoring System before discharge to the environment. See Section 7.12.4.

During normal operation of the Gland Seal Holdup System, a 2,200 lb/hr saturated air-water vapor mixture containing trace amounts of hydrogen, oxygen, and radioactive gases is exhausted from the turbine generator gland seal condenser and enters the 16 in dia holdup line. After being delayed for a period of approximately 1.75 minute, the effluent is routed to the main stack where it is mixed with the Augmented Offgas System effluent and the discharge of the stack dilution fans before release to the environment. See Figure 11.4-1.

9.4.4.2.2 System Operation

The Gland Seal Holdup System shares with the Augmented Offgas System the main stack, dilution fans and the stack Radiation Monitoring System.

During normal operation, the amount of radioactive activation and fission gases associated with the Gland Seal Holdup System is extremely small. The radioactivity that is collected and processed by the Gland Seal Holdup System is proportional to the amount of main steam utilized in the Main Turbine Sealing System. This amount of steam is less than 0.1 percent of the full power rated steam flow. In addition to the small amount of radioactivity processed, there is a correspondingly small amount of radiolytic hydrogen and oxygen which are well below the explosive limits.

The Gland Seal System is designed to provide a 1.75 minute holdup delay time for the radioactive gases before discharge to the main stack. This design is consistent with maintaining discharges within allowable limits due to the extremely small amount of radioactivity associated with this system.

During startup operations, the condenser mechanical vacuum pump is used to assist the steam jet air ejectors in achieving condenser vacuum. The discharge of the mechanical vacuum pump is routed through the Gland Seal Holdup System.

The holdup normally provided by the Gland Seal Holdup System is reduced during startup due to higher air throughput when the mechanical vacuum pump is operating. Because the radioactive gases in the main condenser during startup are only a small fraction of the design evolution rate, the effect on radioactive effluents released to the environment is negligible.

The magnitude of the sources and resultant site boundary exposures resulting from station startups utilizing mechanical vacuum pump operation are difficult to quantify because the number, nature, and duration of the preceding shutdowns are difficult to estimate. An order of magnitude estimate of the annual average exposure from ten startups per yr was performed, assuming 4 hr of mechanical vacuum pump operation per startup, which indicated that maximum whole body exposures are less than approximately 0.05 mrem/yr. These estimated exposures can be reduced by minimizing the duration of mechanical vacuum pump operation.

9.4.4.2.3 Safety Evaluation

The amount of radioactivity associated with the Turbine Sealing System is negligible. The extremely low levels of radioactivity released from the Gland Seal Holdup System make direct radiation monitoring impractical; therefore, the total stack effluent is continuously monitored by the stack Radiation Monitoring System. Excessive release of radioactivity from this system is not considered credible due to its passive design and the small amount of main steam utilized in the sealing process.

The Gland Seal Holdup System is a passive system operating at atmospheric pressure requiring no particular control or instrumentation. Monitoring of the Gland Seal Holdup System effluent is provided by the stack Radiation Monitoring System which monitors the combined effluents of the Gland Seal Holdup System and Augmented Offgas System.

9.4.4.2.4 Inspection and Testing

The Turbine Sealing System is continuously operated during station operation and does not require specific testing to ensure operability.

9.4.4.3 Miscellaneous Gaseous Effluents

9.4.4.3.1 Low Release Potential Effluents

Miscellaneous gaseous effluents are categorized into two classes, those from areas having a negligible or low potential for the release of airborne radioactivity, and those from areas likely to experience radioactive contamination. Following is a list of station areas which fall into these categories. These areas are exhausted directly to the environment.

1. Diesel Generator Building
2. Administration Building
3. Machine Shop
4. Battery Room and Lube Oil Compartments

5. Recirculation Pump MG Set Area
6. Reactor Auxiliary Bay
7. Turbine Building Operating Floor and Switchgear Area

The ventilation air from the first six areas listed above has a negligible potential for the release of radioactive effluents. The Turbine Building operating floor including the reactor feedwater pump area are considered to have a low potential for release. Any release from the Turbine Building basement area or the Turbine Building ground floor to the Turbine Building operating floor or adjacent areas above elevation 51 foot is precluded since the Turbine Building basement and ground floor are maintained at a slight negative pressure relative to the Turbine Building operating floor.

The airborne radiation concentration levels at elevation 51 foot in the Turbine Building are routinely monitored by means of the Turbine Building Effluent Monitoring System described in Section 7.12.11. Airborne activity levels in those areas of the station having a direct release path to the environs not monitored by a Process Radiation Monitoring System will under normal operating conditions be within those levels allowed for in Appendix B, Table I, of 10 CFR 20, revised as of January 1, 1970. Assuming release from the Turbine Building operating floor at concentrations up to 3 X 10^{-9} microcuries/cm^3 the resulting concentrations at the site boundary would be less than 10^{-3} to 10^{-2} of MPC, on an unidentified basis.

The expected airborne activity on the Turbine Building operating floor will normally be below the values assumed above and the releases from the Turbine Building operating floor and the reactor feedwater pump area are expected to be insignificant relative to the releases from the main stack and the Reactor Building exhaust vent.

9.4.4.3.2 Potentially Contaminated Effluents

Gaseous effluents from areas of potential radioactive contamination are monitored and discharged to the environment through either the main stack or the Reactor Building exhaust vent. See Figures 10.9-4, 10.9-5, 11.4-1, and Section 10.9. The station ventilation systems are designed to combine the ventilation air flow from these areas and exhaust that air past process radiation monitoring equipment. The operation of the process radiation monitoring equipment is described in Sections 7.12.4 and 7.12.7.

Miscellaneous sources of potential low level radioactive airborne contaminants in the station which could be released to the environment are:

a. Primary Containment Venting

   Primary system leakage inside the primary containment could occur as a result of recirculation pump seal leakage , valve flange leakage, and valve stem packing leakage. The latter two are also sources of potential leakage outside the primary containment. The magnitudes of these leaks are

minimized to the extent possible by regular periodic inspections and station maintenance activities.

An analysis was performed to estimate the site boundary exposures resulting from primary containment purging assuming a 5-gal/min unidentified steam leak for a period of time sufficient to reach equilibrium concentrations in steam equivalent to a 25,000 microcurie/sec offgas rate after 30 min decay was used. The resultant whole body exposure per purge is estimated to be less than 0.001 mrem assuming that purging commences after the reactor has been brought to hot standby. During station operation, the drywell atmosphere is sampled for activity level to ensure that releases from this source will be minimal.

b. Steam Leakage Outside the Primary Containment

The site boundary exposures resulting from steam leakage outside the primary containment have been estimated based upon releases equivalent to a continuous steam leak of 7 gal/min of saturated liquid from the station ventilation exhaust. This has been selected based on experience at operating plants. The release to the environment may occur from the Turbine Building roof vent or the reactor building exhaust vent. Upper estimates of the magnitude of the whole body exposure resulting from noble gas releases from the steam range from 0.1 to 0.4 millirem/yr.

Assuming a leak rate of 7 gal/min and a coolant concentration concentration consistent with an offgas release rate of 25,000 microcuries/sec as measured at 30 min decay and a condensation plateout factor of 2 results in an environmental release rate of 0.04 microcuries/sec of I-131, with corresponding releases of I-132 to I-135. The value of 0.04 microcuries/sec release rate for I-131 can be compared to measurements which have been made on operating BWRs which have shown release rates from the building ventilation systems of 2×10^{-3} microcuries/sec to 4×10^{-2} microcuries/sec. The rate of release predicted results in a site boundary exposure rate of 0.6 millirem/yr.

c. Tank Vents and Sumps

Vents from liquid waste storage tanks, aerated resin regeneration tanks, open equipment, and floor drain sumps provide very little potential for contamination release, as the quantities of radioactive noble gases present in these liquids are generally negligible.

Particulate activity in the air space above stored liquid radwaste solutions is related to the gas liquid partition coefficient at the air water interface. The magnitude of this coefficient coupled with the filtration of a majority of the vents through high efficiency particulate (HEPA)

filters minimizes the potential for particulate releases from liquid waste storage tanks and open sumps. The collection of ionic halogens on station demineralizer resins creates an additional potential source of noble gases through the decay of halogens to their noble gas daughters. However, these gases are not released promptly to the environment. The operation of the liquid radwaste system minimizes the release of gaseous daughter fission products by allowing the system components to act as gaseous delay tanks to effect the decay of the significant noble gas daughters. Only the occasional necessary air scrubbing and air sparging of certain radwaste tankage and normal tankage filling provides potential release mechanisms. The site boundary dose contribution from these sources is expected to be negligible.

d. Hood Vents

Radiochemical hood vents provide a potential miscellaneous source of release of airborne activity from the station. However, the sampling frequencies and volumes result in releases which are small fractions of the releases from other miscellaneous sources from the station. Further, the HEPA filters installed in the exhaust ducting from the radiochemical hoods act to ensure that no particulate radioactivity is released.

e. HPCIS Testing

The site boundary exposure due to testing of the High Pressure Coolant Injection System (HPCIS) for an assumed 30 hr/yr has been evaluated. The HPCIS turbine uses primary system steam for motive force of which 500 lb/yr is used as HPCIS turbine gland sealing steam and is condensed in the HPCIS gland seal condenser. The associated noncondensibles including trace amounts of noble gases are released during test operation to the environment through the reactor building exhaust vent or the Standby Gas Treatment System (SGTS) which discharges to the main stack. The resultant site boundary whole body exposure is negligible less than approximately 1 percent of that expected due to primary system leaks outside the primary containment.

9.4.5 Estimates of Radioactive Gaseous Releases During Normal Operation

Estimates of radioactive gaseous releases and resultant doses during normal operation are given in the Pilgrim Station Unit 1 Appendix I Evaluation, dated April 1977.

TABLE 9.4-1

DESIGN BASIS ESTIMATED OFFGAS RELEASE RATES
Assuming Charcoal Bed Holdup Times of 17 Hours for Kr and 289 Hours for Xe

(Release Rates in Microcuries/Second)

Isotope	Discharge From Existing 30 Minute Holdup Line	Discharge From Charcoal Adsorbers	Offgas Activity Reduction Factors
Kr-83m	2.90E+03	4.62E+00	628
Kr-85	2.00E+01	2.00E+01	1
Kr-85m	5.60E+03	4.02E+02	14
Kr-87	1.50E+04	1.42E+00	10,600
Kr-88	1.80E+04	2.84E+02	63
Kr-89	1.80E+02	<1E-12	>1E+12
Xe-131m	1.50E+01	7.41E+00	2
Xe-133	8.20E+03	1.67E+03	5
Xe-133m	2.80E+02	6.17E+00	45
Xe-135	2.20E+04	6.18E-06	>1E+12
Xe-135m	6.90E+03	<1E-12	>1E+12
Xe-137	6.70E+02	<1E-12	>1E+12
Xe-138	2.10E+04	<1E-12	>1E+12
TOTAL	Approximately 100,000	Approximately 2,390	Overall Offgas Activity Reduction Factor 42

TABLE 9.4-2

NONCONDENSIBLE GAS INPUTS TO AUGMENTED OFFGAS SYSTEM

Hydrogen	(From Radiolytic Decomposition of Water)	90 ft^3/min @ 130°F
Oxygen	(From Radiolytic Decomposition of Water)	45 ft^3/min @ 130°F
Water Vapor	(For 100% Relative Humidity Mixture at SJAE)	21 to 31 ft^3/min Range @ 130°F
Air		12 to 40 ft^3/min Range @ 75°F

TABLE 9.4-3

CONDENSER INLEAKAGE

Plant	*MWe*	Number of Condenser *Shells*	Type of Augmented *Offgas System*	Total Air Inleakage *(standard ft³/min)*
KRB	250	1	Recombiner/Charcoal	4.1
Tsuruga	342	1	Recombiner/Compressed Gas	4.7
Fukushima 1	440	2	Recombiner/Compressed Gas	7.0

This data is consistent with leakage observed at fossil power plants where leakage rates range from 2 to 11 ft^3/min for units in the 350-500 MWe range.

TABLE 9.4-4

EQUIPMENT DESIGN REQUIREMENTS

Principal Component	Principal Construction Code (*)
1. Tank	D100 or API-650 & SR(a)
2. Heat Exchangers (containing offgas)	III-3 & TEMA-C
3. Piping and Valves (auxiliary systems)	B31.1.0
4. Piping and Valves (containing offgas)	III-3, B31.1.0 After Sept. 1984
5. Pumps	III-3
6. Valves, Flow Control	III-3
7. Charcoal Adsorber Vessels	III-3

* Legend

D100	AWWA-D100, Standard for Steel Tanks, Standpipes, Reservoirs, and Elevated Tanks for Water Storage
API-650	API 650, Welded Steel Tanks for Oil Storage
SR(a)	Nondestructive Tests Examination Requirements per ASME Section VIII, Division 1
III-3	ASME Boiler and Pressure Vessel Code, Section III, Class 3
TEMA-C	Tubular Exchanger Manufacturers Association, Class C
B31.1.0	USAS B.31.1.0, Power Piping

General Notes:

(1) This table applies to equipment and piping procured for the Augmented Offgas System after July 1, 1971.

(2) The equipment for the Augmented Offgas System is seismic Class II. Site boundary doses resulting from failure of system components do not exceed 10CFR20 whole body limits.

(3) Reg. Guide 1.143 of July 1978, off-gas pipe and valve design and fabrication is in accordance to ANSI B31.1.

TABLE 9.4-5

PROCESS INSTRUMENTS

	Control Room Indicated	Control Room Recorded	Local Indicated
1. Preheater discharge temp--low	X	--	--
2. Recombiner catalyst temp--high/low	--	X	--
3. Offgas condenser drain well (dual) level--high/low	--	--	X
4. Offgas condenser gas discharge	--	--	X
5. Hydrogen analyzer (condenser discharge) (dual)--high	--	X	--
6. Gas flow (offgas condenser discharge)--high/low	--	--	X
7. Gas flow (offgas charcoal adsorbers) high/low	-- --	--	X
8. Cooler--condenser discharge temp--high/low	--	--	--
9. Glycol solution temp--high/low	X	X	X
10. Gas humidity--high	--	X	--
11. Carbon bed temp--high	--	X	--
12. Carbon vault temp--high/low	X	X	--
13. After filter ΔP--high	X	--	X

Instrumentation Elements:

Temperature:thermocouple
Level:differential pressure diaphragm
Hydrogen:thermal conductivity
Gas flow:flow orifice
Differential pressure:differential pressure diaphragm

TABLE 9.4-6

EQUIPMENT MALFUNCTION ANALYSIS

Equipment Items	Malfunction	Consequences	Design Precautions
A. Preheaters	1. Steam leak	Would further dilute process offgas. Steam consumption would increase.	Spare preheater.
	2. Low pressure steam supply	Recombiner performance would fall at low power level and hydrogen content of recombiner gas discharge would increase, eventually to a combustible mixture.	Low temperature alarms on preheater exit and recombiner inlet.
B. Recombiners	1. Catalyst gradually deactivates	Temperature profile changes through catalyst. Eventually excess hydrogen would be detected by meter. Eventually the gas could become combustible.	Temperature probes in recombiner and hydrogen analyzer. Spare recombiner.
	2. Catalyst gets wet at startup	Hydrogen conversion falls off and hydrogen is detected by down stream analyzers. Eventually the gas could become combustible.	Condensate drains, temperature probes in recombiner. Air bleed system at startup. Recombiner thermal blanket, spare recombiner and heater. Hydrogen analyzer.
C. Offgas condenser	1. Cooling water leak	The coolant would leak to the process gas (shell) side. This would be detected if drain well liquid level increases. Moderate leakage could be of no concern from a process standpoint.	None.
D. Drain well	1. Liquid level instruments fail	If both drain valves fail to open, water will build up in the condenser and pressure drop will increase. The high ΔP, if not detected by instrumentation, could cause pressure buildup in the main condenser and eventually cause a reactor scram.	Two separate drain systems, each provided with high and low alarms.

TABLE 9.4-6 (Cont)

Equipment Items	Malfunction	Consequences	Design Precautions
		If a drain valve fails to close, gas will recycle to the main condenser increasing the load on the SJAE and causing back-pressure on the main condenser, eventually causing a reactor scram.	
	2. Liquid level control trips	If the float should sink, the gas would be recycled back to the main condenser.	The condenser level transmitter low level alarm shall activate.
E. Water separator	1. Corrosion of wire mesh element	High quantity of water collected in 30 minute holdup line and routed to radwaste.	Stainless steel mesh specified.
F. Cooler condensers	1. Corrosion of finned tube	Glycol-water solution would leak into process (shell) side and be discharged to clean radwaste. It would be detected at radwaste prior to being discharged to the reactor condensate system.	Stainless steel finned tubes specified. The inventory of glycol solution can be observed in tank. Spare cooler condenser provided.
	2. Icing up of finned tube	Shell side of cooler could plug up with ice, gradually building up pressure drop. If this happens the spare unit could be activated. Complete blockage of both units would increase main condenser pressure leading to a reactor trip.	Design glycol water solution temperature of 35-40°F. Spare unit provided. Temperature alarms.
G. Moisture separators	1. Corrosion of wire mesh element	Increased moisture would be retained in process gas routed to charcoal absorbers. Over a long period of time, the charcoal performance would deteriorate due to moisture pickup.	Stainless steel mesh specified. Relative humidity instrumentation provided. Spare unit provided.
H. Charcoal adsorbers	1. Charcoal gets wet	Charcoal performance will deteriorate gradually as charcoal get wet. Holdup times for krypton and xenon will decrease and plant emissions will increase.	Highly instrumented, mechanically simple gas dehumidification system with redundant equipment.

TABLE 9.4-6 (Cont)

Equipment Items	Malfunction	Consequences	Design Precautions
I. Vault air conditioning units	1. Mechanical failure	If ambient temperature exceeds about 80°F, increased emission could occur.	Spare refrigerator unit provided. Vault temperature alarm provided.
J. After filters	1. Hole in filter media	Probably of no real consequence. The charcoal media themselves should be a good filter at the low air velocity.	Δp instrumentation and high Δp alarm provided. Spare unit provided.
K. Glycol refrigeration machines	1. Mechanical failure	If spare unit fails to operate, the glycol solution temperature will rise and the dehumidification system performance will deteriorate. This will cause gradual buildup of moisture on the charcoal, with increased plant emissions.	Spare refrigerator provided. Glycol solution temperature alarms provided.
L. Steam jet ejectors	1. Low flow of motive high pressure steam	When the hydrogen and oxygen concentrations exceed 4 and 6 volume percent, respectively, the process gas becomes combustible.	Alarms provided for low steam flow and low steam pressure.
		Inadequate steam flow will cause over-heating and deterioration of the catalyst.	Steam flow to be held at constant maximum flow regardless of plant power level.
	2. Wear of steam supply nozzle of ejector.	Increased steam flow to recombiner. This could reduce degree of recombination at low power levels.	
O. Radiation monitors	1. One downscale trip	Alarms; also closes outlet if other channel on high-high-high.	Fail safe logic.
	2. Two downscale trips	Alarms and closes outlet.	Fail safe logic.

Figure 9.4-1 has been removed.

Please refer to BECo Controlled Drawing M 254 .

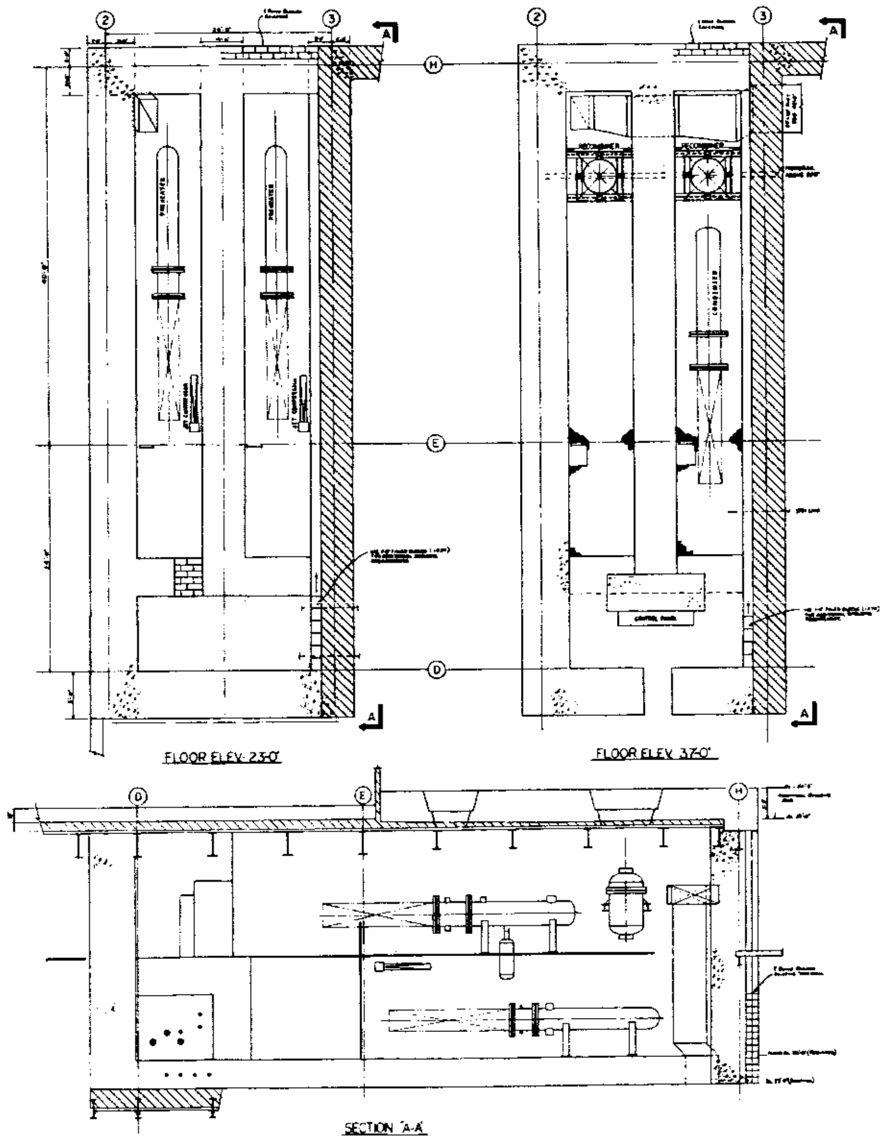


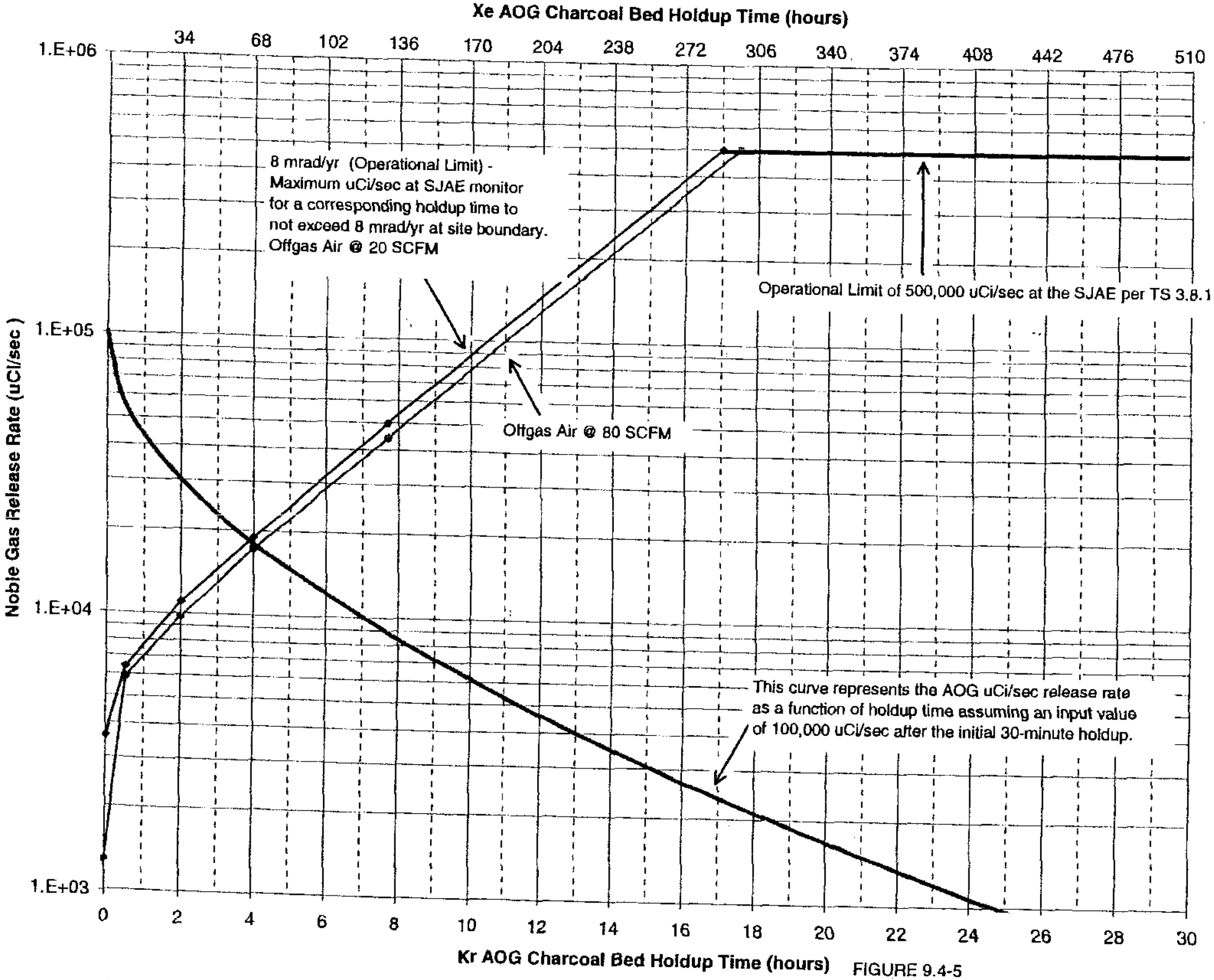
FIGURE 9.4-2
EQUIPMENT LOCATION AND
ARRANGEMENT AUGMENTED OFFGAS
SYSTEM "FRONT END" COMPONENTS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 9.4-3 has been removed.

Please refer to BECo Controlled Drawing M 29.

Figure 9.4-4 has been deleted.

Please refer to Figure 9.4-3.



Note: Acceptable region of operation is bounded by 8 mrad/yr dose limit curves and 500,000 uCi/sec release rate limit.

FIGURE 9.4-5
SJAE Monitor Release Rate as a Function of AOG Holdup Time
Pilgrim Nuclear Power Station
Final Safety Analysis Report
Rev 24 - Oct 2003

9.5 TRASH COMPACTION FACILITY AND DECONTAMINATION AND TRASH AND LAUNDRY FACILITY

9.5.1 TRASH COMPACTION FACILITY (TCF)

9.5.1.1 Power Generation Objective

The historic power generation objective of the TCF was to collect, prepare, package, and provide interim storage for radioactive material prior to shipment for offsite disposal.

There is no current power generation objective.

9.5.1.2 Power Generation Design Basis (Historic)

1. Historically the TCF was designed to provide collection, segregation, separation, compaction, and staging of radioactive material resulting from normal station operations.

2. Historically the facility was designed to provide a safe and reliable means for handling radioactive material and to minimize radiation exposure to station personnel.

9.5.1.3 Safety Design Basis (Historic)

1. The TCF was designed to include equipment, instrumentation, and operating procedures such that the radioactive material was collected and prepared for offsite shipment such that radiation exposure was as low as reasonably achievable.

2. Packaging was performed as necessary to conform to all codes and federal regulations.

9.5.1.4 General Description

Historically the radioactive material processing areas were located in the TCF.

The TCF is now used for storage of contaminated equipment which will be reused within the plant and interim storage of contaminated hazardous material.

9.5.1.5 System Function (Historic)

The historic purpose of the TCF was to process both non-contaminated and contaminated material generated from normal operating conditions. The TCF utilized sorting tables to sort the non-contaminated material from the contaminated, a non-contaminated waste compactor was used to compact non-contaminated material, a barrel compactor to compact contaminated material, and a contaminated trash compactor was used to compact contaminated material.

9.5.1.6 System Operation (Deleted)

9.5.1.6.1 Contaminated Material (Deleted)

9.5.1.6.2 Non-Contaminated Material (Deleted)

9.5.1.7 Equipment

The following equipment has been abandoned in place in the TCF:

1. Non-contaminated trash compactor.

2. Contaminated trash compactor.

3. Shredder.

4. Barrel compactor.

9.5.1.8 Safety Evaluation (Historic)

Operation of the TCF was by semi-remote means and the shielding design in the working areas minimized radiation exposure to personnel. The operating procedures, storage cells, and the radioactive material containers of the TCF reduced radiation exposures to levels which were as low as reasonably possible.

9.5.1.9 Inspection and Testing (Deleted)

9.5.1.10 Materials for Disposal

9.5.1.10.1 Contaminated Material for Disposal

The yard of the TCF contains Seavans in which separated contaminated dry active waste, metal, and wood and temporarily stored before shipment to an offsite radwaste processor.

9.5.1.10.2 Contaminated Hazardous Material For Disposal

Material identified as contaminated hazardous material is transported to the TCF Hazardous Material Area for storage until offsite disposal.

9.5.2 Decontamination and Trash and Laundry Processing Facility

The decontamination and trash and laundry processing facility is located in the north side of the redline building. As a facility to support station operation, it contains equipment for decontamination tools and equipment and also working space for handling trash, metals, wood, and potential HAZMAT being transferred to the TCF. This facility also handles incoming and outgoing shipments of laundry and contains space to permit temporary storage of various dry materials and equipment.

Hazardous material (other than radioactive material), liquids containing radioactive material, or wastes from plant water treatment processes e.g., spent resin, sludge, DE, are not stored in the facility. There is no running water and no floor drains in the facility.

Both administrative and physical controls are in place to maintain radiation exposure to personnel ALARA and to preclude releases to the environment in excess of the limits set forth in 10CFR20.

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

SECTION 10

AUXILIARY SYSTEMS

10.1 SUMMARY DESCRIPTION

This section describes the objectives, design basis, system design, safety considerations, and the inspection and testing requirements for the reactor and station auxiliary systems. The systems are described in the sections that follow.

10.2 NEW FUEL STORAGE

10.2.1 Power Generation Objective

The power generation objective of the new fuel storage vault and the new fuel storage racks is to provide a dry location for upright storage of new fuel assemblies which will allow efficient handling of the assemblies during station operations.

10.2.2 Power Generation Design Basis

1. The new fuel storage racks are designed to accommodate greater than 30 percent of the full core loading of fuel assemblies in an upright storage position.

2. The new fuel storage racks and the concrete storage vault are designed to allow efficient handling of the fuel assemblies during station operations.

10.2.3 Safety Design Basis

1. The new fuel racks are designed with sufficient spacing between the new fuel assemblies to assure that the fully loaded array will have a $K_{eff} \leq 0.90$ for normal dry conditions and a $K_{eff} < 0.95$ for abnormal conditions where the assemblies are completely flooded with water.

2. The fully loaded new fuel storage vault and storage racks are designed to Class I standards.

10.2.4 Description

The new fuel storage vault is a reinforced concrete Class I structure, accessible only through top hatches. There is an open drain in the floor of the vault to prevent flooding. New fuel racks are provided for at least 30 percent of the full reactor core load. Each new fuel storage rack holds up to 10 unchanneled fuel assemblies in a row spaced approximately 6.6 in apart center-to-center. The racks are arranged in rows having an 11 in center-to-center spacing that will limit the effective multiplication factor (K_{eff}) of the array to less than 0.90 assuming the fuel to be in the dry condition.

Each space for a fuel assembly has adequate clearance for inserting or withdrawing the assembly from above while enclosed in a protective plastic wrapping. Guides are provided to guide the fuel assemblies for the full length of their insertion into the rack. The design of the racks prevents accidental insertion of the fuel assembly into a position not intended for the fuel. The weight of the fuel assembly is supported at the bottom, and the rack provides full longitudinal support for the new fuel assembly spacers. Removable gratings (approximately 11 in wide and 6 ft 7 1/2 in long) over each fuel rack are provided to minimize the number of uncovered assemblies.

Each new fuel storage rack is designed as a Class I structure. Stresses in a fully loaded rack are designed not to exceed applicable specification requirements of the American Institute of Steel Construction (AISC) or the American Society of Civil Engineers (ASCE) when subjected to a horizontal earthquake load of 0.25g applied in any direction. A safety factor of approximately 2, based upon the material yield strength or local critical buckling, is used where these specifications are not applicable.

The storage rack structure is designed to absorb an impact energy of at least 7,000 ft-lb on an impact surface no larger than 3 inches in diameter. Under this impact force, the members that function to physically maintain the subcritical spacing (to assure that K_{eff} will not exceed 0.95 when flooded) will remain intact. Those members whose local and general strain exceed 25 percent of the material ultimate strain are assumed to be nonexistent for further energy absorption or for spacing purposes. Those members and their connections whose continued presence is required to maintain the subcriticality margin are designed using a minimum safety factor of approximately 1.33 based on the lower of the material yield or buckling stresses.

The storage racks are designed to withstand a pull-up force of 5 tons, equal to the load rating of the overhead crane's auxiliary hoist, and a horizontal force of 1,000 lb applied to the top of the rack. This is necessary in the event that the fuel assembly or grappling device binds during removal. The stress in these members required to maintain the abnormal storage subcriticality conditions will not exceed 75 percent of the material yield strength or 75 percent of that stress at which local buckling occurs.

The new fuel racks are designed to be restrained by hold-down lugs to assure that rack spacing does not vary under specified earthquake loads. Hold-down bolts will restrain the rack in case a stuck fuel assembly is inadvertently hoisted. Each hold-down bolt is designed to withstand 500 lb horizontal shear and an uplift force of 5,000 lb. All materials used in the construction of the new fuel storage racks are specified in accordance with the applicable ASTM specifications, and all welds are in accordance with AWS standards. Materials selected are corrosion resistant or are treated to provide the necessary corrosion resistance.

Criticality monitoring shall be in accordance with the requirements of 10 CFR 50.68(b).

10.2.5 Safety Evaluation

The calculations of K_{eff} are based upon the geometrical arrangement of the fuel array, and subcriticality does not depend upon the presence of neutron absorbing materials. The arrangement of the fuel assemblies in the fuel storage racks results in K_{eff} below 0.90, when dry. In an abnormal condition which assumes the vault is flooded with water and the fuel elements are brought to their most reactive spacing, the rack spacing is designed such that K_{eff} will not exceed 0.95.

Design of the new fuel storage vault to Class I standards effectively eliminates the possibility of vault damage due to earthquake loads.

A floor drain prevents accumulation of water in the vault. A radiation monitor in the vault provides warning of any radiation level increase above normal operating conditions. It is concluded that the safety design bases are met.

10.2.6 Inspection and Testing

The new fuel storage racks do not require any special inspection and testing for nuclear safety purposes.

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 and fuel handling 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.

NRC Order EA-12-051 required the installation of at least one permanent Spent Fuel Pool (SFP) level indication system. Pilgrim has installed two permanent SFP level indicating systems. The systems were designed and manufactured by MOHR Industries of Richland Washington.

Each of the two systems consist of a probe in the SFP, a power conditioner in the Control Room, a display unit in the Control Room, and a backup battery in the Control Room. The system can measure the level from approximately 6 inches above the top of the fuel racks to approximately 1-1/2 inches below the flange on the probe. Therefore the range is from an elevation of 93 ft. 3 inches to 116 ft. 7-1/2 inches. Reference drawing C2900.

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.

The reactor building crane upgrade modification installed for dry fuel storage cask handling utilizes a reactor building crane main hoist that has been designed as a single-failure-proof component. When used with casks and below-the-hook cask handling equipment designed to function as a single-failure-proof handling system, consideration of a cask drop accident is not required per the guidance of NUREG-0612 (Reference 14).

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.

Field Tests

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 Uuse of conservatively designed hoisting equipment, load testing, and examination prior to cask handling to verify sound equipment and minimizes the possibility of a dropped cask (see Section 10.3.7).

Pilgrim evaluated a load handling accident involving a cask up to 35 tons in weight being dropped through the refuel floor equipment hatch opening in a submittal letter to the NRC (Reference 15). This letter is cited as an input to the NRC Safety Evaluation supporting Amendment 33 to the Pilgrim Operating License (Reference 16)., 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.

This evaluation is associated with NUREG-0612 requirements when a non single-failure-proof handling system is in use. In the unlikely event of a fuel cask drop through the equipment hatch during cask handling operations, the cask it 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. maydo not stop the cask, itthe 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 Dry Fuel Storage

The PNPS has established as Independent Spent Fuel Storage Installation (ISFSI) west of the Reactor Building inside the plant protected area. The ISFSI Area includes an ISFSI Pad, an Approach Slab, and a Radiation Control Area (RCA) fence. The ISFSI concrete pad has a capacity for 40 vertical spent fuel storage casks.

The Spent Fuel Dry Cask Storage operations at PNPS will be conducted under a general license in accordance with Subpart K of 10 CFR Part 72. The general license issued by 10 CFR 72.210, "General license issued," authorizes a 10 CFR Part 50 nuclear power plant licensee to store spent fuel at an onsite ISFSI. Subpart K of 10 CFR Part 72 also includes 10 CFR 72.212, "Conditions of general license issued under §72.210," which requires the use of a dry cask storage system that is pre-approved by the Nuclear Regulatory Commission, as evidenced by its listing 10 CFR 72.214.

The PNPS ISFSI uses the Holtec HI-STORM 100S Version B vertical cask storage overpack and the Holtec MPC-68 multi-purpose canister (MPC), as described in the HI-STORM 100 Cask System FSAR (Reference 17) and approved by the Nuclear Regulatory Commission via the HI-STORM Certificate of Compliance No. 1014 (Reference 18).

The MPC provides the confinement boundary for the stored fuel. The MPC is a welded, cylindrical canister with a honeycombed fuel basket. All MPC confinement boundary components are made entirely of stainless steel. The honeycombed basket, which is equipped with neutron absorbers, provides criticality control.

The HI-STORM 100S Version B storage overpack provides shielding and structural protection of the MPC during storage. The HI-STORM 100S Version B overpack design includes a lid which incorporates the air outlet ducts into the lid. The overpack is a heavy-walled steel and concrete, cylindrical vessel. Its side wall consists of plain (un-reinforced) concrete that is enclosed between inner and outer carbon steel shells. The overpack has four air inlets at the bottom and four air outlets at the top to allow air to circulate naturally through the cavity to cool the MPC inside. The inner shell has supports attached to its interior surface to guide the MPC during insertion and removal, and allow cooling air to circulate through the overpack. A loaded MPC is stored within the HI-STORM 100S Version B storage overpack in a vertical orientation.

Loading the MPC with spent fuel assemblies takes place in the Reactor Building. Using the 100-ton Reactor Building crane and a lift yoke, a transfer cask with an empty MPC is lowered into the spent fuel pool. The MPC is then loaded with spent fuel assemblies utilizing the refueling platform. Once loaded, the transfer cask and MPC are transferred by the Reactor Building crane to the Reactor Building decontamination area, where the MPC is decontaminated, welded shut, drained, dried, and backfilled with helium. The transfer cask containing the loaded MPC is again lifted using the Reactor Building crane and lift yoke, lowered through the hoist way and placed on top of the HI-STORM 100 storage overpack inside the Reactor Building truck bay where the MPC is transferred from the transfer cask to the HI-STORM 100 storage overpack. The loaded HI-

STORM 100 storage overpack is then transported out of the Reactor Building to the ISFSI.

10.3.98 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

14. NUREG-0612, Coontrol of Heavy Loads at Nuclear Power Plants, July 1980 (Encloosure 1 to NRC Letter dated December 22, 1980; Ltr. 1.81.0114).

15. Pilgrim Letter #78-109 to NRC dated June 26, 1978 (Ref. ELNRC1.2.78.109).

16. NRC Saafety Evaluation Report for Amendment No. 33 to the Pilgrim Operaating License (Ref. NRCLE1.1.78.120).

17. Holtec International Final Safety Analysis Report for the HI-STORM 100 Cask System, Revision No. 9, USNRC Docket No. 72-1014, Holtec Report No.: HI-2002444, February 13, 2010.

18. USNRC Certificate of Compliance No. 1014, Docket No. 72-1014, Amendment No. 7, for the HI-STORM 100 Cask System, December 28, 2009.

