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INTRODUCTION AND SUMMARY

1.1 PROJECT IDENTIFICATION

This Updated Safety Analysis Report (FSAR) Annual Update of Pilgrim Nuclear Power Station is submitted as a unique document in compliance with regulations of the NRC for "Periodic Updating of FSAR" as specified in 10CFR50.71(e).

The original FSAR was submitted in support of the Boston Edison Company (BECo), for a facility operating license for The Pilgrim Nuclear Power Station, Unit 1 (687 MWe), Docket 50-293.

This Updated FSAR is a complete document and does not reference or rely on the original FSAR, as amended. The original outline has been maintained with new sections added for material which was not required in the original FSAR.

1.1.1 Identification and Qualification of Contractors

1.1.1.1 Applicant

As Owner, the Applicant engaged the noted suppliers (see Sections 1.1.1.2, 1.1.1.3, and 1.1.1.4) to perform engineering and construction services for the station.

Description of Business

The Applicant is an operating public utility engaged in electric and steam businesses, supplying electricity at retail in the cities of Boston (except the Charlestown district), Somerville, Newton, Chelsea, Waltham, and Woburn; in the towns of Brookline, Arlington, Watertown, Framingham, and in 30 other smaller towns in eastern Massachusetts, covering an area of approximately 590 mi^2 within 30 mi of Boston. The population of the territory served with electricity at retail according to the United States Census was 1,510,050 in 1960 as compared with 1,444,427 in 1950. It also supplies electricity in bulk at wholesale to other utilities, including the total electric requirements of the Charlestown District of Boston and 13 other cities and towns in the vicinity of Boston.

Other than the Pilgrim Nuclear Power Station, the Applicant's electric generating facilities consist of two oil-fired steam electric generating stations, ten combustion turbine generators, and a 36,000 kW ownership in Yarmouth Unit #4 built by Central Maine Power Company located at Yarmouth, Maine, for a total peak capacity of approximately 2,802,000 kW. The steam electric generating stations are the Mystic station in Everett and the New Boston station in South Boston.

Applicant's transmission system comprises approximately 359 mi of overhead circuits operating at 115,000, 230,000, and 345,000 V, and approximately 145 mi of underground circuits operating at 115,000 and 345,000 V. The overhead distribution system covers approximately 3,367 mi of streets and the underground distribution system covers approximately 799 mi of streets.

Description of Corporate Organization

The applicant is a publicly held corporation incorporated under the laws of The Commonwealth of Massachusetts in 1886, with its principal executive office at 800 Boylston Street, Boston, Massachusetts.

Technical Qualifications

The applicant owns 9.5 percent of the common stock of Yankee Atomic Electric company which operated atomic electric generating units with a net capability of 175,000 kW in Rowe, Massachusetts.

The applicant owns 9.5 percent of the common stock of Connecticut Yankee Atomic Power Company which operated atomic electric generating units with a rated capacity of approximately 575,000 kW in Haddam Neck, Connecticut. Applicant is entitled to receive 9.5 percent of the output of this unit.

1.1.1.2 Engineer Constructor

The Boston Edison Company retained Bechtel Corporation to provide engineering and construction services for the initial design and construction of the station, integrating the items furnished by General Electric Company with complete balance of plant items. Bechtel Corporation was also responsible for procurement and shop inspection of all equipment other than the nuclear steam supply system, and the turbine generator. Bechtel Corporation and successors have been continuously engaged in construction or engineering activities since 1898. Since 1948, Bechtel has been active in the fields of pipeline, petroleum, power generation and distribution, harbor development, offshore drilling, mining and metallurgy, and chemical and industrial processing. The Bechtel organization has grown progressively to become one of the world's largest engineer-constructors for industrial facilities. From the close of World War II to the completion of Pilgrim I, Bechtel was responsible for the design of over 188 thermal power generating units, representing more than 52,200,000 kilowatts of new generating capacity of which more than 21,000,000 kilowatts is nuclear.

Since the successful completion of Pilgrim I, Bechtel has gone on to play a major role in either design, construction, or project management for over a third of the country's nuclear generating capacity. Bechtel, now Bechtel Power Corporation, is also active in the maintenance, repair, and support of a number of operating nuclear units.

1.1.1.3 Nuclear Steam Supply System Supplier

General Electric Company designed, fabricated, and delivered the nuclear steam supply system and nuclear fuel for the plant, as well as provided technical direction for installation and startup of this equipment. GE has been engaged in the development, design, construction, and operation of boiling water reactors since 1955. GE has designed and built 24 boiling water reactors for operation in the U.S., and 15 more boiling water reactors for operation in foreign countries. In addition, numerous GE boiling water reactors are currently under construction, both domestic and foreign. Thus, GE has substantial experience, knowledge, and capability to design, manufacture, and furnish technical assistance for installation and startup of reactors.

1.1.1.4 Turbine Generator Supplier

GE designed, fabricated, and delivered the turbine generator for the plant as well as provided technical assistance for installation and startup of this equipment. GE has a long history in the application of turbine generators in nuclear power stations going back to the inception of nuclear facilities for the production of electrical power. GE is furnishing the turbine generator units for most of its BWR nuclear steam supply contracted stations. GE has firm orders to supply numerous turbine generator units for use in similar nuclear facilities. The inlet pressures of these units vary from saturation to approximately 40°F superheat. The ratings of these units range from 500,000 kW to 1,305,000 kW. GE is therefore competent to design, fabricate, and deliver the turbine generator unit and to provide technical assistance for the installation and startup this equipment.

1.2 DEFINITIONS

The following definitions apply to the terms used in the Safety Analysis Report.

1. Radioactive Material Barrier - A radioactive material barrier includes the systems, structures, or equipment that together physically prevent the uncontrolled release of radioactive materials. The barriers are identified as follows:

   a. Reactor Fuel Barrier - Uranium dioxide sealed in metal cladding

   b. Nuclear System Process Barrier - The systems of vessels, pipes, pumps, tubes, and similar process equipment that contain the steam, water, gases, and radioactive materials coming from, going to, or in communication with the reactor core. The actual boundaries of the nuclear system process barrier depend upon the status of plant operation

      For example, process system isolation valves, when closed, form part of the barrier. The steam jet ejector offgas path forms a planned process opening in the barrier during power operation

      Because the nuclear system process barrier is designed to be divided by isolation valve action into two major sections under certain conditions, this barrier is considered in two parts as follows:

      (1) Nuclear System Primary Barrier - The reactor vessel and attached piping out to and including the second isolation valve in each attached pipe. In various codes and standards used in the industry, this barrier is sometimes referred to as the "primary system pressure boundary"

      (2) Nuclear System Secondary Barrier - That portion of the nuclear system process barrier not included in the nuclear system primary barrier

c. Primary Containment - The drywell in which the reactor vessel is located, the pressure suppression chamber, and process lines out to the first isolation valve outside the containment wall. Portions of the nuclear system process barrier may become part of the primary containment, depending upon the location of a postulated failure. For example, a closed main steam line isolation valve is part of the primary containment barrier when the postulated failure of the main steam line is inside the primary containment.

d. Secondary Containment - The Reactor Building, which completely encloses the primary containment, the Standby Gas Treatment System, and the main stack, constitute this barrier

2. Radioactive Material Barrier Damage - Radioactive material barrier damage is defined as an unplanned, undesirable breach in a barrier, except that the operation of a relief or safety valve does not constitute barrier damage.

3. Nuclear System - The nuclear system generally includes those systems most closely associated with the reactor vessel which are designed to contain, or be in communication with the water and steam coming from or going to the reactor core. The nuclear system includes the following:

   Reactor vessel
   Reactor vessel internals
   Reactor core
   Main steam lines from reactor vessel to the isolation valves outside the primary containment
   Neutron Monitoring System
   Reactor Recirculation System
   Control Rod Drive System
   Residual Heat Removal System
   Reactor Core Isolation Cooling System
   Core Standby Cooling Systems
   Reactor Water Cleanup System
   Feedwater System piping between the reactor vessel and the first valve outside the primary containment safety and relief valve system

4. The word safety, when used to modify such words as objective, design basis, action, and system, indicates that the objective, design basis, action, or system is related to concerns considered to be of primary safety significance, as opposed to the plant mission - to generate electrical power. Thus, the word safety is used to identify aspects of the station which are considered to be of primary importance with respect to safety.

5. Power Generation - The phrase power generation, when used to modify such words as objective, design basis, action and system, indicates that the objective, design basis, action, or system is related to the mission of the station - to generate electrical power - as opposed to concerns considered to be of primary safety importance. Thus, the phrase power generation is used to identify aspects of the station which are not considered to be of primary importance with respect to safety.

6. Operational - The objective operational, along with its noun and verb forms, is used in reference to the working or functioning of the station, in contrast to the design of the station.

7. Scram - Scram refers to the automatic rapid insertion of control rods in response to the detection of undesirable conditions.

8. Safety Limit - A safety limit is an established limit above normal operational limits on the value of a nuclear system process or analytical variable, or an established limit specifying an allowable degree of barrier damage.

9. Planned Operation - Planned operation is normal station operation under planned conditions in absence of significant abnormalities. Operations subsequent to an incident (transient, accident, or special event), are not considered planned operations until the actions taken in the station are identical to those which would be used had the incident not occurred. The established planned operations can be considered as a chronological sequence:

   refueling outage -->achieving criticality -->heatup --> power operation -->achieving shutdown --> cooldown -->refueling outage.

   The following planned operations are identified:

   a. Refueling Outage - Refueling outage included all of the planned operations associated with a normal refueling outage:

      (1) Planned, physical movement of core components (fuel, control rods, etc.)

      (2) Refueling test operations

      (3) Planned maintenance

b. Achieving Criticality - Achieving criticality includes all the actions which are normally accomplished in bringing the station from a condition in which all control rods are fully inserted to a condition in which nuclear criticality is achieved and maintained

c. Heatup - Heatup begins where achieving criticality ends and includes all actions which are normally accomplished in approaching nuclear system rated temperature and pressure by using nuclear power (reactor critical). Heatup extends through warmup and synchronization of the turbine-generator

d. Power Operation - Power operation begins where heatup ends and includes continued operation of the station at power levels in excess of heatup power

e. Achieving Shutdown - Achieving shutdown begins where power operation ends and includes all actions normally accomplished in achieving nuclear shutdown (more than one rod subcritical) following power operation

f. Cooldown - Cooldown begins where achieving shutdown ends and includes all actions normally accomplished in the continued removal of decay heat and the reduction nuclear system temperature and pressure

10. Incident - An incident is any event - abnormal operational transient, or accident - not considered as part of planned operation.

11. Abnormal Operational Transient - An abnormal operational transient includes the events following a single equipment malfunction or a single operator error that is reasonably expected during the course of planned operations. Power failures, pump trips, and rod withdrawal errors are typical of the single malfunctions or errors initiating the events in this category.

12. Abnormal Occurrence - Abnormal occurrence refers to the occurrence of any station condition that:

a. Exceeds a Limiting Safety System Setting as established in the Technical Specifications

b. Violates a Limiting Condition for Operation as established in the Technical Specifications

c. Causes any abnormal operational transient

d. Causes any uncontrolled or unplanned release of radioactive material from the site

13. Accident - An accident is a single event, not reasonably expected during the course of station operations, that has been hypothesized for analysis purposes or postulated from unlikely but possible situations, and that causes or threatens a rupture of a radioactive material barrier. A pipe rupture qualifies as an accident; a fuel cladding defect does not.

14. Design Basis Accident - A design basis accident is a hypothesized accident the characteristics and consequences of which are utilized in the design of those systems and components pertinent to the preservation of radioactive material barriers, and the restriction of radioactive material release from the barriers. The potential radiation exposures resulting from a design basis accident are greater than any similar accident postulated from the same general accident assumptions.

15. Special Event - A special event is an event which neither qualifies as an abnormal operational transient nor an accident but which is postulated to demonstrate some special capability of the system or its systems.

16. Safety Action - A safety action is an ultimate action in the station which is essential to the avoidance of specified conditions considered to be of primary safety significance. The specified conditions are those that are most directly related to the ultimate limits on the integrity of the radioactive material barriers or the release of radioactive material. There are safety actions associated with planned operation, abnormal operational transients, accidents, and special events. Safety actions include such actions as the indication to the operator of the values of certain process variables, reactor scram, core standby cooling, and reactor shutdown from outside the control room. See Figures 1.2-1 through 1.2-3 and Table 1.2-1.

17. Power Generation Action - A power generation action is an action in the station which is essential to the avoidance of specified conditions considered to be of primary significance to the station mission - the generation of electrical power. The specified conditions are those that are most directly related to the following:

    a. The ability to carry out the station mission - the generation of electrical power - through planned operation

    b. The avoidance of conditions which would limit the ability of the station to generate electrical power

c. The avoidance of conditions which would prevent or hinder the return to conditions permitting the use of the station to generate electrical power following an abnormal operational transient, accident, or special event. There are power generation actions associated with planned operation, abnormal operational transients, accidents, and special events. See Figure 1.2-3.

18. Protective Action - A protective action is an ultimate action at the system level which contributes to and is essential to the accomplishment of a safety action. System level actions which are essential to accomplishing reactor scram, reactor vessel isolation, containment isolation, pressure relief, automatic depressurization, and core standby cooling are some of the protective actions. See Figures 1.2-1, 1.2-2, and 1.2-3

19. Protective Function - A protective function encompasses the monitoring of one or more station variables or conditions and the associated initiation of intra system actions which eventually result in protective action. See Figure 1.2-2.

20. Safety System - A safety system is any system, group of systems, component, or group of components, the actions of which are essential to accomplishing a safety action. See Figure 1.2-3 and Table 1.2-1.

21. Process Safety System - A process safety system is a safety system the actions of which are essential to a safety action required during planned operation. See Figure 1.2-3 and Table 1.2-1.

22. Nuclear Safety System - A nuclear safety system is a safety system the actions of which are essential to a safety action required in response to an abnormal operational transient. See Figure 1.2-3 and Table 1.2-1.

23. Engineered Safeguard - An engineered safeguard is a safety system the actions of which are essential to a safety action required in response to accidents. See Figure 1.2-3 and Table 1.2-1.

24. Protection System - Protection system is a generic term which may be applied to nuclear safety systems and engineered safeguards. See Figure 1.2-3 and Table 1.2-1.

25. Special Safety System - A special safety system is a safety system the actions of which are essential to a safety action required in response to a special event. See Figure 1.2-3 and Table 1.2-1.

26. Power Generation System - A power generation system is any system the actions of which are not essential to a safety action, but which are essential to a power generation action. Power generation systems are provided for any of the following purposes:

    a. To carry out the mission of the station - generate electrical power - through planned operation

    b. To avoid conditions which would limit the ability of the station to generate electrical power

    c. To facilitate and expedite the return to conditions permitting the use of the station to generate electrical power following an abnormal operational transient, accident, or special event. See Figure 1.2-3 and Table 1.2-1

27. Safety Objective - A safety objective describes in functional terms the purpose of a system or component as it relates to conditions considered to be of primary significance to the protection of the public. This relationship is stated in terms of radioactive material barriers or radioactive material release. The only systems which have safety objectives are safety systems. See Figure 1.2-3.

28. Power Generation Objective - A power generation objective describes in functional terms the purpose of a system or component as it relates to the mission of the station. This includes objectives which are specifically established so the station can fulfill the following purposes:

    a. The generation of electrical power through planned operation

    b. The avoidance of conditions which would limit the ability of the station to generate electrical power

    c. The avoidance of conditions which would prevent or hinder the return to conditions permitting the use of the station to generate electrical power following an abnormal operational transient, accident, or special event. See Figure 1.2-2

    A system or piece of equipment has a power generation objective if it is a power generation system. A safety system can have a power generation objective, in addition to a safety objective, if parts of the system are intended to function for power generation purposes.

29. Analytical Objective - An analytical objective describes the purpose or intent of a portion of the Safety Analysis Report presenting an analysis.

30. Safety Design Basis - The safety design basis for a safety system states in functional terms the unique design requirements which establish the limits within which the safety objective shall be met. A power generation system may have a safety design basis which states in functional terms the unique design requirements that ensure that neither planned operation nor operational failure by the system results in conditions for which station safety actions would be inadequate.

31. Power Generation Design Basis - The power generation design basis for a power generation system states in functional terms the unique design requirements which establish the limits within which the power generation objective shall be met.

    A safety system may have a power generation design basis which states in functional terms the unique design requirements which establish the limits within which the power generation objective for the system shall be met.

32. Safety Evaluation - An evaluation of a change in the design or operation of systems, structures, and components to determine if an unreviewed safety question will result, specifically to determine if:

    a. The probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the Final Safety Analysis Report may be increased; or

    b. The possibility for an accident or malfunction of a different type than any evaluated previously in the Final Safety Analysis Report may be created; or

    c. The margin of safety as defined in the basis for any Technical Specification is reduced.

33. Power Generation Evaluation - A power generation evaluation is an evaluation which shows how the system satisfies some or all of the power generation design bases. Because power generation evaluations are not directly pertinent to public safety, they are generally not included. However, where a system or component has both safety and power generation objectives, a power generation evaluation can be used to clarify the safety versus power generation capabilities.

34. Operational Nuclear Safety Requirements - An operational nuclear safety requirement is a limitation or restriction on either the value of a process variable or the operability of a station system. Such operational nuclear safety requirements must be observed in the operation (not necessarily at power) of the station to satisfy specified operational nuclear safety criteria. The aggregate of all operational nuclear safety requirements defines an operational framework within which actual station operations must remain.

35. Operational Nuclear Safety Criteria - A set of standards which are used to select operational nuclear safety requirements.

36. Design Power - The stated design power in megawatts thermal is the result of a heat balance for a particular plant design. For the Pilgrim Nuclear Station, design power is 1,998 MWt.

37. Single Failure - A single failure is a failure that can be ascribed to a single causal event. Single failures of active components are considered in the design of certain systems, and are presumed in the evaluations of incidents to investigate the ability of the station to respond in the required manner under degraded conditions.

38. Operable, Operability - A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified functions(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal or emergency electrical power sources, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s).

39. Operating - Operating means that a system or component is operating when it is performing its intended function in its required manner.

40. Shutdown - The reactor is shut down when the effective multiplication factor (K_{eff}) is sufficiently less than 1.0, that the full withdrawal of any one control rod could not produce criticality.

41. Shutdown Mode - The reactor is in the shutdown mode when the reactor is shut down, the reactor mode switch is in the shutdown mode position, and all operable control rods are fully inserted.

42. Cold Shutdown Condition - The reactor is in the cold shutdown condition when the reactor is in the shutdown mode, the reactor coolant is maintained at less than 212°F, and the reactor vessel is vented to the atmosphere.

43. Place in Shutdown Mode - Place in the shutdown mode means conduct an uninterrupted normal station shutdown operation until the shutdown mode is attained.

44. Place in the Cold Shutdown Condition - Place in the cold shutdown condition means conduct an uninterrupted normal station shutdown operation until the cold shutdown condition is attained.

45. Refuel Mode - The reactor is in the refuel mode whenever the reactor mode switch is in the refuel mode position.

46. Startup Mode - The reactor is in the startup mode whenever the reactor mode switch is in the startup mode position.

47. Run Mode - The reactor is in the run mode whenever the reactor mode switch is in the run mode position.

48. Place in Isolated Condition- Place in isolated condition means conduct an uninterrupted normal isolation of the reactor from the main (turbine) condenser including the closure of the main steam line isolation valves.

49. Primary Containment Integrity - Primary containment integrity means that the drywell and suppression chamber are intact and all of the following conditions are satisfied:

    a. All manual containment isolation valves on lines connected to the reactor coolant system or containment which are not required to be open during plant accident conditions are closed.

    b. At least one door in the airlock is closed and sealed.

    c. All automatic primary containment isolation valves and all instrument line flow check valves are operable or at least one containment isolation valve in each line having an inoperable valve shall be deactivated in the isolated position.

    d. All containment isolation check valves are operable or at least one containment valve in each line having an inoperable valve is secured in the isolated position.

50. Secondary Containment Integrity - Secondary containment integrity means that the reactor building is intact and the following conditions are met:

    a. At least one door in each access opening is closed

    b. The standby gas treatment system is operable

c. All automatic ventilation system isolation valves are operable or secured in the isolated position

51. Core Fuel to Water Total Power - The core fuel to water total power is the sum of (a) the instantaneous integral, over the entire fuel clad outer surface, of the product of heat transfer area increment and position dependent heat flux, and (b) the instantaneous rate of energy deposition by neutron and gamma reactions in all the water and core components except fuel rods in the cylindrical volume defined by the active core height, and the inner surface of the core shroud.

52. Refueling Outage (as applicable to surveillance frequency requirements) - For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled refueling outage.

53. Core Alteration - Core Alteration shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed, and fuel in the vessel. The following exceptions are not considered to be Core Alterations:

    a. Movement of source range monitors, local power range monitors, intermediate range monitors, traversing incore probes, or special movable detectors (including undervessel replacement); and

    b. Control rod movement, provided there are no fuel assemblies in the associated core cell.

54. Risk - Risk is the product of the probability of an event and the adverse consequences of the event.

55. Reliability - Reliability is the probability that an item will perform its specified function without failure for a specified time period in a specified environment.

56. Unreliability - Unreliability is the probability that a component or system will fail to perform its specified action for a specified time period in a specified environment. (The sum of reliability and unreliability equals unity.)

57. Availability - Availability is the probability that an item will be operable when called upon to perform its specified function.

58. Unavailability - Unavailability is the probability that a component or system will be inoperable when called upon to perform its specified action. (The sum of availability and unavailability equals unity.)

59. Repair Rate - The repair rate is the number of repairs completed per unit time.

60. Failure Rate - The failure rate is the number of failures per unit time.

61. Test Duration - The test duration is the elapsed time between test initiation and test termination.

62. Test Interval - The test interval is the elapsed time between the initiation of identical tests.

63. Active Component - A device characterized by an expected significant change of state or discernible mechanical motion in response to an imposed design basis load demand upon the system. Examples are: switch, relay, valve, pressure switch, turbine, transistor, motor, damper, pump, analog meter, etc.

64. Passive Component - A device characterized by an expected negligible change of state or negligible mechanical motion in response to an imposed design basis load demand upon the system. Examples are: cable, piping, valve in stationary position, resistor, capacitor, fluid filter, indicator lamp, cabinet, case, etc.

65. Nuclear Safety Operational Analysis - A systematic identification of the requirements for and the limitations on station operation necessary to satisfy nuclear safety operational criteria.

66. Automatic Primary Containment Isolation Valve - A primary containment isolation valve which receives an automatic primary containment isolation signal.

67. Operation with the Potential to Drain the Reactor Vessel (OPDRV) - Any repair, maintenance, or their associated system restoration activity that could result in draining or siphoning the reactor vessel water level below the top of fuel limit without crediting the use of mitigating measures (e.g., operator actions, reliance on automatic isolation valves) to terminate the uncovering of fuel. This excludes activities where a qualified passive engineered device which meets plant design basis (e.g., blind flange, closed manual valve, deactivated automatic valve, back-seated valve) is credited or installed to ensure there is not a credible failure that could lead to draining the reactor vessel. Normal operation of plant systems to perform their design functions with reactor cavity water level maintained as required in applicable technical specifications are not considered to pose an OPDRV.

68. The "Security Owner Controlled Area" (SOCA), is an area where access is restricted for security reasons. It is not considered as Radiological Restricted Area. The SOCA is a permanently owner controlled area clearly demarcated with physical security barriers, access to which is controlled in accordance with the Pilgrim Station Access Control Program to enter into the Protected Area for the purpose of plant operational activities. This definition complies with the objectives of the requirements of 10 CFR 73.55, Requirements for Physical protection of Licensed Activities in Nuclear Power Reactors against Radiological Sabotage".

69. The "Radiological Restricted Area" is any area to which access is limited by the Licensee for the purpose of protecting individuals against undue risk from exposure to radiation or radioactive materials. The Radiological Restricted Area boundaries exclude any area to be used for residential use purposes. The boundaries between radiological restricted area and unrestricted area are defined by the licensee. This definition complies with 10 CFR 20.1003, as discussed in FSAR Section 12.3.

TABLE 1.2-1
CLASSIFICATION OF BWR SYSTEMS, CRITERIA, AND REQUIREMENTS FOR SAFETY EVALUATION

	ACTUAL PLANT DESIGN AND OPERATION									
	SAFETY CONSIDERATIONS					POWER GENERATION CONSIDERATIONS				
TYPE OF OPERATION OR EVENT	UNACCEPTABLE SAFETY RESULTS	TYPES OF APPLICABLE CRITERIA	TYPES OF ACTIONS REQUIRED TO AVOID UNACCEPTABLE RESULTS	TYPES OF SYSTEMS REQUIRED TO CARRY OUT ACTION	TYPES OF REQUIREMENTS TO BE OBSERVED IN OPERATION OF PLANT TO AVOID UNACCEPTABLE RESULTS	UNACCEPTABLE RESULTS FOR POWER GENERATION WHERE MORE RESTRICTIVE THAN UNACCEPTABLE SAFETY RESULTS	TYPES OF APPLICABLE CRITERIA	TYPES OF ACTIONS REQUIRED TO AVOID UNACCEPTABLE RESULTS WHERE NOT REQUIRED AS A SAFETY ACTION	TYPES OF SYSTEMS REQUIRED TO CARRY OUT ACTION WHERE NOT REQUIRED AS A SAFETY SYSTEM	TYPES OF REQUIREMENTS TO BE OBSERVED IN OPERATION OF PLANT TO AVOID UNACCEPTABLE RESULTS
1 PLANNED OPERATION	1-1 THE RELEASE OF RADIOACTIVE MATERIAL TO THE ENVIRONS TO SUCH AN EXTENT THAT THE LIMITS OF 10CFR20 ARE EXCEEDED 1-2 FUEL FAILURE TO SUCH AN EXTENT THAT WERE THE FREED FISSION PRODUCTS RELEASED TO THE ENVIRONS VIA THE NORMAL DISCHARGE PATHS FOR RADIOACTIVE MATERIAL THE LIMITS OF 10CFR20 WOULD BE EXCEEDED 1-3 NUCLEAR SYSTEM STRESS IN EXCESS OF THAT ALLOWED FOR PLANNED OPERATION BY APPLICABLE INDUSTRY CODES 1-4 THE EXISTENCE OF A PLANT CONDITION NOT CONSIDERED BY PLANT SAFETY ANALYSIS	NUCLEAR SAFETY DESIGN CRITERIA TYPE S-1 NUCLEAR SAFETY OPERATIONAL CRITERIA TYPE S-1 - - - - - - - - - - - - - PROCESS SAFETY DESIGN CRITERIA PROCESS SAFETY OPERATIONAL CRITERIA - - - - - - - - - - - - - VARIOUS INDUSTRY CODES RADWASTE CRITERIA LOADING CRITERIA NORMAL CONDITIONS	SAFETY ACTION TYPE S-1 - - - - - - - - - - - - - PROCESS SAFETY ACTION A CATEGORY OF SAFETY ACTION - - - - - - - - - - - - - INDICATION OF PROCESS VARIABLES RODWORTH CONTROL ROD PATTERN CONTROL CONTROL OF PROCESS VARIABLES CONTROL ROD CONTROL REFUELING BLOCK CORE REACTIVITY CONTROL	SAFETY SYSTEMS TYPE S-1 - - - - - - - - - - - - PROCESS SAFETY SYSTEMS A CATEGORY OF SAFETY SYSTEMS - - - - - - - - - - - - INDICATORS PROCESS RADIATION MONITORS REFUELING INTERLOCKS NEUTRON MONITORING SYSTEM FLUX INDICATIONS	OPERATIONAL NUCLEAR SAFETY REQUIREMENTS TYPE S-1 OPERATIONAL NUCLEAR SAFETY LIMITS TYPE S-1 - - - - - - - - - - - - - - TECHNICAL SPECIFICATIONS TYPE S-1 - - - - - - - - - - - - - - ENVELOPE LIMITS LIMITING CONDITIONS FOR OPERATION FOR INDICATORS RADIOACTIVE MATERIAL RELEASE LIMITS REACTIVITY LIMITS LIMITING CONDITIONS FOR OPERATION FOR RADWASTE SYSTEMS NUCLEAR SYSTEM LEAKAGE LIMITS	1-1 INABILITY TO GENERATE ELECTRICAL POWER 1-2 FUEL FAILURE 1-3 INABILITY TO PERFORM ROUTINE MAINTENANCE WITH PLANT AT POWER 1-4 INABILITY TO OPTIMIZE FUEL PERFORMANCE 1-5 INABILITY TO RESPOND TO CHANGES IN POWER DEMAND 1-6 INABILITY TO SHUT DOWN REACTOR WITH CONTROL RODS IN THE NORMAL MANNER	POWER GENERATION DESIGN CRITERIA TYPE PG-1 - - - - - - - - - - - - - POWER GENERATION OPERATIONAL CRITERIA TYPE PG-1 - - - - - - - - - - - - - PROCESS OPERATIONAL CRITERIA - - - - - - - - - - - - -	POWER GENERATION ACTION TYPE PG-1 - - - - - - - - - - - - - PROCESS ACTION, A CATEGORY POWER GENERATION ACTION - - - - - - - - - - - - - INDICATIONS OF PROCESS VARIABLES PROCESS OPERATIONS FUEL PERFORMANCE CALCULATIONS POWER LEVEL CONTROL CONDENSATION OF EXHAUST STEAM	POWER GENERATION SYSTEMS TYPE PG-1 - - - - - - - - - - - - - PROCESS SYSTEMS, A CATEGORY OF POWER GENERATION SYSTEMS - - - - - - - - - - - - - INDICATORS PROCESS COMPUTER SYSTEM RECIRCULATION FLOW CONTROL SYSTEM REACTOR MANUAL CONTROL SYSTEM CONTROL ROD DRIVE SYSTEM FEEDWATER SYSTEM TURBINE GENERATOR MAIN CONDENSER	OPERATIONAL POWER GENERATION REQUIREMENTS TYPE PG-1 OPERATIONAL POWER GENERATION LIMITS TYPE PG-1 - - - - - - - - - - - - - - NORMAL OPERATING PROCEDURES MAINTENANCE PROCEDURES CALIBRATION PROCEDURES REFUELING PROCEDURES
2 ABNORMAL OPERATIONAL TRANSIENTS	2-1 THE RELEASE OF RADIOACTIVE MATERIAL TO THE ENVIRONS TO SUCH AN EXTENT THAT THE LIMITS OF 10CFR20 ARE EXCEEDED 2-2 ANY FUEL SAFETY LIMIT EXCEEDED AS A DIRECT RESULT OF THE TRANSIENT 2-3 NUCLEAR SYSTEM STRESS IN EXCESS OF THAT ALLOWED FOR TRANSIENTS BY APPLICABLE INDUSTRY CODES	NUCLEAR SAFETY DESIGN CRITERIA TYPE S-2 NUCLEAR SAFETY OPERATIONAL CRITERIA TYPE S-2 - - - - - - - - - - - - - VARIOUS INDUSTRY CODES IEEE 279 LOADING CRITERIA UPSET CONDITIONS SINGLE FAILURE CRITERION TESTABILITY CRITERIA	SAFETY ACTION TYPE S-2 - - - - - - - - - - - - - SCRAM PRESSURE RELIEF CORE COOLING RESTORE AC POWER	SAFETY SYSTEMS - TYPE S-2 - - - - - - - - - - - - PROTECTION SYSTEM GENERIC TERM - - - - - - - - - - - - NUCLEAR SAFETY SYSTEMS A CATEGORY OF PROTECTION SYSTEMS - - - - - - - - - - - - REACTOR PROTECTION SYSTEM SCRAM CONTROL ROD DRIVE SYSTEM SCRAM NEUTRON MONITORING SYSTEM SRM APRM PRESSURE RELIEF SYSTEM REACTOR VESSEL ISOLATION CONTROL SYSTEM HIGH PRESSURE COOLANT INJECTION SYSTEM REACTOR CORE ISOLATION COOLING SYSTEM DC POWER SYSTEM STANDBY AC POWER INCIDENT DETECTION CIRCUITRY	OPERATIONAL NUCLEAR SAFETY REQUIREMENTS TYPE S-2 OPERATIONAL NUCLEAR SAFETY LIMITS TYPE S-2 - - - - - - - - - - - - - - TECHNICAL SPECIFICATIONS TYPE S-2 - - - - - - - - - - - - - - SAFETY LIMITS LIMITING SAFETY SYSTEM SETTINGS LIMITING CONDITIONS FOR OPERATION FOR PROTECTION SYSTEMS SURVEILLANCE REQUIREMENTS FOR PROTECTION SYSTEMS	2-1 FUEL FAILURE 2-2 THE LIFTING OF SAFETY VALVES 2-3 CONDITIONS REQUIRING THE OPENING OF THE REACTOR VESSEL FOR INSPECTION OR REPAIR 2-4 INABILITY TO RETURN TO POWER OPERATION 2-5 INADVERTENT CRITICALITY DURING REFUELING	POWER GENERATION DESIGN CRITERIA TYPE PG-2 POWER GENERATION OPERATIONAL CRITERIA TYPE PG-2 - - - - - - - - - - - -	POWER GENERATION ACTION TYPE PG-2 - - - - - - - - - - - - - - ROD BLOCK PRESSURE RELIEF REFUELING BLOCK	POWER GENERATION SYSTEMS TYPE PG-2 - - - - - - - - - - - - - REACTOR MANUAL CONTROL SYSTEM ROD BLOCK PRESSURE RELIEF SYSTEM REFUELING INTERLOCKS	OPERATIONAL POWER GENERATION REQUIREMENTS TYPE PG-2 OPERATIONAL POWER GENERATION LIMITS TYPE PG-2 - - - - - - - - - - - - - - NORMAL OPERATING PROCEDURES POST TRANSIENT RECOVERY PROCEDURES REFUELING RESTRICTIONS

TABLE 1.2-1 CONT'D

CLASSIFICATION OF BWR SYSTEMS, CRITERIA, AND REQUIREMENTS FOR SAFETY EVALUATION

	ACTUAL PLANT DESIGN AND OPERATION									
	SAFETY CONSIDERATIONS					POWER GENERATION CONSIDERATIONS				
TYPE OF OPERATION OR EVENT	UNACCEPTABLE SAFETY RESULTS	TYPES OF APPLICABLE CRITERIA	TYPES OF ACTIONS REQUIRED TO AVOID UNACCEPTABLE RESULTS	TYPES OF SYSTEMS REQUIRED TO CARRY OUT ACTION	TYPES OF REQUIREMENTS TO BE OBSERVED IN OPERATION OF PLANT TO AVOID UNACCEPTABLE RESULTS	UNACCEPTABLE RESULTS FOR POWER OPERATION WHERE MORE RESTRICTIVE THAN UNACCEPTABLE SAFETY RESULTS	TYPES OF APPLICABLE CRITERIA	TYPES OF ACTIONS REQUIRED TO AVOID UNACCEPTABLE RESULTS WHERE NOT REQUIRED AS A SAFETY ACTION	TYPES OF SYSTEMS REQUIRED TO CARRY OUT ACTION WHERE NOT REQUIRED AS A SAFETY SYSTEM	TYPES OF REQUIREMENTS TO BE OBSERVED IN OPERATION OF PLANT TO AVOID UNACCEPTABLE RESULTS
3 ACCIDENTS	3-1 RADIOACTIVE MATERIAL RELEASE TO SUCH AN EXTENT THAT THE GUIDELINE VALUES OF 10CFR100 WOULD BE EXCEEDED 3-2 EXCEEDING THE CRITERIA 10CFR50.46 3-3 NUCLEAR SYSTEM PRESSURE IN EXCESS OF THAT ALLOWED FOR ACCIDENTS BY APPLICABLE INDUSTRY CODES 3-4 CONTAINMENT STRESSES IN EXCESS OF THAT ALLOWED BY APPLICABLE INDUSTRY CODES WHEN CONTAINMENT IS REQUIRED 3-5 OVEREXPOSURE TO RADIATION OF OPERATING PERSONNEL IN THE CONTROL ROOM	NUCLEAR SAFETY DESIGN CRITERIA TYPE S-3 NUCLEAR SAFETY OPERATIONAL CRITERIA TYPE S-3 VARIOUS INDUSTRY CODES IEEE-279 LOADING CRITERIA EMERGENCY AND FAULTED CONDITIONS SINGLE FAILURE CRITERION TESTABILITY CRITERIA	SAFETY ACTION TYPE S-3 SCRAM CORE COOLING CONTAINMENT COOLING STOP CONTROL ROD EJECTION LIMIT REACTIVITY INSERTION RATE PRESSURE RELIEF REACTOR VESSEL ISOLATION ESTABLISH PRIMARY CONTAINMENT ESTABLISH SECONDARY CONTAINMENT ISOLATION RESTRICTION OF COOLANT LOSS RATE CONTROL ROOM ENVIRONMENTAL CONTROL	TYPE S-3 PROTECTION SYSTEM (GENERIC TERMS) ENGINEERING SAFEGUARDS REACTOR PROTECTION SYSTEM CONTROL ROD DRIVE SYSTEM NEUTRON MONITORING SYSTEM PRESSURE RELIEF SYSTEM SAFETY VALVES REACTOR VESSEL ISOLATION CONTROL SYSTEM PRIMARY CONTAINMENT ISOLATION CONTROL SYSTEM PRIMARY CONTAINMENT SECONDARY CONTAINMENT MAIN STEAM LINE ISOLATION VALVES MAIN STEAM LINE FLOW RESTRICTOR HIGH PRESSURE COOLANT INJECTION SYSTEM AUTOMATIC DEPRESSURIZATION LOW PRESSURE COOLANT INJECTION CORE SPRAY SYSTEM RHR CONTAINMENT COOLING CONTROL ROD VELOCITY LIMITER CONTROL ROD DRIVE HOUSING SUPPORTS STANDBY GAS TREATMENT SYSTEM STANDBY AC POWER SYSTEM DC POWER SYSTEM MAIN STEAM LINE RADIATION MONITORING SYSTEM REACTOR BUILDING VENTILATION RADIATION MONITORING SYSTEM RHR SERVICE WATER SYSTEM (SSW, RBCCW) EQUIPMENT AREA COOLING SYSTEM	REQUIREMENTS TYPE S-3 OPERATIONAL NUCLEAR SAFETY LIMITS TYPE S-3 TECHNICAL SPECIFICATIONS TYPE S-3 LIMITING SAFETY SYSTEM SETTINGS LIMITING CONDITIONS FOR OPERATION FOR PROTECTION SYSTEMS SURVEILLANCE REQUIREMENTS FOR PROTECTION SYSTEM SURVEILLANCE REQUIREMENTS FOR NUCLEAR SYSTEM	RETURN TO POWER OPERATION	POWER GENERATION DESIGN CRITERA TYPE PG-3 POWER GENERATION OPERATIONAL CRITERIA TYPE PG-3	POWER GENERATION ACTION TYPE PG-3	POWER GENERATION SYSTEMS TYPE PG-3	OPERATIONAL POWER GENERATION REQUIREMENTS TYPE PG-3 OPERATIONAL POWER GENERATION LIMITS TYPE PG-3 POST ACCIDENT RECOVERY PROCEDURES
4 SPECIAL EVENT SHUTDOWN FROM OUTSIDE	4-1 THE INABILITY TO BRING THE REACTOR TO THE SHUTDOWN CONDITION BY MANIPULATION OF THE LOCAL CONTROLS AND EQUIPMENT WHICH ARE AVAILABLE OUTSIDE THE CONTROL ROOM 4-2 THE INABILITY TO BRING THE REACTOR TO THE COLD SHUTDOWN CONDITION FROM OUTSIDE THE CONTROL ROOM	NUCLEAR SAFETY DESIGN CRITERIA TYPE S-4 NUCLEAR SAFETY OPERATIONAL CRITERIA S-4 SPECIAL SAFETY DESIGN CRITERIA SPECIAL SAFETY OPERATIONAL CRITERIA	SAFETY ACTION TYPE S-4 SPECIAL SAFETY ACTION SHUTDOWN FROM OUTSIDE CONTROL ROOM COOLDOWN FROM OUTSIDE CONTROL ROOM	SAFETY SYSTEMS TYPE S-4 SPECIAL SAFETY SYSTEMS LOCAL CONTROLS OUTSIDE CONTROL ROOM LOCAL INDICATORS OUTSIDE CONTROL ROOM CONDENSATE STORAGE SYSTEM HIGH PRESSURE COOLANT INJECTION PRESSURE RELIEF SYSTEM REACTOR PROTECTION SYSTEM CONTROL ROD DRIVE SYSTEM	OPERATIONAL NUCLEAR SAFETY REQUIREMENTS TYPE S-4 OPERATIONAL NUCLEAR SAFETY LIMITS TYPE S-4 TECHNICAL SPECIFICATIONS TYPE S-4 LIMITING CONDITIONS FOR OPERATION FOR SPECIAL SAFETY SYSTEMS SURVEILLANCE REQUIREMENTS FOR SPECIAL SAFETY SYSTEMS	4-1 INABILITY TO RETURN TO POWER OPERATION	POWER GENERATION DESIGN CRITERIA TYPE PG-4 POWER GENERATION OPERATIONAL CRITERIA TYPE PG-4	POWER GENERATION ACTION TYPE PG-4	POWER GENERATION SYSTEM TYPE PG-4	OPERATIONAL POWER GENERATION REQUIREMENTS TYPE PG-4 OPERATIONAL POWER GENERATION LIMITS TYPE PG-4 POST EVENT RECOVERY PROCEDURES
5 SPECIAL EVENT SHUTDOWN WITHOUT CONTROL RODS	5-1 THE INABILITY TO SHUTDOWN THE REACTOR INDEPENDENT OF CONTROL RODS	NUCLEAR SAFETY DESIGN CRITERIA TYPE S-5 NUCLEAR SAFETY OPERATIONAL CRITERIA TYPE S-5 SPECIAL SAFETY DESIGN CRITERIA SPECIAL SAFETY OPERATIONAL CRITERA	SAFETY ACTION TYPE S-5 SPECIAL SAFETY SYSTEMS SHUTDOWN WITHOUT CONTROL RODS	SAFETY SYSTEMS TYPE S-5 SPECIAL SAFETY SYSTEMS STANDBY LIQUID CONTROL SYSTEM RECIRCULATION PUMP TRIP SECTION DC POWER SYSTEM (125/250V)	OPERATIONAL NUCLEAR SAFETY REQUIREMENTS TYPE S-5 OPERATIONAL NUCLEAR SAFETY LIMITS TYPE 2-5 TECHNICAL SPECIFICATIONS TYPE S-5 LIMITING CONDITIONS FOR OPERATION FOR SPECIAL SAFETY SYSTEMS SURVEILLANCE REQUIREMENTS FOR SPECIAL SAFETY SYSTEMS	5-1 INABILITY TO RETURN TO POWER OPERATION	POWER GENERATION DESIGN CRITERIA TYPE PG-5 POWER GENERATION OPERATIONAL CRITERIA TYPE PG-5	POWER GENERATION ACTION TYPE PG-5	POWER GENERATION SYSTEMS TYPE PG 5	OPERATIONAL POWER GENERATION REQUIREMENTS TYPE PG-4 OPERATIONAL GENERATION LIMITS TYPE PG-5 POST ACCIDENT RECOVERY PROCEDURES

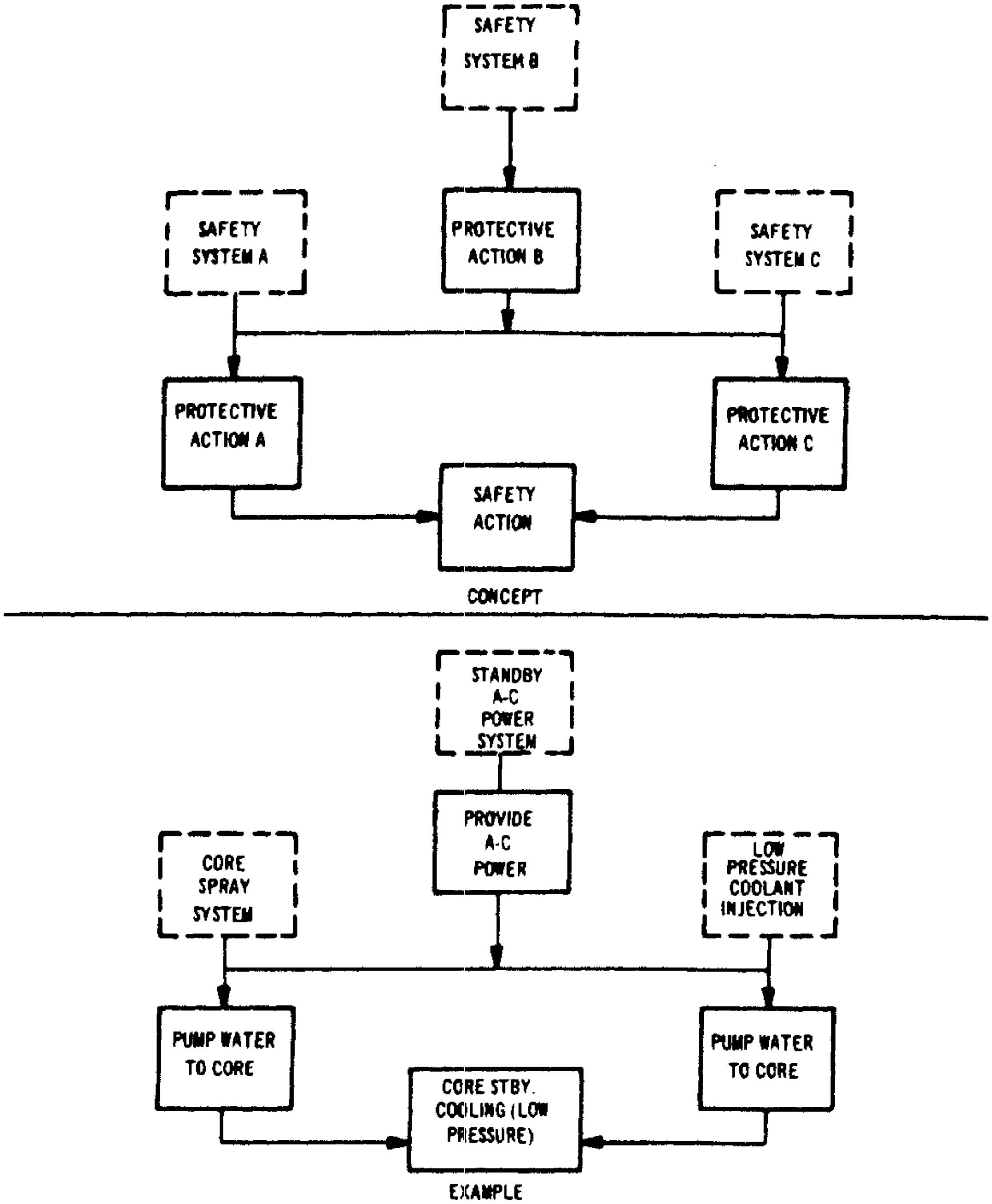
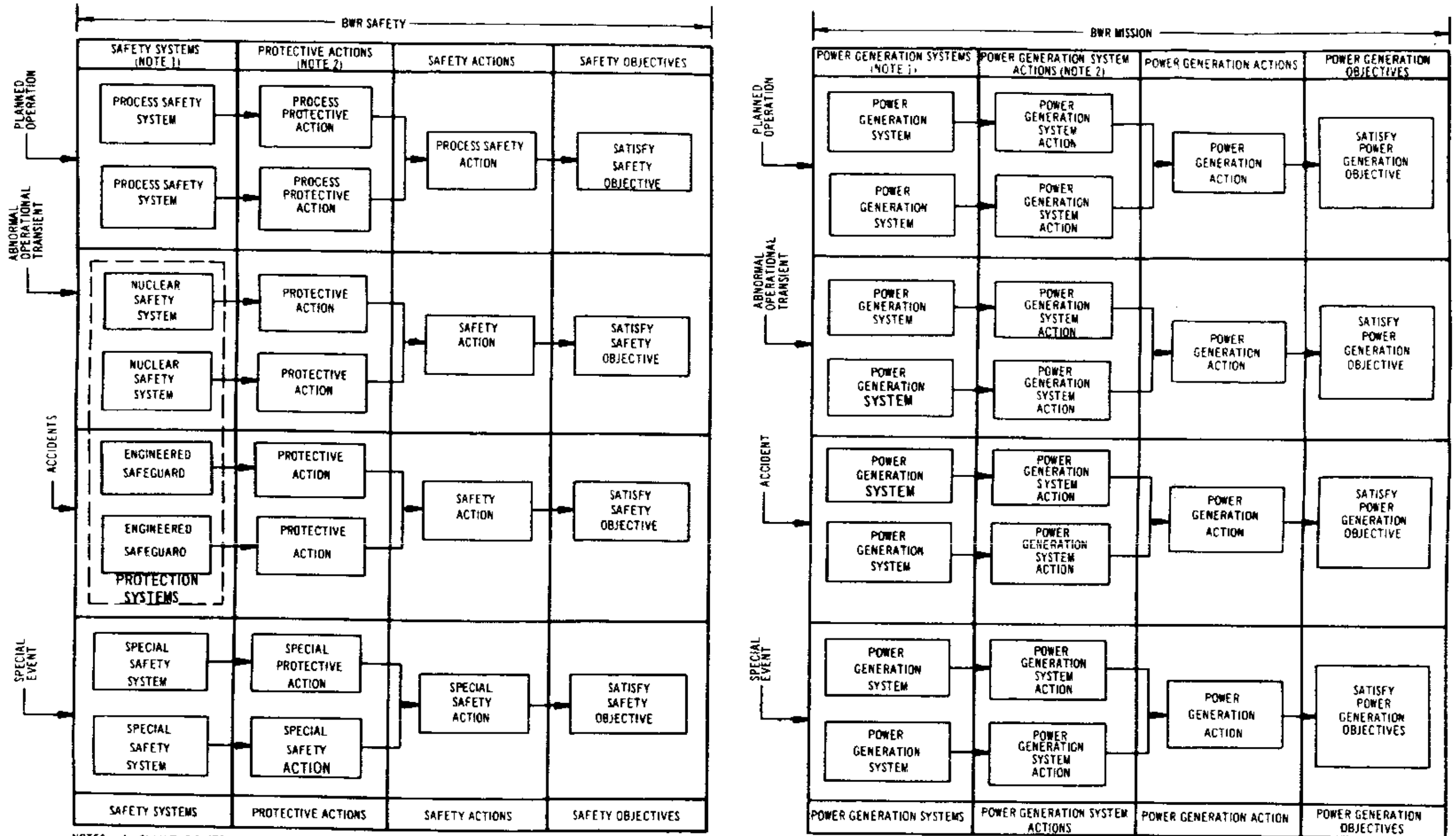


FIGURE 1.2-1
RELATIONSHIP BETWEEN SAFETY ACTION AND PROTECTIVE ACTION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



NOTES 1 ONLY TWO SYSTEMS OF EACH TYPE ARE SHOWN THERE MAY BE MORE THAN THIS NUMBER OF SYSTEMS IN ANY CATEGORY.

2 THERE MAY BE CASES WHERE THE SYSTEM LEVEL ACTION IS IDENTICAL TO THE ULTIMATE ACTION IN THE PLANT. IN SUCH A CASE THE INTERMEDIATE SYSTEM LEVEL ACTION NEED NOT BE IDENTIFIED

FIGURE 1.2-2
RELATIONSHIP BETWEEN DIFFERENT TYPES OF SYSTEMS ACTIONS, AND OBJECTIVES

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

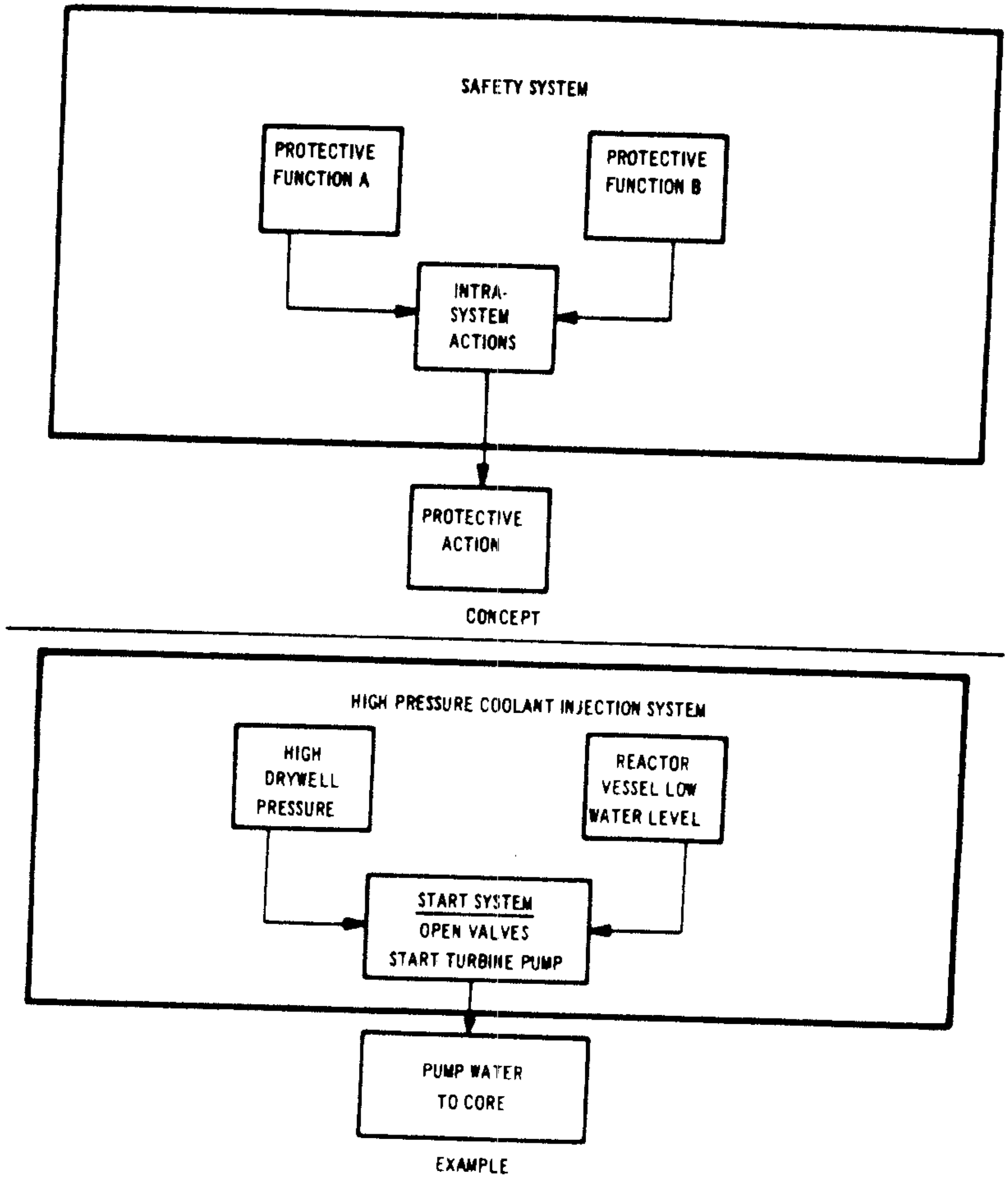


FIGURE 1.2-3
RELATIONSHIP BETWEEN PROTECTIVE FUNCTIONS AND PROTECTIVE ACTIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

1.3 METHODS OF TECHNICAL PRESENTATION

1.3.1 Purpose

The purpose of this Safety Analysis Report is to provide the technical information required by 10CFR50.34 to establish a basis for evaluation of the station with respect to the issuance of a facility operating license. The Safety Analysis Report has been updated to be consistent with the requirements of 10CFR50.71(e).

1.3.2 Radioactive Material Barrier Concept

Because the safety aspects of this report pertain to the relationship between station behavior under a variety of circumstances and the radiological effects on persons offsite, the report is oriented to the radioactive material barriers. This orientation facilitates evaluation of the radiological effects of the station on the environment. Thus, the presentation of technical information is considerably different from that which would be expected in an operational manual, maintenance manual, or nuclear engineer's handbook.

The overriding consideration that determines the depth of detailed technical information presented about a system or component is the relationship of the system or component to the radioactive material barriers. Systems that must operate to preserve or limit the damage to the radioactive material barriers are described in the greatest detail. Systems that have little relationship to the radioactive material barriers are described only with as much detail as is necessary to establish their functional role in the station.

1.3.3 Organization of Contents

The Safety Analysis Report is organized into 14 major sections each of which consists of a number of sections. A system for classifying the various aspects of the BWR with respect to safety is given in Section 1.4. This classification system is fundamental to assessing the adequacy of the station with respect to the relative importances of different safety concerns. The principal architectural and engineering criteria, which define the broad frame of reference within which the station is designed, are set forth in Section 1.5. Section 1.6 presents a brief description of the station in which the nuclear safety systems and engineered safeguards are separated from the other systems, so that those systems essential to safety are clearly identified.

Sections 2 through 13 present detailed information about the design and operation of the station. The nuclear safety systems and engineered safeguards are integrated into these sections according to system function (core standby cooling, control), system type (electrical, mechanical), or according to their relationship to a particular radioactive material barrier. Section 3, Reactor, describes station components and presents design details that are most pertinent to the fuel barrier. Section 4, Reactor Coolant

System, describes station components and systems that are most pertinent to the nuclear system process barrier. Section 5, Containment, describes the primary and secondary containments. Thus, Sections 3, 4, and 5 are arranged according to the four radioactive material barriers.

The remainder of the sections group system information according to station function (radioactive waste control, core standby cooling, power conversion, control) or system type (electrical, structures). Section 14, Station Safety Analysis, provides an overall safety evaluation of the station which demonstrates both the adequacy of equipment designed to protect the radioactive material barriers, and the ability of the safeguard features to mitigate the consequences of situations in which one or more radioactive material barriers are assumed damaged.

1.3.4 Format Organization of Sections

Sections are numerically identified by representing their order or appearance in a section by two numbers separated by a decimal point, e.g., 3.4, the fourth subsection in Section 3. Sections are further subdivided by numbers separated by decimal points (3.4.1, 3.4.1.1, etc.). Pages within each section are consecutively numbered (3.4-1, 3.4-2, etc.; or 11.1-1, 11.1-2, etc.).

Tabulations of data are designated "Tables" and are identified by the Section number followed by a dash and the number of the table according to its order of mention in the text, e.g., Table 3.4-5 is the fifth table of Section 3.4. Drawings, pictures, sketches, curves, graphs, and engineering diagrams are identified as "Figures" and are numbered consecutively with a dash separating the second and third numbers. Figures 1.3-1 and 1.3-2 define the meanings of piping and instrumentation symbols used in the figures of this report. Figures 1.3-3, 4, and 5 show the functional control diagram symbols and Figure 1.3-6 shows the instrument symbols used in figures of this report.

The general organization of a Section describing a system or component is as follows:

Objective
Design Basis
Description
Evaluation
Inspection and Testing
Operational Nuclear Safety Requirements (if applicable)

To clearly distinguish the safety versus power generation aspects of a system, the objective, design basis, and evaluation titles are modified by the word "safety" or "power generation," according to the definitions given in Section 1.2. Systems that have safety objectives are safety systems. A safety evaluation is included only when the system has a safety design basis; the evaluation shows how the system satisfies the safety design basis. A power generation

evaluation is included only when needed to clarify the safety versus power generation aspects of a system that has both safety and power generation functions.

A nuclear safety operational analysis of the station has been performed to systematically identify the operational limitations or restrictions which must be observed with regard to certain process variables, and certain station systems to satisfy specified nuclear safety operational criteria. The method used for this analysis is described in Appendix G and the Sections describing the applicable systems. The limiting conditions for operation and surveillance requirements are contained in the Technical Specifications referenced in Appendix B.

Sections presenting information on topics other than systems or components are arranged individually according to the subject matter so that the relationship between the subject and public safety is emphasized.

Within each section of the text, applicable supporting technical material is referenced. References are cited in a list of references at the end of a section.

1.3.5 Power Level Basis for Analysis of Abnormal Operational Transients and Accidents

For those abnormal operational transients and accidents for which high power operation increases the severity of the results, the analyses assume station operation at design power as an initial condition. For those events for which an initial condition of low or intermediate power level operation renders the most severe results, the analyses presented in this report represent the most severe case within the operating spectrum.

Figure 1.3-1 has been deleted

Please refer to figure 1.3-2.

Figure 1.3-2 has been removed
Please refer to BECo Controlled Drawing M 200.

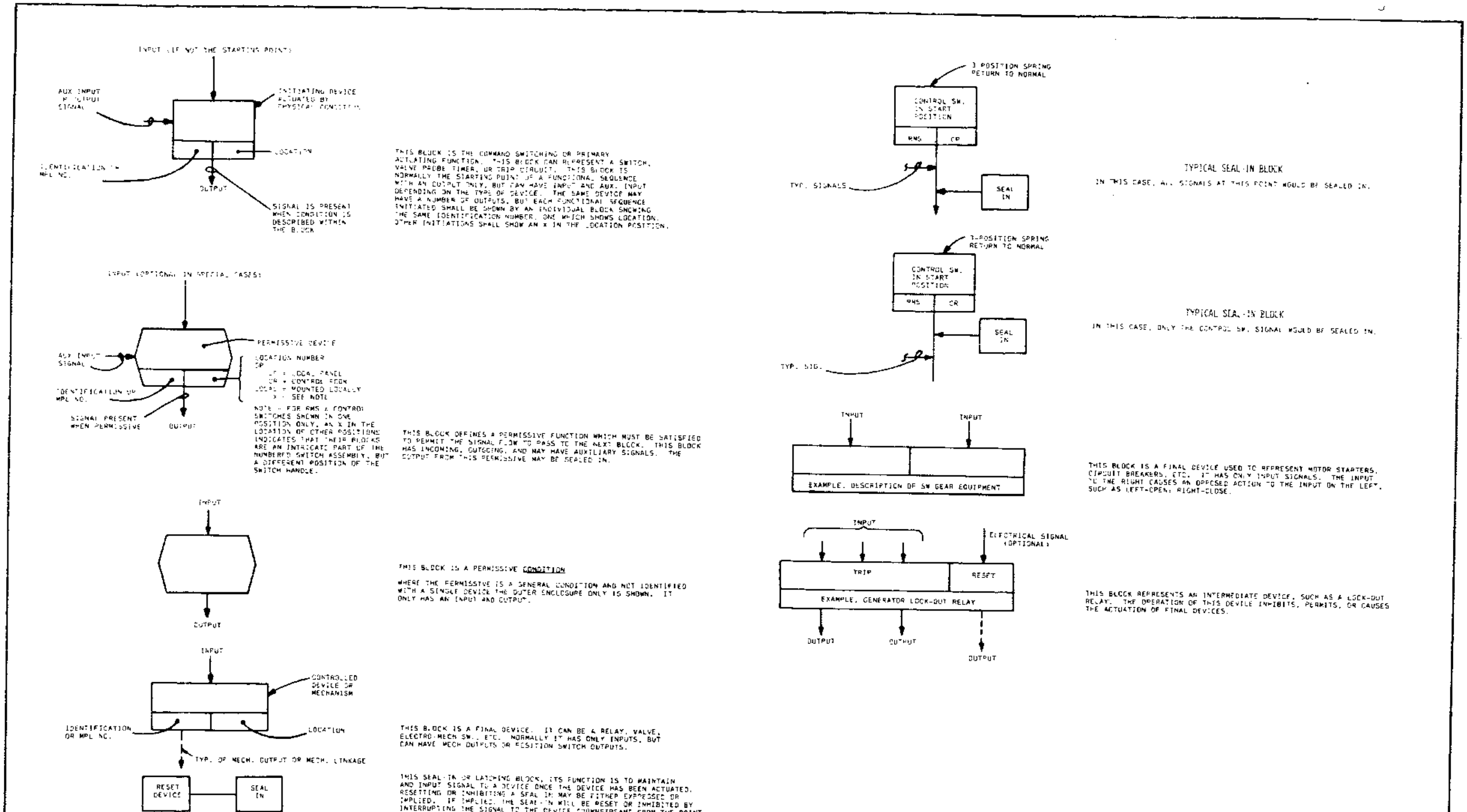
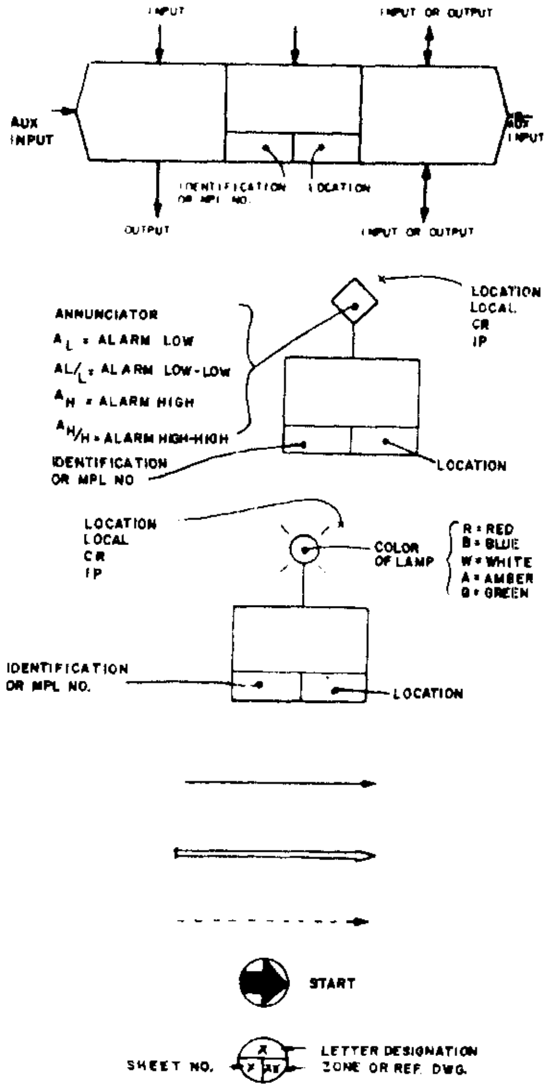


FIGURE 1.3-3
FUNCTIONAL CONTROL DIAGRAM SYMBOLS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



THIS BLOCK IS A PERMISSIVE OPERATED BY DEVICES SUCH AS VALVE OR PUMP SWITCH GEAR DESIGNATED IN THE INNER BLOCK THIS COND. OR DEVICE EFFECTS THE OPERATION OF THE FINAL DEVICE. IT HAS ELECT. INPUTS, MECH INPUTS, AUX INPUTS (MECH OR ELEC), AND MECH OR ELECT OUTPUTS. THIS DEVICE IS NORMALLY A VALVE. THIS IS ALSO USED FOR OTHER INPUT/OUTPUT POWER SOURCES SUCH AS AIR OR HYDRAULIC A SOLENOID PILOT VALVE FOR AN AIR OPERATED VALVE IS AN EXAMPLE OF THIS TYPE DEVICE.

THIS BLOCK IS A PRIMARY FUNCTION FOR ANNUNCIATORS

THIS BLOCK IS A PRIMARY FUNCTION FOR IND. LIGHTS
THE LIGHT SYMBOLS REPRESENTS LIGHTS ON THE CONTROL PANELS UNLESS OTHERWISE SPECIFIED

THIS LINE REPRESENTS AN ELEC FLOW SIGNAL THIS LINE MAY ACTUATE A FINAL DEVICE AND MAY BE USED TO REPRESENT ACTUATION OF A PERMISSIVE BLOCK

THIS LINE REPRESENTS AN AUXILIARY SIGNAL SOURCE SUCH AS AIR OR HYDRAULIC AND IS NOT ELECTRICAL

THIS LINE REPRESENTS MECHANICAL OUTPUTS AND/OR MECHANICAL LINKAGE.

THIS SYMBOL REPRESENTS THE START OF THE PRIMARY AUTOMATIC INITIATING SIGNAL

THIS SYMBOL REPRESENTS A MATCH CIRCLE THE LETTER DESIGNATION ON ONE DWG MUST MATCH THE LETTER ON THE INTERFACING DWG.

FIGURE I. 3-4
FUNCTIONAL CONTROL DIAGRAM SYMBOLS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

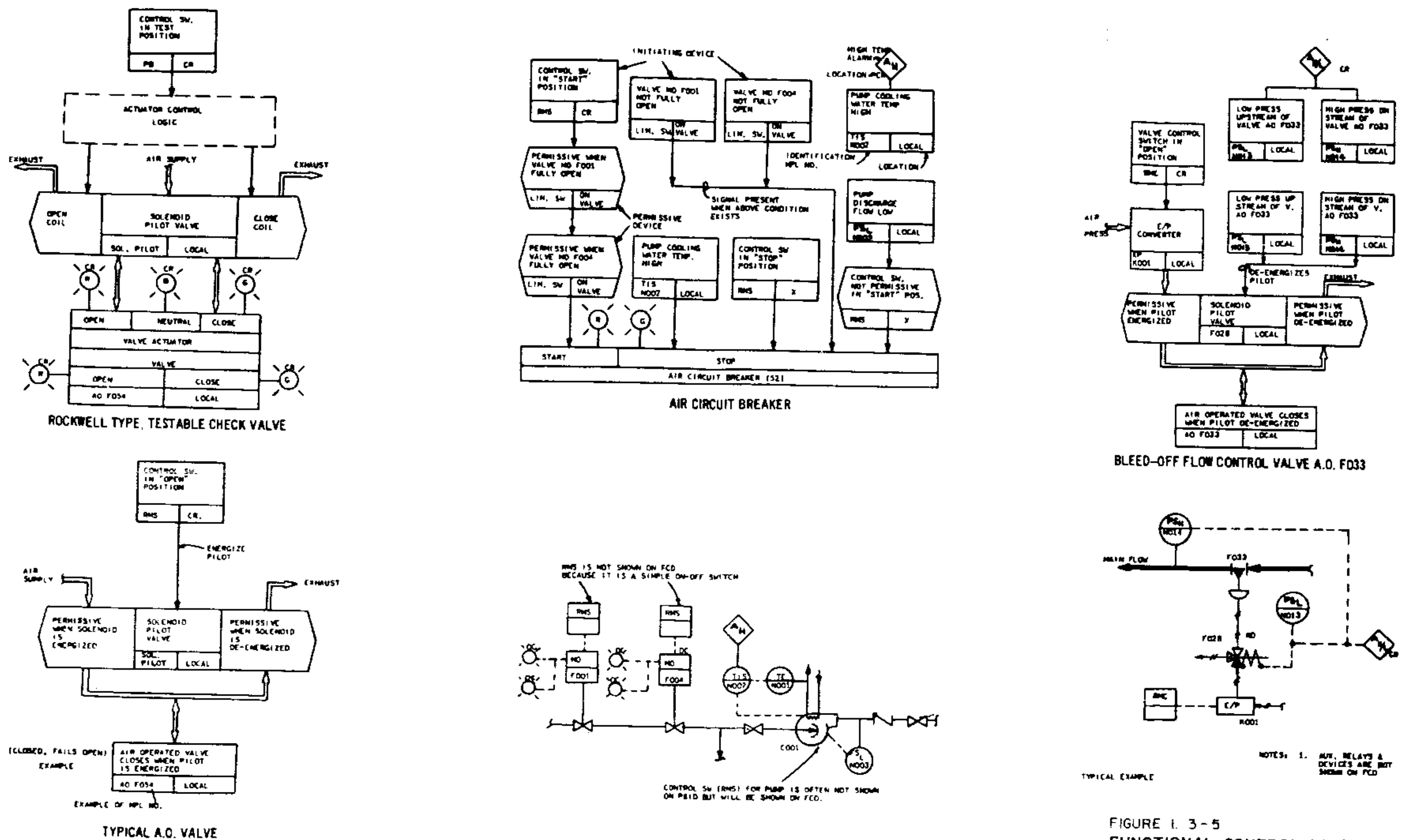


FIGURE I. 3-5
FUNCTIONAL CONTROL DIAGRAM SYMBOLS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

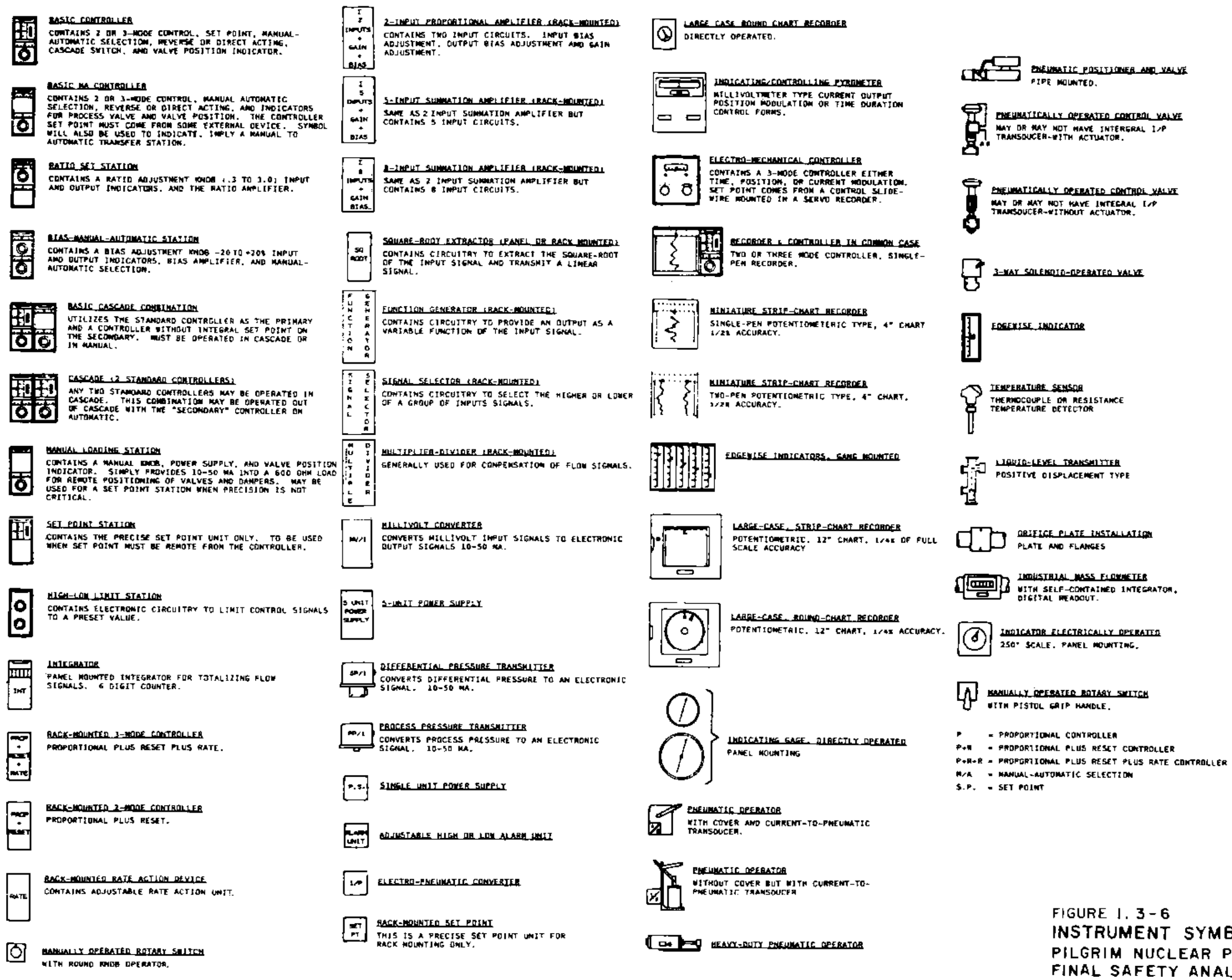


FIGURE 1.3-6
INSTRUMENT SYMBOLS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

1.4 CLASSIFICATION OF BWR SYSTEMS, CRITERIA, AND REQUIREMENTS FOR SAFETY EVALUATION

1.4.1 Introduction

At the highest level, nuclear power station safety is a matter of judgement. To evaluate for safety purposes the many aspects of the design and operation of the boiling water reactor station, it is necessary to distinguish those station components which are essential to meeting specified measures of safety from those that are not. To be valid, such a determination must be performed in a consistent, systematic manner.

A systematic method has been developed to evaluate functionally the nuclear safety aspects of the BWR. The first step in this method is to specify in measurable terms the major judgements to be considered as the primary safety requirements. These top level judgments are offered as unacceptable safety results associated with each major category of station events. The following sets of unacceptable safety results are those used in evaluating the Pilgrim Nuclear Power Station:

Event Category		Unacceptable Safety Results
1. Planned Operation	1-1	The release of radioactive material to the environs to such an extent that the limits of 10CFR20 are exceeded.
	1-2	Fuel failure to such an extent that were the freed fission products released to the environs via the normal discharge paths for radioactive material, the limits of 10CFR20 would be exceeded.
	1-3	Nuclear system stress in excess of that allowed for planned operation by applicable industry code.
	1-4	The existence of a station condition not considered by station safety analyses.
2. Abnormal Operational Transients	2-1	The release of radioactive material to the environs to such an extent that the limits of 10CFR20 are exceeded.
	2-2	Fuel safety limits are exceeded.

Event Category		Unacceptable Safety Results
	2-3	Nuclear system stress in excess of that allowed for transients by applicable industry codes
3. Accidents	3-1	Radioactive material release to such an extent that the guide-line values of 10CFR100 would be exceeded
	3-2	The acceptance criteria of 10CFR50.46 are exceeded
	3-3	Nuclear system stresses in excess of that allowed for accidents by applicable industry codes
	3-4	Containment stresses in excess of that allowed by design or code when containment is required
	3-5	Overexposure to radiation of station operation personnel in the control room
4. Special Event-Ability to Shut-down Reactor from Outside Control Room	4-1	The inability to bring the reactor to the shutdown condition by manipulation of the local controls and equipment which are available outside the control room
	4-2	The inability to bring the reactor to the cold shutdown condition from outside the control room
5. Special Event-Ability to Shut-down Reactor Without Control Rods	5-1	The inability to shutdown the reactor independent of control rods
	5-2	The inability to automatically trip the recirculation pumps to reduce reactor power while shutting down the reactor independent of control rods

Using the unacceptable safety results, the criteria for selecting the events of each category, and a consistent set of ground rules for evaluating the station events, it is possible to identify all the station actions essential to avoiding the unacceptable safety results. Such actions are called safety actions. Similarly, it is

possible to identify all the systems (safety systems) and all the system components essential to avoiding the unacceptable safety

results. The Station Nuclear Safety Operational Analysis (Appendix G) details this analysis method and presents the results.

The most significant results of the Station Nuclear Safety Operational Analysis are the protection sequences shown for abnormal operational transients and accidents. A single failure proof path to avoiding the unacceptable safety results is shown for every transient and accident case in Appendix G.

With the results of the Station Nuclear Safety Operational Analysis it is possible to classify the various station systems according to their functional roles relative to the unacceptable safety results. This classification can be extended to such items as subsidiary design criteria and operating limits.

Table 1.4-1 illustrates the concept used in the classification process. The concept applies to the total station design and operation. A major distinction is made between those BWR aspects which are essential to the avoidance of the unacceptable safety results and those which are most pertinent to the station mission - the generation of electrical power. Those aspects essential to the avoidance of the unacceptable safety results appear under the "safety consideration" side (left side) of the table, and the aspects most pertinent to the station mission appear under the "power generation" side (right).

All station components contribute in some measure to safety, but those classified under "power generation" considerations are not essential to avoiding the unacceptable safety results. Thus, the right and left sides of the table represent major differences in importance to safety. On left side of Table 1.4-1 are listed the various categories of events. The left hand column is actually a gross probability scale. Planned operation is certain, abnormal operational transients are reasonably expected, and accidents are very improbable.

The items listed under the safety considerations heading and the power generation heading represent potential classification categories for BWR criteria, systems, and operational requirements. This classification concept, when applied, allows a consistent, accurate distinction between the importances of the various aspects of BWR design and operation.

1.4.2 Classification Plan

Table 1.2-1 presents the plan for classifying various BWR items. The format of the table is identical to that used on Table 1.4-1, which presented the classification concept. Within each classification category, a list of unacceptable results is given. The unacceptable results represent a set of master criteria, from which the design and operation of the BWR can be consistently evaluated. The only unacceptable results listed on the power generation (right) side of

the chart are those that result in a more conservative design requirement.

In the various columns inside each classification category, generic labels are assigned to the specific elements which appear or would appear, if listed, in the column. A generic label is given only to facilitate discussion and identification of a group of elements united by their common classification. Beneath the generic names are listed some of the more illustrative BWR items which can be classified in the different columns. Some of the listed items are the limits and restrictions found in the Technical Specifications. Technical Specifications are limited to those concerns that are only on the safety (left) side of the table.

Classification analyses (see Appendix G) have been performed to establish the essentiality of the various BWR systems to the avoidance or prevention of the listed unacceptable results. Such analyses consider any applicable criteria (see Appendix G), requiring redundancy in the avoidance of unacceptable results. Once a system is classified, it is evaluated with reference to the criteria applicable to the group in which it performs an essential action. A classification analysis is not the same as a "worst case" event analysis. A classification analysis is concerned with the identification of all essential protection sequences. A "worst case" analysis is concerned with the case giving the most fuel damage, the highest pressure, the greatest activity release, etc.

1.4.3 Use of the Classification Plan

The classification plan illustrated on Table 1.2-1 permits the classification of any BWR criterion, system, or operational requirement into one or more of the classification categories, the plan facilitates a stationwide safety overview. The plan explains the reasons for the differences in the designs of apparently similar systems by relating the actions of the systems to specified unacceptable results. With the design complete, the classification plan is used to establish operational requirements and procedures whose differences are consistent with the different importances of unacceptable results.

It should be noted that a system may be classified in several categories. This occurs because classification is the result of a functional analysis of the station. When classified in more than one category, a system must satisfy all of the requirements for each category with regard to its contributions to the various safety actions within each of the categories.

TABLE 1.4-1

BWR SAFETY ENGINEERING
CONCEPT FOR CLASSIFICATION OF BWR SYSTEMS, CRITERIA, AND REQUIREMENTS FOR SAFETY EVALUATION

ACTUAL PLANT DESIGN AND OPERATION

Type of Operation or Event	Safety Considerations	Power Generation Considerations
1. Planned Operation	In this category are classified the unacceptable safety results, criteria, station actions, systems, and operational requirements pertinent to safety during planned operation. This space represents the aspects of the BWR which must be considered to assure that the BWR operator can operate the station within specified safety limitations. Certain process indicators, process variable limits and limits on the release of radioactive material would be classified here.	In this category are classified the unacceptable results for power generation, criteria, station actions, systems and operational requirements pertinent to the production of electrical power during planned operation. Process systems and normal operational procedures would be classified here.
2. Abnormal Operational Transients	In this category are classified the unacceptable safety results, criteria, station actions, systems and operational requirements pertinent to safety in regard to abnormal operational transients. Certain protection systems, safety limits, and limiting safety system settings would be classified here.	In this category are classified the unacceptable results for power generation, criteria, station actions, systems and operational requirements pertinent to the ability to produce electrical power as that ability is affected by abnormal operational transients. Certain systems not used for planned operation would be classified here.
3. Accidents	In this category are classified the unacceptable safety results, criteria, station actions, systems and operational requirements pertinent to safety in regard to accidents. Engineered safequards would be classified here.	In this category are classified the unacceptable results for power generation, criteria, station actions, systems and operational requirements pertinent to the ability to produce electrical power as that ability is affected by accidents. Design considerations and post-accident procedures provided to enable the station to be used for power generation after an accident would be classified here.

1.5 PRINCIPAL DESIGN CRITERIA

There are two ways of considering principal design criteria. One way is to consider the criteria on a system by system (or system group) basis. The second way is to consider criteria classification by classification as given on Table 1.2-1.

In the classification by classification approach the criteria must be stated in sufficient detail to allow placement of each criterion into one classification category. Thus, there may be closely related criteria pertaining to any given system in each classification category. This is a natural outgrowth of the functional (unacceptable result) approach to classification. The actual design of a system must reflect all of the criteria that pertain to it; thus, the less restrictive (but more important) criteria pertaining to the system in the classification approach will be masked by the more restrictive (and less important) criteria.

Safety analysis requires the information gained in the classification by classification approach to criteria, but system description is more easily understood through the system by system method. In this section both approaches to criteria are given; both are useful.

1.5.1 Principal Design Criteria Classification By Classification

The principal architectural and engineering criteria for the design and construction of the station are summarized below. The criteria are grouped according to the classification plan given on Table 1.2-1. Some of the more general criteria are so broad in that they are applicable, at least in part, to more than one classification. In these very general cases all of the affected classifications are indicated. Specific design bases and design features are detailed in other sections of this report. Criteria pertaining to operation of the station are given in Appendix G.

1.5.1.1 General Criteria

1. The station is designed so that it can produce electric power in a safe and reliable manner. The station design is in accordance with applicable codes and regulations.

2. The station is designed in such a way that the release of radioactive materials to the environment is limited, so that the limits and guideline values of applicable regulations pertaining to the release of radioactive materials are not exceeded.

3. The reactor core and reactivity control system is designed so that control rod action is capable of bringing the core subcritical and maintaining it so, even with the rod of highest reactivity worth fully withdrawn and unavailable for insertion.

4. Adequate strength and stiffness with appropriate safety factors is provided so that a hazardous release of radioactive material will not occur.

1.5.1.2 Power Generation Design Criteria, (Planned Operation)

1. The nuclear system employs a boiling water reactor to produce steam for direct use in a turbine generator.

2. The fuel cladding is designed to retain integrity as a radioactive material barrier for the design power range.

3. The fuel cladding is designed to accomodate the pressures generated by the fission gases released from the fuel material throughout the design life of the fuel without loss of integrity.

4. Heat removal systems are provided in sufficient capacity and operational adequacy to remove heat generated in the reactor core for the full range of normal operational conditions from plant shutdown to design power. The capacity of such systems is adequate to prevent fuel clad damage.

5. Control equipment is provided for recirculation flow control to allow the reactor to respond automatically to minor load changes.

6. It is possible to manually control the reactor power level.

7. Control of the nuclear system is possible from a single location.

8. Nuclear system process controls are arranged to allow the operator to rapidly assess the condition of the nuclear system and to locate process system malfunctions.

9. Fuel handling and storage facilities are designed to maintain adequate shielding and cooling for spent fuel.

10. Interlocks or other automatic equipment are provided as a backup to procedural controls to avoid conditions requiring the functioning of nuclear safety systems or engineered safeguards.

1.5.1.3 Power Generation Design Criteria, (Abnormal Operational Transients)

1. The fuel cladding, in conjunction with other station systems, is designed to retain integrity throughout any abnormal operational transient.

2. Heat removal systems are provided in sufficient capacity and operational adequacy to remove heat generated for any abnormal operational transient.

3. Standby electrical power sources are provided to allow removal of decay heat under circumstances where normal auxiliary power is not available.

1.5.1.4 Nuclear Safety Design Criteria, (Planned Operation)

1. The station is designed so that fuel failure during planned operation is limited to such an extent that were the freed fission products released to the environs via the normal discharge paths for radioactive materials, the limits of 10CFR20 would not be exceeded.

2. The reactor core is designed so that its nuclear characteristics do not contribute to a divergent power transient.

3. The nuclear system is designed so there is no tendency for divergent oscillation of any operating characteristic, considering the interaction of the nuclear system with other appropriate station systems.

4. Gaseous, liquid, and solid waste disposal facilities are designed so that the discharge and offsite shipment of radioactive effluents can be made in accordance with applicable regulations.

5. The design provides means by which station operations personnel can be informed whenever limits on the release of radioactive material are exceeded.

6. Sufficient indications are provided to allow determination that the reactor is operating within the envelope of conditions considered by station safety analysis.

7. Radiation shielding is provided and access control patterns are established to allow a properly trained operating staff to control radiation doses within the limits of applicable regulations in any mode of normal station operation. See Table 1.5-1.

1.5.1.5 Nuclear Safety Design Criteria, (Abnormal Operational Transients)

1. The station is designed so that safety limits are not exceeded as a result of any abnormal operational transient.

2. Those portions of the nuclear system which form part of the nuclear system process barrier are designed to retain

integrity as a radioactive material barrier following abnormal operational transients.

3. Nuclear safety systems act to assure that no damage to the nuclear system process barrier results from internal pressures caused by abnormal operational transients.

4. Where positive, precise action is immediately required in response to abnormal operational transients, such action is automatic and shall require no decision or manipulation of controls by operations personnel.

5. Essential safety actions are carried out by equipment of sufficient redundance and independence that no single failure of active components can prevent the required actions.

6. The design of nuclear safety systems include allowances for environmental phenomena at the site.

7. Provision is made for control of active components of nuclear safety systems from the control room.

8. Nuclear safety systems are designed to permit demonstration of their functional performance requirements.

9. Standby electrical power sources are provided to allow prompt reactor shutdown and removal of decay heat under circumstances where normal auxiliary power is not available.

10. Standby electrical power sources have sufficient capacity to power all nuclear safety systems requiring electrical power.

1.5.1.6 Nuclear Safety Design Criteria (Accidents)

1. Those portions of the nuclear system which form part of the nuclear system process barrier are designed to retain integrity as a radioactive material barrier following accidents.

2. Engineered safety standards act to assure that no damage to the nuclear system process barrier results from internal pressures caused by accident.

3. Where positive, precise action is immediately required in response to accidents, such action is automatic and requires no decision or manipulation of controls by operations personnel.

4. Essential safety actions are carried out by equipment of sufficient redundance and independence that no single failure of active components can prevent the required actions.

5. Features of the station which are essential to the mitigation of accident consequences are designed so that they can be fabricated and erected to quality standards which reflect the importance of the safety action to be performed.

6. The design of engineered safeguards include allowances for environmental phenomena at the site.

7. Provision is made for control of active components of engineered safeguards from the control room.

8. Engineered safeguards are designed to permit demonstration of their functional performance requirements.

9. A primary containment is provided that completely encloses the reactor vessel.

10. The primary containment is designed to retain integrity as a radioactive material barrier during and following accidents that release radioactive material into the primary containment volume.

11. It is possible to test primary containment integrity and leak tightness at periodic intervals.

12. A secondary containment is provided that completely encloses both primary containment and fuel storage areas.

13. The secondary containment is designed to act as a radioactive material barrier under the same conditions that require the primary containment to act as a radioactive material barrier.

14. The secondary containment is designed to act as a radioactive material barrier, if required, whenever the primary containment is open for expected operational purposes.

15. The primary and secondary containments, in conjunction with other engineered safeguards, act to prevent the radiological effects of accidents resulting in the release of radioactive material to the containment volumes from exceeding the guideline values of applicable regulations.

16. Provisions are made for the removal of energy from within the primary containment as necessary to maintain the integrity of the containment system following accidents that release energy to the primary containment.

17. Piping that both penetrates the primary containment structure and could serve as a path for the uncontrolled release of radioactive material to the environs is

automatically isolated whenever such uncontrolled radioactive material release is threatened. Such isolation can be effected in time to prevent radiological effects from exceeding the guideline values of applicable regulations.

18. Core standby cooling systems are provided to meet the criteria of 10CFR50.46.

19. The core standby cooling systems provide for continuity of core cooling over the complete range of postulated break sizes in the nuclear system process barrier.

20. The core standby cooling systems are reliable and redundant.

21. Operation of the core standby cooling systems is initiated automatically when required.

22. Standby electrical power sources have sufficient capacity to power all engineered safeguards requiring electrical power.

23. The control room is shielded against radiation so that continued occupancy under accident conditions is possible.

1.5.1.7 Nuclear Safety Design Criteria (Special Event)

In the event that the control room becomes inaccessible, it is possible to bring the reactor from power range operation to a hot shutdown condition by manipulation of the local controls and equipment which are available outside of the control room. Furthermore, station design does not preclude the ability, in this event, to bring the reactor to a cold shutdown condition from the hot shutdown condition.

1.5.1.8 Nuclear Safety Design Criteria, (Special Event)

Backup reactor shutdown capability is provided independent of normal reactivity control provisions. This backup system has the capability to shut down the reactor from any normal operating conditions, and subsequently to maintain the shutdown condition. Additionally, during abnormal transients a system is provided to automatically trip the recirculation pumps and thereby reduce reactor power.

1.5.2 Principal Design Criteria, System By System

The principal architectural and engineering criteria for design are summarized below on a system by system or system group basis. The system by system presentation facilitates the understanding of the actual design of any one system, but significant distinctions to the importance to safety of different criteria pertaining to a system cannot be made clear, as they are in the classification by classification presentation. To make consistent judgements regarding station safety, the classification by classification approach to criteria must be used.

In the system by system presentation of criteria, only the most restrictive of any related criteria are stated for a system. Where the most restrictive criterion is one which is classified as a power generation consideration on Table 1.2-1, less restrictive but more important safety criteria may be hidden (not stated) in the system by system presentation.

1.5.2.1 General Criteria

1. The station is designed so that it can be fabricated, erected, and operated to produce electric power in a safe and reliable manner. The design is in accordance with applicable codes and regulations.

2. The station is designed in such a way that the release of radioactive materials to the environment is limited, so that the limits and guideline values of applicable regulations pertaining to the release of radioactive materials to the environment is limited, and the limits and guideline values of applicable regulations pertaining to the release of radioactive materials are not exceeded.

1.5.2.2 Nuclear System Criteria

1. The nuclear system employs a General Electric boiling water reactor to produce steam for direct use in a turbine generator.

2. The fuel cladding is designed to be within its safety limits for the design power range and for any abnormal operational transient.

3. Those portions of the nuclear system which form part of the nuclear system process barrier are designed to retain integrity as a radioactive material barrier following abnormal operational transients and accidents.

4. The fuel cladding is designed to accomodate the pressures generated by the fission gases released from the fuel material throughout the design life of the fuel without loss of integrity.

5. Heat removal systems are provided in sufficient capacity and operational adequacy to remove heat generated in the reactor core for the full range of normal operational conditions from shutdown to design power, and for any abnormal operational transient. The capacity of such systems are adequate to prevent fuel safety limits from being exceeded.

6. Heat removal systems are provided to remove decay heat generated in the core under circumstances wherein the normal operational heat removal systems become inoperative. The capacity of such systems are adequate to prevent fuel safety limits from being exceeded.

7. The reactor core and reactivity control system are designed so that control rod action is capable of bringing the core subcritical and maintaining it so, even with the rod of highest reactivity worth fully withdrawn and unavailable for insertion.

8. The nuclear system is designed so there is no tendency for divergent oscillation of any operating characteristic, considering the interaction of the nuclear system with other appropriate station systems.

9. The reactor core is designed so that its nuclear characteristics do not contribute to a divergent power transient.

1.5.2.3 Power Conversion System Criteria

Components of the power conversion systems are designed to perform two basic objectives:

1. Produce electrical power from the steam coming from the reactor, condense the steam into water, and return the water to the reactor as heated feedwater, with a major portion of its gases and particulate impurities removed.

2. Assure that any fission products or radioactivity associated with the steam and condensate during normal operation are safely contained inside the system or are released under controlled conditions in accordance with waste disposal procedures.

1.5.2.4 Electrical Power System Criteria

The station electrical power systems are designed to efficiently deliver the electrical power generated to the 345 kV Transmission system.

Sufficient normal and standby auxiliary sources of electrical power are provided to attain prompt shutdown and continued maintenance of the station in a safe condition. The capacity of the power sources

are adequate to accomplish all required engineered safeguard functions under postulated design basis accident conditions.

1.5.2.5 Radioactive Waste Disposal Criteria

Gaseous, liquid, and waste disposal facilities are designed so that the discharge and offsite shipment of radioactive effluents can be made in accordance with applicable regulations.

These facilities include means of informing station operations personnel whenever operational limits on the release of radioactive material are exceeded.

1.5.2.6 Nuclear Safety Systems and Engineered Safeguards Criteria

1.5.2.6.1 General

1. Nuclear safety systems act in response to abnormal operational transients so that safety limits are not exceeded.

2. Nuclear safety systems and engineered safeguards act to assure that no damage to the nuclear system process barrier results from internal pressures caused by abnormal operational transients or accidents.

3. Where positive, precise action is immediately required in response to accidents, such action is automatic and requires no decision or manipulation of controls by operations personnel.

4. Essential safety actions are carried out by equipment of sufficient redundance and independence that no single failure of active components can prevent the required actions.

5. Features of the station which are essential to the mitigation of accident consequences are designed so that they can be fabricated and erected to quality standards which reflect the importance of the safety function to be performed.

6. The design of nuclear safety systems and engineered safeguards include allowances for environmental phenomena at the site.

7. Provision is made for control of active components of nuclear safety systems and engineered safeguards from the control room.

8. Nuclear safety systems and engineered safeguards are designed to permit demonstration of their functional performance requirements.

1.5.2.6.2 Containment and Isolation Criteria

1. A primary containment is provided to completely enclose the reactor vessel. It is designed to act as a radioactive material barrier during the following accidents that release radioactive material into the primary containment. It is possible to test the primary containment integrity and leak tightness at periodic intervals.

2. A secondary containment that completely encloses both primary containment and fuel storage areas is provided and designed to act as a radioactive material barrier.

3. The primary and secondary containments, in conjunction with other engineered safeguards, act to prevent the release of radioactive material from the containment volumes from exceeding the guideline values of applicable regulations.

4. Provisions are made for the removal of energy from within the primary containment as necessary to maintain the integrity of the containment system following accidents that release energy to the primary containment.

5. Piping that both penetrates the primary containment structure and could serve as a path for the uncontrolled release of radioactive material to the environs is automatically isolated whenever such uncontrolled radioactive material release is threatened. Such isolation is effected in time to prevent radiological effects from exceeding the guideline values of applicable regulations.

1.5.2.6.3 Core Standby Cooling Criteria

1. Core standby cooling systems are provided to meet the criteria of 10CFR50.46.

2. The core standby cooling systems provide for continuity of core cooling over the complete range of postulated break sizes in the nuclear system process barrier.

3. The core standby cooling systems are diverse, reliable, and redundant.

4. Operation of the core standby cooling systems is initiated automatically when required, regardless of the availability of offsite power supplies and the normal generating system of the plant.

1.5.2.6.4 Standby Power Criteria

Standby electrical power sources are provided to allow prompt reactor shutdown and removal of decay heat under circumstances where normal auxiliary power is not available. They also provide sufficient power to all engineered safeguards requiring electrical power.

1.5.2.7 Reactivity Control Criteria

1. Backup reactor shutdown capability is provided independent of normal reactivity control provisions. This backup system shall have the capability to shut down the reactor from any operating condition, and subsequently to maintain the shutdown condition.

2. In the event that the control room is inaccessible, it is possible to bring the reactor from power range operation to a hot shutdown condition by manipulation of the local controls and equipment which are available outside of the control room. Furthermore, station design does not preclude the ability, in this event, to bring the reactor to a cold shutdown condition from the hot shutdown condition.

1.5.2.8 Process Control Systems Criteria

1.5.2.8.1 Nuclear System Process Control Criteria

1. Control equipment is provided for recirculation flow control to allow the reactor to respond automatically to limited load changes.

2. It is possible to manually control the reactor power level.

3. Control of the nuclear system is possible from a single location.

4. Nuclear system process controls are arranged to allow the operator to rapidly assess the condition of the nuclear system and to locate process system malfunctions.

5. Interlocks or other automatic equipment are provided as a backup to procedural controls to avoid conditions requiring the actuation of nuclear safety systems or engineered safeguards.

1.5.2.8.2 Power Conversion Systems Process Control Criteria

1. Controls are provided to maintain temperature and pressure to below design limitations. This system results in a stable operation and response for all allowable variations.

2. Controls are designed to provide indication of system trouble.

3. Control of power conversion system is possible from a single location.

4. Sensors are provided to detect a loss of the main condenser.

5. Controls are provided to ensure adequate cooling of power conversion system equipment.

6. Controls are provided to ensure adequate condensate purity.

7. Controls are provided to regulate the supply of water so that adequate reactor vessel water level is maintained.

1.5.2.8.3 Electrical Power System Process Control Criteria

1. Controls are provided to ensure that sufficient electrical power is provided for startup, normal operation, and to attain prompt shutdown and continued maintenance of the station in a safe condition.

2. Control of the electrical power system is possible from a single location.

1.5.2.9 Auxiliary Systems Criteria

1. Multiple independent station auxiliary systems are provided for the purpose of cooling and servicing the station, the reactor, and the station containment systems under various normal and abnormal conditions.

2. Fuel handling and storage facilities are designed to prevent criticality and to maintain adequate shielding and cooling for spent fuel.

1.5.2.10 Shielding and Access Control Criteria

1. Radiation shielding is provided and access control patterns are established to allow the operating staff to control radiation doses within the limits of applicable regulations in any mode of normal station operation. See Table 1.5-1. The design and the establishment of the above include conditions which deal with fission product release from failed fuel elements and contamination of station areas from system leakage.

2. The control room is shielded against radiation and has suitable environmental control so that occupancy under design basis accident conditions is possible.

1.5.2.11 Structural Loading Criteria

The station structures are designed to withstand all applicable loading conditions including environmental loads, so that a hazardous release of radioactive material shall not occur.

TABLE 1.5-1

STATION SHIELDING
Design Basis Limitations

Description of Access Control	Design Base Rate (MRem/hr) on 40 hr/week basis
Unlimited, uncontrolled access	<1.0
Limited, controlled access up to 40 hr/week	<2.5
Limited controlled access (between 6 to 40 hr/week)*	<15
Limited controlled access (between 1 to 6 hr/week)*	<100
Normally inaccessible	>100

NOTE:

*Indicates expected access conditions

1.6 STATION DESCRIPTION

1.6.1 General

1.6.1.1 Site and Environs

The site is located on the western shore of Cape Cod Bay in the Town of Plymouth, Plymouth County, Massachusetts. It is 38 mi southeast of Boston, Massachusetts and 44 mi east of Providence, Rhode Island. Section 2 discusses the site locations with respect to the surrounding communities.

1.6.1.1.1 Site Ownership

The 517 acre plant site is wholly owned by Entergy.

1.6.1.1.2 Activities at the Site

The Applicant intends to develop the site solely for the purpose of generating and transmitting electrical energy in support of its normal business activities.

Provisions have been made for controlled public access to the shorefront breakwater area. This area is shown on Figures 1.6-1 and 1.6-2. The exclusion area is depicted on Figure 1.6-3.

1.6.1.1.3 Access to Site

Direct access to the site is available by road and sea. Normal land access is by a two lane paved road built across the site to Route 3A, leading to either Plymouth or nearby Route 3. Alternate access from the site to Plymouth and Route 3 via Route 3A is provided by Rocky Hill Road.

1.6.1.1.4 Description of the Environs

<u>Population</u>

The area within 3 mi of the site is sparsely developed having an estimated 2,358 permanent residents. The number of residents is estimated to increase to 3,301 within this radius due to the seasonal residence along Priscilla and White Horse Beaches. Brockton is the nearest densely populated center with more than 25,000 residents, with the nearest boundary about 23 mi from the site.

<u>Land Use (Refer to Section 2)</u>

The site is located along the coast with approximately 60 percent of the area within a 50 mi radius open water. Approximately 85 percent of the land area within a 10 mi radius is open space and vacant.

The area within 2 mi of the site is sparsely developed with the exception of the seasonal residences along Priscilla Beach and White Horse Beach.

An estimate of the present land use for the towns of Plymouth, Carver, and Kingston is presented in Section 2. Portions of these towns constitute approximately 90 percent of the land area within a 10 mi radius of the site. The data indicates that over 85 percent of the land is categorized as open space and vacant. Approximately 7 percent of the land use is agricultural, the major portion of which is cranberry bogs. The adjacent waters are used for commercial fishing, shell fishing, and sport fishing.

1.6.1.1.5 Geology and Seismology

The surface stratum in the station area consists of approximately 20 ft of silty and clayey fine sands with scattered boulders. The stratum is moderately compact. The soils underlying the upper stratum are moderately compact to compact, poorly to well graded sands with some gravel and cobbles. Boulders are scattered throughout the overburden soil, and a discontinuous thin layer of small boulders overlies bedrock. Bedrock is approximately 60 to 70 ft below msl. There are no known faults at or near the station site.

It is indicated from geologic and tectonic history that the region is relatively quiescent. Low magnitude seismic events can occur, but should be infrequent. The horizontal ground acceleration at the site due to maximum expected earthquake would be less than 8 percent of gravity, and this magnitude has been used for design purposes. Structures and equipment have been examined for an acceleration of 15 percent of gravity to ascertain that no failure could occur that would prevent safe shutdown of the station.

1.6.1.1.6 Hydrology

Surface drainage at the site is entirely within the Applicant's property and toward Cape Cod Bay. The ground water table has fairly steep gradients which generally follow the topography with ground water flow toward the bay. Ground water usage in the area is limited to a few locations since most of the residences are supplied with water from the Town of Plymouth. The closest Plymouth water supply source is 2 3/4 mi from the site and there is no current or proposed ground water development in the vicinity of the site.

Circulation off the site is a result of the combined effects of tidal and wind driven currents. Studies indicate that coastal upwelling also occurs at the site. These three processes, plus the momentum mixing of the circulating water discharge with the waters of the bay, will provide efficient mixing of waters discharged during station operation. Prevailing littoral drift is to the southeast (downcoast) from the site. The net effect of all circulation factors will result in the transport of discharged waters either offshore or parallel to shore.

1.6.1.1.7 Meteorology

The main features of the weather in eastern Massachusetts are its variety and changeability. The site meteorology is influenced by the coastal location on Cape Cod Bay. Present data indicates that

favorable atmospheric dilution conditions prevail. The annual average wind velocity is approximately 6 mph with the most frequent wind directions offshore. There are no long periods of light winds or calms. The high monthly average temperature of 72°F occurs in July and a low of 31°F in January and February. The storm cycle in the area consists of "northeasters" in the winter and spring, thunderstorms in late spring and summer, and hurricanes in the late summer and fall. Tornado activity in eastern Massachusetts is uncommon.

1.6.1.1.8 Station Design Bases Dependent upon the Station Site and Environs

Offgas System

A stack is provided for the continuous dispersal of gaseous effluent to the atmosphere. Height and location of the stack took into consideration such factors as station operational characteristics and site meteorological conditions. Gaseous releases shall be in compliance with 10CFR20 and 10CFR50 Appendix I.

Wind Loading Design

All station structures have been designed to withstand wind velocities in accordance with ASCE Paper 3269. Structures whose failure could affect the operations, functions, and integrity of the Primary Containment System have been designed to assure that safe shutdown of the reactor can be achieved when these structures are subjected to the effects of a tornado.

Seismic Design

The station seismic design criteria for Class I structure and equipment, important to safety, are based on dynamic analyses using acceleration or velocity response spectrum curves which are based on a ground horizontal acceleration of 8 percent of gravity. As an additional requirement, the design is such that a safe shutdown of the station can be made based on a ground acceleration of 15 percent of gravity. All structures not Class I have been designed to meet applicable codes.

Shoreline Protection

The station site will be protected from storm waves by rubble breakwaters and a stone revetment which also stabilizes the shoreline by preventing erosion.

1.6.1.1.9 Environs Radiation Surveillance Program

A study of preoperational environmental radiation levels was initiated in August 1969, which includes sampling and laboratory radioactivity analyses of airborne particulates, airborne iodine, fresh water, sea water, marine life, marine sediments, milk, and crops. Background radiation levels were established. Sampling activities are concentrated within a few miles of the station; however, in addition, selected sampling is also conducted at control

locations over 20 mi from the station. These studies are being continued after station startup. Comparison of the operational and preoperational data permits detection of any significant increase in radiation levels in the environment.

1.6.1.2 Facility Arrangement

The station is arranged such that the turbine-generator axis is oriented parallel to the shoreline of Cape Cod Bay, and the Reactor Building is located on the north or seaward side of the Turbine Building. Auxiliary bays are located between and adjacent to the Reactor Building and Turbine Building and house the main control room, the radwaste and machine shop equipment, and other service equipment and systems. The Old Administration Building is to the west of the Turbine Building, the New Administration/Service Building is to the east of the Turbine Building, and the Trash Compaction Building is to the North-East of the Turbine Building. The Diesel Generator Building is adjacent to the north side of the Reactor Building.

The main offgas stack is located about 700 ft to the west of the centerline of the station.

1.6.1.3 Nuclear System

The nuclear system includes a single cycle, forced circulation, General Electric Boiling Water Reactor producing steam for direct use in the steam turbine. A heat balance showing the major parameters of the nuclear system for the design power condition is shown on Figure 1.6-4.

1.6.1.3.1 Reactor Core and Control Rods

The fuel for the reactor core consists of slightly enriched uranium dioxide pellets contained in sealed Zircaloy 2 tubes. These fuel rods are assembled into individual fuel assemblies, each containing 64 rods or more. The number of fuel assemblies in the complete core is 580.

Gross control of the core is achieved by movable, bottom-entry control rods, supplemented in the initial fuel load with temporary control curtains. The control rods are of cruciform shape and are dispersed throughout the lattice of fuel assemblies. The rods are controlled by individual hydraulic drives.

1.6.1.3.2 Reactor Vessel and Internals

The reactor vessel contains the core and supporting structure; the steam separators and dryers; the jet pumps; the control rod guide tubes; distribution lines for the feedwater, core spray, and standby liquid control; the incore instrumentation; and other components. The main connections to the vessel include the steam lines, the coolant recirculation lines, feedwater lines, control rod drive housings, and core standby cooling lines.

The reactor vessel is designed and fabricated in accordance with applicable codes for a pressure of 1,250 psig. The nominal operating pressure ranges from 1,020 to 1,050 psia in the steam space above the separators. The vessel is fabricated of carbon steel and is clad internally with stainless steel.

The reactor core is cooled by demineralized water which enters the lower portion of the core and boils as it flows upward around the fuel rods. The steam leaving the core is dried by steam separators and dryers, located in the upper portion of the reactor vessel. The steam is then directed to the turbine through the main steam lines. Each steam line is provided with two isolation valves in series; one on each side of the primary containment barrier.

1.6.1.3.3 Reactor Recirculation System

The Reactor Recirculation System pumps reactor coolant through the core to remove the energy generated in the fuel. This is accomplished by two recirculation loops external to the reactor vessel but inside the primary containment. Each loop has one motor driven recirculation pump. Recirculation pump speed can be varied to allow some control of reactor power level through the effects of coolant flow rate on moderator void content.

1.6.1.3.4 Residual Heat Removal System

The Residual Heat Removal System (RHRS) is a system of pumps, heat exchangers, and piping that fulfills the following functions:

1. Removal of decay heat during and after station shutdown.

2. Injection of water into the reactor vessel following a loss of coolant accident (LOCA) rapidly enough to reflood the core, and prevent fuel clad melting independent of other Core Cooling Systems. This is discussed in Section 1.6.2 under Engineered Safeguards.

3. Removal of heat from the primary containment following a LOCA to limit the increase in primary containment pressure. This is accomplished by cooling and recirculating the water inside the primary containment. The redundancy of the equipment provided for containment cooling is further extended by a separate part of the RHRS which sprays cooling water into the containment. This latter capability is discussed in Section 1.6.2.12.

1.6.1.3.5 Reactor Water Cleanup System

A Reactor Water Cleanup System, which includes a filter-demineralizer arrangement, is provided to clean up the reactor cooling water, reduce the amounts of activated corrosion products in the water, and to remove reactor coolant from the nuclear system under controlled conditions.

1.6.1.4 Power Conversion Systems

To produce electrical power the station utilizes a power conversion system which includes turbine-generator, main condenser, air ejector, air ejector condensers, turbine gland seal condenser, condensate demineralizers, and a feedwater heating system. See Figure 1.6-5. The steam comes from the reactor, drives the turbine generator and is exhausted to the condenser. The deaerated condensate is demineralized prior to regenerative heating necessary for its return as feedwater to the reactor. The heat dumped to the main condenser is removed by the Circulating Water System.

1.6.1.4.1 Turbine Generator

The turbine is a General Electric 1,800 rpm tandem compound, four-flow, non reheat unit with 43 in last stage buckets. It has a double flow high pressure cylinder and two double flow low pressure cylinders. Exhaust steam from the high pressure unit passes through moisture separators before entering the low pressure units. The turbine has five extraction stages for reactor feedwater system heating. Turbine controls include a speed governor, steam admission (control) valves, emergency stop valves, crossover intercept valves, and a pair of initial pressure regulators. The generator is a direct coupled, 60 cycle, 24,000 V synchronous unit, with a liquid cooled stator and hydrogen cooled rotor.

1.6.1.4.2 Turbine Bypass System

A Bypass System is provided to allow passing of the steam from the reactor directly to the main condenser under control of the pressure regulator. Steam is bypassed to the condenser whenever the reactor steam rate exceeds that corresponding to the load connected to the turbine generator at that time. For example, the bypass system would be used during generator synchronization or rejection of a large electrical load. The system has the capacity to pass 25 percent of turbine design steam flow.

1.6.1.4.3 Main Condenser

The main condenser is of the single pass, divided water box, deaerating type. It consists of two shells, one for each low pressure turbine cylinder. Each half capacity condenser has two feedwater heaters located in its neck. The hotwells of each condenser are designed to provide a minimum condensate retention time of 2 min, permitting decay of short lived radioactive isotopes. Deaeration is provided in the condensers for removal of dissolved gases from the condensate.

1.6.1.4.4 Main Condenser Air Ejector and Turbine Steam Sealing Systems

One twin element (100 percent spare capacity) two stage steam jet air ejector complete with inter and after condensers are provided for evacuating gases from the turbine and main condenser. One mechanical vacuum pump is provided to remove gases from the main condenser during startup and shutdown when steam is not available for the air ejectors.

The Turbine Sealing System provides steam to the seals on the turbine valve glands and the turbine shaft glands at a pressure slightly above atmospheric. This system collects and condenses sealing steam and discharges air leakage through the Gland Seal Holdup System to the main stack. The Holdup System serves mainly to allow short half life radioactive gases to decay before discharge to the main stack.

1.6.1.4.5 Circulating Water System

Two vertical, removable element circulating water pumps located in the intake structure will provide a continuous supply of condenser cooling water. The water is pumped from and returned to Cape Cod Bay. Trash racks, and traveling water screens will protect the circulating water pump from debris. The screens are kept clean by a screen wash system.

1.6.1.4.6 Condensate Demineralizer System

The Condensate Demineralizer System consists of seven parallel circuit purifying vessels to maintain reactor feedwater of required purity. Ionic and particulate materials from the reactor, main steam line, turbine, main condenser, etc., are removed from the condensate in this system.

1.6.1.4.7 Condensate and Reactor Feedwater Systems

The Condensate and Reactor Feedwater System will take condensate from the main condenser and after five stages of heating deliver it to the reactor.

Condensate will be pumped by three, motor driven, vertical pumps through the steam jet air ejector inter and after condensers, and the gland seal condenser. After leaving the gland seal condenser, it will pass through the condensate deep bed demineralizers. The purified flow will then combine into two parallel streams, each with three stages of low pressure feedwater heating. Feedwater will then be boosted in pressure by the reactor feed pumps. There will be no regulating valves in the piping between the condensate pumps and the reactor feed pumps. The flow from the three centrifugal, motor driven reactor feedwater pumps will be combined into two parallel streams, each with two stages of high pressure feedwater heating. The feedwater will then flow to the reactor. Control valves will be located in the piping between the high pressure feedwater heaters and the reactor for regulation of feedwater flow.

1.6.1.5 Electrical Power System

The station main generator feeds electrical power at 24 kV via an isolated phase bus into the main transformer which steps the voltage up to 345 kV. A 345 kV power connection is made between the main transformer and the 345 kV switchyard ring bus. The 345 kV switchyard ring bus is connected to the startup transformer. Power from the station is transmitted to the Boston Edison System at 345 kV through transmission lines which are interconnected with the major power systems in the New England area.

Station auxiliary power during startup will be from the startup transformer connected to the 345 kV switchyard ring bus. In addition, power for station emergency shutdown will be from two standby diesel generators or from the shutdown transformer fed from a 24 kV line which is connected to the New England grid by an independent 115 kV line. In the unlikely event these shutdown power sources are unavailable, a non-safety related, Blackout AC Power Source is provided to supply power to the 4.16kV emergency service buses.

1.6.1.6 Radioactive Waste Systems

The Radioactive Waste Systems are designed to control the release of station produced radioactive material to within the limits specified in 10CFR20, and to meet the design objectives of 10CFR50, Appendix I. This is done by various methods such as collection, drumming, filtration, holdup for decay, and dilution. The methods employed for the controlled release of these contaminants are dependent primarily upon the state of the material: liquid, solid, or gaseous.

1.6.1.6.1 Liquid Radwaste System

The Liquid Radioactive Waste Control System collects, treats, stores, and disposes of all radioactive liquid wastes. These wastes are collected in sumps at various locations throughout the station and then transferred to the appropriate collection tanks in the Radwaste Building for treatment, storage, dilution, and disposal as necessary. Wastes are processed on a batch basis. Processed liquid wastes may be returned to the Condensate System or discharged to the environs through the circulating water discharge canal. The liquid wastes in the discharge canal are diluted with condenser effluent circulating water to achieve a permissible concentration at the site boundary.

Equipment is selected, arranged, and shielded to permit operation, inspection, and maintenance with minimum personnel exposure. For example, tanks and processing equipment which are expected to contain significant radiation sources are located behind shielding. Similarly, sumps, pumps, instruments, and valves are located in controlled access rooms or shielded spaces. Processing equipment is designed to require a minimum of maintenance.

Protection against accidental discharge of liquid radioactive waste is provided by radiation monitoring and procedural controls.

1.6.1.6.2 Solid Radwaste System

With the Solid Radwaste System, solid radioactive wastes are collected, processed, and packaged for storage, shipment, and offsite disposal. Process solid wastes are collected, dewatered, and containerized for offsite shipment. Examples of these solid wastes are filter residue, spent resins, paper, air filter elements and non-reusable contaminated clothing. Solid wastes from equipment originating in the nuclear system are stored for radioactive decay in the fuel storage pool and prepared for offsite shipment in approved shipping containers.

1.6.1.6.3 Gaseous Radwaste System

The Gaseous Radwaste System collects, processes, and delivers to the main stack, for elevated release to the atmosphere, gases from the main condenser air ejector, startup vacuum pump, and gland seal condenser.

Non-condensible 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 N-13 is present in small amounts which are further reduced by decay. The air ejector offgas also contains the radioactive noble gas parents of biologically significant Sr-89, Sr-90, Ba-140, and Cs-137. The concentration of these noble gases depends upon the amount of tramp urainum 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 condensibles to reduce the volume, the remaining non-condensibles (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 HEPA filters and on the charcoal. 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 entering and leaving the Offgas Treatment System is continuously monitored. This system results in a reduction of the offgas activity (curies) released by a factor of approximately 185 relative to a 30 min holdup system.

Holdup in this system provides ample time to prevent release of fission product gases in excess of the permissible main stack release rate limits. When concentrations which would cause the stack release rate limits to be exceeded are detected, the holdup line is automatically isolated after a 15 min delay, unless corrective action has been taken to obviate station shutdown.

The system is designed to accommodate the possible explosive hazard due to the hydrogen and oxygen present from the radiolytic decomposition of reactor coolant.

The gland seal condenser is exhausted by a blower into shielded piping which provides 1.75 min holdup to reduce the activity of short lived radioactive gases (N-16 and O-19) which are then discharged to the main stack.

1.6.2 Nuclear Safety Systems and Engineered Safeguards

1.6.2.1 Reactor Protection System

The Reactor Protection System (RPS) initiates a rapid, automatic shutdown (scram) of the reactor. This action is taken in time to

prevent fuel cladding damage and any nuclear system process barrier damage following abnormal operational transients. The RPS overrides all operator actions and process controls.

1.6.2.2 Neutron Monitoring System

Although not all of the Neutron Monitoring System qualifies as a nuclear safety system, those portions that provide high neutron flux signals to the RPS do. The intermediate range monitors (IRM) and average power range monitors (APRM), which monitor neutron flux via incore detectors, signal the RPS to scram in time to prevent excessive fuel cladding damage as a result of overpower transients.

1.6.2.3 Control Rod Drive System

When a scram is initiated by the RPS it is the Control Rod Drive System that inserts the negative reactivity necessary to shut down the reactor. Each control rod is controlled individually by a hydraulic control unit. When a scram signal is received, high pressure water from an accumulator for each rod inserts each control rod rapidly into the core.

1.6.2.4 Nuclear System Pressure Relief System

A Pressure Relief System consisting of relief and safety valves mounted on the main steam lines is provided to prevent excessive pressure inside the nuclear system following either abnormal operational transients or accidents.

1.6.2.5 Reactor Core Isolation Cooling System

The Reactor Core Isolation Cooling System (RCICS) provides makeup water to the reactor vessel whenever the vessel is isolated. The RCICS uses a steam driven turbine-pump unit and operates automatically in time and with sufficient coolant flow to maintain adequate reactor vessel water level.

1.6.2.6 Primary Containment

The design employs a pressure suppression primary containment inerted with nitrogen during normal operation which houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the Reactor Primary System. The Primary Containment System consists of a drywell, a pressure suppression chamber which stores a large volume of water, a connecting vent system between the drywell and the water pool, Venting and Vacuum Relief System, isolation valves, Containment Cooling Systems, and other service equipment. In the event of a Process System piping failure within the drywell, reactor water and steam would be released into the drywell air space. The resulting increased drywell pressure would then force a mixture of nitrogen, steam, and water through the vent system into the pool of water which is stored in the suppression chamber. The steam would condense in the suppression pool, resulting in a rapid pressure reduction in the drywell. Nitrogen which was transferred to the suppression chamber pressurizes the suppression chamber, and is subsequently vented to

the drywell to equalize the pressure between the two vessels. Cooling systems are provided to remove heat from the reactor core, the drywell, and from the water in the suppression chamber and thus provide continuous cooling of the primary containment under accident conditions. Appropriate isolation valves are actuated during this period to ensure containment of radioactive materials within the primary containment which otherwise might be released from the reactor during the course of the accident.

1.6.2.7 Primary Containment and Reactor Vessel Isolation Control System

The Primary Containment and Reactor Vessel Isolation Control System automatically initiates closure of isolation valves to close off all potential leakage paths for radioactive material to the environs. This action is taken upon indication of a potential breach in the nuclear system process barrier.

1.6.2.8 Secondary Containment

The design employs a low inleakage, elevated release point secondary containment system which houses the Primary Containment System, refueling facilities, and most of the components of the Nuclear Steam Supply System. The Secondary Containment System provides secondary containment when the Primary Containment System is closed and in service, and it provides primary containment when the Primary Containment System is open, as in refueling. The Secondary Containment System consists of the Reactor Building, Standby Gas Treatment System, Reactor Building Isolation Control System, and main stack.

In the event of a postulated pipe break inside the drywell or a fuel handling accident, the Reactor Building is isolated by the Reactor Building Isolation Control System to provide a low leakage barrier. The Standby Gas Treatment System is initiated by the same conditions that isolate the Reactor Building. The Standby Gas Treatment System exhausts air from the Reactor Building to maintain a reduced pressure within the Reactor Building relative to the outside atmosphere, treats the air to remove particulates and iodines, and releases the air through the elevated release point, the main stack.

1.6.2.9 Main Steam Line Isolation Valves

Although all pipelines which both penetrate the primary containment and offer a potential release path for radioactive material are provided with redundant isolation capabilities, the main steam lines, because of their large size and large mass flow rates, are given special isolation consideration. Two automatic isolation valves, each powered by both air pressure and spring force, are provided in each main steam line. These valves fulfill the following objectives:

1. Prevent excessive damage to the fuel barrier by limiting the loss of reactor coolant from the reactor vessel resulting from either a major leak from the steam piping outside the primary containment, or a malfunction of the

pressure control system resulting in excessive steam flow from the reactor vessel

2. Limit the release of radioactive materials by closing the primary containment barrier in case of a major leak from the nuclear system inside the primary containment

1.6.2.10 Main Steam Line Flow Restrictors

A venturi type flow restrictor is installed in each steam line close to the reactor vessel. These devices limit the loss of coolant from the reactor vessel before the main steam line isolation valves are closed in case of a main steam line break outside the primary containment and prevent uncovering of the core.

1.6.2.11 Core Standby Cooling Systems

A number of Standby Cooling Systems are provided to prevent fuel clad melting in the event of a breach in the nuclear system process barrier, that results in a loss of reactor coolant.

The four core standby cooling systems are:

High Pressure Coolant Injection System (HPCI)

Automatic Depressurization System

Core Spray System

Low Pressure Coolant Injection (LPCI) (an operating mode of the RHR)

The core standby cooling system's initiation and control instrumentation is divided in two parts, the incident detection circuitry (IDC) and the control instrumentation. The IDC includes those channels which detect a need for core cooling systems operation and the corresponding trip systems which initiate the proper core standby cooling system response.

1. High Pressure Coolant Injection System

   The HPCI provides and maintains an adequate coolant inventory inside the reactor vessel to prevent fuel clad melting as a result of postulated small breaks in the nuclear system process barrier. A high pressure system is needed for such breaks because the reactor vessel depressurizes slowly, preventing low pressure systems from injecting coolant. The HPCI includes a turbine pump powered by reactor steam. The system is designed to accomplish its function on a short term basis without reliance on station auxiliary power supplies other than the dc power supply.

2. Automatic Depressurization System

The automatic depressurization system acts to rapidly reduce reactor vessel pressure during postulated accident situations in which the HPCI fails to automatically maintain reactor vessel water level. The depressurization provided by the system enables the low pressure standby cooling systems to deliver cooling water to the reactor vessel. The automatic depressurization system uses some of the relief valves which are part of the nuclear system pressure relief system. The automatic relief valves are arranged to open upon conditions indicating both that a break in the nuclear system process barrier has occurred, and that the HPCI is not delivering sufficient cooling water to the reactor vessel to maintain the water level above a pre-selected value. The automatic depressurization system will not be activated unless either the core spray or LPCI cooling is available.

3. Core Spray System

The core spray system consists of two independent pump loops that deliver cooling water to spray spargers over the core. The system is actuated by conditions indicating that a breach exists in the nuclear system process barrier, but water is delivered to the core only after reactor vessel pressure is reduced. This system provides the capability to cool the fuel by spraying water onto the core.

4. Low Pressure Coolant Injection

LPCI is an operating mode of the RHR but is discussed here because the LPCI mode acts as an engineered safeguard in conjunction with the other standby cooling systems. LPCI uses the pump loops of the RHR to inject cooling water at low pressure into an undamaged reactor recirculation loop. LPCI is actuated by conditions indicating a breach in the nuclear system process barrier, but water is delivered to the core only after reactor vessel pressure is reduced. LPCI operation, together with the core shroud and jet pump arrangement, provides the capability of core reflooding following a LOCA in time to prevent fuel clad melting.

1.6.2.12 Residual Heat Removal System (Containment Spray, Suppression Pool Cooling, LPCI with Heat Rejection)

The suppression pool (torus) cooling subsystem is placed in operation to limit the temperature of the water in the suppression pool following a design basis LOCA. In the suppression pool cooling mode of operation the RHR main system pumps take suction from the suppression pool, and pump the water through the RHR heat exchangers where cooling takes place by transferring heat to the station

cooling systems. The fluid is then discharged back to the suppression pool.

Long-term core and suppression pool cooling can be performed by use of the LPCI with Heat Rejection mode for liquid breaks inside primary containment of sufficient size to support continuous recirculation as described below including the design basis LOCA. In the LPCI with Heat Rejection Mode, the RHR pumps take suction from the suppression pool, and pump the water through the RHR heat exchanger where cooling takes place by transferring heat to the station cooling water systems. The fluid is then discharged back to the reactor vessel where sensible and decay heat is absorbed. The fluid returns to the suppression pool by flowing out the pipe break, into the drywell, and back to the suppression pool through the drywell to wetwell vent system. This method of cooling sets up a recirculation loop including the suppression pool, RHR heat exchanger, and reactor vessel.

Another portion of the RHR is provided to spray water into the containment as an augmented means of removing energy from the containment following a LOCA. This capability is in excess of the required energy removal capability for a design basis LOCA and can be placed into service at the discretion of the operator.

1.6.2.13 Control Rod Velocity Limiter

A control rod velocity limiter is attached to each control rod to limit the velocity at which a control rod can fall out of the core should it become detached from its control rod drive. The rate of reactivity insertion resulting from a rod drop accident is limited by this action. The limiters contain no moving parts.

1.6.2.14 Control Rod Drive Housing Supports

Control rod drive housing supports are located underneath the reactor vessel near the control rod housings. The supports limit the travel of a control rod in the event that a control rod housing is ruptured.

The supports prevent a nuclear excursion as a result of a housing failure, thus protecting the fuel barrier.

1.6.2.15 Standby AC Power Supply

The Standby AC Power Supply System consists of two diesel generators capable of providing electrical power that is self-contained within the station and is independent of normal sources of supply. Each of the diesel generators is of sufficient capacity to carry the essential loads of their respective buses.

1.6.2.16 DC Power Supply

The Station Battery System, consisting of three batteries, each with its own charger is sized to supply emergency DC power for a time period adequate to safeguard the station. The three batteries, two 125V DC for control, one 250V DC for power are each connected to

their associated DC power distribution buses to supply uninterrupted power to vital loads.

1.6.2.17 Salt Water Service System

The Salt Water Service System supplies coolant to the secondary sides of the heat exchangers of the Reactor Building and Turbine Building Closed Cooling Water Systems to remove heat produced during normal operation, shutdown, and accident conditions. Cooling water is taken at the intake structure by the five service water pumps and discharged with the condenser circulating water.

1.6.2.18 Reactor Building Closed Cooling Water System

The Reactor Building Closed Cooling Water System is provided to supply self-contained coolant to the Reactor Auxiliary Systems equipment (potentially radioactive) and accessories, and to the RHRS to remove heat during normal operation, shutdown, and accident conditions. The system consists of two independent loops, each with three pumps, one heat exchanger, and associated piping and valves. The loops are cross tied to permit operation with various combinations of equipment.

1.6.2.19 Main Steam Line Radiation Monitoring System

The Main Steam Line Radiation Monitoring System consists of gamma radiation monitors located external to the main steam lines just outside of the primary containment. The monitors are designed to detect a gross release of fission products from the fuel.

1.6.2.20 Refueling Ventilation Exhaust Radiation Monitoring System

The Refueling Ventilation Exhaust Monitoring System consists of a number of radiation monitors arranged to monitor the activity level of the ventilation exhaust from the refueling area of the Reactor Building. The monitors are designed to detect gross release of fission products from the spent fuel stored and handled in the refueling area. Upon detection of high radiation, the trip signals generated by the monitors are used to isolate the Reactor Building and to actuate the Standby Gas Treatment System.

1.6.2.21 Main Control Room Environmental Control System

The Main Control Room Environmental Control System consists of two fans and filter trains to supply filtered air to the main control room upon detection of high radiation in the normal ventilation air.

1.6.2.22 Equipment Area Cooling System

The Equipment Area Cooling System consists of a number of fan cooling units provided to remove heat from the pump room compartments in the Reactor Building that house Core Standby Cooling Systems.

1.6.3 Special Safety Systems

1.6.3.1 Standby Liquid Control System

Although not intended to provide prompt reactor shutdown, the Standby Liquid Control System provides a redundant, independent, and different way from the control rods to bring the nuclear fission reaction to subcriticality, and to maintain subcriticality as the reactor cools. The system makes possible an orderly and safe shutdown in the event that not enough control rods can be inserted into the reactor core to accomplish shutdown in the normal manner. The system is sized to counteract the positive reactivity effect from full power to the cold shutdown condition.

1.6.3.2 Station Equipment Outside the Control Room

Sufficient equipment and controls are available outside the control room to enable an operator to shut down the reactor and maintain it in a safe condition if access to the control room is lost.

1.6.3.3 Recirculation Pump Trip System

In accordance with NUREG 0460, independent and diverse means are provided to introduce negative reactivity to the reactor core in the event of failure of the reactor to scram from power. The Recirculating Pump Trip (RPT) System is discussed in Section 3.9.

1.6.4 Process Control and Instrumentation

1.6.4.1 Nuclear System Process Control Instrumentation

1.6.4.1.1 Reactor Manual Control System

The Reactor Manual Control System provides the means by which control rods are manipulated from the control room for gross power control.

The system controls valves in the Control Rod Drive Hydraulic System. Only one control rod can be manipulated at a time. The Reactor Manual Control system includes the controls that restrict control rod movement (rod block) under certain conditions as a backup to procedural controls.

1.6.4.1.2 Recirculation Flow Control System

The Recirculation Flow Control System controls the speed of the reactor recirculation pumps. Adjusting the pump speed changes the coolant flow rate through the core. This effects changes in core power level.

1.6.4.1.3 Neutron Monitoring System

The Neutron Monitoring System is a system of incore neutron detectors and out of core electronic monitoring equipment. The system provides indication of neutron flux, which can be correlated to thermal power level, for the entire range of flux conditions that

may exist in the core. The source range monitors (SRM) and the intermediate range monitors (IRM) provide flux level indications during reactor startup and low power operation. The local power range monitors (LPRM) and average power range monitors (APRM) allow assessment of local and overall flux conditions during power range operation. Rod block monitors (RBM) are provided to prevent rod withdrawal when reactor power should not be increased at the existing reactor coolant flow rate. The Traversing Incore Probe System (TIPS) provides a means to calibrate the individual neutron monitoring sensors.

1.6.4.1.4 Refueling Interlocks

A system of interlocks that restricts the movements of refueling equipment and control rods when the reactor is in the refuel mode is provided to prevent an inadvertent criticality during refueling operations. The interlocks back up procedural controls that have the same objective. The interlocks affect the refueling platform, the refueling platform hoists, the fuel grapple, control rods, and the service platform hoist.

1.6.4.1.5 Reactor Vessel Instrumentation

In addition to instrumentation provided for the nuclear safety systems and engineered safeguards, instrumentation is provided to monitor and transmit information that can be used to assess conditions existing inside the reactor vessel and the physical condition of the vessel itself. The instrumentation provided monitors reactor vessel pressure, water level, surface temperature, internal differential pressures and coolant flow rates, and top head flange leakage.

1.6.4.1.6 Process Computer System

An online process computer is provided to monitor and log process variables, and to make certain analytical computations. The rod worth minimizer function of the computer prevents rod withdrawal under low power conditions if the rod to be withdrawn is not in accordance with a preplanned pattern. The effect of the rod block is to limit the reactivity worth of the control rods by enforcing adherence to the preplanned rod pattern.

1.6.4.2 Power Conversion Systems Process Control and Instrumentation

1.6.4.2.1 Pressure Regulator and Turbine Control

The pressure regulator controls both the turbine admission (control) valves and the turbine bypass valves and maintains constant reactor pressure. Pressure regulation is coordinated with the turbine speed and Load Control Systems. The turbine control utilizes a mechanical Hydraulic Control System arranged for remote operation.

1.6.4.2.2 Feedwater System Control

A three element controller is used to regulate the feedwater system so that proper water level is maintained in the reactor vessel. The controller uses main steam flow rate, reactor vessel water level, and feedwater flow rate signals. The feedwater control signal is used to regulate the feedwater valves to adjust flow.

1.6.4.3 Electrical Power System Process Control

High speed protective relaying is provided on the generator, station buses, and lines to isolate and disconnect faulted equipment in event of a failure and maintain system integrity. Relay types employed are impedance, ground differential, voltage, overcurrent, overexcitation, and negative sequence. Generator voltage, load frequency, metering, and telemetering systems are also used.

1.6.4.4 Radiation Monitoring and Control

1.6.4.4.1 Process Radiation Monitoring

Radiation monitors are provided on various lines to monitor either for radioactive materials released to the environs via process liquids and gases or for process system malfunctions. The following monitors are provided:

Main Steam Lines
Air Ejector Offgas
Main Stack
Reactor Building Exhaust Vent
Drywell Airborne Activity
Standby Gas Treatment Exhaust
Drywell Atmosphere High Range
Control Room Ventilation Intake
Torus Atmosphere High Range
Main Stack High Range
Refueling Floor Exhaust
Reactor Building Exhaust Vent High Range
Turbine Building Roof Vent Exhaust High Range
Radwaste Liquid Discharge
RBCCW

1.6.4.4.2 Area Radiation Monitors

A number of radiation monitors are provided to monitor for abnormal radiation at various locations in the Reactor Building, Turbine Building, Radwaste Building, and main control room. These monitors annunciate alarms when abnormal radiation levels are detected.

1.6.4.4.3 Liquid Radwaste System Control

The Liquid Radwaste System collects, treats, and stores liquid radioactive wastes on a batch basis with protection against accidental discharge provided by the design, supplemented by procedural controls. Liquid wastes are discharged on a batch basis at a controlled rate after sampling and laboratory analysis.

Instrumentation with alarms to detect abnormal radioactivity concentration in the liquid radwaste discharges is provided.

1.6.4.4.4 Solid Radwaste Control

The Solid Radwaste System collects, treats, and packages solid radioactive wastes for offsite shipment. Wastes are handled on a batch basis. Radiation levels of the various batches are determined by the operator.

1.6.4.4.5 Gaseous Radwaste System Control

The Gaseous Radwaste System is continuously monitored by the main stack radiation monitor. A high level signal from the Air Ejector Offgas Radiation Monitoring System will automatically isolate the Offgas System by closing a valve between the Air Ejector System and the stack. A main steam line high radiation condition will automatically close a valve on the mechanical vacuum pump discharge line and trip the pump. A shutoff valve between the main condenser and air ejector is closed upon high temperature or pressure signals in the offgas line.

1.6.5 Auxiliary Systems

1.6.5.1 Auxiliary AC Power

Normal auxiliary power is supplied from the main generator to the auxiliary buses via the unit auxiliary transformer. The startup transformer can also supply auxiliary power during operation. Either the unit auxiliary transformer or startup transformer can be connected to all auxiliary buses in the plant. Also, the shutdown transformer is available as an independent offsite power source to provide power to the emergency buses. Each offsite source has capacity for operation of all systems required to shut down the station and maintain it in a safe condition.

1.6.5.2 Turbine Building Closed Cooling Water System

The Turbine Building Closed Cooling Water System supplies self-contained coolant to equipment located in the Turbine and Auxiliary Building to remove heat produced during station operation.

1.6.5.3 Fire Protection System

The Fire Protection System consisting of fire pumping equipment and an underground water loop provides an adequate supply of water throughout the station. Carbon dioxide and chemical fire fighting equipment is also provided for selected areas.

1.6.5.4 Heating, Ventilation, and Air Conditioning Systems

The Station Heating, Ventilating, and Air Conditioning Systems provide appropriate ambient temperature environmental conditions for station operating personnel and equipment. Normal air flow is routed from nonradioactive areas to areas of progressively greater contamination potential prior to final exhaust.

1.6.5.5 New and Spent Fuel Storage

New fuel is stored in a dry storage vault located adjacent to the spent fuel pool area in the Reactor Building. Transport of spent fuel and irradiated channels during refueling is handled underwater. Spent fuel is stored underwater in the spent fuel pool in the Reactor Building and in dry storage casks at the Independent Spent Fuel Storage Installation until prepared for shipment from the site.

1.6.5.6 Fuel Pool Cooling and Filtering System

The Spent Fuel Pool Cooling and Demineralizer System is provided to clean the pool water and remove decay heat from the spent fuel stored in the spent fuel storage pool.

1.6.5.7 Service and Instrument Air Systems

Three non-lubricated, reciprocating, double acting compressors (in long term layup) and the two non-lubricated, screw, compound compressors supply the station with oil free air for instrument air, and high pressure service air. The compressors each take a suction from El 23 ft lower switch gear room through a dry type filter, and discharge through an after cooler with an integral moisture separator to an air receiver.

1.6.5.8 Makeup Water Treatment System

The Makeup Water System is provided to maintain a supply of treated water suitable as makeup for the station. Water from the Town of Plymouth water system is processed through a demineralization system and stored in an onsite storage tank.

1.6.5.9 Potable and Sanitary Water Systems

Water for drinking and sanitary use is supplied from the Town of Plymouth Water System. Shower and lavatory waste water that does not contain radioactive material is directed to sewage disposal facilities.

1.6.5.10 Equipment and Floor Drainage Systems

Station Equipment and Floor Drainage Systems will handle radioactive and nonradioactive drains. Drainage which may contain potentially radioactive materials is pumped to the Radwaste System for determination of radioactivity followed by cleanup, decay, or discharge directly to the condenser circulating water discharge. Nonradioactive drains will be disposed of through storm sewers.

1.6.5.11 Process Sampling System

The station Process Sampling System is provided to monitor the quality of station process flows. Information required for making operational decisions is obtained from analysis of samples from pertinent system streams.

1.6.5.12 Station Communication Systems

Separate external and internal communication systems are provided. The external system provides typical telephone communications. The internal system consists of several party channels and a central paging channel providing effective operational communication between various locations at the station site.

1.6.5.13 Technical Support Center (TSC)

In conformance with NUREG-0737, Supplement 1, Section 8.2, a closed circuit television (CCTV) camera is located in the main control room to record and transmit the following types of information to the TSC:

1. panel meter readings
2. annunciator window displays
3. plant computer video data
4. trend recorder readings

In addition, the following equipment is provided to further enhance the access ability of information at the TSC:

1. A functional duplicate of the plant computer input/output printer is installed at the TSC to allow access to the computer data.

2. Independent reliable voice communication is provided between the TSC and the main control room.

Refer to the Emergency Plan (Appendix N) for further information concerning the use of this facility.

1.6.6 Shielding

Shielding implemented by occupancy requirements in the various areas of the station is provided to meet the limits of applicable regulations. Access limits are given on Table 1.5-1.

1.6.7 Implementation of Loading Criteria

Structures and equipment are designed to resist structural and mechanical damage due to loads produced by environmental thermal forces. For the purpose of categorizing mechanical strength designs for these loads, the following definitions are established:

a. Class I

   This class includes those structures, equipment, and components whose failure or malfunction might cause or increase 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

b. 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.

1.6.8 Independent Spent Fuel Storage Installation

The PNPS site contains an Independent Spent Fuel Storage Installation inside the plant protected area as shown on Figure 1.6-1. The ISFSI consists of a concrete pad with space for 40 natural convection air-cooled, HI-STORM shielded dry spent fuel storage casks, each capable of storing 68 spent nuclear fuel assemblies in a welded multi-purpose container.

Figure 1.6-1 has been removed.