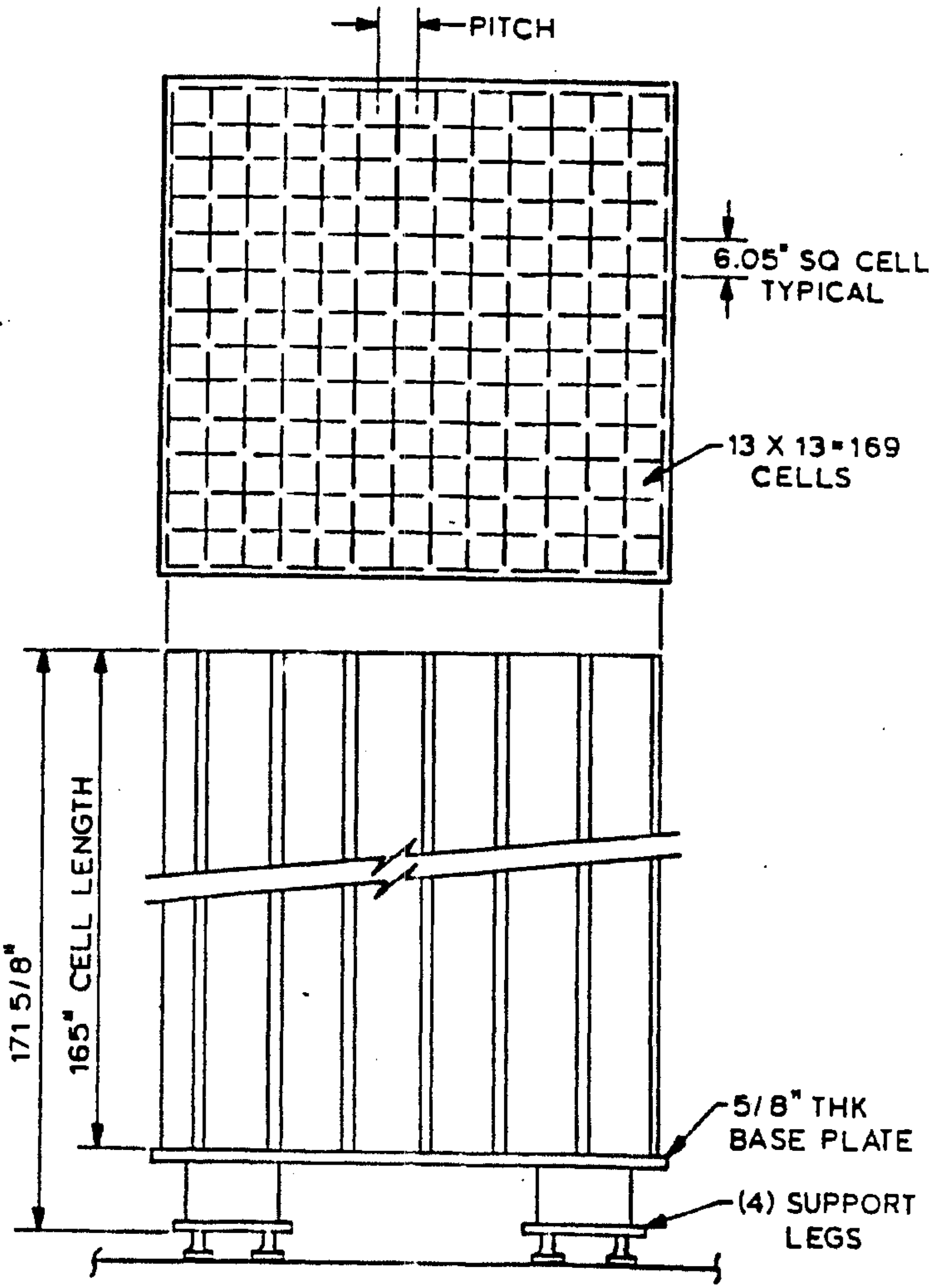


FIGURE 10.3-1
TYPICAL "E" RACK MODULE

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 18 – SEPTEMBER 1996

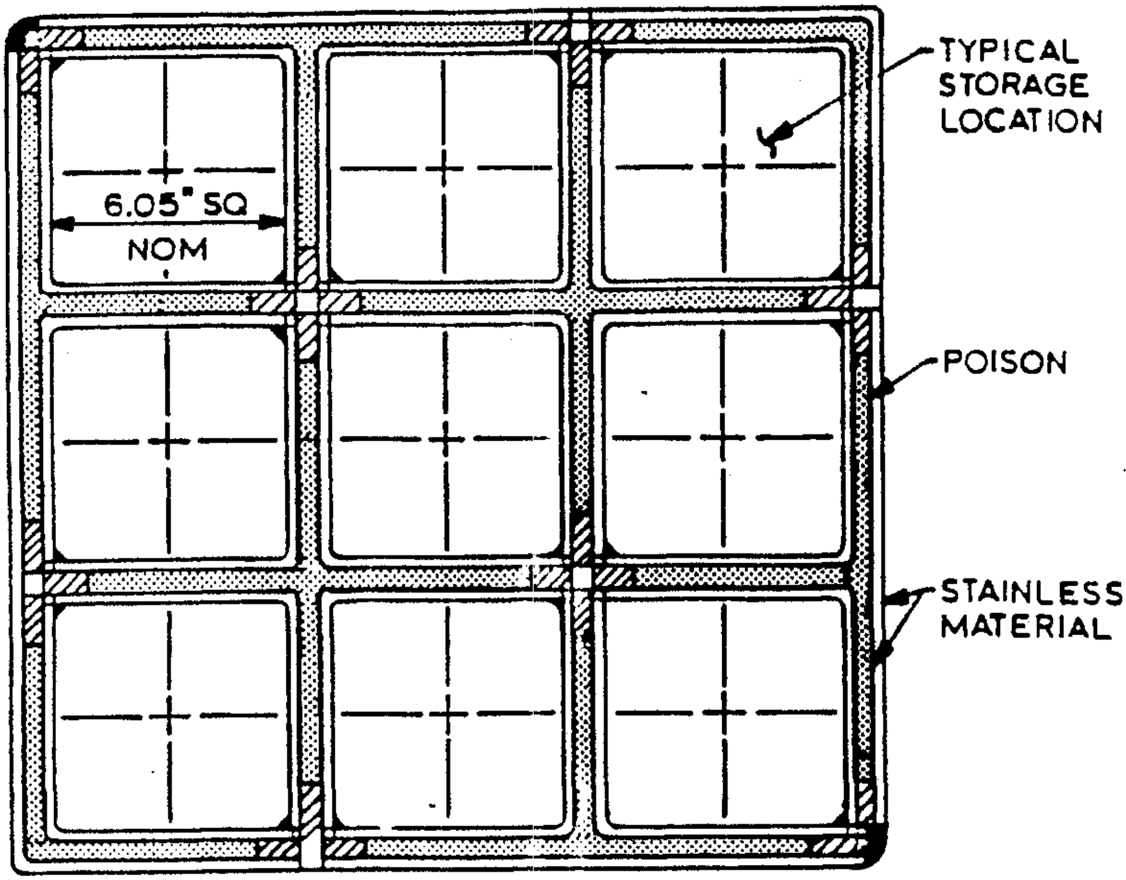


FIGURE 10.3-2
ARRAY OF "E" RACK CELLS (3 X 3)

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 18 – SEPTEMBER 1995

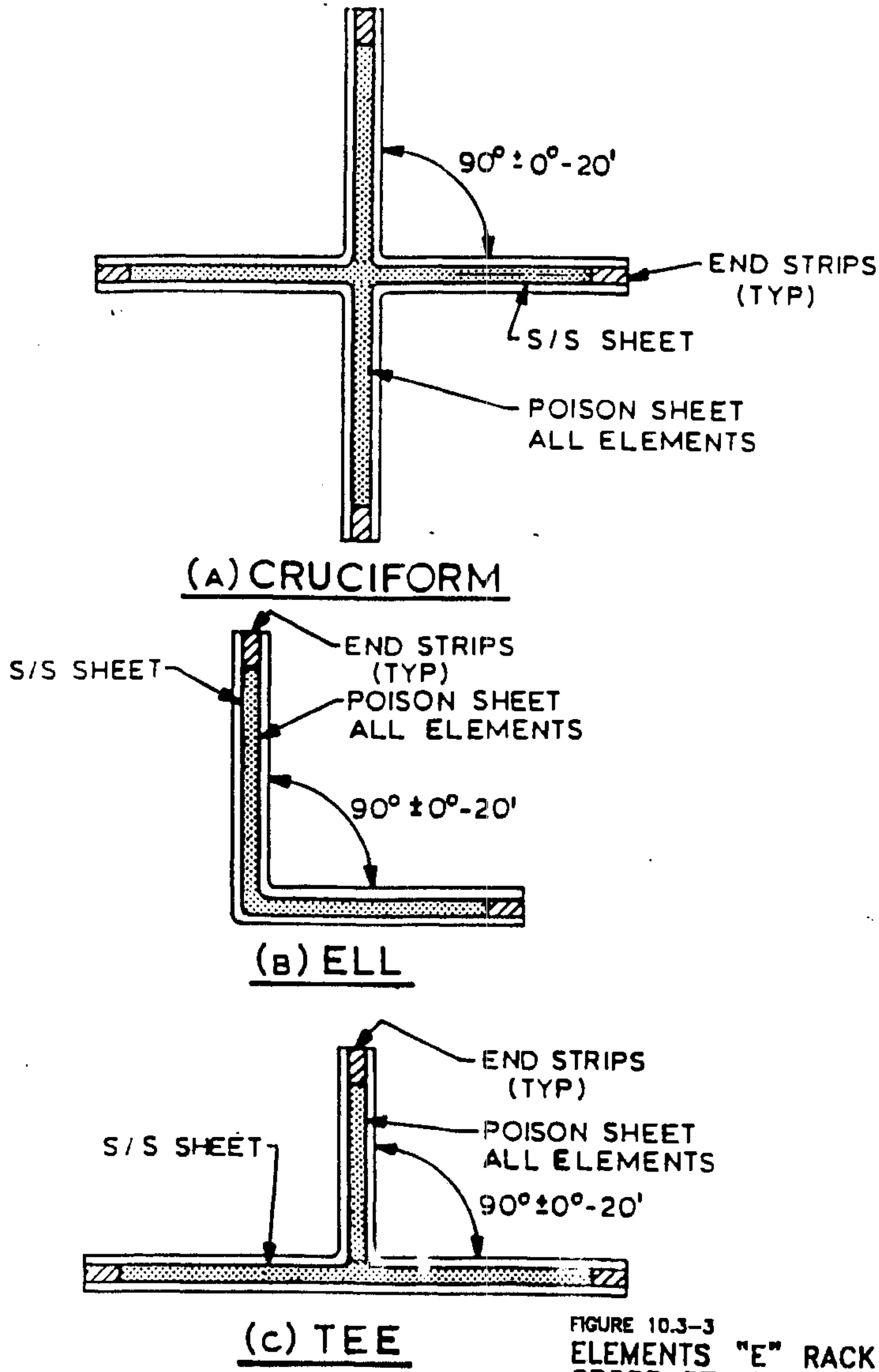


FIGURE 10.3-3
ELEMENTS "E" RACK CROSS SECTION

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 18 – SEPTEMBER 1995

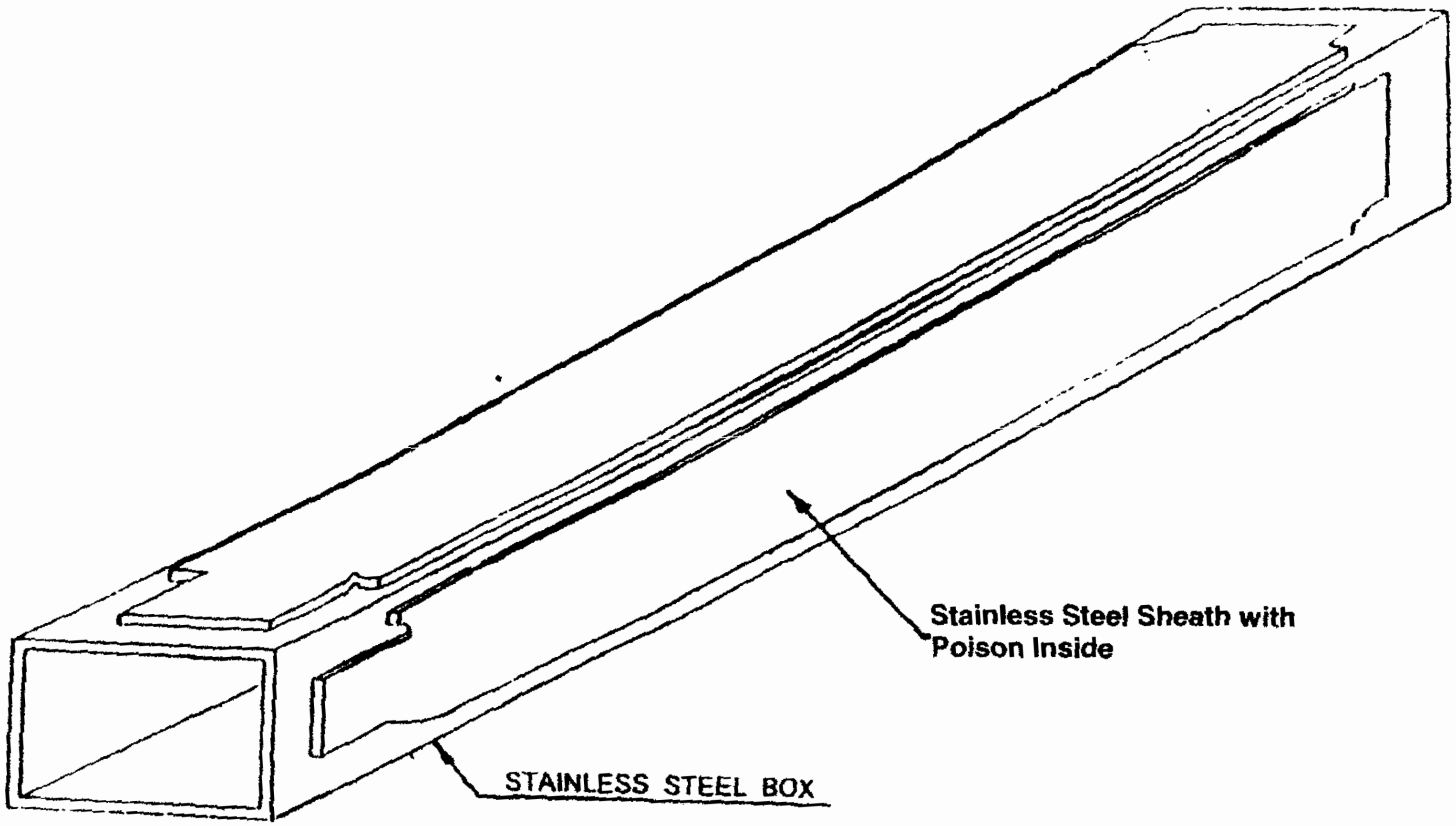


FIGURE 10.3-4
SHEATHING SHOWN INSTALLED ON "N" RACK BOX

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 27 - October 2009

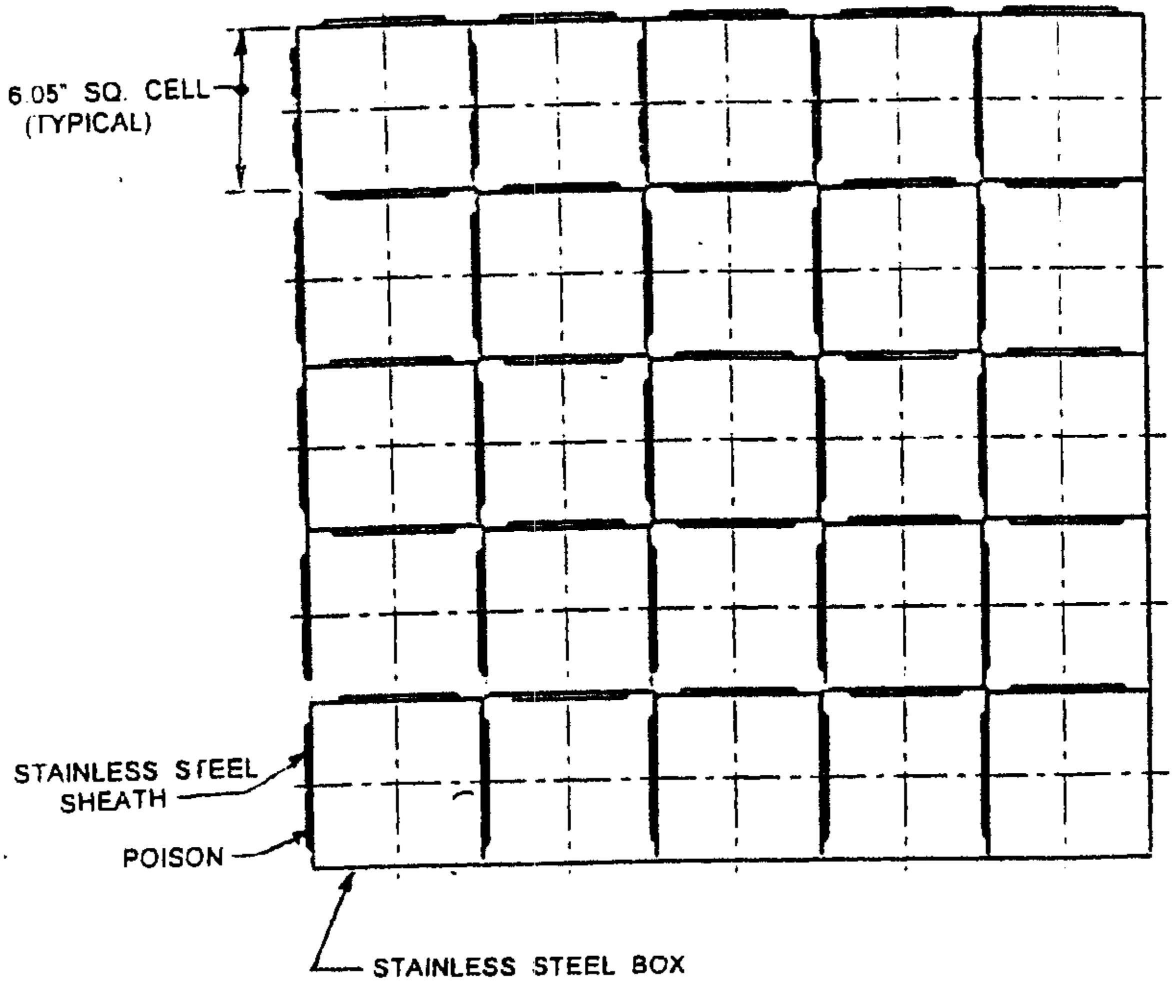


FIGURE 10.3-6
A CROSS-SECTIONAL VIEW OF "N" ARRAY OF STORAGE LOCATIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
Revision 27 - October 2009

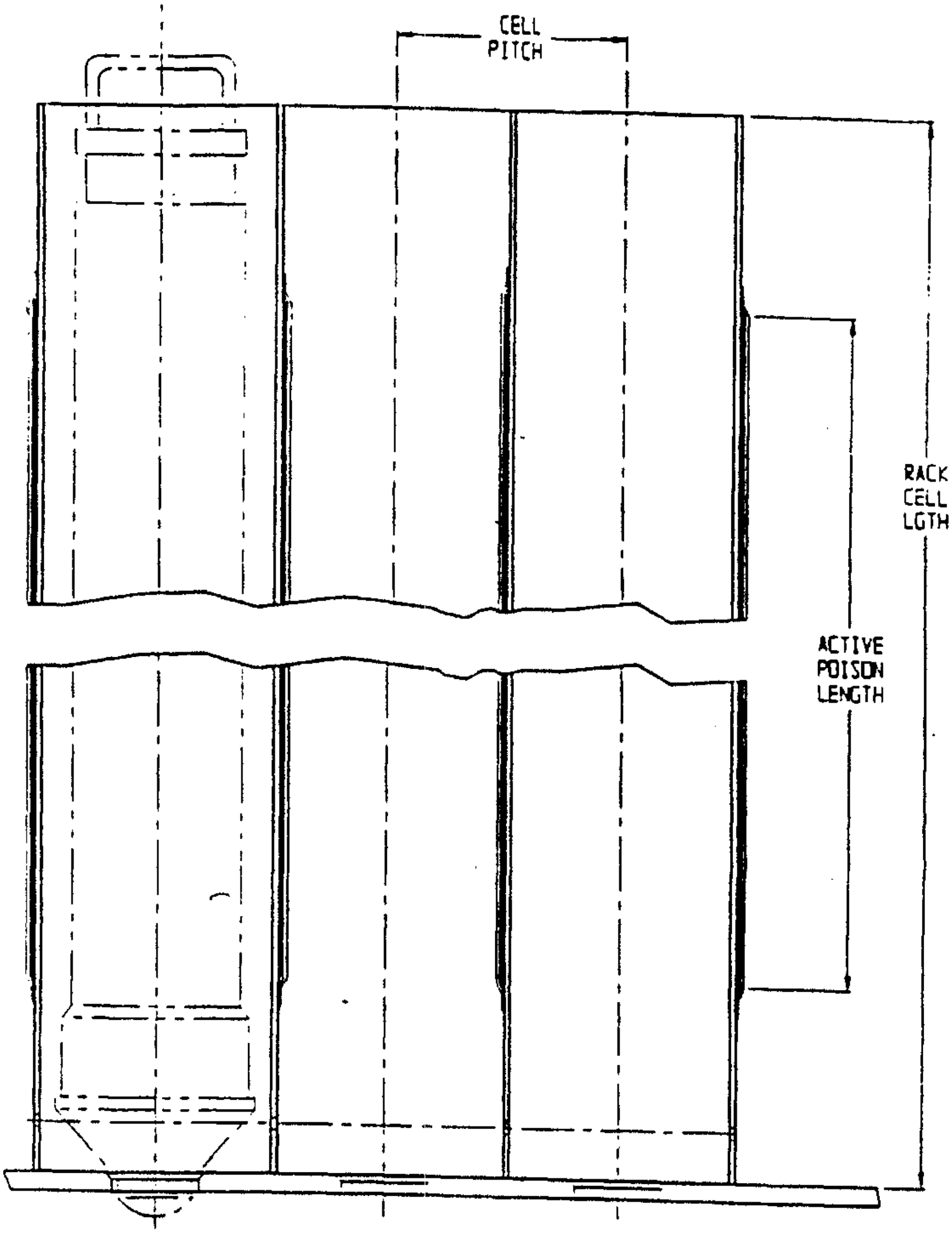
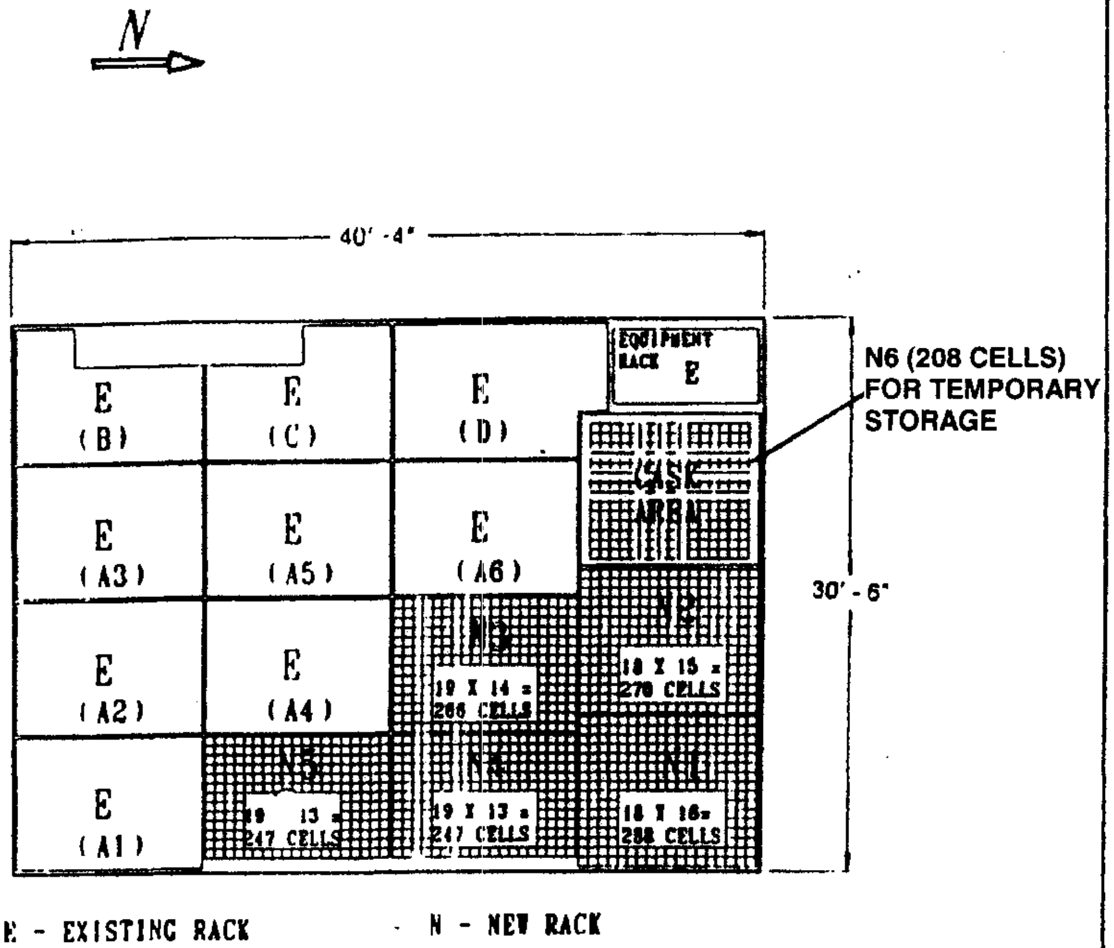


FIGURE 10.3-6
THREE "N" RACK CELLS IN ELEVATION VIEW

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Revision 18 – SEPTEMBER 1995



NOTE:
FULL SIZE TABLES ON N1 & N2
PARTIAL SIZE TABLES ON N3 & N4

FIGURE 10.3-7
PILGRIM SPENT FUEL POOL - CAPACITY EXPANSION

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
Revision 27 - October 2009

10.4 FUEL POOL COOLING AND CLEANUP SYSTEM

10.4.1 Power Generation Objective

The power generation objectives of the Fuel Pool Cooling and Cleanup System (FPCC) are to maintain fuel pool water clarity, to minimize the concentration of spent fuel fission and corrosion products in the fuel pool water, and to provide fuel pool water temperature control such that operating personnel can efficiently perform necessary manual operations above the pool.

10.4.2 Power Generation Design Basis

The FPCC is designed to maintain the spent fuel pool temperature below 125°F during normal reactor power operation and maintain fuel pool water clarity by removing fission and corrosion products and other foreign matter from the water through filtration and demineralization.

During refueling operations, the FPCC in combination with the Residual Heat Removal System (RHR) provides the necessary decay heat removal for the reactor core and fuel pool. With the reactor basin flooded and fuel pool gate open, the reactor basin and spent fuel pool form a common reservoir with the total heat load consisting of the reactor core plus the spent fuel discharged from previous refuelings. The decay heat removal methods and practices used during refueling outages ensure that acceptable fuel pool temperatures are maintained under normal conditions and that there is sufficient time-to-boiling without cooling under abnormal conditions.

Acceptance criteria for normal refueling conditions are as follows:

1. The primary method of decay heat removal shall have sufficient cooling capacity such that the bulk temperature in the spent fuel pool will be at or below a nominal 125°F with the peak not exceeding 142°F at the point of maximum heat load occurring at the end of a spent fuel transfer or at any time during a full core off-load. The analysis of system cooling capabilities shall be based on an appropriate salt service water heat sink temperature for the refueling outage. The primary methods of cooling included AFPC Modes 1 or 2 and normal fuel pool cooling with both pumps and heat exchangers.

2. For decay heat and fuel transfer calculations, the spent fuel pool minimum time-to-boiling without cooling shall not be less than 6.4 hours. This minimum time shall be determined for the peak heat load to be placed in the spent fuel pool and shall be based on a heat capacity that includes only the water in the spent fuel pool. The maximum heat load in the spent fuel pool shall not exceed 25 x 10^6 BTU/Hr.

Using the above criteria, an evaluation of the refueling practices to be used for a specific refueling outage can be performed. The allowable transfer and accumulation of fuel assemblies in the spent fuel pool is determined by applying the above criteria to an analysis that includes the decay heat load, available cooling capacities, and heat capacities without cooling. There is no inherently defined minimum decay time before fuel assemblies can be transferred to the spent fuel pool. The essential criteria are the maximum temperature with cooling, peak heat load, and minimum time-to-boiling without cooling.

10.4.3 Description

The FPCC, shown on Figure 10.4-1 (Drawing M231), cools the fuel storage pool by passing the pool water through a heat exchanger, thereby transferring heat to the Reactor Building Closed Cooling Water System (RBCCW). Water purity and clarity in the storage pool, reactor well, and dryer-separator storage pit are maintained by filtering and demineralizing the pool water.

The system also provides the capability to allow processing torus water and reactor cavity water through the fuel pool filter and demineralizer in order to reduce radwaste water processing and makeup waste processing.

The system includes two pumps, two heat exchangers, one filter, a filter backwash system, and one demineralizer arranged as shown on Figure 10.4-1 (Drawing M231). Normally one pump takes suction from the spent fuel pool skimmer surge tanks' common suction header and pumps water through one of two heat exchangers to the etched disc, backflushable-type filter. The filtered water, depending on its quality and conductivity, is then either routed through the fuel pool deep bed resin demineralizer and associated mesh basket strainer, or through a bypass, before returning to the fuel pool. The cooled water traverses the pool picking up heat and crud before starting a new cycle by discharging over the adjustable weirs into the epoxy lined skimmer surge tanks.

The Filter Backflush System contains a backflush expansion and entrainment separation (BEES) tank, an entrainment separator, and an air accumulator skid. During the backflush evolution the filter is isolated before high pressure air from the accumulator forces filter contaminants from the filter to the BEES tank. The entrainment separator scrubs residuals from the air vented from the BEES Tank. This operation can be performed manually, semi-automatically, or automatically.

During refueling operations both pumps and heat exchangers are normally operated to maintain reduced pool water temperatures. The filter and/or demineralizer are operated continuously to maintain the required pool water clarity. However, a portion of the system flow will be passed through the filter and demineralizer bypass lines to restrict filter and demineralizer flow to design ratings.

System flow indication is provided in the discharge of the fuel pool filter, in the discharge line after the demineralizer and basket strainer, and in the main line returning to the fuel pool. A three point temperature recorder is provided to give local system temperatures, thus indicating the performance of the heat exchangers, and determining whether the system load requires operation of two heat exchangers or one.

Differential pressure indication is provided separately for the filter and demineralizer. An alarm is actuated on high filter differential pressure, and automatic filter isolation occurs on high-high filter differential pressure. Conductivity instrumentation is provided in the system effluent to indicate when resin replacement is required.

The pumps are controlled from a local panel in the reactor building. Pump low suction pressure automatically turns off the pumps. A pump low discharge pressure alarm indicates locally and in the main control room.

Except where stated otherwise, stainless steel piping, valves, and equipment are used throughout the system to minimize corrosion product addition to the pool.

Fuel pool level monitors are provided to ensure that the pool water level remains within limits necessary for safe fuel handling. Abnormally high or low water levels in the pool are alarmed in the main control room.

Level switches are provided on the skimmer surge tanks to indicate high, normal, low, and low-low fuel pool levels. High level signal alarms occur only to indicate possible excess water input from other areas. The normal level signal automatically cuts off automatic makeup water supply. The low level alarm initiates automatic makeup. The low-low level signal alarms and trips the fuel pool pump. A local level indicator is also provided on the wall beneath the skimmer surge tank.

Makeup water for the system is transferred from the condensate storage tank to the skimmer surge tanks to make up any pool losses. Cooling water for the fuel pool heat exchangers is provided by the RBCCW System. See Section 10.5.

Except for the pool stainless steel liner, all other equipment in the system is Class II.

In order to handle the heat load immediately following refueling, the two heat exchangers are sized for a combined heat load of 6.3 x 10^6 BTU/Hr, allowing for a fuel pool temperature of 125°F with both pumps operating. The loss of one pump would require an increased pool temperature in order to maintain the same heat transfer capability.

Interconnection of the RHR System to the Fuel Pool Cooling System is possible in the event that unloading of the full core or a large number of fuel assemblies during refueling is required. The RHR/Fuel Pool Cooling System intertie was sized to remove a heat load of 23 x 10^6 BTU/Hr at 1200 gpm (see Section 4.8.5.6). There are two modes of operation for the RHR/Fuel Pool interconnection; Augmented Fuel Pool Cooling (AFPC) Modes 1 and 2.

AFPC Mode 1 is available when RHR shutdown cooling is operating with the reactor basin flooded and the fuel pool gate open. This mode provides additional cooling for the fuel pool by diverting a portion or all of the reactor vessel shutdown cooling flow to the fuel pool spargers and/or the vessel refueling cavity spargers. This configuration can be run simultaneously with normal fuel pool cooling and cleanup and provides the greatest total decay heat removal capability for the spent fuel pool and reactor.

AFPC Mode 2 uses a single RHR pump drawing water from the fuel pool skimmer surge tanks and returning the cooled water to the fuel pool spargers and, if needed, the refueling cavity spargers. In order to satisfy the minimum sustained flow rate for the RHR pump selected to drive Mode 2, this mode is operated at a minimum of 1800 gpm with a maximum flow rate of 2200 gpm as limited by pump NPSH requirements. Therefore, the actual decay heat removal realized is in excess of 23 x 10^6 BTU/Hr.

Table 10.4-1 provides additional description of the major equipment included in the FPCCS.

A separate pool is provided for temporary storage of the steam dryer and shroud/steam separators during refueling outages. See Section 12.2.2.1 for details.

10.4.4 Inspection and Testing

No special equipment tests are required because at least one pump, heat exchanger, and filter-demineralizer are continuously in operation while fuel is stored in the pool. Operating and standby components are alternated periodically to verify operability of all equipment. Routine visual inspection of the system components, instrumentation, and trouble alarms are adequate to verify system operability. The two pool low level float indicators and associated alarms are periodically tested by lifting the float assembly to effect low water level indication.

TABLE 10.4-1

FUEL POOL COOLING AND CLEANUP SYSTEM
EQUIPMENT LIST

Pumps
- type-centrifugal, horizontal
- number - 2
- capacity - 670 gal/min
- total head - 225 ft

Heat Exchangers
- type - shell and tube
- number - 2
- total heat transfer capability - 6.3 X 10^6 Btu/hr @ 125°F

Demineralizer
- type - deep resin bed
- number - 1
- flow rate - 670 gal/min
- max. pressure drop - 35 psi

Filter
- type - etched disc, backflushable
- number - 1
- flow rate - 600 gal/min
- pressure drop (clean) - 5 psid
  (dirty) - 75 psid
- Code - ASME, Section VIII, Div. 1

Tanks

(a) Backflush Expansion and Entrainment Separation Tank
capacity - approximately 32 ft^3
number - 1
design pressure - 150 psig
design temperature - 150°F
Code - ASME, Section VIII, Div. 1

(b) Filter Backflush Air Accumulator Skid
capacity - 10 ft^3
number - 1
design pressure - 375 psig
design temperature - 15°F
Code - ASME Section VIII, Div. 1

Figure 10.4-1 has been removed.

Please refer to BECo Controlled Drawing M 231.

10.5 REACTOR BUILDING CLOSED COOLING WATER SYSTEM

10.5.1 Safety Objective

The safety objectives of the Reactor Building Closed Cooling Water (RBCCW) System are to provide cooling to the Core Standby Cooling Systems (CSCS) components and provide a heat sink for the Residual Heat Removal (RHR) heat exchangers.

10.5.2 Power Generation Objective

The power generation objectives of the RBCCW system are to provide required cooling to the equipment located in the reactor building during normal planned station operations, and to provide a barrier between the primary system and the Salt Service Water System.

10.5.3 Safety Design Basis

1. The system is designed with sufficient redundancy so that no single system component failure can prevent the system from achieving its safety objective.

2. The system is designed to provide an adequate supply of cooling water to the CSCS, the Equipment Area Cooling System, and the RHR heat exchangers under all accident and transient conditions.

3. The system is operable from the standby ac power source.

10.5.4 Power Generation Design Basis

The system shall be designed with sufficient redundancy and flexibility of components such that the system will be continuously able to perform its power generation objectives, and maintain a constant loop inlet temperature to equipment during planned operation.

10.5.5 Description

10.5.5.1 System Components

The system consists of two independent closed loops. See Figure 10.5-1. Those components in each loop which must function during postulated accidents and transients are designed to Class I criteria. See Sections 12, 14, and Appendix C. Motor-operated gate valves are provided in each loop to manually isolate non-essential cooling loads under accident conditions. The two independent loops have the capability to be interconnected through two 12 inch cross-ties. The valves in the crossties are normally closed.

Each loop has three centrifugal pumps, rated 1,700 gal/min at 100 ft total dynamic head (TDH), taking suction from the reactor building cooling water heat exchanger and capable of delivering inhibited

demineralized water to the equipment listed on Table 10.5-1. RBCCW pump specifications and RBCCW heat exchanger specifications are listed on Table 10.5-2.

The 500 gal capacity head tank, located at the highest point of each loop, accommodates system volume changes, maintains static pressure in the loop, detects gross leaks in the RBCCW System, and provides a means for adding makeup water. Makeup water to the RBCCW System from the demineralized water storage tank is supplied by a connection from the demineralized water transfer pump to the head tank. Head tank level is maintained automatically by means of level transmitters and controllers mounted locally. The head tank is readily accessible during reactor operation for level adjustment if desired. Venting of the tank is directed to the reactor building. An inhibitor is added as necessary to the demineralized water by means of a chemical addition tank to limit corrosion.

The common discharge header for the pumps is monitored for low pressure and alarmed in the control room. A pressure test point and indicator are located at the outlet of each closed cooling water heat exchanger for pressure testing if desired. Temperature elements are provided to indicate the temperature of the cooling water on the indicator-controllers in the main control room. A constant water temperature is maintained automatically by the controller which governs the quantity of water flowing through the bypass around the cooling water heat exchangers. Cooling water sampling points are located at the outlet of each RBCCW heat exchanger and pump discharge header. Samples will be taken periodically to determine activity levels and quality of the cooling water.

The following conditions will alarm in the main control room:

1. Head tank low level
2. Head tank high level
3. Pump discharge header low pressure
4. High radiation level

The RBCCW System is powered by the emergency service buses.

Those portions of the RBCCW designated as Class I Pressure Boundary Only are seismic Class I with respect to their ability to retain their integrity (pressure boundary), and prevent loss of water during and after the operating Basis Earthquake or Safe Shutdown Earthquake.

10.5.5.2 Planned Operations

During normal power operation, one pump in each loop is operating providing coolant flow to all the equipment listed on Table 10.5-1 except the RHR heat exchangers which are valved off. The other CSCS components have continuous coolant flow during normal operation. The design inlet water temperature to the equipment coolers and area cooling coils is 80°F. The design heat transfer for each loop under these conditions is 20 x 10^6 Btu/hr.

The normal shutdown cooling mode of the RBCCW heat exchanger is based on a rated shell flow of 4250 gpm that corresponds to 3 RBCCW pumps in operation. The original rated shutdown heat transfer of 58 x 10^6 BTU/hr is based on a reactor water temperature of 125°F and a SSW heat sink temperature of 56°F for the RBCCW heat exchanger. The RHR system operating in the shutdown cooling mode is capable of reducing reactor water temperature to 125°F within 20 hours after reactor shutdown. With the maximum decay heat load, a normal shutdown may require two RHR loops operating at rated flow conditions with a 75°F SSW heat sink to achieve this rate of cool down. Under limiting shutdown conditions of only one RHR loop operating with two RBCCW pumps and two SSW pumps, the cold shutdown condition (212°F) can be achieved within 8 hours after reactor shutdown with a 75°F SSW heat sink.

During planned operations, the RBCCW system also functions as an intermediate barrier between nuclear system equipment and the salt service water system. The pressure in the RBCCW loops is higher than the pressure in the service water system to prevent salt water contamination of the RBCCW system. Detectors are located in the system to continuously monitor radioactivity level. On detection of a high radiation level, an alarm will be set off automatically in the control room.

10.5.5.3 Accident and Transient Operations

Either RBCCW loop has sufficient capacity with two pumps operating to transfer the RHR System heat load plus an additional 1 x 10^6 Btu/hr heat load from other essential equipment during a design basis LOCA assuming a 65°F or 75°F service water inlet temperature. Table 10.5-2 provides RBCCW heat exchanger peak capacity, flow rates, and fluid temperatures for the design basis accident for both a 65°F and 75°F service water inlet temperature. Section 14.5 describes the containment cooling system analysis for a design basis loss of coolant accident (LOCA) at both a salt water inlet temperature of 65°F and 75°F.

Following a postulated loss of coolant accident (LOCA) coincident with loss of the preferred (offsite) AC power source, the operating RBCCW pumps will trip. One RBCCW pump in each loop is automatically restarted on its respective diesel generator approximately 30 seconds after AC power is restored to the emergency service bus. Sufficient pressure is normally generated by one pump in each loop to preclude automatic starting of additional RBCCW pumps. In the event of pump failure, the low pressure condition in the pump discharge header will result in automatic sequential start of other pumps in the loop until the low pressure condition is corrected.

For the design basis LOCA, the immediate indications will prompt the control room operators to take actions to initiate the containment heat removal function of the RHR, RBCCW, and SSW systems after core cooling is established. The design basis LOCA transfers heat energy to the suppression pool in the most rapid manner possible such that the pool temperature immediately following the reactor vessel

blowdown is above 130°F. At approximately 10 minutes after the accident, control room operators will manually initiate cooling to the RHR system by starting a second RBCCW pump in each operation loop and opening either one of the two inlet valves supplying RBCCW cooling water to the RHR heat exchanger in each loop. The RBCCW heat exchanger bypass is closed by lowering the temperature control valve setpoint or by closing the motor-operated bypass isolation valve as needed. A second SSW pump in each loop is also started to provide the design SSW flow to the RBCCW heat exchangers.

For the design basis LOCA analysis, it is assumed that there is only one loop of containment heat removal (RHR, RBCCW, and SSW) operable. Under these conditions, it is necessary to isolate the nonessential loads in the operable RBCCW loop to ensure design heat transfer performance from the RHR and RBCCW heat exchangers. 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. The RBCCW heat transfer parameters at the peak suppression pool temperature are given in Table 10.5-2 and the resulting containment and suppression pool temperature profiles are given in Section 14.5.3.

The same automatic RBCCW pump start sequence also takes place in the event that the preferred (offsite) AC power source is lost without concurrent LOCA conditions.

Additional flexibility of system operation has been provided through the capability of interconnection of the two loops through the crossties. Thus, the system could still function under a variety of degraded conditions.

10.5.6 *Safety Evaluation*

The RBCCW System is designed with sufficient redundancy so that no single active system component failure, nor any single active component failure in any other plant system can prevent it from achieving its safety objective. Two independent closed loops, each with full heat transfer capacity, are provided. Additional criteria that address RBCCW system interface with the primary containment are discussed in FSAR Section 5.2.3.5.

Additional flexibility of system operation has been provided through the capability of interconnection of the two loops through the crossties. Thus the system could still function under a variety of degraded conditions.

It is concluded that the safety design bases are met.

10.5.7 Inspection and Testing

Pumps in the RBCCW Systems shall be proven operable by their use during normal station operations. Motor-operated isolation valves can be tested to assure they are capable of opening and closing by operating manual switches in the control room and observing the position lights.

10.5.8 Nuclear Safety Requirements for Plant Operation

General

This section represents the nuclear safety requirements for the RBCCW for each BWR operating state which result from the stationwide BWR systems analysis of Appendix G. The following referenced portions of the safety analysis report provide important information justifying the entries in the section:

	Reference	Information Provided
1.	Section 10.5.5	Description of RBCCW System
2.	Station Nuclear Safety Operational Appendix G	Identifies conditions and events for which RBCCW Systems actions are required

Each detailed requirement in the following analysis is referenced, if possible, to the most significant station condition originating the need for the requirement by identifying a matrix block on Table G.5-3.

The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" section.

The matrix block references identify the BWR operating state, the event number, and the system number. For example, F39-97, identifies BWR operating state F, event (row) No. 39, and system (column) No. 97, on Table G.5-3.

System Action

The RBCCW System provides a heat sink for the residual heat removal heat exchangers and provides cooling to the CSCS.

Number Provided by Design

This system consists of two full capacity closed loops with provision for cross connection. Each loop has three pumps, one cooling water heat exchanger, piping, valving, instrumentation, and controls to provide coolant to the following essential equipment:

For Each Loop (A & B):

2 RHR pump mechanical seal coolers
1 RHR heat exchanger
2 Reactor core isolation cooling (RCIC) or high pressure coolant injection (HPCI) pump area cooling coils
2 RHR pump area cooling coils
1 Core spray pump motor thrust bearing

Minimum Required for Action

BWR Operating States A & B:
One pump and one cooling water heat exchanger.
(A35-97) (B35-97)
BWR Operating States C,D,E, and F:
Two pumps in one loop and one cooling water heat exchanger.
(C39-97) (D39-97)
(E39-97) (F39-97)

10.5.9 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.

TABLE 10.5-1

EQUIPMENT SUPPLIED BY THE RBCCW SYSTEM

Loop A

* Two RHR pump mechanical seal coolers
One fuel pool heat exchanger
* One RHR heat exchanger
Two Recirculation pump MG set fluid coupling oil and bearing coolers
* Two RCIC pump area cooling coils
* Two RHR pump area cooling coils
Four MG set area cooling coils
* One Core spray pump motor thrust bearing

Loop B

* Two RHR pump mechanical seal coolers
One fuel pool heat exchanger
* One RHR heat exchanger
Two Control rod drive pump oil and bearing coolers
Two Recirculation pump seal water coolers
Two Recirculation motor lube oil coolers
Two Cleanup recirculation pump seal water coolers
One Cleanup non-regenerative heat exchangers
* Two HPCI pump area cooling coils
Two Control rod drive pump area cooling coils
• Two RHR pump area cooling coils
Six Drywell air cooling units with two coils each
Two Drywell air cooling units with two coils each
* One Core spray pump motor thrust bearing

* Denotes essential equipment

TABLE 10.5-2

REACTOR BUILDING COOLING WATER SYSTEM
EQUIPMENT DATA
NO. OF INDEPENDENT LOOPS - 2

RBCCW Pumps	
Quantity per loop	3
Type	Horizontal Centrifugal
Flow and Head	1,700 gal/min at 100 ft TDH
Material:	
Casing/impeller/shaft	Cast Steel/Bronze/Stainless Steel
Motor: Size	60 hp
Voltage/phase/cycle	460 V/3 phase/60 cycle
rpm	1,750 (Nominal)
RBCCW Heat Exchangers	
Quantity per loop	1
Type	Horizontal, Shell and Tube, TEMA type AGM
Heat Transfer Area	10,200 ft^2 (effective)
Shell Design:	
Pressure/Temperature	150 psig/200°F
Material	Carbon Steel
Flow Medium	Inhibited Demineralized Water
Tube Design:	
Pressure/Temperature	150 psig/200°F
Materials: Tube	90-10 copper nickel
Tube sheet	90-10 copper nickel
Tube Joint	Rolled and welded
Flow Medium	Sea Water
RBCCW heat transfer rate at peak suppression pool temperature, BTU/hr	71.8 x 10^6 (at 75°F SSW inlet temperature and 185°F suppression pool temperature) 65 x 10^6 (at 65°F SSW inlet temperature and 166°F suppression pool temperature)
Reactor Building Closed Cooling Water flow rate, gpm	3200
Salt Service Water flow rate, gpm	4,500

Figure 10.5-1 has been removed.

Please refer to BECo Controlled Drawing M 215 .

10.6 TURBINE BUILDING CLOSED COOLING WATER SYSTEM

10.6.1 Power Generation Objective

The power generation objective of the Turbine Building Closed Cooling Water (TBCCW) System is to provide cooling to the equipment located in the Turbine Building and to the Station Air Conditioning Systems.

10.6.2 Power Generation Design Basis

The TBCCW System is designed to provide an adequate supply of coolant to the essential power generation equipment located in the Turbine Building and to the Station Air Conditioning Systems.

10.6.3 Description

The TBCCW System, as shown on Figure 10.6-1, consists of a single closed loop with two centrifugal pumps in parallel, taking suction from TBCCW heat exchangers arranged in parallel, and delivering cooling water to the equipment listed on Table 10.6-1. The TBCCW pump, TBCCW heat exchanger, and Retention Building Booster Pump specifications are given on Table 10.6-2. The TBCCW loop is designed for a system pressure of 150 psig. The TBCCW pump shutoff head of 110 ft plus the Retention Building Booster Pump shutoff head of 125 ft plus the static head of 75 ft combined will not exceed the design pressure downstream piping and components.

The 500 gal capacity head tank, located at the highest point of the loop, accommodates system volume changes, maintains static suction pressure on the pumps, detects gross leaks in the TBCCW System and provides a means for adding makeup water. Makeup water to the TBCCW System from the demineralized water storage tank is supplied by a connection from the demineralized water transfer pump to the head tank. Tank level is maintained automatically by means of level transmitters and controllers mounted locally. A signal from these transmitters opens the valve on the makeup line to fill the surge tank to the desired level. The surge tank is readily accessible during reactor operation for level adjustment if desired. Venting of the tank is directed to the Reactor Building. An inhibitor is added as necessary to the demineralized water by means of a chemical addition tank to limit corrosion.

The discharge side of each TBCCW System pump has a pressure indicator. The common discharge header for the pumps is monitored for low pressure and alarmed in the control room. A pressure indicator, located on the outlet header of the heat exchangers, and a pressure test point on the inlet header may be used for pressure testing. A temperature element is located on the cooling water pump discharge to indicate the temperature of the cooling water on the indicator controller in the main control room. A constant water temperature is maintained automatically by the controller, which governs the quantity of water flowing through the bypass around the cooling water heat exchangers. Cooling water sampling points are located at the outlet of each TBCCW heat exchanger. Samples will be taken periodically to determine activity levels and quality of the cooling water.

The following conditions will alarm in the main control room:

1. Head tank low level

2. Head tank high level

3. Pump discharge header low pressure

The original design ratings for the TBCCW system are based on the operation of both system heat exchangers. The TBCCW system is designed to transfer a maximum heat load of 38 MBtu/Hr in order to limit equipment inlet temperature to 95°F, assuming a seawater inlet temperature of 75°F. The actual TBCCW System heat load has been estimated to be less than 30 MBtu/Hr during normal full power operation and is typically shared equally by the two TBCCW heat exchangers operating at an average heat load of less than 15 MBtu/Hr each. During normal station full power operation, only one TBCCW pump is typically operated with both heat exchangers, which provides adequate flow and cooling for all normal heat loads during most conditions. At times of peak SSW heat sink temperatures, typically occurring from June into October, there may be periods when it is preferred to operate both TBCCW Pumps with both heat exchangers to raise the component cooling water flow rates in the system to their rated values and to maintain the cold loop temperature at 85 to 95°F.

At times of low SSW heat sink temperatures, typically from October to June, there are periods when it is possible to operate adequately with one TBCCW Pump and only one heat exchanger providing cooling. This configuration allows for online maintenance to be performed on one heat exchanger under these conditions.