Please refer to BECo Controlled Drawing C2

Figure 1.6-2 has been deleted

See Figure 1.6-1

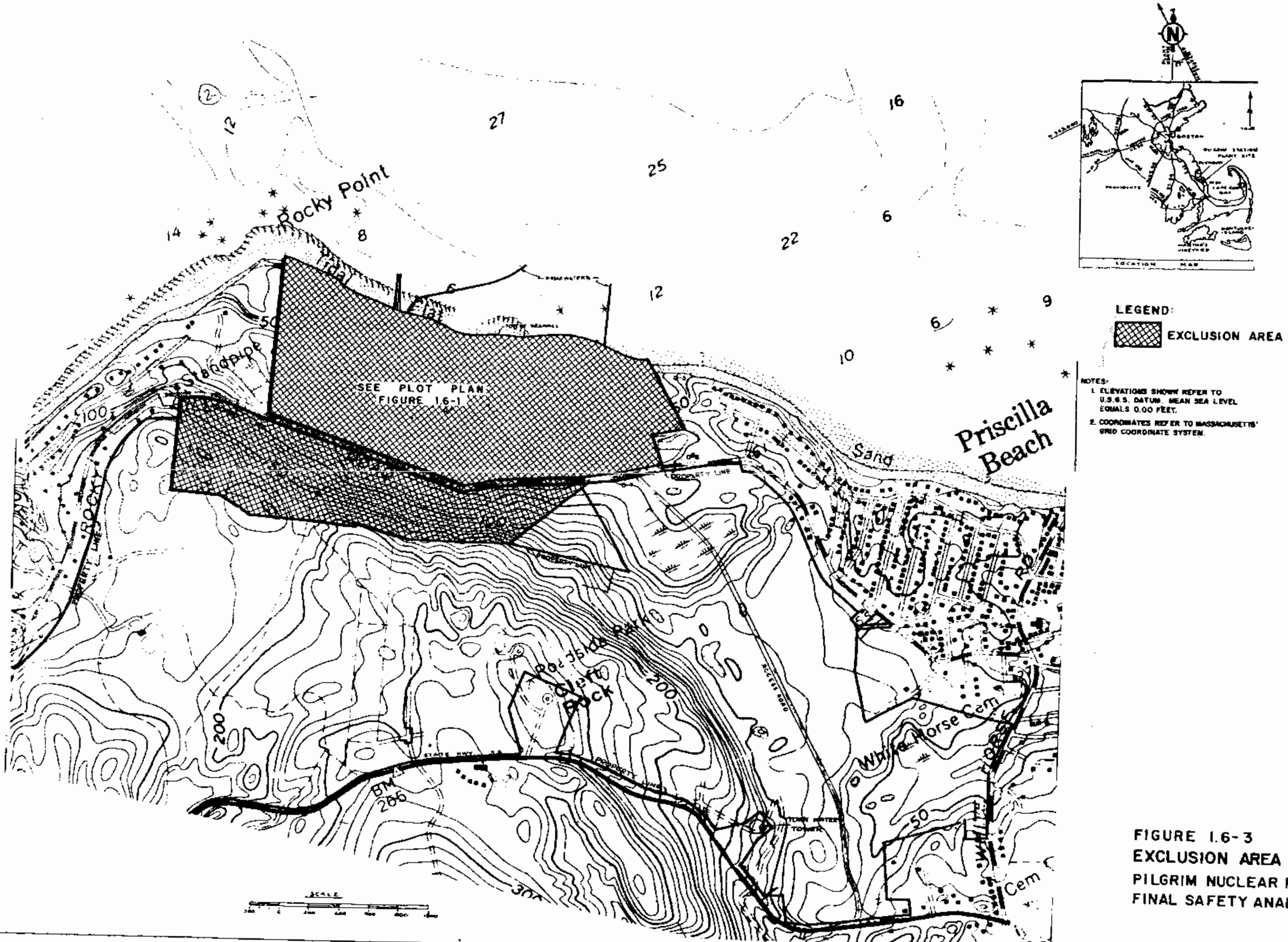
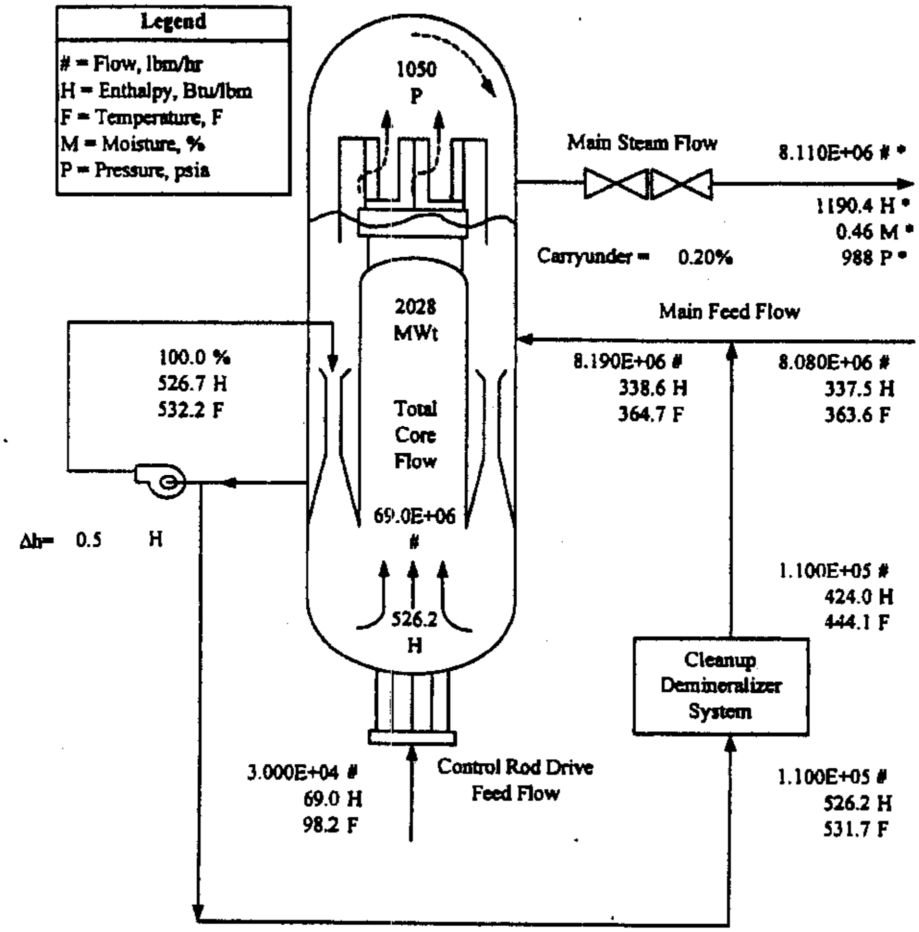


FIGURE 1.6-3
EXCLUSION AREA
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISED 2-10-86



* Conditions at upstream side of TSV

Core Thermal Power	2028.0
Pump Heating	5.5
Cleanup Losses	-3.3
Other System Losses	-0.6
Turbine Cycle Use	2029.6 MWt

Reactor Heat Balance Diagram

RHB.015.96MSE.xls

FIGURE 1.6-4
REACTOR HEAT
BALANCE
DESIGN POWER
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

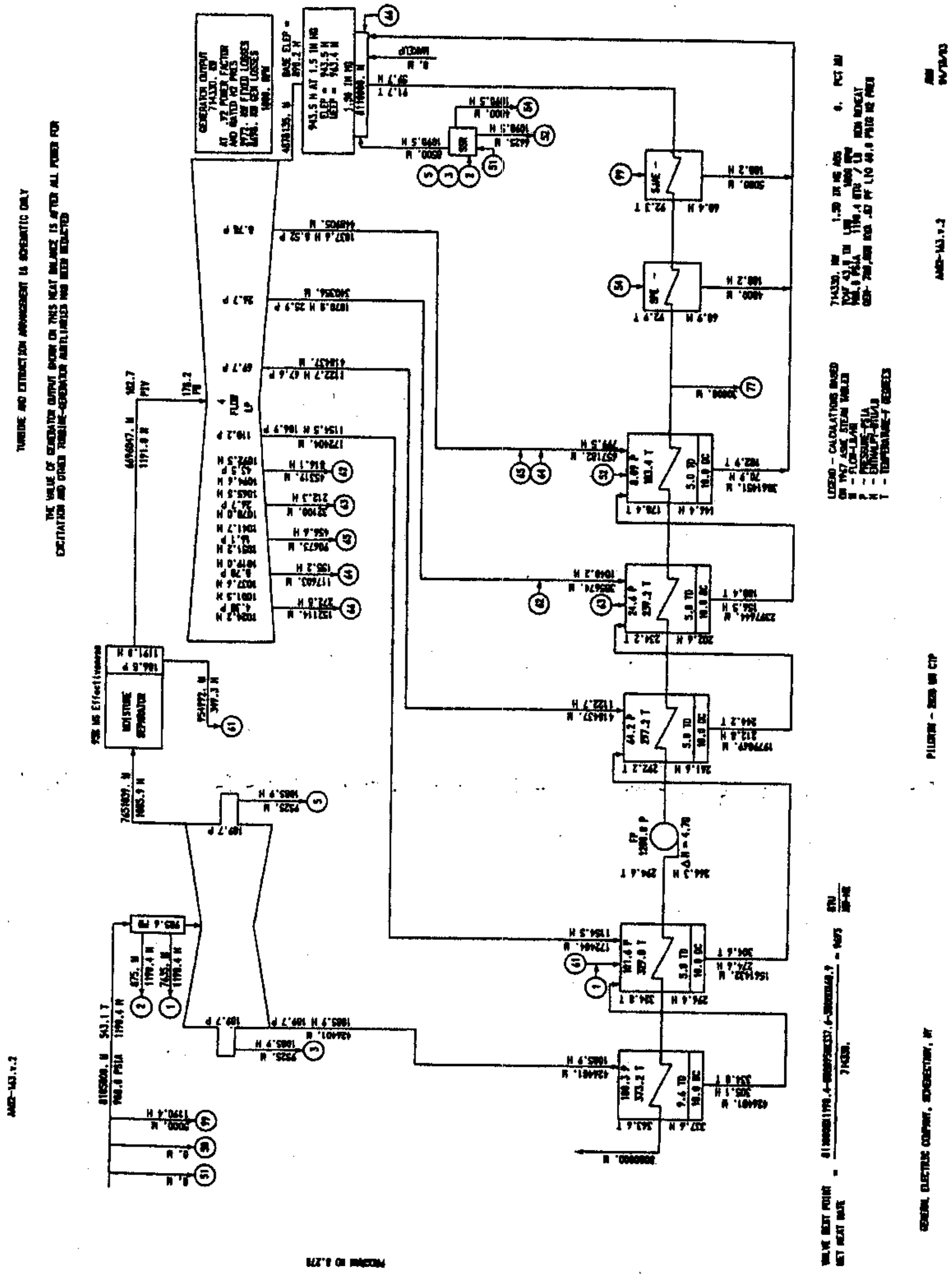


FIGURE 1.6-5
TURBINE-GENERATOR
HEAT BALANCE, DESIGN POWER
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

1.7 COMPARISON OF PRINCIPAL DESIGN CHARACTERISTICS

This section provided the principal design features of the station and provided a comparison of the major features with other boiling water reactor facilities at the time of the application for the Operating License.

This section summarized the design and operating characteristics for the nuclear, electrical power, structural, and containment systems of the Pilgrim Nuclear Power Station. Similar characteristics were presented for Dresden II, Monticello, and Millstone I.

The characteristics presented in these tables were accurate at the time of the operating licensing application for Pilgrim for the initial Core. The tables contain information which is of historical interest only and have been deleted. For copies of these tables, please refer to the Pilgrim Nuclear Station - Final Safety Analysis Report, Amendment 30 dated June 18, 1971.

1.8 SUMMARY OF RADIATION EFFECTS

1.8.1 Planned Operations

The gaseous and liquid radioactive waste systems are designed so that dose to any offsite person will not exceed that permitted by 10CFR20 and the system will meet the design objectives of 10CFR50, Appendix I.

1.8.2 Abnormal Operational Transients

A design objective is to avoid fuel damage as a result of abnormal operational transients. Analyses of these events, which are described in the "Station Safety Analysis," show that abnormal operational transients do not result in any significant increase of radioactive material release to the environs over that experienced during planned operation.

1.8.3 Accidents

The ability of the station to withstand the consequences of accidents without posing a hazard to the health and safety of the public is evaluated by analyzing a variety of postulated accidents. The calculated consequences of the design basis accidents, which result in the greatest potential offsite radiation exposures, are summarized on Table 1.8-1. These doses are substantially below the guideline doses given in 10CFR100.

TABLE 1.8-1

SUMMARY OF MAXIMUM OFFSITE EFFECTS
OF DESIGN BASIS ACCIDENTS

Design Basis Accident	Maximum Offsite Exposure (Rems) Whole Body	Thyroid
Control Rod Drop Accident	5.0×10^{-2}	24.4
Loss of Coolant Accident	2.9	98
Refueling	2.0×10^{-1}	1.2
Main Steam Line Break Accident	1.0×10^{-1}	76

1.9 STATION MANAGEMENT

1.9.1 Organization Structure

The Pilgrim Nuclear Power Station is owned and operated by Entergy.

The station is under the direction of the Site Vice President who has the authority and responsibility for the safe operation of the station.

More detail is contained in Section 13.

1.9.2 Operator Training

The operating, maintenance, technical, and administrative staffs receive extensive training and instruction in academic subjects and practical operations. These instructions are given both within and outside the station to qualify the staff for their responsibilities and to enable them to obtain NRC operator and senior operator licenses. Detailed training plans are described in Section 13.3.

1.9.3 Safety Responsibilities

Entergy is responsible for the selection and training of personnel, all station operations, and the execution of written normal and emergency procedures. The General Electric Company was responsible for the design of the nuclear steam supply system and for providing technical guidance to the Applicant during initial startup.

1.9.4 Emergency Plans

All emergencies that can be anticipated are covered by detailed written procedures. The appropriate personnel are trained in these procedures. Periodic tests and reviews are conducted. An outline of the emergency procedures is presented in Section 13 and the Emergency Plan is provided in Appendix N.

1.9.5 Cooperation with Other Agencies

Procedures to handle emergencies have been developed in cooperation with such agencies as the Massachusetts Department of Public Health, Massachusetts Civil Defense Agency, U.S. Coast Guard, Massachusetts State Police, local hospital and medical personnel, officials and appropriate agencies of the Town of Plymouth, and the NRC.

1.10 QUALITY ASSURANCE PROGRAM

1.10.1 Introduction

Boston Edison Company, as original owner and operator of Pilgrim Nuclear Power Station, assumed full responsibility and authority for facility operation and has taken appropriate action to ensure the station is designed, modified, operated, and maintained in accordance with sound engineering principles and safe operating practices. The Boston Edison Company Quality Assurance Program for operation of PNPS was defined in the Boston Edison Quality Assurance Manual Volume II (BEQAM).

The ownership and operation of PNPS was transferred From Boston Edison Company to the Entergy Nuclear Generation Company (ENGC), effective July 13, 1999.

The ENGC Quality Assurance Program for operation of PNPS was defined in the Pilgrim Quality Assurance Manual (PQAM), which was the governing document for quality related activities relating to Pilgrim Station until May 5, 2002, when the NRC approved ENGC's transfer of plant operating responsibility to Entergy Nuclear Operations Inc. (ENOI). At this time the PQAM was replaced by adopting the Entergy QA Program Manual (QAPM), as the QA program description for PNPS.

The requirements in the QAPM, and its Predecessors (BEQAM and PQAM), were established to comply with the requirements of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants."

1.10.2 QA Program Objectives

The quality assurance program's objectives are to ensure compliance with regulatory requirements, company commitments, and established practices for efficient design, modification, maintenance, testing, and operation of Pilgrim Station. The program requires every person involved in quality assurance program related activities to comply with the provisions of the program.

1.10.3 QA Program Organization

The function of the Pilgrim Quality Assurance Organization established by Entergy is to monitor the quality oriented activities of all organizations involved in the design, modification, operation, and maintenance of Pilgrim Station and report the results of such monitoring activities to the appropriate levels of management.

The site quality assurance organization reports off-site to the Director, Oversight. This reporting relationship ensures the appropriate organizational freedom required by 10 CFR 50 Appendix B, Criteria I as needed for the site QA organization to effectively perform their assigned functions.

1.10.4 Quality Control and Assurance Measures

The degree to which quality control and assurance measures are assigned is a direct function of the safety and operating requirements of the various structures, systems, and components.

Essential equipment and nuclear systems are emphasized; however, nonessential and non-safety related systems and components may be included in the Quality Assurance Program to the extent necessary to assure reliability of station operation.

The quality assurance organization has developed an integrated system of planned audits, reviews, surveillances, inspections, and assessments in order to fulfill its responsibility for monitoring of QA Program implementation. The system has been designed to meet or exceed applicable regulatory, license, and national code or standard requirements. The audits, reviews, and surveillances are scheduled to provide comprehensive oversight and verification of all aspects of the QA Program and to provide management of the affected areas with continuous assessments of facility operation.

In addition to the commitments to NRC Regulatory Guides and ANSI Standards described in the Entergy QAPM, the following Regulatory Guides and associated ANSI Standards will be applied to construction related activities associated with major modifications during the operational phase that are comparable in nature and extent to related activities occurring during initial plan design and construction:

- Regulatory Guide 1.54, Rev. 0, 1973. "QA Requirements for Protective Coating Applied to Water-Cooled Nuclear Power Plants."
- Regulatory Guide 1.55, Rev. 0, 1973. "Concrete Placement in Category I Structures."
- ANSI N45.2.16, "Requirements for the Calibration and Control of Measuring and Test Equipment Used in the construction and Maintenance of Nuclear Power Generating. Stations."

UFSAR, Appendix D describes the quality assurance program for the initial design and construction phase of Pilgrim Station.

1.10.5 Quality Records and Documentation

Documentation to support quality assurance is essential to the safe operation, integrity and proper maintenance of Pilgrim Station. It is compiled and maintained throughout the life of the plant. In general, the minimum requirements for documentation for PNPS are those requirements imposed by the QAPM.

Refer to Section 13.7.5 relative to records retention.

1.10.6 Quality Program Review

Periodic, independent reviews of the QA Program policies and implementation are conducted to evaluate the continued adequacy and effectiveness of the program.

1.10.7 QA Program Update

The QA Program applied to operation and modification of Pilgrim Station is set forth in the QAPM.

1.11 STATION RESEARCH, DEVELOPMENT, AND FURTHER INFORMATION REQUIREMENTS AND RESOLUTIONS SUMMARY FOR THE INITIAL OPERATING LICENSE

The design of the General Electric boiling water reactor for this station is based upon proven technological concepts developed during the development, design, and operation of numerous similar reactors. The AEC, in reviewing the Pilgrim Station docket at the Construction Permit stage, identified several areas where further R&D efforts were required. Also both the AEC Staff and the Advisory Committee for Reactor Safeguards (ACRS) have, in their review of this and other reactor projects, identified several additional technical areas for which further detailed support information should be obtained. Appendix J provides a complete, comprehensive examination and discussion of these areas indicating the resolution. These areas are grouped in the following categories:

A. Areas Specified in the ACRS Construction Permit Letters for Pilgrim Station. Refer to Table 1.11-1

B. Areas Specified in the AEC Staff construction Permit Safety Evaluation Report for Pilgrim Station. Refer to Table 1.11-2

C. Areas Specified in Recent, Related ACRS Construction and Operating Permit Letters. Refer to Table 1.11-3

The scope of many of the areas of technology for items in A, B, and C above is discussed in detail as part of General Electric Topical Report APED-5608.

General Electric Company has submitted many Topical Reports to the AEC in support of this application and those of other GE-BWR facilities which are listed on Table 1.11-4.

These publications are technical reports which normally have generic or across the board applicability. Topical reports are used to clarify a position, substantiate a claim, respond to an ACRS concern, or make known a major accomplishment within the General Electric Company.

All topical reports referenced in the FSAR were reviewed for relevancy to the Pilgrim project as requested. With the noted exception, all publications are to remain applicable:

1. APED-5453, Vibration Analysis and Testing of Reactor Internals (April 1967)

This topical report is partly relevant because it relates to the then anticipated vibration tests on Dresden 2, a plant which incorporates the same jet pump feature as Pilgrim. A number of vibration tests have been run at other plants which are applicable to Pilgrim. Extensive tests at KRB indicated negligible vibrations of the core support, fuel channels, diffuser baffle, and steam dryer.

Where there have been significant changes in plant design, vibration tests are scheduled to assure that no new problems have been introduced for any critical component. The control rod guide tubes, for example, are vibration tested at each new plant in which the water impingement velocity is higher than that of plants which have already been tested. Guide tube tests have been run at Dresden 2, Monticello, Fukushima 1, and Peach Bottom 2.

The shroud has been vibration tested on KRB, Tarapur, and Oyster Creek, all of which are non jet pump plants. To prove the design of jet pump plants, vibration tests have been run for the jet pumps and the shroud of Millstone, Dresden 2, Fukushima 1, Monticello, and Peach Bottom 2. Cold tests have been successfully run at Dresden 2.

The steam separators have been vibration tested at Millstone 1, Dresden 2, Monticello, and Peach Bottom 2.

No vibration tests have been run for Pilgrim. Design changes from the older plants are not believed to be great enough to cause significant increases in vibration.

Vibration test results for the tests noted above have been reported in the following document:

2. APED-5458, Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors (March 1968)

With the exception of the data provided in Appendices A, B, and D of the topical report which remain valid, the topical report should not be used as a reference for the Pilgrim Station. The methods and model of analysis for evaluating the consequences of loss of coolant accidents for Pilgrim are described in topical report NEDO-10045 (Item 27 of Table 1.11-4). This description of the analytical methods is applicable to both steam and recirculation line breaks, even though the subject of this report is the steam line break. See also Section 6.5.

1.11.1 Reference

1. Bray, A.P., et al. "The General Electric Company, Analytical and Experimental Programs for Resolution of ACRS Safety Concerns," APED-5608, April 1968.

TABLE 1.11-1

PILGRIM NUCLEAR POWER STATION
ACRS CONCERNS - RESOLUTIONS

Appendix J Section No.	ACRS Concern	Pilgrim Resolutions
J.2.2	Station Wave Run-up and Water Rise Studies	Incorporated in Design, refer to Section 2.
J.2.3.1	Effects of Fuel Failure on CSCS Performance	Topical Report (NEDO-10208) Adequate Testing Complete.
J.2.3.2	Consequences of Postulated Flow Blockage Incident in a Boiling Water Reactor	Topical Report (NEDO-10174) Analysis and testing complete
J.2.3.3	Verification of Fuel Damage Limit	Topical Report (GE-APED-5608) Adequate testing complete, refer to Dresden 2/3 - Amendment 14/15.
J.2.3.4	Effects of Cladding Temperature and Materials on CSCS Performance	Topical Report (CE-APED-5608) Adequate testing complete, refer to Topical Report (NEDO-10179)
J.2.3.5	Design of Piping systems to Withstand Earthquake Forces	Incorporated in Design - Section 12 and Appendix C
J.2.3.6	Reevaluation of Main Steam Line Break Accident	Topical Report (GE-APED-5608) Topical Report (NEDO-10045) Incorporated in Design, refer to Section 14.
J.2.3.7	Control Block Rod Monitor Design	Incorporated in Design, refer to Sections 1, 7, and Appendix G.
J.2.3.8	Main Steam Line Isolation Valve Testing Under Simulated Accident Conditions	Incorporated in Design, refer to Section 4. Topical Report (GE-APED-5750) Topical Report (GE-NEDO-10045) Topical Report (GE-APED-5608)
J.2.3.9	Depressurization Performance of HPCIS	Incorporated in Design, refer to Section 6. Topical Report (GE-APED-5608) Topical Report (GE-APED-5447)
J.2.3.10	CSCS Thermal Effects on the Reactor Vessel and Internals	Topical Report (GE-NEDO-10029) Incorporated in Design, refer to Sections 3 and 4.
J.2.3.11	Effects of Blowdown Forces on Reactor Primary System Components	Incorporated in Design, refer to Sections 3, 4, and Appendix C.
J.2.3.12	Instrumentation for Prompt Detection of Gross Fuel Failures	Incorporated in Design, refer to Section 7. Brunswick 1/2 - Supplements 3 and 4.

TABLE 1.11-1 (Cont)

Appendix J Section No.	ACRS Concern	Pilgrim Resolutions
J.2.3.13	Diversification of CSCS Initiation Signals	Incorporated in Design, refer to Sections 6 and 7.
J.2.3.14	Control Systems for Emergency Power	Incorporated in Design, refer to Section 8.
J.2.3.15	Misorientation of Fuel Assemblies	Incorporated in Design, refer to Section 3.
J.2.4	AEC General Design Criteria No. 35 Design Intent and Conformance	Incorporated in Design, refer to Appendix A.
J.2.5	Fuel Clad Disintegration Limitations	Incorporated in Design, refer to Section 6 and 8. Topical Report (NEDO-10179).
J.2.6	Automatic Depressurization System - Initiation Interlock	Incorporated in Design, refer to Sections 6 and 7.
J.2.7	Applicant's Role - Quality Assurance Program	Incorporated in Design, refer to FSAR Appendix D.
J.2.8	Offsite Emergency Plans	Incorporated in Design, refer to Section 13.

TABLE 1.11-2

PILGRIM NUCLEAR POWER STATION
AEC-STAFF CONCERNS - RESOLUTIONS

Appendix J Section No.	AEC-STAFF Concern	Pilgrim Resolutions
J.3.2.2	Fuel Damage Limits	Topical Report (GE-APED-5608) Adequate testing complete, refer to Dresden 2/3 - Amendment 14/15.
J.3.2.3	Flow Channel Blockage	Topical Report (NEDO-10174) Analysis and testing complete.
J.3.2.4	Effects on Fuel Clad Failure on Emergency Core Cooling	Topical Report (GE-APED-5608) Adequate testing complete, refer to Topical Report (NEDO-10208).
J.3.2.5	Control Rod Worth Minimizer	Topical Report (GE-APED-5449) Incorporated in Design, refer to Section 7
J.3.2.6	Control Rod Velocity Limiter	Topical Report (GE-APED-5446) Incorporated in Design, refer to Section 3.
J.3.2.7	Incore Nuclear Instrumentation	Topical Report (GE-APED-5456) Topical Report (GE-APED-5706) Incorporated in Design, refer to Section 7.
J.3.2.8	Jet Pump Development	Topical Report (GE-APED-5460) Incorporated in Design, refer to Section 4.
J.3.2.9	Load Control Using Variable Speed Recirculation Pumps	Incorporated in Design, refer to Sections 7 and 14.
J.3.2.10	Core Spray Cooling Effectiveness	Incorporated in Design, refer to Section 6. Adequate testing complete, refer to Topical Report (GE-APED-5458)
J.3.2.11	BWR System Stability Analysis	Incorporated in Design, refer to Section 7. Topical Report (GE-APED-5652) Topical Report (GE-APED-5640) Peach Bottom 2/3 - Amendment 2.
J.3.2.12	Provisions for Inservice Inspection	Incorporated in Design, refer to Section 4 and Appendix K.
J.3.2.13	Analysis of Thermal Shock Effects From CSCS	Topical Report (GE-NEDO-10029) Incorporated in Design, refer to Sections 3 and 4.
J.3.2.14	HPCIS Depressurization Model (Peal Clad Temperatures)	Incorporated in Design, refer to Section 6. Topical Report (GE-APED-5608) Topical Report (GE-APED-5447)

TABLE 1.11-2 (Cont)

Appendix J Section No.	AEC-STAFF Concern	Pilgrim Resolutions
J.3.2.15	Main Steam Line Isolation Valve Operability	Incorporated in Design, refer to Section 4. Topical Report (GE-APED-5608) Topical Report (GE-APED-5750) Topical Report (GE-NEDO-10045)
J.3.2.16	Electrical Equipment Inside Containment	Incorporated in Design.
J.3.2.17	Primary System Leakage Detection	Incorporated in Design, refer to Section 4.
J.3.4.1	Criterion 35 Intent	Incorporated in Design, refer to Appendix A.
J.3.4.2	Emergency Planning	Incorporated in Design, refer to Section 13.
J.3.4.3	Meteoroligical Program	Incorporated in Design, refer to Sections 2 and 14 and Appendices E and I.
J.3.4.4	Hydrology and Oceanography Program	Incorporated in Design, refer to Section 2.
J.3.4.5	RPV-Stub Tube Design	Incorporated in Design, refer to Section 4. Topical Report (GE-APED-5703).
J.3.4.6	Flow Reference Scram Design	Incorporated in Design.
J.3.4.7	RPS-Flow/Power Instrumentation Design - (IEEE-279)	Incorporated in Design, refer to Section 7. Topical Report (NEDO-10139).
J.3.4.8	LPCIS Logic Control System Design - (IEEE-279)	Incorporated in Design, refer to Sections 6 and 7. Topical Report (NEDO-10139).
J.3.4.9	RPS-Instrumentation Test Capability During Operation	Incorporated in Design, refer to Section 7. Topical Report (NEDO-10139).
J.3.4.10	RPS and CSCS Instrumentation Cable Markings and Identification	Incorporated in Design, refer to Section 7 Pilgrim Amendment 18.
J.3.4.11	Drywell-Accident Conditions Electrical Component Testing	Incorporated in Design.
J.3.4.12	RPS and CSCS Instrumentation Design Criteria - (IEEE-279)	Incorporated in Design, refer to Sections 5, 6, 7, and Appendix G. Topical Report (NEDO-10139).

TABLE 1.11-3

PILGRIM NUCLEAR POWER STATION, ACRS CONCERNS ON OTHER RECENT, RELATED DOCKETS - PILGRIM CAPABILITY FOR RESOLUTION

Appendix J Section No.	ACRS Concern	Pilgrim Capability for Resolution
J.4.1	Scram Reliability Study	Topical Report (NEDO-10189) and Topical Report (NEDO-10349).
J.4.2	Design Basis of Engineered Safety Features	Topical Report (GE-APED-5756). Refer to Section 14.9 for study of TID-14844 capability.
J.4.3	Hydrogen Generation Study	Topical Report (GE-APED-5454) Topical Report (GE-APED-5654) Study in progress as described in Brunswick 1&2, Supplement 4. Refer to Dresden 3,Amendment 23
J.4.4	Primary Containment Inerting	Topical Report (GE-APED-5454) Topical Report (GE-APED-5654). Refer to Dresden 3, Amendment 23.
J.4.5	Seismic Design and Analysis Models	Incorporated in Design, refer to Section 12 and Appendix C.
J.4.6	Automatic Depressurization System - Single Component Failure Capability - Manual Operation	Incorporated in Design.
J.4.7	Standby Gas Treatment System Design	Incorporated in Design, refer to Sections 5 and 8.
J.4.8	Flow Reference Scram	Incorporated in Design during initial operation.
J.4.9	Development of Instrumentation - Primary Containment Leakage Detection System - Increased Sensitivity Studies	Studies in progress.
J.4.10	Development of Instrumentation - Vibration and Loose Parts Detection Studies	Refer to Section 3.3.5.2.
J.4.11	CSCS - Leakage Detection, Protection, and Isolation Capability	Incorporated in Design, refer to Sections 4, 6, and 10.
J.4.12	Main Steam Lines - Standards for Fabrication, Q/C, and Inspection	Incorporated in Design, refer to Section 4.

TABLE 1.11-4

PILGRIM NUCLEAR POWER STATION TOPICAL REPORTS
SUBMITTED TO THE AEC IN SUPPORT OF DOCKET

	GE Report No.	Title
1.	APED 5286	Design Basis for Critical Heat Flux in Boiling Water Reactors (September 1966)
2.	APED 5446	Control Rod Velocity Limiter (March 1967)
3.	APED 5449	Control Rod Worth Minimizer (March 1967)
4.	APED 5453	Vibration Analysis and Testing of Reactor Internals (April 1967)
5.	APED 5555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RDB144A (November 1967)
6.	TR67SL211	An Analysis of Turbine Missiles Resulting from Last Stage Wheel Failure (October 1967)
7.	APED 5608	General Electric Company Analytical and Experimental Program for Resolution of ACRS Safety Concerns (April 1968) (Not Class I)
8.	APED 5455	The Mechanical Effects of Reactivity Transients (January 1968)
9.	APED 5528	Nuclear Excursion Technology (August 1967)
10.	APED 5448	Analysis Method of Hypothetical Super-Prompt Critical Reactivity Transients in Large Power Reactors (April 1968)
11.	APED 5458	Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors (March 1968)
12.	APED 5640	Xenon Considerations in Design of Large Boiling Water Reactors (June 1968)
13.	APED 5454	Metal Water Reactions - Effects on Core Cooling and Containment (March 1968)
14.	APED 5460	Design and Performance of General Electric Boiling Water Reactor Jet Pumps (September 1968)
15.	APED 5654	Considerations Pertaining to Containment Inerting (August 1968)

TABLE 1.11-4 (Cont)

GE Report No.	Title
16. APED 5696	Tornado Protection for the Spent Fuel Storage Pool (November 1968)
17. APED 5706	Incore Neutron Monitoring System for General Electric Boiling Water Reactors, Rev. 1 (April 1969)
18. APED 5703	Design and Analysis of Control Rod Drive Reactor Vessel Penetrations (November 1968)
19. APED 5698	Summary of Results Obtained From a Typical Startup and Power Test Program for a General Electric Boiling Water Reactor (February 1969)
20. APED 5750	Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves (March 1969)
21. APED 5756	Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor (March 1969)
22. APED 5652	Stability and Dynamic Performance of the General Electric Boiling Water Reactor (April 1969)
23. APED 5736	Guidelines for Determining Safe Test Intervals and Repair Times for Engineered Safeguards (April 1969)
24. APED 5447	Depressurization Performance of the General Electric Boiling Water Reactor High Pressure Coolant Injection System (June 1969)
25. NEDO 10017	Field Testing Requirements for Fuel, Curtains, and Control Rods (June 1969)
26. NEDO 10029	An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident (July 1969)
27. NEDO 10045	Consequences of a Steam Line Break for a General Electric Boiling Water Reactor (July 1969)
28. NEDO 10139	Compliance of Protection Systems to Industry Criteria: GE-BWR Nuclear Steam Supply Systems (June 1970)

TABLE 1.11-4 (Cont)

GE Report No.		Title
29.	NEDO 10173	Current State of Knowledge High Performance BWR Zircaloy-Clad UO^2 Fuel (May 1970)
30.	NEDO 10174	Consequences of a Postulated Flow Blockage Incident in a Boiling Water Reactor (May 1970)
31.	NEDO 10179	Effects of Cladding Temperature and Material on ECCS Performance (June 1970)
32.	NEDO 10189	An Analysis of Functional Common Mode Failures in General Electric Boiling Water Reactor Protection Systems (September 1970)
33.	NEDO 10208	Effects of Fuel Failure on ECCS Performance (July 1970)
34.	NEDO 10320	The General Electric Pressure Suppression Containment Analytical Model (April 1971)
35.	NEDO 10329	Loss of Coolant Accident & Emergency Core Cooling Models for General Electric Boiling Water Reactors (April 1971)
36.	NEDO 10329	Loss of Coolant Accident & Emergency Core Cooling Models for General Electric Boiling Water Reactor (Supplement 1) (April 1971)
37.	NEDO 10349	Analysis of Anticipated Transients Without Scram (March 1971)

SECTION 2

STATION SITE AND ENVIRONS

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SECTION 2

STATION SITE AND ENVIRONS

2.1 INTRODUCTION

Section 2 provides information on the site and environs of the Pilgrim Nuclear Power Station, summarizes the analyses and studies which have been conducted pertinent to the site, and sets forth the conclusions which confirm the suitability of the site.

The following consultants were employed in the capacities listed for site studies and evaluations:

TRC Service Corporation, Meteorology

Dames & Moore, Geology and Seismology

Dames & Moore, Hydrology and Oceanography

Dames & Moore, Site Description

Dr. D.W. Pritchard, Physical Oceanography

R.O. Eaton, Coastal Engineering

Dr. J.H. Ryther, Ecology

Dr. L.J. Hooper, Hydraulic Model-Alden Laboratory

Dr. L.C. Neale, Hydraulic Model-Alden Laboratory

Dr. R.F. Harleman, Thermal Model-MIT

2.2 SITE DESCRIPTION

2.2.1 Location and Area

The site is located on the western shore of Cape Cod Bay in the Town of Plymouth, Plymouth County, Massachusetts and contains approximately 517 acres owned by the Entergy Nuclear Generation Company (Entergy Nuclear) as shown on Figures 2.2-1 and 2.2-2. The nearest residences outside the site boundaries are a minimum of 400 m from the Reactor Building to the northwest and southeast. The site boundary is posted and a perimeter security fence provides a distinct secure boundary for the protected area of the station.

Figures 1.6-1 (Drawing C2), 1.6-2 (Drawing C2), and 1.6-3 show relative locations and elevations of the principal plant structures and site boundaries, as well as the precise location (Massachusetts Coordinate System) of the main stack, Reactor and Turbine Buildings, meteorological tower, and the location of the site boundary.

Direct access to the site is available by road and sea. Normal land access is by a two lane paved road which was built across the site to Route 3A, leading to either Plymouth or nearby Route 3. Alternate access from the site to Plymouth and Route 3 via Route 3A is provided by Rocky Hill Road.

2.2.2 Population

2.2.2.1 Resident Population

The estimated resident population distributions for the years 1965 and 2015 are presented on Figures 2.2-3 through 2.2-6. The estimated 1965 residential population within a 1 mile radius was 309 while the corresponding total estimated summer population was 737. The total estimated residential population increases rapidly as the urban areas of Brockton (25 miles to the west-northwest) and New Bedford (27 miles to the southwest) are included. In 1965, Brockton was the nearest densely populated center having more than 25,000 residents, with the nearest boundary about 23 miles from the site. The distance of 23 miles is greater than 1 1/3 times the distance from the reactor to the outer boundary of the low population zone.

The nearest major population centers are Boston, Massachusetts (36 miles to the northwest) and Providence, Rhode Island (44 miles west of the site). The nearest urbanized area is Plymouth, located approximately 4 miles to the west. The location of the site in relation to these and other areas is shown on Figure 2.2-1. Cities and towns which in 1965 had populations of 50,000 or greater within a 50 mile radius of the site are shown on Figure 2.2-4.

2.2.2.2 Seasonal Population

The coastal region of Massachusetts has a large influx of seasonal visitors during the summer months. Many towns experience a larger seasonal population than resident population. This is especially

true on Cape Cod and Martha's Vineyard. Estimates of the seasonal population for the years 1965 and 2015 are presented on Figure 2.2-5. Estimates of the total resident and seasonal population for the years 1965 and 2015 are presented on Figure 2.2-6. Table 3.3-32 of the report, An Update of Population Distribution Around the Pilgrim Site,(1), contains population data up to the year 2020.

2.2.2.3 Exclusion Area and Low Population Zone

The "exclusion area" is defined as that area within the site boundary up to, but not including, the triangular piece of property not owned by Entergy Nuclear as shown on Figure 1.6-3. Entergy Nuclear determines all activities including exclusion or removal of personnel and property from this area. The traversing Rocky Hill Road will in no way interfere with the normal operations of the station. Appropriate arrangements have been made to control traffic on Rocky Hill Road to protect the public health and safety in case of an emergency. Recreational activities may be allowed in defined areas within the exclusion area. During periods of time when recreational occupancy is permitted, these areas will be monitored to assure that no significant hazards to the public health and safety exist. Based upon the above information and the results tabulated on Table 14.5-2 which indicate the maximum dose at the edge of the exclusion area using the assumptions of TID-14844 as a basis for fission product source terms, it is concluded that the requirements of 10 CFR 100.3(a) and 10 CFR 100.11(a)(1) have been met.

The "low population zone" is that area immediately surrounding the exclusion area for a radius of 6,840 meters (4.25 miles) from the reactor. The total population within the low population zone in 1965 was estimated at 7,700 residents. Entergy Nuclear has developed, in conjunction with appropriate Federal, State, and local agencies, plans and protective measures which would be implemented in the event of an accident.

2.2.2.4 Current Population

The current population data as of 1981, is included in An Update of Population Distribution Around the Pilgrim Site.[1]

2.2.3 Land Use

Since the site is located along the coast, approximately 60 percent of the area within a 50 mile radius is open water. The area within 2 miles of the site is sparsely developed with the exception of the seasonal residences along Priscilla Beach and White Horse Beach.

A triangular tract of land located within Entergy Nuclear's property is owned by a private party. This area is shown on Figure 1.6-2 (Drawing C2). Entergy Nuclear has made no arrangements with the current owner regarding future use or occupancy of the property. The Technical Specifications referenced in Appendix B, (Section 5.1) defines that the reactor is located approximately 1,800 feet from the nearest property boundary and no part of the present property shall be sold

or leased by Entergy Nuclear which would reduce the minimum distance to less than 1,800 feet without prior NRC approval. The triangular tract of land is beyond this distance.

The stack release limit calculations for Pilgrim Station Site, Sections E.3 through E.5, considered the triangular tract of land and the results for the annual average gamma dose at ground level are shown on Figure E.3-9. The analyses demonstrate compliance with the requirements of 10CFR20 as administered by the controls defined in Technical Specification 5.5 to limit the amount of radioactive releases to the environs via gaseous effluents.

An estimate of the present land use in 1964 for the towns of Plymouth, Carver, and Kingston is presented on Table 2.2-1. Portions of these towns constitute approximately 90 percent of the land area within a 10 mile radius of the site. The data indicates that in 1964 over 85 percent of the land was categorized as open space and vacant. Approximately 7 percent of the land use was agricultural, the major portion of which is cranberry bogs. The adjacent waters are used for commercial fishing, shellfishing, and sport fishing.

The land nearby was and is also predominantly open space and vacant, although the metropolitan areas of Brockton and Boston to the northwest and New Bedford, Fall River, and Providence to the southwest are highly developed. Brockton is the closest of these metropolitan areas.

Although little published data is available for predicting future land use, it appears that the increased land use will be primarily residential as the resort areas and suburbs experience growth.

2.2.4 Recreational Use

Entergy Nuclear has made provisions for public access to the shorefront and breakwater area, as shown on Figure 1.6-1 (Drawing C2).

The shorefront and breakwater area will permit observation from the shorefront, and fishing from the shorefront and main breakwater. Parking space has been provided for about 100 automobiles in this area.

Entergy Nuclear maintains control of access to this area by a gate provided at the entrance to the access road from Rocky Hill Road. The gate will be closed, locked, and posted during those periods when access is not permitted. The following restrictions on public access are planned:

1. Access to the shorefront breakwater area is permitted generally from March to November, during daylight hours, at the discretion of the station management and dependent upon weather conditions

2. Access to the shorefront breakwater area will be terminated whenever necessary to permit continued station operation

within the radiation exposure limitations established by regulatory agencies or by Entergy Nuclear's corporate policy

Station emergency procedures provide necessary controls and provisions to evacuate and secure the shorefront and breakwater area when required.

Environs radiation monitoring in these areas is described in Section 2.6.

2.2.5 Reference

An Update of Population Distribution Around the Pilgrim Site, July 31, 1981. H.M.M. Associates

TABLE 2.2-1

LAND USE AS OF 1964
TOWNS OF PLYMOUTH, CARVER, AND KINGSTON

Land Use	Acres	Percent
Residential	4,644	4.5
Commercial	208	0.2
Industrial	1,428	1.4
Public and Quasi-Public Buildings	275	0.3
Public and Quasi-Public Open Space	12,162	11.8
Agricultural	7,563	7.3
Vacant	77,089	74.5
TOTAL	103,369	100.0

SOURCE:

Massachusetts Department of Public Works

South East Massachusetts Regional Planning District - 1964

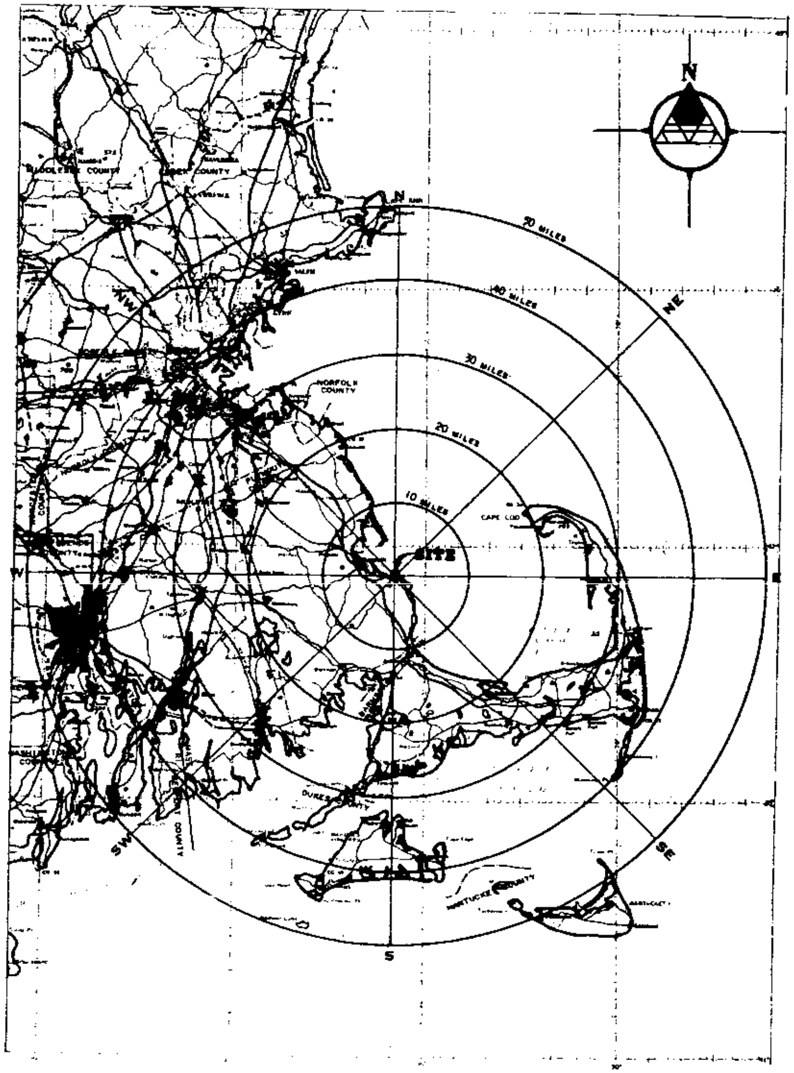


FIGURE 2.2-1
STATION SITE-LOCATION MAP
(0 TO 50 MILES RADIUS)
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

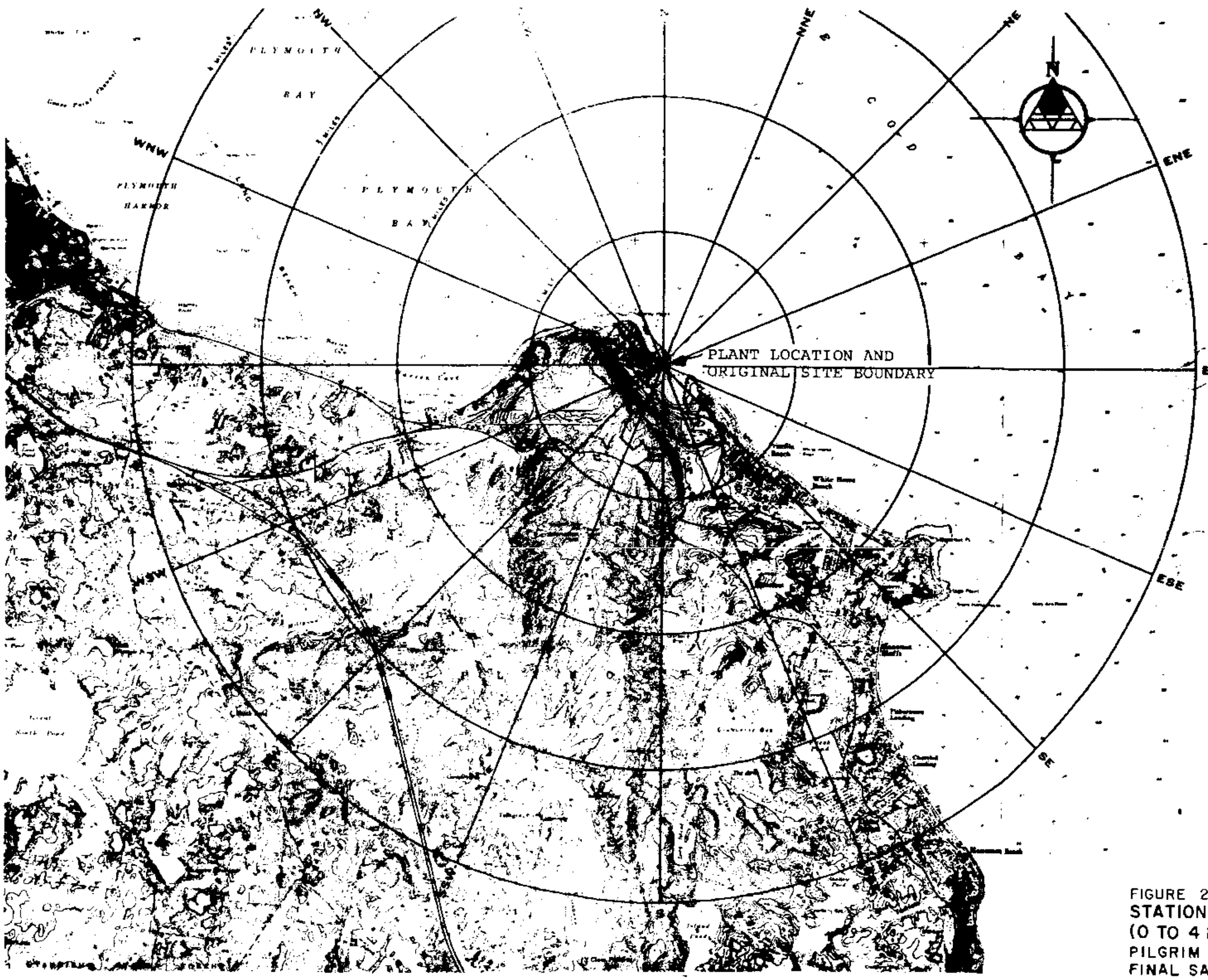
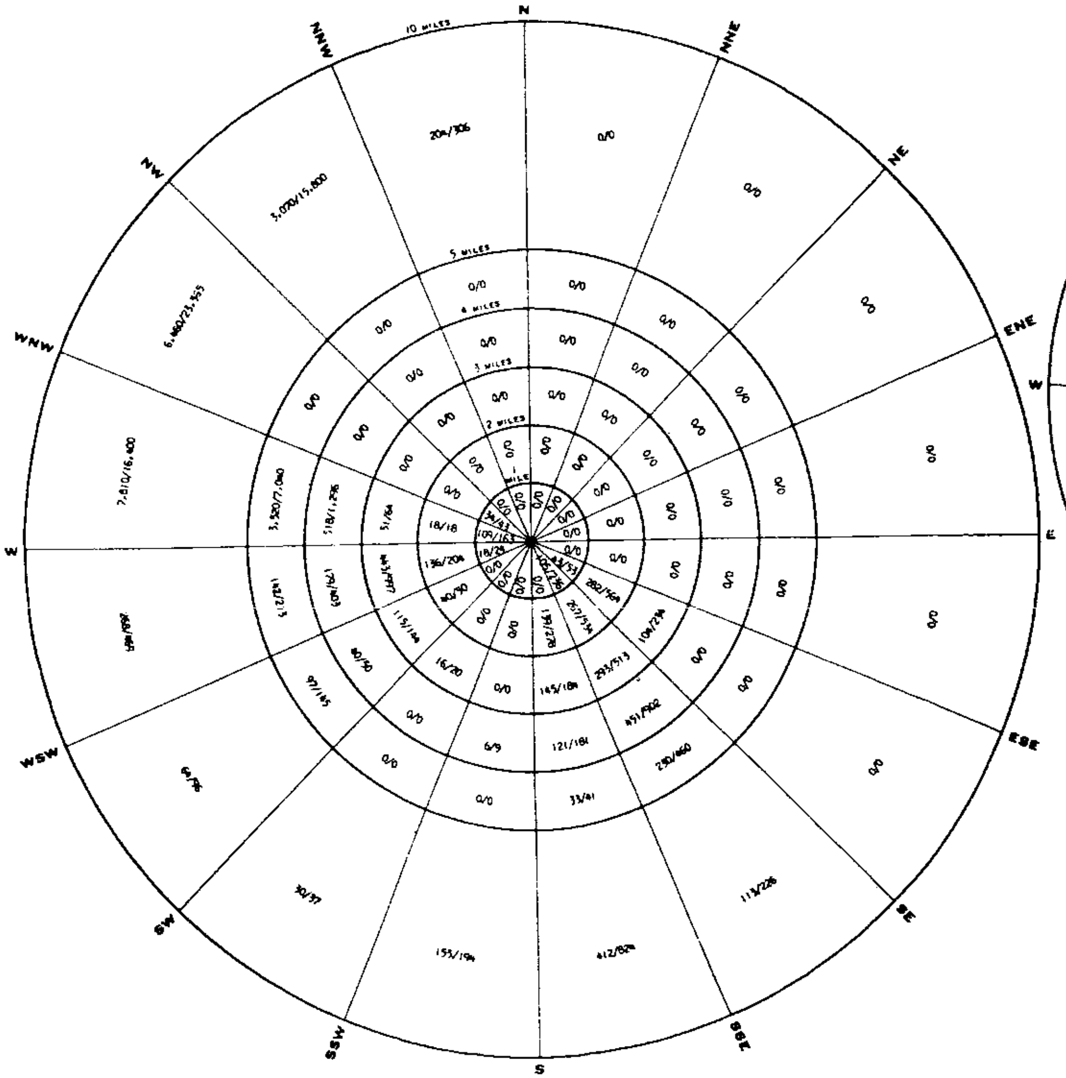
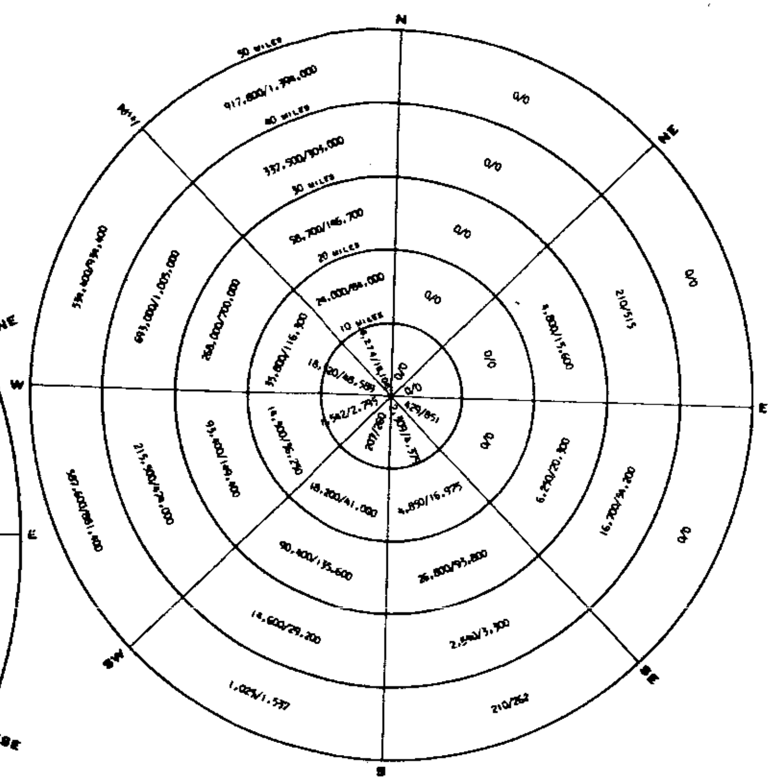


FIGURE 2.2-2
STATION SITE-LOCATION MAP
(0 TO 4 MILES RADIUS)
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT





RADIUS IN MILES		0–1	0–2	0–3	0–4	0–5	0–10	0–20	0–30	0–40	0–50
ACCUMULATIVE TOTAL	1965	309	1,191	2,398	3,673	7,695	26,881	123,631	671,981	1,952,131	3,993,166
	2015	519	2,167	4,925	7,164	15,065	72,980	367,505	1,628,905	3,498,120	6,709,719

KEY:

EST. 1965 POPULATION/EST. 2015 POPULATION.

FIGURE 2.2-3
INITIAL STATION SITE-RESIDENT POPULATION DISTRIBUTION YEARS 1965 & 2015
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

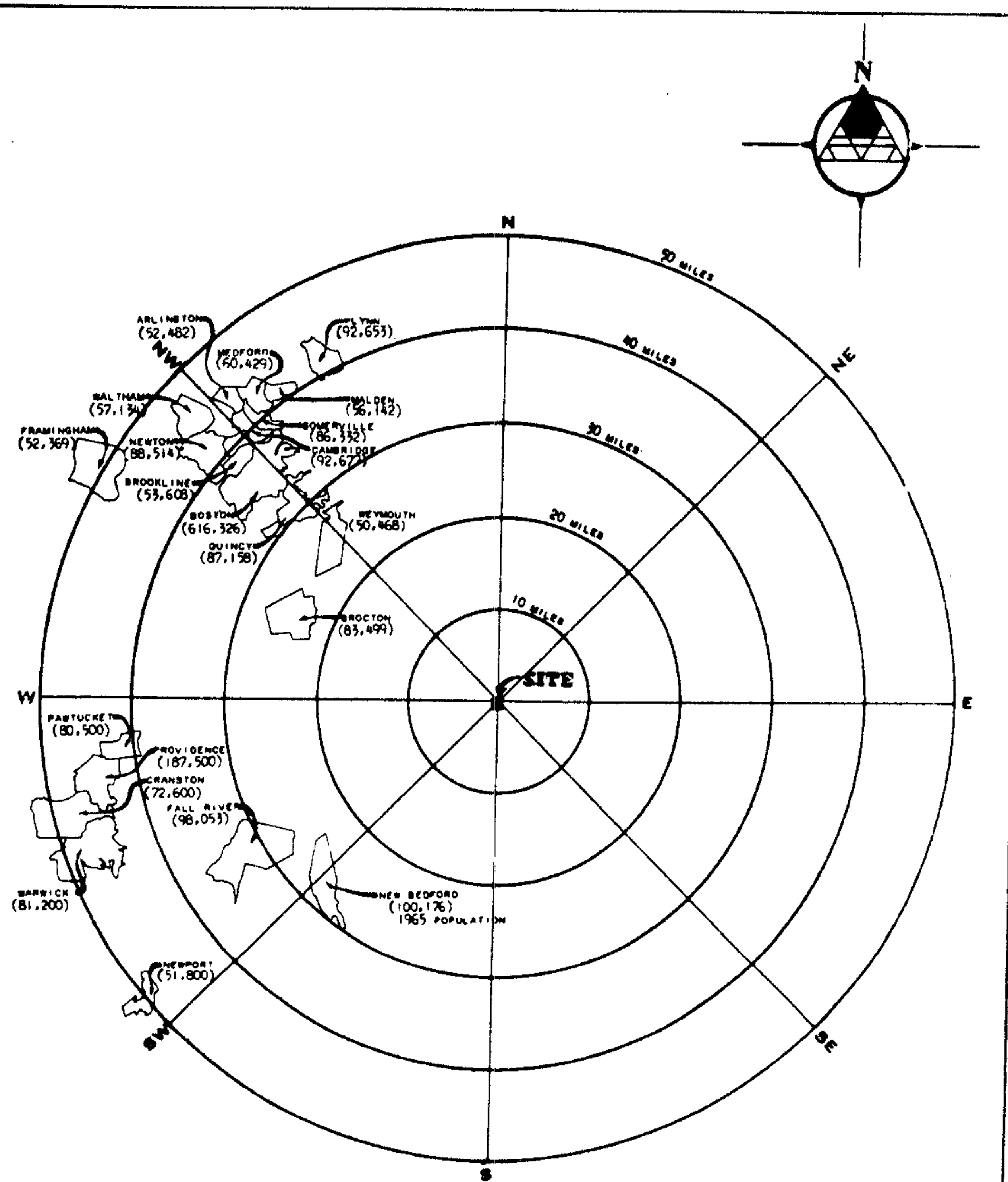
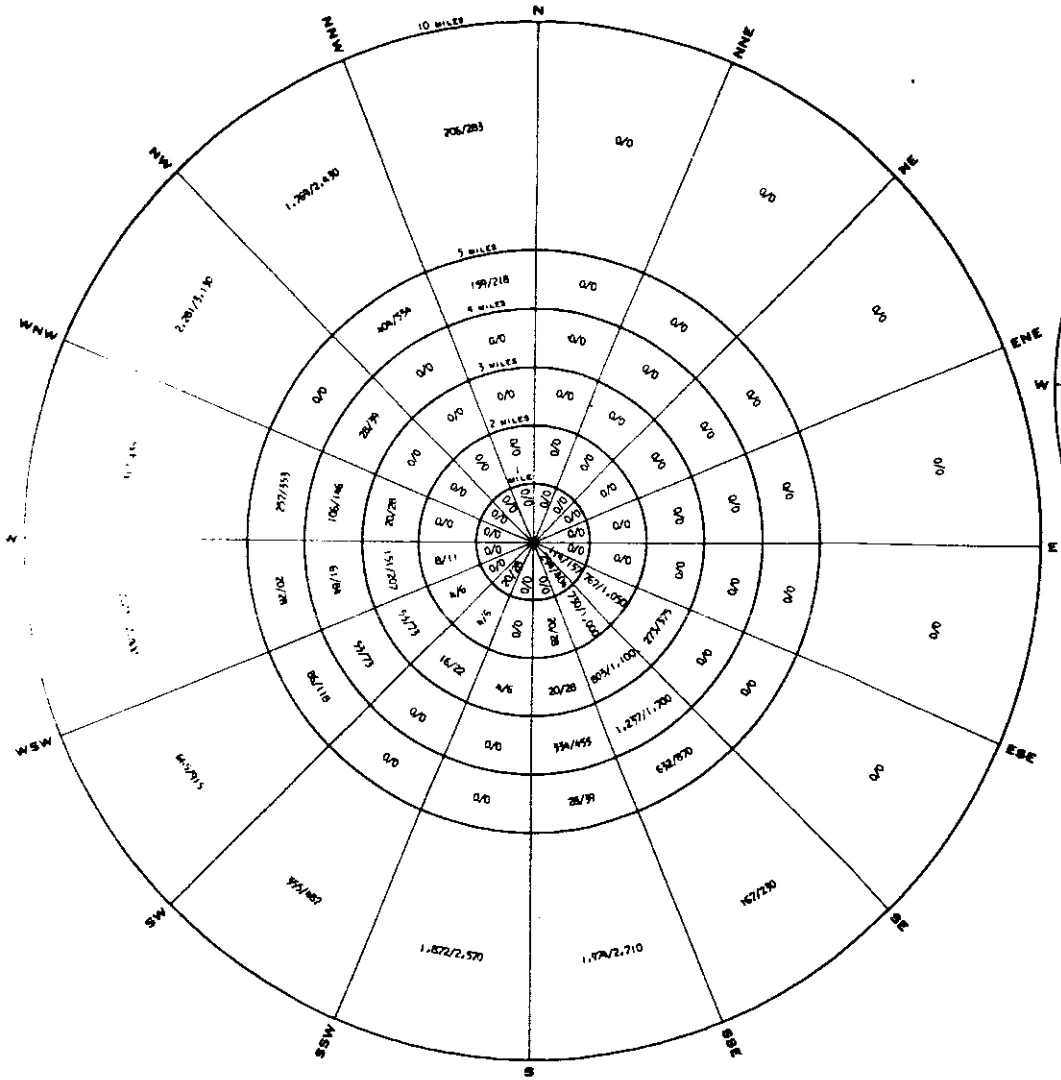
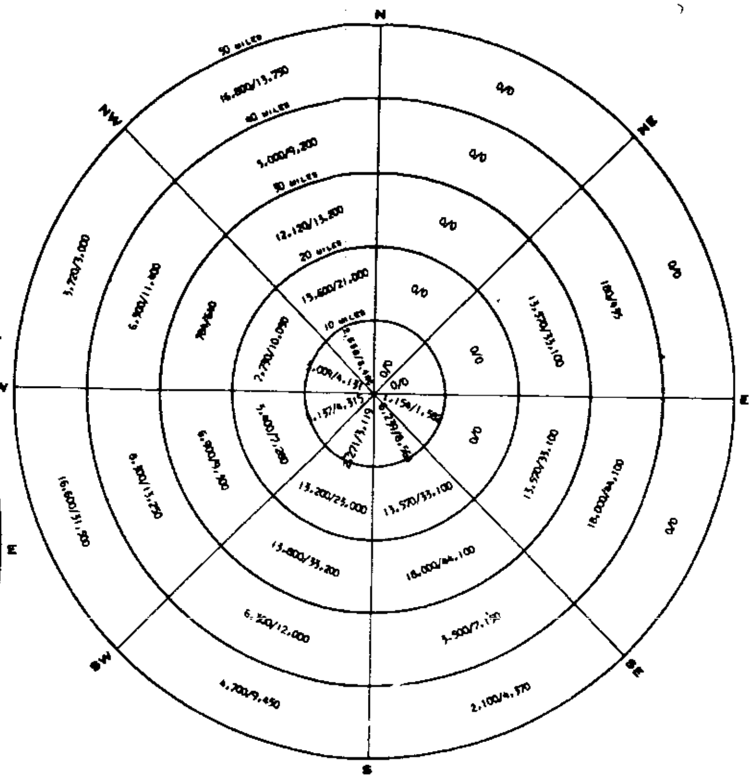


FIGURE 2.2-4

STATION SITE-MAJOR CITIES-TOWNS POPULATION YEAR 1965

PILGRIM NUCLEAR POWER STATION FINAL SAFETY ANALYSIS REPORT





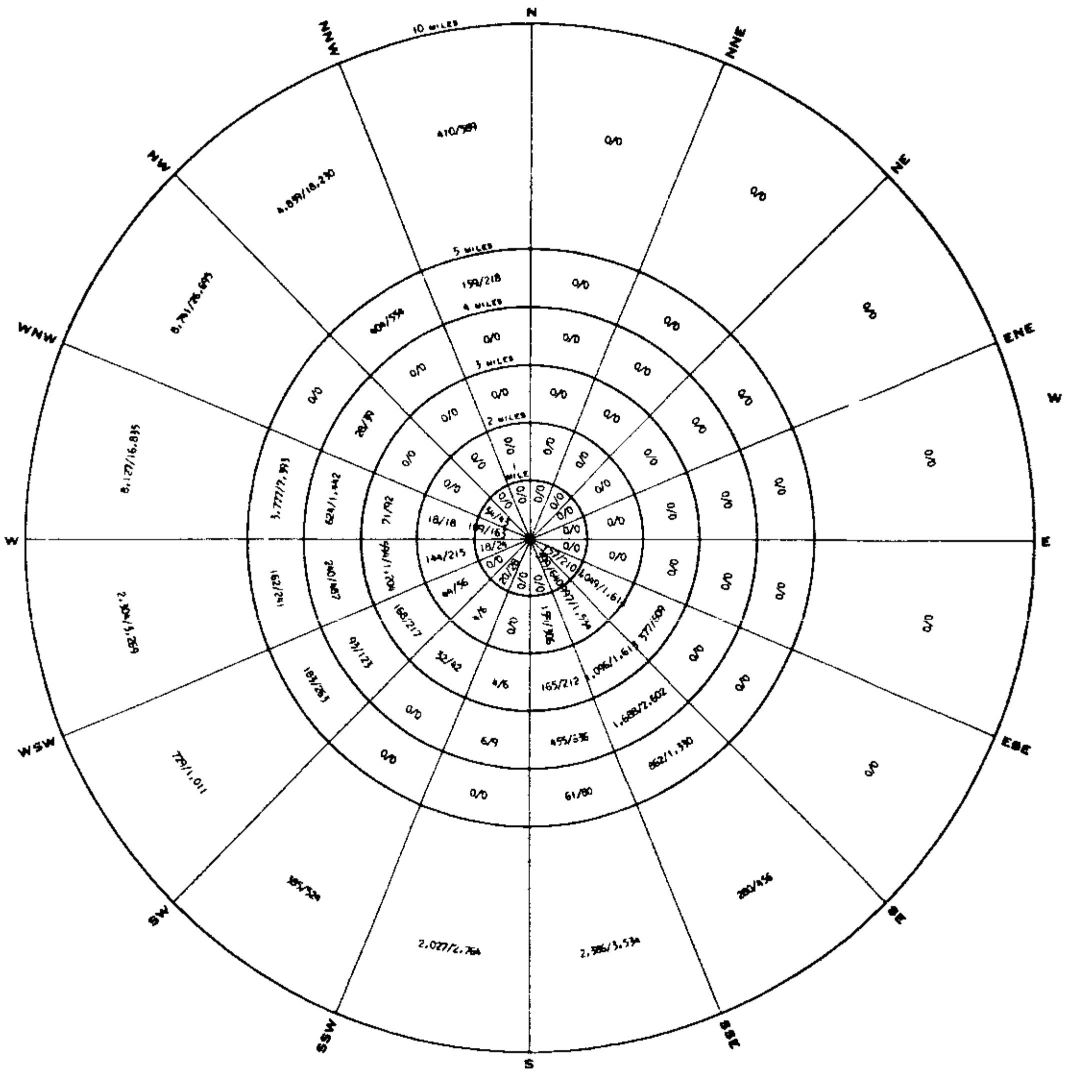
RADIUS IN MILES		0-1	0-2	0-3	0-4	0-5	0-10	0-20	0-30	0-40	0-50
ACCUMULATIVE TOTAL	1965	428	1,961	3,501	5,120	6,706	18,398	73,848	152,592	200,372	244,292
	2015	589	2,690	4,529	7,026	9,206	25,196	119,626	286,266	385,801	445,871

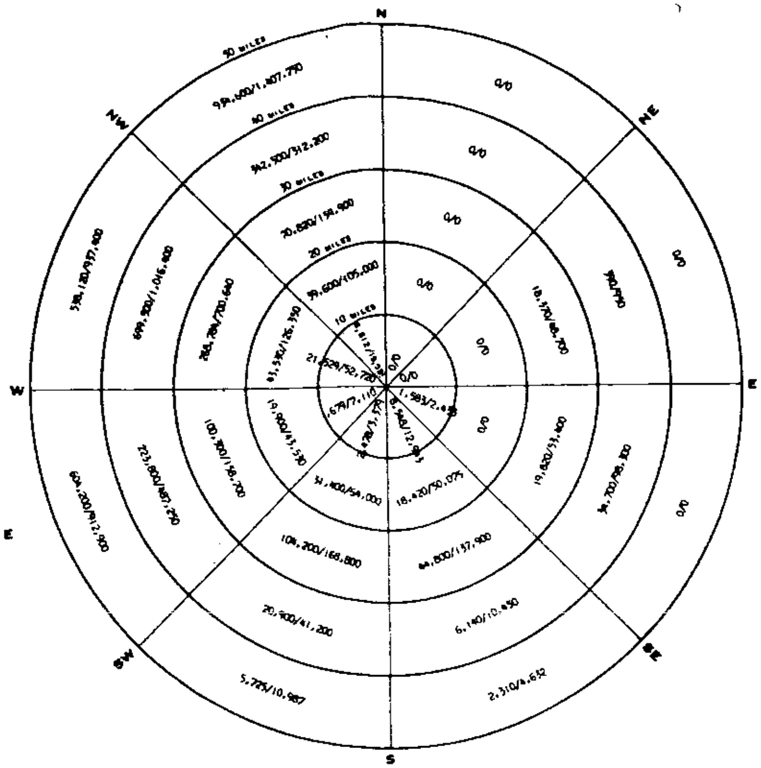
KEY:

EST. 1965 POPULATION/EST. 2015 POPULATION.

FIGURE 2.2-5
INITIAL STATION SITE-SEASONAL POPULATION DISTRIBUTION YEARS 1965 & 2015

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT





RADIUS IN MILES		0-1	0-2	0-3	0-4	0-5	0-10	0-20	0-30	0-40	0-50
ACCUMULATIVE TOTAL	1965	757	3,152	5,659	8,793	14,401	44,629	197,479	824,575	2,152,503	4,237,458
	2015	1,108	4,857	8,852	14,190	24,269	95,176	487,131	1,915,171	3,881,921	7,155,990

KEY:

EST. 1965 POPULATION/EST. 2015 POPULATION.

FIGURE 2.2-6
INITIAL STATION SITE-RESIDENT & SEASONAL POPULATION DISTRIBUTION YEARS 1965 & 2015
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

2.3 METEOROLOGY

2.3.1 General

The main features of the weather of eastern Massachusetts are variety and changeability. The area lies in a transition zone of westerly air currents which encompass the southward movement of polar air masses and northward movement of tropical air masses. The area is frequently in or near the tracks of low pressure systems during the fall, winter, and spring. As a result, the region has no dry season, with summer precipitation coming in the form of showers or thunderstorms. The coastline location of the site results in seasonal temperatures which are less extreme than inland locations due to onshore winds in the summer (seabreeze) and the presence of relatively warm water in the winter.

Meteorological data are available from the onsite weather station. As specified in Regulatory Guide 1.23, data on wind speed, wind direction, and atmospheric stability are recorded and displayed in the control room. Special seabreeze studies have been conducted to provide a better understanding of the local wind regime and are discussed in detail in Appendix I to the FSAR. In order to improve emergency response capabilities as recommended by Regulatory Guide 1.23, continuous readings of the prevailing winds and outside temperatures at the site are recorded in the main control room.

2.3.2 Meteorological Field Program

A meteorological tower has been in continuous operation since May 1968. The tower is 220 ft high and is located on the ground at 80 ft elevation referred to mean sea level (msl). The following observations have been made:

1. Wind speed, direction and directional variability at 20 ft (100 ft msl) and 220 ft (300 ft msl,) using wind sensors

2. Temperatures at 5, 110, and 220 ft (85, 190, and 300 ft msl) and temperature differences between 5 to 110 ft and 110 to 220 ft by means of resistance type thermometers housed in aspirated solar radiation shields. Temperature measurements are currently taken at the 33' and 220' elevations using thermostats. The 33' measurement is recorded and the 220' measurement is used to determine the temperature differential.

3. Occurrence or nonoccurrence of precipitations by means of a precipitation duration sensor (no longer installed).

In addition to the meteorological data, water temperatures obtained as part of the oceanographic program, described in Section 2.4, were used in the seabreeze analysis. An infrared radiometer survey of the bay was conducted to assure that representative water temperatures were obtained.

On April 2, 1969, the lower anemometer on the tower was raised from 20 ft to 70 ft (150 ft msl) to obtain more representative data during onshore flow regimes. The data at the previous level was adversely affected by the aerodynamic effect of the bluff along the beach to the east.

Onshore winds diverted upward by the bluff placed the lower part of the tower in the cavity created by the aerodynamic wake. Although the wake boundary varies with wind speed and angle of attack on the bluff, it was readily detected by a person climbing the tower. In a matter of a foot or so, the climber passed from practically no wind or even a light offshore flow, into a strong onshore flow. Comparisons of the wind speed and direction at the 150 ft and the 300 ft levels indicated little difference.

An additional temperature sensor and wind sensor were installed on June 20, 1969, on a radio tower at a level 100 ft above grade (elevation of 370 ft msl). This tower is located on the south side of Route 3A about 4,800 ft south-southwest of the reactor location, and 4,300 ft due south of the meteorological tower.

Additional measurements taken at the radio tower referred to were spotty in nature and were maintained only during the few weeks in the summer of 1968 when smoke tests were being conducted. The radio tower wind was at 350 ft msl and gave no additional information over that obtained from the 300 ft msl level on the 220 ft meteorological tower. Since the data collected from this tower did not differ from that collected on the 220 ft meteorological tower, the observations were discontinued. Temperature soundings up to 1,500 ft msl were obtained by an aircraft during each smoke run to supplement the tower observations.

The Pilgrim site meteorological data presented in this report includes the first annual period from May 1968 through April 1969. The data collection program was supplemented by a second meteorological tower in February 1972. This additional meteorological tower was erected in close proximity to PNPS in anticipation of the licensing of Pilgrim II. The tower is 160' high and is located on the ground at 23' elevation above mean sea level (MSL). When the Pilgrim II project was abandoned, it was decided to utilize this meteorological tower to obtain a larger data base to aid in understanding the varying meteorological conditions surrounding the site and as a backup for the primary meteorological tower (220').

The instrumentation for the 160' tower, as well as the 220' tower, consists of wind speed, wind direction, and temperature detectors. On the 160' tower, these are located at the 33' level (53' MSL) and the 160' level (180' MSL). On the 220' tower, the instrumentation is located at the 33' level (113' MSL), and at the 220' level (300' MSL).

Similar instrumentation is utilized for both towers and is calibrated and maintained as described in Section 7.21. Additional details of this tower are provided in the response to NRC Question

B.4.b in the Appendix I report.[1] The location of the new tower is shown on Figure 1.6-1.

2.3.3 Winds

Seasonal and annual wind roses for the 20 ft and 220 ft tower level (100 and 300 ft msl) data collected from May 1968 through April 1969 at the Pilgrim site are shown on Figures 2.3-1 through 2.3-10. Additional onsite wind data for the May 1, 1974-April 30, 1975 period are contained on Tables B.1-1 through B.1-6 of the Appendix I report while offsite wind data are presented in Tables B.2-1 through B.2-6 of the Appendix I report.[1] The predominate wind directional frequencies at the 220 ft tower level (300 ft msl) are in the sectors W-WNW, SSW-SW, WSW-WNW, and WSW-WNW for spring, summer, fall, and winter, respectively. Winds occur in the SSW-WNW sectors 53 percent of the time. The annual frequency of calm is 0.43 percent. The annual mean wind speed is 16 mph.

2.3.4 Diffusion Climatology

The frequent changes in weather systems and the proximity of the ocean yield a changeable wind velocity regime which results in favorable atmospheric diffusion conditions. The ocean's proximity results in low frequency of inversion (stable) conditions with light winds. There are times, however, during the warm months of the year, that the waters off the Massachusetts coast are cold compared to the land. When an easterly wind develops, this stable air will be adverted over land, resulting in somewhat less favorable diffusion conditions.

Monthly average morning and afternoon mixing depths for the May 1, 1974 - April 30, 1975 period are presented on Table B.2-14 of the Appendix I report.[1] The coastline at the site generally follows a northwest-southeast direction. Thus, the land breeze is intensified and the seabreeze is moderated by the regional wind pattern which is generally from the southwest (offshore) in the summer. However, the site is situated so that any wind from about 315 degrees through north to 100 degrees will have an overwater trajectory upwind of the site and an overland trajectory immediately downwind from the station.

Diffusion climatology has been analyzed from meteorological data obtained at the Pilgrim site for the period May 1968 through April 1969. The most pertinent results are presented in the following tables and figures.

1. Annual Stability Summary and comparison of Seasonal Inversion Frequencies, Tables 2.3-1 and 2.3-2

2. Annual wind summaries, wind directional persistence and inversion persistence at 300 ft msl, Tables 2.3-3 through 2.3-10

3. Windroses at 300 ft msl by 16 compass points, Figures 2.3-11 through 2.3-14

4. Wind directional variability and wind speed ($\Delta\theta\bar{u}$) by six wind speed ranges, Tables 2.3-11 through 2.3-14. These data give a direct measure of lateral diffusibility and an indirect measure of vertical diffusibility

Additional data concerning onsite wind speed, wind direction, and atmospheric stability distributions for the May 1, 1974 - April 30, 1975 period are presented on Tables B.1-7 through B.1-12 and Figures B.1-2 through B.1-25 of the Appendix I report.[1]

The radiological consequences of the diffusion climatology are described in Appendix E.

Of particular interest at the Pilgrim site is the potential behavior of a plume from an elevated release under the influence of an onshore wind (seabreeze), during periods when the water surface is appreciably colder than the land surface. The modification of a cold, overwater, stable airmass into an unstable regime as it moves inland and is heated, can result in a pseudofumigation condition. This phenomenon is discussed by Van der Hoven.[2] Pseudofumigation behavior under seabreeze conditions was studied by a series of smoke releases from the top of the 220 ft tower (300 ft above msl) during the summer of 1969. The details of this seabreeze study are reported in Appendix I to the FSAR.

The seabreeze test results in Appendix I to the FSAR demonstrate the application of the technique wherein the initial overwater stability and average onshore wind speed can be used to determine the point inland at which the mixing layer would grow vertically and cause a downward mixing ("fumigation") of a portion of an elevated plume. The study further indicated that the technique could be modified to apply to hilly terrain and a "fumigation" climatology could be compiled for the site based on local wind, plus air and sea surface temperatures.

Although "fumigation" is potentially possible whenever there is onshore flow of stable marine air over a much warmer land surface, it is most apt to occur with a seabreeze. The predominating air flow at the Pilgrim site during the normally warmer months of the year is from the southwest. Any seabreeze must oppose this gradient wind. In order to create such a counterflow, the overall pressure gradient must be weak and clear skies must prevail to permit solar heating to create the necessary sea-land temperature contrast. Typically, a seabreeze starts with a light NNE wind which in a matter of an hour or two veers to ESE. During the 1969 study, it was observed that the mixing level grows rapidly upward as the wind veers so that a 300 to 400 ft elevated emission point within 1/2 mi or less of the shore would not remain in the stable layer, (and hence be subject to "fumigation") for more than about 30 to 40 min. The only exception to the above was noted during the occurrence of a "dry northeaster," wherein the top of the tower remained in the stable layer for over 1.5 hr. According to local seafaring people, such "dry northeasters" occur on the average of 2 to 3 times a year. At other times these cyclonic disturbances are accompanied by cloudiness and rain which greatly reduces the contrast between

overland and overwater stability, and hence the possibility of fumigation.

Frequently, too, strong onshore winds create an adiabatic, or neutral, vertical temperature gradient which precludes a fumigation situation, even though the land surface temperature is warmer than the sea.

The basis for the fumigation analysis is the Van der Hoven model shown on Figure I.1-1. The object is to develop frequency distributions of $\bar{u}\Delta\theta$ by months and by onshore wind directions (NNW, clockwise through ESE).

Assuming that the stack, to which the climatology will be applied, is in the range of 300 to 400 ft msl, the mean wind expressed in m/sec, for the layer of marine air moving inland is taken from the 150 ft msl elevation (72 ft on the meteorological tower).

The initial overwater stability is determined by reducing the top air (220 ft level, 300 ft msl) temperature on the tower adiabatically to sea level (by adding 0.91°C to the 300 ft temperature) and subtracting the sea surface water temperature to obtain $\Delta\theta$. If this value is zero, or negative, the potential for fumigation does not exist.

Van der Hoven's graph has been modified for hilly terrain by determining cross-sectional profiles for various directions inland from the shore. See Appendix I, Figures I.2-1 to I.2-7. In the absence of heating, aerodynamic flow over an obstruction would result in converging streamlines over the crest of the hills, such that the thickness of the layer of marine air would be less on top of the hill than where it first crosses the coast. On the other hand, a sloping surface, particularly in the case where it faces to the east and has been subjected to solar heating for several hours prior to the seabreeze reaching a maximum, heats much more rapidly than a flat surface and would cause a more rapid vertical growth of the mixing layer. Assuming the greater rate of heating balances, the streamline pattern required by aerodynamic flow seems to work in practice and one can assume the mixing layer grows at a uniform rate and follows the contours. Appendix I, Figures I.2-1 to I.2-7 illustrate graphically the effect of terrain on the growth of the mixing level.

Another useful chart can be prepared if one knows the original elevation of a plume and plots its elevation above grade as a function of downwind (inland) distance directly on Van der Hoven's original graph. This has been done for a 400 ft msl stack (122 m) and a NNE wind, and is shown on Figure 2.3-15.

The first step in the potential fumigation climatology analysis was to prepare monthly "potential temperature wind roses," using hourly 72 ft tower wind speeds by 22.5 degree onshore directions (seven compass points); 220 ft tower hourly temperatures reduced adiabatically to sea level; and monthly average sea surface temperatures. The $\Delta\theta$ values were determined by subcontracting the

average sea surface temperatures from the hourly potential temperatures. If $\Delta\theta$ comes out zero, or with a negative value, then fumigation will not occur. By multiplying the wind speed by $\Delta\theta$, the initial potential temperature windroses are transferred into frequency distributions of $\bar{u}\Delta\theta$.

In order to evaluate the frequency of fumigation conditions at a particular ground location around the site boundary, the following method was used:

1. The distance of the site boundary for each onshore wind direction was determined

2. Zones of 100 m each were then established, such that one zone is centered on the boundary, and extends 50 m either side thereof

3. Sufficient zones of 100 m each were added to cover a distance of about 500 m on both sides of the boundary where possible

4. For a given plume elevation, a range of $\bar{u}\Delta\theta$ values exist which could result in fumigation in any discrete 100 m zone. These values are determined from Figures I.2-1 through I.2-7 from a plot similar to Figure 2.3-15 or for greater accuracy, by computation from $H = 8.8\sqrt{x}/\bar{u}\Delta\theta$ where H = height (m) at which the mixing level intersects the plume and X = inland distance (m).

5. The frequency of occurrence of all $\bar{u}\Delta\theta$ values which would result in potential fumigation were then summarized for each 100 m zone.

One technical point in the use of these diagrams should be mentioned. Once the mixing level has risen to a given elevation due to heating and terrain influences, it will not descend again if the land falls away.

In other words, once a mixing layer surface, as represented by $\bar{u}\Delta\theta$ is intercepted by the plume, a lower value cannot be encountered thereafter.

The results of these preliminary analyses showed that:

1. Seabreeze fumigation had the greatest frequency of occurrence for wind directions ranging from north through east

2. The frequency of fumigation at particular ground locations during the months of June, July, August, and September ranged from about 0.1 percent per month up to a maximum of about 1 percent per month from the site boundary out to 500 m beyond the site boundary

3. The maximum frequency of fumigation in these directions typically occurred at ground locations ranging from about 600 to 1,000 m from the stack based upon these analyses

The analyses summarized in Appendix E indicate that stack releases are limited considering winds from the northeast (land to the southwest of the stack). In this direction, fumigation frequency (at 100 m ground segments) averaged about 0.5 percent per month during June, July, August, and September considering distances from 480 to 1,080 m from the stack (site boundary at 530 m) based upon these fumigation analyses.

A design change in the main stack has been made which results in higher plume rises than were initially utilized in Appendix E. The stack release rate limits are not more conservative since these higher plume rises were not used. This design change increased the inside diameter of the stack top from 1.17 to 2.44 ft.

2.3.5 Temperature

The temperature regime of the region is influenced by the proximity of the adjacent waters and as such does not exhibit the wider diurnal and seasonal variations of nearby inland locations. The average annual temperature at Plymouth is 50°F with a high monthly average of 71°F in July and low monthly average of 29°F in February. A 53 yr record of temperatures for Plymouth is shown on Table 2.3-15.

2.3.6 Precipitation

The 20 ft level precipitation windrose for the Pilgrim site is shown on Figure 2.3-16. The climatological precipitation quantities in eastern Massachusetts show that the region does not have a wet or a dry season. Monthly averages vary from about 3 in to 4 1/2 in at Plymouth. Summer precipitation is generally in the form of showers or thunderstorms while most fall, winter, and spring precipitation comes from storms which track past the region. Large rainfall amounts in a short period of time can occur during all seasons resulting from thunderstorms in the late spring and summer, hurricanes during late summer and fall and extratropical coastal cyclones (northeasters) during the winter and spring. Historical precipitation data for Plymouth, Massachusetts, is shown on Table 2.3-16.

Additional precipitation data are presented on Tables B.1-13, B.1-14, B.2-15, and B.2-16, of the Appendix I report.(1)

The monthly average and maximum snowfall, the maximum 24 hr snowfall, and the average number of days per month with a snowfall of 1.0 in or more for Boston are shown on Table 2.3-17. Snowfall in the site vicinity is generally less than in Boston.

A few times each winter a weather situation favorable for ice glaze formation develops. The coastal location of the site reduces the likelihood of a glaze forming storm compared to nearby inland locations. During the period of record 1928 to 1936, the site area

experienced between six and eight storms which deposited ice glaze 0.25 in thick or more.

2.3.7 Storms

The storm cycle in this area consists of northeasters in the winter, thunderstorms in late spring and summer, and hurricanes in the late summer and fall. High winds in eastern Massachusetts are most frequently associated with the northeasters. The maximum sustained 5 min wind speed (not peak gusts) recorded at Boston for each month are shown on Table 2.3-18.

Fifteen hurricanes classified as "extreme" have affected the Massachusetts coastal area since 1635. Hurricanes classified as "extreme" (maximum winds greater than 136 mph) have occurred in 1938, 1944, 1954 (2 storms), 1955, and 1960, with a maximum sustained 5 min wind of 87 mph at Boston.

Severe tornado activity in eastern Massachusetts is not common. Thom(3) shows a total number of seven tornadoes during the period of 1953-62 in a 1 degree square which includes the site. These tornadoes did not inflict major damage. The proximity to the ocean and the terrain in the vicinity of the site are unfavorable to severe tornado activity.

2.3.8 Summary

The meteorology of the Pilgrim site is typical of a New England coastal location with generally favorable atmospheric diffusion conditions.

Onsite wind and air temperature measurements taken over a 1 yr period indicate that moderately stable or slightly stable atmospheric conditions with onshore winds are observed 8.2 percent of the time. These figures compare with an inversion frequency of 23 percent for all wind directions for the North Atlantic States given by Hosler.(4)

The most frequent wind directions are from SSW through WNW which are all offshore directions occurring 53 percent of the time. The frequency of calm is 0.43 percent. The site experiences onshore winds 36 percent of the time and offshore winds 63.6 percent of the time.

For a typical 22 1/2 degree sector, summarizing wind direction persistence: 52 percent of all cases observed were for only 1 hr; 72 percent were 2 hr or less; 90 percent were 4 hr or less; and 99 percent were 13 hr or less. The longest period observed was 39 hr, and that was associated with an offshore wind.

Since 1938, six hurricanes classified as "extreme" have passed the area. The maximum sustained 5 min wind speed reported at Boston due to hurricane was 87 mph in September 1938. A total of seven tornadoes have been reported during the period 1953 through 1962 in a 1 degree square which includes the site; however, they inflicted

minor damage and could not be considered severe. High winds at the site are most frequently associated with "northeasters."

The effects of diffusion climatology at the site on radioactive discharges from the station are described in Appendix E, Station Release Limit Calculation and Section 14, Station Safety Analysis.

2.3.9 References

1. Pilgrim Station Unit I, Appendix I Evaluation, June 1976 and April 1977.

2. Van der Hoven, Isaac. Atmospheric Transport and Diffusion at Coastal Sites Nuclear Safety, Vol. 8, No. 5, Sept- Oct 1967.

3. Thom, H. C. S. Tornado Probabilities Monthly Weather Review, Vol. 91, No. 10-12, 1963, pp 730-736.

4. Hosler, C. R. Climatological Estimates of Diffusion Conditions in the United States Nuclear Safety, Vol 5, No. 2, Winter, 1963-1964.

TABLE 2.3-1

ANNUAL STABILITY SUMMARY - PILGRIM SITE
(Percent of Total Hours)

Condition	Onshore[1] Wind, NW-ESE	Offshore Wind SE-WNW	Calm	Total
Moderately Stable[2]	3.8	12.1	0.2	16.1
Slightly Stable[3]	6.8	14.4	0.1	21.3
Moderately plus Slightly Stable	10.6	26.5	0.3	37.4
Hosler Inversion Frequency[1]				23.1

NOTES:

1. Direction taken from 300 ft msl elevation

2. Lapse rate exceeds 1.5°C per 100 m

3. Lapse rate between -0.5°C and 1.5°C per 100 m

TABLE 2.3-2

COMPARISON OF SEASONAL
INVERSION FREQUENCIES
(Percent of Possible Hours)

Season	Onshore[1] Wind, NW-ESE	Offshore Wind, SE-WNW	Calm	Total Winds	Total Hosler Inversion Frequency
Winter-Moderately Stable[2]	2.3	5.7	0.1	8.1	
Slightly Stable[2]	5.7	10.7	*	16.4	
Sub-Total	8.0	16.4	0.1	24.5	20-40
Spring-Moderately[3] Stable[3]	3.3	12.4	0.2	15.9	
Slightly Stable	5.5	11.6	0.1	17.2	
Sub-Total	8.8	24.0	0.3	33.1	15-25
Summer-Moderately Stable	4.4	18.0	0.2	22.6	
Slightly Stable	8.4	17.7	0.2	26.3	
Sub-Total	12.8	35.7	0.4	48.9	10-20
Fall-Moderately Stable	5.8	12.2	0.1	18.1	
Slightly Stable	8.3	18.7	0.1	27.1	
Sub-Total	14.1	30.9	0.2	45.2	20-35

NOTES:

1. Direction taken from 300 ft msl elevation
2. Lapse rate exceeds 1.5°C per 100 m
3. Lapse rate between-0.5°C and 1.5°C per 100 m

* is more than 0 but less than 0.1 percent

TABLE 2.3-3

ANNUAL WIND SUMMARY - PILGRIM SITE - ELEVATION 300 FEET MSL
MODERATELY STABLE, LAPSE RATE EXCEEDS 1.5°C PER 100M
(Percent of Observations, May 1968 - April 1969)

Wind Direction	Wind Speed (mph) 1-3	4-7	8-12	12-18	19-24	25-31	32-38	Total
N	0.16	0.39	0.78	1.33	0.24	0.0	0.0	2.90
NNE	0.31	0.78	0.63	0.63	0.16	0.0	0.0	2.51
NE	0.24	0.86	1.33	0.63	0.0	0.0	0.0	3.06
ENE	0.0	1.18	1.02	0.71	0.0	0.0	0.0	2.90
E	0.16	0.71	0.78	0.08	0.0	0.0	0.0	1.72
ESE	0.08	1.10	1.02	0.08	0.0	0.0	0.0	2.27
SE	0.24	1.18	1.25	1.57	0.08	0.0	0.0	4.31
SSE	0.24	0.86	0.86	1.49	0.55	0.0	0.0	4.00
S	0.0	0.31	1.65	1.25	0.31	0.0	0.0	3.53
SSW	0.24	1.80	3.92	7.21	3.29	1.65	0.08	18.18
SW	0.24	0.71	1.96	4.08	6.43	1.65	0.0	15.05
WSW	0.16	0.71	1.88	4.94	2.90	0.39	0.0	10.97
W	0.24	0.71	2.04	5.64	1.57	0.0	0.16	10.34
WNW	0.24	0.63	3.45	3.21	1.18	0.16	0.08	8.93
NW	0.08	0.86	2.12	2.27	0.31	0.08	0.0	5.72
NNW	0.08	0.63	0.94	0.78	0.16	0.0	0.0	2.59
Calm	-	-	-	-	-	-	-	1.02
Total	2.66	13.40	25.63	35.89	17.16	3.92	0.31	100

NOTE: Total number of valid observations is 1,276
Number of missing observations is 195
Cases this stability class are 16.1% of total observation

TABLE 2.3-4

ANNUAL WIND SUMMARY - PILGRIM SITE - ELEVATION 300 FEET MSL
SLIGHTLY STABLE, LAPSE RATE BETWEEN -0.5°C AND 1.5°C PER 100M
(Percent of Observations, May 1968 - April 1969)

Wind Direction	Wind Speed (mph) 1-3	4-7	8-12	13-18	19-24	25-31	32-38	39-50	51-75	Total
N	0.0	0.65	0.82	1.24	0.53	0.18	0.24	0.18	0.0	3.83
NNE	0.06	0.59	0.77	0.71	0.24	0.29	0.12	0.12	0.0	2.89
NE	0.12	0.59	0.71	0.29	0.18	0.24	0.29	0.0	0.0	2.42
ENE	0.12	0.65	1.47	1.30	0.18	0.12	0.06	0.12	0.0	4.01
E	0.06	1.06	1.06	0.53	0.41	0.47	0.06	0.0	0.0	3.65
ESE	0.18	0.71	1.53	1.00	0.47	0.29	0.12	0.0	0.0	4.30
SE	0.12	0.35	2.42	0.94	0.29	0.0	0.06	0.0	0.0	4.18
SSE	0.12	0.35	0.35	0.94	0.47	0.0	0.0	0.0	0.0	2.24
S	0.0	0.41	0.59	0.94	0.71	0.0	0.0	0.0	0.0	2.65
SSW	0.12	0.65	2.83	6.72	3.77	1.00	0.0	0.0	0.0	15.09
SW	0.06	0.12	1.00	3.18	3.59	0.71	0.06	0.0	0.0	8.72
WSW	0.06	0.53	1.77	4.18	3.12	0.35	0.06	0.0	0.0	10.08
W	0.18	0.71	1.77	5.66	4.60	0.82	0.41	0.06	0.0	14.20
WNW	0.12	0.47	2.24	4.66	1.89	0.59	0.18	0.0	0.0	10.14
NW	0.06	0.53	1.30	2.24	1.53	0.77	0.53	0.0	0.0	6.95
NNW	0.06	0.77	0.82	1.00	0.71	0.29	0.29	0.06	0.06	4.07
Calm	-	-	-	-	-	-	-	-	-	0.59
Total	1.41	9.13	21.45	35.53	22.69	6.13	2.47	0.53	0.06	100

NOTE: Total number of valid observations is 1,697
Number of missing observations is 127
Cases this stability class are 21.3% of total observation

TABLE 2.3-5

ANNUAL WIND SUMMARY - PILGRIM SITE - ELEVATION 300 FT MSL
NEUTRAL, LAPSE RATE BETWEEN -1.5°C AND -0.5°C PER 100M
(Percent of Observations, May 1968 - April 1969)

Wind Direction	Wind Speed (mph) 1-3	4-7	8-12	13-18	19-24	25-31	32-38	39-50	51-75	Total
N	0.07	0.30	0.57	0.63	0.73	0.47	0.80	0.20	0.0	3.76
NNE	0.07	0.40	0.77	0.77	0.87	0.60	0.43	0.17	0.0	4.06
NE	0.20	0.60	0.70	1.50	1.40	0.50	0.10	0.23	0.07	5.30
ENE	0.10	0.53	0.87	1.77	1.10	0.37	0.17	0.30	0.07	5.26
E	0.10	0.50	1.37	1.27	0.47	0.07	0.13	0.0	0.0	3.90
ESE	0.17	0.80	1.33	1.27	0.60	0.43	0.20	0.0	0.0	4.80
SE	0.03	0.50	0.83	1.23	0.37	0.37	0.10	0.0	0.0	3.43
SSE	0.13	0.17	0.60	0.73	0.20	0.30	0.10	0.0	0.0	2.23
S	0.07	0.53	1.27	1.23	0.33	0.27	0.02	0.0	0.0	3.73
SSW	0.03	0.87	3.03	5.63	3.36	0.73	0.03	0.0	0.0	13.69
SW	0.20	0.37	1.27	2.10	1.43	0.67	0.0	0.0	0.0	6.03
WSW	0.07	0.33	1.23	2.66	2.83	1.17	0.27	0.0	0.0	8.56
W	0.17	0.50	1.50	3.83	2.86	1.90	0.60	0.23	0.0	11.59
WNW	0.07	0.57	1.63	2.86	3.36	1.53	1.07	0.0	0.0	11.09
NW	0.03	0.63	0.97	1.67	2.90	1.00	0.50	0.10	0.0	7.79
NNW	0.03	0.40	0.87	1.10	0.57	0.20	0.53	0.40	0.37	4.46
Calm										0.30
Total	1.53	7.99	18.79	30.25	23.38	10.56	5.06	1.63	0.50	100

NOTE: Total number of valid observations is 3,002
Number of missing observations is 129
Cases this stability class are 37.8% of total observations

TABLE 2.3-6

ANNUAL WIND SUMMARY - PILGRIM SITE - ELEVATION 300 FT MSL
UNSTABLE, LAPSE RATE LESS THAN 1.5°C PER 100M
(Percent of Observations, May 1968 - April 1969)

Wind Direction	Wind Speed (mph) 1-3	4-7	8-12	13-18	19-24	25-31	32-38	39-50	Total
N	0.0	0.66	1.17	1.22	0.51	0.81	0.25	0.10	4.72
NNE	0.05	0.96	1.27	0.96	1.02	1.02	0.46	0.10	5.84
NE	0.10	1.12	1.93	1.22	0.56	0.36	0.10	0.15	5.53
ENE	0.15	1.27	2.13	0.76	0.41	0.05	0.0	0.05	4.82
E	0.25	1.37	1.68	0.30	0.20	0.05	0.0	0.0	3.86
ESE	0.10	1.32	2.69	1.27	0.10	0.05	0.0	0.0	5.53
SE	0.05	0.15	1.32	1.42	0.41	0.30	0.0	0.0	3.65
SSE	0.0	0.15	0.15	0.71	0.15	0.15	0.0	0.0	1.32
S	0.05	0.36	1.92	2.69	0.46	0.05	0.0	0.0	5.53
SSW	0.15	0.15	3.91	5.48	2.69	0.96	0.25	0.0	13.96
SW	0.05	0.30	1.27	3.71	2.18	0.66	0.15	0.0	8.32
WSW	0.0	0.05	1.98	3.10	1.68	0.66	0.0	0.0	7.46
W	0.0	0.46	1.17	2.23	2.89	1.37	0.30	0.0	8.43
WNW	0.0	0.51	1.32	2.03	2.59	2.18	0.41	0.0	9.04
NW	0.0	0.61	0.71	1.88	1.27	0.46	0.05	0.05	5.03
NNW	0.05	0.56	2.08	2.49	1.37	0.05	0.10	0.15	6.85
Calm	-	-	-		-	-		-	0.10
Total	1.02	10.36	26.70	31.47	18.48	9.19	2.08	0.61	100

NOTE: Total number of valid observations is 1,970
Number of missing observations is 164
Cases this stability class are 24.8% of total observation

TABLE 2.3-7

ANNUAL WIND DIRECTION SUMMARY BY STABILITY CLASS
PILGRIM SITE-ELEVATION 300 FT MSL
(Percent of Observations, May 1968-April 1969)

Wind Direction	Moderately Stable	Slightly Stable	Neutral	Unstable	All Stabilities
N	2.90	3.83	3.76	4.72	3.88
NNE	2.51	2.89	4.06	5.84	4.00
NE	3.06	2.42	5.30	5.53	4.38
ENE	2.90	4.01	5.26	4.82	4.51
E	1.72	3.65	3.90	3.86	3.49
ESE	2.27	4.30	4.80	5.53	4.47
SE	4.31	4.18	3.43	3.65	3.79
SSE	4.00	2.24	2.23	1.32	2.29
S	3.53	2.65	3.73	5.53	3.91
SSW	18.18	15.09	13.69	13.69	14.78
SW	15.05	8.72	6.03	8.32	8.62
WSW	10.97	10.08	8.56	7.46	9.00
W	10.38	14.20	11.59	8.43	11.16
WNW	8.93	10.14	11.09	9.04	10.03
NW	5.72	6.95	7.79	5.03	6.60
NNW	2.59	4.07	4.46	6.85	4.67
Calm	1.02	0.59	0.30	0.10	0.43
Total	100	100	100	100	
%of Total	16.1	21.3	37.8	24.8	100

NOTE:

Each column adds independently to 100%. To obtain percent of total for any single category, multiply percent by percent of total for that column, e.g., N winds and moderately stable conditions occur 2.90% times 16.1% of total or 0.47% of the total observations

7,945 valid observations, 615 missing observations

TABLE 2.3-8

WIND DIRECTION PERSISTENCE IN 22.5 DEGREE SECTORS
PILGRIM SITE-ELEVATION 300 FT MSL
(Persistence Duration in Hours, May 1968-April 1969)

Wind Direction	1	2	3	4	5	6	7	8	9
N	97	31	16	12	1	1			2
NNE	98	29	16	6	1	7	1	1	
NE	85	28	12	13	8	5		1	
ENE	76	22	19	10	3	2	1	2	
E	85	27	15	8	3		5	1	
ESE	63	44	16	9	6	2	3	3	2
SE	93	26	17	10	4	3	1	1	
SSE	82	18	5	2	3	2	1		
S	99	40	17	5	1	2	3	3	
SSW	109	61	52	19	21	8	7	9	6
SW	167	67	38	26	5	9	2	2	3
WSW	162	61	27	17	11	10	8	4	1
W	151	75	31	18	15	12	5	4	3
WNW	147	63	24	17	12	13	1	9	4
NW	133	49	22	13	7	5	4	3	
NNW	110	34	23	11	2	4	4		
Calm	24	1	1	1					
Total	1781	676	351	197	103	85	46	43	21

TABLE 2.3-8 (Cont)

Wind Direction	10	11	12	13	14	15	16	17	18	19	20	21	26	27	37	39
N			2													
NNE				1		1										
NE	1				1					1						
ENE	1		1	1	1	1	1		1							
E								1								
ESE	1									1						
SE	1			1												
SSE	1															
S		1	1													
SSW	5	3	2	2	2		2	3	2			1	1	1	1	1
SW	1	1		1												
WSW	1	5		1												
W	3	4	2	1	2	2			1							
WNW	3	2	1	1		1		1					1			
NW		2	1		1		1									
NNW		3														
Calm																
Total	18	21	10	9	7	5	4	5	4	2	0	1	2	1	1	1

TABLE 2.3-9

FREQUENCY DISTRIBUTION OF INVERSION PERSISTENCE
PILGRIM SITE - TOTAL TOWER
(Persistence Duration in Hours
May 1968 - April 1969)

Hours	1	2	3	4	5	6	7	8
Frequency	159	63	38	36	20	24	21	18
Hours	9	10	11	12	13	14	15	16
Frequency	9	8	19	21	30	12	16	15
Hours	17	18	19	20	21	29	46	
Frequency	11	4	2	4	5	1	1	

NOTE:

The longest inversion lasted 46 hr and ended on July 2, 1968 at 10:00 EST

TABLE 2.3-10

ANNUAL WIND SUMMARY, ALL STABILITIES COMBINED
PILGRIM SITE-ELEVATION 300 FT MSL
(Percent of Observations, May 1968-April 1969)

Wind Direction	Speed in mph 1-3	4-7	8-12	13-18	19-24	25-31	32-38	39+	Total
N	0.05	0.48	0.81	1.02	0.55	0.42	0.42	0.14	3.88
NNE	0.10	0.64	0.87	0.78	0.65	0.54	0.30	0.11	4.00
NE	0.16	0.77	1.11	1.03	0.78	0.33	0.13	0.13	4.38
ENE	0.10	0.84	1.33	1.25	0.55	0.18	0.08	0.15	4.51
E	0.14	0.87	1.28	0.68	0.31	0.14	0.06	0.0	3.49
ESE	0.14	0.96	1.66	1.02	0.35	0.24	0.10	0.0	4.47
SE	0.09	0.49	1.36	1.27	0.31	0.21	0.05	0.0	3.79
SSE	0.11	0.31	0.48	0.89	0.30	0.15	0.04	0.0	2.29
S	0.04	0.43	1.35	1.54	0.44	0.11	0.01	0.0	3.91
SSW	0.11	0.88	3.35	6.90	3.27	0.99	0.09	0.0	14.78
SW	0.14	0.35	1.32	3.05	2.88	0.83	0.05	0.0	8.62
WSW	0.06	0.37	1.64	3.46	2.62	0.74	0.11	0.0	9.00
W	0.14	0.57	1.56	4.12	3.03	1.23	0.42	0.10	11.16
WNW	0.09	0.54	1.98	3.10	2.50	1.27	0.55	0.0	10.03
NW	0.04	0.64	1.16	1.94	1.79	0.67	0.31	0.05	6.60
NNW	0.05	0.55	1.17	1.37	0.73	0.15	0.29	0.35	4.67
Calm									0.43
TOTAL	1.56	9.69	22.42	32.59	21.02	8.21	3.01	1.08	100

NOTE:

Number valid observations is 7,945
Number of missing observations is 615

TABLE 2.3-11

SIGMA THETA U-BAR, ALL STABILITIES
ELEVATION 300 FT MSL, PILGRIM SITE,
MAY 1968 - APRIL 1969
($\bar{u}$ = 1-3 mph)

			Cumulative	
$\sigma\theta\bar{u}$	Frequency	Percent	Frequency	Percent
0.0	7	11.7	7	11.7
0.05	13	21.7	20	33.3
0.1	19	31.7	29	65.0
0.2	15	25.0	54	90.0
0.3	3	5.0	57	95.0
0.4	2	3.3	59	98.3
0.5	1	1.7	60	100

NOTE:

$\sigma\theta$ in radians, $\bar{u}$ in m/sec

TABLE 2.3-12

SIGMA THETA U-BAR, ALL STABILITIES
ELEVATION 300 FT MSL, PILGRIM SITE,
MAY 1968 - APRIL 1969
($\bar{u}$ =4-7 mph)

			Cumulative	
$\sigma\theta\bar{u}$	Frequency	Percent	Frequency	Percent
0.0	0	0.0	0	0.0
0.05	16	5.0	16	5.0
0.1	24	7.5	40	12.6
0.2	55	17.3	95	29.6
0.3	83	26.1	178	56.0
0.4	43	13.5	221	69.5
0.5	58	18.2	279	87.7
0.6	18	5.7	297	93.4
0.7	9	2.8	306	96.2
0.8	4	1.3	310	97.5
0.9	5	1.6	315	99.1
1.0	0	0.0	315	99.1
1.1	1	0.3	316	99.4
1.2	1	0.3	317	99.7
1.2	1	0.3	318	100

NOTE:

$\sigma\theta$ in radians, $\bar{u}$ in m/sec

TABLE 2.3-13

SIGMA THETA U-BAR, ALL STABILITIES
ELEVATION 300 FT MSL, PILGRIM SITE,
MAY 1968 - APRIL 1969
($\bar{u}$ = 8-12 mph)

$\sigma\theta\bar{u}$	Frequency	Percent	Cumulative Frequency	Cumulative Percent
0.0	0	0.0	0	0.0
0.05	27	4.2	27	4.3
0.1	37	5.7	64	9.9
0.2	35	5.4	99	15.3
0.3	93	14.4	192	29.7
0.4	110	17.0	302	46.7
0.5	96	14.8	398	61.5
0.6	89	13.8	487	75.3
0.7	56	8.7	543	83.9
0.8	41	6.3	548	90.3
0.9	30	4.6	614	94.9
1.0	8	1.2	622	96.1
1.1	12	1.9	634	98.0
1.2	4	0.6	638	98.6
1.3	3	0.5	641	99.1
1.4	4	0.6	645	99.7
1.5	0	0.0	645	99.7
1.6	1	0.2	646	99.8
1.7	0	0.0	646	99.8
1.8	0	0.0	646	99.8
1.9	0	0.0	646	99.8
2.0	0	0.0	646	99.8
2.1	1	0.2	647	100

NOTE:

$\sigma\theta$ in radians, $\bar{u}$ in m/sec

TABLE 2.3-14

SIGMA-THETA U-BAR, ALL STABILITIES,
ELEVATION 300 FT MSL, PILGRIM SITE,
MAY 1968-APRIL 1969
(= 13 - 31 mph)

	13 - 18		19 - 24		25 - 31	
	Frequency	Cum. %	Frequency	Cum. %	Frequency	Cum. %
0.0	0	0.0	0	0.0	0	0.0
0.05	0	0.0	0	0.0	0	0.0
0.1	33	4.3	9	3.0	0	0.0
0.2	54	11.4	1	3.4	1	2.1
0.3	23	14.4	15	8.4	2	6.3
0.4	94	26.6	0	8.4	2	10.4
0.5	81	37.2	37	20.9	0	10.4
0.6	66	45.8	29	30.9	0	10.4
0.7	113	60.6	22	38.2	11	33.3
0.8	76	70.5	28	47.6	1	35.4
0.9	62	78.6	25	56.1	0	35.4
1.0	40	83.8	30	66.2	16	68.8
1.1	31	87.9	20	73.0	3	75.0
1.2	39	93.0	20	79.7	1	77.1
1.3	12	94.5	8	82.4	1	79.2
1.4	15	96.5	12	86.5	2	83.3
1.5	15	98.4	13	90.9	2	87.5
1.6	5	99.1	13	95.3	2	91.7
1.7	0	99.1	5	97.0	2	95.8
1.8	2	99.3	3	89.0	0	95.8
1.9	1	99.5	2	98.6	0	95.8
2.0	1	99.6	1	99.0	2	100
2.1	1	99.7	1	99.3		
2.2	0	99.7	0	99.3		
2.3	1	99.9	1	99.7		
3.3	11	100	0	99.7		
3.7	0	0	1	100		

NOTE: in radians, in m/sec

TABLE 2.3-15

TEMPERATURES - PLYMOUTH, MASS
(°F)

	Mean Maximum	Mean Minimum	Daily Average	Extreme Maximum	Extreme Minimum
January	38	25	30	68	-8
February	38	23	29	71	-14
March	45	29	37	87	0
April	55	37	46	91	15
May	66	46	56	94	27
June	74	55	65	102	33
July	79	62	71	102	44
August	77	61	69	102	41
September	71	55	62	100	32
October	62	46	53	87	23
November	52	37	43	82	10
December	41	29	33	67	-14
Annual	58	41	50	102	-14

TABLE 2.3-16

PRECIPITATION - PLYMOUTH, MASS.

	Normal, in	Mean No. Days ≥0.10 in	≥0.50 in	24 hr. Maximum, in
January	4.22	7	4	2.75
February	3.46	6	4	2.37
March	4.53	8	3	3.01
April	4.13	8	3	2.76
May	3.43	7	2	3.28
June	3.34	6	1	5.68
July	2.92	6	2	4.13
August	4.22	7	4	4.14
September	3.90	5	2	6.88
October	3.53	6	3	4.12
November	4.50	7	3	4.36
December	4.05	9	4	3.53
Annual	46	82	35	

TABLE 2.3-17

SNOWFALL - BOSTON, MASS.

	Monthly Average, in	Monthly Maximum, in	24 hr. Maximum, in	Mean No. Days ≥1.0 in
January	12	36	15	4
February	12	35	16	3
March	7	33	13	2
April	2	28	9	*
May	T	T	T	0
June	0	0	0	0
July	0	0	0	0
August	0	0	0	0
September	0	0	0	0
October	T	1	1	0
November	2	18	12	*
December	7	27	12	2
Annual	42	36	16	11

T - Trace
* - Less than 0.5 in

TABLE 2.3-18

MAXIMUM SUSTAINED 5 MINUTE WIND SPEED
(BOSTON, MASSACHUSETTS)

Month	Year	Description	Speed (mph)
January	1945	SW	66
February	1940	NE	58
March	1947	E	73
April	1935	NE	63
May	1935	W	55
June	1935	NW	46
July	1935	NW	52
August	1947	NE	52
September	1938	S	87*
October	1933	NW	63
November	1950	SE	80
December	1934	W	73

NOTE:

*Due to the hurricane of September 21, 1938

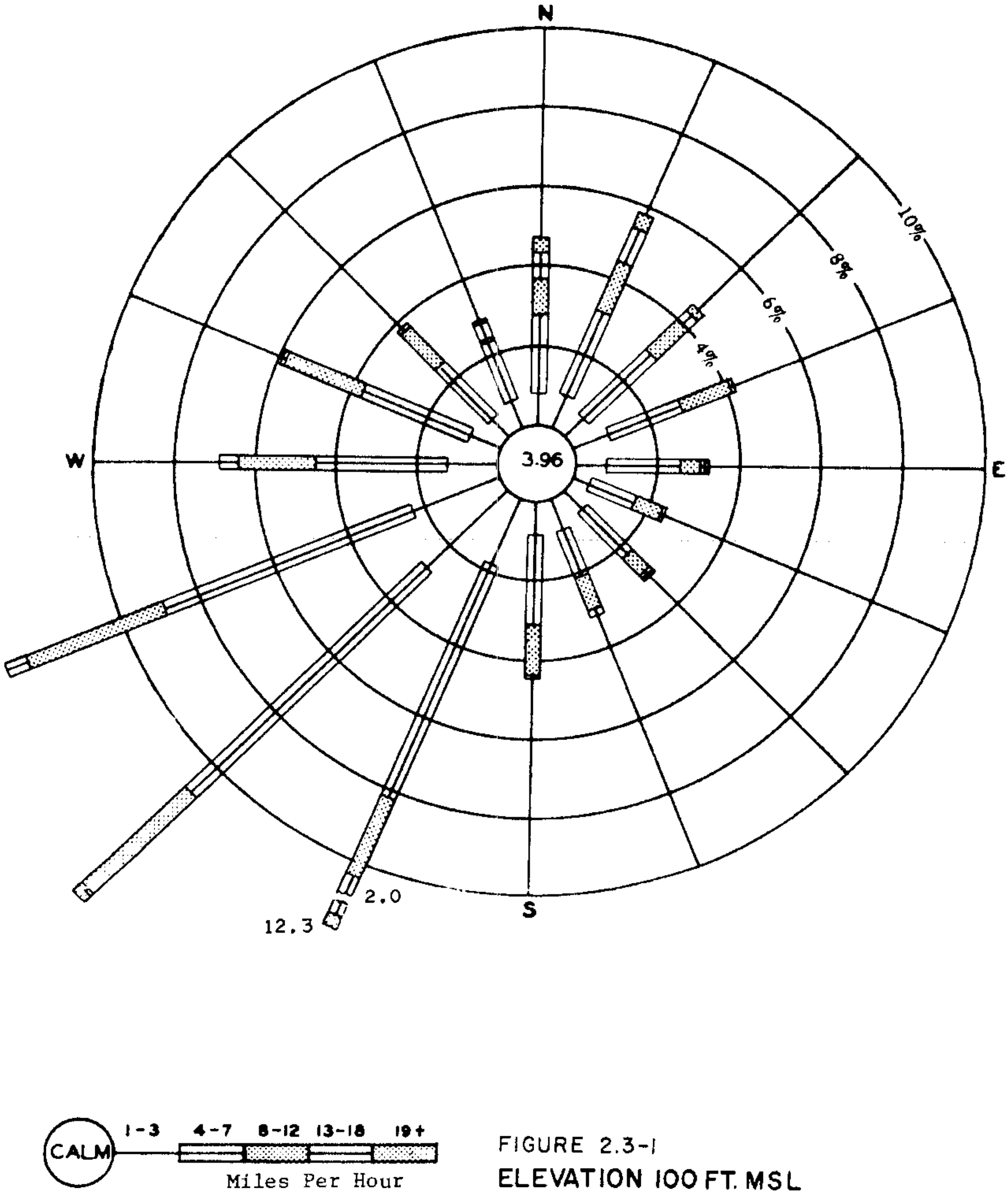


FIGURE 2.3-1
ELEVATION 100 FT. MSL
WIND ROSE ANNUAL
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

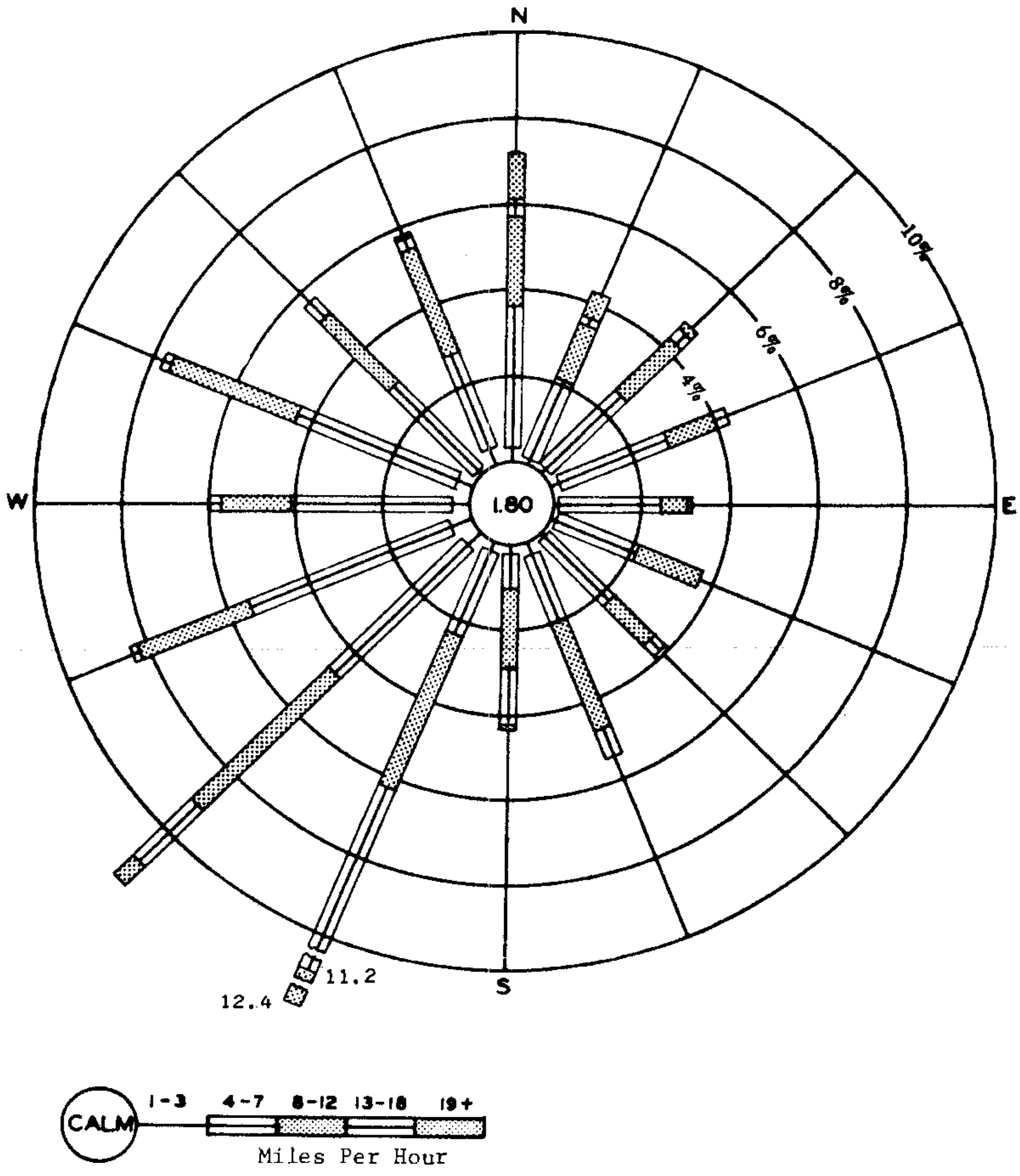


FIGURE 2.3-2
ELEVATION 100 FT. MSL
WIND ROSE SPRING
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

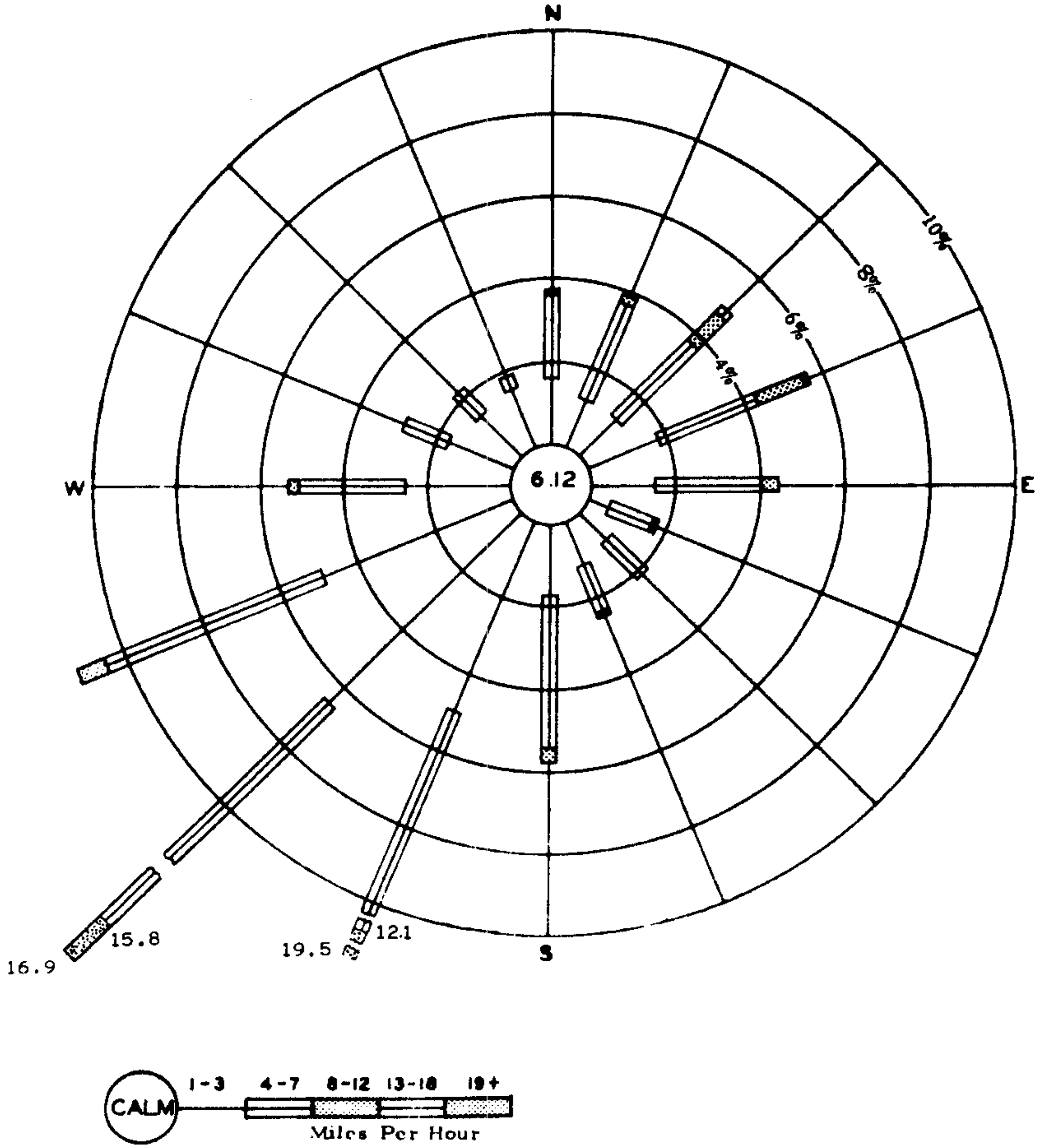


FIGURE 2.3-3
ELEVATION 100 FT. MSL
WIND ROSE SUMMER
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

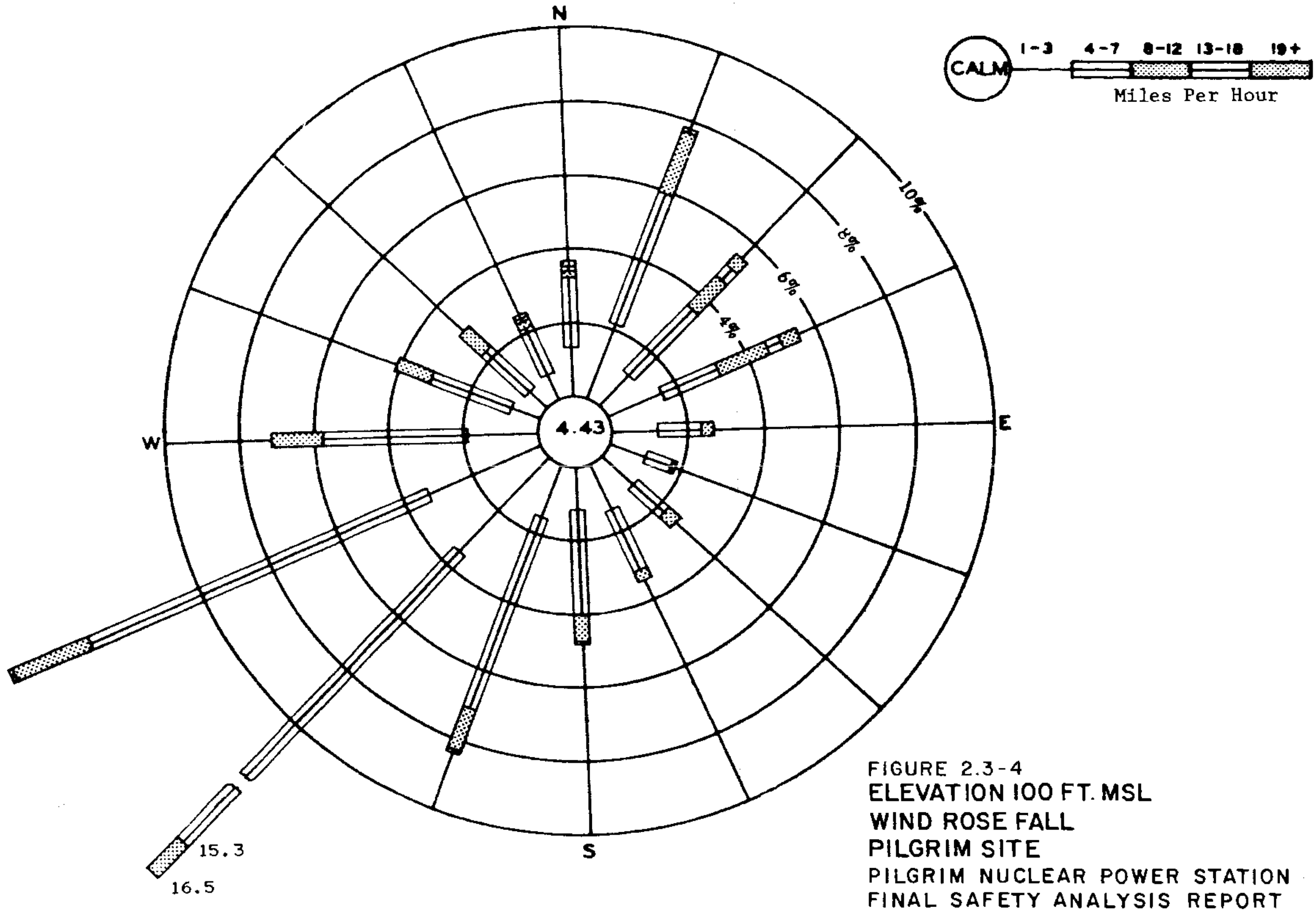


FIGURE 2.3-4
ELEVATION 100 FT. MSL
WIND ROSE FALL
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

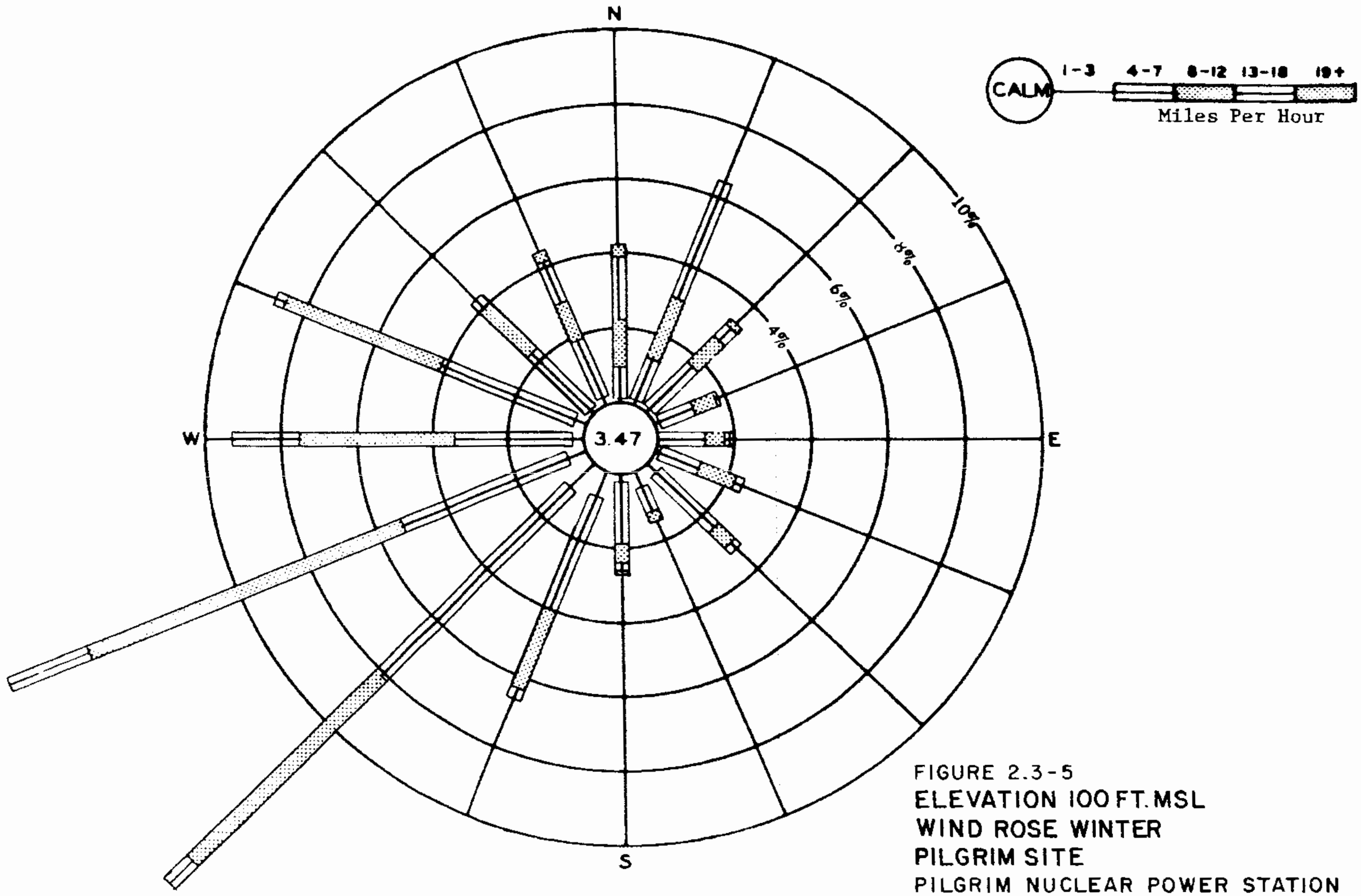


FIGURE 2.3-5
ELEVATION 100 FT. MSL
WIND ROSE WINTER
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

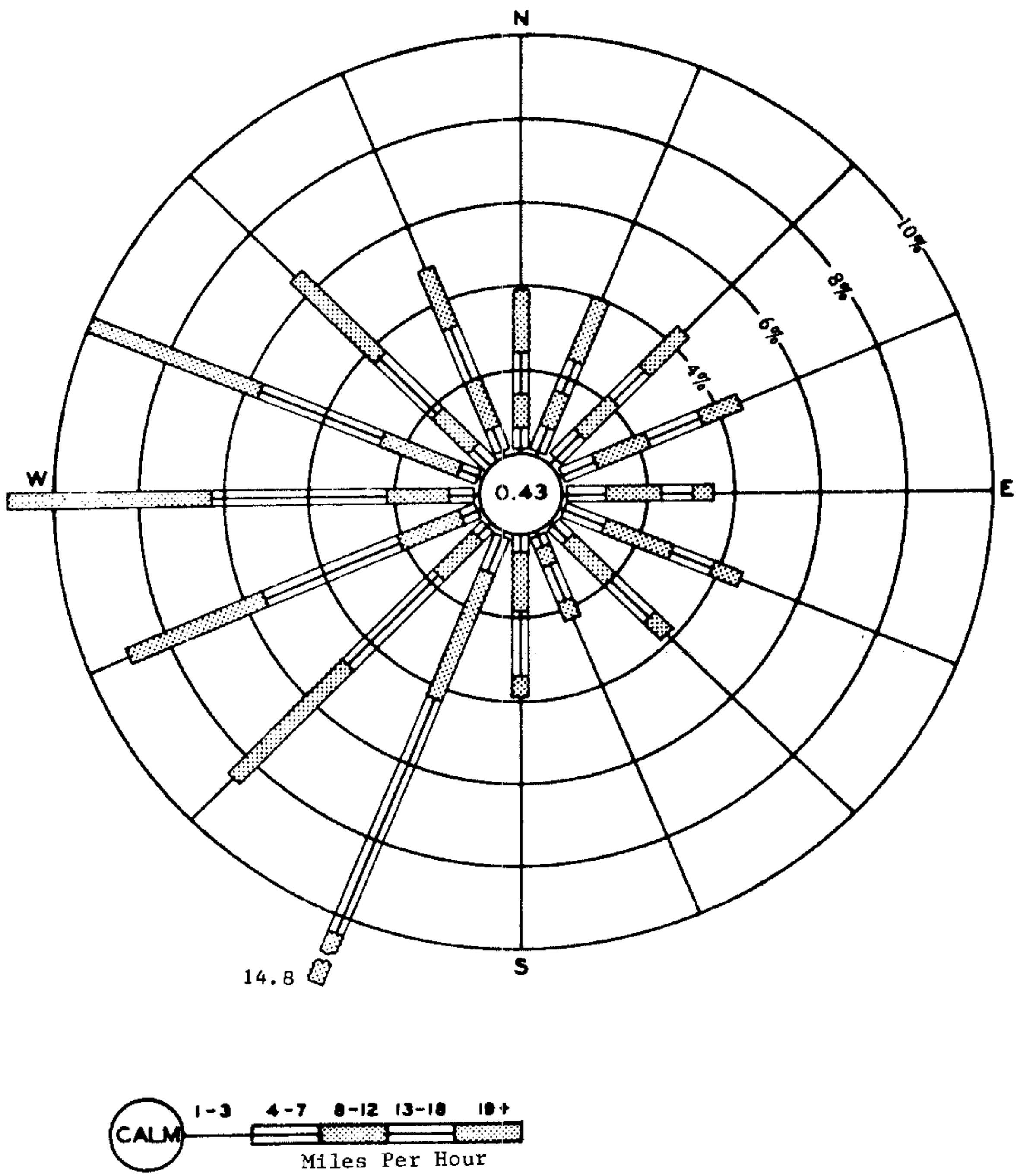


FIGURE 2.3-6
ELEVATION 300 FT. MSL
WIND ROSE ANNUAL
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

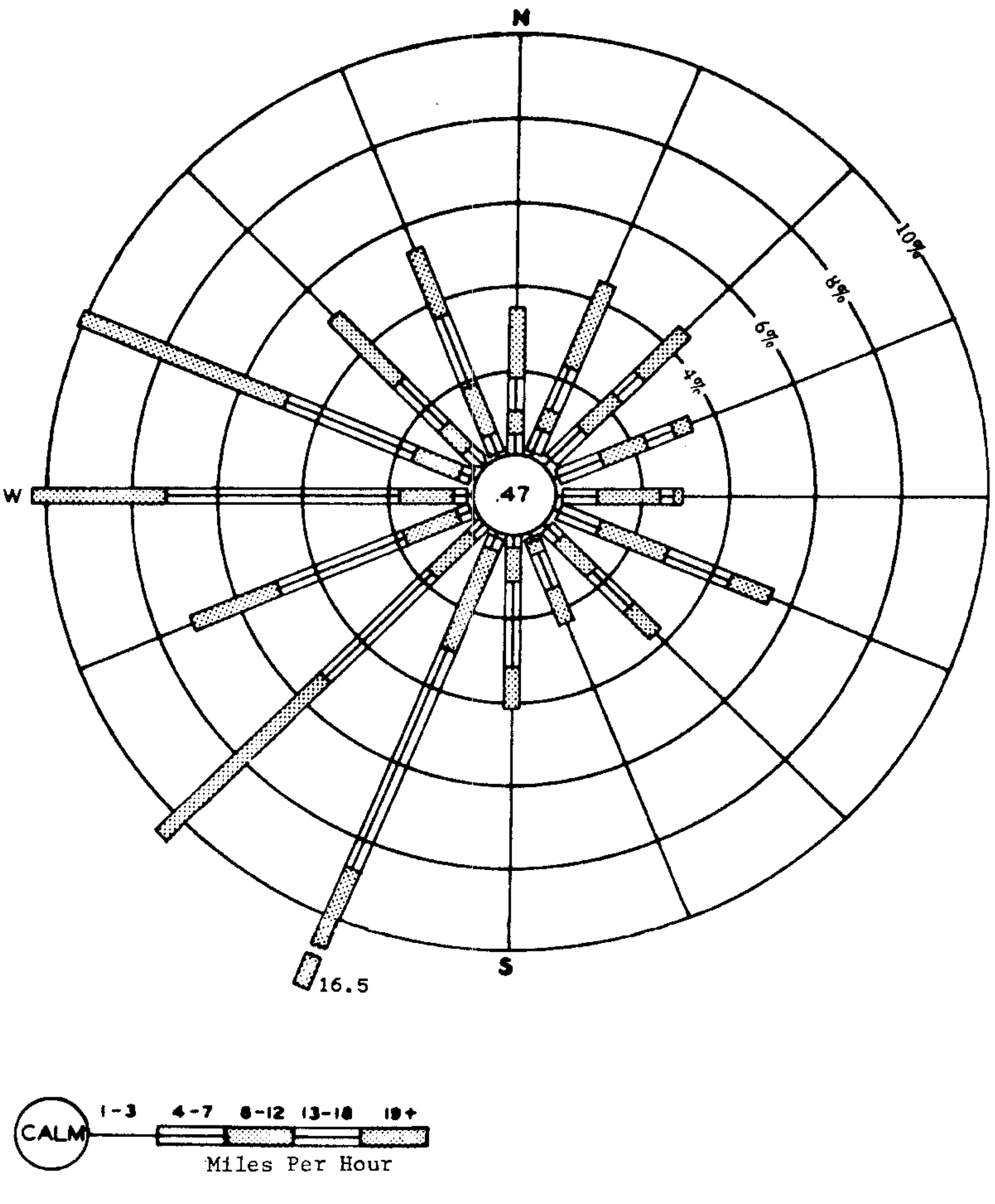


FIGURE 2.3-7
ELEVATION 300 FT. MSL
WIND ROSE SPRING
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

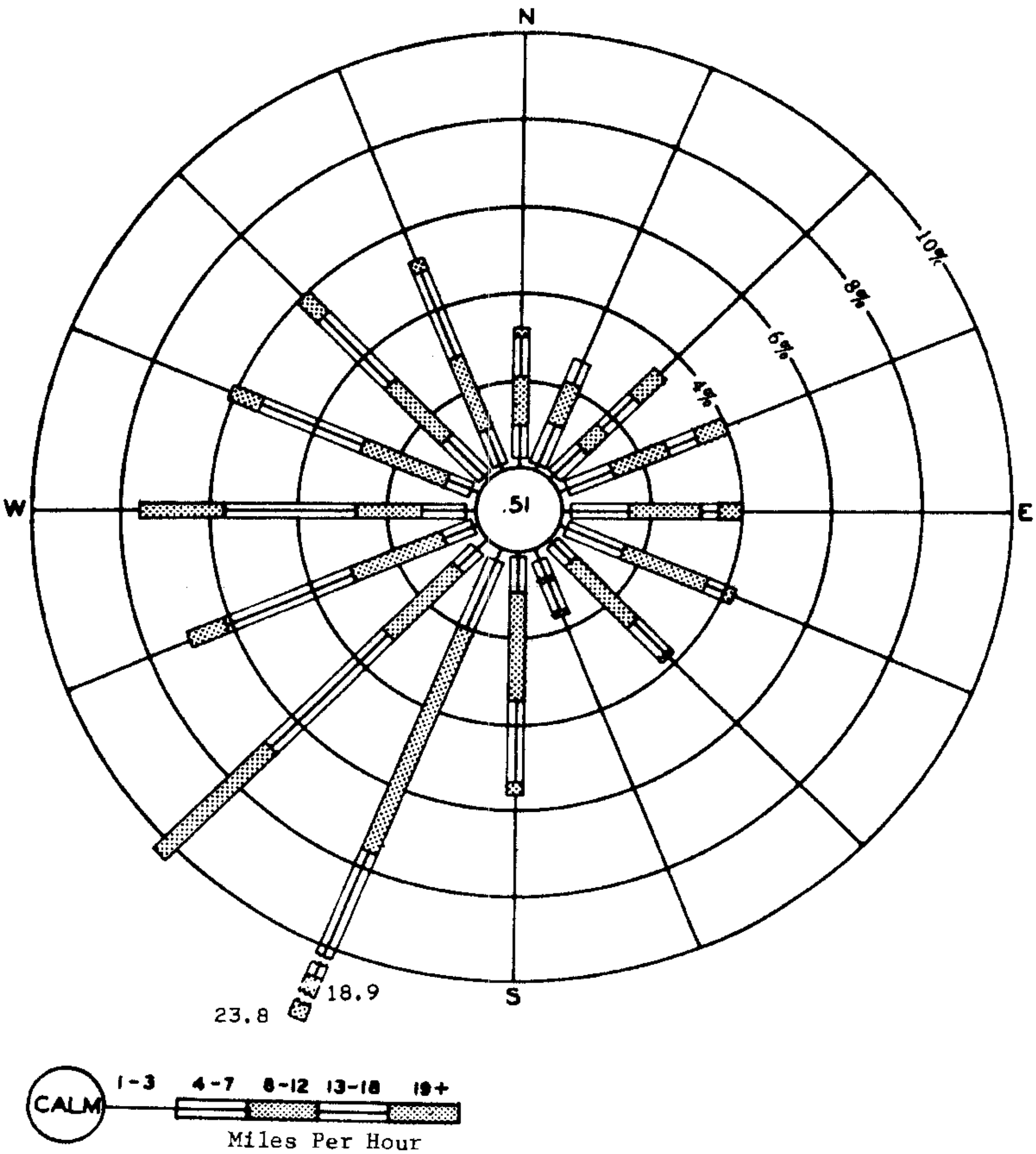


FIGURE 2.3-8
ELEVATION 300 FT. MSL
WIND ROSE SUMMER
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

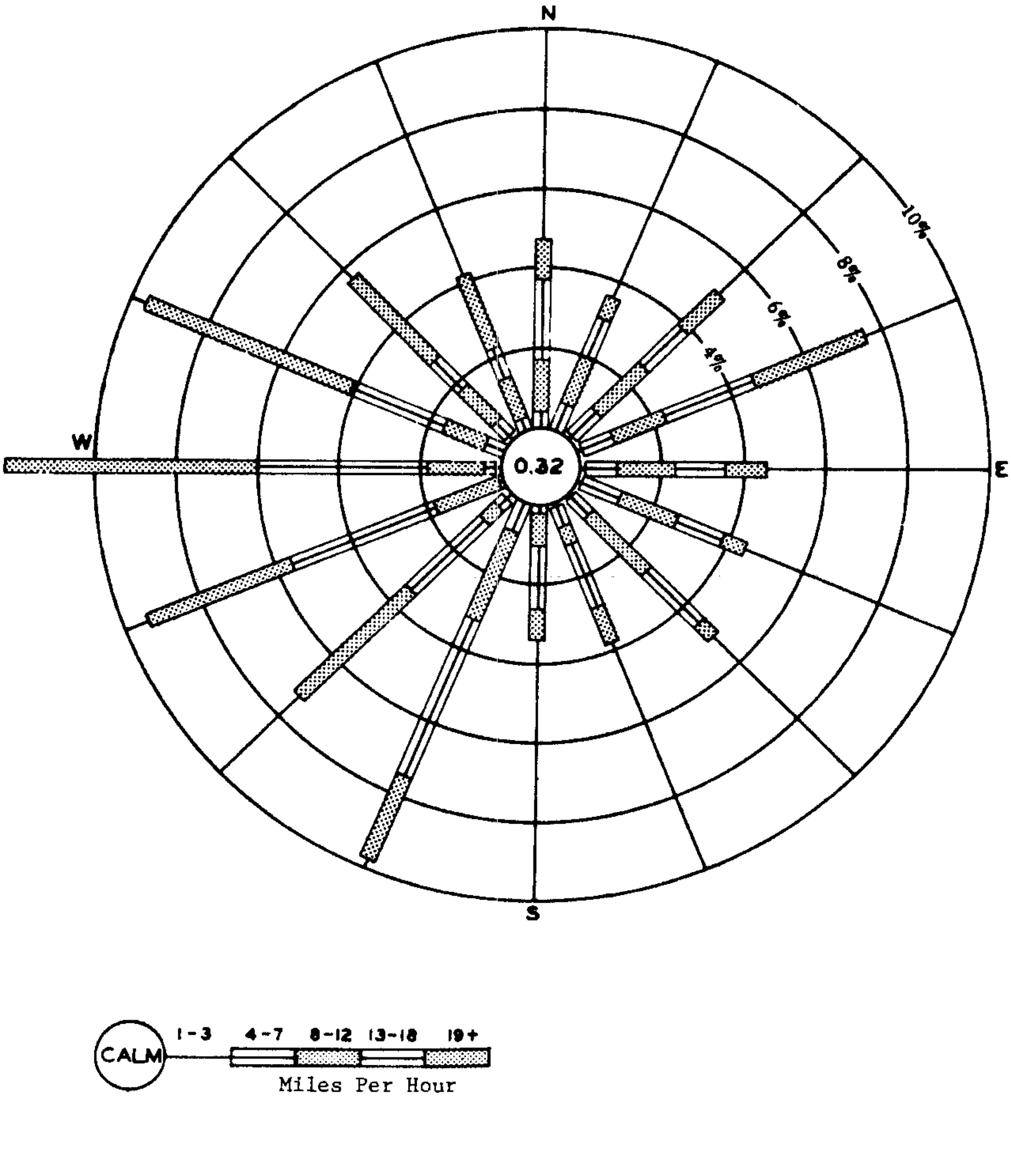


FIGURE 2.3-9
ELEVATION 300 FT. MSL
WIND ROSE FALL
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

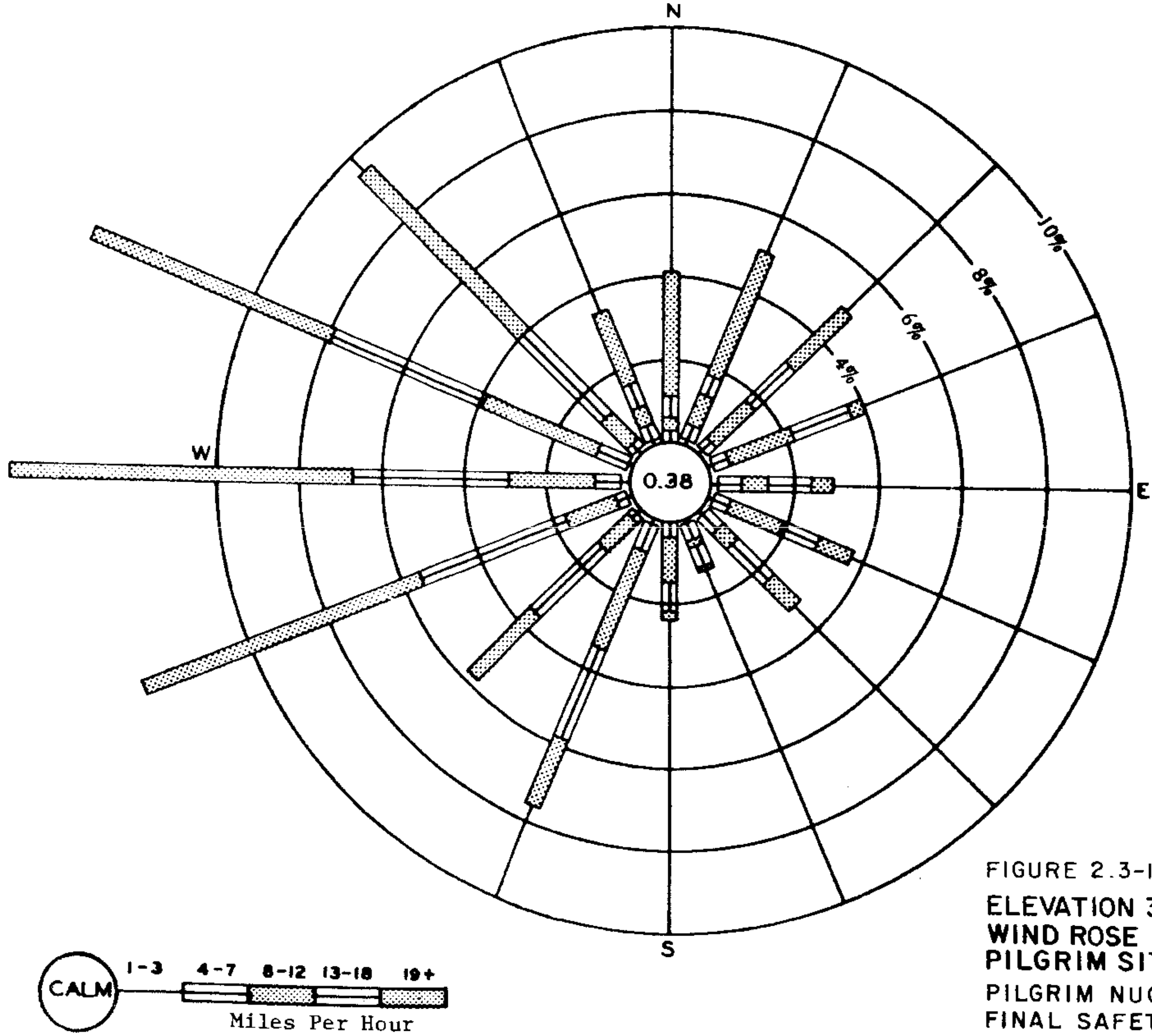
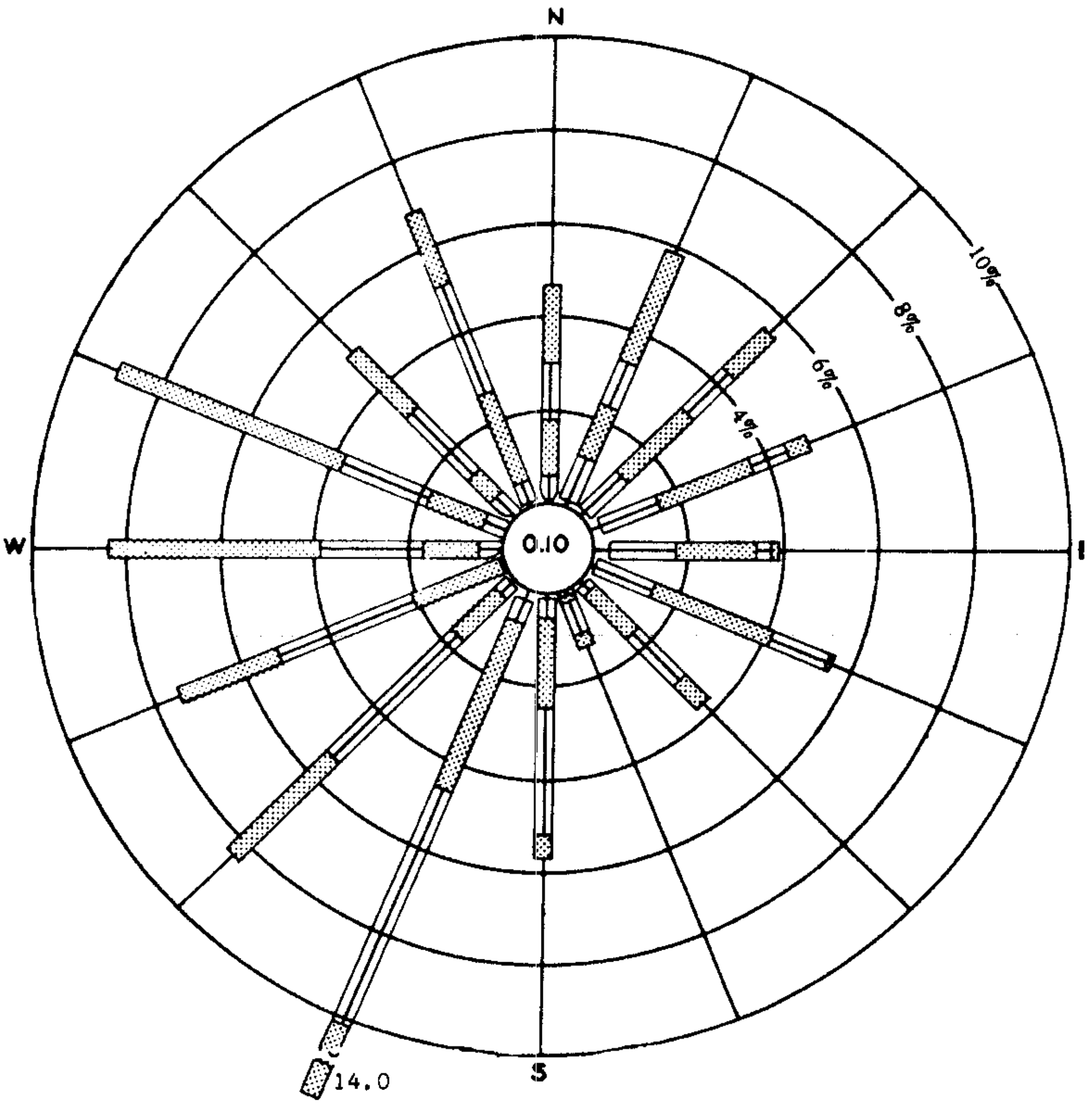


FIGURE 2.3-10

ELEVATION 300 FT. MSL
WIND ROSE WINTER
PILGRIM SITE

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



Note:
This stability class accounts for 24.8% of total annual observations.