Following the loss of the preferred AC power source without a LOCA initiation signal, a TBCCW pump will be started automatically and loaded on its respective diesel generator. A time delay relay will start the P-110A pump within approximately 35 seconds from the loss of power. If header pressure remains low due to the failure of the first pump or other abnormality, the P-110B pump is started within approximately 55 seconds from the loss of power.

Following the loss of the preferred AC power source with a LOCA initiation signal, the TBCCW pumps will not be enabled to start until one of the ECCS pumps is no longer in service. The time delay relays will remain in place but since the logic will have energized them as soon as power is restored there will be no additional delay after one of the ECCS pumps is removed from service.

The system is provided with two remote manual motor operated valves that serve to isolate the nonessential loads from the system. Cooling water continues only to the main control room, computer room, and cable spreading room air conditioning units, and air

compressors following this isolation. A single TBCCW pump operates at a low flow condition and higher brake horsepower when only the essential loads are provided with cooling water. Since adequate cooling is provided to essential and nonessential loads one TBCCW Pump, the isolation of the nonessential heat loads is not required.

The TBCCW System contains a coolant sidestream particulate filter. When in service, the filter sidestream bypasses less than 1% of the coolant flow around the TBCCW heat exchangers. The filter removes particulates 5 microns and larger from the coolant without removing corrosion inhibitor chemicals.

The Class I seismic designation to certain portions of the TBCCW System was initiated at an early design stage and prior to the finalization of design for the major plant, air, and control room ventilation systems.

As a result of incorporating the Main Control Room Environmental Control System and Class I air accumulators on critical air-operated valves, etc., into the plant design, the need for Class I piping and components in the TBCCW System was eliminated. Currently, the TBCCW System is Class II. The portions of piping in the RBCCW/TBCCW Heat Exchanger Room are designed MQCI (II/I) to protect Class I equipment belonging to other systems in this room. Since the loss of the TBCCW System will not affect the safe shutdown of the plant, special controls or emergency procedures are not required.

10.6.4 Inspection and Testing

Pumps in the TBCCW have been proven operable by their use during normal station operations. Motor-operated isolation valves in the system can be tested to assure that they are capable of opening and closing by operating manual switches in the control room, and observing the position lights. System subsections normally closed to flow can be tested periodically to ensure their operability and the integrity of the system.

TABLE 10.6-1

EQUIPMENT COOLED BY THE TURBINE BUILDING
CLOSED COOLING WATER SYSTEM

Air Ejection & Off-gas System:

1 Condenser Vacuum Pump Seal Water Cooler

Augmented Off-gas System:

1 Hydrogen Analyzer Cooler
2 Glycol Coolers

Circulating Water System:

2 Scavenging Pump Seal Water Heat Exchangers

Compressed Air System:

3 Instrument Air Compressor Aftercoolers
5 Instrument Air Compressors
1 Instrument Air Filter/Dryer Blower Heat Exchanger
2 Service Air Blower Heat Exchangers

Condensate & Feedwater System:

3 Reactor Feed Pump Seal Water Coolers
3 Condensate Pump Motor Bearing Coolers

Containment Atmospheric Control System:

1 Integrated Leak Rate Test Aftercooler

Control, Computer & Cable Spreading Rooms HVAC System:

2 Control & Computer Room Air Conditioners

Lube Oil System:

2 Turbine/Generator Lube Oil Coolers
6 Reactor Feed Pump Lube Oil Coolers

Off-gas Retention Building HVAC System:

2 Recombiner Area Unit Coolers
2 Off-gas Retention Building Condensers

Radioactive Waste Concentrator System:

1 Concentrator Cooler
1 Concentrator Vent Cooler
1 Concentrator Drain Cooler

TABLE 10.6-1 (Cont.)

EQUIPMENT COOLED BY THE TURBINE BUILDING
CLOSED COOLING WATER SYSTEM

Radwaste Building HVAC System:

1 Radwaste Control Room Air Conditioner
2 Access Control Area Air Conditioners

Radwaste System

1 Thermex Radwaste Cooler

Turbine Building HVAC System:

2 Condensate Pump Area Cooling Coils
6 Condenser Compartment Cooling Coils
1 Administration Building Air Conditioner
1 Health Physics Counting Room Heat Pump
1 Health Physics Counting Room Air Conditioner

Turbine-Generator & Isolated Phase Bus Cooling System:

4 Generator Hydrogen Coolers
2 Stator and Alterex Coolers
1 Alterex Cooler
2 Isolated Phase Bus Coolers

TABLE 10.6-2

TURBINE BUILDING CLOSED COOLING WATER
SYSTEM EQUIPMENT DATA

TBCCW Pumps

Quantity	2
Type	Half Capacity Horizontal Centrifugal
Flow and Head (each)	4,500 gal/min at 65 ft
Material:	
Casing	Cast Steel
impeller	Bronze
shaft	Stainless Steel
Motor: Size	100 hp
Voltage	440
Phase	3
Cycle	60
rpm	1,750

Retention Building Booster Pumps

Quantity	2
Type	In-line Centrifugal
Flow and Head (each)	200 gal/min at 100 ft
Material	
Casing	Cast Steel
impeller	Cast Iron
shaft	Low Alloy Steel
Motor Power	10 horsepower
Voltage	460
Phases	3
Cycles	60
Speed	3600 rpm (Nominal)

TBCCW Heat Exchangers

Quantity	2
Type	Horizontal, Shell and Tube, TEMA type AEM
Heat Transfer Area (each)	4,500 ft^2
Shell Design:	
Pressure/Temperature	150 psig/200°F
Material	Carbon Steel
Coolant Medium	Inhibited Demineralized Water

TABLE 10.6-2 (Cont)

TURBINE BUILDING CLOSED COOLING WATER
SYSTEM EQUIPMENT DATA

Tube Design:	
Pressure/Temperature	150 psig/200°F
Material: tube	90-10 Copper Nickel
tube sheet	90-10 Copper Nickel
Tube Joint	Rolled and Welded
Coolant Medium	Salt Service Water

<u>TBCCW Filter</u>

Quantity	1
Type	Cylindrical Fiber Filter Cartridges
Code	ASME Section VIII Division 1 Vessel
Vessel Rated Temp/Press	150 psig at 450°F
Flow	7 to 25 GPM
Filtrate Particle Size	> 5 micron

Figure 10.6-1 has been removed.

Please refer to BECo Controlled Drawing M 216 .

10.7 SALT SERVICE WATER SYSTEM

10.7.1 Safety Objective

The safety objective of the Salt Service Water (SSW) System is to provide a heat sink for the Reactor Building Closed Cooling Water (RBCCW) System under transient and accident conditions.

10.7.2 Safety Design Basis

1. The system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective.

2. The system is designed to continuously provide a supply of cooling water to the secondary side of the RBCCW heat exchangers adequate for the requirements of the RBCCW under transient and accident conditions.

10.7.3 Power Generation Objective

The power generation objective of the SSW System is to provide a heat sink for the RBCCW System and the Turbine Building Closed Cooling Water (TBCCW) System during planned operations in all operating states.

10.7.4 Power Generation Design Basis

The system is designed to function as the ultimate heat sink for all the systems cooled by the RBCCW and TBCCW during all planned operations in all operating states by continuously providing adequate cooling water flow to the secondary sides of the RBCCW and TBCCW heat exchangers.

10.7.5 Description

The entire SSW System shown on Figure 10.7-1 is designed in accordance with Class I criteria, and there is no Class II Seismic piping in the system. See Appendix C and Section 12.

The Service Water System consists of five vertical service water pumps located in the intake structure, and associated piping, valving, and instrumentation. The pumps discharge to a common header from which independent piping supplies each of the two cooling water loops, each loop consisting of one Reactor Building and one Turbine Building cooling water heat exchangers. Two division valves are included in the common discharge header to permit the SSW System to be operated as two independent loops. The water then returns to the bay from the outlet of the heat exchangers. The heat exchangers are valved such that they can be individually backwashed without interrupting system operation. Any marine growth occurring in the heat exchangers will be controlled by hypochlorination based upon residual chlorine content measured in the discharge headers.

Sample valves have been installed in each of the independent cooling water loops, between the pumps and the heat exchangers. These valves are to be used for the following purposes:

1. To obtain a grab sample of service water.

2. To provide access to the header for venting

Each service water pump has an automatic air vent to prevent water hammer. Pump bearings are marine cutlass type, suitable for sea water application and are lubricated by water as it rises through the pump column.

The following number of pumps will be used during each of the indicated modes:

	Number of Pumps
Normal Operations	1 to 4
Accident Conditions (LOCA)	2
Shutdown Conditions	4

The number of pumps required for normal operation is selected based on plant cooling needs and SSW inlet temperature. Pressure transmitters mounted at the discharge header provide indication in the control room to allow operators to monitor SSW pump performance.

Plant Technical Specifications originally described the minimum required SSW pump performance as 2700 gpm at 55 ft TDH. Actual SSW pump rated performance is 2700 gpm at 95 ft TDH and minimum required performance for in-service testing is defined as 2700 gpm at 87.5 ft TDH. These TDH values are for the pump bowl not including the 40 ft vertical pump column. The 55 ft value represents the minimum required pressure, in feet, measured at the centerline of the pump discharge piping (EL 23.9 ft) for a pump bowl operating at 2700 GPM at 87.5 ft TDH.

The sea water tide level used in accident analysis calculations is 7.1 ft below msl, the yearly astronomical minimum low tide. This is the value used for the design basis analysis of the minimum SSW system performance required to perform the emergency containment cooling function. This low tide occurs for short periods of time during the semidiurnal tidal variations once every year. For the SSW system performance analysis, this lowest tide level is assumed to be constant, thereby yielding a conservatively low SSW system flow rate during accident analyses that span a several day period. The SSW pumps are also assumed to be operating at their minimum performance thereby providing only the required 4500 gpm to the RBCCW heat exchanger.

The minimum sea water level for maintaining SSW pump rated performance is approximately 13 feet 9 inches below msl. This represents the lowest sea water at which a SSW pump bowl operating at its rated performance of 95 feet TDH at 2700 gpm will produce a discharge head of 55 feet at 2700 gpm as measured at EL 23.9 feet. The lowest postulated instantaneous sea water level is 10.1 feet below msl(Section 2.4.4.2) caused by a hurricane producing 110 mph winds blowing directly offshore during the same critical hour at which the yearly astronomical low tide occurs. At this lowest water level, the pumps are capable of maintaining rated performance which implies that they have adequate NPSH and submergence (to prevent vortexing). It is not appropriate to assume that this condition will exist long enough to require that it be the design basis for the long term emergency cooling function of the SSW system for which these pumps are assumed to be at their minimum required performance level.

The buried portions of the 22″ nominal diameter discharge piping from the last flange connections in the Auxiliary Building piping vault to the end of the discharge pipes at the Seal Well opening have been provided with a Cured-In-Place-Pipe (CIPP) lining. The 240 ft total length Loop "A" lining was installed in RFO-14 and the 225 ft total length "B" lining was installed in RFO-13. The CIPP liner material consists of a tube composed of nonwoven polyester felt material that is saturated with either an isophthalic polyester resin and catalyst system (Loop "A") or epoxy resin and hardener system (Loop "B") with a polyurethane or polyethylene inner membrane surface. The liner has a nominal 1/2″ installed thickness. The resulting configuration is a rigid resin composite pipe within the original pipe with no requirements for bonding between the pipes.

The Salt Service Water System is designed to provide a heat sink for the Reactor Building Closed Cooling Water System under accident and transient conditions. Section 14.5 describes the Containment Cooling System analysis for a design basis loss of coolant accident (LOCA) at both a salt water inlet temperature of 65°F and 75°F.

Modifications have been made to help improve salt service water pump reliability and to allow greater maintenance and operational flexibility within the salt service water east and west bays. Flow conditions have been improved by the addition of a rear sluice gate at the opening in the common wall separating the east and west salt service water bays, and by the addition of baffle plates in the west salt service water bay. Restraints have also been installed to stabilize each service water pump column. Salt service water pump design functions can be accomplished with the rear sluice gate either in the open or closed position, and with or without baffle plates or pump column restraints.

To ensure that sufficient seawater flow is maintained through the RBCCW heat exchangers (minimum of 4500 gpm for each heat exchanger), motor-operated butterfly valves on the TBCCW heat exchanger outlets will automatically adjust to preset throttling positions and the RBCCW outlet valves will simultaneously open. Automatic adjustment of the outlet valves occur following a loss of coolant accident (LOCA) with a coincident Loss of Offsite Power (LOOP), or a LOCA with degraded voltage on the safety buses while being supplied from the startup transformer. If a LOCA occurs without a LOOP or degraded voltage condition, the heat exchanger outlet valves remain as-is. Manual adjustments of the outlet valves will be made by operators to achieve adequate cooling water flow.

The loss of AC power will trip all service water pumps and will close one of the two division valves in the common pump discharge header, effectively dividing the service water system into two independent loops. Two pumps would be connected to each loop. The two division valves are arranged to permit the fifth (middle) pump to be operated on either loop. The operator preselects the division valve to be closed and thereby determines which loop will be connected to the middle pump. Either valve can also be closed by a hand switch.

For the limiting design basis emergency condition, the Circulating Water System pumps (Section 11.6) are not operating. This assumption is based on the need for the containment heat removal function of the SSW System versus the Circulating Water System when the Main Condenser is not being used as the heat sink. For either emergency containment heat removal or normal shutdown cooling, the SSW System is the main heat sink for the reactor core decay heat only after the discharge of steam to the Main Condenser has stopped. For the bounding design basis LOCA (Section 14.5), it is only the RHR, RBCCW, and SSW Systems that provide containment heat removal. To maximize the containment heat removal from a single loop of these systems, when required, the circulating water pumps are secured so that the level in the SSW pumps bay(s) will be equal to the ocean tide level and unaffected by operation of the Circulating Water System.

There are a number of single failures that can result in a SSW System configuration where one SSW pump will be supplying flow to both trains of SSW during the first ten minutes of an accident. Should this occur, operators are then expected to align the SSW System for optimal performance by starting additional pumps and/or closing division valves as required. This mode of operation has been analyzed and determined to be acceptable.

The pumps are separated into two loops electrically. In the event of the loss of the preferred AC power source, the two SSW pumps on loop A are powered by diesel generator A. They provide cooling to RBCCW loop A (also powered by diesel generator A) which provides cooling to all Core Standby

Cooling System components loaded on diesel generator A. The two salt service water pumps on loop B have the same relationship, both to their standby AC power source, diesel generator B, and to RBCCW Loop B. The fifth pump is loaded on a common emergency service bus which can be powered from either standby AC power source.

Initiation of standby AC power following loss of the preferred AC power source will automatically start at least one pump in each loop during normal conditions. Following a LOCA and loss-of-offsite power one and only one pump will start in each loop because of diesel load limitations. Additional pumps are started manually by the operator as additional cooling loads are established and diesel capacity is made available.

10.7.6 Safety Evaluation

The SSW System is designed with sufficient redundancy so that no single active system component failure nor any single active component failure in any other system can prevent it from achieving its safety objective. Two independent closed loops with full heat transfer capacity on each loop are provided.

The existence of single failures which place the SSW system in the mode of one pump supplying both trains of heat exchangers for the first ten minutes of an accident has been analyzed and found to be acceptable. Operator action is credited after ten minutes to realign the system for optimal performance.

The 22 inch discharge headers leave the Reactor Building at an elevation of 15 ft 7 in msl. The two parallel lines run approximately parallel to the shoreline with a 2.8 percent slope. At a point approximately in line with the edge of the intake structure the lines turn and then parallel the centerline of the discharge structure with a 1.98 percent slope. At an elevation of -6 1/2 ft msl the two discharge lines turn and enter the side of the discharge structure sealwell.

Detection of leakage in the Reactor Building auxiliary bay is provided by two water level detectors mounted in each area. The detectors provide control room personnel with early indication of flooding such that personnel can be dispatched to the area to identify the source and effect isolation.

Dewatering of a major pipe rupture is accomplished by two 14 inch drain lines in each area which direct the water to the torus compartment. The discharge of the drain lines is submerged in a water trough to ensure that a sufficient water seal exists between the torus compartment and the Reactor Building auxiliary bay. The drain line dewatering capacity is sized on the maximum possible flooding rate which results from a single failure in any one line.

Numerous small diameter floor drains in the RBCCW compartments are plugged to prevent chloride and nitrate intrusions in radwaste. Therefore, normal leakage can accumulate to a level of four inches before overflowing the lip around the fourteen inch dewatering lines located in each of the RBCCW compartments. All safety related equipment in the RBCCW compartments will be unaffected by flooding four inches above the floor level. Normal leakage will not prevent safety related systems or components from performing their intended safety functions.

A major pipe break in this area will not result in a loss of both RBCCW and TBCCW Systems because the redundant portions of each system are separated by a watertight barrier. The watertight barrier consists of a watertight door and a spray barrier. The spray barrier is located in the pipeway immediately above the watertight door. Position switches provide station personnel with status information for the watertight door at all times.

In order to evaluate Pilgrim Station's susceptibility to damage due to a major oil spill in Cape Cod Bay near the Pilgrim Nuclear Power Station, previous oil spills have been examined relative to power plant and industrial proximity to the spill and the effects observed. Additionally, the various mechanisms by which spilled oil can be transported in water have been analyzed relative to the station design. The basis for these comparisons was Systems Study of Oil Cleanup Procedures (Dillingham Corporation, 1969) and the American Petroleum Institute (API) Conference on Prevention and Control of Oil Spills (December 1969).

Floating oil would be prevented from entering the intake structure by various devices. The primary oil containment device of the intake structure is its entrance skimmer wall, which functions as a submerged baffle. Minimum submergence of the baffle is 5 ft at design low water level. A secondary oil containment device is a concrete baffle wall inside the intake structure, downstream from the trash racks and upstream of the traveling screens and pumps. This baffle provides 2.2 ft submergence at mlw level. The final and most effective oil containment devices in the intake structure are the sluice gates through which the service water pump suction water must flow. The sluice gates are designed to allow isolation and dewatering of either circulating water bay. Positioning of the gates halfway closed would allow effective baffling to a submergence of 5 ft at design low water level.

In the unlikely event of some oil penetrating the aforementioned barriers, the minimum submergence at design low water level of the service water pumps of 11 ft would prevent the oil from being drawn into the pump suction.

Should slight amounts of emulsified oil reach the salt service water pump suction the observable effects would be limited to a small decrease in pumping efficiency and higher system head losses due to slightly increased fluid viscosity.

10.7.7 Inspection and Testing

Testing is performed on the SSW pumps, safety related check valves, and all safety related motor and air operated valves in the SSW system in accordance with the In-Service Testing (IST) program. The testing is performed per the ASME code as required by 10 CFR 50.55a(f), to demonstrate compliance with plant technical specifications for the SSW pumps. Operational performance testing is also conducted on the SSW system to verify that the system meets design criteria. Examinations are conducted on SSW system components in accordance with the In-Service Inspection (ISI) program.

10.7.8 Nuclear Safety Requirements for Plant Operation

General

This section represents the nuclear safety requirements for the SSW System for each BWR operating state which result from the station wide BWR systems analysis of Appendix G. The following referenced portions of the safety analysis report provide important information justifying the entries in this section:

	Reference	Information Provided
1.	Section 10.7.5	Description of the SSW System hardware
2.	Station Nuclear Safety Operational Analysis, Appendix G	Identifies conditions and events for which SSW System action is required

Each detailed requirement in the following analysis is referenced, if possible, to the most significant station condition originating the need for the requirement by identifying a matrix block on Table G.5-3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" section. The matrix block references identify the BWR operating state, the event number and the system number. For example, F39-99, identifies BWR operation state F, event (row) No. 39, and system (column) No. 99, on Table G.5-3.

System Action

The SSW System provides a heat sink for the RBCCW System.

Number Provided by Design

This system consists of two open loops. Each loop has two pumps (plus a common spare), piping, valving, instrumentation, and controls as necessary to provide coolant to one RBCCW heat exchanger and one TBCCW heat exchanger on each loop.

Minimum Required for Action

BWR Operating States A, B, C, D, E, & F:
Two pumps with associated controls and instrumentation on one loop must be operable and the following valves on that loop operable:

1. One TBCCW heat exchanger outlet valve unless valve is throttled
2. One RBCCW heat exchanger outlet valve unless valve is open
3. One discharge header valve (for loop separation unless valve is fully closed

(A35-99)	(B35-99)
(C39-99)	(D39-99)
(E39-99)	(F39-99)

10.7.9 Current Technical Specifications

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

Figure 10.7-1 has been removed.

Please refer to BECo Controlled Drawing M212.

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).

There are fire wraps for some safe shutdown raceways routed in certain areas as follows:

- "B" Switchgear Room - Enclosures #1 and #2, three hour rated.
- Cable Spreading Room - Enclosure #3, one hour rated.
- Torus Room (Bay 15) - Fire Wrap, one hour rated for instrumentation raceway M994.
- Control Room, Shift Managers Office - Fire Wrap, Three hour rated for raceway A-260.

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.

Isolation for other components and systems is achieved by manual tripping of switchgear breakers and MCC breakers such that components which are not required to change status between "Normal" and "Shutdown" conditions will not be affected by faults in their control circuitry.

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. One 2000 gpm and one 2500 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 one pump starts and delivers at least 2000 gpm and one pump 2500 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.

<u>ACTION</u>: 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: Approximately 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.

4. Fire barrier enclosures and fire wrap systems: Each fire barrier enclosure and fire wrap system will be visually inspected for integrity once each operating cycle.

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.

TABLE 10.8-1

FIRE DETECTION INSTRUMENTS

Building Fire Area	Elevation	Local Panel No./ Zone No.	Total No. Detectors In Zone	Minimum[1] Instruments Operable In Zone
Reactor Building Clothes Change Area	91'3"	C225/5C2	2	1
Reactor Building RBCCW "A"	3'0"	C222/2A	11	6
Reactor Building RBCCW "B"	3'0"	C222/2B	13	7
Reactor Building Recirc. Pump M.G. Set Room	51'0"	C96/A/B	8	4
Turbine Building Switchgear Room "A"	37'	C94/3	11	6
Turbine Building Switchgear Room "B"	23'	C221/1B C94/2	7 13	4 7
Turbine Building Battery Room "A"	37'	C94/7	3	2
Turbine Building Battery Room "B"	23'	C94/8	3	2
Off Gas Retention Building	23'	C113/1 Outside vault Inside vault	4 2	2[2] 1

1 No more than two (2) adjacent detectors shall be out of service.
2. Only 2 of the 4 detectors outside of the charcoal vault need to be operable, and 1 of 2 in the vault

TABLE 10.8-1 (Cont)

FIRE DETECTION INSTRUMENTS

Building Fire Area	Elevation	Local Panel No./ Zone No.	Total No. Detectors In Zone	Minimum* Instruments Operable In Zone
Control Room Cabinets	37'	C94/6	1	1
		C221/1C	3	2
		C221/1D	3	2
		C221/1E	3	2
		C221/1F	3	2
		C221/1G	3	2
		C221/1H	3	2
		C221/1I and 1J	5	3
Vital M.G. Set Room	23'	C221/1A	5	3
Reactor Building RHR - Core Spray "A"	(-)17'6"	C224/4A	3	2
Reactor Building RHR - Core Spray "B"	(-)17'6"	C223/3C	3	2
Reactor Building HPCI	(-)17'6"	C223/3D	2	1
		C223/3E	2	1
Reactor Building RCIC	(-)17'6"	C223/3A	2	1
		C223/3B	2	1
Reactor Building CRD - East	23'	C224/4E	12	6
		C224/4F	7	4
		C224/4C	9	5
		C224/4D	9	5
		C224/4G	5	3
		C224/4H	2	1

*No more than two (2) adjacent detectors shall be out of service.

TABLE 10.8-1 (Cont)

FIRE DETECTION INSTRUMENTS

Building Fire Area	Elevation	Local Panel No./ Zone No.	Total No. Detectors In Zone	Minimum* Instruments Operable In Zone
Reactor Building CRD - West	23'	C223/3F	10	5
		C223/3J	9	5
		C223/3G	10	5
		C223/3H	11	6
		C223/3I	2	1
Reactor Building	51'	C225/5A1	18	9
		C225/5A2	6	3
		C225/5A3	2	1
		C225/5A4	4	2
Reactor Building Fuel Pool Heat Exchanger Area	74'3"	C225/5B2	8	4
Reactor Building North Side	74'3"	C225/5B1	18	9
		C225/5B3	2	1
Reactor Building Standby Liquid Control System Tank Area	91'3"	C225/5C3	6	3
Reactor Building	91'3"	C225/5C1	25	13

* No more than two (2) adjacent detectors shall be out of service.

TABLE 10.8-2

FIRE HOSE STATIONS

REACTOR BUILDING

Sta. #	
RB-13-117	North Wall, Elev. 117'
RB-06-117	South Wall, Elev. 117'
RB-12-91	North Wall, Elev. 91'
RB-05-91	Standby Liquid Control, System Area, Elev. 91'
RB-11-74	North Wall, Elev. 74'
RB-04-74	Fuel Pool Heat Exchanger Area, Elev. 74'
RB-09-51	North Wall, Elev. 51'
RB-03-51	Outside MG Set Room - West Wall, Elev. 51'
RB-10-51	Inside North MG Set Airlock Elev. 51'
RB-14-23	Decontamination Room North Wall, Elev. 23'
RB-07-23	West Wall, RHR Loop B Stairway, Elev. 23'
RB-02-23	West Wall, RCIC Stairway Elev. 23'
RB-16-23	Reactor Bldg. Access Lock Elev. 23'
RB-15-03	CRD Quadrant Elev. 2'9"
RB-17-03	RHR Quad Loop A Elev. 2'9"
RB-01-03	RCIC Quad Elev. 2'9"
RB-08-03	HPCI QUAD Elev. 3'-0"

SECONDARY CONTAINMENT ACCESS LOCK

Sta. #	
SL-81-23	Reactor Bldg. Truck Lock Elev. 23'

REACTOR AUX. BAY

RA-41-23	Auxiliary Plant Heating Boiler Room Elev. 23'
RA-43-06	RBCCW Loop B Area Elev. 3'
RA-44-06	Condensate Demin./Resin Corridor Area Elev. 3'

RADWASTE & CONTROL AREA

RC-57-01	Radwaste Stairway to Turbine Bldg. Elev. -1'
RC-69-01	Outside Radwaste Control Room Elev. -1'
RC-56-23	Water Box Scavenging Pump Area, Elev. 23'
RC-58-23	Stairway Outside Vital MG Set Room Elev. 23'
RC-72-23	Corridor Switchgear Room B Elev. 23'
RC-71-51	East Wall Near B-8 Load Center Elev. 51'

TABLE 10.8-2 (Cont)

FIRE HOSE STATIONS

TURBINE BUILDING

Sta. #	
TB-35-06	West End Elev. 6'
TB-29-06	East Wall Elev. 6'
TB-31-51	South Wall Elev. 51'
TB-34-51	West Wall Elev.51'

TURBINE AUX. BAY

TA-86-51	Outside Standby Gas Room

OFF-GAS RETENTION BUILDING

OR-91-23	Retention Building, Elev. 23'
OR-93-05	Retention Building, Elev. 5'

DIESEL GENERATORS

DG-46-23	Diesel Generator Room A
DG-47-23	Diesel Generator Room B

INTAKE STRUCTURE

IS-96-23	Near Fire Pumps

RADWASTE & CONTROL AREA (Continued)

RC-59-37	Stairway Outside Control Room Elev. 37'
RC-66-37	Radiation Chemical Lab Elev. 37'

Figure 10.8-1 has been removed.

Please refer to BECo Controlled Drawing M218.

10.9 HEATING, VENTILATION, AND AIR CONDITIONING SYSTEMS

10.9.1 Power Generation Objective

The power generation objective of the Heating, Ventilation, and Air Conditioning (HVAC) systems is to control the station air temperatures and the flow of airborne radioactive contaminants to ensure the operability of station equipment, and the accessibility and habitability of station buildings and compartments.

10.9.2 Power Generation Design Basis

The HVAC systems:

1. Provide temperature and humidity control and air movement for personnel comfort and optimum equipment performance

2. Provide a sufficient filtered fresh air supply for personnel

3. Provide for air movement from lesser to progressively greater areas of radioactive contamination potential prior to final exhaust

4. Minimize the possibility of exhaust air recirculation into the air intake

10.9.3 Description

10.9.3.1 General

The HVAC systems provide individual air supplies to main areas of the station. Normal airflow is routed from lesser to progressively greater areas of radioactive contamination potential prior to final exhaust.

Most of the heating and ventilating systems utilize 100 percent outside air with no recirculation. All inlet air can be temperature controlled with heating coils.

Air from areas containing potential sources of radioactive contamination such as the Reactor Building, Radwaste Building basement, Turbine Building basement, and Radwaste Heating and Ventilation Building are discharged through the building exhaust vent. Air from other areas is discharged at building roof levels.

The Equipment Area Cooling System (EACS) is described in Section 10.18. Main control room heating, ventilation, and environment control are described in Section 10.17.

10.9.3.2 Station Heating System

The station is heated during plant operation by a forced circulation, hot water system. See Figures 10.9-1 and 10.9-2. The system consists of two package boilers, five hot water circulating pumps, two fuel oil transfer pumps, two 25,000 gal fuel storage tanks, one compression tank and associated piping, valves, combustion controls, and instrumentation.

Heating system water is heated by two oil-fired package boilers. The boilers are located in the Reactor Building auxiliary bay. The hot water boilers are each rated at 16.7 X 10^6 Btu/hr at 125 psig, utilizing No. 2 diesel fuel oil.

The station heating system utilizes a low temperature (210°F max.), two pipe, forced circulation hot water system. System water temperature is automatically controlled based on outside air temperature. Water at temperatures adequate to maintain space temperatures is provided to unit heaters located throughout the station.

Three main system circulating pumps, each sized for one-half of the total design flow rate, provide continuous flow throughout the system. Normally, two run with one standby. Two booster pumps sized for full Turbine Building hot water coil capacity will provide additional capacity during low temperature periods. One pump runs with one pump a standby. The main heating piping headers are cross connected to allow isolation of either boiler when their use is not required. The auxiliary boilers and circulating pumps will be accessible for maintenance.

Heating system water temperature control is provided by a three-way mixing valve located in the hot water supply line on the suction side of the heating system circulating pumps. The actuating device for the three-way valve is an outdoor air sensing element controlling the position of the valve mixing unit to blend boiler supply and return water. This varies system water temperature inversely with outdoor temperature to reduce fluctuations in space temperatures as demand varies. During mild weather periods the boilers have a reduced flow; however, the heating input is reduced proportionately. The auxiliary boiler water temperature is controlled by a temperature insertion element controlling a modulating oil burner metering assembly.

Heating and ventilating equipment hot water coils have constant flow during pump operation. Leaving air temperature is controlled by an air temperature sensor modulating face and bypass air dampers.

Air conditioning fan unit hot water coils leaving air temperatures is controlled by a three-way valve located in the return line. Unit heaters have constant flow through their coils at all times during pump operation. Space temperatures are controlled by a space thermostat controlling the unit heater fan motor.

Winter design temperatures for the system are given on Table 10.9-1 and summer design temperatures are given on Table 10.9-2.

10.9.3.3 Reactor Building Heating and Ventilation System

The Reactor Building is divided into three major ventilation zones. One zone encloses the spaces above the operating (refueling) floor. The second zone encloses the recirculation pump motor generator sets and the third zone encloses the remainder of the Reactor Building. Each zone is served by its own air supply and exhaust system in order to maintain the independence of the zones. See Figure 10.9-3. The systems for the first and third zones employ once-through ventilation without recirculation. The design basis summer maximum temperatures are area specific (See Table 10.9-2).

The operating floor ventilation zone is normally supplied with 30,000 ft^3/min of filtered and tempered outside air which enters the Reactor Building through louvers in the east wall. Two supply fans, each rated at design capacity, are located in the Reactor Building in a fan room. The fans are manually started. For normal operation one fan runs while the other fan is on standby. However, both fans can be operated in parallel to provide additional ventilation during refueling operations. If the operating fan fails during normal operations, the standby fan starts automatically and an alarm is received in the main control room. Air is exhausted from the operating floor through ducts located in the roof truss area and the south wall area adjacent to the floor. Additional exhaust ducts are located above the water level in the fuel pool, steam dryer, and separator pool, and in the reactor cavity. Two operating floor exhaust fans, each rated at design capacity, are located in the main fan room outside the Reactor Building. These fans discharge into the main exhaust plenum at the base of the building vent. The building vent is square in cross section extending from the top of the main exhaust plenum to the discharge point at elevation 182 ft msl.

The zone enclosing the recirculation pump motor generator sets is normally supplied with 50,000 ft^3/min of filtered outside air or recirculated air. Outside air enters through louvers in the west wall. Two supply fans, each rated at design capacity, are manually started. For normal operation one fan runs with the other as standby. Both fans can be operated in parallel to provide additional ventilation if required. If the operating fan fails, the standby fan starts automatically, and an alarm is received in the main control room. Two exhaust fans, each rated at design capacity, recirculate or exhaust zone air. Exhaust air is discharged through louvers in the north wall. Temperature control is provided by an air temperature sensor modulating the supply, exhaust, and recirculation dampers. Supplementary cooling for summer conditions is provided by unit coolers supplied by the Reactor Building Closed Cooling Water (RBCCW) System. Four unit coolers, each rated at half design capacity, are installed. Unit heaters are installed to provide zone heating during winter shutdown conditions. The heaters are supplied by the station heating system.

The remainder of the Reactor Building is supplied with a total of 60,000 ft^3/min of filtered and tempered outside air which enters the Reactor Building through louvers in the east wall into two fan rooms. Each fan room contains two supply fans rated at design capacity. Each fan is capable of supplying 30,000 ft^3/min of air to various reactor building areas. The fans are manually started, and for normal operation, one fan in each fan room runs while the other fan is at standby. If the operating fan fails during normal operations, the standby fan starts automatically, and an alarm is received in the main control room.

The air supplied to the Reactor Building from the two operating supply fans is routed through the building to areas of progressively higher contamination potential. Air exhausted from areas of higher contamination potential (contaminated area exhaust) is routed independently of the exhaust from areas of expected lesser contamination (clean area exhaust).

Two contaminated area exhaust fans, each rated at design capacity, are located in the Reactor Building. The fans discharge to the main exhaust plenum at the base of the building vent. An additional smaller exhaust fan located in the Reactor Building, exhausts only from the control rod drive maintenance shop, and discharges to the main exhaust plenum. Constant volume control is maintained by inlet vanes which are automatically positioned.

All the Reactor Building supply fans are electrically interlocked with their corresponding exhaust fans and run only when their associated exhaust fans are operating.

10.9.3.4 Turbine Building Heating and Ventilation System

The Turbine Building air flow diagram is shown on Figure 10.9-4.

10.9.3.4.1 General

The Turbine Building Ventilating System supplies filtered air to all areas of the Turbine Building and is routed to areas of progressively greater radioactive contamination potential prior to final exhaust.

The ventilation system supplies filtered and tempered outdoor air to the operating floor and all other areas below the operating floor. The main condenser area is maintained at a slightly negative pressure to prevent the spread of radioactive contaminants to the adjacent operating areas.

The exhaust air from the Turbine Building operating floor and switchgear areas is discharged to the atmosphere through exhaust fans located on the Turbine Building roof. The exhaust air from the reactor feedwater pump area will be discharged to atmosphere through exhaust fans located on roof above. The exhaust air from the condenser compartment and other adjacent potentially contaminated areas will be discharged through the building vent. The exhaust air from the battery rooms and lube oil compartments will be discharged

by independent exhaust fans located on the turbine building operating floor through ductwork to the turbine building roof.

The condenser and condensate pump compartments depend on fan coil cooling units to supplement the main ventilation system when outside air temperatures are above 60°F.

An independent switchgear room emergency ventilation system (SREVS) is provided for each of the two switchgear rooms (i.e. switchgear and battery rooms). This system provides a safety-related source of ventilation to maintain a mild environment for safety-related equipment in the event the normal turbine building ventilating system is not available.

10.9.3.4.2 Main Turbine Building Ventilation Supply Fans

There are three main turbine building ventilation supply fans, each of half capacity. Under normal operating conditions two fans are running, with one at standby. The fans are shut down in the event of loss of offsite power. During normal operations, any two fans are started. If an operating fan fails, a flow switch will sense a reduction of pressure and annunciate in the main control room. The standby fan is then started manually. If the fan discharge air temperature drops below 40°F, a temperature switch will stop the fans and annunciate in the main control room.

Heating coils are provided to heat the outside supply air when necessary. The supply air temperature is controlled by modulating the amount of air flow over the heating coils with face and bypass dampers. Hot water flow to the heating coils is constant. The supply air volume is constant, with no recirculation. Outside air dampers are heated with resistance cable to prevent freezing. Constant volume is maintained by inlet vanes which are positioned automatically.

10.9.3.4.3 Turbine Building South Wall Ventilation Louvers (Operating Floor Level)

There are 3 louvered openings in the south wall of the turbine operating floor. Each is 5' x 6', and they were originally designed to provide additional cooling for the operating floor during unusually warm weather. The unit on the west side has been permanently blocked off and the other two dampers are normally closed but can be manually opened if needed.

10.9.3.4.4 Turbine Building Basement Exhaust Fans (Condenser Compartment)

There are three half capacity turbine building basement exhaust fans which discharge to the building vent. The fans are shut down in the event of loss of offsite power. The fans are started manually. If an operating fan fails, a flow switch will sense a reduction of pressure and annunciate in the main control room. The operator will then start the standby fan manually. Constant volume control is maintained by inlet vanes which are automatically positioned. The

air volume exhausted by the fans is sufficient to maintain a negative pressure relative to all adjacent areas.

10.9.3.4.5 Turbine Building Operating Floor Exhaust Fans

Nine direct drive fans (two are spares) are located on the roof, and seven run during normal operation. The fans are shut down in the event of loss of offsite power. The fans are manually started. Fan motor malfunction is annunciated in the main control room.

10.9.3.4.6 Lube Oil and Battery Room Exhaust Fans

Two full capacity fans are installed which exhaust to the turbine building roof. The fans are shut down in the event of loss of offsite power. The fans are manually started. If the operating fan fails, a flow switch will sense a loss of pressure and automatically start the standby fan and annunciate in the main control room. In order to detect fire damper failures, additional flow switches are provided to sound an alarm in the control room upon loss of flow in each battery room exhaust system. Constant volume control is automatically maintained by the inlet vanes.

10.9.3.4.7 Condensate Pump Room Unit Coolers

Two full capacity fan unit coolers are installed. The units are shut down in the event of loss of offsite power. The fans are manually started. If the operating fan fails, a flow switch senses reduction of pressure, automatically starts the standby unit, and annunciates in the main control room. A temperature element (with local transmitter) is located in the discharge of each unit to give temperature indication on the Turbine Building HVAC control panel C-60. Cooling water supply is from the turbine building closed cooling water (TBCCW) system.

10.9.3.4.8 Condenser Compartment Unit Coolers

Six unit coolers (two are standby) are installed in the condenser compartment and are supplied with cooling water from the TBCCW System. The fans are started manually. High compartment temperature will alarm in the main control room and a standby unit is manually started. The leaving air temperature is adjusted by regulating the flow of cooling water to each unit cooler.

10.9.3.4.9 Off-gas Retention Building

The off-gas retention building is supplied 5400 CFM of air from the Turbine Building HVAC System and 100 CFM of air from process air systems. This is all exhausted back to the turbine building HVAC system (refer to Figure 10.9-5).

<u>Off-gas retention building unit coolers</u>

Three 2 horsepower unit coolers handle air received by the retention building. One cooler provides 3060 CFM to the operating floor and control room and utilize the TBCCW system as a heat sink. The other two (one is standby) provide 2340 CFM to the charcoal vault (refer to Figure 10.9-5).

Off-gas retention building exhaust fans

Two 5500 CFM exhaust fans (one is standby) draw air from the charcoal vault filters, equipment room, operating floor, process vents and drains, and other building sources to the Turbine Building HVAC System (refer to Figure 10.9-5).

10.9.3.4.10 Off-gas Retention Room Unit Coolers

Each off-gas recombiner room contains a 5000 CFM unit cooler which circulates and cools room air. These units utilize the TBCCW system as their heat sink.

10.9.3.4.11 Switchgear Room Emergency Ventilation System

Each switchgear room emergency ventilation system (SREVS) is a safety related system that consists of an inlet plenum, fan, a backdraft damper at the fan discharge, ductwork, and associated instrumentation and controls. Each system penetrates the east wall of the turbine building and takes suction from the outside environment. The SREVS discharges outside air into the switchgear room creating a slightly positive pressure in the associated switchgear room. Outlet air from each switchgear room discharges to the turbine building through penetrations in the south wall of switchgear room. Backdraft dampers are installed at these wall penetrations to prevent reverse airflow from the turbine building into the switchgear rooms. The SREVS is designed to start automatically upon high switchgear room temperature and automatically shuts down on low temperature. Each system may be started manually by placing the control switch in the start position. The systems are powered by Class 1E sources and will operate with a loss of offsite power.

10.9.3.5 Radwaste Building Heating and Ventilating System

Radwaste area air flow diagram is shown on Figure 10.9-5 (BECo M290).

10.9.3.5.1 General

The radwaste building heating and ventilating system maintains required space temperatures, provides adequate ventilation to remove heat rejected from operating equipment compartments, and provides adequate supply and exhaust to maintain the direction of air flow from lesser to increasingly greater areas of potential radioactive contamination. Exhaust hoods with negative pressure are provided at locations where, under normal operation, contaminants could escape to the surrounding areas. A pipe manifold vent system is provided for expected contaminated tanks and equipment. Filtered and tempered air is supplied to all personnel occupancy areas, the monitor tank compartment, and treated waste holdup tank areas in sufficient quantity to maintain space temperatures and ventilation. The air is supplied through ductwork by two full capacity air handling units, (one is normally running and one is a standby).

Exhaust air from the contaminated equipment tank cells, the vent pipe manifold, and the baling machine area, and other ventilation system exhausts are routed through the two banks of exhaust air filter assemblies and discharged to the building vent.

10.9.3.5.2 Radwaste Heating and Ventilating Units

Each of the two heating and ventilating units is full capacity. The fans are shut down in the event of loss of offsite power. The fans are manually started. If the normal operating fan fails, a flow switch senses a reduction of pressure and automatically starts the standby fan and annunciates in the main control room. The fan discharge air temperature is controlled by a thermostat through a limit sensor and controller which modulates the heating coil face and bypass air damper. The heating coil is supplied by the station hot water heating system. The outside air damper is heated with a resistance cable to prevent freezing.

10.9.3.5.3 Radwaste Exhaust Fans and Filters

The two exhaust fans are each full capacity. The fans are shut down in the event of loss of offsite power. The fans are manually started. If the normal operating fan fails, a flow switch senses loss of pressure, automatically starts the standby fan, and annunciates in the main control room. Constant volume is maintained by inlet vanes automatically positioned. Two half capacity filter assemblies are installed. Each filter assembly can be isolated manually. Prefilter and HEPA filter differential pressures are indicated outside the filter assembly compartment.

10.9.3.6 Access Control Area Air Conditioning

10.9.3.6.1 General

The access control area air conditioning system maintains ventilation and constant temperature and humidity in the access control area. See Figure 10.9-6. The equipment, ductwork, and controls are completely independent from other station HVAC systems. The system independence will insure uninterrupted operation during normal and shutdown modes.

The access control area is served by full capacity redundant units including dual duct (hot-cold) air conditioning units, reciprocating condensing units, and recirculation and exhaust fans.

Conditioned air is distributed through ductwork to the mixing boxes and diffusers located in the various zones. The zones independent from each other are:

Corridor

Instrument Repair

Chemical Laboratory and Counting Rooms

Frisking Area

Decon Shower

Dressing Area

H.P. Office

Chemical Lab Expansion

Undressing Area

Air is recirculated from the instrument repair room only. All the other rooms will be kept at a positive pressure with respect to the chemistry laboratory, thus allowing air to infiltrate from the lobby in the upper level into the chemistry laboratory. The exhaust from the laboratory fume hoods is exhausted by a booster fan through the radwaste filtering system prior to release from the building vent.

10.9.3.6.2 Access Control Area Air Conditioning Units

Two full capacity units are installed. The units are shut down in the event of loss of offsite power. The fans are manually started. If the normal operating fan fails, a flow switch will sense a loss of pressure, automatically start the standby fan, and alarm in the main control room. One full capacity air conditioning unit is provided for the H.P. Office area on El. 37'-0". The unit is shut down in the event of loss of offsite power. The unit is manually started and stopped. Space temperatures will be controlled by electric duct heaters. Each room is provided with its own thermostat for individual control.

10.9.3.6.3 Access Control Area Recirculation and Exhaust Fans

Two full capacity recirculation and two full capacity exhaust fans are installed. The fans are manually started and are shut down in the event of loss of offsite power. The exhaust fans discharge to the building vent. The recirculation fans either recirculate the air or discharge to the environment at roof level. If the normal operating fan fails, a flow switch senses loss of pressure, automatically starts the standby fan, and alarms in the main control room. Portions of the air exhausted from the counting room and H.P. counting work space is discharged into hot machine shop on El. 23'-0". The remainder of the air is returned to the air conditioning unit, mixed with outside air and redistributed to the space. The exhaust fan will shut down on loss of offsite power.

10.9.3.7 Intake Structure

10.9.3.7.1 General

The intake structure is comprised of five heating and ventilating areas: one area containing the salt service water pumps; two areas containing the condenser circulating water pumps; an area containing the fire pumps; and an area containing the hypochlorite storage tank. See Figure 10.9-6 (Drawing M292).

Exhaust fans are provided for the ventilation of each area. The salt water service pump area has redundant fan units while the other areas are served by single fans. Unit heaters are provided for heating. Air is supplied to the various areas from outside louvers. Outside air dampers are heated with resistance cable to prevent freezing of controls.