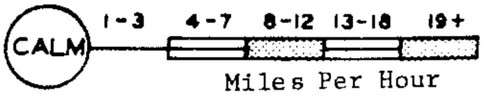
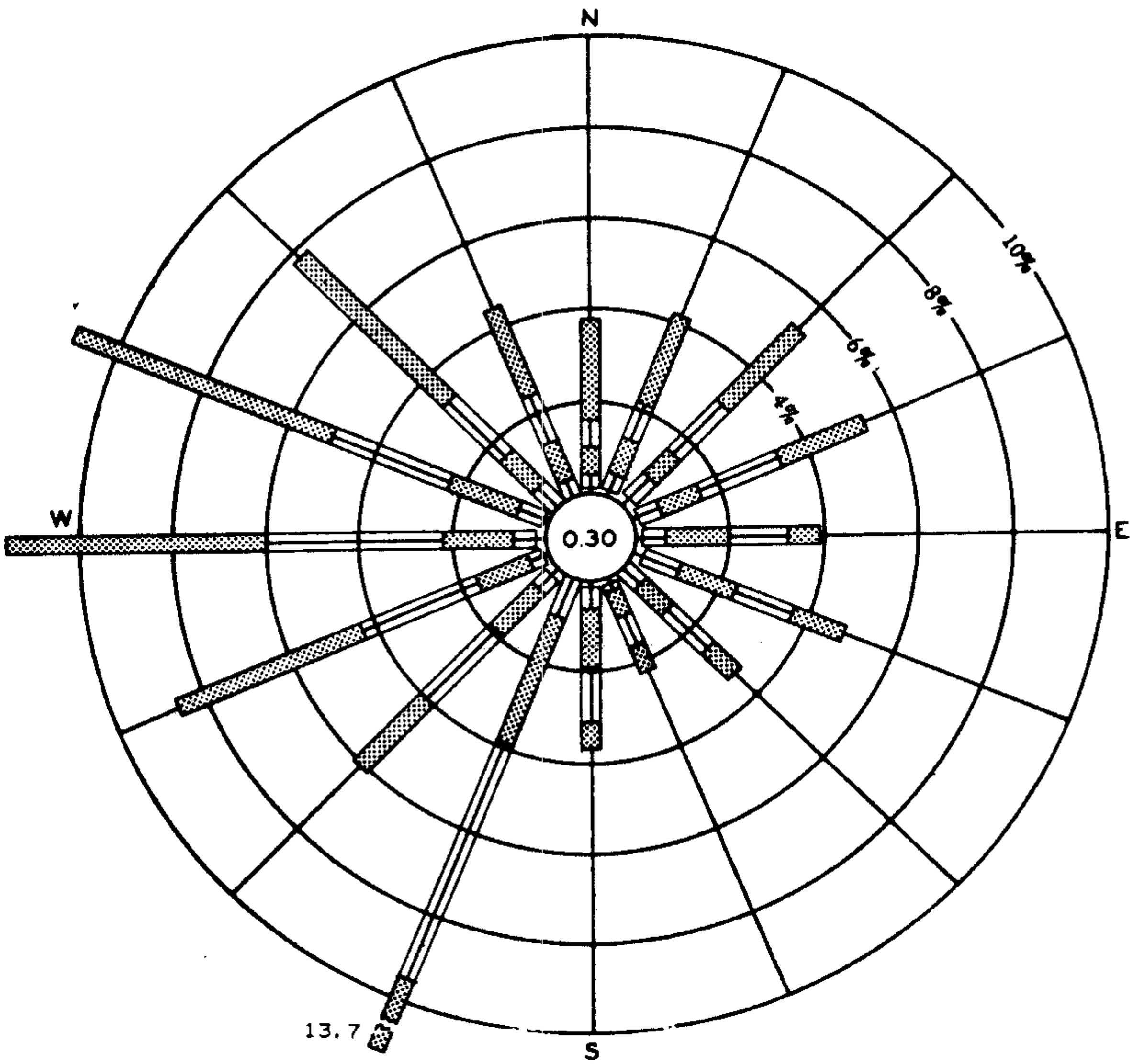


FIGURE 2.3-11

ELEVATION 300 FT. MSL-WIND ROSE
UNSTABLE LAPSE RATE
PILGRIM SITE

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



Note:
This stability class accounts for 37.8%
of total annual observations.

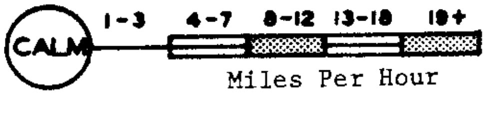


FIGURE 2.3-12
ELEVATION 300 FT. MSL - WIND ROSE
NEUTRAL LAPSE RATE
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Note:
This stability class accounts for 21.3% of total annual observations.

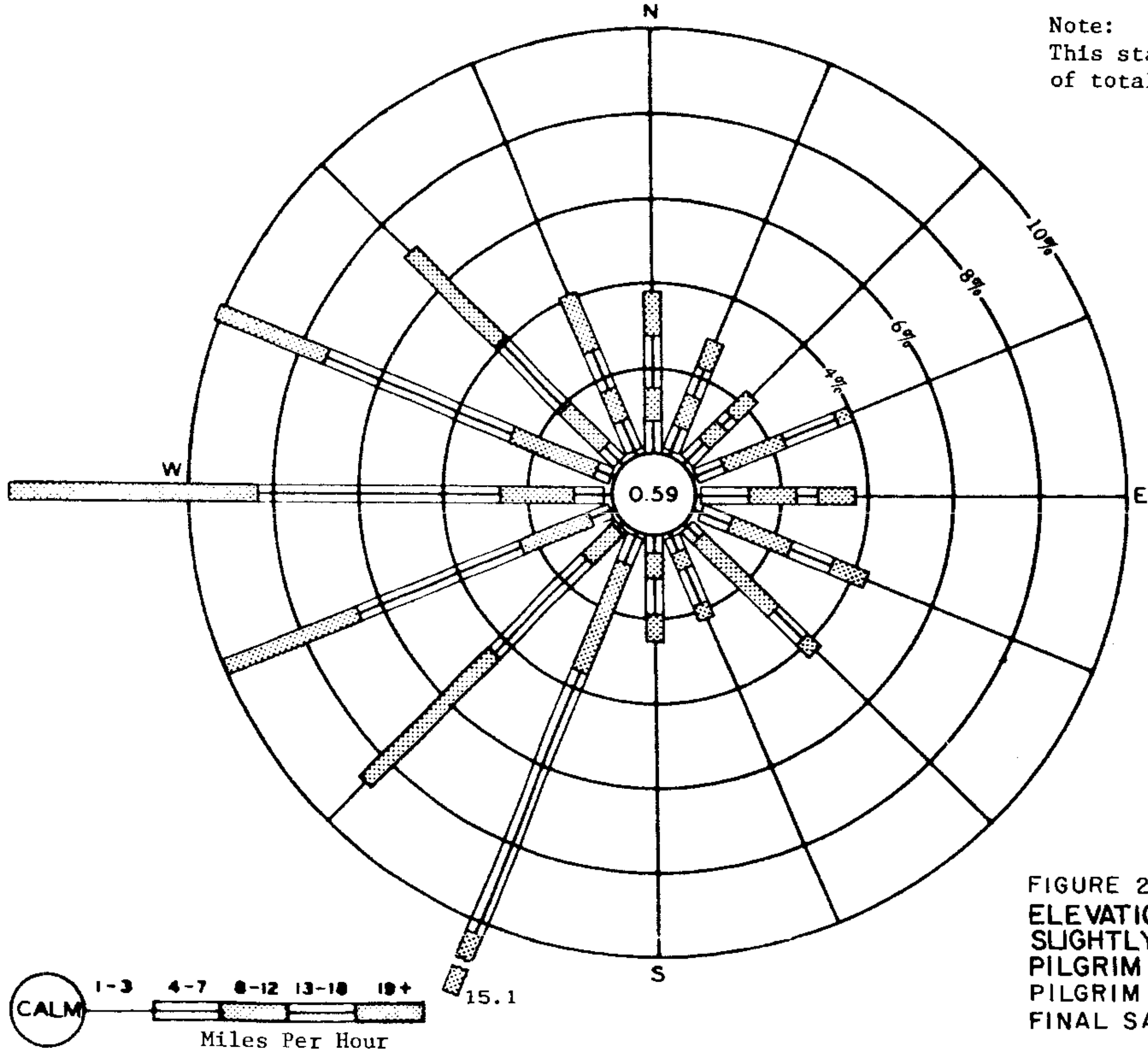
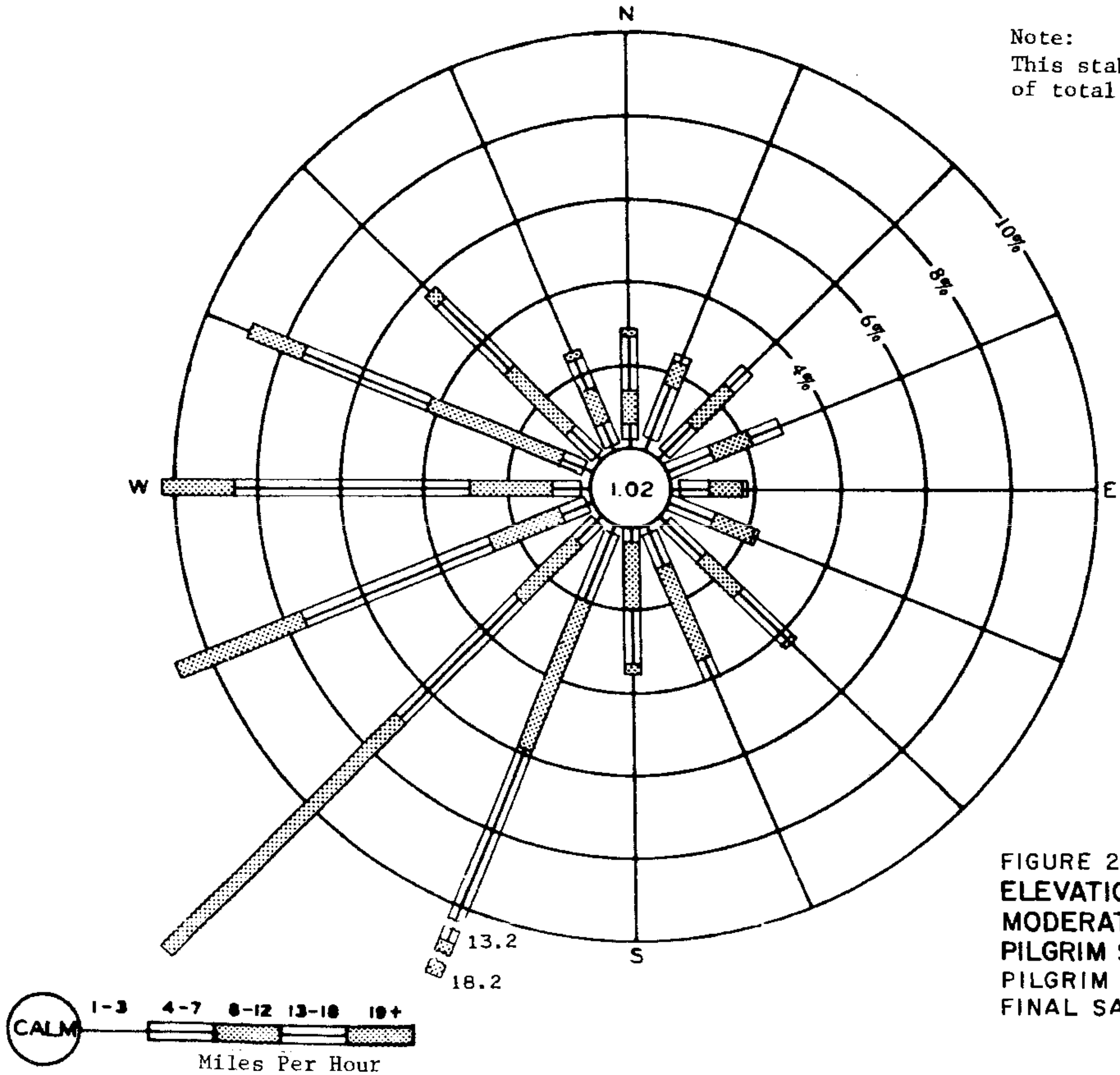


FIGURE 2.3-13
ELEVATION 300 FT. MSL-WIND ROSE
SLIGHTLY STABLE LAPSE RATE
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



Note:
This stability class accounts for 16.1% of total annual observations.

FIGURE 2.3-14
ELEVATION 300 FT. MSL-WIND ROSE
MODERATLY STABLE LAPSE RATE
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

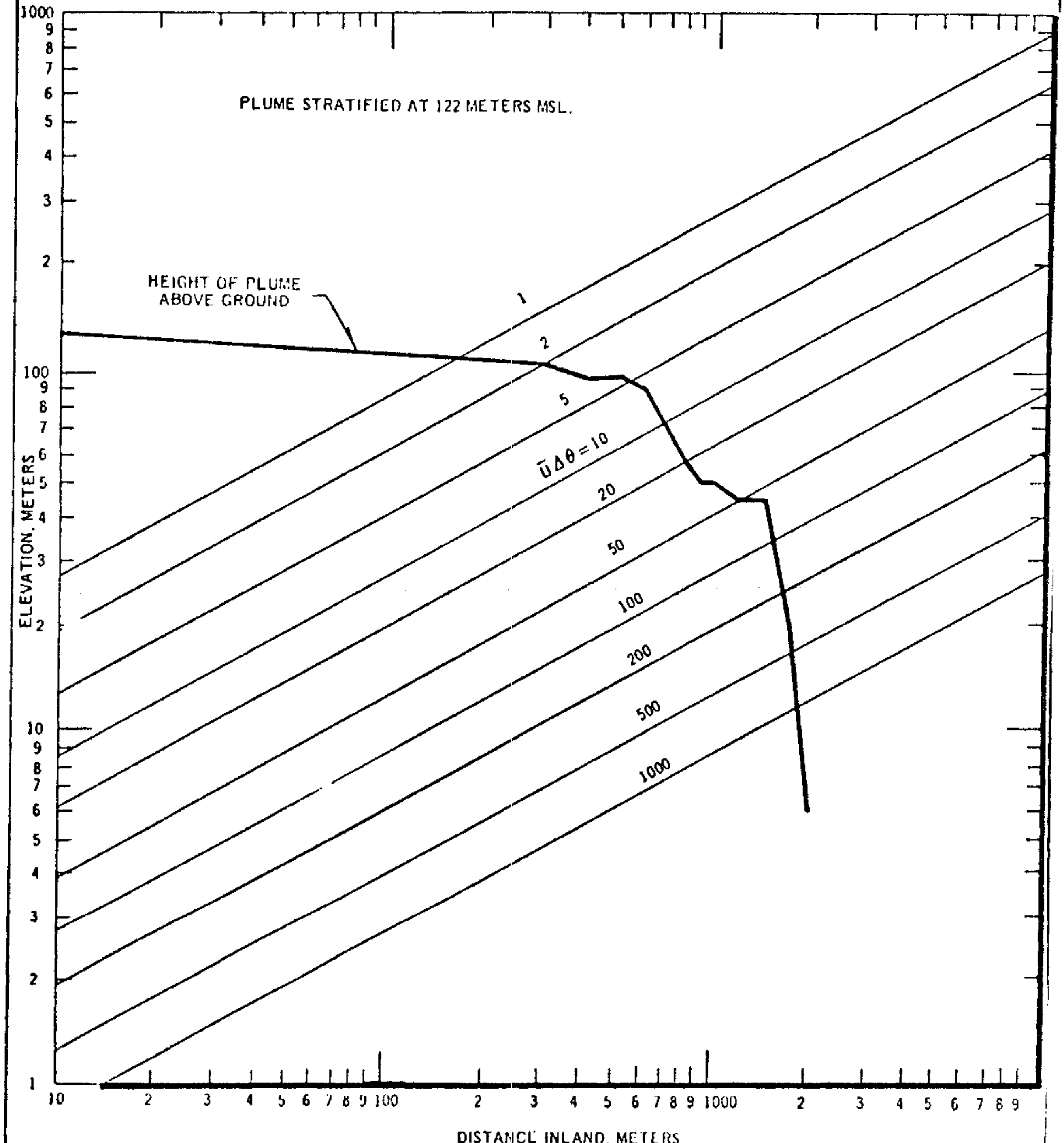


FIGURE 2.3-15
VERTICAL MIXING DEPTH
NNE WIND
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

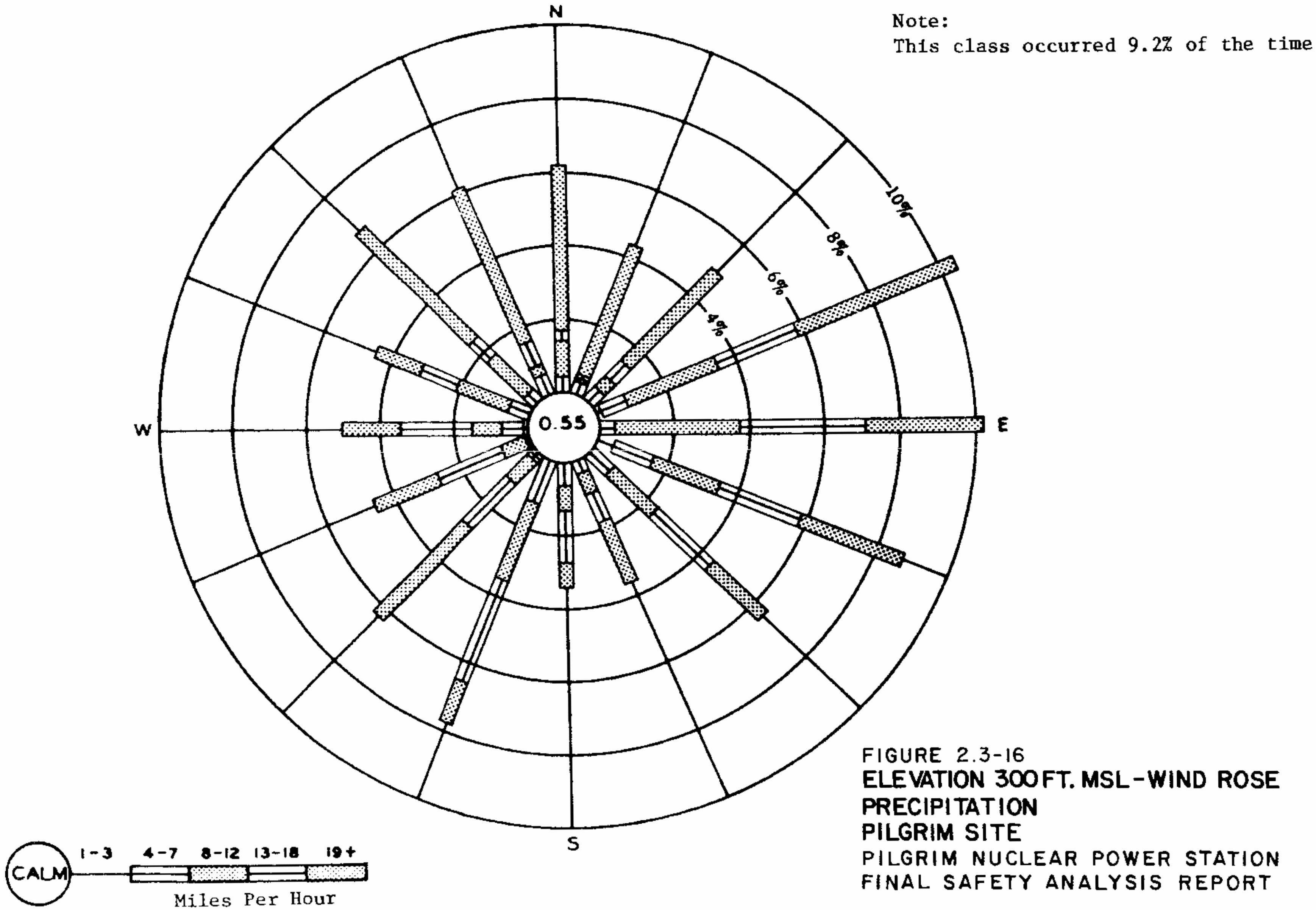


FIGURE 2.3-16
ELEVATION 300 FT. MSL-WIND ROSE
PRECIPITATION
PILGRIM SITE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

2.4 HYDROLOGY

2.4.1 Land Area Hydrology

2.4.1.1 Introduction

The site is located on the northeast side of the Pine Hills. The Pine Hills consist of a north-south trending ridge approximately 4 mi long which rises to an elevation of 395 ft mean sea level (msl). The ridge is the major drainage divide in the area.

Hydrologic studies include a field survey, a review of significant published and unpublished literature, and discussions with representatives of local and state agencies. The field investigation included borings, measurement of ground water levels, and collection of well data.

2.4.1.2 Surface Water

The site is located in a small, isolated drainage area on the northeast side of the Pine Hills, as shown on Figure 2.4-1. All surface drainage in the station site area is into Cape Cod Bay. The 40 ft msl ground surface contour closes within the property boundary and is open only to the bay. Thus, any flow along the ground surface will trend to the ocean. This contour crosses Rocky Hill Road, a public road. The 24 ft msl contour closes seaward of this road. Station grade is 20 ft msl. Therefore, there is no possibility of surface drainage from the station site area to any property not owned by the Applicant.

The surface soils consist primarily of sands with varying amounts of silts, clays, and some gravel and boulders. In general, the surface permeability in the area is moderately high. The vegetation cover consists mainly of relatively small deciduous trees and some conifers. Low brush is found throughout the site.

Surface water use by the plant is discussed in the responses to Questions A.1 and A.2 of the Pilgrim Nuclear Power Station, Unit 1, Appendix I Information Responses, 1977.[1]

2.4.1.3 Ground Water

2.4.1.3.1 Regional Area

Most of the residences in the area receive their water from the Town of Plymouth. The town water supplies are obtained from:

1. Great South Pond and Little South Pond, located 5 mi southwest of the site

2. Lout Pond and Lout Pond Well, located 4 3/4 mi west of the site

3. Manomet Well, located 2 3/4 mi southeast of the site

The average daily usage from the two town water wells during 1965 and 1966 was approximately one million gal/day.

Residents within a 2 1/2 mi radius of the site receive water from the town supply with three known exceptions. These exceptions, which operate their own wells are:

1. Mariner Boat Shop, approximately 1 mi southwest of the site

2. Plymouth Country Club well, approximately 1 1/2 mi southwest of the site. This well is used for irrigation of the golf course

3. Private well, adjacent to southern site boundary. This well is occasionally used to irrigate a cranberry bog

The locations of the town water mains and the known water wells are shown on Figure 2.4-1.

Plant groundwater use is described in the responses to Questions A.1 and A.2 of the Pilgrim Nuclear Power Station, Unit 1, Appendix I Information Responses, 1977.[1]

2.4.1.3.2 Site Area

Most of the subsurface conditions at the site are similar to those in the surrounding area. The ground water table generally follows the site surface topography. As a result, moderately steep ground water gradients are present with flow toward Cape Cod Bay.

2.4.2 Physical Oceanography

2.4.2.1 Introduction

General oceanographic data from outside sources has been supplemented by the following studies conducted specifically for the site:

1. Preliminary drogue studies and collection of sea temperature data by Dames and Moore (1967)

2. Interim drogue studies (November 1967)

3. Extended drogue and dye studies (August 1968)

4. Installation and operation of an offshore instrumentation station to measure sea temperatures and currents (1968)

Results of the studies are summarized in the following sections.

2.4.2.2 Circulation Patterns

The general current regime in Cape Cod Bay is discussed in detail in Section 2.4.4. Currents offshore at the site have been measured and

recorded by a series of drogue studies, a dye study, and by offshore instrumentation.

The regime within 1/2 mi of the site is much less well defined farther out because current velocities are much lower near shore. During a period of 4 weeks in April and May 1968, currents measured 5 ft below the surface exceeded 0.6 knots for less than one percent of the total time. The counterclockwise movement within Cape Cod Bay is reduced but not entirely eliminated by the reduction in depth and the proximity of submarine ledges offshore from Rocky Point and Manomet. This basic southeasterly direction is modified but not reversed by tidal action, and the resultant currents are small on the surface and almost negligible near the bottom.

A close correlation between wind and surface water motion was observed in all the drogue tests and also by the dye test. During the latter, conditions were almost wind free for the early part of the test and the southeasterly movement persisted throughout the tidal cycle. During the latter part of the test, offshore winds approached 10 knots and the direction of dye dispersion closely followed the wind.

The behavior of near-surface currents during 4 weeks of April and May 1968, has also been compared with wind records from the site weather station. Close correlation was established between wind and surface water movements. Wind influences normally decrease sharply with depth and are occasionally offset by upwellings and reversals in direction of lower level flow. The correlative movement of water at the site is southeasterly in direction and corresponds to the well defined counterclockwise movement farther out. The basic direction is modified but not reversed by tidal action. The net southeasterly movement probably averages less than 0.1 knot over the entire depth. Short term surface currents are closely correlated to wind action, which is more readily detected than tidal effects. The currents at the site are relatively small and highly irregular in magnitude and direction.

Additional information on circulation patterns and currents in Cape Cod Bay is presented in the response to Question A.6 of Pilgrim Nuclear Power Station, Unit 1, Appendix I Information Responses, 1977.[1]

2.4.2.3 Temperature and Salinity

2.4.2.3.1 Temperature

This Section reviews ocean temperature records for the Cape Cod Bay area and presents data obtained offshore, adjacent to the site.

The longest term measurements of seawater temperatures in Cape Cod Bay are those made at Coast and Geodetic Survey Tide Stations. Two tide stations are considered in this study: Boston, north of the site, and the eastern entrance of Cape Cod Canal, south of the site. Surface temperatures are measured daily at each station by a single

bucket thermometer. The depth of water at both tide stations is about 10 ft at mean low water. Records are available for Boston from 1922 to 1962, and for Cape Cod from 1955 to 1962. In addition, there have been continuous measurements of bottom water temperature at Boston since 1955.

The World Atlas of Sea Surface Temperatures is a source of mean monthly temperatures for the Cape Cod area. Published in 1944, these figures are the results of a number of temperature surveys in the North Atlantic.

Figure 2.4-2 shows maximum, minimum, and mean surface temperatures for the Cape Cod Canal and Boston Tide Stations. Also plotted are mean temperatures from the World Atlas of Sea Surface Temperatures. The maximum at Boston is 75°F, while Cape Cod Canal is slightly cooler with a maximum of 74°F during the summer. The mean temperature at Cape Cod Canal is less than at Boston due to much lower minimum temperatures. The mean temperatures from the World Atlas closely follow the means for the two tide stations. The difference in temperatures between Boston and Cape Cod Canal is possibly due to Boston's large estuary and Cape Cod's more exposed location.

Figure 2.4-3 shows average seawater temperature measurements recorded offshore at the site for the month of August 1967, and comparable records from Boston U.S.C. & G.S. Station. The temperatures plotted are daily averages of the highest and lowest readings. The highest single reading was 66°F and within a 24 hr period surface temperature differences of up to 9°F were observed. The differences between surface and seabed temperatures at the site ranged between 1°F and 7.5°F. The surface temperatures are typically more than 5°F less than those recorded at Boston.

Figure 2.4-4 presents 1968 average surface and seabed water temperature records from the site and U.S.C. & G.S. surface records for a comparable period at Boston. The site records were obtained from the offshore instrumentation for the periods April 26 to May 21, and August 12 to August 24. Hand samples were used between June 29 and August 10, 1968. Figure 2.4-5 shows 1969 temperature records. The records show good correlation, with a consistently higher temperature at Boston and a typical differential of about 5°F above the surface temperature at the site. The difference between surface and seabed temperatures at the site ranges between 0°F and 10°F indicating the instability of the thermocline which develops in the summer. The incidence of a high surface temperature is accompanied by a relatively low seabed temperature. During August, a sharp reduction in surface temperature and an increase in seabed temperature occur together, implying that the vestigial thermocline (T) was lost due to increased mixing of surface and lower waters.

The collected seawater temperature data for the site indicates a temperature pattern similar to both the eastern entrance of Cape Cod Canal and Boston. The temperatures will be cooler at the site than at Boston. In deep water a thermocline develops at depths of between

30 and 60 ft during the months of June through October. At -30 ft mean low water (mlw) offshore at the site, the temperature stratification is less consistent. Although a differential of up to 10°F commonly exists between surface and bottom temperatures, the temperature stratification is very sensitive to disruption by turbulence following wind action when differential temperatures of 1° to 2°F are commonly observed. However, the decrease in temperature differential is accompanied by a drop in absolute surface temperature. Short term natural temperature fluctuations exceeding 7°F are routinely observed at the site within 24 hr periods.

2.4.2.3.2 Salinity

Mean surface salinity offshore at the site is essentially static, with an annual observed deviation of not more than 0.6 ppt. Peak salinity has been observed in August at 33.7 ppt with a minimum of 29.1 ppt in May.

2.4.3 Condenser Circulating Water Dispersion

2.4.3.1 Oceanographic Factors

2.4.3.1.1 Physical Description of Cape Cod Bay

The U.S. Coast and Geodetic Survey Chart 1208 shows Cape Cod Bay to be a broad, open mouthed water body formed by the eastward and then northward extension of Cape Cod out from the coast of Massachusetts. The bay faces to the north, with Race Point, the westward extension of the hook of Cape Cod, distinctively marking the mouth of the bay on its eastern side. The mouth is not well marked on the western side, but for purposes of this brief description, a line extending from Race Point westward to Bartlet Rock, just off the entrance to Green Harbor, is considered to designate the mouth of Cape Cod Bay. The length of this line is 17 1/2 nautical mi, and the bay has its greatest width of 24 nautical mi along an east-west line near the southern limits of the bay. The north-south dimension of the bay is just under 20 nautical mi.

Cape Cod Bay has a surface area of approximately 430 mi^2 (nautical), or 365,000 acres. Except for the southeast corner of the bay, where Billingsgate shoal is found, depths generally increase rapidly from shore. The largest depths, about 180 ft, occur at the mouth of the bay. About 1/2 the surface area of the bay has depths greater than 100 ft, and the volume-mean depth is also about 100 ft. The volume of Cape Cod Bay is therefore about 1.6 X 1012 ft^3.

2.4.3.1.2 Tide and Tidal Currents

Information compiled by the U.S. Coast and Geodetic Survey indicates that the tidal wave entering Cape Cod Bay from the north proceeds southward along the western shore of the bay, and then eastward along the southern shore of the bay somewhat faster than the southward movement of the wave along the eastern shore of the bay. The following lists the time difference between the time of high water at

several locations around the bay, and the time of the corresponding high water at Boston. Also listed is the time difference between the time of low water at these locations and the time of low water at Boston, as well as the average of these two differences for each location. The locations are listed in order of increasing distance from Boston, proceeding along the shoreline of Cape Cod Bay in a counterclockwise direction.

Location	Time Difference High Water (Min)	Time Difference Low Water (Min)	Average Time Difference (Min)
Gurnet Pt.	+02	+07	+04 1/2
Plymouth	+05	+20	+12 1/2
Barnstable	+09	+28	+18 1/2
Wellfleet	+12	+28	+20
Provincetown	+14	+16	+15
Race Pt.	-03	-04	-03 1/2

The data for the northern end of Cape Cod Canal have not been included in this compilation, since the canal produces anomalous time differences at that location. The above data show that the tide is progressively later for successive locations proceeding southward along the western shore of the bay, and then eastward along the southern coastline of the bay. Likewise, the tide is progressively later for successive positions proceeding southward along the eastern shore of the bay from Race Point at the mouth of the bay as far as Wellfleet, which appears to be close to the location of the nodal point for the tide in Cape Cod Bay.

If high water occurred simultaneously throughout the bay, the tide in Cape Cod Bay would have the characteristics of a pure standing wave. In this case high water would occur at the time of slack water (that is, zero tidal current) between flood and ebb flows, and low water would occur at the time of slack water between ebb and flood flows. The observed progressive differences in the time of high water, and in the time of low water at the several locations along the shore of Cape Cod Bay, indicate that the tide in the bay departs slightly from a pure standing wave. We would therefore expect that high water would not occur at the same time as slack before ebb in the tidal current, but rather a short time before slack water during the later half of the flood current phase. Likewise, low water should occur at a time between the time of maximum ebb current and the succeeding slack water.

The results of the measurement and analysis of tidal currents made off Gurnet Point, off Manomet Point, and a mile east of Ellisville Harbor have been published by the U.S. Coast and Geodetic Survey. Tidal currents along the western and southwestern sides of Cape Cod Bay are generally directed parallel to the coast, except in or near the entrances to appended harbors. Flood currents are directed down the coastline, that is toward the southeast, while ebb flow is directed northerly up the coastline. A comparison of the times of

the various stages of the tide and of the tidal current show that for the coastline in the vicinity of the plant site, high water occurs approximately 1 hr before the end of flood flow, and low water occurs approximately 1 hr before the end of ebb flow. Maximum ebb and flood current speeds appear to vary considerably with location. For the three locations nearest the plant site for which tidal current data are given by the U.S. Coast and Geodetic Survey (that is, for Gurnet Point, Manomet Point, and off Ellisville Harbor) the maximum predicted tidal current speeds varied from 0.3 knots and 1.4 knots.

A current measurement program was initiated in the immediate vicinity of the plant site as part of an overall environmental study. The results of these measurements indicate that in the inshore waters off the plant site, out to a distance of about 3/4 mi from shore (i.e., in water depths of 40 ft and less), the tidal component of the currents is quite weak, being certainly less than 0.1 knot and probably less than 0.05 knot. The local water movement near the plant site appears to be primarily related to wind action.

Tidal data compiled from a number of locations around the periphery of Cape Cod Bay show that the range in tide is reasonably uniform throughout the bay, with a mean value of about 9.3 ft. Even though the departure of the tidal wave in Cape Cod Bay from a pure standing wave leads to a measurable phase difference between high water and slack current, the actual differences in the time of high water from one location to another in the bay are small compared to a quarter tide period. Consequently, the net fractional change in volume of the bay due to the rise and fall of the tide is closely approximated by the ratio of the mean tidal range to the mean depth of the bay. Since, as stated in the previous section, the mean depth of the bay is about 100 ft, the change in the volume of the bay during one tidal cycle is then about 9.3 percent.

Additional information on current measurements and mathematical model studies of bay circulation is presented in Section 2.5.3 and Appendix P, Amendment 1 of the Pilgrim Station Unit 2 Environmental Report, and the response to Question A.6 of the Pilgrim Nuclear Power Station, Unit 1, Appendix I Information Responses, 1977.[1]

2.4.3.1.3 General Circulation Pattern

Available information on the general pattern of flow in the northwest Atlantic off the coasts of the New England states and the Maritime Provinces of Canada,[2] shows that a coastal current flows southward along the coast of Maine and Massachusetts. A portion of the flow enters Cape Cod Bay along the western shore of the bay, circulates in a counterclockwise direction, and leaves the bay on the eastern side. The flow then swings eastward around the cape and then southward again. Interpolation of the isopleths of mean speed given in the above cited reference suggests that the probable average speed of this counterclockwise flow in the bay is not less than 0.2 knot.

2.4.3.1.4 Wind Induced Motion

The speeds associated with the tidal motion and with the general circulation pattern in Cape Cod Bay are in a range which suggests that wind induced motion will at times dominate the flow. Wind blowing over deep water produces a direct wind driven motion in the surface layers directed to the right of the wind in the Northern Hemisphere. In shallow water the wind induced flow is more nearly in the direction of the wind. The speed of the surface wind induced flow has been shown to be about 2 percent of the wind speed. Thus, a wind speed of 15 knots would produce a wind induced surface current of about 0.3 knot.

The variation of wind velocity in time and space over Cape Cod Bay should produce relatively rapid large scale exchange and mixing of the surface waters within the bay. Also, prolonged winds from the northwest quarter should produce an additional mechanism for exchange of waters in the bay with adjacent open coastal waters. The wind induced surface layer flow into the bay under such wind conditions would be accompanied by a subsurface counterflow out of the bay. A sustained wind from the south would produce a surface flow out of the bay and a subsurface counterflow into the bay.

The rate at which the waters of the bay are renewed by this mechanism can be only very grossly estimated, and will in any case be of an intermittent character. From a long term standpoint, however, wind induced flushing of Cape Cod Bay certainly contributes to the renewal of the waters of the bay.

2.4.3.1.5 Water Movements Near Station Site

An oceanographic observational program was initiated in the vicinity of the site to provide information on the temperature regime and on the movement and mixing of the waters off the site. As part of this program a buoy supported instrument array was anchored about 1/2 mi offshore from the site where the water depth is about 30 ft at mlw. In addition to temperature sensors set at several depths, this array included two recording current meters, one located near the bottom and the other located near the surface. The instrument array was connected to the shore by cable, and a digital printout of speed and direction at the two current meters was provided every 1/2 hr.

Records for the period April 26 though May 20, 1968, have been analyzed. During this period approximately 1,150 individual measurements of current speed and direction near the surface and near the bottom were obtained.

These observations show that both the speed and direction of the current at this location are highly variable. The speed of the current decreases with depth, with the mean speed near the bottom less than one-half that near the surface. During this period of observation, the current was directed down the coast (i.e., roughly toward the southeast) about twice as frequently as in the upcoast, or northwesterly direction. The shoreline at the site is approximately

parallel to the line 310 degrees T to 130 degrees T. Thus, currents having a direction falling in the quadrant 40 degrees T to 130 degrees T would have components both downcoast and offshore; those falling in the quadrant 130 degrees T to 220 degrees T would have components both downcoast and onshore; those falling in the quadrant 220 degrees T to 310 degrees T would have components both upcoast and onshore; and those falling in the quadrant 310 degrees T to 40 degrees T would have components both upcoast and offshore. The same 1,150 individual measurements of the surface current off the site were subjected to a frequency sort into these four quadrants, depending on the observed direction, with the results as shown on Table 2.4-1. The magnitude of the current velocity varied from below the threshold of the current meter to a high of 1.1 knots. The average of the approximately 1,150 measures of the near surface current was 0.15 knot. The statistical distribution of speeds as shown by a frequency sort is given below:

Speed Range (Knots)	Percent of Total Observations
<0.09	40.7
0.10 - 0.19	31.9
0.20 - 0.29	16.0
0.30 - 0.39	7.9
0.40 - 0.49	2.0
0.50 - 0.59	0.8
>0.60	0.7

Both current speed and direction appear to be related most closely to the wind. In the absence of the wind, a weak tidal oscillation is superimposed on a small net drift down the coast toward the southeast. This weak southeastward drift is associated with the general counterclockwise circulation of Cape Cod Bay.

2.4.3.2 Rate of Renewal of the Waters of Cape Cod Bay

The waters of Cape Cod Bay are exchanged for "new" water from outside the bay by at least three processes: (1) tidal exchange, (2) the general counterclockwise circulation, and (3) wind induced motion. The first two of these are amenable to first order numerical estimates of the fractional rate at which the waters of the bay are replaced by new water.

2.4.3.2.1 Tidal Flushing

The intertidal volume (that is, the difference in the volume of the bay at high water and at low water), represents about 9.3 percent of the mean volume of the bay. This means that 9.3 percent of the volume of the bay moves in and out through the mouth each tidal cycle. Experience in other coastal water bodies has shown that perhaps as much as 70 percent to 80 percent of the water which leaves the bay on ebb tide returns to the bay on the next flood. The remaining 20 percent to 30 percent represents "new" water. Taking

the lower limit of this range, and also taking into account the fact that two tidal cycles occur each 24.84 hr, the fractional rate of renewal of the waters of the bay per day by tidal action is about 3.5 percent.

2.4.3.2.2 Rate of Renewal of the Waters of Cape Cod Bay by the General Counterclockwise Circulation Pattern

The inflowing current at the mouth of the bay, with a mean speed of at least 0.3 ft/sec, is conservatively estimated to occupy at least one-third of the cross-section at the mouth. The mean depth at the mouth of the bay is 150 ft, and the width is 17.5 nautical mi, or 1.064 X 105 ft. The cross-sectional area of the mouth is therefore 1.6 X 107 ft^2. The volume rate of inflow of new water into the bay with the current is then 1.4 X 1011 ft3/day. Since the volume of the bay is 1.6 X 1012 ft3, the fractional rate of renewal by this process is about 8.8 percent per day.

Considering that, in addition to the combined effect of tidal flushing and renewal by the general circulation pattern, wind induced flows will also, in the long run, contribute to renewal of water in the bay, we can assume that the mean renewal rate is at least on the order of 10 percent per day and probably larger. A renewal rate of 10 percent per day would provide a mean residence time for water, or for any waterborne component, of 10 days.

This means that no more than 10 days of discharge from the station could accumulate in the bay before being effectively flushed out of this water body. During a 10 day period, the volume of water discharged from the plant at full load would be approximately 6.2 X 108 ft3.

This volume, mixed into the volume of the bay (1.6 X 1012 ft3) would be diluted by the ratio 1:2580. This dilution is sufficiently large, so that in computing the close-in pattern of concentration of excess heat (temperature) or of any other component of the condenser cooling water discharge, we can consider that the discharge is made into a water body of infinite size.

2.4.3.3 Description of the Dispersion of the Rejected Heat and of Other Components of the Condenser Circulating Water after Discharge

2.4.3.3.1 Introduction

The Pilgrim Station will reject about 4.3 X 109 Btu/hr of heat to the condensers. The analysis and evaluations reported in this section were made assuming a total salt water flow of 720 ft3/sec and a temperature rise in the station of 28.7°F which result in a total heat rejection of about 4.5 X 109 Btu/hr. Periodically, low levels of radioactive isotopes will be discharged with the cooling water. This Section discusses the dispersion within and ultimate loss from the bay of the rejected heat and of any other contaminants carried with the cooling water effluent.

The dispersion (that is, the movement and mixing of the condenser discharge in and with the receiving waters), is considered in three stages. First, the excess momentum associated with the condenser cooling water as it is discharged into the waters of Cape Cod Bay will produce an entraining jet which will be diluted by the mechanical entrainment required to reduce the velocity of the jet to that of the surrounding waters. Secondly, natural turbulent diffusion will further mix the waters of the diluted condenser water plume as it moves downcurrent with the natural flow. Finally, the large scale circulation pattern coupled with the tidal flushing, as discussed in the previous section, will carry any conservative component out of the bay. In the case of the rejected heat, surface cooling will have returned the temperatures to ambient long before the large scale circulation pattern will have carried the condenser cooling water out of the bay.

2.4.3.3.2 Distribution of Temperature in the Vicinity of the Site

The most important mechanism for rapid reduction of the temperature rise above ambient of the condenser cooling water discharge is the mechanical entrainment required to reduce the initial momentum of the discharge to that of the receiving waters. Both theoretical and empirical studies of momentum entrainment in a jet discharge provide a means of computing the probable temperature distribution in the vicinity of the site. The term "temperature distribution" is used in place of the longer expression "temperature rise above ambient." The temperature distribution in the vicinity of the discharge will be somewhat higher than the ambient water temperature because of the heat content of the station discharge.

There are two factors at the site which restrict the degree of confidence which can be placed on the use of existing momentum entrainment relationships for the analytical prediction of the temperature distribution off the site resulting from the discharge of the heated condenser cooling water. First, in the presence of a current flow directed along the coast in the bay waters off the site, the plume of mixed, heated water will be bent in the direction of the current, ultimately becoming parallel to the coastline. It is not possible to determine on a theoretical basis alone whether or not entrainment will occur on the inshore side of such a bent jet. Secondly, the effective velocity of the discharge for this design, an important parameter in considering the effectiveness of momentum entrainment, is not readily determined from theory alone.

In order to determine the effective velocity of discharge, as well as to determine the shape and extent of the plume of heated water in the vicinity of the discharge, a hydraulic model of a segment of Cape Cod Bay, centered on the plant site, was constructed and a series of model tests have been run. This model is built on a scale of 1:250 in the horizontal and 1:40 in the vertical. It extends along the shore for a distance equivalent to about 11,000 ft in the prototype, and outward from the plant site for an equivalent prototype distance of about 6,000 ft. Currents offshore from the plant site are simulated in the model by introducing water through a control

structure running approximately perpendicular to the general trend of the shoreline in the vicinity of the plant, and located at the northwesterly end of the model (prototype direction), and withdrawing water from a control structure extending along the southeasterly end of the model. The station intake and discharge structures are properly scaled in the model. Water is withdrawn from the model through the intake structure, and heated water is introduced to the model through the discharge structure, to simulate operations.

A series of tests under the most critical conditions has been completed. These tests show three significant features:

1. Even when a current flow near the maximum observed at the site is simulated in the model, and directed downcoast, thus bending the plume of heated water toward the intake structure, very effective two sided entrainment of cool diluting water occurs. The circulation pattern set up by the entraining jet actually brings new water at near ambient temperature to the intake

2. There is little significant difference in the effectiveness of the jet entrainment between low tide and high tide conditions. In both cases, the heated plume appears confined primarily to the upper 5 ft of the water column, and the areas within given temperature isolines appear to be essentially independent of tidal height

3. There is little difference in the shape and size of the heated plume for ambient current conditions varying from 0.2 knot, which is near the average observed off the plant site, to 0.6 knot, a speed exceeded in the observations to date less than one percent of the time. The effective doublesided entrainment demonstrated by the tests indicates that criteria for determining breakwater length could be based on storm protection requirements rather than thermal requirements

The tidal oscillations and the residual net southeastward drift off the site are quite small, and at any given time the speed and direction of the current depend primarily on the time history of the wind. Thus, the current may extend either upcoast in a northwesterly direction or downcoast in a southeasterly direction, and in either case may have components directed either onshore or offshore. The current observations to date show that a flow in a southeasterly direction, with an offshore component, occurs most frequently. However, flows in other directions are of sufficient frequency to require consideration.

Predictions of the distribution of excess temperature resulting from operation of the station have been prepared using the results of the hydraulic model tests combined with theory, to take into account the finite size of the model and to extend the distribution beyond the model boundaries. Because only a finite segment of the Cape Cod Bay can be modeled in this way, and because the water withdrawn from the

model to simulate the current regime must be recirculated to provide the inflow at the upstream end, care must be taken in applying the model results directly to the prototype. In the predictions of the temperature distributions given here, the model results have been modified to take into account the finite renewal rate of the segment of the coastal waters represented by the mode. Thus, in all cases, the predicted distributions of the temperature rise above ambient are conservative compared to the model results. That is, the plume of heated water is here shown to be more extensive than is shown by direct application of the model results to the prototype. The analysis assumed a total cooling water flow of 720 ft3/sec and a temperature rise in the station of 28.7°F. Two cases are considered, the first with the offshore current directed toward the east-southeast, and the second with the offshore current directed toward the west-northwest. See Figures 2.4-6 and 2.4-7. The temperature distributions appear to be relatively independent of tidal stage and of the strength of the current in the range from 0.2 knot to 0.6 knot, at least with respect to the general shape of the temperature isotherm and the area within a given isotherm. The strength of the current will influence the rate of bending of the plume from the initial offshore directed jet discharge to a plume extending downcurrent. Thus, for the weaker current speeds, the heated discharge will extend somewhat farther offshore than in the case of strong current parallel to shore.

The shoal extending out from Rocky Point appears to exert considerable influence on the currents flowing past the site inshore of about the 25 ft mlw depth contour. As a consequence of the sheltering effect of this shoal, the model studies showed that the plume of heated water extends outward from the point of discharge very nearly along the extension of the axis of the discharge canal for about 1,200 ft before starting to bend in a downcurrent direction, even in the presence of a 0.6 knot current directed toward the east-southeast. This feature is shown on Figure 2.4-8 in which the temperature distribution in the vicinity of the discharge canal, as observed in the model studies, is depicted. The size, shape, and orientation of the plume as defined by the 10°F temperature isotherm apparently depend primarily on the dynamics of the discharge and are insignificantly influenced by the ambient currents in the bay waters adjacent to the site.

Measurements of the vertical distribution of temperature in the model tests have shown that for the conditions studied, the temperature rise above ambient is primarily restricted to the upper 5 ft. Figure 2.4-9 shows three representative vertical profiles (temperature distribution vs depth) from the model studies. Somewhat greater vertical mixing will probably occur in the presence of wind induced waves, but on the basis of the evidence now available, it is very unlikely that the temperatures at 10 ft below the water surface will exceed 4°F above ambient, and then only in the very small area in the vicinity of the discharge. On Figure 2.4-10 the predicted distribution of maximum temperatures above ambient on the bottom is shown. Isotherms are drawn for temperatures, above ambient, of 3°F

and greater. Areas outside the 3°F isotherm as shown should have bottom temperatures less than 3°F above ambient.

Table 2.4-2 summarizes the area inside each of the surface temperature isotherms shown on Figures 2.4-6 through 2.4-8. To indicate the importance of dilution due to momentum entrainment and natural diffusion, the last column of this table gives the area inside each isotherm which would be required if the effluent were to gently spread over the surface without mixing with the receiving waters and lose heat only by surface cooling.

The predicted temperature distributions given here apply to an ambient temperature of 75°F, which represents the extreme ambient temperatures observed in the waters of Cape Cod Bay. While the ambient temperature will influence both the amount of entrainment and the rate of surface cooling slightly, these effects would not significantly alter the shape and size of the individual temperature isotherms, and for all practical purposes, the predicted temperature distribution above ambient given here can be applied to any ambient temperature from 50°F up to 80°F.

2.4.3.3.3 Concentration Distribution of Radioactive Isotopes Released in the Condenser Circulating Water

Introduction of any radioactive isotopes into the condenser circulating water discharge would be controlled so that, after mixing, the concentration in the cooling water effluent would not exceed the maximum concentrations specified for offsite areas in 10CFR20. This section discusses the further physical dilution of such radioisotopes in the natural environment. Such further dilution serves as an additional safety factor which is not, however, used in computing allowable release rates.

There is no physical process which would lead to reconcentration of the radionuclides within the receiving waters of Cape Cod Bay nor in any of the tributary embayments. The temperature distributions above ambient shown on Figures 2.4-7 and 2.4-8 result primarily from physical dilution of the condenser circulating water discharge by the receiving waters. For the situation studied here, surface cooling does not become a significant contributor to the reduction of temperature except for surface temperatures less than 2°F above ambient.

The isotherms given on Figures 2.4-7 and 2.4-8 may therefore be interpreted as dilution lines for radioisotopes discharged with the condenser cooling water by dividing the labeled temperature rise values by 28.7°F, the initial temperature rise in the station. Thus, the isotherms of 20°, 10°, 5°, 3° and 2°F shown on Figures 2.4-7 and 2.4-8 represent dilutions of 1: 1.43, 1: 287, 1: 5.74, 1: 9.56, and 1: 14.35, respectively. Dilution will continue with distance from the site, producing a decrease in concentration approximately in proportion to the inverse of the distance from the source. On this basis the concentration of any component in the condenser circulating

water discharge would be reduced by a factor of 100 at a distance of 11 nautical mi from the point of discharge.

Information on this topic is presented in the response to Question A.8 of the Pilgrim Station Unit 1 Appendix I Information Responses (1977).[1]

2.4.4 Storm Flooding Protection

2.4.4.1 Introduction

Shoreline and offshore structures are required to provide the functional requirements of the cooling water systems in the station, and the necessary protection of the station under storm conditions. They consist of an intake structure near the shoreline with protective breakwaters along a dredge intake channel, and a discharge structure near the shoreline with a dredged outlet channel which is protected by short jetties. The waterfront development is shown on Figure 2.4-11.

The breakwaters and jetties are of rubble mound construction; both are protected by heavy capstone. The breakwater on the northwest is approximately 1,400 ft long and the breakwater on the southeast is approximately 700 ft long. Top elevation of both breakwaters is +11.2 ft msl (+16 ft mlw). The breakwaters are required to prevent rapid siltation of the dredged channels. They also provide a first line of defense, to protect the intake structure and revetment from excessive wave action and overtopping due to wave runup, and to limit storm flooding of the site. The revetments on either side of the intake structure provide shore stabilization and prevent flooding of the Reactor Building during severe storms. They are designed to act as a second line of defense in conjunction with the breakwaters such that any overtopping that might occur under the extreme design storm tide level of +13.5 ft msl (+18.3 ft mlw) would not affect the Reactor Building or the emergency systems required to safeguard the reactor.

Damage to the breakwater was sustained during the winter of 1977-1978 and again during the winter of 1978-1979. Both times the breakwater was repaired to return it to the original configuration. U.S. NRC concerns about this matter were addressed in a series of letters [3,4,5,6] and were resolved. The resolution [6,10] included a commitment to a monitoring program to ensure the integrity of the breakwater structure.

The intake structure houses two sets of pumps. One set provides cooling water for the condenser circulating water system and the other set provides cooling water for the service water system. The service system pumps supply cooling water for the Reactor and Turbine Building closed cooling systems. These systems remove heat during normal, shutdown, and accident conditions. It is essential that the service water pumps function properly even under extreme storm or tide conditions. The waterfront development is designed to prevent

overtopping of the intake structure, and assures continuous operation of the service system.

The discharge structure and channel are to the northwest of the intake structure as shown on Figure 2.4-11. The circulating water system and the service water system will discharge through this channel back to the bay. The discharge channel is approximately 870 ft long and is extended over the beach to mlw by rock-fill jetties. The jetties have a nominal elevation of +16 mlw (+11.2 msl) sloping down to a height of 4 ft at mlw. The elevation of the bed of the discharge channel is 0 ft mlw. The discharge channel jetties will also serve as protection for the intake and discharge structures from wave action.

2.4.4.2 Tide Levels

Tides at the site are of the semidiurnal type, with two highs and two lows occurring each day. Tide records for this area are available from Coast and Geodetic Survey Tide Stations in Boston Harbor and at the eastern entrance to Cape Cod Canal. Tide levels at the site are similar to those at Boston. The mean tidal range is 9.1 ft and the spring tidal range is 10.6 ft. The datum relationship at the site is that msl is 4.78 ft above mlw. The highest still water tide level ever recorded in this area is +10.5 ft msl. This level occurred at Boston on February 24, 1723, and has not been repeated. Tide levels of +10.0 ft msl have occurred twice; once in 1851 and again in 1909. The extreme design storm tide level selected for the site of +13.5 ft msl is 3.0 ft higher than has been observed in the Boston Harbor area in 244 years of record. The estimated average yearly maximum astronomical high tide is +6.7 ft msl, and the estimated average yearly minimum astronomical low tide is -7.1 ft msl. These water elevations are expected to occur once every year.

It has been calculated that the 100 yr storm could produce a still water level of +15.8 ft mlw. This is a combination of storm surge combined with astronomical high tide. This tide level is based on National Hurricane Research Project (NHRP) tide data for 1922 to 1960.[7] This tide is 0.5 ft higher than the high tide of 1723.

The hydrometeorological section of the U.S. Weather Bureau has established a standard project northeaster for New England. Using this storm, the peak storm surge, having a return frequency of 1,000 yr, is 6.6 ft. The concurrence of peak storm surge with an astronomical high tide of +11.7 ft mlw would give an extreme storm tide level of +18.3 ft mlw with a probability of occurrence of once every 4,000 yr.

The probable maximum surge hydrograph as shown on Figure 2.4.12, has been determined using the bathystrophic storm tide theory.[8] The analysis results in a maximum hurricane produced storm surge at the site of the Pilgrim Nuclear Power Station which corresponds to a still water level of 18.3 ft above mlw. The most severe hurricane parameters from Hydrometeorological Branch Memorandum HUR 7-97 were used in the analysis and were included in the following:

Direction of approach	315 degrees (true)
Maximum wind velocity	131 mph
Radius to region of maximum winds	52 nautical mi
Initial water level rise	1.0 ft
Spring high tide	+11.7 ft mlw
Control Pressure Index (CPI)	3.13 in Hg

Sound meteorological reasoning and data negate the possibility of a severe hurricane moving into Cape Cod Bay from the northeast.[9] Hurricanes must draw upon a thermal source in order to maintain hurricane wind force velocities. Any storm postulated having a path with an azimuth less than 315 degrees (true) would travel over the cold ocean waters of the North Atlantic Ocean and hurricane force winds could not be maintained. Storms on a more northerly course (compass headings greater than 315 degrees (true)) would result in lesser storm surges than the 315 degrees (true) path storm and would, in fact, begin to approach the maximum drawdown condition.

The effects of wave setup and wave runup are included in the wave action model studies performed for the Pilgrim Nuclear Power Station (Section 2.4.4.3). The test results run at a still water level of 18.3 ft above mlw showed that the Reactor Building was not subjected to flooding.

The highest water level experienced by the breakwater since its completion in 1970 was 14.5 ft mlw, which occurred on February 7, 1978. This water level was the result of high astronomical tides and a surge of 4 ft, which were caused by an intense northeaster on February 6-7, 1978.

For an extreme low tide condition to occur at the plant site, a hurricane path from due south is required, with the center passing to the west of the site area. Wind directions in the critical hour would be from the west-southwest blowing directly offshore with the center of the hurricane a distance equal to the radius of maximum winds north and west of the site.

A drawdown in water surface elevation at the shore of approximately 3 ft results. This is based upon successive approximations of drawdown using hourly average wind speeds of 110 mph at shore to 114 mph some 15 to 20 mi offshore. The estimated average yearly minimum astronomical low tide is equal to -7.1 ft msl. Therefore, the predicted minimum low water level elevation is -10.1 ft msl.

The minimum instantaneous water level would include the effect of concurrent wave troughing at the intake structure during the predicted minimum low water level. Wave troughing effects at the intake structure would be negligible during offshore winds in the range of 110 mph. These winds would dissipate any incoming swells, and would not have any available fetch to generate waves at the intake structure. Therefore, the predicted minimum instantaneous water level elevation would also be -10.1 ft msl.

The design low water level for the Circulating Water and Salt Service Water Systems is - 7.1 ft msl. The minimum sea water level at which the Circulating Water and Salt Service System pumps can maintain rated performance, based on suction head, NPSH required, and sumbmergence, is -8.0 ft msl for the Circulating Water pumps and -13 ft 9 in msl for the Salt Service Water pumps. Refer to Section 10.7 for a description of the sea water levels used for the design basis analyses of the Salt Service Water System.

2.4.4.3 Model Studies

A series of wave action model studies was performed for the site waterfront development. The purpose of the studies was to assist in developing the design of the waterfront development including the breakwaters and jetties, the intake and discharge channels, and the onshore revetments. Wave action model studies considered the present orientation and design of the intake structure and shoreline protection. Wave runup effects were determined by operation of the wave action model at appropriate wave conditions in the model. The effectiveness of the selected design in protecting the plant site and circulating water system against wave action was demonstrated and evaluated.

The model was constructed to an undistorted scale of 1:50. It is a fixed bed model, with topography simulated by a thin layer of cement mortar on compacted sand. Crushed rock was used in the model for the breakwaters and jetties. Station structures and the circulating water flow were simulated in the model. Wave generation was by means of a paddle with a variable stroke and speed capable of producing waves of variable heights and periods, including wave periods of 8 to 12 sec, which are those most likely to occur at the site during a severe storm. Wave heights were measured with variable resistance probes and recorded on a multichannel moving mirror galvanometer oscillograph. Test results were documented by still and moving photography.

The waterfront design has been subjected to tests at three still water elevations:

1. Elevation +15.8 mlw, the level of the 100 yr storm, expected not more than once during the life of the installation
2. Elevation +18.3 mlw, the design maximum storm level
3. Elevation +19.5 mlw, an arbitrary elevation which exceeds any postulated design condition and is the highest elevation at which the model could be operated satisfactorily

Slope protection and the effectiveness of the breakwaters were evaluated by tests at all three stillwater elevations during which waves were simulated from due north and from north 60 deg east, with wave periods ranging from 8 to 18 sec. The wave heights were adjusted to give maximum runup at the intake structure and revetments.

Results of wave action model studies conducted at the Alden Research Laboratories of Worcester Polytechnic Institute are given on

Tables 2.4-3 and 2.4-4 for waves from north 60 deg east and for waves from due north at the site, respectively. Tables 2.4-3 and 2.4-4 provide the measured maximum model wave heights at the locations indicated for stillwater levels of 19.5 ft above mlw and wave periods of 8, 10, and 12 sec.

No Reactor Building wetting occurred during any of these tests although open ocean wave heights as high as 31 ft were generated.

Test results indicated adequate reduction of the generated wave at the intake structure. Minor overtopping of the adjacent revetment occurred with the 18.3 mlw stillwater elevation but yard flooding was limited to the open space northeast of the Reactor Building. The Reactor Building was at no time subjected to flooding. It was concluded that no Reactor Building flooding would occur even at the maximum estimated stillwater level based on ESSA Report 7-97 for hurricanes.

Observation of tests with periods of 8 to 12 sec at the 19.5 still water elevation (upper limit of the model) indicated no flooding at the station structures. A series of tests were run which confirmed that storm-wave action at the intake structure for still water elevations up to 19.5 mlw would not adversely affect circulating water or service water pump operation.

Additional model studies were subsequently conducted at the University of California. These studies were performed in order to obtain information on the stability of various armor stone sizes and sideslopes for various breakwater heights and water depths. Details of this study are included in the report entitled "A Model Study for Design of Armor for the Pilgrim Station Breakwaters.[3]

2.4.5 References

1. Boston Edison Company. Pilgrim Nuclear Power Station, Unit 1, Appendix I Information Responses, 1977.

2. Oceanographic Atlas of the North Atlantic Ocean, Section 1, Tides and Currents. U.S. Naval Oceanographic Office, Publication No. 700.

3. Andognini to Ippolito. Letter on Information on the Pilgrim Station Breakwater, September 28, 1979. BECo Letter No. 79-199.

4. Andognini to Ippolito. Letter on Information on the Pilgrim Station Breakwater, April 15, 1980. BECo letter No. 80-66.

5. Andognini to Ippolito. Letter, December 5,1980. BECo Letter No. 80-311.

6. Andognini to Ippolito. Letter, March 31, 1981. BECo Letter No. 81-67.

7. Criteria for a Standard Project Northeaster for New England North of Cape Cod. Figure 27, NHRP Report No. 68, Hydrometeorological Section, Hydrologic Services, Washington D.C.

8. Marinos G. and Woodward J.W. Proceedings of the American Society of Civil Engineers. Journal of the Waterways and Harbor Division, Vol. 94, pp 189-216, May 1968.

9. Cry G.W. Tropical Cyclones of the North Atlantic Ocean. Tech Paper No. 55, U.S. Weather Bureau, Washington D.C., 1965.

10. Boston Edison to NRC. Letter, January 15, 1990. BECo Letter No. 90-14.

TABLE 2.4-1

DIRECTION OF CURRENTS

Quadrant 1	
Downcoast* and offshore	36.9%
Quadrant 2	
Downcoast and onshore	29.4%
Quadrant 3	
Upcoast* and onshore	12.9%
Quadrant 4	
Upcoast and offshore	20.8%
Total with Downcoast Component	66.3%
Total with Upcoast Component	33.7%
Total with Offshore Component	57.7%
Total with Onshore Component	42.3%

NOTE:

* Downcoast is roughly towards the SE, while upcoast is roughly towards the NW.

TABLE 2.4-2

SURFACE TEMPERATURE ISOTHERMS
DIMENSIONS AND AREA
(Refer to Figures 2.4-6 through 2.4-8)

Temperature Rise Above Ambient (°F)	Length of Area (ft)	Width of Area (ft)	Predicted Area (Acres)	Comparable Area* Surface Cooling Only (Acres)
20	430	110	1.1	248
10	1100	250	6.3	725
5	3400	900	70.3	1203
3	5900	1300	176	1557
2	8400	2200	425	1834

NOTE:

* This column is shown for purposes of comparison only, and represents the area within the designated isotherms which would be required if the temperature reduction resulted only from surface cooling.

TABLE 2.4-3

WAVE HEIGHTS FOR NORTH 60 DEGREES EAST
STILL WATER LEVEL 19.5 FT ABOVE MEAN LOW WATER

Test No	Stroke Model (in)	Period Prototype (sec)	Probe 1 (ft) Prototype	Probe 2 (ft) Prototype	Probe 7 (ft) Prototype	Probe 9 (ft) Prototype
55	18	12	9.5	2.2	23.2	24.7
56	18	10	9.3	2.5	21.1	28.3
60	16	12	8.1	1.7	26.5	30.4
61	16	10	5.4	1.7	19.6	28.9
65	14	12	10.4	2.0	18.1	20.6
66	14	10	5.0	1.8	21.4	26.7
67	14	8	7.0	2.4	24.1	25.7
71	12	12	8.4	1.7	14.4	13.7
72	12	10	5.6	1.2	23.2	25.6
73	12	8	7.3	2.0	19.6	25.4
77	10	12	7.3	1.7	12.6	11.1
78	10	10	6.6	1.5	22.6	18.9
79	10	8	10.2	1.2	16.6	24.7

Wave Height Sensor (Probe) Locations

Probe 1 - Intake Structure

Probe 2 - Discharge Structure

Probe 7 - Breakwater Tip

Probe 9 - Open Ocean

TABLE 2.4-4

WAVE HEIGHTS FOR NORTH 0 DEGREES EAST AT
STILL WATER LEVEL 19.5 FT ABOVE MEAN LOW WATER

Test No.	Stroke Model (in)	Period Prototype (sec)	Probe 1 (ft) Prototype	Probe 2 (ft) Prototype	Probe 7 (ft) Prototype	Probe 10 (ft) Prototype
169	16	12	5.3	1.8	25.3	31.0
176	14	12	4.8	2.2	23.4	28.5
177	14	10	4.5	1.3	24.7	27.5
180	12	10	5.3	1.7	26.3	24.2
181	12	12	6.2	1.0	18.1	19.9
188	10	12	5.3	1.8	18.1	16.6
189	10	10	6.4	1.7	18.1	21.6

Wave Height Sensor (Probe) Locations

Probe 1 - Intake Structure
Probe 2 - Discharge Structure
Probe 7 - Breakwater Tip
Probe 10 - Open Ocean

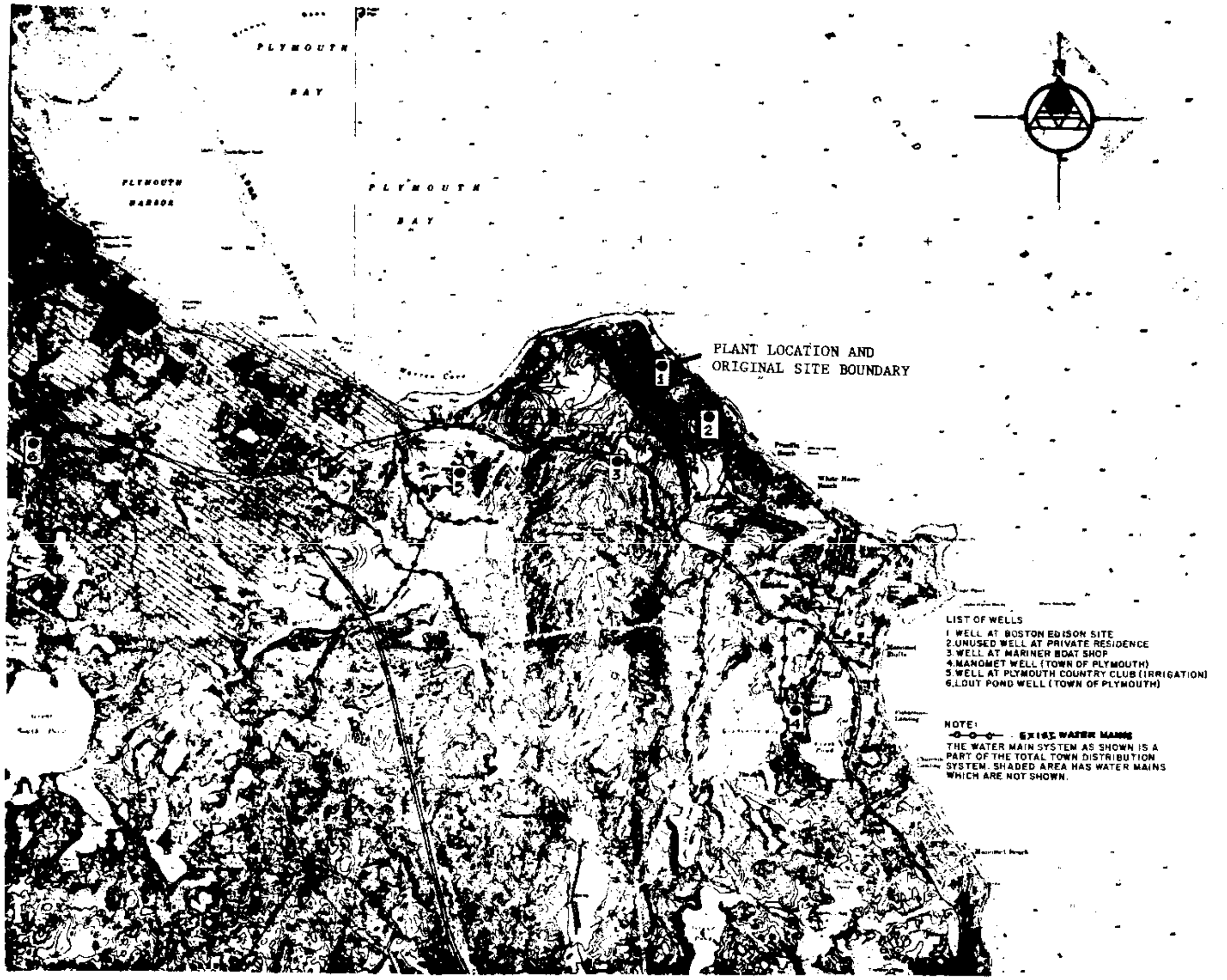


FIGURE 2.4-1
INITIAL STATION SITE AREA
WATER MAINS AND WELLS
(0 TO 3 MILES RADIUS)
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

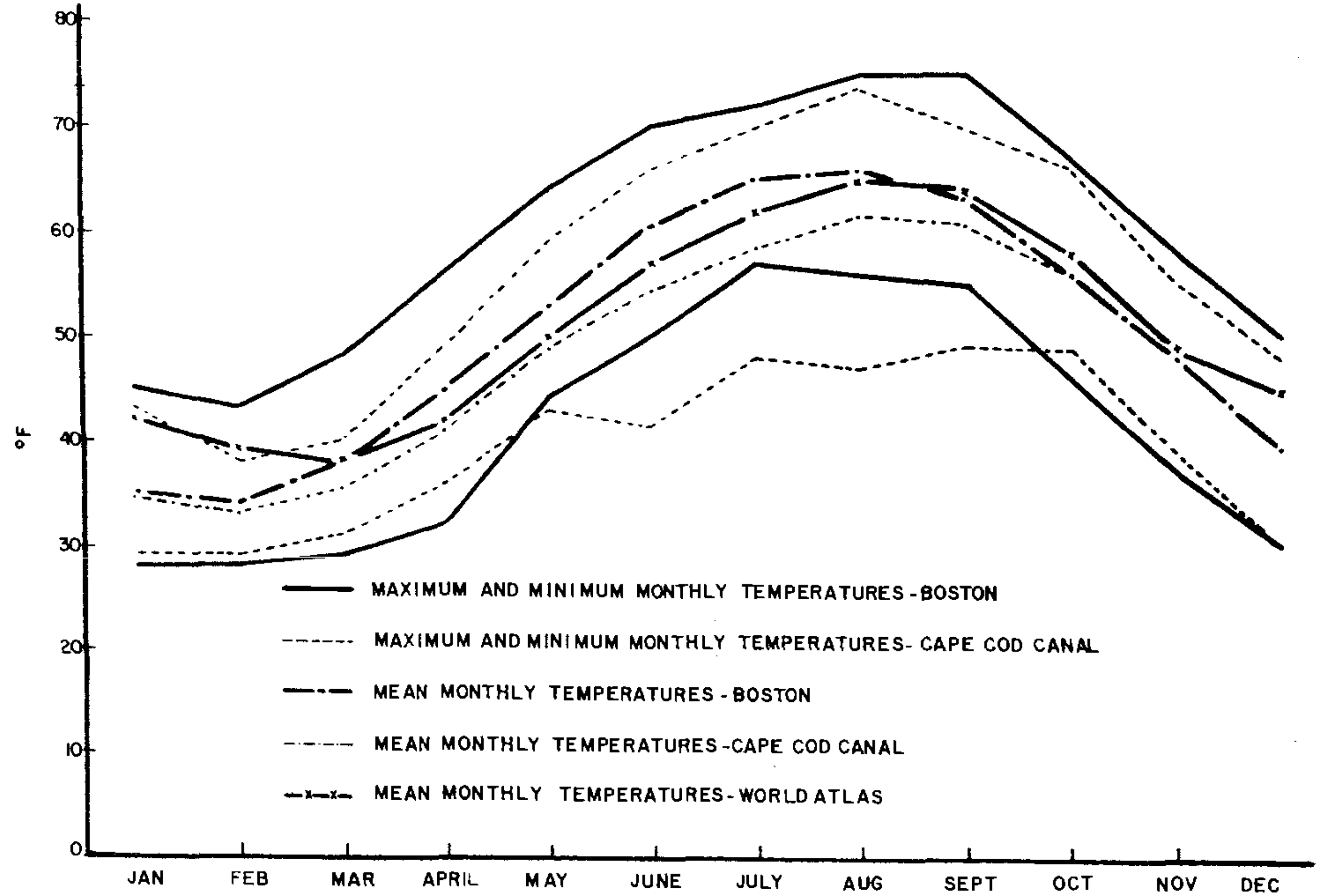
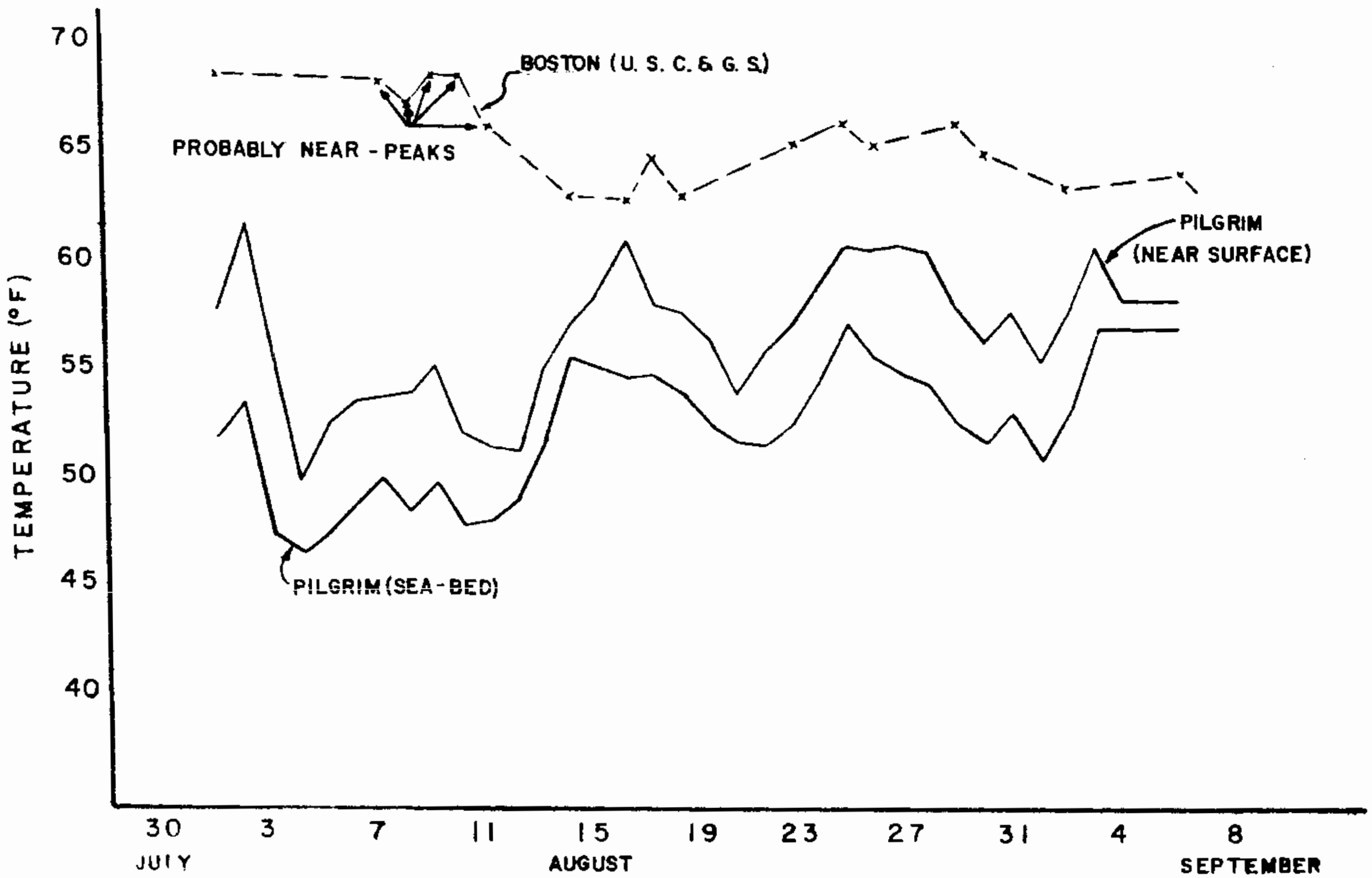


FIGURE 2.4-2

MAXIMUM, MINIMUM AND MEAN TEMPERATURES FOR CAPE COD BAY AND BOSTON TIDE STATIONS

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT



(PILGRIM TEMPS ARE AVERAGES OF HIGHEST & LOWEST DAILY READINGS)

FIGURE 2.4-3
1967 TEMPERATURES
PILGRIM STATION AND BOSTON
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

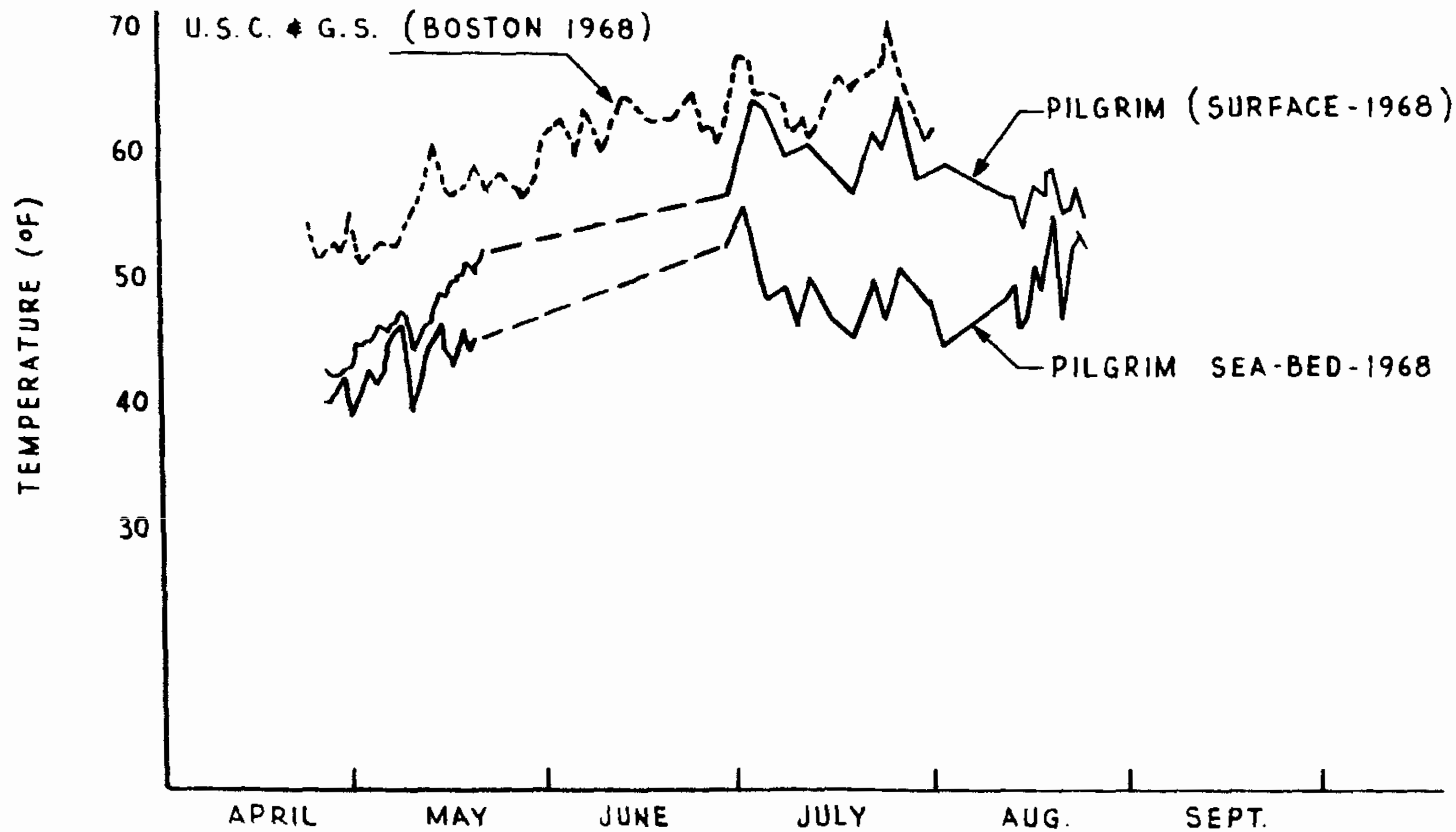


FIGURE 2.4-4
1968 TEMPERATURES
PILGRIM STATION AND BOSTON
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

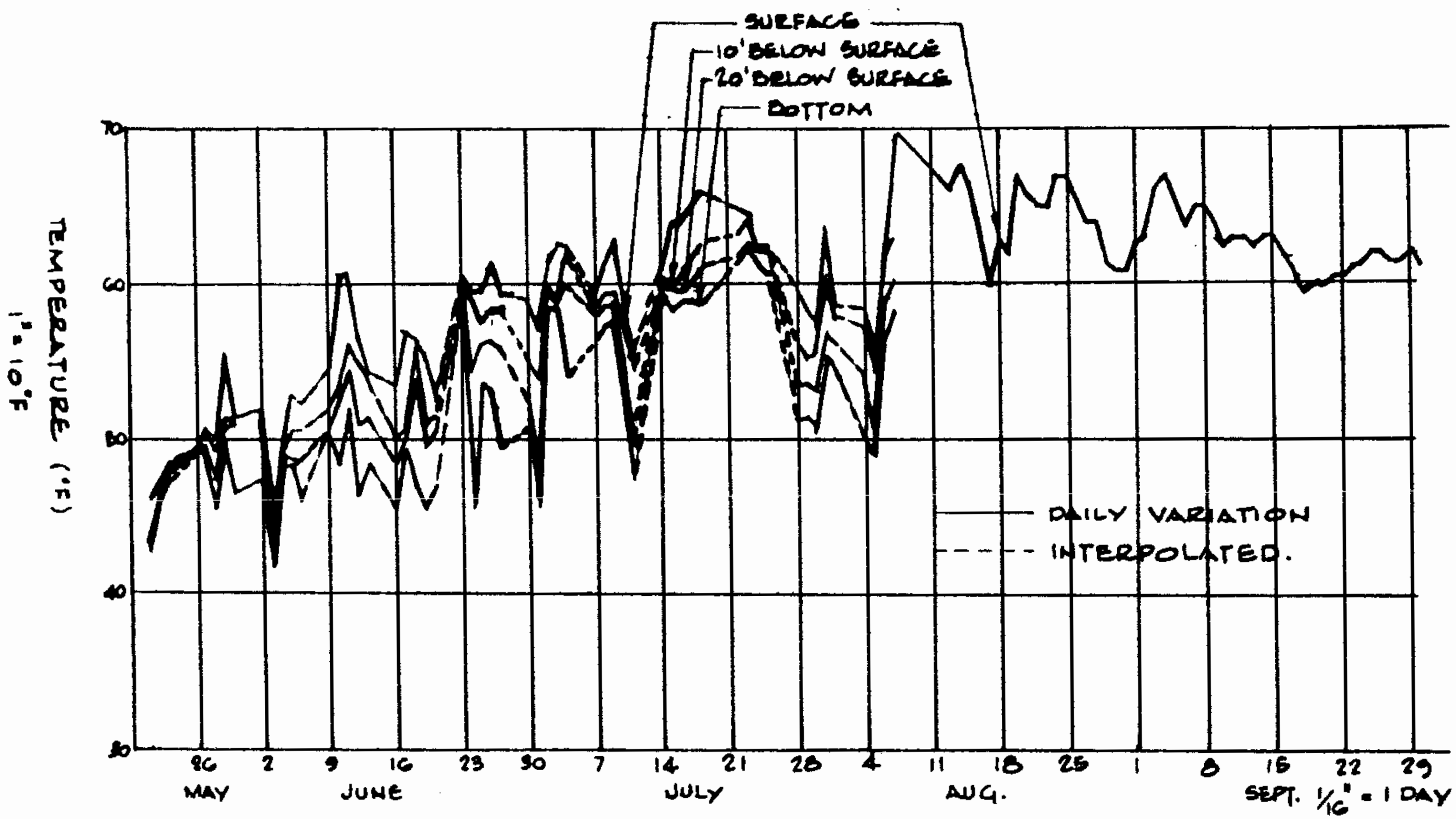


FIGURE 2.4-5
1969 TEMPERATURES
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

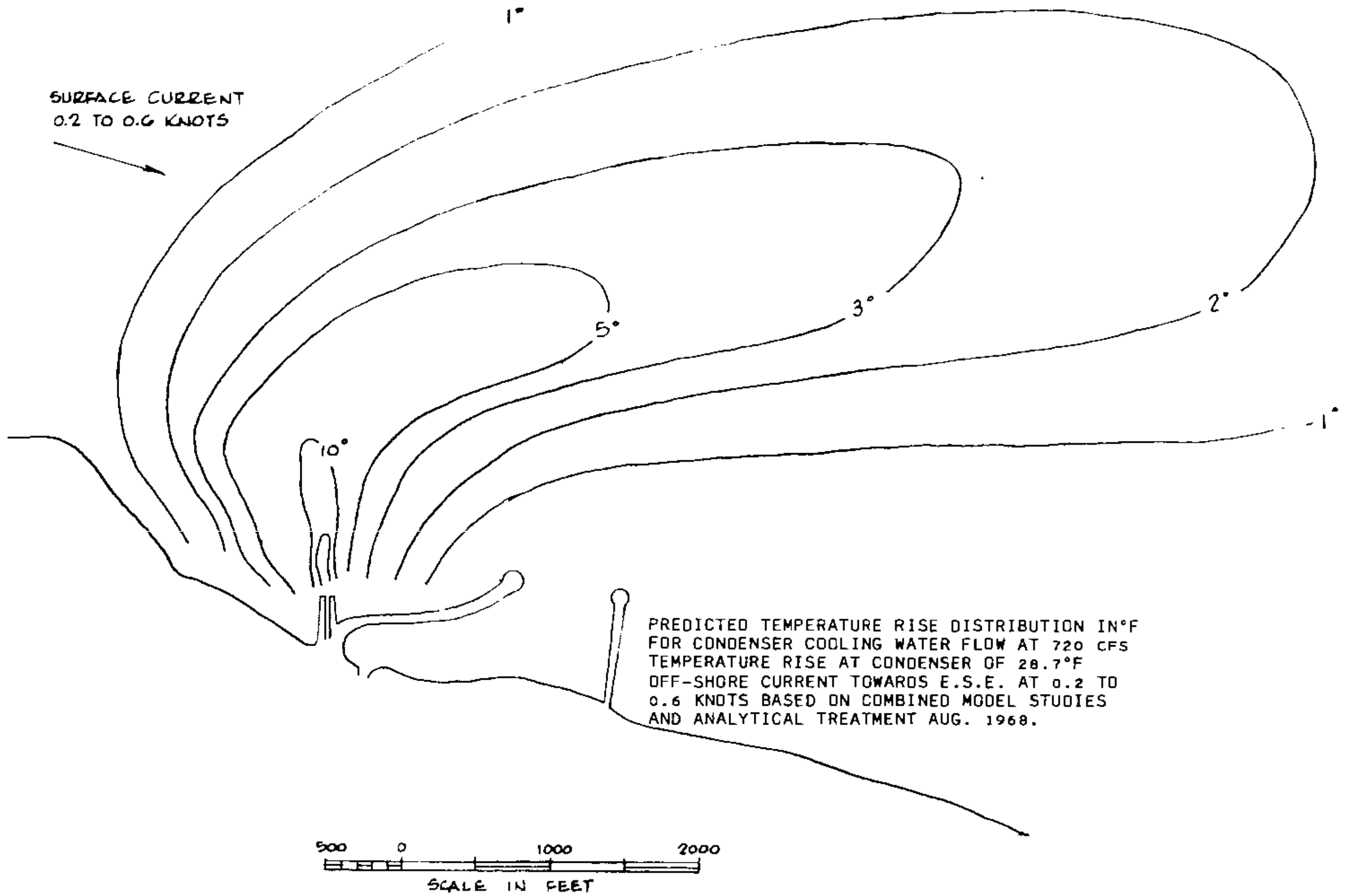
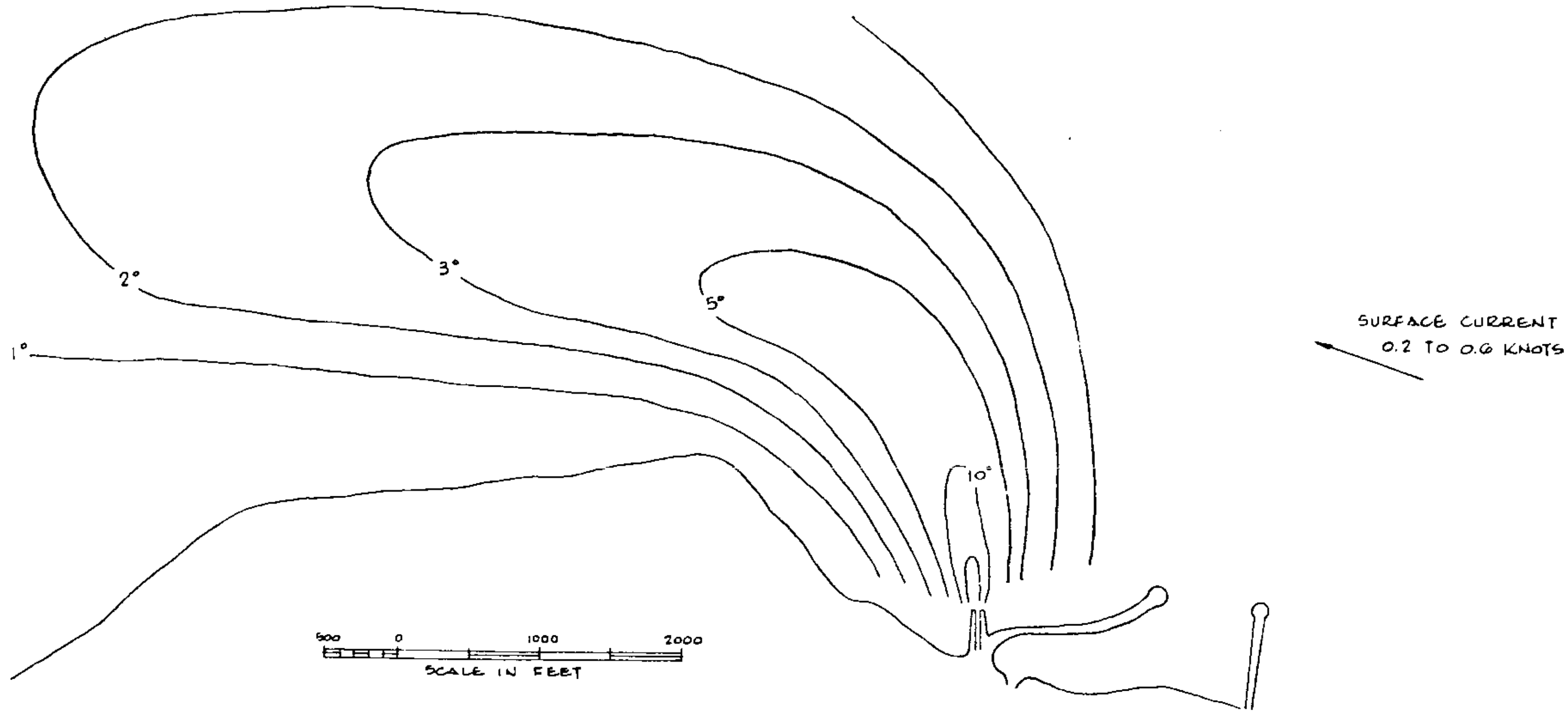


FIGURE 2.4-6
COOLING WATER DISPERSION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



PREDICTED TEMPERATURE RISE DISTRIBUTION IN°F
FOR CONDENSER COOLING WATER FLOW AT 720 CFS
TEMPERATURE RISE AT CONDENSER OF 28.7°F
OFF-SHORE CURRENT TOWARDS W.N.W. AT 0.2 TO
0.6 KNOTS BASED ON COMBINED MODEL STUDIES
AND ANALYTICAL TREATMENT AUG. 1968.

FIGURE 2.4-7
COOLING WATER DISPERSION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

PREDICTED TEMPERATURE RISE ABOVE AMBIENT IN °F IN VICINITY OF DISCHARGE FOR CONDENSER COOLING WATER FLOW OF 720 CFS, TEMPERATURE RISE AT CONDENSER OF 28.7°F BASED ON MODEL STUDIES.

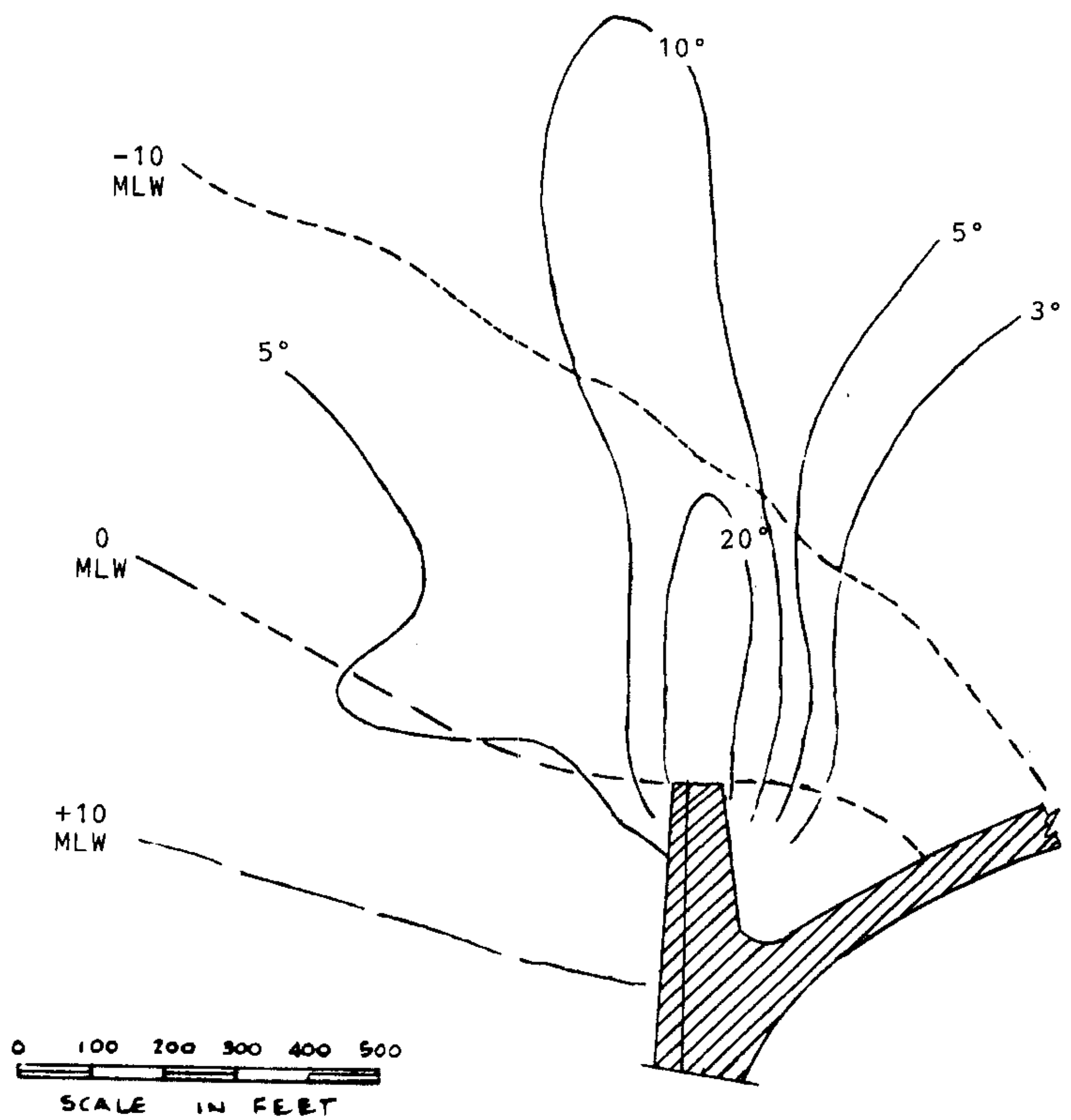


FIGURE 2.4-8
COOLING WATER DISPERSION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

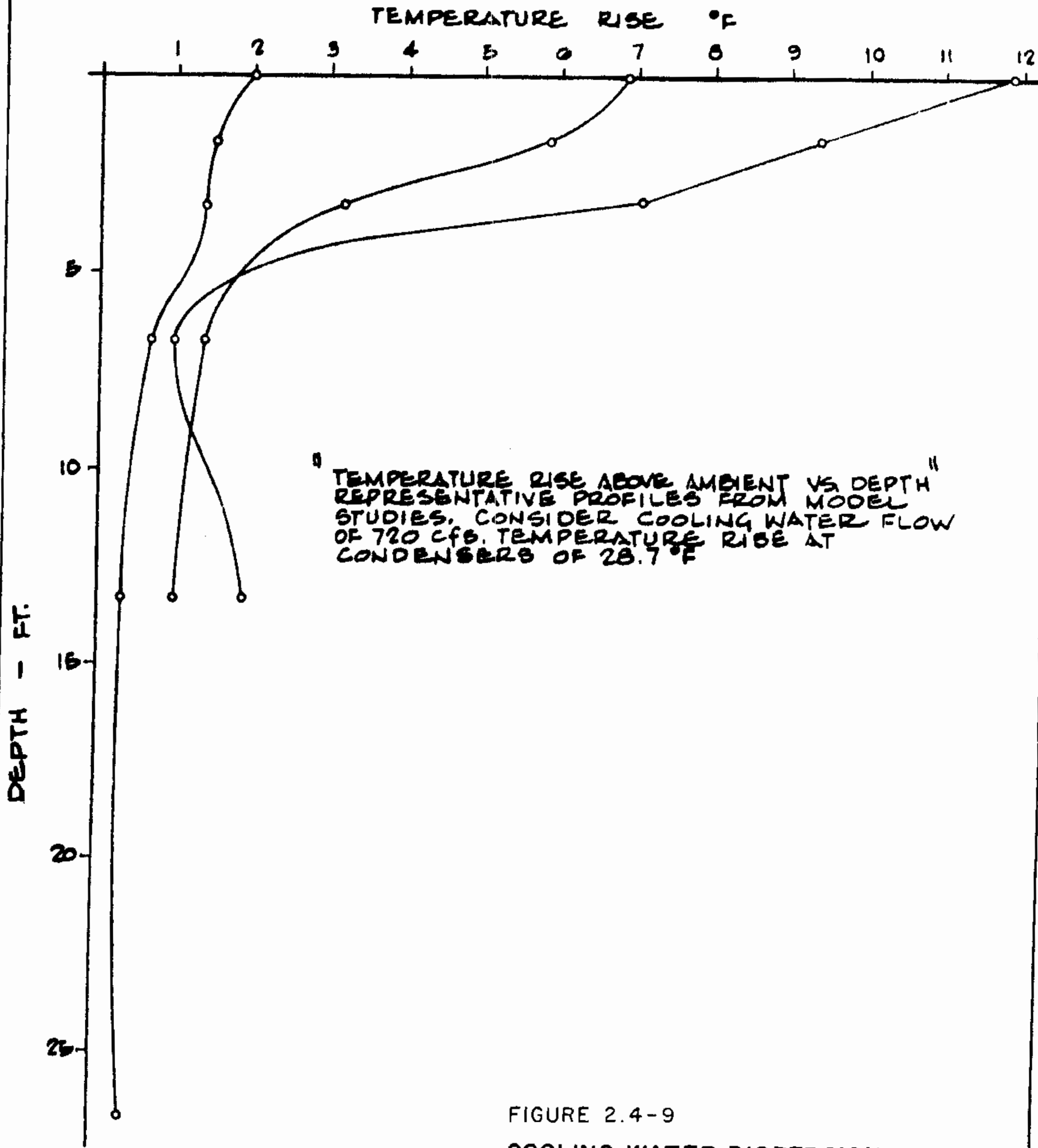
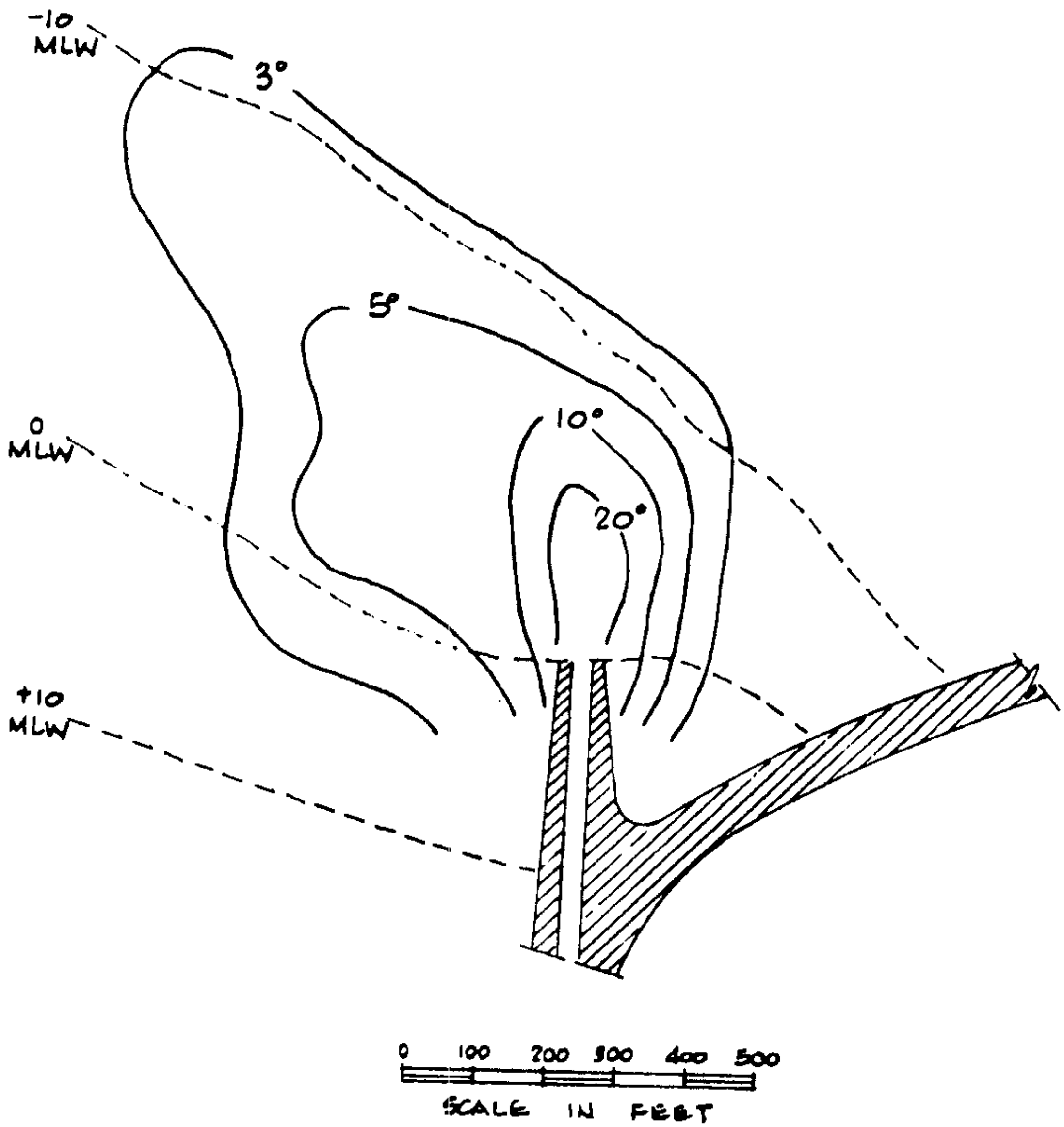


FIGURE 2.4-9

COOLING WATER DISPERSION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



"PREDICTED MAXIMUM TEMPERATURE RISE DISTRIBUTION ON THE BOTTOM" FOR CONDENSER COOLING WATER DISCHARGE OF 720 CFS, TEMPERATURE RISE AT THE CONDENSER OF 28.7°F

FIGURE 2.4-10
COOLING WATER DISPERSION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

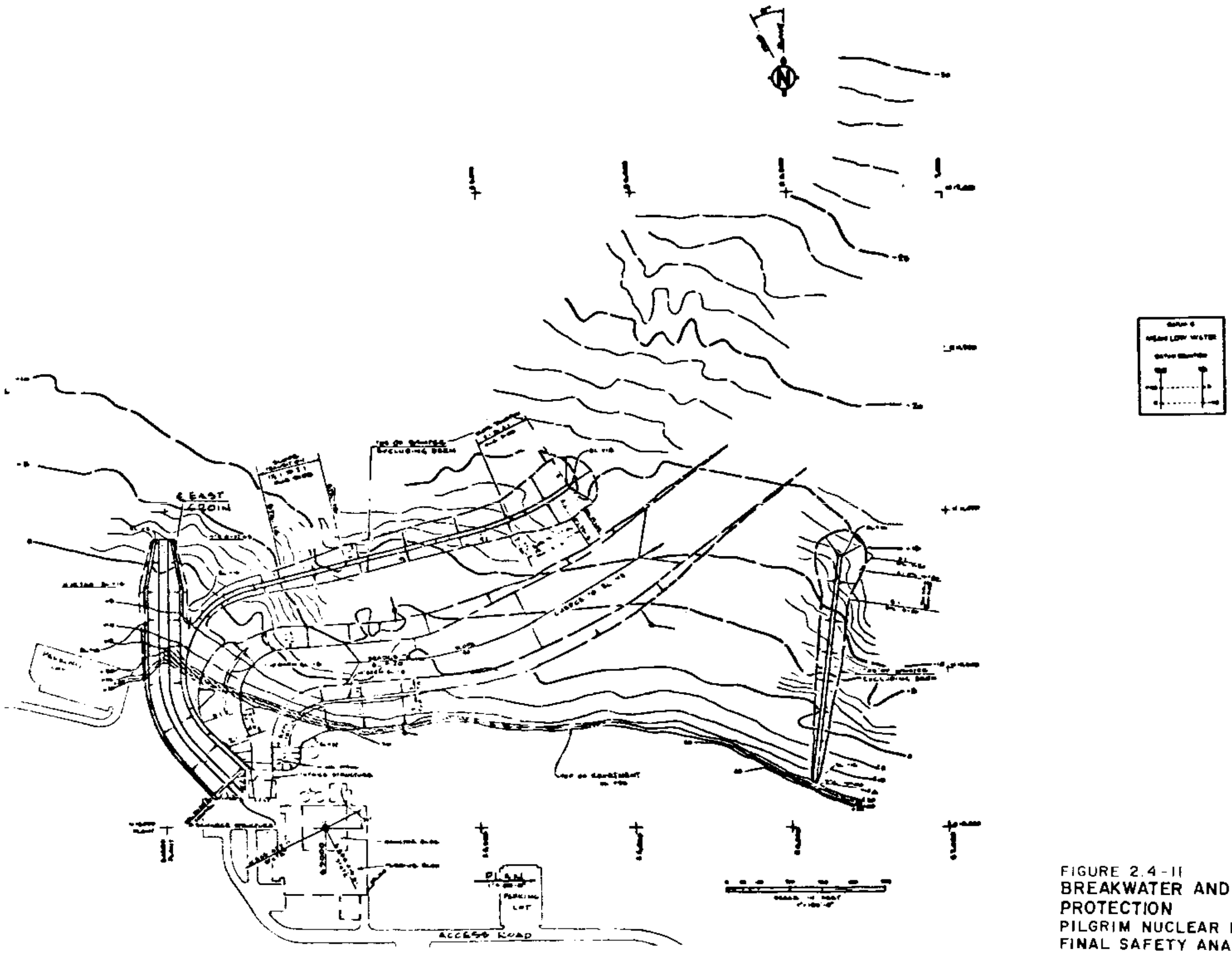


FIGURE 2.4-11
BREAKWATER AND SHORE PROTECTION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

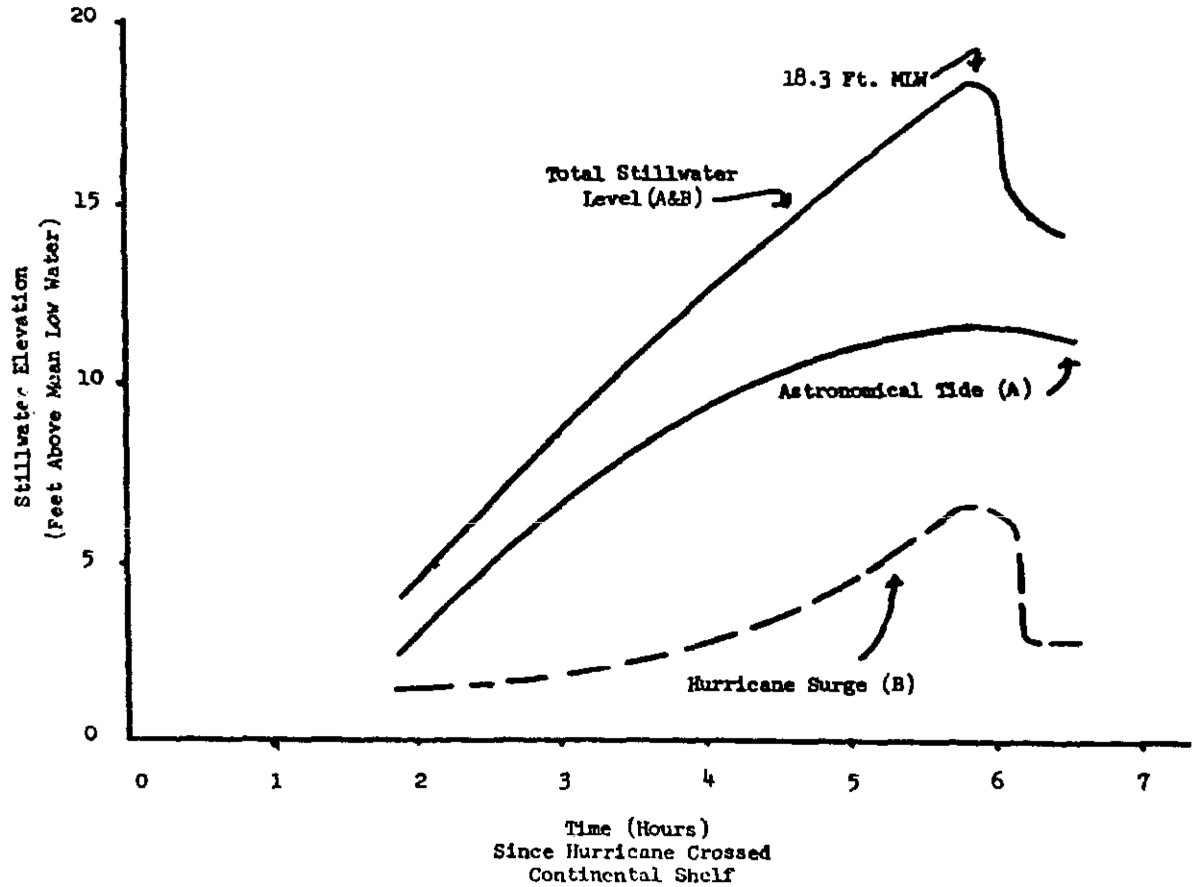


FIGURE 2.4-12
PROBABLE MAXIMUM SURGE
HYDROGRAGH
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

2.5 GEOLOGY AND SEISMOLOGY

2.5.1 General

Geologic and seismic investigations have been made of the station site and surrounding areas. Geologic field observations, inshore and offshore drillings, seismic studies, and bathymetric studies were performed in addition to the evaluation of previous geologic and seismic investigations.

The programs and their significant results are summarized in the following sections. Refer to Figures 2.5-1 through 2.5-6.

2.5.2 Geology

2.5.2.1 Introduction

The site is located on the shoreline of Cape Cod Bay near Rocky Point in Plymouth, Massachusetts. The rocks and sediments in the region range in age from Precambrian to Recent. Pleistocene glacial till and outwash of variable thickness generally mantles the region. The site is within the deeply eroded Appalachian Mountain System and since Precambrian time, the region has had several episodes of folding, faulting, and igneous intrusion with associated metamorphism of pre-existing rocks. Glaciation and the Atlantic Ocean's rise to its present level have also modified the region's topography. There are six regional structural provinces but there are three basins which characterize the geology of eastern Massachusetts.

The site is located in a depression from 14 to 32 ft above mean sea level (msl) on the northeast side of a glacial ridge. Bedrock at the site is about 64 ft below msl and is topped by glacial and recent deposits. An upper discontinuous, erratic zone of sandy silts, and silty and clayey sands up to about 20 ft thick was disclosed. Boulders are also scattered throughout the overburden soils. No known faults at or near the site were revealed.

Cape Cod Bay is a circular embayment of the Atlantic Ocean and slopes gently to the north. The sea floor is broken in a few isolated locations by outcrops of hard rock. Bedrock ranges from 51 to 70 ft below sea bottom, and is topped by sandy, gravelly, glacial deposits, clays, organic silts, and sand.

2.5.2.2 Geologic Investigative Program

In the 150 years since the publication entitled "Outline of the Mineralogy and Geology of Boston and its Vicinity" by J.F. and S.L. Dana (American Academy of Arts & Science Mem. Vol. 4, 1818), the geologic mapping of eastern Massachusetts has been extended and refined, but is essentially the same as mapped by Emerson (1917). The structural interpretation, however, is still debated after a century and a half which demonstrates the complexity of the geology.

The geologic maps compiled for this area are still subject to various interpretations. However, interpretation of evaluations of numerous geologic investigations made during the period 1880 to 1967, and interviews with investigators presently working in the area were carried out.

In addition to field observations, other methods have been employed. Onshore site and foundation studies were made by drilling borings and performing a seismic study.

Offshore, several drilling and seismic studies were carried out. This was to determine the depth to bedrock and the seismic velocities of the overburden materials. In addition to the seismic profile line, a series of seismic point shots were made to extend seismic information. A bathymetric study offshore was also conducted.

2.5.2.3 Regional Geology

2.5.2.3.1 Regional Stratigraphy

The exposed rocks and sediments in the region range in age from Precambrian to Recent. Precambrian, Cambrian, Ordovician, Silurian, and Devonian rocks, consisting of metamorphics, igneous intrusives and extrusives, and a few small areas of relatively unmetamorphosed sedimentary rocks, predominate in the region.

Carboniferous and Triassic rocks are presently exposed in, and generally restricted to, some faulted basins in the region. Sediments were accumulated in these basins primarily under non-marine conditions, and are preserved due to subsidence and down faulting within the basins. Carboniferous rocks are known to occur in the Boston and Narragansett Basins and in Nova Scotia and New Brunswick. Triassic rocks occur in the Connecticut Valley and in the south of Nova Scotia. Igneous intrusives of Permian Carboniferous and Triassic Jurassic Age are also exposed in the region.

Relatively undisturbed Cretaceous, Eocene, and Miocene marine sedimentary strata are known to occur in isolated locations along the present coast and offshore. In places, these sediments were deformed by the glaciers which subsequently advanced across the region. The contortion of these sediments by the movement of the great thickness of glacial ice is particularly evident in exposures on Martha's Vineyard.

Pleistocene glacial deposits of greatly varying thickness, consisting primarily of till and outwash, generally mantle the region. Isolated bedrock outcrops occur west of a line between Kingston, Massachusetts, and Buzzard's Bay. This line passes about 7 mi west of the site. East of this line, the bedrock is usually completely mantled by the glacial deposits. The existence of glacial deposits covering the bedrock and the lack of Tertiary and Mesozoic Rocks make

structural interpretation and dating of geologic events difficult and in some cases questionable.

2.5.2.3.2 Regional Geologic History

This site is located within the Appalachian Mountain System which extends from Newfoundland to Alabama. The Appalachian Mountain System in the New England area extends from eastern New York state to the edge of the continental shelf. This mountain system has been deeply eroded to its present elevation.

The geologic history of the New England portion of this Mountain system can be separated into four major time periods.

Not much is known about the Precambrian period in the New England region since the rocks of this age have been greatly altered. However, during this period several episodes of mountain building took place to the northwest, in the Canadian Shield area.

During the early Palezoic, two major episodes of folding, faulting and igneous intrusion, with associated metamorphism of preexisting rocks, occurred. These major tectonic episodes took place during the Ordovician, 425 million or more years ago and the Devonian 350 million or more years ago. These major episodes formed the backbone of the Appalachian Mountain System in the New England region.

During late Paleozoic and early Mesozoic time, two less intense but important tectonic episodes occurred. This activity took place during the Permian to Carboniferous, 230 million or more years ago, and during the Triassic to Triassic, 135 million or more years ago. These episodes concluded the major tectonic sequence of events which formed the Appalachian System. The major events of these two tectonic episodes were: the trust faulting of the western part of the region, the formation of the Carboniferous and Triassic basins; and the emplacement of the final igneous intrusives (the Permo-Carboniferous granites, and the White Mountains Magma Series).

Since the Cretaceous the region has not experienced any strong tectonic activity. The Cretaceous and Tertiary sediments deposited along the flank of the continental mass under maring conditions are, therefore, relatively undisturbed.

During the Pleistocene, glaciers advanced several times across the entire region and greatly modified the existing topography. Glacial erosion removed most of the overburden soils and some of the bedrock. The glaciers also deposited large amounts of material in the form of moraines and outwash plains. Cape Cod and the islands south of New England are largely terminal moraines with associated outwash plains. The final retreat of the glaciers from the rock took place approximately 10 to 15 thousand years ago.

The irregular topography consisting of moraines, outwash plans and kettles with generally unintegrated drainage, has been modified since the retreat of the glaciers by the rise of the Atlantic Ocean to its present level and by the effect of rain and wind. The modifications of the topography consisted of coastal retreat, the introduction of better integrated drainage and the gradual filling of the swampy areas in the kettle depressions.

2.5.2.3.3 Regional Structure

The region of New England and its continental shelf consists of six structural provinces. These structural provinces are related to, but not coincident with, physiographic provinces. Insufficient geologic information precludes the use of structural province terminology offshore.

Onshore, most of the structural trends are aligned north-south in Southern New England and change to northeast-southwest alignment in Northern New England.

The six structural provinces are related to the Tectonic history of the region which produced the various structures and metamorphic zones apparent within the Appalachian Mountain System. From the northwest to the southwest across the System the degree of metamorphism increases from the unmetamorphosed sediments of New York, west of the Taconic Belt, to a maximum with the Central New England Upland, and thence decreases again to the southwest. The major fault systems apparently comprise the boundary zones between the areas of differing degrees of metamorphism.

The major known fault systems in the region are:

1. The overthrust fault system in the Taconic Belts

2. The thrust and normal fault systems along the Triassic-Devonian axis

3. A thrust fault along the boundary between the Central New England Upland and the Southeastern Platform Provinces

Recently, an east-west alignment, which may be a fault, has been inferred. This alignment, forms the northern boundary of the Southern Connecticut Province. This alignment is similar and parallel to the Cornwall-Kelvin alignment which is considerably south of New England.

These two alignments apparently form an ancient strike slop or transform fault system which offsets the Appalachian System south of New England. The age of this inferred faulting is apparently pre-Triassic.

Many other smaller faults have been mapped within the region. Apparently, these are secondary faults related to the major fault system or related to the various igneous intrusions which have occurred within the region.

There are no known active faults within the region. The most recent known activity is associated with the emplacement of the White Mountain igneous intrusives which are approximately 170 to 190 million years old.

The site is located within the Southeastern Platform Province. The province is bounded on the northwest and west by a thrust fault. On the south, it is probably bounded by the aforementioned southern Connecticut east-west alignment.

The eastern and northeastern boundaries of the province are not fully known. In these directions, the basement structure lies below the waters of the Gulf of Maine and is covered by Cretaceous to Recent sediments. However, the province probably extends northeastward to include the southeast portion of Maine, and an area between Maine and Nova Scotia occupied by a Triassic basin. It is likely that it also extends farther into New Brunswick and Nova Scotia to include the Carboniferous basins there.

The southeastern Platform Province in Massachusetts and Rhode Island consists of three major rock groups:

1. Precambrian, Cambrian, and Ordovician metamorphic and igneous rocks along the western side of the province

2. Dedham granodiorite (of Precambrian or Devonian Age) which forms the major part of the crystalline basement within the province

3. Carboniferous sedimentary rocks of the Narragansett and Boston Basins and related granites

The eastern part of Massachusetts is characterized by these northeast-southeast trending elongated basins which have been filled with predominantly Carboniferous sediments.

The Newbury, Boston, and Narragansett Basins in eastern Massachusetts have undergone intense folding and moderate faulting. Except for the Quaternary glacial deposits, the youngest rock units known in the basins are of late Carboniferous to early Permian age. The time gap between the Carboniferous, Permian, and Quaternary rocks is about 250 million years.

The present review of available geologic data revealed that the north-south trending faults between Boston and Narragansett Basins are apparently exaggerations of minor faults and/or hypothetical faults. Recently published detailed geologic maps of this area do

not confirm the continuation of these minor faults from one basin to the other. The exaggeration may have been needed to show the minor faults on the small scale (1:2,500,000) Tectonic Map.

The gravity contours show no evidence of a north-south structural relationship between the three basins, but there is a general confirmation of the regional northeast structural trend.

Newbury Basin

The synclinal Newbury Basin extends northeastward from Rowley across Plum Island and continues seaward. Its dimensions on land are about 7 mi long and 2 mi wide. Emerson's study of the basin indicated that as a whole it is a unit comprised of rocks of approximately the same age. These rocks are primarily unmetamorphosed volcanics (rhyolites, andesites, volcanic conglomerates, and tuffs) which are overlain by a thin fossiliferous marine shale and a thick volcanic conglomerate or mudflow. The marine fossil evidence, while not definite, indicates that the rocks are late Silurian or early Devonian. The fossil discovery is important in that it makes possible an age differentiation between the Newbury Basin and the younger Carboniferous basins of southeastern Massachusetts with which it has heretofore been grouped. The late Silurian early Devonian age indicates the basin was formed prior to the Acadian orogeny.

Boston Basin

The Boston Basin is a roughly triangular structure extending from Boston Bay to about 25 mi southeastward. The base of the Carboniferous rocks is marked by the Roxbury conglomerate which is overlain by the Cambridge slate and argillite. Emerson (1917) and Billings (1929) believed the rocks in the basin to be Pennsylvanian or Permian.

LaForge (1932) states that because of the nonmarine character of the rocks and lack of fossils, differences in sections a few miles apart, and the lack of persistent beds, the rocks cannot be positively correlated with any other rocks in southeastern New England. Evidence for age must be indirect such as the age of the surrounding rocks. Based on such evidence he estimated the age to be not older than Devonian or younger than Carboniferous.

Current investigators believe however, that the Boston Basin is mid-Devonian or perhaps Mississippian in age.

The northwest side of Boston Basin is bounded by the Merrimack thrust fault. The older rocks northwest of this fault have been thrust southeastward over the younger Carboniferous sediments found in the basin. These sediments have been folded into plunging anticlines and synclines as determined by Billings (1929) and have been classified as a northern synclinorium which has been overthrust by the central

anticline. The southern side of the anticline is bordered by a series of steep reverse faults comprising a shingleblock zone.

The main anticline has been displaced by the north-south trending Stony Brook fault which offset the east-west trending Savin Hill fault.

In summary the basin can be described as a sinclinorium fanning out to the northeast with folds that plunge northeastward so that the basin is deeper in Boston Bay than on land. Faulting, mainly thrusting, has complicated the geologic structure so that it is much more complex than the structure of the Narragansett Basin.

Blue Hill Complex

The Blue Hill granite porphyry is believed (Emerson 1917) to be a peripheral shell or zone of the Quincy granite stock. The porphyry may have originally covered the whole stock and subsequently been eroded from the northern part after faulting and tilting to the south. Billings described the Blue Hill complex as a granite porphyry which has been thrust from the south into contact with the younger sediments of Boston Basin. More recent field information indicates that the Blue Hill granite porphyry is a separate intrusion which is younger than the Quincy granite. However, the Blue Hill complex structurally separates the Boston and Narragansett Basins, which contain sediments of different ages.

Narragansett Basin

The Narragansett Basin extends northward from Newport to Taunton and then northeastward to Brockton. The basin is about 55 mi long and is described as a synclinorium comprised of many folds which have been deformed and intruded by igneous rocks.

The basal sedimentary formation is the Pondville conglomerate which contains material derived from nearby granitic rocks. The overlying Wamsutta Formation consists of distinctive red beds of sandstone, agglomerates, arkose, and shale which have some interbeds of tuff and volcanic flow rock.

The overlying Rhode Island Formation is the predominant unit in the basin, both in areal extend and thickness. The formation consists of shaly and slatey coal bearing strata interbedded with sandstone and conglomerate. The coal has fossil plant remains of Pennsylvania age.

Long lenses of Dighton conglomerate have been infolded into the Rhode Island Formation which give a late Pennsylvania age to the rocks.

Structural Relationship of the Narragansett, Boston, and Newbury Basins

The regional structural trend in this part of New England is southeast-southwest. Hence, any north-south relationship of the Newbury, Boston, and Narragansett Basins does not conform to the regional structural trend.

The Newbury Basin, as described earlier in this report, is primarily a synclinal basin with a northeast-southwest trend. It is believed to be of late Silurian or early Devonian age. This age predates the Acadian progeny, and therefore preceded deposition of the Carboniferous sediments in the Boston and Narragansett Basins. The northeasterly striking volcanic rocks of Newbury Basin are not overlain by Carboniferous sediments as in the Boston Basin. This indicates that the two basins were not formed contemporaneously and that each basin had its individual geologic events.

The Boston Basin is a fault basin. It was formed either as a dropped block or graben type structure or chiefly as a result of thrust faulting. The basin is believed to be mid-Devonian or possibly Mississippian in age. The sediments in the basin trend generally east-west.

Separating the Boston Basin from the Narragansett Basin is the Blue Hill complex. It is an east-west trending fault block complex. Rocks of this structural unit are chiefly of granite porphyry, probably of Carboniferous age.

The Narragansett Basin is described as a synclinorium comprised of folded and faulted sediments trending generally northeast. The basin was formed during Mississippian or Pennsylvanian time. It is bounded primarily by the Dedham granodiorite of Devonian age.

There is no valid evidence that indicates these basins are connected as a single north-south structural unit. There is however, considerable evidence that the three basins were not formed contemporaneously, and that they are separate basins related only in the regional northeast trending structural complex of New England.

2.5.2.4 Site Geology

2.5.2.4.1 Physiography

The site is located on the northeast side of the Pine Hills. Pine Hills consist of a north-south trending glacial ridge which rises to a maximum elevation of 395 ft. The last advance of the Cape Cod glacier lobe carved the topography on the eastern side of Pine Hills and overtopped the hill to build the Ellisville Moraine to the south and southeast. The site varies from about 14 to 32 ft above msl and is partially located in a depression, probably a kettle, which has been eroded on the seaward side.

2.5.2.4.2 Site Bedrock

The bedrock is part of the Dedham granodiorite group. Bedrock does not outcrop onshore within 7 mi from the site.

Five seismic refraction traverses were made in the area of the plant site. These traverses indicate an irregular bedrock surface from 30 to 90 ft below msl. Because of boulders near the bedrock surface, the depths to bedrock may be too shallow by as much as 15 percent.

Bedrock was encountered in two borings in the site area at 64 ft below msl. The bedrock, as indicated by the cores, is slightly weathered to a depth of 6 ft, but competent with infrequent joints and fractures below this depth.

2.5.2.4.3 Site Surficial Deposits

The subsurface investigations in the site area indicated about 65 to 115 ft of glacial and recent deposits overlie bedrock. An upper discontinuous, erratic zone of sandy silts, and silty and clayey sands up to about 20 ft thick, often overlain by a thin stratum of sand and gravel, was disclosed. The lower glacial zone, which extends to bedrock, consists of poorly graded to well graded sands with varying amounts of gravel and cobbles. Pockets of silty sand were detected in this stratum. Boulders are scattered throughout the overburden soils and an approximately 10 ft thick, apparently discontinuous boulder zone overlies bedrock. The borings encountered boulders which averaged about 2 ft in diameter and varied to 6 ft in diameter. Larger boulders up to 20 or 30 ft are occasionally observed at the site. The materials below about 35 ft in depth are compact to dense.

2.5.2.4.4 Site Faulting

There are no known faults at or near the site and none were revealed by the drilling or geophysical investigations.

The nearest mapped fault is located about 17 mi to the west in the Narragansett Basin. The site is located in the Southeastern Platform Structural Province near the geometric center formed by the arcuate Boston Basin, 25 mi to the north and the Narragansett Basin, 25 mi to the west. All known faulting in these basins is ancient, i.e. pre-Cretaceous. The most seismically significant structural features are located in the Cape Ann area about 60 mi to the north. The structure responsible for this activity is probably the faults forming the northwest border of the Southeastern Platform Structural Province. The possible east-west Connecticut structural alignment about 30 mi south of the site is also one of the closest major fault systems.

2.5.2.5 Marine Geology

2.5.2.5.1 General

Cape Cod Bay is a circular embayment of the Atlantic Ocean off the eastern coast of Massachusetts. The floor of the bay slopes gently to the north where maximum depths of 180 to 190 ft are found along a line between Plymouth Bay and Race Point, the northern tip of Cap Cod. Isobaths (depth contours) are essentially concentric to the circular coastline of the Bay. The sea floor is generally smooth, but is broken in a few isolated locations by outcrops of hard rock.

A geophysical study published in 1961 indicates that the basement rock beneath the Bay consists of eroded Paleozoic sedimentary, metamorphic, and igneous rocks. Discontinuous deposits of sedimentary rock interpreted as Cretaceous materials lie atop the basement complex. These deposits are overlain by Early Tertiary marine sediments which may be considered as essentially unconsolidated. Pleistocene glacial till is widespread above these layers and, in turn, is covered by a relatively thin veneer of recent unconsolidated sediments composed, in part, of reworked Pleistocene deposits. The study indicates that these deposits are less than about 50 ft thick to a minimum distance of about 4 nautical mi offshore of the site.

The survey which provides these data consisted of approximately 200 mi of seismic reflection lines run over a variety of vessel courses crossing the diameter of the bay. The seismic reflection device used in this survey was capable of resolving soil or rock units having a vertical separation of more than about 15 ft.

Throughout this survey, the records failed to reveal any faulting or folding which exceeded the resolution limits (15 ft) of the survey instrument.

Much of the bay floor surface is composed of mud with varying amounts of sand and shells. In the area several miles offshore of Rocky and Manomet Points, there is a hard rocky or sandy bottom.

The sea floor within an area of one square nautical mile, centered off the site, consists of a blanket deposit of relatively thin, unconsolidated sediments lying atop an irregular surface of glacial till. A smooth central area is flanked by two rocky projections which extend diagonally offshore in a northerly direction. Interpretations based on limited data suggest that these two features consist of local bedrock, possibly crystalline igneous rock. The buried extensions of these features are not well defined by the techniques used in this survey. However, irregular isolated reflecting horizons beneath glacial till probably represent a bedrock surface whose irregularities are attributed to Pleistocene glaciation.

Glacial till, probably similar in character to those materials encountered in the onshore drilling program, is superimposed over the suspected bedrock surface, and in places fill depressions where such features were recognized. The upper surface of this till unit is also irregular, but its proximity to the present sea floor surface permits a more accurate interpretation of its topography. There are several channel-like depressions which head toward the present shoreline. These features are probably old drainageways carved in the glacial till at a time when these materials were exposed during the most recent low stand of sea level. Similar depressions were encountered onshore during the test boring program.

During the latest rise in sea level, the reworking of these materials, plus contributions from sources outside the survey area, provided materials which filled the old drainageways and eventually smoothed over the eroded surface of the till. Continued erosion of exposed shoreline till has provided a ready supply of materials which now form the uppermost blanket deposit of recent unconsolidated sediment.

The boulders within this till have remained near shore as a "lag" deposit forming the boulder bar inshore of the central flat area. Finer materials have been deposited offshore or swept clear of the survey area. Documented rates of local cliff retreat indicate that this process is continuing in those areas not now protected by natural concentrations of large boulders or by man-made coastal protective works. The number of boulders decreases rapidly seaward of the -10 ft contour.

The wedge shaped reentrant in the boulder bar off the site is aligned with the axial trend of a major buried offshore channel. This reentrant is believed to be a landward extension of the buried channel. Test borings onshore near the projected axis of these two features indicate that a similar, and perhaps related, partially filled depression exists at the site.

2.5.2.5.2 Site

A bathymetric survey covering a 1 mi^2 area in front of the site established the limits of two submerged projections within the area of interest. To the north, what appears to be the submerged extension of Rocky Point trends diagonally offshore in a northerly direction and continues beyond the area surveyed. A similar projection, extending northward from White Horse Rock to the south, enters the southern portion of the survey area approximately 1,500 yd off the shore of the southern border of the survey area. Boulders and ridges atop these features create a highly irregular surface which displays local relief up to 15 ft.

A major portion of the offshore area within the square mile surveyed consists of an essentially smooth sea floor between the two rocky

projections. The survey indicates this surface is rippled, and isolated boulders were found in several areas within this region.

The inshore margin of the survey area consists of a boulder bar developed through continuing erosion of coastal outcrops of glacial till. With the exception of a wedge shaped re-entrant directly off the plant site, this bar is more than 100 yd wide. The re-entrant, whose axis points inshore along a northeasterly trend, is 100 yd wide at a point 160 yd offshore. It narrows to a width of approximately 30 yd at the mlw line. This feature is the only break in an otherwise continuous boulder bar between Rocky Point and the southern limit of the survey area.

The 20, 30, and 40 ft isobaths (depth contours) lie approximately 400, 800, and 1,400 yd, respectively, offshore of the mlw line fronting the site.

A seismic survey, required to plan dredging operations and breakwater construction, indicated that bedrock ranges from 50 to 70 ft below sea bottom. The sand on the sea floor is gray and contains a moderate amount of shell fragments. The sand ranges from 6 to 11 ft in thickness and overlies organic soils. The organic soils range in thickness from 3 to 8 ft and contain rootlets and fibrous vegetal matter. The organic silts generally overlie stiff clays or sandy clays ranging from 6 to 11 ft in thickness. The clays are underlain by silty, well graded, sandy, gravelly, glacial deposits which continue to bedrock.