10.9.3.7.2 Service Water Pump Exhaust Fans

Two full capacity fans are installed and either fan will provide the required air flow for the pump rooms. The fans may be powered by the diesel generators. One fan is manually started, and should the operating fan fail, a flow switch senses loss of pressure, automatically starts the standby fan, and annunciates in the main control room. Temperature is maintained by manually positioned inlet vanes that are normally fully open.

10.9.3.7.3 Other Area Exhaust Fans

One full capacity fan is installed for each of the remaining intake structure areas. The fans are manually started and are shut down in the event of loss of offsite power.

10.9.3.8 Warehouse, Machine Shop, and PASS Mezzanine MCC Rooms

10.9.3.8.1 General

Filtered and temperature controlled air is supplied to the tool room, machine shop, and warehouse. See Figure 10.9-6 (Drawing M292). The air is supplied through ductwork by one air handling unit. Approximately 20 percent of the total supply air is exhausted through the exhaust hood over the decontamination trough, then into the radwaste air filtering unit. The remainder is exhausted to atmosphere through louvers at roof level.

The electrical equipment rooms containing MCCs B17A and B18A on the PASS mezzanine are each cooled by a Class 1E qualified ventilation system designed to limit the temperature to less than 104°F. The fans supporting the ventilation systems are controlled by temperature switches located in the rooms. High temperature alarms are provided to the Control Room should the system fail to control the temperatures as designed. Each system supplies outside air into its respective room to remove heat generated by the equipment in the room. These systems will operate with a loss of off site power.

The equipment, ductwork, and controls are completely independent from other HVAC Systems except for the decontamination exhaust to the radwaste area.

10.9.3.8.2 Heating and Ventilating Unit

One full capacity unit is installed. The fan unit is manually started and is shut down in the event of loss of offsite power. Fan failure is annunciated in the main control room. The supply air temperature is controlled by modulating face and bypass air dampers. Hot water flow to heating coils is supplied by the station heating system. Supply air flow is straight through with no recirculation. The outside air inlet dampers are interlocked with the supply fan and closed when the fan stops. Outside air dampers are heated with resistance cable to prevent freezing of controls.

10.9.3.8.3 Exhaust Fans

Full capacity fans exhaust the warehouse and machine shop areas and the machine shop decontamination trough. The fans are started manually and shut down in the event of loss of offsite power. If the area fan fails, a flow switch will sense a reduction of pressure and annunciate in the main control room.

10.9.3.9 Diesel Generator Building Heating and Ventilation

Each standby diesel generator room is heated by hot water unit heaters supplied by the station heating system. See Figure 10.9-3 (Drawing M289). Heating units are controlled by individual thermostats located in the vicinity of the heating units. A separate thermostat controls a supply and exhaust fan in each room to provide room cooling when the diesels are idle. The fans and their respective dampers are automatically shut down after the diesel generators start. The heating units are not interlocked with the diesel generator start or shutdown controls.

EDG cooling is provided by a direct coupled fan and radiator arrangement. During EDG operation, outside air is drawn into the building through a missile protected intake opening located on the north end of the structure. The intake air for each diesel room enters a common plenum and then flows into two parallel ducts, each of which is connected to a radiator located in the fan housing at the south end of the EDG room.

Dampers VD-206A-D are located at the inlet to each parallel duct run at the connection to the common inlet plenum. These dampers have two modes of operation. In the summer they are maintained closed and the cooling air is directed through the engine room via openings VD-215A/B and VD-216A/B in the common inlet plenum. This alignment maximizes the air flow through the engine room to maintain the temperature below the design limit. In the winter the manual openings are closed and VD-206A-D open when the EDG starts to direct the cooling flow to the radiators via the parallel ducts.

A supplemental fresh air intake provides air directly to the EDG room through dampers VD-208A/B located in a missile protected enclosure on the south end of the EDG rooms. Dampers VD-208A/B also have two modes of operation. In the summer they open to direct cooling air flow into the engine room. In the winter they are maintained closed to maintain engine room temperature above a minimum value.

The room cooling air flow is drawn from the engine room through openings in each of the parallel ducts. During the summer, air is also drawn into the fan inlet plenum through removable panels adjacent to the engine room plenum door as well as the open door. In the winter the doors are closed and the panels are installed over the openings.

Room cooling flow is also drawn from the common intake plenum duct through dampers VD-207A/B at the north end of each EDG room. Dampers VD-207A/B are also normally closed when the EDG is not running and open when the EDG is started.

All of the diesel cooling ventilation dampers are pneumatically operated and fail open on loss of air. A Class 1 backup air system, consisting of high pressure cylinders and associated tubing and valves, is provided to maintain dampers VD-286A-D closed in the summer and VD-208A/B closed in the winter should the normal instrument air system be unavailable. An additional damper air supply is provided from the diesel air start tanks. This connection is normally closed and would be available following depletion of the high pressure cylinder supply.

The EDG jacket water pump circulates the engine coolant through the radiator tubes where it transfers engine heat to the air. The engine driven fan draws suction through each of the parallel radiators and discharges the heated air through a cylindrical discharge duct which exits at the roof.

Engine freeze protection is provided by the jacket water cooling system heater which maintains the engine coolant temperature at a constant value during shutdown mode. Moreover, the engine coolant contains antifreeze in the event that coolant cannot be heated during shutdown mode.

Ventilation system ducts, dampers, fan, and controls are Class I design.

10.9.3.10 Executive Building Air Conditioning

The executive building is supplied by a hot and cold duct air-conditioning unit with air returned or exhausted by a recirculation fan. Conditioned air is distributed through ductwork to zone mixing boxes and ceiling diffusers.

During the winter, hot water baseboard convectors located along the outside walls help maintain the required temperature inside the building. Zone temperatures are controlled by a thermostat in each zone. The leaving air temperature of the heating and cooling coils is preset with conditioned air flowing to zone mixing boxes. Zone thermostats control metering valves in each mixing box to control air temperature. Base board convectors are controlled independently by a thermostatic valve in the return line to each zone.

The executive building air conditioning uses the TBCCW System as a heat sink.

10.9.3.11 Operations and Maintenance Building HVAC

The operations and maintenance building HVAC system is independent to those of the process buildings.

TABLE 10.9-1

DESIGN TEMPERATURES (WINTER)

Outdoor: 10° F Dry Bulb*

Indoor:	Minimum
Turbine Building	60° F
Reactor Building	60° F
Access Control Area	75° F BD 50% relative humidity
Administration Building	75° F BD 50% relative humidity
Radwaste Area	65° F
Diesel Generator Building**	40° F (standby), >32° F (operating)
Intake Structure***	60° F (normal) >35° F (maintenance)
Machine Shop & Warehouse Area	65° F
Fire Water Storage Tanks	45° F
Demin. Water & Condensate Storage Tanks	45° F

*The outdoor design temperature used for rating HVAC equipment is selected in accordance with guidance from the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE). The design low temperature for outdoor ambient is a value with an associated exceedance criteria, i.e., the percent of time that the value is expected to be exceeded. The design winter outdoor condition is 10° F dry bulb. The corresponding design indoor temperatures are listed for various locations. These temperatures correspond to the 97.5% exceedance values for the site location. During the winter months of December, January, and February, there will be approximately 54 hours at or below the 97.5% value based on the ASHRAE design standards. The design method conforms to conventional engineering practice. FSAR Table 2.3-15 lists (-)14° F as the extreme minimum expected outside air temperature that may occur during the months December, January, and February, while the temperature may be at or below 10° F during any of the months November through March.

TABLE 10.9-1 (Cont.)

DESIGN TEMPERATURES (WINTER)

** The design minimum temperatures for the Diesel Generator Building applies to the EDG rooms and air compressor/tank areas. These temperatures do not apply to the walk-thru plenum passageways. These passageways are part of the ventilation and cooling ductwork and are therefore subjected to outside ambient temperatures.

Note - With respect to the station fire protection systems, the design minimum temperature is 40° F in accordance with the NFPA codes to which the systems were designed.

*** The intake structure houses redundant components intended to be maintained while systems remain in service. The equipment is accessed through designed openings in the structure, allowing ambient temperatures lower than design to be reached. The equipment within the structure has been evaluated, and it remains operable down to actual temperatures of > 35° F.

TABLE 10.9-2
DESIGN TEMPERATURES (SUMMER)

Outdoor***: 88° F Dry Bulb

74° F Wet Bulb

Indoor:	Maximum
Turbine Building	105°F - 120°F
Reactor Building	See Note (1 Below)
Control Room Area	78°FDB 50% ** relative humidity
Access Control Area	78°FDB 50% relative humidity
Administration Building	78°FDB 50% relative humidity
Radwaste Area	100°F
Diesel Generator Building	105°F (Max)* - 95°F (5ft above Floor)*
Intake Structure	105°F*****
Machine Shop and Warehouse Area	105°F
Cable Spreading Room	-102°F to +76°F

NOTE 1: The following data represent the Reactor Building maximum summer design temperatures by specific location:

Location	Max. Room Temp. (°F)	Av. Room Temp (°F) 5 Feet Above Floor Level
Refueling Floor	105	95
General Floor Area	105	95
Main Steam Pipe Tunnel	135****	110
RHR/Core Spray Pump Area	115*	100*
CRD Pump Area	115	100
RCIC Pump Area	115*	100*
HPCI Pump Area	115*	100*
Cleanup Regn. & Nonregn. Heat Exchanger	115	100

* These temperatures apply only to conditions when the equipment in the area is operating. Under normal plant operation, temperature in these areas will be lower than indicated above.

TABLE 10.9-2 (Cont.)
DESIGN TEMPERATURES (SUMMER)

Outdoor***: 88°F Dry Bulb
74°F Wet Bulb

** See Section 7.1.8 for loss of HVAC conditions.

*** The outdoor design temperature used for rating HVAC equipment is selected in accordance with guidance from the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE). The design high temperature for outdoor ambient is a value with an associated exceedance criteria, i.e., the percent of time that the value is expected to be exceeded. The design summer outdoor conditions are 88° F dry bulb, 74° F wet bulb. The corresponding design indoor temperatures are listed for various locations. These temperatures correspond to the 1% exceedance values for the site locations. The 1% value would be expected to be exceeded for a total of 30 hours during the summer months (June to September) based on the ASHRAE design standards. This design method conforms to conventional engineering practice. FSAR Table 2.3-15 lists 102° F as the maximum expected outside air temperature that may occur during the months June, July, and August while 88° F may be exceeded during any of the months April through September.

**** With intermittent peaks to 140°F. Intermittent is defined as "one week per year".

***** Individual safety-related components have been evaluated and determined to be operable up to 127°F.

The following FSAR figures have been removed from the FSAR. Please refer to the corresponding BECo controlled drawing.

FSAR FIGURE	BECO CONTROLLED DRAWING
10.9-1	M236
10.9-2	M237
10.9-3	M289
10.9-4	M288
10.9-5	M290
10.9-6	M292

10.10 MAKEUP WATER TREATMENT SYSTEM

10.10.1 Power Generation Objective

The power generation objective of the makeup water treatment system is to provide a supply of treated water suitable as makeup for the station and reactor coolant cycles and other demineralized water requirements.

10.10.2 Power Generation Design Basis

The makeup water treatment system shall be designed to:

1. Provide makeup water of reactor coolant quality

2. Provide an adequate supply of treated water for all station operating requirements

10.10.3 Description

10.10.3.1 General

The makeup water system (WTM) receives supply water from the Town of Plymouth’s municipal water system and discharges filtered and demineralized water to the 50,000 gal demineralized water storage tank, T-108 (see Figure 10.10-1).

The WTM system has a flow path consisting of a three-stage Reverse Osmosis (RO) module and an Electrodionization (EDI) module. Additionally, two mixed bed resin polisher bottles are included as a backup system for the EDI module. Each RO is three vessels that each contain three semi-permeable membrane elements that separate the municipal water supply into two streams. The first is the permeate stream which has approximately 75% of the supply water flow and contains approximately 2% of the supply impurities. The second is the reject stream, which has approximately 25% of the supply and contains approximately 98% of the municipal’s impurities. The reject stream is sent to the storm drainage system. The reject stream is in compliance with the station’s NPDES permit and EPA has approved its discharge by letter dated April 18, 1990 (BECo letter 5.94.040).

The permeate stream is processed further through the EDI module. This stream will meet the quality levels established in the Chemistry program.

The RO module is manually operated. It is continuously monitored for quality by a conductivity meter with temperature compensation, inlet/outlet flow meters, a TOC analyzer, and a silicon analyzer.

In addition to the demineralized water storage tank (T-108), two 275,000 gal condensate storage tanks (T-105A/B) are provided to store and supply the necessary volume of high purity water for initial testing and cleaning, and to provide the required volume for refueling and emergency requirements (HPCI, RCIC, condensate makeup and reject).

The WTM system has a capacity to produce approximately 25 gpm of demineralized water. The PNPS annual usage is approximately 700,000 gallons which is approximately 2000 gallons per day or approximately 1.5 gpm. The WTM can fill the demineralized water tank (T-108, 50,000 gallons) in approximately 33 hours on a continuous process basis and it can fill one condensate storage tank (T-105 A or B, 250,000 gallons each) in approximately seven days.

10.10.3.2 Neutralizing Sump

All regeneration drains and floor drains in the regeneration area are routed to the neutralizing sump for pH neutralizing and filtering prior to being pumped by one of two pumps rated at 100 gal/min to the storm drain system orr to the discharge canal at the location of storm drain outtfall 005 as an alternate discharge path.

10.10.3.3 Demineralized Water Service

The demineralized water is taken from the demineralized water storage tank by one of two pumps and supplies the following services:

Condensate storage tank

Reactor building closed cooling loops - head tank makeup

Turbine building closed cooling loops - head tank makeup

Standby liquid control system

Heating system fill and makeup

Stator winding makeup

Condensate pump seal water supply (backup)

Reactor well and dryer - separator pool service

Laboratories

10.10.4 Inspection and Testing

The makeup water treatment System is an operational system in periodic use and as such does not require periodic testing to assure operability. The performance of the system is under surveillance at all times. High demineralizer effluent conductivity initiates an alarm and automatically isolates the system requiring operator action. Grab samples are periodically tested in the laboratory to verify demineralizer performance and to ascertain stored water quality.

Figure 10.10-1 has been removed.

Please refer to BECo Controlled Drawings M224 & M225.

10.11 INSTRUMENT AND SERVICE AIR SYSTEMS

10.11.1 Power Generation Objective

The power generation objective of the Instrument and Service Air Systems is to provide the station with a continuous supply of oil-free compressed air. This air is directed to station instrumentation and general station services.

10.11.2 Power Generation Design Basis

1. The Instrument Air System is designed to supply clean, dry air to station instrumentation and controls at 70 to 100 psig with a design dewpoint of -40°F at 100 psig.

2. The Service Air System is designed to provide clean air to station services at 70 to 100 psig. The Low Pressure Service Air System is designed to provide clean air at a nominal pressure of 20 psig to station services.

10.11.3 Description

10.11.3.1 General

The air systems are, in general, designed to Class II requirements, although Class I equipment requiring air under accident conditions has Class I air accumulators and piping associated with that equipment. See Figure 10.11-1.

The high pressure air supply (nominal 100 psig with allowance for drops to 90 psig) is developed by three reciprocating (iin long term layyup) and two rotary screw type air compressors operating in parallel. Each compressor has an after cooler and delivers the compressed air to a bank of receivers. There are five air receivers which are connected to a common discharge header that delivers the air to the high pressure service air system and to two instrument air dryers to provide high quality dry air to the various instrument air headers. There is one coalescing air filter located upstream of each instrument air dryer. There is one particulate air filter downstream of the instrument air dryer X-105 and dryer X-160 A&B. The downstream air filters are to ensure that no desiccant or other foreign material enters the instrument air system. There is also a bypass around the dryers and filters which can be opened by remote manual or automatic means for dryers X-105 and X-160A&B to assure a continued supply of instrument air to the essential instrument air header in the event of an air dryer failure. Normally, use of one of the two rotary compressors will maintain the air receivers at the desired pressure for system supply. The remaining compressors serve as standby units. Actuation of the standby units is automatic and is indicated in the control room.

The High Pressure Service Air System delivers air to various plant services which do not require drying, such as air powered tools.

The low pressure air supply (nominal 20 psig) is developed by two centrifugal air blowers. The blowers discharge for distribution through a moisture separator and a mist eliminator. Blower usage is intermittent. No dewpoint control is provided. The Low Pressure Service Air System interfaces with several plant systems which contain radioactivity. As a result of aging of system isolation components, unintentional cross-contamination of the Low Pressure Service Air System has occurred. While it is impractical to decontaminate the system and maintain it free of detectable radioactivity, this system should be operated and maintained so as to keep the levels of radioactivity contained within at a minimum commensurate with the goals of the station ALARA program.

A normally closed pressure reducing cross-over line is provided between the high pressure distribution header upstream of the air dryers and the low pressure distribution header. This cross-over may be used to continue low pressure service in the event of blower failure.

Pressure loss in the high pressure system, sensed by several pressure switches, will cause valves in the service air header, the low pressure service air cross-around line, and the non-essential instrument air header to close in a cascading sequence thus leaving the essential instrument air header as the only header drawing air from the receivers in the event that supply pressure decreases.

Instrumentation is provided to monitor the dew point downstream of each air dryer. Flow meters are provided for each air dryer train.

A 3” back-up air supply system was added to the Instrument Air system, tying into the permanent plant hardpipe connection from the outside of the turbine building where it is connected to a diesel driven oil-free air compressor. This back-up source of instrument air is used for station black-out conditions and/or to provide additional air for times when the system is not available due to maintenance.

The backup nitrogen system consists of two banks of ten cylinders each, a cylinder rack and manifold (X-169), associated piping and valves. The cylinders are arranged to automatically maintain the nitrogen supply to drywell instrumentation once the existing nitrogen supply is not available. The cylinders deliver nitrogen gas through 2 inch piping which ties into the existing drywell instrument supply header. A differential pressure indication switch with annunciator is connected between the cylinder supply and the existing supply which provides control room indication of switchover to the cylinders.

10.11.3.2 Equipment Description

Compressors

The three reciprocating air compressors are vertical, single stage, double acting reciprocating compressors. They are each rated to deliver 159.5 standard ft^3/min at 105 psig. The two rotary compressors are each rated to deliver 655 standard ft^3/min at 102 psig.

The diesel air compressor is sized to accommodate station air loads in a black-out or maintenance condition.

Each reciprocating compressor has a pressurized lubrication system for the power-end parts. The cylinders are non-lubricated having Teflon piston rings. They also have water cooled cylinders and have a displacement of 261 in^3. All intake valves have pneumatic operators which depress the valves allowing the cylinder to unload by venting to the atmosphere each time the motor starts and each time the receiver pressure reaches the top of its operating range.

Each of the three reciprocating compressors is belt-driven (4 belts) by a 40 hp drip proof induction motor. The compressor speed is 514 rpm.

The two rotary screw type compressors are direct driven by an electric motor which provides a shaft output of 156 hp at a compressor discharge pressure of 102 psig. The compressor speed is 3,550 rpm.

The accumulator charging compressor (K-203) and dryer (X-285) are powered by a 5 hp, 460 V/3 phase/60 Hz motor and supplies dry air, with a dew point of (-) 50°F, at 130 psig. This compressor serves as the alternate means of charging the Standby Gas Treatment and Torus Vacuum Breaker accumulators.

Aftercoolers

The reciprocating compressor aftercoolers are shell and tube counter current coolers with air passing through the tubes and water flowing around the tubes. They have an integral moisture separator equipped with an automatic drain trap to remove condensed moisture from the cooled air. Cooling water is supplied by the Turbine Building Closed Cooling Water System.

The rotary screw compressors are provided with intercoolers and aftercoolers, integral with each unit. Cooling water is supplied by the Turbine Building Closed Cooling Water System.

Air Receivers

The air receivers are vertical vessels built to the ASME code for a design pressure of 125 psig. Each receiver is equipped with two relief valves and an automatic drain trap. The volume of each receiver is 151 ft^3.

Air Dryers

The two air dryers are each rated to pass 100% of normal station air demand at 100 psig dried to a dewpoint of -40 F. Each drier has twin towers built to the ASME code for a design pressure of 150 psig. The air is dried by passing it through a desiccant. Moisture is removed from the desiccant by a heated purge air flow.

Class I Accumulators

Class I accumulators, associated piping, and check valves of appropriate size are provided for the following equipment:

1. Torus to Secondary Containment Vacuum Breaker Butterfly Valves

   The torus to secondary containment vacuum breaker butterfly valves are powered by Class I air accumulators. These accumulators are sized for a 30 day mission time without operator action and a design leakage rate of 0.1 SLM. A Class I manual make-up system allows the accumulators to be recharged from outside secondary containment and thus maintain the vacuum breakers valve function for an indefinite period of time. The vacuum breaker and make-up air supply are shown on Figure 10.11-1 (Drawing M220).

2. Main Steam Isolation Valves

3. Main Steam Relief Valves

   A Class I, seismic piping system allows two accumulators to be recharged from outside the Drywell, and thus maintain the RPV pressure control capability for an indefinite period of time.

4. Emergency Diesel Generator Ventilation System Dampers.

10.11.4 Inspection and Testing

The Instrument and Service Air System operates continuously and is observed and maintained during normal operation. No special inspection and testing will be required following preoperational testing.

Figure 10.11-1 has been removed.

Please refer to BECo Controlled Drawing M 220.

10.12 POTABLE AND SANITARY WATER SYSTEM

10.12.1 Power Generation Objective

The power generation objective of the Potable and Sanitary Water System is to provide the drinking water supplies and sewage system water necessary for normal station operation.

10.12.2 Power Generation Design Basis

The Potable and Sanitary System supplies treated water in sufficient quantities to satisfy the normal station demand for potable and sanitary water and meet the design regulations of the Commonwealth of Massachusetts.

10.12.3 Description

Potable water is taken from the town of Plymouth water main and distributed throughout the station piping system at town water pressure. Hot water heating units are provided for domestic uses as necessary.

An onsite Sewage Disposal System is provided to treat normal sewage. The Sewage Treatment System is designed in accordance with the regulations of the Commonwealth of Massachusetts.

The Station Potable and Sanitary Water Systems are independent of the Station Process Systems.

10.12.4 Inspection and Testing

The system is in continuous use and requires no testing.

10.13 EQUIPMENT AND FLOOR DRAINAGE SYSTEMS

10.13.1 Power Generation Objective

The power generation objective of the Equipment and Floor Drainage Systems is to collect and remove all waste liquid from their points of origin and to transfer them to suitable treatment and/or disposal areas in a controlled manner.

10.13.2 Power Generation Design Basis

The Equipment and Floor Drainage System is designed to:

1. Remove equipment and floor drainage water produced during normal station operations.

2. Maintain separation of liquid wastes as follows:

   a. Normal drainage wastes - (non-radioactive)

   b. Clean radwastes - (all drain flows originating from closed drains having no process chemical content and low conductivity)

   c. Chemical radwastes - (all drain flows originating from an open drain, having any process chemical content and high conductivity)

   d. Miscellaneous drainage

10.13.3 Description

10.13.3.1 General

Equipment and Floor Drainage Systems handle both normal and radioactive drainage. Normal non-radioactive wastes are drained by gravity into the Sewer or Storm Drain System.

Radwaste drains are collected in either one of four equipment sumps, one of four floor drain sumps or directed to waste collection tanks. These collected wastes are then transferred to the Radwaste Building as required for filtration, demineralization sampling, and analysis prior to either dilution and safe disposal into the ocean or reuse in the station.

Two pumps are provided in each of the potentially radioactive sumps to transfer the collected drains from the sumps to the Radwaste System. Each pump is a full capacity unit and has an Automatic Pump Starting and Alarm System which, on rising water level, acts as follows:

At the first high water level setting (high) one pump is started (pumps are alternately selected for initial operation by an automatic pump alternator). If the water level continues to rise a further high water level switch (HI-HI) initiates the second pump. A further rise in the water to a prescribed level initiates an alarm (HI-HI-HI), indicating

excessive leakage and/or pump failure to start. The equipment drain and floor drain pumps are tripped by either low sump level or by high level in the clean waste receiver tank or chemical waste receiver tank respectively.

Drywell equipment and floor drain pumps will trip on low level or after a predetermined running time interval (which ever comes first). Reactor Building quadrant floor drains are designed to prevent spread of liquid fire from one quadrant to the other.

Free venting from the enclosed sump pits is prevented by maintaining water level in the sumps to seal the pumps suction, and by venting the sump pit to the controlled ventilation system. The sump level is maintained by normal expected leakage and abnormally low level is alarmed. The drywell equipment and floor drain discharge lines are provided with two isolation valves, both outside of the drywell penetration. These valves close on a drywell isolation signal.

10.13.3.2 Radioactive Equipment Drainage System

In general, potential radioactive equipment drains are collected throughout the station in the four following sumps. See Figure 9.2-2 (Drawings M232, M232A).

1. Drywell equipment drain sump

2. Reactor Building equipment drain sump - Draining the Reactor Building, the reactor auxiliary bay, and the reactor building corner rooms.

3. Turbine Building equipment drain sump - Draining the Turbine Building and certain portions of the Radwaste Building.

4. Radwaste Building equipment drain sump

Besides normal drain flows, the Reactor Building sump receives the condensate storage tank overflow, and the condensate demineralizer regeneration system backwash drains while the Turbine Building sump receives the main turbine gland seal condenser drain tank overflow, feedwater pump seal leakage, condensate pump seal leakage, and the feedwater and condensate sample rack drains.

Due to the relatively large flows of clean water from the main gland seal condenser which normally does not require processing, the Turbine Building equipment drain sump pump flow can be routed to the condenser hotwell rather

than to the clean waste receiver tanks, as in the case of the other equipment drain sump pumps. There is an installed capability to automatically re-route Turbine Building equipment drain sump pump flow to the condenser hotwell rather than to the clean waste receiver tanks. This capability is normally disabled by isolation of the air supply to the valving that swaps the discharge path from the clean waste receiver tanks to the condenser hotwell. If the automatic swap capability is in service, the sump pump is first

started by sump level, and the discharge is routed to the receiver tanks. Then upon signal of low conductivity coincident with pump actuation, the valving automatically changes to redirect the flow to the condenser. High conductivity or pump tripping closes the line to the condenser and opens the line to the receiver tanks.

Equipment drain lines within the Reactor Building "corner" rooms are hard piped from source to sump, to maintain ECCS Train spatial isolation.

10.13.3.3 Radioactive Floor Drainage System

In general, potentially radioactive floor drains are collected throughout the station in four specific sumps which are similar in coverage to the aforementioned equipment drain sumps. All floor drain sump pumps discharge to the chemical waste receiver tanks. See Figure 9.2-2 (Drawings M232, M232A).

Floor drainage flows from the Reactor Building "corner" rooms and torus area are isolated by block valves enroute to the floor sumps, thus providing ECCS Train spatial isolation. The corner rooms have level alarms to indicate leakage in the floor drain inlet pit of each room.

10.13.3.4 Nonradioactive (Normal) Drainage System

Roof drains and some floor drains in the Turbine Building service area are collected and discharged by gravity to the storm sewer.

10.13.3.5 Miscellaneous Drainage System

General chemical and detergent type liquid wastes are collected in the neutralizing sump, or the miscellaneous tanks, sampled, neutralized, and discharged at a controlled rate to the storm sewer system or to the discharge canal at the location of storm drain outfall 005 as an alternate discharge path.

Oil drains and oil contaminated liquid drains are collected locally for offsite disposal.

10.13.3.6 Reactor Building Emergency Drains

Drainage piping has been provided at the North sides of the floor at elevation 23'-0" and 51'-0" to remove any water discharge from the wet pipe sprinkler systems that accumulates to a depth greater than 3 inches on the floor. Any water collected by this piping is discharged to the Torus Compartment floor where it is held until it can be routed to the Radioactive Floor Drainage System.

10.13.4 Inspection and Testing

The system is in continuous use and requires no testing.

10.14 PROCESS SAMPLING SYSTEMS

10.14.1 Power Generation Objective

The power generation objective of the Process Sampling Systems is to monitor the operational performance of station equipment. See Figure 10.14-1.

10.14.2 Power Generation Design Basis

The Process Sampling Systems are designed to:

1. Obtain representative samples in forms which can be used in radiochemical laboratory analysis for determination of station equipment effectiveness.

2. Minimize the radiation effects at the sampling stations.

10.14.3 Description

Samples are taken from various streams and locations as indicated on Table 10.14-1. Sample points are grouped as much as possible at normally accessible locations, and drains are provided at these locations to limit the risk of contamination. Lines are sized to insure purging and sufficient velocities to obtain representative samples. Samples are taken to the laboratory for appropriate analysis. In addition, continuous automatic monitoring and alarm of undesirable conditions is provided using inline detectors where necessary.

TABLE 10.14-1

PROCESS SAMPLING SYSTEM

Descriptions	Locations	No.	Purpose
	Nuclear Steam Supply System		
Reactor Water	Recirculation Pump Discharge (12 inch recirculation riser pipe)	1	Reactor Water Quality
Main Steam	Main Steam Line	4	Carryover, Moisture
Standby Liquid	Test Tank	1	Borate Concentration
	Cleanup Demineralizer		
Filter Demineralizer	Inlet Line	1	Reactor Water Quality
Filter Demineralizer	Outlet Line	2	Filter Effectiveness
	Condensate System		
Condensate	Gland Seal Cond. Outlet	1	Water Quality
Condensate	Condenser Outlet	2	Tube Leakage
Condensate	Condensate Pump Discharge Header	1	Deaeration
	Condensate Demineralizer System		
Cond. Demineralizer	Influent Header	3	Condensate Quality
Cond. Demineralizer	Demineralizer Effluent	7	Demineralizer Effluent
Cond. Demineralizer	Effluent Header	1	Treated Condensate Quality
Cond. Demineralizer	Recycle Line	1	Regeneration Effectiveness
	Feedwater Systems		
Feedwater	Heater E-103 Outlet	2	Water Quality
Feedwater	Reactor Inlet	2	Water Quality

TABLE 10.14-1 (Cont)

PROCESS SAMPLING SYSTEM

Descriptions	Locations	No.	Purpose
	Closed Cooling Water Systems		
Turbine Building	Pump Discharge	2	Water Quality
Reactor Building	Pump Discharge	2	Water Quality
Reactor Building	RHR HX Outlet	2	Tube Leak
Reactor Building	CU. Non. Regen. HX Outlet	1	Tube Leak
Reactor Building	Fuel Pool HX Outlet	2	Tube Leak
Reactor Building	Clng. Water HX Outlet	2	Tube Leak
Turbine Building	Clng. Water HX Outlet	2	Tube Leak
	Circulating Water System		
Circulating Water	Pump Discharge	2	Background Activity
Circulating Water	Discharge Canal	1	Activity Release, Chlorine Residual
	Service Water System		
Service Water	Discharge Header	2	Chlorine Residual
	Liquid Radwaste System		
Radwaste Demin.	Demin. Inlet	1	Filter Effectiveness
Radwaste Demin.	Demin. Outlet	1	Demin. Effectiveness
Radwaste Filter	Clean Waste Pump Discharge	1	Water Quality
Treated Water Tank	Tank Outlet	1	Water Quality
Chem. Waste Tank	Pump Discharge Header	1	Water Quality
Chem. Waste Tank	Tank Recycle Line	2	Water Quality
Chem. Waste Filter	Filter Outlet	2	Filter Effectiveness
Monitor Tank	Discharge Header	1	Background
Monitor Tank	Recycle Header	2	Water Quality
Misc. Waste Drain Tank	Pump Discharge	1	Water Quality
Cleanup Sludge Filter	Filter Outlet	1	Water Quality
Cleanup Sludge Trans. Tank	Pump Discharge	2	Water Quality
Spent Resin Storage	Effluent Line	1	Quality

TABLE 10.14-1 (Cont)

Descriptions	Locations	No.	Purpose
Drywell Equip. Drain Sump	Pump Discharge	1	Quality
Drywell Floor Drain Sump	Pump Discharge	1	Quality
Ion Exchanger System	Inlet	1	Quality
Ion Exchanger System	Outlet	1	Quality
	Makeup Water Treament Systems		
Filters	Filter Outlet	3	Water Quality
Filters	Effluent	3	Filter Effec-tiveness
Cation Tank	Effluent	1	Process Data
Anion Tank	Effluent	1	Process Data
Mixed Bed Demin-eralizer	Effluent	1	Water Quality
Dilute Acid	Header to Cation and Mixed Bed Demineralizer	1	Process Data
Dilute Caustic	Header to Anion Tank Demin. and Mixed Bed Demin.	1	Process Data
Neutralizing Tank	Discharge Line	1	Effluent Quality
Demin. Water Storage Tank	Pump Discharge	1	Water Quality
Condensate Storage Tank	Pump Discharge	1	Water Quality
	Fuel Pool Cooling & Demineralizer System		
Skimmer Surge Tank	Tank Outlet	1	Fuel Pool Quality
Fuel Pool Filter	Filter Inlet	1	Filter Effec-tiveness/Torus Quality

TABLE 10.14-1 (Cont)

Descriptions	Locations	No.	Purpose
Fuel Pool Filter	Filter Outlet	1	Filter Effectiveness
Fuel Pool Demineralizer	Demin. Outlet	1	Demin. Effectiveness
	Plant Offgas Systems		
Offgas Holdup Line	Filter Inlet	1	Filter Condition
Offgas Holdup Line	Filter Outlet	1	Filter Condition
Stack Sample	Main Stack	1	Particulate, Iodine and Noble Gas Sample
Sample	Reactor Building Vent	1	Iodine and Noble Gas
Sample	Turbine Hall	1	Noble Gas
Ventilation Headers	Fan Discharge	8	Activity
Standby Gas Treat. System	Inlet Header	2	Filter Effectiveness
Standby Gas Treat. System	Outlet Header	2	Filter Effectiveness
	Atmospheric Control System		
Inerting System	O_2 Drywell Sample	4	Content
Inerting System	N_2 Supply Header	1	Quality
Inerting System	O_2 Torus Sample	3	______
H_2	Drywell	2	Content
Radioactive	Drywell	2	Drywell
Content	Drywell		Leak Detection

Figure 10.14-1 has been removed.

Please refer to BECo Controlled Drawings M 228, M229 & M230.

10.15 COMMUNICATIONS SYSTEMS

10.15.1 Power Generation Objective

Internal and external communications are established by separate systems of loudspeakers and telephones designed to provide convenient, effective operational communications between various station buildings and locations.

10.15.2 Power Generation Design Basis

1. Voice communications between selected office areas and to points outside the station are provided by a dial telephone system.

2. The Industrial Communication System provides voice communication between various station buildings and locations using transistorized, industrial quality equipment with the following characteristics:

    a. Satisfactory voice communications are possible even in areas of extreme noise.

    b. Six separate and independent communication channels are provided; i.e. one page and five party lines. The page channel may be used to call personnel over the speakers, to issue station wide instructions, or for intercommunication between two or more handset stations.

    c. All system speakers carry the conversation during the page mode of operation.

    d. The party line channels are used for intercommunication after the page call is completed, thereby making the page channel available to others.

    e. Simultaneous conversations may take place on both the page and party channels without interference.

3. The maintenance and special operation system provide voice communication using one independent party line. This system is provided for use in areas requiring maintenance or special communication.

    a. Portable equipment is provided using permanent plug-in receptacles.

    b. Paging from the system is possible using the components of the Industrial Communication System.

    c. A group of receptacles are interconnected for special operations communication between the main control room, control rod drive areas, and the refueling floor.

4. A portable radio system is provided as a backup to the industrial communication system, should it be disabled during a fire, in accordance with Branch Technical Position 9.5-1, Guidelines for Fire Protection for Nuclear Power Plants.

5. A private line P.A. is installed between the control room and the refueling floor.

6. A wireless communication system is available with various Repeater Base Stations located throughout the site. It is accessed by means of a hand held telephone.

10.15.3 Description

The station communication systems are:

1. Public telephone system furnished and installed by the local telephone company consisting of components described below:

   a. Telephones are located in selected office areas and are connected to the Applicant's present CENTREX system providing dial type communication between the office areas within the station and the Applicant's offices at other locations.

   b. Telephones are located in selected areas which are connected to the local community (Plymouth) exchange providing dial type communication between the areas within the station and local community.

2. Industrial Communication System installed throughout the station site. All components of the system receive power from the 120 V AC instrument power bus. The components are described below:

   a. Speakers of various types are provided throughout the station for paging, public address, and carrying the evacuation warning signal. Each speaker was selected to insure adequate sound coverage throughout the area that the speaker covers.

   b. Handsets are provided throughout the station, each with access to five party lines and the page channel. To call an individual, an available party line channel is selected by pushbutton, the individual is paged throughout the station site, and the party line selected is used for conversation. The page channel may be used for conversation and emergency instructions as a sixth line of communication. While paging, handsets mute nearby speakers to eliminate system feedback. The system is operable in high noise areas without soundproof booths.

c. An operator recall alarm is generated by a tone generator. This tone, which lasts 10 to 15 seconds, is different than the evacuation warning signal (d). The operator recall alarm is initiated manually by the control room supervisor to alert the plant operators that a scram, fire, or other emergency has occurred, and they should report to either the control room or their assigned station. This tone eliminates the need for the control room supervisor to page all the operators during an emergency, or a scram.

d. An evacuation warning signal is generated by a tone generator located in the Control Room Communication Console. The signal can only be initiated from the main control room, and is carried over the paging channel, even if in use, through all of the speakers.

3. Maintenance and special operation system installed throughout the station site. All components of the system receive power through the Industrial Communication System from the 120 V ac instrument power bus. The components are described below:

   a. Portable handset/speakers are provided with access to one party line and the same paging channel as the Industrial Communication System. The set must be plugged in to one of the many receptacles to be operable.

   b. Receptacles are provided throughout the station with ac power and the paging channel provided from a nearby component of the Industrial Communication System. The party line from each receptacle is a separate and independent channel connected to the central switching panel. One group of receptacles for special operation has a common uninterruptable party line by interconnecting the group at the rear of the central switching panel. This special group permits uninterrupted conversation between the main control room, control rod drive equipment areas, and the refueling floor. Each receptacle has a low intensity blue light to locate the receptacle in the dark.

   c. A central switching panel is provided in the cable spreading room. It is possible to select 1 of 23 circuits for each portable handset using selector switches in the panel. The special group of receptacles may be connected to additional area using the selector switches. The central switching panel can interconnect 100 receptacles or groups of receptacles.

4. The portable system provides communications within a building between each portable radio unit. The coverage and radio signals are governed by building loss, free space loss, and extra coupling loss. The radio units operate at 153.56 MHz with 5 watt power. A separate coaxial antenna cable (RADIAX) that has been installed in the fire fighting areas of the entire plant. These antennas are connected to a transmitter/receiver base station at the main guardhouse. The RADIAX cable permits any portable radio to operate within 80 feet of it with sufficient signal level at the base station receiver, as well as the base station to the portable radio. Portable communication within the building would be heard at the guardhouse. Communications to the portable would be via the guardhouse base station to the RADIAX cable. No portable-to-portable communication is possible through the RADIAX Cable. However, portable-to-portable communication is possible within the building subject to the signal loss due to the building, free space, and extra coupling.

5. Communication with the Dispatch Center will be done using station telephone lines.

6. The private line P.A. between the control room and the refueling floor has a microphone on panel 905 in the control room. This allows the operator in the control room to communicate without using his hands which then are used to simultaneously operate control rod positioning.

7. A UHF (Ultra High Frequency) radio repeater system provides communications, via handheld radios, for the operators during implementation of the alternate shutdown procedure. Satellite receivers have been installed at the exterior side of the North Wall of the Reactor Building. The two receivers are connected to a radio transmitter located in the Guardhouse. A UHF directional antenna has been installed on the roof of the Guardhouse to direct a radio signal back towards the Reactor Building.

   The two satellite receivers and the transmitter are powered from the UPS (Uninterruptable Power Supply) system in the Guardhouse. The UPS system in the Guardhouse is not affected by the loss of offsite power.

   Two wall mounted handheld radio racks have been installed in the Switchgear Rooms to store the handheld radios required to be used during implementation of the alternate shutdown procedure.

   Each rack contains five handheld radios with an internal battery charger to keep the five radios at a full charge.

8. A wireless telephone system provides communication by way of a handheld telephone. This system consists of a central processing unit, a number of Repeater Base Stations located throughout the site, and hand held telephones which are programmed into the system. This system is operated on high frequency and low output, therefore, no safety related equipment is effected by the wireless communication system.

9. A network based wireless communication system using access point antennas and electronic network switches connected via fiber and Category 5E cables, provides communication capabilities to process buildings throughout the plant. In addition to numerous other areas, this system provides direct communication between the refuel bridge and the control room.

10.15.4 Inspection and Testing

The design of the system permits routine surveillance and testing without disrupting normal communication facilities.

10.16 STATION LIGHTING SYSTEM

10.16.1 Power Generation Objective

The Station Lighting Systems shall provide adequate normal and emergency station lighting using reliable system components, with power supplied from normal and emergency AC sources or from the station battery system.

10.16.2 Power Generation Design Basis

1. Lighting intensities are maintained at levels recommended by the Illuminating Engineering Society.

   Control Room Lighting intensities are maintained at levels required by NUREG-0700.

2. Lighting fixtures are mercury vapor, fluorescent, or incandescent type selected with due consideration for environmental conditions and ease of maintenance. Mercury fixtures and switches are not normally used inside the primary containment or on the 117 ft elevation. An exception is made when the use of mercury-containing lamps is dictated by considerations of lighting quality and durability. Low mercury content lamps (mass of approximately 25 milligrams or less) such as modified high pressure sodium vapor lamps, that have been designed for maximum durability and minimum mercury loss if broken above or in water are acceptable.

3. Emergency lighting is provided in the main control room, diesel generator rooms, emergency service switchgear areas, all areas required for control and maintenance of safety-related equipment, and access routes to and between these areas.

4. Battery powered Emergency Lighting Units have been installed to illuminate the access route to the Alternate Shutdown Panels (ASPs) and to operate the ASPs if the Lighting in Items 2 and 3 were put out of service by a fire (Refer to FSAR Sections 8.9 and 10.8 for additional system descriptions).

10.16.3 Description

The normal Service Lighting System receives power from the normal service buses of the Auxiliary Power Distribution System, described in Section 8.4. Fluorescent fixtures throughout the station, and mercury vapor fixtures for high bay lighting only, are provided for 277 V AC, 3-phase, 4-wire service. Incandescent and fluorescent fixtures are provided in some areas for 120 V AC, 3-phase, 4-wire service.

The Emergency Service Lighting System is divided into three subsystems:

1. The AC subsystem receives power from the emergency service buses of the Auxiliary Power Distribution System, described in Section 8.4. Fluorescent fixtures in most areas required for control and maintenance of safety-related equipment and a minimum of one egress route from each floor of the station are provided for 277 V AC, 3-phase, 4-wire service.

Incandescent fixtures in the remaining areas required for control and maintenance of safety-related equipment and a minimum of one egress route from each floor of the station are provided for 120 V ac, 3-phase, 4-wire service. All of these ac fixtures are normally lighted.

2. The dc subsystem receives power from the 125 V dc power system, described in Section 8.6. Incandescent fixtures in the main control room, diesel generator rooms, emergency service switchgear areas, and access routes between these rooms and areas are provided for 125V dc service. These fixtures are normally not lighted, but are automatically connected to the Station Battery System upon loss of ac power.

3. The portable subsystem consists of battery operated lighting fixtures which are available in a quantity and size to permit maintenance of emergency power sources. They are available in the control room, battery room, diesel generator rooms, emergency service switchgear areas, all areas required for control and maintenance of safety-related equipment, and access routes to and between these areas. This includes those safety-related fire zones that have the potential of losing both normal and other emergency lighting due to a fire.

10.16.4 Inspection and Testing

Design permits routine surveillance and test of all critical lighting systems without disrupting normal lighting service.

10.17 MAIN CONTROL ROOM ENVIRONMENTAL CONTROL SYSTEM

10.17.1 Safety Objective

The safety objective of the Main Control Room Environmental Control System (MCRECS) in conjunction with shielding is to limit radiation exposure of station personnel in the control room.

10.17.2 Safety Design Basis

1. The MCRECS is designed to provide a filtered supply of air to the station operating personnel in the control room.

2. The system is designed to pressurize the control room to prevent air infiltration.

3. The system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective.

10.17.3 Power Generation Objective

The power generation objective of the MCRECS is to maintain conditions which ensure the operability of control room equipment and instruments and habitability for personnel.

10.17.4 Power Generation Design Basis

1. The system is designed to control temperature and humidity in the main control room, cable spreading room, and computer room during planned operations to ensure operability of equipment and instruments in these areas.

2. The system is designed to provide adequate ventilation in the main control room to ensure habitability for operations personnel.

10.17.5 Description

The MCRECS supplies heating, ventilation and air conditioning for the control room, the cable spreading room, and the computer room. See Figure 10.17-1. The principal equipment in the system includes:

1. Two independent supply fans with associated heating and cooling units. (VAC-104 A & B)

2. Mixing boxes to independently control air supply temperatures to the control room areas, the cable spreading room, and the computer room.

3. Two independent exhaust/recirculation fans. (VRF-101 A & B)

4. Two independent, high efficiency, air filtration units for emergency treatment of outside supply air. (VCRF-101 A & B), and associated fans (VSF-103 A & B).

During normal operation, the system recirculates air from the exhaust fan discharge to the suction of the supply fans to reduce the demand on the heating and cooling units. Except for brief periods, e.g. during surveillance testing or maintenance, the control room is maintained at a positive pressure with respect to adjacent station ventilation zones. The air supplied to the control room is a mixture of outside and recirculated air. The outside air and the recirculated air passes through a dust filter before reaching the suction of the supply fans.

The discharge air from the supply fans can be cooled by two air conditioning units or heated as required. The Supply Air System is a two duct system with both a hot and cold air supply. Air is supplied to each separate ventilation zone through a mixing box which regulates the quantity of hot and cold air supplied so as to independently control the air temperature within the zone. Humidity is controlled in the entire system based upon humidity requirements for the control room area.

One exhaust fan and one supply fan are normally in operation. If an operating fan fails, a flow switch senses the loss of pressure, automatically starts the standby fan, and alarms in the control room.

Activation of the Halon fire protection system for the Cable Spreading Room automatically stops the two independent supply and the two independent exhaust/recirculation fans. One of the two 1000 ft^3/min high efficiency filter trains are normally operated with the control switch in the automatic position. The filter train with the control switch in the automatic position will start when the Cable Spreading Room halon system activates. The MCRECS will return to its original status when the Cable Spreading Room halon system is reset following a discharge. A smoke detector is installed in the return air duct to the exhaust fans which automatically closes the recirculation damper, opens the building exhaust damper, and alarms in the control room. With the recirculation damper closed, all air to the suction of the supply fans is obtained from outside the building. The supply air heating and cooling units are sized based upon this mode of operation to assure that control room temperature limitations are observed. The control room operator can manually close the recirculation damper and initiate the once through mode of ventilation to the control room area at any time.

Radiation protection for operating personnel in the control room under accident conditions is provided by operation of either of two high efficiency air filtration trains in conjunction with the installed control room shielding. Refer to Section 12.3.

Two independent 1,000 ft^3/min high efficiency filter trains are provided in parallel with the normal outside air inlet duct. The filter trains each consist of inlet isolation dampers and outlet back draft dampers, a heating coil, prefilter, high efficiency particulate absorber (HEPA), charcoal filter, and final HEPA. Air is drawn through the filter trains by separate filtration fans. Each train is powered from separate diesel generators in the event of loss of preferred AC power supply.

In the event of an accident, the control room operator may manually isolate normal control room air conditioning and initiate high efficiency filtration of the outside air supplied to the control room. Initiation of either of the filtration fans closes a damper in the normal outside air intake duct and opens the inlet isolation dampers. Starting either filtration fan also energizes a heating coil in the appropriate filtration train which is designed to reduce the relative humidity of the incoming air to approximately 70 percent if the temperature and relative humidity interlocks permit. The heating coil is capable of raising Control Room inlet air temperatures in the event the normal heating system is not operational.

The system is designed to effect isolation of the main control room from unfiltered outside air despite the loss of the instrument air supply and/or the loss of DC power to the solenoid valves on the air operated dampers. With the normal system operating, the control room is maintained at a positive pressure with respect to other station ventilation zones. A radiation monitor is provided to detect high radiation in the outside air intake duct and a second radiation monitor is provided in the control room to monitor control room area radiation levels. Refer to Sections 7.12 and 7.13. These two monitors alarm in the main control room upon detection of high radiation conditions. Portable radiation monitoring equipment is also available in the control room.

10.17.6 Safety Evaluation

The system is designed with sufficient redundancy such that no single active system component failure can prevent the control room environmental control system from achieving its safety objective. It is concluded that the safety design bases are met.

10.17.7 Inspection and Testing

Provisions are made for periodic tests of each standby filter train. These tests will include determinations of differential pressure across each filter and of filter efficiency. Connections for testing, such as injection and sampling, are located to provide adequate mixing of the injected fluid and representative sampling and monitoring, so that test results are indicative of performance.

Each HEPA is tested periodically with DOP (dioctylphthalate) smoke. The charcoal filters are periodically tested with freon for bypass air flow. The electric heating coil in each filter train is tested periodically.

Isolation dampers in the normal control room ventilation system are periodically tested during system capacity testing.

The remainder of the system operates during normal operation and does not require special testing.

10.17.8 Nuclear Safety Requirements for Plant Operation

<u>General</u>

This section represents the nuclear safety requirements for the Main Control Room Environmental Control System for each BWR operating state. The following referenced portions of the safety analysis report provide information justifying the entries in this section:

	Reference	Information Provided
1.	Preceding portions of Section 10.17.1 through 10.17	Description of Main Control Room Environmental Control System
2.	Station Nuclear Safety Operational Analysis, Appendix G	Identification of conditions and events for which the MCRECS is required
3.	Jacobs, I. M. Guidelines for Determining Safety 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

Each detailed requirement in this section is referenced to the most significant station condition originating the need for the requirement by identifying a matrix block on Table G.5.3. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" section. The matrix block references identify the BWR operating state, the event number and the system column number. For example, F 39-100 identifies BWR operational state F (Matrix 3), event (row No. 39), and MCRECS (column No. 100).

System Action

The MCRECS limits exposure of station personnel in the control room to airborne fission products released as a result of an accident.

Number Provided by Design

The MCRECS provides for two independent filter trains in parallel, each consisting of inlet isolation dampers and outlet backdraft dampers, a heating coil, prefilter, high efficiency particulate absorber (HEPA), charcoal filter, final HEPA, and fan.

Minimum Required for Action

One filter train with all components in that train operable is the minimum required for action in BWR operating states A,B,C,D,E, and F.

(A40,100) (D39,100)

(B40,100)	(E39,100)
(C39,100)	(F39,100)

10.17.9 Current Technical Specification

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

Figure 10.17-1 has been removed.

Please refer to BECo Controlled Drawing M 287.

10.18 EQUIPMENT AREA COOLING SYSTEM

10.18.1 Safety Objective

The safety objective of the Equipment Area Cooling System (EACS) is to maintain the local environment of the electrical components of the Core Standby Cooling Systems (CSCS) at temperatures within their maximum allowable operating limits.

10.18.2 Safety Design Basis

1. The Equipment Area Cooling System is designed to deliver cooling air as required to the local environment of the CSCS electrical components in the event of an accident or a transient.

2. The system is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective.

10.18.3 Power Generation Objective

The power generation objective of the EACS is to maintain the local environment of the CSCS and control rod drive pumps at temperatures within their normal operating limits.

10.18.4 Power Generation Design Basis

The EACS is designed to deliver cooling air as required to the local environment of the CSCS and the control rod drive pumps to maintain temperatures within normal operating temperatures.

10.18.5 Description

The portion of the system serving the CSCS is designed in accordance with Class I criteria. See Section 12, Appendix C, and Figure 10.9-3. EACS consists of fan-coil unit coolers and their instrumentation which control the environmental temperature in the Reactor Heat Removal System (RHR) - core spray pump corner compartments, the Reactor Core Isolation Cooling System (RCIC) corner compartment, the High Pressure Coolant Injection System (HPCI) equipment room and the control rod drive feedwater pump corner compartment. The RBCCW supplies water to the cooling coils and serves as the heat sink for the EACS. The maximum design temperature for the above mentioned locations is 115°F (as detailed in Table 10.9-2).

Environmental enclosures are installed around Motor Control Centers D7, D8, D9, B17, B18 and B20. The enclosures for B17, B18 and B20 are provided with cooling systems (Reference Section 8.4.5.2).

Two unit coolers (each cooler rated at 347,000 Btu/hr) are located in each of the two RHR-Core Spray pump corner compartments. Two unit coolers (each cooler rated at 116,000 Btu/hr) are located in the RCIC corner compartment. Two unit coolers (each cooler rated at 232,000 Btu/hr) are located in the HPCI equipment room. Two unit coolers

(each cooler rated at 174,000 Btu/hr) are located in the CRD corner compartment.

One fan-coil unit in each compartment has sufficient capacity to meet the design basis (115°F); however, two fan-coil units are provided in each area for redundancy. The two unit coolers and associated fans in each compartment are designed to maintain area temperatures at approximately 100°F during equipment operation.

The fan-coil units in each area are started when the area temperatures reach preselected set points below the setpoint analytical limit of 115°F. The first unit will be set to start approximately 10°F below the set point of the second unit. The actual set points were determined during preoperational testing.

Inadequate cooling in the RHR-core spray pump corner compartments, the RCIC corner compartment, the HPCI equipment room or the CRD pump corner compartments alarms in the control room. Temperature sensors located in the compartment space will originate the alarm signal.

10.18.6 Safety Evaluation

The system is designed with sufficient redundancy so that no single active system component failure can prevent the EACS from achieving its safety objective. The fan-coil units employed by this system at the locations described in Section 10.18.5 implement the stated safety design bases. The design of the Core Standby Cooling Systems (CSCS) is to provide at least two different subsystems of different principles to prevent clad melt over the entire spectrum of postulated breaks. This was accomplished by using the HPCI system (coolant injection) and the ADS (depressurization) for smaller breaks. The CSCS are designed to various levels of component redundancy such that single failures in addition to the accident can not prevent adequate core cooling. Just as single failures within the HPCI system can prevent the system from performing its function, single failures in the cooling water or electrical supply to the HPCI area coolers can prevent the area coolers from performing their function. Loss of HPCI area coolers may result in failure of the HPCI system due to high area temperatures. This is within the design basis for the CSCS since the ADS will be available to ensure adequate core cooling.

10.18.7 Inspection and Testing

The energy removal capability of the unit coolers of the EACS can be evaluated when the HPCI, RCIC, RHR or Core Spray System or the Control Rod Drive System are operating. The effectiveness of energy removal from the local environments of the pump motors of these systems can be evaluated by measuring the inlet and outlet air temperatures from the fan-coil units and by measuring the compartment air temperatures where the equipment is located.

10.18.8 Nuclear Safety Requirements for Plant Operation

General

This section represents the nuclear safety requirements for the EACS for each BWR operating state which represents an extension of the stationwide BWR systems analysis of Appendix G.

The following referenced portions of the safety analysis report provide important information justifying the entries in this section:

	Reference	Information Provided
1.	Section 10.18	Description of the Equipment Area Area Cooling system
2.	Station Nuclear Safety Operational Analysis Appendix G	Identifies conditions and events for which system action is required

Each detailed requirement in the following analysis is referenced, if possible, to the most significant station condition originating the need for the requirement by identifying a matrix block shown on Table G.5-3.

System Action

The EACS provides cooling to the local environment of the components of the RCIC and CSCS.

Number Provided by Design

Two full capacity unit coolers for the EACS are required for each of the following:

1. RHR - Core Spray Corner Compartment A
2. RHR - Core Spray Corner Compartment B
3. RCIC Corner Compartment
4. HPCI Compartment

Minimum Required for Action

Below 104 psig (BWR operating states A,B,C, and D).

One unit cooler of the EACS in the RHR - core spray corner compartment A or B is the minimum required for action.

(A35-107)	(B35-107)
(C39-107)	(D39-107)

Above 104 psig (BWR operating states C,D,E, and F).

One unit cooler in the RHR - Core Spray Corner Compartment A or B

Above 150 psig (BWR operating states C, D, E, and F).
One unit cooler in the RCIC or HPCI Corner Compartment.

(C39-107)	(D39-107)
(E39-107)	(F39-107)

10.18.9 Current Technical Specifications

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

10.19 POST ACCIDENT SAMPLING SYSTEM

10.19.1 Safety Objective

The post-accident sampling system (PASS) and the H_2/O_2 analyzer subsystems are non safety-related, with the exception of the containment isolation valves of the PASS and H_2/O_2 subsystem which are safety-related.

The H_2 analyzers are required to assess the degree of core damage during a beyond-design basis accident (BDBA) and confirm that random or deliberate ignition has taken place. If an explosive mixture that could threaten containment integrity exists during a BDBA, then other severe accident management strategies, such as purging and/or venting, would need to be considered. The hydrogen analyzers are needed to implement these severe accident management strategies. Section 5.4.5 also describes the hydrogen analyzers in the context of combustible gas monitoring.

Combustible gases produced by BDBAs involving both fuel-cladding oxidation and core-concrete oxidation would be risk-significant for Pilgrim Mark I containment if not for the inerted containment atmosphere. If the containment were to become de-inerted during a BDBA, then other severe accident management strategies, such as purging and venting, would need to be considered. The O_2 analyzers are needed to implement these severe accident management strategies.

10.19.2 Safety Design Basis

1. The H_2/O_2 subsystem is designed with sufficient redundancy so that no single system component failure can prevent the system from achieving its safety objective.

2. All electrical components in the H_2/O_2 subsystem are class 1E and are environmentally qualified to 10 CFR 50.49 requirements.

3. All of the H_2/O_2 subsystem is seismic class I.

4. The H_2/O_2 subsystem receives power from the emergency standby AC power system.

5. The H_2 and O_2 analyzer subsystems are maintained at least to the level of Regulatory Guide 1.97 Category 3 and Category 2 respectively, in accordance with Pilgrim License Amendment 206.

10.19.3 Description

The post-accident sample system (Figure 10.19-1, BECo M239) provides a method to sample reactor coolant, torus water, and containment atmosphere under accident conditions and minimizes the exposure of personnel to high radiation levels. The PASS panels C228 and C229 are located on an elevated platform structure within the radwaste building above the hot shop at elevation 37'-0". The platform is designed to maintain integrity during and following a seismic or tornado event. Additionally, the platform is thicker than necessary to meet structural requirements in order to provide sufficient shielding for the hot shop area.

The PASS is comprised of two independent units, the reactor coolant PASS and the containment air PASS. The reactor coolant PASS is capable of obtaining representative samples of reactor coolant or liquid from the suppression pool. The containment air PASS is capable of obtaining a drywell or torus atmosphere sample. After samples are obtained, radiological and chemical analyses can be performed on site, or the samples can be transported off-site for analysis.

The reactor coolant PASS is a dual module unit consisting of one sample module and one remote operating module. Samples are trapped within the sample module and cooled. The equipment within the sample module is operated remotely via the control panel (C-228). The motive force for obtaining reactor coolant samples is the differential pressure between the primary plant and the collection area to which sample effluent is directed. Two sampling modes may be chosen: a 10 ml undiluted sample or a 10 ml diluted sample. In both cases the samples are collected in shielded containers and can be transported for either on site or off site analysis.

The reactor coolant PASS consists of the following major components:

- Sample station
- Sample piping station
- Solenoid operated isolation valves
- Demineralized water flushing tank
- Control Panel (C-228)
- Nitrogen cylinder

The H_2/O_2 Subsystem of the PASS has the capability of collecting a sample of containment air as required by NUREG 0737. The PASS is a dual module unit consisting of one sample module and one remote operating panel each with two independent trains. The motive force for obtaining a sample is a sample pump which draws the sample from the oxygen/hydrogen analyzer system through the sample module, and back to the oxygen/hydrogen analyzer system. The sample pump is a bellows-type vacuum pump with a double containment feature to preclude radioactivity release should the bellows fail. Inlet and outlet lines are electrically heat traced and insulated to prevent condensation of any vapor in the atmospheric sample. However, should condensation occur, the sample lines are sloped back where possible to the containment.

Each train of the H_2/O_2 subsystem has two drywell sample points (High and Low) and one torus sample point. When the system is calibrated and maintained properly the accuracy of the analyzer outputs is adequate to provide the control room with the information necessary to monitor for combustible gas mixture inside the primary containment.

All the PASS sample and return lines are equipped with redundant, safety grade automatic containment isolation valves. When a containment isolation signal is generated all the system isolation valves automatically go shut. The control room has the ability to remotely open each valve. The position of all system isolation valves is continually displayed in the control room. The valve control switches are interlocked such that the isolation valves will not reopen automatically on isolation logic reset. Based on the valve design configuration, the valves will isolate when required and at least one of the two sets of redundant sample lines to each system will be available after a LOCA, a loss of offsite power and a single failure.

Analyzer readouts are provided locally at the analyzers and remotely in the control room. The design of this system also includes high hydrogen and oxygen alarms and strip chart recorders located in the control room.

10.19.4 Safety Evaluation

The H_2/O_2 portion of the PASS system is designed with sufficient redundancy so that no single active system failure, nor any single active component failure in any other plant system can prevent it from achieving its safety objective. Two independent sample trains are provided for monitoring containment H_2/O_2 concentrations.

The H_2/O_2 portion of the PASS is capable of sampling both hydrogen and oxygen in the containment atmosphere when the containment is inerted. The objective of the H_2 analyzer is to provide information to diagnose the course of beyond-design basis accidents (BDBAs) and to implement severe accident management strategies. The objective of the O_2 analyzer is to monitor and verify the status of containment atmosphere during BDBAs and to implement severe accident management strategies. Even though the H_2/O_2 subsystems were originally designed to meet the safety objective of NUREG-0737 items II.B.3 and II.F.1.6, the H_2 and O_2 subsystems are maintained in accordance with Regulatory Guide 1.97 Category 3 and Category 2 respectively, in accordance with Pilgrim License Amendment 206.

The H_2 and O_2 analyzers should be functional, reliable, and capable of measuring the hydrogen and oxygen in the post-accident containment atmosphere. The reliability, availability, and capability of the H_2 and O2 analyzers are assured through periodic testing and calibration within the scope of the Maintenance Rule program.

10.19.5 Information for Emergency Preparedness

As required by Pilgrim License Amendment 204, Pilgrim has developed and maintains capabilities for classifying fuel damage events at the emergency preparedness Alert Level threshold and I-131 site survey capability including an ability to assess radioactive iodine released to off site environs by using effluent monitoring systems or portable sampling equipment. In addition, contingency plans are in place for obtaining and analyzing highly radioactive samples from the reactor coolant system, suppression pool, and containment atmosphere during the recovery phase of an accident.

Figure 10.19-1 has been removed.

Please refer to BECo Controlled Drawing M 239.

10.20 Crack Arrest Verification System

10.20.1 Design Objective

The crack arrest verification system (CAVS) is non-safety related. The CAV system is designed to provide real time measurements of crack growth behavior in materials of interest for the Pilgrim plant.

10.20.2 Design Basis

1. Appropriate equipment is provided to allow the bulk water chemistry and electrochemical corrosion potential (ECP) of the Pilgrim recirculation system water to be fully characterized.

2. A computer based data acquisition system is provided to integrate all data into a common data base and allow for easy manipulation and analysis of the data.

10.20.3 Description

10.20.3.1 General

The crack arrest verification (CAV) system is an on-line monitor used to provide data pertaining to intergranular stress corrosion cracking (IGSCC) behavior in key reactor structural materials. It can monitor electrochemical potential (ECP) information from the "A" recirculation pump suction decontamination flange and an LPRM when purchased with special ECP probes. CAVS data can be used to help assess the behavior of key structural components with known cracks. It can also provide information on the effects of coolant conductivity fluctuations.

The CAV System consists of a series of modules used to acquire the following data:

1. Reactor water chemistry parameters.

2. Electrochemical potentials (ECP).

10.20.3.2 System Description

A flow diagram of the CAV System is given in Figure 10.20-1 (Drawing M256). The modules used to gather the data listed above consist of electrochemical potential (ECP) monitor, and water chemistry monitor. Signal cables from each of these modules are routed to a computer controlled Data Acquisition System, which is located in an air-conditioned shed.

ECP probes are located in the "A" recirculation pump suction decontamination flange and can be located in specially configured LPRM assemblies. Voltage differences between various pairs of electrodes are monitored by the Data Acquisition System.

The water chemistry monitoring system accepts low temperature /low pressure water from the recirculation sample line (via a tube-in-tube cooling coil and a constant temperature bath) and directs it past sensors which measure dissolved oxygen, dissolved hydrogen and conductivity. The water chemistry sensors and instrumentation are contained in a steel cabinet.

Outlet flow from the water chemistry system is routed to the reactor water cleanup sample rack (C121) drain. Analog voltage signals from the water chemistry instruments are routed to the data acquisition system.

The data acquisition system (DAS), which consists of a personal computer and a rack-mounted array of electronic instruments, is housed in an air conditioned shed located near the CAV system modules on reactor building elevation 51. The DAS also performs the ECP measurements, test vessel temperature measurements, and water chemistry measurements. The water temperature data, ECP, and water chemistry data are incorporated into a common data base that is stored on a hard disk.

The crack growth monitoring portions of the CAV system, which included the crack growth vessels (autoclaves) and associated data acquisition signals have been removed from the plant.

10.20.3.3 System Evaluation

The CAV system consists of a water chemistry monitoring station, the "A" recirculation pump suction decontamination flange, an LPRM with ECP probes if purchased, and an air-conditioned control room, all inter-connected by nuclear grade, fire resistant cables. The system is designed as a non-safety related system and is designed not to affect the safe operation of existing safety related systems. The recirculation decontamination flange and the LPRM flange, if used, are designed to meet the ASME Boiler and Pressure Vessel Code of the flanges replaced.

Figure 10.20-1 has been removed

Please refer to BECo Controlled Drawing M256

10.21 Hydrogen Water Chemistry Extended Test System

10.21.1 Design objective

The hydrogen water chemistry extended test system (ETS) is non-safety related. The ETS is designed to suppress the dissolved oxygen level in the reactor coolant system and mitigate intergranular stress corrosion cracking (IGSCC).

10.21.2 Design Basis

1. The ETS is designed to inject up to 15 SCFM hydrogen into the suction of the feedwater pumps for oxygen suppression in the reactor coolant system.

2. The ETS is designed to inject up to 10 SCFM oxygen into the offgas recombiner to recombine with the hydrogen carry-over produced with hydrogen injection into the feedwater.

3. The ETS is designed to inject oxygen into the suction of the condensate pumps for erosion corrosion protection.

4. The ETS is designed to provide redundant features to key components to improve reliability and has been designed to ANSI B31.1. However, it is not designed to Seismic Class I requirements.

10.21.3 Description

10.21.3.1 General

Boiling water reactors use high purity water as the primary recirculation coolant in the direct cycle production of steam. This water contains a steady state value of 100 to 300 ppb of dissolved oxygen and stoichiometrically related dissolved hydrogen because of the simultaneous action of radiolysis and stripping within the core. It is well known that this is sufficient oxygen in the coolant to cause, in conjunction with the presence of high stresses, intergranular stress corrosion cracking (IGSCC) of stainless steels.

Full scale testing at Pilgrim has shown that both the dissolved oxygen concentration in the recirculation water and the electrochemical potential (ECP) of sensitized type 304SS (304SS is the material of construction of the reactor pressure vessel lining) vary inversely with the rate of hydrogen addition to the feedwater.

As the dissolved oxygen concentration drops, so does the ECP; it is the ECP that determines the susceptibility of 304SS to IGSCC.

IGSCC of sensitized Type 304SS does not occur below -0.230V standard hydrogen electrode scale (SHE) (as measured by a standard hydrogen electrode). This critical value was identified and verified by a series of constant extension rate tests (CERTS) run in both laboratory and operating plant facilities while concurrently measuring the ECP.

During RFO 16 (Spring 2007), the initial application of noble metals was performed. The deposition of noble metal compounds on the wetted surfaces of reactor internal systems has been determined to enhance the effect of hydrogen water chemistry in controlling IGSCC. The intent is to deposit noble metal on the material surfaces of the reactor vessel internal components and recirculation system piping to significantly reduce the ECP in the presence of excess hydrogen concentration. (Reference 6). This has the effect of requiring a much lower hydrogen addition rate; the ETS design was modified to permit injection of up to 15 SCFM hydrogen. The exact level of hydrogen injection flow rate is determined as required to establish the required ECP.

The ETS also provides the capability to inject oxygen into the condensate system (suction of each condensate pump). This maintains condensate/feedwater dissolved oxygen levels in accordance with the BWR water chemistry guidelines for erosion-corrosion protection of the condensate/feedwater piping systems.

10.21.3.2 System Description

A flow diagram of the ETS system is given in Figures 10.21-2, 10.21-3, and 10.21-4 (drawings M257, 258, and 260).

The hydrogen water chemistry (HWC) extended test system (ETS) injects hydrogen into the feedwater at the suctions of the feedwater pumps to mitigate IGSCC in the recirculation system. The injected hydrogen forces a reduction in dissolved oxygen within the recirculation piping and lowers the radiolytic production of hydrogen and oxygen exiting the vessel (main steam) and eventually in the main condenser.

The injected hydrogen basically passes through the coolant cycle unreacted. This leaves an “excess” of hydrogen in the main condenser that would not have an equivalent of oxygen to recombine in the Offgas System. To maintain the Offgas System near its normal operating characteristics, a flow rate of oxygen equal to one half the injected hydrogen flow rate is put in the Offgas System upstream of the recombiner. Oxygen is also being injected into the condensate pump suctions to prevent erosion corrosion in carbon steel piping due to low PPM oxygen.

Three sample subsystems are included in the ETS package to measure: 1) feedwater water chemistry, 2) main steam water chemistry, and 3) % oxygen exiting the offgas recombiner. The ETS also uses signals from the CAVS and the MMS to measure Reactor water chemistry. All three subsystems contain built-in gas calibrators and sample stream conditioning controls.

A computer Data Acquisition System (DAS) is included to summarize the performance of the ETS for various report requirements. It is set up to accept analog input and digital alarm signals.

A block diagram indication the relationship of the ETS subsystems is shown in Figure 10.21-1.

Redundant features are incorporated into the ETS to improve reliability. These are:

- Hydrogen Flow Meters
- Oxygen Flow Meters
- Hydrogen Flow Controllers
- Oxygen Flow Controllers
- Oxygen Flow Control Valves
- Hydrogen Isolation Valves
- Offgas % Oxygen Meters
- Reactor Water Dissolved Oxygen Meters
- Reactor Water Conductivity Meters
- Main Steam Dissolved Oxygen Meters
- Feedwater Dissolved Oxygen Meters
- Recording
- Excess Flow Check Valves

Automatic or control features in the ETS minimize the need for operator attention and improve performance. These are:

a) Automatic variation of hydrogen and oxygen flow rate with power level.

b) Automatic offgas oxygen injection rate change delay. This function is also augmented as a function of power level.

c) Automatic shutdown on several alarms (See Table 10.21-1).

d) Isolation on power loss, operator restart.

e) Reprogrammable alarms and controller electronics.

f) Hydrogen and oxygen flow monitor correction functions to compensate for nonlinearities.

The majority of ETS process valving is grouped into three subsystems (modules). One for the hydrogen injection subsystem, the second for the oxygen injection subsystem to the recombiner, and the third for the oxygen injection subsystem to the condensate system. The hydrogen and oxygen gas sources are from high pressure hydrogen gas storage tanks and the liquid oxygen storage tank.

HWC ETS Hydrogen Supply

The gaseous hydrogen supply sub-system is located in the upper parking lot southwest of the Indoctrination and Support Facility.

The equipment consists of a permanent twelve tube bulk modular assembly, equipped with pressure indication, pressure relief, and temperature indication. The twelve tube assembly nominal gas capacity at 70°F is:

Pressure	Standard Cubic Feet
2640 psi	99,247

The storage vessels and system piping, valves and controls are designed and constructed in accordance with all applicable codes and standards including EPRI NP-5283SR-A, (Reference 1).

Provisions have been made at the storage facility to accept up to three (3) additional transportable hydrogen tube trailers to supply the extended test system and the generator cooling system.

HWC ETS Oxygen Supply

The liquid oxygen supply sub-system is located outside of the turbine building west wall near the southwest corner of the building.

The equipment consists of a 1500 gallon liquid oxygen tank (T-125) with pressure indication, level indication, and pressure, temperature control manifolds. Temperature control valves TCV-58 A&B are set at -20°F to close automatically to prevent any liquid oxygen from entering the system.

The storage vessels and system piping, valves and controls are designed and constructed in accordance with all applicable codes and standards including EPRI NP-5283SR-A, (Reference 1).

ETS Safety Features

The ETS process design incorporates several key safety features:

Non-flammable Offgas

Oxygen is injected into the offgas system upstream of the recombiner in stoichiometric or greater proportion to the hydrogen present to produce a non-flammable offgas through catalytic recombination of all hydrogen.

A built-in delay in the ETS control system insures that the oxygen injection rate decrease lags the hydrogen decrease (excess oxygen is present); and there is no oxygen delay during a hydrogen increase, again insuring excess oxygen in the offgas. This delay period is automatically adjusted for power level.

Low Power Isolation

There are two modes of operations for this system. The first mode of operation is to allow the ETS to automatically shutdown; as the reactor percent power decreases to a preset level (30%), the ETS automatically shuts down. Since the lower level is normally seen only during a reactor shutdown, this feature insures a low power isolation which would normally be accomplished by the reactor operating personnel. It also protects against loss of power level signal to the controllers.

The second mode of operation is to control the shutdown manually by implementing a bypass switch. This mode will allow the ETS to inject hydrogen below 30% reactor power, but will require the system to be secured manually. The ETS is operational while the AOG is in-service.

Automatic Reset of Hydrogen and Oxygen Flow Rates to Zero During ETS Shutdown

The hydrogen external and internal setpoints are disabled and are given a zero value immediately on system shutdown.

The oxygen flow will automatically follow the hydrogen flow rate with a delay and decay. A zero setpoint value is also input to the hydrogen rate limiter on shutdown so system restart with an external or internal setpoints proceeds from zero flow. Restart of the system can proceed only if the shutdown condition is cleared and the annunciator panel is reset. Systems restart should also be delayed fifteen minutes to allow for the ramp rate decay in the external or internal setpoint.

Valves

The flow control and remote isolation valves fail closed upon loss of instrument air or control power, insuring that flow does not proceed in an uncontrolled fashion.

Alarms and Shutdowns

The ETS incorporates numerous alarm and automatic shutdown functions. All alarm and shutdown signals have normally closed continuity, thus alarming or shutting the system down on an electrical wire break.

The ETS control hardware and control logic is designed to insure safe and accurate control of hydrogen and oxygen injection. Primary control of the system takes place at the HWC ETS control panel C613 on the turbine deck, but the system can be shutdown, though not adjusted or re-started, from the control room (Panel CP600).

All the parameters monitored are recorded regularly at a pre-set interval by the data acquisition system (DAS). The DAS also records all alarms and automatic and manual shutdowns. In addition to recording of various parameters at the control panel and DAS, the control room panel continuously displays the hydrogen and oxygen flow rates and the offgas percent oxygen., and the recirculation water dissolved oxygen content.

10.21.4 Codes, Standards, and Regulations

The mechanical and electrical aspects of the ETS are designed and selected in accordance with the applicable sections of the codes, standards, and regulations referenced below:

The ETS equipment and services are classified non-safety related.

ANSI B31.1 American National Standards Institute, Power piping
ANSI A13.1 Identification of Piping Systems
ANSI/ASTM G63 Evaluating Nonmetallic Materials for Oxygen Service
NEPA 70 National Fire Protection Association National Electrical Code
NFPA 50A Gaseous Hydrogen System
CGA G-4 Compressed Gas Association, Oxygen
CGA G-4.1 Cleaning Equipment of Oxygen Services
CGA G-4.4 Industrial Practices for Gaseous Oxygen Transmission and Distribution Piping Systems
CGA G-5 Hydrogen
ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications
Mass Building Code
EPRI NP-5283-SR, Dated September 1987, "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations", 1987 Revision

10.21.5 System Evaluation

The ETS consists of the equipment described above and is non-safety related. The ETS is designed not to affect the safe operation of existing safety related systems. The ETS is operational only when the Augmented Offgas is inservice.

Shielding has been added on the turbine deck for on-site and off-site personnel radiation protection. ALARA procedures and maintenance practices have been designed to limit exposure.

10.21.6 References

1. EPRI NP5283SR-A "Guidelines of Permanent BWR Hydrogen Water Chemistry Installations", 1987 Revision.

2. GE-NE-B13-01805-03, "Pilgrim HWC Ramping Test Final Report", December 1995.

3. NESD 95-241, "Optimum HWC Injection Rate for In Core Components IGSCC Protection"

4. PDC 02-122, "Licensing Issues – Thermal Power Uprate"

5. Safety Evaluation 2974, "Increase the ETS H_2 Injection Rate up to 50 SCFM"

6. ER 05117404, "Engineering Evaluation – Plant Configuration & Operation After Noble Metals Application".

EXTENDED TEST SYSTEM ALARMS AND SHUTDOWN SIGNALS

TABLE 10.21-1

Alarms	Units	Normal	Limit
A1 Hydrogen Flow to Setpoint Error	SCFM	+0.6	±1.5
A2 Low Hydrogen Pressure	PSIG	470	350
A3 High Hydrogen Area	%LEL	0	25
A4 High Offgas % O_2	%O_2	21	40
A5 High/Low % O_2 Sample Stream Pressure	PSIG	0	±2
A6 Low % O_2Flow	CCM	1000	500
A7 Low Oxygen Pressure	PSIG	0	50
A8 High Oxygen Pressure	PSIG	100	150
Shutdowns			
SD1 Local Demand		Closed	Open
SD2 Control Room Demand		Closed	Open
SD3 Lower Power	%Power	40-100	30 (Note 3)
SD4 Low Offgas %O_2	%O_2	21	5 (Note 4)
SD5 High-High Hydrogen Area	%LEL	0	75
SD6 High Hydrogen Flow	SCFM	8 (Note 1)	13.5 (Note 2)
SD7 High Hydrogen Pressure	PSIG	470	600
SD8 Low Hydrogen Injection Pressure	PSIG	250	150

Note 1: This value may change subsequent to the addition of noble metals. (Reference 6)

Note 2: There also is a variable high hydrogen flow trip setpoint which is 3.0 X S SCFM, where "S" is the hydrogen injection rate set at the hydrogen controller. (Reference 5)

Note 3: SD3 has a bypass switch to manually bypass this reactor power shutdown

Note 4: SD4 has a 5 second time delay before the shutdown logic is activated

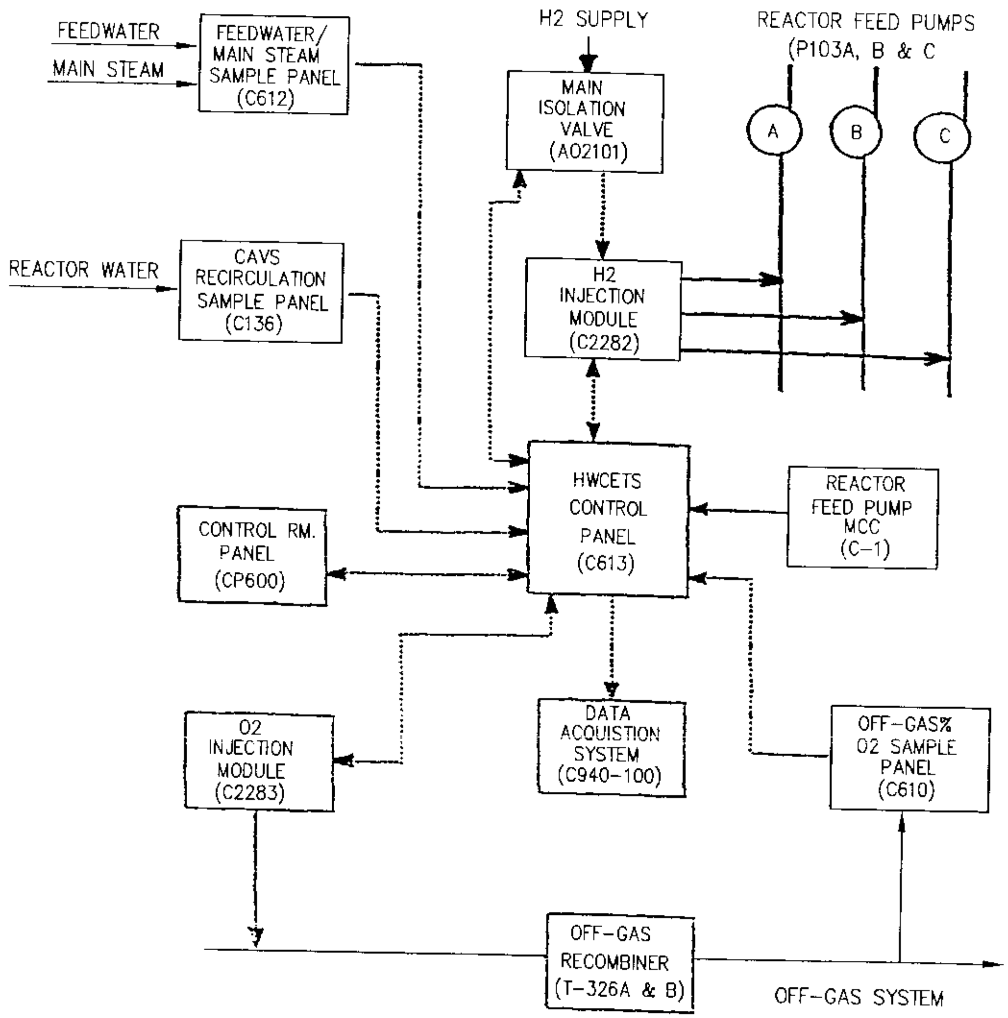


FIGURE 10.21-1

TITLE: ETS SUBSYSTEM DIAGRAM

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 26 OCTOBER 2007

AMM\MECH\FSAR-FIG.-10.21-1.

Figure 10.21-2 has been removed

Please refer to BECo Controlled Drawing M257

Figure 10.21-3 has been removed.

Please refere to BECo Controlled Drawing M258

Figure 10.21-4 has been removed

Please refer to BECo Controlled Drawing M260

10.22 Electrolytic Hydrogen Water Chemistry System (EHWCS)

10.22.1 Design Objective

The Electrolytic Hydrogen Water Chemistry System (EHWCS) is a non-safety related system designed to suppress the radiolytic formation of oxidants in the reactor coolant, thereby mitigating the potential for intergranular stress corrosion cracking (IGSCC) of the RPV recirculation inlet and outlet safe ends, recirculation inlet thermal sleeves, and recirculation piping. Suppression of the oxidants is attained by the controlled addition of hydrogen to the reactor coolant.

10.22.2 Design Basis

1. The EHWCS is designed to automatically inject hydrogen gas into the reactor feedwater to control the amount of oxidants in the reactor coolant.

2. The EHWCS is designed to automatically inject oxygen into the offgas system to recombine with the hydrogen injected into the feedwater.

3. The EHWCS is designed to inject oxygen into the condensate system to maintain a minimum level of dissolved oxygen in the condensate and feedwater piping to prevent erosion/corrosion.

4. The EHWCS is designed to generate its own hydrogen and oxygen gases as they are being used by the system. Gases are generated by the electrolysis of water.

5. The piping and components downstream of the gas generator of the EHWCS are designed to contain explosions.

6. The EHWCS is designed to meet the EPRI NP-5283-SR-A Guidelines for Permanent BWR Hydrogen Water Chemistry Installations.

7. The EHWCS is designed to generate gases at pressures slightly above atmospheric to avoid any air in-leakage and minimize the driving pressure in case of out-leakage.

8. The EHWCS is designed to automatically shut down the gas generator and isolate the downstream system under upset conditions including: a hydrogen leak detection, oxygen is detected in the generated hydrogen, excessive heat and pressure are detected in the EHWCS, or plant shutdown occurs.

10.22.3 Description

10.22.3.1 General

Boiling water reactors use high purity water as the primary recirculation coolant in the direct cycle production of steam. This water contains a steady state value of 100 to 300 ppb of dissolved oxygen in the recirculation system with less than a stoichiometric concentration of dissolved hydrogen. The coolant in the pressure vessel contains considerably higher concentrations of oxidants (oxygen and hydrogen peroxide) and, due to stripping, less than the stochiometric concentration of hydrogen. This oxygen concentration, in conjunction with the presence of high stresses, is sufficient to cause intergranular stress corrosion cracking (IGSCC) of stainless steels.

Full scale testing using ETS (see Section 10.21) has shown that both the dissolved oxygen concentration in the recirculation water and the electrochemical potential (ECP) of sensitized Type 304SS (304SS is the material of construction of the reactor pressure vessel nozzle safe ends and thermal sleeves) vary inversely with the rate of hydrogen addition to the feedwater. As the dissolved oxygen concentration drops, so does the ECP; it is the ECP that determines the susceptibility of 304SS to IGSCC.

Electrochemical potential is measured on the Standard Hydrogen Electrode (SHE) scale. IGSCC of sensitized Type 304SS does not occur below -0.23V (SHE). This critical value was identified and verified by a series of Constant Extension Rate Tests run in both laboratory and operating plant facilities while concurrently measuring the ECP. Measurements have been made at Pilgrim of the ECP at various hydrogen injection rates to determine the injection rate required to reduce the ECP to a value below the IGSCC threshold.

The feedwater hydrogen concentration at Pilgrim to provide IGSCC mitigation to the nozzle safe ends and thermal sleeves, ECP ≥ -0.230V (SHE), is 0.88 ppm with approximately 2 ppb dissolved oxygen in the recirculation water. This condition is obtained with an injection rate of 22.6 SCFM (nominally 23 SCFM) of hydrogen into the feedwater at 100% reactor power.

It has been found that certain reactor internal components are also susceptible to IGSCC and IASCC (Irradiation Assisted Stress Corrosion Cracking). Testing at other utilities has shown that to achieve an ECP OF -230V (SHE) for protection on reactor internals requires considerably more hydrogen injection to the feedwater. At the system capacity injection rate of 50 SCFM the recirculation dissolved oxygen content is about 0.5 ppb and the feedwater dissolved hydrogen concentration is about 2 ppm.

The EHWCS also provides the capability to inject oxygen into the offgas system to combine with the hydrogen injected into the feedwater and into the condensate system (suction of each condensate pump) to maintain the dissolved oxygen at 20 to 50 ppb for erosion/corrosion protection of the condensate/feedwater system piping. EPRI normal water chemistry guidelines recommend and station procedures require the condensate/feedwater system dissolved oxygen level to be within 20-50 ppb.

The EHWCS is shown schematically in Figure 10.22-1 (BECo M269).

10.22.3.2 Gas Generator and Operating Characteristics

Hydrogen and oxygen gases used by the EHWCS are generated by electrolysis of water in a 25% by weight potassium hydroxide solution. Electrolysis is performed in 18 independent cells containing electrodes, electrolyte, and separators. An electric current dissociates the water of the electrolyte solution into hydrogen and oxygen. The gases are separated as they form and move upward into separate compartments above the electrolyte. As water is consumed, it is replaced from the plant demineralized water system. Potassium hydroxide is not consumed in the process.

As the hydrogen and oxygen gases leave the individual cells, they are sent through water cooled scrubbers to remove electrolyte that may be entrained with the gas. From the scrubbers, the gases are conveyed to compartments which are separate, inverted vessels (water seals) placed in a common water tank. These water seals, located on the "gas conditioning skid", are passive pressure regulators configured in a manner to equalize the hydrogen and oxygen pressures and maintain a cell pressure between 3 to 10 inches of water gauge.

From the inverted vessels, the gases pass through separate air operated valves to purification equipment located on the gas conditioning skid. Purification equipment includes additional scrubbers, moisture separators, and for the hydrogen gas, a catalytic purifier which removes residual oxygen from the hydrogen stream. From the gas conditioning skid, the hydrogen gas flows through the inert gas purge module to the compression module. Oxygen flows to the oxygen injection module.

The 18-cell system can generate about 50 standard cubic feet of hydrogen and 25 standard cubic feet of oxygen per minute. The water replacement requirement is about one gallon of demineralized water for each 130 standard cubic feet of hydrogen generated.

10.22.3.3 Compression Modules

Six jet compressors on the hydrogen compression module (HCM) are used for pressurizing the hydrogen sufficiently for injection into the feedwater system. The compressor driving force is nuclear steam. The steam is subsequently condensed in the HCM condensers by plant condensate.

Oxygen is compressed with two jet compressors, one for each offgas train. Oxygen can be sufficiently compressed with just one compressor. The oxygen compressor connected to the operating offgas train is operated. The oxygen compressors use part of the dilution steam (used to drive the Offgas system steam jet compressor) for the motive fluid.

10.22.3.4 Pneumatic Backpressure Regulators

The HCM and oxygen compressors have been designed for inlet pressures corresponding to the maximum required gas generation rate (50 SCFM). At lower gas generation rates, the HCM and oxygen compressors will draw a vacuum at their inlets that is too low for the gas generator. Backpressure regulators have been incorporated in the hydrogen and oxygen flow paths between the gas generator and the jet compressors to prevent a vacuum from being drawn on the gas generator. See Figure 10.22-1 (Drawing M269).

10.22.3.5 Process Flow Path Components

Besides the gas generator, compression modules and backpressure regulators, the other components that comprise the EHWCS include valves, pressure regulators, and sensors. These components are clustered in the following modules: inert gas purge module, hydrogen vent/injection module, hydrogen injection isolation module, offgas oxygen injection module, condensate oxygen injection module, condensate oxygen isolation module, and loop seal module. The hydrogen and oxygen gases flow from the gas generator through the respective pipes, pneumatic backpressure regulators, compressions modules, and these modules to their respective injection points. Automatic valves (operated by system controls that are interlocked with the operating condensate and feedwater pumps and operating offgas train) are located in the respective injection modules. See Figure 10.22-1 (Drawing M269) for the process flow path.

To avoid air in-leakage, all valves in the hydrogen flow path that may operate at sub-atmospheric pressures are made with diaphragms or bellows seals. In addition, the valves have packing type stem seals for backup (except check valve 73-CK-F012, which is an in-line check valve). Pipes between modules are progressively sloped (1/4" per foot) to drain any condensate that may form in the pipe. A loop seal has been added to the oxygen line to drain the condensate in that line.

10.22.3.6 Gas Generator Building

The gas generator, gas conditioning skid, and inert gas purge module are housed in a building shown on the plot plan, Figure 1.6-1 (Drawing C2). The gas generator building (GGB) has continuously open vents sized to provide sufficient air dilution to prevent a detonable mixture of a full capacity (50 SCFM) hydrogen leak. As a further precaution, hydrogen area monitors are mounted in the roof vents clustered over the gas generator and over the gas conditioning skid. These monitors will alarm in the main control room if the hydrogen in air concentration at the monitors exceed one (1) percent and initiate a controlled shutdown of the gas generator and the system if the hydrogen in air concentration at the monitors exceeds two (2) percent. An immediate shutdown of the gas generator and system will be implemented if the hydrogen in air concentration at the monitors exceeds three (3) percent.

10.22.3.7 Electrolytic System Controls

The main control module of the EHWCS is a GE Nuclear Measurement, Analysis, and Control (NUMAC) System computerized process controller. This NUMAC module plus the relay logic, the gas generator local controls, the HCM local controls, and the pressure regulators, solenoid valves and sensors of the above described modules listed in Section 10.22.3.5 constitute the EHWCS controls.