2.5.2.5.3 Shoreline Retreat

A U.S. Army Corps of Engineers report prepared in 1956 states that the south side of Rocky Point exhibited erosion by general landward movement in the amount of about 600 ft between 1857 and 1956. Decreased rate of erosion occurred from there on to Manomet Point. Shore erosion was accounted for in the design of coastal protective works including the breakwaters and revetment.

2.5.3 Seismology

2.5.3.1 Introduction

This discussion presents the summarized results of the engineering seismology performed by Dames and Moore, Bechtel, and several consultants. The investigations had the following objectives: 1) to evaluate the seismicity of area, 2) to evaluate the effect of earthquake motion on the foundation materials, and 3) to develop aseismic design parameters.

2.5.3.2 Summary of Seismic Investigation

Dames and Moore has studied the seismic history and evaluated the geologic conditions of the site and surrounding areas of Newbury

Basin, Boston Basin, Blue Hill complex, and Narragansett Basin. Their study indicates that the structure should be designed to withstand an earthquake of intensity V or VI which might occur near the site.

The Rev. Daniel Linehan, S.J. of Weston Observatory, Weston, Massachusetts was asked to make an independent evaluation of the seismicity of the area. He concluded that the site is not in an active seismic area, and that the critical structures should be designed for an earthquake of intensity V and that a Safe Shutdown Earthquake of intensity VII should be used.

Dr. Perry Byerly, Professor Emeritus in Seismology and Director of Seismographic Station, University of California, Berkley, reviewed the Dames and Moore engineering seismology report, other seismic data available to him, and earthquake damage reports available at Weston Seismological Observatory Library and the Boston and Plymouth city libraries. Upon study of this additional data, Dr. Byerly's evaluation of the seismicity of this site concluded that Class I structures should be designed for a ground acceleration of 0.08 g with 0.15 g used for safe shutdown.

Dr. H. Bolton Seed, Chairman of the Civil Engineering Department, University of California, Berkeley, reviewed the Dames and Moore site studies and other data available to him. Upon study of this information, Dr. Seed has concluded that it is highly unlikely that liquefaction of the foundation material would occur under the postulated earthquake conditions at this site.

2.5.3.3 Seismic Design

2.5.3.3.1 Operating Basis Earthquake

The study of the seismic history of the area indicates that, very probably, the site will not experience any major earthquakes during the life of the station. The following three earthquakes have been determined as the most significant with respect to the site:

1. Southeastern Massachusetts, 1925, intensity V, located about 17 mi southwest of the site

2. Southeastern Massachusetts, 1847, intensity VI, located about 30 mi west of the site

3. Cape Ann area, a series from the early 1600's through recent, maximum intensity VIII, located about 55 to 60 mi north of the site

The ground acceleration at the site due to the recurrence of a shock similar to any of the above earthquakes would be less than 0.05 g.

2.5.3.3.2 Safe Shutdown Earthquake

The Safe Shutdown Earthquake is generally considered to be a recurrence of the largest earthquake in the region at the closest epicentral distance which is consistent with the geologic structure. The Cape Ann series of earthquakes appear to be the most severe earthquakes which need be considered for plant design. The occurrence of an earthquake as large as the maximum Cape Ann sequence (intensity VIII, estimated magnitude 6), with its epicenter at the closest approach of faulting associated with the Boston and Narragansett Basins (17 mi west of the site) is the most critical situation for the site. Horizontal ground acceleration at estimated foundation depths (within the compact glacial deposits) due to the above earthquake would be about 0.15 g.

2.5.3.4 Conclusions

The station Class I structures and systems have been designed for horizontal ground accelerations of 0.08 g (Operating Basis Earthquake and 0.15 g (Safe Shutdown Earthquake).

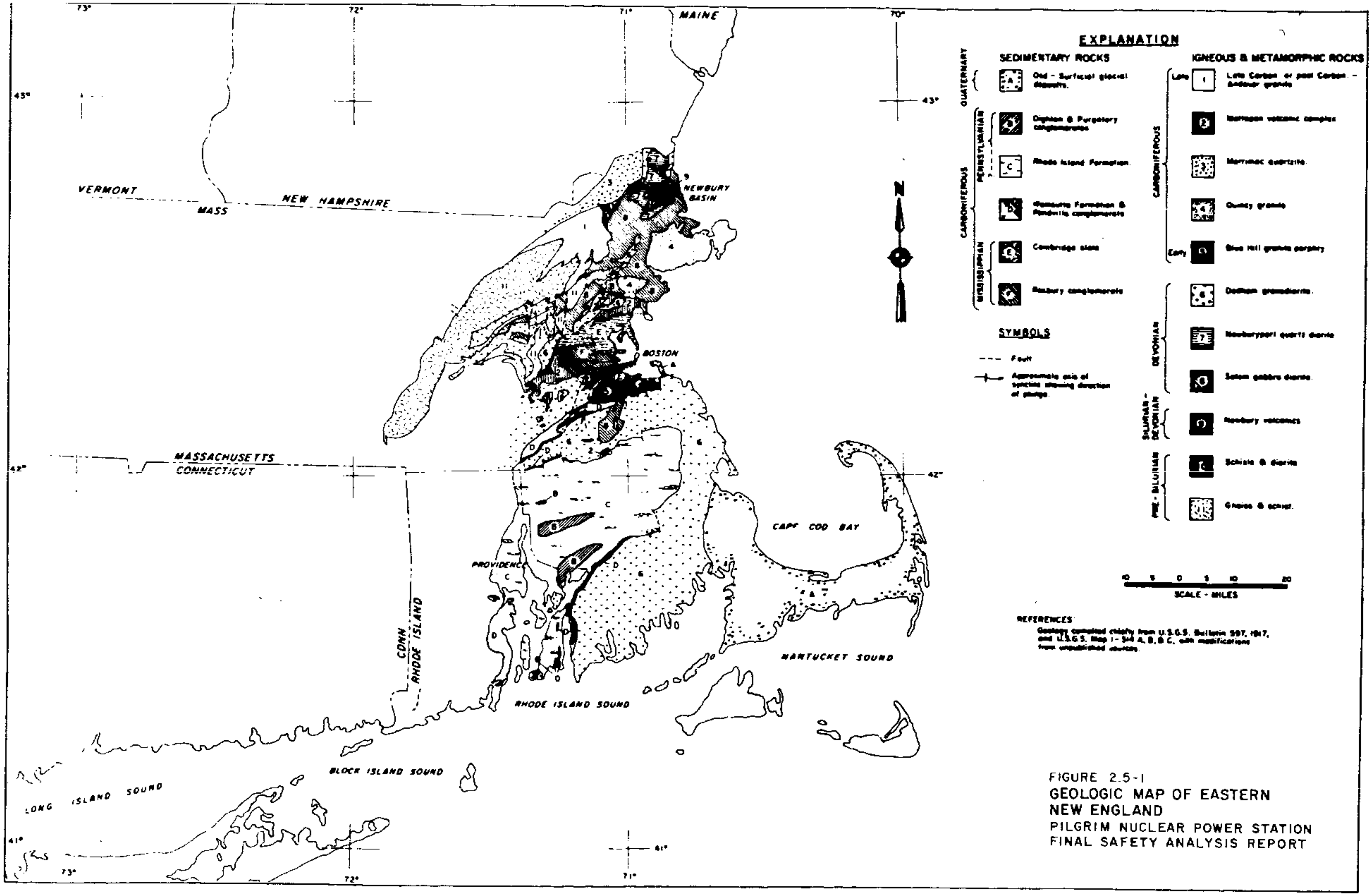
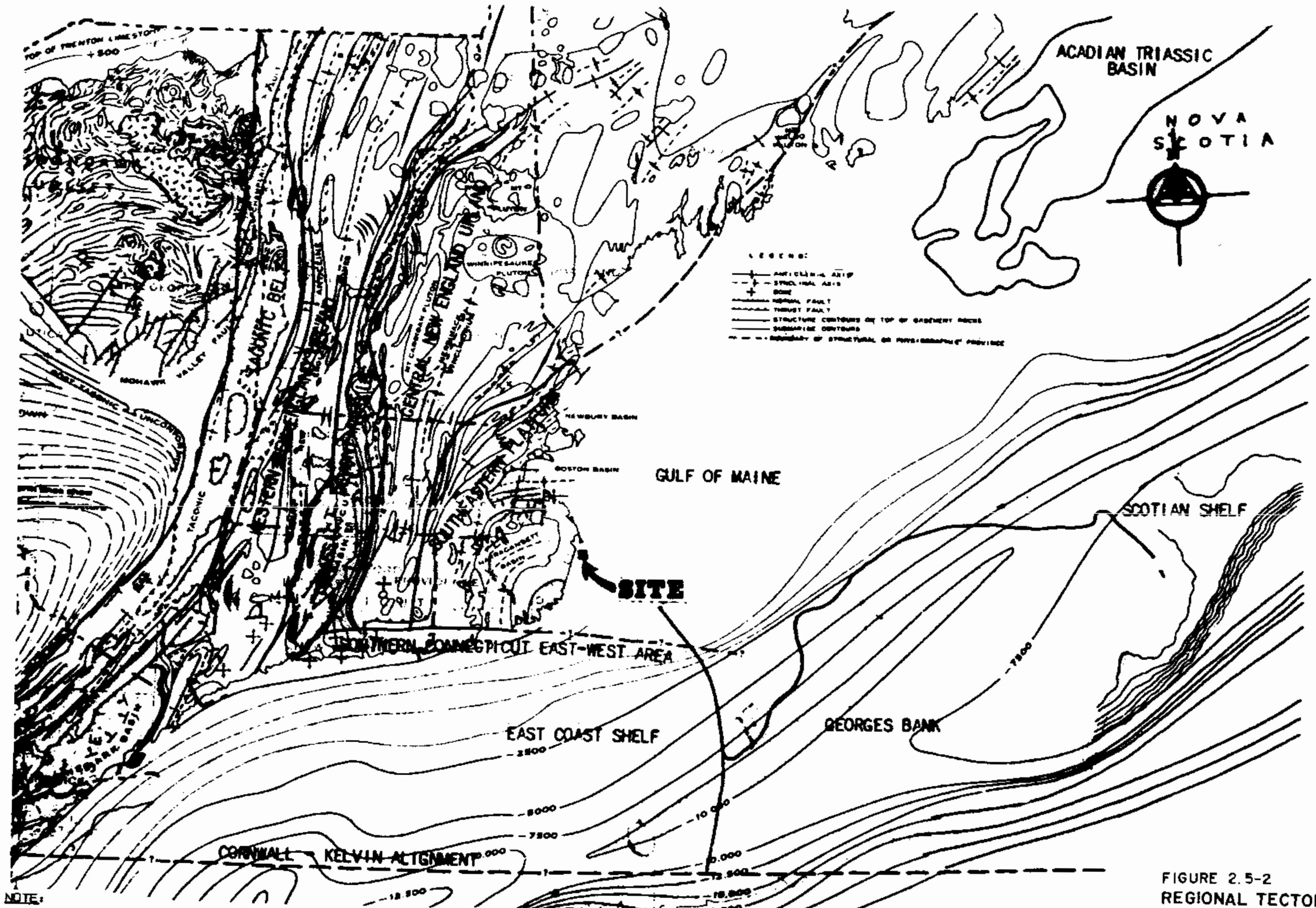


FIGURE 2.5-1
GEOLOGIC MAP OF EASTERN NEW ENGLAND
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



NOTE:

THIS MAP WAS PREPARED FROM A PORTION OF TECTONIC MAP OF THE UNITED STATES, BY THE UNITED STATES GEOLOGICAL SURVEY AND THE AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS, 1962.

FIGURE 2.5-2
REGIONAL TECTONIC MAP
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

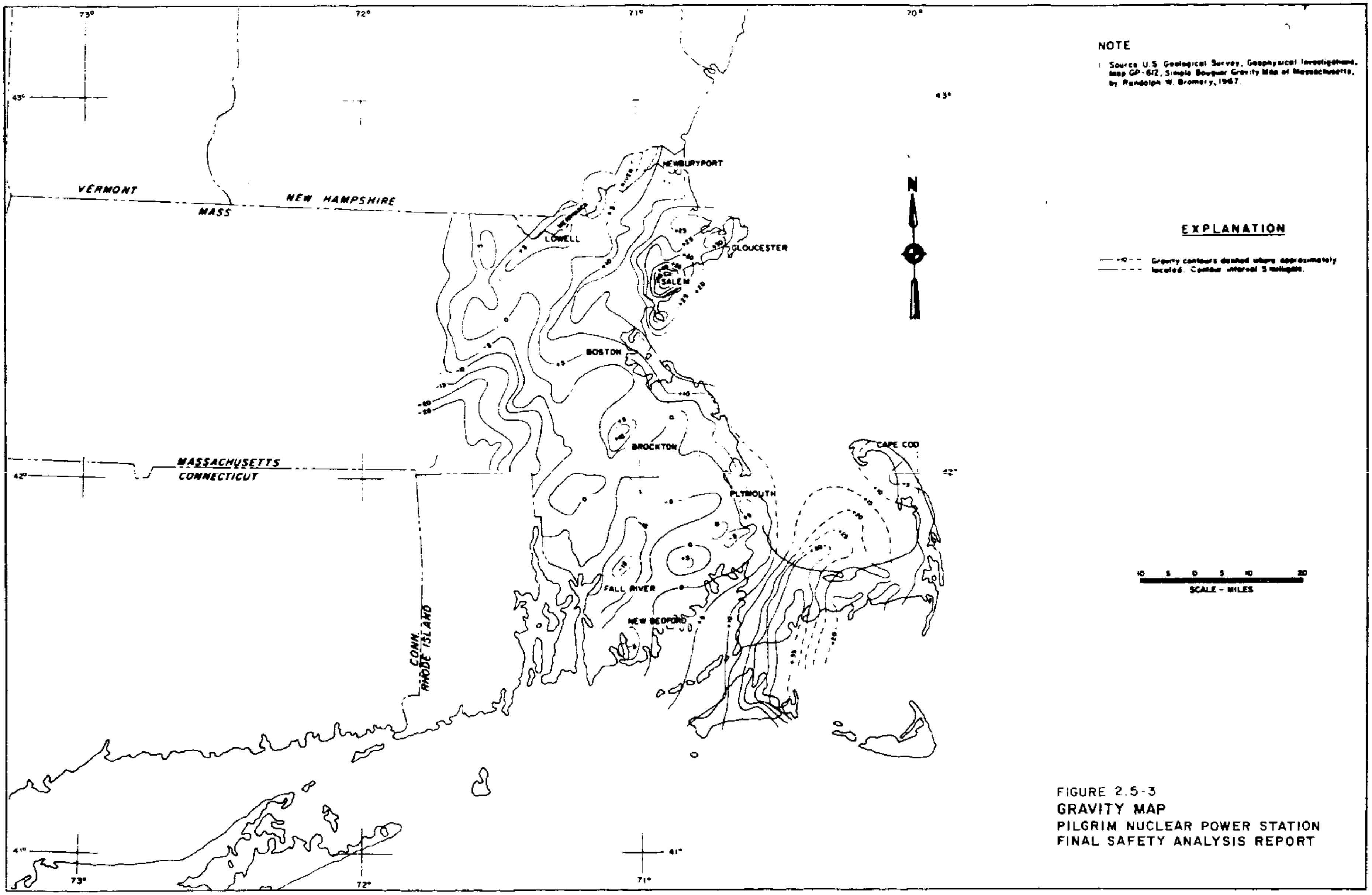


FIGURE 2.5-3
GRAVITY MAP
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

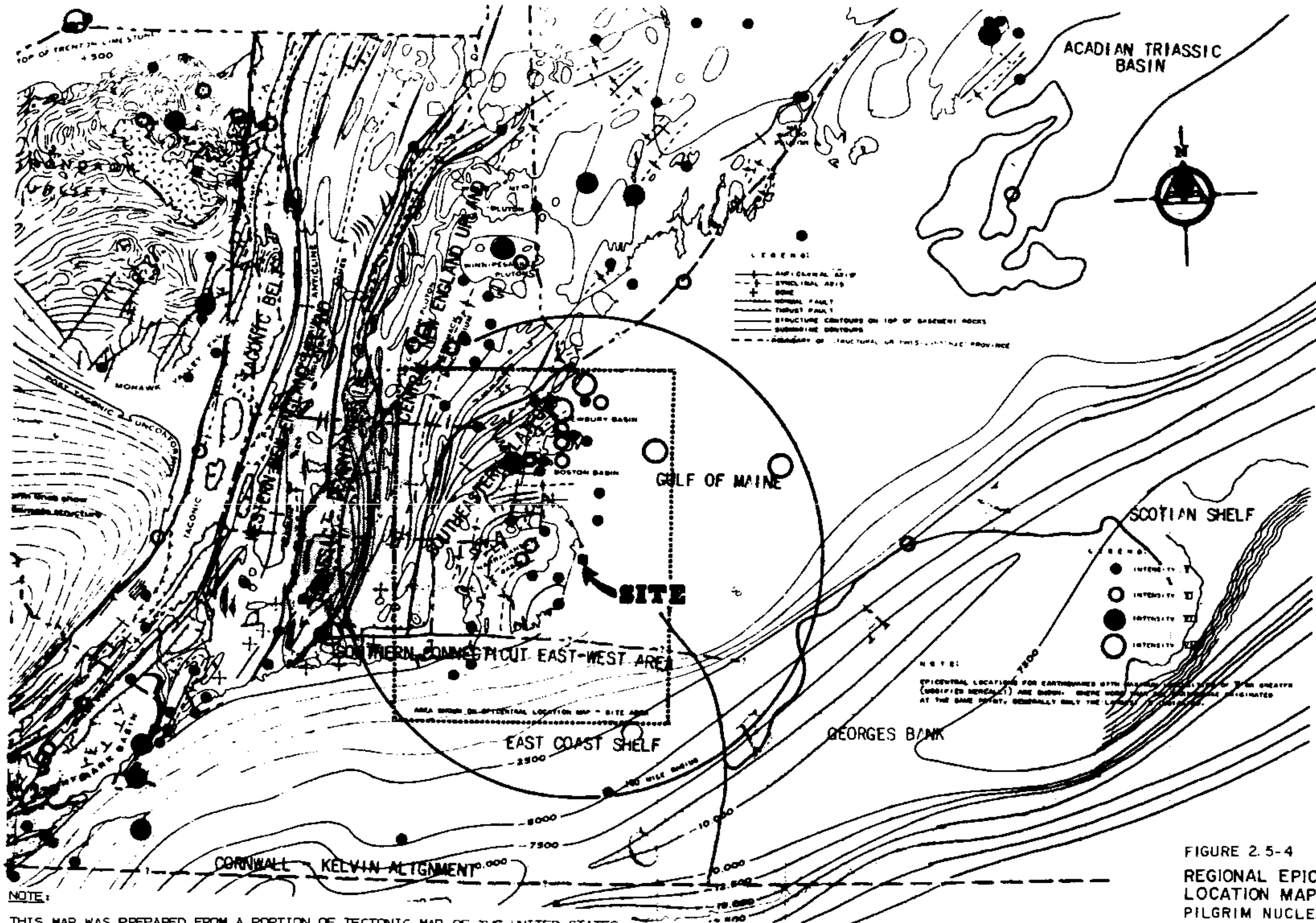


FIGURE 2.5-4

REGIONAL EPICENTRAL LOCATION MAP

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT

NOTE:

THIS MAP WAS PREPARED FROM A PORTION OF TECTONIC MAP OF THE UNITED STATES, BY THE UNITED STATES GEOLOGICAL SURVEY AND THE AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS, 1962.

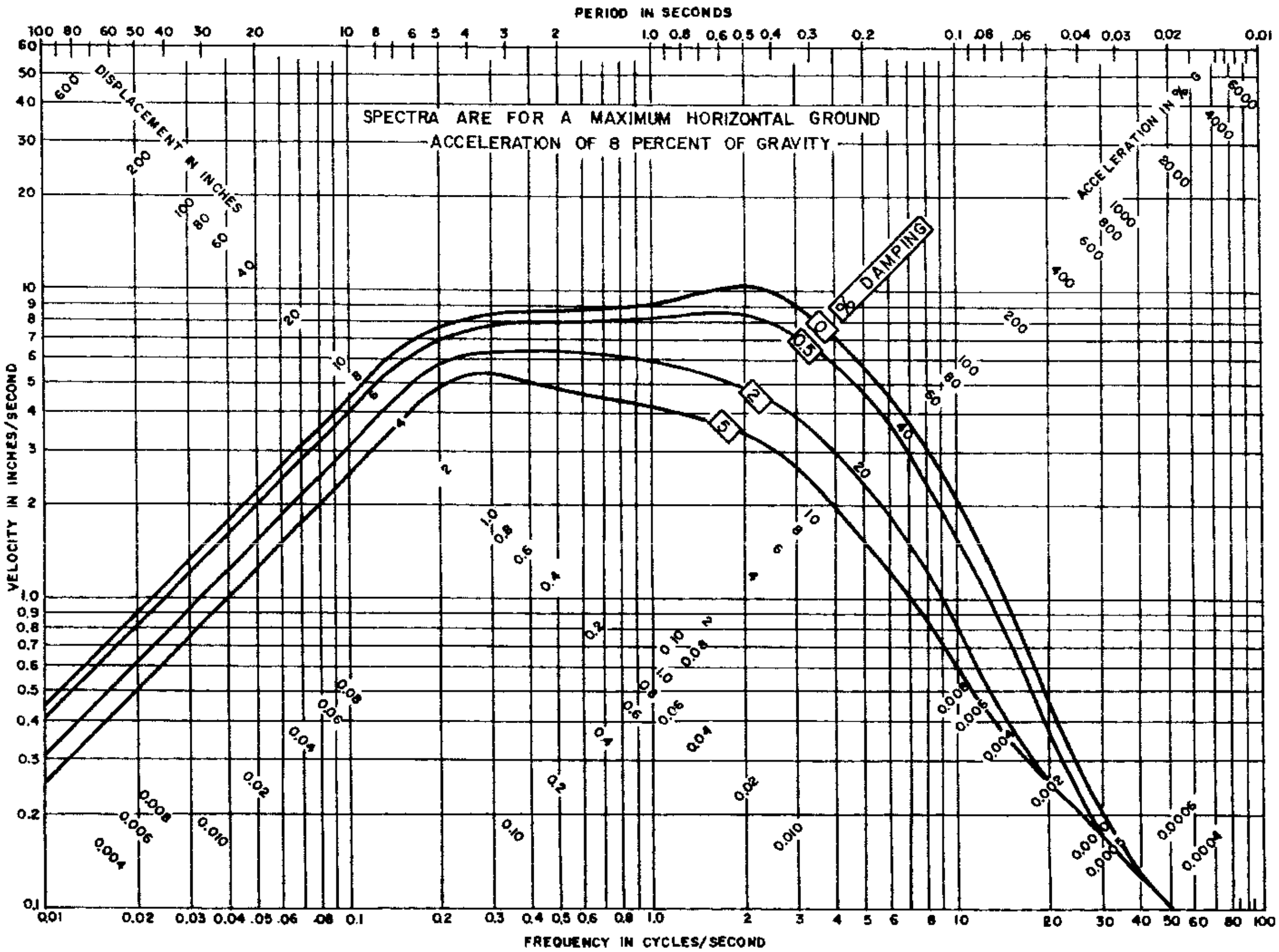


FIGURE 2.5-5

RECOMMENDED RESPONSE SPECTRA
OPERATING BASIS EARTHQUAKE

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

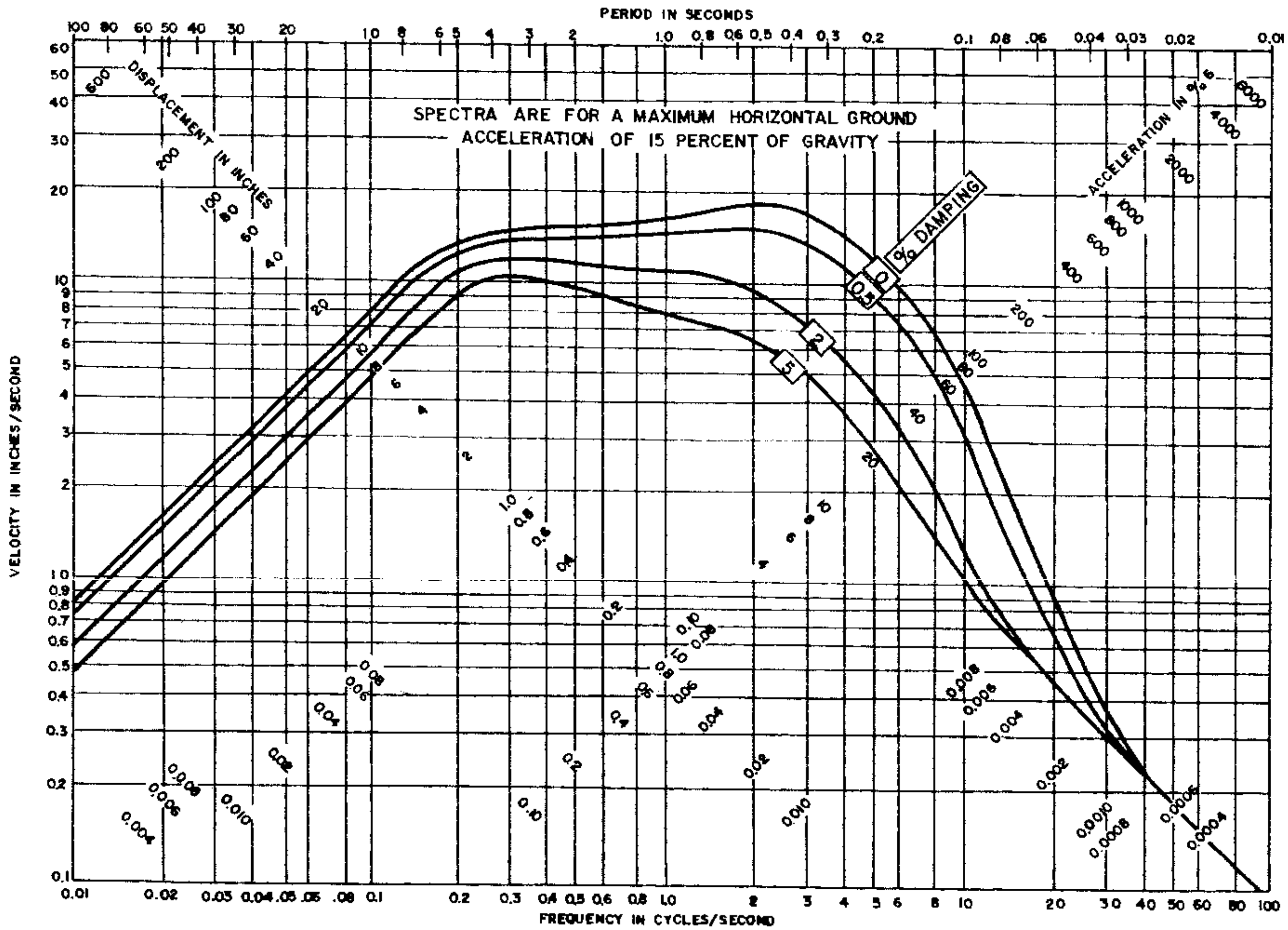


FIGURE 2.5-6

RECOMMENDED RESPONSE SPECTRA
SAFE SHUTDOWN EARTHQUAKE

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

2.6 ENVIRONS RADIATION SURVEILLANCE PROGRAM

The Environs Radiation Surveillance Program is divided into two geographical areas: onsite, which includes the areas within the site property boundaries; and offsite, which is the area beyond the property boundaries of the site.

Preoperational studies of environmental radiation levels were initiated on a limited basis in August 1969. Since then, these studies have been gradually expanded. The principal purpose of these studies was to provide a baseline from which any increase in radiation during operation may be detected and evaluated.

If the surveillance results indicate its necessity, the surveillance program and the technical specifications for the station will be modified.

Surveillance program results for the quarter June through August 1970 were submitted to the AEC.

The Radiological Effluent Technical Specifications (RETS) were incorporated into the Pilgrim Station Technical Specifications in Amendment 89, dated March 1, 1986. This implementation of RETS into the Technical Specifications also incorporated the Radiological Environmental Monitoring Program (REMP), which was described in the Pilgrim Offsite Dose Calculation Manual (ODCM). The NRC reviewed and approved the Amendment 89 implementation of RETS using criteria presented in NUREG-0473, NUREG-0133, and Regulatory Guide 1.109.

In response to Generic Letter 89-01, the radiological effluent control program and environmental monitoring program elements included in the RETS and REMP were relocated from the Pilgrim Technical Specifications into the ODCM. This relocation occurred in Amendment 177, dated July 31, 1998. This relocation was performed in accordance with NUREG-1302.

The Pilgrim Technical Specifications and ODCM require submittal of annual reports describing the results of the effluent control and environmental monitoring programs. The annual Radioactive Effluent and Waste Disposal Report contains information related to effluent control efforts, including releases of radioactive materials in gaseous and liquid discharges, as well as doses to members of the public resulting from those releases. The annual REMP Report contains results of the environmental monitoring efforts, including levels of radioactivity detected in environmental samples, dose impacts of detected radiation levels and radioactivity, and results of the annual land use census.

SECTION 3

REACTOR

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SECTION 3

REACTOR

3.1 SUMMARY DESCRIPTION

This section describes and evaluates those systems most pertinent to the fuel barrier and the control of core reactivity. Section 3.2 describes the mechanical aspects of the fuel material (uranium dioxide), the fuel cladding, the fuel rods, and the arrangement of fuel rods in bundles. Of particular interest is the ability of the fuel to serve as the initial barrier to the release of radioactive material. The mechanical design of the fuel is sufficient to prevent the escape of significant amounts of radioactive material during normal modes of reactor operation.

Section 3.3 describes both the arrangements of the supporting structure for the core and the reactor vessel internal components which are provided properly to distribute the coolant delivered to the reactor vessel. In addition to their main function of coolant distribution, the reactor vessel internals separate the moisture from the steam leaving the vessel, and provide a floodable inner volume inside the reactor vessel in conjunction with the performance with the Core Standby Cooling System (CSCS) that allows sufficient submergence of the core under accident conditions to meet the CSCS acceptance criteria of 10CFR50. The reactor vessel internals are designed to allow the control rods and CSCS to perform their safety functions during abnormal operational transients and accidents.

Section 3.4 describes the mechanical aspects of the movable control rods. These are provided to control core reactivity. The Control Rod Drive Hydraulic System is designed so that sufficient energy is available to insert the control rods into the core under conditions associated with abnormal operational transients and accidents. Control rod insertion speed is sufficient to prevent fuel safety limits from being exceeded as a result of any abnormal operational transient.

Control rod housing supports, described in Section 3.5, are located underneath the reactor vessel near the control rod housings. These supports limit the travel of a control rod in the event that a control rod housing is ruptured. The supports prevent a nuclear excursion as a result of a housing failure, thus protecting the fuel barrier.

Section 3.6 describes the nuclear aspects of the reactor core. The design of the boiling water reactor (BWR) core and fuel is based on a proper combination of design variables, such as moderator-to-fuel volume ratio, core power density, thermal-hydraulic characteristics, fuel exposure level, nuclear characteristics of the core and fuel, heat transfer, flow distribution, void content, heat flux, and operating pressure. All of these conditions are dynamic functions of operating conditions. However, design analyses and calculations,

verified by comparison with data from operating plants, are usually performed for specific steady state conditions. Included in this section are summaries of results of these analyses for the fuel cycle, reactivity control, and control rod worths. Also included are discussions of the reactivity coefficients and spatial xenon characteristics of the core.

Section 3.7 describes the thermal and hydraulic characteristics of the core. A discussion of fuel failure mechanisms and the parameters associated with fuel damage is presented in the section. Also included is the Power-Flow Operating Map and a discussion of plant operations.

The Standby Liquid Control System (SLCS), described in Section 3.8, provides a redundant and different way (independent of the control rods) to make the reactor subcritical, even in the cold condition. The insertion of control rods is expected always to assure prompt shutdown of the reactor; this can be achieved by insertion of only a few of the many independent control rods. The SLCS can maintain subcriticality as the reactor cools without reliance upon insertion of any control rods.

The Recirculation Pump Trip and Alternate Rod Insertion Systems, described in Section 3.9, provide a back-up method for introducing negative reactivity to the reactor in the unlikely event of a failure of the reactor to scram from power.

3.2 FUEL MECHANICAL DESIGN

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

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

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

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

and are evaluated for their capability to withstand:

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

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

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

3.2.1 Fuel System Damage

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

3.2.1.1 Stress/Strain

Bases

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

Limits

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

Evaluations

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

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

3.2.1.2 Fatigue

Bases

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

Limits

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

Evaluations

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

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

3.2.1.3 Fretting Wear

Bases

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

Limits

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

Evaluations

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

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

3.2.1.4 Oxidation, Hydriding, and Corrosion Products

3.2.1.4.1 Oxidation and Corrosion Products

Bases

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

Limits

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

Evaluations

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

3.2.1.4.2 Hydriding

Bases

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

Limits

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

Evaluations

The evaluation of hydriding of the fuel rod cladding for all fuel designs documented in Reference 4 is based on the substantial operating experience with fuel designs which employ the same limit. This operating experience has been documented in Reference 6. The

experience shows that hydriding is not an active failure mechanism for current fuel designs.

3.2.1.5 Dimensional Changes

Bases

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

Limits

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

Evaluations

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

3.2.1.6 Internal Gas Pressure

Bases

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

Limits

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

Evaluations

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

3.2.1.7 Hydraulic Loads

Bases

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

Limits

This limit is discussed in Section 2.2.1.7.2 of Reference 1.

Evaluations

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

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

3.2.1.8 Control Rod Reactivity

See Sections 3.4 and 3.6.

3.2.2 Fuel Rod Failure

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

3.2.2.1 Hydriding

Hydriding is discussed in Subsection 3.2.1.4.2 of this document.

3.2.2.2 Cladding Collapse

Bases

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

Limits

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

Evaluations

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

3.2.2.3 Fretting Wear

Fretting wear is discussed in Subsection 3.2.1.3.

3.2.2.4 Overheating of Cladding

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

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

3.2.2.5 Overheating of Pellets

Bases

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

Limits

These limits are stated in Section 2.2.2.5.2 of Reference 1.

Evaluations

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

3.2.2.6 Excessive Fuel Enthalpy

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

3.2.2.7 Pellet-Cladding Interaction

Bases

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

Limits

The limits are given in Section 2.2.2.7.2 of Reference 1.

Evaluations

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

3.2.2.8 Bursting

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

3.2.2.9 Mechanical Fracturing

Bases

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

Limits

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

Evaluations

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

3.2.3 Fuel Coolability

This subsection applies to postulated accidents.

3.2.3.1 Cladding Embrittlement

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

3.2.3.2 Violent Expulsion of Fuel

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

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

3.2.3.3 Generalized Cladding Melting

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

3.2.3.4 Fuel Rod Ballooning

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

3.2.3.5 Structural Deformation

Structural deformation is addressed in Subsection 3.2.2.9.

3.2.4 Description and Design Drawings

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

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

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

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

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

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

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

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

independent axial expansion by sliding within the holes of the upper tie plate.

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

3.2.4.1 Control Rods

See Section 3.4.

3.2.4.2 Velocity Limiter

See Section 3.4.

3.2.5 Testing, Inspection, and Surveillance Plans

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

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

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

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

3.2.6 References

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

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

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

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

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

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

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

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

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

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

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

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

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

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

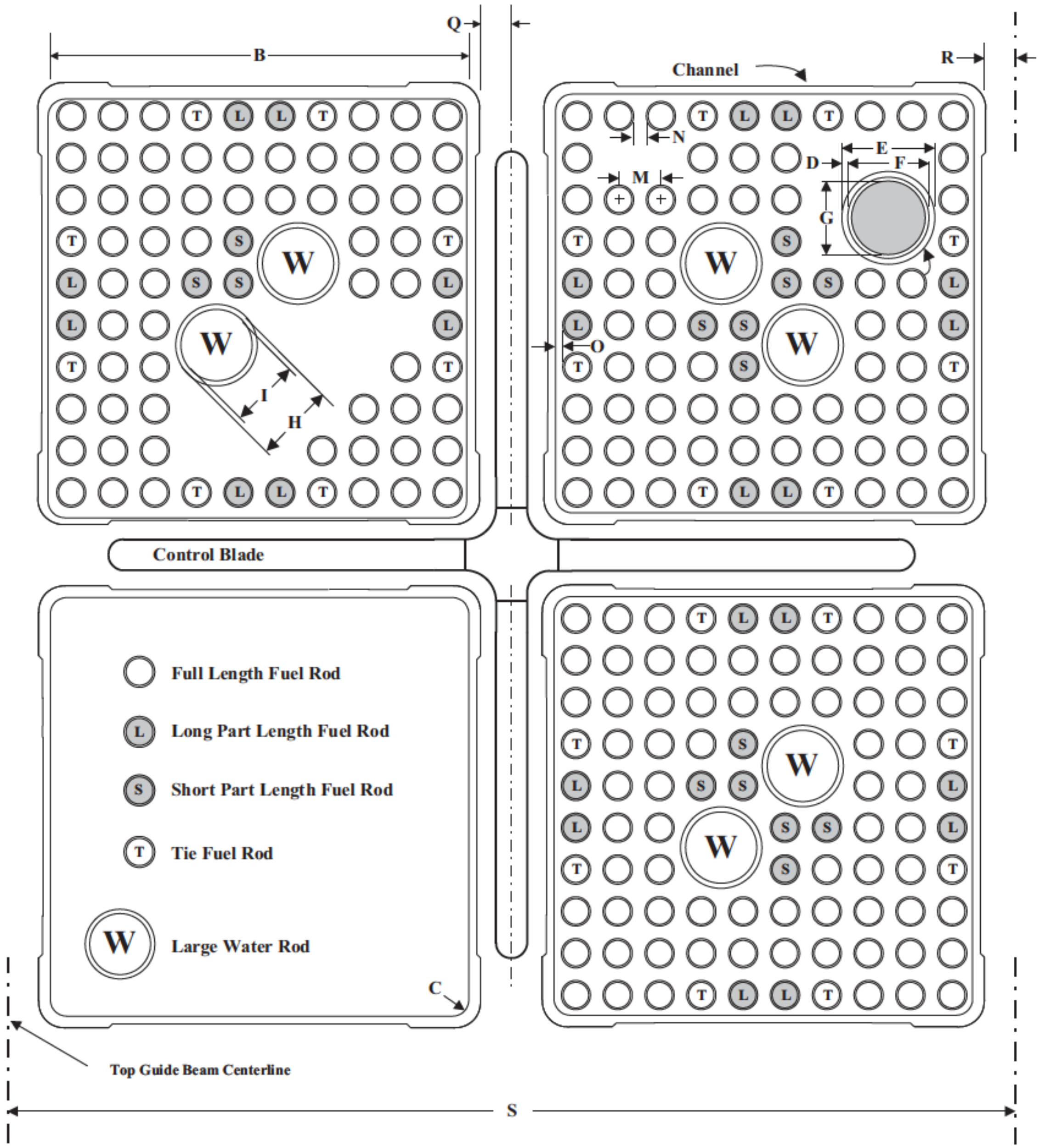
Table 3.2-1

FUEL DATA
GE11, AND GE14, AND GNF2 FUEL DESIGNS

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

* In cycle 17 core, there is no GE11 fuelCycle 21 has a full core of GNF2 Fuel bundles.. The information in this table is maintained as legacy information as GE11 and GE14 fuels are is in the spent fuel pool.

** Based on cross-sectional area.



	CHANNEL		FUEL ROD			PELLET	WATER ROD		BUNDLE LATTICE		
Identification	B	C	D	E	F	G	H	I	M	N	O
Dimension (mm)											
Dimension (inches)											

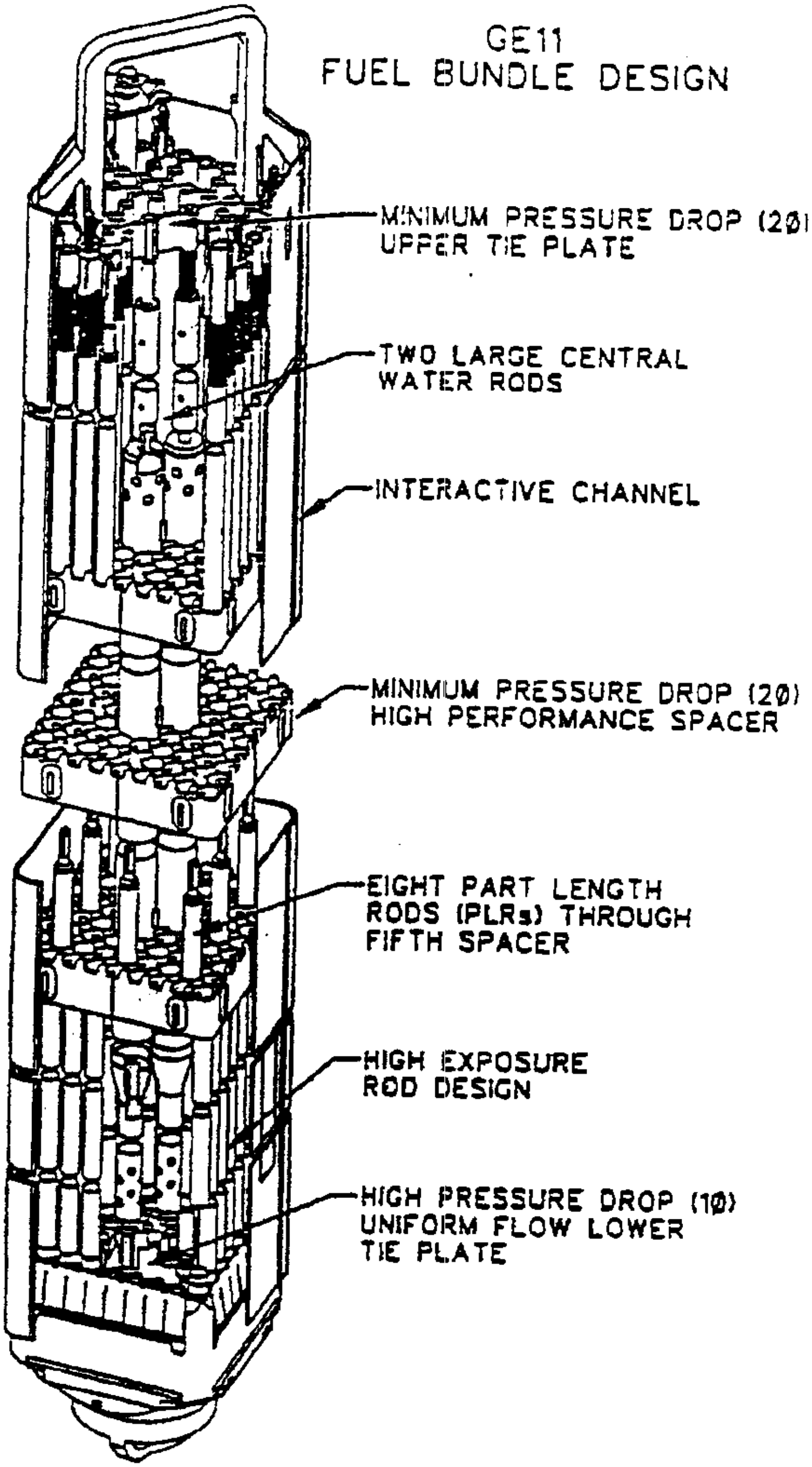


FIGURE 3.2-2
Typical GE11 Fuel Bundle Design

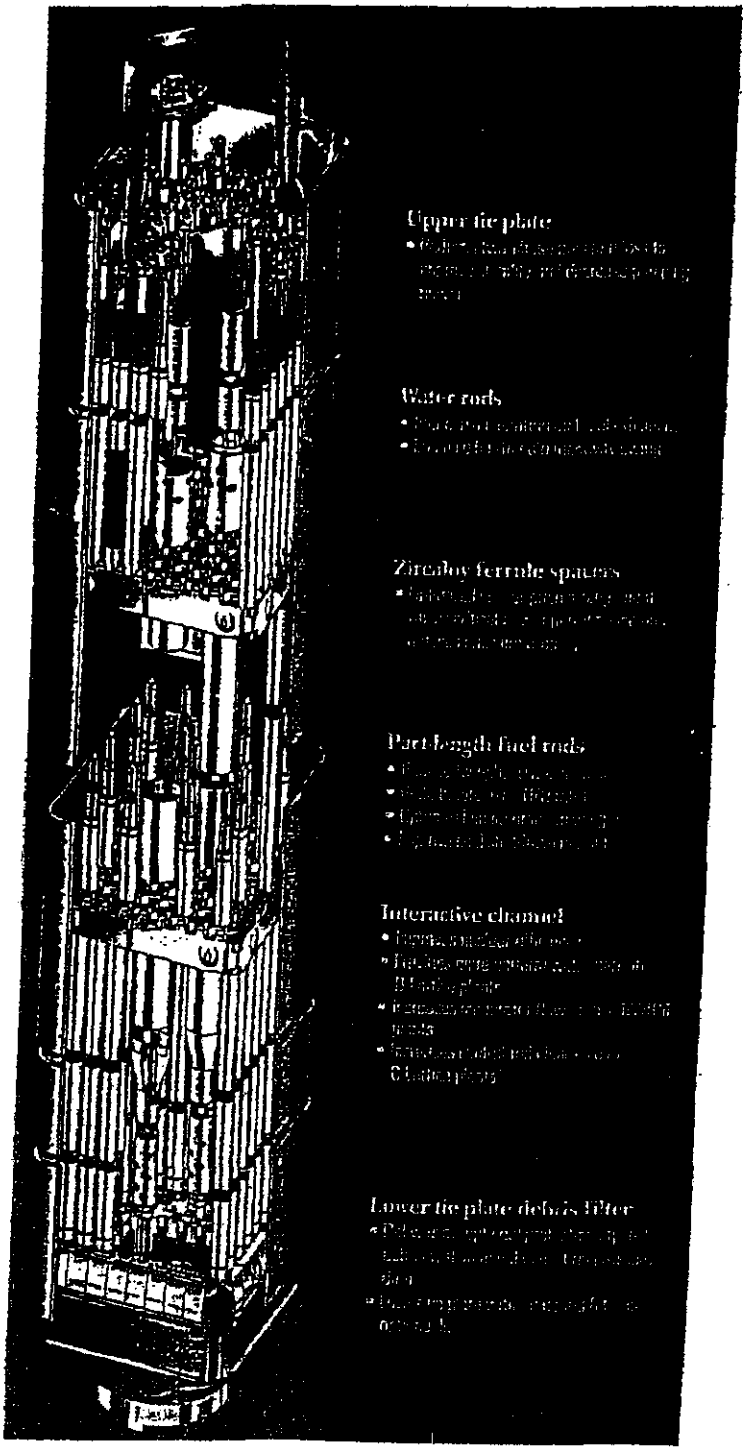


Figure 3.2-3
Typical GE14 Fuel Assembly

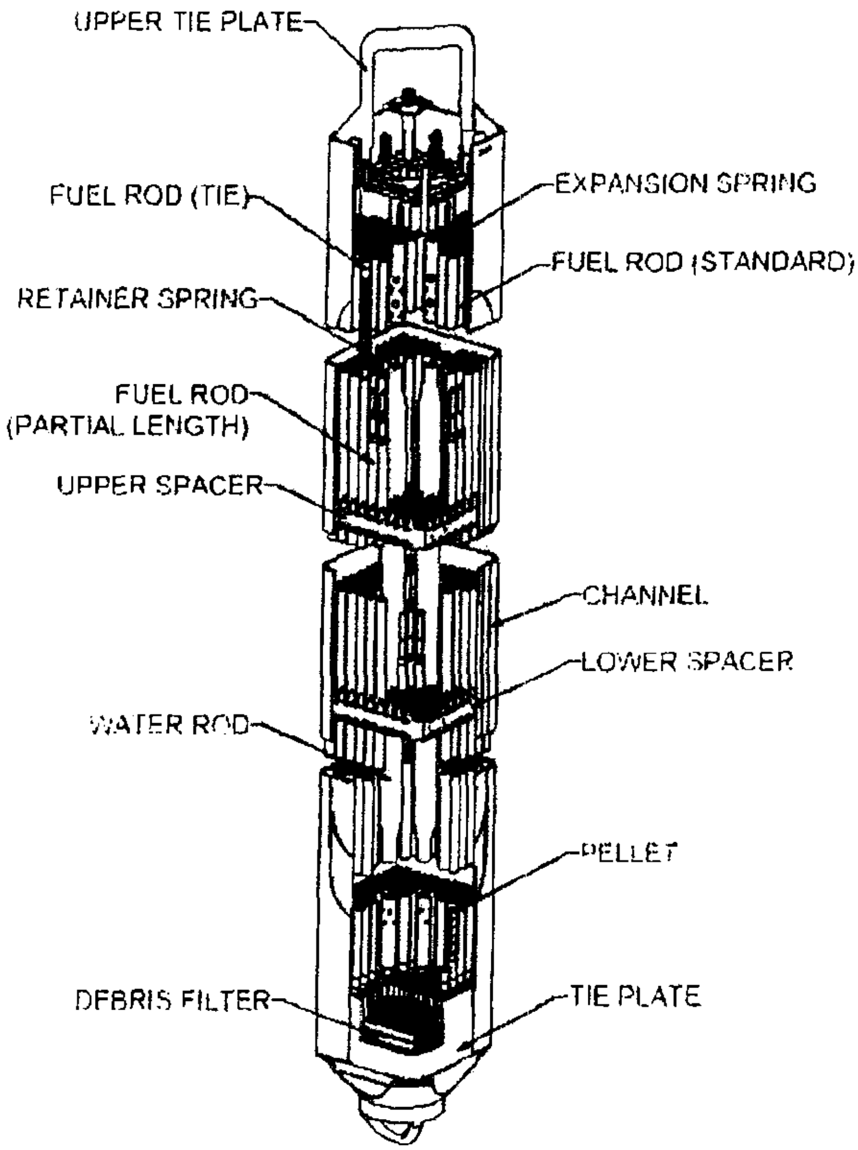


Figure 3.2-4: Typical GNF2 Fuel Assembly

3.3 REACTOR VESSEL INTERNALS MECHANICAL DESIGN

3.3.1 Power Generation Objective

Reactor vessel internals (exclusive of fuel, control rods, and incore flux monitors) are provided to achieve the following objectives:

1. Maintain partitions between regions within the reactor vessel to provide proper coolant distribution, thereby allowing power operation without fuel damage due to inadequate cooling

2. Provide positioning and support for the fuel assemblies, control rods, incore flux monitors, and other vessel internals to assure that control rod movement is not impaired

3.3.2 Power Generation Design Basis

1. The reactor vessel internals shall be designed to provide proper coolant distribution during all anticipated normal operating conditions to allow power operation of the core without fuel damage.

2. The reactor vessel internals shall be arranged to facilitate refueling operations.

3. The reactor vessel internals shall include devices that permit assessment of the core reactivity condition during periods of low power and subcritical operations.

4. Adequate working space and access shall be provided to permit adequate inspection of reactor vessel internals.

3.3.3 Safety Design Basis

1. The reactor vessel internals shall be arranged to provide a floodable volume in which the core can be adequately cooled in the event of a breach in the nuclear system process barrier external to the reactor vessel.

2. Deflections and deformation of reactor vessel internals shall be limited to assure that the control rods and the core standby cooling system (CSCS) can perform their safety functions during abnormal operational transients and accidents.

3. The reactor vessel internals mechanical design shall assure that safety design bases 1 and 2 are satisfied in accordance with the loading criteria of Appendix C, so that the safe shutdown of the station and removal of decay heat are not impaired.

3.3.4 Description

The reactor vessel internals are installed inside the reactor vessel to properly distribute the flow of coolant delivered to the vessel, to locate and support the fuel assemblies, and to provide an inner volume containing the core that can be flooded following a break in the nuclear system process barrier external to the reactor vessel. The reactor vessel internals described include the following components:

Core shroud
Shroud stabilizers
Shroud head and steam separator assembly
Core support (core plate)
Top guide
Fuel support pieces
Control rod guide tubes
Jet pump assemblies
Steam dryers
Feedwater spargers
Core spray lines
Vessel head cooling spray nozzle
Differential pressure and liquid control line
Incore flux monitor guide tubes

The overall arrangement of the internals within the reactor vessel is shown on Figure 3.3-1. Table 3.3-1 gives detailed design data for the various reactor vessel internals.

Although not mandatory, the design of the reactor vessel internals is in accordance with the intent of Section III of the ASME Boiler and Pressure Vessel Code. The material used for fabrication of most of the reactor vessel internals is solution heat treated, unstabilized Type 304 austenitic stainless steel, conforming to ASTM specifications. Weld procedures and welders are qualified in accordance with the intent of Section IX of the ASME Boiler and Pressure Vessel Code. The floodable inner volume of the reactor vessel is shown on Figure 3.3-1. It is the volume inside the core shroud up to the level of the jet pump nozzles. The boundary of the inner volume consists of the following:

1. The jet pumps from the jet pump nozzles down to the shroud support

2. The shroud support, which forms a barrier between the outside of the shroud and the inside of the reactor vessel

3. The reactor vessel wall below the shroud support

4. The core shroud up to the level of the jet pump nozzles

3.3.4.1 Core Structure

The core structure surrounds the active core of the reactor and consists of the core shroud, shroud head and steam separator assembly, core support, and top guide. This structure is used to form partitions within the reactor vessel, to sustain pressure differentials across the partitions, to direct the flow of the coolant water, and to laterally locate and support the fuel assembles, control rod guide tubes, and steam separators. Figure 3.3-2 shows the reactor vessel internal flow paths. The core structure is designed in accordance with the loading criteria of Appendix C.

3.3.4.1.1 Core Shroud

The core shroud is a stainless steel cylindrical assembly which provides a partition to separate the upward flow of coolant through the core from the downward recirculation flow. This partition separates the core region from

the downcomer annulus, thus providing a floodable region following a recirculation line break. The volume enclosed by the core shroud is characterized by three regions, each with a different shroud diameter. The upper shroud has the largest diameter and surrounds the core discharge plenum, which is bounded by the shroud head on top and the top fuel guide below. The central portion of the shroud surrounds the active fuel and forms the longest section of the shroud. This section has the intermediate diameter and is bounded at the bottom by the core support assembly. The lower shroud, surrounding part of the lower plenum, has the smallest diameter and at the bottom is welded to the reactor vessel shroud support. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design.

NRC Generic Letter GL94-03 was issued regarding intergranular stress corrosion cracking (IGSCC) of the circumferential girth welds for core shrouds in boiling water reactors (BWRs). Pilgrim chose to install a preemptive repair that provides structural replacement for all the shroud circumferential girth welds in lieu of continued inspection and analysis for these welds.

In RFO #10, a design change was implemented that provided a permanent repair for the core shroud in the Pilgrim reactor pressure vessel (RPV). This repair was classified as a "repair by replacement" per the ASME Code Section XI. The repair structurally replaces all of the shroud circumferential girth welds by installing vertical tie rod and lateral spring arrangement at each of four locations on the outside of the shroud in the jet pump annulus.

The shroud repair was designed to replace the structural function of the circumferential girth welds. These welds were required to maintain shroud structural integrity for providing vertical and horizontal support to the shroud head, core top guide, and core support plate, and to prevent core flow bypass to the downcomer region. The core top guide and core support plate act together to laterally support the fuel assemblies and maintain the correct fuel channel spacing to permit control rod insertion.
The repair consists of four shroud stabilizer assemblies, each comprised of a vertical tie rod with radially acting springs, installed 90 degrees apart around the perimeter of the shroud (reference Figure 3.3-10). Each stabilizer assembly consists of a tie rod, an upper bracket and a lateral spring, a lower tie rod extension and a lateral spring, two intermediate supports, and other minor parts. The tie rod provides the vertical load carrying ability from the stabilizer upper bracket to the RPV gusset attachment.

The upper spring provides radial load carrying ability from the shroud, at the core top guide elevation, to the RPV. The lower spring provides radial load carrying ability from the shroud, at the core support plate elevation, to the RPV. Two intermediate supports are provided for the tie rod so that its natural frequency is higher than the forcing frequency for flow induced vibration.

Each cylindrical section of the shroud is prevented from unacceptable horizontal motion by the stabilizers for all potential combinations of cracking in the circumferential welds. The upper stabilizer assembly restrains the shroud upper ring, upper cylinder, top guide support ring, and central upper cylinder. The intermediate supports restrain the central mid-cylinder and the upper core support plate ring. The lower stabilizer assembly restrains the central lower cylinder, the core support plate ring, and lower cylinder.

In addition, core plate wedge devices were installed in the annular gap between the top of the core plate and the inside of the shroud. Two such wedges were installed at the same azimuth locations as the four shroud stabilizers (total of eight wedges). These wedges prevent relative motion between the core plate and the shroud.

As a result of the shroud repair, there is no theoretical need for any structural integrity in the circumferential girth welds in the shroud (referred to as welds H1 through H10). The repair design is based on the possibility that these welds all have 360 degree through-wall cracks. The shroud stabilizer design also considered that welds H1 through H10 were intact as well as other bounding cases that produce greater shroud stresses or greater stress on the new shroud repair hardware.

The shroud stabilizer springs are made from nickel-chrome-iron Inconel Alloy X-750. The tie rod material is Type XM-19 austenitic stainless steel. Other small parts of the stabilizers are made from Type 316L stainless steel.

There are no welded components in the new shroud hardware. The new materials are highly resistant to intergranular stress corrosion cracking (IGSCC) compared to welded Type 304 stainless steel and are at relatively low stress levels during normal operating conditions. As a result, the principal contributors to IGSCC are minimized in this design.

3.3.4.1.2 Shroud Head and Steam Separator Assembly

The shroud head and steam separator assembly is bolted to the top of the upper shroud to form the top of the core discharge plenum. This plenum provides a mixing chamber for the steam water mixture before it enters the steam separators. The individual stainless steel axial flow steam separators shown on Figure 3.3-3 are attached to the top of standpipes which are welded into the stainless steel shroud head.

The steam separators have no moving parts. In each separator, the steam water mixture rising through the standpipe passes vanes which impart a spin to establish a vortex separating the water from the steam. The steam exits from the top of the separator and rises up to the dryers. The separated water exits from under the separator cap and flows out between the standpipes, draining into the recirculation flow downcomer annulus.

3.3.4.1.3 Core Support (Core Plate)

The core support assembly consists of a circular stainless steel plate stiffened with a rim and beam structure. Perforations in the plate provide lateral support and guidance for the control rod guide tubes, peripheral fuel support pieces, and incore flux monitor guide tubes, and locations for startup neutron sources. The entire assembly is bolted to a support ledge between the central and lower portions of the core shroud after proper positioning has been assured by alignment pins which fit into slots in the ledge.

Core support plugs have been fitted into bypass flow holes in the core support plate to limit flow and thus reduce movement of the incore neutron monitors to acceptable levels. The bases used in the development of the plug design are discussed in the SR on the Pilgrim Channel Wear Investigation[1] and the second reload licensing submittal[9] Evaluations of the mechanical performance are presented in References 2, 8 and 10.

3.3.4.1.4 Top Guide

The top fuel guide is formed by a series of stainless steel beams joined at right angles to form square openings. Each opening provides lateral support and guidance for four fuel assemblies. Holes are provided at the bottom of the beams to anchor the incore flux monitor guide tubes and neutron sources. The top fuel guide is positioned by alignment pins which fit into radial slots in the top of the shroud.

3.3.4.2 Fuel Support Pieces

The fuel support pieces, shown on Figure 3.3-4, are of two basic types - peripheral and four lobed. The peripheral fuel support pieces, which are welded to the core support assembly, are located at the outer edge of the active core and are not adjacent to control rods. Each peripheral fuel support piece will support one fuel assembly and contains a replaceable orifice assembly designed to assure proper coolant flow to the fuel assembly. The four lobed fuel support pieces will each support four fuel assemblies, and are provided with orifice plates to assure proper coolant flow distribution to each fuel assembly. The four lobed fuel support pieces rest in the top of the control rod guide tubes and are supported laterally by the core support. The control rods pass through slots in the center of the four lobed fuel support pieces. A control rod and the four fuel assemblies which immediately surround it represent a core cell. See Section 3.2, Fuel Mechanical Design.

3.3.4.3 Control Rod Guide Tubes

The control rod guide tubes, located inside the vessel, extend from the top of the control rod drive (CRD) housings up through holes in the core support. Each tube is designed as the lateral guide for a control rod and as the vertical support for a four lobed fuel support piece and the four fuel assemblies surrounding the control rod. The bottom of the guide tube is supported by the CRD housing which in turn transmits the weight of the guide tube, fuel support piece, and fuel assemblies to the reactor vessel bottom head. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. A thermal sleeve is inserted into the CRD housing from below and is rotated to lock the control rod guide tube in place. A key is inserted into a locking slot in the bottom of the CRD housing to hold the thermal sleeve in position.

3.3.4.4 Jet Pump Assemblies

The jet pump assemblies are located in two semicircular groups in the downcomer annulus between the core shroud and the reactor vessel wall. Each stainless steel jet pump consists of a driving nozzle, suction inlet, throat or mixing section, and diffuser. See Figure 3.3-5. The driving nozzle, suction inlet, and throat are joined together as a removable unit and the diffuser is permanently installed. High pressure water from the recirculation pumps is supplied to each pair of jet pumps through a riser pipe welded to the recirculation inlet nozzle thermal sleeve. See Section 4.3, Reactor Recirculation System. A riser brace is welded to cantilever beams extending from pads on the reactor vessel wall.

The jet pump diffuser is a gradual conical section changing to a straight cylindrical section at the lower end. The diffuser is supported vertically

by the shroud support, a flat ring which is welded to the reactor vessel wall, and to which is welded the shroud support cylinder. The joint between the throat and the diffuser is a slip fit. A metal to metal spherical to conical seal joint is used between the nozzle entry section and riser with firm contact maintained by a clamp arrangement which fits under posts on the riser, and utilizes a bolt to provide a downward force on a pad on top of the nozzle entry section. The inlet-mixer section is supported laterally by a bracket attached to the riser pipe. The bracket assembly has swing gates with an adjustable wedge and set screws to provide a mid-span piping restraint for the inlet-mixers. Observed gaps between the restrainer bracket set screws and the inlet-mixers as well as swing gates in which the lock pin is not seated have been evaluated and acceptance criteria for these conditions have been incorporated into the jet pump design documents, drawings, and the reactor in-vessel inspection program. Where necessary, replacement restrainer bracket swing gates and restrainer bracket auxiliary wedges will be installed.

The replacement restrainer bracket swing gates and restrainer bracket auxiliary wedges were designed and fabricated in accordance with GE Specifications that are consistent with the original design requirements for all reactor internals. The fit-up and function of these replacement swing gates is identical to the original design and they are fabricated from upgraded material. Also, instead of a welded keeper, the replacement swing gates have a weldless style keeper with a mechanical ratchet lock, which will reduce installation time.

The auxiliary wedges fit around the set screws and provide a solid load path between the restrainer bracket and the inlet-mixer. The wedges are designed to self-adjust to accommodate alignment variations in the system and to compensate for any wear after installation. These new components were designed to maintain the jet pumps within their original design requirements and do not have any adverse effect on the overall function of the jet pumps.

The materials used for the new components are Type 316 stainless steel with a maximum carbon content of 0.02% and Ni-Cr-Fe Inconel Alloy X-750. These materials are resistant to Intergranular Stress Corrosion Cracking (IGSCC) in the BWR environment. No “Stellite” or cobalt hardfacing or alloys are used in the construction.

The potential effects of “Thermal Power Optimization” (TPO, 2028 MWt maximum normal operating power) on jet pump integrity were considered and found to be acceptable. There is no increase in core flow or recirculation jet pump drive flow associated with TPO conditions.

The cumulative effects of potential vibratory fatigue on the jet pumps were investigated and it was determined that the riser brace is the limiting component. The design basis criteria for the jet pump restrainer bracket maximum allowable set screw gap is based on riser brace fatigue. The allowable deflection of the jet pump riser brace that adversely affects the cumulative fatigue usage for the riser brace. Since this criteria is based on a simple maximum deflection, it is independent of the source, amplitude, or frequency for the equivalent dynamically applied load. The alternating stresses associated with vibratory fatigue within the allowable deflection criteria thereby do not adversely affect the cumulative fatigue usage for the riser brace.

The inlet mixer section of each jet pump is held in place by a beam-bolt assembly located in the riser transition piece. The beam ends are positioned within packets in the transition piece, and the beam load is transferred to the elbow through a bolt located in the center of the beam. See view D-D of Figure 3.3-5 (BECo MIE44-1). A preload is applied to the beam when it is installed to ensure enclosure integrity of the joint between the riser and the inlet mixer assemblies. Ultrasonic testing in mid-1979 and early 1980 detected cracking in some beams in certain BWR/3s. To preclude failure by intergranular stress corrosion cracking which has been observed in jet pump beams in some BWR plants, the existing Pilgrim jet pump beams that were of BWR-3 design have been replaced by improved BWR-4 beam bolt assemblies. These replacement beam bolt assemblies are different in four aspects:

- The beam depth has been increased
- The Inconel material heat treatment has been changed
- The beam bolt material has been changed to 316L
- The retaining device design has been changed

Beams reflecting these design changes are not expected to crack.

These improvements are discussed further in the GE NEDE report of December 1981 (Reference 5), which also presents a recommended schedule for inservice inspection of the replacement beams.

3.3.4.5 Steam Dryers

The steam dryers remove moisture from the wet steam which exits from the steam separators. The wet steam leaving the steam separators flows across the dryer vanes and the moisture flows down through collecting troughs and tubes to the water above the downcomer annulus. See Figure 3.3-6. A skirt extends down into the water to form a seal between the wet steam plenum and the dry steam flowing out the top of the dryers to the steam outlet nozzles. Vertical guide rods facilitate positioning the dryer and shroud head in the vessel. The dryers rest on steam dryer support brackets attached to the reactor vessel wall, and are restricted from lifting by steam dryer hold-down brackets, which are attached to the reactor vessel closure head over the top of the steam dryer lifting lugs when the head is in place.

3.3.4.6 Feedwater Spargers

The feedwater spargers are stainless steel headers located in the mixing plenum above the downcomer annulus. A separate sparger is fitted to each of four feedwater nozzles and is shaped to conform to the curve of the vessel wall. Sparger end brackets are attached to vessel brackets to support the weight of the spargers, and wedge blocks position the spargers away from the vessel wall. Feedwater flow enters the center of the spargers and is discharged through top mounted elbows, each with a converging discharge nozzle. The cooler feedwater blows downward to mix with the downcomer flow from the steam separators before it contacts the vessel wall. The feedwater also serves to collapse any steam voids and to subcool the water flowing to the jet pumps and recirculation pumps.

3.3.4.7 Core Spray Lines

The two 100 percent capacity carbon steel core spray lines separately enter the reactor vessel through the two core spray nozzles as shown on Figure 4.2-2. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The lines divide immediately inside the reactor vessel. The two halves are routed to opposite sides of the reactor vessel and are supported by clamps attached to the vessel wall. The header halves are then routed downward into the downcomer annulus and pass through the upper shroud immediately below the flange. The flow divides again as it enters the center of the semicircular sparger ring which is routed halfway around the inside of the upper shroud. The ends of the two sparger rings for each line are supported by slip-fit brackets designed to accommodate thermal expansion of the rings. The header routing and supports are designed to accommodate differential movement between the shroud and the vessel. The other core spray line is identical except that the header enters the opposite side of the vessel and the sparger rings are at a slightly different elevation in the shroud. The proper spray distribution pattern is provided by a combination of distribution nozzles pointed radially inward and downward from the sparger rings. See Section 6, Core Standby Cooling Systems.

3.3.4.8 Deleted

3.3.4.9 Differential Pressure and Liquid Control Line

The stainless steel differential pressure and liquid control line serves a dual function within the reactor vessel. It injects liquid control solution into the coolant stream as discussed in Section 3.8, Standby Liquid Control System, and senses the differential pressure across the core support assembly, as discussed in Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The line enters the reactor vessel at a point below the core shroud as two concentric pipes. In the lower plenum, the two pipes separate. The inner pipe terminates near the lower shroud with a perforated length below the core support assembly. It is used to sense the pressure below the core support during normal operation and to inject liquid control solution when required. This location assures that good mixing and dispersion are facilitated. The use of the inner pipe also reduces the thermal shock to the vessel nozzle should the Standby Liquid Control System (SLCS) ever be used. The outer pipe terminates immediately above the core support assembly and senses the pressure in the region outside the fuel assembly channels.

3.3.4.10 Incore Flux Monitor Guide Tubes

The incore flux monitor guide tubes are welded to the top of the incore flux monitor housings in the lower plenum and extend up to the top of the core support. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The power range detectors for the power range monitoring units and the dry tubes for the source range monitoring/intermediate range monitoring (SRM/IRM) detectors are inserted through the guide tubes, and are held in place below the top guide by spring tension. A latticework of clamps, tie bars, and spacers give lateral support and rigidity to the guide tubes. The bolts and clamps are welded after assembly to prevent loosening during reactor operation.

3.3.4.11 Startup Neutron Sources

The startup neutron sources are required during the first startup of the reactor. At the end of the first operating cycle, the neutron sources can be removed since the reactor has adequate neutron source in the form of fuel carried to the subsequent operating cycle. Neutron sources have been removed after four operating cycles since experience on other BWR plants has shown that startup neutron source holders left in the core longer than one operating cycle have a tendency to become brittle and are subject to cracking and separation. Cores with an average exposure of 5,000 MWd/t will emit enough neutrons to permit startup following a 120 day outage. Higher core average exposure will allow longer outage periods. For an extended outage, where neutron startup sources would be required, new antimony rods would have to be irradiated and installed in new holders.

To allow full core discharge and reloading without the startup neutron sources and without meeting the activity requirements of the fuel, a spiral reloading and unloading pattern is followed.

3.3.4.12 Surveillance Holders

The surveillance sample holders are welded baskets containing impact and tensile specimen capsules. See Section 4.2, Reactor Vessel and Appurtenances Mechanical Design. The baskets hang from brackets on the inside wall of the reactor vessel at the midheight of the active core, and at radial positions chosen to expose the specimens to the same environment and maximum neutron fluxes experienced by the reactor vessel itself, while at the same time avoiding jet pump removal interference or damage.

3.3.5 Vibration

3.3.5.1 Vibration Analysis

A vibration analysis of reactor vessel internals was performed in the design to determine any potential hydraulically induced equipment vibrations and to check that the structures do not fail due to fatigue. The structures were analyzed for natural frequencies, mode shapes, and vibrational magnitudes that could lead to fatigue at these frequencies. The cyclic loadings were evaluated using the cyclic stress criteria of the ASME Code, Section III as a guide.

3.3.5.2 Vibration Testing

The criteria for selecting BWR plants to be vibration tested is to test each new plant which contains a significant design departure from a plant that has been previously vibration tested (e.g., the first plant of each standard plant design). Since all jet pump plants are geometrically quite similar, it is not expected that there will be a great deal of difference in the vibration response of the various plants of approximately the same size. However, where vessel diameters changed significantly, or where flow velocities increased significantly, vibration tests were scheduled.

Depending on the reactor vessel manufacturer, BWRs are equipped with two types of shroud support structures. Reactors such as Dresden 2 and 3, Peach Bottom 2 and 3, Brunswick, and Zimmer are equipped with a stilt-type shroud support. Reactors such as Fermi 2, Cooper, Millstone 1, and Pilgrim are equipped with a gusset-type shroud support. Pilgrim differs from Millstone 1 in the area of jet pump riser support, both at the inlet thermal sleeve attachment and at the riser brace elevation. Because of these design differences, confirmatory vibration tests were conducted on Pilgrim plant to ensure that the flow induced vibrations do not jeopardize the integrity of internal structure of the reactor vessel. This program supplemented the first of a kind data obtained from the Millstone 1 tests. The vessel internal components monitored were:

1. Shroud - to measure horizontal displacements
2. Jet Pump Assembly Riser Brace - to measure strain in the braces of the riser pipe for two jet pumps
3. Jet Pumps - to measure horizontal radial motion of two pumps with respect to the reactor pressure vessel

The vibration of the various reactor internal components were detected by sensors mounted directly on those components. The vibration amplitude signals from these sensors were amplified and displayed by an oscillograph type recorder and also recorded on magnetic tape. Data were obtained from operable sensors during the power test program and periodically during steady state operation throughout the first operating cycle.

The operating conditions established for the vibration measurements during the power test program are listed below. These operating conditions are indicative of the range of operating conditions applicable for variations in vibration excitations. Actual test points are designed to cover this range of variations in steam and coolant flow.

Operating Conditions

1. 75 percent Thermal Power Line
2. 100 percent Thermal Power Line

Measurements were monitored for each of the above power levels at the following conditions:

1. Four approximately equally spaced flow points from minimum flow to 100 percent flow
2. With 100 percent core flow trip Pump A
3. With Pump B only operating, open equalizer
4. With 100 percent core flow trip Pump B
5. With Pump A only operating, open equalizer
6. With 100 percent core flow trip both pumps simultaneously

3.3.5.3 Increased Core Flow Vibration Analysis

The increased core flow vibration analysis was performed by analyzing the startup test vibration data for Millstone 1 and Pilgrim. The vibration levels for 100% flow operation were conservatively extrapolated by the ratio of flow velocity squared for each of the instrumented reactor internal components. The jet pump riser braces showed the highest vibration response (32.4% of acceptance criteria) at 112.5% of rated core flow. In addition to analyzing the startup test data, an evaluation of the riser brace structural natural frequency was performed to determine if an excitation phenomena exists because of increased recirculation pump speed (blade passing frequency). The results show the riser brace natural frequency is high enough (169% of blade passing) to avoid such an excitation. This riser brace excitation would be most limiting as a result of an increase in pump speed and flow. Based on the results of these analyses and a review of test data it is apparent that operation with increased core flow does not result in flow-induced vibrations of reactor internals which exceed acceptable mechanical design limits (Reference 6).

3.3.6 Safety Evaluation

3.3.6.1 Evaluation Methods

To determine that the safety design basis is satisfied, the responses of the reactor vessel internals to loads imposed during normal operation, abnormal operational transients, and accidents are examined. Determination of these effects on the ability to insert control rods, cool the core, and flood the inner volume of the reactor vessel are made. The various structural loading combinations assumed to be imposed on the reactor vessel internals are as described in Appendix C for Class I equipment. These loading combinations include upset loads, emergency loads, and faulted loads.

The ASME Boiler and Pressure Code, Section III for Class A vessels, is used as a guide to determine limiting stress intensities and cyclic loadings for the reactor vessel internals. For those components for which buckling is not a possible failure mode and stresses are within those stated in the ASME Code, it is concluded that the safety design basis is satisfied. For those components, for which either buckling is a possible failure mode or stresses exceed those presented in the ASME Code, either the elastic stability of the structure or the resulting deformation is examined to determine if the safety design basis is satisfied.

3.3.6.2 Plant Conditions

All events that the plant might credibly experience are evaluated to establish a design basis for plant equipment. These events are divided into four plant conditions. The plant conditions described in the following paragraphs are based on event probability (i.e., frequency of occurrence) and correlated design conditions as defined in the ASME B&PV Code, Section III.

3.3.6.2.1 Normal Condition

Normal conditions are any conditions in the course of system startup, operation in the design power range, normal hot standby (with condenser available), and system shutdown other than upset, emergency, faulted, or testing. For this condition, structural loadings on the reactor vessel internals are evaluated at 100% power and 100% recirculation flow.

3.3.6.2.2 Upset Condition

Upset conditions are any deviations from normal conditions which are anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment. The upset conditions include those transients which result from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power. For this condition, the analysis is based on a reactor power corresponding to 105% of related steam flow and 100% recirculation flow.

3.3.6.2.3 Emergency Condition

Emergency conditions are those deviations from normal conditions which require shutdown to correct the conditions or to repair damage in the reactor pressure coolant boundary (RCPB). These conditions have a low probability of occurrence, but are included to provide assurance that no gross loss of structural integrity results as a concomitant effect of any damage developed in the system. Emergency condition events include, but are not limited to, transients caused by one or more of the following: a multiple valve blow down of the reactor vessel; loss of reactor coolant from a small break or crack which does not depressurize the reactor system, nor result in leakage beyond normal makeup system capacity, but which does require the safety functions of containment isolation and reactor shutdown. The reactor is analyzed at core power corresponding to 102% of rated power and 100% recirculation flow. For Pilgrim the limiting event for this plant condition is an unintentional actuation of the Automatic Depressurization System (ADS). This event results in a sudden depressurization of the reactor system, similar to but less severe than the design basis LOCA.

3.3.6.2.4 Faulted Condition

Faulted conditions are those combinations of conditions associated with extremely unlikely postulated events, with consequences such that the integrity and operability of the system may be so impaired that considerations of public health and safety are involved. Faulted conditions encompass events that are postulated because their consequences include the potential for releasing significant amounts of radioactive material. These postulated events are the most drastic that must be designed against, and thus represent limiting design bases. Faulted condition events include, but are not limited to, one or more the following: a control rod drop accident; a fuel-handling accident; a main steam line break; a recirculation loop break; the combination of small break/large break accident.

For Pilgrim, the reactor is analyzed at two states; 1) 100% recirculation flow and 102% of rated power and 2) 110% recirculation flow and 23% of rated power (the lowest power at which 110% recirculation flow is permissible). The limiting events are an instantaneous circumferential break of a main steam line upstream of the main steam line flow limiters and the instantaneous circumferential break of a recirculation line.

3.3.6.2.5 Correlation of Plant Conditions with Event Probability

The probabilities per reactor year, P, of normal, upset, emergency and faulted events are listed below. These probabilities can be used to identify the appropriate plant condition for any hypothesized event or sequence of events.

Plant Conditions	Events Encountered (probability per reactor year)
Normal (planned)	1.0
Upset (moderate probability)	$1.0>P>10^{-2}$
Emergency (low probability)	$10^{-2}>P>10^{-4}$
Faulted (extremely low probability)	$10^{-4}>P>10^{-6}$

3.3.6.3 Specific Events To Be Evaluated

Examination of the spectrum of conditions for which the safety design basis must be satisfied reveals four significant events:

1. Loss of coolant accident: This accident is a break in a recirculation line. The accident results in some pressure differentials across the reactor vessel internals which exceed normal loads

2. Steam line break accident: This accident is a break in one main steam line between the reactor vessel and the flow restrictor. The accident results in significant pressure differentials across the reactor vessel internals

3. Thermal shock: The most severe thermal shocks to the reactor vessel internals occur when low pressure coolant injection (LPCI) operations or high pressure coolant injection (HPCI) operations reflood the reactor vessel inner volume following either a recirculation line break or a main steam line break. See Section 6, Core Standby Cooling System

4. Earthquake: This event subjects the reactor vessel internals to significant forces as a result of ground motion. These seismic loads are combined with other transients loads such as ADS loads or LOCA loads to demonstrate the structural integrity of the reactor components under such combined events.

Analysis of other conditions existing during normal operation, abnormal operational transients, and accidents show that the loads affecting the reactor vessel internals are less severe than the four postulated events. Hence, the design bases for structural stress evaluations are based on the above limiting events.

3.3.6.4 Pressure Differentials During Rapid Depressurization

A digital computer code (Reference 7) is used to analyze the transient conditions within the reactor vessel following the recirculation line break accident and the steam line break accident. The analytical model of the vessel consists of nine spatial nodes with their boundaries located at interfaces defined by physical restrictions in the reactor system. Each node is connected to the necessary adjoining nodes by flow paths having the required resistance and inertial characteristics. The reactor system model is designed for short-term transients where there is rapid system depressurization. Its calculations typically include the first 30 to 45 seconds of the blowdown. The program solves the energy and mass conservation equations for each node, giving the depressurization rates and pressure in the various regions of the reactor. The flow resistances are evaluated from the irreversible pressure drops associated with known flow rates. Momentum effects are considered for all flow paths. Figure 3.3-7 shows the nine reactor nodes in the model. They are: 1) the subcooled lower plenum, 2) the core, 3) the upper plenum, 4) the mixing region, 5) the downcomer, 6) and 7) the two recirculation loops, 8) the core bypass region, and 9) the steam dome.

This computer code is approved for use in ECCS conformance evaluation under 10CFR 50, Appendix K. In order to adequately predict the blowdown pressure effect on individual reactor assembly components, three features are included in the model that are not applicable to the ECCS analysis and are, therefore, not described in Reference 5. These additional features are:

1. The liquid level in the steam separator region, and in the annulus between the dryer skirt and the pressure vessel, is tracked to determine more accurately the flow and mixture quality in the steam dryer and the steam line.

2. The flow path between the bypass region and the shroud head is more accurately modeled for a steam line break since the fuel assembly pressure differential is influenced by flashing in the guide tubes and the bypass region. In the ECCS analysis, the momentum equation is solved in this flow path but its irreversible loss coefficient is conservatively set at an arbitrary low value.

3. The enthalpies in the guide tubes and the bypass region are calculated separately since the fuel assembly differential pressure is influenced by flashing in these regions. In the ECCS analysis, these regions are lumped together.

3.3.6.5 Recirculation Line Break

3.3.6.5.1 Accident Definition

This accident is the same design basis LOCA as described in Section 6, Core Standby Cooling Systems, and Section 14, Station Safety Analysis. It is assumed that an instantaneous, circumferential break occurs in one recirculation loop (the largest liquid break).

As detailed in Section 3.3.6.5.1, the vessel depressurization rate is less for liquid breaks (recirculation line breaks) than for steam breaks (steam line breaks). Therefore the postulated recirculation line break accident is not the design basis for internal pressure loads. Maximum loads occur following the postulated steam line break and are discussed in Section 3.3.6.5.

3.3.6.5.2 Jet Pump Joints

An analysis has been performed to evaluate the potential leakage from within the floodable inner volume of the reactor vessel during the recirculation line break and subsequent reflooding. The two possible sources of leakage are:

1. Jet pump throat to diffuser joint

2. Jet pump nozzle to riser joint

The jet pump to shroud support joint is welded and therefore is not a possible source of leakage. The throat to diffuser joints for all jet pumps leak no more than a total of 225 gal/min. The jet pump nozzle to riser joint by analysis is shown to leak no more than a total of 225 gal/min. The jet pump nozzle to riser joint analysis is shown to leak no more than 582 gal/min for the pumps through which the vessel is being flooded.

The summary of maximum leakage is then:

Total leakage through all throat to diffuser joints	225 gpm
Total leakage through all operational nozzle to riser joints.	582 gpm
TOTAL MAXIMUM RATE ..	807 gpm

CSCS capacity is sized to accommodate 3,000 gal/min leakage at these locations. It is concluded that the reactor vessel internals retain sufficient integrity during the recirculation line break accident to allow reflooding the inner volume of the reactor vessel.

3.3.6.6 Steam Line Break Accident

3.3.6.6.1 Accident Definition

The analysis of this accident assumes an instantaneous circumferential break of one main steam line between the reactor vessel and the main steam line flow restrictor. This is not the same accident as described in Section 14, Station Safety Analysis, because greater differential pressures across the reactor vessel internals result from this accident. It is noteworthy that this accident results in greater loading of the reactor vessel internals and a higher depressurization rate than does the recirculation line break. The steam line break accident is more severe because the depressurization rate is proportional to the mass flow rate and the difference between the fluid escape enthalpy, he, and the saturated water enthalpy, hf. However, mass flow rate is inversely proportional to escape enthalpy he; therefore, depressurization rate is proportional to 1 - hf/he. Consequently, depressurization rate decreases as he decreases. That is, depressurization is less for mixture flow (recirculation line break) than for steam flow (steam line break).

A steam line break upstream of the flow restrictors produces a larger blowdown area, and thus a faster depressurization rate, than a break downstream of the restrictors. A faster depressurization rate results in greater pressure differentials across the reactor internal structures.

To add conservatism to the analysis it is assumed that only steam is discharged through the break; this maximizes the vessel depressurization rate and the resultant loadings on the vessel internals.

The steam line break accident produces significantly higher pressure differentials across the reactor internal structures than does the recirculation line break. This fact results from the greater reactor depressurization rate associated with the steam line break. Therefore, the steam line break is the design basis accident for internal pressure differentials.

3.3.6.6.2 Effects of Initial Reactor Power and Core Flow

The maximum internal pressure loads can be considered to be composed of two parts: a steady-state part and a transient part. For a given plant, the core flow and the core power are the two major factors which influence the reactor internal pressure differentials. The core flow essentially affects only the steady-state part. For a fixed power, the greater the core flow, the larger the steady-state pressure differentials. The core power affects both the steady-state and the transient parts. As the power is decreased, there is less steam generation rate and, consequently, the steady-state core pressure differential is less. However, less voiding in the core also means that less steam is generated to replace steam flow out of the broken steam line, thus increasing the depressurization rate and the transient part of the maximum pressure load. As a result, the total loads on some components are higher at low power.

To ensure that the calculated pressure differences are bounding, an analysis is conducted at a low power/high recirculation flow combination in addition to the standard safety analysis combination of high power/rated recirculation flow. The power chosen for the low power/high recirculation flow combination is the minimum value permitted by the recirculation system controls at rated recirculation drive flow (that is, the drive flow necessary to achieve rated core flow at rated power). This condition maximizes those loads which are inversely proportional to power. It must be noted that this condition, while possible, is unlikely; the reactor generally operates at or near full power and, at reduced power, high core flow is neither required nor desirable.

3.3.6.7 Reactor Internals Pressure Differences at Normal, Upset, Emergency and Faulted Condition

Table 3.3-2 summarizes the pressure differentials across the reactor internal components for the limiting plant configuration/transient for normal, upset, emergency and faulted conditions. As shown, the maximum pressure loads acting on the reactor internals result from a steam line break (a faulted condition). On most components the loads are maximum when operating at the minimum power associated with the maximum core flow. This observation is substantiated by the analytical comparison of liquid breaks versus steam breaks, and by the investigation of the effects of core power and core flow.

As discussed earlier, it is possible but not probable that the reactor is operating at this rather abnormal condition of minimum power and maximum core flow. More realistically, the reactor is at or near a full power condition. Thus, use of the pressure loads associated with this abnormal condition, where maximum, introduces additional conservatism in the analysis.

The maximum differential pressures in Table 3.3-2 are used, in combination with other assumed structural loads as described in Appendix C, to determine the total loading on the various reactor vessel internals. The various internals are then examined to assess the extent of deformation and collapse, if any. Of particular interest are the responses of the core support assembly, the guide tubes, and the channels around the fuel bundles.

Reference 12 reevaluated pressure differences across reactor internals for maximum extended load line limit (MELLL) region operation. The results were bound by the design limits and have adequate design margin for operation in the MELLL region.

3.3.6.7.1 Core Support

The core support assembly sustains the maximum net force, which is an upward force following the steam line break accident, so the effect on the core support holddown bolts must be established. Analysis shows that the applied stresses are about 1/2 of yield strength for the bolts, indicating that the core support can withstand the effects of the accident.

In RFO #10 a reactor shroud repair was implemented as described in Section 3.3.4.1.1. The design loads for the shroud stabilizers included seismic plus main steam line break accidents. The effect of the shroud repair on the reactor pressure vessel was analyzed and the results included in a stress report that is an addendum to the original design stress report for the reactor pressure vessel. The shroud stabilizers change the points of application of the forces applied to the vessel from the shroud. There are new forces applied to the pressure vessel from the shroud stabilizer springs and a change in the forces applied from the existing shroud support plate and gussets to the vessel wall. These new and revised forces were combined with the forces defined in the original vessel design stress report and analyzed per the original reactor pressure vessel Code of Construction. The analysis concluded that all stresses within the reactor pressure vessel remain within their allowable limits.

3.3.6.7.2 Guide Tubes

Because of the externally applied pressure, the guide tube is examined for collapse. As in the case of the lower shroud and core support assembly, a number of formulae are utilized to calculate the collapse pressure. Unfortunately, the Winderberg test is not applicable because the geometry of the guide tube is outside of the test range. Use of ASME curves indicates the extreme sensitivity to wall thickness. For the minimum wall thickness for a 10 in Schedule 10 pipe, the ASME curves give a collapse load of 45 psi. Using the average wall thickness, the collapse pressure is increased to over 70 psi. Using empirical relations for tubes over the critical length, the calculated collapse pressure is over 100 psi. The ASME curves calculate that the collapse pressure is reached at 54 psi for a wall thickness of 0.150 in, which is 6 mils over the minimum for a 10 in Schedule 10 pipe. The calculated total loading for the guide tubes is considerably below the collapse loading, and it can be concluded that no failure occurs. The analysis also indicates that the control rods are 70 percent to 80 percent inserted at the time the maximum external pressure is applied to the guide tubes.

3.3.6.7.3 Fuel Channels

The BWR fuel channel performs the following functions:

a. forms the fuel bundle flow path outer periphery for bundle coolant flow;

b. provides surfaces for control rod guidance in the reactor core;

c. provides structural stiffness to the fuel bundle during lateral loadings applied from fuel rods through the fuel spacers;

d. minimizes, in conjunction with the finger springs and bundle lower tie plate, coolant bypass flow at the channel/lower tie plate interface;

e. transmits fuel assembly seismic loadings to the top guide and fuel support of the core internal structures;

f. provides a heat sink during loss-of-coolant accident (LOCA); and

g. provides a stagnation envelope for in-core fuel slipping.

The channel is open at the bottom and makes a sliding seal fit on the lower tie plate surface. The upper end of the fuel assemblies in a four-bundle cell are positioned in the corners of the cell against the top guide beams by the channel fastener springs. At the top of the channel, two diagonally opposite corners have welded tabs, one of which supports the weight of the channel from a threaded raised post on the upper tie plate. One of these raised posts has a threaded hole. The channel is attached using the threaded channel fastener assembly, which also includes the fuel assembly positioning spring. Channel-to-channel spacing is provided for by means of spacer buttons located on the upper portion of the channel adjacent to the control rod passage area. Reference 4 provides a complete description and analytical results for channels supplied by the General Electric Company (GE). The channels supplied by other vendors have been evaluated and are predicted to behave in a similar fashion as GE supplied channels. NSF is also zirconium alloy containing a approx. 1% of nickel, Tin, and Iron. Channels made from NSF are introduced into PNPS core as a part of a special Lead Use Channel Program approved by the NRC (Reference 16) for up to 8% of the core in Cycle 21 (Reference 17). NSF is known to be more resistant to bowing compared to Zr-2 and Zr-4 alloy channels.

3.3.6.8 Thermal Shock

The most severe thermal shock effects for the reactor vessel internals result from the reflooding of the reactor vessel inner volume. For some vessel internals, the limiting thermal shock occurs from LPCI operation and for others HPCI operation is controlling, dependent upon the location of the component. These effects occur as a result of any large LOCA, such as the recirculation line break and the steam line break accidents previously described.

The locations are as follows:

1. Shroud support plate

The peak strain resulting in the shroud support plate is about 6.5 percent. This strain is higher than the 5.0 percent strain permitted by the ASME Code, Section III, for 10 cycles, but the 1 cycle, peak strain corresponds to about 6 allowable cycles of an extended ASME Code curve as applied to less than 10 cycles.

Figure 3.3-9 illustrates both the ASME Code curve and the basic material curves from which it was established (with the safety factor of 2 on strain or 20 on cycles, whichever is more conservative). The extension of the ASME Code curve represents a similar criteria to that used in the ASME Code, Section III, but applied to fewer than 10 cycles of loading. For this Type 304 stainless steel material, a 10 percent peak strain corresponds to one allowable cycle of loading. Even a 10 percent strain for a single cycle loading represents a very conservative suggested limit because this has a large safety margin below the point at which even minor cracking is expected to begin. Because the conditions which lead to the calculated peak strain of 6.5 percent are not expected to occur even once during the entire reactor lifetime, the peak strain is considered tolerable.

2. Shroud to shroud support plate discontinuity

The results of the analysis of the shroud to shroud support plate discontinuity region are as follows:

Amplitude of alternating stress.	180,000 psi
Peak strain.	1.34 percent

The ASME Code, Section III, allows 220 cycles of this loading, thus no significant deformations result.

3. Shroud inner surfaces at highest irradiation zone

By the end of station life, the peak thermal shock stress is 155,700 psi, corresponding to a peak strain of 0.57 percent. The shroud material is Type 304 stainless steel, which is not significantly affected by irradiation. The material does experience a loss in reduction of area. Because reduction of area is the property which determines tolerable local strain, irradiation effects can be neglected. The peak strain resulting from thermal shock at the inside of the shroud represents no loss of integrity of the reactor vessel inner volume.

3.3.6.9 Earthquake

The seismic loads on the RPV and internals, due to horizontal motion, are based on a dynamic analysis of the RPV and internals model. Seismic analysis is performed by coupling this lumped mass model of the RPV, and internals with the building soil structure model to determine the system natural frequencies and mode shapes. The relative displacement, acceleration, and load response of the RPV and internals are then determined by either the time history method or the response spectrum method. In the time history method, the dynamic response is determined for each mode of interest and added algebraically for each instant of time. Resulting response time histories are then examined and the maximum value of displacement, acceleration, shears, and moments are used for design calculations. In the response spectrum method, the relative displacements, accelerations, shears, and moments are determined for each mode of interest. The square root of the sum of squares (SRSS) of these individual responses is then used for design calculations. Since the RPV and its internal system are made up of many separate components, there are many natural frequencies spaced closer than the natural frequencies of single component structures. When the time history method of seismic analysis is used as it is on Pilgrim, the physical displacements, accelerations, shears, and moments due to each mode are added algebraically at each instant of time and, hence, no criteria concerning the method of combining loads due to closely spaced modal frequencies needs to be set. When the response spectrum method of seismic analysis is used, it can be argued that, for very closely spaced frequencies, the peak modal response may occur at practically the same time and hence, the absolute sum (instead of SRSS) of the contributions from each mode should be taken. However, this argument overlooks the fact that signs of the mode shapes and participation factors of two neighboring modes, may be such that the load contribution from these modes subtract from one another instead of reinforcing one another, in parts of the structure. If this occurs, the loads would be definitely lower than the loads from an absolute sum.

The best indication of the adequacy of the SRSS method of combining modal load contributions is a comparison of the results from time history methods, and from response spectrum methods with SRSS load combinations and smoothed spectra. Such comparisons for the RPV and internals in BWR plants generally show that the loads determined by both methods are comparable in magnitude with the loads determined by the response spectrum method, being generally on the high side. Therefore, it may be concluded that the SRSS method of combining loads is adequate even for closely spaced modes.

The natural frequencies of the reactor internals, reactor vessel, and pedestal system in the vertical direction have been found to be approximately 20 Hz. Examination of the response spectra shows no significant amplification at this frequency. Hence, omitting the vertical motion from seismic analysis to reduce the analytical complexities is acceptable. The effects of vertical excitations are accounted for by increasing or decreasing (whichever causes higher stress) the weight of the various components by a percentage equal to the vertical acceleration expressed in percent g.

The coupling of the vertical and lateral motions will cause an extremely small change in the bending moment experienced by some components. Since this change is a very small fraction of the moment caused by lateral moment, it can be neglected.

The stresses caused by the combined Safe Shutdown Earthquake and the LOCA conditions have been compared with and found to be within the Appendix C primary stress limits for faulted conditions.

To demonstrate that the reactor vessel internals can adequately resist the stresses resulting from an earthquake, a 1.0g lateral force was assumed. This does not mean that the Operating Basis Earthquake, which is used in combination with the accident loadings described (see Appendix C) is of this magnitude, but that the assumption of 1.0g lateral force is more than adequate to demonstrate the capabilities of the reactor vessel internals. For the reactor shroud, this analysis was superseded by the stress and seismic analyses performed subsequently as part of the shroud repair.

In RFO #10, a reactor shroud repair was implemented as described in Section 3.3.4.1.1. The design loads for the shroud stabilizers included seismic plus main steam line break accidents. The seismic analysis was done with a lumped mass and beam element two-dimensional finite element model of the entire reactor building and reactor vessel structure. To be consistent with the original design basis seismic analysis, the model has a single horizontal translational degree of freedom for each node. The model included in the reactor internals with elements to represent the fuel, guide tubes and shroud. The model was first benchmarked against the original GE seismic analysis. The shroud repair was then added to the model by inserting two linear spring elements representing the upper and lower shroud stabilizer springs and a single rotational spring element to represent the four tie rods by an equivalent restraint against the shroud horizontal (overturning) movement.

The seismic analysis was done via the time history with modal superposition method. The ground motion input was done using both a Housner Response Spectrum synthetic time history per FSAR requirements shown in FSAR Figures 2.5-5 (OBE) and 2.5-6 (SSE), and a Taft earthquake time history consistent with the original seismic analysis. The shroud stabilizer design loads conservatively bound the higher of either the Housner or Taft responses.

The shroud stabilizers limit the displacement of the top guide and core support plates in the horizontal and vertical directions. The displacement limits were specified by General Electric based on analytical and empirical data on the ability to insert control rods with both transient and permanent displacements of the top guide and core support plate. The safety factors from Table C.3-6 were applied to the maximum displacement limits for the upset, emergency, and faulted conditions.

It can be concluded that earthquake forces do not cause deformations of the reactor vessel internals sufficient to prevent the insertion of control rods, the proper operation of the CSCS, or the proper flooding of the inner volume of the reactor vessel.

3.3.6.10 Impact of Increased Core Flow (ICF) and Final Feedwater Temperature Reduction (FFWTR) on Reactor Internal Components

To support plant operation at 107.5% of rated recirculation flow, a safety analysis of the reactor internal components was performed to verify that the expected structural loading increases remain within the safety design bases limits. The analysis includes ICF with both normal feedwater temperature

Feedwater temperature affects the steady state and transient components of the pressure differentials differently. A reduction in feedwater temperature decreases the steady state component due to a reduced void fraction and a corresponding reduction in two-phase friction effects. However, a reduction in feedwater temperature increases the transient portion of the pressure differentials due to the reduced steam generation rate and the corresponding increase in the depressurization rate during a LOCA event (see Section 3.3.6.5.2). When effects on the steady state and transient components are combined, it turns out that the reduced feedwater temperature increases the overall pressure differential across the reactor components located in high steam environments, i.e. above the core region. These reactor internals are typically the top guide, upper shroud, shroud head and steam dryer. The loads for these components are limiting at the reduced feedwater temperature condition. At or below the core region, where the environment is mostly in a liquid or low steam quality state, the reduced feedwater temperature has negligible overall impact on the reactor components. These components include the shroud support, core plate, and fuel channels. For these components, the limiting loads are still experienced at normal feedwater temperatures.

A review was made of the effect of 75°F feedwater temperature reduction on reactor internals pressure differentials (RIPDs). The conclusion was that “normal” and “upset” RIPDs were not adversely affected, and the increase on LOCA RIPDs (<2%) over the 43°F case was very small relative to the margin existing, in the design. This review is documented in General Electrics design record file (J11-02368, Reference 11).

3.3.6.10.1 Reactor Internals

The reactor internals most affected by pressure differences under increased core flow conditions are the core plate, guide tube, shroud support, shroud and top guide. These components were evaluated under normal, upset, emergency, and faulted conditions. The pressure differentials for these components during increased core flow operation were found to produce stresses that are within the allowable limits of the safety design bases.

3.3.6.10.2 Fuel Channels

The fuel channels were also evaluated under normal, upset, emergency and faulted conditions for increased core flow and/or FFWTR. The channel wall pressure differentials were found to be within the allowable design values.

3.3.6.10.3 Fuel Bundles

The margin to fuel bundle lift was re-evaluated for increase core flow operation and/or FFWTR. The analysis considered the added bundle lift component due to increased core flow, with and without FFWTR, in addition to the effect of the design basis LOCA, the control rod friction force due to scram and the design-basis earthquake. The fuel bundle minimum lift margin was found to be 135 pounds (net downward force on fuel bundle) during the worst-case faulted event from rated operating conditions (a steamline break at 102% power, 107.5% flow). This analysis found the effect of increased core flow with or without FFWTR to yield acceptable results in terms of avoiding fuel bundle lift.

3.3.6.11 Conclusions

The analyses of the responses of the reactor vessel internals to situations imposing various loading combinations on the internals show that deformations are sufficiently limited to allow both adequate control rod insertion, and proper operation of the CSCS. Sufficient integrity of the internals is retained in such situations to allow successful reflooding of the reactor vessel inner volume. The analyses considered various loading combinations, including loads imposed by external forces. Thus, safety design bases 1, 2, and 3 are satisfied.

These conclusions extend to plant operation at rated core flow and increased core flow with and without final feedwater temperature reduction.

3.3.7 Inspection and Testing

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

The Reactor Coolant System (RCS), which includes the reactor vessel internals, is thoroughly cleaned and flushed before fuel is loaded initially.

During the preoperational test program, operational readiness tests are performed on various systems. In the course of these tests such reactor vessel internals as the feedwater spargers, the core spray lines, the vessel head cooling spray nozzle, and the SLCS line are functionally tested.

A vibration analysis of reactor vessel internals was performed in the design to reduce failures due to vibration. With this analysis as a guide, the reactor internals are instrumented and tested to ascertain that there are no gross instabilities. Field test data are correlated with the analysis to ensure validity of the analytical techniques on a continuing basis. For vibration testing of reactor vessel internals, refer to Section 3.3.5.2.

The reactor vessel and internals are designed to assure adequate working space and access for inservice inspection. The criteria for selecting the components and locations to be inspected are based on the probability of a defect occurring or enlarging at a given location, and includes areas of known stress concentrations and locations where cyclic strain or thermal stress might occur. When practical, 100 percent inspection is planned at these locations; however, in cases where access is difficult, hazardous, or limited, it is planned to inspect a statistically significant portion. The type of inspection planned at each location is dependent on the type and location of defects anticipated.

3.3.8 References

1. NEDC-20259, "Summary Report on the Pilgrim Channel Wear Investigation and Corrective Measures Taken", January 1974.

2. NEDE-24323-P, "Core Support Plate Plug Service Life", March 1981.

3. "Design and Performance of G.E. BWR Jet Pumps", General Electric Co., Atomic Power Equipment Department, APED-5460, July 1968.

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

5. NEDE-24362-1, "Improvements in Jet Pump Hold-Down Beam Service Life", December 1981.

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

7. NEDE-20566-P, "Analytical Model for Loss-of-Coolant Accident in Accordance with 10CFR50, Appendix K", General Electric Company.

8. NEDC-32120P, "Revision of Core Support Plate Plug Service Life", General Electric Nuclear Energy, July 1992.

9. NEDO-20855-01, "GE BWR Reload No. 2 Licensing Submittal for PNPS, Unit 1 with Bypass Flow Holes Plugged", GE Boiling Water Reactor Projects Department, September, 1975.

10. M-2-ER-Q-EO "Engineering Report for Core Support Plate Plug Life Extension", March 1994.

11. General Electric (D.C. Serell) to Boston Edison (B. Hagemeier), January 16, 1997, "Pilgrim Cycle 11 Reactor Internal Pressure Differences for Increased Core Flow with 75° F Feedwater Temperature Reduction".

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

13. SE3084, "Various jet pumps have mixer swing gates that do not have the latch pins engaged in their associated holes and restrainer bracket set screws not in contact with the inlet mixer", April 4, 1997. [Includes SUDDS/RF 97-41, SIA Report No. SIR-97-028, "Evaluation of the Pilgrim Jet Pumps with and without Gaps at Set Screws and Wedges" dated April 1997]

14. SUDDS/RF 97-41 Rev. 1 of vendor report SIR 97-028 Rev. 2.

15. SUDDS/RF 03-036 SIA Calculation PNPS-10Q-313 "Jet Pump Gap Analysis" dated 3/7/03.

16. MFN12-074, Enclosure 1, Proprietary, NRC SER on Enhanced NSF LUC Program.

17. EC47671, Pilgrim Cycle 21 Fuel Receipt.

TABLE 3.3-1

REACTOR VESSEL INTERNALS, DESIGN DATA

Core Shroud	
Upper Portion, od, in	195.5
Central Portion, od, in	184
Central Portion, thickness, in	1.5
Weight, lb	82,000
Shroud Head-Steam Separator Assembly	
Head Thickness, in	2.0
Number of Separators	154
Separator, od, in	12.75
Standpipe, id, in	6.065
Standpipe, od, in	6.625
Weight, lb	94,000
Core Support Plate	
Weight, lb	18,500
Top Guide	
Weight, lb	8,400
Fuel Support Pieces	
Number	145
Weight, lb	9,500
Control Rod Guide Tubes	
Number	145
Weight, lb	32,250
Jet Pumps	
Number	20
Throat Diameter, in	6.80
Weight, lb	24,200
Steam Dryers	
Weight, lb	46,000
Feedwater Sparger	
Dimensions of Oval, in	6 Sched. 40
Cross Section Area, ft^2	0.2006
Number	4
Core Spray Sparger	
Diameter, in	3.5 Sched. 40S
Cross Section Area, ft^2	0.0686
Number of Spray Outlets	224
Weight, lb	1,500 (approximately)

TABLE 3.3-1 (Cont)

Differential Pressure & Liquid Control Line	
Inner Pipe (Liquid Control), in	1 Sched. 40
Outer Pipe, in	2 Sched. 40
Incore Flux Monitor Guide Tubes	
Number	42

Table 3.3-2

Reactor Internal Pressure Differences
for Rated Flow Operation

REACTOR COMPONENT	N	U	E	F1	F2
Core Plate and Guide Tube	16.39	18.8	20.5	22.5	26.
Shroud Support Ring and Lower Shroud	21.69	24.1	28.5	39.0	43.
Upper Shroud	5.3	8.0	8.9	22.5	24.5
Shroud Head	5.6	8.4	9.5	23.5	24.5
Shroud Head to Water Level, irreversible differential pressure	7.5	11.3	10.7	24.5	25.0
Shroud Head to Water Level, elevation differential pressure	0.85	1.3	1.1	1.0	1.8
Channel Wall					
Core Average Power Bundle (Bulge)	6.59	9.5	7.6	10.1	9.2
Maximum Power Bundle (Bulge)	8.96	11.9	10.5	12.7	10.1
Average Central Power Bundle (Bulge)	7.69	10.6	-	-	-
Top Guide	0.46	<1.	0.1	0.4	0.5
Steam Dryer	0.2	0.3	2.7	1.5	5.0

N - Normal Condition

U - Upset Condition

E - Emergency Condition

F1 - Faulted Condition, 102% Power/100% Flow

F2 - Faulted Condition, 22.6% Power/110% Flow

Table 3.3-3
Reactor Internal Pressure Differences
for Increased Core Flow Operation

REACTOR COMPONENT	N	U	E	F1	F2
Core Plate and Guide Tube	18.23	20.63	24.5	29.	32.
Shroud Support Ring and Lower Shroud	25.0	27.4	30.0	48.	51.
Upper Shroud	7.0	10.5	11.0	25.	26.
Shroud Head	7.5	11.25	11.5	25.5	26.
Shroud Head to Water Level, irreversible differential pressure	8.7	13.05	12.8	27.	27.
Shroud Head to Water Level, elevation differential pressure	1.0	1.05	1.0	1.0	1.5
Channel Wall					
Core Average Power Bundle (Bulge)	6.90	9.8	11.2	11.8	10.8
Maximum Power Bundle (Bulge)	9.44	12.34	14.2	15.7	13.1
Average Central Power Bundle (Bulge)	7.84	10.7	-	-	-
Top Guide	0.46	<1.0	<1.	<1.	<1.
Steam Dryer	0.20	0.30	2.7	1.5	5.0

N - Normal Condition

U - Upset Condition

E - Emergency Condition

F1 - Faulted Condition, 102% Power/107.5% Flow

F2 - Faulted Condition, 40% Power/117.5% Flow

Figure 3.3-1 has been removed.

Please refer to BECo Controlled Drawing M1A48-4.

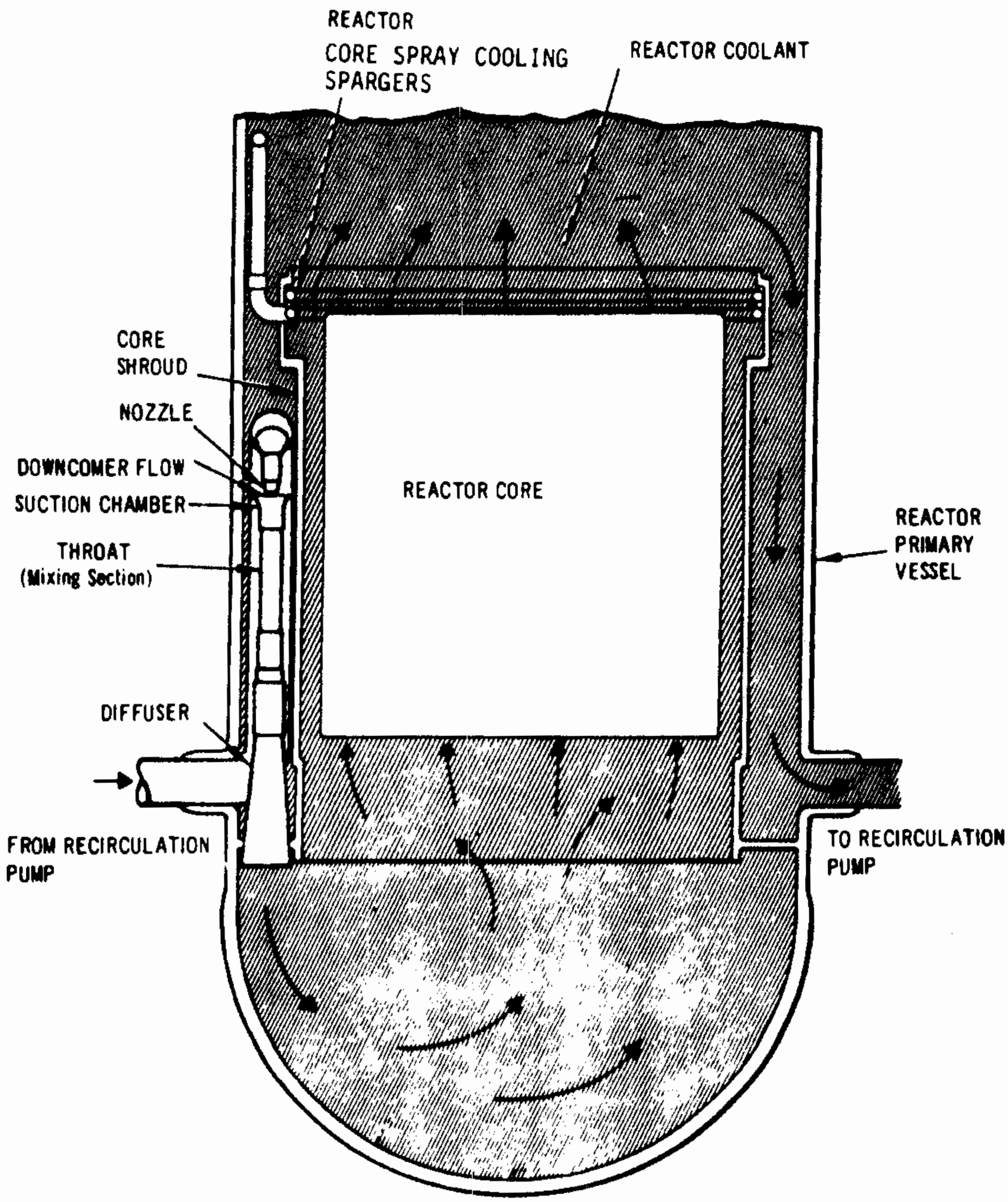


FIGURE 3.3-2
REACTOR VESSEL INTERNAL
FLOW-SCHEMATIC
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

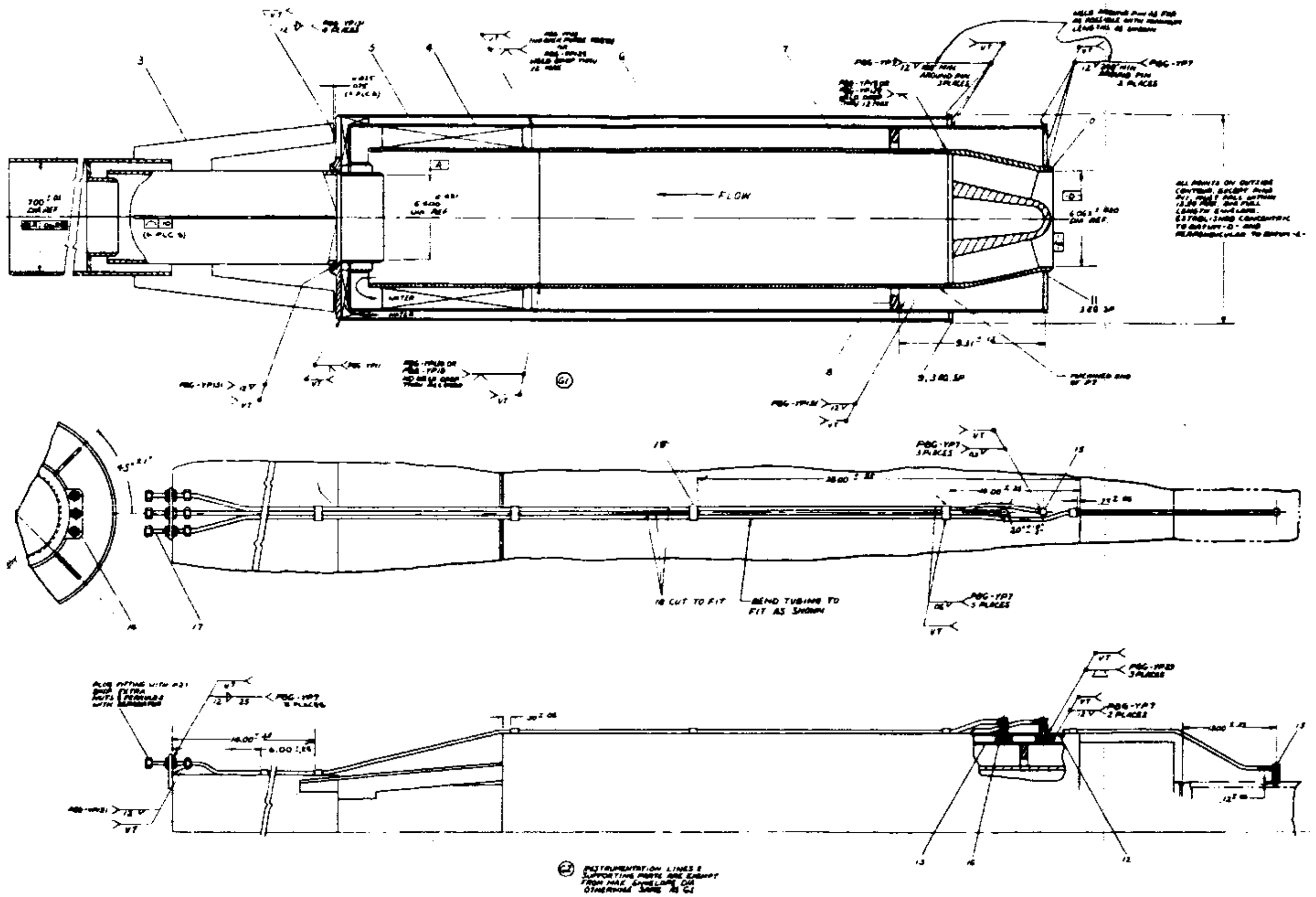


FIGURE 3.3-3
STEAM SEPARATOR
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

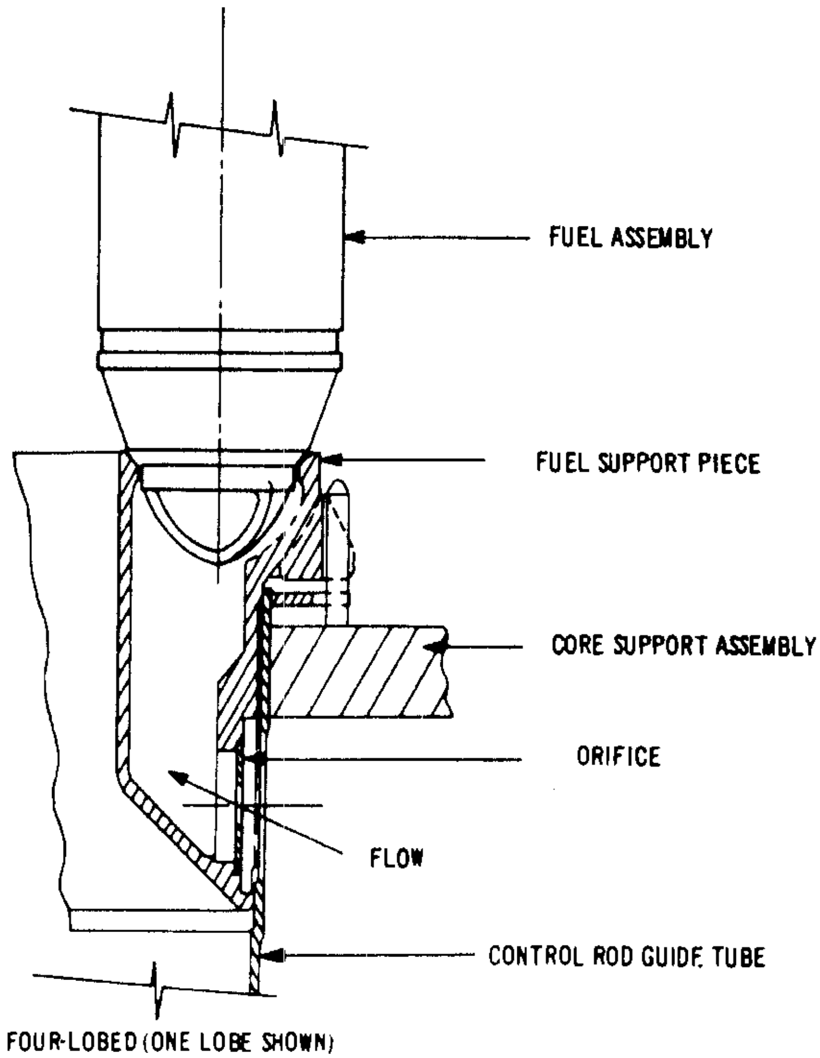


FIGURE 3.3-4
FUEL SUPPORT PIECE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 3.3-5 has been removed.

Please refer to BECo Controlled Drawing M1E44-1.

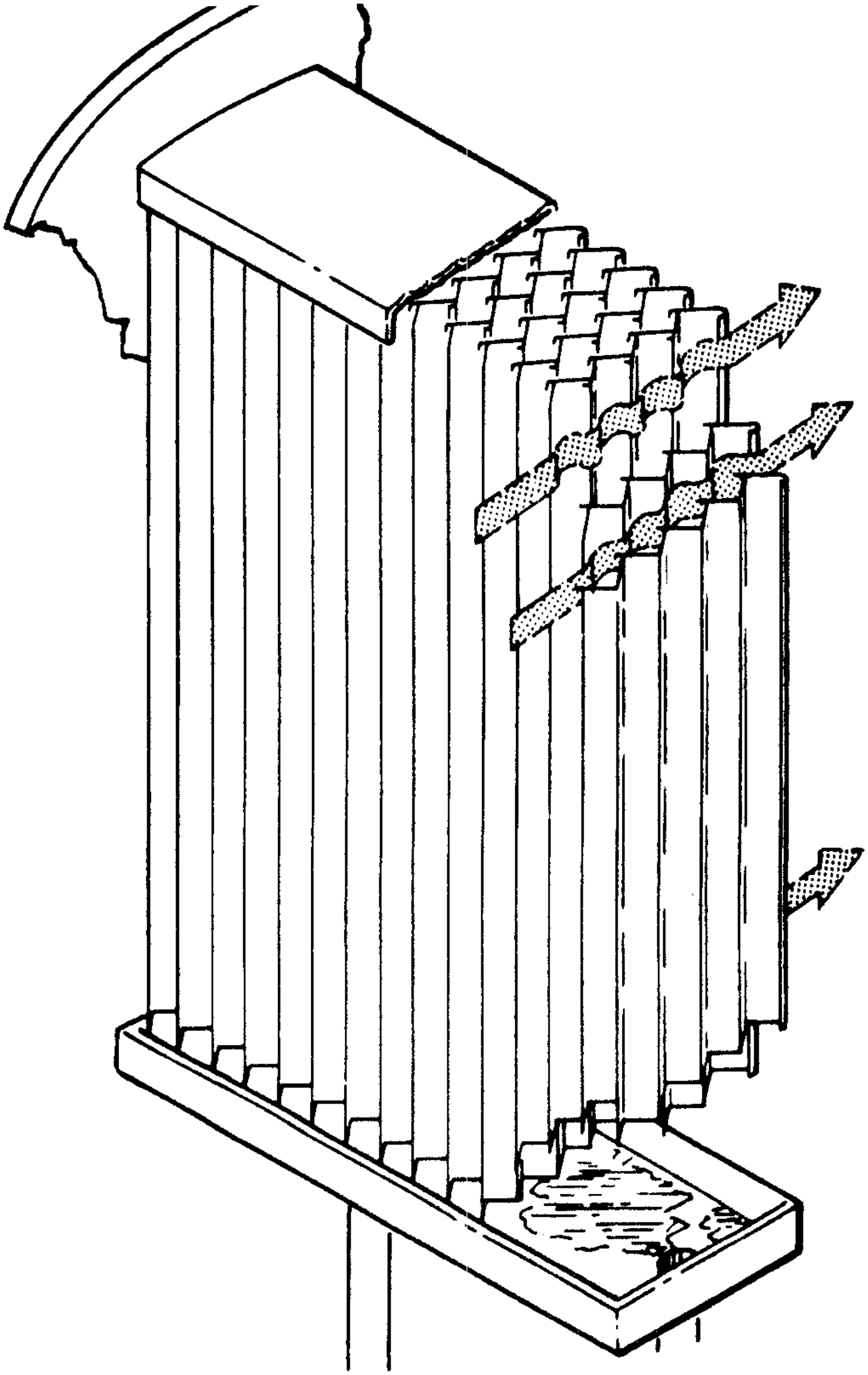


FIGURE 3.3-6
STEAM DRYER
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

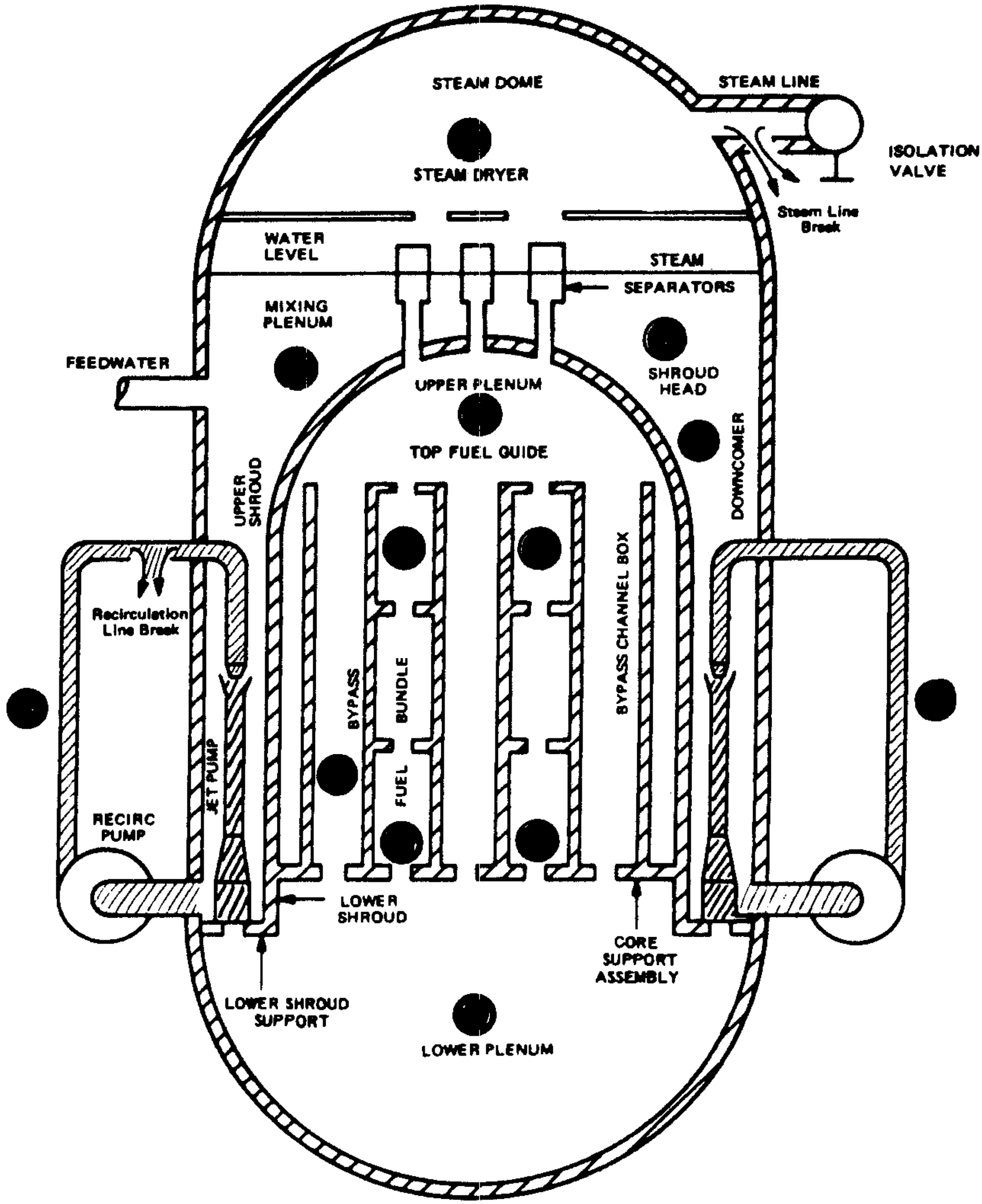


FIGURE 3.3-7

PRESSURE NODES USED FOR DEPRESSURIZATION ANALYSIS

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

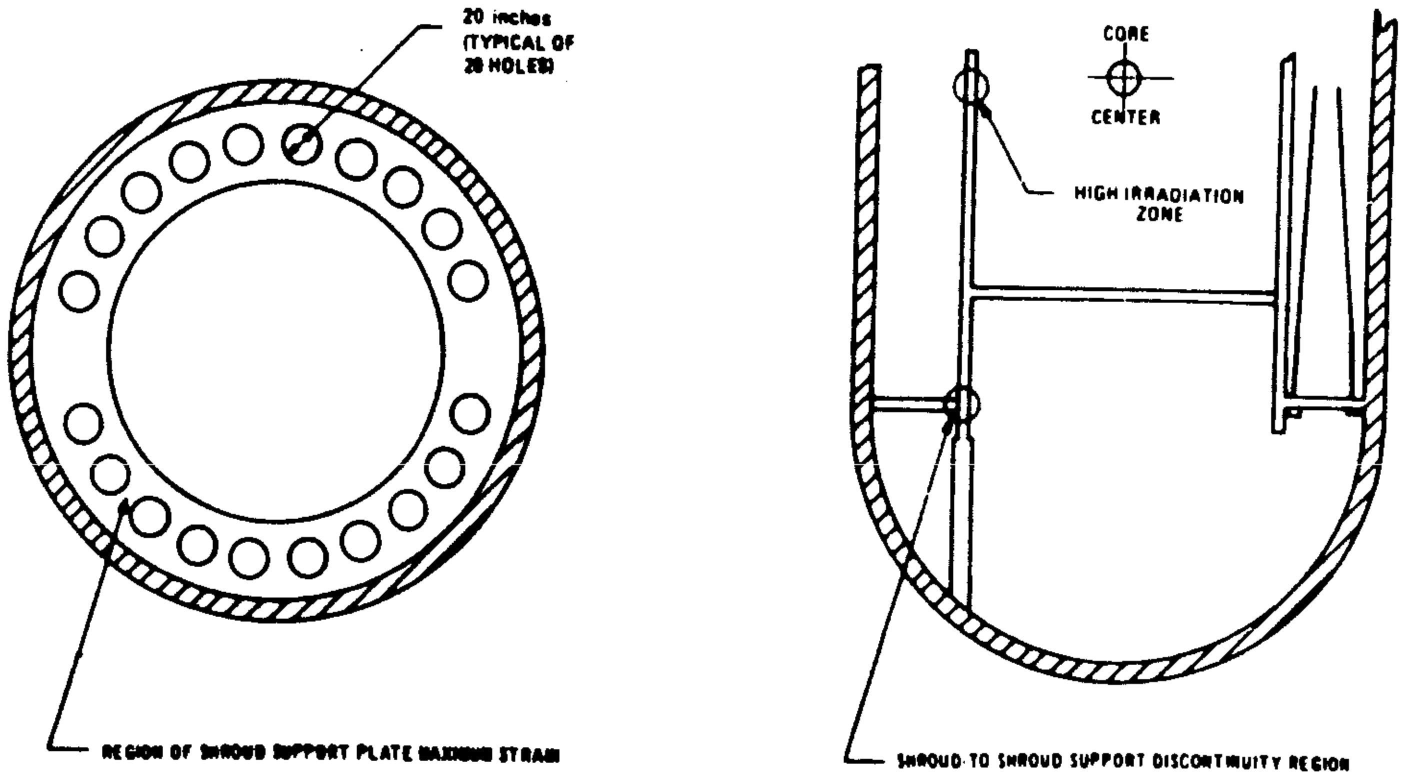


FIGURE 3.3-8
THERMAL SHOCK
TRANSIENT ANALYSIS ZONES
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 9 – JULY 1988

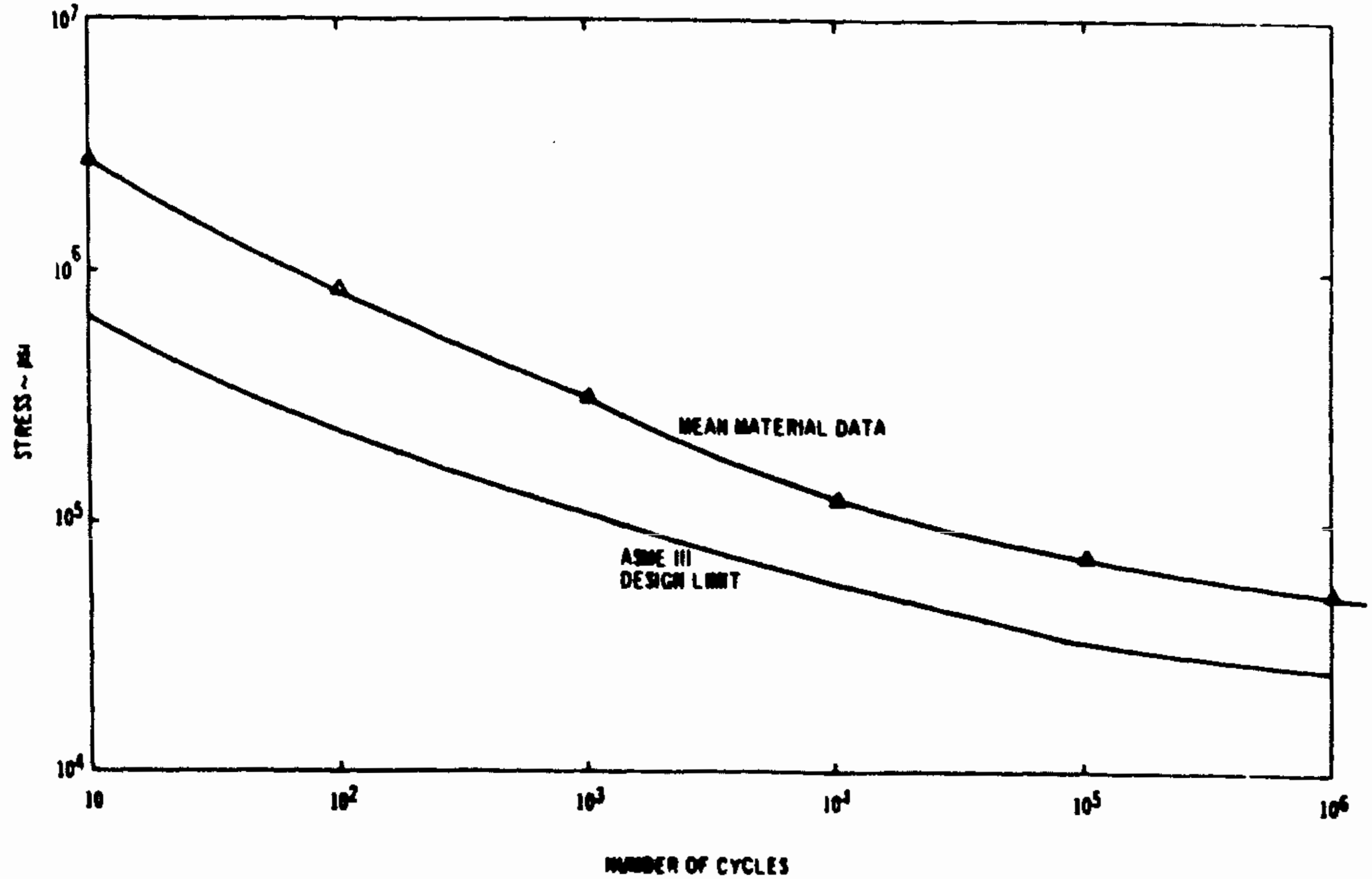


FIGURE 3.3-9
MATERIAL BEHAVIOR GRAPH CYCLES VERSUS STRESS FOR STAINLESS STEEL

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

REVISION 9 - JULY 1988

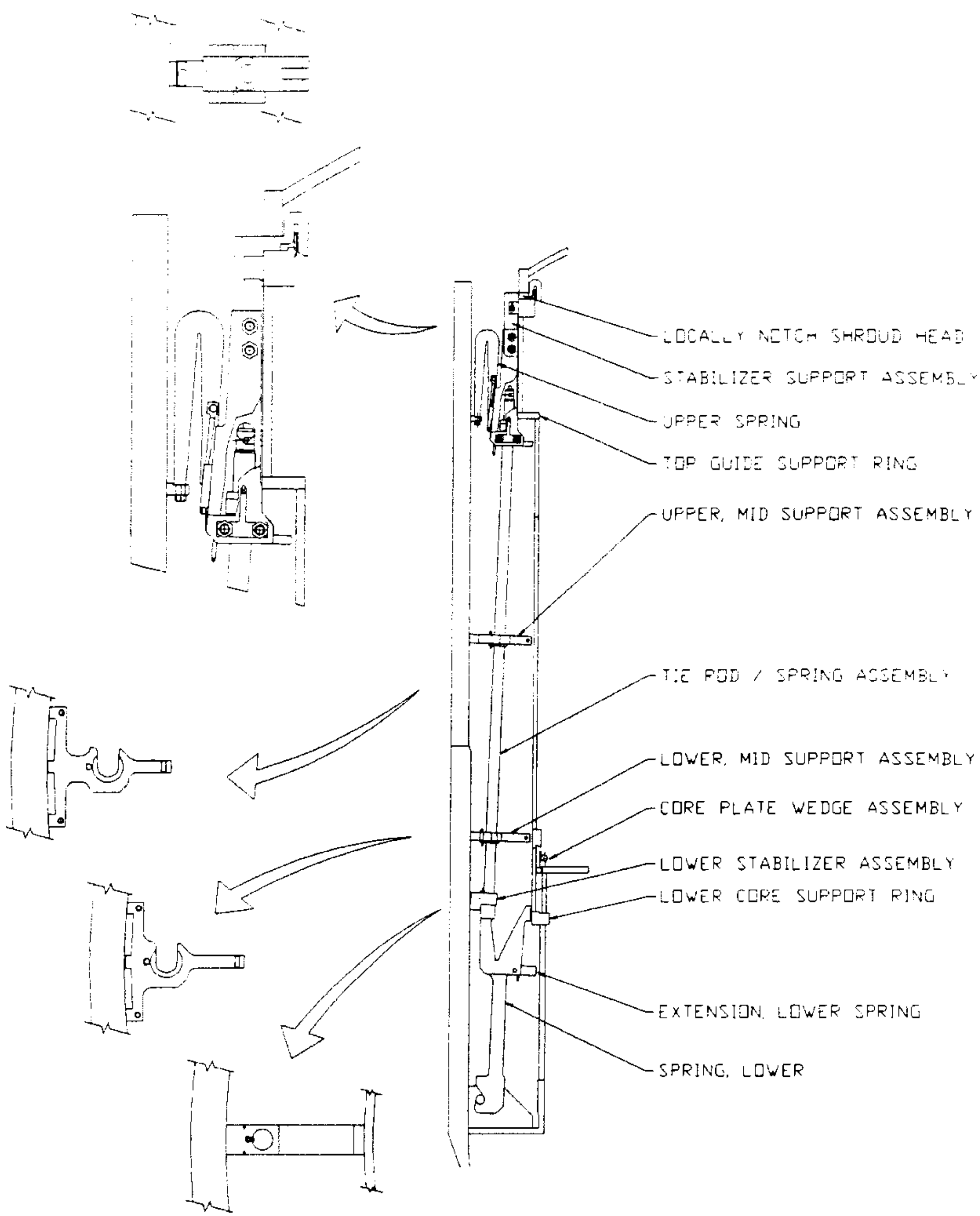


Figure 3.3-10 Pictorial View of Pilgrim Shroud Repair Hardware
Pilgrim Nuclear Power Station
Final Safety Analysis Report

Revision 19 June 1996

3.4 REACTIVITY CONTROL MECHANICAL DESIGN

3.4.1 Safety Objective

The safety objective of the reactivity control mechanical design is to provide a means to quickly terminate the nuclear fission process in the core so that damage to the fuel barrier is limited.

3.4.2 Safety Design Basis

1. The reactivity control mechanical design includes control rods. Each control rod:

    a. Has sufficient mechanical strength to prevent the displacement of their reactivity control material.

    b. Has sufficient strength and are of such design as to prevent deformation that could inhibit their motion.

    c. Includes a device to limit its free fall velocity to such a rate that the nuclear system process barrier is not damaged due to a pressure increase, caused by the rapid reactivity increase resulting from the free fall of one control rod from its fully inserted position.

2. The reactivity control mechanical design provides for a sufficiently rapid insertion of control rods so that no fuel damage results from any abnormal operating transient.

3. The reactivity control mechanical design includes positioning devices, each of which individually supports and positions a control rod. Each positioning device:

    a. Prevents its control rod from withdrawing as a result of a single malfunction

    b. Avoids conditions which could prevent its control rod from being inserted

    c. Is individually operated such that a failure in one positioning device does not affect the operation of any other positioning device

    d. Is individually energized when rapid control rod insertion (scram) is signaled so that failure of a power source external to the positioning device does not prevent other control rods from being inserted

    e. Is locked to its control rod to prevent undesirable separation

4. The reactivity control mechanical design includes reactivity control devices (control rods and initial core control curtains) which contain and hold the reactivity control material necessary to maintain the core at least 1 percent Δ k/k subcritical with the highest worth rod in the fully withdrawn position.

3.4.3 Power Generation Objective

The power generation objective of the reactivity control mechanical design provides a means to control power generation in the fuel.

3.4.4 Power Generation Design Basis

The reactivity control mechanical design includes provisions for adjustment of the control rods to permit control of power generation in the core.

3.4.5 Description

The reactivity control mechanical design consists of control rods which can be positioned in the core during power operation by individual control rod drive (CRD) mechanisms.

The CRD mechanisms are part of the CRD system. The CRD system hydraulically operates the CRD mechanisms using water from the Condensate and Demineralized Water Storage and Transfer System as a hydraulic fluid. The CRD mechanisms manually position the control rod during normal operation but act automatically to rapidly insert the control rods during abnormal (scram) conditions.

The control rods, CRD mechanisms, and that part of the CRD Hydraulic System necessary for scram operation are designed as seismic Class I equipment in accordance with Appendix C.

3.4.5.1 Reactivity Control Devices

3.4.5.1.1 Control Rods

The control rods perform the dual function of power shaping and reactivity control. See Figure 3.4-2. Power distribution in the core is controlled during operation of the reactor by manipulation of selected patterns of control rods. The control rods are positioned in a manner which counterbalances steam void effects at the top of the core and results in significant power flattening.

The control rods are 9.75 inches in total span and are located uniformly through the core on a 12 inch pitch. Each control rod is surrounded by four fuel assemblies.

Control rods in the following categories are used:

Standard control rods that maintain the same dimensions and characteristics as the original equipment control rods.

Hybrid control rods that maintain the same external dimensions as the original control rods and utilize hafnium in the blade tips and wing edges to improve nuclear and mechanical lifetimes. These control rods are the Duralife 160 series described in Reference 7.

Hybrid control rods that introduce a larger diameter absorber tube to obtain a greater load of neutron absorber material. These control rods are the Duralife 230 series described in Reference 8.

Hybrid control rods that replace the sheath-enclosed absorber tube with square tubes welded together to form each wing. The square tubes contain hafnium in the wing tips and encapsulated boron carbide elsewhere. These control rods are the Marathon D series described in Reference 11.

All of the above control rods have been designed to ensure interchangeability with the original equipment control rods from both the reactivity perspective, system performance, and mechanical fit. The reactivity worth is approximately identical (within $\pm$ 5%) to the original equipment control rods and can be used interchangeably without affecting lattice physics, core reload analyses or core monitoring software.

The nuclear lifetime of the standard control rod is determined by the burnup of Boron-10 from neutron absorption. The nuclear lifetime limit of the standard equipment control rod is reached when depletion results in a 10 percent reduction in the reactivity worth of any quarter axial segment of the control rod relative to its zero depletion cold worth. The nuclear lifetime of a replacement control rod is defined as the quarter-segment depletion at which the cold worth is the same as the end-of-nuclear life cold worth of the standard control rod it replaces. For example, if a replacement control rod has an initial cold worth 4% greater than the standard control rod, then it may be depleted to a reduction of 14% from its initial cold worth. Additional details are provided in Reference 9.

In order to maintain the nuclear lifetime discussed above, each control rod design must ensure the absorber material remains capable of performing its function. The design bases for control rod mechanical lifetime is based on maintaining absorber tube integrity. The mechanical lifetime limit is reached when the depletion-induced B_4C swelling or tube pressurization results in stresses in any absorber tube of the control rod in excess of the yield stress. For those designs that incorporate hafnium as a poison, there are no mechanically based lifetime limiting mechanisms associated with hafnium. Additional details are provided in Reference 9.

The plant computer is used to track total accumulated exposure for each quarter segment of each control rod in the reactor core. Percent Boron-10 depletion is calculated for each control rod based on conversion factors that correlate accumulated exposure to percent Boron-10 depletion (Reference 2 and 9). Recommended limits in terms of percent Boron-10 depletion from the manufacturer are adhered to as provided in the current revision of Reference 9.

Standard Control Rod

The main structural member of a control rod is made of Type 304 stainless steel and consists of a top casting which incorporates a handle, a bottom casting which incorporates a velocity limiter and control rod drive coupling, a vertical cruciform center post, and four U-shaped absorber rod sheaths. The two end castings and the center post are welded into a single skeletal structure. The U-shaped sheaths are resistance welded to the center post and castings to form a rigid housing to contain the absorber rods. Rollers at the top and the bottom of the control rod provide guidance for the control rod as it is inserted and withdrawn from the core. The control rods are cooled by the fuel assembly bypass flow.

The U-shaped sheaths are perforated to allow the coolant to freely circulate about the absorber rods. Operating experience has shown that control rods constructed as described above are not susceptible to dimensional distortions, as required by safety design basis 1.b.

The absorber rods in a standard control rod are comprised entirely of boron carbide (B_4C) powder in stainless steel tubes. The boron carbide (B_4C) powder in the absorber tubes is compacted to about 70 percent of its theoretical density; the boron carbide contains a minimum of 76.5 percent by weight natural boron. The Boron-10 (B^{10}) content of the boron is 18.0 percent by weight minimum. The absorber tubes are made of Type 304 stainless steel. An absorber tube has a 0.188 inch outside diameter and a 0.05 inch wall thickness. An absorber tube is sealed by a plug welded into each end. The boron carbide is separated longitudinally into individual compartments by stainless steel balls at approximately 16 inch intervals. The steel balls are held in place by a slight crimp of the tube. Should the boron carbide tend to compact further in service, the steel balls will distribute the resulting voids over the length of the absorber tube.

If the control rod blades are subjected to sufficient exposure to cause approximately 50 percent local depletion of the poison tube Boron-10 (B^{10}), the potential for tube cracking and boron leaching exists. (See References 1, 2, 3 and 4). Local depletion levels are measured in 6-inch axial segments.

The cracking is due to stress corrosion induced by solidification of boron carbide (B_4C) particles and swelling of the compacted B_4C as helium and lithium concentrations grow. Once primary coolant penetrates the cladding (i.e. the cracking has progressed through the cladding wall and the helium-lithium pressures are sufficient to open the crack), boron is leached out of the tube. The cracking and boron loss shorten the design life of the control rod. To extend the control rod mechanical lifetime, the absorber rod at the outer end of each control rod blade is constructed in two half-length sections.

Since the control rods enter from the bottom of the core, the neutron exposure of the control rods is skewed towards the top half

of the control rod. The absorber rod at the outer edge of each blade of the control rod receives more neutron irradiation than any other rod in the blade. Neutron irradiation is significantly less for each absorber rod located closer to the center of the control rod. The absorber rod tubing at the lower end of the control rods undergoes negligible fast flux irradiation and, as a result, retains its initial annealed material properties throughout the lifetime of the control rods. Thus, the allowable design stress for all absorber rod tubes which extend into the bottom end of the control rod is based upon the mechanical properties of fully annealed Type 304 stainless steel. The tubing of the top half length absorber rod undergoes full irradiation strengthening such that the allowable design stress for this tube is determined by the mechanical properties of fully irradiated material. Thus, by making the outer absorber rod in two sections, the absorber rod tube with the highest internal pressure benefits from a higher allowable design stress. As a result, the mechanical lifetime of the control rod is extended.

The standard control rods meet the requirements of safety design basis 1.a.

Hybrid Control Rod

The principle design change in the hybrid control rod is the use of hafnium absorber rods in place of B_4C absorber rods in selected high-flux locations. Hafnium is a proven long-life absorber that does not swell during reactor service. Each hybrid control rod contains a total of twelve hafnium absorber rods, three per control rod wing, located as shown in Figure 3.4-14. The number of hafnium rods was determined by establishing an acceptable local boron depletion limit for B_4C absorber rods and then placing hafnium in locations where local burnup exceeded this limit. The local depletion limit for the B_4C absorber rods was maximized since hafnium increases both the weight and cost of the control rod.

Besides the use of hafnium, hybrid control rods are improved over standard control rods by:

1) substitution of high-purity Type 304 stainless steel absorber tubes in place of commercial-quality Type 304 stainless steel and

2) substitution of new pin and roller materials in place of cobalt-bearing stellite.

High-purity Type 304 stainless steel is more resistant to stress corrosion cracking than commercial-quality Type 304 stainless steel. Stress corrosion cracking is a precursor to boron leaching. Elimination of cobalt-bearing stellite yields lower end-of-life gamma activity and attendant reductions in personnel exposures and radionuclide disposal requirements.

Except for the thickness of the sheath material, the dimensions of the hybrid control rod are identical to the dimensions of the standard control rod. The sheath material thickness is reduced by

22 mils to offset the greater weight of the hafnium absorber rods. Gross weights of the hybrid and standard control rods are identical. The dimensional similarity of the hybrid control rod makes this rod compatible with NSSS hardware designed for the standard control rod.

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

Operational lifetime of the hybrid control rods is determined by the same set of nuclear and mechanical design constraints as with the standard control rod.

The hybrid control rods meet the requirements of Safety Design Basis 1.a.

Model Duralife 230

The General Electric Model Duralife 230 (D230) Control Blade is an extension of the Hybrid Design described above with improvements. See Figure 3.4-15. Improvements to and differences from the Hybrid Blade can be used to describe the D230 blade. The three hafnium rods in each hybrid wing have been replaced by a solid strip of hafnium in the D230. The D230 also has a six inch plate of hafnium atop each wing. As in the hybrid blade, the D230 uses hafnium in areas where the thermal flux tends to be the highest for the same reasons. Mechanically and dimensionally, the D230 blade is very similar to the hybrid blade. B_4C tubing is a larger diameter and the sheath thickness is the same as the hybrid (0.045 inch) which does not quite compensate for the larger diameter B_4C tubing. Therefore, the wing thickness is 0.012 inch thicker than the original blade. The entire D230 is manufactured from low cobalt stainless steels.

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

Operational lifetime of the hybrid control rods is determined by the same set of nuclear and mechanical design constraints as with the standard control rod.

The Model D230 control blade meets the requirements of Safety Design Basis 1.a. (Reference 8)

Model Marathon D

The General Electric Marathon D control rod is an extension of the hybrid design described above with improvements. The Marathon design is directly interchangeable with previously installed control rod designs: Standard, Hybrid or D230. The essential difference between the Marathon control rod and the D230 design is replacement

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

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

Operational lifetime of the Marathon control rod is determined by the same set of nuclear and mechanical design constraints as with the standard control rod. GE Hitachi Inc. has substituted Marathon D with M7 control rods, which are essentially identical to Marathon D, except that they have spacer pads instead of pins and rollers to avoid cracking/corrosion problems with pin-holes. GE Hitachi Inc. has substituted Marathon D with Marathon Ultra HD (High Duty) control rods. The Marathon Ultra HD control rods are functionally equivalent to the Marathon D blades. The Marathon Ultra designs eliminate swelling induced strains on the outer absorber tube by resizing the inner capsule diameter. Marathon Ultra are designed such that a diametric clearance exists between the inner capsule and the outer absorber tube at 100% local Boron-10 depletion, worst-case capsule and absorber tube dimensions, and upper bound $+3\sigma$ boron carbide swelling rates. Capsule cross-sectional geometry provides a larger gap between the inner capsule and the outer absorber tube. Therefore, Marathon Ultra HD control rods have more tolerance to the stress corrosion cracking phenomenon than Marathon D control rods leading to longer blades lifetime. The Marathon Ultra HD control rods have been approved by NRC. (Reference 12)

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

3.4.5.1.2 Control Rod Velocity Limiter

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

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

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

To limit control rod velocity during dropout but not during scram, the velocity limiter is provided with a streamlined profile in the scram (upward) direction. Thus, when the control rod is scrammed, the velocity limiter assembly offers little resistance to the flow of water over the smooth surface of the upper conical element into the annulus between the guide tube and the limiter. In the dropout direction, however, water is trapped by the lower conical element and discharged through the annulus between the two conical sections. Because this water is jetted in a partially reversed direction into water flowing upward in the annulus, a severe turbulence is created,thereby slowing the descent of the control rod assembly to less than 5 ft/sec at 70°F.

3.4.5.2 Control Rod Drive Mechanisms

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

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

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

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

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

The positions of the drive selected for movement, together with positions of three (or less) adjacent drives, and Local Power Range Monitor signals in the vicinity of the selected drive, are continuously displayed as described in Section 7.5, Neutron Monitoring System. The selected rod is indicated by a status light. The positions of all drives not selected for movement are continuously monitored for motion. A change in drive position (drive drifting) initiates an audible alarm and indicates the faulty drive. The rod position information received from the drive position indicator probes are processed by the Rod Position Indicator System (RPIS), and distributed to various displays, annunciators, and the computer.

The status of all drives, scram valves, and accumulators are continuously indicated by panel lights. The indicated status include the following:

- Drive fully inserted
- Drive fully withdrawn
- Drive selected for movement
- Drive drifting (position change when not selected)
- Scram valve not closed
- Accumulator trouble (low pressure and/or leak)

In addition to the above, an annunciator signal is also produced by a rod overtravel.

Status indicators are differentiated by location and color in order to minimize operator error. The indicator arrangement is such as to graphically depict the actual location of rods in the reactor core. The position signals of selected drives, together with a drive identification signal, are provided for recording by a computer in accordance with the requirements of Section 7.16, Process Computer. The acquisition of a position signal by the computer does not interrupt the position indication.

The previous CRD design (Model 7RDB144-A2) used on other reactors utilized an inner filter which is attached to the lower end of the coupling spud. In this location, the inner filter moved with the moving drive whenever the CRD was normally inserted and withdrawn or scrammed. During scram, the downward forces on the CRD index tube was minimized by passing water through the inner filter at low pressure drops. In this location, if the resistance to flow through this inner filter increased due to various degrees of plugging, the pressure drop across the inner filter increased, resulting in increased downward force on the CRD index tube and consequent increase in scram times.

The Pilgrim CRD design (Model 7RDB144-B1) has changed the location of the inner filter from the moving spud to stationary location on top of the stop piston assembly. In this location, the inner filter is no longer a part of the moving drain line, and consequently, if plugging of this filter should occur, it will not affect scram times. In the previous location, the inner filter passed seal leakage water plus the necessary water to fill the volume between the stop piston seals and the inner filter. In the Pilgrim location, the inner filter must only pass seal leakage water. The location of the new inner filter design in the CRD is shown on Figure 3.4-8.

The effectiveness and reliability of this design modification was demonstrated under field conditions by surveillance, and testing performed during the preoperational and startup programs. Those informal surveillance procedures which demonstrated their effectiveness in diagnosing degradation of drive scram performance, due to dirt accumulation, were modified to improve their effectiveness and formalized by incorporation in the preoperational and startup testing program. These surveillance test procedures supplement the tests which demonstrate conformance with operating techniques specification limits, and are designed to detect changes in scram performance. The principles on which the surveillance tests were based are as follows:

1. A sample of all operable installed drives will be periodically tested to measure a characteristic scram performance parameter which will be evaluated for significant changes. Indication of a change suggesting performance degradation will require additional testing to determine the extent and cause of the fault

2. The sample size and acceptance limits were chosen to provide at least a 95 percent confidence that a change in performance is detected with 5 percent chance of making a false assumption of change. The basis for the choice of sample size and acceptance limits is the observed statistical characteristics of the results of the performance demonstration tests of the drives. Experience indicates that a sample size of 15 to 25 is adequate

3. The sample contains drives uniformly distributed in the core and are reconstituted for each successive measurement to measure the entire core progressively. With this routine sample is measured those drives which exceed the normally anticipated performance limits and therefore require continued surveillance

   The characteristic parameter of drive scram performance that yields the greatest accuracy and is most indicative of drive condition, is the time required to reach 90 percent stroke insertion at rated vessel pressure (1,000 psig)

Following the low vessel pressure scram performance tests of the preoperational test program, and before power operation, the scram performance of all drives at rated vessel pressure was measured and compared with predicted performance and operating technical specifications. This demonstration test was used as a basis for setting surveillance limits.

Thereafter, surveillance tests of a drive sample were performed before zero power and before each power increase during the startup program. Furthermore, during the startup program, periodic surveillance tests were performed at 4, 8, and 16 week intervals, continuing at 16 week intervals until the startup program was finished. In the event of a shutdown requiring vessel head removal or extensive work on the major reactor systems during the startup program, a performance measurement was required on all drives before resuming power operation, and the surveillance test of drive samples reverted to the 1, 2, 4, 8, and 16 week intervals until the startup program was finished.

3.4.5.2.1 Components

Figure 3.4-5 illustrates the principle of operation of a drive. Figures 3.4-6 and 3.4-7 illustrate the drive in more detail. Following is a description of the main components of the drive and their functions.

Drive Piston and Index Tube

The drive piston is mounted at the lower end of the index tube which functions as a piston rod. The drive piston and index tube make up the main moving assembly in the drive. The drive piston operates between positive end stops, with a hydraulic cushion provided at the upper end only. The piston has both inside and outside seal rings and operates in an annular space between an inner cylinder (fixed piston tube), and an outer cylinder (drive cylinder).

The effective piston area for down travel or withdraw is about 1.2 in^2 versus 4.0 in^2 for up travel or insertion. This difference in driving area tends to balance out the control rod weight, and makes it possible to always have a higher insertion force than withdrawal force.

The index tube is a long hollow shaft made of nitrided Type 304 or ASTM A479 Grade XM-19 stainless steel. This tube has circumferential locking grooves spaced every 6 in along the outer surface. These grooves transmit the weight of the control rod to the collet assembly which positions the rod.

Collet Assembly

The collet assembly serves as the index tube locking mechanism. It is located in the upper part of the drive unit. The collet assembly prevents the index tube from accidentally moving downward. The collet assembly consists of the collet fingers, a return spring, a guide cap, a collet housing (part of the cylinder, tube, and flange), and the collet piston seals.

Locking is accomplished by six fingers mounted on the collet piston at the top of the drive cylinder. In the locked or latched position the fingers engage a locking groove in the index tube.

The collet piston is normally held in the latched position by a return spring force of approximately 150 lb.

Metal piston rings are used to seal the collet piston from reactor vessel pressure. The collet assembly will not unlatch until the collet fingers are unloaded by a short, automatically sequenced, drive in signal. A pressure of approximately 180 psi above reactor vessel pressure acting on the collet piston is required to overcome spring force, slide the collet up against the conical surface in the guide cap, and spread the fingers out so that they do not engage a locking groove. The collet piston is nitrided to minimize wear due to rubbing against the surrounding cylinder surfaces.

Fixed in the upper end of the drive assembly is a guide cap. This member provides the unlocking cam surface for the collet fingers. It also serves as the upper bushing for the index tube and is nitrided to provide a compatible bearing surface for the index tube.

If reactor water is used to supplement accumulator pressure during a scram, it is drawn through a filter on the guide cap.

Piston Tube and Stop Piston

Extending upward inside the drive piston and index tube is an inner cylinder or column called the piston tube. The piston tube is fixed to the bottom flange of the drive and remains stationary. Water is brought to the upper side of the drive piston through this tube. A series of orifices at the top of the tube provides progressive water shutoff to cushion the drive piston at the end of its scram stroke.

A stationary piston, called the stop piston, is mounted on the upper end of the piston tube. This piston provides the seal between reactor vessel pressure and the space above the drive piston. It also functions as a positive end stop at the upper limit of control rod travel. A stack of spring washers just below the stop piston helps absorb the final mechanical shock at the end of control rod travel. The piston rings are similar to the outer drive piston rings. A bleed off passage to the center of the piston tube is located between the two pairs of rings. This arrangement allows seal leakage from the reactor vessel during a scram, to be bled directly to the discharge line, rather than to the space above the drive piston. The lower pair of seals is used only during the cushioning of the drive piston at the upper end of the stroke.

Position Indicator

The center tube of the drive mechanism forms a well to contain the position indicator probe. The position indicator probe is an aluminum extrusion attached to a cast aluminum housing. Mounted on the extrusion are a series of hermetically sealed, magnetically operated, position indicator switches. Each switch is sheathed in a braided glass sleeve, and the entire probe assembly is protected by a thin walled stainless steel tube. The switches are actuated by a ring magnet carried at the bottom of the drive piston. The drive piston, piston tube, and indicator tube are all of nonmagnetic stainless steel, allowing the individual switches to be operated by the magnet as the piston passes. One switch is located at each

position corresponding to an index tube groove, thus allowing indication at each latching point. An additional switch is located at each midpoint between latching points, allowing indication of the intermediate positions during drive motion. Thus, indication is provided for each 3 in of travel. Duplicate switches are provided for the full-in and full-out positions. One additional switch (an overtravel switch) is located at a position below the normal full-out position. Because the limit of down travel is normally provided by the control rod itself as it reaches the backseat position, the index tube can pass this position and actuate the overtravel switch only if it is uncoupled from its control rod. A convenient means is thus provided to verify that the drive and control rod are coupled after installation of a drive or at any time during station operation.

Flange and Cylinder Assembly

A heavy flange is welded to the drive cylinder. A sealing surface on the upper face of this flange is used in making the seal to the drive housing flange. Teflon coated, stainless steel O-rings are used for these seals. In addition to the reactor vessel seal, the two hydraulic control lines to the drive are sealed at this face. A drive can thus be replaced without removing the control lines, which are permanently welded into the housing flange. The drive flange contains the integral ball or two way check (shuttle) valve. This valve is so situated as to direct reactor vessel pressure or driving pressure, whichever is higher, to the underside of the drive piston. Reactor vessel pressure is admitted to this valve from the annular space between the drive and drive housing through passages in the flange. A screen is provided to intercept foreign material at this point.

Water used to operate the collet piston passes between the outer tube and the cylinder tube. The inside of the cylinder tube is honed to provide the surface required for the drive piston seals.

Both the cylinder tube and outer tube are welded to the drive flange. The tops of these tubes have a sliding fit to allow for differential expansion.

Coupling Spud, Plug, Unlocking Tube

The upper end of the index tube is threaded to receive a coupling spud. The coupling (Figure 3.4-3) is designed to accommodate a small amount of angular misalignment between the drive and the control rod. Six spring fingers allow the coupling spud to enter the mating socket on the control rod. The control rod weight is sufficient to force the spud fingers to enter the socket (control rod weight is approximately 250 lb). The lock plug then enters the spud and prevents uncoupling.

With the lock plug in place, a force in excess of 50,000 lb is required to pull the coupling apart.

Two means of uncoupling are provided. With the reactor vessel head removed, the lock plug may be raised against the spring force of approximately 50 lb by a rod extending up through the center of the control rod to an unlocking handle, located above the control rod velocity limiter. The control rod, with the lock plug raised, can then be separated from the drive. The lock plug may also be pushed up from below, if it is desired to uncouple a drive without removing the reactor pressure vessel head for access. In this case, the central portion of the drive mechanism is pushed up against the uncoupling rod assembly which raises the lock plug, and allows the coupling spud to disengage the socket as the drive piston and index tube are driven down.

The coupling spud and locking tube thus meet the requirements of safety design basis 3.e.

3.4.5.2.2 Materials of Construction

Factors determining the choice of materials are listed below:

1. The index tube must withstand the locking and unlocking action of the collet fingers. A compatible bearing combination must be provided which is able to withstand moderate misalignment forces. The reactor environment limits the choice of materials suitable for corrosion resistance. The column and tensile loads can be satisfied by an annealed 300 series stainless steel. The wear and bearing requirements are provided by Malcomizing the completed tube, or by using ASTM A479 Grade XM-19 stainless steel. To obtain suitable corrosion resistance, a carefully controlled process of surface preparation is employed

2. The coupling spud is made of Inconel 750 which is aged to produce maximum physical strength and also provide the required corrosion resistance. As misalignment tends to produce a chafing in the semispherical contact area, the entire part is protected by a thin vapor deposited chromium plating (Electrolizing). This plating also serves to prevent galling of the threads attaching the coupling spud to the index tube

3. Inconel 750 is used for the collet fingers, which must function as leaf springs when cammed open to the unlocked position. Colmonoy 6 hard facing is applied to the area contacting the index tube, and unlocking cam surface of the guide cap to provide a long wearing surface adequate for design life

4. Graphitar 14 is selected for seals and bushings on the drive piston and stop piston. The material is inert and has a low friction coefficient when water lubricated. Since loss of strength is experienced at higher temperatures, the drive is supplied with cooling water to hold temperatures below 250°F. The Graphitar is

relatively soft, which is advantageous when an occasional particle of foreign matter reaches a seal. The resulting scratches in the seal reduce sealing efficiency until worn smooth, but the drive design can tolerate considerable water leakage past the seals into the reactor vessel

All drive components exposed to reactor vessel water are made of AISI 300 series stainless steel except the following:

1. Seals and bushings on the drive piston and stop piston are Graphitar 14

2. All springs and members requiring spring action (collet fingers, coupling spud, and spring washers) are made of Inconel 750

3. The ball check valve employs a Haynes Stellite cobalt base alloy

4. Elastomeric O-ring seals are ethylene propylene

5. Collet piston rings are Haynes 25 alloy

6. Certain wear surfaces are hard faced with Colmonoy 6

7. Nitriding by a proprietary new Malcomizing process, electrolizing (a vapor deposition of chromium), and chromium plating or ASTM A479 Grade XM-19 stainless steel are used in certain areas where resistance to abrasion is necessary

8. The drive piston head is made of Armco 17-4Ph

Pressure containing portions of the drives are designed and built in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code.

3.4.5.3 Control Rod Drive Hydraulic System

The CRD Hydraulic System supplies and controls the pressure and flow requirements to the drives. See Figure 3.4-9 (Drawing M250).

There is one supply subsystem which supplies water at the proper pressures and sufficient flow to the hydraulic control units (HCUs). Each HCU controls the flow to and from a drive. The water discharged from the drives during a scram flows through the HCUs to the scram discharge volume. The water discharged from a drive during a normal control rod positioning operation flows through its HCU and returns it to the reactor vessel by backflow through the 121 valves of other CRD HCUs.

3.4.5.3.1 CRD Hydraulic Supply and Discharge Subsystems

The CRD hydraulic supply and discharge subsystems control the

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

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

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

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

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

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

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

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

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

Pumps

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

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

Filters

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

Accumulator Charging Pressure

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

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

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

Drive Water Pressure

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

A flow rate of approximately 6 gpm (the sum of the flow rates required to insert and to withdraw a control rod) normally passes from the drive water pressure header through two solenoid operated stabilizing valves (arranged in parallel) and, then to the cooling water supply header down steam of the drive water pressure control

valve. One stabilizing valve passes flow equal to the drive insert flow. The other passes flow equal to the drive withdrawal flow. The appropriate stabilizing valve is closed when operating a drive to divert the required flow to the drive. Thus, the flow through the drive pressure control valve is always constant.

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

Cooling Water Pressure

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

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

Exhaust Water Header

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

Scram Discharge Volume

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

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

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

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

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

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

3.4.5.3.2 Hydraulic Control Units

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

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

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

Insert Drive Valve

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

Insert Exhaust Valve

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

Withdrawal Drive Valve

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

Withdrawal Exhaust Valve

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

Speed Control Valves

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

Scram Pilot Valves

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

Scram Inlet Valve

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

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

Scram Exhaust Valve

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

Scram Accumulator

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

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

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

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

3.4.5.4 Control Rod Drive System Operation

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

Rod Insertion

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

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

Rod Withdrawal

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

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

Rod Scram

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

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

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

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

3.4.6 Safety Evaluation

3.4.6.1 Evaluation of Control Rods

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

3.4.6.2 Evaluation of Control Rod Velocity Limiter

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

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

1. The rod to drive coupling fails.

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

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

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

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

3.4.6.3 Evaluation of Scram Time

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

3.4.6.4 Analysis of Malfunctions Relating to Rod Withdrawal

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

1. Drive Housing Fails At Attachment Weld

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

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

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

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

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

   (a) Pressure Under Line Breaks

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

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

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

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

(b) Pressure Over Line Breaks

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

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

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

3. All Drive Flange Bolts Fail in Tension

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

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

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

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

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

4. Weld Joining Flange to Housing Fails in Tension

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

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

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

5. Housing Wall Ruptures

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

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

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

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

6. Flange Plug Blows Out

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

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

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

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

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

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

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

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

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

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

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

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

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

9. Hydraulic Control Unit Valve Failures

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

10. Failure of the Collet Fingers to Latch

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

11. Withdrawal Speed Control Valve Failure

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

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

3.4.6.5 Scram Reliability

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

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

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

3.4.6.6 Control Rod Support and Operation

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

3.4.7 Inspection and Testing

3.4.7.1 Development Tests

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

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

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

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

3.4.7.2 Factory Quality Control Tests

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

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

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

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

CRD Mechanism Tests

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

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

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

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

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

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

Hydraulic Control Unit Tests

Each HCU receives the following tests:

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

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

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

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

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

3.4.7.3 Operational Tests

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

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

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

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

3.4.8 Deleted

3.4.9 Operational Nuclear Safety Requirements

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

3.4.10 References

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

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

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

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

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

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

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

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

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

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

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

12. GE Licensing Topical Report NEDE-333284P-A, Supplement 1P-A Revision 1, "Marathon-Ultra Control Rod Assembly".

Figure 3.4-1 has been deleted

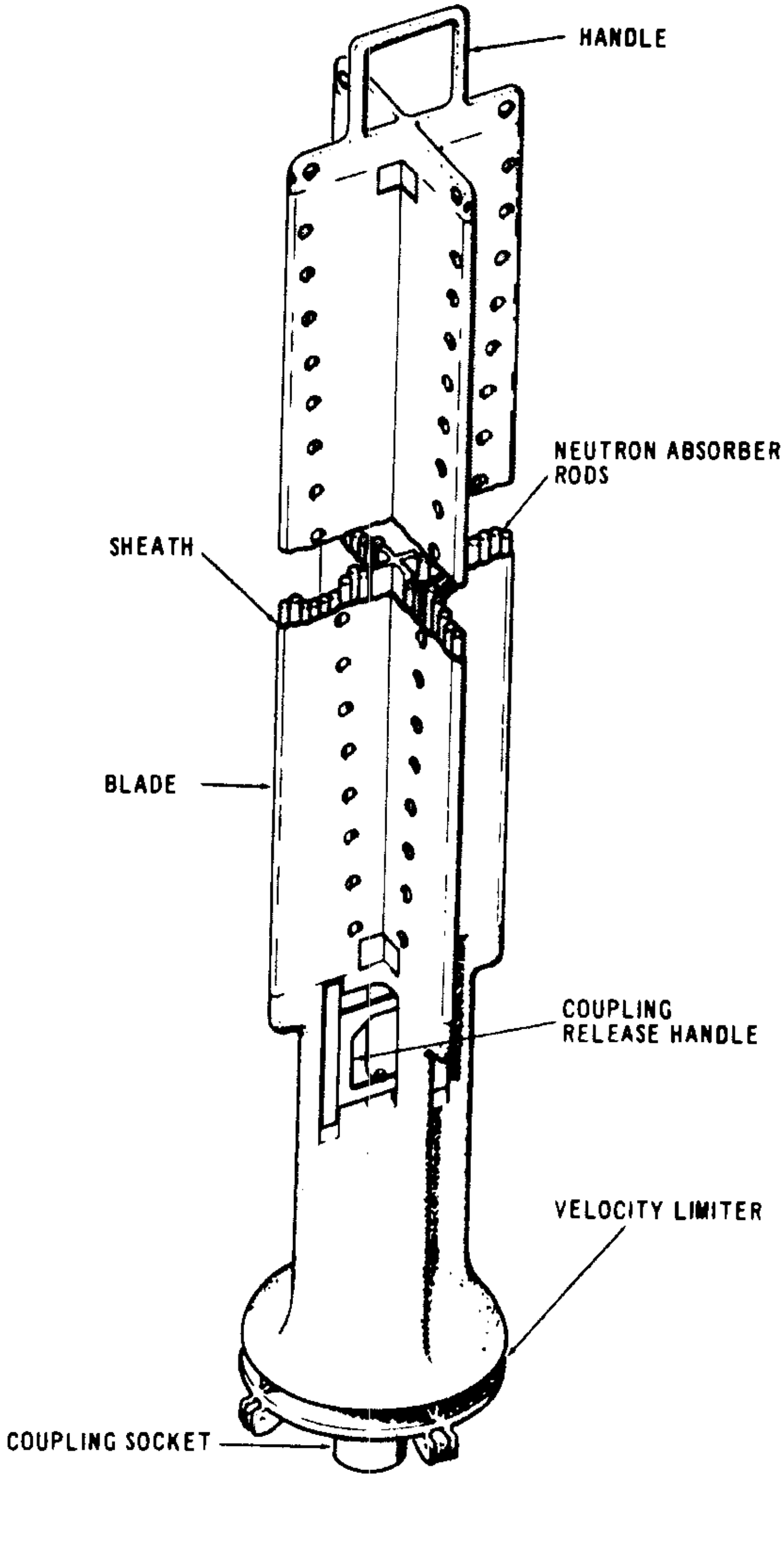


FIGURE 3.4-2
CONTROL ROD-ISOMETRIC
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

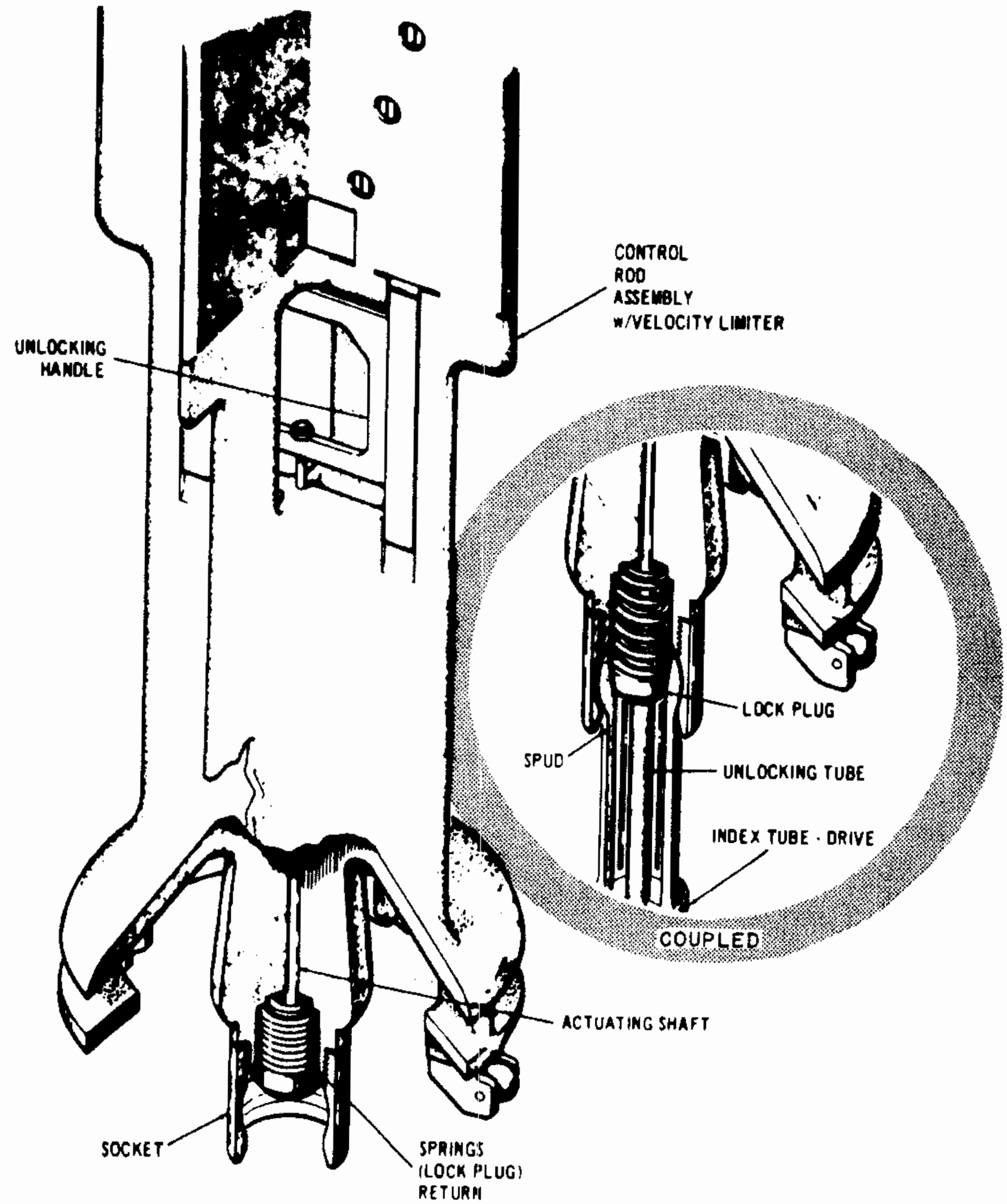


FIGURE 3.4-3
CONTROL ROD TO CONTROL ROD
DRIVE COUPLING - ISOMETRIC
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

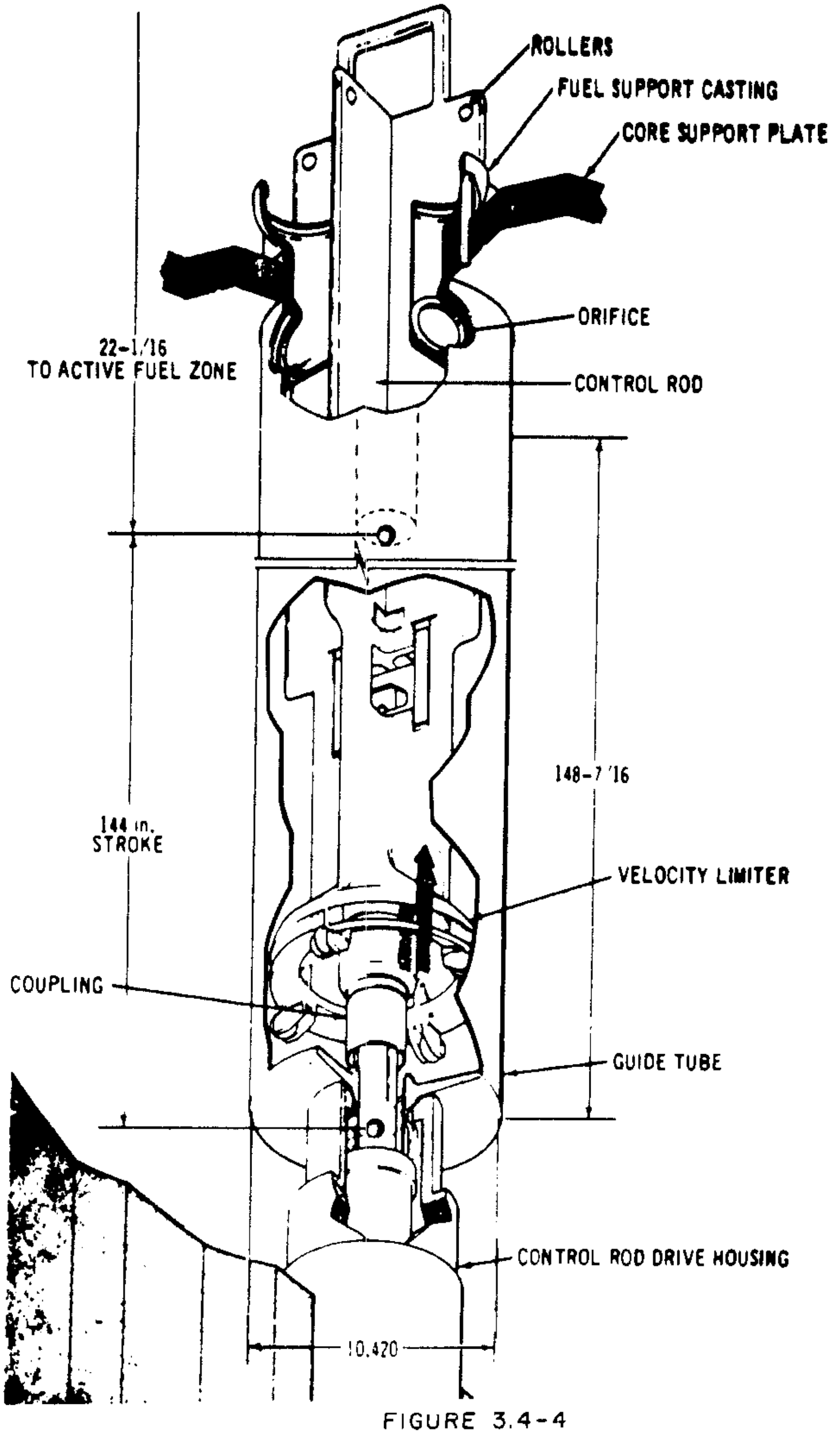


FIGURE 3.4-4
CONTROL ROD VELOCITY LIMITER
ISOMETRIC
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

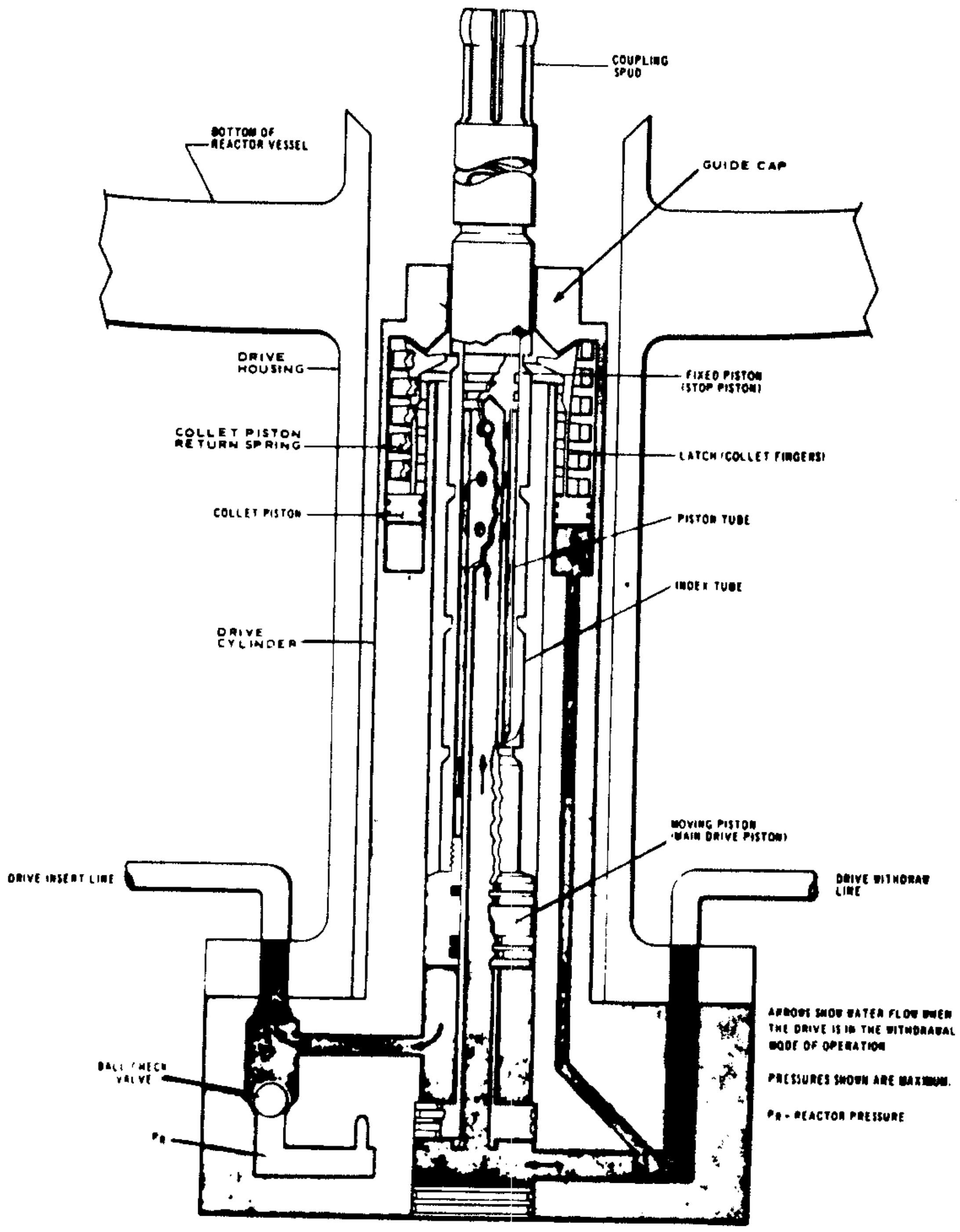


FIGURE 3. 4-5

CONTROL ROD DRIVE, SIMPLIFIED COMPONENT ILLUSTRATION

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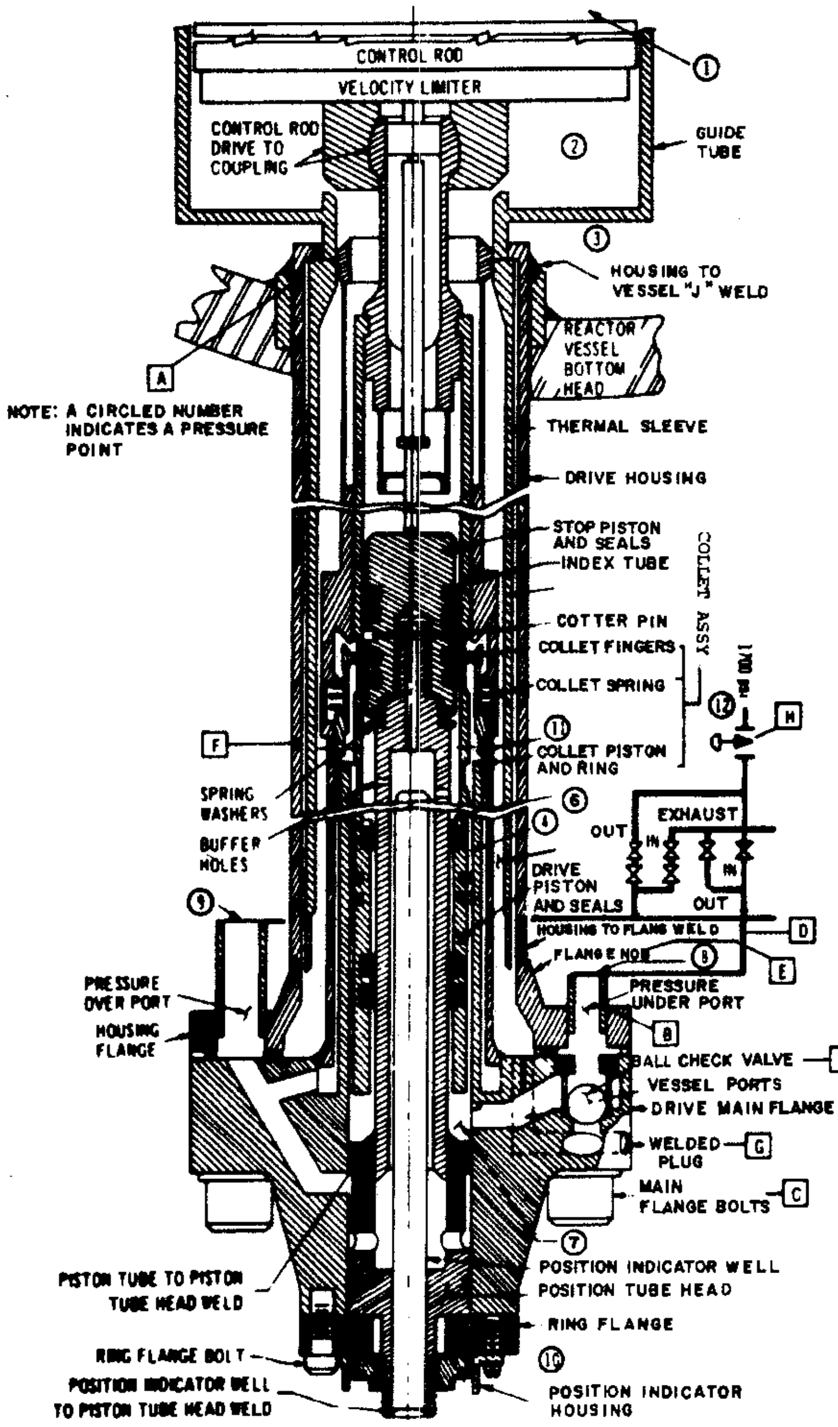

FIGURE 3.4-6
CONTROL ROD DRIVE
SCHEMATIC DIAGRAM
PILGRIM NUCLEAR POWER STATION
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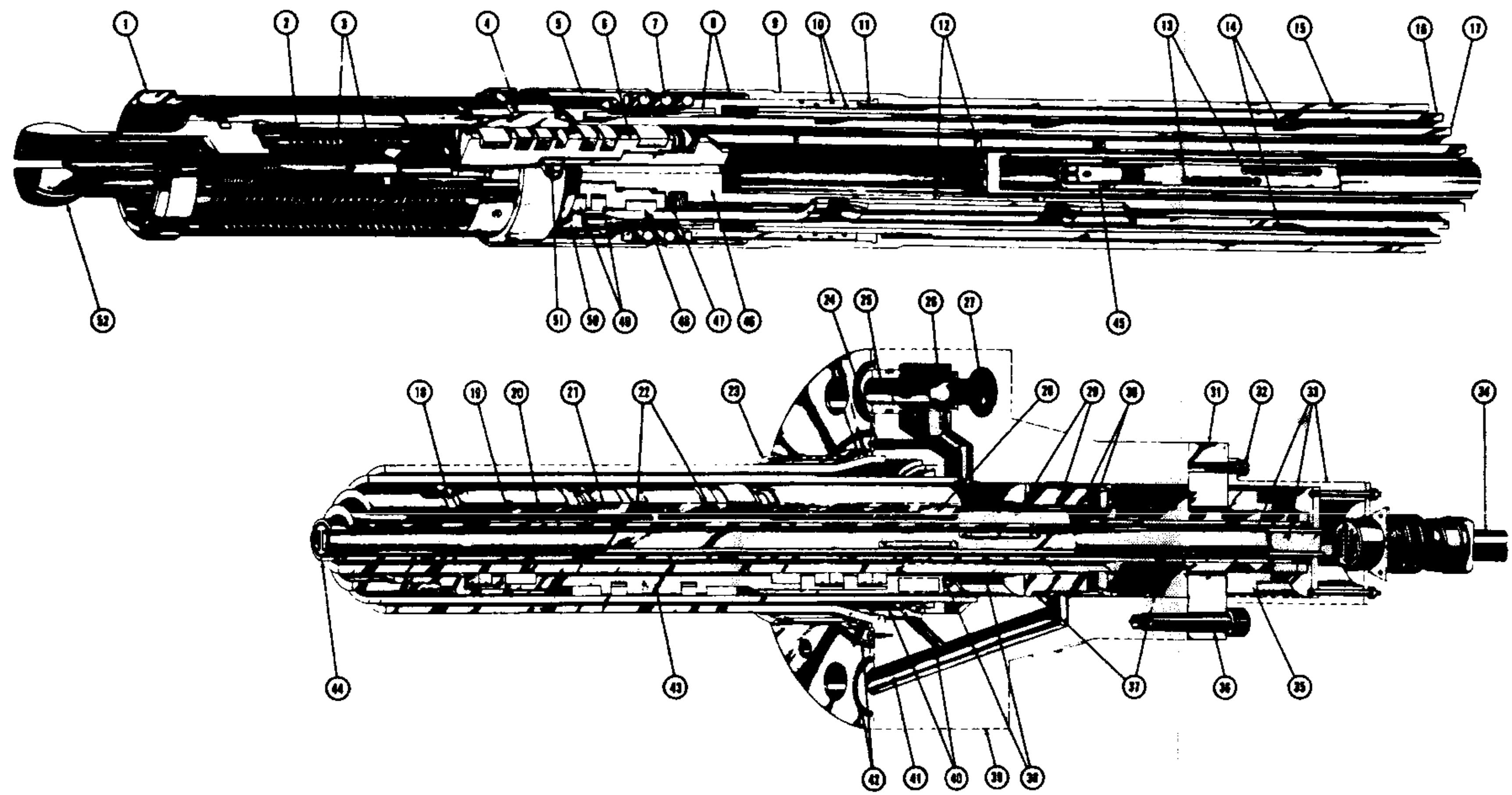

1. EXTERNAL FILTER ASSEMBLY
2. INTERNAL FILTER ASSEMBLY
3. UNCOUPLING ROD ASSEMBLY
4. GUIDE CAP
5. BARREL
6. STOP PISTON
7. COLLET SPRING
8. COLLET AND COLLET PISTON
9. COLLET HOUSING (PART OF CYLINDER, TUBE, AND FLANGE)
10. COLLET PISTON SEALS
11. SPACER (PART OF CYLINDER, TUBE, AND FLANGE)
12. BUFFER ORIFICES (TYPICAL)
13. PISTON INDICATOR SWITCHES (TYPICAL)
14. LOCKING GROOVE (TYPICAL)
15. OUTER TUBE (PART OF CYLINDER, TUBE, AND FLANGE)
16. CYLINDER TUBE
17. INDEX TUBE
18. LOCKING BAND (TYPICAL)
19. INTERNAL PISTON SEAL RINGS (TYPICAL)
20. INTERNAL PISTON BUSHINGS (TYPICAL)
21. EXTERNAL PISTON BUSHINGS
22. EXTERNAL PISTON SEALS
23. STRAINER
24. COOLING WATER ORIFICE
25. DRIVE - INSERT WATER INLET
    (NORMAL AND SCRAM, DRIVE - WITHDRAWAL OUTLET)
26. BALL - SHUTTLE VALVE
27. REACTOR WATER INLET (THROUGH DRIVE HOUSING)
28. SWITCH - ACTUATING MAGNET (PART OF DRIVE PISTON)
29. PISTON TUBE ASSEMBLY
30 DRIVE - WITHDRAW PORTS AND ANNULUS
    (ALSO SCRAM OUTLET)
31. RING FLANGE
32. MACHINE SCREW (TYPICAL)
33. POSITION INDICATOR PROBE
34. POSITION INDICATOR CABLE
35. PISTON TUBE NUT
36. CAP SCREW (TYPICAL)
37. O-RING SEALS
38. DRIVE - INSERT PORTS AND ANNULUS
39. DRIVE FLANGE (PART OF CYLINDER, TUBE, AND FLANGE)
40. UNLOCKING PORT AND ANNULUS
    (WITHDRAW PRESSURE TO COLLET PISTON)
41. DRIVE - WITHDRAW WATER INLET
    (ALSO OUTLET FOR SCRAM WATER)
42. METAL O-RING SEAL (DRIVE TO HOUSING)
43. DRIVE PISTON
44. INDICATOR TUBE (PART OF PISTON TUBE)
45. THERMOCOUPLE (PART OF POSITION INDICATOR PROBE)
46. STUD (PART OF PISTON TUBE)
47. SPRING WASHERS
48. STOP PISTON BUSHINGS (TYPICAL)
49. STOP PISTON SEAL RINGS (TYPICAL)
50. COLLET FINGER (TYPICAL)
51. COTTER PIN
52. COUPLING SPUD

FIGURE 3.4-7
CONTROL ROD UNIT DRIVE CUTAWAY ILLUSTRATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

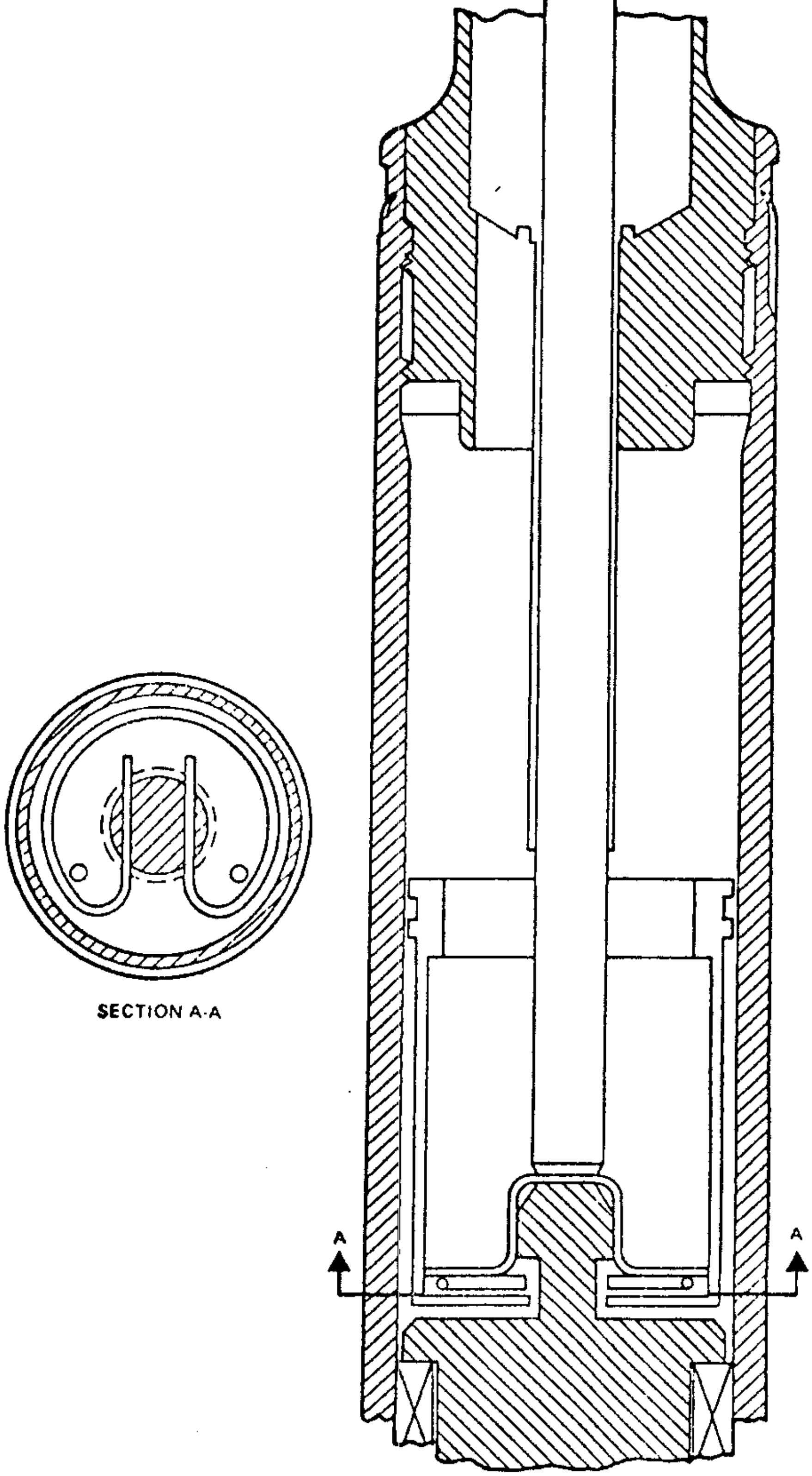

FIGURE 3.4-8

INNER FILTER ARRANGEMENT

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 3.4-9 and 3.4-10 have been removed

Please refer to BECo Controlled Drawings M250 and M1D12-4.

Figure 3.4-11 has been deleted

See Figure 3.4-10

NOTE: Figure 3.4-12 has been deleted

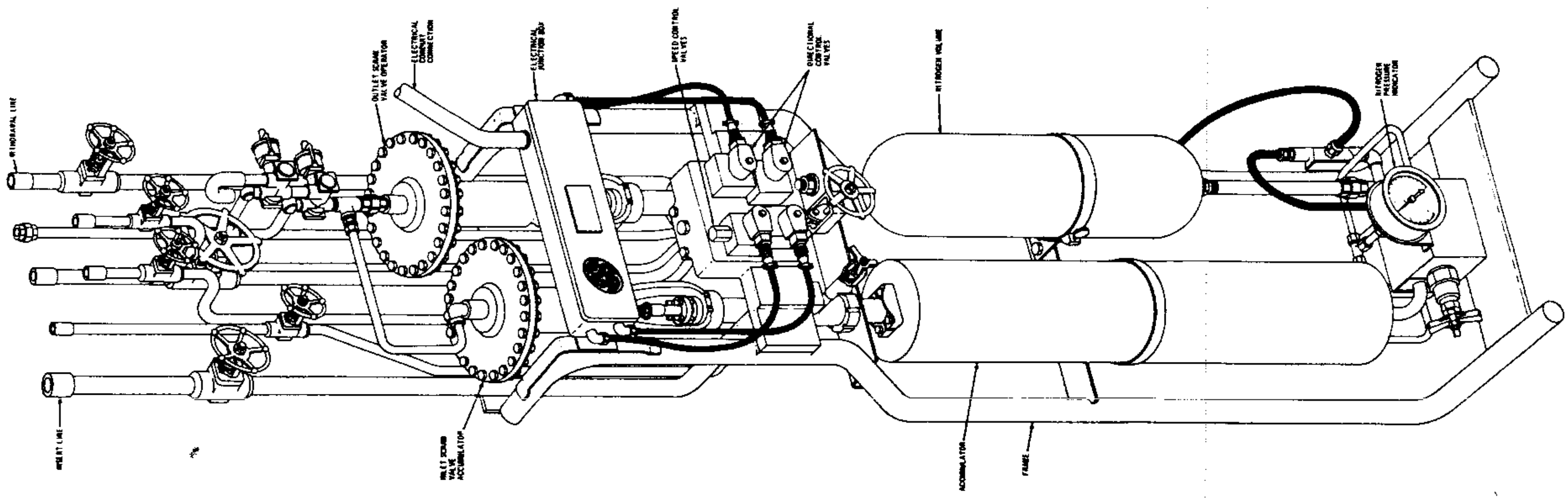

FIGURE 3.4-13
CONTROL ROD HYDRAULIC CONTROL UNIT, ISOMETRIC

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

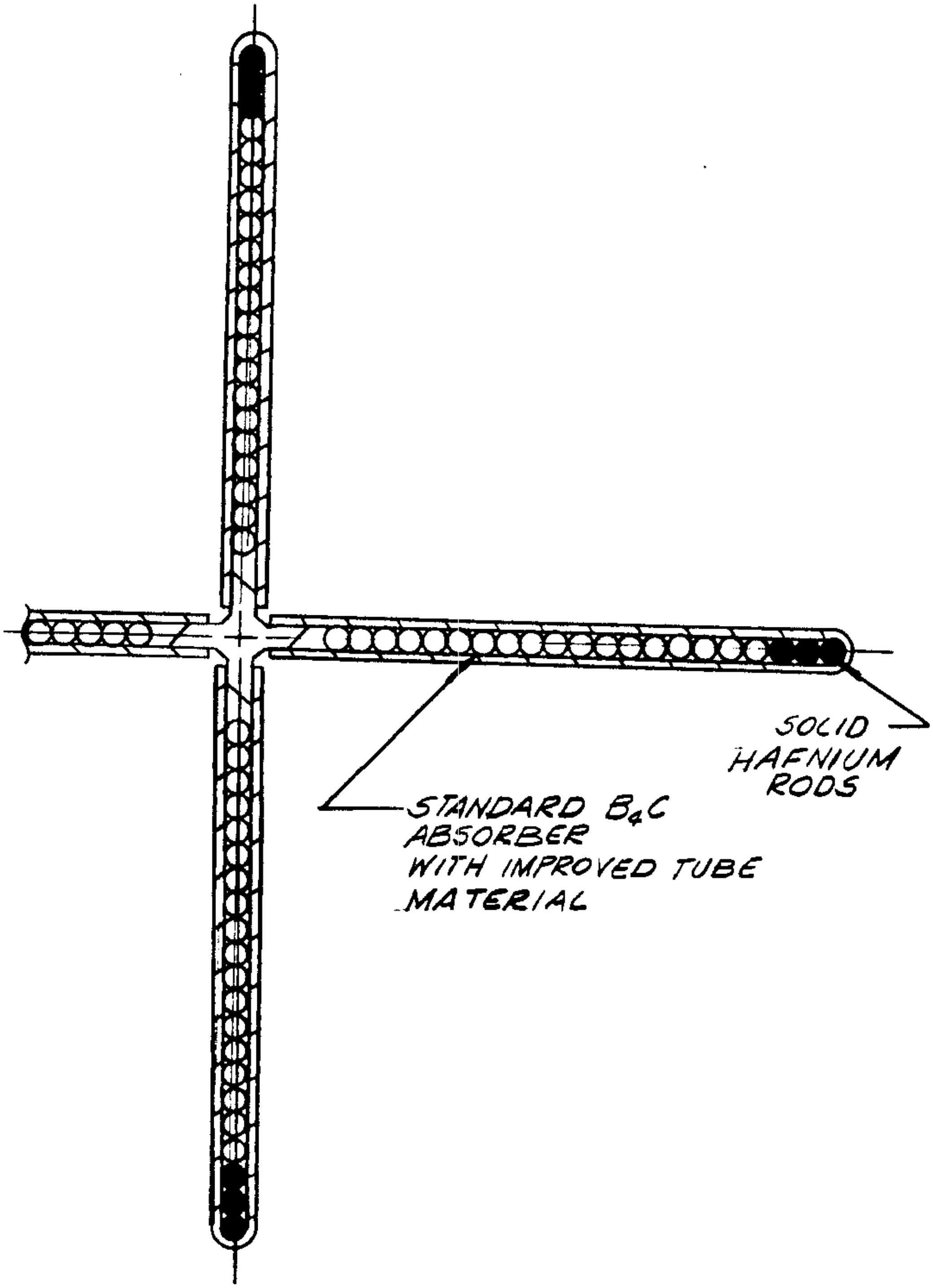

FIGURE 3.4-14
HYBRID CONTROL ROD BLADE DESIGN
PILGRIM NUCLEAR POWER STA.
FINAL SAFETY ANAL. REPORT

REVISION 9— JULY 1988

Figure 3.4-15 has been removed.

Please refer to BECo Controlled Drawing M1D-86.

3.5 CONTROL ROD DRIVE HOUSING SUPPORTS

3.5.1 Safety Objective

The Control Rod Drive (CRD) housing supports limit additional damage to the nuclear system process barrier, or damage to the fuel barrier, by preventing any significant nuclear transients in the event a drive housing breaks or separates from the bottom of the reactor vessel.

3.5.2 Safety Design Basis

1. Control rod downward motion shall be limited, following a postulated CRD housing failure, so that any resulting nuclear transient could not be sufficient to cause fuel damage.

2. Clearance shall be provided between the housings and the supports to prevent vertical contact stresses due to their respective thermal expansion during plant operation.

3.5.3 Description

The control rod housing supports are illustrated on Figure 3.5-1. Horizontal beams are installed immediately below the bottom head of the reactor vessel, between the rows of control rod housings, and are bolted to brackets which are welded to the steel form liner of the drive room in the reactor support pedestal.

Hanger rods about 10 ft long by 1-3/4 inches in diameter, are supported from the beams on stacks of disc springs which compress about 2 in under the design load.

The support bars are bolted between the bottom ends of the hanger rods. The spring pivots at the top and the beveled loose fitting ends on the support bars prevent substantial bending movement in the hanger rods if the support bars are ever loaded.

Individual grids rest on the support bars between adjacent beams. Because a single piece grid would be difficult to handle in the limited work space and because it is necessary that CRDs, position indicators, and incore instrumentation components be accessible for inspection and maintenance, each grid is designed to be assembled or disassembled in place. Each grid assembly is made from two grid plates, a clamp, and a bolt. The top part of the clamp acts as a guide to assure that each grid is correctly positioned directly below the respective CRD housing which it would support in the postulated accident.

When the support bars and grids are installed, a gap of 1 in at room temperature (approximately 70°F) is provided between the grid and the bottom contact surface of the CRD flange. During system heatup this gap is reduced by a net downward expansion of the housings with respect to the supports. In the hot operating condition, the gap is approximately 1/4 in.

In the postulated CRD housing failure, the CRD housing supports are loaded when the lower contact surface of the CRD flange contacts the grid. The resulting load is then carried by two grid plates, two support bars, four hanger rods, their disk springs, and two adjacent beams.

The American Institute of Steel Construction (AISC) Specification for the Design, Fabrication, and Erection of Structural Steel for Building was used in the design of the CRD housing support system. However, to provide structure that absorbs as much energy as practical without yielding, the allowable tension and bending stresses were taken as 90 percent of yield, and the shear stress as 60 percent of yield. These are 1.5 times the corresponding AISC allowable stresses of 60 percent and 40 percent of yield.

This stress criterion is considered desirable for this application and adequate for the "once in a lifetime" loading condition.

For mechanical design purposes, the postulated failure resulting in the highest forces is an instantaneous circumferential separation of the CRD housing from the reactor vessel, with an internal pressure of 1,250 psig (reactor vessel design pressure) acting on the area of the separated housing. The weight of the separated housing, CRD, and blade, plus the force of 1,250 psig pressure acting on the area of the separated housing gives a force of approximately 35,000 lb. This force is multiplied by a factor of 3 for impact, conservatively assuming the housing travels through a 1 in gap before contacting the supports. The total force (105 lb) is then treated as a static load in design formulas. The CRD housing supports are designed as Class I equipment in accordance with Appendix C.

All CRD housing support subassemblies are fabricated of ASTM-A-36 structural steel, except for the following:

grid	ASTM-A-441
disc springs	Schnorr Type BS-125-71-8
hex bolts and nuts	ASTM-A-307

3.5.4 Safety Evaluation

Downward travel of CRD housing and its control rod following the postulated housing failure is the sum of the compression of the disk springs under dynamic loading, and the initial gap between the grid and the bottom contact surface of the CRD flange. If the reactor were cold and pressurized, the downward motion of the control rod would be limited to the approximate 2 in spring compression plus approximately a 1 in gap. If the reactor were hot and pressurized, the gap would be approximately 1/4 in and the spring compression slightly less than in the cold condition. In either case, the control rod movement following a housing failure is limited substantially below any drive "notch" movement (6 in). The nuclear transient from sudden withdrawal of any control rod through a distance of one drive notch at any position in the core, does not result in a transient sufficient to cause damage to any radioactive

material barrier. This meets the fuel damage limitation of safety design basis 1.

The CRD housing supports are in place any time the reactor is to be operated. The housing supports may be removed when the reactor is in the shutdown condition because all control rods are then inserted. Even if a control rod is ejected under the shutdown condition, the reactor remains subcritical, because it is designed to remain subcritical with any one control rod fully withdrawn at any time.

At plant operating temperature, a gap of approximately 1/4 in is maintained between the CRD housing and the supports; at lower temperatures the gap is greater. Because the supports do not come in contact with any of the CRD housings, except during the postulated accident condition, vertical contact stresses are prevented as required by safety design basis 2.

3.5.5 Inspection and Testing

When the reactor is in the shutdown mode, the CRD housing supports may be removed to permit inspection and maintenance of the CRDs. When the support structure is reinstalled, it is inspected for proper assembly, particular attention being given to assure that the correct gap between the CRD flange lower contact surface and the grid is maintained.

3.5.6 Deleted

3.5.7 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.

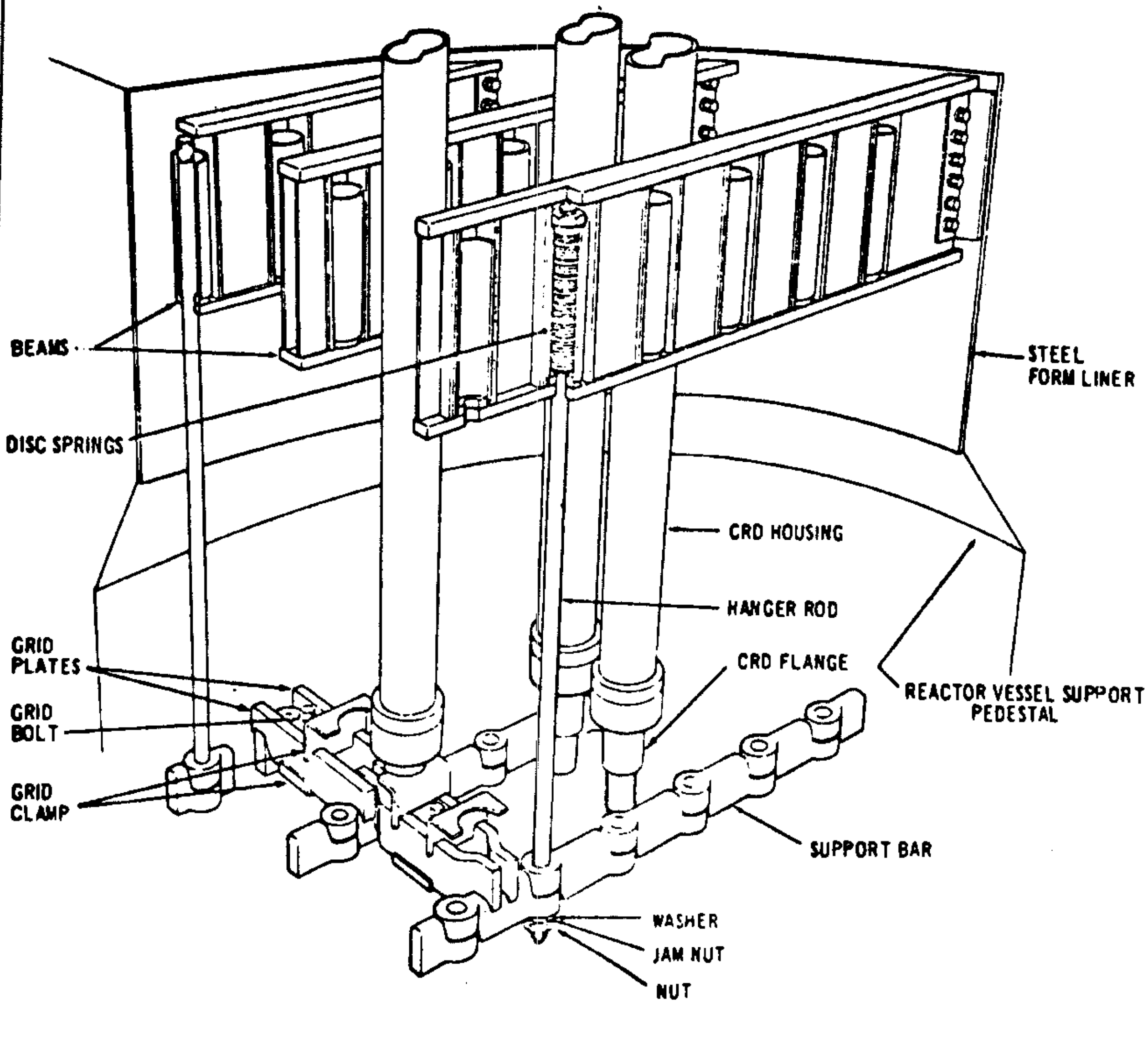

FIGURE 3.5-1
CONTROL ROD DRIVE
HOUSING SUPPORT-ISOMETRIC
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

3.6 NUCLEAR DESIGN

The nuclear core design presented herein is based on the fuel documented in Reference 1. The design bases and licensing requirements are independent of enrichment.

3.6.1 Design Bases

The nuclear design bases are conveniently divided into two specific categories. The safety design bases are those that are required for the plant to operate from safety considerations. The second category is the plant performance design bases that are required in order to meet the objective of producing power in an efficient manner.

3.6.1.1 Safety Design Bases

The safety design bases are requirements which protect the nuclear fuel from a violation of the design integrity limits. In general, the safety bases fall into two categories: (1) the reactivity basis which prevents an uncontrolled positive reactivity excursion, and (2) the overpower bases, which prevents the core from operating beyond the fuel integrity limits.

3.6.1.1.1 Reactivity Basis

The nuclear design shall meet the following basis: The core shall be capable of being rendered subcritical at any time or at any core conditions with the highest worth control rod fully withdrawn.

3.6.1.1.2 Overpower Bases

The Technical Specification limits on Linear Heat Generation Rate (LHGR), Minimum Critical Power Ratio (MCPR), and the Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) shall not be exceeded during steady-state operation.

3.6.1.2 Plant Performance Design Bases

The nuclear design shall meet the following bases:

(1) The design shall provide adequate excess reactivity to attain the desired cycle length.

(2) The design shall be capable of operating at rated conditions without exceeding Technical Specification limits.

(3) The nuclear design and the reactivity control system shall allow continuous, stable regulation of reactivity.

(4) The nuclear design shall have adequate reactivity feedback to facilitate normal operation.

(5) Core nuclear design analyses results are used as inputs to the core transient and stability analyses and do not have separate limits.

3.6.2 Description

The boiling water reactor (BWR) core design utilizes a light-water moderated reactor, fueled with slightly enriched uranium dioxide. The use of water as a moderator produces a neutron energy spectrum in which fissions are caused principally by thermal neutrons. At normal operating conditions, the moderator boils, producing a spatially variable distribution of steam voids in the core. The BWR design provides a system for which reactivity changes are inversely proportional to the steam void content in the moderator. This void feedback effect is one of the inherent safety features of the BWR system. Any system input which increases reactor power, either in a local or gross sense, produces additional steam voids which reduce reactivity and thereby reduce the power.

3.6.2.1 Nuclear Design Description

The reference core loading pattern is the basis for all fuel licensing. This loading plan is contained in the supplemental reload licensing report for the Pilgrim Nuclear Power Station, which can be found in Appendix Q. The bundle and lattice designations for the fuel enrichments used in the core loading plan are given in Reference 1. Additionally, uranium dioxide and gadolinia distributions for bundle enrichment, typical lattice nuclear characteristics, and steady-state core characteristics can also be found in Reference 1.

3.6.2.2 Power Distribution

The local peaking, gross, radial, axial, and total peaking factors are design parameters related to core analysis. These peaking factors do not constitute a limiting condition, but help determine, directly or indirectly, the thermal performance parameters such as Maximum Linear Heat Generation Rate (MLHGR), Minimum Critical Power Ratio (MCPR), and Maximum Average Planar Linear Heat Generation Rate (MAPLHGR). These peaking factors are discussed in Reference 1.

3.6.2.2.1 Power Distribution Calculations

A full range of power distributions along with the resultant exposure shapes and the corresponding control rod patterns are calculated. Sample distributions are shown in Appendix 4A of Reference 4.

3.6.2.2.2 Power Distribution Measurements

The techniques for a measurement of the power distribution within the reactor core, together with instrumentation correlations and operation limits, are discussed in Reference 2.

3.6.2.2.3 Power Distribution Accuracy

The accuracy of the calculated power distributions is discussed in Reference 1.

3.6.2.2.4 Power Distribution Anomalies

Stringent inspection procedures are utilized to ensure the correct rearrangement of the core following refueling. Although a misplacement of a bundle in the core would be a very improbable event, calculations have been performed in order to determine the effects of such accidents on linear heat generation rate (LHGR) and critical power ratio (CPR). These results are presented in Section 14.

The inherent design characteristics of the BWR are well suited to limit gross power tilting. The stabilizing nature of the large moderator void coefficient effectively reduces perturbations in the power distribution. In addition, the in-core instrumentation system, together with the on-line computer, provides the operator with prompt information on power distribution so that he can readily use control rods or other means to limit the undesirable effects of power tilting. Because of these design characteristics, it is not necessary to allocate a specific margin in the peaking factor to account for power tilt. If, for some reason, the power distribution could not be maintained within normal limits using control rods, then the operating power limits would have to be reduced as prescribed in the Technical Specifications.

3.6.2.3 Reactivity Coefficients

Reactivity coefficients, the differential changes in reactivity produced by differential changes in core conditions, are useful in calculating relative stability and evaluating response of the core to external disturbances. The base initial condition of the system and the postulated initiating event determine which of the several defined coefficients are significant in evaluating the response of the reactor.

There are two primary reactivity coefficients that characterize the dynamic behavior of boiling water reactors over all operating states. These are the Doppler reactivity coefficient and the moderator void reactivity coefficient. Also associated with the BWR is a power reactivity coefficient and a fuel temperature coefficient. However, the power coefficient is just a combination of the Doppler and void reactivity coefficients in the power operating range and the fuel temperature coefficient is merely a combination of the Doppler and moderator temperature coefficients. Because these two quantities provide only redundant information, they are no longer calculated for the reload cores.

The Doppler coefficient is of prime importance in reactor safety. The Doppler coefficient is a measure of the reactivity change associated with an increase in the absorption of resonance-energy neutrons caused by a change in the temperature of the material in question. The Doppler reactivity coefficient provides instantaneous negative reactivity feedback to any rise in fuel temperature, on either a gross or local basis. The magnitude of the Doppler coefficient is inherent in the fuel design and does not vary significantly among BWR designs having low fuel enrichment. For most structural and moderator materials, this effect is not significant, but in U-238 and Pu-240 an increase in temperature produces a comparatively large increase in the absorption cross-section. The resulting non-parasitic fission absorption of neutrons causes a significant loss in reactivity. In BWR fuel, in which approximately 98% of the uranium in UO_2 is U-238, the Doppler coefficient provides an immediate reactivity response that opposes fuel fission rate changes.

Although the reactivity change caused by the Doppler effect is small compared to other power-related reactivity changes during normal operation, it becomes very important during postulated rapid power excursions in which large fuel temperature changes occur. The most severe power excursions are those associated with rod drop accidents. A local Doppler feedback associated with a 3000°F to 5000°F temperature rise is available for terminating the initial excursion.

The most important of the reactivity effects is the void reactivity effect. The void coefficient must be large enough to prevent power oscillation due to spatial xenon changes yet small enough that pressurization transients do not unduly limit plant operation. In addition, the void coefficient in a BWR has the ability to flatten the radial power distribution and to provide ease of reactor control due to the void feedback mechanism. The overall void coefficient is always negative over the complete operating range since the BWR design is undermoderated. The reactivity change due to the formation of voids results from the reduction in neutron slowing down due to the decrease in the water-to-fuel ratio.

The moderator temperature coefficient is not a significant reactivity coefficient because its effect is limited to primarily the reactor startup range. Once the reactor reaches the power producing range, boiling begins and the moderator temperature remains essentially constant. As with the void coefficient, the moderator temperature coefficient is associated with a change in the moderating power of the water. The temperature coefficient is negative during power operation.

Further discussion of the reactivity coefficients can be found in Reference 1.

3.6.2.4 Control Requirements

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

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

3.6.2.4.1 Shutdown Reactivity

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

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

3.6.2.4.2 Reactivity Variations

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

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

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

3.6.2.5 Control Rod Patterns and Reactivity Worths

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

Scram reactivity is calculated as described in Reference 1.

3.6.2.6 Criticality of Reactor During Refueling

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

3.6.2.7 Stability

3.6.2.7.1 Xenon Transients

Boiling water reactors do not have instability problems due to xenon. This has been demonstrated by operating BWRs for which xenon instabilities have never been observed (such instabilities would readily be detected by the LPRM's) by special tests which have been conducted on operating BWRs in an attempt to force the reactor into xenon instability, and by calculations. All of these indicators have proven that xenon transients are highly damped in a BWR due to the large negative power coefficient.

Analysis and experiments conducted in this area are reported in Reference 3.

3.6.2.7.2 Thermal Hydraulic Stability

This subject is covered in Subsection 3.7.4.6.

3.6.2.8 Vessel Irradiations

The neutron fluence calculations at the vessel are discussed in Subsection 4.2, Reactor Vessel and Appurtenances Mechanical Design.

3.6.3 Analytical Methods

The analytical methods and nuclear data used to determine the nuclear characteristics are provided in Reference 1. Qualification of these models is also described.

3.6.4 Changes

General Electric fuel design philosophy is based on three principles: (1) standardization, (2) evolution; and (3) test before use. This process has resulted in a series of fuel designs. Details of these designs are provided in Reference 1.

3.6.5 References

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

2. J. F. Carew, "Process Computer Performance Evaluation Accuracy," June 1974 (NEDO-20340).

3. R. L. Crowther, "Xenon Considerations in Design of Boiling Water Reactors," June 1968 (APED-5640).

4. "GESSAR II - 238 Nuclear Island," 22A7007 (Rev. 5).

3.7 THERMAL AND HYDRAULIC DESIGN

3.7.1 Design Basis

3.7.1.1 Safety Design Bases

Thermal-hydraulic design of the core shall establish:

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

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

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

3.7.1.2 Power Generation Design Bases

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

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

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

3.7.1.3 Requirements for Steady-State Conditions

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

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

3.7.1.4 Requirements for Transient Conditions

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

3.7.1.5 Summary of Design Bases

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

3.7.2 Description of Thermal-Hydraulic Design of the Reactor Core

3.7.2.1 Summary Comparison

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

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

3.7.2.2 Critical Power Ratio

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

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

3.7.2.3 Linear Heat Generation Rate (LHGR)

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

3.7.2.4 Void Fraction Distribution

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

3.7.2.5 Core Coolant Flow Distribution and Orificing Pattern

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

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

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

3.7.2.6 Core Pressure Drop and Hydraulic Loads

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

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

3.7.2.7 Correlation and Physical Data

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

3.7.2.8 Thermal Effects of Operational Transients

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

3.7.2.9 Uncertainties in Estimates

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

3.7.2.10 Flux Tilt Considerations

For flux tilt considerations, refer to Subsection 3.6.2.2.4.

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

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

3.7.3.1 Plant Configuration Data

Reactor coolant system geometric data is provided in Section 4.

3.7.3.2 Operating Restrictions on Pumps

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

3.7.3.3 Power-Flow Operating Map

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

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

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

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

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

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

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

These regions are illustrated on Figures 3.7-1. See also the discussion in Section 3.7.4.6 and References 8 through 12. Froom Cycle 19 oonwards, the use flow clamp is not required. Also, the ATWS analysis became Cycle independent again and did noot require P-F map restrictions too meet ATWS analysis criteria. Ref. 18 and Cycle 20 SRLR doocument these conclusions.

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

3.7.3.4 Temperature-Power Operating Map (PWR)

Not applicable.

3.7.3.5 Load-Following Characteristics

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

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

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

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

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

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

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

2. Load following with recirculation flow control.

3. Strong damping of spatial power disturbances.

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

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

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

3.7.3.6 Thermal and Hydraulic Characteristics Summary Table

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

3.7.4 Evaluation

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

3.7.4.1 Critical Power

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

3.7.4.2 Core Hydraulics

Core hydraulic models and correlations are discussed in Reference 1.

3.7.4.3 Influence of Power Distributions

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

3.7.4.4 Core Thermal Response

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

3.7.4.5 Analytical Methods

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

3.7.4.6 Thermal-Hydraulic Stability Analysis

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

mid-range frequency (≈0.5 to ≈2 Hz) components of the total signal "noise".

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

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

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

under conditions of reduced coolant flow. The various phenomena of thermo hydraulic instability are described in NUREG/CR-6003 (Reference 7).

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

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

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

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

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

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

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

3.7.5 Testing and Verification

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

3.7.6 Instrumentation Requirements

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

3.7.7 References

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 3.7-1

THERMAL AND HYDRAULIC ANALYSIS PARAMETERS
FROM RELOAD LICENSING ANALYSIS

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

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

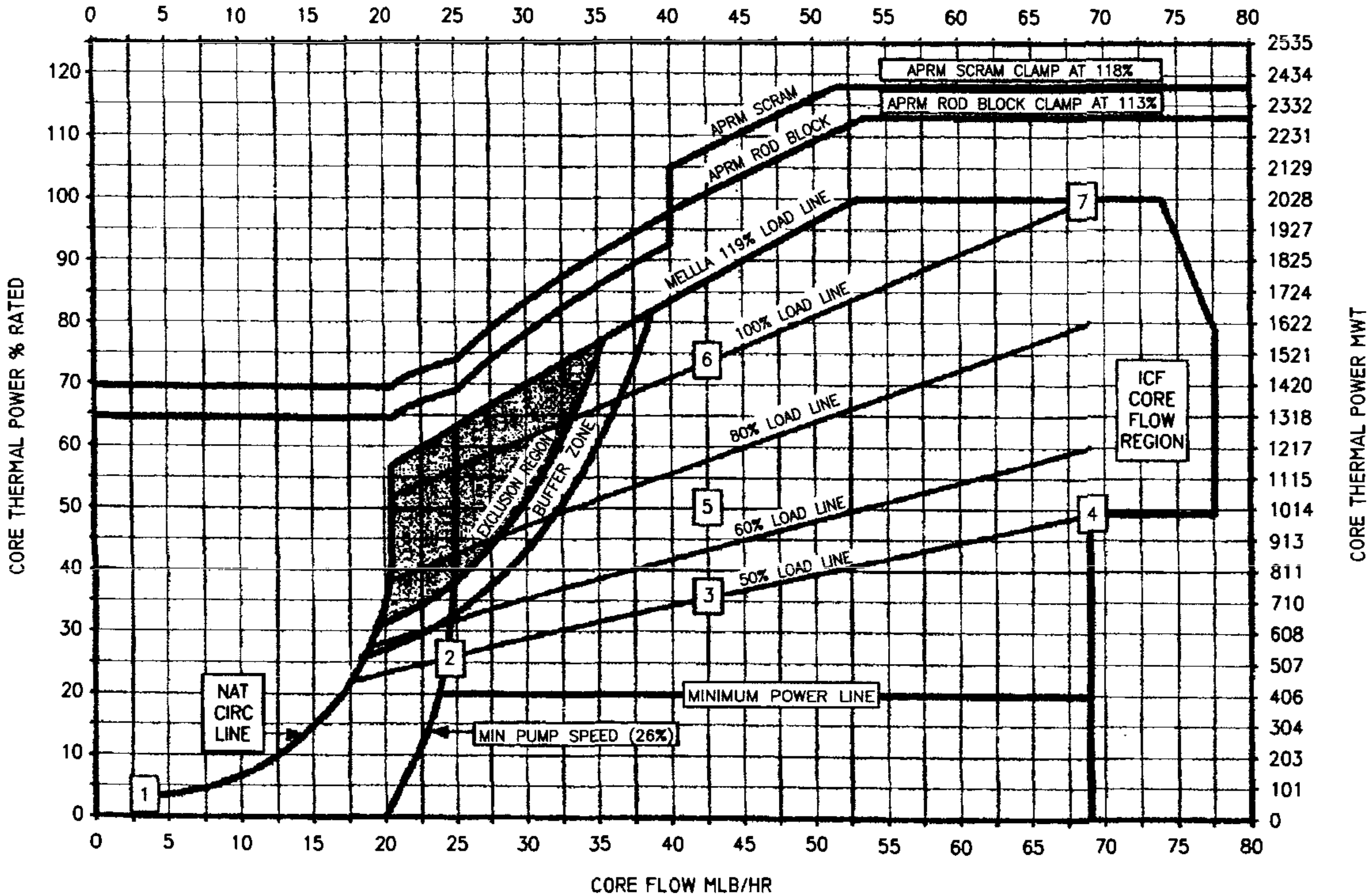

FIGURE 3.7-1
POWER / FLOW OPERATING MAP
FINAL SAFETY ANALYSIS REPORT
PAGE 1 OF 1

Figure 3.7-2 has been removed

3.8 STANDBY LIQUID CONTROL SYSTEM

3.8.1 Safety Objective

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

3.8.2 Safety Design Basis

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

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

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

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

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

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

3.8.3 Description

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.8.4 Safety Evaluation

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

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

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

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

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

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

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

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

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

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

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

3.8.5 Inspection and Testing

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

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

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

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

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

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

3.8.6 Compliance with 10CFR50.62

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

3.8.7 Current Operational Nuclear Safety Requirements

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

3.8.8 References

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

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

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

Figures 3.8-1 and 3.8-2 have been removed.

Please refer to BECo Controlled Drawings M 249 and M1F2-3 .

Figure 3.8-3 has been deleted.

Figure 3.8-4 has been removed.

Please refer to BECo Controlled Drawing M1F1-2.

Figure 3.8-5 has been deleted.

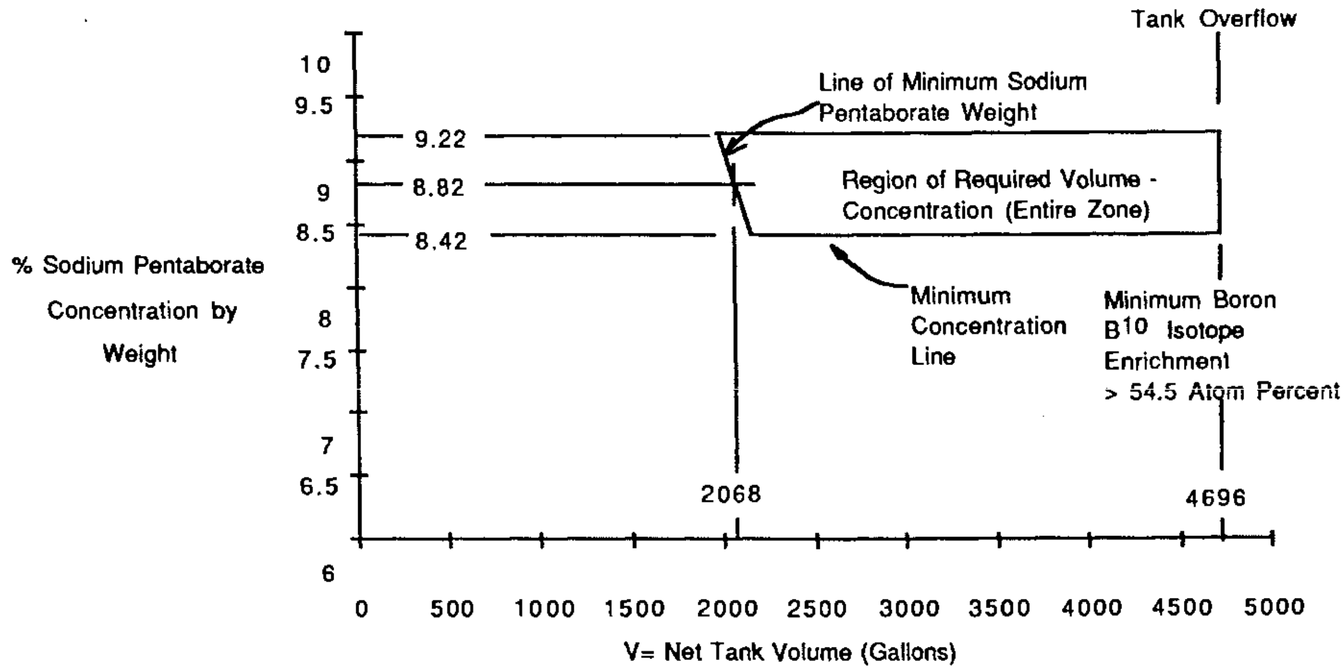

FIGURE 3.8-6

SODIUM PENTABORATE SOLUTION VOLUME and CONCENTRATION REQUIREMENTS

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

3.9.1 Design Objective

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

3.9.2 Design Basis

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

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

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

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

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

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

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

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

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

3.9.3 Description

3.9.3.1 Recirculation Pump Trip System

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

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

3.9.3.2 Alternate Rod Insertion System

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

3.9.3.3 Feedwater Pump Trip System

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

3.9.3.4 System Trip Logic

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

3.9.4 References

1. Deleted.

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

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

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

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

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

Figures 3.9-1, 3.9-2 and 3.9-3 have been removed
Please refer to BECo Controlled *Drawings M1Y-4, M1Y-6 and* M1Y-9

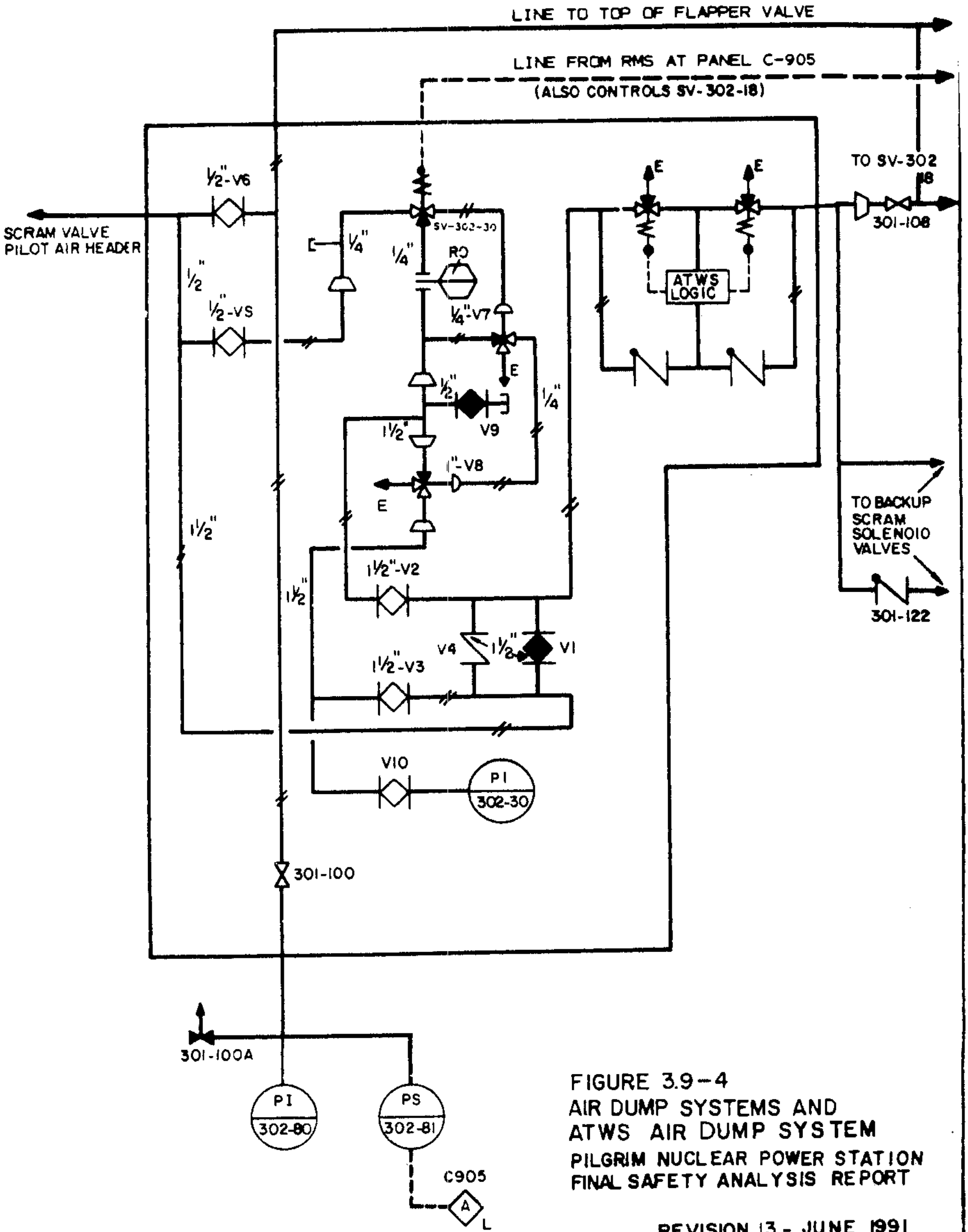

FIGURE 3.9-4
AIR DUMP SYSTEMS AND
ATWS AIR DUMP SYSTEM
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SECTION 4

REACTOR COOLANT SYSTEM

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SECTION 4

REACTOR COOLANT SYSTEM

4.1 SUMMARY DESCRIPTION

Section 4, Reactor Coolant System, describes those systems and components that form the major portions of the nuclear system process barrier. These systems and components contain or transport the fluids coming from or going to the reactor core.

Section 4.2, Reactor Vessel and Appurtenances Mechanical Design, describes the reactor vessel and the various fittings with which other systems are connected to the vessel. The major safety considerations for the reactor vessel are concerned with the ability of the vessel to function as a radioactive material barrier. Various combinations of structural loading are considered in the vessel design. The vessel meets the requirements of various applicable codes and criteria. The possibility of brittle fracture is considered, and suitable limits are established that avoid conditions where brittle fracture is possible.

The Reactor Recirculation System pumps coolant through the core. Adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting control rods. The Recirculation System is designed with sufficient fluid and pump inertia that fuel thermal limits cannot be exceeded as a result of Recirculation System malfunctions. The arrangement of the Recirculation System is designed so that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel.

The Nuclear System Pressure Relief System is designed to protect the nuclear system process barrier from damage due to overpressure. To accomplish overpressure protection a number of pressure operated relief valves are provided that can discharge steam from the nuclear system to the primary containment. The nuclear system Pressure Relief System also acts to automatically depressurize the nuclear system in the event of a loss of coolant accident in which the High Pressure Coolant Injection System (HPCIS) fails to restore and maintain reactor water level. The depressurization of the nuclear system allows low pressure core standby cooling systems to supply enough cooling water to adequately cool the fuel. Only some of the valves used to provide overpressure protection are arranged to effect automatic depressurization.

The main steam line flow restrictors are venturi type flow devices. One restrictor is installed in each main steam line close to the reactor vessel, but downstream from the pressure relief and safety valves. The restrictors are designed to limit the loss of coolant resulting from a main steam line break outside the primary containment. The coolant loss is limited so that reactor vessel water level remains above the top of the core during the time

required for the main steam line isolation valves to close. This action protects the fuel barrier.

Two main steam line isolation valves are installed on each main steam line. One valve in each line is located inside the primary containment, the other outside. These valves act automatically to close off the nuclear system process barrier in the event a pipe break occurs downstream of the valves. This action limits the loss of coolant and the release of radioactive materials from the nuclear system. In the event that a main steam line break occurs inside the primary containment, closure of the isolation valve outside the containment acts to seal the primary containment itself.

The Reactor Core Isolation Cooling System includes a turbine pump driven by reactor vessel steam. The system provides the ability to cool the core during a reactor shutdown in which feedwater flow is not available.

The Residual Heat Removal System (RHRS) includes a number of pumps and heat exchangers that can be used to cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, the RHRS removes residual and decay heat. One operational mode of the RHRS is low pressure coolant injection (LPCI). LPCI operation is an engineered safeguard for use during a loss of coolant accident. This operation is described in Section 6, Core Standby Cooling Systems. Another mode of RHRS operation allows the removal of heat from the primary containment following a loss of coolant accident.

The Reactor Water Cleanup System functions to maintain the required purity of reactor coolant by circulating coolant through a system of filters and demineralizers.

Section 4.10, Nuclear System Leakage Rate Limits, establishes the limits on nuclear system leakage inside the primary containment so that appropriate action can be taken before the nuclear system process barrier is threatened by a crack large enough to propagate rapidly.

Four steam lines are utilized between the reactor and the turbine, which permits turbine stop valve and primary steam isolation valve tests during plant operation with a minimum amount of load reduction. In addition, differential pressures on reactor internals under assumed accident conditions of a broken steam line are limited. Feedwater lines provide water to the reactor vessel entering near the top of the vessel downcomer annulus. Drains are provided at the low point of each main steam line, at the reactor vessel bottom head, at the relief valves, and on each side of the recirculation pumps.

4.2 REACTOR VESSEL AND APPURTENANCES MECHANICAL DESIGN

4.2.1 Safety Objective

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

4.2.2 Safety Design Basis

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

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

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

4.2.3 Power Generation Objective

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

4.2.4 Power Generation Design Basis

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

2. The original reactor vessel design lifetime was 40 years. Subsequent evaluation of the vessel determined it acceptable for 60 years (54 EFPY) of operation

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

4.2.5 Description

4.2.5.1 Reactor Vessel

The reactor vessel is a vertical cylindrical pressure vessel with hemispherical heads of welded construction. The reactor vessel was designed and fabricated for a useful life of 40 years based upon the specified design and operating conditions. Subsequent evaluation of the vessel determined it acceptable for 60 years (54 EFPY) of operation. The vessel is designed, fabricated, inspected, tested, and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III (1965 Edition and January 1966 addenda), its interpretations, and applicable requirements for Class A Vessels as defined therein. The reactor vessel and its supports are designed in accordance with the loading criteria of Appendix C. The materials used in the design and fabrication of the reactor pressure vessel are shown on Table 4.2-1. Reactor vessel data is shown on Table 4.2-2.

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

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

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

Another way of minimizing any increases to the NDTT is by reducing the integrated neutron exposure at the inner surface of the reactor vessel.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.2.5.2 Shroud Support

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

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

4.2.5.3 Reactor Vessel Support Assembly

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

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

4.2.5.4 Vessel Stabilizers

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

4.2.5.5 Refueling Bellows

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

4.2.5.6 Control Rod Drive Housing

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

4.2.5.7 Control Rod Drive Housing Supports

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

4.2.5.8 Incore Flux Monitor Housings

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

4.2.5.9 Reactor Vessel Insulation

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

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

4.2.6 Safety Evaluation

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

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

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

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

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

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

1.0×10^{17} n/cm^2 were developed in accordance with Nuclear Regulatory Commission (NRC) Regulatory Guide 1.99, Revision 2 (RG1.99).

The reactor assembly is designed such that the average annular distance from the outermost fuel assemblies to the inner surface of the reactor vessel is approximately 80 cm. This annular volume, which contains the core shroud, the jet pump assemblies, and reactor coolant, serves to attenuate the fast flux incident upon the reactor vessel wall. For plant operation at 1,998 MWt, 80 percent station availability, and 40-year station life, the neutron fluence at the inner surface of the vessel was calculated to be 1.5 x 1018 nvt for neutrons having energies greater than 1 MeV. Initially the "worst case" curve from Figure 4.2-5 would produce a NDTT shift of less than 50°F. This figure is retained for historical purposes. With an initial NDTT in the vessel plate material of 40°F, the resulting maximum NDTT of the vessel wall at the end of 40-years would be less than 90°F. This end of life NDTT provides a substantial margin for brittle fracture prevention, since the vessel cannot be pressurized until coolant temperatures in excess of 212°F are reached. Vessel operation up to 60 years (54 EFPY) was projected using the methods of Regulatory Guide 1.99, Revision 2. This projection resulted in a maximum fluence to the vessel inner wall of 1.28×10^{18} n/cm^2. The limiting CvUSE for the lower shell welds and lower intermediate shell welds remain above the 50 ft-lb minimum required. The lower intermediate shell welds remain limiting for RT_{NDT}, with an adjusted RT_{NDT} of 92.7°F

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

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

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

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

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

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

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

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

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

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

$\sigma_y.5$ = Material yield stress

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

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

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

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

4.2.7 Inspection and Testing

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

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

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

4.2.8 Proposed Nuclear Safety Requirements for Initial Plant Operation

4.2.8.1 General

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

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

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

The limits are placed on:

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

4.2.8.2 Safety Limit

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

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

4.2.8.3 Proposed Limiting Conditions for Initial Plant Operation

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

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

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

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

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

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

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

Detailed stress analyses have been made on the reactor vessel for both steady state and transient conditions with respect to material fatigue. The results of these analyses are compared to allowable stress limits. The specific conditions analyzed included numerous cycles of normal startup and shutdown with a heating and cooling rate of 100°F/hr applied continuously over a temperature range of 100°F to 546°F. The expected number of normal heatup and cooldown cycles to which the vessel will be subjected is listed in the "Reactor Thermal Cycles" document (Figure C.3-1, MIA12-2) and as modified by analyses performed for License Renewal per EC12412.

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

The NDTT is defined as the temperature below which ferritic steel breaks in a brittle rather than a ductile manner. Radiation exposure from fast neutrons (>1 MeV) above about 10^{17} nvt may increase the NDTT of the vessel base metal. Extensive tests have established the magnitude of changes in the NDTT as a function of integrated neutron exposure. The initial maximum NDTT of the reactor vessel is not greater than 40°F. The original design life of the reactor vessel was 40 years and the maximum fast neutron fluence calculated for 40 years was calculated to be 2.5 x 10^{18} nvt. The fluence calculated for 60 years (54 EFPY) is still below this estimated bounding value. See Section 4.2.6 for details.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.2.8.4 Proposed Surveillance Requirements for Initial Plant Operation

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

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

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

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

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

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

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

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

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

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

4.2.9 Current Operational Nuclear Safety Requirements

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

4.9.10 References

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

2. South West Research Report 02-5951.

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

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

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

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

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

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

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

TABLE 4.2-1
REACTOR PRESSURE VESSEL MATERIALS

Component	Form	Material	Spec. (ASTM/ASME)
Heads, shell	rolled plate	low alloy steel	SA533 Gr B cc 1332-3
Closure flange	forged rings	low alloy steel	SA508 Cl 2 cc 1332-3
Cladding	weld overlay	austenitic stainless steel	SA371 Type ER309 Type ER308 (and carbon content <0.08 w/o)
Nozzles	forged shapes	low alloy steel	SA508 Cl 2 cc 1332-3
Control rod drive stub tubes	tube	Ni-Cr-Fe	SB167 cc 1336
Control rod drive housing	pipe	austenitic stainless steel	--
Incore housing	pipe	austenitic stainless steel	--
Vessel support skirt cylinder	rolled plate	carbon steel	SA516 Grade 70
Shroud support	rolled plate	Ni-Cr-Fe	SB168
Nozzle thermal sleeves	pipe	austenitic stainless steel	SA312/376 Type 304
Nozzles for instrument penetrations	forging	Ni-Cr-Fe	SB166 cc 1336
Vessel support skirt forging (welding to bottom head)	forging	low alloy steel	SA336
Safe ends recirculation	forging	austenitic stainless steel	SA182 F316NG
Core Spray	forging	austenitic stainless steel	SA182,F316

TABLE 4.2-2

REACTOR VESSEL DATA

Reactor Vessel	
Inside Diameter, (minimum)	224 in
Inside Length	770 1/2 in
Design Pressure and Temperature	1,250 psig at 575°F
Vessel Nozzles (number and size)	
Recirculation Outlet	2-36 in to 28 in
Steam Outlet	4-10 in
Recirculation Inlet	10-12 in
Feedwater Inlet	4-12 in
Core Spray Inlet	2-10 in
Instrument	2-6 in
Control Rod Drive	145-6 in
Jet Pump Instrumentation	2-4 in
Vent and Level Instrumentation	1-4 in
Instrumentation	4-2 in
Control Rod Drive Hydraulic System Return	1-3 in
Core Differential Pressure and Liquid Control	1-2 in
Drain	1-2 in
Incore Flux Instrumentation	42-2 in
Head Seal Leak Detection	2-1 in
Weight	
Total Vessel without Top Head	961,620 lb
Top Head	160,348 lb
Total Vessel	1,121,968 lb

TABLE 4.2-3

REACTOR VESSEL ATTACHMENTS

Internal Attachments	Quantity
Guide Rod Bracket	2
Steam Dryer Support Bracket	4
Dryer Holddown Bracket	4
Feedwater Sparger Bracket	8
Jet Pump Riser Support Pads	1 each; 20 places
Core Spray Bracket	4
Surveillance Brackets	6
External Attachments	
Stabilizer Brackets	4
Top Head Lifting Lug	4
Insulation Support Brackets	12 each; 2 places
Thermocouple Pad	32

TABLE 4.2-4

SUMMARY OF CHARPY V-NOTCH AND DROP-WEIGHT TESTS
FOR REACTOR PLATES AND FORGINGS

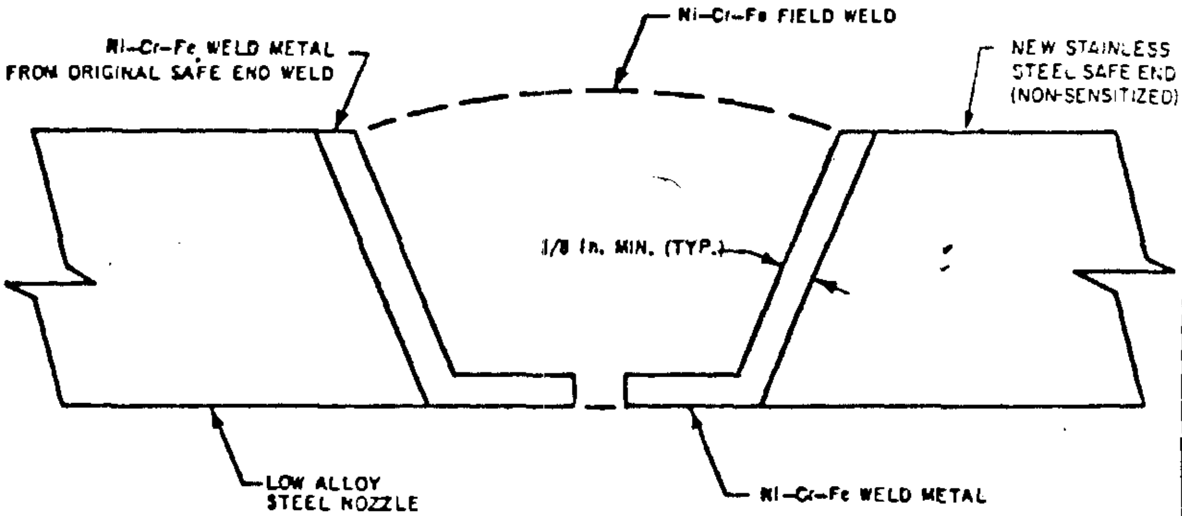
Material	Charpy V Required		Drop-Weight Required
Main closure flanges	10°F	and	10°F
Other low alloy steel forgings	No		40°F
Plate connecting to closure flanges	10°F	or	10°F
Weld material and heat affected zone to be determined in procedure qualification tests	10°F	or	10°F
Closure bolting material	10°F		N/A
Other bolting	10°F		N/A
Other pressure containing material and structural material of carbon or low alloy steel in belt line core region	10°F	or	10°F
Other pressure containing material and structural material of carbon or low alloy steel	40°F	or	40°F

Figure 4.2-1 has been deleted.

Please refer to Figure 3.3-1 Sheet 1 of 2.

Figure 4.2-2 has been deleted.

Please refer to Figure 3.3-1 Sheet 2 of 2.



APPLIES TO THE FOLLOWING:

NOZZLE	QUANTITY	SIZE (INCHES)
RECIRCULATION OUTLET *	2	28
RECIRCULATION INLET **	10	12
CORE SPRAY	2	10
CRD HYDRAULIC SYSTEM RETURN	1	3

* Note: The NIB nozzle and safe end and the NIA safe end Ni-Cr-Fe butter material were replaced with Ni-Cr material during the 1984 recirculation pipe replacement program.

** Note: The safe end Ni-Cr-Fe butter material was replaced with Ni-Cr material during the 1984 recirculation pipe replacement program.

FIGURE 4.2-3
TYPICAL DETAIL FOR FIELD WELDED SAFE END
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

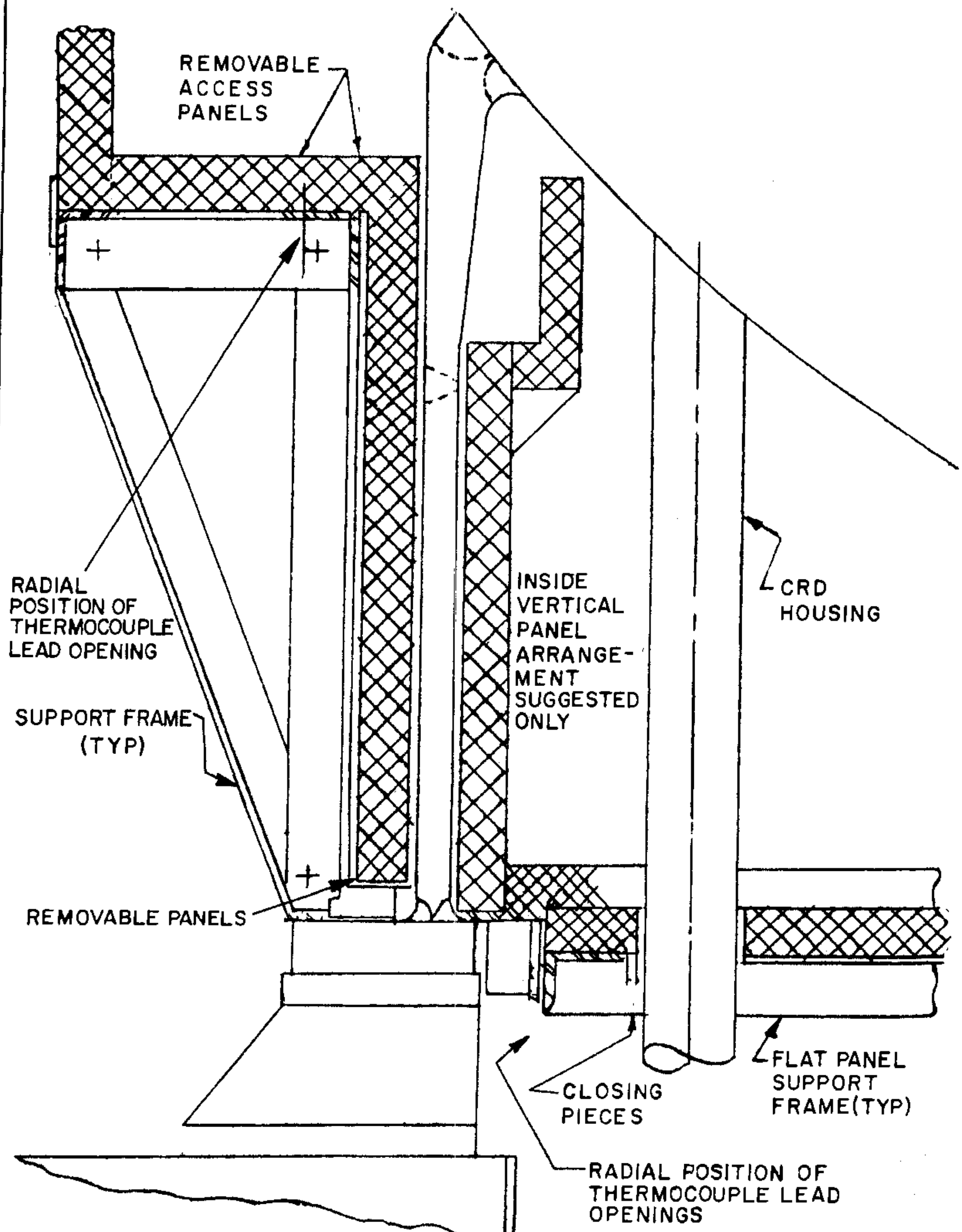
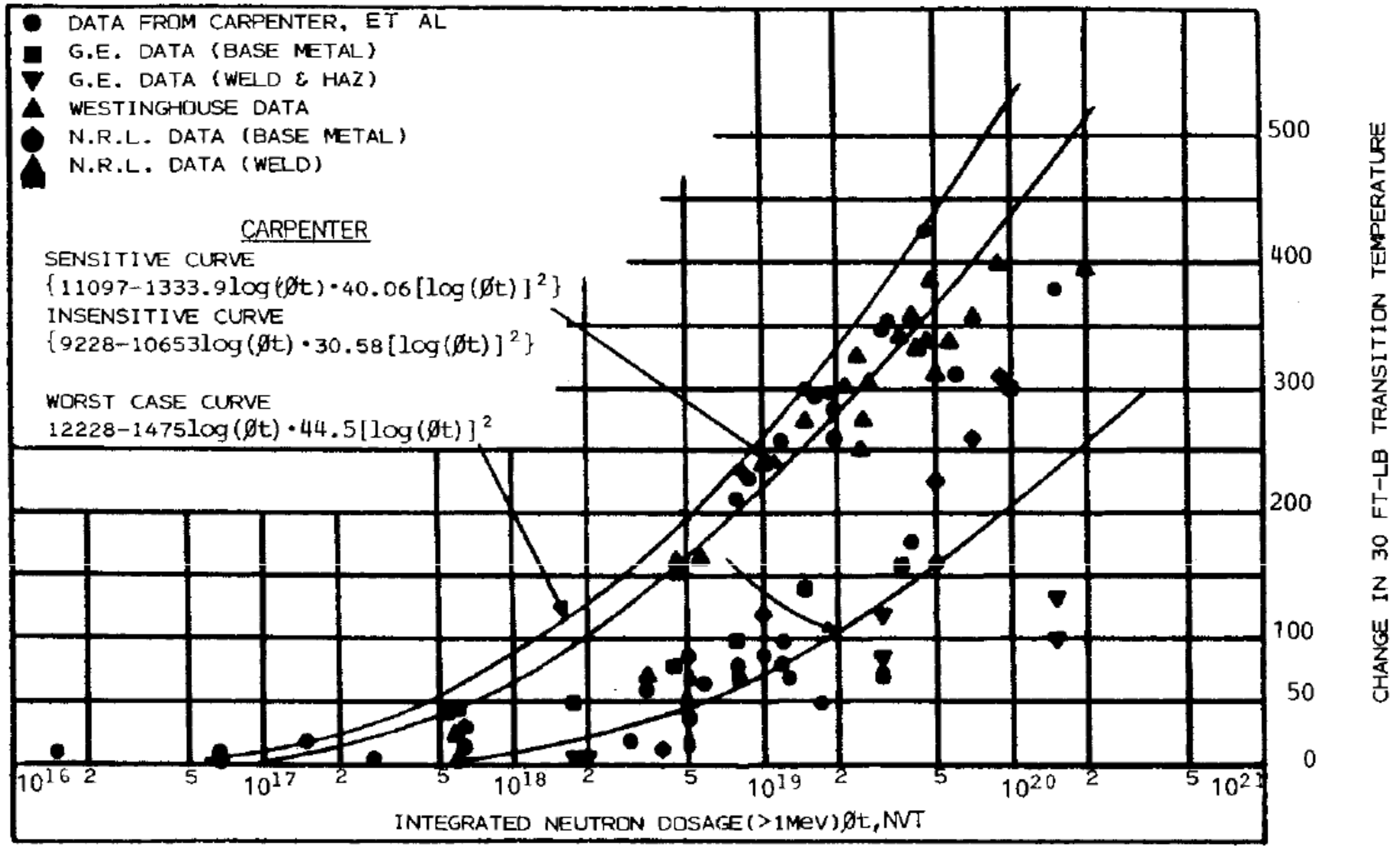


FIGURE 4.2-4
REACTOR VESSEL-SKIRT INSULATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



ALL SPECIMENS IRRADIATED AT 450° TO 575°F.

UPPER TWO CURVES ARE FOR THICK-WALLED PRESSURE VESSELS AND THE LOWER CURVE IS REPRESENTATIVE OF THAT USED BY PNPS.

WORST CASE CURVE IS USED IN ESTABLISHING NDTT SINCE IT IS MOST CONSERVATIVE

FIGURE 4.2-5
CHANGE IN NDTT
VERSUS NEUTRON EXPOSURE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

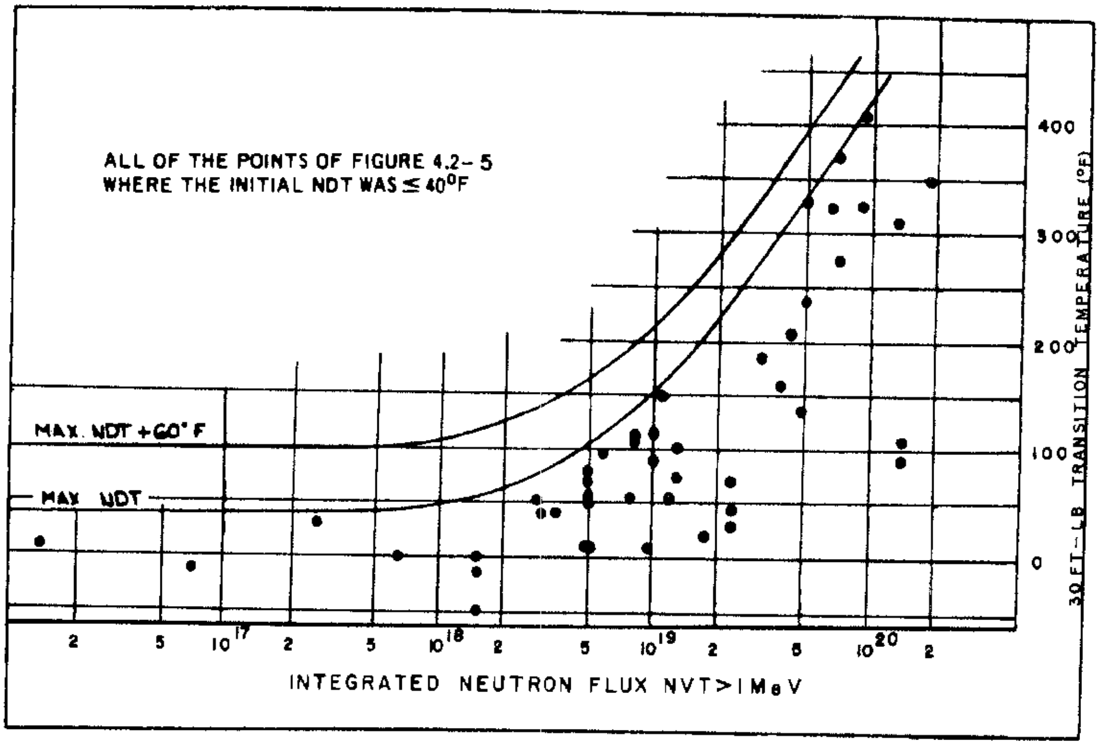


FIGURE 4. 2-6

NDTT VERSUS NEUTRON EXPOSURE USED IN INITIAL SAFETY ANALYSIS

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

4.3 RECIRCULATION SYSTEM

4.3.1 Power Generation Objective

The power generation objective of the Reactor Recirculation System is to provide a variable moderator (coolant) flow to the reactor core for adjusting reactor power level.

4.3.2 Power Generation Design Basis

1. The Reactor Recirculation System shall provide sufficient subcooled water to the core during normal power operation to maintain normal operating temperatures.

2. The Reactor Recirculation System shall operate over a flow control range of 20 percent to 100 percent flow to allow power variation.

3. The Reactor Recirculation System shall be designed to minimize maintenance situations that would require core assembly and fuel removal.

4.3.3 Safety Design Basis

1. The Reactor Recirculation System shall be designed so that adequate fuel barrier thermal margin is assured following Recirculation Pump System malfunctions.

2. The Reactor Recirculation System shall be designed so that failure of piping integrity does not compromise the ability of the reactor vessel internals to provide a refloodable volume.

4.3.4 Description

The Reactor Recirculation System consists of the two recirculation pump loops external to the reactor vessel which provide the driving flow of water to the reactor vessel jet pumps. See Figures 4.3-1, 4.3-2 (Drawing M251), and 4.3-3 (Drawing M252). Each external loop contains one high capacity motor-driven recirculation pump and two motor-operated gate valves for pump maintenance. Each pump discharge line contains a venturi type flowmeter nozzle. The recirculation loops are a part of the nuclear system process barrier and are located inside the drywell containment structure. The jet pumps are reactor vessel internals and their location and mechanical design are discussed in Section 3.3, Reactor Vessel Internals Mechanical Design; however, certain operational characteristics of the jet pumps are discussed in this section. A summary of the characteristics of the Reactor Recirculation System is presented on Table 4.3-1.

The recirculated coolant consists of saturated water from the steam separators and dryers which has been subcooled by incoming feed water. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant exits from the vessel and passes through the two external recirculation loops to become the driving flow for the jet pumps. The two external recirculation loops each discharge high pressure flow into external manifolds from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pumps at the suction inlet and is accelerated by the driving flow. The driving and driven flows are mixed in the jet pump throat section resulting in partial pressure recovery. The balance of recovery is obtained in the jet pump diffusing section. See Figure 4.3-4. The adequacy of the total flow to the core is discussed in Section 3.7, Thermal and Hydraulic Design. Tests have been conducted and documented(1) to show that the jet pump design is sound and that jet pump operation is stable and predictable.

Each discharge gate valve has the capability of being jogged in the open direction only. By jogging the valve so that it is just cracked open, the system can be used to preheat an idle loop by reverse flow prior to returning a pump to service. The pump is started to slow speed with the main discharge valve closed and the operator must start to open the valve within 10 seconds of a successful pump start with the nuclear system at full pressure. Pump speed is not increased until after the main valve has been fully opened. There is actually a very low probability that a recirculation loop that has been allowed to cool would need to be placed in service again with the nuclear system hot. The only potential reason for closing both the pump discharge valve and the suction valve is to prevent leakage out of that portion of the recirculation loop between the valves. A leak of this nature cannot be repaired without shutting the plant down to permit access to the drywell. As such, the suction and discharge valves were not explicitly designed to close to isolate a leak between them. The nuclear system would in all probability have been cooled prior to repairing the leak. To limit the amount of unheated water which could be added to the reactor vessel from a cold loop startup, interlocks are provided to allow pump start only if the suction valve is open and the discharge valve is closed. To assure that the recirculation pump suction valves remain open, aiding the vessel depressurization for a LOCA (when pipe break occurs between recirculation pump suction and discharge valves), the automatic closure feature of the suction valves has been removed.

Since the removal of Reactor Recirculation System valve internals requires unloading of the nuclear fuel, the valves are provided with high quality back seats and trim to facilitate stem packing renewal without draining the vessel and to provide adequate leak tightness during normal operation.

It is possible to operate at reduced power with one recirculation pump. PNPS is licensed for continuous Single Loop Operation (Ref 3). The acceptable operating domain is administratively limited during SLO. This mode of operation requires adjustment of thermal limits as discussed in Section 3.7. The APRM flow biased are also adjusted as discussed in Section 14.4 (Ref 4).

The idle pump loop is not completely valved off if it is desired to return the idle loop to service prior to the next reactor cooldown (such as pump shutdown for motor generator set repair). The recirculation pump casing allowable heatup rate is 100°F/hr, the same as the loop hot with the idle loop valves left open, permitting the pressure head created by reverse flow through the idle jet pumps to cause reverse flow through the idle loop. The feedwater flowing into the reactor vessel annulus during operation provides subcooling for the fluid passing to the recirculation pumps, thus determining the additional net positive suction head (NPSH) available beyond that provided by the pump location below the reactor vessel water level. If feedwater flow is below 20 percent, the recirculation pump speed is automatically limited.

The recirculation pumps can be operated during nuclear system heatup for hydrostatic tests, with pump speed being limited so that due consideration is given to NPSH and vibration concerns. At this time, they act in conjunction with any contribution from reactor core decay heat to raise nuclear system temperature above the limit imposed on the reactor vessel by nil-ductility transition temperature (NDTT) considerations so that the hydrostatic test can be conducted.

Decontamination connections are provided in the piping on the suction and discharge side of the pump as shown on Figure 4.3-2, to permit flushing and decontamination of the pump and adjacent piping. These connections are arranged for convenient and rapid connection of temporary piping. The "A" pump suction decontamination flange has the capability of accepting up to four chemistry probes for special monitoring. The piping low point drain is used during flushing or decontamination to conduct crud away from the piping low point and is also designed for connection of temporary piping.

Each recirculation pump is a single stage, variable speed, vertical, centrifugal pump equipped with mechanical shaft seal assemblies. The pump is capable of stable and satisfactory performance while operating continuously at any speed corresponding to a power supply frequency range of 11.5 to 57.5 Hz. For loop startup, each pump operates at a speed corresponding to a power supply frequency of 11.5 Hz with the main discharge gate valve closed.

The recirculation pump shaft seal assembly consists of two individual seals built into a cartridge which can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or operating. It must seal over a wide range of pressures and temperatures. Each seal is designed for a minimum service time of two 24 month fuel cycles. Seal rebuilds are scheduled based on actual seal performance.

Each individual seal in the cartridge is capable of sealing against pump design pressure so that any one seal can adequately limit leakage in the event that the other seal(s) should fail. A breakdown annulus is provided along the pump shaft to reduce leakage in the event of a gross failure of all shaft seals. Provision is made for monitoring the pressure drop across each individual seal as well as the cavity temperature of each seal. Provision is also made for piping the seal leakage to a flow measuring device.

In addition, a recirculation pump seal purge system is provided to cool the sealing faces of the recirculation pump mechanical seals, thus improving the seal life and also to minimize leakage from the recirculation pump seals. High pressure reactor coolant water is supplied from the CRD drive water header. Flow is through the recirculation pump seals into the reactor recirculation loop. The purge system is seismically supported but performs no safety function. In the event of a loss-of-seal purge flow, the recirculation pump may continue to operate using water from the closed cooling water system.

Each recirculation pump motor is a variable speed ac induction motor which can drive the pump over a controlled range of 20 percent to 102 percent of rated pump speed. The motor is designed to operate continuously at any speed within the power supply frequency range of 11.5 to 57.5 Hz. Electrical equipment is designed, constructed, and tested in accordance with the applicable sections of the NEMA standards.

A variable frequency ac motor generator set located outside the drywell supplies power to each recirculation pump motor.

Each motor generator set consists of a horizontal induction motor driving a synchronous generator through an adjustable speed fluid drive, all mounted on a common base to form an integrated unit.

The normal procedure for starting a pump is to close the discharge valve, start the motor generator set drive motor with the fluid drive control in the minimum torque or speed position, accelerate the fluid drive to drive the generator to minimum speed, and apply sufficient exciter field excitation by the control rectifier from

an external 120 V ac source. After the pump has been accelerated to a minimum speed, transfer the controlled silicon rectifier from an external source to the generator terminal potential source, open the discharge valve, and increase the fluid drive torque and generating speed to bring the pump to desired speed.

The inertia of the rotating elements in the motor generator sets supplements the inertia of the rotating elements in the pump and pump motor to extend the deceleration time upon loss of station electrical power. The full flywheel effect required to maintain circulation in order to protect the nuclear fuel against excessive temperature following a power failure, depends upon adequate generator excitation and dependable fluid drive scoop tube control during the coastdown following a power failure.

The generator speeds of both units are normally adjusted in unison by means of a manually operated master speed selector in the main control room. In addition to the master speed selector, an individual speed selector for each generator is provided to control the frequency while taking a pump out of service or returning it to normal operation.

The recirculation pumps are classified as machinery and as such are specifically exempt from the jurisdiction of any section of the ASME Boiler and Pressure Vessel Code or of the USA Standard Code for Pressure Piping. The Standards of the Hydraulic Institute are the only standards which are applicable. However, they are more pertinent to the testing and performance of the pump and consequently provide little or no guidance in the areas of casing quality and structural integrity.

To assure that the pump casing can withstand a pressure equivalent to that inside the reactor vessel, the pump casing is designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class C, as far as this code can be applied. This class is used because the pump casing does not experience temperature transients as severe as those that portions of the reactor vessel and certain piping connections experience. Therefore, it is not necessary to make the cyclic analysis required for Class A equipment.

The design objective for the recirculation pump casing was a useful life of 40 years, accounting for corrosion, erosion, and material fatigue. The pump drive motor, impeller, wear rings, and seals are designed for as long a life as is practical. The design provides a unit which should not require removal from the system for rework or overhaul at intervals of less than 5 years. The pump casing was reviewed for license renewal and loss of material due to corrosion, erosion, and cracking due to material fatigue are managed such that the casing will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

The Recirculation System piping is of all welded construction and is designed and constructed to meet the requirements of the ASME Boiler and Pressure Vessel Code Section III for Class 1 Piping. The system is classified as Class A as described in Appendix A, Pressure Integrity of Piping and Equipment Pressure Parts. The suction and discharge pipes are welded to the pump casing.

The requirements of Section III of the ASME Boiler and Pressure Vessel Code for Class C vessels are used as a guide in calculating the thickness of pressure retaining parts of the recirculation pumps. The casings and forgings are fabricated from austenitic stainless steel.

The coolant in the Nuclear Process System is at high pressure and contains a large amount of energy. Substantial failure of the Nuclear Process System could result in a rapid loss of coolant. Although loss of the moderator (coolant) would render the reactor core subcritical, lack of cooling could cause overheating of the reactor core from residual and decay heat, leading to fuel damage and fission product release. The CSCS (which adequately cool the reactor core following a design basis LOCA), and the primary containment and containment cooling systems (which control the release of fission products and absorb the energy released by the accident), are not intended to diminish the overall design objective of the entire nuclear system (to design and construct a nuclear system which will not fail). The intent of the Recirculation System design is to provide quality equivalent to the reactor pressure vessel to which it is attached.

The Reactor Recirculation System, except for the motor generator sets, is designed as Class I seismic equipment (see Appendix C) to resist sufficiently the response motion at the installed location within the supporting structure for the Operating Basis Earthquake with the pump assumed filled with water for the analysis. Vibration snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist the horizontal reactions.

The recirculation piping, valves, and pumps are supported by constant and variable support hangers to avoid the use of piping expansion loops which would be required if the pumps were anchored. In addition, the recirculation loops are provided with a system of supports designed to limit pipe motion so that reaction forces associated with any split or circumferential break do not jeopardize containment integrity. This support system provides adequate clearance for normal

Thermal expansion movement of the loop. The spacing between limit stops is set on the basis that a split pipe retains its structural load resisting characteristics. Impact loading is not considered on limit stops since possible pipe movement is limited to slightly more than the clearance required for thermal expansion movement.

The Recirculation System piping, valves, and pump casings are covered with thermal insulation having an average maximum heat transfer rate of 65 Btu/hr-ft2 with the system at rated operating conditions. The insulation is flexible blanket insulation, composed of fiberglass, covered by a woven glass cloth, (some are protected in addition by a stainless steel metal jacket) and is prefabricated into components for field installation. Special features for easy removal is provided at various locations to allow for periodic inspection of the insulated equipment.

4.3.5 Safety Evaluation

Reactor Recirculation System malfunctions that pose threats of damage to the fuel barrier are described and evaluated in Section 14, Station Safety Analysis. There it is shown that none of the malfunctions results in fuel damage; thus, the Recirculation System has sufficient flow coast down characteristics to maintain fuel thermal margins during abnormal operational transients. This satisfies safety design basis 1.

Interlocks provide protection against a significant addition of unheated water from a cold recirculation loop. Pump start permissive is allowed only if the suction valve is open, and the discharge valve is closed.

The core flooding capability which is provided by a jet pump design plant is pictured on Figure 4.3-5. There is no recirculation line break which can prevent reflooding of the core to the level of the jet pump suction inlet. The core flooding capability of a jet pump design plant is discussed in detail in the CSCS document filed with the AEC as a GE Topical Report.(2) This satisfies safety design basis 2.

The Reactor Recirculation System piping and pump design pressures are based on peak steam pressure in the reactor dome plus the static head above the lowest point in the recirculation loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the listed code design criteria provides assurance that a system designed, built, and operated within design limits has an extremely low probability of failure due to any known failure mechanism.

No equipment to protect against overspeed is provided on the recirculation pump. An analysis (1), applicable to all GE BWRs, demonstrates that for the complete spectrum of breaks in piping on the discharge side of the recirculation pump, no overspeed conditions will exist. The study indicates by conservative analysis that in the unlikely event of a completely offset guillotine suction break, potential overspeed may be calculated. However, further considerations support the conclusion that this calculated overspeed condition would not realistically create an unsafe condition.

4.3.6 Inspection and Testing

Quality control methods were used during the fabrication and assembly of the Reactor Recirculation System to assure that the design specifications were met. Inspection and testing were carried out as described in Appendix A, Pressure Integrity of Piping and Equipment Pressure Parts. The Reactor Coolant System was thoroughly cleaned and flushed before fuel was loaded initially.

During the preoperational test program, the Reactor Recirculation System was given a hydrostatic test at 125 percent of reactor vessel design pressure. Subsequent to the Recirculation Pipe Replacement Program in 1984, the Reactor Recirculation System was given a pressure test at 110 percent of reactor vessel design pressure. A hydrostatic test in accordance with ASME Code Section I is made every 10 yr and a leak test is made following each removal and replacement of the reactor vessel head. Other preoperational tests on the Reactor Recirculation System include operating valves and verifying that seat leakage is small enough to permit pump maintenance work, operating pumps and motor generator sets, and checking flow control transient operation.

During the startup test program, the horizontal and vertical motions of the Reactor Recirculation System piping and equipment were observed and adjustments of supports are made, as necessary, to assure that components are free to move as designed. Nuclear system responses to recirculation pump trips at rated temperatures and pressure were evaluated during the startup tests, and the plant power response to recirculation flow control was determined. Following the Recirculation Piping Replacement Program in 1984, a thermal expansion, vibration and strain measurement test was made during pre-op and initial start-up conditions. The purpose of these tests is to verify that piping vibrations are within acceptable limits as required by NB-3622.3 of ASME III, and to demonstrate that obstructions to thermal expansion do not exist.

Inservice inspection is considered in the design of the Reactor Recirculation System to assure adequate working space and access for inspection of selected components. The criteria for selecting the components and locations to be inspected are based on the probability of a defect occurring or enlarging at a given location, including areas of known stress concentrations and locations where cyclic strain or thermal stress might occur.

4.3.7 Operational Nuclear Safety Requirements for Plant Operation

A stationwide BWR systems analysis (Appendix G) indicates that a restriction against starting a recirculation pump in a cold, idle loop must be observed to ensure that the change in coolant temperatures at the reactor vessel nozzles and bottom head remain within the conditions analyzed for planned operation. The restriction is as follows:

The pump in an idle recirculation loop shall not be started unless the temperature of the coolant within the idle recirculation loop is within 50°F of the reactor coolant temperature.
Normally, the temperature of the coolant in an idle recirculation loop is expected to remain at reactor coolant temperature unless the loop is valved out of service. This limiting condition for operation is derived from the following matrix blocks of Table G.5-3:

Matrix 3

Operating State	Row	Column
A	1	55
B	2	55
C	2	55
D	3	55
E	2	55
F	4	55

Matrix 3 of Table G.5-3 also indicates that the Recirculation System must be considered in setting limits on water quality and nuclear system leakage. Analysis reveals that it is the reactor vessel that is most limiting with regard to water quality and leakage; therefore, no separate limits are observed on these parameters for the Recirculation System.

4.3.8 Current Technical Specifications

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

4.3.9 References

1. Design and Performance of GE BWR Jet Pumps, General Electric Company, Atomic Power Equipment Department, APED-5460, September 1968.

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

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

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

TABLE 4.3-1

REACTOR RECIRCULATION SYSTEM
DESIGN CHARACTERISTICS

External Loops	
Number of Loops	2
Pipe Sizes (nominal od)	
Pump Suction, in	28
Pump Discharge, in	28
Discharge Manifold, in	22
Recirculation Inlet Line, in	12
Design Pressure/Design Temperature, psig/°F	
Suction Piping	1,148/562
Discharge Piping	1,241/562
Pumps	1,400/575
Operation at Original Design Conditions (Ref. 1)	
Recirculation Pump	
Flow, gal/min (approximate)	45,000
Flow, lb/hr	17.1×10^6
Total Developed Head, ft	370
Suction Pressure, psig	1,015
Available NPSH* (min.), ft	441
Water Temperature (max.), °F	530
Pump Brake HP (min.), hp	3,670
Flow Velocity at Pump Suction, ft/sec (approximate)	28.3
Drive Motor and Power Supply	
Frequency (at original design conditions), cps	56
Frequency (operating range), cps	11.5-57.5
Total Required Power to Motor Generator Sets @ 56 H_z (Ref. 2)	
kW/set	3,000
kW total	6,000
Jet Pumps	
Number	20
M-Ratio	1.07
Throat id, in	6.8
Diffuser id, in	16.75

NOTE:

*Includes velocity head

REFERENCES

1. GE Specification 21A1209, Recirculation Pumps and Drives with Mechanical Seals.

2. GEK-26227, Variable Frequency MG-Set and Associated Control Equipment for PNPS.

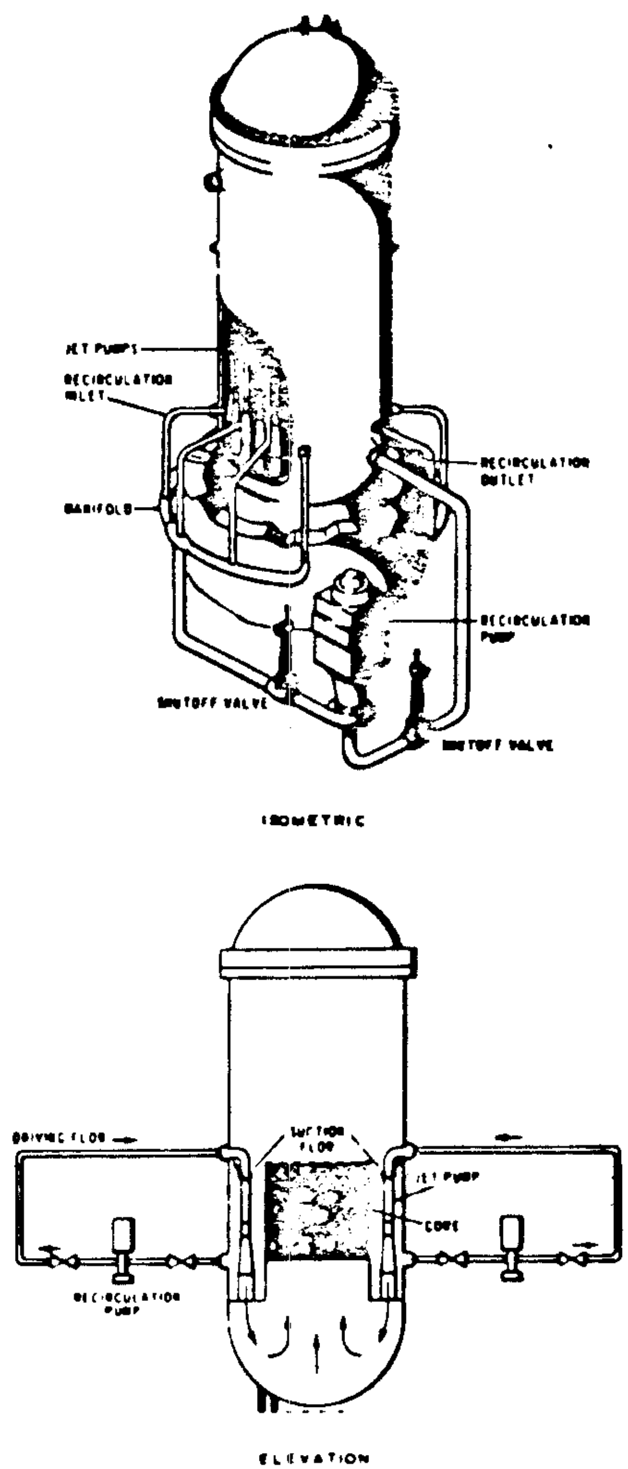


FIGURE 4.3-1
RECIRCULATION SYSTEM
ELEVATION, ISOMETRIC
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figures 4.3-2 and 4.3-3 have been removed.

Please refer to BECo Controlled Drawings M 252 and M 251.

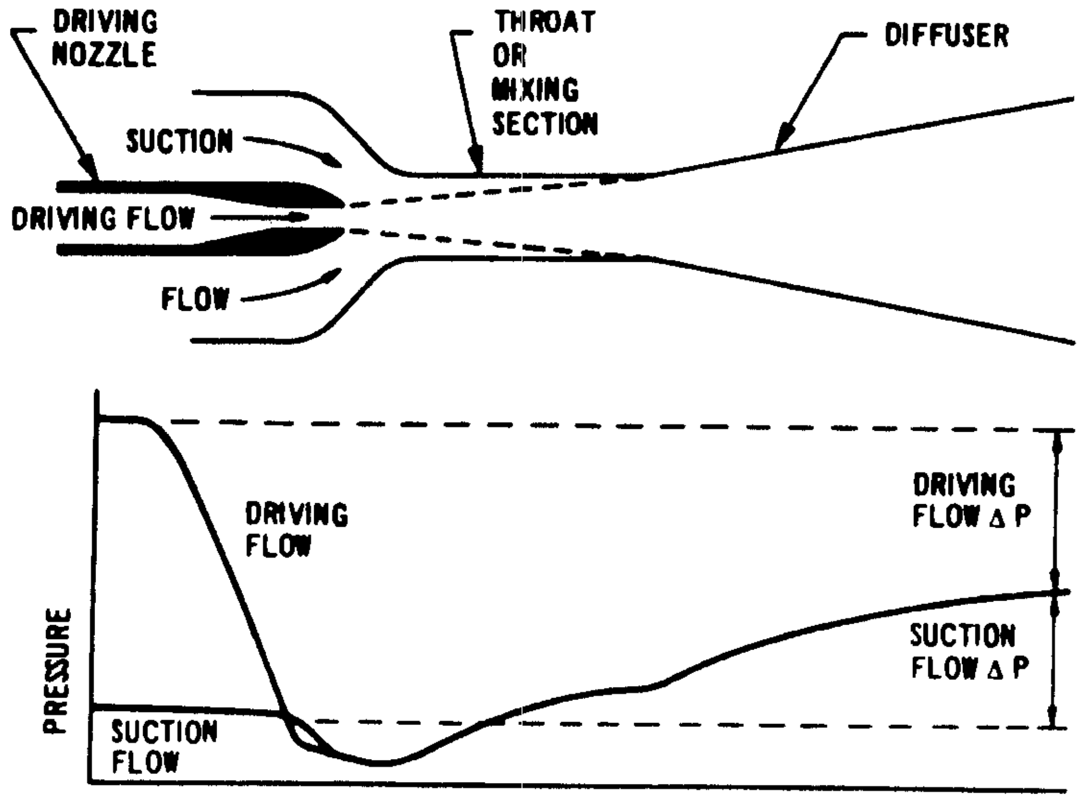


FIGURE 4.3-4
JET PUMP
OPERATING PRINCIPLE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

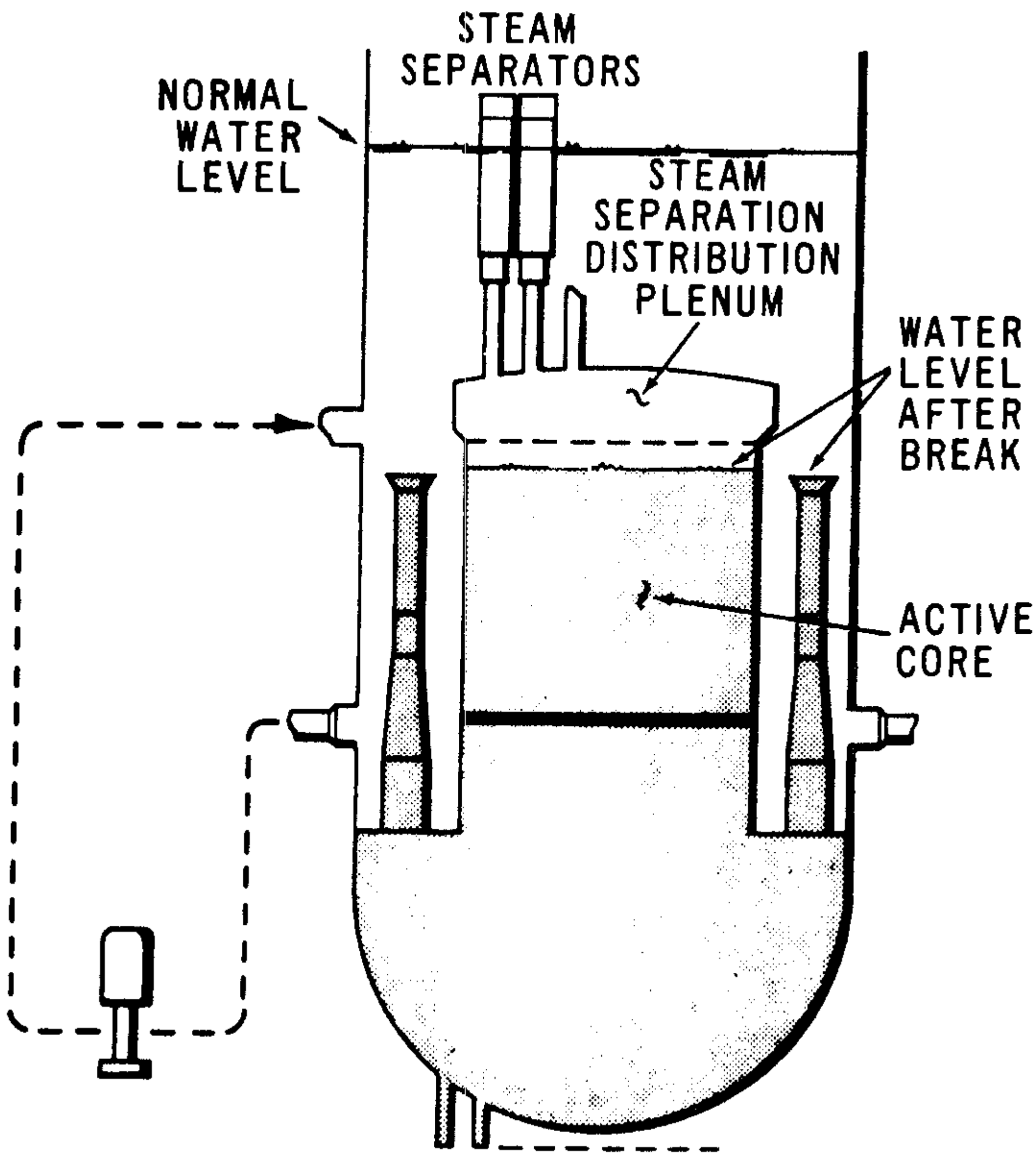


FIGURE 4.3-5
RECIRCULATION SYSTEM
CORE FLOODING CAPABILITY
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

4.4 NUCLEAR SYSTEM PRESSURE RELIEF SYSTEM

4.4.1 Safety Objective

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

4.4.2 Safety Design Basis

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

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

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

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

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

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

4.4.3 Power Generation Objective

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

4.4.4 Power Generation Design Basis

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

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

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

4.4.5 Description

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

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

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

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

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

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

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

Temp Mod EC 44839 R1 accommodates the replacement of all four (4) Safety Relief Valves (SRVs) with 2-stage SRVs.

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

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

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

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

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

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

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

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

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

The 2-stage pilot operated safety relief valve consists of two principle assemblies: a pilot valve section (top works) and the main valve section (Fig. 4.4-3) The pilot valve section (first stage) is the pressure sensing and control element and the main valve (second stage) provides the pressure relief function. The first stage consists of a pilot-stabilizer disc assembly. The pilot is the pressure sensing member to which the stabilizer disc movement is coupled. Though not mechanically connected, a light spring keeps the stabilizer in contact with the pilot. A pilot preload spring permits set point adjustment of the valve and provides pilot seating

force. The second or main stage consists essentially of a large piston which includes the main valve disc, the main valve chamber, and a preload spring.

A typical sequence of operation for overpressure relief self actuation for the 2-stage SRV can be described as follows. Refer to Figure 4.4-3:

1. When the reactor is at operating pressure, below the set point of the valve, the first stage and main stage chamber are at system pressure with the valve in the closed position (Figure 4.4-3). The preload spring force seats the pilot valve tightly and prevents reverse leakage at low system pressures or high back pressures. The main valve disc is tightly seated by the combined forces exerted by the main valve preload spring and the system internal pressure which acts over the area of the main valve disc. In the closed position, the static pressures will be equal in the valve body and in the chamber over the main valve piston. Leakage through the piston orifice equalizes the pressure.

2. As the system pressure increases to the set point of the valve, the pressure acting on the pilot below the seat produces a force great enough to overcome the preload spring force and lifts the pilot off its seat.

3. As the pilot moves to full open, the stabilizer disc follows the pilot until the stabilizer is seated.

4. With the pilot full open and the stabilizer disc seated, the main piston chamber is vented to the discharge piping. This venting action creates a differential pressure across the main valve piston in a direction tending to open the valve. The main valve piston is sized such that the resultant opening force is greater than the combined spring load and hydraulic seating force. The stabilizer disc is designed to control the valve seating force. The stabilizer disc is designed to control the valve blowdown by holding the pilot open until the proper reclosing pressure is reached. The stabilizer chamber is connected by a passage to the inlet side of the valve.

5. As occurs in the case of the pilot valve, once the main valve disc starts to open, the hydraulic seating force is reduced; this causes a significant increase in opening force and the characteristic full opening or "popping" action.

6. When the pressure has been reduced sufficiently to permit the pilot valve to close, leakage of system fluid past the main valve piston repressurizes the chamber over the piston, eliminates the hydraulic opening force, and permits the preload spring to close the valve. Once the valve is closed, the additional hydraulic seating force due to system pressure acting on the main valve disc seats the main valve tightly and prevents leakage.

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

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

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

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

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

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

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

4.4.6 Safety Evaluation

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

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

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

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

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

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

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

It is concluded that the safety design bases are satisfied.

4.4.7 Power Generation Evaluation

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

4.4.8 Inspection and Testing

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

1. Hydrostatic test.

2. Seat leakage test.

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

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

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

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

4.4.9 Operational Nuclear Safety Requirements for Plant Operation

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

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

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

Example of Matrix Reference:

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

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

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

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

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

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

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

4.4.10 Current Technical Specifications

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

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

4.4.11 References

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

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

TABLE 4.4-1

NUCLEAR SYSTEM SAFETY AND RELIEF VALVES

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

Notes:

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

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

TABLE 4.4-2

NUCLEAR SYSTEM PRESSURE RELIEF SYSTEM
REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action*
4.4.1 Overpressure Relief	Relief Valves and Safety Valves	4 Relief Valves and 2 Safety Valves	A	None
			B	None
			C	4 relief and 2 safety valves** (C16-64)
			D	4 relief and 2 safety valves** (D16-64)
			E	4 relief and 2 safety valves** (E16-64)
			F	4 relief and 2 safety valves** (F16-64)

*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.

**Minimum number of valves required for all states are established from analysis at t he most limiting which is State F.

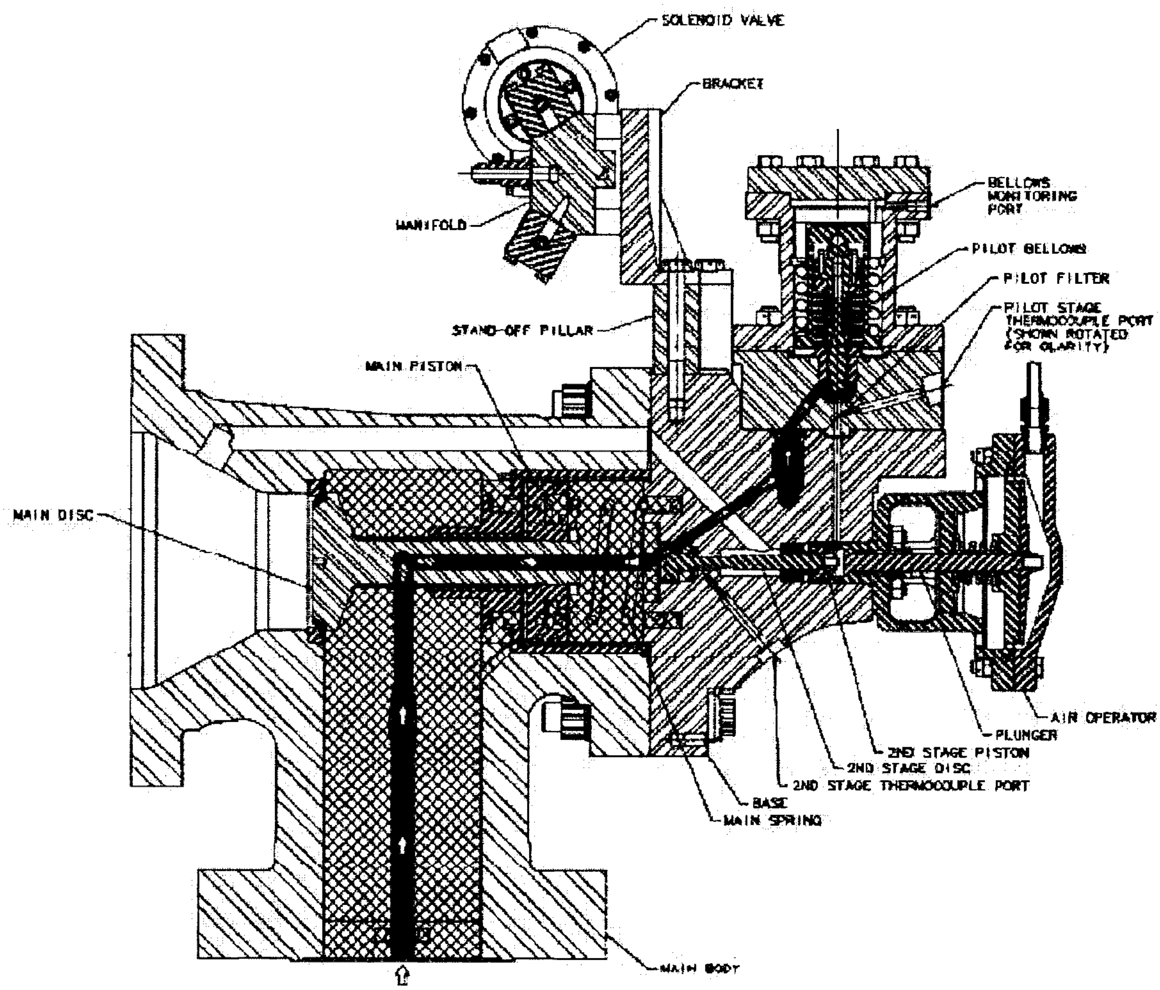


FIGURE 4.4-1
NUCLEAR SYSTEM RELIEF VALVE
THREE-STAGE – CLOSED POSITION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

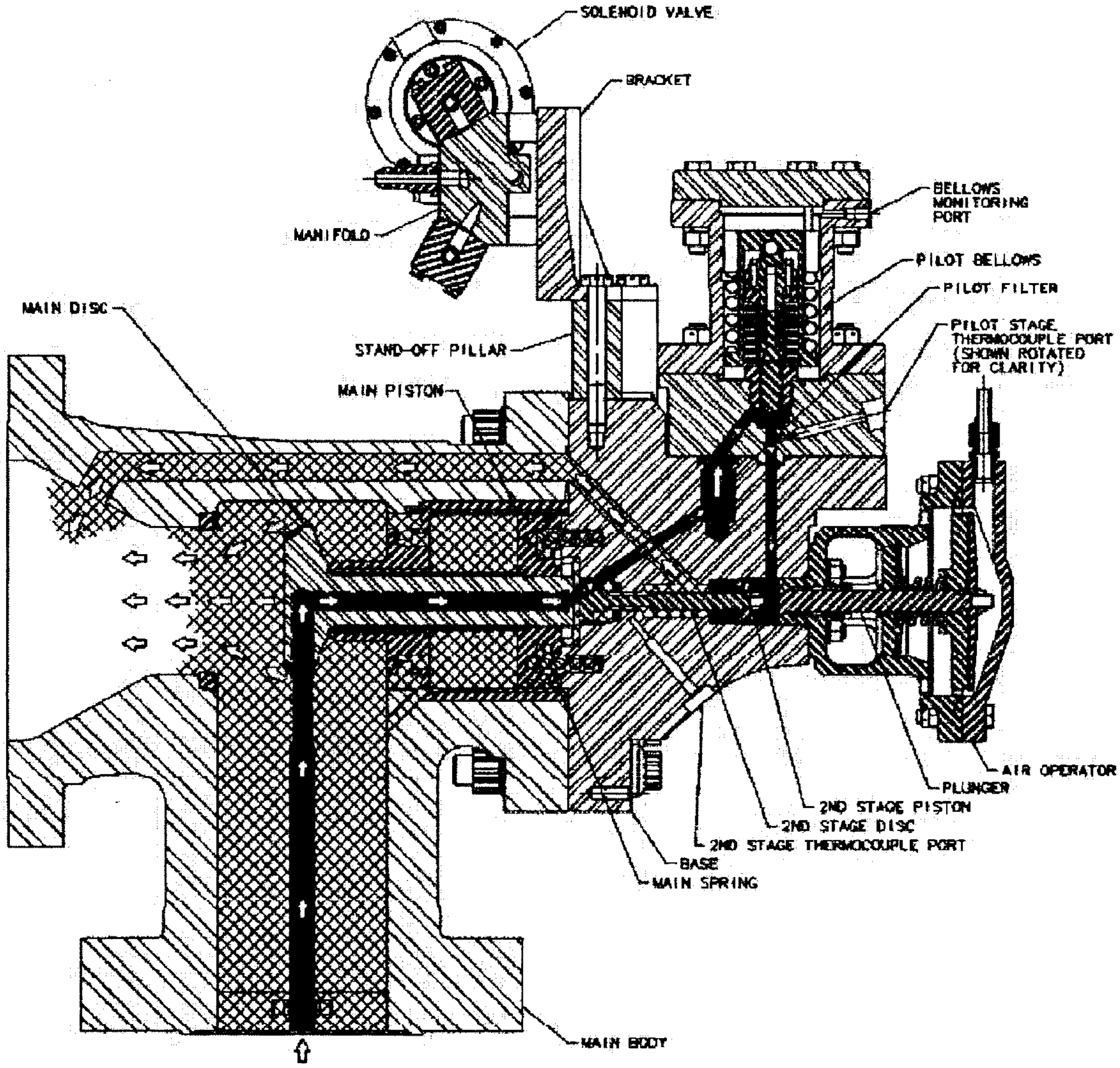


FIGURE 4.4-2
NUCLEAR SYSTEM RELIEF VALVE
THREE-STAGE – OPEN POSITION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

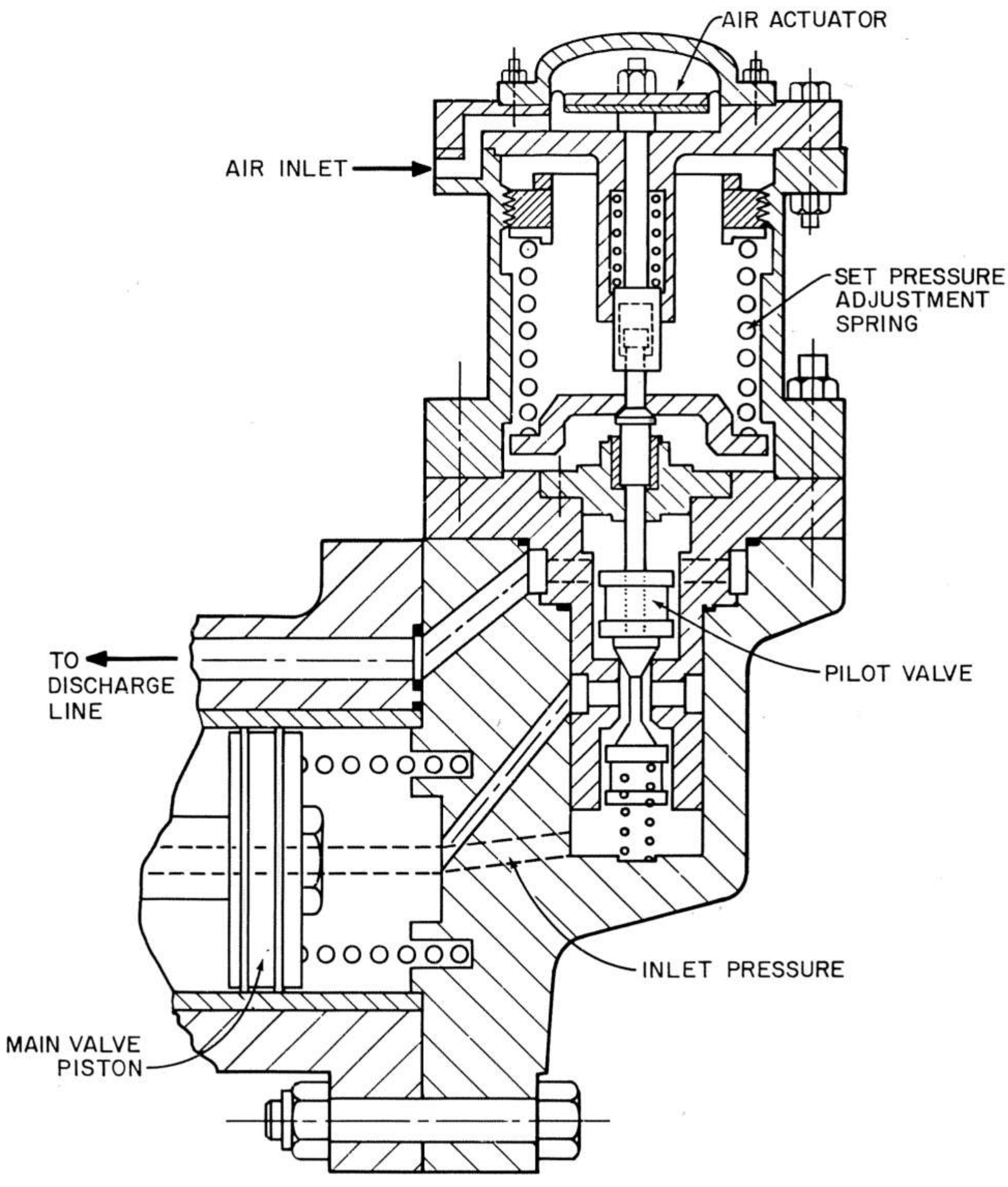


FIGURE 4.4 - 3
NUCLEAR SYSTEM RELIEF
VALVE TWO-STAGE TOPWORKS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

4.5 MAIN STEAM LINE FLOW RESTRICTOR

4.5.1 Safety Objective

To protect the fuel barrier, the main steam line flow restrictors limit the loss of water from the reactor vessel before main steam line isolation valve closure in case of a main steam line rupture outside the primary containment.

4.5.2 Safety Design Basis

1. The main steam line flow restrictor shall be designed to limit the loss of coolant from the reactor vessel following a steam line rupture outside of the primary containment, so that the reactor vessel water level does not fall below the top of the core within the time required to close the main steam line isolation valves.

2. The main steam line flow restrictor shall be designed to withstand the maximum pressure difference expected across the restrictor following complete severance of a main steam line.

4.5.3 Description

One main steam line flow restrictor is provided for each of the four main steam lines. The restrictor is a complete assembly welded into the main steam line between the reactor vessel and the first main steam line isolation valve, and downstream of the main steam line safety and relief valves. The restrictor limits the coolant flow rate from the reactor vessel in the event of a main steam line break outside of the primary containment to the maximum (choke) flow specified. The restrictor assembly (consisting of a venturi type nozzle insert welded into a carbon steel pipe) is constructed utilizing all austenitic stainless steel and is held in place with a full circumferential fillet weld. The restrictor assembly is self draining.

The flow restrictor is designed and fabricated in accordance with USAS B31.1.0. Preinstallation inspection and testing is in accordance with the ASME Boiler and Pressure Vessel Code, Sections I and III, as specified in Appendix A. The container pipe is also designed and fabricated in accordance with USAS B31.1.0, and with the ASME Boiler and Pressure Vessel Code Sections I and III as specified in Appendix A. The flow restrictor has no moving parts, and the mechanical structure of the restrictor is capable of withstanding the velocities and forces under main steam line break conditions where maximum differential pressure is approximately 1,375 psi.

The ratio of the venturi throat diameter to a steam line diameter is approximately 0.6. This results in less than a 9 psi pressure difference at rated flow. This design limits the steam flow in a severed line to about 200 percent of its rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used in the measurement of steam

flow to initiate closure of the main steam line isolation valves in the event the steam flow exceeds preselected operational limits.

4.5.4 Safety Evaluation

In the event of a main steam line break outside the primary containment, steam flow rate is restricted in the venturi throat by a two phase mechanism similar to the critical flow phenomena in gas dynamics. This mechanism limits the steam quantity flow rate, thereby reducing the reactor vessel coolant blowdown.

The probability of fuel failure and its consequences are, therefore, decreased.

Analysis of the steam line rupture accident (see Section 14, Station Safety Analysis) shows that the core remains covered with water, and that the amount of radioactive materials released to the environs through the main steam line break does not exceed the guideline values of 10CFR100.

Pressure surges caused by a two phase mixture impinging on the flow restrictor result in stresses which do not exceed code allowable limits. There is adequate margin in the code for withstanding the pressure load due to impact pressure from the possible oncoming two phase mixture predicted during main steam line break accident condition.

Tests were conducted on a scale model to determine final design and performance characteristics of the flow restrictor, including maximum flow rate of the restrictor corresponding to the accident conditions, irreversible losses under normal plant operating conditions, and discharge moisture level. The tests show that the flow restrictor operation at critical throat velocities is stable and predictable. Unrecovered differential pressure across the scale model restrictor is consistently about 10 percent of the total nozzle pressure differentials, and the restrictor performance is in agreement with existing ASME correlation. Full size restrictors have slightly different hydraulic shape and a differential pressure loss of approximately 15 percent.

4.5.5 Inspection and Testing

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned. Only very slow erosion will occur with time, and such a slight enlargement will not have safety significance.

4.6 MAIN STEAM LINE ISOLATION VALVES

4.6.1 Safety Objectives

Two isolation valves, one as close as practical to each side of the primary containment barrier, in each main steam line close automatically upon receipt of certain isolation signals to:

1. Prevent damage to the fuel barrier by limiting the loss of reactor cooling water in case of a major leak from the steam piping outside the primary containment

2. Limit release of radioactive materials by closing the primary containment barrier in case of a major leak from the nuclear system inside the primary containment

4.6.2 Safety Design Basis

The main steam line isolation valves, individually or collectively, shall:

1. Close the pipelines within the time established by design basis accidents to limit the release of reactor coolant or radioactive materials

2. Close the pipelines at a speed slow enough so that simultaneous (inadvertent) closure of all steam lines will not induce a more severe transient on the nuclear system than closure of the turbine stop valves coincident with failure of the bypass valves to open

3. Close the pipeline when required despite single failure in either valve or the attached controls, to provide a high level of reliability for the safety function

4. Use separate energy sources for the motive force to independently close the redundant isolation valves in each steam line

5. Use local stored energy to close at least one isolation valve in each steam pipeline without relying on continuity of any variety of electrical power for the motive force to achieve closure

6. Be able to close the pipelines during or after seismic loadings to assure isolation if the nuclear system is breached by the earthquake

7. Be testable during normal operating conditions to demonstrate that the valves will function

4.6.3 Description

Two isolation valves are provided in series in a horizontal run of each main steam line, as close as practical to the primary containment, one inside (inboard) and the other outside (outboard). The valves, when closed, form part of the primary containment barrier for nuclear system breaks inside the containment, and part of the nuclear system process barrier for main steam line breaks outside the primary containment.

The description and testing of the controls for the main steam line isolation valves are included in Section 7.3, Primary Containment and Reactor Vessel Isolation Control Systems.

A drawing of a main steam isolation valve is shown on Figure 4.6-1. These valves each employ a pneumatic cylinder operator and closing springs as separate, locally stored energy sources for rapid closure.

Each valve is a 20 in globe valve having a Y-pattern body with a cylindrical main disc moving in a centerline 45 deg upward from the axis of the horizontal main steam inlet line. The valve is of full port design in that the main valve seat is very nearly the same diameter as the inside diameter of the pipe. This design provides essentially straight line flow through the valve with less than 6 psi pressure drop through the valve at rated flow with the valve fully open during normal station operation. It also enables the normal steam flow and pressure to aid in closing the valve and holding it closed.

The main disc, guided at the bottom by hard faced ribs cast integral with the valve body, has a hard faced seal surface at the bottom which mates with a hard faced seat welded into the valve body when the valve is closed. The main disc is attached to the lower end of the valve stem which penetrates the bonnet through a stuffing box. The upper end of the stem is connected to a spring seat member. The air cylinder and an oil dashpot are mounted in tandem on a common shaft which extends downward and which is also connected to the spring seat member. The cylinder and dashpot assembly is also supported by four tie rods which use the valve bonnet as their support surface. Four of these support rods also act as guides for four stacks of two helical valve closing springs, each of which is fitted between the spring seat member and the air cylinder mounting plate.

The bottom end of the valve stem is chamfered and seals against a mating hard faced seat in the middle of the main disc to act as a pilot valve. This provides a means of balancing the pressure across the main disc, just before the main disc is lifted and while it is off its seat. A helical spring between the stem and the disc keeps

this pilot valve open when the disc is off its seat, but failure of this spring will not prevent closure of the valve. The air cylinder is capable of lifting the disc with differential pressures across the isolation valve in either direction as great as 200 psi; opening of the pilot valve enables disc opening at higher differential pressures due to the pressure balancing which it affords. Approximately the last 0.5 in of disc travel as it seats closes the pilot valve.

The upper edge of a shoulder on the valve stem is chamfered and seals against a mating surface on the bottom bonnet to provide a backseat when the isolation valve is fully open. This prevents leakage through the stem packing. The bonnet, which is bolted to the body, has provisions for seal welding in case leaks develop after the valve has extensive service.

The main disc is guided at the top inside a cylinder liner fitted snugly into the valve body to provide support when it is off its seat. Running clearances are provided to permit the disc to align with the seat ring in the body. Other design features which eliminate the possibility of the disc binding in its guides are:

1. The cylindrical shape of the disc with length greater than diameter

2. Sufficient clearance between the disc and its guide surfaces such that some cocking of the disc or warpage of the seat can be tolerated and still allow tight seating

3. Force from the valve actuation is applied through the valve stem to the bottom of the disc such that the possibility of cocking the disc is minimized

The air cylinder is utilized to operate the isolation valve. Opening and closing of the valve is affected by the admission of valve operating air to the bottom and top, respectively, of the air cylinder piston. This is accomplished through the control unit which is attached to the air cylinder and contains the pneumatic, ac, and dc control valves. The valve operating air is supplied to the Control System from the plant Instrument Air/Nitrogen System through a check valve. An air tank accumulator is connected to the system between the check valve and the control valve to provide backup operating air. The Valve Pilot System and the accumulator are piped in such a way that when one or both pilots are energized the accumulator pressurizes the valve operator to overcome the closing force exerted by the spring to open the main valve. When both pilots are deenergized, as in a two channel trip or manual switch in the closed position, the accumulator pressure is switched to pressurize the opposite side of the valve operator and help the spring close the valve. The pressure from the accumulator and the spring force are each capable of independently closing the valve against full reactor pressure. This is in the event that if one fails the other will successfully close the valve.

The accumulator volume is adequate to provide full stroking of the valve through one half cycle (open to close) when supply air 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 closure.

The hydraulic dashpot functions as a hydraulic buffer and is utilized to control the speed with which the isolation valve is closed by the air actuator. Oil is displaced from one side of the dashpot piston to the other through the hydraulic return line along side the dashpot; the rate at which it is displaced and thus the rate at which the valve can be closed is controlled by the speed control valve in this return line. Increasing the flow through this line decreases the time it takes to close the isolation valve, and vice versa. In this way, the valve closing time is adjustable between 3 and 10 sec.

Each of the four spring guide shafts contains three stacks of springs which are compressed when the valve is open. These springs function to expand when air pressure is either vented or lost from under the air cylinder piston and thus exert a downward force against the spring seat member which pushes the valve stem and disc down to close the valve. There are spring guides installed on each guide shaft which prevent scoring during normal operation and binding should one of the springs break. The spring seat member is also closely guided on the support shafts and rigidly attached to the stem to offset any eccentric force being applied in case of a broken spring. The design is such that springs on three guide shafts will close the valve in the event that one set is broken or otherwise placed out of service.

Either manual or automatic signals can be sent to the Pneumatic Control System for each isolation valve. The Control System (see Figure 4.6.2) consists of:

1. Normal opening and closing components operated four way poppet valve (part 2), an ac solenoid valve (part 5), and a dc solenoid valve (part 4)

2. Exercising components - four way poppet valve (part 1) and solenoid valve (part 6)

All Control System components except the air storage tank (part 3) and the check valve (part 9) are bolted to a sub-plate that is fastened to the air cylinder mounting plate on each isolation valve.

The control power available is 120 V ac, 60 cycles, 0.5 amps control and 125 V dc, 0.5 amps control.

Remote manual switches in the control room enable the operator to open or close at normal speed (3 to 10 sec) or at the slow speed (45 to 60 sec) for exercising and testing. Position indicating lights actuated by limit switches on each isolation valve give the control room operator valve full open, full closed, and partially

closed display. Pairs of switches at 90 percent open and closed valve positions are actuated by motion of the spring seat member. The 90 percent open switches turn off the open lights for purposes of valve testing, and initiate reactor scram if three of the four main steam lines isolate (closure of one valve in each main steam line - see Section 7.2, Reactor Protection System).

The isolation valve is designed to pass saturated steam at 1,250 psig and 575°F with a moisture content of approximately 0.23 percent, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The design objective for the valve is a minimum of 40 years of service at the specified operating conditions. The estimated operating cycles were 100 cycles during the first year and 50 cycles/year thereafter. In addition to minimum wall thickness required by applicable codes, a corrosion allowance of 0.120 inches minimum was added. For license renewal, aging management programs were identified, as necessary, to address the effects of aging, including loss of material due to corrosion, for the MSIV through the term of the renewed license. Projected operating cycles through the term of the renewed license are less than the total operating cycles estimated during design.

Design specification ambient operating conditions are 135°F normal, 150°F maximum, at 100 percent relative humidity, in a radiation field of 15 Rad/hr gamma and 25 Rad/hr neutron plus gamma, continuous for design life. The inboard valves are not exposed to these maximum conditions continuously and the outboard valves are in much less severe ambient conditions.

In the event that the main steam line breaks downstream from the isolation valve, the steam flow quickly increases to 200 percent of rated flow. The flow is limited from further increase by the venturi flow restrictor installed upstream of the inboard isolation valve. During approximately the first 75 percent of closing, the isolation valve has little or no effect in reducing flow because the flow is restricted by the venturi. During the last 25 percent of valve closure travel, flow is reduced by the isolation valve as a function of the valve area vs travel characteristic.

The main steam line valve installations are designed as Class I equipment to resist sufficiently the response motion at the installed location within the supporting building from the Operating Basis Earthquake (see Appendix C). The valve assembly is manufactured to withstand the design basis seismic forces applied at the mass center assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are considered to act simultaneously and are added directly. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on the ordinary allowable stress as set forth in the applicable codes. The parts of the main steam isolation valves which constitute a process fluid pressure

boundary are designed, fabricated, inspected, and tested as described in Appendix A, Pressure Integrity of Piping and Equipment Pressure Parts. The control valves and other equipment provided in the valve assembly are designed, manufactured, and shop tested in accordance with the following codes and standards where applicable.

USA Standards Institute B31.1.0 and B16.5
American Society for Testing Materials (ASTM)
American Society of Mechanical Engineers (ASME)
Boiler and Pressure Vessel Code, Sections I, III and VIII
American Institute of Electrical and Electronic Engineers
Pipe Fabrication Institute
National Electrical Manufacturers Association

4.6.4 Safety Evaluation

The ability of the isolation valve to close within the times established by the design basis accidents, under conditions of high pressure differentials and fluid flows, with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test facilities. A full size, 20 in valve produced for actual use in a BWR was tested in a range of steam/water blowdown conditions simulating postulated accident conditions. The test valve was opened and closed more than 400 times (200 cycles) during the test program, during which it shut off 40 flow tests which simulated accident conditions up to those more severe than postulated for the design basis accident in the nuclear power plant. The extensive analytical program utilized resulted in finding no conditions more severe than the design basis accident. The variety of steady flow conditions on which the valve was closed covered the following ranges:

Steam Tests:	50-1,080 lb/sec
Water Tests:	240-3,490 lb/sec
Mixture Tests:	1,530-3,860 lb/sec (quality 17-45 percent)
Surge Tests:	520-2,970 lb/sec (quality 1-33 percent)

The analysis of valve closing performance on this wide variety of conditions demonstrated that closure is not critically sensitive to temperature, pressure, fluid in the valve, and fluid flow through the valve. In every case, the valve opened and closed when signaled and shut off the flow completely and reliably. It was further observed that steam and mixture flows assisted valve closure, with closing speeds up to 20 percent faster than those obtained under cold station conditions. A detailed description and analysis of this test program is contained in Design and Performance of General Electric Boiler Water Reactor Main Steam Isolation Valves, APED-5750, D.A. Rockwell and E.H. van Zylstra, March 1969.

The analysis of a complete sudden steam line break outside the primary containment is described in the Section 14, Station Safety Analysis. It shows that the fuel barrier is protected against loss of cooling if main steam isolation closure takes as long as 10.5 sec (including up to 0.5 sec for the instrumentation to initiate valve closure after the break). The calculated radiological effects of the radioactive material assumed released with the steam are shown to be well within the guideline values of 10CFR100 for such an accident.

Thus, Safety Design Basis 1 is shown to be satisfied with considerable margin.

The shortest closing time (approximately 3 seconds) of the main steam isolation valves is also shown to be satisfactory in Section 14, Station Safety Analysis. The switches on the valves initiate reactor scram when either the inboard or outboard valve on three or more steamlines are more than 10 percent closed. The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in fuel cladding temperature will be insignificant. The transient is less than that from sudden closure of the turbine stop valves (in approximately 0.1 seconds) coincident with postulated failure of the turbine bypass valves to open. No fuel damage results. Thus, Safety Design Basis 2 is shown to be satisfied with considerable margin.

The following design features of the valve and the system ensure reliable mechanical operation under the most adverse conditions:

1. Use of the venturi flow limiters upstream of the inboard isolation valve plus ensuring a tortuous flow through main steam piping runs significantly reduce (by approximately a factor of 4) impact pressure that could impinge on a partially closed isolation valve as a result of the design steam break accident

2. Utilization of steam dryer and separator materials and construction which ensure that all associated components can withstand higher than normal loading due to flooding, such that no parts are expected to break loose to be carried into steam lines and foul isolation valve closure

3. Significant margin between maximum yield strengths and maximum operating parameters for all pressure containing parts. The valve body, bonnet, bonnet bolting, valve stem, disc, disc guides, stuffing box, and packing can all withstand pressures and forces of from 4 to 6 times those expected under all expected operating conditions

4. Utilization of the pilot valve arrangement to balance differential pressure across the disc during the closing stroke, and to ensure that maximum loading cannot be applied to the disc until it is fully seated

5. Utilization of closure devices capable of applying a mechanical closing force of more than sufficient strength to close the valve, and to keep it seated against maximum back pressures expected. Further insurance is obtained by utilizing the orientation of the operator/stem/disc which takes advantage of normal steam flow, and higher inlet pressure to assist in closing the valve and maintaining a tight seal

6. Design of springs such that breakage cannot result in binding of the valve or the application of eccentric forces

It is therefore concluded that mechanical operation of the valve is extremely reliable, which has been borne out by all test programs which have been conducted. This contributes to the satisfaction of all safety design bases.

The valves are of fail-safe design in that they will be closed by the springs in the event of loss of instrument air. They will also be closed by the air operator in the event of loss of both ac and dc to the two solenoids associated with each valve. Both solenoids must be deenergized, however, to effect closure of the isolation valve to prevent spurious closure if one solenoid power supply is lost.

Two redundant isolation valves are provided in each steam line so that either can perform the isolation function, and either can be tested for leakage after closing the other. The inside valve and the outside valve and their control systems are separated physically. Considering the redundancy, the mechanical strength, the closing forces, and the leakage tests discussed above; the main steam isolation valves satisfy safety design bases 3 through 5.

The isolation valves and their installation are designed as Class I equipment for inclusion of seismic loadings, as delineated in Appendix C. Therefore, the seismic loading requirement of safety design basis 6 is met.

4.6.5 Inspection and Testing

The main steam isolation valves can be tested during station operation and tested and inspected during refueling outages. The requirements for testing are shown in the Technical Specifications referenced in Appendix B.

The valves can be tested and exercised individually to the 90 percent open position without reducing reactor power because the valves still pass rated steam flow.

The valves can be tested and exercised individually to the fully closed position at 75 percent power. During reactor shutdowns for refueling, the main steam isolation valves can be tested and visually inspected.

During pre-startup tests following an extensive shutdown, the valves receive the same hydrotests (=1,000 psi) which are imposed on the primary system.

This test and leakage measurement program will insure that the valves are operating properly, and that a leakage trend is detected.

4.6.6 Operational Nuclear Safety Requirements

Table 4.6-1 presents the operational nuclear safety requirements for the Main Steam Line Isolation Valves for each applicable BWR operating state. The entries in Table 4.6-1 represent an extension of the plant-wide BWR systems described in Appendix G to the Main Steam Line

Isolation Valves. The following referenced portions of the safety analysis report provide information substantiating entries in Table 4.6-1.

Reference	Information Provided
1. Preceding parts of subsection 4.6	Description of Main Steam Line Isolation Vavles and associated components.
2. Station Safety Analysis, Section 14	Analyses verifying response of Main Steam Line Isolation Valves to transients and accidents.
3. Station Nuclear Safety Analysis, Appendix G.	Identifies conditions and events for which Main Steam Line Isolation Valve 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, April 1969, (APED-5736).	Describes methods used to establish allowable repair times for engineered engineered safeguards.

Each requirement in Table 4.6-1 is referenced to the most significant plant condition originating the need for the requirement by identifying a matrix block on one of the six matrices of Appendix G. These references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns of Table 4.6-1 and are coded as follows:

Example of Matrix Reference:

```
F41-57
|-|--|---F =  BWR operating state F
  |--|---41 =  Event (row #41)
     |----57 =  Main Steam Line Isolation Valves (column 57)
```

There are no requirements imposed on the Main Steam Line Isolation Valves in operating states A and B. Operability of the Main Steam Line Isolation Valves is necessary only when the associated main steam lines are unisolated; with the head off in these two states, all Main Steam Line Isolation Valves would be closed or steam line plugs installed. The requirements imposed on the Main Steam Line Isolation Valves in operating states C, D, E, and F result from considerations for the main steam line break design basis accident or lesser cases thereof.

These operational nuclear safety requirements pertain only to mechanical aspects of the Main Steam Line Isolation Valves. Those pertaining to associated sensors and control systems are contained and discussed in subsection 7.3 "Primary Containment and Reactor Vessel Isolation Control System".

TABLE 4.6-1

MAIN STEAM LINE ISOLATION VALVES REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Physical closure of valves on automatic signal	Main steam line isolation valves	2 valves per main steam line	A	None
			B	None
			C	With nuclear system pressurized, 1 valve operable per un-isolated line (C41-57)
			D	With nuclear system pressurized, 1 valve operable per un-isolated line (D41-57)
			E	With nuclear system pressurized, 1 valve operable per un-isolated line (E41-57)
			F	With nuclear system pressurized, 1 valve operable per un-isolated line (F41-57)

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

Figure 4.6-1 has been removed.

Please refer to Drawing 2518-2-6 (Sh 1 + 2).

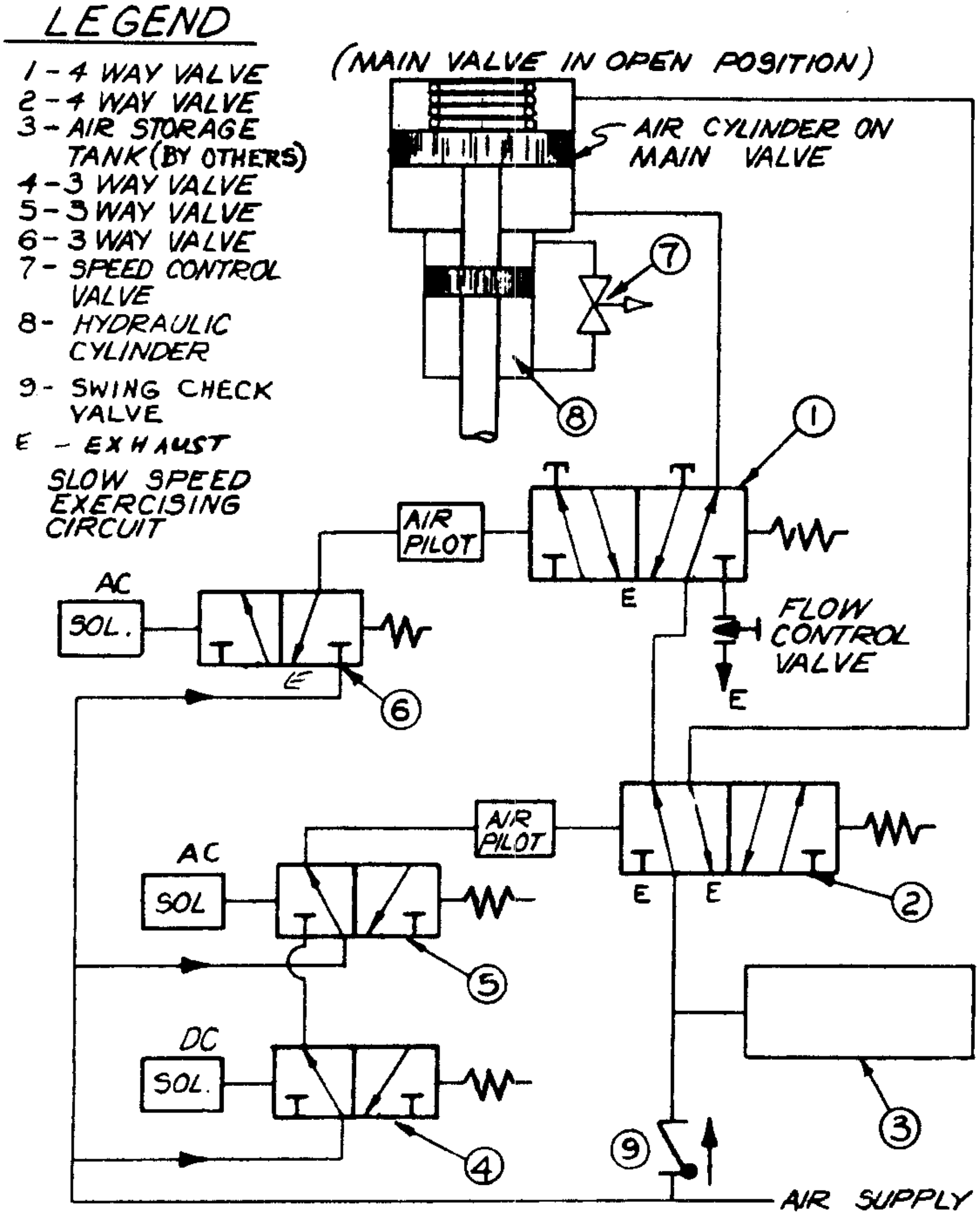


FIGURE 4.6-2
MAIN STEAM LINE
ISOLATION VALVE SCHEMATIC
CONTROL DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

4.7 REACTOR CORE ISOLATION COOLING SYSTEM

4.7.1 Safety Objective

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

4.7.2 Safety Design Basis

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

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

4.7.3 Power Generation Objective

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

4.7.4 Power Generation Design Basis

1. The system shall operate automatically.

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

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

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

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

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

4.7.5 Description

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

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

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

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

submergence, an additional amount of volume in the CST is administratively controlled to ensure adequate inventory is available for HPCI and RCIC to support an 8 hour station blackout duration.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.7.6 Safety Evaluation

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

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

4.7.7 Inspection and Testing

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

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

the control room. See Figure 4.7-6 (Drawing M1G3-4). The instrument specifications for control of the RCIC for current plant operation are defined on Table 4.7-2. The pump discharge injection valve is tested in accordance with Technical Specification 3.13.

4.7.8 Operational Nuclear Safety Requirements for Plant Operation

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

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

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

Example of Matrix Reference:

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

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

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

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

4.7.9 Current Technical Specifications

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

4.7.10 References

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

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

TABLE 4.7-1

REACTOR CORE ISOLATION COOLING SYSTEM TURBINE-PUMP DESIGN DATA

Pump

Number Required - 1
Capacity - 100%
Design Temperature - 40°F to 140°F
Design Pressure - 1,500 psig
NPSH-20 ft (minimum)
Developed Head - 2,800 ft at 1,135 psia reactor pressure*
525 ft at 165 psia reactor pressure
Flow Rate
Injection Flow - 400 gal/min
Cooling Water Flow - 16 gal/min
Total Pump Discharge - 416 gal/min

Turbine

Number Required - 1
Capacity - 100%
Steam Inlet Pressure Range (psia) - 150 to 1,120 (saturated)
Steam Exhaust Pressure Range (psia) - 20 to 25

* The RCIC system is capable of delivering 400 gpm to the reactor vessel for a system head corresponding to a reactor pressure of 1126 psid, the highest analytical setpoint of the safety relief valves.

Table 4.7-2

REACTOR CORE ISOLATION COOLING SYSTEM FOR CURRENT
PLANT SAFETY ANALYSIS
INSTRUMENT SPECIFICATIONS

RCIC FUNCTION	INSTRUMENT	RANGE	TRIP SETTING	DESIGN BASIS REFERENCE
Pump Discharge H/L Flow	FS1360-7	N/A	Low 43 GPM	I-N1-202 (See note 2)
Pump Suction H/L Pressure	PS1360-21A PS1360-21B	30 in. Hg Vac to 75 psig	Low 15 in. Hg Vac High 70 psig	
Turbine Exhaust High Pressure	PS1360-26A,B	0 to 200 psig	50 psig	
Turbine Exhaust Diaphragm High Pressure	PS1360-27	2 to 20 psig	5 psig	BECo Calc. I-N1-210 (See note 2)
Reactor Vessel High Water Level Turbine Trip	LT263-72A,B LIS263-72A,B LS263-72A-3,B-3	-50 to +50 in. (See Note 1)	542.5 in. above vessel zero	BECo Calc. I-N1-99 (See note 2)
Reactor Vessel Low Water Level	LT263-72A,B,C,D LIS263-72A,B,C,D	-50 to +50 in. (See Note 1)	425.6 in. above vessel zero	BECo Calc. I-N1-96 (See note 2)

NOTE: 1. Referenced to instrument zero (482 1/2 inches above vessel zero).
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 4.7-3

REACTOR ISOLATION COOLING SYSTEM OPERATIONAL REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
4.7.1 Reactor Vessel Water Level Control	Pump Loop (includes 1 pump, turbine and turbine controls, pump discharge valve, piping, root valve, and isolation valves)	1	A,B	None
			C	Above 150 psig, 1 operable RCIC pump loop or the HPCI loop operable (C27-60)
			D	Above 150 psig, 1 operable RCIC pump loop or the HPCI loop operable (D27-60)
			E	1 operable RCIC pump loop or the HPCI loop operable (E27-60)
			F	1 operable RCIC pump loop or the HPCI loop operable (F27-60)

* 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 4.7-3 (Cont)

REACTOR ISOLATION COOLING SYSTEM OPERATIONAL
REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
4.7.2 RCIC Automatic Start	1. Trip System		A,B	None
			C	Above 150 psig, RCIC Trip System operable and the HPCI Trip System inoperable (D27-60)
			D	Above 150 psig, RCIC Trip System operable and the HPCI Trip System inoperable (D27-60)
			E	RCIC Trip System operable and the HPCI Trip System inoperable (E27-60)
			F	RCIC Trip System operable and the HPCI Trip System inoperable (F27-60)

* 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 4.7-3 (Cont)

REACTOR ISOLATION COOLING SYSTEM OPERATIONAL REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
4.7.2 RCIC Automatic Start (Cont)	2. Reactor Vessel Low Water Level Trip Channels	4 trip channels per trip system	A,B	None
			C	Above 150 psig, 1 channel operable in each of the 2 parallel logic pairs (C27-60)
			D	Above 150 psig, 1 channel operable in each of the 2 parallel logic pairs (D27-60)
			E	1 channel operable in each of the 2 parallel logic pairs (E27-60)
			F	1 channel operable in each of the 2 parallel logic pairs (F27-60)

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

FSAR FIGURE	BECO CONTROLLED DRAWING
4.7-1	M245
4.7-2	M246
4.7-3	M1G 1-2
4.7-4	M1G 2-5
4.7-5	M1G 4-5
4.7-6	M1G 3-4

4.8 RESIDUAL HEAT REMOVAL SYSTEM

4.8.1 Safety Objective

The safety objective of the residual heat removal system (RHR) is to provide core cooling, in conjunction with other core standby cooling systems (CSCS), and to provide containment cooling as required during abnormal operational transients and postulated accidents.

4.8.2 Safety Design Basis

The safety design basis of the RHR is to:

1. Restore and maintain the coolant inventory in the reactor vessel after a loss of coolant accident (LOCA) as required for core cooling in conjunction with other CSCS (low pressure coolant injection (LPCI) mode)

2. Provide cooling for the suppression pool and thereby remove heat from the containment following a LOCA to reduce containment pressure (suppression pool cooling (SPC) mode)

3. Maintain pressure suppression pool temperature during normal operation to within the limits assumed in the station safety analysis

4. The suppression pool shall be the source of water for the LPCI mode of operation of the RHR in order to provide a complete recycle path for water lost from the reactor vessel following reflooding

5. To provide a high degree of assurance that the RHR operates satisfactorily during a LOCA, each active component shall be capable of being tested during operation of the nuclear system

4.8.3 Power Generation Objective

The power generation objective of the RHR is to provide residual heat removal capability when the main condenser heat sink is unavailable.

4.8.4 Power Generation Design Basis

The power generation design basis of the RHR is to:

1. Remove residual heat from the nuclear system so that refueling and nuclear system servicing can be performed (shutdown cooling (SDC) mode)

2. Supplement the fuel pool cooling system capacity when necessary to provide additional cooling capacity

4.8.5 Description

4.8.5.1 General

The RHR system is designed for four modes of operation to satisfy all the objectives and bases. To provide clarity to the information presented herein, each mode of operation is defined as a subsystem of RHR and is discussed separately. It is shown how each subsystem contributes toward satisfying all the objectives and bases of the RHR. The four modes of RHR operation are:

1. (SDC) Mode
2. (LPCI) Mode
3. (SPC) Mode
4. Containment Spray Mode

The major equipment of RHR consists of two heat exchangers and four main system pumps. The heat exchangers (tube side) are cooled by the reactor building closed cooling water system, which is in turn cooled by the station salt water service system (see Section 10.6 and 10.8). The equipment is connected by associated valves and piping, and controls and instrumentation are provided for proper system operation. A schematic diagram of RHR is shown on Figures 4.8-1 (BECo M 241) and 4.8-2 (BECo M1H44).

The main system pumps are sized on the basis of the flow required during LPCI mode of operation, which is the mode requiring the maximum system flow rate. The heat exchangers are sized on the basis of their required duty for the SDC function, which is the mode requiring the maximum heat exchanger surface area. A summary of the design data of the main system pumps and the heat exchangers is presented on Table 4.8-1. The pump head may degrade from design value and still deliver the required LPCI flows. A total dynamic head of 380 ft at 4800 gpm will ensure that required LPCI flows are obtained or exceeded for all pump combinations.

The effects on available NPSH for the RHR pumps due to a postulated accumulation of LOCA generated debris on the suction strainers in the suppression pool were evaluated in accordance with Regulatory Guide 1.82 Rev. 2. The RHR and core spray suction strainers in each loop were replaced with a large capacity (670 ft^2) stacked disk strainer spanning the width of one torus bay and connected to the three pumps. The debris analysis determined the maximum volume of shredded fiberglass, sludge, dirt/dust, rust flakes, and paint chips generated from the bounding line break inside primary containment. Based on a bounding analysis for debris generation, transport, and accumulation, the increase in suction strainer head loss is within the margin for NPSH available to the RHR pumps following the design basis LOCA. Refer to Section 14.5.3 for the NPSH evaluation.

One loop, consisting of one heat exchanger, two main system pumps in parallel, and associated piping, is located in one corner compartment of the reactor building. The other heat exchanger, pumps, and piping, forming a second loop, are located in the diagonally opposite corner compartment of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system.

RHR equipment is designed in accordance with Class I seismic design criteria (see Section 12 and Appendix C). The system is assumed to be filled with water for the seismic analysis.

The system piping and main system pumps are designed, constructed, and tested in accordance with the requirements of Appendix A. The pumps are also designed and constructed in accordance with the Standards of the Hydraulic Institute. The shell side of the heat exchangers are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class C vessels, and the tube side is designed in accordance with Section VIII. The provisions of the Winter Addenda of 1966, paragraph N2113 apply.

Power for four RHR pumps (two pumps on each of two loops) is normally provided through the two independent 4,160V emergency buses. In the event that the normal auxiliary power supply is not available, the 4,160V buses serving the two loops of RHR are powered separately from the two diesel generators.

Additional flexibility has been provided in the design by the addition of a permanent piping connection from the station salt water service pumps to the RHR Piping System. This connection is sized to provide 5,000 gal/min at 0 psig reactor pressure. All piping and equipment in the Service Water System which serves Class I equipment and this additional piping connection are designed to Class I seismic requirements.

The interconnection of the service water and RHR is manually initiated. Inadvertent admission of salt water to the RHR is prevented by requiring the operator to switch over a spectacle flange, and to open two locked-closed valves. Leaks from either system can be detected by periodic inspections of locked-open drains on each side of the spectacle flange.

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. All piping and equipment which is part of the RHR system is designed to Class I seismic requirements.

The interconnection of the fire protection system and the RHR system is manually initiated. Inadvertent admission of fire water to RHR system 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. This prevents RHR from contaminating the fire protection system during normal operation.

4.8.5.2 Shutdown Cooling Subsystem

The shutdown cooling (SDC) subsystem is an integral part of the RHR and is placed in operation during a normal shutdown and cooldown. The initial phase of nuclear system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser with the main condenser acting as the heat sink. When nuclear system pressure has decreased to 50 psig the steam supply pressure is no longer sufficient to maintain vacuum in the main condenser, and the RHR is placed in the SDC mode of operation to complete cooldown of the nuclear system.

In the SDC mode, reactor coolant is pumped by the RHR main system pumps from one recirculation loop through the RHR heat exchanger(s) where heat is transferred to the reactor building closed cooling water system (RBCCW). Reactor coolant is then returned to the reactor vessel through connections to the recirculation loop(s). Shutdown cooling suction valves are interlocked with the torus suction and torus return line valves so that they cannot be opened simultaneously. This is to prevent an inadvertent rapid draindown of the reactor vessel to the torus. Similar interlocks are provided between shutdown cooling suction valves and the torus cooling return line valves such that they cannot be opened simultaneously. Temperature control is provided by varying flow rate in the RHR or RBCCW and by use of the RHR or RBCCW heat exchanger bypass line(s).

During a nuclear system shutdown and cooldown, when the SDC Subsystem is initially placed in operation, decay heat levels are high and operation of two RBCCW heat exchangers may be required to remove the decay heat. When decay heat level has decreased sufficiently, the entire shutdown cooling load can be shifted to one RBCCW heat exchanger. The heat transfer capability of each RHR heat exchanger is shown on Figure 4.8-3.

The SDC subsystem is capable of reducing reactor water temperature to 125°F within 20 hours after reactor shutdown so that the reactor can be refueled and serviced. 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, the cold shutdown condition (212°F) can be achieved within 8 hours after reactor shutdown with a 75°F SSW heat sink.

It is concluded that power generation Design Basis number 1 is satisfied by this subsystem.

4.8.5.3 Low Pressure Coolant Injection Subsystem

The low pressure coolant injection (LPCI) subsystem is an integral part of the RHR. It operates to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a LOCA in combination with other CSCS.

A detailed discussion of the requirements and response of the equipment which operates during LPCI for a LOCA may be found in Section 6, Core Standby Cooling Systems. A detailed discussion of the requirements and response of the controls and instrumentation of LPCI during a LOCA may be found in Section 7.4, Core Standby Cooling Systems Control and Instrumentation.

In general, LPCI operation involves restoring the water level in the reactor vessel to a sufficient height for initial cooling after a LOCA. The LPCI subsystem operates in conjunction with the high pressure coolant injection system (HPCI), the automatic depressurization system, and the core spray system to achieve this goal as described in Section 6, Core Standby Cooling System.

The HPCI is a high head, low flow system and pumps water into the reactor vessel when the nuclear system is at high pressure. If the HPCI fails to deliver the required flow of cooling water to the reactor vessel, the automatic depressurization feature of the nuclear system pressure relief system functions to reduce nuclear system pressure so that LPCI operates to inject water into the pressure vessel. LPCI is a low head, high flow subsystem. All these operations are carried out automatically. LPCI is designed to reflood the reactor vessel to at least two thirds core height. After the core has been flooded to this height, the capacity of one RHR main system pump is more than sufficient to maintain the level. This capability satisfies safety design basis 1.

During LPCI operation, the main system pumps take suction from the suppression pool and discharge to the reactor vessel into the core region through one of the recirculation loops. Instrumentation is provided to detect the undamaged path for injection of LPCI flow (see Section 7.4, Core Standby Cooling Systems Control and Instrumentation). Water lost from the vessel through a break in the piping within the primary containment returns to the suppression pool through the pressure suppression vent pipes. It is concluded that safety design basis 4 is satisfied.

Coolant flow to the RHR heat exchangers from the reactor building closed cooling water system is not required immediately after a LOCA because heat rejection from the containment is not necessary during the time it takes to flood the reactor.

4.8.5.4 Suppression Pool Cooling Subsystem

The suppression pool cooling (SPC) subsystem is an integral part of the RHR and is placed in operation to remove heat from the pressure suppression pool to reduce pressure in the primary containment following a LOCA. This system is also operated as required during planned operations to control suppression pool water temperatures within the limits assumed in the Station Safety Analysis.

With the RHR in the SPC mode of operation, the RHR pumps are aligned to pump water from the suppression pool through the RHR heat exchangers, where cooling takes place by transferring heat to the reactor building closed cooling water system. Torus cooling return line valves are interlocked with the shutdown cooling suction valves, such that they cannot be opened simultaneously. The flow returns to the suppression pool via return lines which discharge below to the pool surface.

The RHR in the SPC mode functions to transfer heat from the primary containment to the reactor building closed cooling water system thereby lowering the primary containment pressure. It is concluded safety design bases 2 and 3 are satisfied by this mode of RHR operation.

4.8.5.4.1 LPCI with Heat Rejection

Long-term core and suppression pool cooling can be performed by use of the LPCI with Heat Rejection mode for liquid breaks inside primary containment of sufficient size to support continuous recirculation as described below including the design basis LOCA. In the LPCI with Heat Rejection Mode, the RHR pumps take suction from the suppression pool, and pump the water through the RHR heat exchanger where cooling takes place by transferring heat to the station cooling water systems. The fluid is then discharged back to the reactor vessel where sensible and decay heat is absorbed. The fluid returns to the suppression pool by flowing out the pipe break, into the drywell, and back to the suppression pool through the drywell to wetwell vent system. This method of cooling sets up a recirculation loop including the suppression pool, RHR heat exchanger, and reactor vessel.

In LPCI with Heat Rejection mode, with two RHR pumps in operation, the heat exchanger bypass valve remains in its full open normal position. No disruption of LPCI flow is required to enter this mode of suppression pool cooling. This configuration will provide maximum core cooling but does not provide rated heat removal because more than half of the two pump LPCI flow rate goes through the heat exchanger bypass line and not the heat exchanger.

Rated heat removal from the containment is obtained using the LPCI with Heat Rejection mode by removal of one RHR pump from LPCI service and closure of the RHR heat exchanger bypass valve while maintaining maximum LPCI injection flow from the single RHR pump. The RHR heat exchanger can accommodate the maximum flow of one RHR pump operating with the bypass valve closed in the LPCI mode. This mode of operation ensures a minimum RHR flow rate of 5100 gpm through the heat exchanger.

4.8.5.5 Containment Spray Subsystem

The containment spray subsystem provides containment spray capability as an alternate method for reducing containment pressure following a LOCA. A portion of the water pumped through the RHR heat exchangers can be diverted to spray headers in the drywell and above the suppression pool. The portion of the RHR heat exchanger flow to the spray headers in the drywell condense any steam that may exist in the drywell thereby lowering containment pressure. The remaining portion returns to the suppression pool via the suppression pool return line. The spray collects in the bottom of the drywell until the water level rises to the level of the pressure suppression vent pipes where it overflows, and drains back to the suppression pool. Approximately 24 percent of the total flow may be directed to the suppression chamber spray ring to cool any noncondensable gases collected in the free volume above the suppression pool. The containment spray subsystem will remove energy from the drywell by condensing steam, thereby making available the drywell volume to accommodate additional quantities of gases from any postulated metal water reactions above that which the containment can inherently accommodate without spray.

The containment spray mode of the RHR cannot be operated unless the level inside the reactor vessel shroud is above the two thirds core height set point and the drywell pressure exceeds a setpoint greater than 1, but less than 2 psig.

Interlocks are provided to prevent LPCI flow from being diverted to the containment spray mode unless the core is flooded. A keylock switch in the control room permits the overriding of this interlock to reduce containment pressure if required. Interlocks are also provided to prevent SDC flow unless the reactor vessel pressure is below 80 psig.

4.8.5.6 Augmented Fuel Pool Cooling

The RHR system can be intertied with the fuel pool cooling and demineralizer system, if required. See Figure 4.8-3. The AFPC modes are opted only when the reactor is in the cold shutdown or refueling mode. This capability increases the spent fuel pool cooling capacity in the event that such additional capacity is necessitated by removal of the full reactor core or a large number of fuel assemblies during a normal refueling. The RHR/fuel pool cooling system intertie was sized to remove a heat load of 23 x 10^6 BTU/Hr at 1200 gpm from the fuel pool which corresponds to full core loading plus spent fuel discharge from previous outages. There are two modes of operation for the RHR/Fuel Pool interconnection; Augmented Fuel Pool Cooling (AFPC) Modes 1 and 2, see Section 10.4, Fuel Pool Cooling and Cleanup System.

The fuel pool cooling system piping is non-safety related. Failures of the FPC piping may be postulated when the RHR/FPC intertie is in use. In AFPC Mode 1, a failure of the FPC piping can result in draining of the reactor basin through the RHR shutdown cooling loop until operator action is taken to shut down the RHR pump and isolate the RHR piping from the reactor recirculation piping. The draindown rate at an upper bound flow rate of 5000 gpm is 2.4 inches/minute. Reactor basin draindowns have been analyzed and it is shown that sufficient time is available for the required operator actions to prevent unacceptable radiological consequences.

4.8.6 Safety Evaluation

Satisfaction of Safety Design Bases stated in Section 4.8.2 are covered in the Description and the Inspection and Testing portions of this section.

Since the LPCI Subsystem acts with other CSCS to satisfy the safety objective, it is evaluated in conjunction with the other CSCS in Section 6, Core Standby Cooling Systems. The safety evaluation of the controls and instrumentation of the LPCI Subsystem is in Section 7.4, Core Standby Cooling Systems Control and Instrumentation.

4.8.7 Inspection and Testing

A design flow functional test of the RHR main system pumps is performed during normal plant operation by taking suction from the suppression pool, and discharging through the cooling lines back to the suppression pool. The discharge valves to the reactor recirculation loops remain closed during this test, and reactor operation is undisturbed. The discharge injection valves are tested in accordance with Technical Specifications 3.13.

The discharge valves to the containment spray headers are tested per Technical Specification 3.13 by operating the upstream and downstream valves individually. All these valves with the exception of check valves 1001-68A and 1001-68B can be actuated from the control room using remote manual switches. Control system design provides automatic return from test to operating mode if LPCI initiation is required during testing. It is concluded that Safety Design Basis 5 is satisfied.

4.8.8 Nuclear Safety Requirements for Plant Operation

Table 4.8-2 presents the nuclear safety requirements for the RHR (SPC mode) for each BWR operating state. The entries on Table 4.8-2 represent an extension of the stationwide BWR systems analysis of Appendix G to the components of the RHR (SPC mode). The following referenced portions of the Safety Analysis Report provide important information justifying the entries on Table 4.8-2:

	Reference	Information Provided
1.	Earlier parts of Section 4.8	Description of the SPC Subsystem hardware
2.	Station Safety Analysis, Section 14	Analyses verifying response of RHR (containment cooling mode) to transients and accidents
3.	Operational Nuclear Safety Analysis, Appendix G	Identifies conditions and events for which SPC Subsystem action is required

Each detailed requirement on Table 4.8-2 is referenced, if possible, to the most significant plant condition originating the need for the requirement by identifying a matrix block on one of the six matrices of Appendix G. The matrix block references are given in parentheses beneath the detailed requirements in the "minimum required for action" columns on Table 4.8-2 and are coded as follows:

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

F39-63

F = BWR operating state F
39 = Event (row 39)
63 = RHR (column 63)

In most cases, the basis for an operational nuclear safety requirement is clear from the information provided in the previously noted references. The RHR (SPC mode) requirements in states C (with nuclear system pressurized), D (with nuclear system pressurized), E, and F result from considerations of the LOCA. Operation of the containment cooling mode (one RHR containment cooling loop with containment spray, one RHR heat exchanger, one Reactor Building closed cooling water loop, plus associated valves and piping) is essential to provide cooling for the suppression pool and drywell following a LOCA. Any failed part in the containment cooling loop constitutes a loop failure for repair time purposes.

4.8.9 Current Technical Specifications

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

TABLE 4.8-1

RESIDUAL HEAT REMOVAL SYSTEM EQUIPMENT DESIGN DATA

PUMPS

Number Installed - 4   Design Temperature - 350°F
Shutoff Head - 750 ft   Design Pressure - 450 psi

Total injection flow rates used in the core cooling analysis for the two, three, and four pump LPCI modes:

2 Pump LPCI Injection Flow ≥ 9,100 gpm @ 20 psig Rx Press

2 Pump LPCI Injection Flow ≥ 9,500 gpm @ 0 psig Rx Press

3 Pump LPCI Injection Flow ≥ 12,100 gpm @ 20 psig Rx Press

3 Pump LPCI Injection Flow ≥ 12,600 gpm @ 0 psig Rx Press

4 Pump LPCI Injection Flow ≥ 13,800 gpm @ 20 psig Rx Press

4 Pump LPCI Injection Flow ≥ 14,500 gpm @ 0 psig Rx Press

RHR Heat Exchanger flow rates used for containment heat removal analysis for the single pump Torus Cooling, LPCI w/Heat Rejection, and Containment Spray Modes:

Torus Cooling RHR Heat Exchanger Flow ≥ 5100 gpm

LPCI w/Heat Rejection RHR Heat Exchanger Flow ≥ 5100 gpm

Containment Spray RHR Heat Exchanger Flow ≥ 4500 gpm

HEAT EXCHANGERS

Number Installed - 2
Shell Side Fluid - Reactor Water or Suppression Pool Water
Tube Side Fluid - Reactor Building Closed Cooling Water
Design Pressure - 450 psig   Design Temperature 40-350°F
Pressure Drop at Design Conditions - shell and tube side - 6 psi

Heat Transfer Capability

Shutdown Cooling Mode (two heat exchangers)	90 x 10^{6} Btu/hr at 130°F RHR Inlet and 55°F Service Water
Shutdown Cooling Mode (two heat exchangers)	67 x 10^{6} Btu/hr at 130°F RHR Inlet and 75°F Service Water
Containment Cooling Mode (one heat exchanger)	64 x 10^{6} Btu/hr at 166°F RHR Inlet and 65°F Service Water
Containment Cooling Mode (LPCI with Heat Rejection, one heat exchanger)	70.8 x 10^{6} Btu/hr at 185°F RHR Inlet and 75°F Service Water

TABLE 4.8-2

RESIDUAL HEAT REMOVAL SYSTEM (SUPPRESSION POOL COOLING MODE)
OPERATIONAL REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Provide cooling for the suppression pool and drywell so that containment over-pressure does not result following a loss of coolant accident	RHR suppression pool cooling loop	2 loops (2 RHR pumps and 1 heat exchanger per loop)	A, B	None
			C	With the nuclear system pressurized 1 operable RHR suppression pool cooling loop (C39-63)
			D	With the nuclear system pressurized 1 operable RHR suppression pool cooling loop (D39-63)
			E	1 operable sup-sion pool RHR cooling loop (E39-63)
			F	1 operable sup-sion pool RHR cooling loop (F39-63)

* 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 4.8-1 and 4.8-2 have been removed.

Please refer to BECo Controlled Drawings M 241 and M1H4-4.

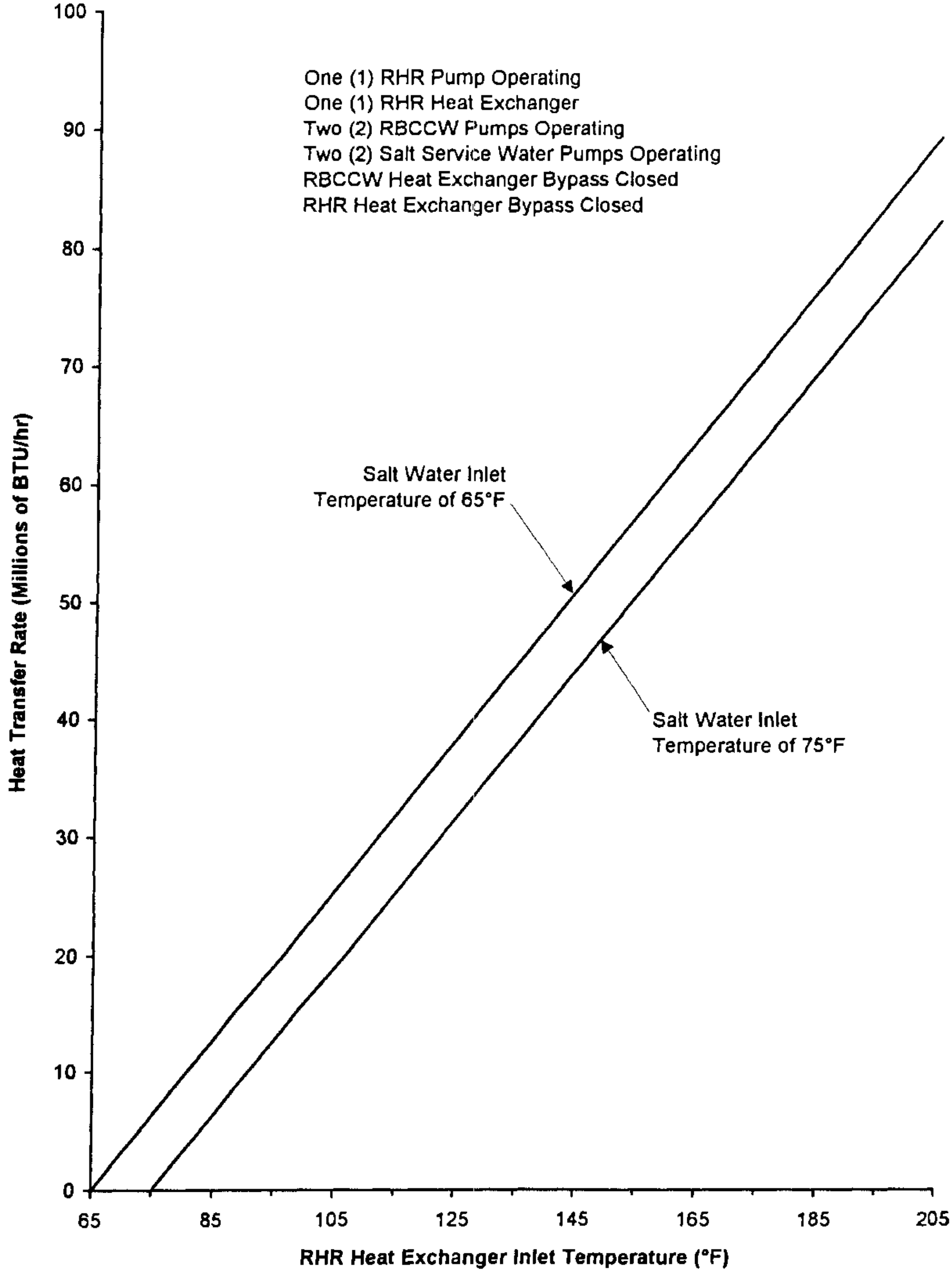


Figure 4.8-3
Residual Heat Removal System Heat Transfer Capability
Pilgrim Nuclear Power Station
Final Safety Analysis Report
Revision 19 - June 1996

4.9 REACTOR WATER CLEANUP SYSTEM

4.9.1 Power Generation Objectives

The power generation objectives of the Reactor Water Cleanup System are:

1. To maintain high reactor water purity to limit chemical and corrosive action

2. To remove corrosion products to limit impurities available for neutron flux activation

3. To provide a method for decreasing reactor water inventory during heatup

4.9.2 Power Generation Design Basis

The design of the Reactor Water Cleanup System shall contain provisions for the following:

1. Continuous removal of radioactive waterborne materials which are generated in the reactor coolant as a result of the fission and corrosion processes

2. Continuous removal of soluble inorganic impurities (e.g., chlorides) which may enter with the reactor feedwater and could, if not controlled, subsequently concentrate to exceed the specified water quality limits

3. Removal of coolant from the reactor system at acceptable activity levels during startups and shutdowns

4. Limitation of heat and fluid losses from the nuclear system during the satisfaction of the above design bases

4.9.3 Description

The Reactor Water Cleanup System purifies the reactor coolant water by continuously removing a portion of the reactor recirculation flow from the suction side of a recirculation pump, sending the removed flow through filter demineralizer units to undergo mechanical filtration and ion exchange processes, and returning the processed fluid back to the reactor via the feedwater line. See Figure 4.9-1. The nominal system flow rate of 110,000 lb/hr will process the reactor operating water volume in approximately 4 1/2 hr. The system has a "stretch" flow rate of approximately 151,000 lb/hr which is available when accelerated cleanup of reactor water is desired. The driving head for the system is provided by two 100% capacity cleanup recirculation pumps, which provide the necessary system pressure to overcome piping and equipment losses and to return the processed water to the reactor via the feedwater line. The system also allows routing of the treated water to the Liquid Radwaste System or the main condenser hotwell during various modes of system operation.

The major equipment of the system consists of the two cleanup recirculation pumps, regenerative and nonregenerative heat exchangers, and two filter demineralizer units with supporting equipment, as shown on Figures 4.9-2 and 4.9-3. The entire system is connected by associated valves and piping with appropriate controls and instrumentation to effect the desired system operation. Design data for the major equipment are presented on Table 4.9-1

The system has been modified to relocate the cleanup recirculation pumps downstream of the heat exchangers. Water from the reactor first enters the regenerative heat exchanger, then the nonregenerative heat exchanger, and finally the pumps. A pump bypass system with a manual valve is installed. The pump discharge is flanged and a seal injection system with a centrifuge is provided. These modifications facilitate maintenance, increase pump reliability, and minimize the effect of nozzle loads on the cleanup recirculation pumps.

The reactor water is first sent through the tube sides of regenerative and nonregenerative heat exchangers due to the necessity for reducing the temperature of the reactor water to a level acceptable for the protection and satisfactory performance of the filter demineralizer ion exchange resins and to minimize temperature effects on the cleanup recirculation pump mechanical seals. A regenerative heat exchanger is utilized for the first stage, larger part of the cooling process to satisfy the power generation design basis of minimizing the heat loss from the primary system. This arrangement recovers a good part of the sensible heat in the reactor water by utilizing return (treated) water from the filter demineralizer units as the shell side cooling medium.

Regenerative heat exchanger size and temperature range limitations make further cooling of the water necessary to reduce the temperature to that value acceptable from the standpoint of resin protection and satisfactory ion exchanger resin performance. The passage of the water through the nonregenerative heat exchanger transfers the remaining heat to the Reactor Building Closed Cooling Water System. The nonregenerative heat exchanger is designed to maintain this lower temperature even when the effectiveness of the regenerative heat exchanger is reduced. This takes place during reactor startup when the system is used to remove excess coolant inventory ("swell"), and control rod drive water from the reactor system by diverting a part of the filter demineralizer effluent either to the main condenser, or to the Radwaste System, rather than sending it back to the Reactor Feedwater System via the shell side of the regenerative heat exchanger. During normal operation the temperature of reactor water from the nonregenerative heat exchanger is 120°F, but it can be increased to 130F during the startup or water removal modes.

The water cooled by the heat exchanger then flows through two parallel filter demineralizer units for the removal of impurities. These half capacity units are pressure precoat type filter demineralizers utilizing finely ground, nonregenerable, mixed cation and anion ion exchange resins. The operating service cycle of a

filter demineralizer unit is terminated by either a high pressure drop across the unit, normally limiting except during an abnormal condenser leak, or by exhaustion of the ion exchanger resins. When a unit's service cycle is terminated, the unit is isolated by closure of associated inlet and outlet valves while the parallel unit remains in operation. The out of service unit is backwashed using air and condensate to remove all of the resinous material and accumulated insoluble material. The spent resins are sluiced from the unit to a sludge receiver tank, where short lived radioactive decay is allowed to take place, and then flows to the Radwaste System for further processing and disposal. The unit is then precoated with a slurry of new resins, and the unit holding pump is operated until such time as the unit is placed back into cleanup service.

A strainer is installed on the outlet of each filter demineralizer unit to prevent resin from entering the reactor in the event of failure of a resin holding element. The strainer screens are capable of withstanding a pressure drop greater than the developed cleanup recirculation pump head, when the strainer is full of resin. Each strainer is provided with an alarm energized by high differential pressure, which indicates a clogged strainer caused by resin holding element failure. A bypass line with a throttling type remote manual control valve is provided for bypassing the filter demineralizer units whenever necessary.

Normal routing of flow from the filter demineralizer units is then through the shell side of the regenerative heat exchanger where it is heated by the incoming (untreated) coolant, to the temperature range of reactor feedwater. It then returns to the reactor through the Feedwater System via a thermal sleeve which is designed to accommodate, without excessive thermal stresses, the maximum temperature difference that can occur between the two fluid streams under any mode of plant operation.

Relief valves, alarms, and control instrumentation are provided to protect the system and equipment against overpressurization and resin overheating. Relief valves are furnished on the shell and tube sides of both regenerative and nonregenerative heat exchangers, at the filter demineralizer units, and for the Low Pressure Precoat System auxiliary equipment. A high temperature condition at the inlet to the filter demineralizer units will actuate an alarm in the main control room. In the inlet piping to the regenerative heat exchangers, two motor-operated isolation valves, one on either side of the primary containment, are automatically closed by any of the following conditions:

1. High temperature at the inlet to the filter demineralizer units. This protects the ion exchange resins against damage due to high temperature

2. Reactor vessel low water level. This protects the core in case of a possible break in the Reactor Water Cleanup System piping or equipment. See Section 7.3, Primary Containment and Reactor Vessel Isolation Control System

3. Standby Liquid Control System actuation. This prevents the ion exchange resins from removing the boron from the reactor

4. High space temperature. This indicates a leak and/or break in the system

5. High flow. This indicates a break in the system

The high temperature condition at the inlet to the filter demineralizer units will also generate a signal which trips the cleanup recirculation pumps. This protects the pumps against loss of suction when the isolation valves shut.

In the event of a reduction or loss of system flow, the holding pumps associated with each filter demineralizer unit will automatically start to maintain flow through the unit. Constant volumetric flow through the unit is maintained by a manually adjusted flow control valve in the effluent line. This valve will function to close completely if the pressure drop across the unit continues to increase above the value which actuates an alarm. This function is to protect the resin holding elements. Continuous conductivity sampling stations are located in the influent header to the filter demineralizer, and downstream of each filter demineralizer unit, with the influent sample point also being used as the normal source for reactor water samples. Analyses of the samples provide an indication of the effectiveness of the filter demineralizer units.

Operation of the Reactor Water Cleanup System is effected from the main control room where instrumentation for flow, pressure, temperature, and conductivity indicates or records. In addition, keylock bypass switches are provided in the cable spreading room to facilitate surveillance testing of the high temperature and flow sensors in the Reactor Water Cleanup System. The associated alarms also actuate in the control room. Backwashing and precoating operations are controlled from a local control panel in the Reactor Building. During heatup operations, the system is utilized to remove excess coolant inventory resulting from the coolant density decrease during heatup ("swell"), and control rod drive cooling water from the reactor. During this operation, a cleanup recirculation pump is running, the regenerative heat exchanger is under partial load (not receiving all of the filter demineralizer effluent), the nonregenerative heat exchanger is under maximum startup load, the filter demineralizer units are in operation, and excess water is routed to the main condenser or the Radwaste System.

The water removal operation ("blowdown mode") of the system can be utilized to remove excess water from the reactor. In this operation, all of the Cleanup System flow is discharged to the Radwaste System or to the main condenser hotwell. A cleanup recirculation pump is in operation, the regenerative heat exchanger is under no load, the nonregenerative heat exchanger is under full load, and the filter demineralizer units are in operation. This necessitates a restricted flow rate because of the maximum allowable outlet temperature to the

reactor building closed cooling water from the shell side of the nonregenerative heat exchanger, and results in the maximum temperature differential across the nonregenerative heat exchanger.

The system has been modified to incorporate a bypass line around the cleanup recirculation pumps. Flow during the "blowdown mode" can be diverted from the pumps and maintenance can be performed. During cold shutdown conditions, both the cleanup recirculation pumps and the filter demineralizers can be bypassed to letdown excess water from the reactor. Additionally, the system has been modified to locate flanged spool piece sections upstream of valve MO-1201-80 and downstream of valve MO-1201-5 to facilitate future decontamination of the system's major piping and components.

Original Type 304 stainless steel piping and fittings between drywell penetration X-14 and the 6" x 4" reducer downstream of MO-1201-5 was replaced with type 316L stainless steel.

During the refueling operation, the reactor water cleanup system, in conjunction with the fuel pool cooling and cleanup system, provides continuous cleaning of the reactor water.

During operations when the reactor is being maintained in a hot standby condition, a cleanup recirculation pump is in operation, the regenerative heat exchanger is under full load, the nonregenerative heat exchanger is under partial load, the filter demineralizer units are in operation, and system flow is back to the reactor without bypass flow. This condition establishes the minimum net positive suction head (NPSH) condition for the cleanup recirculation pumps and requires maximum pump capacity.

The reactor water cleanup system filter/demineralizer pressure vessel is designed, fabricated, tested, and stamped in accordance with ASME Boiler and Pressure Code, Section III, Class C. The materials utilized in the filter/demineralizer unit are described on Table 4.9-2.

The reactor water cleanup system backwash receiving tank is designed and fabricated in accordance with the American Petroleum Institute Specification No. 650. The materials utilized are described on Table 4.9-2. Radiography and radiographic acceptance criteria of the backwash receiver tank is in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code. Each completed receiver tank is leak tested following all fabrication or erection operations, but prior to any painting, lining, or coating the tank. Liquid penetrant examination is performed in accordance with Appendix VIII of Section VIII of the ASME Boiler and Pressure Vessel Code, and ASTM-E-165.

The regenerative heat exchangers and tube side of the nonregenerative heat exchangers are designed, fabricated, tested, and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class C, and TEMA Class R. The shell side of the nonregenerative heat exchangers are designed, fabricated, inspected, tested, and stamped in accordance with Section VIII of the ASME Boiler and Pressure Vessel

Code, and TEMA Class R. Connecting piping between shells and between channels meet the requirements of Sections 1 and 6 of the ASA B31.1 Code for Pressure Piping. Cyclic operating conditions will not exceed the limitations of paragraph N415.1 for ASME Boiler and Pressure Vessel Code, Section III, Class A vessels. The materials utilized are described on Table 4.9-2.

Leak testing of the tube to tube sheet joint is required and must be leaktight at 50 psig pressure using air or inert gas. Hydrotests are conducted.

4.9.4 Inspection and Testing

Periodic chemical analyses of reactor water can be made to ensure that the reactor water cleanup system is functioning to maintain the water within limits. Specific provisions are made to determine the effectiveness of demineralization and ion exchange functions of filter-demineralizer units, such that the end of a unit's operating service cycle may be anticipated in a timely fashion. In all other respects, because the reactor water cleanup system is normally in operation during all modes of nuclear plant operation, satisfactory operation is demonstrated continuously without the need for any special inspection or testing.

TABLE 4.9-1

REACTOR WATER CLEANUP SYSTEM EQUIPMENT DESIGN DATA

MAIN CLEANUP RECIRCULATION PUMPS

Design Temperature (°F) - 575
Design Pressure (psig) - 1,450
Discharge Head @ Rated Flow (ft) - 520
Max Shutoff Head (ft) - 600
Number Required - 2
Capacity (each) - 100%
Rated Flow (gal/min/pump) - 200[1]
Min Available NPSH (ft) - 10[2]

HEAT EXCHANGERS (Design Basis)

	Regenerative	Nonregenerative
Shell Side Pressure (psig)	1,450	150
Shell Side Temperature (°F)	575	370
Tube Side Pressure (psig)	1,450	1,450
Tube Side Temperature (°F)	575	575

FILTER DEMINERALIZERS

Design Temperature (°F) - 150
Design Pressure (psig) - 1,450
Time to remove a unit from service, backwash, precoat, and return to service (min) - 60
Number Required - 2
Capacity (each) - 50%
Normal Flow Rate/Unit (lb/hr) - 55,000[3]
Effluent Conductivity (mho max) 0.1
Effluent pH - 6.5 to 7.5
Effluent Insolubles (ppb-measured as residue on 0.45 micron filter paper) - <10

NOTES:

(1) Reduce maximum flow to 160 gpm when reactor temperature is below 230°F

(2) Minimum available NPSH applies when reactor temperature is below 230°F

(3) 75,500 lb/hr - "stretch" flow rate

TABLE 4.9-2

REACTOR WATER CLEANUP SYSTEM
EQUIPMENT MATERIALS SPECIFICATIONS

FILTER/DEMINERALIZER PRESSURE VESSEL

	Materials Used
Shell:	ASME SA240 TP 304L, hot rolled, annealed, pickled finish
Bolting Material:	ASME SA193
Element Support:	ASTM A240 TP304L
Internals:	304L Stainless Steel
Forgings:	*ASTM SA182 F304L*

BACKWASH RECEIVER TANK

	Materials Used
Shell:	ASTM SA-285-C
Bolting Material:	SA-307-B
Internal Supports:	T-304
Forgings:	ASTM SA182, Gr F-1

HEAT EXCHANGERS

	Materials Used	
	Regenerative	Nonregenerative
Shell and Shell Cover	Stainless Steel or Clad	Carbon Steel
Tube Sheet and Channel	Stainless Steel or Clad	Stainless Steel or Clad
Channel Cover	Stainless Steel or Clad	Stainless Steel or Clad
Tubes	Stainless Steel	Stainless Steel
Connecting Pipe and Fittings	Stainless Steel	Carbon Steel *between* Shells Stainless Steel between Channels

Figures 4.9-1, 4.9-2 and 4.9-3 have been removed.

Please refer to BECo Controlled Drawings M1L2-8, M 247 and M248.

4.10 NUCLEAR SYSTEM LEAKAGE RATE LIMITS

4.10.1 Safety Objective

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

4.10.2 Safety Design Basis

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

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

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

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

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

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

4.10.3 Description

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

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

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

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

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

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

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

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

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

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

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

4.10.3.1 Identified Leakage Rate

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

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

4.10.3.2 Unidentified Leakage Rate

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

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

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

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

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

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

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

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

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

4.10.3.3 Reactor Pressure Boundary Leak Detection System

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

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

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

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

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

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

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

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

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

4.10.4 Safety Evaluation

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

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

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

4.10.5 Inspection and Testing

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

4.10.6 Proposed Nuclear Safety Requirements for Initial Plant Operation

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

4.10.7 Current Operational Nuclear Safety Requirements

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

Figure 4.10-1 has been deleted.

Please refer to Figure 10.19-1 (BECo Drawing M239)

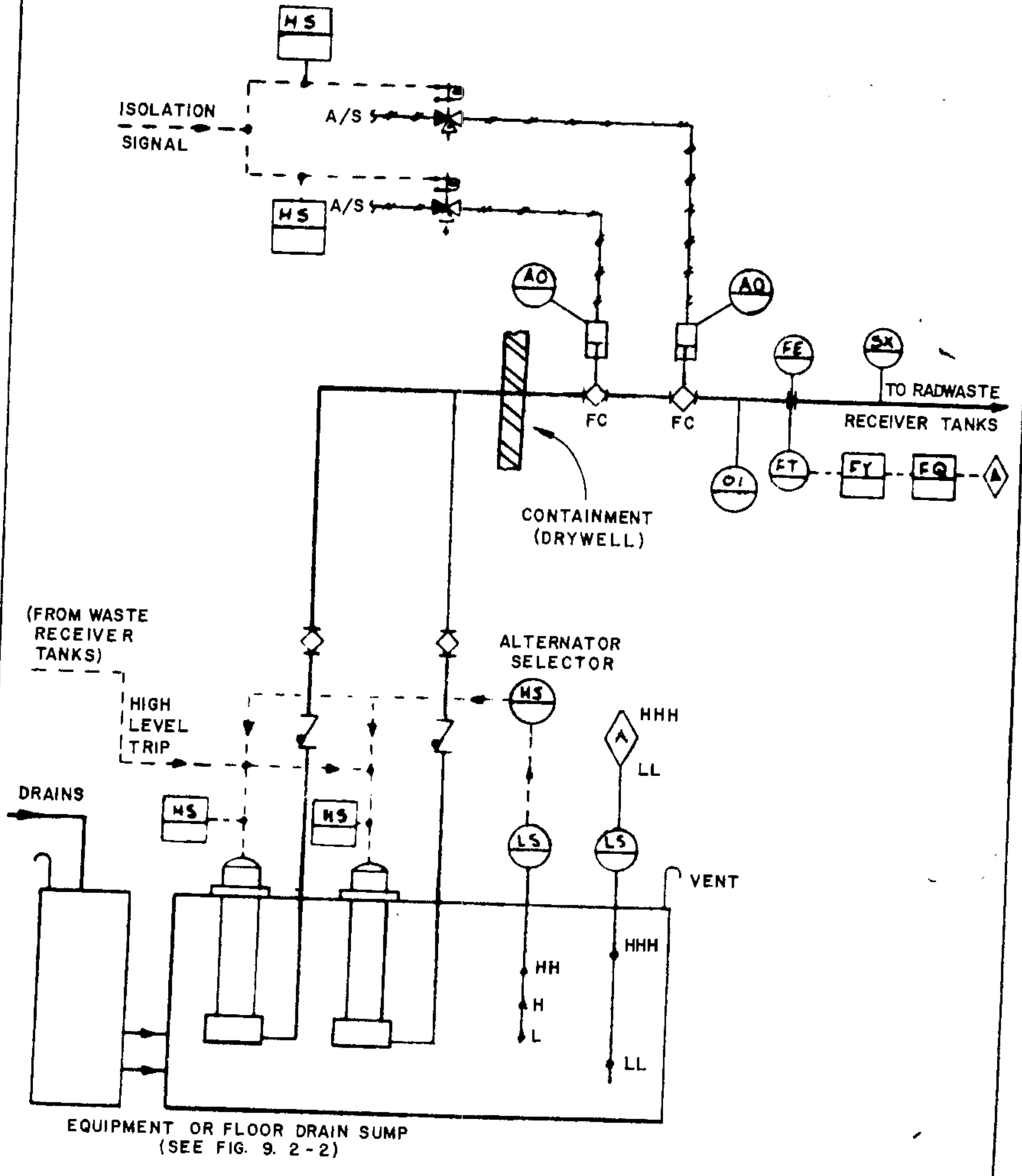


FIGURE 4.10-2

DRYWELL SUMPS DIAGRAM

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

4.11 MAIN STEAM LINES AND FEEDWATER PIPING

4.11.1 Power Generation Objective

The power generation objective of the main steam lines is to conduct steam from the reactor vessel through the primary containment to the steam turbine. The power generation objective of the feedwater lines is to provide a piping path for delivery of water through the primary containment to the reactor vessel.

4.11.2 Safety Design Basis

The portions of the main steam and feedwater lines which are part of the nuclear system primary boundary shall be designed to accommodate all operational stresses and to withstand the effects of earthquake loadings.

4.11.3 Power Generation Design Bases

1. The main steam lines shall be designed to conduct steam from the reactor vessel over the full range of reactor power operation.

2. The feedwater piping shall be designed to conduct water to the reactor vessel over the full range of reactor power operation.

4.11.4 Description

The feedwater piping is designed to conduct water from sources outside the primary containment to the reactor vessel. The general requirements of the Feedwater System are covered in Section 7.10, Feedwater Control System and Section 11.8, Condensate and Feedwater Systems.

The main steam piping is designed to conduct steam from the reactor vessel through the primary containment to the steam turbine. Four steam lines are utilized between the reactor and the turbine. The use of these multiple lines permits turbine stop valve and main steam line isolation valve tests during station operation with a minimum amount of load reduction. To fully achieve this objective, the four steam lines are headed through a bypass valve chest upstream of the turbine stop valves. This also insures that the Turbine Bypass System is connected to the active steam lines. A drain line is connected to the low points of each main steam line, both inside and outside the drywell. Both sets of drains are headered and connected by valving to permit drainage to the main condenser hotwell. An orifice is provided around the final valve to the condenser hotwell to permit continuous draining of the steam line low points. The inside steam line drains slope downward from the steam line low point to the orifice outside the drywell.

The drain line from the orifice to the condenser hotwell slopes down to the main condenser. An additional drain is provided from the low point of the drains to clean radwaste, to permit purging the lines for maintenance.

The inside and outside steam line drains are capable of being utilized to equalize pressure across the main steam line isolation valves prior to restart following a steam line isolation. Assuming all steam line isolation valves have closed and the steam lines outside the drywell have been depressurized, the isolation valves outside the drywell are opened first; the drain lines are then used to warm up and pressurize the outside steam lines. Finally, the main steam line isolation valves inside the drywell are opened.

All main steam and feedwater piping is classified according to service and location. The materials used in piping are, as a minimum, in accordance with USAS B31.1.0.

The main steam and feedwater piping inside the Reactor Building is designed to Class I criteria. See Section 12 and Appendix C. All of the main steam and feedwater piping is designed in accordance with Appendix A.

The main steam lines outside the drywell are anchored at the containment penetrations. The anchors used to rigidly affix the flued head fittings to the Reactor Building structure have been designed to withstand the following simultaneous loads as applicable (i.e., thermal expansion and pipe rupture loads would not occur simultaneously):

1. Thermal Expansion - a summation of reactions from piping both inside and outside the drywell

2. Dead Weight - weight of pipe and fluid inside and outside the drywell

3. Pipe Rupture Loads - jet forces resulting from either a circumferential break or slot type failure of the process line. Reactions at the anchor were determined by an analysis of the load transmitting capability of the process line based on the ultimate strength and strain hardening properties of the materials

4. Seismic Reactions - reactions resulting from seismic disturbance on piping outside the drywell

With all of the above loads considered, the anchor and flued head have sufficient strength so that pipe failure either inside or outside the containment will not fail the anchor or flued head.

In addition to the above, the main steam piping outside of the drywell is designed or further restrained downstream of the outer isolation valve, so that a rupture resulting from a seismic disturbance in the Class II piping will not fail the Class I portions of the system, which includes that portion of pipe between the outer isolation valve and the flued head. Various pipe rupture locations in the Class II main steam piping is considered which results in the maximum possible torsion, movement, or axial forces in the Class I piping.

From the outer isolation valve to the turbine stop valve, hydrous calcium silicate insulation is used which, although designed for permanent installation, can be removed for visual or volumetric inspection as required.

Inspections and startup tests for the main steam lines include examination of both hot and cold hanger placement, clearances for expansion in the cold "as built" condition, and measurement of thermal expansion at selected points. These tests and inspections are an integral part of the preoperational testing sequence and assure conformance to design specifications and calculations.

4.11.5 Safety Evaluation

Differential pressures on reactor internals under the assumed accident conditions of a ruptured steam line are limited by both the utilization of flow restrictors and the utilization of four main steam lines. Main steam and feedwater piping is designed, as a minimum, in accordance with the USAS B31.1.0 Code for Power Piping, which describes the primary and secondary allowable stresses associated with the main steam and feedwater piping, plus the added requirements listed in Section 4.11.4. The safety design basis is met by design of main steam and feedwater piping within the Reactor Building to Class I criteria as described on Section 4.11.4.

4.11.6 Testing and Inspections

Inspection and testing is carried out in accordance with USAS B31.1.0. Access requirements for inservice inspection were considered in the design of the main steam and feedwater piping to assure adequate working space and access for inspection of selected components and areas.

Nondestructive testing is applied to the pipe, valves, and fittings in the main steam lines up to and including the turbine stop valves:

Piping within the Reactor Pressure Boundary

1. Piping

   a. Spool Assemblies

      (1) Materials

      Sweepolets, weldolets, flanges, and ells were all examined by the magnetic particle method.

      Pipe (Seamless A106 Gr. B). No examinations were performed, except for the outside surfaces of shop bends (header sections; PS-1-3, PS-1-8, PS-1-13, and PS-1-18), which were examined by the magnetic particle method after bending.

      (2) Shop Welds

      All branch connections 4 in and greater and all circumferential butt welds were examined by radiography and the magnetic particle method. All branch connections less than 4 in were examined by the magnetic particle method.

      All attachment welds were examined by the magnetic particle method.

   b. Installation

   100 percent radiography of all pressure containing welds. Where size or configuration of the weld does not permit radiography, the final pass was examined by magnetic particle or liquid penetrant examination.

2. Castings

   All pressure containing castings are liquid penetrant or magnetic particle examined after at least one heat treatment in accordance with paragraphs N627 or N626 of the ASME Boiler and Pressure Vessel Code, Section III.

   All machined surfaces on the inlet and outlet nozzles of the valve casting are liquid penetrant or magnetic particle examined in accordance with the above requirements, after machining of the weld end preparations and nozzles.

3. Forgings

All pressure containing forgings over 4 in thick and the valve stem of each main steam line isolation valve are liquid penetrant or magnetic particle examined in accordance with paragraphs N627 orN626 of the ASME Boiler and

Pressure Vessel Code, Section III and are ultrasonic examined in accordance with ASTM A388.

4. Welds

All pressure containing welds and major weld repairs are radiographed in accordance with paragraph N624 of the ASME Boiler and Pressure Vessel Code, Section III. The final surface of all welds are liquid penetrant or magnetic particle examined in accordance with ASME Boiler and Pressure Vessel Code, Section III, paragraph N627 and N626, respectively.

5. Hardfacing

Final machined and ground surfaces of hardfacing, including at least 1/2 in of the base metal adjacent to the hardfacing, are examined with liquid penetrant in accordance with paragraph N627, Section III of the ASME Boiler and Pressure Vessel Code.

6. Bolting of each main steam isolation valve, safety valve, and relief valve

All bolts, studs, nuts, and bolting material greater than 1 in nominal bolt size are examined after final machining, by the magnetic particle or liquid penetrant method in accordance with paragraph N626 or N627 of the ASME Boiler and Pressure Code, Section III. This examination is performed on the finished component after threading or on the material stock of approximately the finished diameter before threading and after heading, if involved.

7. Main Steam Isolation Valves

All pressure containing castings are radiographed after at least one heat treatment in accordance with paragraph N323 of the ASME Boiler and Pressure Vessel Code, Section III. The technique for radiography is in accordance with paragraphs N624.2 through N624.7 of the above code.

<u>Piping External to the Reactor Pressure Boundary (i.e., second isolation valve to turbine stop valves)</u>

1. Piping

a. Spool Assemblies

Materials: Pipe (seamless A-106 Gr. B). No examinations were performed.

Shop Welds: All welds on piping 2 1/2 in and larger were 100 percent examined by radiography in

accordance with ASME Boiler and Pressure Vessel Code, Section III, paragraph N-624.

b. Installation: All welds on piping 2 1/2 in and larger were 100 percent examined by radiography in accordance with ASME Boiler and Pressure Vessel Code, Section III, paragraph N-624.

2. Castings, forgings, handfacing, and bolting. Nondestructive testing is not required.

3. Turbine Stop Valves. All pressure containing castings and welds were examined by radiography.

8. Impact Test Requirements

The specification for the piping tees, welding, and adjacent valves at the point where the high pressure coolant injection and reactor core isolation cooling lines join the feedwater lines requires that the materials be V-notch impact tested in accordance with ASME Code Section III and the proposed General Design Criterion 35. The lowest service temperature for these systems is 40°F, which requires a test temperature of -20°F and minimum impact energy of 20 ft lb.

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CONTAINMENT

5.1 SUMMARY DESCRIPTION

5.1.1 General

The containment systems of Pilgrim Nuclear Power Station utilize a "multibarrier" concept which consists of two systems. The Primary Containment System (PCS) is a pressure suppression system which forms the first barrier. The Secondary Containment System (SCS) is a system which minimizes the ground level release of airborne radioactive materials, and forms the second barrier. The fuel, fuel cladding, and Reactor Primary System (RPS) form additional barriers to the release of fission products and are described in Section 3.2.

5.1.2 Primary Containment System

The PCS houses the reactor vessel, the Reactor Coolant Recirculation System and other branch connections of the Reactor Coolant System (RCS). The primary containment is a pressure suppression system consisting of a drywell, pressure suppression chamber which stores a large volume of water, a connecting vent system between the drywell and water pool, isolation valves, vacuum relief system, containment cooling systems, and other service equipment. The drywell is a steel pressure vessel in the shape of a light bulb, and the pressure suppression chamber is a torus shaped steel pressure vessel located below and encircling the drywell.

The PCS is designed to withstand the forces from any size breach of the nuclear system primary barrier up to and including an instantaneous circumferential break of the reactor recirculation piping, and provides a holdup time for decay of any radioactive material released. The PCS also stores sufficient water to condense the steam released as a result of a breach in the nuclear system primary barrier and to supply the Core Standby Cooling Systems (CSCS).

5.1.3 Secondary Containment System

The SCS encloses the PCS, the refueling and reactor servicing areas, new and spent fuel storage facilities, and other reactor auxiliary systems. The SCS serves as the only containment during reactor refueling and maintenance operations, when the primary containment is open, and as an additional barrier when the PCS is functional. The SCS consists of the reactor building, Standby Gas Treatment System (SGTS), main stack, Reactor Building Isolation and Control System (RBICS), and other service equipment.

The SCS is designed to withstand the maximum postulated seismic event, and be capable of providing holdup treatment, and an elevated release point for any fission products released to it. In addition, the Reactor Building is designed to provide protection for the engineered safeguards and nuclear safety systems located in the building from all postulated environmental events including tornadoes.

5.2 PRIMARY CONTAINMENT SYSTEM

5.2.1 Safety Objective

The safety objective of the Primary Containment System (PCS) is to provide the capability in conjunction with other safeguard features, to:

1. limit the release of fission products in the event of a postulated design basis accident (DBA) so that offsite doses would not exceed the guideline values set forth in 10CFR100 and,

2. to prevent excessive fuel cladding temperatures.

5.2.2 Safety Design Basis

1. The PCS shall have the capability of withstanding the conditions which could result from any of the postulated DBAs for which the PCS is assumed to be functional, including the largest amount of energy release and mass flow associated with the accident.

2. The PCS shall have a margin for metal water reactions and other chemical reactions subsequent to any postulated DBA for which the PCS is assumed to be functional, consistent with the performance objectives of the nuclear safety systems and engineered safeguards.

3. The PCS shall have the capability to maintain its functional integrity during any postulated external or environmental event.

4. The PCS shall have the capability to be filled with water to a height above the top of active fuel as an accident recovery method for any postulated DBA in which a breach of the nuclear system primary barrier cannot be sealed.

5. The PCS, in conjunction with other Nuclear Safety Systems and engineered safeguards, shall have the capability to limit leakage during any of the postulated DBAs for which it is assumed to be functional, such that offsite doses do not exceed the guideline values set forth in 10CFR100.

6. The PCS shall have the capability to rapidly isolate all pipes or ducts necessary to establish the primary containment barrier.

7. The PCS shall have the capability to store sufficient water to supply the Core Standby Cooling System (CSCS) requirements.

8. The primary containment shall have the capability to be maintained during normal operation within the range of initial conditions assumed in the Station Safety Analysis in Section 14.

5.2.3 Description

5.2.3.1 General

The design employs a Low Leakage Pressure Suppression Containment System which houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the Reactor Primary System. The Pressure

Suppression System consists of a drywell, a pressure suppression chamber (torus) which stores a large volume of water, a connecting vent system between the drywell and the pressure suppression pool, isolation valves, Vacuum Relief System, Containment Cooling Systems, and other service equipment. The PCS design parameters are given on Table 5.2-1.

In the event of a Process System piping failure within the drywell, reactor water and steam will be released into the drywell gas space. The resulting increased drywell pressure forces a mixture of air, steam, and water through the vent system into the pressure suppression pool. The steam condenses rapidly in the suppression pool resulting in rapid pressure reduction in the drywell. Air transferred during reactor blowdown to the suppression chamber pressurizes the chamber, and subsequently is vented to the drywell through the vacuum relief system as the pressure in the drywell drops below that in the suppression chamber.

Cooling systems are provided to remove heat from the water in the suppression chamber. This provides for continuous cooling of the primary containment under the postulated DBA conditions for which the PCS is assumed to be functional. Isolation valves are provided to ensure containment of radioactive materials within the primary containment, which might be released from the reactor to the containment during the course of an accident. Other service equipment is provided to maintain the containment within its design parameters during normal operation.

The drywell (primary containment) coolers are designed to maintain drywell atmosphere temperatures within an acceptable range during normal station operation. See Table 5.2-2. The reduction of atmosphere temperature by the coolers will also result in partial condensation of water vapor when the incoming humidity levels are high.

The drywell fan motors are rated for continuous operation in atmospheres having 100 percent rh and 104°F temperatures. In the design of the cooler, the motor has been placed in the exhaust of the cooler where the leaving air temperature is a maximum of 100°F, so that the motor is exposed to the lowest humidity and lowest temperature atmosphere available within the drywell. Pressure increases to the 2.5 psig high drywell pressure condition used to sense a possible loss of coolant accident (LOCA) would not affect the continued operability of the coolers. The drywell coolers are automatically shut down in the event of a LOCA combined with the loss of offsite ac power.

The drywell coolers, including the fans, with their power and control systems were tested during the preoperational tests at the station to demonstrate the required operability of the power and control systems, the fans, and the Reactor Building closed cooling water supply to the coolers. The capability of the coolers to maintain the required drywell atmosphere temperatures was verified during the startup program as the drywell heat loads increased during the heatup and pressurization of the Nuclear Steam Supply System.

The Reactor Building Closed Cooling Water System (RBCCWS) piping supplying the drywell coolers was revised to seismic Class I to maintain the pressure boundary integrity of this piping under seismic loading. Refer to Section 10.5.5.1. The drywell coolers were originally purchased as seismic Class I equipment to serve as pressure boundary only.

The PCS design loading considerations are given in Section 12 and Appendix C. The Station Safety Analysis presented in Section 14 demonstrates the effectiveness of the PCS as a radiological barrier. In addition, primary containment pressure and temperature transients from postulated DBAs are also presented in Section 14.

5.2.3.2 Drywell

The drywell is a steel pressure vessel with a spherical lower portion, 64 ft in diameter, and a cylindrical upper portion 34 ft 2 inches in diameter. The overall height is approximately 110 ft. The design, fabrication, inspection, and testing of the drywell vessel complies with requirements of the ASME Boiler & Pressure Vessel Code, Section III, Subsection B, Requirements for Class B Vessels, which pertain to containment vessels for nuclear power stations.

The drywell structure is designed for an internal pressure of 56 psig coincident with a temperature of 281°F with applicable dead, live, and seismic loads imposed on the shell. Thus, in accordance with the ASME Code, Section III, Code Case N-1312-(2), the maximum drywell pressure is 62 psig. Thermal stresses in the steel shell due to temperature gradients are taken into account in the design.

Special precautions not required by codes were taken in the fabrication of the steel drywell shell. Charpy V-notch specimens were used for impact testing of plate and forging material to give assurance of proper material properties. Plates, forgings, and pipe associated with the drywell have an initial NDT temperature of 0°F or lower when tested in accordance with the appropriate code for the materials. It is intended that the drywell will not be pressurized or subjected to substantial stress at temperatures below 30°F.

The drywell is enclosed in reinforced concrete for shielding purposes, and to provide additional resistance to deformation and buckling in areas where the concrete backs up the steel shell. Above the transition zone, the drywell is separated from the reinforced concrete by a gap of approximately 2 inches Shielding over the top of the drywell is provided by removable, segmented, reinforced concrete shield plugs.

In addition to the drywell head, one double door air lock and two bolted equipment hatches are provided for access to the drywell. The locking mechanisms on each air lock door are designed so that a tight seal will be maintained when the doors are subjected to design pressures. The doors are mechanically interlocked so that neither door may be operated unless the other door is closed and locked. The drywell head and equipment hatch covers are bolted in place and sealed with gaskets.

The spectrum of primary system leak rates up to a double ended blowdown of a recirculation line has been analyzed relative to the temperature and pressure response of the drywell. Steam issuing from a leak and expanding at constant enthalpy may result in a superheated containment atmosphere. The maximum amount of superheat possible is a function of both the source pressure (reactor pressure) and the receiver pressure (drywell). The enthalpy of saturated steam goes through a maximum value at a reactor pressure of 400 to 500 psia. Steam issuing from a leak at

this pressure will result in the maximum superheat for a given containment pressure.

If a steam leak occurs, the containment pressure and temperature increase at a rate dependent on the size of the leak, containment characteristics, and the pressure of the reactor. The containment pressure and temperature rises as non-condensable gases are swept into the suppression chamber. Containment pressure levels off after all non-condensable gases are driven into the suppression chamber. The containment shell temperature rises as steam condenses on the relatively cool wall. When the drywell shell temperature reaches the saturation temperature dictated by this containment pressure, steam condensation is terminated. The only energy available to further increase the wall temperature is the superheat energy. The result is a decrease in the rate of temperature rise of the drywell shell and an increase in the bulk atmosphere temperature of the drywell.

Figure 5.2-1 illustrates the reactor vessel pressure response to steam leaks ranging in size from 0.02 to 0.50 ft2. Figures 5.2-2 through 5.2-6 illustrate the containment response to steam leaks covering the same size range. The response of the containment to small steam leaks is slow, but the continued high reactor pressure results in high containment temperature, given enough time. Leaks so small that the high drywell pressure trip does not occur will not result in a high temperature. Leaks large enough to result in a high containment temperature will be large enough to sweep air into the suppression chamber and result in significant drywell pressure increase. Large leaks will either depressurize the reactor rapidly or result in auto-relief such that steam temperatures, reaching levels up to 330°F, will not persist long enough to result in structural wall temperatures exceeding 281°F.

Safety grade temperature monitoring instrumentation is provided in the control room so that activation of one of the two containment sprays would be effective in terminating the temperature rise because the superheat is quickly removed. The spray nozzles are designed to give a small particle size, and the heat transfer to the subcooled spray is very effective. Since the total amount of heat in the drywell atmosphere is low relative to the spray rate of 300 gpm, the containment atmosphere temperature is quickly reduced below the containment design temperature of 281°F and held below the design temperature throughout the primary system and containment cooldown.

A containment pressure condition exceeding 16 psig torus bottom pressure was selected as the basis for determining when to initiate the containment spray. See Figure 5.2-8 for time required to reach 16 psig. The operator will be instructed to initiate the containment sprays if torus bottom pressure exceeds 16 psig. Safety grade pressure monitoring instrumentation is provided in the Control Room for this purpose. This procedure will ensure that the containment wall never exceeds 281°F. Depressurization of the reactor vessel can take place at the normal rate, but depressurization is not required to ensure that the wall temperature remains below 281°F. The environmental conditions considered in the design of the reactor protective system instrumentation, engineered safety feature equipment, and the qualification tests that have been

conducted are described in Section 7.1.7. The analyses of steam leaks inside the containment is given in detail in references 7 and 8.

5.2.3.3 Pressure Suppression Chamber and Vent System

5.2.3.3.1 General

The pressure suppression pool, which is contained in the pressure suppression chamber, initially serves as the heat sink for any postulated transient or accident condition in which the normal heat sink, main condenser, or Shutdown Cooling System is unavailable. Energy is transferred to the pressure suppression pool by either the discharge piping from the reactor pressure relief valves or the Drywell Vent System. The relief valve discharge piping is used as the energy transfer path for any condition which requires the operation of the relief valves. The Drywell Vent System is the energy transfer path for all energy releases to the drywell.

Of all the postulated transient and accident conditions, the instantaneous circumferential rupture of the reactor coolant recirculation piping represents the most rapid energy addition to the pool. For this accident the vent system, which connects the drywell and suppression chamber, conducts flow from the drywell to the suppression chamber without excessive resistance and distributes this flow effectively and uniformly in the pool. The pressure suppression pool receives this flow, condenses the steam portion of this flow, and releases the non-condensable gases and any fission products to the pressure suppression chamber air space.

5.2.3.3.2 Pressure Suppression Chamber

The pressure suppression chamber is a steel pressure vessel in the shape of a torus below and encircling the drywell, with a centerline vertical diameter of 29 ft 6 in and a horizontal diameter of 131 ft 6 in. The pressure suppression chamber contains approximately 84,000 ft^3 of water and has a net air space above the water pool of approximately 120,000 ft^3. The suppression chamber will transmit seismic loading to the reinforced concrete foundation slab of the Reactor Building. Space is provided outside of the chamber for inspection.

The toroidal suppression chamber is designed to the same material and code requirements as the steel drywell vessel. The material has an NDT temperature of 0°F or less.

5.2.3.3.3 Vent System

Large vent pipes connect the drywell and the pressure suppression chamber. A total of eight circular vent pipes are provided, each having a dia of 6.75 ft. The vent pipes are designed for the same pressure and temperature conditions as the drywell and suppression chamber. Jet deflectors are provided in the drywell at the entrance of each vent pipe to prevent possible damage to the vent pipes from jet forces which might accompany a pipe break in the drywell. The vent pipes are fabricated of SA-516 steel, and comply with requirements of the ASME Boiler and Pressure Vessel Code, Section III, Subsection B. The vent pipes are provided with expansion joints which are enclosed within sleeves, to

accommodate differential motion between the drywell and suppression chamber.

The drywell vents are connected to a 4 ft 9 in dia vent header in the form of a torus which is contained within the airspace of the suppression chamber. Projecting downward from the header are 96 downcomer pipes, 24 inches in dia, terminating approximately 3'0" to 3'5" ft below the water surface of the pool. The vent header has the same temperature and pressure design requirements as the vent pipes. Vent pipes and vent headers are braced to withstand expected loads from steam blowdown into the pool.

5.2.3.3.4 Pressure Suppression Pool

The pressure suppression pool is approximately 84,000 ft^3 of demineralized water contained within the pressure suppression chamber. It serves both as a heat sink for postulated transients and accidents and as a source of water for the CSCS.

The suppression pool receives energy in the form of steam and water from the reactor pressure relief valve discharge piping, or the drywell vent system downcomers which discharge under water. The steam is condensed by the suppression pool. The condensed steam and any water carryover cause an increase in pool volume and temperature. Energy can be removed from the suppression pool when the Residual Heat Removal System (RHR) is operating in the suppression pool cooling mode.

The suppression pool is the primary source of water for the Core Spray and Low Pressure Coolant Injection (LPCI) Systems, and the secondary source of water for the Reactor Core Isolation Cooling (RCIC) and High Pressure Coolant Injection (HPCI) Systems. The waterlevel and temperature of the suppression pool are continuously monitored in the main control room.

5.2.3.4 Penetrations

5.2.3.4.1 General

Containment penetrations have the following design characteristics:

1. They are designed for the same pressure and temperature conditions as the drywell and pressure suppression chamber

2. They are capable of withstanding the forces caused by impingement of the fluid from the rupture of the largest local pipe or connection without failure

3. They are capable of accommodating the thermal and mechanical stresses, which may be encountered during all modes of operation including environmental events, without failure

4. They are capable of withstanding the maximum reaction that the pipe to which they are attached is capable of exerting

The penetration schedule, including the number and size of these penetrations, is shown on Table 5.2-3. Load combinations and allowable stresses are described in Appendix C.

5.2.3.4.2 Pipe Penetrations

Two general types of pipe penetrations are provided. Type 1 is used where the design must accommodate thermal movement. Figure 5.2-9 is typical of this type of penetration. Type 2 is used where stresses due to thermal movement are relatively small. Typical penetrations of this type are illustrated on Figures 5.2-10 and 5.2-11. Figure 5.2-12 shows a typical instrument penetration.

The piping penetrations which have special provisions for thermal movement, such as the steam lines, are shown on Figure 5.2-9. In these penetrations, the process line is enclosed in a guard pipe that is attached to the main steam line through a multiple head fitting. This fitting is a one-piece forging with integral flues or nozzles and is designed to meet all requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class B. The forging is radiographed and ultrasonically tested as specified by this code. The guard pipe and flued head are designed to the same pressure requirements as the process line. The process line penetration sleeve is welded to the drywell, and extends through the biological shield where it is welded to a two-ply expansion bellows assembly, which in turn is welded to the flued head fitting. The pipe is guided through pipe supports at the end of the penetration assembly to allow steam pipe movement parallel to the penetration, and to limit pipe reactions of the penetration to allowable stress levels.

Where necessary, the penetration assemblies are anchored outside the containment to limit the movement of the line relative to the containment. The bellows accommodates the relative movement between the pipe and the containment shell.

The design of the penetration takes into account the stresses associated with normal thermal expansion, live and dead loads, seismic loads, and loads associated with a LOCA within the drywell. The design takes into account the loadings given above in addition to the jet force loadings resulting from any pipe failure. The resultant stresses in the pipe and penetration for the condition do not exceed 90 percent of the material yield stress.

The cold piping, ventilation duct, and instrument line penetrations are generally welded directly to the sleeves. In some cases, where stress analyses indicate the need, double flued head fittings are used. Bellows and guard pipes are not necessary in these designs, since the thermal stresses are small and are accounted for in the design of the weld joint.

5.2.3.4.3 Electrical Penetrations

The electrical penetrations include electrical power, signal, and instrument leads. Typical electrical penetrations are shown on Figures 5.2-13, 5.2-14, and 5.2-15. The penetrating sleeve is welded to the primary containment vessel. Medium voltage power penetrations primary seals are made of alumina-ceramic materials. The seals are formed at

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

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

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

The LOCA environmental condition:

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

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

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

5.2.3.4.4 Traversing Incore Probe Penetrations

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

These seals would also meet the intent of Section III of the code even though the code has no provisions for qualifying the procedures or performances.

5.2.3.4.5 Personnel and Equipment Access Locks

One personnel access lock is provided for access to the drywell. The lock has two gasketed doors in series, and each door is designed to withstand the drywell design pressure. The doors are mechanically interlocked to ensure that at least one door is locked at all times when primary containment is required. The locking mechanisms are designed so that a tight seal will be maintained when the doors are subjected to either the design internal or external pressure. The seals on this access opening are capable of being tested for leakage.

A personnel access hatch with testable seals is provided on the drywell head. This hatch is bolted in place.

Two equipment access hatches with testable seals are also provided. These hatches are bolted in place.

5.2.3.4.6 Access to the Pressure Suppression Chamber

Access to the pressure suppression chamber is provided at two locations from the Reactor Building. There are two 4 ft dia manhole entrances with double gasketed bolted covers connected to the chamber by 4 ft dia steel pipes.

5.2.3.4.7 Access for Refueling Operations

The drywell vessel head is removed during refueling operations. The head is held in place by bolts and is sealed with a double-seal arrangement.

5.2.3.5 Primary Containment Isolation Valves

5.2.3.5.1 General Criteria

The basic function of all primary containment isolation valves is to provide necessary isolation to the containment in the event of accidents or similar critical conditions when the free release of containment atmosphere cannot be permitted. The containment isolation valves are listed on Table 5.2-4. This table also defines the valve status (normally open or normally closed) during normal reactor operation and shows the signals required to initiate their desired operation. The primary containment isolation valves are grouped into three into three basic classes.

Class A valves are on process lines that communicate directly with the reactor vessel and penetrate the primary containment. These lines require two valves in series, one inside the primary containment and one outside the primary containment. They are located as close to the primary containment boundary as practical. Except in the case of check valves, both valves shall close automatically on isolation signal. Both valves shall receive the isolation (closure) signal even if normally closed during reactor operation. Since check valves close on reverse process flow, they are used to isolate some incoming lines. All Class A

valves except check valves are capable of remote manual control from the control room.

Class B valves are on process lines that do not directly communicate with the reactor vessel, but penetrate the primary containment and communicate with the primary containment free space. These lines require two valves, in series, both of them located outside the primary containment, and as close to the primary containment boundary as practical. For process lines that have a water seal (such as ECCS (CSCS) pump suction lines), one isolation valve without an automatic isolation signal closure, in addition to the water seal is adequate to meet isolation requirements. Except in the case of check valves or valves in water sealed process lines, both valves close automatically on isolation signal. Both valves receive the isolation closure signal even if normally closed during reactor operation. See Table 5.2-4 for valve status during reactor operation. All Class B motor operated or solenoid operated valves are capable of remote manual control from the control room.

Class C valves are on process lines that penetrate the primary containment but do not communicate directly with the reactor vessel, with the primary containment free space, or with the environs. Class C lines require only one valve located outside the primary containment which closes automatically by process action (i.e., reverse flow) or by remote manual operation from the control room (Reference 6, Section 5.2.9).

Motive power for the valves on process lines which require two valves shall be from physically independent sources to provide a high probability that no single accidental event could interrupt motive power to both closure devices.

Variations to the above definitions are referenced on Table 5.2-4 by their class designations followed by an "X" suffix. The lines in this class are generally instrument lines or lines used for core standby cooling systems.

Automatic isolation valves, in the usual sense, are not used on the inlet lines of the Emergency Core Cooling Systems and Reactor Feedwater Systems, since operation of these systems is essential following a design basis LOCA. Since normal flow of water in these systems is inward to the reactor vessel or to the primary containment, check valves located in these lines will provide automatic isolation, if necessary.

No automatic isolation valves are provided on the Control Rod Drive System hydraulic lines. These lines are isolated by the normally closed hydraulic system control valves located in the Reactor Building, and by check valves comprising a part of the drive mechanisms.

Small diameter instrument lines are not provided with automatic isolation valves.

5.2.3.5.2 Additional Considerations

Large diameter effluent lines which are normally open, such as main steam lines, which connect to the reactor vessel or which are open to the primary containment, have air-powered valves. This arrangement provides

a high reliability with respect to functional performance. These valves are closed automatically by the signals indicated on Table 5.2-4.

The MSIV's are also connected to the nitrogen supply system. This redundant source of MSIV actuation results in greater system reliability.

TIP system guide tubes are provided with an isolation valve which closes automatically upon receipt of proper signal and after the TIP cable and fission chamber have been retracted. In series with this isolation valve, an additional or backup isolation shear valve is included. Both valves are located outside the drywell. The function of the shear valve is to assure integrity of the containment in the unlikely event that the other isolation valve should fail to close or the chamber drive cable should fail to retract if it should be extended in the guide tube during the time that containment isolation is required. This valve is designed to shear the cable and seal the guide tube upon an actuation signal. Valve position (full open or full closed) of the automatic closing valves will be indicated in the control room. Each shear valve will be operated independently. The valve is an explosive type valve and each actuating circuit is monitored. In the event of a containment isolation signal, the TIP system receives a command to retract the traveling probes. Upon full retraction, the isolation valves are then closed automatically. If a traveling probe were jammed in the tube run such that it could not be retracted, instruments would supply this information to the operator, who would in turn investigate to determine if the shear valve should be operated.

The two 18 inch purge and vent line pipe entrances into the drywell have been provided with baffle plates to prevent debris from entering the lines during an accident. Any debris would threaten the ability to close the applicable isolation valve.

The N_2 makeup and vent isolation valves are used to relieve high drywell pressure during non-accident conditions. However, these valves may be used after an accident provided the required power supplies are available and a low-low water level signal is not present. Section 5.4.3 describes the N_2 makeup and vent valves used following an accident condition.

Lines, such as those of the RBCCW which do not connect to the Reactor Primary System or open into the primary containment, are provided with at least one AC-powered valve on the effluent line and a check valve on the influent line. The RBCCW lines are considered closed inside primary containment. Primary coolant system breaks inside containment are not assumed to result in pressure boundary failure of the RBCCW system, e.g. due to pipe whip, jet impingement, missiles, or water hammer. Failures of RBCCW system pressure boundary are passive failures and are not assumed coincident with other passive failures, i.e. a break in the primary coolant system. See Safety Evaluation 3255 for further details.

The Control Rod Hydraulic System is provided with three valves which can be utilized for isolation purposes. The first is a ball check valve which comprises an internal portion of the control drive mechanism. The other valves are normally closed hydraulic system control valves located in the Reactor Building.

5.2.3.5.3 Instrument Piping Connected to the Reactor Primary System

Instrumentation piping connecting to the Reactor Primary System which leaves the primary containment is dead-ended at instruments located in the Reactor Building. These lines are provided with flow limiting orifices, manual isolation valves, and excess flow check valves.

Instrument sensing lines that originate within the reactor coolant pressure boundary and penetrate the primary containment are 1 inch dia seismic Class I lines; 1/4 inch diameter orifices are installed in each of these lines inside the primary containment. This orifice size was selected to provide the same effective fluid cross sectional area as the excess flowcheck valves when fully open. A manually operated stop valve and excess flowcheck valve are installed in each line immediately outside, and as close as practicable to the primary containment consistent with the requirement for access to the stop valve. The combination of orifice and excess flowcheck valve will reduce leakage to as low a value as practicable in the unlikely event of line failure. A line failure downstream of the excess flow check valve will result in a maximum leakage rate of 2 gpm prior to actuation. A failure of the excess flowcheck valve body or the instrument line upstream of this valve would result in a maximum leakage rate of 20 gal/min. In each of these instances the leakage is well within the capability of the Reactor Coolant Makeup System.

The amount of steam released to the Reactor Building from a 20 gal/min leak would not result in a failure of secondary containment. If the Reactor Building is not isolated, there would not be any significant pressure rise due to the relatively high Reactor Building ventilation exhaust rates. If the Reactor Building is isolated, the operation of one standby gas treatment filter train will prevent Reactor Building pressure from exceeding its design value.

An analysis of the potential offsite exposure that would result from a 20 gal/min leak into the Reactor Building has been performed. Such a leak corresponds to an assumed failure of an instrument line outside the primary containment but upstream of the excess flowcheck valve. It was assumed in the analysis that manual shutdown and depressurization would be initiated within 30 min. The delay of 30 min is extremely conservative considering the numerous ways such a leak may be detected.

The analysis assumed that steam from the leak would be released to the environment through the normal ventilation path until the reactor had been depressurized.

Based on these assumptions, the total dose for the duration of the release was calculated for the following locations, and is documented in S&SA calculation #PNPS-1-ERHS-XIII.Z-66, Rev. 0: (All exposures are below the guidelines of 10 CFR 100 and GDC 19.)

Site Boundary 2-Hour Dose (Rem)		Low Population Zone 30-Day Dose (Rem)		Control Room 30-Day Dose (Rem)		
Thyroid	Whole Body	Thyroid	Whole Body	Thyroid	Whole Body	Skin
7.76	0.00353	0.0382	0.000118	(w/o CRHEAFS)		
				4.86	0.000834	0.00852
				(with CRHEAFS)		
				1.67	0.000424	0.00483

Pressure retaining welds of instrument sensing lines that are part of the reactor coolant pressure boundary receive magnetic particle or liquid penetrant examination of the last pass.

Instrument line "bundles" are routed so as to minimize the potential for accidental damage. They are generally routed high in compartments to ensure they are not stepped on or otherwise damaged. The lines are equipped with flow limiting orifices and excess flowcheck valves and are of the same size and schedule; therefore, the possibility of one line causing failure in another is extremely remote.

The containment penetrations for these sensing lines are shown on Figure 5.2-12. The 10 in drywell penetration sleeve contains six, equally spaced, 1 in, schedule 80 stainless steel instrument lines. The manual isolation valves are 1 in stainless steel globe valves and are located as close to the penetration as practical, consistent with the need for access to the valve. The excess flowcheck valves close automatically on flow in excess of 2 gal/min. Neither the manual isolation valves nor the excess flowcheck valves are equipped with position indicators. Regular monitoring of measured variables and comparison between redundant instruments provides operating personnel with sufficient information to identify malfunctioning or inoperative instruments and sensing lines. Operating and/or testing procedures will assure the operability of the safety related instrument lines and their associated orifices and excess flow check flows.

An analysis was conducted to determine the amount of Reactor Building ventilation that would be required to prevent exceeding the design internal pressure of the Reactor Building for an instrument line blowdown through a 1/4 in orifice. The required ventilation flow rate under these conditions is approximately 2,000 ft^3/min, which is far below the available flow rate through either the normal Reactor Building Ventilation System or the Standby Gas Treatment System (SGTS). An instrument line failure will therefore not result in a loss of integrity of the Secondary Containment System (SCS).

An estimate of the potential offsite exposure that would result from an instrument line failure has been calculated. The assumptions employed in this analysis were:

1. An instrument line failure occurs and results in an initial blowdown of 2.13 lb mass/sec into the Reactor Building

2. This blowdown continues undiminished and undetected for a period of 30 min

3. After a period of 30 min, the reactor is shut down, depressurized, and cooled down at a controlled 100°F/hr

4. The water which flashes to steam is carried out of the Reactor Building by the normal ventilation system for the duration of the blowdown

5. The I-131 concentration in the blowdown is 6.1×10^{-2} microcurie/ml and the total iodine concentration is 1.6×10^{0} microcurie/ml without an iodine spike. Iodine concentrations were then increased to a Technical Specification limit of 20 microcurie/ml.

6. The atmospheric diffusion factors (X/Q) used in this analysis, for a ground level, unfiltered release to the environment from the Reactor Building, are as follows:

Site Boundary (X/Q) (Sec/M^3)	Low Population Zone (X/Q) (Sec/M^3)	Control Room (X/Q) (Sec/M^3)
0-2 hr: 4.48E-03	0-8 hr: 1.79E-05	0-2 hr: 2.41E-03
	8-24 hr: 1.01E-05	0-8 hr: 1.78E-03
	24-96 hr: 3.29E-06	8-24 hr: 1.53E-03
	96-720 hr: 7.78E-07	24-96 hr: 1.10E-03
		96-720 hr: 6.83E-04

7. Breathing rates (m^3/sec):

   3.47E-04 m^3/sec from 0-2 hours for SB;
   3.47E-04 m^3/sec from 0-8 hours for LPZ
   3.47E-04 m^3/sec from 0-720 hours for CR
   1.75E-04 m^3/sec from 8-24 hours for LPZ
   2.32E-04 m^3/sec from 24-720 hours for LPZ

The above estimates assume that corrective action would not begin for a period of 30 minutes. The detection of a sensing line break would be almost immediate by one or a combination of the means listed

below. Proper corrective action would then be taken by the operating staff in accordance with station procedures such that the leak would be isolated or station shutdown and depressurization be initiated. It is believed that it is not credible to assume no operator action would be taken in 30 min to terminate the consequences, and that the analysis based on a 30 min allowance for these actions is very conservative.

Sensing line break detection means are:

1. By a scram, annunciation, and possible instrument readouts and/or initiation of reactor safeguards systems if rupture occurred on a Reactor Protection System instrument line

2. By annunciation of the control function, either high or low in the control room

3. Operator comparing readings with several instruments monitoring the same process variable such as reactor level, jet pump flow, and steam pressure

4. By increases in area temperature monitor readings and high temperature alarms in the Reactor Building, and/or ventilation exhaust air ducts

5. By a general increase in the area radiation monitor readings throughout the Reactor Building

6. The leak should be audible either inside the Turbine Building or outside the Reactor Building to the operating staff members on a normal tour

7. By detecting the leak as soon as an access door to the Reactor Building is opened or approached

   Routine surveillance and the multiplicity of detection methods on the part of the operator as given in items 1 through 7 above, represent an adequate means for detection of incipient or sudden failure of these small diameter instrument lines and components.

5.2.3.6 Venting and Vacuum Relief System

1. General

The purpose of the vacuum relief valves is to limit the negative pressure within the drywell and suppression chamber so that the structural integrity of the containment is maintained. The vacuum relief system from the pressure suppression chamber to reactor building consists of two 100-percent vacuum relief breakers (2 parallel sets of 2 valves in series). Operation of either system will maintain the negative pressure differential less than 2.0 psig: the external design pressure. One valve may be out of service for repairs for a period of 7 days. If repairs cannot be completed within 7 days, the reactor coolant system is brought to a condition where vacuum relief is no longer required.

The capacity of the 10 drywell vacuum relief valves are sized to limit the pressure differential between the suppression chamber and drywell during post-accident drywell coolant operations to the design limit of 2.0 psig. They are sized on the basis of the Bodega Bay pressure suppression system tests[1]. The ASME Boiler and Pressure Vessel Code, Section III, Subsection B, for this vessel allows a 5 psig vacuum; therefore, with two vacuum relief valves secured in the closed position and eight operable valves, containment integrity is not impaired.

Reactor operation is permissible if the bypass area between the primary containment drywell and suppression chamber does not exceed an allowable area. The allowable bypass area is based upon analysis considering primary system break area, suppression chamber effectiveness, and containment design pressure. Analyses show that the maximum allowable bypass area is 0.2 ft^2.

Reactor operation is not permitted if the differential pressure decay rate is demonstrated to exceed 25 percent of allowable, thus providing a margin of safety for the primary containment in the event of a small break in the primary system.

2. Vacuum Relief Valve Monitors

The drywell to torus vacuum breakers are installed to limit the drywell negative pressure. In addition, when the vacuum breakers are in the closed position, the drywell atmosphere (postulated steam) is directed through the suppression chamber downcomers during conditions of drywell pressurization. To fulfill this engineered safety feature, proper positioning and operation of the vacuum breakers must be ensured. Therefore, each Pressure Suppression Chamber-Drywell Vacuum Breaker is fitted with redundant "closed" position switches, each of which provides an alarm signal to a common annunciator in the main control room if the disk is open more than the allowable limit. In addition, one of the switches provides a signal to the closed position indicator located above the vacuum breaker air-operated test actuator control switch.

5.2.3.7 Primary Containment Cooling and Ventilation System

The Primary Containment (drywell) Cooling System utilizes eight fan coil units distributed inside the drywell. See Figure 5.2-18 (Drawing M291). The Primary Containment Cooling and Ventilation System design parameters are given on Table 5.2-2. Each fan coil unit consists of two trains of cooling coils and two direct-connected motor-driven vaneaxial fans. Each cooling coil is connected to a cooling water supply and return piping system inside the drywell. One or both trains of cooling coils may be utilized for temperature control. Each unit recirculates the drywell atmosphere through the cooling coils to control the drywell space temperature. Cooling water is supplied from the RBCCW system.

Thermocouples are provided to monitor the performance of the drywell cooling system. They are installed in the air and water connections of the drywell coolers as well as the air outlets of the reactor vessel recirculation pump motors as shown on Figure 5.2-18, BECo Drawing M291. (The thermocouples on water connections are also shown on Figure 10.5-1), Beco Drawing M215). Temperature readouts are provided on the Kaye Temperature Computer System located in the Main Control Room.

Fan coil units circulate cooled air around the recirculating pumps and motors, the control rod drive area, and the annular space between the reactor pressure vessel and the biological shield. The personnel access and control rod drive removal openings are sealed to ensure positive flow of cool air from the control rod drive area into the annular space between the reactor vessel and the biological shield, through pipe openings in the reactor vessel support located primarily at the upper level of the control rod drive space.

Cooled air will also be circulated through the reactor vessel head area, the space immediately below the refueling seal plate, and the relief valve area.

Dust filters can be installed on the inlet(s) to each drywell cooler fan unit. Due to the potential for some drywell maintenance activities to generate dust, when deemed necessary, filters are installed on the unit(s) that could be exposed to the dust. The filters are removed prior to resuming normal station operation.

Cooling water flow to each coil is controlled independently by an electric motorized modulating valve positioned by a valve positioner in the control room. The cooling coil leaving air temperature can be adjusted by regulating the flow of cooling water. A cooling coil failure can be detected by a flow device located in the cooling unit condensate drain line, which is annunciated in the main control room. The standby coil can be put in service and the other isolated by their motorized valves and a check valve in the return line.

Each fan is started from a local panel by using run-off-standby type switches. Each fan can be manually started by switching to RUN. If the fan switch is placed in the STANDBY position and the normal operating fan fails, a flow switch will sense a reduced pressure and automatically start the standby fan, light an amber light at a local panel, and annunciate in the control room. Cooling unit discharge air temperature is sensed by a temperature element and indicated in the control room. Upon scram, standby fans will be placed in service automatically after an approximate 45 second time delay to provide additional cooling. All fan coil units can be operated from the emergency power supplies.

Reactor Building exhaust vent. If necessary, SGTS is used for cleanup and the drywell air is exhausted through the main stack.

The ventilation lines supplying the primary containment are provided with two fast acting, pneumatic, cylinder-operated butterfly valves in series for isolation purposes. These valves are normally closed during station operation.

Procedures for normal primary containment venting and purging are established such that gaseous effluent releases from the station remain within the normal release limits. As noted above, purge or vent exhausts can be directed to elevated release points through the Reactor Building vent, or through the SGTS to the main stack.

Drywell and torus purging will normally be conducted to facilitate personnel access subsequent to periods of operation with the primary containment inerted. Primary containment purge operations would normally release on the order of 1 million standard ft3 of gas. Drywell and torus venting is required during reactor startups in order to maintain normal operational primary containment pressure control as heat loads increase drywell atmosphere temperatures. The volume of gas released during venting operations is expected to be small with respect to purge volumes.

Before purging or venting the containment, airborne contamination levels will be determined and estimates made of expected gaseous activity releases. Selection of release routes and release rates will be made so as to assure compliance with the Technical Specifications. No special area controls or monitoring procedures are imposed during primary containment purging or venting operations.

5.2.3.8 Primary Containment Atmospheric Control System

The Primary Containment Atmospheric Control System (PCACS) has been provided in the design to introduce makeup air or nitrogen into the primary containment.

The capability to operate the primary containment with an inert atmosphere has been provided in the design in accordance with previous licensing commitments. This system is capable of reducing and maintaining the oxygen content of the atmosphere and complies with the requirements set forth by the American Gas Association. The PCACS will be isolated from the primary containment in the event of an accident.

Basically, the equipment in the PCACS performs two functions: (1) initial purging of the primary containment, and (2) providing an automatic supply of makeup gas. If the inerting system is used, the purging equipment converts liquid nitrogen into gaseous nitrogen. Gaseous nitrogen can be introduced into the suppression chamber or the drywell. The PCACS is also capable of automatically providing makeup gas to the primary containment.

5.2.3.9 Drywell Temperature and Pressure Indication

Drywell temperature and pressure are recorded in the main control room. These instruments can be utilized to monitor the essential drywell parameters that are used in the Station Safety Analysis in Section 14.

5.2.3.10 Pressure Suppression Pool Temperature and Level Indication

Pressure suppression pool local and bulk temperature is indicated, recorded and alarmed in the main control room. Pressure suppression pool level is continuously indicated in the main control room. Pressure suppression pool temperature and level can be monitored locally at the Alternate Shutdown Panel C165. These instruments can be utilized to monitor the essential pressure suppression pool parameters that are assumed for initial values in the Station Safety Analysis in Section 14.

5.2.3.11 Drywell Level and Torus Pressure

The Drywell Level and Torus Bottom Pressure are indicated in the Main Control Room. The level indicator measures from plant elevation 47 feet to the containment purge and vent line, elevation 77 feet. The pressure indicator measures from 0 to 100 psig. These parameters are also provided to the EPIC computer. The parameters are used in conjunction with the Emergency Operating Procedures.

5.2.4 Safety Evaluation

5.2.4.1 General

The primary containment and its associated safeguard systems accomplish the following safety design bases:

1. Accommodate the transient pressures and temperatures associated with the postulated equipment failures within the containment (safety design basis 1)

2. Provide a margin for the effects of a metal water and other chemical reactions subsequent to postulated accidents involving loss of coolant (safety design basis 2)

3. Provide a high integrity barrier against leakage of any fission products associated with these equipment failures (safety design basis 3 and 5)

4. Provide for long term core flooding (safety design basis 4)

5. Provide for rapid actuation of the containment barrier (safety design basis 6)

6. Store water for the CSCS (safety design basis 7)

7. Maintain the containment parameters during planned operation to within those assumed in the Station Safety Analysis (safety design basis 8)

These factors are considered in the following evaluation of the integrated PCS.

5.2.4.2 Primary Containment Characteristics Following a Design Basis Accident

In order to establish a design basis for the pressure suppression containment with regard to pressure and temperature rating and steam condensing capability, the maximum rupture size of the Reactor Primary System must be defined. For this design, an instantaneous, circumferential rupture with double ended flow of one recirculation line has been selected as a basis for determining the maximum gross drywell pressure, and the condensing capability of the pressure suppression system. The selection of a failure of this size for the design basis is entirely arbitrary, since the circumferential failure of a recirculation pipe of this magnitude is considered to be of exceedingly low probability. Nevertheless, for design purposes these failure conditions have been selected to establish the containment parameters.

The design pressure is established on the basis of the Bodega Bay pressure suppression tests. The design pressure is primarily a function of the postulated rupture area, the drywell to suppression chamber vent area and configuration, vent submergence below the water level in the suppression pool, and the final equilibrium pressure in the pressure suppression chamber.

In establishing the containment design, circumferential pipe ruptures are assumed with sufficient distance separation to allow full potential flow from each end of the pipe. Pipeline flow restrictions are not considered in establishing rupture flow rates. Since the assumed initial rupture rate and the accompanying reactor depressurization is so rapid, progressive failure of the piping is not a limiting factor in the containment design.

The containment design parameters listed on Table 5.2-1 are concerned primarily with the effects on the primary containment caused by the blowdown immediately following the postulated double ended rupture of the recirculation piping or equivalent failure.

The parameters having the greatest effect on drywell design pressure are the ratio of pipe break area to total vent area, the vent submergence

below the water level in the suppression pool, initial system pressure, and the equilibrium pressure in the pressure suppression chamber before the postulated rupture.

Sufficient water is provided in the suppression pool to accommodate the initial energy which can be released into the drywell from the postulated pipe failure. The suppression chamber is sized to contain this water, plus the water displaced from the Reactor Primary System together with the free air initially contained in the drywell.

The primary containment response analysis to the design basis LOCA is presented in the Station Safety Analysis in Section 14.

It is concluded that safety design basis 1 is met.

5.2.4.3 Primary Containment Capability

The pressure of the PCS depends on both the system temperatures and the amount of noncondensible gases. Thus, the capability of the system to store gases resulting from metal water reaction varies with the rate and extent of the reaction.

Containment capability is defined in terms of the maximum percent of fuel channels and fuel cladding material which can enter into a metal water reaction during a specified duration without the design pressure of the containment structure being exceeded. The analysis of the postulated LOCA discussed in the Station Safety Analysis in Section 14, shows that the operation of either of the two core spray systems will maintain continuity of core cooling such that the extent of the resultant metal water reaction is negligible. However, to evaluate the containment system design capability various percentages of metal water reaction were assumed to take place over various durations of time. This analysis presents an arbitrary method of measuring system capability without requiring prediction of the detailed events in a particular accident condition. The results are presented in Section 14, Station Safety Analysis.

It is concluded that safety design basis 2 is met.

5.2.4.4 Primary Containment Leakage Analysis

The primary containment was tested to verify that the initial leakage rate was not in excess of the maximum allowable leak rate at the calculated peak accident pressure. The maximum allowable leak rate was derived from the maximum allowable accident leak rate when corrected for the effects of containment environment under accident and test conditions.

The resultant doses from the DBA for assumed leakage rates are presented in Section 14.

It is concluded that safety design basis 5 is met.

5.2.4.5 Containment Integrity Protection

The PCS is designed for the loading considerations given in Section 12 and Appendix C. In addition, special consideration is given to missile protection under the assumed accident conditions. The following summarizes the pertinent design considerations.

All large pipes which penetrate the containment are designed so that they have anchors or limit stops located outside of the containment to limit the movement of the pipe. These stops are designed to withstand the jet forces associated with the clean break of the pipe and thus maintain the integrity of the containment. Jet forces which may act on the containment are taken as equal to reactor pressure acting directly on the containment over an area equal to the cross sectional area of the largest local pipe or nozzle.

The drywell is enclosed in reinforced concrete for shielding purposes and to provide additional resistance to deformation and buckling in areas where the concrete backs up the steel shell. Where concrete is not available, such as at the vent openings, barriers are put across these openings for jet protection.

Based upon the conservative piping design utilizing proven engineering design practice, the proper choice of piping materials, the use of conservative quality control standards and procedures for piping fabrication and installation, and extensive studies of modes of pipe failure, it is concluded that pipes will not break in such a manner as to bring about movement of the pipes sufficient to damage the primary containment vessel.

Although it has been concluded that with the application of conservative piping design and proven engineering practices pipes will not break in such a manner as to bring about movement of pipes sufficient to damage the primary containment vessel, the design of the containment and piping systems does consider the possibility of missiles being generated from the failure of flanged joints such as valve bonnets, valve stems, recirculation pumps, and from instrumentation such as thermowells.

The most positive manner to achieve missile protection is through basic station arrangement such that, if failure should occur, the direction of flight of the missile is away from the containment vessel. The arrangement of station components takes this possibility into account even though such missiles may not have enough energy to penetrate the containment.

Spatial separation and utilization of the biological shield to the maximum extent practical are the measures taken to minimize the possibility of a single potential missile causing a loss of more than one redundant subsection of a vital safety system or a loss of more than one functionally independent safety system.

In order to minimize post-accident containment leakage, the containment penetrations are designed to retain their integrity during postulated accidents.

It is concluded that safety design basis 3 is met.

5.2.4.6 Containment Isolation

One of the basic purposes of the PCS is to provide a minimum of one protective barrier between the reactor core and the environmental surroundings subsequent to an accident involving failure of the piping components of the Reactor Primary System. To fulfill its role as a barrier, the primary containment is designed to remain intact before, during, and subsequent to any LOCA in a process system either inside or outside the primary containment. The process system and the primary containment are considered as separate systems, but where process lines penetrate the containment, the penetration design achieves the same integrity as the primary containment structure itself. The process line isolation valves are designed to achieve the containment function inside the process lines when required.

Since a rupture of a large line penetrating the containment and connecting to the Reactor Coolant System may be postulated to take place at the containment boundary, the isolation valve for that line is required to be located within the containment. This inboard valve in each line is required to be closed automatically on various indications of reactor coolant loss. A certain degree of additional reliability is added if a second valve, located outboard of the containment and as close as practical to it, is included. This second valve also closes automatically on an isolation signal. Both valves shall receive the isolation (closure) signal even if normally closed during reactor

operation. If a failure involves one valve, the second valve is available to function as the containment barrier.

By physically separating the two valves there is less likelihood that a failure of one valve would cause a failure of the second. The two valves in series are provided with independent power sources.

The ability of the steam line penetration and the associated steam line isolation valves to fulfill the containment objectives under several postulated break locations in the steam line is described below, and demonstrates the adequacy of the isolation valve design:

1. The failure occurs within the drywell upstream of the inner isolation valve

   Steam from the reactor is released into the drywell and the resulting sequence is similar to that of a design basis LOCA except that the pressure transient is less severe since the blowdown rate is slower. Both isolation valves close upon receipt of the signal indicating low-low water level in the reactor vessel. This action provides two barriers within the steam pipe passing through the penetration and prevents further flow of steam to the turbine. Thus when the two isolation valves close subsequent to this postulated failure, the primary containment barrier is established, and the reactor is effectively isolated from the external environment

2. The failure occurs within the drywell and renders the inner isolation valve inoperable

Again the reactor steam will blow down into the primary containment. The outer isolation valve will close upon receipt of the low-low water level signal, establishing the primary containment barrier

3. The failure occurs downstream of the inner isolation valve either within the drywell or within the guard pipe

   Both isolation valves will close upon receipt of a signal indicating low-low water level in the reactor vessel. The guard pipe is designed to accommodate such a failure without damage to the drywell penetration bellows, and the design of the pipeline supports protect its welded juncture to the drywell vessel. Thus the reactor vessel is isolated by the closure of the inner isolation valve and the primary containment barrier is established by closure of the outer isolation valve. It should be noted that this condition provides two barriers between the reactor core and the external environment

4. The failure occurs outside the primary containment between the guard pipe and the outer isolation valve

   The steam will blow directly into the pipe tunnel through the blowout panel and into the turbine building until the isolation valves are automatically closed. Closure of the inner isolation valve places a barrier between the reactor core and the external environment. This barrier serves to isolate the reactor and complete the containment integrity. Closure of the outer isolation valve in this incident serves no useful purpose

5. The failure occurs outside the primary containment and renders the outer isolation valve inoperative

   The primary containment barrier and isolation of the reactor is achieved by closure of the inner isolation valve

6. The failure occurs outside the primary containment between the outer isolation valve and the turbine

   The steam will blow down directly into the pipe tunnel or the turbine building until both isolation valves are automatically closed. This action isolates the reactor, establishes the primary containment barrier, and places two barriers in series between the reactor core and the outside environment

The exceptions to the arrangement of isolation valves described above for lines connecting directly to the containment or reactor primary system are made only in cases where it leads to a less desirable situation because of required operation or maintenance of the system in which the valves are located. In the cases where, for example, the two isolation valves are located outside the containment, special attention is given to assure that the piping to the isolation valves has an integrity at least equal to the containment.

The TIP system isolation valves are normally closed. When the TIP system cable is inserted, the valve of the selected tube opens automatically and

the chamber and cable are inserted. Insertion, calibration, and retraction of the chamber and cable requires approximately 5 min. Retraction requires approximately 1 1/2 min. If closure of the valve is required during calibration, the isolation signal causes the cable to be retracted and the valve to close automatically on completion of cable withdrawal.

It is neither necessary nor desirable that every isolation valve close simultaneously with a common isolation signal. For example, if a process pipe were to rupture in the drywell, it would be important to close all lines which are open to the drywell, and some effluent process lines such as the main steam lines. However, under these conditions, it is essential that containment and core cooling systems be operable. For this reason, specific signals are utilized for isolation of the various process and safeguard systems.

Isolation valves must be closed before significant amounts of fission products are released from the reactor core under DBA conditions.

Because the amount of radioactive materials in the reactor coolant is small, a sufficient limitation of fission product release will be accomplished if the isolation valves are closed before the coolant drops below the top of the core.

It is concluded that safety design basis 6 is met.

5.2.4.7 Containment Flooding

As is discussed in Section 12, the PCS is designed for the conditions associated with flooding the containment.

It is concluded that safety design basis 4 is met.

5.2.4.8 Pressure Suppression Pool Water Storage

Based on the Station Safety Analysis presented in Section 14, the quantity of water stored in the suppression pool is sufficient to condense the steam from a DBA and to provide water for the CSCS. As discussed in Section 12, the suppression pool is considered in the loading conditions on the PCS.

Reference 10 describes the analysis performed in support of Technical Specification 3.5.f, that allows a single control rod drive mechanism to be removed when the plant is in the refueling condition, with irradiated fuel in the reactor vessel, and the torus drained.

It is concluded that safety design basis 7 is met.

5.2.4.9 Limitations During Planned Operations

As is discussed in Sections 5.2.3.6, 5.2.3.7, and 5.2.3.8, the PCS is designed to be kept within the limits of parameters assumed in the Station Safety Analysis presented in Section 14 during planned operations.

It is concluded that safety design basis 8 is met.

5.2.4.10 Primary Containment Steam Quenching

The suppression chamber, or torus, is designed to contain a pool of water in order to suppress the pressure during a postulated LOCA by condensing the steam released from the reactor primary system. The reactor system energy released by relief valve operation during operating transients also is released into the suppression pool.

Technical specification limits on bulk suppression pool temperature ensure effective steam condensation during a LOCA or SRV discharge. The water temperature in the vicinity of the SRV discharge to the suppression pool is referred to in design and licensing documents as the local pool temperature. During plant transients and accidents involving SRV actuation, the suppression pool temperature is elevated by steam discharged from the primary system to the suppression pool through the relief valve discharge line. Past experimental data and plant experience indicated the potential for unstable steam condensation during safety-relief valve (SRV) operation at elevated pool temperatures (Reference 2) related to high water temperature near the SRV discharge. The unstable condensation process in a heated pool was observed to cause cyclical pressure loads on the pool boundary and structures inside the wetwell.

Further experimental data demonstrated that quenchers on the SRV discharge effectively eliminated the previously observed condensation oscillations at higher pool temperatures. The NRC issued an SER in August 1994 accepting the conclusions contained in NEDO-30832-A (Reference 4) regarding "T" quencher performance to mitigate steam condensation loads. On the basis of the experimental evidence provided to the NRC by the BWROG, the local pool temperature limits related to SRV discharges previously required by Reference 1 are eliminated.

Current Technical Specification limits on suppression pool temperature ensure bulk pool temperature remains within an acceptable range to condense steam discharged to the suppression pool during a LOCA or SRV actuation.

5.2.4.11 Steam Bypass

Following a reactor coolant pipe break inside the containment, the potential exists for the air-steam mixture within the drywell to pass through various leakage paths into the suppression chamber, thereby causing pressurization of the suppression chamber. This increased back pressure in the suppression chamber might lead to an increase in pressurization of the drywell, and possible over pressurization of the containment beyond the design limits.

The bypass area is expressed in terms of $A/\sqrt{k}$, where A is the total bypass (leakage) area and k is the pressure loss coefficient. The maximum allowable leakage area that could exist between the drywell and the suppression chamber is a function of the area of the break as well as the duration of pressurization. The former depends on the ΔP between the drywell and suppression pool, and the latter relates to the time delay until containment sprays are initiated.

In order to assess this relationship, an analysis was performed with various steam break sizes. For large breaks the ΔP is high, but has a short duration. The maximum ΔP results from the DBA. Primary system breaks greater than approximately 0.3 ft^2 will result in rapid depressurization of the primary system. Figure 5.2-22[(3)] shows the allowable bypass capacity ($A/\sqrt{k}$) as a function of primary system break area.

The allowable $A/\sqrt{k}$ is determined on the basis of the allowable steam mass that can be bypassed without exceeding the containment design pressure of 62 psig. For the Pilgrim Nuclear Power Station the maximum allowable bypass capacity is an $A/\sqrt{k}$ =0.13 ft^2. Typically, the geometric loss factor would be 3 or greater. Thus, the actual allowable bypass area would be approximately 0.2 ft^2. This is equivalent to a 6 in orifice.

When calculating the allowable leakage capacities shown on Figure 5.2-22, the following sequence of events is assumed. Immediately after a break in the primary system, a rapid rise in containment pressure would occur as the non-condensible gases in the drywell are transferred to the suppression chamber. For the allowable leakage calculations, no operator action is assumed until the suppression chamber pressure reaches 35 psig. Further, a 10 min delay is assumed before any action is taken to terminate the transient. In addition to the 10 min operator delay, a 5 min delay is assumed for corrective action to become effective.

The following assumptions were made in calculating the allowable leakage capacities:

1. Flow through the postulated leakage is pure steam. This is a conservative assumption as the amount of steam released into the suppression pool is maximized

2. There is no condensing of the leakage flow on either the suppression pool surface or the torus and vent system structure. This assumption results in a conservative peak pressure calculation

Station emergency procedures ensure that operator corrective action appropriate to the postulated events is taken. If the low-low water level point has not been reached, the operators can depressurize the reactor vessel through the main steam lines to the main condenser or alternately, utilize the relief valves to rapidly reduce reactor pressure. Existing emergency procedures require the initiation of the pressure suppression pool spray mode of the RHR after verification that the reactor vessel water level is adequate. Further, the procedures require the initiation of the drywell spray mode of the RHR if the torus bottom pressure exceeds 16 psig and other criteria are met.

5.2.5 Inspection and Testing

The following discussion details the surveillance and testing that will be conducted on the various systems or components of the primary containment during construction or station operation.

5.2.5.1 Primary Containment Integrity and Leak tightness

Fabrication procedures, nondestructive testing, and sample coupon tests were made in accordance with the ASME Code of Boilers and Pressure Vessels, Section III, Subsection B. The integrity of the Primary Containment System was verified during construction. The verification included a pneumatic test of the drywell and suppression chamber at 1.25 times their design pressure in accordance with code requirements.

After complete installation of all penetrations in the drywell and suppression chamber, the vessel was pressurized to the calculated peak accident pressure, and measurements taken to verify that the integrated leakage rate from the vessel did not exceed the maximum allowable leak rate. A second test was run at reduced pressure to establish a relationship between leakage rate and containment pressure. The necessary instrumentation is installed in the station to provide the data required to calculate and verify the leakage rate.

Provisions are made so that integrated, containment leakage rate tests may be periodically performed during periods of reactor shutdown, in compliance with 10CFR50, Appendix J, Primary Containment Leakage Testing for Water Cooled Power Reactors.

5.2.5.2 Penetrations

The design permits the testing of penetrations which have resilient seals or expansion bellows without pressurizing the entire containment system. Leak detection may then be accomplished either by the use of soap suds, pressure decay techniques, or other acceptable methods.

Pipe penetrations which must accommodate thermal movement are provided with two ply bellows expansion joints. These two ply bellows are provided with test taps so that the space between the plies can be pressurized to the calculated peak accident pressure to permit testing of the individual penetrations for leakage.

Electrical penetrations are also separately testable. The test taps are located so that the tests of the electrical penetrations can be conducted without entering or pressurizing the drywell or suppression chamber.

All containment closures which are fitted with resilient seals or gaskets are separately testable to verify leak tightness. The covers on flanged closures, such as the equipment access hatches, the drywell head, access manholes, and personnel air lock doors, are provided with double seals, and with a test tap which allows pressurization of the space between the seals without pressurizing the entire containment system.

5.2.5.3 Isolation Valves

The test capabilities which are incorporated in the PCS to permit leak detection testing of containment isolation valves are separated into two categories.

The first category consists of those pipelines which open into the containment atmosphere and do not terminate in closed loops outside the containment, and contain two isolation valves in series. Test taps are provided between the two valves which permit leakage monitoring of the first valve when the containment is pressurized.

The test tap can also be used to pressurize between the two valves to permit leakage testing of both valves simultaneously.

The second category consists of those pipelines which connect to the Reactor System and contain two isolation valves in series. A leakoff line is provided between the two valves, and a drain line is provided downstream of the outboard valve. This arrangement permits monitoring of leakage on the inboard and outboard valves during Reactor System hydrostatic tests, which can be conducted at pressures up to the reactor system operating pressure of 1,000 psig.

Generally, leakage testing is not required for isolation valves contained in pipelines whose terminal end will remain submerged in the suppression pool throughout the duration of the design basis LOCA. Therefore, these valves are not relied upon to prevent the release of fission products, and therefore do not perform a containment isolation function. Reference Number 5, Section 5.2.9 provides a list of valves which fit the above category.

Isolation valve closing time is determined during the functional performance test performed prior to reactor startup.

5.2.6 Nuclear Safety Requirements for Plant Operation

The entries in this section represent the nuclear safety requirements for the PCS for each BWR operating state which represents an extension of the station wide BWR systems analysis of Appendix G. 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 5.2	Description of PCS
2.	Section 7.2, Primary Containment and Reactor Vessel Isolation Control System	Description of PCICS

3.	Station Safety Analysis Section 14	Analyses verifying primary containment responses and radiological effects of postulated accidents
4.	Station Nuclear Safety Operational Analysis, Appendix G	Identification of conditions and events for which PCS is required
5.	Bodega Bay Preliminary Hazards Summary Report Appendix 1, Docket 50-205	Pressure suppression test information
6.	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 the following analysis is referenced, if possible, to the most significant station condition originating a need for the requirements by identifying a matrix block on one of the Matrix 3 sheets of Table G.5-3. The matrix block referenced is 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, F39-82, identifies BWR operation state F (Matrix 3), event (row) No. 39, and system (column) No. 82.

Minimum Required for Action

1. Vacuum Relief System
   (C39-109) (E39-109)
   (D39-109) (F39-109)

2. Primary Containment
   (C39-82) (E39-82)
   (D39-82) (F39-82)

3. Drywell Pressure and Temperature Indicators
   (C2-103) (E2-103)
   (D3-103) (F4-103)

4. Pressure Suppression Pool Water Level and Temperature Indicators
   (A35-104) (D3-104) (F4-104)
   (B35-104) (D39-104) (F39-104)
   (C2-104) (E2-104)
   (C39-104) (E39-104)

5. Pressure Suppression Pool Water Storage

(A35-83)	(D39-83)
(B35-83)	(E39-83)
(C39-83)	(F39-83)

Requirements are placed on the operating status of systems essential to containment to assure their availability to control the release of any radioactive material from irradiated fuel in the event of an accident condition. The PCS provides a barrier against uncontrolled release of fission products to the environs in the event of a break in the Reactor Coolant Systems. Whenever the reactor is in states C, D, E, and F (with nuclear system pressurized), failure of the Reactor Coolant System could cause rapid expulsion of the coolant from the reactor, with an associated pressure rise in the primary containment. Primary containment is required, therefore, to limit the release of fission products to the station environs so that offsite doses would be well below the values specified in 10CFR100.

The calculated radiological doses given in Section 14 were based on an assumed leakage rate of 0.5 percent. Increasing the assumed leakage rate at 56 psig to 2.0 percent would increase those doses by approximately a factor of four, still leaving a substantial margin between the calculated dose and the 10CFR100 regulation.

The suppression pool water volume provides the heat sink for the Reactor Coolant System energy released following the LOCA. In states A and B the suppression pool water is available as a source of makeup water to replace possible leakage from the reactor vessel and primary system.

The maximum water volume limit allows for an operating range without significantly affecting the accident analyses with respect to free air volume in the suppression pool. The maximum pool bulk temperature of 130°F would accommodate a complete accident blowdown with minimum water volume without exceeding the design temperature limit of 170°F immediately after blowdown. The design minimum water temperature of 40°F assures that the water is always in the liquid state. Suppression pool temperature limits have been selected to assure reactor depressurization can occur without high pressure suppression chamber loadings caused by instability during steam condensation.

The Drywell Suppression Pool Vacuum Breaker System is required to prevent water oscillation in the downcomers due to low steam flow rates in the downcomers, and to provide protection against negative pressure conditions in the containment vessel. Allowing one valve to be inoperative reduces the total vacuum relief area by only 10 percent. Since the valves are totally enclosed within the containment, possible leakage through them does not affect the containment system leakage.

The Suppression Pool Reactor Building Vacuum Relief System assures that the primary containment is not operated at a significant negative pressure relative to its surroundings. The 0.5 psi differential pressure setting was chosen on the basis of Relief System pressure drop, valve opening times, and peak mass flow to limit the external pressure on the suppression chamber to less than its design value of 2.0 psig. The Vacuum Relief System is a redundant system and full relief capacity is available through either valve. If one vacuum breaker or its block valve

becomes inoperable, there is no immediate threat to primary containment integrity, thus, reactor operation may continue while repairs are being made, provided the repair procedure does not violate primary containment integrity. Possible leakage of these valves is included in the containment system integrated leakage rate tests performed periodically.

5.2.7 Current Technical Specifications

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

5.2.8 Pipe Break Transient Analysis

5.2.8.1 Pipe Mechanical Failure and Safety Design

The Pilgrim Nuclear Power Station primary containment satisfies safety design basis 1 by its capability "to accommodate the transient pressures and temperatures associated with the postulated equipment failures within the containment." The intent of safety design basis 1 is to provide a basis for determining the primary containment internal design pressure and associated temperature, and that basis is that the primary containment must remain functional after accommodating the largest mass flow and energy release associated with the design basis LOCA. See Section 5.2.4.1.

Section 5.2.4.2 discusses the selection of the failure conditions that establish containment design parameters. The capability to satisfy safety design basis 1 is demonstrated in the primary containment response analysis to the design basis LOCA present in the Station Safety Analysis in Section 14. It is not the intent, nor has it ever been assumed that it would be the intent, that safety design basis 1 be used as a basis for evaluating the abilities of the primary containment to accommodate the mechanical forces and energies that might be associated with the movement of unrestrained pipe during a postulated LOCA.

Section 5.2.4.5 discusses containment integrity protection within the scope and the intent of safety design basis 3 and defines the pertinent loading considerations that have been evaluated in order to meet safety design basis 3.

In order to minimize the probability of an instantaneous failure in the Reactor Primary System piping, design provisions were made to minimize or identify conditions that could lead to such a failure.

As discussed in Appendices J.2.4 and F.2.6, the Reactor Primary System is designed to meet the intent of Criterion 35 of the Proposed AEC General Design Criteria, thus reducing even further the extremely low probability of an instantaneous piping failure due to brittle fracture.

In addition, a Nuclear System Leak Detection System, as described in Section 4.10, is provided to identify primary system leakage rates well below those leakage rates which correspond to the critical size for rapid crack propagation. The capability of this system to identify these leakage rates will provide significant protection against an instantaneous primary system piping failure due to crack propagation by

allowing station personnel sufficient time to take appropriate corrective measures. Supplementary protection will be provided by the comprehensive inservice inspection program discussed in Appendix K.

In conclusion, the design fabrication, testing, and inspection of the Reactor Primary System has emphasized the elimination of potential causes for instantaneous piping failures, and thus obviates the need to design the PCS to withstand the mechanical effects of the failed pipe. Therefore, the protection of the primary containment from the mechanical effects of an unrestrained failed pipe is not a safety design basis for Pilgrim Nuclear Power Station.

5.2.8.2 Pipe Protection System

As a result of an investigation, selected areas of the interior of the drywell shell were protected to reduce the possibility of breaching of the primary containment by postulated failure of a large, unrestrained pipe in the primary pressure boundary.

All pipe penetrations through the drywell have been designed to withstand the forces and moments resulting from a pipe rupture inside the drywell. Main steam and feedwater piping have restraints outside the drywell for protection of the penetration assemblies and outboard isolation valves.

The piping systems considered for postulated failure and having the potential to breach the containment are those which are located within the spherical section of the drywell and normally pressurized to reactor pressure (main steam, HPCI steam supply, feedwater, RHR). These large pipes are postulated to fail at circumferential butt welds with the jet reaction force acting normal to the rupture surface, and resulting in pipe rotation around a plastic hinge. The drywell areas requiring protection are shown on Figure 5.2-23, and are those areas in the spherical section where the single postulated large pipe weld failure could result in pipe movement to the extent that the ruptured pipe could contact the interior of the drywell shell with sufficient energy to perforate the drywell.

The protection system consists generally of steel members attached to a reinforcing plate. The protection system is arranged to receive a postulated rupture pipe, absorb a portion of the impact energy, and distribute the impact load over an area of the drywell shell such that the combined energy absorption capacity of the protection system and the drywell shell is greater than the impact energy of the ruptured pipe. The protection system and the drywell shell will deform through the 2 in air gap between the drywell and the concrete shield without causing breaching of the drywell. Details of the protection system are shown on Figure 5.2-23.

Areas of the spherical section of the drywell shell requiring protection have been determined by plotting the potential area at which each ruptured pipe end could contact the drywell when the pipe is rotated around various possible plastic hinge points. The force causing pipe movement and deformation around a plastic hinge is the jet reaction resulting from blowdown from the reactor system.

The impact energy of a ruptured pipe has been determined as a function of the jet reaction force, pipe plastic bending moment, and the configuration of the pipe with respect to the drywell shell. The energy required for perforation of the drywell shell has been determined from an empirical relation developed from a series of experiments using steel projectiles.

The protection system component size and placement is based upon the requirement to distribute the pipe impact energy over a sufficient area of the drywell shell, such that the combined energy absorbing capability of the protection system and drywell shell is greater than the impact energy of the ruptured pipe. The steel beams are arranged to minimize the possibility of a ruptured pipe end from resulting in a localized load bearing directly on the drywell shell. The beams are attached to a steel plate located between the beams and the drywell shell. This plate results in increasing the energy absorbing capability of the drywell by increasing the impact area, and increasing the effective thickness of the drywell shell. The plate also serves as a means of restraining the beams against potential jet impingement loads and the component of pipe impact loads tangential to the drywell shell.

The protection system is attached to the drywell shell at the weld pads with additional support from the floor structures as required. The protection system supports are designed to withstand the loads from the Safe Shutdown Earthquake.

The protection system components have been selected and located such that maximum protection is provided for the drywell shell against postulated pipe ruptures with minimum interference to required access for inservice inspection.

Pipe ruptures within the cylindrical section of the drywell have been considered and no protection is required because:

1. Pipe movement distances to contact the drywell are insufficient to obtain an impact energy exceeding the energy required to perforate the 1 1/4 inch shell thickness.

2. The close proximity of the drywell shell to the piping systems is such that pipe rotation around a plastic hinge is insufficient to result in the ruptured end becoming a localized load on the drywell.

The analysis and basis for design of the protection system is conservative because:

1. Jet reaction forces have not been reduced due to the throttling effect of partial pipe closure at the plastic hinge point.

2. Pipe impact energies have not been reduced by the energy absorbed by pipe deformation at the point of contact between the protection system and the drywell shell.

3. Impact energy required to perforate the drywell shell is based on test data using tool steel projectiles, and is therefore lower than the energies required for perforation with typical pipe materials.

5.2.8.3 Design Basis Line Break

The design basis steam line break accident (SLBA) is described in detail in Section 14. Considerations of the effect of operating in maximum extended load limit region on recirculation line breaks were addressed in Reference 9. The results continue to be bounded by the SLBA. This accident is assumed to result in a complete guillotine break of the main steam line, resulting in a 1.74 ft^2 break area. All other breaks in piping attached to the vessel above the core result in peak clad temperatures which are lower than those resulting from the SLBA. Since there are no perforations for the SLBA, there will be none for smaller steam line breaks. While the SLBA evaluated in Section 14 considers isolation of the reactor vessel, an analysis of an SLBA inside the primary containment (i.e., no isolation) is described in Section 5.2.3.2. The results of this analysis show that the core will remain covered throughout the transient, and the resultant peak clad temperature will be less than normal operating temperatures, which are well below the temperature where clad perforation could occur. As in the case of the design basis SLBA, all other smaller steam lines which could fail in such a manner that isolation is not achieved would also not result in clad perforations. Consideration of those liquid breaks which could conceivably result in containment breaching as a result of pipe whip has also resulted in the conclusion that no fuel perforations will occur. In particular, for the feedwater line break (approximately 0.5 ft^2) incore is also not uncovered. It can therefore be concluded that the resultant radiological exposures for the above pipe failures will at the maximum be based on only that activity contained in the primary coolant, which is discharged to the secondary containment.

To provide an upper limit to the radiological exposures, the assumptions have been made that:

1. All of the primary coolant which contained activity is eventually discharged to the secondary containment

2. Considering the thermodynamics of the coolant discharged, a maximum of 1/3 of the coolant is flashed to steam resulting in the release to the secondary containment of 1/3 of the coolant activity

3. Consideration of the condensing and plateout surfaces that the released steam will have to come in contact with prior to being released from the top of the reactor building results in a minimum reduction factor of 3 for the released iodine activity

4. The activity is released from the top of the reactor building under those meteorological conditions, which maximize the offsite exposures

5. The activity contained in the reactor coolant is consistent with an offgas emission rate of 10^5 microcuries/sec

Based on the above considerations, the resultant site boundary thyroid dose is 0.08 rem while the LPZ thyroid dose is 0.002 rem. If the conservative assumption is made that downwash of the released effluent occurs and that the coolant activity is at a level consistent with the technical specification offgas activity (i.e., 0.9 ci/sec), the resultant

site boundary thyroid dose is 15 rem and the LPZ thyroid dose is 0.6 rem, both of which are well below the 300 rem guideline set forth in 10CFR100.

5.2.9 References

1. Bodega Bay Preliminary Hazards Report, Appendix I, Docket 50-205, December 28, 1962.

2. U. S. Nuclear Regulatory Commission, "Suppression Pool Temperature Limits for BWR Containments," "USNRC Report NUREG-0783," November 1981.

3. J. M. Caroll, BECo Letter to NRC, May 15, 1973.

4. General Electric Company, "Elimination of Limit on BWR Suppression Pool Temperature for SRV Discharge with Quenchers," NEDO-30832-A, May 1995.

5. Franklin Research Center Technical Evaluation Report, "Containment Leakage Rate Testing", TER-C5257-40, May 5, 1981.

6. NRC letter, "Licensee Response to IE Bulletin 79-08 and Acceptability of Single Check Valves as Containment Isolation for Pilgrim," Ronald Eaton (NRC) to G. W. Davis, February 4, 1991.

7. General Electric Company, "Impact on Containment Pressure Temperature Response of Proposed Capping of Certain Drywell Spray Sparger Nozzles," EAS52-0587, Rev. 1, May 1987.

8. General Electric Company, "Information on the Effect of Reduced Drywell Spray Flow Rates," EAS56-0888, September 1988.

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

10. Safety Evaluation No. 3092 "Change the Technical Specification Basis Section 3.5.F, Minimum Low Pressure Cooling and Diesel Generator Availability, to correct:

    1. amount of water in refuel cavity and dryer/separator pool when flooded to elevation 114 feet,

    2. amount of water needed in torus for ECCS/CS pumps to start."

TABLE 5.2-1

PRIMARY CONTAINMENT SYSTEM
PRINCIPAL DESIGN PARAMETERS AND CHARACTERISTICS

Pressure suppression chamber:

Internal design pressure................................ +56 psig
External design pressure................................ +2 psig

Drywell:

Internal design pressure................................ +56 psig
External design pressure................................ +2 psig

Drywell free volume..............................132,000 to 147,000 ft^3

Pressure suppression chamber free volume..........115,800 to 124,500 ft^3

Pressure suppression pool water volume, maximum......(approx) 94,000 ft^3

Pressure suppression pool water volume, minimum......(approx) 84,000 ft^3

Submergence of vent pipe below
pressure suppression pool surface... (approx) 3 ft - 0 in to 3 ft - 5 in

Design temperature of drywell....................................281°F

Design temperature of pressure suppression chamber.................281°F

Downcomer vent pressure loss factor.............................. 6.21

Break area/total vent area...................................... 0.0194

Drywell free volume/pressure suppression chamber free volume....... 1.34

Primary system volume/pressure suppression pool volume............ 0.268

Drywell free volume/primary system volume.......................... 7.4

Calculated maximum pressure during blowdown:

Drywell .... 45 psig
Pressure suppression chamber .... 27 psig
Initial pressure suppression chamber temperature rise ....35°F

TABLE 5.2-2

DRYWELL ATMOSPHERE COOLING DATA SHEET

Location	Average	Maximum*
General	135°F	148°F
Recirculation Pump Motor Area	-	128°F
Entering Air Temperature to Cooling Units	135°F	148°F
Leaving Air Temperature from Cooling Units	85°F	95°F
Cooling Water Supply Temperature	75°F	85°F
Cooling Water Return Temperature	90°F	100°F
Drywell Heat Gain	2.4×10^6 Btu/hr	3.4×10^6 Btu/hr
Total Cooling Unit Capacity	3.6×10^6 Btu/hr	5.6×10^6 Btu/hr
Total Cooling Unit Fan Capacity	72,000 ft^3/min	110,000 ft^3/min
Total Fan Brake hp	54.8	67.8
Drywell Temperature 10 hr after shutdown	105°F	105°F

NOTE:

*As a result of higher cooling water supply temperature and extra heat load from scram of the control rod drives.

TABLE 5.2-3, PENETRATION SCHEDULE, HAS BEEN DELETED

REFER TO TABLE L.2-1, PENETRATION SCHEDULE

TABLE 5 2-4

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
AO-203-1A	Main Steam Line “A”	X-7A,IPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2A	Main Steam Line “A”	X-7A,OPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-1B	Main Steam Line “B”	X-7B,IPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2B	Main Steam Line “B”	X-7B,OPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-1C	Main Steam Line “C”	X-7C,IPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2C	Main Steam Line “C”	X-7C,OPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-1D	Main Steam Line “D”	X-7D,IPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
AO-203-2D	Main Steam Line “D”	X-7D,OPC	3 0-5 0	A	Globe	Air/AC,DC	Air & Spring	Open	1 Closed	B,D,P,Q	1
MO-220-1	Main Steam Drain	X-8,IPC	30 0	A	Gate	AC	AC	Closed	1 Closed	B,D,P,Q	9
MO-220-2	Main Steam Drain	X-8,OPC	35 0	A	Gate	DC	DC	Closed	1 Closed	B,D,P,Q	9
6-58A	F W Line “A”	X-9A,IPC	--	A-X	Check	--	process	Open	-- --	Rev Flow	
6-62A	F W Line “A”	X-9A,OPC	--	A-X	Check	--	process	Open	-- --	Rev Flow	
1301-50	RCIC Pp Discharge	X-9A,OPC	--	A-X	Check	--	process	Closed	-- --	Rx, Rev Flow	
MO-1301-49	RCIC Pp Discharge	X-9A,OPC	--	A-X	Gate	DC	DC	Closed	-- --	RM	
MO-1201-80	RWCU Return	X-9A,OPC	30 0	A-X	Globe	AC	AC	Open	6 Closed	A,J,W,Y,RM	29
6-58B	F W Line “B”	X-9B,IPC	--	A-X	Check	--	process	Open	-- --	Rev Flow	
6-62B	F W Line “B”	X-9B,OPC	--	A-X	Check	--	process	Open	-- --	Rev Flow	
2301-7	HPCI Pp Discharge	X-9B,OPC	--	A-X	Check	--	process	Closed	-- --	Rx Rev Flow	
MO-2301-8	HPCI Pp Discharge	X-9B,OPC	--	A-X	Gate	DC	DC	Closed	-- --	RM	
MO-1001-47	RHR S/D Cooling	X-12,OPC	51 0	A-X	Gate	DC	DC	Closed	3 Closed	A,F,M,U,RM	
MO-1001-50	RHR S/D Cooling	X-12,IPC	32 0	A-X	Gate	AC	AC	Closed	3 Closed	A,F,M,U,RM	

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
MO-1201-2	RWCU Suction	X-14;IPC	20 0	A-X	Gate	AC	AC	Open	6 Closed	A,J,W,Y,RM	29
MO-1201-5	RWCU Suction	X-14;OPC	34 0	A-X	Gate	DC	DC	Open	6 Closed	A,J,W,Y,RM	29
SV-5065-31B	H2/02 Analyzer Supply	X-15E;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-35B	H2/02 Analyzer Supply	X-15E;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
1400-9A	Core Spray to Rx Loop A /B	X-16A/IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev Flow	
MO-1400-24A	C S to Rx "A" Loop	X-16A;OPC	22 0	A-X	Gate	AC	AC	Open	-- --	RM	11
MO-1400-25A	C S to Rx "A" Loop	X-16A;OPC	22 0	A-X	Gate	AC	AC	Closed	-- --	RM	11
1400-9B	Core Spray to Rx Loop A/B	X-16B/IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev Flow	
MO-1400-24B	C S to Rx "B" Loop	X-16B;OPC	22 0	A-X	Gate	AC	AC	Open	-- --	RM	11
MO-1400-25B	C S to Rx "B" Loop	X-16B;OPC	22 0	A-X	Gate	AC	AC	Closed	-- --	RM	11
AO-7017A	R/W Collection & DW Floor Sump	X-18;OPC	20 0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
AO-7017B	R/W Collection and D/W Floor Sump	X-18;OPC	20 0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
AO-7011A	R/W Collection and D/W Equipment Sump	X-19;OPC	20 0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
AO-7011B	R/W Collection and D/W Equipment Sump	X-19;OPC	20 0	B	Plug	Air/AC	Spring	Open	2 Closed	A,F, RM	
31-CK-167	Instrument Air	X-22;OPC	--	C	Check	--	Process	Open	-- --	Rev Flow	
30-CK-432	RBCCW Supply	X-23;OPC	--	C	Check	--	Process	Open	-- --	Rev Flow	

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
MO-4002	RBCCW Return	X-24;OPC	--	C	Gate	AC	AC	Open	-- --	RM	
AO-5043A	Drywell 2" Exhaust Bypass	X-25;OPC	10 0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5043B	Drywell 2" Exhaust Bypass	X-25;OPC	10 0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5044A	Drywell Purge Exhaust	X-25;OPC	5 0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
AO-5044B	Drywell Purge Exhaust	X-25;OPC	5 0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
SV-5081A	Post Acc Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5081B	Post Acc Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5082A	Post Acc Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5082B	Post Acc Purge and Vent	X-25;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
9-CK-340	Drywell Purge/Makeup	X-26;OPC	--	B	Check	--	Process	Closed	-- --	Rev Flow	
AO-5033A	Drywell Purge/Makeup	X-26:OPC	10 0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,27,30
AO-5033B	Drywell/Torus Purge	X-26;OPC	10 0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	9,21,27
AO-5035A	Drywell Purge/Makeup	X-26;OPC	5 0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
AO-5035B	Drywell Purge/Makeup	X-26;OPC	5 0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
SV-5085A	Post Acc Purge and Vent	X-26;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5086A	Post Acc Purge and Vent	X-26;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5086B	Post Acc Purge and Vent	X-26;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5065-33A	H2/O2 Analyzer & PASS Supply	X-29E;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-37A	H2/O2 Analyzer & PASS Supply	X-29E;OPC	2 0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
CV-5065-91	C-19 Return	X-32A:OPC	5 0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	
CV-5065-92	C-19 Return	X-32A;OPC	5 0	B	Globe	AC	Spring	Open	2 Closed	A,F,RM	
45-300A	Tip Drive	X-35C;OPC	5 0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
45-300B	Tip Drive	X-35D;OPC	5 0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
45-300C	Tip Drive	X-35B:OPC	5 0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
45-300D	Tip Drive	X-35A;OPC	5 0	A-X	Ball Solenoid	AC	Spring	Closed	2 Closed	A,F	9,16
Shear Valve A	Tip Drive	X-35C;OPC	--	A-X	Explosive Shear	DC	DC	Open	-- --	RM	22
Shear Valve B	Tip Drive	X-35D;OPC	--	A-X	Explosive Shear	DC	DC	Open	-- --	RM	22
Shear Valve C	Tip Drive	X-35B;OPC	--	A-X	Explosive Shear	DC	DC	Open	-- --	RM	22
Shear Valve D	Tip Drive	X-35A;OPC	--	A-X	Explosive Shear	DC	DC	Open	-- --	RM	22
9-CK-353	Tip Purge	X-35E;OPC	--	B-X	Check	--	Process	Open	-- --	Rev Flow	
FCV-302-120	CRD Insert (Typ of 145)	X-37;OPC	--	A-X	FCV	Air/AC	Spring	Closed	-- --	RM	4
FCV-302-123	CRD Insert (Typ of 145)	X-37;OPC	--	A-X	FCV	Air/AC	Spring	Closed	-- --	RM	4
SV-305-121	CRD Withdraw (Typ of 145)	X-38;OPC	--	A-X	SOV	Air/AC	Spring	Closed	-- --	RM	4
SV-305-122	CRD Withdraw (Typ of 145)	X-38;OPC	--	A-X	SOV	Air/AC	Spring	Closed	-- --	RM	4
MO-1001-23A	RHR Containment Spray	X-39A;OPC	45 0	B-X	Gate	AC	AC	Closed	-- --	G,S,RM	2,24,25
MO-1001-26A	RHR Containment Spray	X-39A;OPC	45 0	B-X	Gate	AC	AC	Closed	-- --	G,S,RM	2,24,25
MO-1001-23B	RHR Containment Spray	X-39B;OPC	45 0	B-X	Gate	AC	AC	Closed	-- --	G,S,RM	2,24,25
MO-1001-26B	RHR Containment Spray	X-39B;OPC	45 0	B-X	Gate	AC	AC	Closed	-- --	G,S,RM	2,24,25
SV-5065-63	PASS Rx Sample	X-40Aa;OPC	2 0	A	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-64	PASS Rx Sample	X-40Aa;OPC	2 0	A	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5065-85	PASS Rx Sample	X-40Dc;OPC	2 0	A	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-86	PASS Rx Sample	X-40Dc;OPC	2 0	A	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
AO-220-44	Reactor Sample Line	X-41A;IPC	10 0	A	Gate	Air/AC	Spring	Open	1 or 2 Closed	A,B,D,F,P,Q,RM	9,23
AO-220-45	Reactor Sample Line	X-41A;OPC	10 0	A	Y-Globe	Air/AC	Spring	Open	1 or 2 Closed	A,B,D,F,P,Q,RM	9,23
CK-1101-15	SBLC System	X-42;IPC	--	A-X	Check	Process	Process	Closed	-- --	Rev Flow	
CK-1101-16	SBLC System	X-42;OPC	--	A-X	Check	Process	Process	Closed	-- --	Rev Flow	
45-HO-106	D/W Test Connection	X-43;OPC	--	B	Gate	Manual	--	Closed	-- --	--	
262-FO-13A	Recirc Pp Seals	X-46A;IPC	--	C	Check	--	Process	Open	-- --	Rev Flow	
262-FO-17A	Recirc, Pp Seals	X-46A;OPC	--	C	Check	--	Process	Open	-- --	Rev Flow	
262-FO-13B	Recirc, Pp Seals	X-46B;IPC	--	C	Check	--	Process	Open	-- --	Rev Flow	
262-FO-17B	Recirc Pp Seals	X-46B:OPC	--	C	Check	--	Process	Open	-- --	Rev Flow	
9-HO-378	Backup Nitrogen Supply to RV-203-3B and RV-203-3C	X-46E;OPC	--	B	Gate	Manual	--	Closed	--	--	
9-HO-379	Backup Nitrogen Supply to RV-203-3B and RV-203-3C	X-46E;OPC	--	B	Gate	Manual	--	Closed	--	--	
SV-5065-24A	H2O2 & PASS Gas Return	X-46F;OPC	2 0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-26A	H2O2 & PASS Gas Return	X-46F;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F, RM	18
45-HO-102	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
45-HO-103	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
45-HO-104	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
45-HO-105	D/W Test Connection (ILRT Supplemental Test)	X-47;OPC	--	B-X	Globe	Manual	--	Closed	-- --	--	
SV-5065-13B	H2/O2 Analyzer Supply	X-50Ad;OPC	2 0	B	Globe	AC	Spring	Open	2 Closed	A,F,RM	18

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5065-20B	H2/O2 Analyzer Supply	X-50Ad;OPC	2 0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	18
MO-1001-28A	RHR Injection "A" Loop	X-51A;OPC	30 0	A-X	Globe	AC	AC	Open	-- --	E,T,RM	
MO-1001-29A	RHR Injection "A" Loop	X-51A;OPC	30 0	A-X	Gate	AC	AC	Closed	3 Closed	A,E,F,U,T,RM	11,17
1001-68A	RHR Injection A	X-51A;IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev Flow	
MO-1001-28B	RHR Injection "B" Loop	X-51B;OPC	30 0	A-X	Globe	AC	AC	Open	-- --	E,T,RM	
MO-1001-29B	RHR Injection "B" Loop	X-51B;OPC	30 0	A-X	Gate	AC	AC	Closed	3 Closed	A,E,F,U,T,RM	11,17
1001-68B	RHR Injection B	X-51B;IPC	--	A-X	Check	--	Process	Closed	-- --	Rx, Rev Flow	
M0-2301-4	HPCI Steam to Turbine	X-52;IPC	25 0	A-X	Gate	AC	AC	Open	4 Closed	L,RM,AA	13
MO-2301-5	HPCI Steam to Turbine	X-52;OPC	34 0	A-X	Gate	DC	DC	Open	4 Closed	L,RM AA	13
MO-1301-16	RCIC Steam to Turbine	X-53;IPC	20 0	A-X	Gate	AC	AC	Open	5 Closed	K,RM,AA	10
MO-1301-17	RCIC Steam to Turbine	X-53;OPC	29 0	A-X	Gate	DC	DC	Open	5 Closed	K,RM,AA	10
SV-5065-14A	$H_2/0_2$ Analyzer Supply	X-106Ab;OPC	2 0	B	Globe	AC	Spring	Open	2 Closed	A,F,RM	18
SV-5065-21A	$H_2/0_2$ Analyzer Supply	X-106Ab;OPC	2 0	B	Globe	DC	Spring	Open	2 Closed	A,F,RM	18
9-CK-341	Torus Makeup	X-205;OPC	--	B	Check	--	Process	Closed	-- --	Rev Flow	9
AO-5033B	Drywell/Torus Purge	X-205;OPC	10 0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	9,21,27
AO-5033C	Torus Makeup	X-205;OPC	10 0	B	Gate	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,27 30
AO-5036A	Torus Purge Inlet	X-205;OPC	5 0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27,35
AO-5036B	Torus Purge Inlet	X-205;OPC	5 0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27,35
SV-5087A	Post Accident Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5087B	Post Accident Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5088A	Post Acc Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5088B	Post Acc Purge and Vent	X-205;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
MO-1001-36A	RHR to Torus	X-210A;OPC	30 0	B-X	Globe	AC	AC	Closed	-- --	G,RM	2,9,35
MO-1001-18A	RHR Minimum Flow	X-210A;OPC	25 0	B-X	Gate	AC	AC	Open	-- --	RM	9,31
CK-1400-35	Core Spray Recirc	X-210A;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev Flow	28
MO-1001-36B	RHR to Torus	X-201B;OPC	30 0	B-X	Globe	AC	AC	Closed	-- --	G,RM	2,9,35
MO-1001-18B	RHR Minimum Flow	X-210B,OPC	25 0	B-X	Gate	AC	AC	Open	-- --	RM	9,31
1301-47	RCIC Minimum Flow	X-201B;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev Flow	28
CK-1400-214	Core Spray Recirc	X-210B;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev Flow	28
2301-40	HPCI Minimum Flow	X-210B,OPC	--	B-X	Check	--	Process	Closed	-- --	Rev Flow	28
10-CK-515	Torus Makeup From CST	X-210B;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev Flow	28
MO-1001-34A	RHR to Torus “A” Loop	X-211A;OPC	30 0	B-X	Gate	AC	AC	Closed	-- Closed	G,RM	2,9,24
MO-1001-34B	RHR to Torus “B” Loop	X-211B;OPC	30 0	B-X	Gate	AC	AC	Closed	-- Closed	G,RM	2,9,24
MO-1001-37A	RHR to Torus Spray Header “A”	X-211A;OPC	45 0	B-X	Globe	AC	AC	Closed	-- Closed	G,S,RM	2,24,35
MO-1001-37B	RHR to Torus Spray Header “B”	X-211B;OPC	45 0	B-X	Globe	AC	AC	Closed	-- Closed	G,S,RM	2,24,35
MO-2301-33	HPCI Turbine Ex Vac Brkr	X-219/OPC	30 0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
MO-2301-34	HPCI Turbine Ex Vac Brkr	X-219/OPC	30 0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
MO-1301-25	RCIC Pp Suction From Torus	X-220;OPC	125 0	B-X	Gate	DC	DC	Closed	-- --	RM	28
MO-2301-36	HPCI Pp Suction From Torus	X-221;OPC	37 0	B-X	Gate	DC	DC	Closed	4 Closed	L,RM	26,28
MO-1001-7A	RHR Pp Suction	X-222A;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7B	RHR Pp Suction	X-222D;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7C	RHR Pp Suction	X-222B;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
MO-1001-7D	RHR Pp Suction	X-222C;OPC	150	B-X	Gate	AC	AC	Open	-- --	RM	22,28
2301-45	HPCI Turbine Exhaust	X-223; OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev Flow	
2301-74	HPCI Turbine Exhaust	X-223;OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev Flow	
2301-218	HPCI Low Point Drain	X-223;OPC	--	B-X	Check	--	Process	Closed	-- Closed	Rev Flow	
CV-9068A	HPCI Gland Seal Condenser	X-223;OPC	--	B-X	Globe	DC	Spring	Closed	4 Closed	L,AA,RM	
CV-9068B	HPCI Gland Seal Condenser	X-223;OPC	--	B-X	Globe	DC	Spring	Closed	4 Closed	L,AA,RM	
MO-2301-33	HPCI Turbine Ex Vac Brkr	X-223;OPC	30 0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
MO-2301-34	HPCI Turbine Ex Vac Brkr	X-223;OPC	30 0	B-X	Gate	AC	AC	Open	7 Closed	N,RM	36
2301-217	HPCI Exhaust Line Drain	X-224;OPC	--	B-X	Check	--	Process	Closed	-- --	Rev Flow	28
1301-64	RCIC Turbine Exhaust	X-225; OPC	--	B-X	Stop Check	--	Process	Closed	-- --	Rev Flow	28
1301-59	RCIC Vac Pp Discharge	X-226; OPC	--	B-X	Check	--	Process	Closed	-- --	Rev Flow	28
SV-5084A	Post Acc Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5084B	Post Acc Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5083A	Post Acc Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19
SV-5083B	Post Acc Purge and Vent	X-227;OPC	--	B	Globe	AC	Spring	Closed	-- --	RM	19

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
AO-5040A	Torus Vacuum Bkrs	X-227;OPC	45 0	B	Butterfly	Spring	Air/DC	Closed	2 Closed	A,F,Z	34,3
AO-5040B	Torus Vacuum Bkrs	X-227;OPC	45 0	B	Butterfly	Spring	Air/DC	Closed	2 Closed	A,F,Z	34,3
X-212A	Torus Vacuum Bkrs	X-227;OPC	--	B	Check	Vacuum	Process	Closed	-- --	Rev Flow	34
X-212B	Torus Vacuum Bkrs	X-227;OPC	--	B	Check	Vacuum	Process	Closed	-- --	Rev Flow	34
AO-5025	Direct Torus Vent	X-227,OPC	--	B	Butterfly	Spring	Air/DC	Closed	-- --	RM	19
AO-5041A	Torus Exhaust Bypass	X-227;OPC	10 0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5041B	Torus Exhaust Bypass	X-227;OPC	10 0	B	Globe	Air/AC	Spring	Closed	2 Closed	A,B,F,Z,RM	9,15,27,30
AO-5042A	Torus Main Exhaust	X-227;OPC	5 0	B	Butterfly	Air/AC	Spring	Closed	2 Closed	A,F,Z,RM	27
AO-5042B	Torus Main Exhaust	X-227;OPC	5 0	B	Butterfly	Air/DC	Spring	Closed	2 Closed	A,F,Z,RM	27
SV-5065-22B	$H_2/0_2$ Analyzer Supply	X-228C;OPC	2 0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-15B	$H_2/0_2$ Analyzer Supply	X-228C;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
31-CK-434	Air to D/W to Torus Vacuum Breakers	X-228E;OPC	--	B	Check	Process	Process	Closed	-- --	Rev Flow	
CV-5046	Air to D/W to Torus Vac Breakers	X-228E;OPC	--	B	Globe	Air/AC	Spring	Closed	-- --	RM	
SV-5065-77	PASS Liquid Return	X-228G;OPC	2 0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-78	PASS Liquid Return	X-228G;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-71	PASS Liquid Return	X-228H;OPC	2 0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-72	PASS Liquid Return	X-228H;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-18A	$H_2/0_2$ Analyzer Supply	X-228J;OPC	2 0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-11A	$H_2/0_2$ Analyzer Supply	X-228J;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18

TABLE 5 2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

VALVE #	LINE ISOLATED	PENE # & OPC/IPC	(NOTE 37) MAX OP TIME (SEC)	CLASS	VALVE TYPE (NOTE 6)	POWER TO OPEN (NOTES 5 & 6)	POWER TO CLOSE	NORMAL POSITION (NOTES 9 & 12)	ISOLATION GRP POSITION	ISOLATION SIGNAL	NOTES
SV-5065-25B	H2/O2 Analyzer Supply	X-228K;OPC	2 0	B	Globe	DC	Spring	Closed	2 Closed	A,F,RM	18
SV-5065-27B	H2/02 analyzer Supply	X-228K;OPC	2 0	B	Globe	AC	Spring	Closed	2 Closed	A,F,RM	18
MO-1400-3A	Core Spray Pump Suction	X-229A;OPC:	--	B-X	Gate	AC	AC	Open	-- --	RM	28
MO-1400-3B	Core Spray Pump Suction	X-229B;OPC	--	B-X	Gate	AC	AC	Open	-- --	RM	28
MO-1001-21	RHR Discharge to RW	None;OPC	40 0	--	Gate	DC	DC	Closed	2 Closed	A,F,RM	8,9
MO-1001-32	RHR Discharge to RW	None;OPC	30 0	--	Gate	AC	AC	Closed	2 Closed	A,F,RM	8,9
Various	Type A Instru Line (typ)	--;OPC	--	A-X	Hand Globe	Manual	Manual	Open	-- --	--	
Various	Type A Instru Line (typ)	--;OPC	--	A-X	Flow	Spring	Process	Open	-- --	Excess Flow	
Various	Type B Instr Line (typ)	--;OPC	--	B-X	Hand Globe	Manual	Manual	Open	-- --	-- --	

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

ISOLATION SIGNAL CODES FOR TABLE 5.2-4

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

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

ISOLATION SIGNAL CODES FOR TABLE 5.2-4

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

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

Notes for Table 5.2-4

1. Main steam isolation valves require that both solenoid pilots be deenergized to close valves. Accumulator air pressure plus spring act together to close valves when both pilots are deenergized. Voltage failure at only one pilot does not cause valve closure. The valves are designed to fully close in less than 10 seconds, but in no less than 3 seconds.

2. Containment spray and suppression cooling valves have interlocks that allow them to be manually reopened after automatic closure. This setup permits containment spray, for high drywell pressure conditions, and/or suppression pool cooling. When automatic signals are not present, valves may be opened for test and operating convenience.

3. On loss of air, this valve fails open.

4. Control rod hydraulic lines can be isolated by the solenoid valves (directional control) outside the primary containment. Lines that extend outside the primary containment are small and terminate in a system that is designed to prevent outleakage. Solenoid valves (directional control) normally are closed, but they open on rod movement.

5. AC motor operated valves are powered from the AC standby power busses. DC isolation valves are powered from the station batteries.

6. All motor operated isolation valves remain in the last position upon failure of valve power. All air operated valves close on motive air failure or power at the solenoid pilots.

7. Not used.

8. MO1001-21 and MO1001-32 are not primary containment isolation valves. They are included for information only since they receive F and A isolation signals.

9. Valves identified by this note can be opened or closed by remote manual switch for operating convenience during any mode of the reactor except when an automatic signal is present. RHR minimum flow valves receive automatic open signal on low flow; they receive no automatic close signal.

10. RCIC Steam supply turbine valves open on Signal B. Line Break signal K overrides to close valves.

11. Coincident signals “G” and “T” open core spray and selected LPCI valves. Special interlocks permit testing these valves by manual switch except when automatic signals are present.

12. Normal status position of valve (open or closed) is the position during normal power operation of the reactor (see “Normal Position” column).

13. HPCI Steam to turbine valves open on Signal GE. Line Break signals L and AA override to close.

14. Not used.

15. Manual switches override all automatic signals on the smaller valves that bypass the suppression chamber and drywell exhaust valves.

TABLE 5.2-4

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

Notes for Table 5.2-4

16. Signal “A” or “F” causes automatic withdrawal of TIP probe. When probe is withdrawn, the valve automatically closes by mechanical action.
17. MO-1001-29A & B isolate on reactor low water level (signal A) OR high drywell pressure (Signal F) if RHR Shutdown cooling supply valves MO-1001-50 and 47 are NOT fully closed AND reactor pressure (signal U) is below 80 psig. Valve position indicating lights are not required at the isolation valve display panel.
18. Isolation signals are overridden with control switch in the “emergency open” position.
19. Key locked switch to operate valves administratively control closed.
20. Deleted.
21. These valves are isolation valves for both penetration X-26 and X205. They are shown twice for clarity.
22. Remote manual actuation to close (key locked)
23. Reactor Sample valves isolate on Group 1 signal or Group 2 signal.
24. Isolates on LPCI initiation Signal.
25. May be manually open for high drywell pressure conditions.
26. These valves open on a low CST, or high torus level, if no isolation signal present.
27. In addition to Group 2 isolation, these valves also receive a Refueling Floor High Radiation isolation.
28. Those Class B lines which terminate below the water line of the suppression pool only require one isolation valve. (See Section 7.3.2).
29. High space temperature (Signal J) activates alarm in the control room. Pumps are signaled to stop as a result of valve closure.
30. These valves also receive a reactor low-low water level signal which cannot be bypassed by utilizing the valves emergency open feature.
31. Open on RHR pump low flow. No automatic close signal.
32. Not used.
33. Not used.
34. Valve opens when suppression chamber pressure is 0.5 psi below reactor building pressure.
35. Throttling type valve.
36. These valves are isolation valves for both penetration X-219 and X-223. They are shown twice for clarity.
37. Maximum operating time for AC powered valves are determined assuming AC power is available to the valve. For loss of AC power scenarios, the diesel start and loading time must be added to the maximum operation time.

TABLE 5.2-4 (CONT)

CONTAINMENT AND REACTOR VESSEL ISOLATION VALVES

Group Isolation Signals

Group 1: The valves in this group are closed upon any one of the following conditions.

B*	Reactor low-low water level
D*	Main Steam Line high flow
D*	Main Steam Line tunnel high temperature
P*	Main Steam Line low pressure (in run mode, only)
Q	Reactor high water level (not in run mode, below Main Steam Line Low Pressure MSIV Isolation Setpoint)

Group 2: The valves in this group are closed upon any one of the following conditions.

A*	Reactor low water level
F*	High drywell pressure

Group 3: The valves in this group are closed upon any one of the following conditions.

A*	Reactor low water level
U	High reactor pressure
F*	High drywell pressure

Group 4: The valves in this group are closed upon any one of the following conditions.

L*	HPCI steam line high flow
L*	HPCI steam line area high temperature
AA*	Low Reactor Pressure

Group 5: The valves in this group are closed upon any one of the following conditions.

K*	RCIC steam line high flow
K*	RCIC steam line area high temperature
K*	RCIC steam line low pressure

Group 6: The valves in this group are closed upon one of the following conditions.

A*	Reactor low water level
J*	Cleanup area high temperature
J*	Cleanup inlet high flow

Group 7: The valves in this group are closed upon any one of the following conditions.

N*	Reactor Low Pressure and High Drywell Pressure

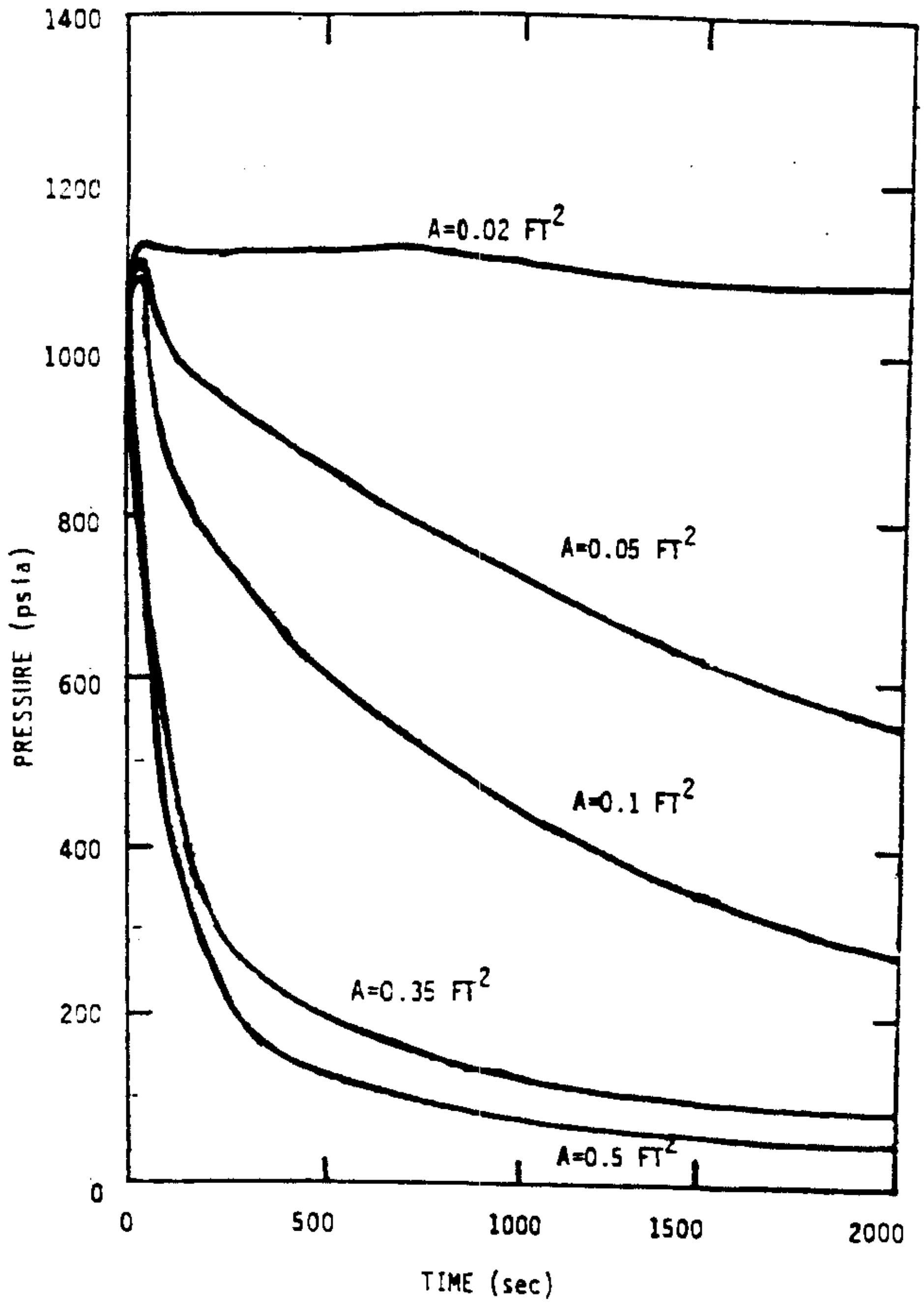

FIGURE 5.2-1
REACTOR PRESSURE RESPONSE FOR
VARIOUS SIZE STEAM LEAKS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 13 – JUNE 1991

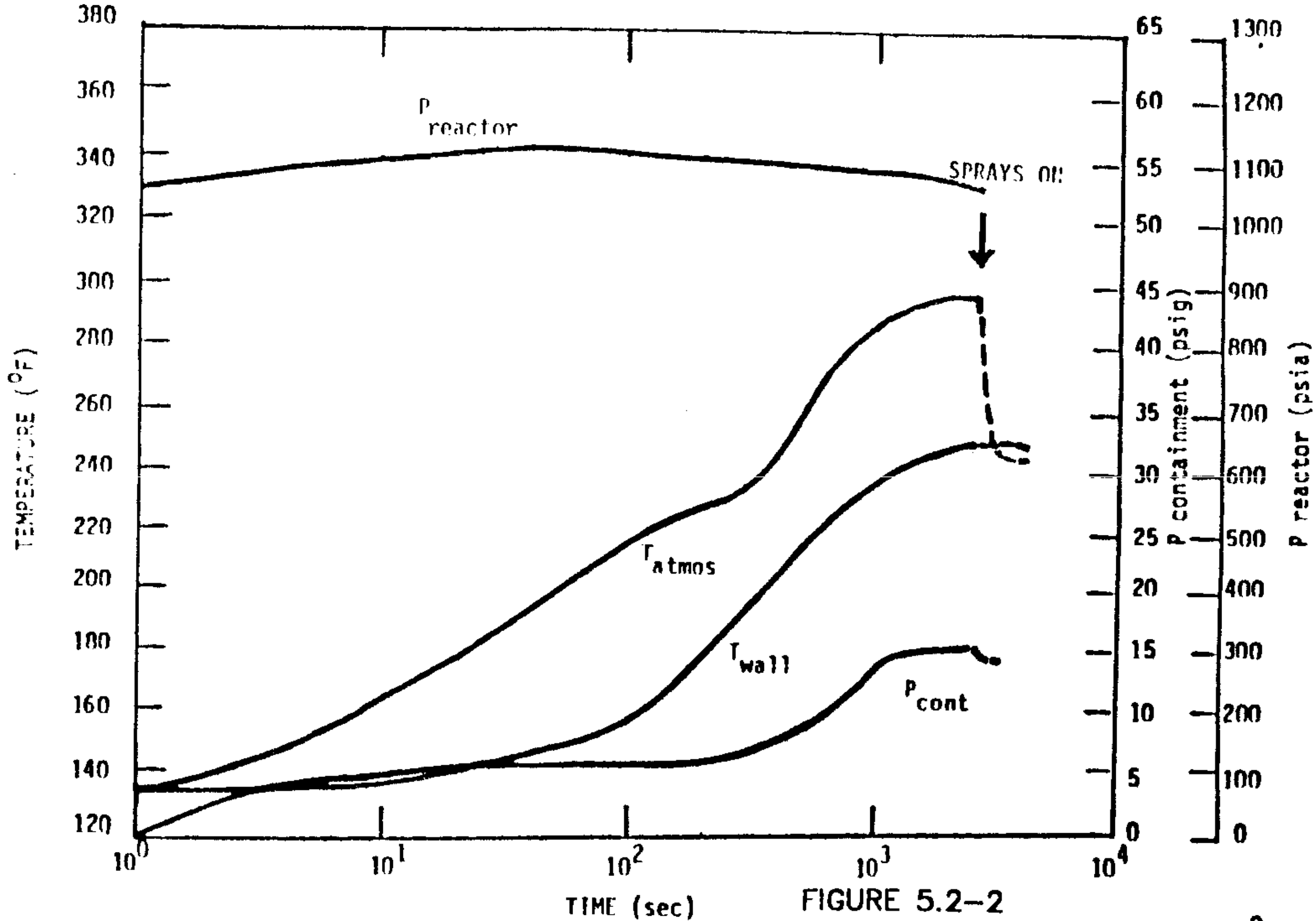

FIGURE 5.2-2
CONTAINMENT RESPONSE TO 0.02 FT^2 STEAM LEAK
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 10 – JULY 89

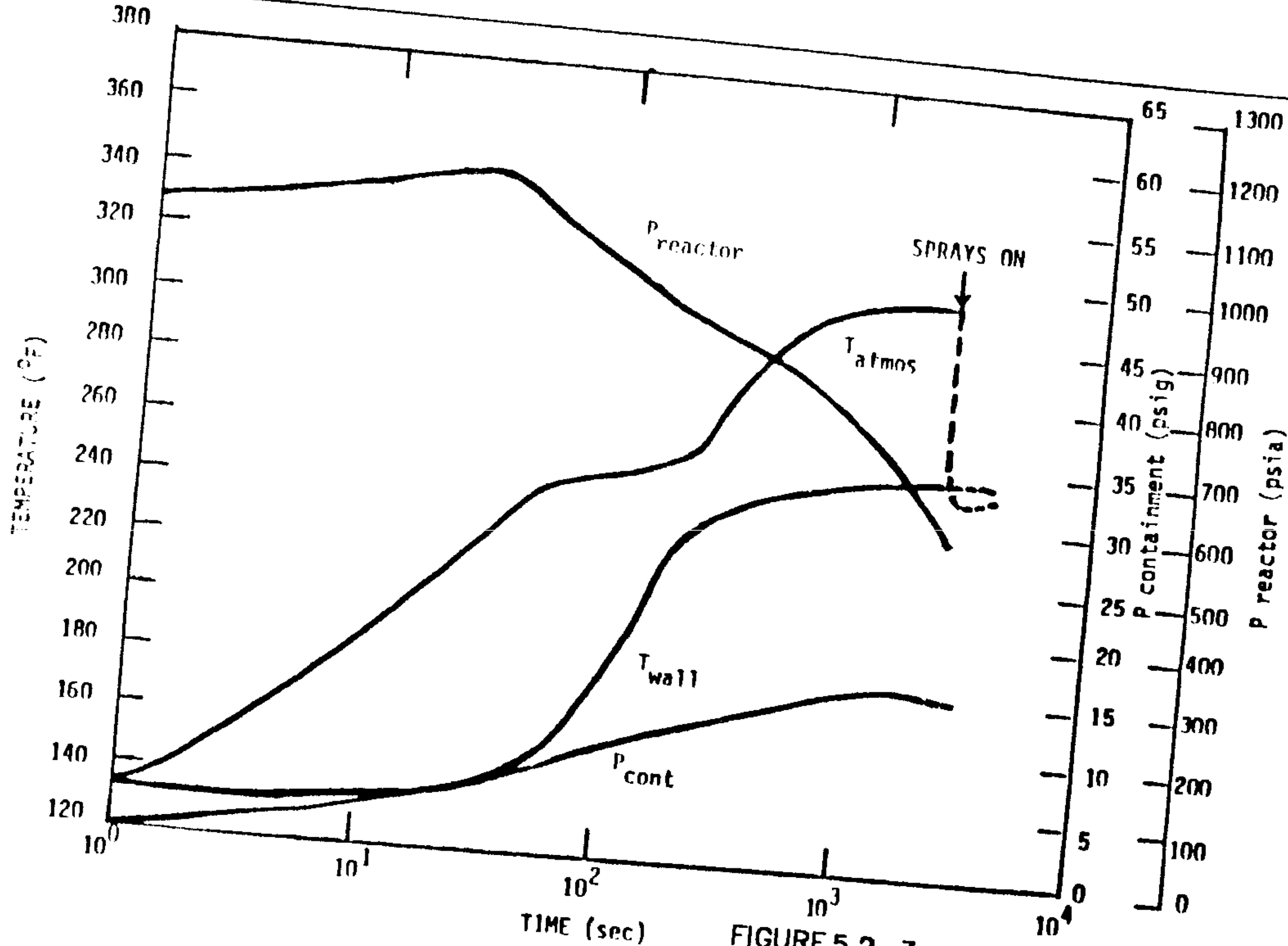

FIGURE 5.2-3
CONTAINMENT RESPONSE TO 0.05 FT^2 STEAM LEAK
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 10 - JULY 89

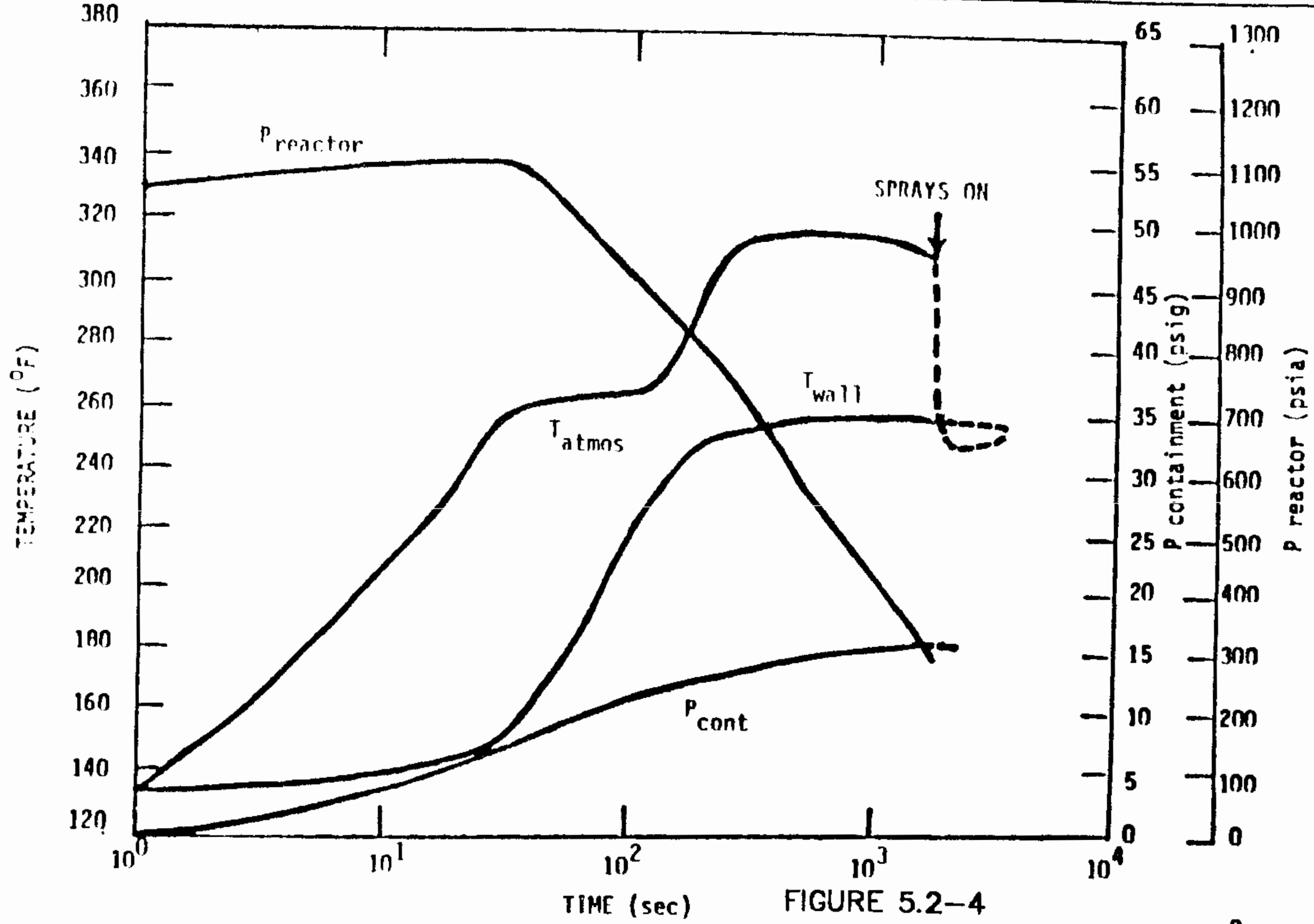

FIGURE 5.2-4

CONTAINMENT RESPONSE TO 0.10 FT^2 STEAM LEAK

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT

REVISION 10 – JULY 89

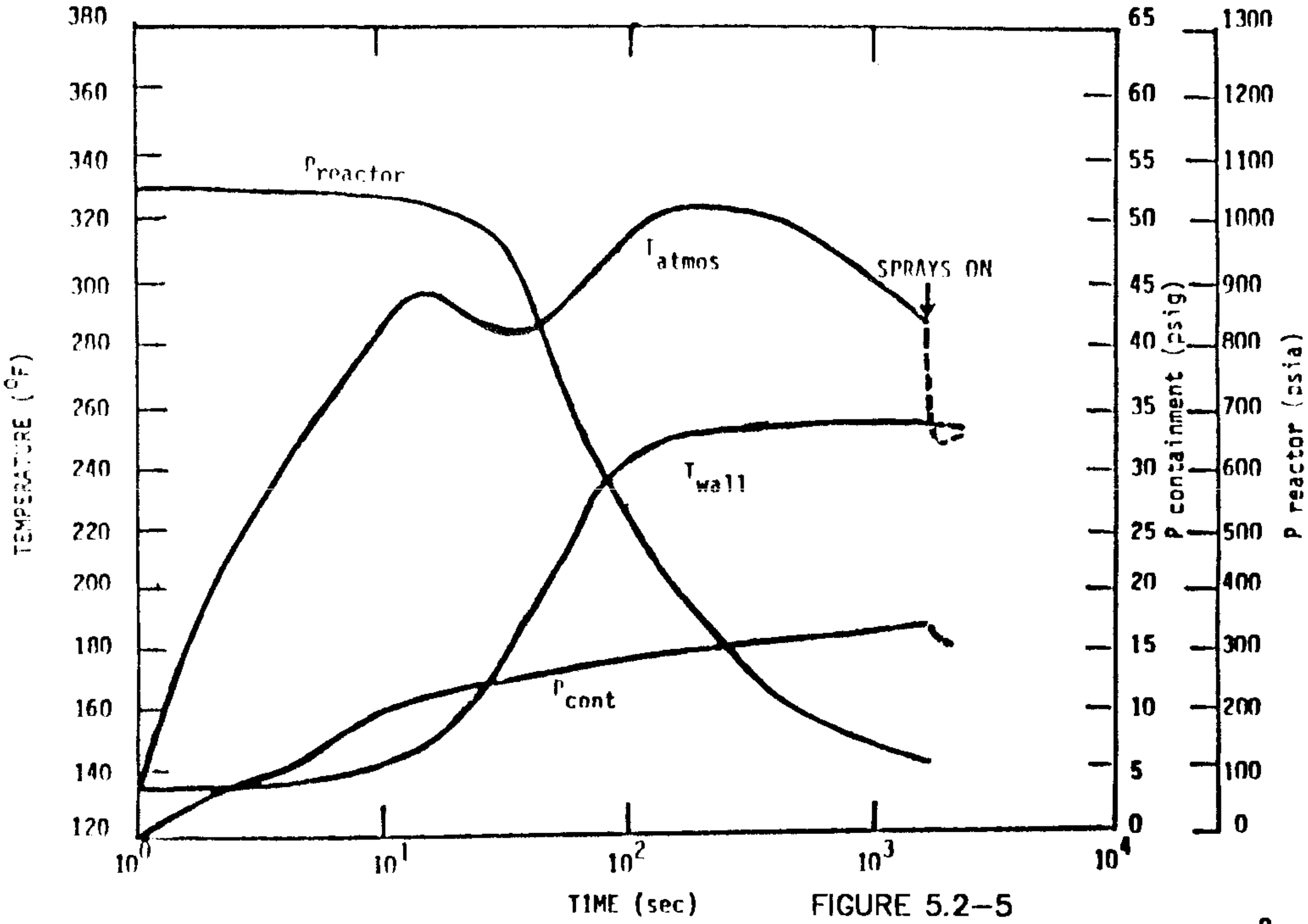

FIGURE 5.2-5

CONTAINMENT RESPONSE TO 0.35 FT^2 STEAM LEAK

PILGRIM NUCLEAR POWER STATION

FINAL SAFETY ANALYSIS REPORT

REVISION 10 – JULY 89

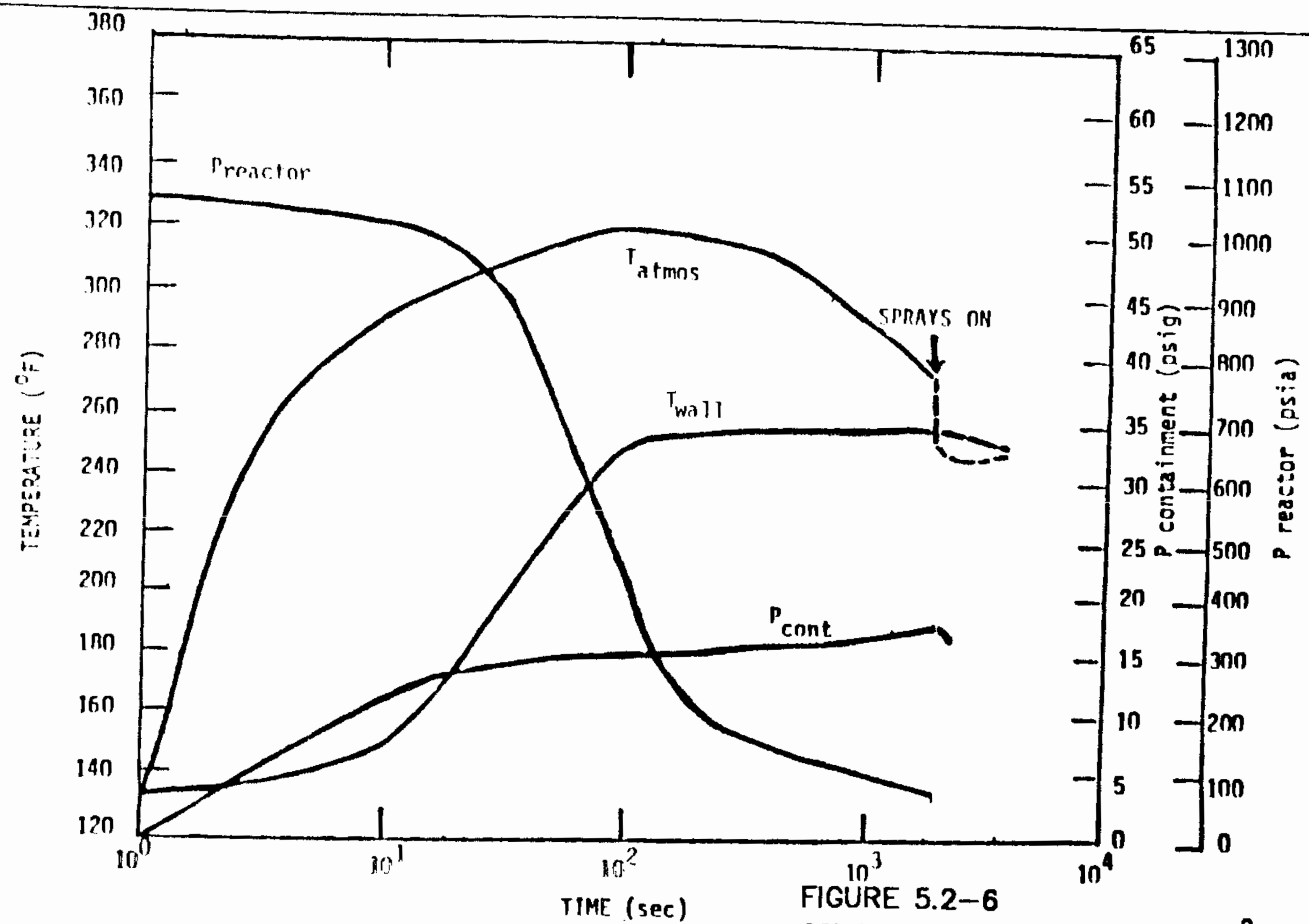

FIGURE 5.2-6
CONTAINMENT RESPONSE TO 0.5 FT^2 STEAM LEAK
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 10 - JULY 89

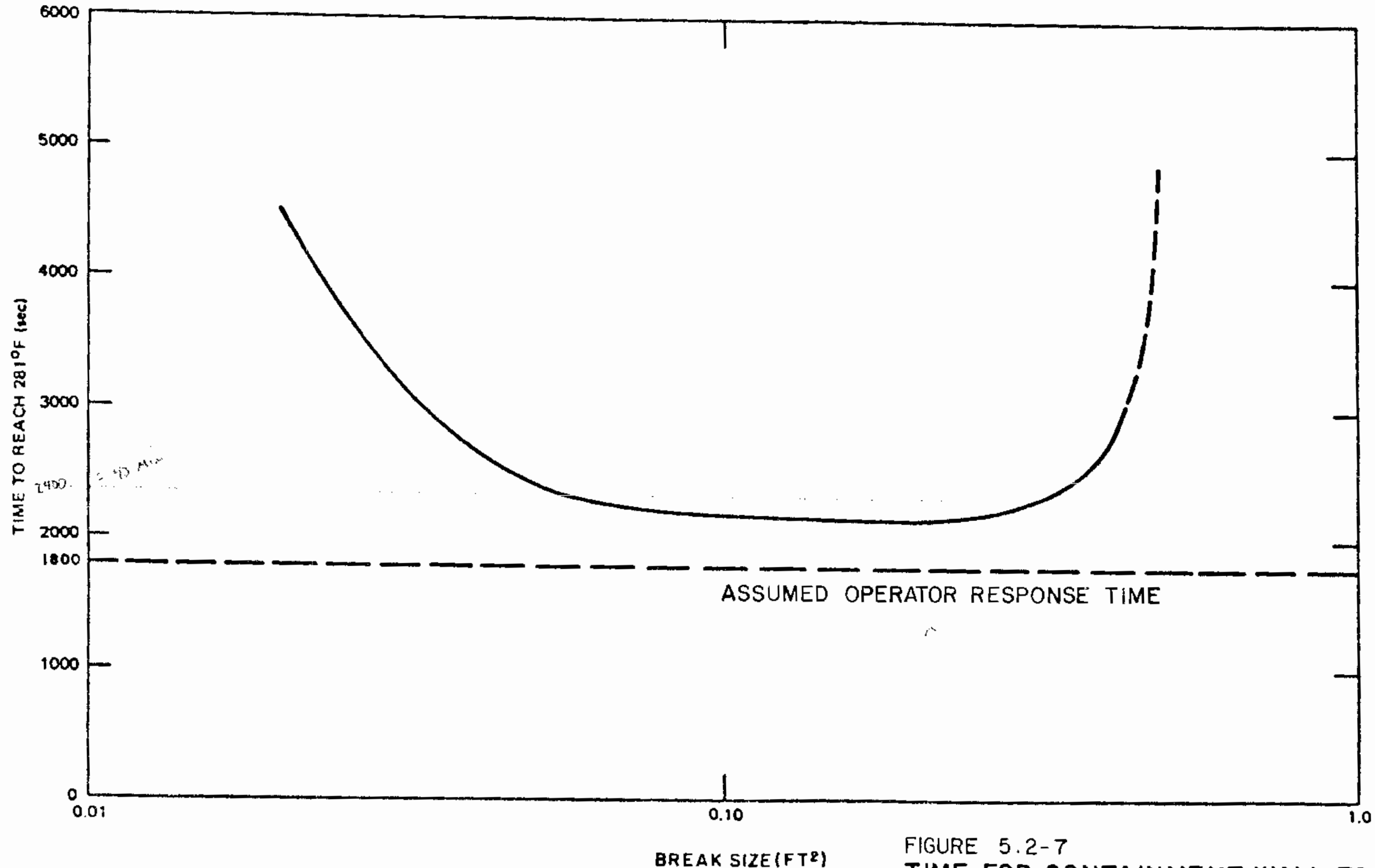

FIGURE 5.2-7

TIME FOR CONTAINMENT WALL TO REACH 281°F FOR VARIOUS SIZE STEAM LEAKS

PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

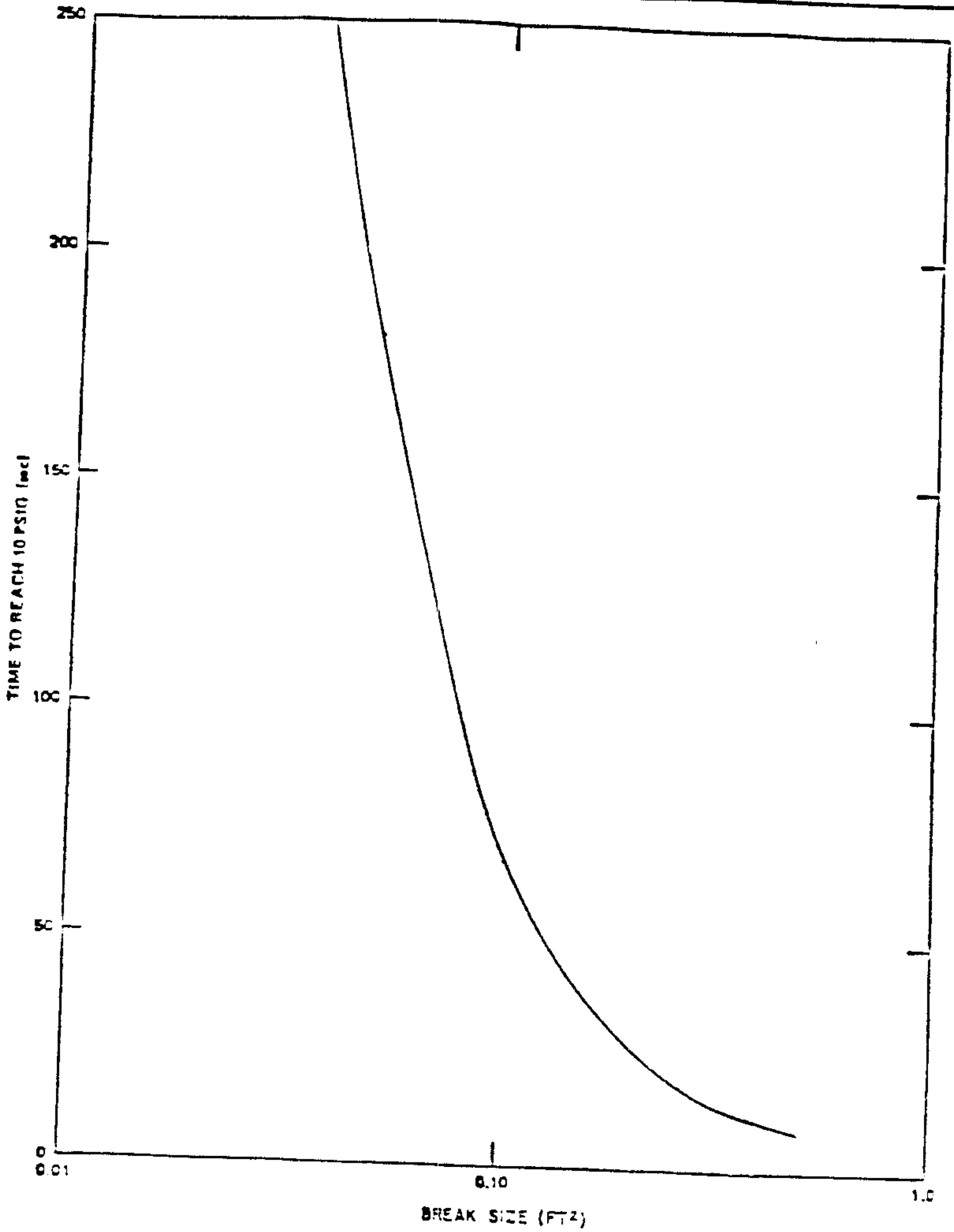

FIGURE 5.2-8
TIME TO REACH 10 PSIG IN DRYWELL FOR VARIOUS SIZE STEAM LEAKS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT
REVISION 10 - JULY 89

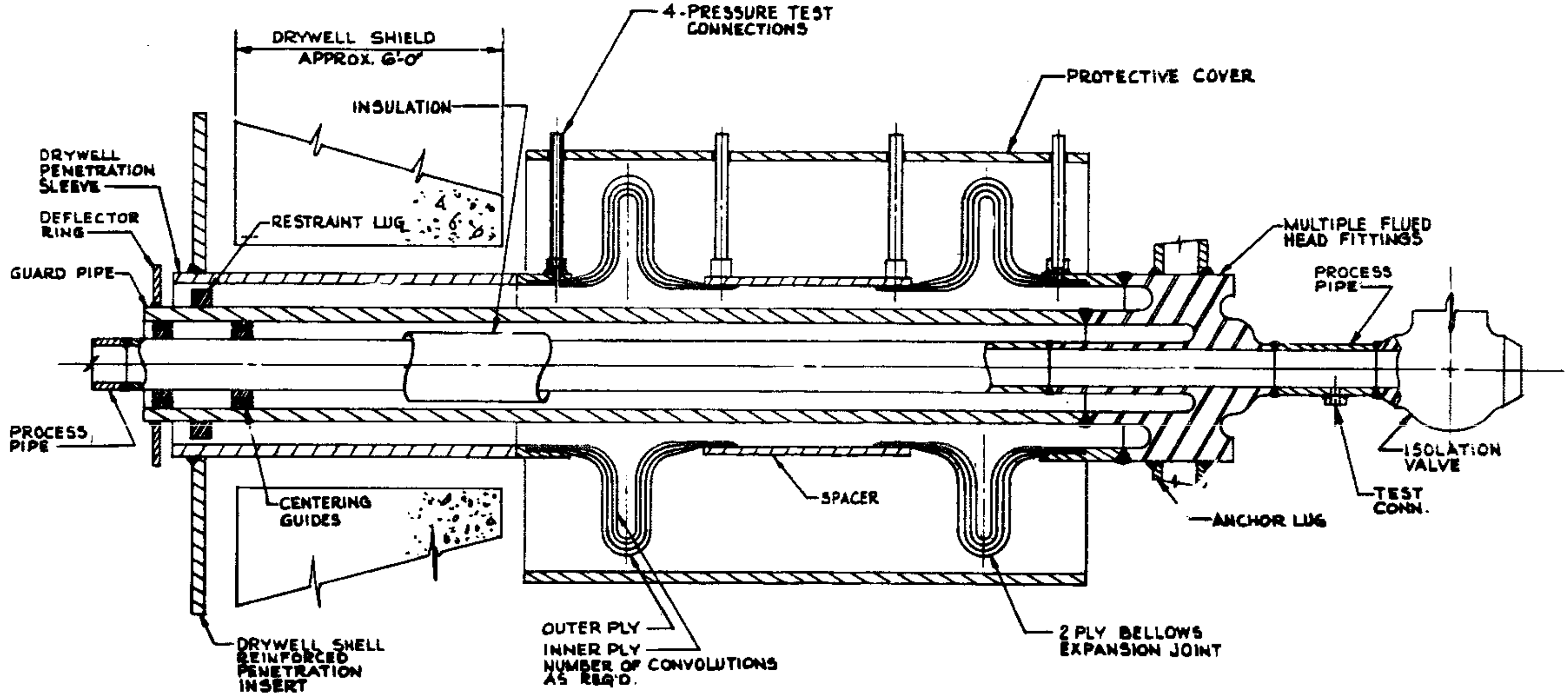

FIGURE 5.2-9
TYPICAL PIPING PENETRATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

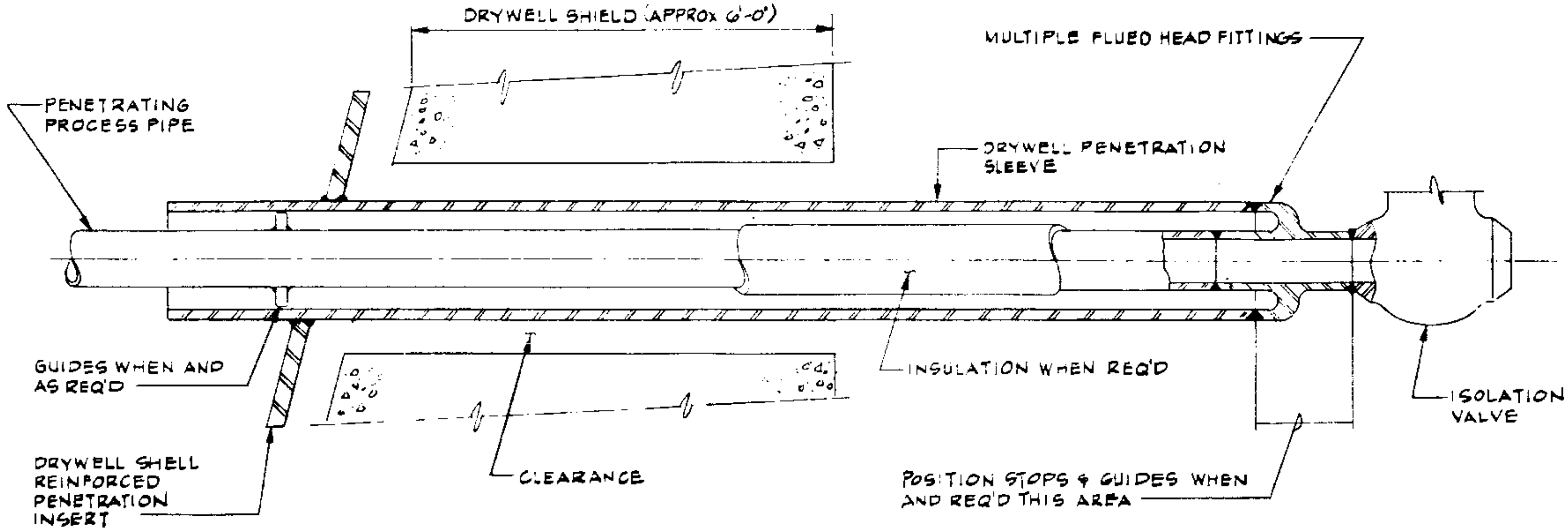

FIGURE 5.2-10
TYPICAL PIPING PENETRATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

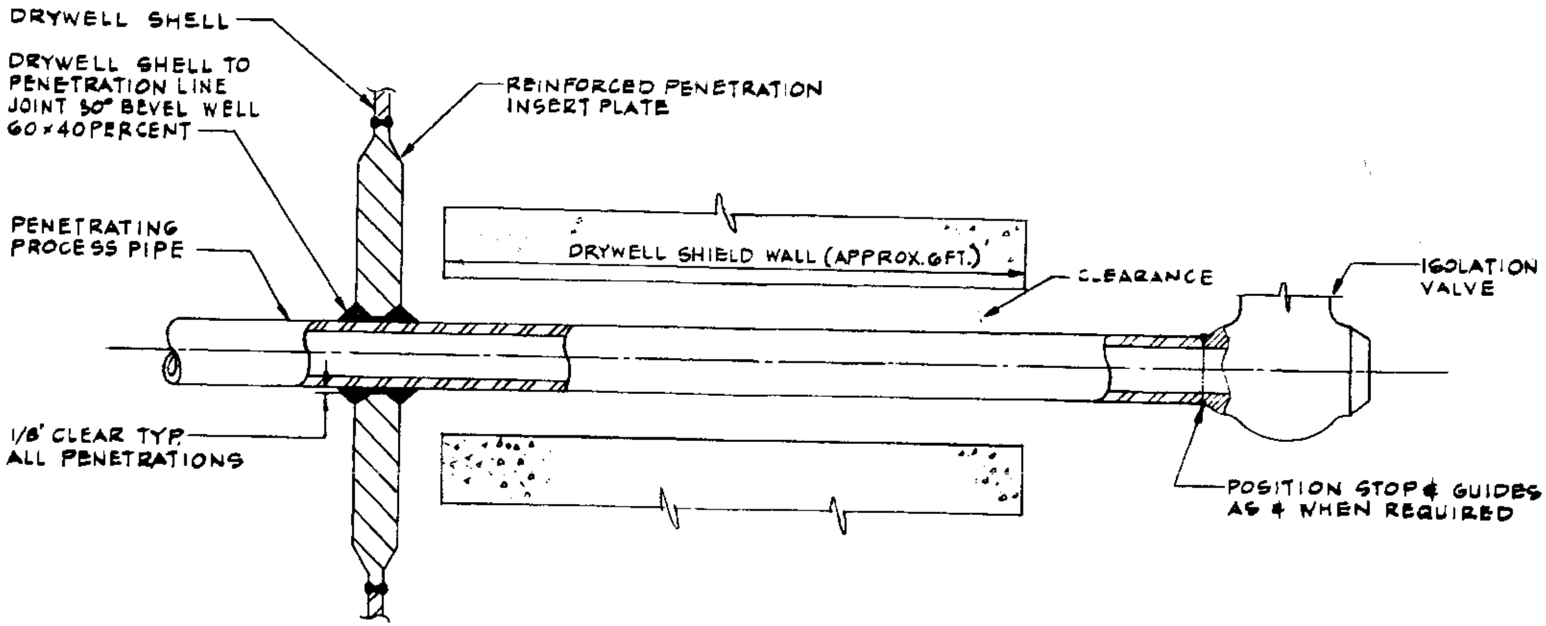

FIGURE 5.2-11
TYPICAL PIPING PENETRATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

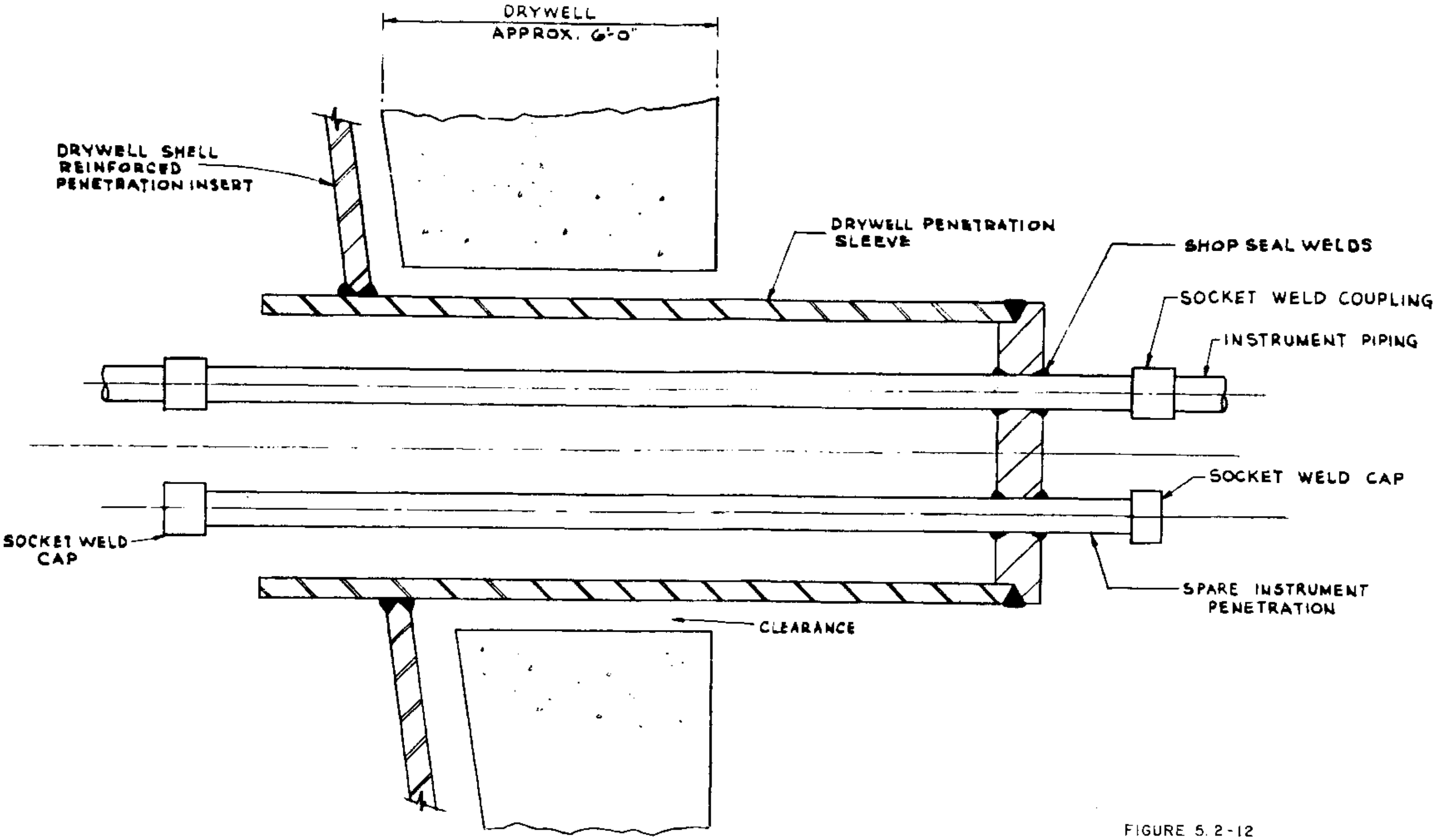

FIGURE 5.2-12
TYPICAL INSTRUMENT PENETRATION
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

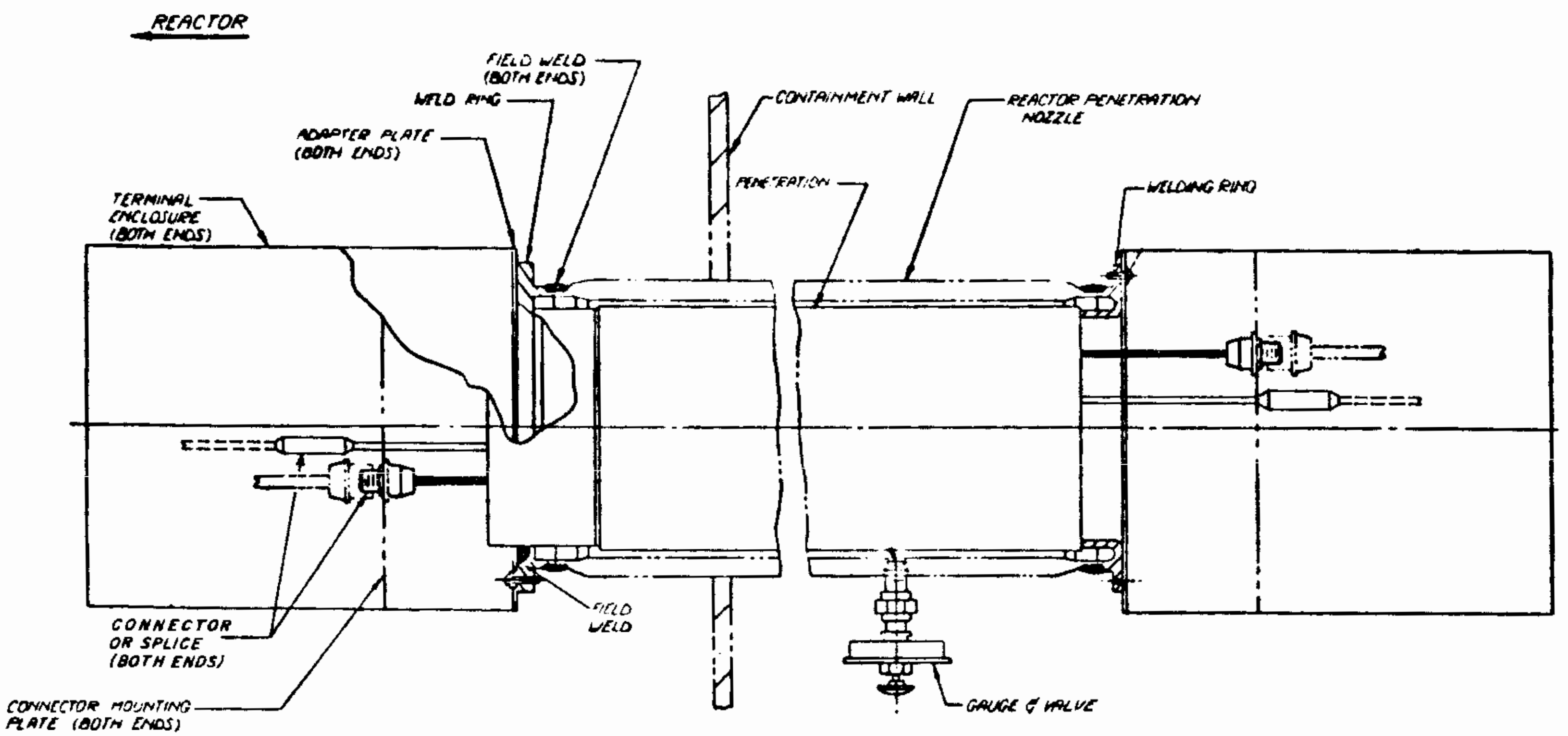

FIGURE 5.2-13
TYPICAL ELECTRICAL PENETRATION FOR LOW VOLTAGE POWER, CONTROL AND INSTRUMENTATION CABLE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

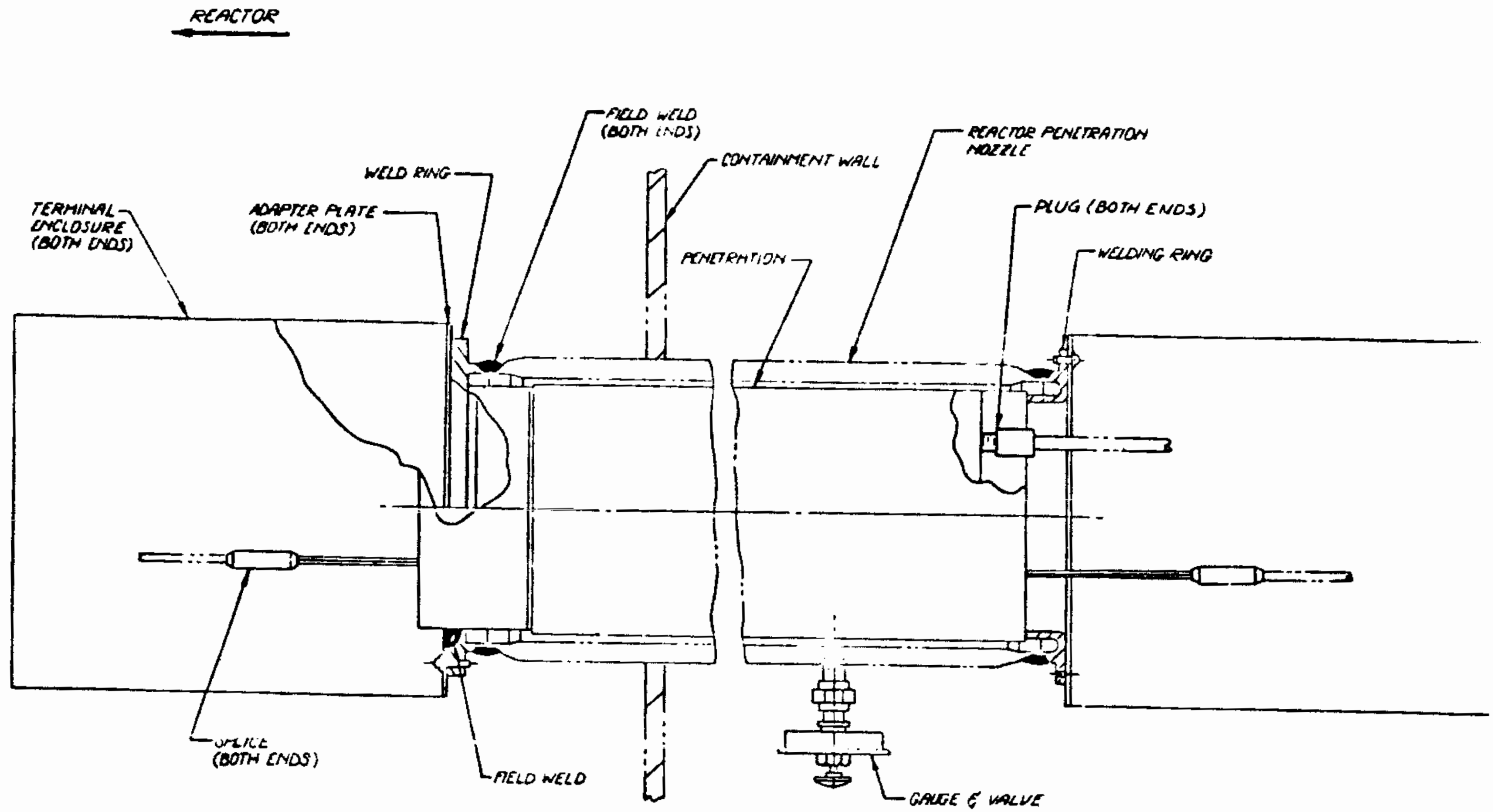

FIGURE 5.2-14
TYPICAL ELECTRICAL PENETRATION FOR COAXIAL CABLE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

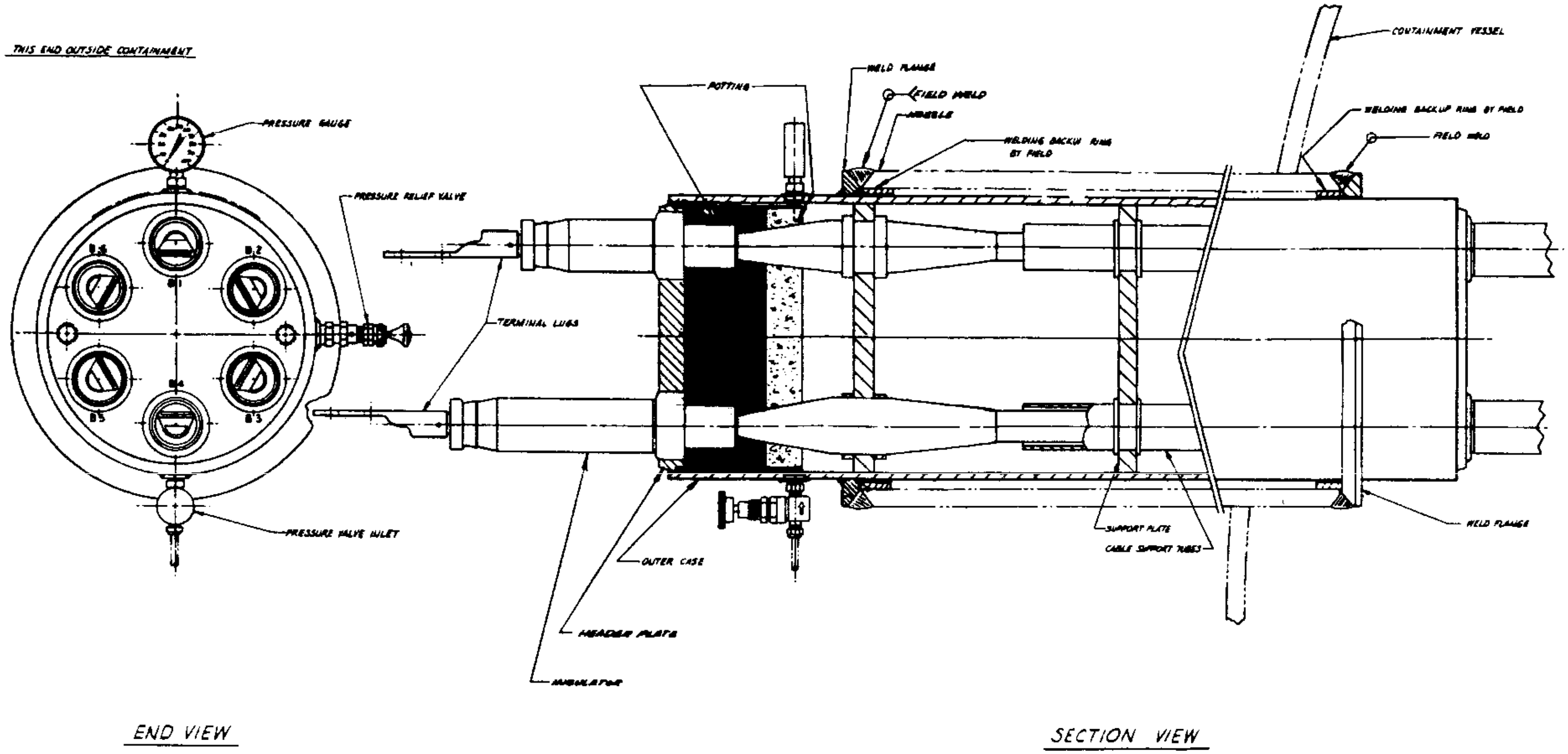

FIGURE 5.2-15
TYPICAL ELECTRICAL PENETRATION FOR MEDIUM VOLTAGE POWER CABLE
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

Figure 5.2-16 has been deleted.

See Figure 5.4-1 (Drawing M227) for information on the Containment Atmospheric Control System

Figure 5.2-17 has been deleted.

Please refer to Figure 7.18-2.

Beco drawing M294.

Figure 5.2-18 has been removed.

Please refer to BECo Controlled Drawing M 291.

Figure 5.2-19 has been deleted.

Figure 5.2-20 has been deleted.

Figure 5.2-21 has been deleted.

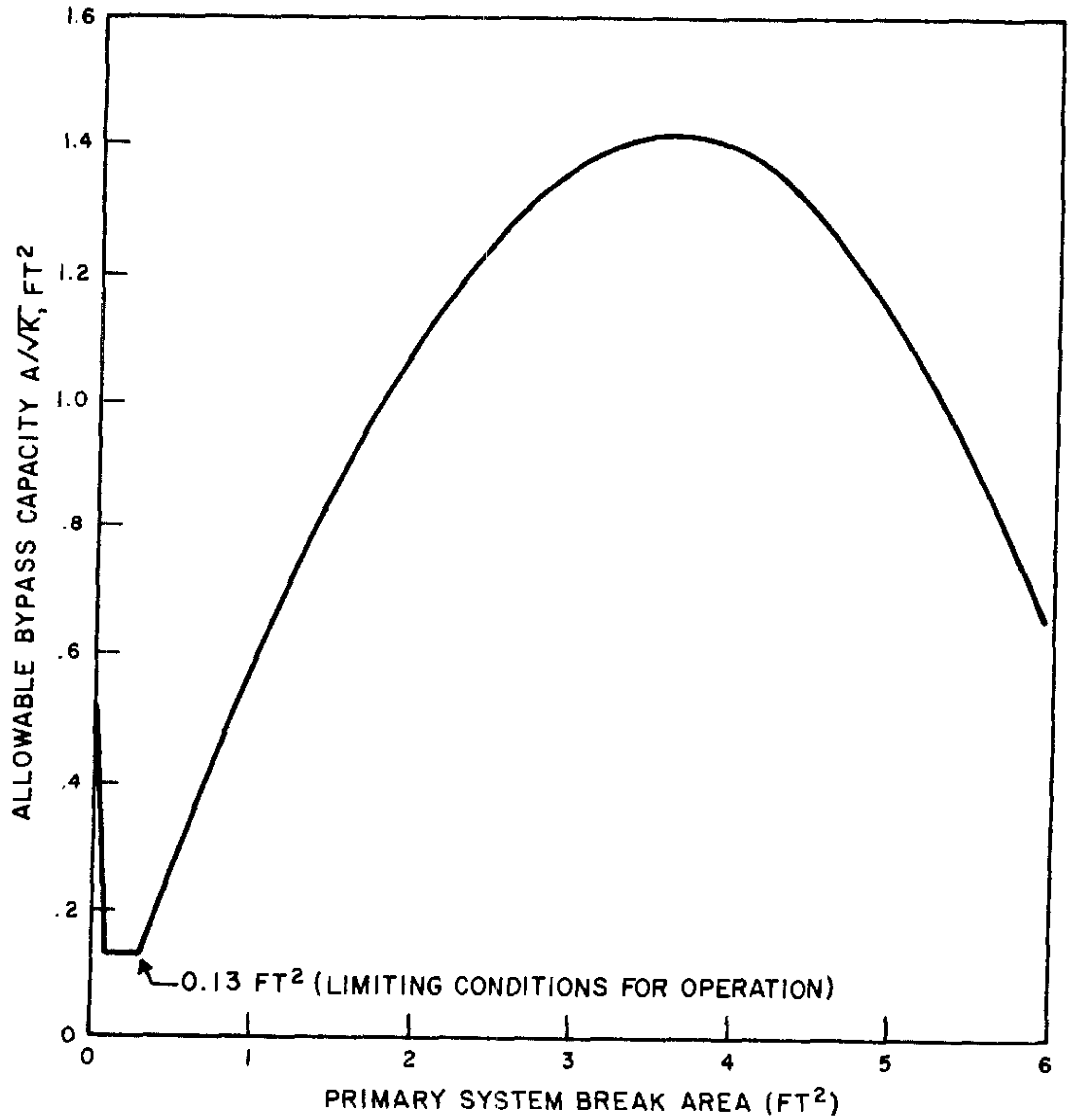

FIGURE 5. 2-22
ALLOWABLE DRYWELL TO SUPPRESSION POOL BYPASS CAPACITY VS. PRIMARY SYSTEM BREAK AREA
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

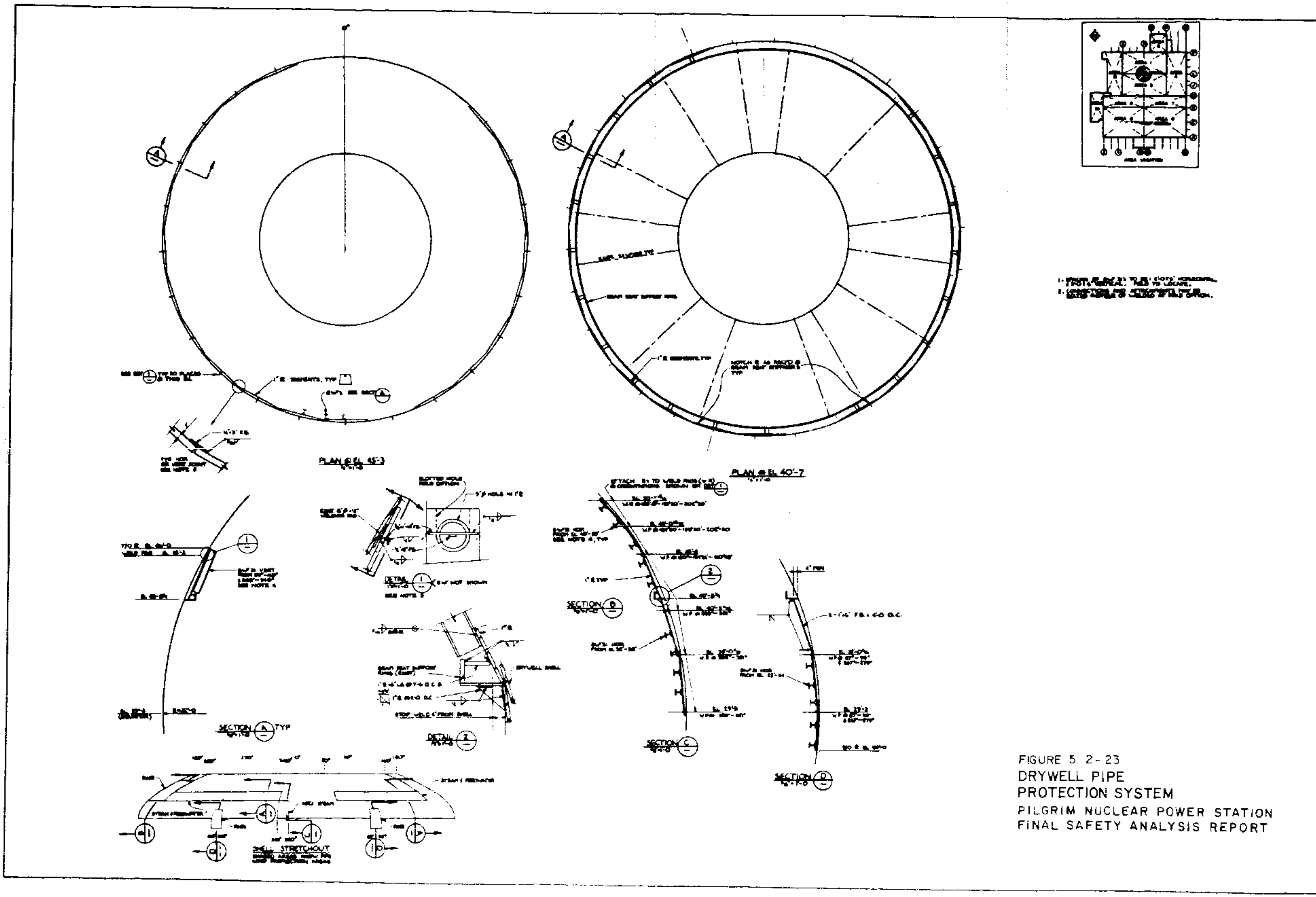

FIGURE 5.2-23
DRYWELL PIPE
PROTECTION SYSTEM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

5.3 SECONDARY CONTAINMENT SYSTEM

5.3.1 Safety Objective

The safety objective of the secondary containment system (SCS), in conjunction with other engineered safeguards and nuclear safety systems, is to 1) limit radioactive material release during normal plant operations to within 10CFR20 limits and 2) limit the release to the environs of radioactive materials so that offsite doses from a postulated DBA will be below the guideline values of 10CFR100.

5.3.2 Safety Design Basis

The safety design bases of the SCS are as follows:

1. The SCS shall be designed to provide secondary containment when the primary containment is operable and when the primary containment is open

2. The SCS is designed with sufficient redundancy so that no single active system component failure can prevent the system from achieving its safety objective

3. The SCS shall be designed in accordance with Class I design criteria. (Exception to this is the containment access locks. Since simultaneous LOCA's and SSE's are not postulated, the access locks shall be designed in accordance with Class II design criteria. The access lock door lying directly in the SCS shall be designed in accordance with Class I design criteria so that the possibility of a ground level release to the environs through the access locks is eliminated if a seismic event were to follow or precede an accident which results in a contaminated reactor building atmosphere.) The SCS is not designed to withstand tornado loads

4. The SCS shall be designed to limit radioactive material release during normal plant operations to within 10CFR20 limits.

5. The secondary containment shall be designed to limit the ground level release to the environs of airborne radioactive materials so that offsite doses from a design basis fuel handling, or loss of coolant accident (LOCA) will be below the guideline values stated in 10CFR100

6. The reactor building shall be designed to contain a positive internal pressure of at least 7 in of water

7. The SCS shall be designed to be sufficiently leaktight to allow the standby gas treatment system (SGTS) to reduce the reactor building pressure to a minimum subatmospheric pressure of 0.25 in of water, under neutral wind conditions, when the SGTS fans are exhausting reactor building atmosphere at a maximum of 4,000 ft^3/min

8. The reactor building isolation and control system (RBICS) shall be designed to 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

9. The SCS is provided with means to conduct periodic tests to verify system performance

5.3.3 Description

5.3.3.1 General

The SCS consists of four subsystems. These subsystems are the Reactor Building, the RBICS, the SGTS, and the main stack. The SCS surrounds the Primary Containment System, and is designed to provide secondary containment for the postulated LOCA. The SCS also surrounds the refueling facilities and is designed to provide primary containment for the postulated refueling accident.

The SCS utilizes four different features to mitigate the consequences of a postulated LOCA (pipe break inside the drywell) and the refueling accident (fuel handling accident). The first feature is a negative pressure barrier which minimizes the ground level release of fission products by exfiltration. The second feature is a low leakage containment volume which provides a holdup time for fission product decay prior to release. The third feature is the removal of particulates and iodines by filtration prior to release. The fourth feature is the exhausting of the secondary containment atmosphere through an elevated release point which aids in dispersion of the effluent by atmospheric diffusion. Each of the features is provided by a different combination of subsystems: the first by the Reactor Building, the RBICS, and the SGTS exhaust fans; the second by the Reactor Building and the RBICS; the third by the SGTS filters; and the fourth by the main stack.

5.3.3.2 Reactor Building

The Reactor Building completely encloses the reactor and its pressure suppression Primary Containment System. The Reactor Building houses the refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment. Also housed within the Reactor Building are the CSCS, Reactor Cleanup Demineralizer System, Standby Liquid Control System (SLCS), Control Rod Drive (CRD) System, Reactor Protection System (RPS), and electrical equipment components.

The structural design features of the Reactor Building are described in Section 12. Discussions of the Reactor Building's Class I design are included in Section 12 and Appendix C. The Reactor Building is also designed to meet the shielding requirements discussed in Section 12.

5.3.3.3 Reactor Building Isolation and Control System

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 SCS. These 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 SCS. Secondary containment can also be initiated manually from the control room.

Normally open, air-operated isolation dampers are provided on the discharge side of the Reactor Building and operating floor supply fans. Normally open, air-operated isolated 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 5.3-1. Two dampers in series are provided throughout the isolation system to provide the required redundancy. Both dampers fail closed upon loss of dc power to the solenoids or upon loss of instrument air to the dampers. The isolation dampers are piston operated and designed to close after receipt of the secondary containment initiation signal to prevent release of radioactive material from the secondary containment. The refueling floor exhaust isolation dampers must close in 3 sec to isolate the most direct path outside secondary containment. A 5 sec closing time is sufficient for the remaining dampers.

Penetrations of the secondary containment are designed to have leakage characteristics consistent with secondary containment leakage requirements. Electrical penetrations in the Reactor Building are designed to withstand normal environmental conditions and to retain their integrity during the postulated fuel handling accident and the LOCA inside the drywell. Two interlocked sealed doors on the equipment and personnel access locks assure that building access can not interfere with maintaining the secondary containment integrity.

All normally open drains which are open both to the secondary containment and the outside atmosphere are provided with water seals to maintain containment integrity. This is exemplified by the four 14 in dewatering lines for the reactor auxiliary bay floor sumps. These lines penetrate the secondary containment boundary, two below each of the two sumps, and terminate in a pair of troughs within the torus compartment. The two 4 ft cubic shaped troughs, located adjacent to the east wall, maintain containment integrity by providing water seals for each of the four lines. High and low levels are alarmed in the control room. On low level, the operators are directed by procedure to refill the troughs, to ensure containment integrity.

5.3.3.4 Standby Gas Treatment System

The SGTS consists of two, similar, parallel air filtration assemblies separated by an 18 in thick concrete block wall and completely enclosed within a Class I structure. Each of the filtration assemblies are full capacity. Each consists of a demister (use of the demister is optional), an electrical heating coil, a high efficiency particulate absorber (HEPA), two charcoal filter beds, and a final HEPA filter. With the Reactor Building isolated, each of the two fans has the necessary capacity to reduce and hold the building at a minimum subatmospheric pressure of 0.25 in of water.

Each fan has a design flow rate of 4,000 ft^3/min. Motor-operated exhaust fan outlet damper controls are provided to maintain the required negative pressure. See Figure 7.18-2 (M294). The system consists of two filter banks. Loss of dc power and/or supply air to the solenoids causes the valves in filter bank A to open and the valves in filter bank B to close. A dedicated air system is provided for long-term damper actuation. The air system consists of two high pressure air tanks, a pressure reducing regulator with inlet and outlet pressure gages, relief valve, two low pressure gages, one low pressure switch, five low pressure air receivers, solenoids valves and manual valves, and tubing required to make a complete system. The low pressure section of the system is designed to Class I design criteria. The high pressure section is designed to Class II design criteria. The low pressure system of the dedicated air system is designed to provide two complete actuation cycles of the SGTS filter isolation dampers/valves and allow for air system leakage for long-term operation.

The demister is designed to remove entrained water droplets and mist from the entering air stream. Use of the demister is optional since there are no design basis accident scenarios which would expose the SGTS to water droplets or mist. The electric heating coil is designed to reduce the relative humidity of the air stream to 70 percent. An interlock with its associated exhaust fan prevents the heating coil from operating when the fan is shut down. Each HEPA filter is designed to be capable of removing at least 99.97 percent of the 0.30 micron particles which impinge on the filter. The charcoal filters are iodide-impregnated activated carbon filters capable of removing in excess of 99 percent of the iodine in the air stream with 10 percent of the iodine in the form of methyl iodide (CH_3I) under entering conditions of 70 percent relative humidity.

The accident evaluations using the standard NRC approach are described in Section 14.5 and appendix R14.5 and Appendix R. In these analyses, the SGTS charcoal filters were credited with removal of 95 or 99 percent of the influent iodine.

The system will start automatically upon a high radiation signal from the operation (refueling) floor ventilation exhaust duct monitor, or upon receipt of high drywell pressure or low reactor water level signals. The system can also be manually started from the control room. Upon receipt of any of the initiation signals, the AUTO "A" train fan and heater start and its associated isolation valves open, the STANDBY "B" train suction valve opens, starting the "B" train fan and heater and in turn, opening the "B" train discharge isolation valve. In the event that the "A" train is down for maintenance the STANDBY "B" train suction valve opens when the train mode switch is in the MAINTENANCE position. Each fan and heater draws air from the isolated reactor building at a flow rate up to approximately 4000 ft^3/min. After a preset time delay period, the "B" train suction valve closes, which in turn trips the "B" train fan and heater, closing its discharge valve. Cross-connections between the filter trains are provided to maintain the required decay heat removal cooling air flow of low humidity air on the charcoal filters in the inactive treatment train.

The STANDBY "B" filter train is automatically started in the event of an AUTO "A" train heater, and/or fan failure. In addition, the "B" train is automatically started in the STANDBY mode whenever the STANDBY "B" train suction valve is not fully CLOSED. The system discharges to the main stack through a 20 in. underground line. The SGTS fans are powered from the emergency service portions of the auxiliary power distribution system.

Drywell and torus purge exhaust can also be directed to the SGTS for processing before release up the main stack. See Section 5.2.

The high pressure coolant injection system (HPCI) gland seal steam condenser exhauster discharge is also routed to the SGTS during accident conditions. The reactor building heating and ventilating system is discussed in Section 10.9.

During a severe accident, the torus can be directly vented to the main stack bypassing the SGTS. See Section 5.4.7.

5.3.3.5 Main Stack

The location of the main stack is shown on Figure 1.6-1 (BECo C-2). The top of the stack is at elevation 400 ft msl. The structural design of the stack is discussed in Section 12.

5.3.4 Safety Evaluation

The SCS provides the principal mechanisms for the mitigation of the consequences of an accident in the reactor building. The primary and secondary containment act together to provide the principal mechanisms for the mitigation of the consequences of an accident in the drywell. If the leakage rate of the building is low, and the leakage air is filtered and discharged to the elevated release point (utilizing the SGTS and the main stack) the offsite radiation doses that result from postulated accidents are reduced significantly. The reactor building is a Class I structure (with the exception of the secondary containment access locks which are Class II structures) designed in accordance with all applicable codes. Design of the reactor building for a maximum inleakage rate of 4,000 ft3/min at a building subatmospheric pressure of 0.25 in of water at neutral wind conditions, results in a low exfiltration rate even during high wind conditions.

In the event of a pipe break inside the primary containment or a fuel handling accident, reactor building isolation will be effected and the SGTS will be initiated. Both SGTS exhaust fans will start. After a preset time delay, one fan is stopped.

With the reactor building isolated, each fan in the SGTS has the capability to hold the building at a subatmospheric pressure of 0.25 in of water when drawing air from the building at a flow rate of 4,000 ft3/min. Exhaust fan outlet damper controls on each fan are provided to maintain the required flow rate.

The RBICS performs the required isolation actions of the SCS following receipt of the appropriate initiation signals. Following initiation, the reactor building ventilation isolation dampers close within a specified time to prevent release of radioactive material from the secondary containment. The refueling floor exhaust isolation dampers must close in 3 sec to isolate the most direct path outside secondary containment. A 5 sec closing time is sufficient for the remaining dampers. The RBICS also automatically trips the reactor building supply and exhaust fans, and starts the SGTS. The normal design flow rate in the reactor building operating (refueling) floor exhaust duct is 40,000 ft3/min. During shutdowns, the flow rate is increased to approximately 50,000 ft3/min at which time it takes more than 3 sec for fission products released in any postulated fuel handling accident to travel from the operating (refueling) floor ventilation exhaust radiation monitors to the isolation dampers. Thus, no direct release of fission products to the environment (bypassing the SGTS filtration processes, and the elevated release point provided by the main stack) is possible, except when the direct torus vent path is used following a beyond design basis accident.

The SGTS filters exhaust air from the reactor building and discharges the processed air to the main stack. The system filters particulates and iodines from the air stream in order to reduce the level of airborne contamination released to the environs via the main stack. When the system is exhausting from the Reactor Building, the building is held at a minimum subatmospheric pressure of 0.25 in of water.

Appendix G identifies requirements for establishing secondary containment (Safety Action 27), following an assumed pipe break inside the primary containment (Event 39), and following an assumed spent fuel handling accident (Event 40). Secondary containment is not

established following assumed pipe failures which result in the release of steam into the Reactor Building (Event 41).

Steam leakage into the Reactor Building could be exhausted through the ventilation exhaust systems operating at normal building pressures at a calculated rate of 63 lb/sec of steam. The SGTS operating at normal Reactor Building pressures could exhaust about 5 lb/sec of steam. Steam leakage in excess of these amounts would result in Reactor Building pressure increases above normal. Refer to Appendix O.

The Reactor Building is designed to relieve excessive internal pressures so as to preserve main structural integrity, considering the rapid pressure reduction outside the building associated with tornadoes. Refer to Appendix H.5. Reactor Building differential pressures exceeding about 0.5 psi will be relieved through the Reactor Building roof.

Steam leakage within the normal operating capability of the ventilation exhaust systems would be ducted to the main building exhaust vent. The ventilation exhaust from the principal Reactor Building compartments housing the RCIC steam supply line and turbine, the HPCI steam supply line and turbine, and the RWCU are monitored by temperature elements. These elements provide temperature indication and high temperature alarms in the main control room. The temperature set points for these alarms will alert the operator to potential steam leakage conditions at leakage rates that are less than the normal operating capability of the ventilation exhaust systems.

Steam leakage rates that exceed the capability of the normal operating ventilation exhaust systems could result in abnormal ventilation flow paths and abnormal Reactor Building exhaust locations. The design of the Reactor Building would indicate that likely abnormal release

locations would include the building roof and building access locations.

Steam leakage into a compartment within the operating capability of the ventilation exhaust systems would be confined within the normal exhaust paths, and therefore would limit the steam flooding principally to the compartment where the leakage originated. Thus the operability of safety related equipment, controls, and instrumentation located in other compartments would be maintained.

The ventilation exhaust temperature sensors will detect steam leakage from the RCIC steam line, the HPCI steam line, or the RWCU piping at leakage rates that are below the normal operating capability of the ventilation exhaust from the compartments housing these hot, pressurized lines. Early detection of steam leakage at rates below the capability of the normal ventilation systems and subsequent isolation of leaks provide protection of safety related equipment within the Reactor Building. See Section 7.3.

The main stack provides an elevated release point for airborne activity during the postulated station loss of coolant and refueling accidents. Release of activity to the environs from the Secondary Containment System is analyzed in detail in Section 14, Station Safety Analysis. It is concluded that the safety design bases are met.

5.3.5 Inspection and Testing

The secondary containment leakage rate can be determined in the following manner. The Reactor Building is isolated and the SGTS is started with one treatment train and its associated exhaust fan. The exhaust flow rate is controlled by the fan outlet damper control position as determined by flow rate measurements in the SGTS exhaust duct. The fan outlet damper positioner is used to control the exhaust flow rate at 4,000 ft3/min.

If the subatmospheric pressure as measured within the Reactor Building is equal to or exceeds 0.25 in of water (with neutral wind conditions at the site) the building safety design basis leak tightness with respect to inleakage is verified.

Tests of the ability of the various isolation initiation signals to automatically render the Reactor Building isolated, to trip the supply and exhaust fans, and to start the SGTS can be conducted by simulating the isolation signals.

Provisions are made for periodic tests of each filter unit. These tests 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 with DOP (Di-octyl-phthalate) smoke. The charcoal filters can be tested for bypass with freon.

The electric heating coil in each filter train is tested to show that the relative humidity of an entering air stream is reduced.

5.3.6 Nuclear Safety Requirements for Plant Operation

General

The entries in this section represent the nuclear safety requirements for the SCS 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.	Earlier parts of Section 5.3	Description of the SCS
2.	Station Nuclear Safety Operational Analysis Appendix G	Identifies conditions and events for which the SCS is 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 one of the Matrix 3 sheets of 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, F40-91 identifies BWR operating state F (Matrix 3), event (row) No. 40, and system (column) No. 91.

System Action

The SCS operates to limit the release of airborne radioactive materials to the environs.

Number Provided by Design

1. One Reactor Building

2. One main stack

3. One RBICS, with two dampers in series provided throughout the isolation system to provide redundancy. The control system is designed such that all dampers fail closed on loss of dc power to the solenoids or on loss of instrument air to the valves.

4. One SGTS consisting of two identical, parallel air filtration assemblies and two full capacity exhaust fans.

Minimum Required for Action

BWR Operating States A,B,C,D,E, and F:

The Reactor Building

(A40-90)	(B40-90)
(C39-90)	(D39-90)
(E39-90)	(F39-90)

The Main Stack

(A40-105)	(B40-105)
(C39-105)	(D39-105)
(E39-105)	(F39-105)

One damper at each isolation point (with associated controls)

(A40-102)	(B40-102)
(C40-102)	(40-102)
(E40-102)	(F40-102)

One filtration assembly train and one exhaust fan

(A40-91)	(B40-91)
(C39-91)	(D39-91)
(E39-91)	(F39-91)

5.3.7 Current Technical Specifications

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

Figure 5.3-1 has been removed.

Please refer to BECo Controlled Drawing M283.

5.4 CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT

5.4.1 Introduction

A system for control and monitoring of containment atmosphere is provided as required by 10 CFR 50.44. This system is provided for control of oxygen and hydrogen gases that may be generated following a postulated loss of coolant accident (LOCA) combined with degradation, but not total failure, of core standby cooling systems (CSCS). Degradation, but not total failure of the core standby cooling function means that the performance of the CSCS is postulated, for the purpose of design of the combustible gas control system (CGCS), not to meet the acceptance criteria in 10 CFR 50.46 and that there could be localized clad melting and metal-water reaction. The degree of performance degradation of the CSCS is not postulated to be sufficient to cause core meltdown.

The combustible gas control system was originally designed, built, and maintained as safety-related to control the hydrogen and oxygen that may be generated following a postulated LOCA. However, since the promulgation of Final Rule, 10 CFR 50.44, the regulatory basis of the combustible gas control system has shifted from having to cope with a design basis accident (DBA) LOCA to the mitigation of combustible gas generated by a beyond design basis accident (BDBA). The Final Rule has down graded the system to non-safety related, Reg. Guide 1.97 Category 3 for Hydrogen and Category 2 for oxygen subsystems. The regulatory commitment made in the Pilgrim License Amendment 206 requires Pilgrim to maintain the system at least to the level of Reg. Guide 1.97 Category 3 for hydrogen and Category 2 for oxygen monitoring. With the elimination of the design-basis LOCA hydrogen release, the hydrogen monitors are no longer required to mitigate design-basis accidents, and therefore, the hydrogen monitors do not meet the definition of safety-related component as defined in 10 CFR 50.2. Likewise, the oxygen monitors are also down graded to Reg. Guide 1.97, Category 2.

The containment atmospheric control system (CACS) is provided to obviate the possibility of an energy release within the primary containment from a hydrogen-oxygen reaction following a postulated LOCA combined with degraded CSCS functioning. This is to be accomplished by maintaining an atmosphere containing less than 4% oxygen in the drywell and pressure suppression chamber (torus). The system will:

1. Perform initial purging of the primary containment

2. Provide for a supply of nitrogen makeup gas during normal operation or emergency

3. Provide for normal and purge exhaust lines to the standby gas treatment system (SBGT) for normal operating conditions

4. Provide for emergency exhaust from the drywell and torus for release of contaminated drywell and torus gases to the SBGT

5. Provide pneumatic supply to instruments inside the drywell

An adjunct to the CACS is the direct torus vent line. This line can be used to vent excessive pressure generated inside containment (following a beyond design accident) directly to the main stack, bypassing the SBGT.

5.4.2 Source of Hydrogen and Oxygen Accumulation in Containment

Following the postulated design basis LOCA combined with degraded CSCS function, hydrogen may be produced by the postulated metal-water (zirconium-water) reaction. Hydrogen and oxygen may be produced by radiolysis of reactor coolant. Radiolysis of water is the only source of oxygen in the PNPS inerted containment. Under design basis accident conditions, oxygen would be produced in much more limited quantities than hydrogen and is therefore chosen as the parameter to control.

Procedures are in place to control primary containment atmosphere and to maintain the containment inerted during normal operations and transients. The development and implementation of Emergency Operating Procedures (EOPs) industry-wide has fundamentally changed the way in which operators respond to accidents from an "event-based" approach to a "symptom-based" approach. The EOPs do not specifically differentiate between symptoms that are within design basis and those that are beyond design basis.

The EOPs and support procedures contain specific instructions for maintaining the concentrations of both hydrogen and oxygen below their respective thresholds for combustibility. The procedures are structured to effect containment purging with nitrogen and/or venting as the control method for reducing combustible gas concentrations inside containment. Containment oxygen concentration in excess of 5% in the presence of detectable hydrogen i.e., $\geq$ 1%, is not credible for design basis accidents and would be considered beyond PNPS design basis. The EOPs and support procedures contain appropriate instructions for implementing the strategies of BWROG Emergency Procedure Guidelines to control combustible gases for events beyond PNPS design basis for the purpose of preserving primary containment integrity.

5.4.3 System Description

10 CFR 50.44(b)(1) requires all containments must have a capability for ensuring a mixed atmosphere. 10 CFR 50.44(b)(2) requires all boiling water reactors with Mark I or Mark II type containments must have an inerted atmosphere. 10 CFR 50.44(b)(4)(i) requires equipment for monitoring oxygen in containments that use an inerted atmosphere for combustible gas control. The equipment for monitoring oxygen must be functional, reliable, and capable of continuously measuring the concentration of oxygen in the containment atmosphere following a significant beyond design-basis accident for combustible gas control and accident management, including emergency planning. 10 CFR 50.44 (b)(4)(ii) requires equipment for monitoring hydrogen in the containment. The equipment for monitoring hydrogen must be functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere following a significant beyond design-basis accident for accident management, including emergency planning.

Pilgrim is a Mark I type containment and is provided with an inerted atmosphere to preclude the possibility of a hydrogen combustion event within the containment. The oxygen deficient atmosphere assures that hydrogen build-up due to metal-water reaction is not a concern for these plants. Combustible gas control for these plants is based on control of oxygen, which is produced in more limited quantities than hydrogen following a LOCA or transient event.

The CACS in conjunction with the SBGT are the systems which Pilgrim Station utilizes for primary containment atmospheric control as required by 10CFR50.44. See Figure 5.4-1 (Drawing M227).

The containment combustible gas control system is used primarily for purging (i.e., inerting) with Nitrogen (N_2) or can be used for containment venting. Exhaust from both the torus and drywell can be routed to the main stack via the redundant trains of the SGTS. Makeup of nitrogen (or air) is supplied via the 1 inch redundant solenoid valve trains. See Figure 5.4-1 (Drawing M227).

The primary method of controlling combustible gas inside the primary containment is by maintaining an oxygen free atmosphere by inerting. When the containment is deinerted oxygen is present, but containment integrity post-LOCA is ensured by monitoring containment for hydrogen. Should hydrogen levels rise when deinerted, purging with air (dilution) or the CACS can be used to maintain containment atmosphere hydrogen gas accumulation below stoichiometric proportions. This is achieved by inerting the drywell and suppression chamber atmosphere with nitrogen. The inerted atmosphere is maintained by the following controls:

1. Technical Specification 3.7.A.5.a and 3.7.A.5.b require that, when the containment is required to be inerted, the containment atmosphere must be less than four percent oxygen.

2. The pneumatic control systems located inside the primary containment use only nitrogen when the containment is required to be inerted. Additional capability to address USI-A46 is provided and available.

3. There are no potential sources of oxygen in containment other than that resulting from radiolysis of reactor coolant when the containment is required to be inerted.

In addition to operating with the primary containment atmosphere inerted with nitrogen, PNPS must maintain a safety grade purge/repressurization system in conformance with the general requirements of Criteria 41, 42, and 43 of Appendix A of 10 CFR 50. This basis for maintaining the purge/repressurization system is given in the "Safety Evaluation by the Office of Nuclear Reactor Regulation Relating to Generic Letter 84-09 on Hydrogen Recombiner Capability Pilgrim Nuclear Power Station, Unit 1" (April 30, 1986). It states

> "...the "Safety Grade" purge/repressurization system is still necessary to control combustible gas mixtures for a narrow range of accident scenarios which have the potential to generate hydrogen and oxygen at rates that are comparable to the radiolysis rates described in Regulatory Guide 1.7".

The Purge/Repressurization System controls oxygen concentration below flammability limits (5 volume percent) by a feed and bleed method. The time required before initiation of purge (vent) of the primary containment is controlled by repressurization techniques consisting of nitrogen (or air) addition to the primary containment.

Sixteen (16) solenoid valves are arranged to provide redundant paths to and from the drywell and torus for Nitrogen makeup/repressurization and venting. Nitrogen makeup/repressurization is provided by:

1. Connecting, to hose connections outside containment, a portable nitrogen supply via truck with vaporizer or using the existing (non-seismic) nitrogen storage tank with vaporizer (requires opening a manual block valve located outside containment in the yard area Reactor Building north wall) (Primary emergency make-up)

2. Alternatively, provide a compressed air supply from service air connections outside the primary and secondary containment or from portable (gasoline driven) air compressors located on site (secondary emergency make-up)

The solenoid valves are designed to remain closed against maximum containment pressure, to vent containment so that the maximum containment pressure will not be exceeded, and to provide a nitrogen flow sufficient to maintain the oxygen concentration inside containment below the flammability limits.

The valves in redundant paths are powered from independent Class IE distribution systems each of which is powered from an emergency diesel generator after a loss of offsite power or from essential DC supply. The control switches for redundant valves are located in separate Class IE control panels in the main control room. Conduit and permanently installed equipment required for purging and repressurization functions are located in seismically designed,

missile protected buildings, except all the fill connections which are located outside of secondary containment but separated. Redundant conduit systems are separated commensurate with identified hazards. All conduit and permanently installed equipment required for purging and repressurization functions are supported to meet seismic Category I requirements except for N_2 supply equipment described previously.

The solenoid valves are ASME III Class 2 and are qualified environmentally and seismically to the requirements of IEEE 323-1974, IEEE 382-1973, and IEEE 344-1975 for the expected conditions. The valves are rated at 120V ac and are designed to operate between 80 and 110 percent of rated voltage. This range is compatible with expected bus voltages at Pilgrim Nuclear Power Station. The valves which need to operate the direct torus vent system receive control power from essential 125 volts DC.

The control switches have been qualified to the requirements of IEEE 323-1974 for operation in a control room environment. The switches are mounted on Class IE panels (see Table 7.8-3) and the combination has been qualified to IEEE 344-1975 for the Operating Basis Earthquake. The switch's electrical ratings exceed loading requirements.

The cable and wire used for this modification have been qualified to IEEE 383-1974 for fire and ambient conditions exceeding those required for this installation. The 600 V No. 12 AWG control cable has voltage and current capabilities well above that required.

Control of the solenoid valves is remote manual, there is no automatic isolation capability. Isolation signals have not been provided because:

1. The valves are always keylocked closed during normal operation
2. The valves are required to be operated during a high drywell pressure condition and must be available independent of reactor water level. High drywell pressure and low-low reactor water level are the normal containment isolation signals

Nitrogen makeup and ventilation valves are also provided for use under nonaccident conditions. These will automatically close upon receipt of an accident signal. However, these valves may be used after an accident provided the required power supplies are available and a low-low water level signal is not present. Refer to Section 5.2.3.5 and Tables 5.2-4 and 7.3-1.

Indicator lights are provided to continuously monitor valve position. The indicators are driven by reed-type limit switches mounted within the valve electrical housing. Contacts from all control switches are wired to an annunciator window to provide an alarm when a valve is open.

All containment vent and purge valves receive power from either the onsite or offsite emergency power system.

Hydrogen generation rates and amounts are based upon the guidance of Regulatory Guide 1.7. The amount of hydrogen generated by a fuel cladding and water reaction was obtained by using the larger of:

1. Five times the total amount of hydrogen calculated in a previous Pilgrim reload submittal

2. An average core wide cladding penetration of 0.23 mils

In a previous Pilgrim Station reload submittal, GE calculated an average metal water reaction percentage of 0.13 percent (Reference 1). Five times 0.13 is 0.65 percent cladding interaction. A 0.23 mil average cladding penetration is equivalent to 0.68 percent cladding interaction. Hence, the 0.23 mil average cladding penetration was used. All hydrogen generated by the core metal water reaction was assumed to be released to the primary containment immediately. Radiolytic hydrogen generation rates and accumulation curves were calculated by GE (Reference 2). GE used AEC Safety Guide 7 to generate their curves. These assumptions are the same as those used in Regulatory Guide 1.7.

Hydrogen inputs from corrosion for Pilgrim (no chemical spray) are minor (Reference 3). Hence, no other significant source exists from this event.

5.4.4 Containment Mixing

Significant combustible gas concentration stratification within the drywell or the torus is not expected. Organizations such as Energy Incorporated and GE have investigated containment mixing. Energy Incorporated has estimated less than 0.1 percent variation in hydrogen concentration in the drywell and expects good mixing will take place in the torus because of thermal gradients (Reference 4). Energy Incorporated's conclusion are supported by GE's evaluation of mixing in the containment around their BWR 6. GE believes that a very small temperature (T) or concentration (C) difference is sufficient to promote good mixing ($T = 2.6 \times 10^{-5}$ °F or $C = 4.3 \times 10^{-8}$ in the containment around a BWR 6).

GE also believes that the analysis used on the containment around a BWR 6 will also apply to a Mark I Containment. Based upon the above analysis, in the open Pilgrim BWR Mark I containment, no significant combustible gas concentration stratification is expected within the drywell or torus.

5.4.5 Combustible Gas Monitoring

The existing containment combustible gas monitoring system (CCGMS) consists of two redundant, remotely operable, seismically qualified hydrogen analyzers. The hydrogen analyzers are capable of continuously monitoring drywell hydrogen concentration for 30 days following their initiation. They initiate 30 minutes after safety injection begins. They have a remote readout in the main control room. System operation requires manual initiation by control room operators when directed by procedures. Additional information regarding the hydrogen analyzers is contained in Section 10.19, "Post-Accident Sampling System."

5.4.6 Radiological Consequences of Containment Venting

An evaluation of offsite doses which would be incurred as a result of containment venting to limit containment pressure has been performed in a manner consistent with Regulatory Guides 1.3, 1.7, and 1.45.

The results of this analysis indicate that the doses to receptors at the LPZ would be well within the limits of 10 CFR 100. This analysis assumed that venting at the rate of 50 standard ft^3/min through the SGTS would be initiated at 80 hours after the reactor was made subcritical and venting would continue for 30 days.

5.4.7 Direct Torus Vent Line

5.4.7.1 Introduction

The consequences of several beyond design basis accident scenarios are more severe than the accidents previously considered herein. The primary containment pressure during these accidents is estimated to exceed its design capacity. Thus, the primary containment fails, releasing reactor fission products to the secondary containment and potentially to the environment as well. The direct torus vent line (DTVL) provides an emergency primary containment vent path to prevent, or at least slow down, the buildup of potentially damaging pressure within the primary containment.

5.4.7.2 System Description

The DTVL is an 8" carbon steel line connecting the 20" torus main exhaust line to the underground 20" main stack exhaust line. The 8" DTVL starts at a branch between the 8" containment isolation valves AO-5042A&B. The DTVL terminates in the 20" main stack exhaust line, several feet downstream of the SBGT outlet valves. The line includes AO-5025, an 8" air-operated, normally-closed butterfly valve which serves as the outboard containment isolation valve for the DTVL rupture disk plate is removed per EC-46822 upstream of the connection to the 20" main stack exhaust line. Both electrical power and valve operator active gas (air or nitrogen) supply are taken from "essential" or reliable sources, or are backed-up to ensure that the system is available during a station blackout or loss of instrument air event. FSAR Figure 5.4-1 (Drawing M227) shows the DTVL arrangement, but the rupture diskc plate is removed per EC-46822 and tie into the 20" main stack exhaust line is shown in FSAR Figure 7.18-2 (Drawing M294).

The DTVL meets ASME B&PV Code (1980 Edition with Winter 1980 Addenda), Section III, Subsection NC for Nuclear Class 2 requirements up to and including the isolation valve. The new piping downstream of the isolation valve meets ANSI B31.1 (1977 Edition through Winter 1979 Addenda) requirements.

During normal or general transient conditions, the DTVL outboard isolation valve would remain closed. In response to a beyond design basis accident, plant management could direct the control room operators to employ the DTVL to relieve excessive pressure within the containment. In this case, the operator would follow a written procedure to perform the following basic actions:

- Close, or confirm closed, the outboard isolation valve for the torus main exhaust line
- Optimally, turn off the SBGT which likely came on automatically in response to a high drywell pressure signal
- Close, confirm closed, the SBGT outlet valves to prevent the high containment pressures from back-pressurizing the SBGT filters
- Open the two DTVL isolation valves
- Close the two DTVL isolation valves to terminate the release.

5.4.7.3 Radiological Consequences of DTVL Use

The exhaust gases released by the DTVL following a beyond design basis accident would have initially been "washed" by the suppression pool water which would reduce the particulates released. These exhaust gases are vented to the highest vent point (main stack), avoiding the groundlevel release of radioactive material from containment failure due to over-pressurization.

5.4.8 References

1. GE Letter No. SSX:79-64.

2. July 13, 1979 Letter, W. J. Neal (GE) to S. A. Giusti (Bechtel).

3. BLE-459 dated September 25, 1975.

4. Supplement No. 1 to Dresden Station Special Report No. 39 and Quad Cities Special Report No. 14.

5. NRC SER Supporting Amendment 55 to Facility License No. DPR-35, Containment Atmospheric Dilution System.

6. NRC SER Relating to Generic Letter 84-09 on Hydrogen Recombiner Capability, PNPS Unit 1.

7. Pilgrim License Amendment No. 206, dated July 22, 2004.

Figure 5.4-1 has been removed.

Please refer to BECo Controlled Drawing M 227 .

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CORE STANDBY COOLING SYSTEMS

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CORE STANDBY COOLING SYSTEMS*

6.1 SAFETY OBJECTIVE

The objective of the Core Standby Cooling Systems (CSCS), in conjunction with other engineered safeguard systems, is to limit the release of radioactive materials to the environs during postulated accident conditions so that resulting radiation exposures are within the guideline values given in published regulations.

*Also known as the Emergency Core Cooling Systems.

6.2 SAFETY DESIGN BASES

1. To provide, in conjunction with other systems, adequate cooling of the reactor core under abnormal transient and postulated accident conditions, the Core Standby Cooling Systems (CSCS) shall be provided of such number, diversity, reliability, and redundancy that only a highly improbable combination of events could result in inadequate cooling of the core.

2. In the event of a loss of coolant accident, the CSCS shall remove the residual stored heat and heat from radioactive decay of the reactor core at such a rate that the acceptance criteria of 10CFR50.46 are met.

3. The CSCS shall provide for continuity of core cooling over the complete range of postulated break sizes in the nuclear system process barrier.

4. CSCS shall be initiated automatically by conditions which sense the potential inadequacy of normal cooling.

5. Operation of the CSCS shall be initiated regardless of the availability of offsite power supplies.

6. Action taken to effect containment integrity shall not negate the ability to achieve core cooling.

7. To provide assurance that the CSCS shall operate effectively, each component required to operate in a loss of coolant accident shall be testable during normal operation of the nuclear system.

8. The components of the CSCS within the reactor vessel shall be designed to withstand the transient mechanical loadings during postulated accident conditions, so that the required standby cooling flow is not restricted.

9. The equipment of the CSCS shall withstand the physical effects of postulated accident conditions so that the core can be effectively cooled. These effects include missiles, fluid jets, high temperature, pressure, and humidity.

10. The CSCS shall be capable of withstanding earthquake ground motions without impairment of their functions.

6.3 *SUMMARY DESCRIPTION - CORE STANDBY COOLING SYSTEMS*

During normal operations, when normal electrical power for the station auxiliaries is available, heat is removed from the reactor core through the boiling water-steam-turbine-condenser-feedwater cycle during power operation or during shutdown through use of the Residual Heat Removal System (RHRS). During certain postulated accident conditions, the continuity of normal core cooling is lost and the Core Standby Cooling Systems (CSCS) are required to function. The most demanding accident condition on the CSCS is the loss of coolant accident (LOCA). For postulated LOCA conditions, coolant is lost from a breach in the nuclear process system. The reactor is shut down by the reactor low water level or high drywell pressure scram. As the water level in the reactor vessel continues to drop, the main steam line isolation valves are shut and the Reactor Core Isolation Cooling System (RCIC) is started. High drywell pressure or reactor vessel low water level signals will start one or more CSCS automatically to maintain core cooling.

The CSCS consist of:

High Pressure Coolant Injection System (HPCIS)

Automatic Depressurization System

Core Spray System

Low Pressure Coolant Injection (LPCI) (an operating mode of the *RHRS*)

The CSCS are designed to limit clad temperature over the complete spectrum of possible break sizes in the nuclear system process barrier, including the design basis break. The design basis break is defined as the complete and sudden circumferential rupture of the largest pipe connected to the reactor vessel with displacement of the ends so that blowdown occurs from both ends. The range of operation of the CSCS to cover the break spectrum for the initial core are illustrated on Figure 6.3-1.

The individual CSCS - HPCIS, Automatic Depressurization, Core Spray System, and LPCI - are described in the following paragraphs. A summary of the principal parameters of the CSCS core cooling capacity, flow, pressure, and backup systems is given on Table 6.3-1.

This section gives the safety analysis of the CSCS from the system viewpoint. The process diagrams are included in this section to show a simplified schematic of each system, and the principal operating parameters (flow, pressure, temperature) in the various operating, test, and accident design modes. Other sections of this report which give further specific details are the following:

Reactor Vessel Internals (core spray), Section 3.3.

Nuclear System Pressure Relief System (depressurization valves), Section 4.4.

RHRS (LPCI function), Section 4.8.

CSCS Controls and Instrumentation, Section 7.4.

The piping and instrument diagrams, and the functional control diagrams are included in Section 7.4, Core Standby Cooling Systems Controls and Instrumentation, which also evaluates the controls and instrumentation for all of the CSCS.

The equipment and operation of each of the CSCS are discussed, followed by a description of the analytical model which is used to calculate reactor vessel pressure and coolant inventory during a LOCA. Using this analytical model, reactor vessel pressure and coolant inventory are calculated assuming individual operation of each of the CSCS for some typical size breaks in the nuclear system process barrier. The results of the analyses are presented to indicate the capability of each system. The analytical model is then used to calculate reactor vessel pressure and coolant inventory, assuming the design basis LOCA has occurred and the CSCS operate in an integrated manner as designed. The results of the analysis show how operation of the CSCS satisfies the safety objective. The model is then used to perform the analyses which show the redundant capability of the CSCS.

The section concludes with a discussion of the testing and inspection which are performed to provide assurance that the CSCS will operate as required.

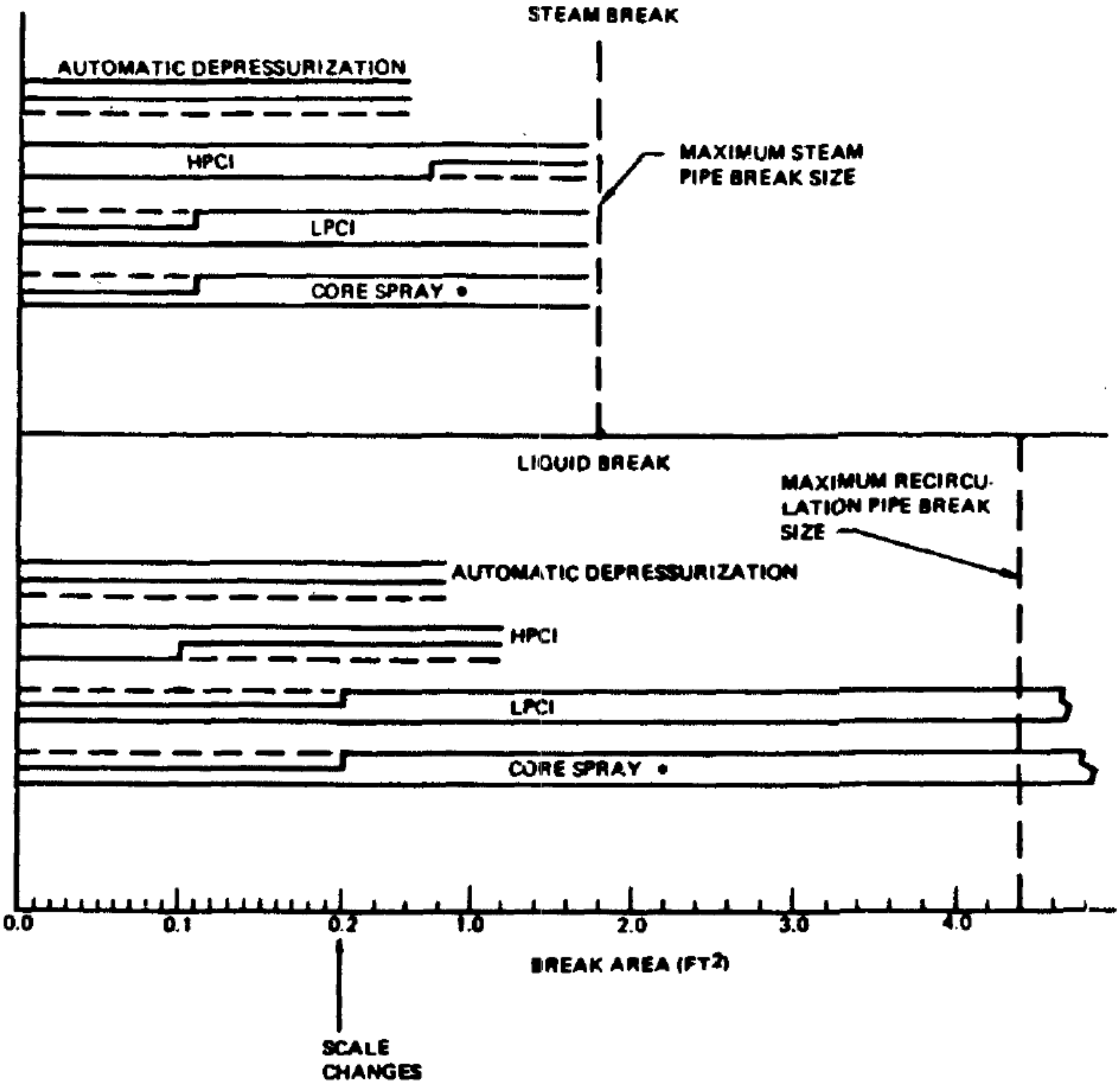
TABLE 6.3-1

CORE STANDBY COOLING SYSTEMS EQUIPMENT DESIGN DATA SUMMARY

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

NOTE:

* psid-pounds per in^2 differential between reactor vessel and primary containment
** Minimum required flow is 800,000 lb/hr @ 1095 psig
*** Minimum required flow is 3240 gpm @ 104 psig reactor pressure
**** Periodic pump testing demonstrates the HPCI system is capable of delivering 3000 gpm to the reactor vessel for a system head corresponding to a reactor pressure of 1126 psig, the highest analytical setpoint of the safety relief valves.



* 2 loops operable

FIGURE 6.3-1
CORE STANDBY
COOLING SYSTEMS PERFORMANCE
CAPABILITY BAR CHART
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

6.4 DESCRIPTION

6.4.1 High Pressure Coolant Injection System (HPCIS)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The system was designed for an original service life of 40 years, accounting for corrosion, erosion, and material fatigue. The HPCI system was reviewed for license renewal and loss of material due to corrosion, erosion, and cracking due to material fatigue are managed such that the system will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

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

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

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

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

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

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

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

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

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

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

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

HPCIS initiation automatically actuates the following valves:

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

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

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

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

6.4.2 Automatic Depressurization System

In case the capability of the Feedwater System, the control rod drive water pumps, Reactor Core Isolation Cooling System (RCICS), and HPCIS is not sufficient to maintain the reactor water level, the Automatic Depressurization System functions to reduce the reactor pressure so that flow from LPCI and the core spray system enters the reactor vessel in time to cool the core and limit fuel clad temperature.

The automatic depressurization system utilizes the four nuclear system pressure relief valves to relieve the high pressure steam to the suppression pool. The design, description, and evaluation of the pressure relief valves are discussed in detail in Section 4.4, Nuclear System Pressure Relief System and it is shown that Safety Design Bases 5, 9, and 10 are satisfied.

The pressure relief valves automatically open upon coincident signals of reactor vessel low-low water level, primary containment (drywell) high pressure, and discharge pressure indication of any low pressure cooling system (LPCI or core spray), but only after a time delay. The time delay provides time for the high pressure systems to restore reactor water level and for the operator to cancel the automatic depressurization signal if main control room information indicates the signal is false or is not needed.

6.4.3 Core Spray System

Two independent loops are provided as a part of the core spray system. Each loop consists of a core spray pump, a sparger ring, a spray nozzle, and the necessary piping, valves, and instrumentation. Figure 6.4-2 (Drawing M1K 2-4) shows a schematic process diagram of the core spray system.

In case of low water level in the reactor vessel or high pressure in the drywell, the core spray system, when reactor vessel pressure is low enough, automatically sprays water onto the top of the fuel assemblies in time and at a sufficient flow rate to cool the core and limit fuel clad temperature (The LPCI System starts from the same signals and operates independently to achieve the same objective by flooding the reactor vessel).

The core spray system provides protection of the core for the large break in the nuclear system when the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are unable to maintain reactor vessel water level.

The protection provided by the core spray system also extends to a small break (see Figure 6.3-1) in which the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are all unable to maintain the reactor vessel water level and the automatic depressurization system has operated to lower the reactor vessel pressure so LPCI and the core spray system can provide core cooling.

The core spray pumps receive power from the station 4,160V auxiliary buses. Each core spray pump motor and the associated automatic motor valves receive AC power from different buses. Similarly, control power for each loop of the core spray system comes from different DC buses. This arrangement satisfies Design Basis 5.

The core spray pumps and all automatic valves can be operated individually by manual switches in the main control room. Operating information is provided in the main control room with pressure indicators, flow meters, and indicator lights.

The major equipment for one loop is described in the following paragraphs.

When the system is actuated, water is taken from the suppression pool. Flow then passes through a normally open butterfly valve and a motor operated valve which can be closed by a remote manual switch from the main control room. This motor operated valve is normally open. The butterfly valve is located in the core spray pump suction line as close to the suppression pool as practical. This valve is equipped with an extension operator to permit manual closure of the valve from the floor above the suppression chamber.

The core spray pumps are located in the reactor building below the water level in the suppression pool to assure positive pump suction. The pump, piping, controls, and instrumentation of each loop are separated and protected so that any single physical event, or missiles generated by rupture of any pipe in any system within the containment drywell, cannot make both core spray loops inoperable. The switchgear for each loop is in a separate cabinet for the same reason. This arrangement satisfies safety design basis 9.

The effects on available NPSH for the core spray pumps due to a postulated accumulation of LOCA generated debris on the suction strainers in the suppression pool were evaluated in accordance with Regulatory Guide 1.82 Rev. 2. The RHR and core spray suction strainers in each loop were replaced with a large capacity (670 ft^2) stacked disk strainer spanning the width of one torus bay and connected to the three pumps. The debris analysis determined the maximum volume of shredded fiberglass, sludge, dirt/dust, rust flakes, and paint chips generated from the bounding line break inside primary containment. Based on a bounding analysis for debris generation, transport, and accumulation, the increase in suction strainer head loss is within the margin for NPSH available to the core spray pumps following the design basis LOCA. Refer to Section 14.5.3 for the NPSH evaluation.

A shaft seal drain line is provided from the pump casings which drains to the radwaste system.

A low flow bypass line is provided from the pump discharge to below the surface of the suppression pool. The bypass flow is required to prevent the pump from overheating when pumping against a closed discharge valve. An orifice limits the bypass flow. A manual valve, normally locked open, is used to close the bypass line for maintenance.

A relief valve, set for 500 psig, protects the low pressure core spray system upstream of the outboard shutoff valve from reactor pressure. The relief valve discharges to the radwaste system.

A full flow test line permits circulating water to the suppression pool for testing the system during planned operations. A normally closed, motor operated valve in the line is controlled by a remote manual switch in the main control room. Partial opening of the valve combined with an orifice in the test line permits test operation at rated core spray flow at a pressure drop equivalent to discharging into the reactor vessel. A flow indicator is provided in the main control room to monitor core spray system flow rate.

Two motor operated valves are provided to isolate the core spray system from the nuclear system when the core spray pump is not running. These valves admit core spray water to the reactor when signaled to open. Both valves are installed outside the drywell to facilitate operation and maintenance, but as close as practical to the drywell to limit the length of line exposed to reactor pressure. The valve nearer the containment is normally closed to back up the inside check valve for containment purposes. The outboard valve is normally open, to limit the equipment needed to operate in an accident condition. A drain line is provided between the two shutoff valves to measure leakage through the inside check valve or the inboard shutoff valve. A drain line is normally closed with two valves and a pipe cap to assure containment.

A check valve is provided in each core spray pipeline just inside the primary containment, to prevent loss of reactor coolant outside containment in case the core spray line breaks. A normally locked open manual valve is provided downstream of the inside check valve to shut off the core spray system from the reactor during shutdown conditions for maintenance of the upstream valves. The two core spray system pipes enter the reactor vessel through nozzles 120 deg apart. Each internal pipe then divides into a semicircular header with a downcomer at each end which turns through the shroud near the top. A semicircular sparger is attached to each of the four outlets to make two practically complete circles, one above the other. Short elbow nozzles are spaced around the spargers to spray the water radially into the tops of the fuel assemblies.

Core spray piping upstream of the outboard shutoff valve is designed for the lower pressure and temperature of the core spray pump discharge. The outboard valve and piping downstream are designed for reactor vessel pressure and temperature. The system is designed in accordance with Appendix A. The core piping and support structures are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. The core spray system is assumed filled with water for seismic analysis. It is concluded that Safety Design Basis 10 is satisfied.

Upon signals of reactor low-low water level and low vessel pressure or drywell high pressure, the automatic controls turn on the core spray pumps and restore other valves to the spray mode. When reactor pressure decreases, the core spray shutoff valves are signaled to open. Flow to the sparger begins when the pressure differential opens the inside check valve. Section 7.4, Core Standby Cooling System Controls and Instrumentation, contains further details and evaluation.

6.4.4 Low Pressure Coolant Injection

In case of low-low water level in the reactor and low vessel pressure or high pressure in the containment drywell, LPCI mode of operation of the residual heat removal (RHR) system pumps water into the reactor vessel in time to flood the core to limit fuel clad temperature.

(The core spray system starts from the same signals and operates independently to achieve the same objective.)

LPCI operation provides protection to the core for the case of a large break in the nuclear system when the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are unable to maintain reactor vessel water level.

Protection provided by LPCI also extends to a small break (see Figure 6.3-1) in which the feedwater system, control rod drive water pumps, RCICS, and the HPCIS are all unable to maintain the reactor vessel water level and the automatic depressurization system has operated to lower the reactor vessel pressure so LPCI and the core spray system start to provide core cooling.

Figure 6.4-3 shows a schematic process diagram of LPCI. LPCI operation consists of using at least three of the four ac motor driven centrifugal pumps taking water from the suppression pool and pumping it into one or the other recirculation loop. The water enters the reactor through the jet pumps to restore the water level in the reactor vessel. LPCI operation includes using associated valves, controls, instrumentation, and pump accessories. The LPCI pump motors receive power from the station 4,160V auxiliary busses. The LPCI pump motors and the associated automatic motor valves within each loop receive ac power from the same bus. This arrangement satisfies safety design basis 5.

LPCI pumps and piping equipment are described in detail in Section 4.8, Residual Heat Removal System, which also describes the other functions served by the same pumps if not needed for the LPCI function. The portions of the RHR System required for accident protection are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. It is concluded that safety design basis 10 is satisfied.

LPCI pump motors and the associated automatic motor valves within each loop receive ac power from the same bus. This arrangement satisfies safety design basis 5.

LPCI pumps and piping equipment are described in detail in Section 4.8, Residual Heat Removal System, which also describes the other functions served by the same pumps if not needed for the LPCI function. The portions of the RHR System required for accident protection are designed in accordance with Class I seismic criteria. See Section 12 and Appendix C. It is concluded that safety design basis 10 is satisfied.

Figures 6.4-1 and 6.4-2 have been removed.

Please refer to BECo Controlled Drawings M136-4 and M1K 2-4.

Figure 6.4-3 has been deleted.

See Figure 4.8-2 for the Process Diagram
for the Residual Heat Removal System

6.5 SAFETY EVALUATION

The safety design basis for the Core Standby Cooling System (CSCS) for limiting peak clad temperature is to demonstrate compliance with the acceptance criteria of 10 CFR 50.46. The safety analysis models and methodology used to demonstrate conformance with the criteria of 10 CFR 50.46 are in compliance with the requirements of 10 CRF 50, Appendix K.

6.5.1 Summary

In order to satisfy the safety design basis, four (4) means for core standby cooling are provided:

High Pressure Coolant Injection (HPCI)
Automatic Depressurization System (ADS)
Core Spray System (CSS)
Low Pressure Coolant Injection (LPCI)

These are in addition to the other systems which supply core coolant: Feedwater, Control Rod Drive, and Reactor Core Isolation Cooling (RCIC).

For reliability, each Standby Cooling System uses equipment with as few components required to actuate as feasible, and makes provisions for testing during normal operation. To provide diversity, two different cooling methods are provided - spraying and flooding.

Evaluation of the reliability and redundancy of the controls and instrumentation for the CSCS shows that no failure of a single initiating sensor either prevents or falsely starts the initiation of these cooling systems. No single control failure prevents the combined cooling systems from providing the core with adequate cooling. The controls and instrumentation can be calibrated and tested to assure proper response to conditions representative of accident situations.

As stated in the safety objective and in safety design basis 2, the CSCS removes the residual and decay heat from the reactor core so that fuel clad melting is prevented. The design basis used is that the fuel clad will not reach 2200°F.

All of the safety design bases for the CSCS are shown to be met by the previous descriptions, the referenced descriptions and evaluations in other sections, and by the following safety evaluations of the individual and combined CSCS.

Peak clad temperatures are determined in accordance with the models described in Reference 20.

Evaluation of the cooling performance of the CSCS is calculated by an analytical model and digital computer program to cover the spectrum of conditions in detail, and assure that core cooling is adequate across the entire spectrum of break sizes.

6.5.2 Performance Analysis

The manner in which the CSCS operates to protect the core is a function of the rate at which coolant is lost from the break in the nuclear system process barrier. The High Pressure Coolant Injection System (HPCIS) is designed to operate while the nuclear system is at high pressure. The Core Spray and Low Pressure Coolant Injection (LPCI) Systems are designed for operation at low pressures. If the break in the nuclear system boundary is of such a size that the loss of coolant exceeds the capacity of the HPCIS, nuclear system pressure drops at a rate fast enough for the Core Spray System and LPCI to commence coolant addition to the reactor vessel in time to cool the core.

Automatic depressurization is provided to automatically reduce nuclear system pressure if a break has occurred and vessel water level is not maintained by the HPCIS and the other water addition systems. Rapid depressurization of the nuclear system is desirable to permit flow from the Core Spray System and LPCI to enter the vessel, so that the temperature rise in the core is limited.

If, for a given size break, the HPCIS has the capacity to make up for all the coolant loss from the nuclear system, flow from the low pressure portion of the CSCS is not required for core protection until nuclear system pressure has decreased below LPCI pump shutoff head. This pressure is above the value at which the HPCIS turbine steam stop valve shuts due to low steam supply pressure. (See Section 7.3 Primary Containment Reactor Vessel Isolation Control)

The redundant features of the CSCS are shown on Figure 6.3-1 in bar chart form. Capability for cooling exists over the entire spectrum of break sizes even with concurrent loss of offsite auxiliary power. To provide clarification of the action taken by each system of the CSCS during a LOCA, the results of the analysis as applied to an individual system of the CSCS is presented in the form of graphs of coolant level and pressure in the reactor vessel versus time for a typical size break in the nuclear system process barrier. In addition, these graphs show peak clad temperature versus break area for integrated CSCS operation.

6.5.2.1 Analysis Model

References 1-6 describe the analysis model used for LOCA analysis up to 1990. References 17-21 describe an updated analytical model currently used for analysis of LOCA for PNPS. A detailed description of the model is found in Reference 20. References 7-16 which supported the original LOCA analysis are listed in Section 6.5.6 for continuity.

6.5.2.2 Plant Specific Application

The plant specific analysis for PNPS for the entire spectrum of LOCA events is described in detail in Reference 17. The analysis in Reference 17 covers particular fuel types in use when the analysis was prepared. Additional LOCA analysis has been performed for each fuel type in use at PNPS (Reference 27). The reload license submittal documented in Appendix Q provides both the analysis results for each fuel type and pertinent references. This analysis has its foundations built upon a licensing methodology and BWR 3/4 generic analysis described in Reference 19. The methodology is generally referred to as SAFER/GESTR-LOCA and uses both best estimate and limiting calculations of LOCA consequences to demonstrate that the fuel clad boundary is not breached following a LOCA event. Uncertainties in the outcome of LOCA are specifically accounted for in the calculations of peak fuel clad temperature.

6.5.2.3 High Pressure Coolant Injection System (HPCIS)

The HPCIS is designed to provide adequate reactor core cooling for small breaks by maintaining vessel water level or by depressurizing the reactor primary system such that the LPCI and Core Spray System can be initiated. A detailed discussion of the performance of the HPCIS in conjunction with the LPCI and Core Spray System is given in Section 6.5.3.

The plant specific analysis for PNPS for the entire spectrum of LOCA events in Reference 17 includes an assumption that the HPCIS is unavailable for large break sizes and for small break sizes the HPCIS was considered a single failure. Therefore, the plant specific analysis in Reference 17 does not evaluate HPCIS capability.

The small break analysis in Reference 17 assumes ADS is used to lower reactor pressure to allow low pressure LPCI and Core Spray systems to provide makeup. Reactor depressurization by ADS involves core uncovery and the resulting clad temperature changes are evaluated in Reference 17. However, for small break sizes that lie within the range of HPCI, the reactor depressurization that accompanies HPCIS operation allows low pressure LPCI and Core Spray systems to provide makeup and the core never uncovers. Therefore, for small breaks within the range of HPCI, the core is continuously cooled throughout the accident so that no core damage of any kind occurs.

FSAR Figure 6.3-1 shows that the HPCIS range can be divided into two categories: (1) the half width bars show break sizes for which HPCI requires assistance by low pressure systems within 1000 seconds to prevent core uncovery, and (2) the full width bars show break sizes for which HPCI can alone maintain reactor water level above top of active fuel (TAF) for at least 1000 seconds. The 1000 seconds is included in the definition because the HPCIS requires a minimum vessel pressure to sustain the operation of the turbine.

The upper limit of the HPCIS unassisted capability (0.1 ft2 for liquid breaks and point 0.7 ft2 for steam breaks on Figure 6.3-1) is defined as the largest break size for which the HPCIS can protect the core for a period of at least 1000 seconds without assistance from any other Core Standby Cooling System. Since the decay heat generation continually decreases with time a point will eventually be reached where the energy additions from decay heat will no longer be sufficient to maintain the required operating pressure for the HPCIS turbine. However, this point is well below the pressure at which either the Core Spray System or the LPCI System is sufficient to keep the core cool after the HPCIS shuts off. Analysis of this break size is illustrated on Figure 6.5-1 which shows that the HPCIS delivers enough water into the reactor vessel before shutdown because of low reactor pressure, that reactor level does not reach TAF until 1000 seconds. As indicated on Figure 6.5-1, reactor pressure remains below 1000 psia throughout the period of the HPCIS operation. This analysis for the upper limit of the HPCIS unassisted capability (0.1 ft2 liquid line break) defines HPCI pump performance requirements at a flowrate of 4250 gpm.

The HPCIS turbine is designed to accommodate dry and saturated steam. The design objective for the turbine casing was a useful life of 40 years accounting for corrosion, erosion, and material fatigue. The HPCI system was reviewed for license renewal and loss of material due to corrosion, erosion, and cracking due to material fatigue are managed for the period of extended operation. Condensate and moisture carryover are prevented from accumulating by a drain pot and steam traps located immediately upstream of the turbine inlet valve. When the turbine is shutdown, the inlet line is kept at an elevated temperature and the condensate is continuously drained.

An analysis has been made to determine if any carryover occurs in the steam supply to the HPCIS turbine which could have a detrimental effect on turbine operation. In the case of a break in a liquid line, when the HPCIS is energized, the level in the reactor vessel is low enough to prevent carryover in the steam which leaves the reactor vessel. In the case of a small break in the reactor steam region simultaneously with a loss of offsite power, reactor scram, recirculation pump coastdown, and loss of feedwater, analysis shows that the initial decrease of pressure in the reactor results in no significant level swell and no carryover of water into the

steam supply to the HPCIS turbine. The HPCIS cold water quenches any steam formation in the downcomer region. After the HPCIS has been operating, and as the level rises in the reactor vessel, natural circulation within the vessel becomes established and steam to the HPCIS turbine passes through the steam separators and dryers eliminating any moisture carryover. It is concluded that a mechanism to cause bypassing of the steam separators, by the swelling steam water mixture, is not available. Therefore, gross moisture carryover to the HPCIS turbine should not occur over the range of steam line breaks of interest in this system.

The HPCIS turbine has been designed for high reliability under its design requirements of quick starting. Moreover, the turbine has adequate capacity to accept the small losses in efficiency due to any credible moisture carryover, and HPCIS turbine efficiency is not of paramount importance.

Tests on a production unit of the HPCIS turbine have been completed to verify the capability of the turbine to take low quality steam. Preliminary results confirm that the pressure integrity of the turbine housing is maintained during two-phase mixture conditions at the turbine inlet. This testing did not compromise the turbine housing pressure boundary. The closure time for the HPCIS system AC steamline isolation valve is 25 seconds and for the DC isolation valve is 34 seconds.

The feedwater spargers are utilized in the reactor for HPCIS injection. Each sparger is mounted to the inside of the reactor vessel surface. The thermal sleeve is attached to the sparger midpoint; however, the sleeve is not welded to the vessel nozzle. Therefore, the feedwater sparger is removable. The spargers are mounted in the vessel at one elevation to distribute the feedwater in a symmetric pattern about the vessel axis. Each sparger is supported by the thermal sleeve and a bracket mounted to each end of the sparger. Provision is made for the differential expansion between the stainless steel sparger and carbon steel vessel. Radial differential expansion is taken up by the slip fit of the thermal sleeve into the vessel nozzle. Tangential differential expansion is taken up by tangential slots cut in the bracket mounted to each end of the feedwater sparger bracket. The sparger is analyzed assuming the thermal sleeve is welded into the nozzle. Additionally, pressure differentials, jet reactions, and earthquake loadings are all added; these stresses within the sparger are all within ASME Code Section III for Class A Vessels.

The resultant bracket loads are sized to meet the loading criteria (see Appendix C). It is concluded that Design Basis 8 is satisfied.

6.5.2.4 Automatic Depressurization System

When the Automatic Depressurization System is actuated, the flow of steam through the valves provides a maximum energy removal rate while minimizing the corresponding fluid mass loss from the reactor vessel. Thus, the specific internal energy of the saturated fluid in the reactor vessel is rapidly decreased causing pressure reduction. The system provides the backup for the HPCIS.

Actuation of the automatic depressurization function does not require any source of offsite power. The relief valves require DC power from the station batteries for control and air power from accumulators for operation. This satisfies Safety Design Basis 5.

The accumulators and the nuclear system relief valves are within the primary containment and this satisfies the containment isolation requirements of safety design basis 6.

6.5.2.5 Core Spray System

The Core Spray System is designed to maintain continuity of reactor core cooling for a large spectrum of LOCA. The integrated performance of the Core Spray System in conjunction with other CSCS is given in Section 6.5.3.

Performance analyses of the reactor Core Spray System are based on an analytic prediction of the reactor vessel pressure and mass inventory as a function of time following a postulated rupture of the coolant system piping. In all cases, the analyses are begun with the coolant system liquid inventory at low level scram and the reactor operating at design power. For all loss of coolant analyses, the break is assumed to occur instantaneously and simultaneous with the loss of offsite auxiliary power.

There exists a break size below which the Core Spray System alone cannot protect the core. This is because vessel pressure does not drop rapidly enough to allow sufficient core spray injection before the clad hot spot reaches excessively high temperature. Below this break size either the HPCIS or the Automatic Depressurization System extend the range of the Core Spray System to breaks of insignificant magnitude.

To assure continuity of core cooling, signals to isolate the primary or secondary containments do not operate any Core Spray System valves. This arrangement satisfies safety design basis 6.

The discharge check valve is the only core spray equipment in the primary containment required to actuate during a loss of coolant accident which requires consideration for the high temperature and humidity environment in the containment from the accident. The selected valve actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor accident environment in the containment affects the operability of the core spray equipment for the accident. It is concluded that safety design basis 9 is satisfied.

Taking the core spray water from the suppression pool establishes a closed loop for recirculation of the spray water escaping from the break.

The core spray spargers and piping are designed as Class I (see Section 12 and Appendix C) so that they meet design basis 8.

6.5.2.6 Low Pressure Coolant Injection

LPCI is provided to automatically reflood the reactor core after a nuclear system LOCA when the reactor vessel pressure is below the shutoff head of the pumps. LPCI provides cooling by flooding which differs from the Core Spray System which provides cooling by spraying.

The LPCI pumping system is designed with both adequate head and adequate coolant flow capacity to meet flooding requirements for the entire break spectrum, when operating in conjunction with either the HPCIS or the Automatic Depressurization System.

The maximum vessel pressure against which the LPCI pumps must deliver some flow is determined by the required overlap with HPCI which has a low pressure cutoff for the HPCIS turbine at about 100 psig.

LPCI cooling capability is analyzed by the computerized method summarized previously, based on the mass and energy flows to and from the reactor. The break in the nuclear system process barrier is assumed to occur instantaneously and simultaneously with loss of offsite auxiliary AC power.

The analysis begins at reactor scram from design power because of a reactor vessel low water level signal.

The LPCI control system senses if the break is in a recirculation loop, closes the recirculation pump discharge valve in the unbroken loop, and opens the LPCI valve to the unbroken loop. When the nuclear system pressure decreases to the pumping head of LPCI, the check valve in the injection line opens and LPCI water is pumped into the reactor vessel to reflood the core.

These actions provide an integral flow path for the injection of the LPCI flow into the bottom plenum of the reactor vessel. As the LPCI flow accumulates, the level rises inside the shroud. When the level reaches the top of the jet pumps, spillover occurs for a time raising the level outside the shroud. As the subcooled LPCI flow begins spilling into the region outside the shroud, the depressurization effect of the break is reduced since the subcooled water is now flowing out the break. As the pressure begins to rise, the LPCI flow is reduced until a quasi-equilibrium pressure is reached. At this point, the break is partially covered by subcooled water which has spilled over the top of the jet pumps and the equivalent area of the break available for steam blowdown is thus reduced. The size of the break available for steam blowdown is maintained at the required equilibrium value by the LPCI spillage. If pressure were to rise the LPCI flow would be reduced, the equivalent break size for steam blowdown would increase, and pressure would drop. Complete equilibrium will be reached when the rate of saturating the LPCI water becomes equal to the boiloff rate.

It is noted that this condition will not actually be attained because of the HPCIS and Automatic Depressurization System effects on the transient. Although HPCI flow will be lost when pressure is reduced sufficiently, the auto depressurization valves would also be open.

To assure continuity of core cooling, signals to isolate the primary or secondary containments do not operate any LPCI valves. This arrangement satisfies safety design basis 6.

The two discharge check valves are the only LPCI equipment in the primary containment required to actuate during a LOCA which require consideration for the high temperature and humidity environment in the containment from the accident. The type of valve chosen actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor accident environment in the containment affects the operability of the LPCI equipment for the accident. It is concluded that safety design basis 9 is satisfied.

Using the suppression pool as the source of water for LPCI establishes a closed loop for recirculation of LPCI water escaping from the break.

The LPCI and appropriate portions of the recirculation loops are designed as Class I. See Section 12 and Appendix C so that they meet design basis 8.

6.5.3 Integrated Operation of the Core Standby Cooling Systems

The previous discussion has described the performance and operation of each of the CSCS individually. This discussion is directed toward the integrated performance of the CSCS, i.e., how the CSCS operate together to provide core cooling for the entire spectrum of LOCA. The discussion is subdivided based on the two types of loss of coolant accidents; recirculation line breaks and non-recirculation line breaks. The primary emphasis of the discussion is placed on the recirculation line break since the consequences of a break in a recirculation line are more severe than for a break in a non-recirculation line.

It is demonstrated that at least two different and independent core cooling systems are provided to limit fuel clad temperature over the entire spectrum of postulated reactor primary system breaks. Such cooling capability is available assuming the loss of all offsite ac power.

6.5.4 Recirculation Line Breaks

6.5.4.1 Model Applicability and BWR 3/4 Generic Analysis

The Generic analysis for BWR 3/4's in Reference 19 determined the limiting LOCA event as the double-ended recirculation suction line break coincident with a failure of a train of stand-by batteries. The licensing methodology was applied on this basis to show that margin existed between calculated peak fuel clad temperature and clad temperature limits established as acceptance criteria. PNPS specific analysis showed the same limiting LOCA event scenario for nominal (non-Appendix K) conditions as was shown in the generic analysis. However, for the Appendix K input assumptions, analysis results indicate the single failure associated with the highest peak clad temperature is failure of the LPCI injection valve. Plant specific uncertainties were generated consistent with the licensing methodology. Adequate margin between calculated fuel clad temperatures and the established clad temperature limits exists for PNPS. Reference 17 details these results. The analysis in Reference 17 covers particular fuel types in use when the analysis was prepared. Additional LOCA analysis will be performed for each fuel type in use at PNPS (Reference 27). The reload license submittal documented in Appendix Q provides both the analysis results for each fuel type and pertinent references.

6.5.4.2 Recirculation Break Spectrum Analysis

The LOCA analysis for recirculation line breaks, based on the use of the above models, is performed using the procedures outlined in Reference 17. The total LOCA analysis is generally provided for each plant independent of the reload license submittal. However, when new fuels are introduced, the reload license submittal will contain the MAPLHGR and PCT as a function of exposure for fuel not previously licensed to operate at PNPS. MAPLHGR and PCT as a function of exposure for fuel bundles licensed for use by PNPS are provided in the PNPS Technical Specifications. MAPLHGR and PCT are documented in Reference 17. Significant input parameters to the LOCA analysis are provided in Table 6.5-1.

A number of break sizes and single failure combinations were analyzed with nominal inputs to the PNPS-specific SAFER/GESTR-LOCA model. Further calculations with Appendix K (10 CFR 50) input assumptions provide limiting peak fuel clad temperatures for the range of recirculation line break sizes. Several fuel types were considered. The results of this analysis are detailed in Reference 17. The most limiting break (highest fuel clad temperature) was a 4.21 square foot suction line break that includes the area of the bottom head drain.

All peak fuel clad temperatures were below the limits established in Reference 26 by the NRC. Also, other criteria which insures fuel cladding integrity were met as discussed in Reference 17.

6.5.4.3 Conclusions of Recirculation Line Break Analysis

LOCA analyses have been performed for PNPS utilizing an NRC approved methodology. With ECCS performance characteristics assumed to be below the capacities and response times actually measured and maintained at PNPS, the analyses demonstrated adequate margin to the safety limits required via conformance to 10 CFR 50.46 and Appendix K. These analyses establish the current licensing basis for PNPS. (References 17 through 21 and 26 support this basis)

Further, these analyses accounted for alternate modes of plant operation to include ARTS/ELLA, increased core recirculation flow, single recirculation loop operation, and maximum extended load line limit region operation. These modes of operation are described in References 17 and 22 through 25.

With the explicit verification of the licensing PCT for PNPS being greater than the 95th percentile PCT, the level of safety and conservatism of this analysis meets the NRC approved criteria. Therefore, the requirements of Appendix K are satisfied.

The single failure evaluation showing the remaining ECCS following an assumed failure is shown in Table 6.5-2.

6.5.5 Non-Recirculation Line Breaks

The analyses of LOCA for PNPS included postulated non-recirculation line breaks such as LPCS line, feedwater line, and steamlines. The results of PNPS specific calculations are reported in Reference 17. The calculated peak clad temperature is significantly lower than that calculated for postulated recirculation line breaks. Non-recirculation line break analysis is not performed for new fuel types in use at PNPS because of the non-limiting nature of these break types as documented in Reference 17.

6.5.6 References

1. "Analytical Model for Loss-of-Coolant Analyses in Accordance With 10CFR50 Appendix K", NEDE-20566-P and NEDO-20566, January 1976.

2. "Fuel Rod Pressurization - Amendment 1", NEDE-23786-1-P, May 1978.

3. Letter, T. A. Ippolito (NRC) to R. L. Gridley (GE), "Generic Reload Fuel Application - NEDE-24011-P-A", April 16, 1979.

4. Letter, A. J. Levine (GE) to D. F. Ross (NRC), "General Electric (GE) Loss-of-Coolant (LOCA) Analysis Model Revisions--Core Heatup Code CHASTE05", January 27, 1977.

5. "Emergency Core Cooling Tests of an Internally Pressurized, Zircaloy-Clad, 8x8 Simulated BWR Fuel Bundle", NEDO-20231, December 1973.

6. Letter, H. Bernard (NRC) to G.G. Sherwood (GE), "Supplementary Acceptance of Licensing Topical Report NEDE-20566A(P)", May 11, 1982.

7. Letter, G. L. Gyorey (GE) to V. Stello, Jr. (NRC), "Compliance With Acceptance Criteria of 10CFR50.46", May 12, 1975.

8. Letter, L. Liu (IEL&P) to E. G. Case (NRC), Letter No. IE-77-1453, dated July 29, 1977.

9. "Loss of Coolant Accident Analysis Report for Duane Arnold Energy Center (Lead Plant)", NEDO-21082-02-1A, July 1977.

10. "Loss of Coolant Accident Analysis Report for Pilgrim Nuclear Power Station", NEDO-21696, August 1977.

11. Letter, D. G. Eisenhut (NRC) to E. D. Fuller (GE), "Documentation of the Reanalysis Results for the Loss-of-Coolant Accident (LOCA) of Lead and Non-Lead Plants", June 30, 1977.

12. Letter, T. J. Galligan, Jr., (BECO) to Director, Division of Reactor Licensing (NRC), "10CFR50 Appendix K and Proposed Technical Specifications for Pilgrim Nuclear Power Station, Unit 1", July 9, 1975.

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14. BECO Letter 80-223 to NRC Staff, "Effect of a DC Power Supply Failure on ECCS Performance", September 1980.

15. "Pilgrim Nuclear Power Station Loss of Coolant Accident (LOCA) Analysis Update", NEDO-30767, September 1984.

16. "Safety Evaluation for Interim Operation of Pilgrim Nuclear Power Station with Reduced Core Spray System Flow Rate," EAS-55-0889, DRF A00-03585, August, 1989.

17. "Safer/ GESTR-LOCA Loss-of-Coolant Accident for Pilgrim Nuclear Power Station", NEDC-31852P, Rev. 4. January, 2008.

18. Letter, C. O. Thomas (NRC) to J. F. Quirk (GE), "Acceptance for Referencing of Licensing Topical Report NEDE-23785, Revision 1, Volume III (P), 'The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident'," June 1, 1984.

19. "The GESTR-LOCA and SAFER models for the evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," NEDE-23785-1-PA, General Electric Company, Revision 1, October 1984.

20. "General Electric Standard Application for Reactor Fuel (U.S. Supplement)", NEDE-24011-P-A, General Electric Company, September 1988. Revision number listed in the latest Supplemental Reload License Submittal in Appendix Q.

21. "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K", NEDO-20566A, General Electric Company, September 1986.

22. "ARTS Improvement Program Analysis for Pilgrim Nuclear Power Stations," NEDO-31312P, General Electric Company, September 1987.

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

24. "Pilgrim Nuclear Power Station Single-Loop Operation," NEDO-24268, General Electric Company, June 1980.

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

26. "GESTR-LOCA and SAFER Models for Evaluation of Loss-of-Coolant Accident, Volume III, Supplement 1, Additional Information for Upper Bound PCT Calculation," NEDE-23785P-A, Supplement 1, Revision 1, March 2002.

27. Pilgrim Nuclear Power Station GNF2 FLCCS-LOCA Evaluation, 0000-0095-4071-RO, February 2009.

Table 6.5-1

Plant Operational Parameters Used in Pilgrim LOCA Analysis

Plant Parameters	Nominal	Appendix K
Core Thermal Power (MWt)	2028	2070
Corresponding Power (%)	100	102
Vessel Steam Output (lbm/hr)	8.117E6	8.303E6
Core Flow (lbm/hr)	69E6	69E6
Corresponding Flow (%)	100	102
Vessel Steam Dome Pressure (psia)	1050	1050
Maximum Recirc. Line Break Area (ft^2)	4.21[1]	4.21[1]

(1) Includes area of bottom head drain.

Table 6.5-2

Pilgrim Single-Failure Evaluation

Assumed Failure[a]	Recirculation[b] Suction or Discharge Break Systems Remaining
Battery	1 LPCS + 2 LPCI + ADS[c]
LPCI Injection Valve (LPCI IV)	HPCI + 2 LPCS + ADS[c]
Diesel Generator (D/G)	HPCI + 1 LPCS + 2 LPCI + ADS[c]
HPCI	2 LPCS + 4 LPCI + ADS

a Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed failures.

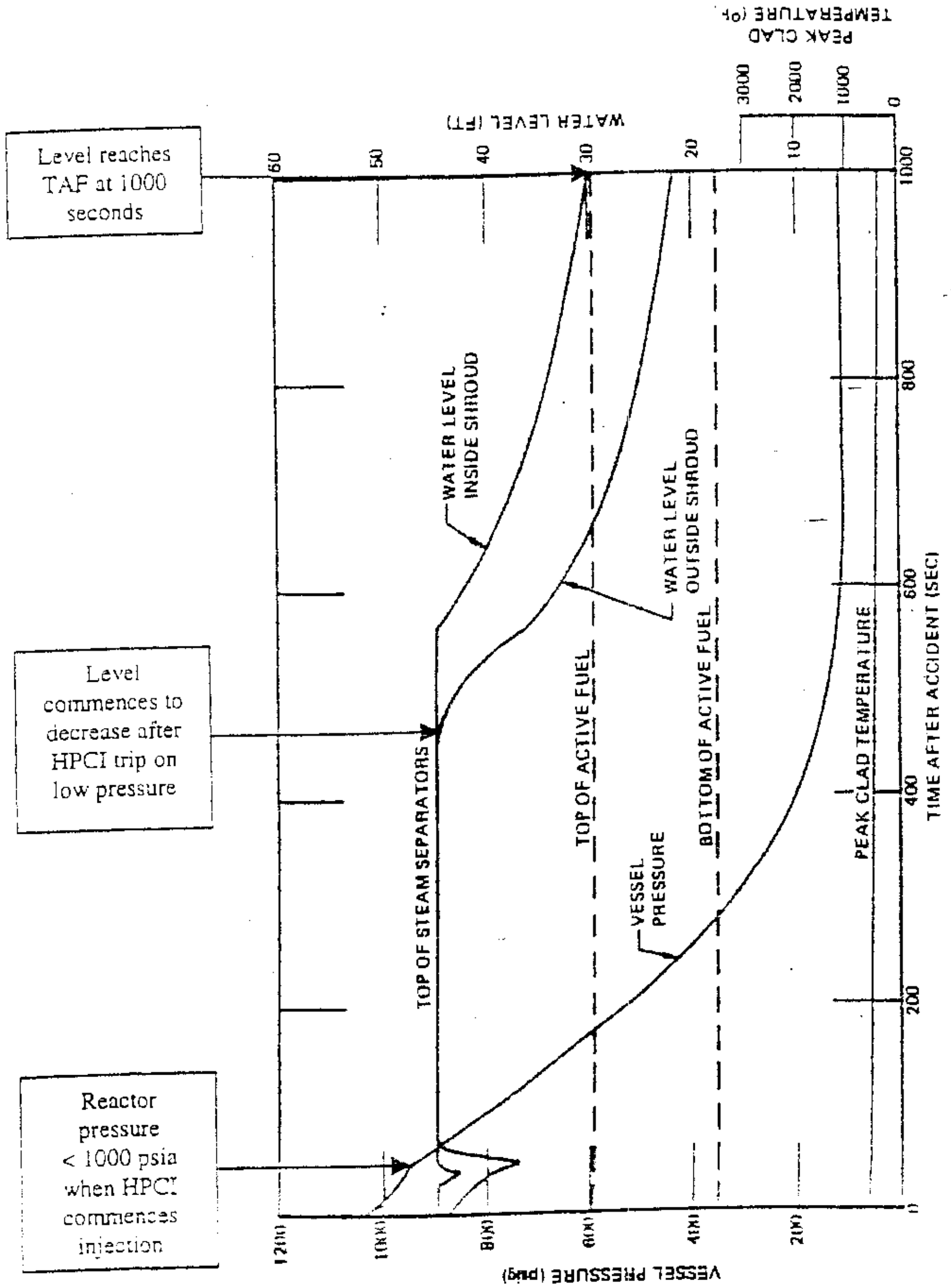
b Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS in which the break is assumed.

c The SAFER/GESTR-LOCA analyses performed assuming that for large breaks, the HPCIS was unavailable. For small break analysis, the HPCIS was considered as a single failure.

Table 6.5-3

MAPLHGR MULTIPLIERS ASSUMING NO CORE SPRAY HEAT TRANSFER CREDIT

Fuel Type	Core Flow > 90% Rated	Core Flow < 90% Rated
8DB219L	0.93	0.85
8D8H219H	0.93	0.85
8DB262	0.94	0.86
P8DRB265L	0.91	0.84
P8DRB282/BP8DRB282	0.92	0.85
P8DRB265H	0.90	0.82
BP8DRB300	0.90	0.82



PILGRIM
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FINAL SAFETY ANALYSIS REPORT

Unassisted HPCI Performance
(0.10 ft^2 Liquid Break Area)

FIGURE 6.5-1

6.6 INSPECTION AND TESTING

Each active component of the core standby cooling systems (CSCS) provided to operate in a design basis accident is designed to be operable for test purposes during normal operation of the nuclear system.

The high pressure coolant injection system (HPCIS), automatic depressurization, and core spray systems have no normal process uses and, therefore, are tested periodically to provide assurance that the CSCS will operate to effectively cool the reactor core in an accident. The four low pressure coolant injection (LPCI) pumps may be placed in use as part of the residual heat removal system, and if so, their status is known from normal process uses. However, the LPCI pumps are tested no less frequently than the rest of the CSCS. Other parts of LPCI, such as the two discharge check valves inside the primary containment drywell and the four shutoff valves outside the drywell, are intended for use only in an accident, so they are also tested periodically.

Preoperational tests of the CSCS were conducted during the final stages of construction prior to initial startup. Testing of the HPCI turbine could not be completed until steam was available during nuclear system heatup. See Section 13, Conduct of Operations. These tests assured the proper functioning of all controls and instrumentation pumps, piping, and valves. System reference characteristics such as pressure differentials and flow rates were documented during the preoperational tests and are used as base points for measurements obtained in the subsequent operational tests.

During normal operation, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the reactor vessel is open, for refueling or other purposes, the spargers and other internals can be inspected.

When the system is tested, the operation of most of the components is indicated in the main control room. There are exceptions which require local observation at the component and may require special tests for which there are special provisions and methods.

Pressure operated relief valves may leak after operation and it is not advisable to over pressurize the system for test, so relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments. Bench tests of the automatic depressurization valves are discussed in Section 4.4, Nuclear System Pressure Relief System.

Flow operated check valves for reverse flow or excess flow are tested periodically in place by isolating that portion of the system and simulating the function conditions, either with the system pump or through test connections provided for this purpose.

The proper position of manual valves for the accident mode is indicated by flow and pressure instrumentation during the periodic system tests and after maintenance.

Test lines are provided between pairs of containment isolation valves in the CSCS to measure leakage when the containment is pressurized for tests. The test line is also used to pressurize between the closed valves to identify which one is leaking.

Pumps for the CSCS are equipped with face type mechanical shaft seals. Normal leakage for these seals is small at operating conditions.

A design flow functional test of the HPCIS up to the normally closed pump discharge valve is performed during normal operation by pumping water from the condensate storage tank and back through the full flow test return line to the reservoir. The HPCIS turbine pump is driven at its rated output by steam from the reactor. The suction valves from the suppression pool and discharge valve MO2301-8 to the reactor feedwater line remain closed. The design of MO2301-9 has been changed such that it only serves as a maintenance isolation valve and it must be open at any time the HPCIS is required to be operable. Although MO2301-9 receives an automatic signal to open on HPCI initiation, the opening stroke time is not evaluated for the HPCIS operability requirements with this valve initially closed. The valve must therefore be open and has no active safety function.

The HPCIS test conditions are tabulated on the HPCIS process flow diagram, Figure 6.4-1 (Drawing M1J6-4). The HPCI pump is tested during normal operation at two different operating points: (1) 4250 gpm for a system head that corresponds to the reactor pressure during the test per Technical Specification 4.5.C, and (2) 3000 gpm for a system head that corresponds to a reactor pressure of 1190 psig. For further discussion of these pump requirements, refer to sections 6.4 and 6.5. These operating points exceed the required capability of the HPCIS in the accident and transient analysis. If an initiation signal occurs while the HPCIS is being tested, the system returns to the automatic startup mode. The HPCIS test return isolation valves are opened for testing and will automatically close if a system initiation signal occurs. The control scheme for one HPCIS test return isolation valve uses seal-in contacts in the opening and closing circuit. The upstream HPCIS test return isolation valve is a throttle valve used for system control during testing and will automatically operate in the closed direction while a system initiation signal remains present. The automatic closing cycle of this HPCIS test return isolation valve is terminated if either the system initiation signal clears or the test return isolation valve reaches the full closed position.

The HPCIS may be tested at full flow with condensate at any time except when the reactor vessel water level is low, drywell pressure is high, the valves from the suppression pool to the pump are open, or if the water level in the condensate storage tank is less than 20 feet above the tank bottom. These restrictions are automatic, except for the condensate storage tank level limit. The condensate storage tank level is controlled administratively in order to prevent return flow from causing air entrainment into the pump suction.

To conduct the full flow test, the minimum flow bypass valve is initially opened. Initially, the pump delivers bypass flow to the suppression pool until the minimum flow bypass valve automatically closes after pump flow reaches a predetermined level.

The HPCIS test line includes a manual adjustable orifice which partially simulates the resistance that the pump is required to overcome while delivering the required flow rate to the reactor vessel. During pump testing, the remainder of the system resistance is introduced via a remote manual throttle valve located on the test line. This manual adjustable orifice reduces the throttling duty of the test line globe valve, reducing the degradation of the valve.

The HPCIS is not capable of achieving rated flow at 150 psig reactor pressure when the test line manual adjustable orifice is positioned for the high pressure test that is conducted quarterly at normal reactor operating pressure. Therefore, the manual adjustable orifice valve must be repositioned at or near full open for conduct of the pump test at less than or equal to 150 psig reactor pressure.

The pump discharge valve is tested in accordance with Technical Specification 3.13. The pump discharge check valve in the steam tunnel may be tested by manually actuating the disk using the square nut located on the valve.

Each loop of the Core Spray System may be tested during reactor operation. The test conditions are tabulated on the Core Spray System process diagram, Figure 6.4-2 (Drawing M1K2-4). The normal system test can not inject cold water into the reactor because the discharge check valve is held closed by the reactor pressure which is higher than core spray pump pressure. The injection isolation valves are also interlocked to maintain at least one valve closed whenever reactor pressure exceeds the preset interlock value. To test the reactor injection portion of the system, using demineralized water, the reactor must be shut down and depressurized. This prevents unnecessary thermal stresses.

To test the core spray pumps at rated flow, the full flow test bypass valve is opened to the suppression pool, the pump suction valve from the suppression pool is opened, and the pumps are started using the remote manual switches in the main control room. Proper operation is determined by observing the instruments in the control room. The Core Spray System outside the drywell is checked for leaks periodically.

The injection valves are tested in accordance with Technical Specification 3.13.

If an initiation signal occurs during the test, the Core Spray System is signaled to start and the system returns to the automatic startup mode.

Similarly, LPCI pumps and valves are tested periodically during reactor operations. With the injection valves closed and the return line open to the suppression pool, full flow pumping capability is demonstrated. The injection valves are tested in accordance with Technical Specification 3.13. The system test conditions during reactor shutdown are shown on the Residual Heat Removal System (LPCIS) process diagram, Figure 6.4-3 (see Figure 4.8-2). The portion of the LPCI outside the drywell is inspected for leaks periodically during tests. Controls and instrumentation are tested as described in Section 7.4, Core Standby Cooling Systems Control and Instrumentation.

Upon receipt of an LPCI initiation signal during tests, the valves in the test bypass lines and in the shutdown cooling system are closed automatically to ensure that the LPCI pump discharge is routed properly to the reactor vessel.

It is concluded that Safety Design Basis 7 is satisfied.

6.7 THE NUCLEAR SAFETY REQUIREMENTS FOR PLANT OPERATION

The typical operational sequence of the Core Standby Cooling Systems (CSCS) for the initial core safety analysis is shown on Table 6.7-1 with assumed coincidental Loss of Offsite Power. With the assumption that the preferred power source is degraded, the sequence of CSCS operation is represented in Table 6.7-1A.

Table 6.7-2 represents the operational nuclear safety requirements for initial plant operation for CSCS for each BWR operating state. The entries on Table 6.7-2 represent an extension of the stationwide BWR systems analysis of Appendix G to the CSCS and their components. The following referenced portions of the safety analysis report provide important information justifying the entries on Table 6.7-2:

Reference	Information Provided
1. Earlier parts of Section 6	Description of the CSCS hardware, CSCS initiation setpoints
2. Station Safety Analysis Section 14	Analysis verifying response of CSCS to transients and accidents
3. Station Nuclear Safety Operational Analysis Appendix G	Identifies conditions and events for which CSCS action is required

Each detailed requirement on Table 6.7-2 is referenced, if possible, to the most significant conditions 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 6.7-2 and are coded as follows:

Example of Matrix Reference

```
F39-65
o o  o
  --------- F = BWR Operating State F
    --------39 = Event (row = 39)
      ------65 = HPCI (column = 65)
```

The pressure below which one of the low pressure CSCS (Low Pressure Coolant Injection mode of Residual Heat Removal System or Core Spray System) can develop rated system flow rate is 104 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 into the shutdown cooling range by turbine bypass to the condenser

or by limited use of safety relief valves. 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. Thus, while all four CSCS are required to cool the core at pressures over 150 psig, only the low pressure CSCS are required at pressures below 150 psig.

If the reactor vessel is not pressurized in states C or D, the requirements on the low pressure CSCS are the same as the requirements in states A and B. As shown by the notation C28-62 on Table G.5-3, these systems are only required as a source of makeup water during the loss of auxiliary power transient and the requirements are thus much less severe than when pressurized, (based on a loss of coolant accident).

TABLE 6.7-1

TYPICAL OPERATIONAL SEQUENCE OF CORE STANDBY COOLING SYSTEMS

Event	Time (sec)*
Design basis loss of coolant accident starts, normal auxiliary power assumed lost.	0
Drywell high pressure and reactor low water level reached. Start diesel generators. Initiate scram. Start RCIC and HPCI. Start closing main steam line isolation valves. Isolate primary containment.	3
Diesel generators ready for load. Close loop valves in unbroken recirculation line. Start the core spray pump on each diesel.	13
Start first LPCI (RHR) pump on each diesel. (Core spray pump at speed.)	18
Reactor pressure decreases to 350 psig. Open core spray and LPCI (RHR) injection valves.	19
Start second LPCI (RHR) pump on each diesel. (First, LPCI (RHR) pump at speed.)	23
All CSCS pumps at speed.	28
Core spray valves open and core spray systems fully operable.	29
Recirculation valves closed. LPCI (RHR) valves open, and LPCI (RHR) system fully operable.	43
Start required cooling water pumps and auxiliary loads.	43+

* All times are approximate.

TABLE 6.7-1A
TYPICAL OPERATIONAL SEQUENCE OF CORE STANDBY COOLING SYSTEMS
(all times are approximate)

Event	Time (seconds)
Design basis loss of coolant accident starts, normal auxiliary power with assumed degraded voltage event.	0
Drywell high pressure and reactor low water level reached. Start diesel generators. Initiate scram. Start RCIC and HPCI. Start closing main steam line isolation valves. Isolate primary containment.	3
Normal auxiliary power lost due to degraded voltage relay actuation.	12
Diesel generators ready for load. Close loop valves in unbroken recirculation line. Start the core spray pump on each diesel.	18
Reactor pressure decreases to 350 psig. Open core spray and LPCI (RHR) injection valves.	19
Start first LPCI (RHR) pump on each diesel. (Core spray pump at speed).	23
Start second LPCI (RHR) pump on each diesel. (First, LCPI (RHR) pump at speed).	28
Core Spray Valves open and Core Spray systems fully operable	31
All CSCS pumps at speed	33
Start required cooling water pumps (SSW, RBCCW) and auxiliary loads	38-48
Recirculation valves closed. LPCI (RHR) valves open, and LPCI (RHR) system fully operable.	53*

*Time is approximately 56 seconds with an assumed loss of "A" EDG.

TABLE 6.7-2

CORE STANDBY COOLING SYSTEM OPERATIONAL REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Cool the reactor core	HPCI		A	None
			B	None
			C	Above 150 psig, HPCI must be operable or both ADS and RCIC operable (C39-65)
			D	Above 150 psig, HPCI must be operable or both ADS and RCIC operable (D39-65)
			E	HPCI must be operable or both ADS and RCIC operable (F39-65)
			F	HPCI must be operable or both ADS and RCIC operable (F39-65)

* 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 6.7-2 (Cont)

CORE STANDBY COOLING SYSTEM OPERATIONAL
REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Cool the reactor core (cont)	ADS	(4 valves)	A	None
			B	None
			C	Above 104 psig, 3 ADS valves must be operable if HPCI is inoperable; otherwise, 2 ADS valves must be operable (C39-66)
			D	Above 104 psig, 3 ADS valves must be operable if HPCI is inoperable; otherwise, 2 ADS valves must be operable (D39-66)
			E	3 ADS valves must be operable if HPCI is inoperable; otherwise 2 ADS valves must be operable (E39-66)

* 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 6.7-2 (Cont)

CORE STANDBY COOLING SYSTEM OPERATIONAL REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Cool the reactor core (cont)	ADS	(4 Valves)	F	3 ADS valves must be operable if HPCI is inoperable; otherwise 2 ADS valves must be operable (F39-66)
Core flooding and cooling	RHR (LPCI mode) and Core Spray System (CSS)	2 LPCI loops (2 pumps per loop) and 2 Core Spray loops (1 pump per loop)	A	1 loop with one associated pump (A35-62)
			B	1 loop with one associated pump (B35-62)
			C	For system pressurized: any two loops (C39-62) (C39-67) When system is not pressurized, requirements are same as for states A and B

* 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 6.7-2 (Cont)

CORE STANDBY COOLING SYSTEM OPERATIONAL REQUIREMENTS FOR PLANT OPERATION

System Actions	Components	No. Provided by Design	BWR Operating State	Minimum Required for Action *
Core flooding and cooling (cont)	RHR (LPCI mode) and Core Spray System (CSS)	2 LPCI loops (2 pumps per loop) and 2 Core Spray loops (1 pump per loop)	D	For system pressurized: any two loops (D39-62) (D39-67) When system is not pressurized, requirements are same as for states A and B
			E	Any two loops (E39-62) (E39-67)
			F	Any two loops (F39-62) (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.

6.8 CURRENT TECHNICAL SPECIFICATIONS

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

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CONTROL AND INSTRUMENTATION

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SECTION 7

CONTROL AND INSTRUMENTATION

7.1 SUMMARY DESCRIPTION

This Section presents the details of the more complex control and instrumentation systems in the station. Some of these systems are safety systems; others are power generation systems.

7.1.1 Safety Systems

The safety systems are the following:

Nuclear safety systems and engineered safeguards (required for accidents and abnormal operational transients):

Reactor Protection System (RPS)

Primary Containment Isolation System (PCIS)

Core Standby Cooling Systems Control and Instrumentation

Neutron Monitoring System (specific portions)

Main Steam Line Radiation Monitoring System

Refueling Ventilation Exhaust Radiation Monitoring System

Reactor Building Isolation and Control System

Containment Atmospheric Dilution System (Refer to Section 5.4)

Panels and racks associated with the RPS, PCIS, and Engineered Safeguards Systems (ESS) are identified so that two facts are apparent: first, that the equipment is part of the RPS, PCIS, or the ESS; and second, the grouping (or division) of enforced segregation with which the equipment is associated.

These panels and racks are labeled with marker plates identifying the system which are a different color from the marker plates used on other similar panels.

Certain trip inputs to the RPS, PCIS and ESS are provided by an Analog Trip System. The system consists of analog transmitters as sensors and remote electronic trip units providing the trip input. The system provides continuous monitoring of the sensed process variable with built-in calibration capabilities for each trip unit. A single analog transmitter can operate up to 8 trip units, one master trip unit and seven slave trip units. The master trip unit is a circuit board assembly designed to accept a 4-20 ma signal from

the analog transmitter. The master trip unit produces a trip output signal when the process signal passes through a preset trip point. The master trip unit also produces a buffered analog output signal which isproportional to the input and is used to drive up to seven slave trip units. The slave trip units in the analog trip system are used to provide additional setpoints for a common analog transmitter. The slave trip unit produces a trip output signal when the input signal passes through a preset trip point. Both master and slave trip units operate output relays which are input signals to the RPS, PCIS and ESS logic circuits.

Process safety systems (required for planned operation):

Neutron Monitoring System (specific portions)

Refueling Interlocks

Reactor Vessel Instrumentation

Process Radiation Monitors (except Main Steam Line Radiation Monitoring System and Refueling Ventilation Exhaust Radiation Monitoring System)

7.1.2 Power Generation Systems

The power generation systems are the following:

Reactor Manual Control System

Recirculation Flow Control System

Feedwater System Control and Instrumentation

Pressure Regulator and Turbine Generator Control

Area Radiation Monitors

Site Environs Radiation Monitors

Health Physics and Laboratory Analysis Radiation Monitors

Process Computer System

7.1.3 Safety Functions

The major functions of the safety systems are summarized as follows:

Reactor Protection System

The RPS initiates an automatic reactor shutdown (scram) if monitored nuclear system variables exceed pre-established limits. This action prevents fuel damage and limits system pressure, thus restricting the release of radioactive material.

Primary Containment and Reactor Vessel Isolation Control System

The PCIS initiates closure of various automatic isolation valves in response to off limit nuclear system variables. The action provided limits the loss of coolant from the reactor vessel and contains radioactive materials either inside the reactor vessel or inside the primary containment. The system responds to various indications of pipe breaks or radioactive material release.

Core Standby Cooling Systems Control and Instrumentation

This Section describes the arrangement of control devices for High Pressure Coolant Injection, Automatic Depressurization, Core Spray (CS), and Low Pressure Coolant Injection Systems.

Neutron Monitoring System

The Neutron Monitoring System (NMS) uses incore neutron detectors to monitor core neutron flux. The safety function of the NMS is to provide a signal to shutdown the reactor when an overpower condition is detected. High average neutron flux is used as the overpower indicator. In addition, the NMS provides the required power level indication during planned operation.

Refueling Ventilation Exhaust Radiation Monitoring System

This Section describes the monitoring system used to indicate high radiation in the refueling floor area of the Reactor Building, initiate isolation of the normal Reactor Building ventilation systems, and start the Standby Gas Treatment System.

Reactor Building Isolation and Control System

The Reactor Building Isolation and Control System (RBICS) initiates trip of the Reactor Building supply and exhaust fans, isolates the normal ventilation system, and provides the starting signals for the Standby Gas Treatment System (SGTS) in the event of a loss of coolant accident (LOCA) inside the drywell or a fuel handling accident in the Reactor Building. These actions limit the release to the environs of radioactive material so that offsite doses from these accidents will be below the guideline values listed in 10CFR100.

Refueling Interlocks

The refueling interlocks serve as a backup to procedural core reactivity control during refueling operation.

Reactor Vessel Instrumentation

The reactor vessel instrumentation monitors and transmits information concerning key reactor vessel operating parameters during planned operations to ensure that sufficient control of these parameters is possible.

Process Radiation Monitors

(except Main Steam Line Radiation Monitoring Systems and Refueling Ventilation Exhaust Radiation Monitoring System)

A number of radiation monitoring systems are provided on process liquid and gas lines to provide sufficient control of radioactive material release from the site.

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.

Equipment Area Cooling System

The equipment area cooling system objectives and description is contained in Section 10.18.

7.1.4 Station Operational Control

The major systems used to control the station during planned operations are the following:

Reactor Manual Control System

This system allows the operator to manipulate control rods and determine their positions. Various interlocks are provided in the control circuitry to avoid unnecessary safety system action resulting from operator error.

Recirculation Flow Control System

This system controls the speed of the two reactor recirculation pumps by varying the electrical frequency of the power supply for the pump motors. Varying pump speed will vary the coolant flow rate through the core and cause a change to the power output level. The system is arranged to allow for manual control (operator action) or automatic control (through the turbine speed/load control instrumentation).

Feedwater System Control and Instrumentation

This system regulates the feedwater system flow rate so that proper reactor vessel water level is maintained. The feedwater system controller uses reactor vessel water level, main steam flow, and feedwater flow signals to regulate feedwater flow. The system is arranged to permit single element control (level only), three element control (level, steam flow, feedwater flow), or manual flow control operation.

Pressure Regulator and Turbine Generator Controls

Normally, the pressure regulator, EPR and MPR adjusts steam control valve position to maintain constant reactor pressure. The ability of the station to follow system load is not used.

A single pressure regulator, with a backup regulator, is used to control both the turbine admission valves and the turbine bypass system valves. The two valves are coupled together by a linkage system.

The backup pressure regulator is provided to take over control of pressure in the event the operating regulator should fail. The setpoint of the backup regulator is normally a few psig above the setpoint of the normal operating pressure regulator. The linkage system also contains a mechanical stop arrangement (lift limit) which limits the total steam flow to a value about 110 percent of the turbine design flow.

7.1.5 Seismic Design Criteria (Reactor Protection and Engineered Safeguards Systems)

The seismic design bases for the RPS and ESS require that they withstand the loading forces and perform their required functions during the Operating Basis Earthquake or the Safe Shutdown Earthquake of 0.08g and 0.15g horizontal, respectively.

The equipment and instruments in these systems are designed to withstand and perform their functions during an Operating Basis Earthquake or a Safe Shutdown Earthquake. This qualification will be ascertained by either analytical techniques or vibration testing techniques or by a combination of the two techniques.

Specific evaluation, testing, or investigation have not yet been performed regarding the ability of Class I electrical control components to initiate a protective action during peak acceleration. However, since the electrical contacts of Class I components are capable of maintaining their position during the seismic disturbance, it is expected that initiation of protective action will not be precluded by the seismic disturbance. The time duration of the peak acceleration is short, sufficiently so that any momentary delay of the initiation of the safety action induced by the peak seismic disturbance will not affect the ability of safety systems to meet their intended functions.

If a seismic disturbance occurs during post accident operation shocking the Reactor Protection and Safeguard Systems, emergency core cooling would not be interrupted. The design is such that, once the system is initiated, it will not shut down except by proper signal from the operator or, in the case of some systems, after sensing a high reactor water level condition.

Class I pressure boundary devices in these systems are considered qualified if the combined seismic and normal loads will not cause stresses to exceed allowable stresses as defined in Appendix C.

Acceptability of other Class I components in these systems will be based on the ability of the equipment to withstand mechanical stresses and to perform its principal safety functions when subjected to the specified seismic loadings. Procurement specifications identify components that are required to meet Class I seismic requirements. The horizontal and vertical g forces that the equipment is expected to endure while performing its function is specified. Procurement specifications also require the vendor to show by test and/or analysis that the equipment will meet the seismic criteria.

The vendor must submit the test data and/or the seismic analysis for the responsible design engineer's approval as a condition of acceptance of the equipment for the intended function. The vendor may use test data on the particular components or equipment, applicable data from previously tested comparable equipment, performance data from comparable equipment which, during normal operating conditions, has been subjected to equal or greater shock loadings and/or suitable analytical results.

Seismic test and analyses were performed on instrumentation, devices, panels, and racks supplied by General Electric Company to qualify them for use in critical safety applications. These tests confirm that "g" levels will remain within the range of operability of the instrumentation. Instrumentation, devices, panels, and racks supplied by General Electric Company and used in critical safety applications have been reviewed for their response to calculated accelerations and been found to be acceptable at Pilgrim Nuclear Power Station.

Bechtel Corporation has reviewed or is currently reviewing panels, racks, instrumentation and control components, and electrical components associated with the RBICS. The seismic evaluation of the panels and instrumentation associated with the RBICS is not yet complete. However, on the basis of seismic evaluations of comparable panels supplied by the same panel vendor, it is expected the forthcoming vendor seismic calculation will show the panel will be able to sustain the specified accelerations within the stress levels given in the purchase specification.

The electrical components are evaluated primarily from test results supplied from their respective manufacturer. These test reports are reviewed to ensure that the proper acceleration levels were applied and that their testing procedures adequately represent the installed condition.

7.1.6 Radiation Resistance Design Criteria

The design criteria as discussed in Section 12.3.1.2 for Pilgrim Nuclear Power Station safety system equipment are:

1. Safety system equipment shall be capable of withstanding, without loss of function, the potential effects of the total integrated radiation dose from normal operation during the expected lifetime of the station plus a one time dose from an accident exposure. See Sections 12.3 and 14.9

2. The radiological consequences accident analysis methods and models employed in the design of the Pilgrim facility are those cited in the GE Topical Report, Analytical Methods for Evaluating the Radiological Aspects of the GE-BWR. GE-APED-5756, March 1969

3. Comparison of the potential exposures which equipment within the primary containment could experience from the design basis LOCA source terms, (derived from GE-APED-5756) to the expected original 40-year lifetime exposures shows that the expected doses are usually greater than the potential APED accident doses. The safety system equipment specification for components inside the primary containment require that materials used in the component's fabrication are able to withstand a specified total integrated dose which is based upon the component's expected original 40-year lifetime dose plus a LOCA. The environmental qualification (EQ) of electrical components program ensures that EQ components are maintained in accordance with their qualification bases.

4. RPS and engineered safety feature electrical and mechanical equipment will withstand, without loss of capability for performance of their safety functions, the total exposure

   resulting from a design basis LOCA using source terms as stated in Section 14.9 at the end of station life.

5. Section 14.9 demonstrates the capability of Pilgrim Station engineered safety feature systems to withstand the radiation effects. This section contains the source term assumptions and specific evaluations of the SGTS, the CSCS components, electrical penetrations, the control room, and materials within the primary containment

6. The electrical power and control cabling for safety system equipment which must function in a radiation environment is not discussed in Section 14.9, but it has been tested under simulated post accident radiation environment. The cabling has been irradiated with a CO-60 source to a dose of at least 5 X 107 rads which is far in excess of that which safety system cabling inside the primary containment would experience during normal operations plus that which would be experienced over a 30 day period from the release into the primary containment according to the assumptions stated in Section 14. The results of the test indicate that the power and control cabling run to Pilgrim Station safety systems is capable of satisfactory performance in a boiling water reactor (BWR) primary containment environment

7. The individual components and greases of Limitorque operators have been reviewed by the manufacturer for their ability to withstand the design basis radiation environment; i.e., that experienced during normal operation plus that radiation which would be experienced resulting from a fission product release into the primary containment according to the assumptions stated in Section 14 during that portion of a LOCA in which valve operation would be required. The manufacturer's review indicates that the Limitorque operators are capable of proper operation after irradiation in excess of the design basis radiation environment. In fact, the manufacturer expects proper operation after irradiation up to approximately 1.5 X 108 rads

8. Windings of solenoids on the main steamline isolation valves and relief/safety valves utilize Class H insulation, which has been proven capable of withstanding the design basis radiation environment with considerable margin

7.1.7 Safety Related Components Inside Containment: Environmental Qualification

Safety related equipment inside the primary containment which must operate in an accident environment is limited to isolation valves, recirculation line valves, auto relief valves, acoustic monitors, limit switches, junction boxes, solenoid valves, splicers, terminators, and their associated electrical penetrations and cabling. These cables, operators, and penetrations are designed for in excess of the required period of usage under their design basis accident conditions. In addition, indication of drywell pressure and torus water temperature are required and provided for the full range of postulated accident environmental conditions. The containment isolation and recirculation line valves are required to operate for only short time durations. This is true for the full spectrum of break sizes.

Electrical cables use an insulation type that has been environmentally tested to demonstrate suitability for this service for periods of time greatly in excess of the required operating time.

Specifications for the above equipment included the requirement to remain operable as required during and/or subsequent to a design basis LOCA. Manufacturer's proposals, manuals, and drawings are carefully reviewed for selection of materials and conformance to the specified temperature, pressure, and humidity requirements.

Qualification tests have not been required for the temperature sensors because their design range of operation and calibration encompasses the environmental conditions expected within the primary containment as the result of LOCA or steam line break accident.

Qualification tests (prototype tests) have been performed on the Limitorque operators, and power and control cabling runs to engineered safety feature equipment inside the primary containment, and on electrical penetrations to ensure required operation and/or leakage integrity under LOCA conditions.

The Limitorque valve operators and the solenoids associated with the relief and main steam line isolation valves have been tested and the results of these tests were originally submitted in Amendment 18 of Millstone Unit 1 FSAR. These results show that suitable operation of these components can be expected during that portion of the transient in which operation would be required.

Power and control cabling samples were tested in a saturated steam environment above the peak design basis LOCA conditions. Satisfactory operation was verified throughout the test including the peak test conditions. Subsequent to these tests, electrical tests were performed to verify that insulation properties were maintained.

Drywell electrical penetration qualification tests have been accomplished. The design specifications of these components required that a prototype of each type be tested under design basis LOCA conditions. The tests satisfactorily demonstrated the penetrations will maintain its electrical and leak tightness characteristics at peak conditions.

For equipment inside the drywell that is not safety-related, purchase specifications include the requirement to remain operable under normal operating environmental conditions. A non-safety related components ability to function for restart following a lesser incident has not been evaluated. Following any LOCA, equipment and components would be checked for functional operability before station restart.

7.1.8 Effect of Loss of Heating, Ventilation, or Air Conditioning System on Safety-Related Equipment

Safety-related control and electrical equipment located in the control room or other equipment rooms is not dependent upon normal station air-conditioning and/or ventilation.

An analysis of the control room assumed that all normal ventilation and air conditioning systems were inoperative; the only ventilation being through one of two Main Control Room Environmental Control Systems (MCRECS) filter trains (1,000 ft3/min). See Section 10.17.

Under the conditions imposed, a loss of all normal ventilation and air-conditioning, the control room operator would initiate an emergency shutdown of nonessential equipment and lighting to reduce the heat generation to a minimum. Heat removal would be accomplished by conduction through the floors, ceilings, and walls to adjacent rooms and to the environment. Additionally, at least one of the 1,000 ft3/min MCRECS would remove heat.

The equilibrium condition for temperature and humidity in the control room and other equipment rooms following the loss of all air-conditioning and normal ventilation would be 114#F, 48 percent relative humidity. The equilibrium temperature of 114#F would be achieved during ambient conditions of 90#F, 90 percent relative humidity.

All control board instrumentation is specified to be operable up to 120#F and 90 percent relative humidity. Therefore, the temperature within the control room will never increase to a point that will require reactor shutdown. All instrumentation will be functionally tested after installation and prior to plant startup to confirm satisfactory operability of control and electrical equipment under normal environmental conditions. The extreme of environmental conditions is far less than the design requirement of the instrumentation. Operation below this design value is always expected so that additional testing is not warranted.

Areas of the station where heat generation occurs as a result of safety-related mechanical equipment operation, i.e., the High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), and the Residual Heat Removal (RHR)/Core Spray compartments, have been provided with two redundant, full capacity, Class I equipment area coolers which will maintain the ambient temperatures below the specified design temperature limits for the equipment in these compartments. See Section 10.18.

7.1.9 Safety System Periodic Testing Criteria

Provisions have been made in the Pilgrim design for periodic testing of engineered safety feature instrumentation and control equipment as described below:

Core Spray Subsystem

All sensors are of the pressure sensing type and are installed with calibration taps and instrument valves to permit testing during normal plant operation or during shutdown. The reactor low pressure sensors can be easily checked for operability during plant operation by comparing the A & B train analog trip unit indicators associated with these sensors. The reactor vessel level sensors can be similarly checked for operability by comparing the A & B train analog trip unit indicators associated with these sensors. The drywell high pressure sensors can be checked by comparing the A & B train analog trip unit indicators associated with these sensors.

The CSCS is capable of being completely tested during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. Sensors can be checked by comparing the A & B train for agreement at the analog trip unit indicators. The trip unit can be tested/calibrated by applying a simulated signal to its input and observing the scale reading/trip indication. Logic relays can be exercised by means of plug-in test switches used alone or in conjunction with single sensor tests. Pumps can be started by the appropriate breakers to pump against system check valves (or return to suppression pool through test valves) while the reactor is at pressure. Motor-operated valves can be exercised by the appropriate control relays and starters, and all essential indications and annunciations can be observed as the system is tested. CS water will not actually be introduced into the vessel except initially before fuel loading and during refueling outages when the torus is drained to verify core spray pump operability.

Low Pressure Coolant Injection Subsystem

The capability for sensor checks applies equally to the Core Spray (CS) Subsystem and Low Pressure Coolant Injection (LPCI) Subsystem. The capability for test and calibration also applies equally to the CS Subsystem and LPCI Subsystem, except that the only portion of the LPCI logic which cannot be tested with the reactor at full power is the recirculation pump trip portion of the loop selection logic. However, a continuity check on this portion of the LPCI logic can be made during power operation.

High Pressure Coolant Injection Subsystem

The capability for test, calibration, and sensor checks applies equally to the CS Subsystem and HPCI Subsystem.

Automatic Depressurization Subsystem

All sensors are of the pressure sensing type and are installed with calibration taps and instrument valves which allow for the application of a test pressure for calibration and/or functional tests during normal plant operation or during shutdown.

The reactor vessel level sensors can be checked for operability during plant operation by comparing the A&B train analog trip unit indicators associated with these sensors. The trip units can be tested/calibrated by applying a simulated signal to its input and observing trip indication.

The drywell high pressure sensors can be checked for operability during plant operation by comparing the A&B train analog trip unit indicators associated with these sensors. The trip units can be tested/calibrated by applying a simulated signal to its input and observing trip indication.

The Automatic Depressurization Subsystem is not tested in its entirety during actual plant operation, but provisions are incorporated so that operability of all elements of the system can be verified at periodic intervals. Testing of control circuitry is accomplished at the control relay cabinet by means of test jacks, switches, and indicator lights while exercising trip units one at a time. The test method is generally as follows:

ACTION	OBSERVATION
1. Exercise a trip unit	a. Trip unit relay pickup b. Alarm is given
2. Start a CS or RHR (LPCI mode) pump	a. Off-normal alarm b. Low pressure cooling system available relay pickup
3. Exercise logic subchannel by test switch	a. Logic subchannel relay pickup b. Continuity lights on each valve circuit are energized
4. Reset logic subchannel	a. Annunciators clear
5. Repeat above steps for other trip units, other low pressure core cooling pumps, other logic subchannels.	Same as for associated steps above

Primary Containment and Reactor Vessel Isolation Control System

The reactor vessel instruments can be checked one at a time by

application of simulated signals. These include level, pressure, radiation, and flow. HPCI and RCIC temperature sensors can be checked periodically during full power operation. Temperature sensors in the ventilation exhausts from the main steamline tunnel and the condenser compartment area are fully testable during full power operation.

All active components of the PCIS, with the exception of the analog trip sensors, are tested and calibrated during plant operation. The analog trip sensors can be cross-checked against their companions for verification of operability. Since the radiation sensors are used with reference to background and the analog trip sensors are highly reliable, they do not require actual sensitivity verification on a frequent basis. There are certain segments of wiring in the logic that are difficult to check during plant operation. These are wires that make up the parallel contacts in the one-out-of-two taken twice logic for the main steam isolation valves. However, the intercabinet wiring is so arranged that disabling shorts could only be achieved by double grounds, which would cause fuse failure on the grounded system and thus fail safe. In addition, it is very easy to observe the contact action on an HFA type relay during a channel trip condition to verify actual dropout when deenergized. The auxiliary relay circuits can be tested individually by pulling the individual valve circuit fuses and observing relay dropout as manifested by the indicators provided on the contact blocks of each relay. Thus, testability of major elements of the system can be demonstrated without shutting down the station.

Reactor Building Isolation and Control System

The Refueling Ventilation Exhaust Radiation Monitoring System contains four instrument channels to detect radiation resulting from a postulated fuel handling accident. The sensors are separated into two areas: A,B in one area: C,D in another. The upscale trip outputs are arranged in a one-out-of-two taken twice logic configuration. All four instruments are "bugged" with a source to provide a "live" zero, and any one upscale or test switch operation causes a control room annunciation. Testing is accomplished by placing one instrument at a time in the TEST mode by operation of a front panel switch. A simulated signal is introduced into the instrument input to verify operation of the trip unit at the established setpoint. The normally energized channels produce a trip output for power loss, i.e., they are fail-safe.

The SBGT is fully testable during reactor operation as part of the online test capability of the RBICS.

7.1.10 Definitions

The complexity of the control and instrumentation systems requires the use of certain terminology for clarification in the description of the safety systems. See additional definitions in Section 1.2.

1. Channel - A channel is an arrangement of one or more sensors and associated components used to evaluate plant variables and produce discrete outputs used in logic. A channel terminates and loses its identity where individual channel outputs are combined in logic. See Figure 7.1-2.

2. Sensor - A sensor is that part of a channel used to detect variations in the measured station variable. See Figure 7.1-2.

3. Logic - Logic is that array of components which combines individual bistable output signals to produce decision outputs. See Figure 7.1-2.

4. Trip System - A trip system is that portion of a system encompassing one or more channels, logic, and bistable devices used to produce signals to the actuation logic. A trip system terminates and loses its identity where outputs are combined in logic. See Figure 7.1-2.

5. Actuation Device - An actuation device is an electrical or electromechanical module controlled by an electrical decision output used to produce mechanical operation of one or more activated devices to accomplish the necessary action. See Figure 7.1-2.

6. Activated Device - An activated device is a mechanical module in a system used to accomplish an action. An activated device is controlled by an actuation device. See Figure 7.1-2.

7. Trip - A trip is the change of state of a bistable device which represents the change from a normal condition. A trip signal, which results from a trip, is generated in the channels of a trip system and produces subsequent trips and trip signals throughout the system as directed by the logic.

8. Setpoint - A setpoint is that value of the monitored plant variable which causes a channel trip.

9. Component - Items from which the system is assembled (e.g., resistors, capacitors, wires, connectors, transistors, switches, springs, pumps, valves, piping, heat exchangers, vessels, etc.).

10. Module - Any assembly of interconnected components which constitutes an identifiable device, instrument, or piece of equipment.

11. Incident Detection Circuitry - Incident detection circuitry includes those trip systems which are used to sense the occurrence of an incident. Such circuitry is described and evaluated separately where the incident detection circuitry is common to several systems.

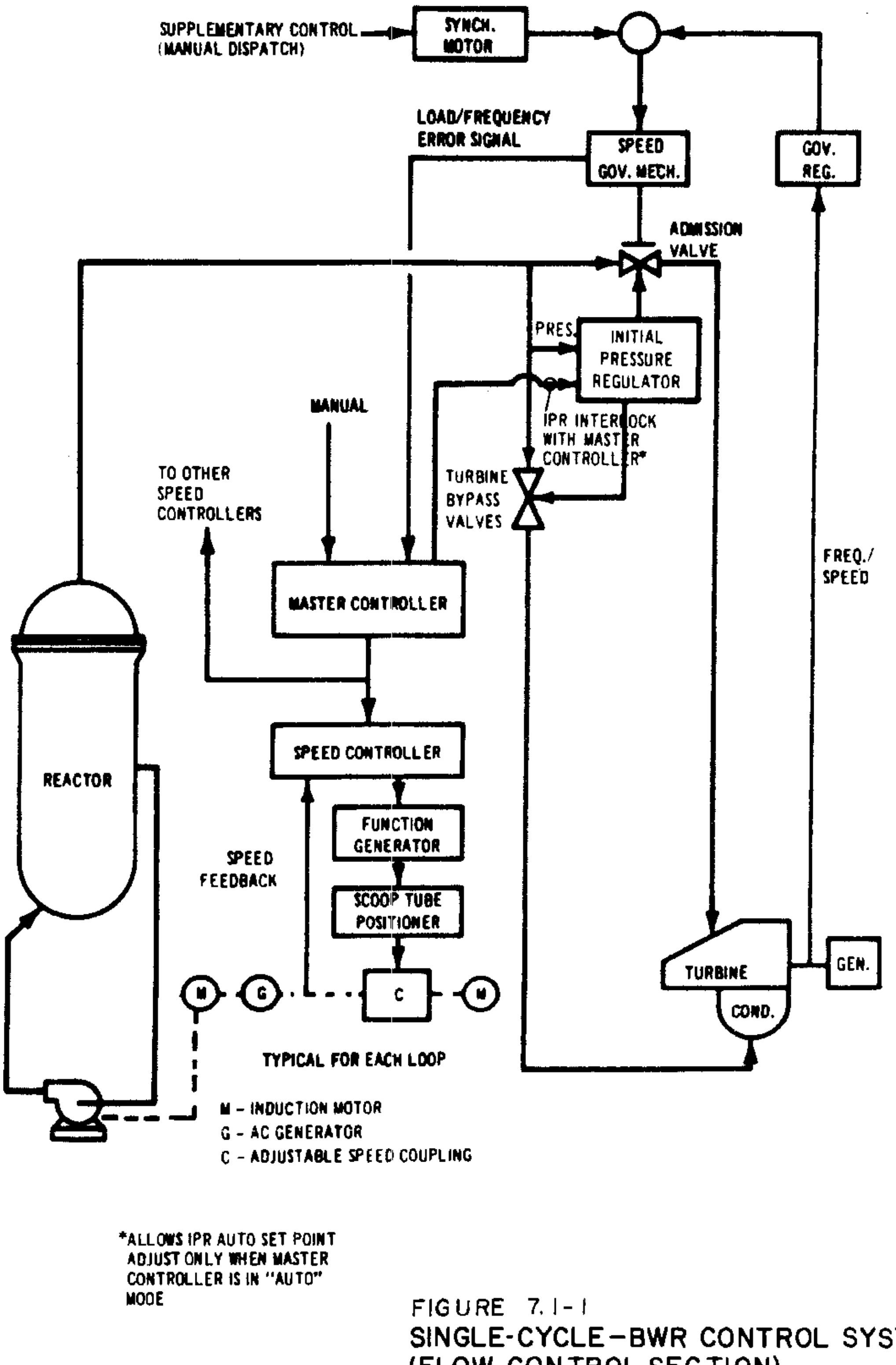
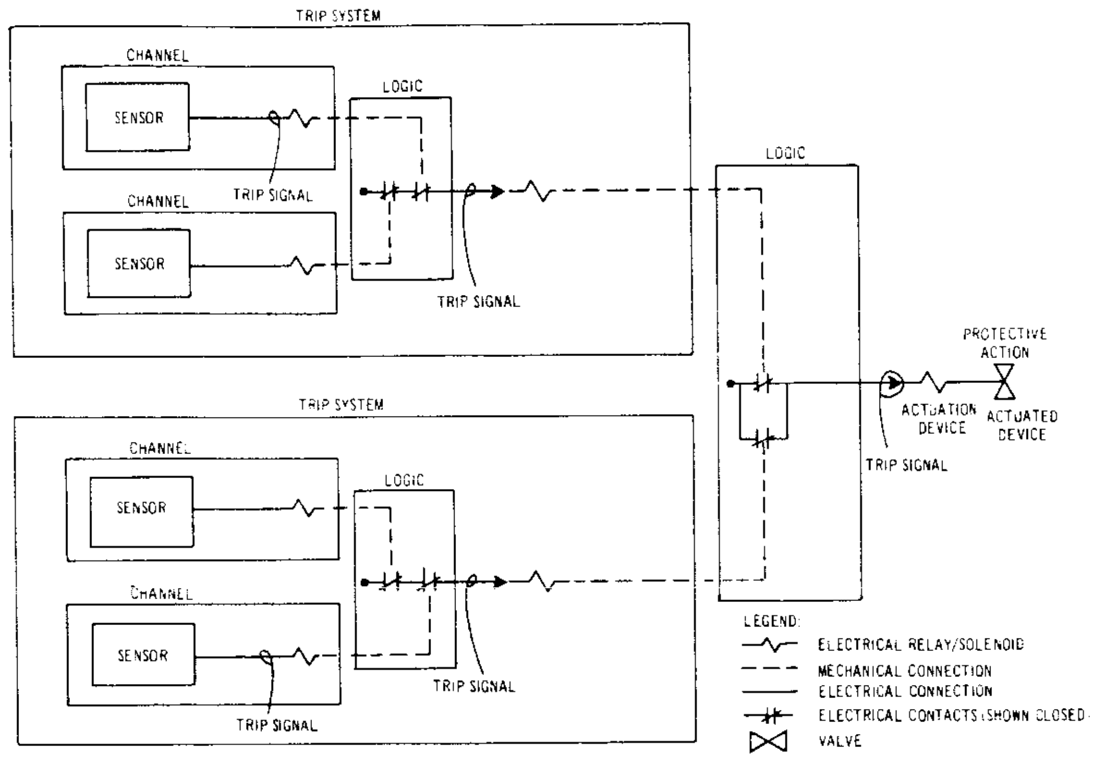


FIGURE 7.1-1
SINGLE-CYCLE-BWR CONTROL SYSTEM
(FLOW CONTROL SECTION)
FUNCTIONAL BLOCK DIAGRAM
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT



TYPICAL PROTECTION SYSTEM (CONTROL AND INSTRUMENTATION PORTIONS)

FIGURE 7.1-2
USE OF PROTECTION SYSTEM CONTROL AND INSTRUMENTATION DEFINITIONS
PILGRIM NUCLEAR POWER STATION
FINAL SAFETY ANALYSIS REPORT

7.2 REACTOR PROTECTION SYSTEM

7.2.1 Safety Objective

The Reactor Protection System (RPS) provides timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier (uranium dioxide sealed in cladding) and the nuclear system process barrier. Excessive temperature threatens to perforate the cladding or melt the uranium dioxide. Excessive pressure threatens to rupture the nuclear system process barrier. The RPS limits the uncontrolled release of radioactive material from the fuel and nuclear system process barrier by terminating excessive temperature and pressure increases through the initiation of an automatic scram.

7.2.2 Safety Design Bases

1. The RPS shall initiate with precision and reliability a reactor scram in time to prevent fuel damage following abnormal operational transients.

2. The RPS shall initiate a scram with precision and reliability in time to prevent damage to the nuclear system process barrier as a result of internal pressure. Specifically, the RPS initiates a reactor scram in time to prevent nuclear system pressure from exceeding the pressure allowed by applicable industry codes.

3. To limit the uncontrolled release of radioactive materials from the fuel or nuclear system process barrier, the RPS shall initiate, with precision and reliability, a reactor scram upon gross failure of either of these barriers.

4. To provide assurance that conditions which threaten the fuel or nuclear system process barriers are detected with sufficient timeliness and precision to fulfill safety design bases 1, 2, and 3, RPS inputs shall be derived, to the extent feasible and practical, from variables that are true, direct measures of operational conditions.

5. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design bases 1, 2, and 3, the RPS shall respond correctly to the sensed variables over the expected range of magnitudes and rates of change.

6. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design bases 1, 2, and 3, an adequate number of sensors shall be provided for monitoring essential variables that have spatial dependence.

7. The following bases provide assurance that the RPS is designed with sufficient reliability to fulfill Safety Design Bases 1, 2, and 3:

   a. No single failure within the RPS shall prevent proper RPS action when required to satisfy Safety Design Bases 1, 2, or 3

   b. Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability shall not impair the ability of the RPS to respond correctly. During such an operation, the requirements of Basis 7a shall continue to be met

   c. The system shall be designed for a high probability so that when any monitored variable exceeds the scram setpoint, the event shall result in an automatic scram and shall not impair the ability of the system to scram as other monitored variables exceed their scram trip points

   d. Where a plant condition that requires a reactor scram 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 RPS channels designed to provide protection against the unsafe condition, the remaining portions of the RPS shall meet the requirements of Safety Design Bases 1, 2, 3, and 7a

   e. The power supply for the RPS shall be arranged so that loss of one supply neither causes nor prevents a reactor scram

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

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

   h. Earthquake ground motions shall not impair the ability of the RPS to initiate a reactor scram. See Section 7.1.6

8. The following bases are specified to reduce the probability that RPS operational reliability and precision will be degraded by operator error:

    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 physical control of station operations personnel

    b. The means for manually bypassing logics, channels, 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 shall be continuously annunciated in the main control room

9. To provide the operator with means independent of the automatic scram functions to counteract conditions that threaten the fuel or nuclear system process barrier, it shall be possible for the control room operator to manually initiate a reactor scram

10. The following bases are specified to provide the operator with the means to assess the condition of the RPS and to identify conditions that threaten the integrity of the fuel or nuclear system process barrier:

    a. The RPS shall be designed to provide the operator with information pertinent to the operational status of the protection system

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

11. It shall be possible to check the operational availability of each channel and logic.

7.2.3 Description

7.2.3.1 Identification

The RPS includes the motor generator power supplies with associated control and indicating equipment, sensors, trip units, relays, bypass circuitry, and switches that cause rapid insertion of control rods (scram) to shutdown the reactor. It also includes outputs to the process computer system and annunciators. The RPS 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. The Process Computer System and annunciators are not part of the RPS. Although scram signals are received from the Neutron Monitoring System, this system is treated as a separate nuclear safety system and is discussed in Section 7.5.

7.2.3.2 Power Supply

Power to each of the two reactor protection trip systems is supplied, via a separate bus, by its own high inertia ac motor generator set.

See Figure 7.2-1 (Drawing M1P 5-5). Each generator has a voltage regulator which is designed to respond to a step load change of 50 percent of rated load with an output voltage change of not greater than 15 percent. High inertia is provided by a flywheel. The inertia is sufficient to maintain voltage within 5 percent of rated value and a frequency of not less than 55 Hz for at least 1.0 second following a total loss of power to the drive motor.

Alternate power is available to either RPS bus from emergency service bus B6 of the auxiliary power distribution system. The alternate power switch prevents simultaneously feeding both buses from the same source. The switch also prevents paralleling a motor generator set with the alternate supply. DC power is supplied to the backup scram valve solenoids from the plant batteries.

7.2.3.3 Physical Arrangement

Instrument piping that taps into the reactor vessel is routed through the drywell wall, and terminates inside the secondary containment (Reactor Building). Reactor vessel pressure and water level information is sensed from this piping by instruments mounted on instrument racks in the Reactor Building. The sensors for RPS signals from equipment in the Turbine Building are mounted locally in the Turbine Building. The two motor generator sets that supply power for the RPS are located in an area where they can be serviced during reactor operation. Cables from sensors and power cables are routed to the analog trip cabinets in the Cable Spreading Room and/or to the two RPS cabinets in the Control Room, where the logic circuitry of the system is formed. One Control Room cabinet is used for each of the two trip systems. The logics of each trip system are isolated in separate bays in each cabinet. The RPS is designed as Class I equipment to assure a safe reactor shutdown during and after seismic disturbances. The detailed requirements for Class I equipment are described in Appendix C.

7.2.3.4 Logic

The basic logic arrangement of the system is illustrated on Figure 7.2-2 (Drawing M1P 6-6). The RPS is arranged as two separately powered trip systems. Each trip system has three logics, as shown on Figure 7.2-3. Two of the logics are used to produce automatic trip signals. The remaining logic is used for a manual trip signal. Each of the two logics used for automatic trip signals receives input signals from at least one channel for each monitored variable. Thus, two channels are required for each monitored variable to provide independent inputs to the logics of one trip system. At least four channels for each monitored variable are required for the logics of both trip systems.

As shown on Figure 7.2-4, each actuator logic is a one-out-of-two arrangement. To produce a scram, the actuator logics of both trip systems must be tripped. The overall logic of the RPS could be termed one-out-of-two taken twice.

7.2.3.5 Operation

To facilitate the description of the RPS, the two trip systems are called trip system A and trip system B. The automatic logics of trip system A are logics A1 and A2; the manual logic of trip system A is logic A3. Similarly, the logics for trip system B are logics B1, B2, and B3. The actuators associated with any particular logic are identified by the logic identity (such as actuators B2) and a letter. See Figure 7.2-3. Channels are identified by the name of the monitored variable and the logic identity with which the channel is associated (such as reactor vessel high pressure channel B1).

During normal operation all sensor and trip contacts essential to safety are closed; channels, logics, and actuators are energized. In contrast, however, trip bypass channels consist of normally open contact networks.

There are two scram pilot valves for each control rod, arranged functionally as shown on Figure 7.2-1 (Drawing M1P 5-5). Each scram pilot valve is solenoid operated. With solenoids normally energized, the scram pilot valves control the air supply to both scram valves for each rod. With either scram pilot valve energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for control rod drive water. One of the scram pilot valves for each control rod is controlled by actuator logics A, the other valve by actuator logics B. There are two dc solenoid operated backup scram valves which provide a second means of controlling the air supply to the scram valves for all control rods. The DC solenoid for each backup scram valve is normally de-energized. The backup scram valves are energized (initiate scram) when both trip system A and trip system B are tripped.

A free standing instrument rack (C3002) is located on the reactor building 23ft elevation to control the SPVAH pressure and assure adequate CRD scram times. The rack consists of two parallel trains of an isolation valve, air pressure regulator, and a second isolation valve. A third pressure regulator with a slightly higher setpoint is located in the common discharge header to ensure that if the in-service parallel regulator fails, the air header to the CRD system does not exceed the pressure at which scram time testing was performed. The equipment on the instrument rack is connected to the existing SPVAH system between the SPVAH dump valve and the ARI solenoids.

The two parallel trains are designed to be redundant. If the on-line regulator fails open (PCV-302-89A or B), the regulator in the common discharge header (PCV-302-89C) will maintain pressure in the air line until the regulator in parallel with the failed regulator is brought on-line. If one of the parallel regulators fails open, the outlet pressure gauge will indicate higher than the normal pressure in addition to the alarm from the Kaye Temperature Computer, TISU-8125.

Single failure criterion is met. Separation criteria is not applied because the location is not subject to seismic or missile hazards that could initiate a common mode failure.

During PBOC, the scram function will be performed before environmental conditions exceed the qualification of the regulators.

The Air Dump System provides a third means for controlling the air supply to the scram valves of all control rods. The Air Dump System consists of a 3-way air operated valve which is actuated by a 3-way snap acting switching valve. The switching valve senses pressure in the scram pilot valve air header and upon sustained low pressure in the header, it actuates the 3-way air operated valve which vents the header and thereby initiates control rod insertion. A remote manual switch located in the control room provides for reset of the Air Dump System.

Means are also provided to scram the reactor through the Alternate Rod Insertion (ARI) function of the Recirculation Pump Trip (RPT) System in the unlikely event that the RPS fails to accomplish a reactor scram from power (Reference Section 3.9).

The functional arrangement of sensors and channels that constitute a single logic is shown on Figure 7.2-2 (Drawing M1P 6-6). A schematic is given on Figure 7.2-3.

Whenever a channel sensor contact opens, its sensor relay deenergizes, causing contacts in the logic to open. The opening of contacts in the logic deenergizes its actuators. When deenergized, the actuators open contacts in all the actuator logics for that trip system. This action results in deenergizing the scram pilot valve solenoids associated with that trip system, (one scram pilot valve solenoid for each control rod). Unless the other scram pilot valve solenoid for each rod is deenergized, the rods are not scrammed. If a trip then occurs in any of the logics of the other trip system, the remaining scram pilot valve solenoid for each rod is deenergized, venting the air pressure from the scram valves, and allowing control rod drive water to act on the control rod drive piston. Thus, all control rods are scrammed. The water displaced by the movement of each rod piston is vented into a scram discharge volume. Figure 7.2-1 (Drawing M1P 5-5) shows that when the solenoid for each backup valve is energized, the backup scram valves vent the air supply for the scram valves; this action initiates insertion of every control rod regardless of the action of the scram pilot valves.

A scram can be manually initiated. There are two scram buttons, one for logic A3 and one for logic B3. Depressing the scram button on the logic A3 deenergizes actuators A3 and opens corresponding contacts in actuator logics A. A single trip system is actuated as a result, but no scram occurs. To affect a manual scram, the buttons for both logic A3 and logic B3 must be depressed. By operating the manual scram button for one manual logic at a time, followed by reset of that logic, each trip system can be tested for manual scram capability. It is also possible for the control room operator to scram the reactor by interrupting power to the RPS. This can be done by operating power supply breakers. The manual scram capability provided in the control room meets Safety Design Basis 9.

To restore the RPS to normal operation following any single trip system trip or scram, the actuators must be manually reset. Reset is possible only if the conditions that caused the trip or scram have been cleared and is accomplished by operating switches in the control room. Figure 7.2-2 (Drawing M1P 6-6) shows the functional arrangement of reset contacts for trip system A. This meets Safety Basis 7f.

7.2.3.6 Single Failure and Channel Independence Criteria (IEEE-279)

Circuitry involving common devices in the RPS has been designed to assure that no single failure (short, open, or ground) can disable a safeguards function. Where single switches accomplish redundant functions (and have no independent backup interlocks), barriers are installed between switch sections to preclude the possibility of inadvertent shorting between adjacent sections. Barriers are installed between adjacent terminal points where potential for shorting exists. Barriers are also installed between switches that are required to accomplish redundant functions if the switches:

a. are located within 6 inches of each other

b. do not have independent backups

The RPS reset switch and associated logic comply with the single failure criterion requirements. Details of the RPS reset switch are shown on Figure 7.2-5. Each contact of the reset switch is wired to an individual auxiliary relay coil whose contacts are used in the RPS trip logic as shown on Figures 7.2-6 and 7.2-7.

Proper operation of the reset switch and its auxiliary relays can be ascertained during periodic test of the RPS, or whenever any particular channel is returned from a tripped state to the normal untripped condition. Failure would be noted as an automatic reset of specific trip actuators (depending upon the cause of failure) rather than remaining in a deenergized state until manually reset.

Since opening of the process sensor trip channels is the initiating event for reactor scram, failure of the reset switch will not prevent deenergization of the trip actuators during the time interval that the process actually exceeds the trip set point.

To comply with the channel independence criterion, the four RPS reset channels to the trip actuators are physically separated and electrically isolated as shown on Figure 7.2-6.

7.2.3.7 Identification of Protective Actions and Information Readouts (IEEE-279)

Whenever a RPS sensor trips, it lights a printed red window (common to all the channels for that variable) on the reactor control panel in the control room to indicate the out of limit variable. Each trip system lights a red window to indicate which trip system has tripped. An RPS channel trip also sounds a buzzer or horn, which can be silenced by the operator. The annunciator window lights latch in until manually reset. Reset is not possible until the condition causing the trip has been cleared. A computer printout identifies each tripped channel. However, the physical positions of RPS relays may be used to identify individual sensors that have tripped from a group of sensors monitoring the same variable. The location of alarm windows provides the operator with the means to quickly identify the cause of RPS trips, and to evaluate the threat to the fuel or nuclear system process barrier.

IEEE-279 design requirement 4.19 requires that the protective actions be indicated and identified down to the channel level. Design requirement 4.20 requires that these indications be accurate, complete, and timely, and that they provide a lucid presentation of information to the operator.

Paragraph 4.19 of IEEE-279 can be very easily misinterpreted. The objective is to make the operator aware of any single trip and allow the operator to determine which specific instrument channel has tripped. This should be satisfied by some common annunciation and visible manifestation of operation of each trip device. This visible manifestation need not be an indicating light, but is just as reasonably an indicating relay or a window type relay with readily visible contact actuation. Indication of protective channel trips occurs at the channel output.

The presentation of this information to the operator is accurate, timely, and adequate for his immediate consideration. When a trip occurs, his first concern should be with which variable has exceeded a setpoint. Consequently, the design uses the annunciator windows to provide this display. A secondary concern is identification of the particular channel of that variable annunciating the trip, and this information is obtained from observation of the relay position.

To provide the operator with the ability to analyze an abnormal transient during which events occur too rapidly for direct operator comprehension, all RPS trips are recorded by an alarm typewriter controlled by the Process Computer System. All trip events are recorded. The first 40 are recorded in chronological sequence except that events occurring within 4 milliseconds of each other are treated as having occurred simultaneously. Use of the alarm typewriter and computer is not required for plant safety, and information provided is in addition to that immediately available from other annunciators and data displays. The printout of trips is of particular use for routinely verifying the proper operation of pressure, temperature level, and valve position switches as trip points are passed during startups, shutdowns, and maintenance operations.

RPS inputs to annunciators, recorders, and the computer are arranged so that no malfunction of the annunciating, recording, or computing equipment can functionally disable the RPS. Signals directly from the RPS sensors are not used as inputs to annunciating or data logging equipment. Relay contact isolation is provided between the primary signal and the information output. The arrangement of indications pertinent to the status and response of the RPS satisfies safety design bases 10a and 10b.

7.2.3.8 Scram Functions and Bases for Trip Settings

The following discussion covers the functional considerations for the variables or conditions monitored by the RPS. Table 7.2-1 lists the specifications for the instruments providing signals for the system that are used in the current plant safety analysis. Figure 7.2-8 shows the scram functions in block form.

Neutron Monitoring System Trip

To provide protection for the fuel against high heat generation rates, neutron flux is monitored and used to initiate a reactor scram. The neutron monitoring system setpoints and their bases are discussed in Section 7.5, Neutron Monitoring System.

Nuclear System High Pressure

High pressure within the nuclear system poses a direct threat of rupture to the nuclear system process barrier. A nuclear system pressure increase, while the reactor is operating, compresses the steam voids and results in a positive reactivity insertion causing increased core heat generation that could lead to fuel failure and system over pressurization. A scram counteracts a pressure increase by quickly reducing the core fission heat generation. The nuclear system high pressure scram setting is chosen slightly above the reactor vessel maximum normal operating pressure, to permit normal operation without spurious scram, yet provide a wide margin to the maximum allowable nuclear system pressure. The location of the pressure measurement, as compared to the location of highest nuclear system pressure during transients, was also considered in the selection of high pressure scram setting. The nuclear system high

pressure scram works in conjunction with the pressure relief system in preventing nuclear system pressure from exceeding the maximum allowable pressure. This same nuclear system high pressure scram setting also protects the core from exceeding thermal hydraulic limits as a result of pressure increases for some events that occur when the reactor is operating at less than rated power and flow.

Reactor Vessel Low Water Level

A low water level in the reactor vessel indicates that the reactor is in danger of being inadequately cooled. The effect of a decreasing water level while the reactor is operating at power is to decrease the reactor coolant inlet subcooling. The effect is the same as raising feedwater temperature. Should water level decrease too far, fuel damage could result as steam forms around fuel rods. A reactor scram protects the fuel by reducing the fission heat generation within the core.

The reactor vessel low water level scram setting was selected to prevent fuel damage following those abnormal operational transients, caused by single equipment malfunctions or single operator errors that result in a decreasing reactor vessel water level. Specifically, the scram setting is chosen far enough below normal operational levels to avoid spurious scrams, but high enough above the top of the active fuel to assure that enough water is available to account for evaporation losses and displacements of coolant following the most severe abnormal operational transient involving a level decrease. The selected scram setting was used in the development of thermal hydraulic limits, which set operational limits on the thermal power level for various coolant flow rates.

Turbine Stop Valve Closure

Closure of the turbine stop valve with the reactor at power can result in a significant addition of positive reactivity to the core, as the nuclear system pressure rise collapses steam voids. The turbine stop valve closure scram, which initiates a scram earlier than either the neutron monitoring system or nuclear system high pressure, is required to provide a satisfactory margin below core thermal hydraulic limits for this category of abnormal operational transients. The scram counteracts the addition of positive reactivity due to pressure by inserting negative reactivity with the control rods. Although the nuclear system high pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine stop valve closure scram provides additional margin to the nuclear system pressure limit.

The turbine stop valve closure scram setting is selected to provide the earliest positive indication of valve closure. The trip logic was chosen both to identify those situations in which a reactor scram is required for fuel protection and to allow functional testing of this scram function.

Turbine Control Valve Fast Closure

With the reactor and turbine generator at power, fast closure of the turbine control valves can result in a significant addition of positive reactivity to the core as nuclear system pressure rises. The turbine control valve fast closure scram, which initiates a scram earlier than either the neutron monitoring system or nuclear system high pressure, is required to provide a satisfactory margin to core thermal hydraulic limits for this category of abnormal operational transients. The scram counteracts the addition of positive reactivity due to pressure by inserting negative reactivity with the control rods. Although the nuclear system high pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine control valve fast closure scram provides additional margin to the nuclear system pressure limit.

The turbine control valve fast closure scram setting is selected to provide timely indication of control valve fast closure. The trip logic was chosen to identify those situations in which a reactor scram is required for fuel protection.

Main Steam Line Isolation

The main steam line isolation valve closure scram is provided to limit the release of fission products from the nuclear system. Automatic closure of the main steam line isolation valves is initiated upon conditions indicative of a steam line break. Immediate shutdown of the reactor is appropriate in such a situation. The scram initiated by main steam line isolation valve closure anticipates a reactor vessel low water level scram. The main steam line isolation scram setting is selected to give the earliest positive indication of isolation valve closure. The trip logic allows functional testing of main steam line isolation trip channels with one steam line isolated.

In conjunction with the low turbine pressure MSIV closure setpoint, the MSIV closure scram also provides automatic protection of the safety limit on core thermal power at low reactor pressures. At reactor pressures <800 psia, the GEXL correlation is no longer valid. Consequently, a safety limit is imposed which protects fuel cladding integrity without the need for CPR calculations. This low pressure safety limit is 25% of rated core thermal power. The RPS protects this core thermal power safety limit when the reactor mode switch is in the REFUEL or STARTUP position by an APRM scram at 15% of rated power. In the RUN mode, the safety limit is protected by a low turbine pressure MSIV closure setpoint which corresponds to a reactor pressure > 800 psia. Tripping this setpoint closes the MSIVs which, in turn, scrams the reactor.

Scram Discharge Volume High Water Level

The scram discharge volume is designed with sufficient volume to accept the water displaced by the motion of the control rod drive pistons during a scram. The volume consists of two separate scram discharge headers and their associated scram discharge instrument volumes (SDIV). Should the scram discharge volume fill up with water to the point where not enough space remains for the water displaced during a scram, control rod movement would be hindered in the event a scram were required. To ensure the operability of the control rod drive system, the reactor is scrammed when the water level in either of the scram discharge instrument volumes attains a value high enough to verify that the volume is filling up, yet low enough to ensure that the remaining capacity in the volume can accommodate a scram.

Primary Containment High Pressure

A high pressure inside the primary containment could indicate a break in the nuclear system process barrier. It is prudent to scram the reactor in such a situation to minimize the possibility of fuel damage and to reduce the addition of energy from the core to the coolant. The reactor vessel low water level scram also acts to scram the reactor for loss of coolant accidents. The primary containment high pressure scram setting is selected to be as low as possible without inducing spurious scrams.

Manual Scram

To provide the operator with means to shutdown, RPS push buttons are located in the control room that initiate a scram when actuated by the operator.

The movement of the mode switch to the SHUTDOWN position is the preferred method to initiate a manual scram.

Mode Switch in SHUTDOWN

The mode switch provides appropriate protective functions for the condition in which the reactor is to be operated. The reactor is to be shutdown with all control rods inserted when the mode switch is in SHUTDOWN. To enforce the condition defined for the SHUTDOWN position, placing the mode switch in the SHUTDOWN position initiates a reactor scram. This scram is not considered a protective function because it is not required to protect the fuel or nuclear system process barrier, and it bears no relationship to minimizing the release of radioactive material from any barrier. The scram signal is removed after a short time delay, permitting a scram reset which restores the normal valve lineup in the control rod drive hydraulic system.

7.2.3.9 Mode Switch

A conveniently located, multiposition keylock mode switch is provided to select the necessary scram functions for various station conditions. In addition to selecting scram functions from the proper sensors, the mode switch provides appropriate bypasses. The mode switch also interlocks such functions as control rod blocks and refueling equipment restrictions, which are not considered here as part of the RPS. The switch itself is designed to provide separation between the two trip systems . The mode switch positions and their related scram functions are as follows:

1. SHUTDOWN; Initiates a reactor scram and bypasses main steam line isolation scram if nuclear system pressure is below 600 psig

2. REFUEL; Selects Neutron Monitoring System scram for low neutron flux level operation, as described in Section 7.5, and bypasses main steam line isolation scram if nuclear system pressure is below 600 psig

3. STARTUP; Selects Neutron Monitoring System scram for low neutron flux level operation, as described in Section 7.5, and bypasses main steam line isolation scram if nuclear system pressure is below 600 psig

4. RUN; Selects Neutron Monitoring System scram for power range operation, as described in Section 7.5

7.2.3.10 Scram Bypasses

A number of scram bypasses are provided to account for the varying protection requirements depending on reactor conditions, and to allow for instrument service during reactor operations. Some bypasses are automatic and others are manual. All manual bypass switches are in the control room under the direct control of the control room operator. If the ability to trip some part of the system has been bypassed, this condition is continuously indicated in the control room.

Automatic bypass of the scram trip from main steam line isolation is provided when both of the following conditions exist concurrently:

a. Mode switch not in RUN
b. Nuclear system pressure less than 600 psig

The bypass allows reactor operations at low power with the main steam lines isolated. These conditions exist during startup and during certain reactivity tests while refueling. The scram initiated by placing the mode switch in SHUTDOWN is automatically bypassed after a time delay of 2 sec. The bypass allows the scram to reset, restoring the Control Rod Drive Hydraulic System valve line up to normal. Note that following a reactor scram, a minimum delay period of 10 seconds must be observed before resetting. An annunciator in the control room indicates the bypassed condition.

Automatic bypass of the turbine control valve fast closure scram and turbine stop valve closure scram is effected by a trip of the high pressure turbine first stage shell low pressure switches. The design basis analytical limit for the switch setpoint in terms of percent rated core thermal power is ≤ 32.5%. An automatic bypass at or below 32.5% of rated core thermal power does not constitute a threat to the integrity of any barrier to the release of radioactive material. A high pressure turbine first stage shell pressure of 140.3 psig corresponds to 32.5% of rated core thermal power based on a limiting balance of plant feedwater heater configuration. This scram bypass trip setpoint is set below the Technical Specification allowable value of 112 psig to accommodate instrument drift and is based on the combined uncertainty of the associated instrument loop components. To maintain an automatic bypass that is compatible with the turbine bypass system and serves to avoid opening of any safety-relief valve during most moderate frequency pressurization transients, the automatic bypass will only be effected whenever core thermal power is ≤ 30% of rated. Bypasses for the Neutron Monitoring System channels are described in Section 7.5. A manual keylock switch located in the control room permits the operator to bypass the scram discharge volume high level scram trip if the mode switch is in SHUTDOWN or REFUEL. This bypass allows the operator to reset the RPS, so that the system is restored to operation while the operator drains the scram discharge volume. In addition to allowing the scram relays to be reset, actuating the bypass initiates a control rod withdrawal block. Resetting the trip actuators opens the scram discharge volume vent and drain valves. An annunciator in the control room indicates the bypass condition. The arrangement of bypasses meets safety design basis 8b.

See Section 7.2.3.6 for Single Failure and Channel Independence Criteria.

Scram Discharge Volume High Water Level Trip Bypass

The single failure criterion is satisfied as follows:

Since the scram discharge instrument volume high water level trip bypass requires manual operation of a bypass switch and the mode switch to establish four bypass channels, the design of the bypass function complies with this design requirement. For the bypass switch, a single operator connects to two separate blocks of switch contacts within the switch body, and wiring from contacts is routed to separate terminal strips.

One set of switch contacts, in conjunction with mode switch contacts, is used to energize two trip channel bypass relays when the bypass condition is desired; in a similar fashion, the other set of bypass switch and mode switch contacts energize two other trip channel bypass relays. Contacts from one relay are connected in series

with contacts from a relay in the other group to produce the RPS A1 trip channel bypass function. The trip channel bypass function for the redundant A2 trip channel is produced from series connected contacts of the other two relays.

Consequently, it is necessary that four out of four relays be energized in order to bypass the automatic RPS trip channels for this protective function. There is no single failure of this bypass function that will satisfy the four out of four condition necessary to establish the bypass condition. Hence, this function complies with the single failure criterion.

The channel independent criterion is satisfied as follows:

The scram discharge instrument volume high water level trip bypass circuitry complies with this design requirement. For operator convenience, a single switch has been selected for the bypass function. Utilization factors considered in this selection were the number of bypass operations required in any given operating period, and the expected duration of each bypass. Since the bypass switch is used only to permit manual reset of the RPS and permit the operator to drain the discharge volume following reactor scram, it was determined that the switch would be used infrequently (i.e., each reactor scram) and for short time periods (i.e., several minutes to accomplish the necessary draining of the volume). A single switch is used to minimize the possibility of operator error in terms of removal of the bypass. However, in order to fully satisfy the design requirement that all four bypass channels be independent of one another, the following techniques are employed:

1. Two manual switch operations are required: one involves the bypass switch, and the other involves the mode switch
2. Both switches are keylock types under administrative control
3. Two contact blocks are used with the single bypass switch operator and two banks of the mode switch are used with its single operator
4. One series connected contact string energizes two relays in RPS panel 915; the other contact string energizes two relays in panel 917
5. For each trip channel, the bypass relay contact arrangement is:

   A1: Relay A upstream and Relay B downstream
   See Figure 7.2-9
   A2: Relay C upstream and Relay D downstream
   B1: Relay B upstream and Relay A downstream
   B2: Relay D upstream and Relay C downstream

6. For each trip channel, both bypass relays must be energized to produce the trip channel bypass function This makes removal of the protective action dependent upon all four relays being energized.

7. Any single trip channel bypass initiates the control room annunciator.

Care has been taken to assure that sufficient physical separation, and electrical isolation exists to assure that the bypass channels are satisfactorily independent. Moreover, the conditions for bypass have been made quite stringent in order to provide additional margin.

Neutron Monitoring System Trip Bypass

The single failure criterion is satisfied as follows:

For any given bypass switch, the following design provisions have been made to assure that one, and only one, channel is bypassed at one time with a given bypass switch.

1. The switch operator is a joy stick type, with four positions located on the quadrant extremes (i.e., 90, 180, 270, and 360 deg) with a vertical center off position. This operator type makes selection of bypass for one channel mutually exclusive from selection of any other channel associated with that same switch.

   Cabling associated with the bypass switch is individually shielded, separated, and grounded such that failures in a common wireway would only result in loss of bypass capability.

2. The switch itself is provided with a physical barrier to reduce probability of shorts that could cause energizing of several APRM or IRM channels associated with a single switch.

The channel independent criterion is satisfied as follows:

The neutron monitoring bypass channels comply with this design requirement. The bypass channel output to the individual APRM or IRM trip channel is obtained from an isolated relay contact, and is introduced into the trip logic as shown on Figure 7.2-10. This contact output is physically separated and electrically isolated from the other Neutron Monitoring System bypass channels.

Main Steam Line Isolation Valve Closure Trip Bypass

The main steam line isolation valve closure trip bypass function complies with the single failure criterion as follows:

One contact from each bank of the mode switch is connected in series with a contact from the trip unit relay of one of four pressure transmitters sensing reactor pressure as shown on Figure 7.2-11. The two contacts in series energize one of four bypass relays whose contacts are connected into the RPS trip logic as demonstrated by Figure 7.2-12.

The relationship of these bypass relays to the RPS trip channels is on a one to one basis. Consequently, two particular bypass relays must be energized in order to bypass the protective function. Hence, no single failure in the bypass circuitry will interfere with the protective action of the trip channels.

The four bypass channels comply with the channel independence design requirement as follows:

One contact from each bank of the mode switch and one contact from the trip unit relay of each of four pressure transmitters monitoring reactor pressure are physically separated, and electrically isolated from the others to satisfy this requirement. The four bypass relays are independent of one another and physically separated and electrically isolated from one another.

Turbine Stop Valve and Control Valve Trip Bypass

This bypass function complies with the single failure criterion as follows:

Two pressure transmitters are mounted on each of two turbine first stage pressure taps as shown on Figure 7.2-13. Contacts from the associated trip unit relays are routed in conduit to the RPS cabinets in the control room. The logic configuration for the bypass is the standard one-out-of-two taken twice arrangement such that a single bypass channel is associated with a single trip channel for stop valve closure, and single trip channel for control valve fast closure.

Each pressure transmitter trip unit relay contact is connected to a single bypass channel output relay as shown on Figure 7.2-14, and the connection of the output relay contacts into the RPS trip logic is shown on Figure 7.2-15.

No single failure of this bypass circuitry will interfere with the normal protective action of the RPS trip channels.

The four bypass channels comply with the channel independence design requirement as follows:

One contact from each pressure transmitter trip unit relay is connected to one bypass relay in the RPS cabinets. The pressure transmitters and taps are physically separated, and their wiring is electrically isolated to provide channel independence. The four bypass relays are independent of one another, and are physically separated to meet this design requirement.

7.2.3.11 Instrumentation

Channels providing inputs to the RPS are not used for automatic control of process systems, thus the operations of protection and process systems are separated. The RPS instrumentation, shown on Figure 7.2-16, is discussed as follows:

Neutron Monitoring System instrumentation is described in Section 7.5. The relationship between Neutron Monitoring System channels, Neutron Monitoring System logics, and the RPS logics is clarified on Figure 7.2-17. The Neutron Monitoring System channels are considered part of the Neutron Monitoring System. The Neutron Monitoring System logics are considered part of the RPS. There are four Neutron Monitoring System logics associated with each trip system of the RPS as shown on Figure 7.2-18. Each RPS logic receives inputs from two Neutron Monitoring System logics. Each Neutron Monitoring System logic receives signals from one IRM channel and one APRM channel. The position of the mode switch determines which input signals will affect the output signal from the logic. The arrangement of Neutron Monitoring System logics is such that the failure of any one logic cannot prevent the initiation of a high neutron flux scram.

Nuclear system pressure is tapped from the reactor vessel at two separate locations. A pipe from each tap is routed outside the primary containment, and terminates in the Reactor Building. Two locally mounted, nonindicating pressure transmitters monitor the pressure in each pipe. Cables from these transmitters are routed to the Analog Trip Units in the Cable Spreading Room and then to the Control Room. The two pairs of transmitters are physically separated. Each transmitter provides a high pressure signal to one channel. The transmitters are arranged so that each pair provides an input to trip system A and trip system B, as shown on Figure 7.2-19. The physical separation, and the signal arrangement assure that no single physical event can prevent a scram due to nuclear system high pressure.

Reactor vessel low water level signals are initiated from differential pressure transmitters which sense the difference between the pressure due to a reference column of water, and the pressure due to the actual water level in the vessel. The transmitters are arranged in pairs in the same way as the nuclear system high pressure transmitters. See Figure 7.2-19. Two instrument pipelines attached to taps, one above and one 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 and inside the Reactor Building. They are physically separated from each other and tap off the reactor vessel at widely separated points. The RPS pressure sensors, as well as instruments for other systems sense pressure and level from these same pipes. The physical separation and signal arrangement assure that no single physical event can prevent a scram due to reactor vessel low water level.

Turbine stop valve closure inputs to the RPS are from valve steam position switches mounted on the four turbine stop valves. Each of the double pole, single throw switches is arranged to open before the valve is more than 10 percent closed, to provide the earliest positive indication of closure. Either of the two channels associated with one stop valve can signal valve closure, as shown on Figure 7.2-20. The logic is arranged so that closure of three or more valves initiates a scram.

Turbine control valve fast closure inputs to the RPS are from four pressure switches sensing discharge oil pressure from the acceleration relay. The acceleration relay is that part of the turbine control system used to effect fast closure of the turbine control valves. These pressure switches provide signals to both RPS trip systems, as shown on Figure 7.2-19. The logic is one-out-of-two taken twice. The switches are normally closed but open after the control valve starts to close.

There are eight main steam line isolation channels, two for each main steam line. Each channel senses isolation of the associated main steam line via a valve stem position switch on each isolation valve in the main steam line. The double pole, single throw switch on each main steam line isolation valve is arranged to open before the valve is more than 10 percent closed, to provide the earliest indication of isolation. The closure of either valve in a main steam line causes both channels associated with that steam line to signal isolation. The arrangement of main steam line isolation channels is shown on Figure 7.2-21. The main steam line isolation valve closure scram function is effective only under either of the following conditions:

a. Reactor mode switch in RUN

b. Reactor vessel pressure greater than 600 psig

The outputs from the channels are combined in RPS logic in such a way that the isolation of three or four main steam lines (closure of one valve in each main steam line) causes a scram. The logic arrangement is shown on Figure 7.2-21. Wiring of the isolation channels from any one main steam line is physically separated in the same way that wiring to a duplicate sensor on a common process tap is separated. The effects of the logic arrangement and separation provided for the main steam line isolation valve closure scram are as follows:

1. Closure of one valve for test purposes with one steam line already isolated without causing a scram due to valve closure

2. Automatic scram upon isolation of all steam lines

3. No single failure can prevent an automatic scram required for fuel protection due to main steam line isolation

Each SDIV (East and West) is provided with two level transmitters and three, RTD type, heat actuated level sensors. The Analog Trip System associated with the level transmitters is located in the cable spreading room of the reactor building. For SDIV-East, a contact associated with each analog transmitter trip unit inputs to RPS Trip Channels A1 and B1. Trip Channels A2 and B2 receive inputs from contacts associated with the RTD type sensors. For DIV-West, the reverse is true. The analog transmitter trip units input to Trip Channels A2 and B2, and the RTD's input to Trip Channels A1 and B1, as shown in Figure 7.2-19. The contacts are arranged in pairs so that no single event will prevent a reactor scram due to scram discharge volume high water level. The trip point for the RTD type of switch cannot be adjusted without physically cutting out the scram discharge instrument volume. However, the trip points associated with the analog trip units can be adjusted at the cable spreading room. A scram is initiated when sufficient capacity remains in the scram discharge volume to accommodate a scram. Both the amount of water discharged and the volume of air trapped above the free surface during a scram, were considered in selecting the trip setting.

Primary containment pressure is monitored by four no indicating pressure transmitters which are mounted on instrument racks outside the drywell in the Reactor Building. Cables are routed from the transmitters to analog trip units in the Cable Spreading Room. Each trip unit provides an input to one channel. See Figure 7.2-19. Pipes that terminate in the secondary containment (Reactor Building) connect the transmitters with the drywell interior. The transmitters and respective trip units are grouped in pairs, physically separated, and electrically connected to the RPS so that no single event will prevent a scram due to primary containment high pressure.

Post accident monitoring of the primary containment pressure is accomplished by four transmitters and two recorders which are redundant and powered from the plant vital instrumentation busses. Each pressure instrumentation loop consists of a high and a low range transmitter wired to a recorder. The two loops are maintained physically separated.

Four nuclear system pressure transmitters and respective trip units are provided to initiate the automatic bypass of the main steam line isolation trip. As noted in Section 7.2.3.10, the automatic bypass is only effective when the mode switch is not in the RUN position and the system pressure is less than 600 psig. The transmitters are mounted outside the drywell on instrument racks that are physically separated. These transmitters are the same transmitters that are used to initiate the nuclear system high pressure scram. The arrangement of the transmitters and trip units is such that no single failure can prevent a scram due to main steam line isolation valve closure or main condenser low vacuum.

Four turbine first stage pressure transmitters and trip units are provided to initiate the automatic bypass of the turbine control valve fast closure, and the turbine stop valve closure scrams when the first stage pressure is below some preset fraction of rated pressure. The transmitters and trip units are arranged so that no single failure can prevent a turbine stop valve closure scram or turbine control valve fast closure scram.

Channel and logic relays are fast response, high reliability relays. Power relays for interrupting the scram pilot valve solenoids are type CR105 magnetic contactors, made by the General Electric Company. All RPS relays are selected so that the continuous load will not exceed 50 percent of the continuous duty rating. Component electrical characteristics are selected so that the system response time, from the opening of a sensor contact up to and including the opening of the trip actuator contacts, is less than 50 milliseconds. The time requirements for control rod movement are discussed in Section 3.4, Reactivity Control Mechanical Design.

To gain access to those calibration and trip setting controls that are located outside the control room, a cover plate, access plug, or sealing device must be removed by operations personnel before any adjustment in trip settings can be effected.

7.2.3.12 Channel Test and Calibration

Scram Discharge Volume High Water Level Scram Trip

Four instrument standpipes are provided on each SDIV to allow individual channel test/calibration procedures during reactor power operation. After closing the upper and lower manual isolating valves of the standpipe in test, demineralized water is added to the standpipe through the appropriate test connection. (The upper test connection is used to flush the standpipe, the lower connection is used for filling during test/calibration procedures.) Verification of level setpoints and adjustments are made at the analog trip units located in the cable spreading room. A sight glass is provided on each SDIV to observe the water level during the test/calibration procedures and means are provided to drain the standpipe to the SDIV drain following test/calibration. Before proceeding to calibrate instruments in another standpipe, the manual isolating valves must be opened and the trip channel must be reset.

At plant shutdown, level switches may be calibrated by introducing a fixed volume of water into the discharge volume and observing that all level switches operate at their specified level settings.

Main Steam Line Isolation Valve and Turbine Stop Valve Closure Trips

During reactor shutdown, verification of the main steam line isolation valve and turbine stop valve limit switch set points at a valve position of 10 percent closure is possible by physical observation of the valve stem. The setpoint is mechanically locked in place.

During plant operation, the operator can confirm that the limit switches operate during valve movement, from the full open to full closed positions and vice versa, by observing the valve position indicator lights in the control room following an RPS trip. This will provide the operator with an indication that the limit switches operate between the limiting positions of the valve.

Turbine Control Valve Fast Closure Scram

In order to test the operation of the RPS interface the individual acceleration relay pressure switches are valved out of service when the plant is operating above the preset fraction of rated pressure (monitored by first stage pressure transmitters). As any one pressure switch is placed in the tripped condition, the control room operator will obtain an annunciation of the channel trip. The pressure switch setpoint may be verified by using a variable source of pressure.

Reactor Vessel Low Water Level Trip

During the calibration procedure, operation of the level trip unit relay contacts can be confirmed to operate at the proper setpoint. When the trip setpoint has been exceeded, the Control Room Operator will obtain an annunciation of the trip, in addition to local indication at the Analog Trip Cabinet.

Neutron Monitoring Scram Trip

The APRMs and IRMs are calibrated to reactor power by using the traversing incore probe (TIP) system to establish the relative local flux profile. LPRM gain settings are determined from these profiles once the total reactor heat balance has been determined.

The gain adjustment factors for the LPRMs are produced as a result of the process computer nuclear calculations involving the reactor heat balance for the TIP flux distributions. These adjustments, when incorporated into the LPRMs, permit the nuclear calculations to be completed for the next operating interval, and establish the APRM calibration and IRM calibration relative to reactor power.

Primary Containment and Reactor Vessel High Pressure Scram Trips

Under administrative control, testing of the pressure trip unit and its setpoint is performed using a test signal. When the trip setpoint has been exceeded, the control room operator will obtain an annunciation of the trip, in addition to local indication at the Analog Trip Cabinet.

Scram Discharge Volume High Water Level Trip Bypass

During plant operation in the startup and run modes, imposition of this bypass function is inhibited by the reactor system mode switch. Under these circumstances, operation of the bypass switch will not produce a bypass condition for any single trip channel. This fact can be determined from the control room annunciator, a visual inspection of the bypass relays, and from the process computer printout of any discharge volume high water level trip channel placed in a tripped condition prior to the bypass switch test.

In the startup and run modes of plant operation, the preceding procedures may be used to confirm that trip channels are not bypassed as a result of operation of the bypass switch. In the shutdown and refuel modes of plant operation, a similar procedure may be utilized to produce bypassing of all four trip channels. Due to the discrete ON-OFF nature of the bypass function, calibration is not meaningful.

Main Steam Line Isolation Valve Closure Trip Bypass

Since each pressure trip unit may be individually removed from service for test and calibration, it is possible during plant operation to confirm the setpoint value for the automatic portion of this bypass. The test procedure is similar to that stated in 7.2.3.12 under the heading Primary Containment and Reactor Vessel High Pressure Scram Trips. Full testing of the bypass circuit can only be accomplished when the mode switch is not in the RUN position. Since it can be confirmed that the bypass is not in effect when operating in the RUN mode, the tests are adequate to confirm proper bypass status during plant operation.