The EHWCS NUMAC module performs the following functions:

- Receives appropriate sensor signals for processing
- Displays messages indicating EHWCS status
- Prompts the operator to take appropriate action
- Records selected data
- Provides control signals to operate EHWCS components including specific valves and alarms
- Provides a gas generation rate demand signal as a function of feedwater flow
- Provides for two types of automatic shutdown
- Provides for adjustments of operational parameters
- Provides for manual operation for system testing

Except for the manual initiation of some events reserved for the operator and manual startup of the gas generator, the EHWCS is automatically controlled during normal operation. Operator action is required (at the NUMAC module) to initiate an EHWCS start and to initiate hydrogen injection. There is a "Standby" (vent) mode that normally occurs automatically between the "Start" and "Injection" modes, but this mode can also be initiated by the operator (at the NUMAC module) while hydrogen injection is in progress.

During hydrogen injection, the gas generation rate is automatically controlled as a function of feedwater flow. This functional relationship was designed to result in just sufficient hydrogen injection for suppressing IGSCC. The functional mathematical relationship between gas generation rate and feedwater flow has some constants that can be manually changed as required to shape the relationship should that become necessary.

The generated oxygen is always the stoichiometric equivalent of the generated hydrogen. During a normal EHWCS start or shutdown, NUMAC automatically ramps the gas generation rate and sequences local venting in a meter to maintain the oxygen concentration in the offgas system within limits.

The control system is designed for automatic shutdowns in the event of most postulated problems; however, the operator can initiate an EHWCS shutdown (at the NUMAC module) if it is deemed necessary.

The start mode automatically purges the hydrogen flow path with helium between the gas generator isolation valve (F010) in the inert gas purge module and the high pressure vent tee in the Hydrogen Vent/Injection Module. The helium and the purged gases discharge through the high pressure vent into the Offgas system. Automatic inert gas purge flow is terminated following a specific time delay after low oxygen is sensed at the high pressure vent.

NUMAC prompts the operator to manually start the gas generator. The gas generator is started manually at a local control panel because local indicators of liquid levels need to be observed before and after the gas generator is started and manual valves and switches must be operated. After the gas generator is started, it is switched to "remote" for control by the NUMAC module.

Under NUMAC control, the HCM will start automatically, provided manual valves and switches have been correctly aligned. The system will begin to pressurize with hydrogen generated at approximately 5 SCFM. When approximately 390 psig supply pressure is reached, the gas generation rate is reduced to approximately 2.5 SCFM in preparation for venting through the high pressure vent backpressure regulator (PCV-F043). When the high pressure vent backpressure regulator setpoint is reached, hydrogen will be vented out the high pressure vent to the offgas system.

Venting will continue until either the operator selects the injection mode (at the NUMAC module) or, after a preset adjustable time of 20 to 240 minutes, the system shuts down automatically. When the injection mode is initiated by the operator, the following actions occur: 1) the vent valve is automatically closed, 2) the air-operated injection valves are automatically opened in the lines to the operating feedwater pumps, and 3) hydrogen pressure continues to increase until it exceeds the hydrogen supply line backpressure regulator (PCV-F082) setpoint. Then the hydrogen line downstream of the hydrogen supply line backpressure regulator pressurizes to the feedwater pumps suction pressure.

After an adjustable time delay (0 to 99 minutes), oxygen injection into the offgas system will commence. Then the hydrogen and oxygen generation rate will automatically increase at a ramp rate designed to keep the oxygen concentration in the offgas within limits until the gas generation rate reaches the NUMAC steady state hydrogen flow corresponding to feedwater flow. The injection rate will be the same as the generation rate as long as pressures are steady. There will be a slight difference between generation rate and injection rate during pressure transient because of the variation in gas flow path contents with pressure.

The NUMAC module is programmed such that the operator may select "Minimum Flow", "Maintenance Flow", or "Return to Vent" mode while injecting. When "Minimum Flow" mode is selected, the gas generation rate is reduced to approximately 2.5 SCFM of hydrogen and approximately 1.25 SCFM of oxygen on a ramp designed to maintain the concentration of oxygen in the offgas within limits. Injection takes place during the ramp-down and continues after the minimum flows are reached.

The purpose of the "Maintenance Flow" mode is to reduce radiation levels in the turbine building without reducing reactor power so that walkthroughs may be performed. When this mode is selected, the gas generation rate is reduced to a hydrogen flow rate which, in turn, reduces the turbine building radiation levels.

When the operator selects the "Return to Vent" mode, the gas generation rate is automatically reduced to approximately 2.5 SCFM of hydrogen and approximately 1.25 CFM of oxygen on a ramp designed to maintain the concentration of oxygen in the offgas within limits. After the approximately 2.5 SCFM of hydrogen flow is reached, hydrogen injection into the feedwater is terminated and, in the vent mode, hydrogen flow is passed through the high pressure vent to the offgas system with dilution air.

There are two types of automatic shutdown for the system. They are designated ASD-1 and ASD-2. They may occur automatically during various abnormal system conditions or they may be selected by the operator from NUMAC.

The ASD-1 stops hydrogen injection immediately, stops the HCM steam compressor, ramps down the gas generation rate to maintain offgas percent oxygen levels within the normal range, then stops oxygen injection and opens the purge valve. During the ramp down, the hydrogen generated is vented out of the gas generator building (GGB) roof vent.

The ASD-2 immediately stops hydrogen and oxygen injection, the gas generator, the HCM, and open the purge valve. Offgas oxygen levels are allowed to go out of limits for a maximum of 24 hours.

10.22.4 Hazards Addressed by the Design

The hazards addressed by the design include: 1) the minimization of potential combustible, explosive or detonable mixtures of hydrogen with air or oxygen, 2) the use of low concentration of potassium hydroxide solution to make the electrolyte, and 3) protection of the operators from high currents necessary to generate the hydrogen and oxygen gases.

The design is based on the fact that combustible, explosive, and detonable sources can be minimized by avoiding air in-leakage, performing proper purges, and applying engineering expertise on proper sealing of hydrogen, combustion limits, explosion characteristics, dilution effects, and detonation run-up distances. Since hydrogen and air mixtures require very little energy to ignite, the design assumes there can be an ignition, minimizes the potential for ignition sources, but provides for the containment of explosive effects wherever possible.

Training of personnel has been provided in the use of potassium hydroxide as the electrolyte solution. The electrolyte is maintained in fully enclosed vessels. A 25% solution (by weight) is used, and any electrolyte carried over with the gas is stripped from the gas and returned to the cells. Multiple scrubbing actions are implemented in the process. If a spill does take place, hose cocks and an eye wash are provided as well as signs in various areas to remind the trained workers of the potential danger and emergency care.

The system minimizes the electrical hazard by using low voltages at the cells (2.1 to 2.4 V between cells and a minimum of 38 to 43 V DC between bus bars). Although the bus bars are open for convective cooling the design is configured so that the bus bars will not have to be handled during operation.

10.22.5 Safety Features of the Design

The EHWCS design incorporates the following key safety features:

Flammable gases generated as needed

Hydrogen and oxygen gases are generated as needed. No volumes of gases under high pressures are stored on site for the EHWCS.

Gases are generated a slightly above atmospheric pressure

Gases are generated above atmospheric pressure to avoid any air in-leakage. The pressures are slightly above atmospheric, less than one (1) psig, to minimize the driving pressure in case of out-leakage and to minimize the overpressure should an internal explosion occur.

Non-Flammable Offgas

Oxygen is injected into the offgas system to recombine with the excess hydrogen evacuated from the main condenser, thereby producing a non-flammable offgas by the catalytic recombination of all the hydrogen.

Containment of Explosions

All components downstream of the gas generator are designed to contain potential explosions.

Automatic Purging

The hydrogen flow path is automatically purged between the purge module and the hydrogen vent/injection module during every start. The purge continues until no oxygen is sensed in the high pressure vent.

Automatic termination of gas supply or isolation of system

The gas generation will automatically stop, or isolation of the downstream system from the gas generator will occur, during system upset conditions including but not limited to the following:

1. A hydrogen leak is detected by hydrogen area monitors located in the GGB vents above the gas generator and gas conditioning module and above the HCM and hydrogen vent/injection module in the turbine building.

2. Excessive heat is detected over the electrolytic cells.

3. A hydrogen leak is detected by a flow mismatch between the gas generation rate and either of the two flowmeters located in the hydrogen vent/injection module.

4. Presence of oxygen is detected in the generated hydrogen.

5. A hydrogen leak is detected by an abnormal pressure at the Hydrogen Vent/Injection Module.

6. The temperature of the hydrogen leaving the HCM exceeds 160°F.

7. Hydrogen pressure exceeds 550 psig at the hydrogen vent/ injection Module.

8. A main turbine trip occurs.

9. Operator selects a shutdown.

Location and Ventilation of the Gas Generator Building

The gas generator is located in a building sited far enough from any potential ignition source, such as a diesel or motor, to preclude the possibility of any ignition of a combustible mixture. In addition, the building is passively ventilated to prevent the accumulation of an explosive mixture of hydrogen and air occurring, if a hydrogen leak is assumed.

As an added precaution, hydrogen monitors are installed in the GGB vents over the hydrogen generation and purification modules which will initiate an automatic shutdown if high hydrogen concentrations are detected.

Pipe Containing Hydrogen

Pipes containing hydrogen pass only through ventilated areas.

Hydrogen Flow Path Materials

All valves in the hydrogen flow path, in and downstream of the sub-atmospheric portion of the system, are spark resistant. All hydrogen flow path pipes downstream of the gas generator are made from stainless steel to minimize corrosion particles that may cause sparks.

Augmented Oxygen Injection System

An augmented oxygen injection system which uses a 75% oxygen gas bottle was added as a modification to the EHWCS. This augmented system will actuate during an ASD2 type system shutdown.

10.22.6 Codes and Standards

The following Codes and Standards were used in the design of the EHWCS:

1. ANSI B31.1, 1983 Edition with Summer 1985 Addenda, American National Standards Institute, Code for Power Plant Piping
2. ASME Section VIII, Div. 1 - 1983 Edition with Summer 1985 Addenda, American Society of Mechanical Engineers - Unfired Pressure Vessels
3. TEMA Class C, Tubular Exchanger Mfg. Association
4. ASME Section IX, 1983 with Summary 1985 Agenda Engineers - Welding Qualifications
5. NFPA 70, National Fire Protection Association, National Electric Code
6. NFPA 50A, National Fire Protection Association, Gaseous Hydrogen Systems
7. EPRI NP-5283-SR, Electric Power Research Institute, Guidelines for Permanent BWR Hydrogen Water Chemistry Installations, September 1987

10.22.7 Safety Evaluation

The following sections represent the results of a safety evaluation for normal operation with hydrogen water chemistry at injection rates of 23 SCFM (piping protection) and 50 SCFM (system capacity).

10.22.7.1 Drain Sumps

The introduction of hydrogen into the feedwater system increases the amount of hydrogen in the reactor and turbine building equipment sumps. These increases were measured during the hydrogen water chemistry pre-implementation test at Pilgrim. Feedwater hydrogen concentration was increased from essentially zero to a maximum of 2.0 ppm at the 50 SCFM injection rate. Reactor recirculation water hydrogen concentration was increased from 10 ppb to a maximum of 250 ppb at the 50 SCFM injection rate. A slight hydrogen decrease occurred in the steam because the feedwater hydrogen suppresses the formation of radiolytic hydrogen. Still, the water from the steam contained more hydrogen than either the feedwater or the recirculation water.

The reactor and turbine building equipment drain sumps can receive water from the main steam, feedwater, and recirculation systems. If it is conservatively assumed that all the sump water comes from the main steam, all the hydrogen escapes from the water in the sump, the water level in the sump is at the high limit and the gas in the sump space is diluted only with steam coming from the sump water, then the hydrogen concentration in the sump air space is lower with HWC than without HWC. It is, therefore, concluded that the hydrogen water chemistry implementation will not adversely impact the safety of the reactor and turbine building drain sumps.

HWC has no effect on the hydrogen concentration in floor drain sumps since this water is not pressurized condensate, reactor water, or feedwater. Also HWC will not affect the hydrogen in the radwaste equipment drain sump since this sump does not receive pressurized reactor water or feedwater.

10.22.7.2 Torus Airspace Hydrogen Concentration After SRV Blowdown

Hydrogen injection into the feedwater at up to 50 SCFM slightly decreases the hydrogen addition rate to the torus by the SRV as compared to no hydrogen injection. Oxygen blowdown is decreased with injection and the inerted containment eliminates the possibility of forming a combustible mixture.

10.22.7.3 Effect of Feedwater Leakage in the Drywell

It is possible for a small feedwater pipe leak to exist that is less than the Technical Specification limit of 25 gpm. If hydrogen is injected into the feedwater at up to the maximum of 50 SCFM, there will be a maximum of approximately 2 ppm of hydrogen in the feedwater. If it is conservatively assumed that all of the hydrogen comes out of solution before the leaked feedwater goes into the drywell floor drain, a 25 gpm leak would correspond with a maximum of approximately 115 SCF of hydrogen being released to the drywell in a 24 hour period. This addition would be less than 0.08% of the drywell free air volume so that even if the drywell was filled with air, a combustible mixture would not accumulate. During normal plant operation (except during startup or shutdown), the drywell is filled with nitrogen. Without oxygen present, hydrogen cannot form a combustible mixture, and plant safety is maintained.

10.22.7.4 Limiting Transient Consequence

The following five transients are considered as limiting in the operation of the EHWCS.

Hydrogen Leaks That Do Not Initiate ASD

Hydrogen leaks from system components that are either too small to be detected or occur during the pressurization transient when the flow and pressure trip features of the system are inoperative will not adversely impact the EHWCS or components.

Small leaks cannot lead to an accumulation of a hydrogen and oxygen mixture that could detonate because the gas generator building has sufficient passive ventilation and the condenser bay and turbine buildings have sufficient forced ventilation to avoid combustible mixtures. Low velocity leaks could ignite either at the leak point or flash back to the leak point resulting in a less than 10-inch length flame that could be detected due to excess heat generation before significant harm or damage could be done. Hydrogen flow path components other than welded pipe that could not be located away from equipment are shielded such that a flame could not impinge onto equipment necessary for plant operation. Baffles to prevent a flame from impinging onto equipment required for operation are designed such that pockets of hydrogen cannot accumulate and hence local detonations cannot occur.

Any leak during the pressurization phase of a start when the flow and pressure initiation automatic shutdown features are inoperative, would be a maximum of approximately 5 SCFM after pressure release. If the leak is at or near the gas generator, the HCM of the hydrogen vent/injection module, the most likely places for leaks, a hydrogen area monitor initiated automatic shutdown will occur.

Failure to Purge Hydrogen Flow Path Components

Failure to purge the hydrogen flow path components or an air leak into the portion of the hydrogen flow path that is at sub-atmospheric pressure during EHWCS operation can lead to combustible mixtures of hydrogen inside the system.

The EHWCS has been designed to avoid ignition sources. All valves in the hydrogen flow path in and downstream of the sub-atmospheric portion of the system are spark resistant. All valves and components downstream of the gas generator are made from stainless steel to minimize the potential for corrosion in the hydrogen flow path. Condensers of the HCM are designed to trap particulates to avoid rust impingement-caused sparks.

If ignition occurs and the hydrogen/air mixture is high enough to support detonation, the pipe runs are long enough for detonations to occur. However, there is not sufficient impact energy from the detonation pressure spikes to fracture the Schedule 80 stainless steel pipes at any pre-detonation pressure within the range of hydrogen injection pressures. If an explosion occurs in the gas generator, the consequences of a plastic tube break would be the same as for any hydrogen leak in the GGB.

Low Offgas Oxygen Transient

This limiting transient occurs when the oxygen injection into the offgas system is terminated while hydrogen injection continues. This condition could result in a combustible mixture of hydrogen and air in the offgas system.

Out-of-limits mixtures due to termination of oxygen should be detected unless the condenser in-leakage is very high (greater than 70 SCFM). Alarms, low oxygen and high oxygen, would annunciate in the main control room. Based on BWR operating experience, an ignition incidence of combustible mixtures in the offgas system occurs in 1 out of every 24,000 hours of operation. Since the excess hydrogen arriving at the offgas would last less than 12 minutes and combustible mixtures would exist in the hold-up part of the offgas system for less than 24 hours, the probability of ignition and subsequent detonation is low. Even in the unlikely event a detonation were to occur, the offgas system is designed to withstand the detonation pressure.

Hydrogen Flow to the Offgas System Without Dilution Air

A limiting transient occurs when a surge of hydrogen flow from the main flow path through the high pressure vent occurs or a leak exists through purge valves F029A,B, or C (See Figure 10.22-1). Either occurrence could result in a combustible mixture of hydrogen and air downstream of the high pressure vent connection. The probability of ignition and subsequent detonation of this combustible mixture is very low; but if it did occur, the Offgas system is designed to withstand the detonation pressure. If the leak continues, it would be detected by monitoring offgas system parameters during EHWCS vent evolution or by operational assessment of water chemistry.

High Offgas Oxygen Transient

The termination of hydrogen injection while oxygen injection continues causes the oxygen concentration in the offgas to increase. An alarm is annunciated in the main control room when the oxygen concentration in the offgas reaches the oxygen setpoint, nominally 40%. Therefore, the operator will be aware of the high oxygen levels within a few minutes.

10.22.7.5 Accidents within the EHWCS

The EHWCS is not safety-related. The system has been designed such that a postulated failure will not affect the operation of any safety-related systems. The piping and components of the system are placed sufficiently distant from any safety-related equipment such that a perturbation from a leak which could potentially lead to a detonation or fire will have no adverse effect on any safety-related equipment.

10.22.7.6 Earthquake

The EHWCS is designed to withstand static loads at the various component centers of gravity of 0.33g horizontal and 0.13g vertical. Because of the design considerations discussed in 10.22.7, the consequences of a seismic induced failure to safety-related components will be no worse than postulated accidents considered in the development of the design.

10.22.7.7 Tornado, Flood, Plane Crash

The total volume of hydrogen in the EHWCS at any given time is less than 200 SCF. If an external event destroyed the gas generator building, gas generation would cease, and the hydrogen gas present would dissipate. If the damage would cause a leak, the gas would continue to vent with no deleterious effects.

10.22.7.8 Radiation -ALARA Considerations

Adding hydrogen to the feedwater results in an increase in Nitrogen 16 (N-16) activity in the reactor steam due to a chemical change that occurs in the reactor core. The N-16 isotope, a gamma emitter with a half life of 7.1 seconds, is formed by neutron reaction with oxygen 16 in the reactor water. Without hydrogen addition, the N-16 reacts with oxygen to form a nitrate ion which is nonvolatile at reactor temperatures. With hydrogen injection, volatile nitrogen compounds are formed which are swept out of the reactor with the steam. Because of the short half life of N-16, radiation levels drop to the pre-hydrogen injection level within minutes after hydrogen addition is terminated. (Dose rates can also be reduced by selecting the "Maintenance" turn down mode).

Concrete shield walls have been installed along the external turbine building walls which are designed to minimize the higher radiation levels caused by hydrogen addition.

10.22.7.9 High Hydrogen in Offgas Post ASD2

During an off normal or emergency ASD2 shutdown, hydrogen and oxygen generation is terminated instantly, but the hydrogen still in transit from the feedwater pumps to the condenser will continue resulting in a hydrogen rich environment in the AOG and a potentially detonable condition when ignition sources are present. A 75% pure oxygen gas storage and injection subsystem is installed to eliminate any threat of AOG/offgas system damage from hydrogen detonation induced by a EHWC ASD2. This subsystem is to be on standby and ready to inject oxygen to reduce hydrogen gas concentration once an ASD2 is detected. The injection will continue for a controlled time to provide adequate oxygen to recombine with the excess hydrogen.

10.22.8 Inspection and Testing

Inspection and Testing will be performed in accordance with EPRI guidelines NP-5283-SR-A 1987 revision.

The electrolytic HWC system is not used. The extended test system (ETS) is the HWC system currently in use. The ETS is inspected and tested per NP-5283-SR-A 1987.

Figure 10.22-1 has been removed

Please refer to BECo Controlled Drawing M269

10.23 Mitigation Monitoring System

10.23.1 Design Objective

The mitigation monitoring system (MMS) is designed to support the noble metals chemical application at Pilgrim Station. The noble metals process has been developed to reduce the potential for intergranular stress corrosion cracking (IGSCC) of reactor vessel internal components and recirculation piping. The process consists of depositing very small amounts of platinum and rhodium metal on the wetted surfaces within the reactor vessel and the reactor recirculation system piping. The noble metal deposits catalyze recombination reactions of hydrogen with oxidants at these surfaces. The MMS provides a means of monitoring the concentration of the applied noble metals coating as a function of plant operating time. The time trend can be used to establish when a reapplication is needed.

10.23.2 Design Basis

1. The MMS is designed to provide a means of monitoring the electrochemical corrosion potential (ECP) of the reactor water.
2. The MMS is designed to provide means of monitoring the concentration of the noble metals coating as a function of plant operating time.
3. A data acquisition system is provided for monitoring MMS parameters, as well as for providing the various analog output signals available from the MMS.

10.23.3 Description

10.23.3.1 General

The MMS includes a skid mounted piping assembly and a data acquisition system. The MMS system consists of three hardware packages:

- ECP monitoring
- Durability monitoring
- Data acquisition system (DAS) panel

The ECP monitoring package consists of a piping manifold that will accept two ECP reference electrodes in a cartridge configuration. The durability monitor (DM) package provides a series of tube samples that can be used as an independent means of monitoring the concentration of the as-applied noble metals coating as a function of plant operating time. The DAS panel provides remote indication for the flow and temperature sensors mounted on the MMS panel. In addition, a personal computer and associated signal processing instruments are provided to select and measure the various analog voltage signals available from the MMS.

10.23.3.2 System Description

The MMS is installed in the reactor building. The MMS panel is provided with high pressure and temperature water; the connection point for the inlet sample line is the existing recirculation system sample line. The sample water first passes through the ECP monitor section and then through the series of DM tube samples. Finally the sample water returns to the reactor water cleanup system.

The durability monitor consists of a series of tube specimens that have been conditioned in BWR primary system water and then treated with noble metals at the same time as the plant. These specimens then represent typical plant surfaces in other regions of the plant primary system. The samples can be removed at convenient intervals and analyzed to determine the quantity of noble metal remaining on the interior surfaces. The data permits a time history of the level of noble metal material remaining so that the need for reapplication can be adequately evaluated.

The ECP monitor provides real time measurements of the electrochemical corrosion potential in the primary system environment. This assembly allows two ECP reference electrodes to be installed in special ports in the MMS piping. The pipe sections in this manifold are sized to maintain the annular flow velocities needed to assure that the noble metal film applied to the DM samples will also be applied to the ECP manifold pipe sections. This will assure that the ECP electrodes will provide a representative measure of the ECP of the noble metal film throughout the plant operating cycle.

The data acquisition panel provides data processing, signal conditioning, and data file manipulation for the ECP electrodes, for the sensors on the MMS skid, and for additional chemistry signals. The DAS panel contains a personal computer with software to acquire and process the analog signal inputs.

10.23.3.3 System Evaluation

The MMS consists of a durability monitoring section, an ECP monitoring section, and a data acquisition system. The system is designed as a non-safety related system and is designed not to affect the safe operation of existing safety related systems. The interconnecting piping design is in accordance with the plant piping specifications and codes.

SECTION 11

POWER CONVERSION SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont)

SECTION 11

LIST OF FIGURES

SECTION 11

POWER CONVERSION SYSTEMS

11.1 SUMMARY DESCRIPTION

The Power Conversion Systems are designed to produce electrical energy through conversion of a portion of thermal energy contained in the steam supplied from the reactor; condense the turbine exhaust steam into water; return the water to the reactor as heated feedwater with a major portion of its gaseous, dissolved, and particulate impurities removed.

The major components of the power conversion system are: turbine-generator, main condenser, condensate pumps, air ejector, turbine gland seal system, turbine bypass system, condensate demineralizers, reactor feed pumps, feedwater heaters, and condensate storage system. The heat rejected to the main condenser is removed by the Circulating Water System.

The saturated steam produced by the boiling water reactor (BWR) is passed through the high pressure turbine where the steam is expanded and then exhausted through the moisture separators. Moisture is removed in the moisture separators and the steam is then passed through the low pressure turbines where the steam is again expanded. From the low pressure turbines the steam is exhausted into the condenser where the steam is condensed and deaerated, and then returned to the cycle as condensate. A small part of the main steam supply is continuously used by the steam jet air ejectors. The condensate pumps, taking suction from the condenser hotwell, deliver the condensate through the air ejector condensers, turbine gland seal condenser, condensate demineralizer, and three stages of low pressure feedwater heaters to the reactor feed pumps. The reactor feed pumps supply feedwater through two stages of high pressure feedwater heaters to the reactor. Steam for heating the feedwater in the heating cycle is supplied from turbine extractions. The feedwater heaters also provide the means of handling the moisture separated from the steam in the turbine and in the moisture separators. Normally, the turbine utilizes all the steam being generated by the reactor. However, an automatic pressure controlled steam bypass system is provided to discharge excess steam, up to 25 percent of the design flow, directly to the condenser.

The power conversion systems are designed for the turbine-generator maximum capacity which occurs at the valves' wide open (VWO) condition.

11.2 TURBINE-GENERATOR

11.2.1 Power Generation Objective

The objective of the turbine-generator is to receive steam from the boiling water reactor (BWR), and economically convert a portion of the thermal energy contained in the steam to electric energy, and provide extraction steam and moisture for feedwater heating.

11.2.2 Power Generation Design Basis

The turbine-generator and the associated systems, and their control characteristics, are integrated with the features of the reactor and associated nuclear systems to obtain an efficient and safe power generating unit.

11.2.3 Description

The turbine-generator consists of the following components: turbine, generator, exciter, controls, and required subsystems.

The turbine is a tandem-compound, non-reheat unit with 43 inch last stage buckets. It consists of a double flow high pressure turbine and two double flow low pressure turbines. There are seven stages in the high pressure turbine and eight stages in each low pressure turbine. Exhaust steam from the high pressure turbine passes through moisture separators before entering the two low pressure turbines. The separators reduce the moisture content of the steam to less than 0.2 percent.

The generator is a direct-coupled, three-phase, 60 Hz, 24,000 V, 18,764 amp, conductor cooled armature winding, synchronous generator rated 780,000 kVA, a short circuit ratio of 0.5 and a maximum hydrogen pressure of 60 psig. The Exciter System is Alterrex type, 1,800 rpm, rated at 1,795 kW, 500 V, and 3,590 amp.

The turbine utilizes a Mechanical Hydraulic Control System consisting of normal governing devices (two initial pressure regulators, speed governor, startup control devices), pre-emergency devices (acceleration relay), emergency devices for turbine and plant protection (overspeed governor, backup overspeed, master trip, two vacuum trips, motoring protection, thrust bearing wear detector, electrical fault protection relays), and special control and test devices. The Mechanical Hydraulic System operates the main stop valves, control valves, bypass valves, crossover combination intercept-intermediate valves, and other protective devices. Turbine governor functions and turbine control is covered more fully under Section 7, Control and Instrumentation.

For overpressure protection of the turbine exhaust hoods and the condenser shells, two rupture diaphragms are provided on each turbine exhaust hood.

A Pressure Averaging Manifold (PAM) is provided to minimize pressure and flow disturbance in the main steam lines caused by periodic testing of the main turbine stop valves. The PAM supplies the pressure regulation with an average of the pressures in all of the main steam lines. The averaging also permits testing of the main turbine stop valves at higher power levels than has been possible in the past.

The turbine-generator is provided with supervisory instrumentation in the control room.

11.2.4 Power Generation Evaluation

The following abnormal operational transient analyses have been made for a component failure in the Turbine-Generator System and are included in Section 14, Station Safety Analysis:

1. Generator trip (turbine control valve fast closure)

2. Turbine trip (turbine stop valve closure)

   a. Turbine trip from high power with bypass
   b. Turbine trip from high power without bypass

3. Pressure regulator malfunction

4. Closure of the main steam isolation valves

   a. All valves
   b. One valve

5. Loss of main condenser vacuum

The capability to conduct a safe shutdown of the Pilgrim Nuclear Power Station is not impaired as the result of the consequences of the most severe turbine disc breakup event postulated. Turbine disc breakup was assumed to occur at a turbine overspeed to 110 percent of rated speed. A complete discussion of turbine overspeed protection devices is presented in Section 7.11. No turbine damage is postulated as a direct result of a 110 percent overspeed transient. Shop overspeed tests have been conducted on turbine components at this speed to verify turbine integrity. However, for the purposes of this analysis, breakup of the last stage of one of the low pressure rotors is assumed to occur at the 110 percent overspeed condition.

The turbine disk was assumed to breakup at an overspeed of 110 percent of rated speed into three 120 deg arc segments. This was calculated to be the most severe breakup configuration possible. The analysis indicated that low pressure turbine rotor missiles generated as the result of the initial conditions described could penetrate the low pressure casing. Missiles penetrating the low pressure casing below the turbine floor (elevation 51 ft) would be contained within the turbine-generator foundation and pedestal. Missiles penetrating the low pressure casing above the turbine floor would have to

traverse significant distances before their continued progress would be contained by building structural barriers.

Penetration depths of missiles in the different types and thicknesses of structural materials used at the Pilgrim Nuclear Power Station were calculated using the analytical technique formulated by Amerikian, (Design of Protective Structures. Bureau of Yards and Docks, Department of the Navy, Washington, D.C. NAV-DOCKS P-51, August 1959). The calculated penetration depths were then compared to the structural barriers to determine if any barrier penetration occurred.

The control room, cable spreading room, battery rooms, and engineered safeguards equipment are all contained within concrete enclosures with several intervening walls and/or floors having a total thickness much greater than the calculated penetration depth of the postulated missiles.

The potential of turbine disk breakup and subsequent missile generation has been greatly reduced with the replacement of original shrunk-on-wheel LP rotor with monoblock LP rotor in RFO #10.

An inspection of one portion of the turbine-generator will normally be scheduled during a major refueling outage. This is commonly called sectionalized maintenance. The turbine-generator has four principal sections (i.e., two low pressure turbine sections, the high pressure turbine section, and the main generator). Inspection of the three principal turbine sections would normally be accomplished every 10 years. It is our intent to reasonably ensure the integrity of the turbine by providing for early detection of defects in the turbine, and its essential control equipment, through the use of nondestructive testing of certain components during the inspection periods. The nondestructive test methods normally include Visual, Magnetic Particle (M.T.), and Ultrasonic (U.T.).

The following is a list of items which are normally inspected and the inspection methods normally utilized:

1. Moving parts

   Turbine wheels and associated blading (Visual and M.T.)
   Exposed portions of turbine shaft (Visual and M.T.)

2. Stationary parts

   Diaphragms and associated blading (Visual and M.T.)
   Internal portions of the high pressure shell (Visual and M.T.)

3. Valves

   Turbine stop valves: stems and disks, seats, valve bodies and bonnets (Visual and M.T.)

   Control valves: stems and disks, seats, valve bodies and bonnets (Visual and M.T.)

   Combination intercept and stop valves: stems and disks, seats, valve bodies and bonnets (Visual and M.T.)

4. Pressure retaining, bolting and studs (U.T.)

11.3 MAIN CONDENSER

11.3.1 Power Generation Objective

The objective of the main condenser is to provide a heat sink for the turbine exhaust steam, turbine bypass steam, and other flows. It also provides deaeration and storage capacity for the condensate which will be reused after a period of radioactive decay.

11.3.2 Power Generation Design Basis

The main condenser is designed for the following conditions:

1.	Condenser Duty	4.4 X 109	Btu/hr
2.	Circulating Water Inlet Temperature	48	°F
3.	Cleanliness Factor	85	%
4.	Number of Passes	1	
5.	Circulating Water Velocity	5.42	ft/sec
6.	Pressure (Single)	1.5	in Hg Abs

11.3.3 Description

During planned operation, steam from the low pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several other flows such as cascading heater drains, air ejector intercondenser drain, gland seal condenser drain, feedwater heater shell operating vents, condensate pump suction vents, etc.

During abnormal conditions, the condenser is designed to receive (not all simultaneously) flow from turbine bypass steam, feedwater heater high level dump(s), and relief valve discharges (crossover steam line, feedwater heater shells, plant heating heat exchanger shells, steam seal regulator, various steam supply lines).

There are other periodic flows into the condenser such as condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low point drains, deaerating steam, extraction steam spills, makeup, and condensate.

The main condenser is a twin shell, horizontal tube, seawater cooled unit. It has an effective condensing surface area of 400,000 ft2 utilizing 7/8 in od, 22 BWG, 50 ft long titanium tubes. The design seawater circulating water flow rate is 311,000 gal/min.

Each condenser shell has divided waterboxes, which permits isolation of the circulating water on one-half shell while the other half remains in operation. The arrangement of circulating water piping allows backwashing of the condenser by sections to remove possible debris accumulated on the inlet tube sheets.

The hotwell storage capacity is 54,000 gal. The condenser is located beneath the low pressure cylinders of the main turbine. Condenser tubes are located transversely to the turbine-generator axis.

To accommodate thermal expansion, a rubber belt expansion joint is provided for each condenser neck. Equalizing connections between the two condenser shells are provided for both the steam space and hotwell.

To provide for detecting tube sheet leakage of the circulating water into the condenser, collecting troughs are located at the tube sheet below the tubes. The troughs are monitored by conductivity elements in order to detect inleakage of the seawater.

The main condenser is equipped with deaerating type hotwells to provide deaeration of the condensate leaving the condenser. It is designed to maintain an oxygen content of 0.005 cc per liter or less. During startup, low load and/or cold circulating water, supplementary steam will be supplied to assist in the deaeration of the condensate. The noncondensible gases are concentrated in the air cooling section of the condenser, and removed by the steam jet air ejectors. To permit a 2 min decay period of the condensed steam, the condenser hotwells are equipped with baffling arrangement to form labyrinths.

A sight glass level indicator is provided on the outlet of each water box to aid in evaluation of the scavenging system and/or condenser performance.

11.4 MAIN CONDENSER GAS REMOVAL AND TURBINE SEALING SYSTEMS

11.4.1 Power Generation Objective

The objective of the main condenser gas removal system (MCGRS) is to remove all noncondensible gases from the condenser.

The objective of the turbine sealing system (TSS) is to prevent air leakage into, or steam leakage out of the turbine.

11.4.2 Power Generation Design Basis

1. The MCGRS is designed to remove all noncondensible gases from the condenser including air inleakage and disassociation products originating in the reactor, and exhaust them to the offgas holdup system. The size of the gas removal system is determined by taking into consideration potential air inleakage, the oxygen and hydrogen formed by disassociation of water in the reactor, and the water vapor contained in the gas mixture.

2. The TSS is designed to provide the means of automatically sealing with steam the turbine shaft glands and the valve stems (main stop, control, intercept, and bypass valves).

11.4.3 Description

11.4.3.1 Main Condenser Gas Removal System

The MCGRS includes a steam jet air ejector unit complete with an inter-condenser and an after-condenser to remove air and noncondensible gases from the main condenser. A mechanical vacuum pump is provided for startup and shutdown. See Figure 11.4-1 (BECo M210).

11.4.3.1.1 Steam Jet Air Ejector

The steam jet air ejector is a full capacity, two stage unit with an automatic steam pressure reducing station. There is one first stage ejector jet per condenser shell, with a single second stage ejector jet. Both first and second stage ejector jets have full capacity standby elements. The inter-condenser and after-condenser are cooled by main condensate flow. As the driving medium, the air ejector uses main steam reduced in pressure from 950 psig to a range of 60 to 70 psig, with 65 psig as the nominal setpoint.

Air inleakage and noncondensible gases as well as entrained water vapor are removed from the condenser by the first stage jets. The gas vapor mixture is then discharged and condensed in the inter-condenser. The resulting condensate is routed back to the main condenser. The second stage ejector removes the resulting noncondensible gases and water vapor from the inter-condenser, discharging them into the after-condenser. The after-condenser drain is routed back to the main condenser.

The noncondensible gases and entrained vapor from the after-condenser are then exhausted to the offgas holdup system. The air ejector exhaust is metered, sampled, and monitored prior to entering the offgas holdup piping. Instrumentation is provided to isolate the air ejector unit by closing the suction lines from the condenser upon sensing high temperature or high pressure in the discharge piping. See Section 7, Control and Instrumentation.

11.4.3.1.2 Mechanical Vacuum Pump

A mechanical vacuum pump is provided to remove air and noncondensible gases from the main condenser during startup and shutdown when adequate steam pressure is not available to operate the steam jet air ejector, and the volume of air and gases exceeds the capacity of the air ejector. The discharge of the mechanical vacuum pump is routed to the gland seal holdup system, in view of the fact that the average gaseous activity is expected to be low under such circumstances of startup and shutdown.

The mechanical vacuum pump discharge is isolated by automatically tripping the pump, and by closing an isolation valve in the discharge line upon sensing a main steam high radiation signal. See Section 7, Control and Instrumentation.

11.4.3.2 Turbine Sealing System

The Turbine Sealing System consists of the steam seal pressure regulator, steam seal header, gland seal condenser, two full capacity exhaust blowers, and the associated piping and valves. The steam seal pressure regulator maintains the steam seal header at constant pressure.

On pressure packing (high pressure turbine and valve stems), sealing steam leakage is extracted. On subatmospheric glands (low pressure turbines), steam sealing is supplied from the steam seal header. The outer ends of all glands are routed to the gland seal condenser which is maintained at a slight vacuum by the exhaust blowers. During planned operation, one blower is operating while the other is on standby. The exhaust blowers deliver air and noncondensible gases to the gland seal holdup system. The gland seal condenser is cooled by main condensate flow after it passes through the air ejector condensers.

Condensed steam from the gland seal condenser is routed to an atmospheric drain tank located outside the main condenser bay. The condensed turbine seal steam is drawn from the atmospheric drain tank to the main condenser hotwell when condenser vacuum is sufficient. The drain tank is equipped with level instrumentation and valves that automatically close to maintain a liquid seal thereby assuring that noncondensibles are not introduced into the main condenser. The drain tank is equipped with overflow piping that is routed to the Turbine Building equipment drain sump. The overflow drain path is available at all power levels but is typically used only during startups and shutdowns when condenser vacuum is insufficient to draw condensate from the drain tank to the condenser hotwell.

Figure 11.4-1 has been removed.

Please refer to BECo Controlled Drawing M 210.

Figure 11.4-1 has been removed.

Please refer to BECo Controlled Drawing M 210.

11.5 TURBINE BYPASS SYSTEM

11.5.1 Power Generation Objective

The objective of the Turbine Bypass System (TBS) is to dissipate the energy of main steam generated by the reactor which cannot be utilized by the turbine.

11.5.2 Power Generation Design Basis

1. The TBS is designed to control reactor pressure: (1) during reactor heatup to rated pressure, (2) while the turbine is brought up to speed and synchronized, (3) during power operation when the reactor steam generation exceeds the transient turbine steam requirements and limitations, and (4) when cooling down the reactor.

2. The TBS capacity is based on 25 percent of the turbine design flow.

11.5.3 Description

The TBS consists of three automatically and sequentially operated regulating valves mounted on a valve manifold. The manifold is connected to the main steam lines upstream of the turbine main stop valves. Each bypass valve outlet is piped to the main condenser and a pressure reducing orifice is located at the condenser connection. See Figure 11.5-1.

The basic operation of the TBS is that it receives a signal from the turbine control system (initial pressure regulator) to open the bypass valves whenever the actual steam pressure exceeds the preset steam pressure by a small margin. This occurs whenever the amount of steam generated by the reactor cannot be entirely absorbed by the turbine.

The bypass valves will be tripped closed whenever the vacuum in the main condenser falls below approximately 7 in Hg vacuum. See Section 7, Control and Instrumentation.

11.5.4 Power Generation Evaluation

The effects of malfunctions of the TBS and the effects of such failure on other components are evaluated in Section 14, Station Safety Analysis.

Figure 11.5-1 has been removed.

Please refer to BECo Controlled Drawing M 203.

11.6 CIRCULATING WATER SYSTEM

11.6.1 Power Generation Objective

The objective of the Circulating Water System (CWS) (also called the Sea Water System) is to provide the main condenser with a continuous supply of cooling water, for removing the heat rejected by the turbine exhaust and turbine bypass steam, as well as from other incidentals over the full range of operating loads.

11.6.2 Power Generation Design Basis

1. Provide the required seawater flow to the condenser.

2. Provide debris removal from seawater, and chemical treatment to minimize bacterial growth.

3. Provide non-thermal condenser backwash for inlet tube sheet cleaning.

4. Provide thermal condenser backwash for intake embayment cleaning and control of fouling organisms.

11.6.3 Description

The CWS uses seawater taken from Cape Cod Bay. The design minimum seawater level for maintaining circulating water pumps design conditions is 8 feet below msl. Water passes through trash racks and then through traveling screens. A major portion of the flow is directed to the circulating water pumps which deliver water to the main condenser. A small portion of the water is used by the service water pumps. The discharge from the condenser and from the Service Water System is returned via the discharge channel to Cape Cod Bay. See Figure 11.6-1 (Drawing M211).

The intake structure is protected by a breakwater. A trash rack is installed in front of the traveling screen to retain pieces of debris larger than 3 inches. A trash rack rake is installed to remove large debris from the racks. The traveling screens will retain particles 3/8 inch and larger.

Each traveling screen has two sets of spray nozzles. The high pressure spray nozzles are for regular backwashing and the low pressure spray nozzles are for washing any impinged marine organisms from the screens. A 50 foot concrete trench carries the marine biota from the intake structure to a 200 foot concrete sluiceway. The sluiceway is supported above ground on the riprap and will carry the marine biota to mean low water of the intake channel.

A reinforced concrete trash pit with an associated metal basket and jib crane is available during high refuse periods to minimize the reintroduction of trash to the discharge channel and prevent clogging of the sluiceway.

The plant has four traveling water screens in parallel; two screens remove debris for each circulating water pump. The intake structure is divided into three bays, one for each of the circulating water pumps and one for the five service water pumps. Water is fed to the service water bay from both of the circulating pump bays. There are two circulating water pumps, with a rated head of 27.5 ft and a rated flow of 155,500 gal/min each. The pumps are vertical, mixed flow, wet pit type. The pump drivers are induction motors rated 1,250 hp, 293 rpm, 4,160 V, 3 phase, 60 Hz.

At the rated circulating water flow of 311,000 gal/min through the condenser and at design power on the turbine-generator, the temperature rise through the condenser will be approximately 29°F.

The maximum allowed temperature rise from the intake structure to the end of the discharge canal has been established by the Environmental Protection Agency. This limit is defined in NPDES Federal Permit No. MA0003557 (State Permit No. 359) Section A.2.a. The allowed temperature rise is 32°F, and the discharge canal temperature shall at no time exceed 102°F at the point of discharge to Cape Cod Bay. As an aid to maintaining this temperature limit, RTD temperature sensors are located at the intake and discharge canals to provide input signals to the station computer. The computer provides printouts of these and other temperature sensors in the area (Figures 10.7-1, M212, and 11.6-1, M211) for review and analysis of the seawater cooling system.

The condenser tubes and intake embayment can be cleaned by non-thermal and thermal backflushing, respectively. This is accomplished by operating only one circulating water pump, closing the discharge valves at each outlet waterbox, and opening the crossover valve connecting the discharge waterboxes. The water will then flow in the normal direction through one side of the condenser, crossover and flow in the reversed direction through the other side, and discharge back to the intake structure through the idle circulating water pump.

Sodium hypochlorite solution is applied to each circulating pump bay alternately at an applied maximum dosage of 0.10 ppm for approximately 1 hr/day for control of slime growth and fouling organisms in the intake bays and circulating water piping systems. Approximately 10% sodium hypochlorite solution from a 14,000 gal storage tank will be metered through two 0-5 gpm Hypochlorination pumps, one operating and one standby. Water from the screen wash pump discharge header is used as dilution water to increase the volume of solution and therefore, the velocity of the solution leading and better mixing in the intake bay diffusers. The diluted hypochlorite solution enters the intake bay diffusers located downstream of the trash racks.

Two separate pumped hypochlorite systems of 0-5 gal/hr capacity provide a direct, metered, hypochlorite solution feed to either service water pump bay inlet at an applied chlorine dosage up to a maximum of 0.25 ppm as an alternative service water continuous chlorination system. This system has three 0-5 gpm pumps, two normally running and one on standby. Hypochlorination systems for the service water system operate continuously.

The maximum allowable discharge limit is 0.1 ppm for total residual clorine (TRC) to Cape Cod Bay as allowed by the NPDES Federal Permit No. MA 0003557 (State Permit No. 359) Section A.2.a.

The purpose of the Dechlorination System is to dechlorinate the Screen Wash Water so that chlorine does not impact the marine life when washing the screens.

The Dechlorination System consists of Sodium Thiosulphate reservoirs (dechlorination liquid), two dechlorination pumps and an event recorder. This equipment interfaces with the 4 traveling screens and the 2 screen wash pumps. The Sodium Thiosulphate is pumped from the dechlorination pumps to the suction side of the screenwash pumps. The dechlorination pumps are electronically interlocked with the screenwash pumps so that they run anytime the corresponding screen wash pump is running if the control switch is left in the automatic position.

The event recorder records the start/stop history of the 4 traveling screens, the 2 dechlorination pumps and the 2 screen wash pumps. This record provides proof that the screen wash water was properly dechlorinated for each screen wash in keeping with the requirements of NPDES Permit No. MA 0003557.

Figure 11.6-1 has been removed.

Please refer to BECo Controlled Drawing M211.

11.7 CONDENSATE DEMINERALIZER SYSTEM

11.7.1 Power Generation Objective

The objective of the Condensate Demineralizer System (CDS) is to maintain the required purity of feedwater to the reactor.

11.7.2 Power Generation Design Basis

The CDS shall be designed to remove the following contaminants from the feedwater:

1. Corrosion products that result from the corrosion and erosion that occurs in the main steam, turbine extraction, feedwater heater shells and drains

2. Suspended and dissolved solids which may be introduced by small leakages of circulating sea water into the condenser

3. Fission products which may be released by failed fuel elements

4. Solids carried in by the makeup water

11.7.3 Description

To assure the specified conditions and to produce best feedwater quality attainable, a full flow mixed bed CDS is provided. See Figures 11.7-1 and 11.7-2.

The CDS consists of seven mixed bed ion exchangers and external resin cleaning equipment. In addition, the CDS includes the associated piping, valving, instrumentation, and controls for proper operation and protection against malfunction.

The demineralizer system is controlled from local panels and designed for pushbutton control initiation. Valves and pumps are remotely operated. Integrated flow and conductivity monitors are provided for each demineralizer to indicate when it is exhausted. Suitable alarms and differential pressure indicators are provided and system influent and effluent conductivity is monitored. The CDS is sized to process condensate impurity concentration during planned operations and peak contamination periods.

Certain expected radioactive material originating from corrosion product and fission product carryover from the reactor may be removed by the demineralizers. Waste from the demineralizers is sluiced to radwaste system for disposal. See Section 9, Radioactive Waste (Radwaste) Systems.

The demineralizer system also provides high quality water to the suction of the control rod drive pumps. Refer to Section 3.4.

Figure 11.7-1 and 11.7-2 have been removed.

Please refer to BECO Controlled Drawings M 213 and M 214 respectfully.

11.8 CONDENSATE AND FEEDWATER SYSTEM

11.8.1 Power Generation Objective

The objective of the Condensate and Feedwater System is to provide a dependable supply of feedwater to the reactor, to provide feedwater heating, and to maintain high quality feedwater.

11.8.2 Power Generation Design Basis

1. Provide the required flow to the reactor with sufficient margin to continue to provide flow under anticipated transient conditions.

2. Provide the required feedwater temperature to the reactor.

3. Provide a startup recirculation line from the reactor feed pump discharge lines to the condenser hotwell for the purpose of minimizing corrosion product input to the reactor during startup conditions.

11.8.3 Description

Three one-third capacity, motor-driven, condensate pumps take the condensate from the condenser hotwells and pump it through the air ejector condensers, gland seal condenser, and condensate demineralizers. Demineralizer effluent is then split into two parallel streams, each with three low-pressure and two high-pressure stages of feedwater heaters. Common bypass lines around the low-pressure and high-pressure feedwater heaters are provided. The bypass line around the high-pressure feedwater heaters is currently unavailable due to a modification to eliminate unintended bypass flow resulting from leakage of the bypass control valve.

Three one-third capacity, motor-driven, reactor feed pumps are installed in the heat cycle between the low-pressure and high-pressure heaters. See Figure 11.8-1 (Drawing M207).

A bypass loop of approximately 50 to 120 gal/min is installed from the feed pump discharge header to the feed pump suction header. A zinc dissolution column in the loop is used to maintain approximately 5-10 parts per billion zinc in the reactor coolant in order to control drywell dose rate build-up. This loop is periodically taken out of service for maintenance.

11.8.3.1 Condensate Pumps

Each condensate pump is a nine stage vertical, canned suction type, centrifugal pump. The pumps are installed at an elevation that permits full capacity operation at any level in the condenserhotwell, including extreme low level. The pumps provide the maximum design flow, plus design margins at the required pressure including static head, friction loss, and suction head of the reactor feed pumps. The pumps are rated at 6,550 gal/min and 1,030 ft. total head at 1,180 rpm when pumping 91.7F condensate. The motors are rated each 2,000 Hp, 1.15 S.F., 1,180 rpm,

4,000 V, 3-phase, 60 Hz, and are induction, open drip proof units with solid vertical shaft.

11.8.3.2 Feedwater Heaters

The lowest pressure (fifth point) heaters for both trains are straight tube; two pass units with external drain coolers. Both fourth point heaters and both third point heaters are U tube type with integral drain coolers.

The high pressure heaters are U tube type units with integral condensing and drain cooling sections.

The fourth point heaters of both trains and the third point heater of train B have stainless steel tubes roller expanded into the tube sheet. All other heaters, low and high pressure have stainless steel tubes welded to the tube sheet.

11.8.3.3 Reactor Feed Pumps

Each reactor feed pump is a three stage, horizontal, centrifugal pumps. The pumps operate in series with the condensate pumps and provide the maximum design flow plus design margins at the required pressure at the reactor inlet nozzles. The pumps are rated at 6,550 gal/min and 2,620 ft total head at 3,570 rpm when pumping 291.1°F water. The motors are rated each 5,000 Hp and are induction, open drip proof units. The Feedwater Control System is described in Section 7.

11.8.4 Power Generation Evaluation

An abnormal operational transient analysis is made for a loss of feedwater heater and is included in Section 14, Station Safety Analysis.

Figures 11.8-1 and 11.8-2 have been removed.

Please refer to BECo Controlled Drawings M207 and M208 respectively.

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.

Figure 11.9-1 has been removed.

Please refer to BECO Controlled Drawing M 209.

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)

SECTION 12

STRUCTURES AND SHIELDING

12.1 SUMMARY DESCRIPTION

The principal buildings and structures consist of the Reactor and Turbine Buildings, each with auxiliary bays, the Radwaste Building, the Diesel Generator Building, the Administration Building, the Guardhouse, the main stack, and the intake structure. These buildings and structures are founded upon suitable material for their intended application and are designed, as a minimum, to be within the limits of applicable codes. In addition, critical structures are designed to withstand more extreme loading conditions than normally considered in conventional design practice.

Location and orientation of the buildings on the site are shown on Figure, 12.1-1 to 12.1-16.

Shielding and access control are provided for the radiation protection of individuals. The radiation protection is in accordance with the limits and guidelines of appropriate regulations.

The following FSAR figures have been removed from the FSAR. Please refer to the corresponding BECo controlled drawing.

FSAR FIGURE	BECO CONTROLLED DRAWING
12.1-1	M11
12.1-2	M12
12.1-3	M13
12.1-4	M14
12.1-5	M15
12.1-6	M16
12.1-7	M17
12.1-8	M18
12.1-9	M19
12.1-10	M20
12.1-11	M21
12.1-12	M22
12.1-13	M23
12.1-14	M24
12.1-15	M25
12.1-16	M26

12.2 STRUCTURAL DESIGN

12.2.1 Classification of Structures and Equipment

12.2.1.1 General

The most severe environmental phenomena which could affect the site have been evaluated in Section 2. Based on these evaluations, the station structures and equipment have been classified with respect to systems which must remain functional during and following the most severe natural phenomena which can be postulated to occur at this site. For the purpose of categorizing the mechanical structural strength designs for loading conditions due to environmental events, the following definitions have been established:

1. Class I

   This class includes those structures, equipment, and components whose failure or malfunction might cause or increase the severity of an accident which would endanger the public health and safety. This category includes those structures, equipment, and components required for safe shutdown and isolation of the reactor

2. Class II

   This class includes those structures, equipment, and components which are important to reactor operation, but are not essential for preventing an accident which would endanger the public health and safety, and are not essential for the mitigation of the consequences of these accidents. Class II designated structures and/or equipment shall not degrade the integrity of any structures and/or equipment designated Class I

The only exception to these definitions is that a system, whose failure or malfunction might increase the severity of an accident, is not designed to withstand the effects of a tornado if the failure of the system will not cause an accident. The probability of the occurrence of a design basis loss of coolant accident or a design basis tornado during the life of a plant is small. Therefore, the probability of the simultaneous occurrence of these two independent events is relatively small.

12.2.1.2 Class I Structures and Equipment

Nuclear Steam Supply System (NSSS)

Reactor vessel and supports

Control Rod and Drive System including equipment necessary for scram operation

Control rod drive housing supports

Fuel assemblies

Core shroud

Core supports

Steam separator assembly

Steam dryer assembly

Reactor Coolant Recirculation System including valves and pumps

All piping connectors from the reactor vessel up to and including the first isolation valve external to the drywell

Main steam piping when located inside a Class I structure

Isolation valves

Reactor Core Isolation Cooling System

High Pressure Coolant Injection System

Standby Liquid Control System

Residual Heat Removal System

Core Spray Systems

Primary Containment System

Drywell

Pressure suppression chamber

Vent System

Vacuum Relief System

Pressure suppression pool

Isolation valves

Containment penetrations

Secondary Containment System

Reactor Building (with the exception of access locks which are Class II structures)

Reactor Auxiliary Bay Pipe Vaults

Standby Gas Treatment System

Main stack

Reactor Building Isolation Control System

<u>NOTE:</u>

The Secondary Containment System is not designated to be functional during or after a tornado; however, the Reactor Building does protect all the Class I equipment located inside the building from the effects of a tornado.

Station Standby Cooling Systems

Reactor Building Closed Cooling Water System (portion serving Class 1 equipment)

Salt Service Water System (portions serving Class I equipment)

Intake structure (housing the Salt Service Water System)

Equipment Area Cooling System (portions serving Class I equipment)

Standby Electrical Power Systems

Standby AC Power System

DC Power System (125/250 V)

DC Power System (24 V)

Emergency service buses and other electrical gear to power Class I equipment

Station battery rooms

Diesel Generator Building and Underground Fuel Storage Tanks

Reactor Building Fuel Storage Facilities

Spent fuel storage equipment

Spent fuel pool

New fuel storage equipment

New fuel storage vault

Main Control Room System

Main control room

Main Control Room Environmental Control System

All instrumentation and controls required for operation of Class I equipment except the Reactor Manual Control System

Parts of structures housing or supporting Class I equipment

Reactor Building Auxiliary Bay Substructure

12.2.1.3 Class II Structures and Equipment

Reactor Building auxiliary bay superstructure and Reactor Building access locks

Reactor Building (truck) access lock

Turbine Building

Radwaste Building
(Except areas housing or supporting Class I equipment)

Old Administration Building

New Administration/Service Building

Intake and discharge structures
(Except areas housing or supporting Class I equipment)

Trash Compaction Building

Turbine Generator System

Main Condenser System

Reactor and Turbine Building cranes

Reactor Feedwater and Condensate Systems

Main Steam System (outside Reactor Building)

Reactor Cleanup System

Radwaste System

Fire Protection System

Condensate Storage and Transfer Systems

Normal Heating and Ventilating System

Station auxiliary power buses

Electrical controls and instrumentation (for above systems) and the Reactor Manual Control System

Other structures, piping, and equipment not listed under Class I

12.2.2 Description of Principal Structures

12.2.2.1 Reactor Building Structure and Crane

The Reactor Building, with its associated auxiliary bays, houses the reactor, the Reactor Coolant System, and auxiliaries associated with the Nuclear Steam Supply System. It also houses the refueling facilities, spent fuel storage pool, steam

separator and dryer storage pool, new fuel storage vault, control rod drive hydraulic equipment, and the Reactor Primary Containment System. The Reactor Building is basically a reinforced concrete structure with structural steel framing, consisting of the following major structural components:

1. The foundation consists of an 8 ft thick heavily reinforced concrete mat

2. Elevated floors consist of concrete slabs simply supported by conventional type structural steel framing

3. The interior walls are reinforced concrete or concrete block

4. The spent fuel storage pool, the reactor well, and the dryer separator storage pool consist of reinforced concrete deep girder walls and base slabs. The pool structures are supported by the drywell shield and the exterior walls. The pools are lined with stainless steel plates on their inside surface

5. The reactor support is a reinforced concrete pedestal. It also serves as a support for the "biological" shield and two steel service platforms. Access through the biological shield is provided in selected areas by means of removable blocks

6. The exterior walls above the refueling floor consist of columns of structural steel and precast concrete wall panels with structural steel bracing

7. The exterior walls below the refueling floor are reinforced concrete with precast panels on the exterior face

8. The roof is an insulated steel deck system supported by structural steel framing and bracing

9. Major structural appurtenances consist of the crane runway, elevator shaft, stairways, and hatches

Loaad handling over the Refueling Floor and hoist-way down to grround grade is conducted utilizing the Reactor Building crane. The Reactor Building crane is a Class II component upgraded to meet the guidance of NUREG-0554 (reference 8) for single-failure-proof cranes and the guidance of NUREG-0612 Appendix C (reference 1) for the modification of existing cranes. The upgraded crane includes a new trolley with a single-failure-proof 100 tone main hoist, designed and qualified in accordance with the appropriate requirements of ASME NOG-1-2004 (reference 9). The trolley also includes a 10 ton non single-failure-proof auxiliary hoist which conforms to the requirements of Crane Manufacturers Association of America Specification #70 (reference 10). The Reactor Building crane has been evaluated for earthquake loading to meet NUREG-0554 seismic design requirements, and the Reactor Building structure

has been evaluated to ensure its integrity for the associated crane reactions.

Notes

1) Use of the Reactor Building Crane Main Hoist as part of a single-failure proof handling system for casks containing irradiated fuel, requires that crane operations be limited to the bridge runway area west of column line 9, and that the ambient air temperature in the vicinity of the bridge girders be ≥65°F.

2) The Reactor Building Crane will not become a missile in the event of an earthquake. Anti-derailment devices installed on the wheel trucks of original crane bridge remain in place but are not required by the upgraded design.

In the area of the reactor well and the storage pools, if the reactor cavity is drained, and the dryer separator pool is filled no higher than el 106.5 ft, the shield block wall has sufficient strength to withstand the hydrostatic head of water, assuming all shield blocks are in place.

Using a mylar sheet over the pool and filling the pool up to the first fixed shield block will reduce airborne contamination. In addition, an area around the pool will be declared an exclusion area and roped off for protection against shine.

12.2.2.2 Turbine Building

The Turbine Building, with its auxiliary bays, houses the turbine generator and associated auxiliaries, the Condensate and Feedwater Systems, switchgear, some radwaste tankage, the Turbine Building crane, and other auxiliary equipment. The Turbine Building is a rigid steel structure with precast concrete siding consisting of the following major structural components:

1. The foundation is a reinforced concrete mat stiffened by the basement walls

2. Elevated floors are concrete slabs simply supported on structural steel framing

3. The interior walls are reinforced concrete or concrete block

4. The turbine pedestal is a heavily reinforced concrete structure resting on the concrete foundation

5. The exterior walls consist of structural steel columns and bracing with precast concrete wall panels

6. The roof is an insulated steel deck system supported by structural steel framing and bracing

12.2.2.3 Radwaste Building

The Radwaste Building houses the radioactive waste treatment equipment, the control room, the cable spreading and computer room, the warehouse, and miscellaneous offices and shops. The Radwaste Building is a reinforced concrete structure with structural steel framing consisting of the following major structural components:

1. The foundation is a reinforced concrete mat

2. Elevated floors are concrete slabs simply supported on structural steel framing

3. The interior walls are reinforced concrete or concrete block

4. Exterior walls are reinforced concrete below grade, and in Class I areas above grade. Other exterior walls above grade consist of structural steel columns and bracing with precast concrete wall panels

5. The roof consists of an insulated steel deck system supported by structural steel framing. In areas requiring missile protection, the metal decking is covered with a reinforced concrete slab

12.2.2.4 Trash Compaction Building

The Trash Compaction Facility processes dry compactable contaminated and non-contaminated waste at Pilgrim Station. The structure is founded on a continuous footing and consists of poured concrete exterior and interior walls and floors. The exterior is surfaced with architectural concrete stock.

12.2.2.5 Diesel Generator Building

The Diesel Generator Building houses two emergency diesel generators and their accessories. The Diesel Generator Building is a reinforced concrete structure with steel framing consisting of the following major structural components:

1. The foundation is reinforced concrete wall footings which are separated from the diesel generator foundation blocks

2. The walls are reinforced concrete with precast reinforced concrete panels on the exterior face

3. The roof is a reinforced concrete slab supported by structural steel framing

12.2.2.6.1 Old Administration Building

The Administration Building provides an office facility for the administrative and clerical personnel. The structure is founded on a continuous footing and consists of a structural steel frame with metal and glass curtain walls, precast concrete panels, and masonry panels. The interior walls are steel stud and plaster. The floors are reinforced concrete on steel framing.

12.2.2.6.2 New Administration/Service Building

The New Administration/Service Building provides an office facility for the administrative and clerical personnel as well as a warehouse, laboratories, and shops. The structure is founded on a continuous footing and consists of a structural steel frame with metal and glass curtain walls. The interior walls are steel stud and plaster. The floors are reinforced concrete on steel framing. The connecting corridor to the process building is located at elevation 23'-0 of the Radwaste Building.

12.2.2.7 Guardhouse

The Main Guardhouse is a facility which houses security equipment and security personnel. It serves as the main entrance and exit to the plant. The structure is founded on spread and continuous footings and consists of a structural steel frame with metal and glass curtain walls and precast concrete panels. Interior walls are masonry block.

The floors are reinforced concrete. The roof is structural steel roof deck with built-up roofing.

12.2.2.8 Intake Structure

The intake structure houses the Salt Service Water System pumps, the Circulating Water System pumps, Fire Protection System pumps, the Chlorination System equipment, stop logs, trash racks, and the traveling screens with their wash pumps. The intake structure consists of a reinforced concrete substructure, and a superstructure of steel framing enclosed with precast panels. Enclosed within the superstructure are the Service Water System pump compartments which are constructed of reinforced concrete and concrete block walls. The four circulating water bays have steel struts on the walls to allow dewatering of the bays. See Figure 12.2-2.

12.2.2.9 Main Breakwater

The main breakwater is of rubble mound construction with the outer layer protected by heavy capstone. The breakwater protects the intake structure against wave attack and damage. In particular, the breakwater is designed to protect the intake structure against wave damage during the design basis storm (see FSAR Section 2.4.4.3.).

12.2.2.10 Main Stack

The main stack is a pipe with a top elevation of 400 ft msl. The main stack is supported by the Filter Building. The Filter Building is a reinforced concrete structure which houses the dilution fans, offgas filters, and heaters. See Figure 12.2-3. The main stack is located 700 ft NW of the Reactor Building as shown on Figure 1.6-1.

12.2.2.11 Gas Bottle Storage Facility

This facility provides a safe and permanent high pressure gas cylinder storage area facilitating control, inventory management and dispensation of gas cylinders. This facility is constructed of concrete block walls, a poured concrete floor and a metal roof. It is open at one side to provide venting in case of a leak. It contains concrete stalls which separate and individually store various gas cylinders used at the Station.

12.2.2.12 Governing Codes and Regulations

The design of all structures and facilities conforms to the applicable code or specification listed below, except where specifically stated otherwise:

1. Uniform Building Code (UBC) 1967

2. American Institute of Steel Construction (AISC) Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, Sixth Edition (for original design), latest edition for modifications

3. American Concrete Institute (ACI) Building Code Requirements for Reinforced Concrete (ACI 318-63)

4. American Welding Society (AWS) Standard Code for Arc and Gas Welding in Building Construction (AWS D.1.0-66)

5. API Specification No. 620 for Welded Steel Storage Tanks

6. ASME Boiler and Pressure Vessel Code, Section III, Class B, governs the design and fabrication of the drywell and suppression chambers

7. AEC Publication TID 7024, Nuclear Reactors and Earthquakes, governs the seismic design of all Class I structures

8. American Water Works Association (AWWA) AWWA M 11 Steel Pipe Manual and Standard D100

9. Regulations of the Commonwealth of Massachusetts as follows:

a. Standard Specifications for Highways, Bridges, and Waterways (1967) for construction

b. Regulations of the Department of Health and Sanitary Water Board with respect to water

c. Department of Labor and Industry Regulations

d. Massachusetts State Police Department Bureau of Fire Protection Regulations for storage of combustible materials

10. Standard Specifications for Highway Bridges by the American Association of State Highway Officials (AASHO) for design

11. U.S. Army Corps of Engineers regulations with respect to dredging and construction of offshore structures for the Bay of Cape Cod

12. American Society of Civil Engineers Paper No. 3269, for wind design requirements

13. American Iron and Steel Institute Specifications for the Design of Light Gage Cold-formed Steel Structural Members, 1962

The design of new structures subsequent to plant construction conforms to the latest revision of the code or standard as applicable.

12.2.3 Loading Considerations

12.2.3.1 General

All structures and equipment are designed for dead, live, seismic, and wind loads in accordance with applicable codes and as described in the following paragraphs. The loading conditions are determined by the function of the structure and its importance in meeting the station safety and power generation objectives. The load combinations and limits are given in Appendix C, Structural Loading Criteria.

12.2.3.2 Vertical Loads

Dead Loads

The dead loads include the weight of the framing, roof, floors, walls, platforms, and all permanent equipment and materials.

Live Loads

The live loads include all vertical loads except the dead loads. The live loads that have been used in the design of structures are given on Table 12.2-1.

12.2.3.3 Lateral Loads

Wind Loads

The design wind loads are derived from ASCE Paper 3269. The wind loads given on Table 12.2-2 apply to the site area and are used in the station design. A one-third increase in allowable stress is permitted for the wind loading conditions.

Tornado Loads

All Class I structures are designed to withstand the effects of tornadoes and to protect Class I equipment. The Class I structures are designed in accordance with Appendix H, Tornado Criteria for Nuclear Power Plants. The basic design criteria for tornado effects are as follows:

1. The velocity components are applied as a 300 mph horizontal wind over the full height of the structure

2. The pressure differential is applied as 3 psi internal (bursting) pressure occurring in 3 sec

3. The missiles are applied as a 4,000 lb automobile flying through the air at 50 mph but not more than 25 ft above ground, as a 4 in x 12 in x 12 ft plank (108 lb) traveling end-on at 300 mph over the full height of the structure, or as a 3 in dia Schedule 40 pipe 10 ft long traveling end-on at 100 mph over the full height of the structure

All three loading conditions are applied simultaneously.

In the case of adjacent Class I and II structures, such as the Reactor Building and portions of the Turbine Building, an expansion joint is provided to allow for possible unequal deflections associated with different structural systems.

The only Class II structure attached to a Class I structure and not designed to withstand tornado loading is the building exhaust vent stack. This structure consists of light steel framing attached to the Reactor Building and is covered with metal wall siding. The design of siding is such that it may be partially blown away by the tornado without affecting the adjacent Reactor Building. The steel framing will remain in place.

The offgas stack is a Class I structure not designed to withstand tornado loadings, as stated in Section 12.2.1.1. The stack is located sufficiently far from other Class I structures to preclude any interaction, assuming the stack were to fall as a result of tornado loads.

The Secondary Containment System is not designated to be functional during or after a tornado; however, the Reactor Building does protect all the Class I equipment located inside the building from the effects of a tornado.

Crane Runway Loads

The lateral and longitudinal forces on crane runways are in accordance with the AISC Code.

12.2.3.4 Pressure and Thermal Loads

The pressure and thermal design conditions for the Primary Containment System are given on Table 5.2-1. The Reactor Building is designed for an internal pressure loading of 36.5

lb/ft2 (7 in H_2O). The spent fuel storage pool has a design temperature of 212°F.

12.2.3.5 Seismic Loads

12.2.3.5.1 General

The design of Class I structures and equipment is for horizontal ground acceleration of 0.08g for the Operating Basis Earthquake (OBE) and 0.15g for the Safe Shutdown Earthquake (SSE).

The vertical acceleration is equal to two-thirds of the horizontal ground acceleration. Both the vertical and either of the responses of two horizontal seismic motions are considered to be applied simultaneously. The larger combination controls the design. The combined stresses resulting from operational loadings and from a SSE are such that a safe shutdown can be achieved. The applicable load combinations and stress limits including all operational and seismic loads for Class I equipment are given in Appendix C, Structural Loading Criteria. The derivation of the OBE and the SSE is given in Section 2.

Equipment seismic loadings were determined from amplified floor response spectra for the appropriate locations. These spectra were generated from acceleration time-histories at each floor, derived from the normalized Taft earthquake response spectrum, applied to the base of each building model. All erratic peaks were averaged to give smoothed curves for various values of critical damping as required for the seismic analysis.

Class II structures and equipment are designed in accordance with the provisions of the Uniform Building Code, Seismic Zone 2. Class I to Class II interfaces are designed so that there will be no functional failure in the Class I structure. In order to accomplish this design objective, Class I structures have the capacity of withstanding the forces resulting from possible failures of Class II structures which are either attached or adjacent to the Class I structures. In the case of Class I and Class II structures rigidly interconnected, the Class I structure is designed to support the latter.

The Class I portion is checked to assure it can carry any loads that may be transmitted from the connected Class II structures. For example, the salt service water pump room reinforced concrete structure in the intake structure will act as a support for the rest of the building superstructure. Wherever a Class II structure supports a Class I portion located above it, the supporting structure is analyzed and designed to the Class I requirements. Where relative movement between buildings may endanger the integrity of Class I piping or other connecting elements, or the Class I structures themselves, a dynamic analysis of the interconnected or adjacent buildings and/or equipment systems is performed.

Relative deflections are computed for each structure both parallel and perpendicular to the interface.

The criteria for the relative movements under the SSE loadings require that the combined movement does not exceed the clearance provided. The relative movements under these loadings are accommodated by sliding expansion joints at adjoining structures and by built-in flexibility for piping systems. The dynamic analysis has shown that the cumulative maximum displacement of adjoining concrete structures will be about one-half of the clearance provided.

12.2.3.5.2 Seismic Recording Instrumentation

The seismic recording instrumentation used at Pilgrim Nuclear Power Station is an analog centralized recording magnetic tape acceleration system consisting of a multichannel strong motion accelerograph, remote triaxial accelerometers, peak acceleration recorders, control panel and a magnetic tape playback system.

The system automatically senses, transmits and records seismic responses from three elevation locations, storing the records for quick replay and analysis in response to exceeding a "trigger" acceleration of (.01 g) at plant elevation -17'6". The system automatically resets in preparation for the next seismic event.

The local accelerometers are mounted in the Reactor Building at elevations -17'6", 23'0" and 91'0". Each elevation's local accelerometer will sense and transmit displacements in each of three axes (horizontal, vertical, and lateral). The Main Control Room instrumentation on panel C-911 records the date on cassette tape which may be played back in the form of a chart record by the playback unit. The time history is recorded, as received, from a standard time receiver also located in panel C-911. The seismic monitoring instrumentation does not perform any safety related function.

If an earthquake should occur and the g levels, as recorded by the described instrumentation, are at or below the accelerations corresponding to the OBE (0.08 g ground acceleration), the station will continue in operation. The station design considered these loadings, taking no credit for code allowable increases in stress values. If the recorded accelerations approach the values corresponding to the SSE (0.15 g ground acceleration), an inspection will be undertaken of selected high stress welds in the primary pressure boundary to verify continued system integrity.

12.2.3.5.3 Structural Analysis

A dynamic analysis is performed for Class I structures. The dynamic analysis is performed in four steps; develop a mathematical model, perform the analysis, obtain the structural response, and make spectrum plots.

A mathematical model is developed to represent the structure in order to determine its response to the earthquake. Essentially the weight of the building and major internal elements are concentrated at each of the building floor levels. Provisions are made in the model to account for rocking by means of springs representing the soil stiffness. The stiffness matrix, natural frequencies, and mode shapes are obtained by computer analysis. The technique used in the program to determine natural frequencies and mode shapes is that of tri-diagonalization by successive rotations. The damping values used are given on Table 12.2-3.

For purposes of computer analysis, the time history of the Taft Earthquake of July 21, 1952 is used with the amplitude scaled to 0.08g and 0.15g ground acceleration for the OBE and the SSE, respectively. The earthquake data is placed into digital information with g levels expressed every 0.01 sec over a time interval of 30 sec. The final design is checked to assure that the results are compatible with smoothed response spectra as given on Figures 2.5-5 and 2.5-6.

The Taft time history record generates plots below the ground response spectrum, for frequencies below 1 cps. However, when generating floor response spectra curves from the Taft record for use in equipment seismic design, each curve is compared to the ground response spectrum and corrected so that no points fall below the ground spectrum curve.

The results of the modal analysis are used to represent the structure as a modal system. The technique of modal synthesis is employed to reduce the structural equations to j (number of modes) independent equations.

The modes are further employed to reduce the earthquake forces into j modal forces. The resulting system of equations are then solved independently to obtain the modal coordinates. The solution employs a Runge-Kutta numerical integration scheme. The integration step used is 0.01 sec. Again using the mode shapes, the modal coordinates are operated upon to obtain the physical coordinates of the model; then solved for displacement, velocity, and acceleration. These values are separated point by point for each of the floors as a record of the response time history.

For each of the floors a spectrum plot is made. The technique for the plots makes use of determining the response of a single mass system. The natural frequency of this system is varied from 0.1 cps to 30 cps. The maximum response, as acceleration, is then plotted for each frequency.

Class I systems and equipment at the supplier's option may be analyzed dynamically to establish the natural frequency of the equipment and accessories complete with supports. If the natural frequency is less than 20 Hz, then the corresponding particular value of the floor response spectrum is used. For all natural frequencies greater than 20 Hz, an appropriate

value of the respective zero period (ZPA) floor acceleration is used.

The equipment supplier is also given the choice, in lieu of performing a dynamic analysis for equipment design, to use the peak value of the applicable floor response spectrum curve.

For the Class I mechanical and electrical equipment, dynamic tests may be carried out, or evidence may be submitted of satisfactory performance through environments of equal or higher dynamic intensity. For such environmental data the levels sustained are required to be greater than the applicable floor response spectrum curve. See paragraph C.3.3.2, Appendix C.

For dynamic test, various approaches may be used. For example, the Class I equipment may be taken at the applicable critical damping curve peak level from 5 Hz to 20 Hz. Alternately, the equipment may be shaken to determine its natural frequency, and the appropriate g level then applied to determine its functional adequacy.

A structure or structural system that cannot be satisfactorily included in the lumped mass structural model analysis are analyzed separately, such as masonry blockwalls and the cable tray and conduit support systems. The analytical technique for the seismic loads induced is similar to that for Class I structures, but is based on response spectrum developed at the structure's support point. The damping values used for the evaluation are based on Table 12.2-3. They are derived from the test results and inherent in the structural system.

12.2.3.5.4 Piping Analysis

For critical piping systems, a dynamic analysis is performed, as described in paragraph C.3.3.1, Appendix C.

Class I piping and associated miscellaneous Class I equipment, instruments, and controls that cannot be satisfactorily included in the lumped mass model representing a structure, are analyzed individually. The analysis is similar to that for Class I structures, but is based on response spectrum developed for points of pipe or equipment supports. These spectra are computed from time history analysis of the structure model, subjected to the north-south horizontal component of the earthquake, normalized to the maximum acceleration associated with the OBE and SSE. Stops, guides, and snubbers are added where necessary to avoid critical natural periods, and to make the system as rigid as practical. Displacements of the piping are checked to assure that there will be no interference with any other equipment or piping.

Essentially the same method of analysis for seismic inertia loads is used on Class I piping, whether located outside or inside the containment structure. To determine the effect of relative differential end displacements on Class I piping systems, the following method is used: The seismic

displacements at the ends and at restraints are known from the seismic analysis of the structures. The displacements applied to the piping restraints and anchors correspond to the maximum differential displacements which could occur. The analysis is made twice; once for north-south differential displacements and once for east-west differential displacements. For each response quantity considered (i.e., moments or displacements at a point, and restraint force or moment), the largest value of the two analyses is chosen. The displacements, restraint forces, and moments due to differential displacement are combined with the corresponding quantity from the inertia load analysis of the piping. The basis of combination is SRSS, since the maximums of the two quantities would not occur at the same time. For recirculation, RWCU and RHR replacement piping the basis of combination is absolute sum. The stresses due to relative support displacements in piping are combined with stresses caused by other secondary effects, and the resulting secondary stresses are compared with the applicable, allowable stresses in USAS B31.1.0. For recirculation, RHR and RWCU replacement piping, stresses due to secondary effects were combined in accordance with ASME B&PV Code Section III Subsection NB 1980 Edition through Winter 1981 Addenda. Allowable stresses were referenced from ASME B&PV Code Section III Division I, Appendix I 1980 Edition through Winter 1980 Addenda.

The results of the differential displacement analysis are usually insignificant compared to those of the inertia force analysis. This is because the differential displacements are usually very small, and most piping systems (especially hot ones) have enough flexibility so that these small displacements have little effect.

Since the movement of buried piping is essentially the same as that of the surrounding soil, piping strains due to seismic ground motion are equated to soil strains, which are calculated from the assumed seismic ground motions. Piping stresses, obtained from the strains, are within the allowable stresses defined in USAS B31.1.0.

Where Class I buried piping enters a structure, the magnitude of the relative movements is expected to be insignificant, because the backfill supporting the piping has been compacted to a relative density of 85 percent. Any differential settlement will be small and readily accommodated by the welded steel pipe.

12.2.3.5.5 Recirculation RHR and RWCU Piping Replacement Seismic Analysis

The recirculation piping replacement seismic analysis uses the multi-support excitation response spectrum methodology in which the individual response spectra are applied to each support degree-of-freedom. The individual input spectra are peak broadened ±15% to account for the potential variation in the primary structure eigenvalues due to modeling, analysis and material property uncertainties.

Piping structural damping is provided in Table 12.2-3 and is 2.0% and 3.0%, respectively, for the OBE and SSE analyses.

The colinear contributions due to the 3 spatial components of seismic excitation are combined by the square root of the sum of the squares (SRSS) method.

Peak modal responses are combined by the Double Sum method which accounts for the effects of closely spaced modes. The Double Sum method is identical to the SRSS method if there are no closely spaced modes. Both combination methods; i.e., for 3D spatial effects and for modal confirmation, are consistent with Regulatory Guide 1.92, Revision 1, February 1976.

Recirculation RHR and RWCU piping differential anchor displacements are evaluated and the primary (inertia) and secondary (anchor displacement) stresses combined as described in Paragraph 12.2.3.5.4.

The piping multi-support input spectra are generated from the acceleration time history responses at the primary structure/piping attachment points obtained from the primary structure time history seismic analysis.

12.2.3.5.6 Protective System Instrumentation

Each type of protective system instrument and its supporting panel or cabinet is analyzed, tested, or investigated to confirm that it will withstand the interaction effects of the floor acceleration from the SSE without loss of function. The interaction effects on a protective system instrument are determined by the dynamic response of its supporting control panel or cabinet, static analysis or test.

12.2.3.5.7 Damping Values

The damping factors used in the seismic analysis are based upon deformations or stresses of various materials, and are shown on Table 12.2-3. These damping values are the lower limits of commonly accepted ranges for the stress levels associated with the respective earthquakes based on recommendations by Newmark and Hall in NUREG/CR-0098.

12.2.3.6 Primary Containment Loading Considerations

The primary containment system is designed to withstand all forces associated with a postulated loss of coolant accident (LOCA). In addition to the pressure and thermal loading conditions shown on Table 5.2-1, the primary containment is designed to withstand the jet forces associated with a LOCA, and a post accident flooded condition. The jet forces given on Table 12.2-5 are assumed to result from the impingement of steam and/or water at 300°F. For the flooded condition, the primary containment is assumed to be filled with water up to the normal refueling level.

12.2.3.7 Handling of Heavy Loads

The Pilgrim Station heavy load handling program provides a defense-in-depth approach to reduce the probability of accidents, or the consequences of such accidents, from handling heavy loads (loads in excess of 1500 lbs). The program establishes administrative controls to address safe load paths, safe load handling procedures, crane and hoist operator training, standards for lifting devices and cranes, and special requirements when handling heavy loads in areas where fuel or safe shutdown equipment could be damaged. The program provides reasonable assurance that heavy load lifts will be performed safely and meet applicable guidance contained in NUREG 0612, "Control of Heavy Loads at Nuclear Power Plants," July 1980 (reference 1). Program details are described in references 2, 3, 4, and 5. NRC evaluation of the program is documented in references 6 and 7.

The approach to NUREG 0612 compliance for Dry Fuel Storage heavy loads differs from the above description. The Pilgrim Heavy Load Handling Program details described in references 1,2,3,4, and 5, and evaluated by the NRC in references 6 and 7, are based on the use of non-single-failure-proof hoisting equipment, hence requiring evaluations to demonstrate acceptable load drop consequences. An upgraded Reactor Building crane with a single-failure-proof main hoist is being used with Dry Fuel Storage components and ancillaries designed to the augmented safety factors ANSI N14.6 for critical loads. This approach does not require postulating and analyzing load drop accidents for Dry Fuel Storage operations involving the handling of heavy loads. Dry Fuel Storage is described in FSAR Section 10.3.8.

12.2.4 Foundation Analysis

12.2.4.1 General

The foundation investigation and analysis for the construction of the station was performed in three parts:

1. Field explorations

2. Laboratory Tests and analyses

3. Establishment of foundation design criteria

The field explorations and laboratory tests led to the conclusions that the subsurface conditions in the station area are somewhat variable especially in the upper 35 to 40 ft. The borings encountered erratic and discontinuous layers of silty fine sand, fine sand, clayey silts, and clayey sands. The soils within about 35 ft of the ground surface range in density from loose to compact and are compressible. Beneath the upper variable strata, dense and relatively incompressible poorly graded to well graded sands with varying amounts of gravel and cobbles are found. Bedrock is generally encountered at a depth of about 80 ft in the station area. See Figure 12.2-4.

The foundation design criteria were established on the basis of these conclusions.

12.2.4.2 Field Exploration

In addition to the overall site geologic and seismic explorations, detailed foundation investigations, including borings and field permeability tests, were carried out for use in establishing the foundation criteria for the station structures. Prior to construction, a series of test borings was drilled in the general station area. Altogether a total of 58 borings were drilled to determine the subsurface condition. The locations of some of the test borings and test wells are shown on Figure 12.2-5. In addition to borings for the station, a number of borings was scattered over the site. Borings were made to various depths from 16 to 130 ft. Bedrock was generally encountered at a depth of about 80 ft in the station area as determined by a seismic refraction survey. Disturbed and undisturbed soil samples, suitable for laboratory testing, were extracted from the test borings, examined, and subjected to the laboratory tests listed in Section 12.2.4.3. Figures 12.2-6 through 12.2-10 are some of the boring logs for borings taken in the station area.

A series of pumping and percolation tests were performed to obtain estimates of the permeability of the onsite materials at predetermined depths. The data obtained from these tests were used in the foundation analysis to establish de-watering requirements during the excavation for the foundations.

12.2.4.3 Laboratory Tests

Representative undisturbed soil samples extracted from the test borings were subjected to a comprehensive laboratory testing program to evaluate the physical and chemical characteristics of the soil encountered at the site. The laboratory tests included:

- Direct shear tests
- Unconfined compression tests
- Confined compression tests
- Triaxial compression tests
- Moisture and density determinations
- Particle size analysis
- Shockscope

12.2.4.4 Foundation Design Criteria for Structures

12.2.4.4.1 General

This section describes the foundation conditions for the major and auxiliary station structures.

12.2.4.4.2 Design Considerations

The major station facilities include the reactor building, turbine building, and radwaste building. The auxiliary structures include the diesel generator building, main stack, administration building, and intake structure. A description of foundations provided for the structures is given in the

following sections. Figure 12.2-5 shows the locations of structures in relation to the test borings drilled.

An analysis of the liquefaction potential of cohesionless soil fill materials indicated that a granular material compacted to an average relative density of 80 percent at station grade, and 75 percent under the surcharge of the turbine building, would have a factor of safety of at least 1.5 against initial liquefaction, with earthquake motions producing a maximum ground surface acceleration of 0.15g. All Class I structures and the turbine building are founded on undisturbed soil, or on select granular fill compacted to a minimum of 85 percent relative density. The relative density tests were performed in accordance with ASTM Standard D-2049, March 1968, Tentative Method of Testing for Relative Density of Cohesionless Soils.

12.2.4.4.3 Major Structures

Reactor Building

The lowest floor of the reactor building is founded at el -25.5 ft msl on dense to very dense silty sand and sand and gravel. At the center of the reactor, bedrock is about el -60 ft msl. Groundwater in-leakage is designed to be prevented or minimized by a waterproof membrane. The estimated total settlement that this structure will experience is 2 to 4 in of uniform elastic compression at the design loads. The differential settlements are expected to be less than 1 in. Since this structure consists primarily of dead load, most of the elastic deformation will occur during construction. Post construction settlement is expected to be on the order of 1/2 in. A survey traverse of points on the building has been established to monitor settlement. The settlement at approximately 30 percent of the load was negligible.

Turbine Generator Building

The subsurface soil below the founding elevation of the turbine building was found to consist of erratic layers of clayey sand, silty sand, and sand and gravel. This soil was excavated to el -27 ft msl, 13 ft below the founding elevation, to remove these undesirable pockets of less dense compressible soils. The excavated area was then backfilled with suitable granular material and compacted to a minimum relative density of 85 percent.

The Turbine Building is protected below grade by a waterproof membrane designed to prevent or minimize ground water in-leakage.

Radwaste Building

The radwaste building rests partially on undisturbed dense relatively incompressible sand, gravel, and cobbles, and partially on structural backfill compacted to 85 percent

relative density. This structure has a waterproof membrane designed to prevent or
minimize ground water in-leakage.

12.2.4.4.4 Auxiliary Structures

Diesel Generator Building

The diesel generator building has a reinforced concrete foundation mat founded on a structural backfill, compacted to 85 percent relative density.

Main Stack

The main stack and filter building structure rests on undisturbed dense relatively incompressible sand, gravel, and cobbles.

Administration Building

This structure is founded on structural fill compacted to 75 percent relative density.

Intake Structure

This structure rests on undisturbed very dense incompressible silty sand and gravel.

Guardhouse

This structure is founded on spread and continuous footings and consists of a structural steel frame with metal and glass curtain walls and precast concrete panels. Interior walls are masonry block. The floors are reinforced concrete. The roof is structural steel roof deck with built-up roofing.

12.2.4.4.5 Foundation Settlement Measurements

Table 12.2-7 6 summarizes the results of foundation settlement measurements taken at various stages of dead load application during construction at points shown on Figure 12.2-11.

Total differential settlements are predicted to be 1 in or less. Measured values of settlement are acceptably low.

12.2.5 Design Organization and Procedures

12.2.5.1 Design Organization

The GE-APED organizations having responsibility for the seismic design of safety related systems and structures in the NSSS were Power Plant Projects, Requisition Engineering, Component Engineering, Seismic Design Engineering, and Plant and Equipment Engineering. The seismic design responsibility was assigned to the functional group, Component Engineering or Plant and Equipment Engineering, responsible for the equipment

and/or structure design. These functional groups are responsible to the Manager, Design Engineering.

The Bechtel Corporation Pilgrim Nuclear Power Station Project design organization consisting of the Mechanical Group, Layout Group, Civil Group, and the Electrical Group, in parallel with the Bechtel Corporation Power and Industrial Division's Structural Dynamics Group, and the Piping Stress Group, had the responsibility for the seismic design of all balance of plant structures, systems, and components related to safety.

Dames and Moore performed the site seismology studies. These studies were reviewed and checked by Bechtel's Soils and Geology Department. Chicago Bridge and Iron performed the primary containment stress analyses.

12.2.5.2 Design Responsibilities

Design organizations of GE-APED have been responsible for proper application of seismic design loads and conditions to the design of equipment components and piping in the NSSS scope. Analytical assistance was available within Design Engineering from analytical components specialized in seismic design. An Engineering Practices and Procedures Manual defined explicitly in writing, all Design Engineering responsibilities, including seismic. The Manager, Design Engineering, had overall responsibility for the adequacy of the seismic design of the General Electric product. Overall coordination of this work was assigned to the Seismic Design Component.

The dynamic analysis of station structures was performed by the Bechtel Structural Dynamics Group after the location of major component masses was determined by the involved Bechtel Project groups. The Civil group had responsibility for station structural design. See Appendix C. The Mechanical and Electrical Groups had responsibility for obtaining vendor seismic design analyses or test results of safety-related equipment and instrumentation; the Layout Group provides input on station piping layout to the Piping Stress Group which performs piping stress calculations for Class I piping systems.

The Structural Dynamics Group performed the dynamic structural analyses. The resulting floor response spectrum curves were promulgated in writing to the Bechtel project groups and to the GE- APED Pilgrim Project Organization through the Civil Group which coordinates, and has overall responsibility for, the balance of plant station seismic design.

12.2.5.3 Documentation and Control Procedure

The mechanism for the interchange of needed design information and changes thereto and the coordination of the various facets of the seismic design among the involved design organizations components, and/or groups is shown on Figure 12.2-12.

The system shown on Figure 12.2-12 is a pattern of interrelationships and checks from which an iterative process

evolves which ensures proper station seismic design for structures, systems, and components related to safety.

Within GE-APED Design Engineering, the design engineer was ultimately responsible for implementation of the seismic design requirements. Within the Bechtel Pilgrim Project organization, the engineer responsible for the safety-related equipment, supported by the engineers qualified in seismic analysis within the Structural Dynamics Group, were responsible for the implementation of the seismic design requirements.

For GE-APED components, the adequacy of seismic design was the responsibility of the individual design engineer. Within the Bechtel Corporation, the seismic certification of safety-related equipment was the responsibility of the design group procuring the equipment. Within each group, one or more engineers coordinated the transfer of vendor seismic certification (analyses, tests, or documentation of suitable performance in comparable vibrational environments) to the Civil Group for engineering review and approval by the Structural Dynamics Group.

12.2.5.4 Purchase of Safety-Related Equipment

Class I Systems and equipment at the supplier's option may be analyzed dynamically to establish the natural frequency of the equipment and accessories complete with supports. If the natural frequency is less than 33 Hz, then the corresponding particular value of the floor amplified response spectrum is used. For all natural frequencies greater than 33 Hz, the zero period acceleration value of the respective amplified floor spectrum is used.

The equipment supplier is also given the choice, in lieu of performing a dynamic analysis for equipment design, to use the peak value of the corresponding floor amplified response spectrum curves for the seismic analysis.

For the Class I mechanical and electrical equipment, dynamic tests may be carried out, or evidence may be submitted of satisfactory performance through environments of equal or higher dynamic intensity. For such environmental data, the g levels sustained are required to be greater than the 2 and 3 percent critical damping curves for OBE and SSE respectively. See paragraph C.3.3.2, Appendix C for further requirement.

For dynamic test, various approaches may be used. For example, the Class I equipment may be taken at the associated critical damping curve push level. Alternately, the equipment may be shaken to determine its natural frequency and the appropriate g level then applied to determine its functional adequacy.

The above three procedures are consistent with the seismic qualification requirements of IEEE 344-1975.

Seismic qualification documentation of electrical and/or mechanical equipment purchased prior to 1983, for initial use

or for replacement-in-kind service, may comply to the requirements of IEEE 344-1987 in lieu of IEEE 344-1975.

12.2.6 References

1. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, July 1980 (Enclosure 1 to NRC Letter dated December 22, 1980; Ltr. 1.81.014).

2. PNPS Letter 2.81.141, A. Morisi to D.G. Eisenhut (NRC), Subject: NUREG-0612, Control of Heavy Loads, dated June 25, 1981.

3. PNPS Letter 2.81.242, A. Morisi to D.G. Eisenhut (NRC), Subject: NUREG-0612, Control of Heavy Loads, dated October 8, 1981.

4. PNPS Letter 2.83.181, W.D. Harrington to D.G. Eisenhut (NRC), Subject: NUREG-0612, Control of Heavy Loads, dated July 13, 1983.

5. PNPS Letter 2.85.017, W.D. Harrington to D.B. Vassallo (NRC), Subject: Additional Information on NUREG-0612, Factors of Safety for Reactor Building Lifting Devices, dated January 25, 1985.

6. NRC Letter dated March 6, 1985 (Ltr 1.85.069), D.B. Vassello (NRC) to W.D. Harrington, Subject: Control of Heavy Loads (Phase 1).

7. NRC Generic Letter 85-11 (Ltr. 1.85.202), Completion of Phase II on "Control of Heavy Loads at Nuclear Power Plants," NUREG-0612, dated June 28, 1985.

8. NUREG-0554, Single Failure Proof Cranes for Nuclear Power Plants, May 1979.

9. ASME NOG-1, Rules for Construction of Overhead and Gantry Cranes (Top Running Bridge, Multiple Girder), 2004 Edition.

8.10. Crane Manufacturers Association of America (CMAA) Specification #70, Specifications for Top Running Bridge and Gantry Type Multiple Girder Electric Overhead Traveling Cranes, 2010 Edition.

TABLE 12.2-1

LIVE LOADS ON STRUCTURES

		Beams and Slabs (psf)	Girders and Columns (psf)
1.	General	30	
	Roof-snow (minimum)	30	30
	Offices	50	50
	Stairway and Walkways	100	100
	Assembly Rooms	100	100
	Partitions (office aréa)	20	20
	Concentrated Loads*	4,000 lb	4,000 lb
2.	Turbine Building		
	Foundation Slab on Ground	4,000	---
	Floor at El 6 ft 0 in	350	---
	Floor at El 23 ft 0 in	350	300
	Floor at El 37 ft 0 in	350	300
	Operating Floor at El 51 ft 0 in Laydown Area	1000	800
	All Other Areas	400	300
	Platforms with Grating Floors	100	100
3.	Reactor Building (excluding drywell and torus areas)		
	Floors at El 3 ft 0 in	200	---
	Floor at El 23 ft 0 in**		
	Loading Areas	1,000	800
	All Other Areas	250	250
	Floor at El 51 ft 0 in and 74 ft 3 in	200	200
	Floor at El 91 ft 3 in		
	Laydown Under Hatch	500	400
	All Other Areas	200	200
	Operating Floor at El 117 ft 0 in		
	Drywell Head Area	1,000	800
	Shipping Cask Area (6 ft dia)	200,000 lb	200,000 lb
	All Other Areas	500	400
	New Fuel Storage Area at El 101 ft 0 in	1,500	1,500
	Spent Fuel Pool and Dryer-Separator Storage Pool	Water Plus Equipment Load	Water Plus Equipment Load

TABLE 12.2-1 (Cont)

		Beams and Slabs (psf)	Girders and Columns (psf)
4.	Drywell Interior		
	Ground Floor at El 9 ft 2 in	200	---
	Floor at El 21 ft 11 1/4 in	150	150
	Floor at El 40 ft 8 1/2 in	150 Plus 30,000 lb Moving Load	150 Plus 30,000 lb Moving Load
5.	Torus Area		
	Floor at El (-) 17 ft 6 in	150 or Torus Water Load	---
6.	Radwaste Building		
	Foundation Slab on Ground	4000	---
	Control Room	250	200
	Floor at El 23 ft 0 in	500 Truck Load at Access	400
	Other Areas	400	300
7.	Machine Shop and Warehouse Area	400 or Truck Load at Access	300
8.	Intake Structure	500 or Truck Load at Access	400

9. Crane and Elevator Loads

Crane and elevator loads are considered in the design as live loads. A 25 percent impact increase to live load is used for traveling crane support girders and connections. A 100 percent impact increase to live load is used for elevator supports.

10. Light Piping Loads

The dead load of light piping is included in the design as a live load; a 50 psf additional dead load is used in areas with heavy piping. Stresses in beams and girders are rechecked after pipe hanger locations are final.

Table 12.2-1 (Cont'd)

NOTES:

* Except for office and access control areas, all floor slabs, beams, and girders are designed for one concentrated load of 4,000 lb, acting simultaneously with the floor live loads. This load is assumed to act at the point of maximum moment or shear. It is not cumulative and is not carried to the columns.

** The area under the hatch is designed for truck load.

*** This table is supplemented by Drawings A705 through A713.

TABLE 12.2-2

DESIGN WIND LOADING

Height above Grade (ft)	Class I Structures (psf) (100 yr recurrence)	Class II Structures (psf) (50 yr recurrence)
0-50	28	26
50-150	44	40
150-400	66	62

TABLE 12.2-3

DAMPING FACTORS

Item	Percent Of Critical Damping: Design Earthquake	Percent Of Critical Damping: Maximum Credible Earthquake
Reinforced Concrete Building	5.0	7.5
Internal Concrete Structures and Equipment Supports	2.0	3.0
Component and Equipment	2.0	3.0
Bolted Steel Assemblies/ Structures	2.0	5.0
Concrete Blockwall	4.0	7.0
Welded Assemblies/Structures	1.0	2.0
Class I Piping Systems (See Note 4)	0.5	1.0
Tray and Conduit Supports	4.0	7.0

NOTES:

1. OBE is the Operating Basis Earthquake which is equivalent to the Design Earthquake.

2. SSE is the Safe Shutdown Earthquake which is equivalent to the Maximum Credible Earthquake.

3. The percent of critical damping values used are derived from and associated with the lower stress values developed and recommended by Newmark and Hall in NUREG/CR-0098.

4. Damping values shown are the Pilgrim design basis applicable to piping systems during original plant design. Subsequent to initial plant startup, modifications were implemented to resolve generic Mark I design issues using project specific criteria applied to selected piping system scopes of work: namely, GE reanalysis for Recirculation, RHR, and RWCU pipe replacement, and Teledyne suppression pool analysis for loadings from the GE Mark I Long Term Program. See FSAR Sections 12.2.3.5.5, C.3.3.1, and L.3.1.

TABLE 12.2-4

RELATIONSHIP BETWEEN DAMPING FACTORS AND DESIGN STRESS LIMITS FOR 0.15g EARTHQUAKE

Reference Table	Location	Design Allowable Stress (psi)	Design Allowable Stress % f_c or % f_y	Damping Factor
Criteria				
12.2.3	Reinforced Concrete		75 f_c	7.5
	Building Structural Steel		90 f_y	5
Relationship				
C-3	Reactor Building			
	Internal Wall Concrete	3,000	75 f_c	5
	Internal Wall Reinforcement	54,000	90 f_y	5
C-7	Drywell Concrete Shield			
	Concrete	3,000	75 f_c	7.5
	Reinforcement	54,000	90 f_y	7.5
C-8	RPV Concrete Pedestal			
	Concrete	1,680	42 f_c	2
	Reinforcement	28,200	47 f_y	2
C-4	Reactor Building Precast Concrete Panels			
	Concrete	4,500	75 f_c	5
	Reinforcement	54,000	90 f_y	5
C-6	Reactor Building Roof Structural Steel Truss	14,600	60 F_a	5

TABLE 12.2-5

JET FORCE LOADING ON PRIMARY CONTAINMENT

Location	Jet Force Maximum(Kip)	Interior Area Subjected to Jet Force(ft^2)
Spherical part of drywell	665	3.69
Cylindrical part of drywell and transition to sphere	316	1.76
Closure head	32.6	0.18
Suppression chamber (reaction force)	21	On each down-comer pipe

TABLE 12.2-6

SETTLEMENT MEASUREMENTS (FEET)

Point No.	11/1/68	11/16/68	1/1/69	1/16/69	2/1/69	3/1/69	4/1/69	4/16/69	May '69	June '69	Aug '69	Apr. '70
1	Initial	0.012	-0.011	0.005	Gone							
1N						Initial	0.011	-0.007				Gone
2	Initial	0.013		Gone								
2N						Initial	0.002	Inac				Gone
3	Initial	0.013	-0.001	0.005	0.014	0.013						
3N							Initial	-0.017	-0.015			Gone
4	Initial	0.014	-0.004	Inac	Inac	0.023	Gone					Gone
5	Initial	-0-	-0.001	-0.001	Inac	Inac	Gone					Gone
6	Initial	-0.008	Inac	-0.011	-0.010	-0-	-0.006	-0.002	0.003	0.001	-0.002	-0.010
7	Initial	-0.008	-0.003	-0.008	-0.012	-0.002	-0.004	-0.004	0.001	-0.001	-0.002	-0.022
8	Initial	Inac	-0-	-0.006	-0.005	-0-	0.001	0.001	0.005	0.004	-0-	Gone
9	Initial	-0.008	-0.002	-0.011	-0.015	-0-	Inac	Inac				Gone
10	Initial	-0.014	-0.004	-0.011	-0.020	Inac	-0.008	-0.007	-0.005	-0.006		Gone
11	Initial	-0.012	-0.005	Gone								Gone
12	Initial	-0.008	0.004	-0.008	-0.012	-0.002	-0.001	-0.004	0.006	0.002		Gone
13	Initial	0.001	-0.004	0.005	0.005	0.003	0.008	-0-	-0-			0.010
14	Initial	0.002	-0.004	0.006	0.003	-0-	0.010	-0-	0.003			Inac
15	Initial	-0.002	Inac	0.008	0.005	0.002	0.012	0.007	0.005		0.006	Inac
16	Initial	Inac	Inac	0.006	0.003	-0-	0.004	-0.002	0.003			Inac
17	Initial	-0-	Inac	0.011	0.008	-0-	0.009	0.003	0.005		0.004	0.026
18	Initial	0.003	-0.007	0.011	0.008	0.005	0.009	0.003	0.003	-0-	0.004	0.023
19	Initial	-0-	-0.012	Inac	-0.027	-0-	0.004	-0.002	0.001	-0-	-0.001	Inac

TABLE 12.2-6 (Cont)

Point No.	11/1/68	11/16/68	1/1/69	1/16/69	2/1/69	3/1/69	4/1/69	4/16/69	May '69	June '69	Aug '69	Apr '70
20	Initial	0.002	-0.008	0.011	0.008	Inac.	0.004	-0.007	-0.002	-0.004	-0.001	0.013
21	Initial	0.002	-0.005	0.010	0.005	0.003	0.005	-0-	-0.002	-0.002	-0.003	0.011
22	Initial	0.007	0.002	0.010	0.010	0.003	0.010	0.002	0.003	-0.021	0.002	Inac
23	Initial	0.007	Inac	0.020	0.009	0.005	0.010	-0-	0.003	0.001	0.002	0.007
24	Initial	0.007	Inac	Inac	Inac	-0.005	0.008	Inac	-0.002	-0.002		0.001
25	Initial	0.005	0.007	0.011	0.006	0.010	0.007	-0-	0.002			Inac
26	Initial	0.002	0.002	Gone								Gone
27		Initial	-0.003	0.005	0.003	-0.001	0.005	-0.003			-0.003	Gone
28		Initial	0.001	0.008	0.006	0.013	0.007	0.009				Gone
29		Initial	0.001	0.013	0.011	0.017	0.014	Inac				Inac
30		Initial	-0-	-0.002	0.006	0.007	0.005	0.004	0.004	0.002	0.015	Inac
31		Initial	-0.004	0.010	0.008	0.004	0.004	-0.004	0.003	-0.004	0.014	Inac
32		Initial	0.002	Inac	Inac	0.005	-0.002	Inac	-0.006	-0.011		Inac
33		Initial	0.001	-0.001	0.007	-0.002	-0.002	-0.007	-0.003	-0.005	0.008	Inac
34		Initial	0.005	0.005	0.003	-0.001	-0.006	-0.009	-0.009	-0.014	-0.001	0.016
35		Initial	-0.002	0.001	0.004	-0-	0.002	-0.001	-0.001	-0.006	0.008	0.023
36		Initial	0.009	0.001	-0.001	0.005	0.005	0.005	0.012	0.009	0.012	Inac
37		Initial	Inac	Inac	Inac	Inac	Inac	Inac	0.004			Inac
38					Initial	0.010	0.001	0.008	0.008	0.009	0.010	Gone
39					Initial	Inac	0.002	0.008	0.011	0.004	0.005	Gone
40								Initial	-0-	-0.006		-0.006
41								Initial	-0-	0.089		0.024
42								Initial	-0-	0.092		0.029

TABLE 12.2-6 (Cont)

Point No.	11/1/68	11/16/68	1/1/69	1/16/69	2/1/69	3/1/69	4/1/69	4/16/69	May '69	June '69	Aug '69	Apr '70
43								Initial				0.026
44								Initial	-0-	-0.009		Inac
45								Initial	-0.002			0.003

ABBREVIATIONS:

Inac - Point temporarily inaccessible due to construction.

Gone - Point permanently covered or rendered inaccessible.

NOTE: Figure 12.2-1 has been deleted.

Figures 12.2-2 and 12.2-3 have been removed.

Please refer to BECo Controlled Drawings M 27 and M 28.

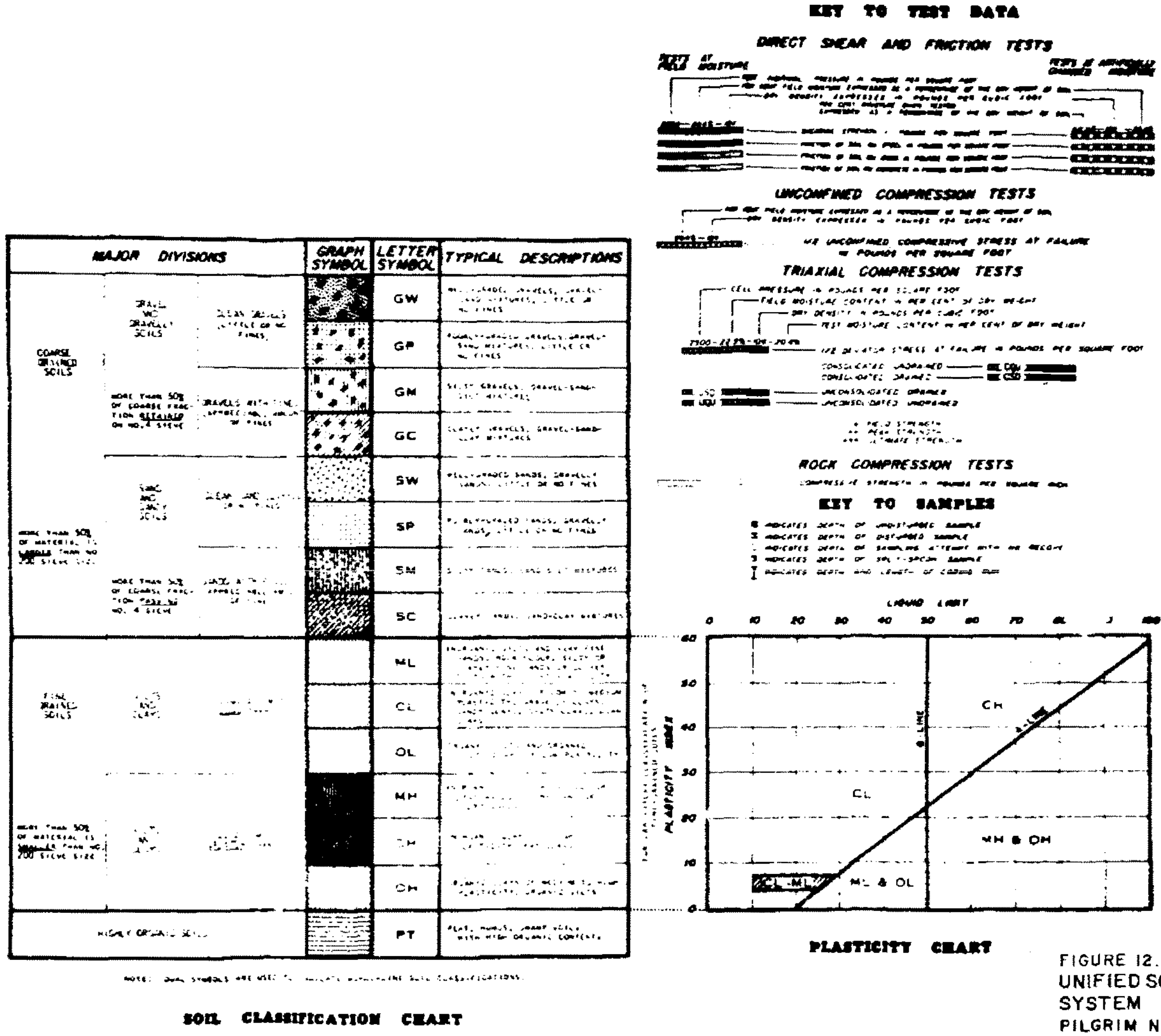


FIGURE 12.2-4
UNIFIED SOIL CLASSIFICATION SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 12.2-5 has been removed.

Please refer to BECo Controlled Drawing C 4.

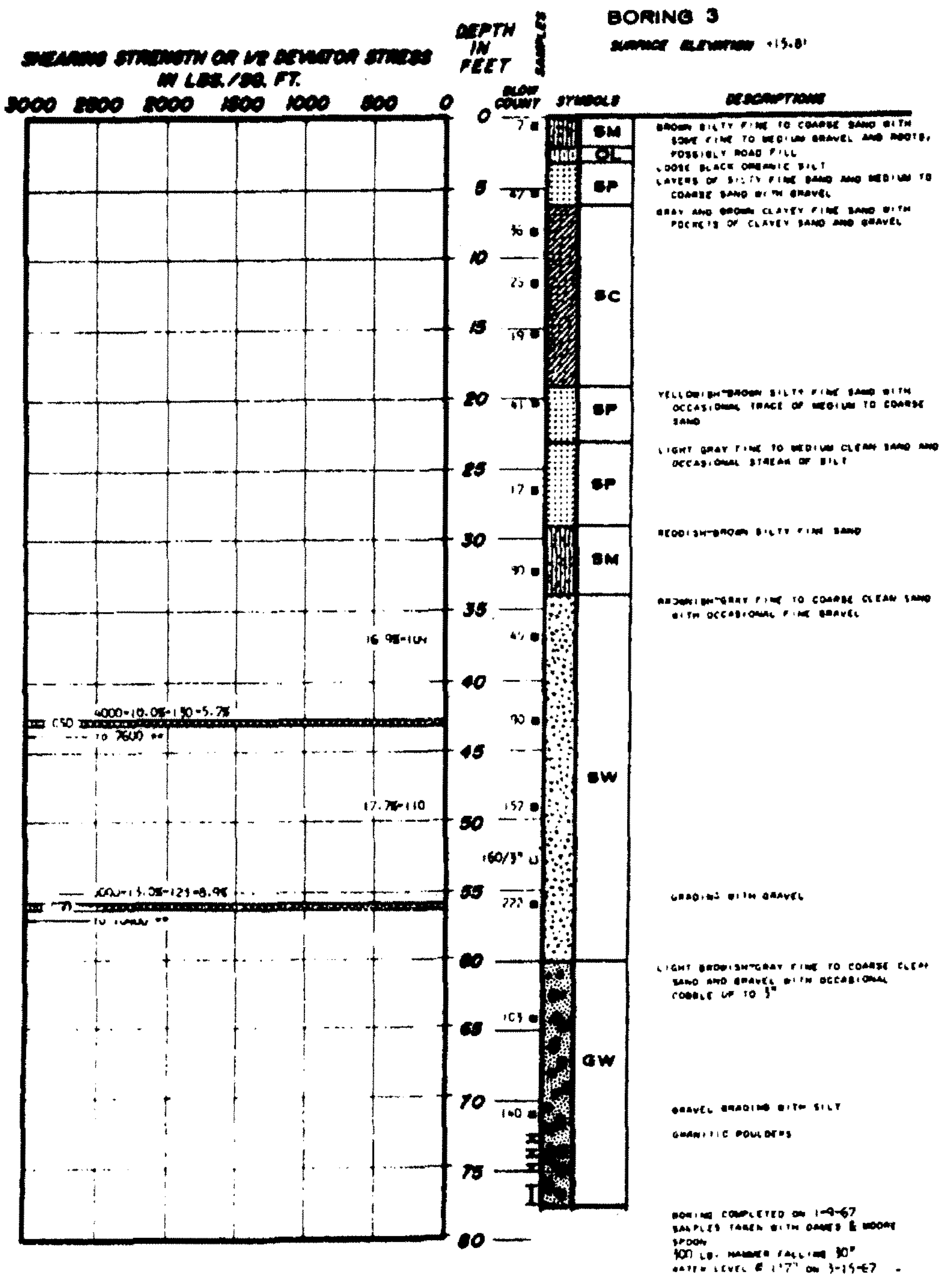


FIGURE 12.2-6

LOG OF BORING (BORING 3)

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT

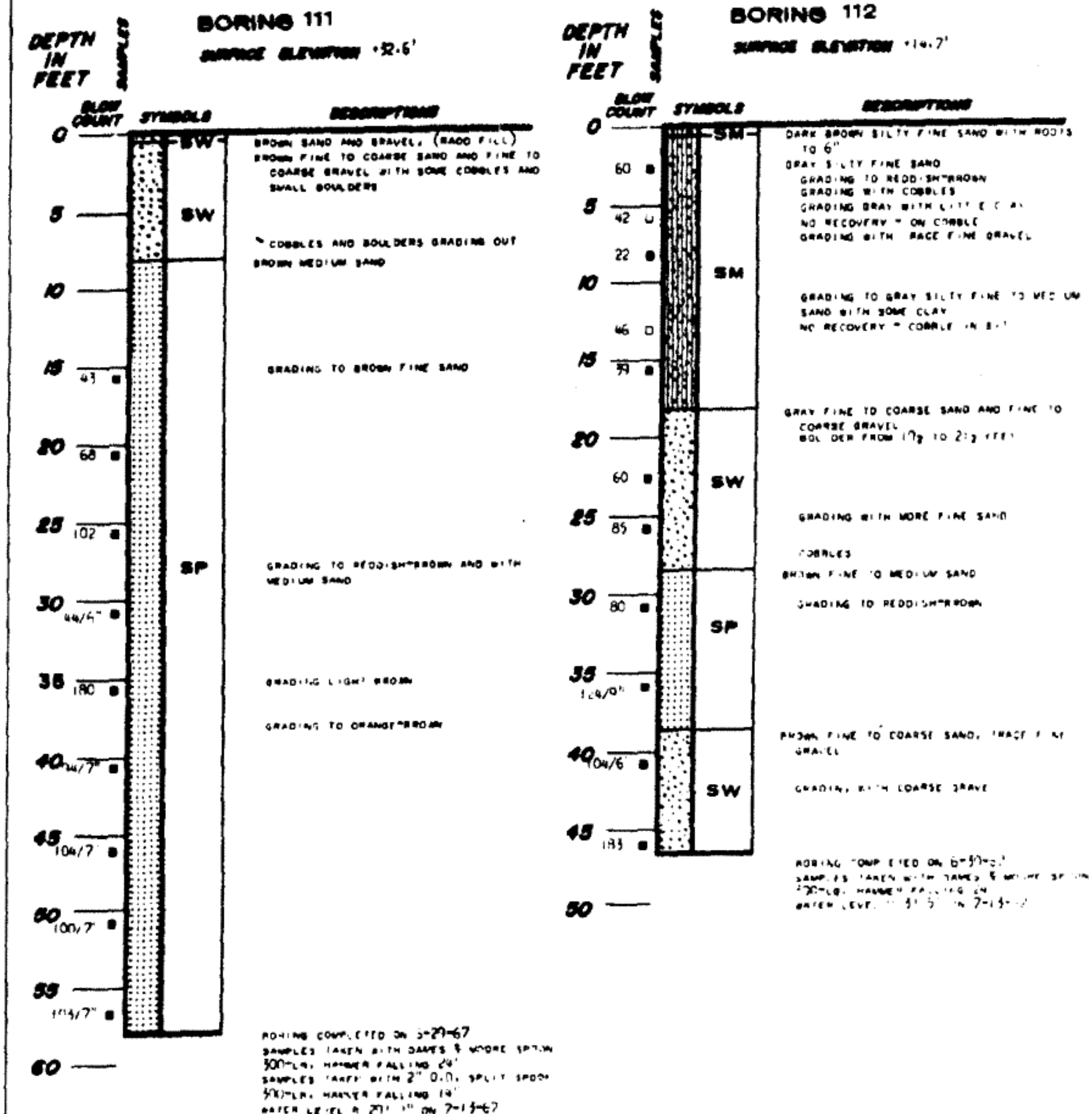


FIGURE 12.2-7
LOG OF BORINGS
(BORINGS 111 & 112)
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

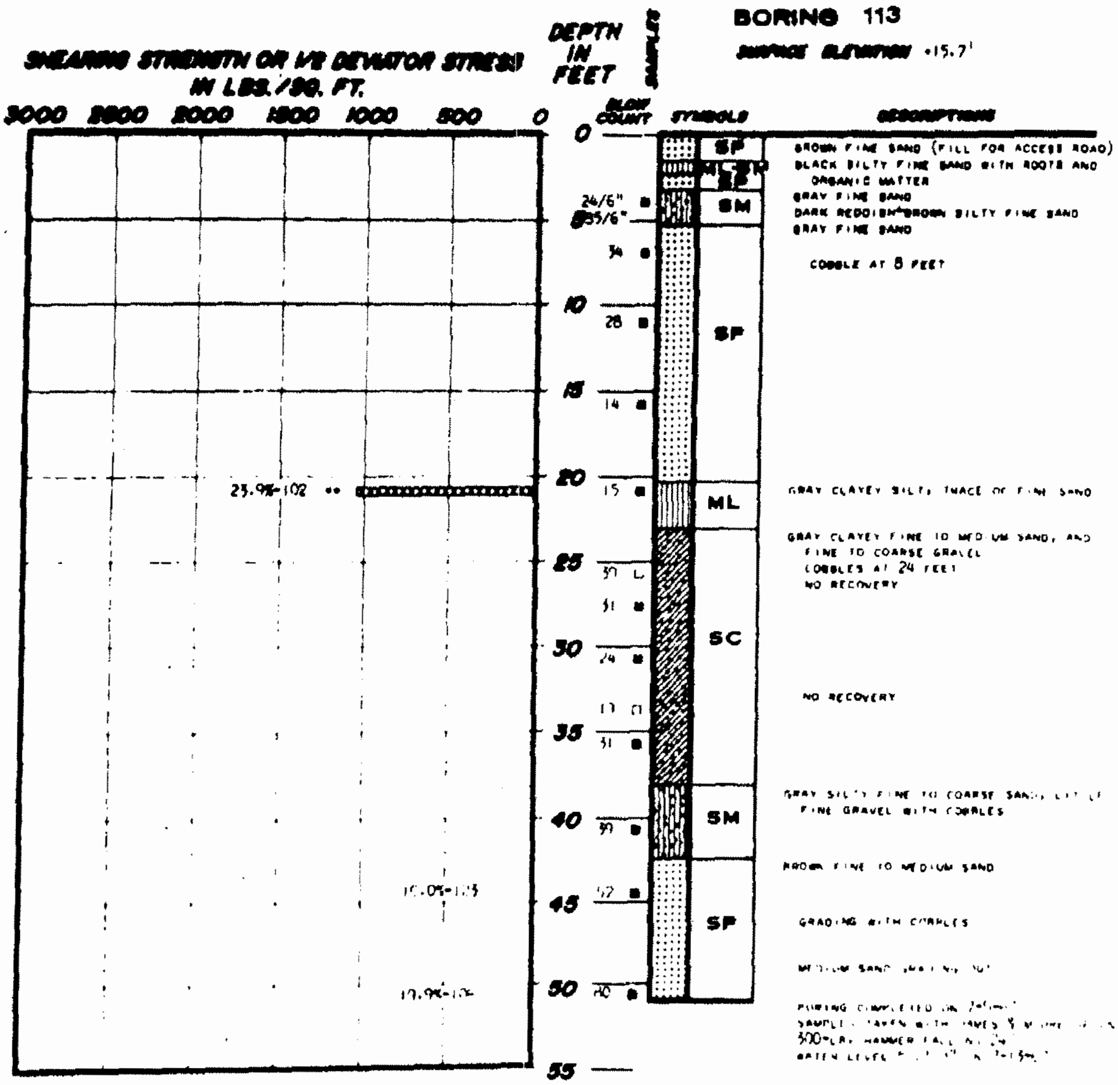


FIGURE 12.2-8

LOG OF BORING (BORING 113)

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT

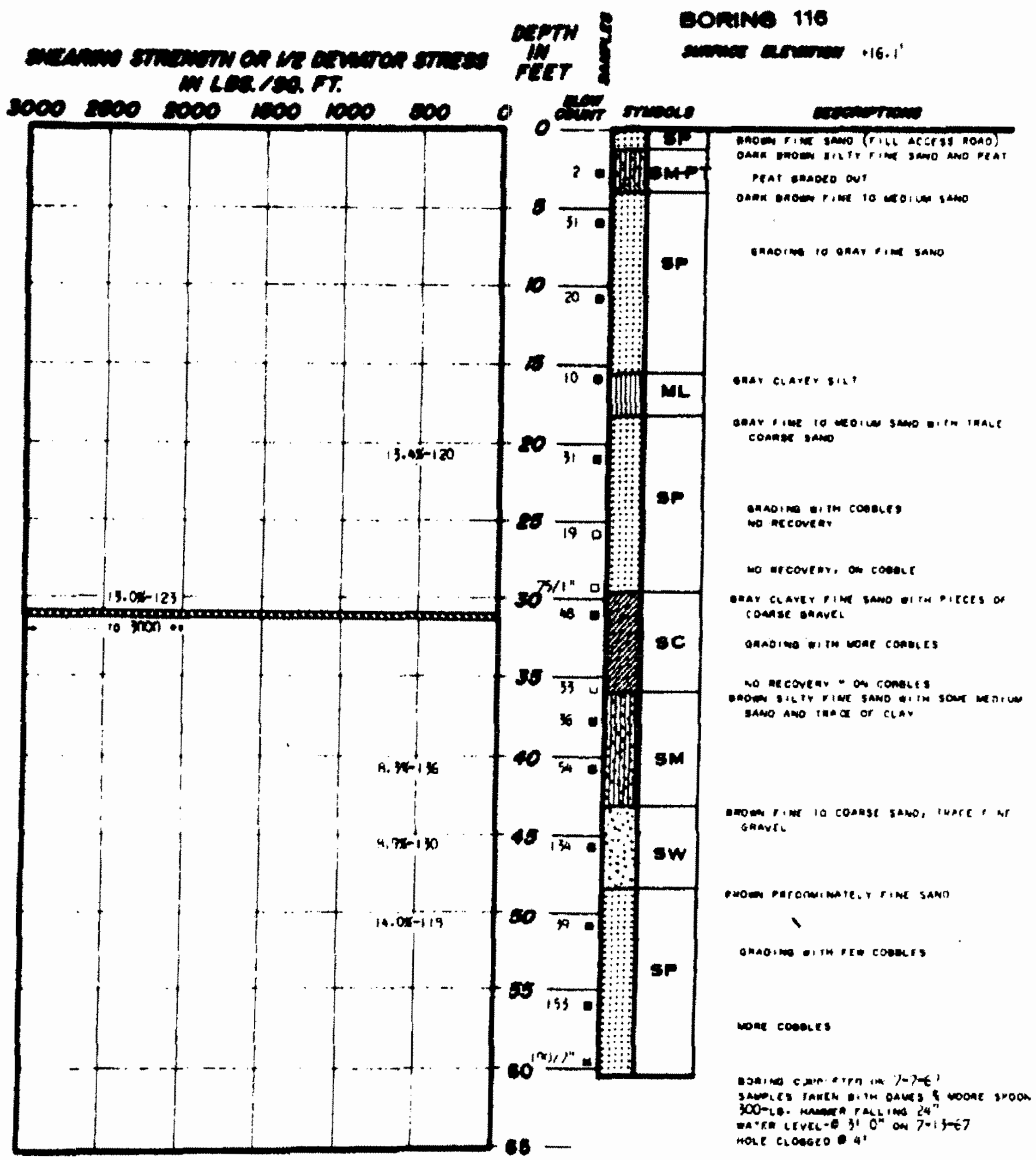


FIGURE 12.2-9

LOG OF BORING (BORING 116)

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

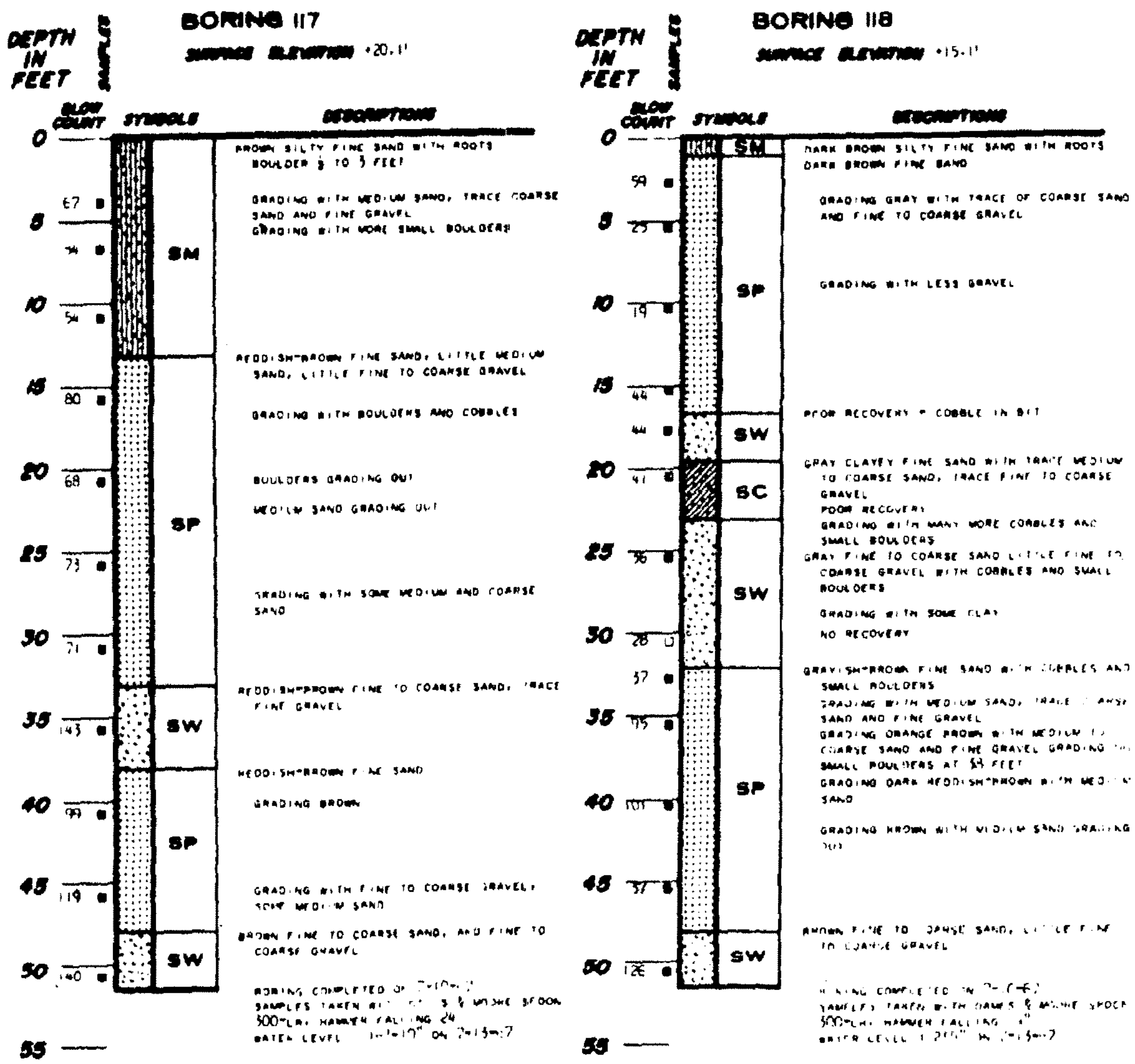
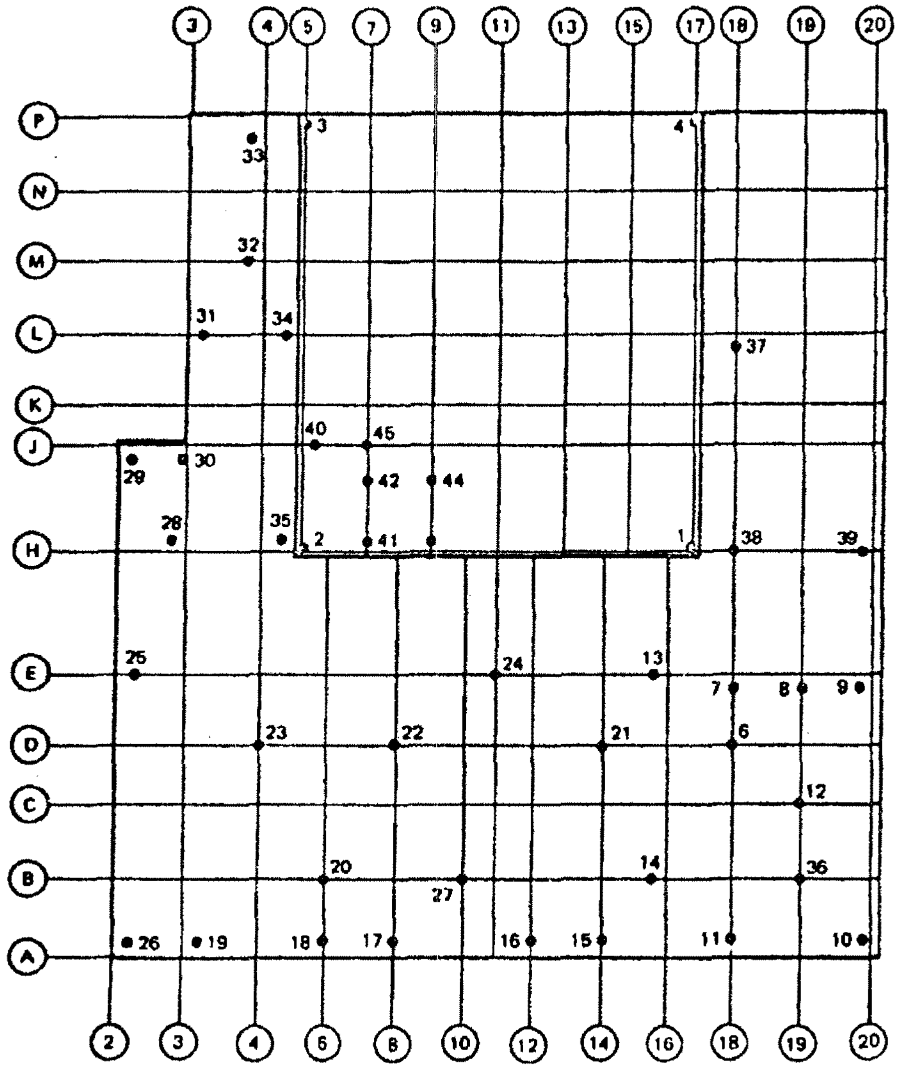


FIGURE 12.2-10
LOG OF BORINGS
(BORINGS 117 & 118)
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



NOTES (REFER TO TABLE 12.2-6

1. METHOD: THE EQUIPMENT USED IS A ZEISS SELF-LEVELING LEVEL AND A 10-FT LO-VAR ROD DIVIDED IN YARDS, 1/10 YARDS AND 1/100 YARDS. A ROD LEVEL IS USED TO MAINTAIN A VERTICAL ROD. EACH OF THE 3 CROSS HAIRS IS READ FOR EACH SETTING AND THE READINGS TOTALED TO OBTAIN THE PROPER ROD READING IN FEET. THE LEVEL TRAVERSE IS RUN FROM THE 31.93 B.M. TO EACH LEVEL OF THE PLANT TO BE CHECKED AND RETURNED TO THE BM. THE ERROR OF CLOSURE IS ADJUSTED ON A STRAIGHT LINE BASIS AND ADJUSTED ELEVATIONS OF ALL POINTS RECORDED. A NEW TRAVERSE IS RUN IN EACH LEVEL THROUGH EACH OF THE POINTS TAKING OFF FROM ONE OF THE ADJUSTED POINTS OF THE ORIGINAL TRAVERSE AND CLOSING IN. ERRORS IN EACH OF THE SECONDARY TRAVERSES ARE THEN ADJUSTED AND FINAL ADJUSTED ELEVATIONS OBTAINED.

2. TABULATED VALUES ARE THE DIFFERENCE BETWEEN INITIAL READING AND THOSE TAKEN ON INDICATED DATES.

3. NEGATIVE VALUES (-0.011) INDICATE UPWARD MOVEMENTS

4. ALL TABULATED DIFFERENTIAL VALUES ARE IN FEET

FIGURE 12.2-11
KEY PLAN 1:40:0
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

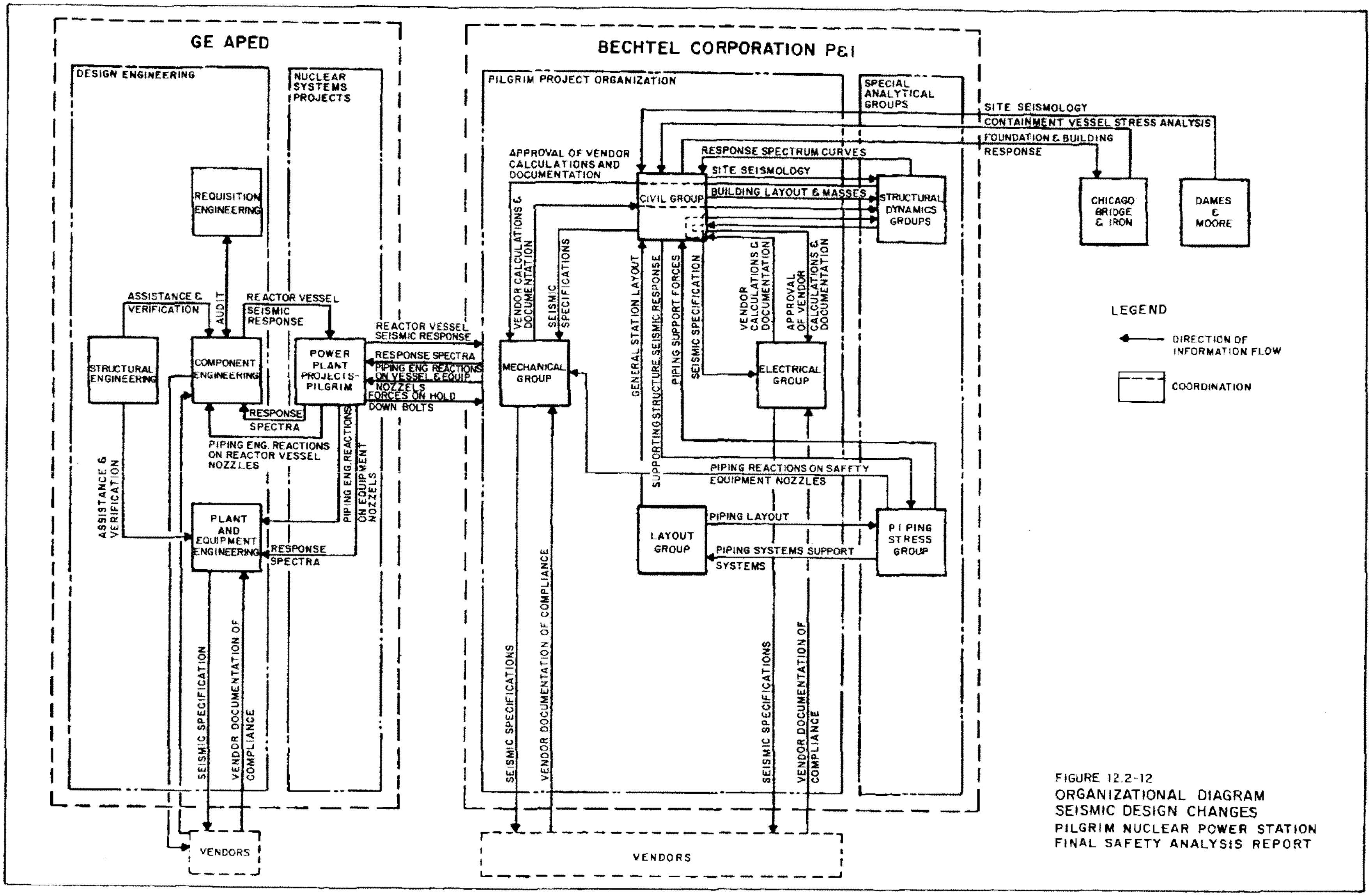


FIGURE 12.2-12
ORGANIZATIONAL DIAGRAM
SEISMIC DESIGN CHANGES
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT