the
System 80+
standard plant

Design Control Document

Volume 16

Combustion Engineering, Inc.

ABB

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Introduction

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14.0 Initial Test Program

14.1 Specific Information to be Included in PSAR

This section is not applicable to the System 80+™ [†] Approved Design Material. See Section 14.2 for a description of the initial test program.

† System 80+ is a trademark of Combustion Engineering, Inc.

14.2 Specific Information to be Included in FSAR

14.2.1 Summary of Test Program and Objectives

14.2.1.1 Summary of the Startup Test Program

The Startup Test Program includes testing activities commencing with the completion of construction and installation and ending with the completion of the power ascension testing. This test program demonstrates that components and systems operate in accordance with design requirements and meet the requirements of 10 CFR 50, Appendix B, Criterion XI. The Startup Test Program results confirm that performance levels meet the operational safety requirements and verify the adequacy of component and system design and system operability over their operating ranges. It also aids in the establishment of baseline performance data and serves to verify that normal operating and emergency procedures accomplish their intended purposes. The Startup Test Program consists of Prerequisite Testing plus the following four phases:

- Phase I: Preoperational Testing
- Phase II: Fuel Loading and Post Core Hot Functional Testing
- Phase III: Initial Criticality and Low Power Physics Testing
- Phase IV: Power Ascension Testing

[[Specific Administrative Controls established for use during the Startup Program are addressed in the site-specific SAR.]][1]

14.2.1.1.1 Prerequisite Testing

Prerequisite Testing consists of tests and inspections required to assure construction is complete and that systems are ready for Phase I Testing.

Prerequisite testing verifies that construction activities associated with structures, components, and systems have been satisfactorily completed. Prerequisite testing consists of preliminary tests and inspections which include, but are not limited to, initial instrument calibration, flushing, cleaning, circuit integrity and separation checks, hydrostatic pressure tests, and functional tests of components. Delineation of specific prerequisite test requirements will be established in accordance with the site-specific administrative procedures.

14.2.1.1.2 Phase I - Preoperational Testing

Phase I - Preoperational Testing is performed to demonstrate that structures, systems, and components operate in accordance with design operating modes throughout the full design operating range. Where required, simulated signals or inputs are used to demonstrate the full range of the systems that are used during normal operation. Systems that are not used during normal plant operation, but must be in a state of readiness to perform safety functions, are checked under various modes and test conditions prior to fuel load.

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1 COL information item; see DCD Introduction Section 3.2.

Whenever practical, these tests are performed under the conditions expected when the systems would be required to function. When these conditions cannot be attained or appropriately simulated at the time of the test, the system is tested to the extent practical under the given conditions, with additional testing completed at a time when appropriate conditions can be attained.

Preoperational Testing ensures that systems and equipment perform in accordance with the Safety Analysis Report. Analysis of test results is made to verify that systems and components are performing satisfactorily, and if not, to provide a basis for recommended corrective action.

Upon completion of the specific preoperational testing, a series of integrated system tests, typically termed Pre-core Hot Functional Testing, are performed to verify proper systems operation prior to fuel Loading.

A listing of preoperational tests is provided in Table 14.2-1, and individual test descriptions are presented in Section 14.2.12.1. A listing of Pre-core Hot Functional tests is also provided in Table 14.2-1.

14.2.1.1.3 Phase II - Fuel Loading and Post-Core Hot Functional Testing

Initial fuel loading starts after completion of the Preoperational Testing. This phase of the initial test program provides a systematic process for safely accomplishing and verifying the initial fuel loadings. Fuel loading is discussed in more detail in Section 14.2.10.1.

The Post-core Hot Functional tests are performed following the completion of Initial Fuel Loading operations and prior to Initial Criticality. The objectives of these tests are to provide additional assurances that plant systems necessary for normal plant operation function as expected and to obtain performance data on core related systems and components. Normal plant operating procedures, in so far as practical, are used to bring the plant from COLD SHUTDOWN conditions through HOT SHUTDOWN to Hot Zero Power (HZP) conditions. Testing normally proceeds directly to Initial Criticality and the beginning of Low Power Physics Testing. A list of Post-core Hot Functional tests is provided in Table 14.2-2, and a description of each test is provided in Section 14.2.12.2.

14.2.1.1.4 Phase III - Initial Criticality and Low Power Physics Testing

The Initial Criticality phase of the startup test program assures that criticality is achieved in a safe and controlled manner. A description of the procedures followed during the approach to Initial Criticality is included in Section 14.2.10.2.

Following Initial Criticality, a series of Low Power Physics Tests is performed to verify selected core design parameters. These tests serve to substantiate the Safety Analysis and Technical Specifications. They also demonstrate that core characteristics are within expected limits and provide data for bench-marking the design methodology used for predicting core characteristics later in life. A list of the Low Power Physics Tests is provided in Table 14.2-3, and a description of each test is provided in Section 14.2.12.3.

14.2.1.1.5 Phase IV - Power Ascension Testing

A series of Power Ascension Tests is conducted to bring the reactor to full power. Testing is performed at plateaus of approximately 20, 50, 80, and 100% power and is intended to demonstrate that the facility operates in accordance with its design during steady state conditions and, to the extent practicable, during anticipated transients. A list of the Power Ascension Tests is provided in Table 14.2-4, and a description of each test is provided in Section 14.2.12.4.

14.2.2 Organization and Staffing

14.2.2.1 Management Organization

The site operator is responsible for appointing a senior level manager to a position of overall responsibility for defining the responsibilities, requirements, and interfaces necessary to safely and efficiently design, construct, start up, operate, maintain, and modify the nuclear power plant. This person is assisted in the performance of these duties by other senior level managers as determined by the site operator.

Responsibilities associated with startup test programs include the preparation of test procedures, performance of applicable initial tests, and the preparation of appropriate test related documentation. Test procedures are prepared by the cognizant Startup or Operations Departments (as applicable) with assistance from ABB C-E, the architect engineer, and other vendors, as required. These procedures are subject to review and comment by the appropriate project organizations.

The organizations assigned responsibility for conducting the tests are responsible for establishing specific requirements for scheduling and accomplishing testing, as well as for providing the necessary direction and coordination of groups having responsibility for specific activities in the startup test program.

The site operator is responsible for specifying a startup organization for conducting the four phased test programs for the plant and for the technical and functional aspects of the Startup program including the conduct of the Prerequisite and Phases I through IV programs. These include the following responsibilities:

- Approval of Startup Administrative Control Procedures.
- Review and recommend approval of requests for modifications or changes required during the test program.
- Approval of prerequisite and Phases I through IV test procedures.
- Maintain liaison with the project vendors through onsite representatives keeping them informed of status, problems, and support requirements.

[[The COL Applicant is responsible for developing the specific organization and staffing level appropriate for its facility.]][1]

The site operator's startup organization consists of System Engineers who have assigned responsibility for specific systems and Startup Engineers who have responsibility for testing evolutions and/or specific tests.

1 COL information item; see DCD Introduction Section 3.2.

14.2.2.2 Systems Engineer

- Assigned responsibility for a specific system or subsystem.
- Provide technical guidance and assistance in the preparation of test procedures.
- Determine the testing requirements, sequence, and test method on assigned systems. Recommend plant scheduling changes as necessary to support the testing effort.
- Review test procedures, test procedure modifications, and test data in accordance with the site-specific administrative procedures.
- Recommend changes in plant design and or/construction to facilitate testing, operation, and maintenance.
- Assist in the preparation of special reports concerning startup activities when required.
- Review system discrepancies and deficiencies and the status of their resolution and correction for assigned systems.

14.2.2.3 Startup Engineer

- Assures that assigned test procedures are written, reviewed, and approved in accordance with the site-specific administrative procedures.
- Assures all prerequisites for assigned tests are completed prior to the performance of the test.
- Conducts assigned tests using and ensuring compliance with approved test procedures.
- Keeps the Startup organization informed of the status of the preparation and performance of assigned tests.
- Suspends testing if the test cannot safely be conducted as written until the problem is resolved.
- Signs off individual steps in test procedures and ensures that required data are recorded.
- Assures that required startup materials, instruments, and consumables are available to support scheduled startup activities.
- Conducts pre-test and pre-shift startup briefings.
- Provides overall direction for all testing activities on each shift, as assigned.

The site-specific startup organization will be augmented by contractor and vendor support personnel, as necessary. These personnel may be integrated into the COL Applicant's startup organization and function in any position designated by the site operator.

14.2.2.4 Plant Designer

ABB-CE will provide onsite technical assistance during the installation, startup, testing, and initial operations of the plant. Through this effort, ABB-CE aids and assures itself that the plant is built, started, tested, and operated in conformance with design intent. ABB-CE onsite personnel provide technical assistance and act as technical liaison with the design headquarters to resolve problems. ABB-CE will provide a member of the Test Working Group and will review and comment on test procedures.

14.2.2.5 Architect Engineer (A/E)

The A/E will provide a representative to serve as a member of the Test Working Group and staff augmentation addressed in Section 14.2.2.3. If the A/E is the Constructor, the A/E will coordinate the construction schedules with Test Program requirements and provide manpower support as needed to meet the schedule, to correct deficiencies, or to make repairs.

14.2.2.6 Other Technical Specialties

In addition to the staff described in Section 14.2.2.3, the utility will augment the Startup Staff from other contractors and vendors as deemed necessary.

14.2.2.7 Test Working Group

The function of the Test Working Group (TWG) is to advise on the technical adequacy of the testing program. The TWG functions include coordinating organizational responsibility in areas of test procedure and test results reviews, evaluations, and approval recommendations. The TWG is headed by a chairman appointed by the applicant and consists of the following minimum membership:

- Startup Representative
- ABB-CE Project Representative
- Architect Engineer Project Representative
- Engineering Department Representative
- Operating Department Representative

The TWG members are chosen to provide expertise in specific phases of testing. As such, the composition of the TWG can be changed to obtain required expertise as the test program progresses.

14.2.2.8 Plant Review Board

The Plant Review Board provides high level review and approval of the test program. The membership of this group is specified by the applicant. This group reviews the results of startup tests performed in accordance with procedures requiring their review. Before fuel load, this group reviews and approves carryover of all prerequisite and Phase I tests to Phases II through IV. The justification for their deferral includes a proposed schedule for their performance.

14.2.2.9 Site Startup Organization

ABB-CE site startup test group will consist of the Site Manager and an appropriate staff of startup consultants. The startup group may be supplemented during the startup by others temporarily assigned to the site as needed.

ABB-CE vendor representatives provide technical advic1xand consultation on matters concerning design, operation, and testing. To achieve this objective, the startup site personnel will:

- Provide advice and consultation during the conduct of the entire test program.
- Provide assistance during the evaluation of test results.
- Resolve problems and inconsistencies utilizing internal engineering expertise and sub-vendor engineering personnel.
- Arrange for onsite representation as required.
- Provide a representative to the appropriate site administrative groups or committees which review and approve all test procedures and changes thereto.

14.2.2.10 A/E Site Startup Organization

The A/E project organization provides technical advice and consultation on matters relating to the design, construction, operation, and testing of systems and equipment.

Accordingly, the A/E project organization is responsible for the following:

- Providing a representative to the appropriate site administrative groups or committees which review and approve all test procedures and changes thereto.
- Reviewing test procedures.
- Evaluating test results.
- Coordinating resolution of problem areas by providing technical support and liaison with the Startup Organization and the A/E construction and design groups.
- Providing startup assistance as requested.

14.2.2.11 Qualifications

The recommendations of Regulatory Guide 1.58 will be followed to insure that the qualification requirements, indoctrination, and training of personnel who perform inspections, examinations, and testing are accomplished and maintained.

14.2.2.12 Utilization of the Plant Staff

The plant operating, maintenance, and engineering personnel are utilized to the extent practicable during the Startup Test Program. The plant staff operates permanently installed and powered equipment for

Phases I through IV and subsequent system tests. Service personnel such as instrument, chemistry, computer, radiation protection, and maintenance personnel are used extensively to perform tests and inspections applicable to their field of specialization.

14.2.3 Test Procedures

The site operator has the responsibility for assuring the preparation and designating the approval process for prerequisite and Phases I through IV test procedures. Detailed procedure guidelines and procedures provided by the appropriate design organization are utilized to develop various system test procedures. Thus, test procedures are based on requirements of system designers and applicable Regulatory Guides.

[[The COL Applicant is responsible for preparing the site-specific test procedures and/or guidelines that will be used for the conduct of the plant startup program.]][1] Submittal of these procedures and/or guidelines to the NRC Staff for review shall be conducted as described in Section 14.2.11. The COL Applicant will prepare a startup administrative manual. The COL Applicant will also provide preoperational and startup test summaries which contain testing objectives and acceptance criteria applicable for its scope of the plant design. The COL Applicant will develop a startup administrative manual and supporting documents that delineate plant operational conditions at which tests are to be conducted, testing methodologies to be utilized, specific data to be collected, and data reduction techniques. The startup administrative manual and supporting documents will be available for review during the COL application process. Testing performed at other than design operating conditions for systems will be reconciled either through the test acceptance criteria or post-test data analysis. The COL Applicant will provide this information in conjunction with the development of the startup manual.

14.2.3.1 Prerequisite Test Procedure Preparation

Test procedures will be prepared by the site operator using pertinent reference material provided by the appropriate design and/or vendor organizations.

Prerequisite test procedures contain (as a minimum) the following major topic areas:

- Purpose/Objective
- References
- Definitions and Abbreviations
- Precautions and Limitations
- Prerequisites (Initial Conditions)
- Instructions (Including Acceptance Criteria)
- Restoration

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1 COL information item; see DCD Introduction Section 3.2.

Prerequisite test procedures are reviewed as specified in administrative procedures. At the completion of these reviews, any required changes are incorporated into each test procedure by the originating organization.

14.2.3.2 Test Procedure Preparation

Detailed test procedures for Phases I through IV tests are prepared by the site operator. Each test procedure is prepared using pertinent reference material provided by the appropriate design and vendor organizations, the SAR, the Technical Specifications, and the applicable regulatory guides. A test procedure is prepared for each specific system test to be performed during the four phases of the test program. Each system test procedure contains (as a minimum) the following major topic areas:

- Test Objectives
- Acceptance Criteria
- References
- Prerequisites
- System Initial Conditions
- Environmental Conditions
- Special Precautions
- Detailed Procedure (Including Data Collection)
- Restoration
- Documentation of Test Results

Test procedures are reviewed as specified by the site-specific administrative control procedures. At the completion of these reviews, any required changes are incorporated into each test procedure by the originating organization.

14.2.3.3 Special Test Procedures

Special test procedures may become necessary during the Phases I through IV test program for investigative purposes. The preparation, review, and approval of these special procedures are governed by site-specific administrative control procedures. Special test procedures that deal with nuclear safety are processed under the same controls as normal startup test procedures.

14.2.4 Conduct of Test Program (Phases I Through IV)

[[The COL Applicant is responsible for planning and, subsequently, executing the plant startup program approved for the site-specific facility.]][1]

1 COL information item; see DCD Introduction Section 3.2.

When a Phases I through IV system test procedure has been released for performance, a Startup Engineer will be assigned responsibility for:

- Ensuring that prerequisites are satisfactorily met or allowable exceptions are noted in accordance with administrative procedures.

- Verifying that the testing is performed as required by the procedure.

The test is then performed by operating personnel or others in accordance with the approved test procedure.

The Operations Shift Supervisor is responsible for the safe operation of the plant during testing and may stop any system test in progress and place the plant in a safe condition.

Required data resulting from the test is compiled within the test procedure in specified data blanks, on specially prepared data sheets, or as otherwise specified by administrative control procedures. Personnel completing data forms or checklists will sign and date the forms. Upon test completion, the test data is compared with the test acceptance criteria, and any discrepancies noted are resolved in accordance with applicable administrative procedures.

Once a procedure has been approved, procedure changes will be made in accordance with the provisions of the administrative procedures.

ABB-CE will participate in the approval process of the test procedures and shall review any proposed changes to the approved procedures.

14.2.4.1 Sign-Off Provisions

Each approved test procedure shall contain sign-off provisions for prerequisites and for all procedural steps. The person responsible for the conduct of the test is responsible for signing and dating each data form in the spaces provided as the data is entered.

14.2.4.2 Maintenance/Modification Procedures

Work authorization documents, controlled in accordance with the site operator procedures, are used to initiate maintenance and implement modifications on systems that are jurisdictionally turned over from the construction organization. The work authorization document assigns an organization responsibility for the completion of the activity and specifies any retest requirements. Upon completion of the activity, a copy of the signed-off form is returned to the responsible testing organization to ensure retest requirements are met. Results of retests due to maintenance will be reviewed by the responsible Startup Engineer. Results of retests due to modifications will be reviewed and approved in the same manner as those from the original tests.

14.2.4.3 Test Performance

For Prerequisite and Phases I through IV testing, a Test Director will be designated. The official copy of the test procedure shall be available in the test area during the performance of a preoperational or startup test. The person conducting the test is charged with responsibility for performing the test in accordance with the approved test procedure. If, during the performance of the test, it is determined that the test cannot be conducted as written, it is the responsibility of the person conducting the test to resolve the problem in accordance with approved administrative control procedures.

14.2.5 Review, Evaluation, and Approval of Phases I Through IV Test Results

Individual test results will be reviewed and approved as provided in the site-specific administrative procedures. Completed procedures and test reports will be reviewed for acceptance. The specific acceptance criteria for determining the success or failure of the test will be included as part of the procedure and will be used during the review.

The responsible Startup Engineer will present the completed test procedure and test report with remarks and recommendations to the responsible reviewer. Following this review, the completed procedure and test report will be submitted to the Test Working Group or the Plant Review Board for final review, evaluation, and approval recommendation. If the as-built configuration of a system is not capable of demonstrating its ability to meet the acceptance criteria, an engineering evaluation will be performed.

Test results for each phase of the test program will be reviewed and verified as complete (as required) and satisfactory before testing in the next phase is started. Preoperational testing on a system will not normally be started until all applicable prerequisite tests have been completed, reviewed, and approved. Prior to initial fuel loading and the commencement of initial criticality, a comprehensive review of required completed preoperational procedures will be conducted by the Test Working Group. This review will provide assurance that required plant systems and structures will be capable of supporting the initial fuel loading and subsequent startup testing.

Phase I testing is planned to be completed prior to commencing initial fuel loading. If prerequisite or Phase I tests or portions of such tests cannot be completed prior to commencement of fuel loading, provisions for carryover testing will be planned and approved in accordance with the site-specific administrative procedures.

In the event carryover testing is required, the site operator will list each test and identify which portions of each test will be delayed until after fuel loading. Technical justification for delaying these portions will be documented together with a schedule (power level) for completing each carryover test. This will be approved by the plant review board as previously stated in Section 14.2.2.8. The documentation for carryover testing will be made available for NRC review and approval, as required, prior to commencing fuel loading.

The startup testing phases (Phases II, III, and IV) of the test program are subdivided into the following categories:

- Initial fuel load
- Post-core hot functional testing
- Initial criticality
- Low power physics testing
- Power ascension testing. It ends with the completion of testing at 100% power.

Each subdivision is a prerequisite which must be completed, reviewed, and approved before tests in the next category are started. Power ascension tests will be scheduled and conducted at pre-determined power levels.

The plateaus for the power ascension testing are indicated in Table 14.2-5. Results from each test conducted at a given plateau will be evaluated prior to proceeding to the next level. For those tests which result in a plant transient for which a realistic plant transient performance analysis has been performed, the test results will be compared to the results of the realistic transient analysis rather than the results of the transient analysis based on accident analysis assumptions.

Following completion of testing at 100% of rated power, final test results will be reviewed, evaluated, and approved.

14.2.6 Test Records

A single copy of each test procedure is designated as the official copy to be used for testing. [[The official copy and information specifically called for in the test procedure, such as completed data sheets, instrumentation calibration data and chart recordings, are retained for the life of the plant by the COL Applicant in accordance with Regulatory Guides for record retention.]][1]

14.2.7 Conformance of Test Programs with Regulatory Guides

The Startup Test Program is consistent with the recommendations of the following Regulatory Guides associated with startup (with exceptions as noted and revisions as specified in Section 1.8):

Regulatory Guides: 1.9, 1.18, 1.20, 1.30, 1.37, 1.41, 1.52, 1.68, 1.68.2, 1.68.3, 1.79, 1.95, 1.108, 1.116, 1.118, 1.139 and 1.140.

14.2.7.1 Regulatory Guide 1.68, Initial Test Programs for Water-Cooled Reactor Power Plants

The following exceptions and/or clarifications address only significant differences between the proposed test program and the applicable regulatory position. Minor terminology differences, testing not applicable to the plant design, and testing that is part of required surveillance tests will not be addressed. Reference is made to the applicable portion of Regulatory Guide 1.68.

14.2.7.1.1 Reference Appendix A, Section 1.h.(5)

Cold Water Interlocks are not applicable to the System 80+ design. This testing will not be performed as it is not applicable.

14.2.7.1.2 Reference Appendix A, Section 1.i.(21)

A containment penetration cooling system is not a design requirement for the System 80+. This testing will not be performed as it is not applicable.

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1 COL information item; see DCD Introduction Section 3.2.

14.2.7.1.3 Reference Appendix A, Section 1.k.(2)

[[Personnel monitors and radiation survey instruments are site-specific items to be addressed by the site operator. The site operator will define the appropriate testing to demonstrate proper operation of personnel monitors and radiation survey instruments.]][1]

14.2.7.1.4 Reference Appendix A, Section 1.n.(15)

A shield cooling system is not a design requirement for the System 80+. This testing will not be performed as it is not applicable.

14.2.7.1.5 Reference Appendix A, Section 2.b

This section suggests that rod drop times be measured for all control element assemblies (CEAs) at hot and cold full-flow and no-flow conditions.

The CEA drop-time testing is consistent with the recommendations of the regulatory guide; however, tests which do not provide meaningful data will be deleted. As outlined in Test Summary (Section 14.2.12.2.4), the CEA drop-time testing will consist of:

- One drop of each CEA at hot, full-flow conditions.
- Those CEAs falling outside the two-sigma limit for similar CEAs will be dropped three additional times.
- Hot no-flow scram insertion rod drops will not be performed. ABB-CE has demonstrated that rod drop times under full-flow conditions are more limiting than the drop times under conditions of no-flow.
- The CEA drop time test at low temperature plateau was eliminated since the hot, full-flow conditions are more bounding and since criticality is not allowed below 500°F except for a short period of time during low power physics testing (if required).
- Cold no-flow drops will not be performed as the Technical Specifications do not normally permit criticality under these conditions.

14.2.7.1.6 Reference Appendix A, Section 4.i

Demonstration of the operability of control rod withdrawal and insertion sequences and control rod inhibit or block functions is performed during pre-critical functional testing. The reactor power level range during which such features must be operable is performed using simulated signals, as required.

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1 COL information item; see DCD Introduction Section3.2.

14.2.7.1.7 Reference Appendix A, Section 5.a

Power reactivity coefficients will be measured at 20, 50, 80 and 100% power levels. Testing can be reduced to only the 50 and 100% power levels if measurements of temperature reactivity coefficients at essentially zero reactor power are within the acceptance criteria established for non-First-of-a-Kind plants.

14.2.7.1.8 Reference Appendix A, Section 5.i

Since the Plant Protection System (CPCs and CEACs) detects the CEA positions by means of two independent sets of reed switches and uses this information in determining margin to trip, it is not necessary to rely on in-core or ex-core nuclear instrumentation to detect control element misalignment/drop. Thus, this testing will not be performed.

14.2.7.1.9 Reference Appendix A, Section 5.k.k

This section requires that the dynamic response of the plant to the most severe reduction in feedwater temperature be demonstrated from 50 to 90% power. The reduction in feedwater temperature results in only minor changes to RCS temperatures and pressure and reactor power. In addition, the performance of this test will result in unnecessary thermal cycling of the steam generator economizer valves. The performance of load rejection test and turbine trip test from full power provides sufficient information to verify design adequacy. Thus, the plant response to reduction in feedwater temperatures will not be demonstrated.

14.2.7.1.10 Reference Appendix A, Section 5.m.m

This section requires that the dynamic response of the plant to automatic closure of all Main Steam Isolation Valves (MSIVs) be demonstrated from full power. Performance of this test could result in the opening of primary and secondary safety valves. Instead, the dynamic response of the plant can be obtained during the performance of the turbine trip test when the turbine stop valves are closed. The turbine trip test from full power will result in essentially similar dynamic plant response and should ensure that primary and secondary safety valves do not lift open during the performance of the test. For these reasons, the plant response to automatic closure of all MSIVs from full power will not be demonstrated.

14.2.7.1.11 Reference Appendix C, Section 3

This section requires that a neutron count rate of at least 1/2 count per second should be registered on the startup channels before the startup begins. The design criterion calls for a neutron count rate of 1/2 count per second with all CEAs fully withdrawn and a multiplication of 0.98. Therefore, prior to the initiation of the initial approach to criticality, the startup channels may see significantly less than 1/2 count per second; but prior to exceeding a multiplication of 0.98, the desired neutron count rate of 1/2 count per second will have been achieved.

14.2.7.1.12 Reference Appendix C, Section 4

The standard test plateau power levels of 20, 50, 80, and 100 percent are used instead of the recommended power levels of 25, 50, 75, and 100 percent.

14.2.7.1.13 Reference C, Regulatory Position 4

This section requires inclusion of acceptance criteria which accounts for uncertainties, etc. Test summaries 14.2.12.2.1, "Post-Core Hot Functional Test Controlling Document" and 14.2.12.1.48, "Pre-Core Hot Functional Test Controlling Document" are essential to the demonstration of conformance with requirements for structure, components, and features important to safety.

14.2.7.2 Regulatory Guide 1.68.2, Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water Cooled Nuclear Power Plants

Shutdown outside the control room will be demonstrated to Hot Standby condition. Plant cooldown to entry into Shutdown Cooling conditions will be demonstrated during Hot Functional testing.

14.2.7.3 Regulatory Guide 1.68.3, Preoperational Testings of Instrument and Control Air Systems

Position C.9 requires that testing demonstrate that the plant equipment designated by design to be supplied by the Instrument Air System is not degraded when supplied by the Station Air System which may have less restrictive air quality requirements. The System 80+ Instrument Air System has no interconnection to any other compressed Air System, and, therefore, ingress of less quality air is not possible. Consequently, Position C.9 does not apply.

14.2.7.4 Regulatory Guide 1.79, Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors

The intent of Section C.1.c(2), Isolation Valve Test, is satisfied by opening the valves under maximum differential pressure (RCS at ambient pressure) using normal electrical power only. Conditions at the valve motor are independent of the power source for this test. The breaker response and the response of the valves to the "confirmatory open" signal is verified during the Integrated Safety Injection Actuation System Test.

14.2.7.5 Security System Test

[[The COL Applicant will develop the detailed description of test and acceptance criteria for the Security System.]][1]

14.2.8 Utilization of Reactor Operating and Testing Experience in Development of Initial Test Program

ABB-CE maintains an ongoing effort which continually provides feedback to its startup organization during the development of, and throughout, the Initial Test Program. This information reflects both ABB-CE operating and test experience and industry wide experience concerning Pressurized Water Reactors.

Unit Operations reviews reactor operating and testing experiences at other facilities similar in design and capacity to the unit starting up.

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1 COL information item; see DCD Introduction Section 3.2.

This review is accomplished by circulating Licensee Event Reports (LERs) or summaries of LERs and NRC I&E Bulletins, circulars, and Information Notices to Startup and Operation personnel so that pertinent information can be utilized in the startup program.

14.2.9 Trial Use of Plant Operating and Emergency Procedures

[[The COL Applicant developed schedule for the development of the plant operating and emergency procedures should allow sufficient time for trial use of these procedures during the Initial Test Program.]][1]

14.2.10 Initial Fuel Loading and Initial Criticality

14.2.10.1 Initial Fuel Loading

[[Overall direction, coordination, and control of the initial fuel loading evolution is the responsibility of the site operator.]][1] ABB-CE will provide technical assistance during the initial fuel loading evolution.

The fuel loading evolution will be controlled by use of approved plant procedures which will be used to establish plant conditions, control access, establish security, control maintenance activities, and provide instructions pertaining to the use of fuel handling equipment. The overall process of initial fuel loading will be directed from the main control room. The evolution itself will be supervised by a licensed Senior Reactor Operator.

In the unlikely event that mechanical damage to a fuel assembly is sustained during fuel loading operations, an alternate core loading scheme, whose characteristics closely approximate those of the initially prescribed core configuration, will be determined and approved prior to implementation.

The fuel assemblies will be installed in the reactor vessel in water containing dissolved boric acid in a quantity calculated to maintain a core effective multiplication constant at less than, or equal to, the Technical Specification value. It is not anticipated that the refueling cavity will be completely filled. However, the water level in the reactor vessel will be maintained above the installed fuel assemblies at all times.

The Shutdown Cooling System will be in service to provide coolant circulation to ensure adequate mixing and a means of controlling water temperature. The IRWST will be in service and will contain borated water at a volume and concentration conforming to the Technical Specifications. Applicable administrative controls will be used to prevent unauthorized alteration of system lineups or change to the boron concentration in the Reactor Coolant System.

Minimum instrumentation for fuel loading will consist of two temporary source range channels installed in the reactor vessel or one temporary channel and one permanently installed ex-core nuclear channel in the event that one of the temporary channels becomes inoperative. Both temporary and permanent channels will be response checked with a neutron source. The temporary channels will display neutron count rate on a count rate meter installed in the containment and will be monitored by personnel conducting the fuel loading operation. The permanent channel will display neutron count rate on a meter and strip chart recorder located in the main control room and will be monitored by licensed operators. In addition, at least one temporary channel and one permanent channel will be equipped with

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1 COL information item; see DCD Introduction Section 3.2.

audible rate indicators in two locations, temporary in the containment and permanent, or temporary, in the main control room.

Continuous area radiation monitoring will be provided during fuel handling and fuel loading operations. Permanently installed radiation monitors display radiation levels in the main control room and will be monitored by licensed operators.

Fuel assemblies, together with inserted components, will be placed in the reactor vessel, one at a time, according to a previously established and approved sequence which was developed to provide reliable core monitoring with minimum possibility of core mechanical damage. The initial fuel loading procedure will include detailed instructions which will prescribe successive movements of each fuel assembly from its initial position in the storage racks to is final position in the core. The procedures will establish a system and a requirement for verification of each fuel assembly movement prior to proceeding with the next assembly. Multiple checks will be made for fuel assembly and inserted component serial numbers to guard against possible inadvertent exchanges or substitutions.

At least two fuel assemblies containing neutron sources will be placed into the core at appropriate specified points in the initial fuel loading procedure to ensure a neutron population large enough for adequate monitoring of the core. As each fuel assembly is loaded, at least two separate inverse count rate plots will be maintained to ensure that the extrapolated inverse count rate ratio behaves as would be expected. In addition, nuclear instrumentation will be monitored to ensure that the "just loaded" fuel assembly does not excessively increase the count rate. The results of each loading step will be reviewed and evaluated before the next prescribed step is started.

14.2.10.1.1 Safe Loading Criteria

Criteria for the safe loading of fuel require that loading operations stop immediately if:

- The neutron count rate from either temporary nuclear channel unexpectedly doubles during any single loading step, excluding anticipated change due to detector and/or source movement or spatial effects (i.e.,. fuel assembly coupling source with a detector), or

- The neutron count rate on any individual nuclear channel increased by a factor of five during any single loading step, excluding anticipated changes due to detector and/or source movement or spatial effects (i.e, fuel assembly coupling source with a detector).

A fuel assembly shall not be ungrappled from the refueling machine until stable count rates have been obtained. In the event that an unexplained increase in count rate is observed on any nuclear channel, the last fuel assembly loaded shall be withdrawn. The procedure and loading operation will be reviewed and evaluated before proceeding to ensure the safe loading of fuel.

14.2.10.1.2 Fuel Loading Procedure

An approved detailed test procedure will be followed during the initial fuel loading to ensure that the evolution will be completed in a safe and controlled manner. This procedure will specify applicable precautions and limitations, prerequisites, initial conditions, and the necessary procedural steps.

14.2.10.2 Initial Criticality

Overall direction, coordination, and control of the initial criticality evolution will be the responsibility of the site operator. It is, however, intended that qualified plant personnel will execute the procedure. ABB-CE will provide technical assistance during the initial criticality evolution.

A predicted boron concentration for criticality will be determined for the precritical CEA configuration specified in the procedure. This configuration will require all CEA groups to be fully withdrawn with the exception of the last regulating group, which will remain far enough into the core to provide effective control when criticality is achieved. This position will be specified in the procedure. The Reactor Coolant System (RCS) boron concentration will then be reduced to achieve criticality, at which time the regulating group will be used to control the chain reaction.

Core response during CEA group withdrawal and RCS boric acid concentration reduction will be monitored in the main control room by observing the change in neutron count rate as indicated by the permanent wide-range nuclear instrumentation.

Neutron count rate will be plotted as a function of CEA group position and RCS boron concentration during the approach to criticality. Primary safety reliance is based on inverse count rate ratio monitoring as an indication of the nearness and rate of approach to criticality during CEA group withdrawal and during the dilution of the reactor coolant boric acid concentration. The approach to criticality will be controlled and specific holding points will be specified in the procedure. The results of the inverse count rate monitoring and the indications on installed instrumentation will be reviewed and evaluated before proceeding to the next prescribed hold point.

14.2.10.2.1 Safe Criticality Criteria

Criteria for ensuring a safe and controlled approach to criticality require:

- That high flux trip setpoints be reduced to a value consistent with the Technical Specification limits.
- That a sustained startup rate of one decade per minute not be exceeded.
- That CEA withdrawal or boron dilution be suspended if unexplainable changes in neutron count rates are observed.
- That CEA withdrawal or boron dilution be suspended if the extrapolated inverse count rate ratio predicts criticality outside the tolerance specified in the procedure.
- That the Technical Specifications are met.
- That criticality be anticipated at any time positive reactivity is added by CEA withdrawal or boron dilution.
- That a minimum of one decade of overlap be observed between the startup and log safety channels of the ex-core nuclear instruments.

14.2.11 Test Program Schedule

[[The schedule for plant startup is developed by the COL Applicant to allow sufficient time to systematically perform the required testing in each phase. No specific time periods for each phase are required.]][1]

The scheduling of individual tests or test sequences is made to ensure that systems and components that are required to prevent or mitigate the consequences of postulated accidents are tested prior to fuel loading. Tests that require a substantial core power level for proper performance are performed at the lowest power level commensurate with obtaining acceptable test data.

Phase I test procedures are scheduled to be approved and available for review by the NRC inspectors at least 60 days prior to their scheduled performance date. Phases II through Phase IV Startup Test Program administrative control procedures, the majority of the individual test procedures, and the following milestone controlling procedures: Fuel Loading, Post-core HFT, Initial Criticality, Low Power Physics Test and Power Ascension, are scheduled to be approved and available for review at least 60 days prior to fuel load. The remaining individual test procedures will be scheduled for approval and available for review by the NRC inspectors at least 60 days prior to their intended performance date.

14.2.11.1 Testing Sequence

[[The site operator shall specify the testing sequence to ensure that the plant's safety is not compromised during the test program.]][1] The test sequence should ensure that the conduct of a specific test does not place the plant in a condition for which untested systems would be relied on for safety.

14.2.12 Individual Test Descriptions

14.2.12.1 Preoperational Tests

Note: Refer to Table 14.2-7 for additional details on the major support systems that are recommended to be available for the preoperational tests.

Note: The individual preoperational tests identified in this section contain general system testing requirements. Specific safety system pump and valve testing is discussed in Section 3.9.6.

14.2.12.1.1 Reactor Coolant Pump Motor Initial Operation

1.0 OBJECTIVE

1.1 To verify the proper operation of each Reactor Coolant Pump motor.

1.2 To collect base data for each RCP motor.

2.0 PREREQUISITES

2.1 RCP motor instrumentation has been calibrated.

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1 COL information item; see DCD Introduction Section 3.2.

2.2 Each RCP motor and its respective pump are uncoupled.

2.3 Support systems required for operation of each RCP motor are operational.

3.0 TEST METHOD

3.1 Start Component Cooling Water (CCW) flow to the RCP motor and observe indicating lights and alarms.

3.2 Using a torque wrench and phase rotation meter, rotate RCP motor and verify proper wiring of motor leads and torque required to rotate the motor.

3.3 Jog RCP motor and verify proper rotation.

3.4 Start RCP motor and verify proper operation. Record motor operating data.

3.5 Determine oil level setpoints of oil reservoirs by draining oil from motor reservoirs and subsequently refilling.

3.6 Simulate oil lift pumps and CCW system starting interlocks preventing RCP motor operation and observe effects.

4.0 DATA REQUIRED

4.1 Motor operating data.

4.2 Torque needed to rotate the RCP motors.

4.3 Setpoints at which indications, alarms, and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The RCP motors, support systems, alarms, indications, and interlocks perform as described in Section 5.4.1.

14.2.12.1.2 Reactor Coolant System Test

1.0 OBJECTIVE

1.1 To perform the initial venting of the RCPs and the Reactor Coolant System (RCS).

1.2 To perform the initial operation of the RCPs.

1.3 To verify RCP performance.

1.4 To verify alarm setpoints.

1.5 To verify the operation of the RCS sample isolation valves.

2.0 PREREQUISITES

2.1 Construction activities on the RCS, RCPs, and RCS sample isolation system have been completed.

2.2 RCP and RCS instrumentation has been calibrated.

2.3 Component cooling water is available.

2.4 RCP motor initial operation preoperational test has been completed.

2.5 Support systems required for operation of the RCPs and RCS sample isolation valves are operational.

3.0 TEST METHOD

3.1 Simulate temperature, pressure, and flow signals from each RCP and verify alarm setpoints.

3.2 Simulate temperature signals from each RCS RTD that has an alarm function and verify alarm setpoints.

3.3 Perform initial venting of RCPs, pressurizer, and reactor vessel.

3.4 Perform initial run of RCPs. Vent the RCS after each run is complete.

3.5 Verify power-operated valves fail to the position specified in Section 5.1 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms occur.

4.2 RCP performance data.

4.3 Position response of valves to loss of motive power.

5.0 ACCEPTANCE CRITERIA

5.1 RCS and RCP performance and alarms are as described in Sections 5.4.1 and 5.4.3.

14.2.12.1.3 Pressurizer Safety Valve Test

1.0 OBJECTIVE

To verify the popping pressure of the pressurizer safety valves.

2.0 PREREQUISITES

2.1 Construction activities on the pressurizer have been completed and all associated instrumentation has been checked and calibrated.

2.2 Reactor coolant system is at hot, zero power temperature and pressure.

2.3 Lifting device with associated support equipment and calibration data is available.

3.0 TEST METHOD

3.1 Using the lifting device, increase the lifting force on the safety valve until the safety valve starts to simmer.

3.2 Determine popping pressure from the lifting device correlation data.

3.3 Adjust valve popping set pressure if necessary and retest.

4.0 DATA REQUIRED

4.1 Pressurizer pressure and temperature.

4.2 Pressure applied to the lifting device to lift the safety valve off its seat.

5.0 ACCEPTANCE CRITERIA

5.1 Safety valves perform as described in Section 5.4.13.

14.2.12.1.4 Pressurizer Pressure and Level Control Systems Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Pressurizer Pressure Control System (PPCS) and Pressurizer Level Control System (PLCS).

2.0 PREREQUISITES

2.1 Construction activities on the PPCS and PLCS have been completed.

2.2 PPCS and PLCS software is installed and instrumentation has been calibrated.

2.3 Support systems required for operation of components in the PPCS and PLCS are operational.

3.0 TEST METHOD

3.1 Close and open backup heater breakers from the main control room. Observe breaker operation and indicating light response.

3.2 Simulate a decreasing pressurizer pressure and verify proper outputs to the heater control circuits. Verify alarm setpoints.

3.3 Simulate an increasing pressurizer pressure and verify proper outputs to the heater and spray valves control valve circuits. Verify alarm setpoints.

3.4 Simulate a low level error in the pressurizer and verify proper outputs to the charging pump control valve circuit. Verify alarm setpoints.

3.5 Simulate a high level error in the pressurizer and verify proper outputs to the pressurizer backup heater and the letdown valve control circuits. Verify alarm setpoints.

3.6 Simulate signals to pressurizer pressure and level controllers and verify proper outputs.

3.7 Simulate a low-low pressurizer level and verify proper system outputs.

3.8 Simulate a low pressurizer level and verify proper output signals to the letdown valve control circuits.

4.0 DATA REQUIRED

4.1 Simulated pressurizer level, pressure signals, and outputs to pressurizer heaters control circuits.

4.2 Simulated pressurizer pressure signals and outputs to spray valve control circuits.

4.3 Simulated pressurizer level signals and outputs to charging pump control valve circuits.

4.4 Simulated pressurizer level to letdown valve control circuits.

4.5 Setpoints at which alarm, indications, and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 Pressurizer Pressure and Level Control Systems perform as described in Section 7.7.1.

14.2.12.1.5 Chemical and Volume Control System Letdown Subsystem Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Chemical and Volume Control System (CVCS) Letdown Subsystem during normal and emergency operation.

2.0 PREREQUISITES

2.1 Construction activities on the CVCS Letdown Subsystem have been completed.

2.2 Letdown subsystem instrumentation has been calibrated.

2.3 Support systems required for the operation of the CVCS Letdown Subsystem control valves are operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions, observe valve operation and position indications and, where required, measure opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Simulate Safety Injection Actuation/Containment Isolation Actuation Signals (SIAS/CIAS) and observe isolation valve response.

3.4 Simulate letdown temperature and observe the response of control valves. Observe alarm and interlock operation.

3.5 Measure Delta P across letdown flow orifice and verify design flow rates.

4.0 DATA REQUIRED

4.1 Valve opening and closing time where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 Response of isolation valves to SIAS/CIAS.

4.5 Response of control valves to simulated letdown temperature.

4.6 Delta P across letdown flow orifice.

4.7 Setpoints at which alarms, indications, and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The CVCS Letdown Subsystem performs as described in Section 9.3.4.

14.2.12.1.6 CVCS Purification Subsystem Test

1.0 OBJECTIVE

1.1 To verify flow paths between the Reactor Makeup Water System, the purification and deborating ion exchangers and the Solid Waste Management System.

1.2 To verify flow paths between the purification and deborating ion exchanger and Gaseous Waste Management System.

2.0 PREREQUISITES

2.1 Construction activities on the CVCS Purification Subsystem have been completed.

2.2 CVCS Purification Subsystem instrumentation has been calibrated.

2.3 Test instrumentation has been calibrated.

2.4 Support systems required for operation of the CVCS purification subsystem are complete and operational.

3.0 TEST METHOD

3.1 Lineup the purification system ion exchangers to complete a flow path from the Reactor Makeup Water (RMW) System through each CVCS Purification Subsystem ion exchanger to the Solid Waste Management system. Start an RMW pump and valve in each ion exchanger sequentially, so that only one ion exchanger is in use at a time. Verify flow by observing RMW flow indicators and changes in RMW and spent resin tank levels. Select all possible flow paths to the Solid Waste Management System.

3.2 Individually connect each purification ion exchanger and the deborating ion exchanger to the plant air system and connect a pressure gage to the ion exchanger vent. Adjust the plant air supply to 15-20 psig. Start air flow to the ion exchangers and individually open each ion exchanger vent valve and valve the ion exchanger to the gaseous waste management system. Observe the ion exchanger vent pressure, air supply pressure, and flow rate.

4.0 DATA REQUIRED

4.1 RMW flow rate

4.2 RMW and Spent Resin Tank levels

4.3 Air supply pressure and flow rate

4.4 Ion exchanger test pressure

5.0 ACCEPTANCE CRITERIA

5.1 Verification of flow paths between the RMW system, the purification and deborating ion exchangers, and the Solid Waste Management System will have been demonstrated upon successful completion of Test Method 3.1.

5.2 Verification of flow paths between the purification and deborating ion exchangers and the Gaseous Waste Management system will have been demonstrated upon successful completion of Test Method 3.2.

5.3 The CVCS Purification Subsystem performs as described in Section 9.3.4.

14.2.12.1.7 Volume Control Tank Subsystem Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Volume Control Tank (VCT) Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the Volume Control Tank Subsystem have been completed.

2.2 Volume Control Tank Subsystem instrumentation has been calibrated.

2.3 Reactor Makeup Water (RMW) is available to the VCT.

2.4 Support systems required for operation of the Volume Control Tank are complete and operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions. Observe valve operation and position indication and, where required, measure opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Partially fill the VCT with RMW and pressurize the VCT using the nitrogen pressurization system. Observe alarm operation.

3.4 Vent the VCT and repressurize using the hydrogen pressurization system. (The hydrogen system will be temporarily connected to a nitrogen supply.)

3.5 Drain and refill the VCT with RMW. Observe level alarms and interlocks.

3.6 Simulate VCT temperature limits and observe alarms.

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 VCT pressurization data.

4.5 VCT level program data.

4.6 Values of parameters at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Volume Control Tank Subsystem performs as described in Section 9.3.4.

14.2.12.1.8 CVCS Charging Subsystem Test

1.0 OBJECTIVE

1.1 To verify the proper performance of the Chemical and Volume Control System (CVCS) Charging Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the reactor coolant charging subsystem have been completed.

2.2 CVCS Charging Subsystem is operational to supply charging pump suction.

2.3 The Volume Control Tank Subsystem is operational to supply charging pump suction.

2.4 The Reactor Vessel is ready to receive water from the charging headers.

2.5 The Pressurizer is ready to receive water from the auxiliary spray line.

2.6 Reactor Coolant Pumps (RCP) are operational.

2.7 Support systems required for operation of the reactor coolant charging subsystem are operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions. Observe valve operation and position indication and, where required, measure opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Manually start each charging pump lube oil pump and observe the operation of the lube oil system.

3.4 Manually start each charging pump. Observe charging pump operation including charging pump alarms and interlocks.

3.5 Simulate pressurizer level error signals and observe charging pump control valve response.

3.6 With a charging pump running, open the seal injection lines, and observe flow.

3.7 With a charging pump running, open the auxiliary spray valve, and observe flow.

3.8 Verify the operation of the RCP Seal Injection Flow Control Valves.

3.9 Verify the operation of RCP Seal Injection Heater.

3.10 Verify performance, including head and flow characteristics, of the charging pumps.

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 Charging pump and oil lubrication system performance.

4.5 Charging pump running data.

4.6 Response of charging pumps to simulated pressurizer level error signals.

4.7 Setpoints at which alarms and interlocks occur.

4.8 Seal injection flow rates.

4.9 Auxiliary spray flow rates.

4.10 Pump head vs. flow.

5.0 ACCEPTANCE CRITERIA

5.1 The Chemical and Volume Control System Charging Subsystem performs as described in Section 9.3.4.

14.2.12.1.9 Chemical Addition Subsystem Test

1.0 OBJECTIVE

1.1 To demonstrate that the Chemical Addition Subsystem can inject water into the charging pump discharge line down stream of the Seal Injection take off connection.

1.2 To verify a flow path from the Chemical Addition Tank to the Miscellaneous Liquid Waste Management System.

2.0 PREREQUISITES

2.1 Support systems required for operation of the Chemical Addition Subsystem are complete and operational.

2.2 The Chemical Addition Tank has been filled from the makeup system with a pre-determined amount of RMW.

2.3 Charging Subsystem is in operation.

2.4 Associated instrumentation has been calibrated.

3.0 TEST METHOD

3.1 With a charging pump in operation, start the Chemical Addition Metering Pump and observe the chemical addition tank level.

3.2 Drain the Chemical Addition Tank to the Miscellaneous Liquid Waste Management System and observe the Chemical Addition Tank level.

4.0 DATA REQUIRED

4.1 Chemical Addition Tank levels.

5.0 ACCEPTANCE CRITERIA

5.1 Chemical addition to charging line down stream of the seal injection take off connection is demonstrated when Test Method 3.1 is completed with a decreasing chemical addition tank level.

5.2 A flow path to the Miscellaneous Liquid Waste Management System is demonstrated when Test Method 3.2 is completed with a decreasing Chemical Addition Tank level.

5.3 The Chemical Addition Subsystem performs as described in Section 9.3.4.

14.2.12.1.10 Reactor Drain Tank Subsystem Test

1.0 OBJECTIVE

1.1 To verify the proper performance of the Reactor Drain Tank (RDT) Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the Reactor Drain Tank Subsystem have been completed.

2.2 Reactor Drain Tank Subsystem instrumentation has been calibrated.

2.3 Equipment Drain Tank Subsystem is ready to accept water from the Reactor Drain Tank.

2.4 Plant nitrogen system is operational.

2.5 Support systems required for operation of the Reactor Drain Tank Subsystem are operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions, observe valve operation and position indication and, where required, measure opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Simulate a Containment Isolation Actuation Signal (CIAS) and observe isolation valve response.

3.4 Fill the Reactor Drain Tank from any convenient source and observe level and pressure indications and alarms.

3.5 Using the N2 system, pressurize the RDT and observe indications and alarms.

3.6 Line up the Reactor Drain Tank to the equipment drain tank and drain the RDT using each RDT pump. Observe level and pressure indicators, alarms, and interlocks.

3.7 Simulate RDT temperature and observe indicators and alarms.

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indications.

4.3 Response of valves to simulated failed conditions.

4.4 Position response of valves to loss of motive power.

4.5 RDT level, pressure, and temperature.

4.6 Setpoints of alarms and interlocks.

5.0 ACCEPTANCE CRITERIA

5.1 The Reactor Drain Tank Subsystem performs as described in Section 9.3.4.

14.2.12.1.11 Equipment Drain Tank Subsystem Test

1.0 OBJECTIVE

1.1 To verify the proper performance of the Equipment Drain Tank (EDT) Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the Equipment Drain Tank Subsystem have been completed.

2.2 Equipment Drain Tank Subsystem instrumentation has been calibrated.

2.3 Holdup Tank Subsystem is operational.

2.4 Reactor Drain Tank Subsystem is operational.

2.5 Reactor Makeup Subsystem is operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions and observe valve operation and position indication.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Fill the EDT from the Reactor Makeup Water Subsystem and observe indications, alarms, and interlocks.

3.4 Drain the EDT using a Reactor Drain tank pump and observe indications, alarms, and interlocks.

3.5 Simulate high EDT temperature and observe indications and alarms.

3.6 Simulate high EDT pressure and observe indications and alarms.

4.0 DATA REQUIRED

4.1 Valve position indications.

4.2 Position response of valves to loss of motive power.

4.3 Equipment Drain Tank level, pressure, and temperature.

4.4 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Equipment Drain Tank Subsystem performs as described in Section 9.3.4.

14.2.12.1.12 Boric Acid Batching Tank Subsystem Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Boric Acid Batching Tank Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the Boric Acid Batching Tank Subsystem have been completed.

2.2 The In-containment Refueling Water Storage Tank (IRWST) Subsystem is operational.

2.3 Support systems required for operation of the Boric Acid Batching Tank are complete and operational.

2.4 The Boric Acid Storage Tank Subsystem is operational.

3.0 TEST METHOD

3.1 Fill the boric acid batching tank with water from the RMW system. Energize heaters and measure the length of time required to heat the tank. Observe heater control setpoints.

3.2 Line up the boric acid batching tank to the Boric Acid Storage Tank. Start a boric acid makeup pump and observe the batching tank level.

3.3 Refill the Boric Acid Batching Tank, dissolve boric acid crystals, and start the batch tank mixer. Take samples as the tank is drained to the equipment drain tank and determine the boric acid concentration.

4.0 DATA REQUIRED

4.1 Batching Tank Heater performance data.

4.2 Heatup rate.

4.3 Boric acid concentration.

5.0 ACCEPTANCE CRITERIA

5.1 The Boric Acid Batching Tank Subsystem performs as described in Section 9.3.4.

14.2.12.1.13 Concentrated Boric Acid Subsystem Test

1.0 OBJECTIVE

1.1 To verify the proper performance of the Concentrated Boric Acid Subsystem.

2.0 PREREQUISITES

2.1 Construction activities of the Concentrated Boric Acid and Boric Acid Storage Tank (BAST) Subsystems have been completed.

2.2 Concentrated Boric Acid Subsystem instrumentation has been calibrated.

2.3 The Reactor Coolant Charging Subsystem is complete and operational.

2.4 The Volume Control Tank (VCT) Subsystem is complete and operational.

2.5 The Boric Acid Batching Tank Subsystem is complete and operational.

2.6 Support systems required for operation of the Concentrated Boric Acid and BAST systems are complete and operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions, observe valve operation and position indication and, when required, measure opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Fill the BAST with RMW from the boric acid batching tank subsystem and observe level alarm setpoints.

3.4 Operate each Boric Acid Makeup (BAMU) pump and observe pump performance.

3.5 Operate BAMU pumps utilizing all interconnections between BAMU pumps and BAST.

3.6 Line up the BAMU to charging pump suction and verify ability of the BAMU pumps to supply adequate flow to the charging pumps.

3.7 Line up the BAST to charging pump suction and verify that adequate flow is delivered to the charging pumps.

3.8 Simulate high and low BAST levels and observe indications, alarms, and controls.

3.9 Simulate high and low BAST temperature and observe indications, alarms, and controls.

3.10 Line up the BAMU pumps to the VCT and verify that the makeup system is capable of supplying BAMU to the VCT and charging pump suction at the selected rates and quantities in all modes of operation. Observe alarms and interlocks.

3.11 Verify performance, including head and flow characteristics, for the BAMU pumps.

4.0 DATA REQUIRED

4.1 Valve opening and closing times where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 BAMU pump performance data.

4.5 Makeup system performance data.

4.6 Setpoints at which alarms, automatic actuations, and interlocks occur.

4.7 Pump head vs. flow.

5.0 ACCEPTANCE CRITERIA

5.1 The Concentrated Boric Acid Subsystem performs as described in Section 9.3.4.

14.2.12.1.14 Reactor Makeup Subsystem Test

1.0 OBJECTIVE

1.1 To verify the performance of the Reactor Makeup Water (RMW) Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the Reactor Makeup Subsystem have been completed.

2.2 Reactor Makeup Subsystem instrumentation has been calibrated.

2.3 Plant makeup system is operational.

2.4 Support systems required for the operation of the Reactor Makeup Subsystem are complete and operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions and observe valve operation and position indication.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Fill the Reactor Makeup Water Tank (RMWT) and observe level indications and alarms.

3.4 Simulate Reactor Makeup Water Tank temperature and observe indications and alarms.

3.5 Drain the Reactor Makeup Water Tank using each RMW pump. Observe tank level and pump discharge pressure, indications, alarms, and controls.

3.6 Simulate RMW filter differential pressure and observe indications and alarms.

3.7 Verify performance, including head and flow characteristics, for the RMW pump.

3.8 Verify makeup to Volume Control Tank and Boric Acid Storage Tank through the RMW pumps.

4.0 DATA REQUIRED

4.1 Valve position indication.

4.2 Position response of valves to loss of motive power.

4.3 RMWT level, pressure, and temperature.

4.4 RMW pump discharge pressure.

4.5 RMWT filter differential pressure.

4.6 Setpoints of alarms and interlocks.

4.7 Pump head vs. flow.

4.8 Volume Control Tank and Boric Acid Storage Tank levels.

5.0 ACCEPTANCE CRITERIA

5.1 The Reactor Makeup Water Subsystem performs as described in Section 9.3.4.

14.2.12.1.15 Holdup Subsystem Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Holdup Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the Holdup Subsystem have been completed.

2.2 Holdup Subsystem instrumentation has been calibrated.

2.3 Boric Acid Concentrator is ready to receive water from the Holdup Tank.

2.4 Support systems required for operation of the Holdup Subsystem are complete and operational.

3.0 TEST METHOD

3.1 Fill the Holdup Tank and observe level indications and alarms.

3.2 Simulate Holdup Tank temperature and observe indications and alarms.

3.3 Using each Holdup Pump, drain the Holdup Tank to the Boric Acid Concentrator. Observe Holdup Tank level indications, alarms, interlocks, and Holdup Pump discharge pressure.

3.4 Refill and isolate the Holdup Tank. Open the Holdup Tank recirculation valves and start each Holdup Pump. Observe tank level. Line up the holdup pumps to the Reactor drain tank filter and observe Holdup Tank level.

3.5 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.6 Verify performance, including head and flow characteristics, for the holdup pumps.

4.0 DATA REQUIRED

4.1 Holdup Tank level and temperature.

4.2 Holdup Pump pressure.

4.3 Setpoints of alarms and interlocks.

4.4 Position response of valves to loss of motive power.

4.5 Pump head vs. flow.

5.0 ACCEPTANCE CRITERIA

5.1 The Holdup Subsystem performs as described in Section 9.3.4.

14.2.12.1.16 Boric Acid Concentrator Subsystem Test

1.0 OBJECTIVE

1.1 To verify the performance of the Boric Acid Concentrator Subsystem.

2.0 PREREQUISITES

2.1 Construction activities have been completed on the Boric Acid Concentrator subsystem.

2.2 Support systems required for operation of the Boric Acid Concentrator are complete and operational.

2.3 Boric Acid Concentrator Subsystem instrumentation has been calibrated.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions and observe valve operation and position indication.

3.2 Simulate interlock signals from interfacing equipment and observe Boric Acid Concentrator Subsystem response observe alarms.

3.3 Line up the Boric Acid Concentrator Subsystem to interfacing systems and, using appropriate operating modes and indications, establish flow paths to these systems.

4.0 DATA REQUIRED

4.1 Valve position indication.

4.2 Boric Acid Condensate Subsystem response to simulated interlocks.

4.3 Setpoints at which alarms interlock and automatic actuations occur.

4.4 Flow indications.

5.0 ACCEPTANCE CRITERIA

5.1 The Boric Acid Concentrator Subsystem performs as described in Section 9.3.4.

14.2.12.1.17 Gas Stripper Subsystem Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Gas Stripper Subsystem.

2.0 PREREQUISITES

2.1 Construction activities have been completed on the Gas Stripper Subsystem.

2.2 Gas Stripper Subsystem instrumentation has been calibrated.

2.3 Support systems required for operation of the Gas Stripper Subsystem are operational.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions and observe valve operation and position indications.

3.2 Verify power-operated valves fail to the position specified in Section 9.3.4 upon loss of motive power.

3.3 Simulate interlock signals from interfacing equipment and observe Gas Stripper Subsystem response.

3.4 Line up the Gas Stripper Subsystem to interfacing systems and, using appropriate operating modes and indications, establish flow paths to these systems.

3.5 Observe alarms.

4.0 DATA REQUIRED

4.1 Valve position indication.

4.2 Position response of valves to loss of motive power.

4.3 Setpoints at which alarms, automatic actuations, and interlocks occur.

4.4 Flow indications.

5.0 ACCEPTANCE CRITERIA

5.1 The Gas Stripper Subsystem performs as described in Section 9.3.4.

14.2.12.1.18 Boronometer Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the Boronometer.

2.0 PREREQUISITES

2.1 The Boronometer has been calibrated and is operational.

2.2 Support systems required for Boronometer Subsystem operation are complete and operational.

3.0 TEST METHOD

3.1 Utilizing the built-in test features observe boronometer indications, outputs to interface equipment, and alarm operation.

4.0 DATA REQUIRED

4.1 Pulse rates and Boronometer output.

4.2 Alarm setpoints and actuation levels.

5.0 ACCEPTANCE CRITERIA

5.1 The Boronometer Subsystem performs as described in Section 9.3.2 and 9.3.4.

14.2.12.1.19 Process Radiation Monitor Subsystem Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the Process Radiation Monitor of the Process Sampling System.

2.0 PREREQUISITES

2.1 The Process Radiation Monitor has been installed, all interconnections have been completed, and the sample chamber has been filled with reactor makeup water.

2.2 The Process Radiation Monitor has been calibrated.

2.3 A check source is available.

2.4 Support systems required for operation of the Process Radiation Monitor are complete and operational.

3.0 TEST METHOD

3.1 Utilizing the built-in test features, observe process monitor indications, outputs to interface equipment, and alarm operation.

3.2 Utilizing the check source, verify calibration of the process monitor.

4.0 DATA REQUIRED

4.1 Check source data.

4.2 Process monitor operating data.

4.3 Process monitor response to the check source.

4.4 Value of parameters required to actuate alarms.

5.0 ACCEPTANCE CRITERIA

5.1 The Process Radiation Monitor of the Process Sampling System performs as described in Section 9.3.2.

14.2.12.1.20 Gas Stripper Effluent Radiation Monitor Subsystem Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the Gas Stripper Effluent Radiation Monitor Subsystem.

2.0 PREREQUISITES

2.1 The Gas Stripper Effluent Radiation Monitor has been installed, all interconnections have been completed, and the sample chamber has been filled with reactor makeup water.

2.2 The Gas Stripper Radiation Monitor has been calibrated.

2.3 Support systems required for operation of the Gas Stripper Effluent Radiation Monitor Subsystem are complete and operational.

2.4 A check source is available.

3.0 TEST METHOD

3.1 Utilizing the built-in test features, observe process radiation monitor indications, outputs to interface equipment, and alarm operation.

3.2 Utilizing a check source, verify calibration of the process monitor.

4.0 DATA REQUIRED

4.1 Process monitor operating data.

4.2 Process monitor response to the check source.

4.3 Value of parameters required to actuate alarms.

5.0 ACCEPTANCE CRITERIA

5.1 The Gas Stripper Effluent Radiation Monitor Subsystem performs as described in Section 9.3.4.

14.2.12.1.21 Shutdown Cooling System Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of Shutdown Cooling System and the Shutdown Cooling Pumps.

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Plant systems required to support testing are operable and temporary systems are installed and operable.

2.3 Permanently installed instrumentation is operable and calibrated.

2.4 Test instrumentation is available and calibrated.

2.5 All lines in the Shutdown Cooling System have been filled and vented.

2.6 The LTOP valve relief capacity has been verified by bench testing.

3.0 TEST METHOD

3.1 Verify proper operation of each shutdown cooling pump with minimum flow established.

3.2 Verify pump performance including head and flow characteristics for all design flow paths which include the normal decay heat removal flow path and

1. Shutdown cooling system flow to the chemical and volume control system for purification.

2. Shutdown cooling system transfer of refueling water to the IRWST.

3. Shutdown cooling system to cool the IRWST.

3.3 Perform a full flow test of the shutdown cooling system.

3.4 Verify proper operation, stroking speed, position indication and response to interlock of control and isolation valves.

3.5 Verify the proper operation of the protective devices, controls, interlocks, indications, and alarms using actual or simulated signals.

3.6 Verify isolation valves can be opened against design differential pressure.

3.7 Verify setpoint of the Low Temperature Overpressure Protection (LTOP) relief valves.

3.8 Verify the interchangeability of the Containment Spray Pumps with the SCS pumps.

3.9 Verify adequate net positive suction head is available to the pumps.

3.10 Verify adequate heat removal capability by the SCS heat exchangers.

3.11 Verify proper operation of flow limiting device in the SCS lines to limit runout flow.

3.12 Verify that each SCS train is capable of being powered by the electrically independent and redundant emergency power supplies.

3.13 Verify power-operated valves fail to the position specified in Section 5.4.7 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Valve position indications.

4.2 Pump head versus flow.

4.3 Valve opening and closing times, where required.

4.4 Setpoints of alarms and interlocks.

4.5 Setpoints of the LTOP relief valves.

4.6 Position response of valves to loss of motive power.

5.0 ACCEPTANCE CRITERIA

5.1 The Shutdown Cooling System performs as described in Section 5.4.7.

14.2.12.1.22 Safety Injection System Test

1.0 OBJECTIVE

1.1 To functionally test the operation and performance of the components within the Safety Injection (SI) System including valve and pump performances.

1.2 To verify proper SI response to a Safety Injection Actuation Signal (SIAS) using normal, alternate, and emergency power sources.

1.3 To verify the flow paths through the Direct Vessel Injection (DVI) Nozzles and the Hot Leg Residual Heat Removal piping.

1.4 To demonstrate the capability to perform full flow test of the Safety Injection System.

1.5 To verify the SI sampling system functions as designed.
1.6 To verify the elevation of SIS containment isolation valves relative to the IRWST water level.

2.0 PREREQUISITES

2.1 Construction activities have been completed on the Safety Injection System.

2.2 Support systems and instrumentation required for operation of the SI subsystem are essentially complete and operational.

2.3 The In-containment Refueling Water Storage Tank (IRWST) is filled with sufficient primary makeup water to conduct testing on the SI subsystem.

2.4 The reactor vessel head and internals have been removed.

2.5 Test instrumentation to be used for pump performance has been installed and calibrated.

2.6 SI System instrumentation has been checked and calibrated.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control locations and observe valve operation and position indication. Where required, measure opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 6.3.2 upon loss of motive power.

3.3 Operate SI from alternate electrical power sources and determine pump and valve responses including response times, when required.

3.4 Start each SI pump using a SIAS signal and collect initial pump operating data. For this portion of the test, the SI pumps will be aligned to discharge to the depressurized RCS with appropriate discharge valves throttled and calibrated instrumentation installed to compare SI pump flow and discharge pressure to the pump manufacturer's head-flow curve. In addition, the throttle capability of the discharge valve will be verified over its full operating position. This test shall be performed using normal, alternate, and emergency power. Suction will be taken from the IRWST under maximum flow conditions in the combined suction header. Measured suction head is compared to the manufacturer's NPSH requirements when corrected for IRWST minimum level attainable during a SIAS and maximum IRWST fluid temperature. Operate each SI pump available for hot leg injection (HLI) through the HLI line and collect pump operating data.

3.5 Run each SI pump to demonstrate the ability to perform full flow test capability.

3.6 Collect fluid samples from each of the system sampling points.

3.7 Run each SI pump at minimum flow recirculation to the IRWST and determine flow rate. Measured flow rate is compared to the required minimum flow rate.

3.8 Open valves in the SI lines between the IRWST and RCS and observe static head of water in pump discharge lines relative to IRWST level.

4.0 DATA REQUIRED

4.1 Valve position indication.

4.2 Valve opening and closing times, where required.

4.3 Position response of valves to loss of motive power.

4.4 SI pump initial operational data including pump head versus flow, pump suction pressure and pumped fluid temperature, chemistry, and debris content.

4.5 Response of SI System to SIAS when powered by normally alternate and emergency power sources.

4.6 SI flow rates.

4.7 Selected water levels.

5.0 ACCEPTANCE CRITERIA

5.1 The SI System performs as described in Section 6.3 to provide adequate flow (manufacturer's curves) under minimum actual suction head to maintain RCS inventory and/or cool the core for the RCS breaks and transients in the scope of the Safety Analysis (Chapters 6 and 15).

5.2 SI System response times are less than those specified in Section 6.3.

5.3 Water samples from the SI System can be obtained.

5.4 Full flow testing of the SI System can be performed.

5.5 Static head of water in pump discharge lines maintains a fluid seal on motor operated containment isolation valves, with the IRWST water level at its calculated minimum post-accident level, as described in Section 6.2.4.2.

14.2.12.1.23 Safety Injection Tank Subsystem Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Safety Injection Tank Subsystem.

2.0 PREREQUISITES

2.1 Construction activities on the Safety Injection Tank Subsystem have been completed.

2.2 Support systems required for the operation of the Safety Injection Tank Subsystem are complete and operational.

2.3 Adequate supply of makeup water from the IRWST is available.

2.4 The reactor vessel head and internals have been removed.

2.5 The reactor vessel is filled above the RV injection nozzles.

2.6 Safety Injection Tank Subsystem instrumentation has been checked and calibrated.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control locations and observe valve operation and position indication. Where required, measure valve opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 6.3.2 upon loss of motive power.

3.3 Simulate a SIAS signal and observe valve interlock and alarm operation.

3.4 Fill the Safety Injection Tanks from the IRWST and observe level indication and alarm operation.

3.5 Pressurize the Safety Injection Tanks and observe pressure indication, control, and alarm operation.

3.6 Simulate a SIAS to each Safety Injection Tank and measure the time required for the Safety Injection Tanks to discharge their contents to the RCS.

3.7 Pressurize each Safety Injection Tank to its maximum operating pressure and verify each SIT discharge valve will open.

4.0 DATA REQUIRED

4.1 Valve position indications.

4.2 Valve opening and closing times, where required.

4.3 Position response of valves to loss of motive power.

4.4 System response to SIAS.

4.5 Setpoints at which alarms and interlocks occur.

4.6 Times required for Safety Injection Tanks to discharge their contents to the RCS.

4.7 Safety Injection Tank pressure when stroking valves.

5.0 ACCEPTANCE CRITERIA

5.1 The Safety Injection Tank Subsystem performs as described in Section 6.3.2.

14.2.12.1.24 Megawatt Demand Setter System Test

1.0 OBJECTIVE

1.1 To verify the proper installation and operation of the Megawatt Demand Setter (MDS) Subsystem.

2.0 PREREQUISITES

2.1 Construction activities are essentially complete and the applicable systems and components are ready for testing.

2.2 Applicable operating manuals are available.

2.3 MDS software is installed and instrumentation has been calibrated.

2.4 Test equipment and instrumentation is available and calibrated.

2.5 Plant systems required to support testing are operable to the extent necessary to perform the testing or suitable simulations are used.

3.0 TEST METHOD

3.1 Verify input data and control paths from systems associated with the MDS.

3.2 Simulate inputs and verify system responses and demand settings.

3.3 Verify the proper functioning of the four operational modes of the MDS; out mode, ready mode, operator set mode, and ADS mode.

4.0 DATA REQUIRED

4.1 Input signals from associated systems.

4.2 MDS demand outputs in response to inputs.

5.0 ACCEPTANCE CRITERIA

5.1 The MDS functionally operates as described in Section 7.7.1.1.3.

14.2.12.1.25 Engineered Safety Features - Component Control System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Engineered Safety Features - Component Control System (ESF-CCS).

2.0 PREREQUISITES

2.1 Construction activities on the Engineered Safety Feature Actuation System (ESFAS) have been completed.

2.2 ESFAS instrumentation has been calibrated.

2.3 External test instrumentation is available and calibrated.

2.4 Support systems required for operation of the ESFAS are operational.

3.0 TEST METHOD

3.1 Energize power supplies and observe output voltages.

3.2 Simulate ground faults and observe operation of the ground fault detectors.

3.3 Individually deenergize each group relay and monitor contact operation.

3.4 Test manual trips and monitor relay operation.

3.5 Deenergize all combinations of the two-out-of-four trip logic for each of the actuation systems (SIAS, CIAS, CSAS, CCAS, MSIS, EFAS) and observe actuation of the appropriate trip circuit and associated alarms.

3.6 Simulate inputs to the appropriate circuits and observe trip initiations.

3.7 Exercise the manual control functions to the Safety Depressurization and Shutdown Cooling System to verify proper operations.

3.8 Exercise automatic and manual test functions to verify control functions of ESF-CCS.

4.0 DATA REQUIRED

4.1 Power supply voltages.

4.2 Resistance for ground fault detector operation.

4.3 Response to manual trips.

4.4 Response to two-out-of-four logic trips.

4.5 Trip setpoints.

4.6 Automatic and manual test function outputs and displays.

5.0 ACCEPTANCE CRITERIA

5.1 The Engineered Safety Feature - Component Control System performs as described in Section 7.3.1.

14.2.12.1.26 Plant Protection System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Plant Protection System (PPS).

1.2 To determine the Reactor Protection System (RPS) and the Engineering Safety Features Actuation System Response Times.

2.0 PREREQUISITES

2.1 Construction activities on the trip circuit breaker and plant protection system and ESF-CCS have been completed.

2.2 PPS system instrumentation has been calibrated.

2.3 External test instrumentation is available and calibrated.

2.4 Support systems required for operation of the trip circuit breakers, ESF-CCS and plant protection system are operational.

3.0 TEST METHOD

3.1 Energize power supplies and verify output voltage.

3.2 Simulate ground faults and observe operation of the ground fault detectors.

3.3 Using simulated reactor trip signals, trip each reactor trip circuit breaker with the breaker in the test position. Observe circuit breaker operation.

3.4 Repeat Step 3.3 with the reactor trip circuit breakers in the operate position.

3.5 Exercise the bistable comparators using internal and external test circuitry and observe the setpoints and operation of the appropriate ESFAS logic.

3.6 Check the operation of trip channel bypass features including, where applicable, observation of the setpoints at which the trip bypasses are cancelled automatically.

3.7 Test manual trips and observe relay operation.

3.8 Check that Low Pressurizer Pressure and Low Steam Generator Pressure trip setpoints track the process variable at the prescribed rate and can be manually reset to the proper margin below the process variable.

3.9 Utilizing the installed testing devices, observe test functions and verify proper Local Coincidence Logic (LCL) operation.

3.10 Using manually initiated semi-automatic test functions to trip the reactor trip circuit breakers and ESF-CCS interfaces, observe interlock, alarm, and interface operation.

3.11 Verify proper operation of the Core Protection Calculator System by input/output and internal function tests.

3.12 Inject signals into appropriate sensors or sensor terminals and measure the elapsed time to achieve tripping of the Reactor Trip circuit breakers or actuation of the ESFAS actuation relays. Trip or Actuation paths may be tested in several segments.

4.0 DATA REQUIRED

4.1 Power supply voltages.

4.2 Resistance for ground fault detector operation.

4.3 Circuit breaker and indicator operation.

4.4 Point of actuation of bistable comparators.

4.5 Reset margin and rate of setpoint change of variable setpoints.

4.6 Maximum and minimum values of variable setpoints.

4.7 RPS and ESF trip and actuation path response times.

4.8 Local Coincidence Logic operation.

5.0 ACCEPTANCE CRITERIA

5.1 The Plant Protection System performs as described in Sections 7.2 and 7.3.

5.2 The total response time of each RPS and EFAS trip or Actuation path is verified to be conservative with respect to the times used in the safety analysis.

14.2.12.1.27 Ex-core Nuclear Instrumentation System Test

1.0 OBJECTIVE

1.1 To verify the proper functional performance of the Ex-core Nuclear Instrumentation System.

1.2 To verify the proper performance of audio and visual indicators.

2.0 PREREQUISITES

2.1 Construction activities on the Ex-core Nuclear Instrumentation System have been completed.

2.2 Ex-core Nuclear Instrumentation System instrumentation has been calibrated.

2.3 External test equipment has been calibrated and is operational.

2.4 Support systems required for operation of the Ex-core Nuclear Instrumentation System are operational.

3.0 TEST METHOD

3.1 Utilizing appropriate test instrumentation, simulate and vary input signals to the startup, safety and control channels of the Ex-core Nuclear Instrumentation System.

3.2 Monitor and record all output signals as a function of variable inputs provided by test instrumentation.

3.3 Record the performance of audio and visual indicators in response to changing input signals.

4.0 DATA REQUIRED

4.1 Values of input and output signals for correlation purposes, as required.

4.2 Values of all output signals triggering audio and visual alarms.

5.0 ACCEPTANCE CRITERIA

5.1 The Ex-core Nuclear Instrumentation System performs as described in Sections 7.2.1 and 7.7.1.

14.2.12.1.28 Fixed In-core Nuclear Signal Channel Test

1.0 OBJECTIVE

1.1 To measure cable insulation resistance.

1.2 To verify proper amplifier operation.

2.0 PREREQUISITES

2.1 Construction activities on the In-core Nuclear Instrumentation System are complete (Detectors do not need to be installed).

2.2 Fixed in-core nuclear signal channel instrumentation has been calibrated.

2.3 External test equipment has been checked and calibrated.

2.4 Support systems required for operation of the In-core Nuclear Instrumentation System are operational.

3.0 TEST METHOD

3.1 Measure and record cabling insulation resistance.

3.2 Using external test instrumentation, simulate in-core detector signals into the signal conditioning circuits.

3.3 Using internal test circuits, test each amplifier for proper operation in accordance with manufacturer's instruction manual.

3.4 Vary the simulated inputs to the amplifier and record its values displayed by the Data Processing System.

4.0 DATA REQUIRED

4.1 Cabling insulation resistance readings.

4.2 Status and performance of the internal test circuits.

4.3 Values of simulated input and derived output signals for correlation purposes.

5.0 ACCEPTANCE CRITERIA

5.1 The fixed in-core nuclear signal channel cables and instrumentation perform as described in Section 7.7.1.

14.2.12.1.29 Control Element Drive Mechanism Control System Test

1.0 OBJECTIVE

1.1 To demonstrate proper input signals and proper sequencing of input signals to Control Element Drive Mechanism (CEDM) coils.

1.2 To demonstrate proper operation of the Control Element Drive Mechanism Control System (CEDMCS) in all modes.

1.3 To verify proper operation of the CEDMCS interlocks and alarms.

2.0 PREREQUISITES

2.1 Construction activities on the CEDMCS have been completed and system software is installed.

2.2 Cable continuity tests have been completed.

2.3 Special test instrumentation has been calibrated and is operational.

2.4 Special test equipment is operational.

2.5 Support systems required for operation of the CEDMCS are operational.

3.0 TEST METHOD

3.1 Using special test instrumentation, observe the sequence in which withdraw and insert signals are passed to the appropriate CEDM coil. Observe operation of the digital CEA position indicators.

3.2 Operate the CEDMCS in all modes. Simulate input signals and observe operation of interlocks and alarms.

4.0 DATA REQUIRED

4.1 CEDM coil current traces.

4.2 CEDMCS totalizer indications.

4.3 CEDMCS operating data.

4.4 Interlock and alarm actuation points.

5.0 ACCEPTANCE CRITERIA

5.1 The Control Element Drive Mechanism Control System performs as described in Section 7.7.1.

14.2.12.1.30 Reactor Regulating System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Reactor Regulating System (RRS).

2.0 PREREQUISITES

2.1 Construction activities on the RRS have been completed.

2.2 RRS software is installed and instrumentation has been calibrated.

2.3 External test equipment has been calibrated and is operational.

2.4 Support systems required for operation of the RRS are operational.

2.5 Cabling has been completed between the RRS and interface equipment.

3.0 TEST METHOD

3.1 Utilizing actual or simulated interface inputs to the RRS, observe receipt of these signals at the RRS.

3.2 Utilizing installed and external test instrumentation, vary all input signals to the system and observe output responses at the RRS and at interfacing equipment.

4.0 DATA REQUIRED

4.1 Input signal values.

4.2 Status of interfacing control board equipment.

4.3 RRS output response.

4.4 Status of outputs received at interfacing equipment.

5.0 ACCEPTANCE CRITERIA

5.1 The Reactor Regulating System performs as described in Section 7.7.1.

14.2.12.1.31 Steam Bypass Control System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Steam Bypass Control System (SBCS).

2.0 PREREQUISITES

2.1 Construction activities on the Steam Bypass Control System (SBCS) and interfacing equipment have been completed.

2.2 Steam Bypass Control System software is installed and instrumentation has been calibrated.

2.3 External test equipment has been calibrated and is operational.

2.4 Support systems required for operation of the Steam Bypass Control System are operational.

3.0 TEST METHOD

3.1 Utilizing actual or simulated interface inputs to the SBCS, observe receipt of these signals at the SBCS.

3.2 Utilizing installed and external test equipment, vary system inputs and observe output responses at the SBCS and at interfacing equipment.

3.3 Verify proper response of the turbine bypass valves and position indicators.

Notes:
1. Dynamic operation of the turbine bypass valves will be demonstrated during hot functional testing.
2. Capacity testing of the turbine bypass valves will be demonstrated during power ascension testing.

4.0 DATA REQUIRED

4.1 Input signal values.

4.2 Status of interfacing control board equipment.

4.3 SBCS output response.

4.4 Status of outputs received at interfacing equipment.

5.0 ACCEPTANCE CRITERIA

5.1 The Steam Bypass Control System performs as described in Sections 7.7.1 and 10.4.4.

14.2.12.1.32 Feedwater Control System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Feedwater Control System (FWCS).

2.0 PREREQUISITES

2.1 Construction activities on the FWCS and interfacing equipment have been completed.

2.2 FWCS software is installed and instrumentation has been calibrated.

2.3 External test equipment has been calibrated and is operational.

2.4 Support systems required for the operation of the FWCS are operational.

2.5 Cabling has been completed between the FWCS and interfacing equipment.

3.0 TEST METHOD

3.1 Utilizing actual or simulated interface inputs to the FWCS, observe receipt of these signals at the FWCS.

3.2 Utilizing installed and external test instrumentation, vary all input signals to the system and observe output responses at the FWCS and at interfacing equipment.

3.3 Monitor the system during initial operation and verify proper operation.

4.0 DATA REQUIRED

4.1 Input signal values.

4.2 Status of interfacing control board equipment.

4.3 FWCS output response.

4.4 Status of output received at interfacing equipment.

5.0 ACCEPTANCE CRITERIA

5.1 The Feedwater Control System performs as described in Sections 7.7.1 and 10.4.7.

14.2.12.1.33 Core Operating Limit Supervisory System Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Core Operating Limit Supervisory System (COLSS) application program contained in the Data Processing System (DPS).

2.0 PREREQUISITES

2.1 The DPS is functioning to support this testing.

2.2 COLSS application program has been implemented into the DPS.

2.3 Test cases have been generated in an off-line computer and adapted to interface with the DPS COLSS test program.

2.4 Results of the test case runs performed on the COLSS FORTRAN code are available.

3.0 TEST METHOD

3.1 Using the COLSS test program contained in the DPS; simulate the COLSS inputs for each test case.

4.0 DATA REQUIRED

4.1 Record values of all simulated inputs, appropriate intermediate values and outputs. The on-line test program automatically performs this task.

5.0 ACCEPTANCE CRITERIA

5.1 The Core Operating Limit Supervisory System performs as described in Section 7.7.1.

14.2.12.1.34 Reactor Power Cutback System Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the Reactor Power Cutback System (RPCS).

2.0 PREREQUISITES

2.1 Construction activities on the RPCS have been completed.

2.2 RPCS instrumentation has been calibrated.

2.3 External test equipment has been checked and calibrated.

2.4 Support systems required for the operation of the RPCS are operational.

3.0 TEST METHOD

3.1 Utilizing actual or simulated interface inputs to the RPCS, observe receipt of these signals at the RPCS.

3.2 Utilizing installed and external instrumentation, vary all input signals to the system and observe output responses at the RPCS and at interfacing equipment.

4.0 DATA REQUIRED

4.1 Input signal values.

4.2 Status of interfacing control board equipment.

4.3 RPCS output response.

4.4 Status of outputs received at interfacing equipment.

5.0 ACCEPTANCE CRITERIA

5.1 The Reactor Power Cutback System performs as described in Section 7.7.1.

14.2.12.1.35 Fuel Handling and Storage System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Fuel Handling Equipment.

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Permanently installed instrumentation is operable and calibrated.

2.3 Plant systems required to support testing are operable or temporary systems are installed and operable.

2.4 Test instrumentation is available and calibrated.

2.5 The reactor vessel head and upper guide structure are removed.

2.6 The core support barrel is installed and aligned.

2.7 Dummy fuel assemblies, dummy CEAs, and test weights are available.

3.0 TEST METHOD

3.1 Verify the proper operation of the new fuel elevator and the associated interlocks.

3.2 Verify the proper operation of the spent fuel handling bridge, checking bridge, trolley, hoist speeds, load limits, interlocks, and limit switches.

3.3 Using the X-Y coordinates and the spent fuel handling machine, trial fit each of the usable spent fuel storage rack positions using the dummy fuel assembly.

3.4 Verify the transfer system using both consoles and upenders to prove proper operation.

3.5 Verify the proper operation of the refueling machine, checking bridge, trolley, hoist speeds, limit switches, interlocks, and load limits.

3.6 Index and record the reactor core positions using the refueling machine.

3.7 Using a dummy fuel assembly, trial fit the core locations and record coordinates.

3.8 Verify the proper operation of the CEA Change Platform and Elevator, including operating speeds, interlocks, load limits, and limit switches.

3.9 Verify the following:

3.9.1 Using the full sequence of focusing, camera tilt and camera rotation, verify the proper operation of the underwater TV camera system.

3.9.2 Utilizing the complete Fuel Handling equipment, transfer a dummy fuel assembly from the new fuel elevator through a total fuel loading cycle in the reactor core and a total spent fuel cycle from the core to the spent fuel storage area both in automatic and manual modes of operation.

3.9.3 Demonstrate the capabilities of the special fuel handling tools through proper operation with dummy fuel assembly and dummy control element assembly.

4.0 DATA REQUIRED

4.1 Applicable indexing coordinates.

4.2 Monitoring instrumentation responses.

5.0 ACCEPTANCE CRITERIA

5.1 The Fuel Handling and Storage System performs as described in Section 9.1.

14.2.12.1.36 Emergency Feedwater System Test

1.0 OBJECTIVE

1.1 To demonstrate the ability of the Emergency Feedwater System (EFW) to supply feedwater to the steam generators for design emergency conditions.

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Permanently installed instrumentation is operable and calibrated.

2.3 Test instrumentation is available and calibrated.

2.4 Plant systems required to support testing are operable, or temporary systems are installed and operable.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify head and flow characteristics of motor driven emergency feedwater pumps.

3.3 Verify the starting time and head and flow characteristics of the steam-driven emergency feedwater pump at the full design range of steam pressures (HFT/PAT).

3.4 During the course of the startup program, demonstrate five consecutive cold quick starts for the steam-driven emergency feedwater pump (HFT/PAT).

3.5 Verify all design flow paths and verify flow downstream of Venturi meets design requirement.

3.6 Verify proper operation in response to signals from the Plant Protection System and the Alternate Protection System.

3.7 Verify, if appropriate, proper operation, stroking speed, and position indication of control valves.

3.8 Verify EFW discharge line isolation valves stroke properly with design basis differential pressure across them.

3.9 Verify proper operation of protective devices, controls, interlocks, instrumentation and alarms using actual or simulated inputs.

3.10 Demonstrate proper pump performance during an endurance test.

3.11 Verify power-operated valves fail to the position specified in Section 10.4.9 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Valve position indications.

4.2 Valve opening and closing times, where required including valve stroke time under design basis differential pressure.

4.3 Pump head versus flow curves.

4.4 Flow rates downstream of Venturi.

4.5 Response of Emergency Feedwater Pumps to ESFAS signals.

4.6 Pump start times.

4.7 Position response of valves to loss of motive power.

5.0 ACCEPTANCE CRITERIA

5.1 The Emergency Feedwater System performs as described in Section 10.4.9 and Section 7.7.1.1.11.

14.2.12.1.37 Reactor Coolant System Hydrostatic Test

1.0 OBJECTIVE

1.1 To verify the integrity of the Reactor Coolant System (RCS) pressure boundary and associated Safety Class I piping.

2.0 PREREQUISITES

2.1 The RCS is filled, vented, and at the required temperature.

2.2 The reactor coolant pumps are operable.

2.3 Test pump is available.

2.4 Primary safety valves are gagged or removed.

2.5 Permanently installed instrumentation necessary for testing is operable and calibrated.

2.6 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Operate reactor coolant pumps to sweep gases from the steam generator tubes.

3.2 Vent the RCS and all control element drive mechanism housings.

3.3 Operate the reactor coolant pumps to increase the RCS temperature to that required for pressurization of RCS to test pressure.

3.4 Perform the test in accordance with the ASME code.

4.0 DATA REQUIRED

4.1 RCS temperature, pressure.

5.0 ACCEPTANCE CRITERIA

5.1 The RCS hydrostatic test meets the requirements of ASME Boiler and Pressure Vessel Code, Section III.

14.2.12.1.38 Control Element Drive Mechanism Cooling System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Control Element Drive Mechanism (CEDM) Cooling System.

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Permanently installed instrumentation is operable and calibrated.

2.3 Test instrumentation is available and calibrated.

2.4 Plant systems required to support testing are operable, or temporary systems are installed and operable.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Operate the system in the normal mode and verify system air flow and balance.

3.3 Verify the proper operation of interlocks and alarms.

3.4 During hot functional testing, verify that the system maintains design temperature under actual heat load conditions.

4.0 DATA REQUIRED

4.1 Air flow rates.

4.2 RCS temperatures and pressures.

4.3 Setpoints at which interlocks and alarms occur.

5.0 ACCEPTANCE CRITERIA

5.1 The CEDM Cooling System performs as described in Section 9.4.6.1.

14.2.12.1.39 Safety Depressurization System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Reactor Coolant Gas Vent System.

1.2 To verify the flow paths of the Rapid Depressurization System.

2.0 PREREQUISITES

2.1 Construction activities on the system to be tested are essentially complete.

2.2 Plant systems required to support testing are operable, or temporary systems are installed and operable.

2.3 Permanently installed instrumentation is operable and calibrated.

3.0 TEST METHOD

3.1 Verify flow paths through the Reactor Coolant Gas Vent System from the Pressurizer to the Reactor Drain Tank and to the In-containment Refueling Water Storage Tank (IRWST).

3.2 Verify flow paths through the Reactor Coolant Gas Vent System from the Reactor Vessel to the Reactor Drain Tank and to the IRWST.

3.3 Verify that the Reactor Coolant Gas Vent System (both the pressurizer vent and the reactor vessel upper head vent) meets design depressurization rates.

3.4 Verify flow paths through the Rapid Depressurization System from the Pressurizer to the IRWST, using water or air.

3.5 Verify power-operated valves fail to the position specified in Section 6.7 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Valve position indications.

4.2 RCS temperature and pressures.

4.3 Depressurization rates using the Reactor Coolant Gas Vent System.

4.4 Reactor Drain Tank temperature, pressure, level.

4.5 IRWST temperature, pressure, level.

4.6 Position response of valves to loss of motive power.

5.0 ACCEPTANCE CRITERIA

5.1 The Reactor Coolant Gas Vent System allows venting of the pressurizer and reactor vessel through designed flow paths, as described in Section 6.7.

5.2 The Reactor Coolant Gas Vent System (both the pressurizer vent and the reactor vessel upper head vent) meets the design depressurization rates, as presented in Appendix 5D.

5.3 The Rapid Depressurization System provides a depressurization path through designed flow paths, as described in Section 6.7.

14.2.12.1.40 Containment Spray System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Containment Spray System (CSS) and the containment spray pumps.

1.2 To verify proper operation of the Emergency Containment Spray Backup (ECSB).

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Plant systems required to support testing are operable and temporary systems are installed and operable.

2.3 Permanently installed instrumentation is operable and calibrated.

2.4 Test instrumentation is available and calibrated.

2.5 The emergency containment spray backup pumping device is operable.

2.6 ECSB components are located in their designated storage area(s).

2.7 The ECSB water source is sufficient for testing.

3.0 TEST METHOD

3.1 Verify proper operation of each containment spray pump with minimum flow established.

3.2 Verify pump performance including head and flow characteristics for all design flow paths.

3.3 Verify, if applicable, proper operation, stroking speed, and position indication of control valves.

3.4 Verify by using service air that the Containment Spray header and nozzles are free of obstructions.

3.5 Verify the automatic operation of all components in response to a Containment Spray Actuation Signal.

3.6 Verify the interchangeability of the Shutdown Cooling pumps with the CSS pumps.

3.7 Verify adequate heat removal capability by the CSS heat exchangers.

3.8 Verify power-operated valves fail to the position specified in Section 6.5.2 and 6.3.2 upon loss of motive power.

3.9 Verify emergency containment spray backup pumping device connectability to the containment spray tee connection. Verify pumping device performance including head and flow characteristics.

3.10 For ECSB testing in each division:

- Confirm that the containment spray header isolation valve is closed.
- Connect the ECSB to the suction (water) source and to the IRWST Fill/CSS Header flange.
- Establish a flow path to a suitable collection tank (e.g., IRWST).
- Verify ECSB pump performance characteristics at rated flow conditions.

4.0 DATA REQUIRED

4.1 Valve position indications.

4.2 Pump head versus flow characteristics.

4.3 Valve opening and closing time, where required.

4.4 Setpoints at which interlocks and alarms occur.

4.5 Position response of valves to loss of motive power.

4.6 For ECSB testing in each division:

- Time to connect ECSB and initiate flow.
- ECSB pump head at rated flow.

5.0 ACCEPTANCE CRITERIA

5.1 The Containment Spray System and Containment Spray Pumps perform as described in Section 6.5.

5.2 The emergency containment spray backup pumping device performs as described in Section 6.5.2.

5.3 The ECSB performs as described in Section 6.5.2.5.1.

14.2.12.1.41 Integrated Engineered Safety Features/Loss of Power Test

1.0 OBJECTIVE

1.1 To verify the full operational sequence of the Engineered Safety Features (ESF).

1.2 To demonstrate electrical redundancy, independence, and load group assignment.

1.3 To demonstrate proper plant response to partial and full losses of offsite power.

2.0 PREREQUISITES

2.1 Individual system preoperational tests are complete.

2.2 Containment spray isolation valves are tagged shut.

2.3 Permanently installed instrumentation is operable and calibrated.

2.4 Test instrumentation is available and calibrated.

2.5 IRWST filled to normal operating level.

3.0 TEST METHOD

3.1 Perform partial and full losses of offsite power. Verify the proper response of ESF systems, alternate power sources, uninterruptible power supplies, and instrumentation and control systems.

3.2 Under loss-of-power conditions, verify operability of systems/components from energized buses and absence of voltage on deenergized buses. Include ESF systems, appropriate HVAC systems, decay heat removal systems, and systems required under post-accident conditions.

3.3 Demonstrate the proper diesel generator response to loss of power including bus energization, load sequencing, and load carrying capability. Verify that full load is within diesel generator design capability.

3.4 Demonstrate proper response to actual or simulated Engineered Safety Features Actuation Signals (ESFAS).

4.0 DATA REQUIRED

4.1 Response to ESFAS signals.

4.2 Diesel start times, load sequence times, frequency, voltage, and current.

4.3 Valve stroke times.

5.0 ACCEPTANCE CRITERIA

5.1 The ESFs respond as described in Chapters 6 and 9 and in Sections 7.3, 8.3, and 10.4.

5.2 Electrical redundancy, independence, and load group assignments are as designed.

5.3 Plant response to partial and full losses of offsite power is as designed.

5.4 The diesel generators re-energize loads as designed and full load is within design capability.

14.2.12.1.42 In-containment Water Storage System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the In-containment Refueling Water Storage Tank (IRWST), the Holdup Volume Tank (HVT) and Cavity Flooding System (CFS).

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Plant systems required to support testing are operable or temporary systems are installed and operable.

2.3 Permanently installed instrumentation is operable and calibrated.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions. Observe valve operation, position indication and, measure opening and closing times.

3.2 Fill the IRWST with reactor makeup water and record volume versus indicated level. Observe level alarms.

3.3 Simulate IRWST temperature and observe alarms.

3.4 Verify design flow path from IRWST to the HVT and reactor cavity.

3.5 Verify the level alarms and indication of the HVT and reactor cavity.

3.6 Verify the operability and adequacy of range of the control room IRWST pressure instrumentation.

3.7 Verify the operation and setpoints of the IRWST pressure relief dampers.

3.8 Verify proper operation of spillways by visually observing flow path capability from the IRWST through the HVT Spillway to the Reactor Cavity Spillway.

4.0 DATA REQUIRED

4.1 Valve position indications.

4.2 Valve opening and closing time, where required.

4.3 Setpoint at which alarms occur.

4.4 Pressure relief damper opening pressure.

5.0 ACCEPTANCE CRITERIA

5.1 The In-containment Water Storage System performs as described in Sections 6.8 and 7.7.1.1.14.

14.2.12.1.43 Internals Vibration Monitoring System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Internals Vibration Monitoring System (IVMS) of the Nuclear Steam Supply System Integrity Monitoring System (NSSS IMS).

2.0 PREREQUISITES

2.1 Construction activities on the NSSS IMS applicable to the IVMS are completed.

2.2 Sensors, cables, and signal conditioning electronics are installed and operable.

2.3 Data analysis software programs are installed and operable.

2.4 Power cabinets are operable to support testing requirements.

2.5 Required test equipment is operable.

3.0 TEST METHOD

3.1 Verify the ability to detect and record reactor core internal motion by applying simulated signals to the core internal motion channels.

3.2 Verify all alarming function, as applicable.

3.3 Verify that data analysis software programs receive appropriate data and perform specified analysis functions.

4.0 DATA REQUIRED

4.1 Data analysis results and evaluations.

5.0 ACCEPTANCE CRITERIA

5.1 The IVMS performs as described in Section 7.7.1.6.1.

14.2.12.1.44 Loose Parts Monitoring System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Loose Parts Monitoring System (LPMS) of the NSSS Integrity Monitoring System (NSSS IMS).

1.2 To adjust the loose parts alarm setpoints for power operation.

2.0 PREREQUISITES

2.1 Construction activities on the NSSS IMS applicable to the LPMS are completed.

2.2 Sensors, cables, and signal conditioning electronics are installed and operable.

2.3 Power cabinets, test circuits, and amplifiers are ready to support testing.

2.4 Required test equipment is operational.

3.0 TEST METHOD

3.1 Verify the calibration and alarm setpoint of the loose parts monitoring channels with a mechanical impulse type device.

3.2 Verify all alarm functions.

3.3 Establish baseline monitoring data for a cold, subcritical plant.

3.4 Establish the alarm level for loose parts channels in a cold, subcritical plant. This alarm level will apply to the preoperational test phase, to startup, and to power operations.

4.0 DATA REQUIRED

4.1 Baseline vibration data.

4.2 Alarm levels applicable to detectable loose parts.

5.0 ACCEPTANCE CRITERIA

5.1 The LPMS performs as described in Section 7.7.1.6.3.

5.2 The loose parts alarm setpoints have been adjusted for power operation.

14.2.12.1.45 Acoustic Leak Monitoring System Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Acoustic Leak Monitoring System (ALMS) of the NSSS Integrity Monitoring System (NSSS IMS).

1.2 To adjust the alarm setpoints under operational conditions.

1.3 To verify automated calibration features.

2.0 PREREQUISITES

2.1 Construction activities on the NSSS IMS applicable to the ALMS are complete.

2.2 Sensors, cables, and signal conditioning electronics are installed and operable.

2.3 Power cabinets, test circuits, and amplifiers are ready to support testing.

2.4 Required test equipment is operable.

2.5 Data analysis, storage, and trending software is operable.

3.0 TEST METHOD

3.1 Verify the calibration and alarm setpoints using simulated signals to the acoustic monitoring channels.

3.2 Verify all alarm functions.

3.3 Establish baseline monitoring data under operating conditions for a cold, subcritical plant.

3.4 Verify the automated electronics calibration functions.

4.0 DATA REQUIRED

4.1 Baseline acoustic data.

4.2 Alarm levels applicable to detection of coolant leaks.

5.0 ACCEPTANCE CRITERIA

5.1 The ALMS performs as described in Section 7.7.1.6.2.

5.2 The alarm setpoints have been established.

14.2.12.1.46 Data Processing System, and Discrete Indication and Alarm System Test

1.0 OBJECTIVE

1.1 To verify that the Data Processing System (DPS), as incorporated in the Advanced Control Complex, is installed properly, responds correctly to external inputs and provides proper outputs to the distributed display, control, and permanent recording equipment.

1.2 To verify proper operation of the Discrete Indication and Alarm System (DIAS).

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Applicable operating manuals are available.

2.3 Required software is installed and operable.

2.4 External test equipment and instrumentation is available and calibrated.

2.5 Plant systems required to support testing are operable to the extent necessary to perform the testing or suitable simulation of these system are used.

3.0 TEST METHOD

3.1 Verify power sources to all related equipment.

3.2 Validate that external inputs are received and processed correctly by the appropriate system devices.

3.3 Verify that alarms and indication displays respond correctly to actual or simulated inputs.

3.4 Verify the operability of required software application programs.

3.5 Verify the correct operation of data output devices and displays at applicable work stations and terminals.

3.6 Evaluate processing system loading under actual or simulated operating conditions.

4.0 DATA REQUIRED

4.1 Computer generated summaries of external input data, data processing, analysis functions, displayed information, and permanent data records.

5.0 ACCEPTANCE CRITERIA

5.1 The DPS and DIAS associated with the Advanced Control Complex performs as described in Section 7.7.1.3, 7.7.1.4, 7.7.1.7, and 7.7.1.8.

14.2.12.1.47 Critical Function Monitoring System Test

1.0 OBJECTIVE

1.1 To verify the proper installation and operation of the Critical Function Monitoring (CFM) System which operates as an application program of the Data Processing System (DPS).

1.2 To verify the proper performance of the Safety Parameter Displays (SPD) as incorporated into the CFM System.

1.3 To verify the proper performance of the Inadequate Core Cooling Monitoring (ICCM) displays as incorporated into the CFM.

2.0 PREREQUISITES

2.1 Construction activites are essentially complete and the applicable systems and components are ready for testing.

2.2 Applicable operating manuals are available.

2.3 Required software is installed and operable.

2.4 External test equipment and instrumentatin is available and calibrated.

2.5 Plant systems required to support testing are operable to the extent necessary to perform the testing or suitable simulation of these systems are used.

3.0 TEST METHOD

3.1 Verify primary and backup power systems to system components.

3.2 Validate that required external inputs are received and processed correctly by the applicable system devices.

3.3 Verify that alarms and indication devices respond correctly to actual or simulated inputs.

3.4 Verify the correct operation of data output devices and displays at applicable terminal points.

4.0 DATA REQUIRED

4.1 Data displays, alarm indications, and hardcopy printouts.

5.0 ACCEPTANCE CRITERIA

5.1 The CFM System with its subfunctions of the SPD and the ICCM functions as described in Sections 7.5 and 7.7.1.10.

14.2.12.1.48 Pre-core Hot Functional Test Controlling Document

1.0 OBJECTIVE

To demonstrate the proper integrated operation of plant systems when in simulated or actual operating configurations. This shall include a demonstration that reactor coolant temperature and pressure can be lowered to permit operation of the shutdown cooling system and the shutdown cooling system can be used to achieve cold shutdown at a cool down rate not exceeding Technical Specification limits and a demonstration of the operation of the steam bypass valves.

2.0 PREREQUISITES

2.1 All construction activities on the systems to be tested are completed.

2.2 All permanently installed instrumentation on systems to be tested have been properly calibrated and are operational.

2.3 All necessary test instrumentation is available and properly calibrated.

2.4 Hydrostatic testing has been completed.

2.5 Steam generators are in wet layup in accordance with the NSSS Chemistry manual.

2.6 Reactor internals, as appropriate for pre-core hot functional testing, have been installed.

3.0 TEST METHOD

3.1 Specify plant conditions and coordinate the execution of the related pre-core hot functional test appendices.

4.0 DATA REQUIRED

4.1 As specified by the individual pre-core hot functional test appendices.

5.0 ACCEPTANCE CRITERIA

5.1 Integrated operation of the Reactor Coolant System (RCS), secondary, and related auxiliary systems perform in accordance with design criteria.

5.2 RCS temperature and pressure can be lowered to permit operation of the shutdown cooling system.

5.3 The Shutdown Cooling System is used to achieve cold shutdown at a cool down rate not in excess of Technical Specification limits.

5.4 The turbine Bypass valves can be operated to control RCS temperature.

5.5 As specified by the individual pre-core hot functional test procedures.

14.2.12.1.49 Pre-core Instrument Correlation

1.0 OBJECTIVE

1.1 To demonstrate that the inputs and appropriate outputs between the Plant Protection System (PPS), Process Instrumentation, Discrete Indication and Alarm System (DIAS) and Data Processing System (DPS) are in agreement.

1.2 To verify narrow range temperature and pressure instrumentation accuracy and operation by comparing similar channels of instrumentation.

2.0 PREREQUISITES

2.1 Instrumentation has been calibrated and is operational.

3.0 TEST METHOD

3.1 Record wide range process instrumentation DIAS and Data Processing System readings as directed by the Pre-core Hot Functional Test.

3.2 Record narrow range process instrumentation DIAS and Data Processing System readings as directed by the Pre-core Hot Functional Test.

4.0 DATA REQUIRED

4.1 Control room panel instrument reading.

4.2 DIAS and DPS readings.

5.0 ACCEPTANCE CRITERIA

5.1 All narrow range instrument readings shall agree within the accuracy of the instrumentation as described in Sections 7.7.1.4, 7.7.1.7, and 7.7.1.8.

5.2 All wide range instrument readings shall agree within the accuracy of the instrumentation as described in Sections 7.7.1.4, 7.7.1.7, and 7.7.1.8.

14.2.12.1.50 Remote Shutdown Panel Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Remote Shutdown Instrumentation.

1.2 To determine transfer of control occurs and that the plant can be cooled down from the Remote Shutdown Panel.

2.0 PREREQUISITES

2.1 All construction activities on the Remote Shutdown Panel have been completed.

2.2 All Remote Shutdown Panel instrumentation has been calibrated.

2.3 The communication systems between the control room and Remote Shutdown Panel location has been demonstrated to be operational.

3.0 TEST METHOD

3.1 Using simulated signals, verify proper operation of remote shutdown panel instrumentation.

3.2 During preoperational Post-Core Hot Functional tests, perform a full transfer of control from the MCR and perform a controlled cooldown from the Remote Shutdown Panel.

4.0 DATA REQUIRED

4.1 RCS temperatures, pressures.

5.0 ACCEPTANCE CRITERIA

5.1 The ability to cooldown using Remote Shutdown Instrumentation and Controls has been demonstrated.

5.2 The Remote Shutdown Panel performs as described in Section 7.4.1.1.10.

14.2.12.1.51 Alternate Protection System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Alternate Protection System (APS).

2.0 PREREQUISITES

2.1 Construction activities on the MG set contactors and the Alternate Protection System have been completed.

2.2 APS instrumentation has been calibrated.

2.3 External test instrumentation is available and calibrated.

2.4 Support systems required for operation of the MG set contactors and APS are operational.

3.0 TEST METHODS

3.1 Energize power supplies and verify output voltage.

3.2 Using simulated signals, trip each reactor trip circuit breaker with the breaker in the test position. Observe MG set contactor operation.

3.3 Using simulated input signals observe Alternate Feedwater Actuation signals.

4.0 DATA REQUIRED

4.1 Power supply voltages.

4.2 Resistance for ground fault detector operation.

4.3 Trip setpoints.

5.0 ACCEPTANCE CRITERIA

5.1 The APS performs as described in Section 7.7.1.1.11.

14.2.12.1.52 Pre-core Test Data Record

1.0 OBJECTIVE

1.1 To monitor instrumentation during integrated plant operation.

1.2 To verify, by cross checking channels, the satisfactory tracking of process instrumentation.

1.3 To provide a permanent record of plant pre-core loading parameter indication.

2.0 PREREQUISITES

2.1 Instrumentation has been calibrated and is operational.

3.0 TEST METHOD

3.1 Record control room instrumentation steady state readings as directed by the pre-core hot functional test controlling document.

4.0 DATA REQUIRED

4.1 Plant conditions at time when instrument readings are recorded.

4.2 Instrument readings.

5.0 ACCEPTANCE CRITERIA

5.1 All like instrumentation readings shall agree within the accuracy limits of the instrumentation.

14.2.12.1.53 Pre-core Reactor Coolant System Expansion Measurements

1.0 OBJECTIVE

1.1 To demonstrate that the Reactor Coolant System (RCS) components are free to expand thermally as designed during initial plant heatup and return to their baseline cold position after the initial cooldown to ambient temperatures.

2.0 PREREQUISITES

2.1 All construction activities have been completed on the RCS components.

2.2 Initial ambient dimensions have been set on the steam generator and Reactor Coolant pump hydraulic snubbers, upper and lower steam generator and reactor vessels keys, and RC pump columns.

2.3 Initial ambient dimensions for the steam generator, reactor vessel, and reactor coolant pump supports have been recorded.

3.0 TEST METHOD

3.1 Clearances at hydraulic snubber joints, keys, and column clevises shall be checked at 50°F increments during heatup and recorded at 100°F increments.

3.2 At stabilized conditions, record all steam generator, reactor vessel, and reactor coolant pump clearances.

4.0 DATA REQUIRED

4.1 Plant conditions.

4.2 Clearances at the steam generator sliding base keys, hydraulic snubber joints, upper keys, and piston setting at hydraulic snubbers.

4.3 Clearance between the reactor vessel upper and lower supports and expansion plates.

4.4 Reactor vessel support temperature.

4.5 Clearances at the reactor coolant pump snubbers, column joints, and piston setting for the hydraulic snubbers.

4.6 Clearances at all test points after cooldown.

5.0 ACCEPTANCE CRITERIA

5.1 Unrestricted expansion for selected points on components as described in Section 3.9.2.

5.2 Verification that components return to their baseline ambient position as described in Section 3.9.2.

5.3 Verification that proper gaps exist for selected points on components as described in Section 3.9.2.

14.2.12.1.54 Pre-core Reactor Coolant and Secondary Water Chemistry Data

1.0 OBJECTIVE

1.1 To demonstrate that proper water chemistry for the RCS and steam generator can be maintained.

2.0 PREREQUISITES

2.1 Primary and secondary sampling systems are operable.

2.2 Chemicals to support hot functional testing are available.

2.3 The primary and secondary chemical addition systems are operable.

2.4 Purification ion exchangers are charged with resin.

3.0 TEST METHOD

3.1 Minimum sampling frequency for the steam generator and RCS will be specified by the chemistry manual. The sampling frequency will be modified as required to ensure the proper RCS and steam generator water chemistry.

3.2 Perform RCS and steam generator sampling and chemistry analysis after every significant change in plant conditions (i.e., heatup, cooldown, chemical additions).

4.0 DATA REQUIRED

4.1 Plant conditions.

4.2 Steam generator chemistry analysis.

4.3 RCS chemistry analysis.

5.0 ACCEPTANCE CRITERIA

5.1 RCS and steam generator water chemistry can be maintained as described in Sections 9.3.4 and 10.3.5.

14.2.12.1.55 Pre-core Pressurizer Performance Test

1.0 OBJECTIVE

1.1 Demonstrate that the Pressurizer Pressure and Level Control Systems function properly.

1.2 Demonstrate proper operation of the Auxiliary Spray Valves and Pressurizer Heaters.

1.3 Demonstrate proper operation of the letdown flow control valves and charging pumps.

2.0 PREREQUISITES

2.1 Pressurizer Pressure and Level Control System instrumentation has been calibrated.

2.2 Support systems required for the operation of the Pressurizer Pressure and Level Control Systems are operational.

2.3 Test equipment is available and calibrated.

3.0 TEST METHOD

3.1 Simulate a decreasing pressurizer pressure and observe heater response and alarm and interlock setpoints.

3.2 Simulate an increasing Pressurizer pressure and observe heater and spray valve response and alarm and interlock setpoints.

3.3 Simulate a low level error in the Pressurizer and observe proper charging pump response and alarm and interlock setpoints.

3.4 Simulate a high level error in the Pressurizer and observe proper charging pump response and alarm and interlock setpoints.

3.5 Simulate a low Pressurizer level and observe operation of the [illegible]own control valves.

3.6 Simulate a low-low Pressurizer level and observe heater response and alarm and interlock setpoints.

4.0 DATA REQUIRED

4.1 Response of Pressurizer heaters to simulated pressure and level signals.

4.2 Response of spray valves to simulated Pressurizer pressure.

4.3 Response of charging pumps to simulated Pressurizer level.

4.4 Response of letdown control valves to simulated Pressurizer level.

4.5 Response of letdown control valves to simulated low Pressurizer level.

4.6 Values of parameters at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Pressurizer performs as described in Sections 7.7.1 and 5.4.10.

14.2.12.1.56 Pre-core Control Element Drive Mechanism Performance Test

1.0 OBJECTIVE

1.1 To determine the effectiveness of the Control Element Drive Mechanism (CEDM) cooling system by measurement of coil resistance at several temperature plateaus during RCS heatup.

1.2 To determine the operating temperature of the upper gripper coils.

1.3 To verify proper operation and sequencing of the CEDM.

2.0 PREREQUISITES

2.1 CEDM coil stacks are assembled and associated cabling is connected.

2.2 Cabling between the reactor bulkhead and the CEDM Control System is disconnected.

2.3 CEDM "cold" coil resistance has been measured and recorded.

2.4 Individual CEDM cable resistance has been measured and recorded.

2.5 CEDM cooling system is operational.

2.6 Test equipment is available and calibrated.

2.7 Support systems required for operation of the CEDM are operational.

3.0 TEST METHOD

3.1 At the specified RCS temperature and pressure, measure and record the loop resistance for each of the CEDM coils.

3.2 Balance CEDM cooling system as required to maintain the coil temperatures within the specified limits.

3.3 Connect cabling between the reactor bulkhead and the CEDMCS cabinets and energize the CEDM. Measure and record the DC voltage across the upper gripper coil and across the shunt on the CEDMCS Power Switch Assembly Panel.

3.4 Operate the CEDM and observe count totalizer operation.

4.0 DATA REQUIRED

4.1 CEDM "cold" coil resistance.

4.2 CEDM cable resistance.

4.3 RCS temperature and pressure.

4.4 CEDM coil loop resistance at specified RCS temperature and pressure.

4.5 DC voltage across the upper gripper coil at the specified RCS temperature and pressure.

4.6 DC voltage across the shunt.

4.7 CEDM count totalizer readings.

5.0 ACCEPTANCE CRITERIA

5.1 The Control Element Drive Mechanism performs as described in Section 7.7.1.

14.2.12.1.57 Pre-core Reactor Coolant System Flow Measurements

1.0 OBJECTIVE

1.1 To determine the pre-core Reactor Coolant System (RCS) flow rate.

1.2 To establish baseline RCS pressure drops.

2.0 PREREQUISITES

2.1 All permanently installed instrumentation has been properly calibrated and is operational.

2.2 All test instrumentation has been checked and calibrated.

2.3 RCS operating at nominal hot, zero power conditions.

2.4 Desired reactor coolant pumps operating.

2.5 COLSS, CPCs, and Data Processing System in operation.

3.0 TEST METHOD

3.1 RCS flow, pressure drops, and the data necessary to calculate RCS flows for four Reactor Coolant Pump (RCP) operations will be obtained.

4.0 DATA REQUIRED

4.1 Data Processing System.

4.2 RCP differential pressure.

4.3 RCS temperature and pressure.

4.4 RCP speed.

4.5 Reactor vessel differential pressure.

4.6 Pump configurations.

5.0 ACCEPTANCE CRITERIA

5.1 The RCS flow exceeds the value necessary to insure that post core flow is in excess of that used for analysis in Chapter 15 but less than the design maximum flow rate as described in Sections 4.4.1.4, 7.2.1.1.1.12, 7.2.1.1.2.4, and 7.7.1.8.1.3.1.

14.2.12.1.58 Pre-core Reactor Coolant System Heat Loss

1.0 OBJECTIVE

1.1 Measure Reactor Coolant System (RCS) heat loss under hot, zero power conditions.

1.2 Measure pressurizer heat loss under hot, zero power conditions.

2.0 PREREQUISITES

2.1 Test instrumentation is available and calibrated.

2.2 Construction activities on the RCS and associated systems are completed.

2.3 All permanently installed instrumentation on the system to be tested is available and calibrated.

3.0 TEST METHOD

3.1 Determine the RCS heat loss using the steam-down method:

3.1.1 Stabilize the Steam Generator levels with the RCS at hot, zero power conditions.

3.1.2 Secure Steam Generator feedwater and blowdown.

3.1.3 Measure both the Pressurizer heater power required to maintain RCS temperature and pressure and RCP power.

3.1.4 Perform a heat balance calculation to determine heat loss.

3.2 Determine the Pressurizer heat loss, with[2] and without continuous spray flow, by measuring the pressurizer heater power required to maintain the RCS at hot, zero power conditions, and then performing a heat balance calculation.

4.0 DATA REQUIRED

4.1 RCS temperatures.

4.2 Pressurizer pressure and level.

4.3 Steam generator pressures and levels.

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2 Pressurizer heat loss with continuous spray flow to be determined during post core hot functional test after spray valve adjustments have been performed per Section 14.2.12.2.6.

4.4 Pressurizer heater power.

4.5 RCP power.

5.0 ACCEPTANCE CRITERIA

5.1 The measured heat loss is less than the capacity of the containment cooling subsystem to remove the heat loads as described in Section 9.4.6.

14.2.12.1.59 Pre-core Reactor Coolant System Leak Rate Measurement

1.0 OBJECTIVE

1.1 To measure the Reactor Coolant leakage at hot, zero power conditions.

2.0 PREREQUISITES

2.1 Hydrostatic testing of the RCS and associated systems has been completed.

2.2 The RCS and the CVCS are operating as a closed system.

2.3 The RCS is at hot, zero power conditions.

3.0 TEST METHOD

3.1 Measure and record the changes in water inventory of the RCS and CVCS for a specified interval of time.

4.0 DATA REQUIRED

4.1 Pressurizer pressure, level, and temperature.

4.2 Volume Control Tank level, temperature, and pressure.

4.3 Reactor Drain Tank level, temperature, and pressure.

4.4 RCS temperature and pressure.

4.5 Safety Injection Tank level and pressure.

4.6 Time interval.

5.0 ACCEPTANCE CRITERIA

5.1 Identified and unidentified leakage shall be within the limits described in the technical specification as described in Section 5.2.5.

14.2.12.1.60 Pre-core Chemical and Volume Control System Integrated Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Letdown Subsystem and ion exchangers.

2.0 PREREQUISITES

2.1 The CVCS is in operation.

2.2 Selected ion exchanger has been filled with an appropriate resin.

2.3 Ion exchangers not to be used have been bypassed.

2.4 Associated instrumentation has been checked and calibrated.

3.0 TEST METHOD

3.1 Taking manual control of the letdown control valve controller, position the letdown flow control valve to obtain various letdown flow rates between 0% and 100% flow, inclusive.

3.2 Measure and record the pressure drops across the ion exchanger, filter, and strainer.

4.0 DATA REQUIRED

4.1 Letdown control valve controller settings.

4.2 Letdown temperature, pressure, and flow rates.

4.3 Charging temperature and flow rates.

4.4 Ion exchanger, filter, and strainer differential pressure.

4.5 Volume Control Tank pressure and level.

4.6 Pressurizer level.

4.7 RCS temperature and pressure.

5.0 ACCEPTANCE CRITERIA

5.1 The Chemical and Volume Control System performs as described in Section 9.3.4.

14.2.12.1.61 Pre-core Safety Injection Check Valve Test

1.0 OBJECTIVE

1.1 To verify that the safety injection tank discharge check valve will pass flow with the RCS at hot, zero power conditions.

1.2 To verify that the safety injection loop check valves will pass flow with the RCS at hot, zero power conditions.

2.0 PREREQUISITES

2.1 RCS at hot, zero power conditions.

2.2 Safety injection tanks are filled and pressurized to their normal operating conditions.

3.0 TEST METHOD

3.1 Verify flow through the safety injection loop check valves. Reduce RCS pressure to below shut-off head for the SI pumps. Start each SI pump and open loop isolation valves and observe flow to the RCS on installed flow indicators.

3.2 Verify flow through each safety injection tank discharge check valve by flowing back to the IRWST.

4.0 DATA REQUIRED

4.1 Safety injection tank level and pressure.

4.2 Safety injection discharge header pressure.

5.0 ACCEPTANCE CRITERIA

5.1 Verification that the loop check valves and safety injection tank discharge check valves will pass flow with the RCS at hot, zero power conditions.

14.2.12.1.62 Pre-core Boration/Dilution Measurements

1.0 OBJECTIVE

1.1 To demonstrate the ability of the CVCS to control the boron concentration of the Reactor Coolant System (RCS) by the feed and bleed method.

1.2 To demonstrate the ability of the CVCS to supply concentrated boric acid to the RCS.

2.0 PREREQUISITES

2.1 BAST is filled with borated water.

2.2 The boron addition system is operational.

2.3 The boronometer is operational.

2.4 RCS and CVCS boron concentration is approximately zero (0) ppm.

3.0 TEST METHOD

3.1 Line up the Boric Acid Makeup (BAMU) pumps to take suction from the BAST and discharge to the charging pump suction and to the RCS, and observe operation of the boron addition system.

3.2 Perform boration and dilution operation of the RCS by operating the boric acid makeup control system in its various modes of operation.

3.3 Sample the RCS during boration and dilution operations and observe operation of the boronometer.

4.0 DATA REQUIRED

4.1 RCS temperature and pressure.

4.2 Makeup controller flow readings and setpoints.

4.3 Chemical analysis of boron concentration.

4.4 VCT level.

4.5 Boronometer readings.

4.6 Charging flow rates.

4.7 Letdown flow rate.

5.0 ACCEPTANCE CRITERIA

5.1 The Boration Subsystem performs as described in Section 9.3.4.

14.2.12.1.63 Downcomer Feedwater System Water Hammer Test

1.0 OBJECTIVE

1.1 To demonstrate the absence of any significant water hammer during steam generator water level recovery following the exposure of the downcomer feedwater sparger to a steam environment.

2.0 PREREQUISITES

2.1 Construction activities on the Emergency Feedwater System (EFWS) and those sections of the Main Feedwater System (MFWS) that are affected have been completed.

2.2 Feedwater Control Systems (FWCS) instrumentation and other appropriate permanently installed instrumentation has been calibrated.

2.3 Main Steam System is available.

2.4 Appropriate AC and DC power sources are available.

2.5 RCS operating at nominal hot, zero power conditions (hot standby).

3.0 TEST METHOD

3.1 Lower the steam generator water level below the feedwater sparger but within the Narrow Range (NR) level indication band for a period of 30 minutes (no feedwater will be introduced into the generator through the sparger during this period).

3.2 Station personnel as appropriate[3] to monitor for noise or vibration.

3.3 Initiate emergency feedwater flow to restore steam generator level in a manner that simulates automatic EFW actuation.

4.0 DATA REQUIRED

4.1 Visual inspection.

5.0 ACCEPTANCE CRITERIA

5.1 Visual inspection indicates that the integrity of feedwater piping, supports, and sparger[4] have not been violated.

14.2.12.1.64 Main Turbine Systems Test

1.0 OBJECTIVE

1.1 Verify the functional performance of the Main Turbine Controls.

1.2 To verify the functional performance of the Main Turbine Support System.

1.3 To perform initial operation of the Main Turbine System (HFT and PAT).

1.4 To verify the Main Turbine Generator Trips in response to a simulated reactor trip signal and to a simulated loss of condenser vacuum signal.

2.0 PREREQUISITES

2.1 Construction activities on the Main Turbine System are complete.

2.2 Main Turbine System instrumentation has been calibrated.

2.3 Appropriate test equipment is available and has been calibrated.

2.4 Proper fluid levels throughout the system have been verified.

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3 Personnel safety will limit proximity to Feedwater System.

4 Visually inspect during next regular SG inspection following testing.

2.5 Appropriate AC and DC power sources are available and operable.

2.6 Support Systems required for the Main Turbine System are complete and operational.

2.7 The Main Steam System is available.

2.8 The Main Condenser is available.

3.0 TEST METHODS

3.1 Demonstrate the Electro Hydraulic Control (EHC) system performs the following:

3.1.1 Automatic control of turbine speed and acceleration through the entire speed range.

3.1.2 Automatic control of load and loading rate from auxiliary to full load, with continuous load adjustment and discrete loading rates.

3.1.3 Standby manual control of speed and load when it becomes necessary to take the primary automatic control out of service.

3.1.4 Limiting of load in response to preset limits on operating parameters.

3.1.5 Detection of dangerous or undesirable operating conditions, annunciation of detected conditions, and initiation of proper control response to such conditions.

3.1.6 Monitoring the status of the control systems, including the power supplies and redundant control circuits.

3.1.7 Testing of valves and controls, including response to a simulated reactor trip signal and simulated loss of condenser vacuum signal.

3.1.8 Prewarming of valve chest and turbine rotor.

3.2 Perform Main Turbine Performance Test per ASME PT-6-1976.

3.3 Operate control valves from all appropriate control positions. Observe valve operation and position indication and, where required, measure opening and closing times.

3.4 Verify power-operated valves fail to the position specified in Section 10.2.3 upon loss of motive power.

3.5 Demonstrate the Turbine Lube Oil System operation.

3.6 Demonstrate the Hydrogen Oil-sealed Cooling System for rotor cooling operation.

3.7 Demonstrate the Stator Water Cooling System operation.

3.8 Demonstrate the Moisture Separators, Reheaters and Extraction Steam Systems operation.

4.0 DATA REQUIRED

4.1 Setpoint at which alarms and interlocks occur.

4.2 Setpoints of automatic trips.

4.3 Conditions under which manual trips operate.

4.4 Verification of all control logic combinations.

4.5 Valve logic verification of EHC system.

4.6 Valve opening and closing times, where required.

4.7 Valve position indication.

4.8 Position response of valves to loss of motive power.

4.9 Operating data and function verification of associated turbine support systems.

5.0 ACCEPTANCE CRITERIA

5.1 The Main Turbine System and Support Systems performance shall be as described in Section 10.2.

5.2 Main Turbine performance is as required by vendor ratings.

5.3 Main Turbine Generator trip is generated in response to a simulated reactor trip signal as described in Section 10.2.4.

5.4 Main Turbine Generator trip is generated in response to a simulated loss of condenser vacuum signal as described in Section 10.4.1.4.

14.2.12.1.65 Main Steam Safety Valve Test

1.0 OBJECTIVE

1.1 To verify the popping pressure of the Main Steam System Safety Valves. (HFT)

2.0 PREREQUISITES

2.1 Construction activities on the Main Steam Safety Valves have been completed.

2.2 Main steam system instrumentation has been calibrated.

2.3 Support systems required for operation of the Main Steam Safety Valves are complete and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Main Steam System is at the valve vendor recommended temperature and pressure for valve testing.

2.6 Lifting device with associated support equipment and calibration data is available.

3.0 TEST METHOD

3.1 Using the lifting device, increase the lifting force on the safety valve until the safety valve starts to simmer.

3.2 Determine popping set pressure.

3.3 Adjust valve popping set pressure if necessary and retest.

3.4 Repeat until three consecutive pops within the required range are obtained.

3.5 Alternative method is to perform the setpoint verification at a certified testing facility.

3.6 Verify all safety valves have no seat leakage.

4.0 DATA REQUIRED

4.1 Main steam system pressure and temperature.

4.2 Pressure applied to the lifting device to lift the safety valve off its seat.

4.3 Popping pressure of each Main Steam Safety Valve.

5.0 ACCEPTANCE CRITERIA

5.1 The Main Steam Safety Valves perform as described in Section 10.3.2.3.2.2.

14.2.12.1.66 Main Steam Isolation Valves, and MSIV Bypass Valves Test

1.0 OBJECTIVE

1.1 To demonstrate the functional performance of the Main Steam Isolation Valves (MSIVs) and MSIV Bypass Valve Controls.

1.2 To demonstrate the proper operation of the MSIVs at normal operating temperatures (HFT).

2.0 PREREQUISITES

2.1 Construction activities on the Main Steam Isolation Valves (MSIVs) have been completed.

2.2 Main steam system instrumentation has been calibrated.

2.3 Support Systems required for operation of the Main Steam Isolation Valves are complete and operational.

2.4 Test Equipment is available and test instrumentation is calibrated.

3.0 TEST METHOD

3.1 Operate the MSIVs and MSIV bypass valves from all appropriate control positions. Observe valve operation and position indication and, where required, measure opening and closing times at ambient and HFT conditions.

3.2 Verify the MSIVs and MSIV bypass valves fail to the position indicated in Figure 10.3.2-1 upon loss of motive power.

3.3 Verify MSIV and MSIV Bypass Valve controls, alarms and interlocks.

3.4 Verify MSIV and MSIV Bypass Valve response to Main Steam Isolation Signal.

3.5 Verify MSIV and MSIV Bypass Valve seat leakage.

3.6 Perform MSIV drift test.

4.0 DATA REQUIRED

4.1 MSIV and MSIV bypass valve opening and closing times at ambient and HFT condition.

4.2 Valve position indication.

4.3 Position response of valves to a loss of motive power.

4.4 Setpoints at which alarms and interlocks occur.

4.5 MSIV and MSIV Bypass Valve seat leakage.

4.6 MSIV and MSIV Bypass Valve response to MSIS.

4.7 MSIV drift data.

5.0 ACCEPTANCE CRITERIA

5.1 The Main Steam Isolation Valves, and MSIV Bypass Valves operate as described in Sections 10.3.2.3.2.1 and 10.3.2.3.3.1.

5.2 The Main Steam Isolation Valves and MSIV Bypass Valves meet the test acceptance criteria described in Section 10.3.4.

14.2.12.1.67 Main Steam System Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of the Main Steam System.

2.0 PREREQUISITES

2.1 Construction activities on the Main Steam System have been completed.

2.2 Main Steam System instrumentation has been calibrated.

2.3 Support systems required for operation of the Main Steam System are complete and operational.

2.4 Test equipment is available and test instrumentation is calibrated.

3.0 TEST METHOD

3.1 Demonstrate automatic drain valve operation.

3.2 Demonstrate all flow paths.

3.3 Verify opening of the Turbine Bypass Valves in response to a signal simulating turbine bypass.

3.4 Verify the operability of the Atmospheric Steam Dump Valves at no-load steam pressure (HFT).

3.5 Verify the operability of the Turbine Bypass Valves at no-load steam pressure (HFT).

3.6 Operate control valves from all appropriate control positions. Observe valve operation and position indication and, where required, measure opening and closing times.

3.7 Verify the Turbine Bypass Valves fail to the position specified in Section 10.4.4.2.4.1 upon loss of motive power.

3.8 Verify proper operation of designated components such as protective devices, controls, interlocks, instrumentation and alarms using actual or simulated inputs.

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 Setpoints at which alarms and interlocks occur.

4.5 Flow path data.

5.0 ACCEPTANCE CRITERIA

5.1 The Main Steam System performance is as described in Section 10.3.

5.2 Turbine Bypass Valves open in response to a signal simulating turbine bypass, as described in Section 10.4.4.

5.3 Turbine Bypass Valves fail upon loss of motive power as described in Section 10.4.4.4.

14.2.12.1.68 Steam Generator Blowdown System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Steam Generator Blowdown System.

2.0 PREREQUISITES

2.1 Construction activities on the Steam Generator Blowdown system have been completed.

2.2 Steam Generator Blowdown System instrumentation has been calibrated.

2.3 Support systems required for operation of the Steam Generator Blowdown system are complete and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify the flow paths for generator blowdown and subsequent condensate recycle. (HFT)

3.2 Verify blowdown flow path flow rates during HFT.

3.3 Operate control valves from all appropriate control positions. Observe valve operation and position indication and, where required, measure opening and closing times.

3.4 Verify power-operated valves fail to the position specified in Section 10.4.8 upon loss of motive power.

3.5 Verify the proper operation of pump, motors, and heat exchanger in all operation modes and flow paths.

3.6 Verify the ability to regenerate resin.

3.7 Verify the proper operation of all protective devices, controls, interlocks, and alarms, using actual or simulated inputs.

3.8 Verify the proper system response to Containment Isolation Actuation Signal (CIAS), Main Steam Isolation Signal (MSIS), Emergency Feedwater Actuation Signal (EFAS).

3.9 Verify Steam Generator Wet Layup system operation.

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 Setpoints at which alarms and interlocks occur.

4.5 Blowdown pump running data.

4.6 Response to MSIS, CIAS and EFAS.

4.7 SG blowdown flow path flow rates.

5.0 ACCEPTANCE CRITERIA

5.1 The Steam Generator Blowdown System operates as described in Section 10.4.8.

14.2.12.1.69 Main Condenser and Main Condenser Evacuation Systems Test

1.0 OBJECTIVE

1.1 To demonstrate the ability of the Main Condenser and Main Condenser Evacuation Systems to provide a continuous heat sink for normal operation as well as a sink for the Turbine Bypass System under certain conditions.

2.0 PREREQUISITES

2.1 Construction activities on the Main Condenser and Main Condenser Evacuation Systems have been complete.

2.2 Main Condenser and Main Condenser Evacuation Systems instrumentation has been calibrated.

2.3 Support systems required for operation of the Main Condenser and Main Condenser Evacuation Systems are complete and operational.

2.4 Test Instrumentation is available and calibrated.

2.5 Steam seals and lagging are available.

2.6 Turbine is on turning gear.

2.7 All electrical testing is complete on the vacuum pumps and condenser valves.

3.0 TEST METHOD

3.1 Verify the vacuum integrity of the condenser by performing both a water hydrostatic test and a vacuum test.

3.2 Operate control valves from all appropriate control positions. Observe valve operation and position indication and, where required, measure opening and closing times.

3.3 Verify power-operated valves fail to the position specified in Section 10.4 upon loss of motive power.

3.4 Demonstrate the proper operation of the vacuum pumps with design operating modes and flow paths.

3.5 Verify the proper operation of protective devices, controls, interlocks, instrumentation, and alarms, using actual or simulated inputs.

3.6 Demonstrate the operation of the condenser makeup and reject to the condensate storage tank controls.

3.7 Demonstrate the operation of the automatic condenser cleaning system.

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 Setpoints at which alarms and interlocks occur.

4.5 Vacuum pump running data.

5.0 ACCEPTANCE CRITERIA

5.1 The Main Condenser and Main Condenser Evacuation Systems perform as described in Sections 10.4.1 and 10.4.2.

14.2.12.1.70 Main Feedwater System Test

1.0 OBJECTIVE

1.1 To demonstrate that the Main Feedwater System (including Startup Feedwater) is capable of supplying feedwater to the steam generators for normal operation.

2.0 PREREQUISITES

2.1 Construction activities on the Main Feedwater System have been completed.

2.2 Main Feedwater System instrumentation has been calibrated.

2.3 Support systems required for operation of the Main Feedwater System are complete and operational.

2.4 Test instrumentation available and calibrated.

2.5 A suitable steam supply available for operation.

2.6 Condensate system operable.

2.7 Main Condenser operable.

2.8 Appropriate AC and DC power available.

3.0 TEST METHOD

3.1 Demonstrate all design flow paths including economizer, downcomer and cleanup recirculation (HFT or PAT).

3.2 Demonstrate proper startup feedwater valve alignments and flow paths.

3.3 Verify the starting, head, and flow characteristics of the motor-driven startup feedwater pump.

3.4 Demonstrate minimum flow recirculation protection using simulated inputs.

3.5 Verify proper operation of protective devices, controls, interlocks, instrumentation, and alarms, using actual or simulated inputs.

3.6 Verify the starting, head, and flow characteristics of the motor driven feedwater pump.

3.7 Operate Main Feedwater Isolation Valves (MFIVs) from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.8 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.9 Verify the Main Feedwater Isolation Valves fail to the position indicated in Figure 10.4.7-1 upon loss of motive power.

3.10 Verify the Main Feedwater Isolation Valves close in response to a Main Steam Isolation Signal (MSIS).

4.0 DATA REQUIRED

4.1 Motor-driven Startup Feedwater Pump head versus flow data.

4.2 Motor-Driven Feedwater Pump head versus flow data.

4.3 Valve opening and closing times, where required.

4.4 Valve position indication.

4.5 Position response of valves to loss of motive power.

4.6 Setpoints at which alarms and interlocks occur.

4.7 Main Feedwater Isolation Valve data.

5.0 ACCEPTANCE CRITERIA

5.1 The Main Feedwater System (including Startup Feedwater) operates as described in Section 10.4.7.

5.2 The MFIVs meet the test acceptance criteria as described in Section 10.4.7.4.

14.2.12.1.71 Condensate System Test

1.0 OBJECTIVE

1.1 To demonstrate that the Condensate System is capable of supplying an adequate flow of water at the design pressure to support the remainder of the Power Conversion System.

2.0 PREREQUISITES

2.1 Construction activities on the Condensate System have been completed.

2.2 Condensate System instrumentation has been calibrated.

2.3 Support systems required for operation of the Condensate System are complete and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Plant conditions are such to provide a flow path for the Condensate and Feedwater Booster Pumps.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify head versus flow characteristics for the condensate and feedwater booster pumps.

3.3 Demonstrate proper operation of the Deareator.

3.4 Demonstrate proper operation of design flow paths including system cleanup operation.

3.5 Demonstrate proper operation of minimum flow recirculation protections.

3.6 Demonstrate proper operation of the Hotwell Level Control System.

3.7 Verify proper operation of designated components, such as protective devices, controls, interlocks, instrumentation, and alarms, using actual or simulated inputs.

3.8 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.9 Verify power-operated valves fail to the position specified in Section 10.4.7 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Head versus flow performance and pump operating data.

4.2 Valve opening and closing times, where required.

4.3 Valve position indication.

4.4 Position response of valves to loss of motive power.

4.5 Setpoints at which alarms and interlocks occur.

4.6 Setpoints of the hotwell level controls.

4.7 Setpoints of the pumps minimum flow recirculation protection.

5.0 ACCEPTANCE CRITERIA

5.1 The Condensate System operates as described in Section 10.4.7.

14.2.12.1.72 Turbine Gland Sealing System Test

1.0 OBJECTIVE

1.1 To verify that the Gland Seal System provides adequate sealing to the turbine shaft and the main feed pump turbine shafts against leakage of air to the turbine casings and escape of steam to the Turbine Building.

2.0 PREREQUISITES

2.1 Construction activities on the Turbine Gland Sealing System have been completed.

2.2 Turbine Gland Sealing System instrumentation have been calibrated.

2.3 Test instrumentation is available and calibrated.

2.4 Plant systems required to support the test including Auxiliary Steam, the Condenser, and Turbine Cooling Water System are operable.

2.5 Plant conditions for the Main Turbine, the Main Feed Pump Turbines and the Turbine Control Valves allow operation of the Gland Sealing System.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.2 Verify power-operated valves fail to the position specified in Section 10.4.3 upon loss of motive power.

3.3 At turbine startup, place the Gland Seal System in operation using Auxiliary Steam and verify proper operation of the system after turbine load has increased and the system has sealed off.

3.4 Verify the proper performance of the Gland Seal Exhauster Blowers and the Gland Seal Condenser.

3.5 Verify the proper operation of the high pressure turbine gland spillover valve for dumping excess gland seal leakage.

3.6 Verify the proper operation of all protective devices, controls, interlocks, instrumentation, and alarms.

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Turbine Gland Sealing System operates as described in Section 10.4.3.

14.2.12.1.73 Condenser Circulating Water System Test

1.0 OBJECTIVE

1.1 To demonstrate the ability of the Condenser Circulating Water System to provide a continuous supply of cooling water to the main condensers and return the water to the cooling tower for heat dissipation.

2.0 PREREQUISITES

2.1 Construction activities on the Condenser Circulating Water System have been completed.

2.2 Condenser Circulating Water System instrumentation has been calibrated.

2.3 Support systems required for operation of the circulating water system are complete and operational.

2.4 Intake structure at the required level and water quality within limits.

2.5 Temporary test instruments installed and calibrated.

3.0 TEST METHOD

3.1 Verify head versus flow and operational characteristics for the Circulating Water Pumps.

3.2 Verify required alarms and verify the corresponding actions.

3.3 Verify automatic and manual systems controls function properly.

3.4 Perform a flow balance of the CWS to the cooling tower.

4.0 DATA REQUIRED

4.1 Verification of trips and alarms.

4.2 Record pump head versus flow and operating data.

4.3 Flow data to upper and lower basins of the cooling tower.

5.0 ACCEPTANCE CRITERIA

5.1 The Circulating Water System operates as described in Section 10.4.5.

14.2.12.1.74 Steam Generator Hydrostatic Test

1.0 OBJECTIVE

1.1 To hydrostatically test the secondary side of the steam generators (SGs) and associated portions of the main steam, feedwater, blowdown and emergency feedwater systems.

2.0 PREREQUISITES

2.1 Construction activities on the SG secondary side are complete.

2.2 The Reactor Coolant System is available to be pressurized and the Reactor Coolant Pumps are operable.

2.3 The main steam safety valves are removed and blind flanges are installed.

2.4 Temporary hydro pump and relief valves are installed.

2.5 Temporary instrumentation calibrated and installed.

2.6 Systems required to support the operation the Reactor Coolant System and Reactor Coolant Pumps are available.

2.7 Any plant instrumentation not able to withstand hydro pressure is removed from service.

3.0 TEST METHOD

3.1 Fill and vent the steam generators and chemically treat as required.

3.2 Operate the RCS and associated systems as needed to operate the Reactor Coolant pumps. Heat the RCS and Steam Generators to the required temperature.

3.3 Pressurize the primary side as required to maintain less than maximum secondary to primary differential pressure.

3.4 Pressurize the steam generator to the pressure required by the technical manual.

3.5 Perform an inspection of all designated items and record any discrepancies.

4.0 DATA REQUIRED

4.1 Record SG pressure and temperatures during performance of the test.

4.2 Record the location of any leaks.

5.0 ACCEPTANCE CRITERIA

5.1 The Steam Generators Hydrostatic Test meets the requirements as stated in the technical manual and the ASME Boiler and Pressure Vessel Code, Section III.

14.2.12.1.75 Feedwater Heater and Drains System Test

1.0 OBJECTIVE

1.1 To demonstrate the Feedwater Heater and Drain System alarms and controls operate as designed.

1.2 To demonstrate that the Feedwater Heaters and Drains System is capable of heating the Main Feedwater System to the design temperature for normal plant operation. [Power Ascension Test (PAT)]

2.0 PREREQUISITES

2.1 Construction activities on the Feedwater Heater and Drains System have been completed.

2.2 Feedwater Heater and Drains System instrumentation has been calibrated.

2.3 Individual component testing is complete

2.4 The power conversions systems are operating as required to support the test.

3.0 TEST METHOD

3.1 Verify the setpoints of alarms and interlock.

3.2 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.3 Verify power-operated valves fail to the position specified in Section 10.4.7 upon loss of motive power.

3.4 Verify Main Feedwater temperature to the Steam Generators at 100% flow is per Section 10.4.7. (PAT)

3.5 Demonstrate that high pressure feedwater heaters' level controls maintain proper level and drain to the deareator. (PAT)

3.6 Demonstrate that the low pressure feedwater heaters' level controls maintain proper level and drain to the main condenser. (PAT)

4.0 DATA REQUIRED

4.1 Valve opening and closing times, where required.

4.2 Valve position indication.

4.3 Position response of valves to loss of motive power.

4.4 Setpoints at which alarms and interlocks occur.

4.5 Feedwater temperature at 100% flow for each heater group.

4.6 Setpoints of Level Controllers

5.0 ACCEPTANCE CRITERIA

5.1 The Feedwater Heater and Heater Drains System performs as described in Section 10.4.7.

14.2.12.1.76 Ultimate Heat Sink Test

1.0 OBJECTIVE

1.1 To verify that Ultimate Heat Sink (UHS) is maintained by its associated support systems.

2.0 PREREQUISITES

2.1 Construction activities on the Ultimate Heat Sink have been completed.

2.2 UHS makeup source available as required.

2.3 UHS blowdown path available as required.

2.4 Ultimate Heat Sink System instrumentation has been calibrated.

2.5 Test instrumentation available and properly calibrated.

3.0 TEST METHOD

3.1 Demonstrate that UHS makeup flow meets design.

3.2 Demonstrate that UHS blowdown flow meets design.

3.3 Demonstrate the operation of UHS level and temperature instruments and alarms.

4.0 DATA REQUIRED

4.1 UHS makeup flow.

4.2 UHS blowdown flow.

4.3 Setpoints of alarms.

5.0 ACCEPTANCE CRITERIA

5.1 The Ultimate Heat Sink operates as described in Section 9.2.5.

14.2.12.1.77 Chilled Water System Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the Essential Chilled Water and Normal Chilled Water Systems.

2.0 PREREQUISITES

2.1 Construction activities on the Chilled Water System have been completed.

2.2 Chilled Water System instrumentation has been calibrated.

2.3 Test instrumentation available and properly calibrated.

2.4 Component Cooling Water System available.

2.5 Appropriate AC and DC power sources available.

3.0 TEST METHOD

3.1 Demonstrate that each Essential Chilled Water System division can be operated from its local and remote manual control station.

3.2 Demonstrate that each Essential Chilled Water System division starts automatically in response to the appropriate signal.

3.3 Verify that the chillers supply chilled water at the rated flow and design conditions.

3.4 Verify chilled water flow to supplied components.

3.5 Verify alarms, interlocks, indicating instruments, and status lights are functional.

3.6 Verify head versus flow characteristics for the Chilled Water System pumps.

3.7 Verify system baseline performance during HFT testing.

4.0 DATA REQUIRED

4.1 Record flows as required to components and throttle valve positions.

4.2 Record alarm, interlock, and control setpoints.

4.3 Record chiller normal operating parameters.

4.4 Record pump head versus flow and operating data.

4.5 System operating parameters during HFT.

5.0 ACCEPTANCE CRITERIA

5.1 The Chilled Water System operates as described in Section 9.2.9.

14.2.12.1.78 Station Service Water System Test

1.0 OBJECTIVE

1.1 To demonstrate the ability of the Station Service Water System to supply cooling water as designed under normal and emergency conditions.

2.0 PREREQUISITES

2.1 Construction activities on the Station Service Water System have been completed.

2.2 Station Service Water instrumentation has been calibrated.

2.3 Support systems required for the operation of the Station Service Water System are complete and operational.

2.4 Test instruments available and calibrated.

2.5 Ultimate Heat Sink is available.

3.0 TEST METHOD

3.1 Verify head versus flow characteristics for the station service water pumps.

3.2 Verify adequate flow of station service water to each supplied component.

3.3 Verify alarms, indicating instruments and status lights are functional.

3.4 Verify system response on a loss of offsite power.

3.5 Verify a low station service water pump discharge pressure starts the idle pump in each division

3.6 Verify proper operation of the control valves, Pump Discharge Check Valves and Strainer Backwash Valves.

3.7 Verify pump control from the control room.

4.0 DATA REQUIRED

4.1 Record pump head versus flow and operating data.

4.2 Flow to CCW heat exchangers using various pump combinations.

4.3 Setpoints of alarms, interlocks and controls.

4.4 Valve position indication.

5.0 ACCEPTANCE CRITERIA

5.1 The Station Service Water System operates as described in Section 9.2.1.

14.2.12.1.79 Component Cooling Water System Test

1.0 OBJECTIVE

1.1 To demonstrate the capability of the Component Cooling Water System (CCWS) to provide cooling water during normal unit operation, during unit cooldown, during refueling, and during an emergency situation; and to demonstrate proper system response to a simulated engineered safety features actuation signal.

2.0 PREREQUISITES

2.1 Construction activities on the Component Cooling Water System have been completed.

2.2 Component Cooling Water System instrumentation has been calibrated.

2.3 Test instrumentation is available and calibrated.

2.4 Plant systems required to support testing are operable, or temporary systems are installed and operable.

3.0 TEST METHOD

3.1 Demonstrate proper operation of the surge tanks and their controls.

3.2 Demonstrate proper system and component flow paths, flow rates, and pressure drops including head versus flow verification for the component cooling water pumps.

3.3 Perform a pump head versus flow verification for all four pumps.

3.4 Verify the non-essential headers and the spent fuel pool heat exchangers are isolated on an SIAS. Verify the component cooling water heat exchanger bypass valves close on an SIAS. Verify the containment spray heat exchanger isolation valves open on a CSAS and on a component cooling water pump high differential pressure signal.

3.5 Verify the non-essential headers and RCP headers are isolated on a surge tank low-low level signal.

3.6 Verify a low CCW pump differential pressure signal starts the idle pump in each division.

3.7 Operate control valves from all appropriate control positions. Observe valve operation and position indication. Measure valve opening and closing times, where required.

3.8 Verify power-operated valves fail to the position specified in Section 9.2.2 upon loss of motive power.

3.9 Verify alarms, interlocks, indicating instruments, and status lights are functional.

3.10 Verify pump control from the control room.

3.11 Demonstrate the ability of the CCWS in conjunction with the Shutdown Cooling System and Station Service Water System to perform a plant cooldown. (HFT)

4.0 DATA REQUIRED

4.1 Record pump head versus flow and operating data for each pump.

4.2 Flow balancing data including flow to each component and throttle valve positions.

4.3 Setpoints of alarms, interlocks and controls.

4.4 Valve opening and closing times, where required.

4.5 Valve position indication.

4.6 Position response of valves to loss of motive power.

4.7 Temperature data during cooldown.

4.8 Response of valves to SIAS, CSAS, low-low surge tank level signal, and component cooling water pump high differential pressure signal.

5.0 ACCEPTANCE CRITERIA

5.1 The Component Cooling Water System operates as described in Section 9.2.2.

14.2.12.1.80 Pool Cooling and Purification System Test

1.0 OBJECTIVE

1.1 To demonstrate the capability of the Pool Cooling and Purification System (PCPS) to provide the proper flow paths and flow rates required to remove decay heat from the Spent Fuel Pool. The purification capability of the system is verified by demonstrating the proper purification flow paths and flow rates.

2.0 PREREQUISITES

2.1 Construction activities on the Pool Cooling and Purification System have been completed.

2.2 Pool Cooling and Purification System instrumentation has been calibrated.

2.3 Test instrumentation available and properly calibrated.

2.4 Component Cooling Water System water available.

2.5 Spent Fuel Pool and Reactor Vessel Cavity construction leak tests completed.

2.6 Support systems required for the operation of the Pool Cooling and Purification System are complete and operable.

2.7 The spent fuel pool is filled to normal level.

3.0 TEST METHOD

3.1 Verify head versus flow for the pumps.

3.2 Verify control logic.

3.3 Verify the proper operation of controls, interlocks instrumentation and alarms using actual or simulated inputs.

3.4 Verify the operability of the fuel pool gates and verify leakage within acceptable limits.

3.5 Verify the anti-siphons holes are free of obstructions.

3.6 Verify no leakage of the spent fuel pool by checking the leak detection system.

3.7 Verify that the PCPS meets the design flow rate and filtration capacity.

3.8 Verify power-operated valves fail to the position specified in Section 9.1.3 upon loss of motive power.

3.9 Test control valves from all positions and observe operation and position indication.

4.0 DATA REQUIRED

4.1 Pump head versus flow and operating data for each pump.

4.2 Setpoints of alarms, interlocks and controls.

4.3 Flow data through various system flow paths.

4.4 Fuel pool gate leakage data.

4.5 Position response of valves to loss of motive power.

4.6 Control valve operation and position.

5.0 ACCEPTANCE CRITERIA

5.1 The Pool Cooling and Purification System operates as described in Section 9.1.3.

14.2.12.1.81 Turbine Building Cooling Water System Test

1.0 OBJECTIVE

1.1 To verify proper operation of the Turbine Building Cooling Water System

2.0 PREREQUISITES

2.1 Construction activities on the Turbine Building Cooling Water System have been completed.

2.2 Support systems required for the operation of the Turbine Building Cooling Water System complete and operational.

2.3 Test instrumentation is available and calibrated.

2.4 Turbine Building Cooling Water System instrumentation has been calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify the proper operation of the cooling pumps, including head and flow characteristics.

3.3 Demonstrate flow paths and verify heat exchanger temperature rise, inlet and outlet water temperatures, equipment temperature and monitor performance and make appropriate flow rate adjustments to satisfy performance parameters.

3.4 Demonstrate that the heat exchangers will operate at design flow rate without exceeding heat exchanger design pressure drop.

3.5 Verify the proper operation of the surge tank level control and upper and lower level alarms.

3.6 Verify the proper operation of all protective devices, controls, interlocks, instrumentation, and alarms.

3.7 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.8 Verify power-operated valves fail to the position specified in Section 9.2.8 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Operating data for the Turbine Building Cooling Water pumps.

4.2 Record throttle valve positions and flows to each component.

4.3 Valve opening and closing times, where required.

4.4 Valve position indication.

4.5 Position response of valves to loss of motive power.

4.6 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Turbine Building Cooling Water System performs as described in Section 9.2.8.

14.2.12.1.82 Condensate Storage System Test

1.0 OBJECTIVE

1.1 To demonstrate that the Condensate Storage System provides a reliable source of water for the designated systems.

2.0 PREREQUISITE

2.1 Construction activities on the Condensate Storage System have been complete.

2.2 Condensate Storage System instrumentation has been calibrated.

2.3 Test instrumentation is available and calibrated.

2.4 Support system required for the operation of the Condensate Storage System are complete and operable.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify pumps' operating parameters.

3.3 Demonstrate the operability of all design flow paths.

3.4 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.5 Verify power-operated valves fail to the position specified in Section 9.2.6 upon loss of motive power.

3.6 Verify operation of protective devices, controls, interlocks, instrumentation, and alarms, using actual or simulated inputs.

3.7 Verify the Condensate Storage Tank is maintained at acceptable water oxygen concentration.

3.8 Verify all flow paths.

4.0 DATA REQUIRED

4.1 Pump operating data.

4.2 Valve opening and closing times, where required.

4.3 Valve position indication.

4.4 Position response of valves to loss of motive power.

4.5 Setpoints at which alarms and interlocks occur.

4.6 Applicable chemistry results.

5.0 ACCEPTANCE CRITERIA

5.1 The Condensate Storage System operates as described in Section 9.2.6.

14.2.12.1.83 Turbine Building Service Water System Test

1.0 OBJECTIVE

1.1 To demonstrate the ability of Turbine Building Service Water System (TBSWS) to supply cooling water under normal plant operations.

2.0 PREREQUISITES

2.1 Construction activities on the Turbine Building Service Water System have been completed.

2.2 Turbine Building Service Water System instrumentation has been calibrated.

2.3 Support system required for operation of the Turbine Building Service Water System are complete and operational.

2.4 Test instruments available and calibrated.

2.5 TBSWS intake at proper water level.

3.0 TEST METHOD

3.1 Verify TBSWS pump and system flow meet design.

3.2 Verify standby TBSWS pump starts on low discharge pressure or a trip of the running pump.

4.0 DATA REQUIRED

4.1 Pump operating data.

4.2 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Turbine Building Service Water System operates as described in Section 9.2.10.

14.2.12.1.84 Equipment and Floor Drainage System Test

1.0 OBJECTIVE

1.1 To demonstrate that the drain lines are correctly routed to their designated destination.

1.2 To demonstrate the sump pumps operate per design including alarms and interlocks.

1.3 To demonstrate the waste tanks operate per design including alarms and interlocks.

1.4 To demonstrate the sump level instrumentation operates per design including alarms and indications.

1.5 To demonstrate system segregation.

1.6 To demonstrate the turbine building floor drain sump operates per design upon detection of radiation in the sump.

2.0 PREREQUISITES

2.1 Construction activities on the Equipment and Floor Drainage System have been completed.

2.2 Equipment and Floor Drainage System instrumentation has been calibrated.

2.3 Support systems required for operation of the Equipment and Floor Drainage System are complete and operational.

2.4 Water is available for flow paths to be checked.

3.0 TEST METHOD

3.1 Verify the operation of alarms and interlocks.

3.2 Verify sump levels as required to demonstrate proper operation of the sump pumps.

3.3 Flow water in each drain path to verify that the drains discharge to their designated destination and that system segregation is maintained.

3.4 Verify the ability of the turbine building floor drain sump to divert liquids to the Liquid Waste Management System upon detection of radiation in the sump.

4.0 DATA REQUIRED

4.1 Sump pump operating data.

4.2 Setpoints at which alarms and interlocks occur.

4.3 Discharge points of each drain.

5.0 ACCEPTANCE CRITERIA

5.1 The Equipment and Floor Drainage System operates as described in Section 9.3.3.

14.2.12.1.85 Normal and Security Lighting Systems Test

1.0 OBJECTIVE

1.1 To demonstrate that the Normal and Security Lighting Systems provide adequate illumination for plant operations.

2.0 PREREQUISITES

2.1 Construction activities on the Normal Lighting System have been completed.

2.2 Construction activities on the Security Lighting System have been completed.

2.3 Test instruments are properly calibrated and available.

3.0 TEST METHOD

3.1 Place the plant lighting in service and check that illumination levels are adequate.

3.2 Demonstrate that a single circuit failure will not cause the loss of all lighting in a room which requires normal access.

3.3 Demonstrate that loss of normal power results in proper activation of the Security Lighting System for each affected room, where required to monitor isolation zones, and outdoor areas within the plant protected perimeter.

3.4 Demonstrate the Security Lighting System provides adequate illumination levels, including, but not limited to, those required to support plant Closed Circuit TV security functions.

4.0 DATA REQUIRED

4.1 Illumination levels in designated areas.

5.0 ACCEPTANCE CRITERIA

5.1 The Normal and Security Lighting Systems operate as described in Section 9.5.3.

14.2.12.1.86 Emergency Lighting System Test

1.0 OBJECTIVE

1.1 To demonstrate that the Emergency Lighting System provides adequate illumination to operate equipment during emergency operations.

2.0 PREREQUISITES

2.1 Construction activities on the Emergency Lighting System have been completed.

2.2 Test instruments are properly calibrated and available.

3.0 TEST METHODS

3.1 Demonstrate that the Emergency Lighting System provides 10 foot candles of illumination as required in designated control areas.

3.2 Demonstrate that the Emergency Lighting System provides 2 foot candles of illumination in other areas of the plant.

3.3 Demonstrate that the Emergency Lighting System comes on upon loss of normal lighting.

3.4 Demonstrate that the battery operated emergency lights provide adequate illumination at designated locations.

3.5 Demonstrate that the battery operated emergency lights are capable of providing lighting for the designated amount of time.

4.0 DATA REQUIRED

4.1 Illumination levels in designated areas.

4.2 Battery powered lighting data.

5.0 ACCEPTANCE CRITERIA

5.1 The Emergency Lighting System operates as described in Section 9.5.3.

14.2.12.1.87 Communications Systems Test

1.0 OBJECTIVE

1.1 To demonstrate the adequacy of the intraplant Communications Systems to provide communications between vital plant areas.

1.2 To demonstrate the offsite Communication Systems provide communications with exterior entities.

2.0 PREREQUISITES

2.1 Construction activities on the intraplant Communications Systems have been completed.

2.2 Support systems required for operation of the intraplant Communications Systems are complete and operational.

2.3 Plant equipment that contributes to the ambient noise level should be in operation.

3.0 TEST METHOD

3.1 Verify the Intraplant Portable Wireless Communication System functions properly.

3.2 Verify that the Intraplant (PABX) Telephone System functions properly.

3.3 Verify the Intraplant Sound Powered Telephone system functions properly.

3.4 Verify the Intraplant Public Address System functions properly.

3.5 Verify the Security Radio System functions properly at all locations throughout the plant.

3.6 Verify the normal offsite telephone system functions properly.

3.7 Verify the Emergency Telephone System (Emergency Notification System, Health Physics Network, and Ringdown Phone System) function properly.

4.0 DATA REQUIRED

4.1 Record the results of all communication attempts from each system and its locations.

5.0 ACCEPTANCE CRITERIA

5.1 The intraplant Communications Systems operate as described in Section 9.5.2.

5.2 The offsite Communication Systems operate as described in Section 9.5.2.

14.2.12.1.88 Compressed Air Systems Test

1.0 OBJECTIVE

1.1 To demonstrate that the Compressed Air Systems provide a safe and reliable source of compressed air for the operation of plant equipment.

2.0 PREREQUISITES

2.1 Construction activities on the Compressed Air System have been completed.

2.2 Compressed Air Systems' instrumentation has been calibrated.

2.3 Support systems required for operation of the Compressed Air Systems are complete and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Sufficient permanent loads are connected to the Compressed Air Systems and are operable to verify air compressor loading.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify the proper operation and capacity of the Instrument Air, Station Air and Breathing Air compressors. Verify proper operation of compressor unloaders, auto and manual start and stop circuits.

3.3 Demonstrate the operability of the air compressor dryers and filters, aftercoolers, moisture separators, air receivers, and pressure reducing stations.

3.4 Verify the proper operation of all protective devices, controls, interlocks, instruments, computer inputs, alarms and resets, pressure switches, safety and relief valves, bypass valves using actual or simulated inputs.

3.5 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.6 Verify power-operated valves fail to the position specified in Section 9.3.1 upon loss of motive power.

3.7 Verify proper operation of all moisture drains.

3.8 Verify relief valve settings.

3.9 Verify appropriate differential pressures (e.g., delta P across prefilters and afterfilters).

3.10 While at system normal steady state conditions, if practicable, simultaneously operate those plant components requiring large quantities of instrument air, to verify pressure transients in the distribution system do not exceed acceptable values.

3.11 Functionally test instrument air systems to ensure credible failures resulting in an increase in supply system pressure will not cause loss of operability.

3.12 Verify that the total air demand at normal steady state conditions, including leakage from the systems, is in accordance with design.

4.0 DATA REQUIRED

4.1 Capacity data on compressors.

4.2 Cycle times and regeneration temperatures of air dryers.

4.3 Air dryer dew point temperatures.

4.4 Air quality measurements (dewpoint, hydrocarbons, particulates).

4.5 Valve opening and closing times, where required.

4.6 Valve position indication.

4.7 Position response of valves to loss of motive power.

4.8 Setpoints at which alarms and interlocks occur.

4.9 Pressure, temperature, and flow rate readings at remote and control board indicators.

4.10 Cycle times for automatic moisture drain valves.

4.11 System response to the simultaneous operation of plant components requiring large quantities of instrument air.

4.12 System response to an increase in supply pressure.

5.0 ACCEPTANCE CRITERIA

5.1 The Compressed Air Systems operate in accordance with Section 9.3.1.

14.2.12.1.89 Compressed Gas Systems Test

1.0 OBJECTIVE

1.1 To verify the functional performance of the Nitrogen System and other plant Compressed Gas Systems.

2.0 PREREQUISITES

2.1 Construction activities on the Compressed Gas System have been completed.

2.2 Compressed Gas System instrumentation has been calibrated.

2.3 Support systems required for operation of the Compressed Gas System are complete and operational.

2.4 Test Instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 erify proper operation of Liquid Nitrogen System to maintain delivery pressure at 700 psig.

3.2 Demonstrate each flow path for the Nitrogen System and that the regulators respond on demand.

3.3 Verify the proper operation of all controls, interlocks, instruments and alarms for the compressed gas systems.

3.4 Verify the operation of the Hydrogen System by demonstrating the flow paths and that the regulators respond on demand.

3.5 Verify the operation of the leak detection systems for Hydrogen and Carbon Dioxide Systems.

3.6 Verify the flow paths for all other compressed gas systems.

4.0 DATA REQUIRED

4.1 Control setpoints of the system regulators.

4.2 Alarm setpoints.

5.0 ACCEPTANCE CRITERIA

5.1 The Compressed Gas Systems operate as described in Section 9.5.10.

14.2.12.1.90 Process Sampling System Test

1.0 OBJECTIVE

1.1 To verify the ability of Process Sampling System to collect and deliver representative samples of liquids and gases in various process systems to sample stations for chemical and radiological analysis during operation, cooldown and post accident modes.

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested have been completed.

2.2 Systems being sampled are at or near normal operating pressure and temperature.

2.3 Calibrating gases and solutions are available.

2.4 Test instrumentation is available and calibrated.

2.5 Process Sampling System instrumentation has been calibrated.

3.0 TEST METHOD

3.1 Withdraw fluid at each sample point, verifying adequate flow.

3.2 Verify the proper operation of all alarms and interlocks.

3.3 Verify the proper operation of all pump and heat exchangers in specified operating modes and flow paths.

3.4 Verify the analytical instrumentation provides proper indication and response.

3.5 Calculate the holdup times using the piping volume and measured flow rate for Reactor Coolant System and Pressurizer samples.

3.6 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.7 Verify power-operated valves fail to the position specified in Section 9.3.2 upon loss of motive power.

3.8 Verify the proper operation of all continuous monitors and verify adequate flow.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms and interlocks occur.

4.2 Sampling flow rate from each sample point.

4.3 Analytical instrument data.

4.4 Valve opening and closing times, where required.

4.5 Valve position indication.

4.6 Position response of valves to loss of motive power.

4.7 Holdup time for RCS and pressurizer samples.

5.0 ACCEPTANCE CRITERIA

5.1 The Process Sampling System performs as described in Section 9.3.2.

14.2.12.1.92 Heat Tracing System Test

1.0 OBJECTIVE

1.1 Verify that plant heat traced components are maintained at design temperature.

2.0 PREREQUISITES

2.1 Construction activities on the Heat Tracing System have been completed.

2.2 Heat Tracing System instrumentation has been calibrated.

2.3 Support systems required for operation of the Heat Tracing system are complete and operational.

2.4 Test Instrumentation is available and calibrated.

2.5 Electrical power supply available.

3.0 TEST METHOD

3.1 With system process at design flow, verify the Heat Tracing System maintains each component within its minimum and maximum design temperature limits by checking temperatures at various points.

3.2 Demonstrate the operation of controls and alarms.

4.0 DATA REQUIRED

4.1 Temperature data for the heat traced components.

4.2 Setpoints of alarms and control points.

5.0 ACCEPTANCE CRITERIA

5.1 The Heat Tracing System maintains designated components within design temperature limits, as described in Section 9.3.4.

14.2.12.1.92 Fire Protection System Test

1.0 OBJECTIVE

1.1 To demonstrate the ability of the Fire Protection System to provide water at acceptable flows and pressures to protected areas.

2.0 PREREQUISITES

2.1 Construction activities on the Fire Protection System have been completed.

2.2 Fire Protection System instrumentation has been calibrated.

2.3 Support systems required for operation of the Fire Protection System are complete and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate the proper operation of the Fire Detection System.

3.2 Demonstrate the head and flow characteristics of the fire water pumps, and the operation of all auxiliaries.

3.3 Verify control logic.

3.4 Verify flow rates in the various flow paths of the Fire Protection Water Distribution System.

3.5 Verify sprinkler and deluge spray patterns where possible.

3.6 Verify alarms, indicating instruments, and status lights are functional.

3.7 Verify proper operation of smoke control and fire dampers.

4.0 DATA REQUIRED

4.1 Setpoints under which alarms and interlocks occur.

4.2 Sprinkler and deluge spray patterns.

4.3 Fire alarm operability.

4.4 Temperature, flame, and smoke sensors operability.

4.5 Pump head versus flow and operating data.

4.6 Smoke control and fire damper operability.

5.0 ACCEPTANCE CRITERIA

5.1 The Fire Protection System operates as described in Section 9.5.1.

14.2.12.1.93 Emergency Diesel Generator Mechanical System Test

1.0 OBJECTIVE

1.1 To demonstrate the Emergency Diesel Generator (EDG) Mechanical System operates reliably.

2.0 PREREQUISITES

2.1 Construction activities on the Diesel Generator System have been completed.

2.2 Emergency Diesel Generator System instrumentation has been calibrated.

2.3 Support systems required for operation of the Emergency Diesel Generator System are complete and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate that each EDG can be started from the Control Room and its local panel in automatic and manual.

3.2 Demonstrate that the following mechanical and electrical trips are operable and function as described in Section 8.3.1.1.4.4 (includes protective trips bypass tests).

3.2.1 Engine overspeed

3.2.2 Generator Differential Protection

3.2.3 Low-Low Lube Oil Pressure

3.2.4 Generator Voltage-Controlled Overcurrent

3.2.5 Low Pressure Turbo Oil

3.2.6 Low Pressure Lube Oil

3.2.7 High Pressure Crankcase

3.2.8 High Temperature Bearings

3.2.9 High Temperature Lube Oil Out

3.2.10 High-High Temperature Jacket Water

3.2.11 High Vibration

3.3 Demonstrate that the following parameters are correctly monitored in the Control Room and at the local panel:

3.3.1 Lube Oil Temperature and Pressures

3.3.2 Bearing Temperatures

3.3.3 Cooling Water Temperatures and Pressures

3.3.4 Speed

3.3.5 Starting Air Pressure

3.4 Demonstrate the operation of the following status indications:

3.4.1 Cooling water not available

3.4.2 Diesel Generator breaker racked out

3.4.3 Diesel Generator overspeed

3.4.4 Loss of control power

3.4.5 Generator fault

3.4.6 Low air and oil pressure

3.4.7 Maintenance mode

3.5 Demonstrate 35 consecutive starts capability.

3.6 Demonstrate full load capability.

3.7 Demonstrate EDG speed control.

4.0 DATA REQUIRED

4.1 EDG Engine operating parameters.

4.2 EDG Engine consecutive starts data.

4.3 Setpoints of EDG trips.

4.4 EDG governor operating data.

4.5 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Emergency Diesel Generator Mechanical System performs as described in Section 8.3.1.

14.2.12.1.94 Emergency Diesel Generator Electrical System Test

1.0 OBJECTIVE

1.1 To verify the Emergency Diesel Generators (EDGs) can supply power at the rated load, voltage and frequency under all design conditions.

2.0 PREREQUISITES

2.1 Construction activities on the Emergency Diesel Generator System have been completed.

2.2 EDG Mechanical System Test is completed.

2.3 Emergency Diesel Generator System instrumentation has been calibrated.

2.4 Support systems required for operation of the Emergency Diesel Generator System are complete and operational.

2.5 Test instrumentation is available and calibrated.

2.6 Electrical testing is complete as needed to allow the buses to be energized.

2.7 DG electrical voltage tests are complete.

2.8 ESF loads are available to be loaded onto the bus.

3.0 TEST METHOD

3.1 Demonstrate all control logic and controls including the EDG sequencer and response to ESF actuation signals.

3.2 Demonstrate 90 to 100 percent of the continuous rating of the emergency diesel generator, for an interval of not less than 1 hour and until temperature equilibrium has been attained.

3.3 Demonstrate that the emergency diesel generator unit starts from standby conditions, reaches required voltage and frequency within acceptable limits and time as defined in the plant technical specifications.

3.4 Demonstrate by simulating a loss of offsite power that:

- the emergency buses are deenergized and the loads are shed from the emergency buses, and

- the emergency diesel generator starts on the auto-start signal from its standby conditions, attains the required voltage and frequency within acceptable limits and time, energizes the auto-connected shutdown loads through the load sequencer, and operates while loaded with its shutdown loads for greater than or equal to 5 minutes.

3.5 Demonstrate that on a safety injection actuation signal (SIAS), the emergency diesel generator starts on the auto-start signal from its standby conditions, attains the required voltage and frequency within acceptable limits and time, and operates for greater than or equal to 5 minutes.

3.6 Demonstrate the emergency diesel generator's capability to reject a loss of the largest single load while operating at power factor between 0.8 and 0.9, and verify that the voltage and frequency requirements are met and that the EDG unit will not trip on overspeed.

3.7 Demonstrate the emergency diesel generator's capability to reject a load equal to 90 to 100 percent of its continuous rating while operating at power factor between 0.8 and 0.9, and verify that the voltage requirements are met and that the emergency diesel generator will not trip on overspeed.

3.8 Emergency diesel generator endurance and margin test: demonstrate full-load carrying capability at a power factor between 0.8 and 0.9 for an interval of not less than 24 hours, of which 2 hours are at a load equal to 105 to 110 percent of the continuous rating of the emergency diesel generator, and 22 hours are at a load equal to 90 to 100 percent of its continuous rating. Verify that voltage and frequency requirements are maintained. Verify that mechanical systems such as fuel, lubrication, and cooling function within design limits.

3.9 Demonstrate hot restart functional capability at full-load temperature conditions (after it has operated for 2 hours at full load) by verifying that the emergency diesel generator starts on a manual or autostart signal, attains the required voltage and frequency within acceptable limits and time, and operates for longer than 5 minutes. This testing is to occur immediately after the full-load carrying capability demonstration.

3.10 Demonstrate the ability to

- synchronize the diesel generator unit with offsite power while the unit is connected to the emergency load,

- transfer this load to the offsite power,

- isolate the diesel generator unit, and
- restore it to standby status.

3.11 Demonstrate that with the emergency diesel generator operating in a test mode while connected to its bus, a simulated safety injection actuation signal overrides the test mode by

- returning the emergency diesel generator to standby operation, and
- automatically energizing the emergency loads from offsite power.

3.12 Demonstrate that, by starting and running both redundant emergency diesel generator units simultaneously, potential common failure modes that may be undetected in single emergency diesel generator unit tests do not occur.

4.0 DATA REQUIRED

4.1 Starting and loading sequence timing.

4.2 Test data traces for starting, stopping and load shedding.

4.3 Running data for the parameters monitored during each of the required testing sequences.

4.4 Verification of field performance data versus shop data.

5.0 ACCEPTANCE CRITERIA

5.1 The Emergency Diesel Generator Electrical System performs as described in Section 8.3.1.

14.2.12.1.95 Emergency Diesel Generator Auxiliary Systems Test

1.0 OBJECTIVE

1.1 Demonstrate that the Emergency Diesel Generator's (EDG's) fuel oil system provides a reliable and adequate supply to each Emergency Diesel Generator.

1.2 Demonstrate the operation of the EDG engine cooling water system.

1.3 Demonstrate that the EDG engine starting air system provides adequate amount of air for 5 consecutive starts of its EDG without makeup air.

1.4 Demonstrate the operation of the EDG engine lube oil system.

2.0 PREREQUISITES

2.1 Construction activities on the Emergency Diesel Generator Auxiliary Systems have been completed.

2.2 Emergency Diesel Generator Auxiliary Systems instrumentation has been calibrated.

2.3 Support systems required for operation of the Emergency Diesel Generator Auxiliary Systems are complete and operational.

2.4 Test instrumentation is available and calibrated.

2.5 The EDGs are available for a loaded run to measure fuel consumption and to perform consecutive starts.

3.0 TEST METHOD

3.1 Demonstrate the operation of the fuel oil automatic transfer feature from the storage tanks to the day tank.

3.2 Demonstrate the operation of the fuel oil and day tank level alarms.

3.3 Demonstrate the day tank can be filled manually.

3.4 Demonstrate the operation of the fuel oil booster pump.

3.5 Demonstrate the operation of the fuel oil recirculation system.

3.6 Demonstrate by performing a loaded run of the EDG with its day tank filled to its low level alarm point, that the day tank provides sufficient fuel for at least 60 minutes of EDG operation with the EDG supplying the power requirements of the most limiting design basis accident.

3.7 Demonstrate by performing a loaded run of the EDG and analysis of EDG fuel storage capacity, that each EDG has sufficient fuel storage capacity to operate for a period of no less than 7 days with the EDG supplying the power requirements of the most limiting design basis accident.

3.8 Demonstrate the operation of the EDG cooling water system keep warm pump.

3.9 Demonstrate the operation of EDG cooling system heaters.

3.10 Demonstrate the operation of the EDG cooling system alarms.

3.11 Demonstrate the operation of EDG starting air compressors.

3.12 Demonstrate that each EDG starting air system has sufficient volume available to perform 5 consecutive starts of its EDGs.

3.13 Demonstrate the EDG starting air system operates the EDG pneumatic controls as designed.

3.14 Demonstrate the EDG starting air alarm interlocks, and automatic operation.

3.15 Demonstrate the operation of the EDG lube oil prelube pump.

3.16 Demonstrate the operation of EDG lube oil heaters.

3.17 Demonstrate the operation of EDG lube oil alarms.

3.18 Demonstrate the operation of the EDG lube oil transfer pump.

3.19 Verify power-operated valves fail to the position specified in Section 9.5 upon loss of motive power.

4.0 DATA REQUIRED

4.1 EDG fuel oil consumption rate.

4.2 Setpoints of alarms, interlocks, and controls.

4.3 Operating data for pumps and compressors.

4.4 Operating data for the heaters.

4.5 EDG starting air volume parameters after consecutive starts.

4.6 Position response of valves to loss of motive power.

5.0 ACCEPTANCE CRITERIA

5.1 The DG Engine Fuel Oil System operates as described in Section 9.5.4.

5.2 The DG Engine Cooling Water System operates as described in Section 9.5.5.

5.3 The DG Engine Starting Air System operates as described in Section 9.5.6.

5.4 The DG Engine Lube Oil System operates as described in Section 9.5.7.

14.2.12.1.96 Alternate AC Source System Test

1.0 OBJECTIVE

1.1 To verify the proper operation of the Alternate AC (AAC) Source System.

2.0 PREREQUISITES

2.1 Construction activities on the Alternate AC Source have been completed.

2.2 Support systems including the AAC Support Systems and the 4160 KV distribution system required for the operation of the AAC source system are complete and operational.

2.3 Alternate AC Source instrumentation has been calibrated.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify the system alarms, instrumentation, interlocks and controls.

3.2 Verify the AAC Source provides rated power at the proper voltage and frequency.

3.3 Verify operation of the AAC Source from all its control stations.

3.4 Demonstrate the AAC Source can be connected in the design configuration to each 4160 V bus combination.

3.5 Verify AAC can carry design loads.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms and interlocks occur.

4.2 AAC Source operating data at designated loads including time to start and connect to each assigned 4160 V bus combination.

5.0 ACCEPTANCE CRITERIA

5.1 The Alternate AC Source System operates as described in Section 8.3.1.

14.2.12.1.97 Alternate AC Source Support Systems Test

1.0 OBJECTIVE

1.1 Demonstrate the proper operation of the Alternate AC Source System fuel, starting, cooling and lubrication subsystems.

2.0 PREREQUISITES

2.1 Construction activities on the AAC Source Support Systems have been completed.

2.2 AAC Source Support System instrumentation has been calibrated.

2.3 Support systems required for operation of the AAC Source Support Systems are complete and operational.

2.4 The AAC Source System is available to be run.

3.0 TEST METHOD

3.1 Demonstrate the adequacy and operation of the AAC Source fuel systems.

3.2 Demonstrate that the AAC Source can be started 5 times from each starting system.

3.3 Demonstrate the operation of the AAC Source lube oil system.

3.4 Demonstrate alarms, interlocks, and controls on the AAC Source fuel systems, starting system, lube oil and cooling system.

3.5 With the AAC Source in operation, verify the AAC Source Cooling System maintains design temperatures.

4.0 DATA REQUIRED

4.1 Setpoints of alarms, interlocks and controls.

4.2 Verification of starts from each AAC Source starting system.

4.3 AAC Source Cooling System Temperature.

4.4 Fuel consumption rate for required configurations.

5.0 ACCEPTANCE CRITERIA

5.1 The AAC Source Support Systems operate as described in Section 8.3.1.

14.2.12.1.98 Containment Polar Crane Test

1.0 OBJECTIVE

1.1 To demonstrate the functional performance of the Containment Polar Crane.

2.0 PREREQUISITES

2.1 Electric power available.

2.2 Containment Polar Crane Instrumentation has been calibrated.

2.3 Construction activities on the crane and associated equipment has been completed.

3.0 TEST METHOD

3.1 Verify operability of trolley, bridge, and hoist.

3.2 Check hoist and trolley speeds.

3.3 Check capability of crane to position over all required Containment Building equipment.

3.4 Perform 150% static load capacity test.

3.5 Perform an operational test of the polar crane at 100% of rated load.

3.6 Verify the operation of protective and safety devices.

4.0 DATA REQUIRED

4.1 Hoist and trolley speeds.

4.2 Verification of proper operation of interlocks.

4.3 Load capacity data.

5.0 ACCEPTANCE CRITERIA

5.1 The Containment Polar Crane performs as described in Section 9.1.4.

14.2.12.1.99 Fuel Building Cranes Test

1.0 OBJECTIVE

1.1 To demonstrate the functional performance of the Cask Handling and Fuel Handling Cranes.

2.0 PREREQUISITES

2.1 Electric power available.

2.2 Fuel Building cranes instrumentation has been calibrated.

2.3 Construction activities on the crane and associated equipment have been completed.

3.0 TEST METHOD

3.1 Verify operability of trolley, bridge, and hoist for each crane.

3.2 Check hoist and trolley speeds.

3.3 Check capability of cask handling and fuel handling crane to position over all required fuel building equipment.

3.4 Perform 150% static load capacity test of the cask handling crane and the fuel handling crane.

3.5 Perform an operational test of the cranes at 100% of rated load.

3.6 Verify the operation of protective and safety devices.

4.0 DATA REQUIRED

4.1 Hoist, and trolley speeds.

4.2 Verification of proper operation of interlocks.

4.3 Load capacity data.

5.0 ACCEPTANCE CRITERIA

5.1 The Cask Handling and Fuel Handling Cranes performs as described in Section 9.1.4.

14.2.12.1.100 Turbine Building Crane Test

1.0 OBJECTIVE

1.1 To demonstrate the functional performance of the Turbine Building Crane.

2.0 PREREQUISITES

2.1 Electric power available.

2.2 Turbine Building crane instrumentation has been calibrated.

2.3 Construction activities on the crane and associated equipment have been completed.

3.0 TEST METHOD

3.1 Verify operability of trolley, bridge, and hoist.

3.2 Check hoist and trolley speeds.

3.3 Check capability of crane to position over all required Turbine building equipment.

3.4 Perform 125% load capacity test.

4.0 DATA REQUIRED

4.1 Hoist, and trolley speeds.

4.2 Verification of proper operation of interlocks.

4.3 Load capacity data.

5.0 ACCEPTANCE CRITERIA

5.1 The Turbine Building Crane meets manufacturers design specification.

14.2.12.1.101 Containment Cooling and Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the capability of the Containment Cooling and Ventilation System to maintain acceptable temperature limits and air quality in the containment during normal operations and normal shutdown.

2.0 PREREQUISITES

2.1 Construction activities inside the containment building have been completed.

2.2 Construction activities on the containment cooling and ventilation system have been completed.

2.3 Containment Cooling and Ventilation System instrumentation has been calibrated.

2.4 Support systems required for operation of the Containment Cooling and Ventilation System are complete and operational.

2.5 Test instrumentation is available and calibrated.

2.6 The RCS is at normal operating temperature and pressure (HFT).

3.0 TEST METHOD

3.1 Verify the operation of the containment recirculation cooling units.

3.2 Verify the operation the pressurizer compartment cooling fans.

3.3 Verify the operation of the reactor cavity cooling fans.

3.4 Verify operation of the control element drive mechanism cooling fans.

3.5 Verify operation of the containment air clean up fans.

3.6 Perform air balance as appropriate for each subsystem.

4.0 DATA REQUIRED

4.1 Operation of all interlocks at proper setpoints.

4.2 Air balancing verification.

4.3 Fan operating data.

4.4 Containment building temperature data.

4.5 Filter and carbon adsorber data for containment air clean up filtration units.

5.0 ACCEPTANCE CRITERIA

5.1 The Containment Cooling and Ventilation System performs as described in Section 9.4.6.

14.2.12.1.102 Containment Purge Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the capability of the Containment Purge System to maintain the containment air temperature and cleanliness at the required value during inspection testing maintenance and refueling operations.

2.0 PREREQUISITES

2.1 Construction activities in the containment have been completed and acceptable levels of cleanliness established.

2.2 Construction activities on the Containment Purge System have been completed.

2.3 Containment Purge Ventilation System Instrumentation has been calibrated.

2.4 Support systems required for operation of the containment purge system are complete and operational.

2.5 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Demonstrate manual and automatic system controls.

3.2 Verify alarms, indicating instruments and status lights are functional.

3.3 Verify design air flows for High Purge, Low Purge and two Containment Cleanup Systems.

3.4 Perform filter and carbon adsorber efficiency tests.

3.5 Demonstrate system responses to a high radiation signal and high relative humidity signal.

3.6 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.7 Verify power-operated valves fail to the position specified in Section 9.4.6 upon loss of motive power.

3.8 Simulate CIAS, HHAS and HRAS and observe isolation valve response.

3.9 Verify the proper operation of Containment Purge Ventilation System radiation monitors.

4.0 DATA REQUIRED

4.1 Air balancing verification.

4.2 Fan operating data for low purge and high purge fans.

4.3 Filter and carbon adsorber data for exhaust filter trains.

4.4 Valve opening and closing times, where required.

4.5 Valve position indication.

4.6 Position response of valves to loss of motive power.

4.7 Setpoints at which alarms and interlocks occur.

4.8 Temperature of chilled water supply and return from cooling coils.

4.9 Temperature of air supply (outside) to high purge supply and discharge into containment.

4.10 Valves respond to simulated CIAS, HRAS, and HHAS signals.

4.11 Containment Purge Ventilation System radiation monitors performance data.

5.0 ACCEPTANCE CRITERIA

5.1 The Containment Purge Ventilation System performs as described in Section 9.4.6.

5.2 The Containment Purge Ventilation System radiation monitors perform as described in Section 11.5.

14.2.12.1.103 Control Complex Ventilation System Test

1.0 OBJECTIVE

1.1 To verify the functional operation of the Control Room Air Conditioning System (CRACS) and the Technical Support Center Air Conditioning System (TSCACS) and to ensure a proper environment for personnel and equipment under all postulated conditions.

Note: The pre-operational tests on the Balance of the Control Complex Ventilation System are described in Section 14.2.12.1.111.

2.0 PREREQUISITES

2.1 Construction activities in the Control Complex have been completed and all penetrations sealed.

2.2 Construction activities on the Control Complex Ventilation System have been completed.

2.3 Control Complex Ventilation System instrumentation has been calibrated.

2.4 Support systems required for operation of the Control Complex Ventilation System are complete and operational.

2.5 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify, the proper operation, stroking speed, and position indication of all dampers.

3.3 In manual operating mode, verify proper operation of the units, system rated air flow, and air balance.

3.4 In automatic mode, demonstrate the transfer to emergency operations as a result of radiation detection, smoke detection, [[toxic chemical detection (COL applicant item)]][1], and safety injection actuation signals.

3.5 Verify the filter particle removal efficiency, carbon adsorber efficiency and filter bank air flow capacity.

3.6 Verify the proper operation of all protective devices, controls, interlocks, instrumentation, and alarms, using actual or simulated inputs.

3.7 Verify that the system maintains the control room and technical support center (TSC) at positive pressure relative to the outside atmosphere during system operation in the pressurized mode as required by the Technical Specifications.

3.8 [[Verify the isolation capability of the control room and technical support center (TSC) upon detection of chlorine gas at the intakes meets the requirements of Reg. Guide 1.95 (COL applicant item).]][1]

3.9 Demonstrate the operation of the battery room exhaust fans.

3.10 Demonstrate the operation of the Electrical Equipment Room Air Handling Subsystem.

3.11 Demonstrate the operation of the Smoke Purge Fan.

3.12 Verify the proper operation of Control Complex Ventilation System radiation monitors.

4.0 DATA REQUIRED

4.1 Air balancing verification.

4.2 Fan and damper operating Data.

4.3 Temperature and humidity data in the Control Room envelope.

4.4 Response to radioactivity, [[toxic gas (COL applicant item),]][1] and products of combustion.

4.5 Setpoints of alarms, interlocks, and controls.

4.6 Pressurization data for the control room and TSC.

4.7 Filter and carbon adsorber data.

4.8 Control Complex Ventilation System radiation monitors' performance data.

5.0 ACCEPTANCE CRITERIA

5.1 The Control Complex Ventilation System operates as described in Section 9.4.1.

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1 COL information item; see DCD Introduction Section 3.2.

5.2 The Control Complex Ventilation System radiation monitors perform as described in Section 11.5.

14.2.12.1.104 Subsphere Building Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Subsphere Building Ventilation System to maintain design condition.

2.0 PREREQUISITES

2.1 Construction activities on the Subsphere Building Ventilation System have been completed.

2.2 Subsphere Building Ventilation System instrumentation has been calibrated.

2.3 Support systems required for operation of the Reactor Subsphere Building Ventilation System are complete and operational.

2.4 Test Instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify the proper operation, stroking speed and position indication of all dampers.

3.3 Verify the system maintains the Subsphere at a negative pressure.

3.4 Verify the system maintains the Reactor Subsphere at a negative pressure.

3.5 Verify the proper operation of the Ventilation Supply Units and Fans.

3.6 Verify the proper operation of the Ventilation Exhaust Units and Fans.

3.7 Verify the proper operation of the Mechanical Equipment Room Cooling Units.

3.8 Verify the proper operation of the Mechanical Equipment Room Ventilation Units.

3.9 Verify filter efficiency carbon adsorber efficiency and air flow capacity.

3.10 Verify the systems rated air flow and air balance.

3.11 Verify the proper operation of all protective devices, controls, interlocks instrumentation and alarms using actual or simulated inputs.

3.12 Verify the proper operation of the Subsphere Building Ventilation System radiation monitors.

4.0 DATA REQUIRED

4.1 Air balancing verification.

4.2 Fan and damper operating data.

4.3 Temperature data of building area.

4.4 Setpoints of alarms interlocks and controls.

4.5 Reactor Subsphere negative pressurization data.

4.6 Filter and carbon adsorber data.

4.7 Subsphere Building Ventilation System radiation monitors' performance data.

5.0 ACCEPTANCE CRITERIA

5.1 The Subsphere Building Ventilation System operates as described in Section 9.4.5.

5.2 The Subsphere Building Ventilation System radiation monitors perform as described in Section 11.5.

14.2.12.1.105 Turbine Building Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate that the Turbine Building Ventilation System provides a suitable operating environment for equipment and personnel during normal operations.

2.0 PREREQUISITES

2.1 Construction activities on the Turbine Building Ventilation System have been completed.

2.2 Turbine Building Ventilation System instrumentation has been calibrated.

2.3 Support systems required for operation of the Turbine Building Ventilation System are complete and operational.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify the proper operation of inlet air dampers and damper controls.

3.3 Verify the proper operation of the exhaust fan units and dampers.

3.4 Verify the proper operation of protective devices, controls, interlocks, instrumentation, and alarms.

4.0 DATA REQUIRED

4.1 Fan and damper operating data.

4.2 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Turbine Building Ventilation System operates as described in Section 9.4.7.

14.2.12.1.106 Station Service Water Pump Structure Ventilation System Test

1.0 OBJECTIVE

1.1 To verify the Station Service Water Pump Structure Ventilation System can maintain the space temperature as required.

2.0 PREREQUISITES

2.1 Construction activities on the Station Service Water Pump Structure Ventilation System have been completed.

2.2 Station Service Water Pump Structure Ventilation System instrumentation has been calibrated.

2.3 Support systems required for operation of the Station Service Water Pump Structure Ventilation System are complete and operational.

2.4 Test Instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic and interlock.

3.2 Verify design air flow of each fan.

3.3 Verify alarms, indicating instruments and status lights are functional.

3.4 Verify design temperatures can be maintained in the structure.

4.0 DATA REQUIRED

4.1 Temperature data for the structure from each fan unit.

4.2 Fan operating data.

4.3 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Station Service Water Pump Structure Ventilation System operates as described in Section 9.4.8.

14.2.12.1.107 Diesel Building Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the Diesel Building Ventilation System.

2.0 PREREQUISITES

2.1 Construction activities on the Diesel Building Ventilation System have been completed.

2.2 Diesel Building Ventilation System instrumentation has been calibrated.

2.3 Support systems required for operation of the Diesel Building Ventilation System are complete and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify design air flow with each Diesel Generator Building Ventilation System in operation.

3.3 Verify design temperature can be maintained in each Diesel Generator Building.

3.4 Verify alarms, indicating instruments and status lights are functional.

4.0 DATA REQUIRED

4.1 Fan and damper operating data.

4.2 Air flow verification.

4.3 Setpoint at which alarms, interlocks and controls, occur.

4.4 Temperature data of each Diesel Building.

5.0 ACCEPTANCE CRITERIA

5.1 The Diesel Building Ventilation System operates as described in Section 9.4.4.

14.2.12.1.108 Fuel Building Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Fuel Building Ventilation System to maintain design conditions.

2.0 PREREQUISITES

2.1 Construction activities on the Fuel Building Ventilation System have been completed.

2.2 Fuel Building Ventilation System instrumentation has been calibrated.

2.3 Support systems required for operation of the Fuel Building Ventilation System are complete and operational.

2.4 Test Instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify the proper operation, stroking speed and position indication of all dampers.

3.3 Verify the system maintains the Fuel Building at a negative pressure.

3.4 Verify the proper operation of the ventilation supply units and fans.

3.5 Verify the proper operation of the fuel handling area ventilation exhaust units and fans.

3.6 Verify the proper operation of the heating and cooling units.

3.7 Verify HEPA filter efficiency carbon adsorber efficiency and air flow capacity.

3.8 Verify the systems rated air flow and air balance.

3.9 Verify the proper operation of all protective devices, controls, interlocks instrumentation and alarms using actual or simulated inputs.

3.10 Verify system response to a high radiation signal.

3.11 Verify the proper operation of the Fuel Building Ventilation System radiation monitor.

4.0 DATA REQUIRED

4.1 Air balancing verification.

4.2 Fan and damper operating data.

4.3 Temperature data in the Fuel Building.

4.4 Setpoints at which alarms, interlocks, and controls occur.

4.5 Fuel Building negative pressurization data during normal and postulated emergency conditions.

4.6 Filter and carbon adsorber data.

4.7 Fuel Building Ventilation System radiation monitor's performance data.

5.0 ACCEPTANCE CRITERIA

5.1 The Fuel Building Ventilation System operates as described in Section 9.4.2.

5.2 The Fuel Building Ventilation System radiation monitor performs as described in Section 11.5.

14.2.12.1.109 Annulus Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the capability of the Annulus Ventilation System to produce and maintain a negative pressure in the annulus following a LOCA and to minimize the release of radioisotopes following a LOCA by recirculating a large volume of filtered annulus air relative to the volume discharged for negative pressure maintenance.

2.0 PREREQUISITES

2.1 Construction activities on the containment wall and shield wall are complete with all penetrations sealed in place.

2.2 Construction activities on the Annulus Ventilation System have been completed.

2.3 Annulus Ventilation System instrumentation has been calibrated.

2.4 Support systems required for operation of the Annulus Ventilation System are complete and operational.

2.5 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic, including response to ESFAS.

3.2 Verify the proper operation, failure mode stroking speed, and position indication of control valves and dampers.

3.3 Demonstrate that the Annulus Ventilation System will achieve a negative pressure in the Annulus greater than or equal to 0.25 inches water gauge within 110 seconds of actuation.

3.4 Verify the proper operation of all protective devices, controls, interlocks, instrumentation, and alarms.

3.5 Verify design air flow for normal and emergency operation.

3.6 Perform filter and carbon absorber efficiency test.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms, interlocks and controls occur.

4.2 Valve and damper operating data.

4.3 Air balancing verification.

4.4 Fan operating data.

4.5 Filter and carbon adsorber efficiency data.

4.6 Annulus negative pressurization data: Annulus pressure and drawdown time.

5.0 ACCEPTANCE CRITERIA

5.1 The Annulus Ventilation System operates as described in Sections 6.2.3 and 6.2.5.

14.2.12.1.110 Radwaste Building Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Radwaste Building Ventilation System to maintain design condition.

2.0 PREREQUISITES

2.1 Construction activities on the Radwaste Building Ventilation System have been completed.

2.2 Radwaste Building Ventilation System instrumentation has been calibrated.

2.3 Support systems required for operation of the Radwaste Building Ventilation System are complete and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify the proper operation, stroking speed and position indication of all damper.

3.3 Verify the capacity of the HVAC System to maintain the area temperature.

3.4 Verify the system maintains the Radwaste Building at a negative pressure.

3.5 Verify the proper operation of the general ventilation supply units and fans.

3.6 Verify the proper operation of the general ventilation exhaust units and fans.

3.7 Verify filter efficiency and air flow capacity.

3.8 Verify the systems rated air flow and air balance.

3.9 Verify the proper operation of all protective devices, controls, interlocks instrumentation and alarms using actual or simulated inputs.

3.10 Verify the proper operation of the Radwaste Building Ventilation System radiation monitor.

4.0 DATA REQUIRED

4.1 Air balancing verification.

4.2 Fan and damper operating data.

4.3 Temperature data.

4.4 Setpoints of alarms interlocks and controls.

4.5 Radwaste Building negative pressurization.

4.6 Radwaste Building Ventilation System radiation monitor's performance data.

5.0 ACCEPTANCE CRITERIA

5.1 The Radwaste Building Ventilation System operates as described in Section 9.4.3.

5.2 The Radwaste Building Ventilation System radiation monitor performs as described in Section 11.5.

14.2.12.1.111 Balance of Control Complex Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of the Balance of Control Complex Ventilation System (CCVS).

1.1.1 Vital Instrument and Equipment Room Ventilation Subsystems.

1.1.2 Computer Room Ventilation Subsystems.

1.1.3 Operations Support Center Ventilation Subsystem.

1.1.4 Shift and Assembly Offices Ventilation Subsystem.

1.1.5 CAS & SEC Group Ventilation Subsystem.

1.1.6 Personnel Decon Room Ventilation Subsystem.

1.1.7 Battery Room Ventilation Subsystem.

1.1.8 Break Room Ventilation Subsystem.

1.1.9 Electrical and Mechanical Equipment Room Air Conditioning Units.

2.0 PREREQUISITES

2.1 Construction activities in the Control Complex are complete with all penetration sealed in place.

2.2 Construction activities on the Control Complex Ventilation Subsystems have been completed.

2.3 Control Complex Ventilation Subsystem instrumentation has been calibrated.

2.4 Support systems required for operation of the Control Complex Ventilation Subsystems.

2.5 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify control logic.

3.2 Verify the operation of the Computer Room air handling units/fans.

3.3 Verify the operation of the Operations Support Center air handling unit/fan.

3.4 Verify the operation of the Shift and Assembly Offices air handling unit/fan.

3.5 Verify the operation of the CAS and SEC Group air handling unit/fan.

3.6 Verify the operation of the Battery Room air handling unit/fan.

3.7 Verify the operation of the Personnel Decon Room air handling unit/fan.

3.8 Verify the operation of the Break Room air handling unit/fan.

3.9 Verify the operation of the Electrical and Mechanical Equipment Room air handling units/fans.

3.10 Verify operation of the smoke purge fans.

3.11 Verify alarms, indicating lights and status lights are functional.

3.12 Perform air flow balancing of the Control Complex Ventilation Subsystems.

3.13 Verify the proper operation of dampers.

3.14 Verify the proper operation of the Vital Instrument and Equipment Room Air Conditioning Units/fans.

4.0 DATA REQUIRED

4.1 Fan operating data for each of the air handling units and the smoke purge fans.

4.2 Damper operating data.

4.3 Air flow and balancing verification.

4.4 Setpoints at which alarms, centerbacks and control occur.

4.5 Temperature data for each of the CCVS subsystems.

5.0 ACCEPTANCE CRITERIA

The Balance of Control Complex Ventilation System operates as described in Section 9.4.1.

14.2.12.1.112 Hydrogen Mitigation System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Hydrogen Mitigation System (HMS).

2.0 PREREQUISITES

2.1 Construction activities on the Hydrogen Mitigation System have been completed.

2.2 Hydrogen instrumentation has been calibrated.

2.3 Electrical power systems required for the Hydrogen Mitigation System are available.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify HMS ignitor control logic and indication.

3.2 Demonstrate each ignitor reaches proper operating temperature.

4.0 DATA REQUIRED

4.1 Ignitor temperatures.

5.0 ACCEPTANCE CRITERIA

5.1 The Hydrogen Mitigation System operates as described in Section 6.2.5.

14.2.12.1.113 Containment Hydrogen Recombiner System Test

1.0 OBJECTIVE

1.1 To demonstrate that the Hydrogen Recombiners can be properly installed and are operable.

2.0 PREREQUISITES

2.1 Construction activities on the Containment Hydrogen Recombiner System (CHRS) have been completed.

2.2 Hydrogen Recombiner System instrumentation has been calibrated.

2.3 Support systems required for operation of the Hydrogen Recombiner System are completed and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Manufacturer Hydrogen Recombiner tests completed and approved.

3.0 TEST METHOD

3.1 Install the CHRS in the specified location and connect the instrumentation, H2 test connection, power supply and piping.

3.2 Verify the proper operation of the Hydrogen Sensors, instrumentation, controls and alarms.

3.3 Verify flow paths from containment to the CHRS and return.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms, interlocks and controls occur.

4.2 Flow data to and from containment.

5.0 ACCEPTANCE CRITERIA

5.1 The Containment Hydrogen Recombiner System operates as described in Section 6.2.5.

14.2.12.1.114 Liquid Waste Management System Test

1.0 OBJECTIVE

1.1 To demonstrate the operability of the Liquid Waste Management System (LWMS) for collection, processing and recycling of liquid wastes and for preparation of liquid waste for release to the environment.

2.0 PREREQUISITES

2.1 Construction activities on the LWMS have been completed.

2.2 Liquid Waste Management System instrumentation has been calibrated.

2.3 Support systems required for operation of the Liquid Waste Management System are completed and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Operate control valves from all appropriate control positions. Observe valve operation and position indication. Measure opening and closing times, where required.

3.2 Verify power-operated valves fail to the position specified in Section 11.2 upon loss of motive power.

3.3 Verify the proper operation of the tank level alarms and interlocks.

3.4 Verify the proper operation of system pumps.

3.5 Verify the proper operation of high differential pressure alarms for the process vessel.

3.6 Verify the proper operation of the tank mixers.

3.7 Demonstrate that discharge isolation features and other system controls function properly. Simulate a high radiation signal to the LWMS discharge radiation monitor.

3.8 Verify alarms, indicating instruments and status lights are functional. Simulate a high radiation signal to the LWMS discharge radiation monitor and verify alarm actuation.

4.0 DATA REQUIRED

4.1 Waste pump operating data.

4.2 Valve opening and closing times, where required.

4.3 Valve position indication.

4.4 Position response of valves to loss of motive power.

4.5 Setpoints at which alarms and interlocks occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Liquid Waste Management System operates as described in Section 11.2.

5.2 The LWMS discharge radiation monitor operates as described in Section 11.5.

14.2.12.1.115 Solid Waste Management System Test

1.0 OBJECTIVE

1.1 To demonstrate the operability of the Solid Waste Management System (SWMS) to collect and package solid wastes for shipment.

2.0 PREREQUISITES

2.1 Construction activities on the Solid Waste Management System have been completed.

2.2 Solid Waste Management System instrumentation has been calibrated.

2.3 Support systems required for operation of the Solid Waste Management System are completed and operational.

2.4 Test Instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify the operation of the slurry pump.

3.2 Verify the Radwaste Building Crane can reach all design points.

3.3 Verify the operation of the dry solids compactor.

3.4 Verify expended resin beds from the Liquid Waste Management System can be sluiced to the Solid Radwaste System High Integrity Containment.

3.5 Verify the operation of the HIC Fill/Dewatering head.

3.6 Verify the proper operation of alarms, controls and interlocks.

3.7 Verify system design flow paths.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms and interlocks occur.

4.2 HIC Fill/Dewatering Head level instrument data.

4.3 Slurry pump operating data.

4.4 Radwaste Building crane data.

4.5 System flow path data.

5.0 ACCEPTANCE CRITERIA

5.1 The Solid Waste Management System operates as described in Section 11.4.

14.2.12.1.116 Gaseous Waste Management System Test

1.0 OBJECTIVE

1.1 To demonstrate the ability of the Gaseous Waste Management System (GWMS) to collect and process radioactive gases vented from plant equipment.

2.0 PREREQUISITES

2.1 Construction activities on the Gaseous Waste Management System have been completed.

2.2 Gaseous Waste Management System instrumentation has been calibrated.

2.3 Support systems required for operation of the Gaseous Waste Management System are completed and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify flow paths.

3.2 Demonstrate that discharge isolation features and other system controls function properly. Simulate a high radiation signal to the GWMS discharge radiation monitor.

3.3 Verify alarms, indicating instruments and status lights are functional. Simulate a high radioactivity signal to the GWMS discharge radiation monitor and verify alarm actuation in the main control room.

3.4 Demonstrate the operation of the gas drying equipment.

3.5 Demonstrate proper hold up time of gas through the charcoal adsorbers.

3.6 Demonstrate the operation of the dryer regeneration equipment.

3.7 Demonstrate the operation of the system gas analyzers.

3.8 Operate control valves from all appropriate control positions. Observe valve operation and position indication. Measure opening and closing times, where required.

3.9 Verify power-operated valves fail to the position specified in Section 11.3 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Setpoints of alarms, interlocks, and controls.

4.2 Gas dryer operating data.

4.3 Dryer regenerating equipment operating data.

4.4 Gas analyzer operating data.

4.5 Gas transport times.

4.6 Position response of valves to loss of motive power.

5.0 ACCEPTANCE CRITERIA

5.1 The Gaseous Waste Management System operates as described in Section 11.3.

5.2 The GWMS discharge radiation monitor operates as described in Section 11.5.

14.2.12.1.117 Process and Effluent Radiological Monitoring System Test

1.0 OBJECTIVE

1.1 To verify that the Process and Effluent Radiological Monitoring System can detect and record specific radiation levels, and to verify all alarms and interlocks.

2.0 PREREQUISITES

2.1 Construction activities on the Process and Effluent Radiological Monitoring System have been completed.

2.2 Process and Effluent Radiological Monitoring System instrumentation has been calibrated.

2.3 Support systems required for operation of the Process and Effluent Radiological Monitoring System are completed and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Calibration check source is available.

3.0 TEST METHOD

3.1 Utilizing the check source and external test equipment, verify calibration and operation of the monitor.

3.2 Check the self-testing feature of the monitor.

3.3 Where applicable, verify proper control actuation by the monitor and record the response time. Simulate a high radiation signal to the appropriate radiation monitors to verify proper control actuations.

3.4 Verify proper alarm actuation in the control room. Simulate a high radiation signal to the radiation monitors to verify proper alarm actuations in the main control or local control room, as appropriate.

4.0 DATA REQUIRED

4.1 The monitor response to check source.

4.2 Technical data associated with the source.

4.3 Signal levels necessary to cause alarm actuation.

4.4 Response time of the monitor to perform control functions.

5.0 ACCEPTANCE CRITERIA

5.1 The Process and Effluent Radiological Monitoring System operates as described in Section 11.5.1.

14.2.12.1.118 Airborne and Area Radiation Monitoring System Test

1.0 OBJECTIVE

1.1 To verify the functional performance of the Airborne and Area Radiation Monitoring System.

2.0 PREREQUISITES

2.1 Construction activities on the Airborne and Area Radiation Monitoring System have been completed.

2.2 Airborne and Area Radiation Monitoring System instrumentation has been calibrated.

2.3 Support systems required for operation of the Airborne and Area Radiation Monitoring System are completed and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Calibration check source is available.

3.0 TEST METHOD

3.1 Utilizing a check source and external test equipment, verify the calibration and operation of the monitor.

3.2 Check the self-testing feature of the monitor.

3.3 Compare local and remote indications.

3.4 Verify proper local and remote alarm actuations.

3.5 Simulate automatic initiation signals and verify proper control actuations.

4.0 DATA REQUIRED

4.1 Monitor response to a check source.

4.2 Technical data associated with the source.

4.3 Local and remote responses to test signals.

4.4 Signals levels necessary to cause alarm actuation.

5.0 ACCEPTANCE CRITERIA

5.1 The airborne and area radiation monitors will perform as described in Sections 11.5 and 12.3.3.

14.2.12.1.119 4160 Volt Class 1E Auxiliary Power System Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of 4160V Class 1E Systems.

2.0 PREREQUISITES

2.1 Construction activities on the 4160 Volt Class 1E Auxiliary Power System have been completed.

2.2 4160 Volt Class 1E Auxiliary Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the 4160 Volt Class 1E Auxiliary Power System are completed and operational.

2.4 Test Instrumentation is available and calibrated.

2.5 All 4.16KV feeders and buses voltage tested with acceptable results.

2.6 4.16KV power is available from the normal and alternate ESF transformer sources.

2.7 Switchgear assembly, breakers, control and protective equipment/circuits have been inspected and tested and are capable of being placed into service.

2.8 The Emergency Diesel Generator and Alternate AC Sources are available.

3.0 TEST METHOD

3.1 Demonstrate the operability of the feeder and cross-tie protective circuit breakers locally and remotely.

3.2 Demonstrate the operability of the bus interlocks, alarms and protective relays.

3.3 Verify the operation of meters and annunciators.

3.4 Load the systems to the extent practical and verify full load voltage is within system design parameters. Verify the capability of bus loads to start and operate properly when connected to the Class 1E 4160V buses at up to 10% above and 10% below nominal voltage.

3.5 Verify the 4160V and 480V safety related systems load shed as designed on undervoltage.

3.6 Verify the 4160V Class 1E buses can be energized from power sources including the Unit Auxiliary Transformer, respective Reserve Auxiliary Transformer, Emergency Diesel Generators, and the Alternate AC Source.

4.0 DATA REQUIRED

4.1 Full load bus voltage data.

4.2 Setpoints at which alarms, interlocks and protective relays occur.

4.3 System response to low bus voltage.

5.0 ACCEPTANCE CRITERIA

5.1 The 4160V Class 1E Auxiliary Power System operates as described in Section 8.3.1.

14.2.12.1.120 480 Volt Class 1E Auxiliary Power System Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of the 480 Volt Class 1E Auxiliary Power System.

2.0 PREREQUISITES

2.1 Construction activities on the 480 Volt Class 1E Auxiliary Power System have been completed.

2.2 480 Volt Class 1E Auxiliary Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the 480 Volt Class 1E Auxiliary Power system are completed and operational.

2.4 Test Instrumentation is available and calibrated.

2.5 Buses and equipment meggered with acceptable results.

2.6 Applicable equipment has been visually inspected.

3.0 TEST METHOD

3.1 Demonstrate the operability of the 480VAC source and feeder circuit breakers locally and remotely.

3.2 Demonstrate the operability of the bus interlocks alarms and protective relays.

3.3 Verify the operation of meters and annunciators.

3.4 Perform energization of 480VAC Class 1E Auxiliary Power system.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms, interlocks and protective relays occur.

5.0 ACCEPTANCE CRITERIA

5.1 The 480 Volt Class 1E Auxiliary Power System operates as described in Section 8.3.1.

14.2.12.1.121 Unit Main Power System Test

1.0 OBJECTIVE

1.1 To demonstrate that the Unit Main Power System is capable of supplying power to designated loads and transmitting power from the main generator to the transmission system.

2.0 PREREQUISITES

2.1 Construction activities on the Unit Main Power System have been completed.

2.2 The Off-site Power Distributions System is available.

2.3 Buses and equipment has been voltage tested with acceptable results.

2.4 Equipment has been visually inspected.

2.5 Control power available.

2.6 Plant conditions are such that the main generator can be operated.

3.0 TEST METHOD

3.1 Demonstrate the ability of the Unit Transformers to supply power to the Unit Auxiliary Transformers from the Offsite Power Source.

3.2 Demonstrate the ability of the Unit Transformers to transmit power from the Main Generator to the Off-site Power Transmission System at rated voltage and load.

3.3 Demonstrate the ability of the Main Generator to generate designed voltage and load.

3.4 Demonstrate the ability of the Unit Auxiliary Transformers to supply station loads.

3.5 Verify the operation of the Generator Circuit Breaker.

3.6 Verify the operation of interlocks, alarms and protective relays.

3.7 Verify the operation of the Main Generator Auxiliary Systems.

4.0 DATA REQUIRED

4.1 Main Generator operating data at load.

4.2 Unit Transformer operating data.

4.3 Unit Auxiliary Transformer operating data.

4.4 Setpoints of alarms, interlocks and controls.

5.0 ACCEPTANCE CRITERIA

5.1 The Unit Main Power System operates as described in Section 8.3.1.

14.2.12.1.122 13800 Volt Normal Auxiliary Power System Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of the 13800 Volt Normal Auxiliary Power System.

2.0 PREREQUISITES

2.1 Construction activities on the 13800 Volt Normal Auxiliary Power System have been completed.

2.2 13800 Volt Normal Auxiliary Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the 13800 Volt Normal Auxiliary Power system are completed and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Unit Auxiliary Transformers available.

2.6 All 13.8KV feeders and buses voltage tested with acceptable results.

2.7 Switchgear assembly, breaker, control and protective equipment/circuits have been inspected and tested and are capable of being placed into service.

3.0 TEST METHOD

3.1 Demonstrate the operability of the 13.8KV feeder circuit breakers locally and remotely.

3.2 Demonstrate the operability of the bus interlocks, alarms and protective relays.

3.3 Verify the operation of meters and annunciators.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms, interlocks and protective relays occur.

5.0 ACCEPTANCE CRITERIA

5.1 The 13800 Volt Normal Auxiliary Power System operates as described in Section 8.3.1.

14.2.12.1.123 4160 Volt Normal Auxiliary Power System Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of the 4160 Volt Normal Auxiliary Power System.

2.0 PREREQUISITE

2.1 Construction activities on the 4160 Volt Normal Auxiliary Power System have been completed.

2.2 4160 Volt Normal Auxiliary Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the 4160 Volt Normal Auxiliary Power System are completed and operational.

2.4 Test instrumentation is available and calibrated.

2.5 All 4.16KV feeders and buses voltage tested with acceptable results.

2.6 4.16KV power is available from the Unit Auxiliary Transformer, the Reserve Auxiliary Transformer and the Alternate AC Source.

2.7 Switch gear assembly, breakers, control and protective equipment/circuit have been inspected and tested and are capable of being placed into service.

3.0 TEST METHOD

3.1 Demonstrate the operability of the feeder protective circuit breakers from the permanent non-safety buses to the safety loads buses.

3.2 Demonstrate the operability of the feeder protective circuit breakers from the Unit Auxiliary Transformer to the non-safety loads locally and remotely.

3.3 Demonstrate the operability of the feeder and cross-tie protective circuit breakers for the permanent non-safety loads locally and remotely.

3.4 Demonstrate the operability of the buses' interlocks, alarms and protective relays.

3.5 Verify the operation of meters and annunciators.

3.6 Verify the permanent non-safety buses can be energized from the unit Auxiliary Transformer, the Reserve Auxiliary Transformers and the Alternate AC source.

3.7 Demonstrate the operation of the bus transfer for the permanent non-safety buses (Preferred 1 [normal] supply power to Preferred 2 [alternate] supply power).

4.0 DATA REQUIRED

4.1 Setpoints at which alarms, interlocks and protective relays occur.

4.2 System response to transfer of Preferred 1 (normal) supply power to Preferred 2 (alternate) supply power.

5.0 ACCEPTANCE CRITERIA

5.1 The 4160V Normal Auxiliary Supply System supplies the loads as described in Section 8.3.1.

14.2.12.1.124 480 Volt Normal Auxiliary Power System Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of the 480 Volt Normal Auxiliary Power System.

2.0 PREREQUISITES

2.1 Construction activities on the 480 Volt Normal Auxiliary Power System have been completed.

2.2 480 Volt Normal Auxiliary Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the 480 Volt Normal Auxiliary Power system are completed and operational.

2.4 Test instrumentation is available and calibrated.

2.5 Buses and equipment have been meggered with acceptable results.

2.6 Equipment has been visually inspected.

2.7 4.16 KV Normal Auxiliary Power Available.

3.0 TEST METHOD

3.1 Demonstrate the operability of the 480 VAC source and feeder circuit breakers locally and remotely.

3.2 Demonstrate the operability of the bus interlocks alarms and protective relays.

3.3 Verify the operation of meters and annunciators.

3.4 Perform energization of 480 VAC Normal Auxiliary Power System.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms, interlocks and protective relays occur.

5.0 ACCEPTANCE CRITERIA

5.1 The 480 Volt Normal Auxiliary Power System operates as described in Section 8.3.1.

14.2.12.1.125 Non-Class 1E DC Power Systems Test

1.0 OBJECTIVE

1.1 To demonstrate the operation of the following systems.

1.1.1 The 125V DC Auxiliary Control Power System.

1.1.2 The 208/120V AC Auxiliary Control Power System.

1.1.3 The 250V DC Auxiliary Power System.

1.1.4 The Alternate AC Source 125V DC Power System.

2.0 PREREQUISITES

2.1 Construction activities on the Non-Class 1E DC Power System have been completed.

2.2 Non-Class 1E DC Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the Non-Class 1E Power System are completed and operational.

2.4 Test Instrumentation is available and calibrated.

2.5 Batteries are fully charged.

2.6 Load banks are available for discharge test.

2.7 Operation of all breakers and cables is verified.

2.8 Ventilation systems are in operation as needed.

3.0 TEST METHOD

3.1 Demonstrate that the batteries and battery chargers of the 125V DC Auxiliary Control Power System meet design capacities by performing discharge and charging tests.

3.2 Demonstrate that the batteries and battery charges of the 250V DC Auxiliary Power System meet design capacities by performing discharge and charging tests.

3.3 Demonstrate that the battery and charger of the Alternate AC 125V DC Power System meet design capacity by performing a discharge and charging test.

3.4 Verify that minimum bank and individual cell limits are not exceeded during battery discharge tests.

3.5 Verify the proper operation of the inverters, manual transfer switches, frequency synchronization, and blocking diodes.

3.6 Verify that the inverters automatically transfer the input to the battery upon loss of preferred power while maintaining uninterrupted power output.

3.7 Place the battery chargers on equalize and verify the DC equalizing voltage will not result in driving the inverter, relieving the rectifier from carrying the inverter load.

3.8 Verify proper operation of all protective devices, controls, interlocks, alarms, computer inputs and ground detection.

3.9 Verify the operation of bus transfer devices.

4.0 DATA REQUIRED

4.1 Battery voltage and load current without charger.

4.2 Charger float voltage and current.

4.3 Test discharge recording of voltage, current, temperature, capacity in ampere hours, and individual cell voltages.

4.4 Charger voltage and current as battery eliminator.

4.5 Inverter voltage, frequency and current from preferred source.

4.6 Inverter voltage, frequency and current from battery source.

4.7 Setpoint at which alarms, interlocks and controls occur.

5.0 ACCEPTANCE CRITERIA

5.1 The Non-Class 1E DC Power System supply the loads as described in Section 8.3.2.

14.2.12.1.126 Class 1E DC Power Systems Test

1.0 OBJECTIVE

1.1 To demonstrate the Class 1E DC Power Systems supply power as designed in required operating modes.

2.0 PREREQUISITES

2.1 Construction activities on the Class 1E DC Power system have been completed.

2.2 Class 1E DC Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the Class 1E DC Power System are completed and operational.

2.4 Test Instrumentation is available and calibrated.

2.5 Batteries fully charged.

2.6 Load banks are available for discharge test.

2.7 Operation of breakers and cables has been verified.

2.8 Ventilation systems are in operation as needed.

3.0 TEST METHOD

3.1 Demonstrate that the batteries and battery chargers meet design capacities by performing discharge and charging tests.

3.2 Verify that minimum bank and individual cell limits are not exceeded during battery discharge test.

3.3 Verify the proper operation of the inverters, manual transfer switches, frequency synchronization and blocking diodes.

3.4 Verify that the inverters automatically transfer input to the battery upon loss of preferred power while maintaining uninterrupted power output.

3.5 Place the battery chargers on equalize and verify DC equalizing voltage will not result in driving the inverter, relieving the rectifier from carrying the inverter load.

3.6 Verify proper operation of protective devices, controls, interlocks, alarms, computer inputs and ground detection.

3.7 Verify the proper operation of the Vital Instrumentation and Control Power Status Information Subsystem.

3.8 Verify proper operation of bus transfer devices.

4.0 DATA REQUIRED

4.1 Battery voltage and load current without charger.

4.2 Charger float voltage and current.

4.3 Test discharge recordings of voltage, current, temperature, capacity in ampere hours, and individual cell voltages.

4.4 Charger voltage and current as battery eliminator.

4.5 Inverter voltage, frequency and current from preferred source.

4.6 Inverter voltage, frequency and current from battery source.

4.7 Setpoint at which alarms, interlocks and controls occur.

4.8 System Status Information Subsystem indications.

5.0 ACCEPTANCE CRITERIA

5.1 The Class 1E DC Power System supply the loads as described in Section 8.3.2.

14.2.12.1.127 Offsite Power System Test

1.0 OBJECTIVE

1.1 To verify the Offsite Power System is capable of supplying power as designed to the unit through the two preferred power circuits.

1.2 To verify the power generated by the turbine generator can be fed to grid through the Offsite Power System.

2.0 PREREQUISITES

2.1 Construction activities on the Offsite Power System have been completed.

2.2 Offsite Power System instrumentation has been calibrated.

2.3 Support systems required for operation of the Offsite Power System are completed and operational.

2.4 Test Instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify operation of the Switchyard Protective Relaying System.

3.2 Verify operation of Switchyard Power Current Breakers and motor-operated disconnects from Main Control Room, Switchyard Relay House and its local control cabinet.

3.3 Verify operation of interlock between the two separate offsite power connections.

3.4 Verify operation of the Switchyard 125V DC Auxiliary Supply System and its associated controls, alarms and batteries.

3.5 Verify the operation of the Switchyard 480V AC Auxiliary Power System and its associated controls, alarms and annunciators.

4.0 DATA REQUIRED

4.1 Setpoints at which alarms and interlocks occur.

4.2 Setpoint of protective relays.

5.0 ACCEPTANCE CRITERIA

5.1 The Offsite Power System operates as described in Section 8.2.1.

14.2.12.1.128 Balance of Plant Piping Thermal Expansion Measurement Test

1.0 OBJECTIVE

1.1 To demonstrate that the Balance of Plant (BOP) components are free to expand thermally as designed during initial plant heatup and return to their baseline cold position after the initial cooldown to ambient temperatures.

2.0 PREREQUISITES

2.1 This test is carried out in conjunction with the initial RCS heatup and all the conditions for initial heatup must be established.

2.2 Construction activities are complete on the pipes to be measured.

2.3 Adjustment, setting, and marking of initial positions of spring hangers, hydraulic restraints, and special devices of the systems have been completed.

2.4 Temporary scaffolding and ladders are installed as required to make observations and record data.

3.0 TEST METHOD

3.1 During Hot Functional Testing and Pre-critical Heatup for power escalation, a visual inspection will be performed to verify that spring supports are within design range (i.e., indicator within spring scale) and recorded. Visual inspection of snubbers will be performed to ensure they have not contacted either stop and are within expected travel range. Snubber piston scales will be read to ensure acceptance criteria for piston to stop gap is met. Also system walkthroughs will be performed during HFT to visually verify that piping and components are unrestricted from moving within their range. Hot displacement measurements of all snubbers will be obtained and motion will be compared with predicted values.

3.2 For systems that do not attain design operating temperature, verify by observation and/or calculation that the snubbers will accommodate the predicted thermal movement.

3.3 Inspect small pipe in the vicinity of connections to large pipe to ensure that sufficient clearance and flexibility exists to accommodate thermal movements of the large pipe.

3.4 The Feedwater System and Emergency Feedwater System hot displacement measurements will be obtained during the initial startup and power escalation phase.

3.5 All snubbers and spring supports, which required adjustments during the test, will be reinspected in its hot condition to assure proper adjustments were made.

4.0 DATA REQUIRED

4.1 Position measurements versus temperature for cold, heatup, steady state, cooldown and return to ambient conditions for designated piping, spring supports and snubbers.

5.0 ACCEPTANCE CRITERIA

5.1 The pipe shall move freely, except at locations where supports/restraints are designed to restrain pipe thermal movement as described in Section 3.9.2.

5.2 Thermal movement of pipe at the locations of spring hangers and snubbers shall be within their allowable travel range as described in Section 3.9.2.

5.3 The thermal movement of the pipe at restricted measurement locations shall be within the acceptable limits or discrepant response be reconciled using acceptable reconciliation methods as described in Section 3.9.2.

14.2.12.1.129 BOP Piping Vibration Measurement Test

1.0 OBJECTIVE

1.1 To verify that piping layout and support/restraints are adequate to withstand normal transients without damage in the designated piping systems.

1.2 To demonstrate that flow induced vibration is sufficiently small to cause no fatigue or stress failures in the designated piping systems.

2.0 PREREQUISITES

2.1 System components and piping supports have been installed in accordance with design drawings for system to be tested.

2.2 System piping has been installed in accordance with design drawings for system to be tested.

2.3 Hot Functional Testing and/or Pre-critical Heatup for power escalation is underway.

2.4 System piping has been filled for normal operation.

3.0 TEST METHOD

3.1 Perform an assessment of piping system vibration.

4.0 DATA REQUIRED

4.1 Pipe response data to include piping drawings, vibration measurements and operating conditions.

5.0 ACCEPTANCE CRITERIA

5.1 Steady State Vibration Testing as described in Section 3.9.2.

5.1.1 Acceptance criteria are based on conservatively estimated stresses which are derived from measured velocities and conservatively assumed mode shapes.

5.2 Transient Vibration Testing as described in Section 3.9.2.

5.2.1 No permanent deformation or damage in any system, structure, or component important to nuclear safety is observed.

5.2.2 All suppressors and restraints respond within their allowable ranges, between stops or with indicators on scale.

14.2.12.1.130 Containment Integrated Leak Rate Test and Structural Integrity Test

1.0 OBJECTIVE

1.1 To verify the structural integrity of the Containment.

1.2 To verify that the integrated leak rate from the Containment does not exceed the maximum allowable leakage.

2.0 PREREQUISITES

2.1 The Containment is operational and penetration local leak rate testing has been completed to the greatest extent possible.

2.2 All systems inside Containment which have containment isolation valves identified are vented and drained as required by Table 6.2.4-1.

2.3 Leakage rate determination instrumentation available and properly calibrated.

2.4 Containment inspection completed as required by 10 CFR 50, Appendix J.

2.5 Systems required including station air, for the test are available.

2.6 Instrumentation to measure containment building movement is installed and calibrated.

2.7 Containment Ventilation System Fans are capable of running for air circulation.

3.0 TEST METHOD

3.1 Close individual containment isolation valves by the means provided for normal operation of the valves as required by 10 CFR 50, Appendix J.

3.2 The internal pressure in the containment building will be increased from atmospheric pressure to a minimum of 1.10 times the Design Basis Accident Pressure (Pac) in at least four approximately equal increments and depressurized in the same increments.

3.3 At each pressure level, during pressurization and depressurization, data will be recorded and an evaluation of the deflections will be made to determine if the response deviates significantly from the expected response.

3.4 A visual inspection of the containment hatches, penetrations and gaskets will be made.

3.5 The containment leak rate will be determined at calculated peak accident pressure and at 1/2 calculated peak accident pressure. Leakage will be verified by reference vessel method and/or absolute pressure method. Test accuracy shall be verified by supplementary means.

4.0 DATA REQUIRED

4.1 Structural Integrity Data

4.1.1 The readings of instrumentation to measure containment building movement will be recorded at selected pressure levels.

4.1.2 Radial displacements will be measured at several points along six meridians spaced evenly around the containment. The locations along the meridian include the apex, springline, elevation 91′-9″ (the top of the concrete), and locations with varying stiffness characteristics such as major penetrations. Radial and tangential deflections of the containment wall adjacent to the equipment hatch opening will be measured at twelve points around the hatch penetration. The twelve points will be three locations each at the three, six nine and twelve o'clock positions around the penetration. The three locations are immediately adjacent to the opening on the reinforcing collar, on the 1-3/4 inch shell at the edge of the reinforcing collar, and at an accessible location on the 1-3/4 inch shell at a distance of approximately 2.5 times the radius of the hatch, or approximately 27.5 feet, from the centerline of the hatch.

4.2 Integrated Leak Rate Data

4.2.1 Containment temperature, pressure and humidity

4.2.2 Reference vessel temperature and pressure

4.2.3 Atmospheric pressure and temperature

4.2.4 "Known leakage" air flow

5.0 ACCEPTANCE CRITERIA

5.1 Structural Integrity Test

5.1.1 The Containment Vessel shows no signs of structural degradation following the 110% strength test.

5.2 Integrated Leak Rate Test

5.2.1 The upper confidence limit plus any local leakage rate additions, shall be less than 75 percent of the maximum allowed leakage rate.

5.2.2 The verification test by removal of a quantity of air is acceptable if the mass calculated from the test instrumentation is 75 to 125% of the metered mass change.

5.3 Containment performs as described in Sections 6.2.6, 6.2.4 and 3.8.2.

14.2.12.1.131 Fuel Transfer Tube Functional Test and Leak Test

1.0 OBJECTIVE

1.1 To verify the measured leakage through the fuel transfer when summed with the total of all other Type B and C Leak Rate Tests tube is within the limits as required by 10 CFR 50 Appendix J.

1.2 To demonstrate the operation of the Fuel Transfer Tube quick closure hatch.

2.0 PREREQUISITES

2.1 Construction activities on the Fuel Transfer Tube have been completed.

2.2 Temporary pressurization equipment is installed and instrumentation calibrated.

3.0 TEST METHOD

3.1 Operate the Fuel Transfer Tube quick closure hatch in accordance with manufacturers instructions. Verify the hatch can be opened and closed within the stated amount of time.

3.2 Place the hatch in the closed position and perform a 10 CFR 50, Appendix J Type B Leak Rate Test on the Fuel Transfer Tube Seal integrity at 110% Design Basis Accident Pressure (Pac).

4.0 DATA REQUIRED

4.1 Fuel Transfer Tube assembly leak data.

4.2 Time to operate the hatch.

5.0 ACCEPTANCE CRITERIA

5.1 The leak rate when summed with the total of all other Type B and C Leak Rate Tests does not exceed the limits as required by 10 CFR 50 Appendix J.

5.2 The Fuel Transfer Tube quick closure hatch operates in accordance with manufacturers instructions.

5.3 The Fuel Transfer Tube penetration and quick closure hatch perform as described in Sections 3.8.2 and 6.2.4.

14.2.12.1.132 Equipment Hatch Functional Test and Leak Test

1.0 OBJECTIVE

1.1 To verify the measured leakage through the Containment Equipment Hatch when summed with the total of all other Type B and C Leak Rate Tests is within the limits as required by 10 CFR 50 Appendix J.

1.2 To demonstrate the operation of the Containment Equipment Hatch and Movable Shield Wall Assembly.

2.0 PREREQUISITES

2.1 Construction activities on the Equipment Hatch and Shield Wall have been completed.

2.2 Temporary pressurization equipment is installed and instrumentation calibrated.

3.0 TEST METHOD

3.1 Demonstrate the operation of exterior shield wall assembly from its normal closed location to the open location and back.

3.2 Demonstrate the operation of the Equipment Hatch from its normal closed location to its open location and back.

3.3 Place the hatch in the closed position and perform a 10 CFR 50, Appendix J Type B Leak Rate Test and Seal Structural Integrity test at 110% of Design Basis Accident Pressure.

4.0 DATA REQUIRED

4.1 Equipment Hatch leak data.

5.0 ACCEPTANCE CRITERIA

5.1 The leak rate when summed with the total of all other Type B and C Leak Rate Tests does not exceed the limits as required by 10 CFR 50 Appendix J.

5.2 The Equipment Hatch and Movable Shield Wall Assembly operate in accordance with manufacturers instructions.

5.3 The Equipment Hatch performs as described in Sections 3.8.2 and 6.2.4.

14.2.12.1.133 Containment Personnel Airlock Functional Test and Leak Test

1.0 OBJECTIVE

1.1 To verify the measured leakage through each Containment Personnel Airlock is within the limits as required by 10 CFR 50 Appendix J.

1.2 To verify each Containment Personnel Airlock operates as designed.

2.0 PREREQUISITES

2.1 Construction activities on the Containment Personnel Airlocks have been completed.

2.2 Temporary pressurization equipment is installed and instrumentation is calibrated.

2.3 Electrical checks are complete on the hatches.

3.0 TEST METHOD

3.1 Operate each airlock in accordance with manufacturers instructions. Verify alarms, interlocks and indications.

Place each airlock in the closed portion and perform a 10 CFR 50, Appendix J, Type B Leak Rate Test and Structural Integrity Test at 110% of Design Basis Accident Pressure (Pac).

4.0 DATA REQUIRED

4.1 Individual airlock leak data.

5.0 ACCEPTANCE CRITERIA

5.1 The leak rates when summed with the total of all other Type B and C Leak Rate Tests do not exceed the limits as required by 10 CFR 50 Appendix J.

5.2 The Containment Personnel Airlocks operate as designed.

5.3 The Containment Personnel Airlocks perform as described in Sections 6.2.6 and 3.8.2.

14.2.12.1.134 Containment Electrical Penetration Assemblies Test

1.0 OBJECTIVE

1.1 To verify the integrity of the electrical penetration o-ring seals, and to verify that a summation of the Type B and C leak rate test results does not exceed the limits as required by 10 CFR 50 Appendix J.

2.0 PREREQUISITES

2.1 Containment electrical penetration assemblies must be complete with no identified exceptions or discrepancies which would affect the test.

3.0 TEST METHOD

3.1 Perform a 10 CFR 50, Appendix J, Type B Leak Rate Test at 100% of Design Basis Accident Pressure (Pac).

4.0 DATA REQUIRED

4.1 Electrical penetration leak data.

5.0 ACCEPTANCE CRITERIA

5.1 The sum of the containment electrical penetration assembly leak rate tests when summed with all other Type B and C tests does not exceed limits as required by 10 CFR 50 Appendix J.

5.2 Containment electrical penetration assemblies perform as described in Sections 3.8.2 and 6.2.4.

14.2.12.1.135 Containment Isolation Valves Leakage Rate Test

1.0 OBJECTIVE

1.1 To verify that the measured leakage through each containment penetration isolation valve when summed with the total of all other Type B and C Leak Rate Tests is within the limits as required by 10 CFR 50 Appendix J.

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested have been completed.

2.2 Temporary pressurization equipment is installed and instrumentation is calibrated.

3.0 TEST METHOD

3.1 Close the individual containment isolation valves by the means provided for normal operation of valve.

3.2 Perform 10 CFR 50 Appendix J, Type C test, by local pressurization of each penetration.

4.0 DATA REQUIRED

4.1 Individual penetration leak data.

5.0 ACCEPTANCE CRITERIA

5.1 The leak rates when summed with the total of all other Type B and C Leak Rate Tests must not exceed the allowable limits as required by 10 CFR 50 Appendix J.

5.2 The Containment Isolation Valves operate as described in Section 6.2.4.

14.2.12.1.136 Loss of Instrument Air Test

1.0 OBJECTIVES

1.1 To demonstrate that a reduction and loss of instrument air pressure causes fail-safe operation of active safety-related pneumatically-operated equipment.

2.0 PREREQUISITES

2.1 Construction activities on items to be tested have been completed.

2.2 Individual valves and equipment are operable.

2.3 The Instrument Air System is in service at rated pressure with support systems operational to the extent necessary to conduct the test. All pneumatic loads are cut-in to the extent possible at the time test begins.

2.4 Components to be tested are given in Table 9.3.1-1 "Active safety-related components serviced by instrument air". Table 9.3.1-1 is a listing of the air-operated active safety-related equipment important to safety which also includes both the loss of air failed position and fail safe position of each component.

2.5 The Compressed Air System Test, in conjunction with this test satisfies the requirements of Regulatory Guide 1.68.3, Regulatory Position C.1-C.11.

2.6 Loss-of-air supply tests should be conducted on all branches of the instrument air system simultaneously, if practicable, or on the largest number of branches of the system that can be adequately managed.

3.0 TEST METHOD

3.1 Place the valves in the normal operating position, and maintain plant in as close to normal conditions as it practicable.

3.2 Where safe to personnel and equipment, conduct a loss of air test on integrated systems by performing the following tests:

- Shut off the instrument air system in a manner that would simulate a sudden air pipe break and verify that the affected components respond properly.
- Repeat Test A, but shut the instrument air system off very slowly to simulate a gradual loss of pressure.

3.3 Where deemed necessary, depressurize individual components. Note component response.

3.4 Return instrument air to the depressurized systems and components. Note responses.

4.0 DATA REQUIRED

4.1 Response of systems and components to loss of instrument air and subsequent restoration.

5.0 ACCEPTANCE CRITERIA

5.1 All valves fail to their designated fail position upon loss of air and remain in the design position upon restoration.

14.2.12.1.137 Mid-Loop Operations Verification Test

1.0 OBJECTIVE

1.1 To verify that installed instrumentation for operations at reduced Reactor Coolant System (RCS) inventory is accurate and reliable.

1.2 To verify the Shutdown Cooling System (SCS) pumps can be operated at reduced RCS level without cavitation.

2.0 PREREQUISITES

2.1 Construction activities on the RCS Mid-Loop Instrumentation system have been completed.

2.2 RCS Mid-Loop System instrumentation has been calibrated.

2.3 Support systems required for Mid-Loop operations are completed and operational.

2.4 Test instrumentation of high accuracy to measure RCS level changes is available and calibrated.

2.5 The RCS is at normal shutdown level in the Pressurizer and depressurized.

2.6 The Shutdown Cooling System is operable.

3.0 TEST METHOD

3.1 Verify the operation of the RCS mid-loop level instrumentation indication and alarms.

3.2 Verify the operation of the SCS pumps while operating at mid-loop level.

3.3 Establish the minimum level at which the SCS pumps can operate without cavitation.

3.4 Establish the maximum flow the SCS pumps can operate at mid-loop without cavitation.

4.0 DATA REQUIRED

4.1 Setpoints of alarms.

4.2 Mid-Loop Instrumentation Data

4.3 Minimum level and maximum flow limits for the SCS pumps.

5.0 ACCEPTANCE CRITERIA

5.1 The Mid-Loop Instrumentation provides accurate indication of RCS parameters as described in Sections 7.7.1.1.15 and 16.13.2.

5.2 The SCS pump operating limits at mid-loop are established and within the expected design range as described in Section 19.6.3.9.

14.2.12.1.138 Seismic Monitoring Instrumentation System Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the Seismic Monitoring Instrumentation System.

2.0 PREREQUISITES

2.1 Construction activities on the Seismic Monitoring Instrumentation System have been completed.

2.2 Seismic Monitoring Instrumentation System instrumentation has been calibrated.

2.3 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify operability of internal calibration devices by recording calibration records on all applicable sensors.

3.2 Verify system response to simulated seismic events by actuating the appropriate trigger units, recording accelerograph outputs and playing back all records for analysis.

3.3 Verify and calibrate all systems alarms and indicators.

3.4 Verify the proper operation and installation of all peak recording accelerographs.

4.0 DATA REQUIRED

4.1 Record sensor response to simulated seismic inputs.

5.0 ACCEPTANCE CRITERIA

5.1 The Seismic Monitoring Instrumentation System operates as described in Section 3.7.4.

14.2.12.1.139 Auxiliary Steam System Test

1.0 OBJECTIVE

1.1 To demonstrate the Auxiliary Steam System provides the steam to various plant components at designed pressures and flow.

2.0 PREREQUISITES

2.1 Construction activities on the Auxiliary Steam system have been completed.

2.2 Auxiliary Steam system instrumentation has been calibrated.

2.3 Support systems required for operation of the Auxiliary Steam system are completed and operational.

2.4 Test Instrumentation is available and calibrated.

2.5 Sufficient loads are available to allow loading to the auxiliary boiler to its designed capacity.

3.0 TEST METHOD

3.1 Verify proper operation of designated components such as protective devices, controls, interlocks, instrumentation and alarms, using actual or simulated inputs.

3.2 Operate control valves from all appropriate control positions. Observe valve operation and position indication and measure opening and closing times.

3.3 Verify power-operated valves fail to their appropriate position upon loss of motive power.

3.4 Demonstrate proper operation and flow rates for all design flow paths.

3.5 Verify proper operation of system pumps.

3.6 Perform measurements of the Auxiliary Boiler performance using ASME PTC-4.1, "Steam Generating Units."

4.0 DATA REQUIRED

4.1 Boiler operating data per PTC-4.1.

4.2 Valve opening and closing times, where required.

4.3 Valve position indication.

4.4 Response of power-operated valves to loss of motive power.

4.5 Setpoints at which alarms and interlocks occur.

4.6 Pump operating data.

5.0 ACCEPTANCE CRITERIA

5.1 The Auxiliary Steam System provides steam flow to designated components and systems.

5.2 The Auxiliary Steam Boiler meets manufacturers design performance.

14.2.12.1.140 Containment Isolation Valves Test

1.0 OBJECTIVE

1.1 Demonstrate that containment isolation valves can be operated manually and operate in response to automatic actuation.

1.2 Verify that upon loss of actuating power, the valves fail as designed.

1.3 Verify that all valves operate in less than the time specified in the valves' test procedure.

2.0 PREREQUISITES

2.1 Construction activities on the containment isolation valves have been completed.

2.2 Support system required to operate the containment isolation valves are operable.

2.3 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Operate containment isolation valves from all appropriate control positions. Verify position indication, and measure opening and closing times, including at rated flow and no flow conditions.

3.2 Verify containment isolation valves fail to their position specified in the safety analysis upon loss of motive power.

3.3 Initiate the following simulated activation signals and verify the appropriate valves go to the design positions.

CIAS	Containment Isolation Actuation Signal
CSAS	Containment Spray Actuation Signal
MSIS	Main Steam Isolation Signal
EFAS	Emergency Feedwater Actuation Signal
AFAS	Alternate Feedwater Actuation Signal
HRAS	High Radiation Actuation Signal
HHAS	High Humidity Actuation Signal
SIAS	Safety Injection Actuation Signal
CCWLLSTAS	Component Cooling Water Low-Low Surge Tank Actuation Signal

4.0 DATA REQUIRED

4.1 Valve opening and closing times under differential pressure, flow and temperature conditions as applicable.

4.2 Valve position indications.

4.3 Position response of valves to loss of motive power.

4.4 Valve response to a simulated actuation signal.

5.0 ACCEPTANCE CRITERIA

5.1 The Containment Isolation Valves operate as described in Section 6.2.4.

14.2.12.1.141 Post Accident Monitoring Instrumentation Test

1.0 OBJECTIVE

1.1 To verify that the Post Accident Monitor Instrumentation (PAMI) is installed properly, responds correctly to external inputs and provides proper outputs to the distributed display and recording equipment.

2.0 PREREQUISITES

2.1 Construction activities on the systems to be tested are complete.

2.2 Applicable operating manuals are available.

2.3 Required software is installed and operable.

2.4 External test equipment and instrumentation is available and calibrated.

2.5 Plant systems required to support testing are operable to the extent necessary to perform the testing or suitable simulation of this system is used.

3.0 TEST METHOD

3.1 Verify power sources to all related equipment.

3.2 Validate that external inputs are received and processed correctly by the appropriate system devices.

3.3 Verify that alarms and indication displays respond correctly to actual or simulated inputs.

3.4 Verify the operability of required software application programs.

3.5 Verify the correct operation of data output devices and displays at applicable work stations and terminals.

3.6 Evaluate processing system loading under actual or simulated operating conditions.

4.0 DATA REQUIRED

4.1 Computer generated summaries of external input data, data processing, analysis functions, displayed information and permanent data records.

5.0 ACCEPTANCE CRITERIA

5.1 The PAMI performs as described in Section 7.5.

14.2.12.1.142 Component Cooling Water Heat Exchanger Structure(s) Ventilation Systems Test

1.0 OBJECTIVE

1.1 To demonstrate proper operation of the CCW Heat Exchanger Structure(s) Ventilation Systems.

2.0 PREREQUISITES

2.1 Construction activities on the CCW Heat Exchanger Structure(s) Ventilation System have been completed.

2.2 CCW Heat Exchanger Structure(s) Ventilation Systems instrumentation has been calibrated.

2.3 Support systems required for operation of the CCW Heat Exchanger Structure(s) Ventilation Systems are complete and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify design air flow with each CCW Hea: Exchanger Structure(s) Ventilation System in operation.

3.3 Verify design temperature can be maintained in each CCW Heat Exchanger Structure.

3.4 Verify alarms, indicating instruments and status lights are functional.

4.0 DATA REQUIRED

4.1 Fan and damper operating data.

4.2 Air flow verification.

4.3 Setpoint at which alarms, interlocks and controls, occur.

4.4 Temperature data of each CCW Heat Exchanger Structure.

5.0 ACCEPTANCE CRITERIA

5.1 The CCW Heat Exchanger Structure(s) Ventilation Systems operates as described in Section 9.4.10.

14.2.12.1.143 Nuclear Annex Ventilation System Test

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the Nuclear Annex Ventilation System to maintain design condition.

2.0 PREREQUISITES

2.1 Construction activities on the Nuclear Annex Ventilation System have been completed.

2.2 Nuclear Annex Ventilation System instrumentation has been calibrated.

2.3 Support systems required for operation of the Nuclear Annex Ventilation System are complete and operational.

2.4 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Verify all control logic.

3.2 Verify the proper operation, stroking speed and position indication of all dampers.

3.3 Verify the system maintains the Nuclear Annex at a negative pressure.

3.4 Verify the system maintains the subsphere at a negative pressure.

3.5 Verify the proper operation of the Ventilation Supply Units and Fans.

3.6 Verify the proper operation of the Ventilation Exhaust Units and Fans.

3.7 Verify the proper operation of the Mechanical Equipment Room Cooling Units.

3.8 Verify the proper operation of the Mechanical Equipment Room Ventilation Units.

3.9 Verify filter efficiency carbon adsorber efficiency and air flow capacity.

3.10 Verify the systems rated air flow and air balance.

3.11 Verify the proper operation of all protective devices, controls, interlocks instrumentation and alarms using actual or simulated inputs.

3.12 Verify the proper operation of the Nuclear Annex Ventilation System radiation monitors.

4.0 DATA REQUIRED

4.1 Air balancing verification.

4.2 Fan and damper operating data.

4.3 Temperature data of building area.

4.4 Setpoints of alarms interlocks and controls.

4.5 Nuclear Annex negative pressurization data.

4.6 Filter and carbon adsorber data.

4.7 Nuclear Annex Ventilation System radiation monitors' performance data.

5.0 ACCEPTANCE CRITERIA

5.1 The Nuclear Annex Ventilation System operates as described in Section 9.4.9.

5.2 The Nuclear Annex Ventilation System radiation monitors perform as described in Section 11.5.

14.2.12.2 Post-core Hot Functional Tests

14.2.12.2.1 Post-core Hot Functional Test Controlling Document

1.0 OBJECTIVE

1.1 To demonstrate the proper integrated operation of plant primary, secondary, and auxiliary systems with fuel loaded in the core.

2.0 PREREQUISITES

2.1 All pre-core hot functional testing has been completed as required.

2.2 Fuel loading has been completed.

2.3 All permanently installed instrumentation on systems to be tested is available and calibrated in accordance with technical specifications and test procedures.

2.4 All necessary test instrumentation is available and calibrated in accordance with technical specifications and test procedures.

2.5 All cabling between the CEDMs and the CEDM control system is connected.

2.6 Steam generators are in wet layup in accordance with the NSSS chemistry manual.

2.7 RCS has been borated to the proper concentration.

3.0 TEST METHOD

3.1 Specific plant conditions and coordinate the execution of the related post-core hot functional test appendices.

4.0 DATA REQUIRED

4.1 As specified by the individual post-core hot functional test appendices.

5.0 ACCEPTANCE CRITERIA

5.1 Integrated operation of the primary, secondary, and related auxiliary systems is in accordance with the system descriptions.

14.2.12.2.2 Loose Parts Monitoring System

1.0 OBJECTIVE

1.1 To obtain baseline data on the Loose Parts Monitoring System (LPMS).

1.2 To adjust LPMS alarm setpoints as necessary.

2.0 PREREQUISITES

2.1 Pre-operational tests on LPMS have been completed.

2.2 All LPMS instrumentation has been calibrated and are operable.

3.0 TEST METHOD

3.1 Collect baseline data using the LPMS during plant heatup and at normal operating conditions.

3.2 Analyze baseline data and, if necessary, adjust alarm setpoints.

4.0 DATA REQUIRED

4.1 Baseline data using LPMS.

4.2 LPMS alarm setpoints.

4.3 RCS temperature and pressure.

5.0 ACCEPTANCE CRITERIA

5.1 LPMS performs as described in Section 7.7.1.6.3.

5.2 The LPMS alarm setpoints have been adjusted as necessary.

14.2.12.2.3 Post-core Reactor Coolant System Flow Measurements

1.0 OBJECTIVE

1.1 To determine the post-core RCS flow rate and flow coastdown characteristics.

1.2 To establish reference post-core RCS pressure drops.

1.3 To make adjustments to the flow related constants of the CPCs as required.

1.4 To collect data on the operation of the flow related portions of the COLSS and the CPCs for steady-state and transient conditions.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 All permanently installed instrumentation is properly calibrated and operational.

2.3 All test instrumentation is available and properly calibrated.

2.4 RCS operating at nominal hot, zero power conditions.

2.5 Required reactor coolant pumps are operational.

2.6 COLSS and CPCs are in operation.

3.0 TEST METHOD

3.1 RCS flow is measured for all operationally allowed reactor coolant pump combinations and the necessary data to calculate RCS flow is collected.

3.2 RCS flow coastdown measurements are performed by tripping the allowable reactor coolant pump(s) for collection of coastdown data.

3.3 CPCs and COLSS flow related data is verified by comparison with measured flows.

4.0 DATA REQUIRED

4.1 COLSS and CPCs flow related data.

4.2 Reactor coolant pump differential pressure and speed.

4.3 Reactor vessel differential pressure.

4.4 RCS temperature and pressure.

4.5 Pump configuration.

4.6 Coastdown time.

5.0 ACCEPTANCE CRITERIA

5.1 Measured RCS flow exceeds the flow rates used in the safety analysis in Chapter 15, but is less than the design maximum flow rate as described in Sections 4.4.1 and 7.2.1.

5.2 Measured RCS flow coastdown is conservative with respect to the coastdown used in the safety analysis.

5.3 CPC and COLSS flow constants are adjusted to be conservative with respect to the measured flows and for those portions of the coastdowns which occur prior to CPC initiation of a trip.

14.2.12.2.4 Post-core Control Element Drive Mechanism Performance

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the CEDMs and CEAs under Hot Shutdown and hot, zero power conditions.

1.2 To verify proper operation of the CEA position indicating system and alarms.

1.3 To measure CEA drop times.

2.0 PREREQUISITES

2.1 The CEDMCS pre-core performance test has been completed.

2.2 All test instrumentation is available and calibrated.

2.3 Plant Monitoring system is operational.

2.4 The CEDM cooling system is operational.

2.5 CEDM coil resistance has been measured.

3.0 TEST METHOD

3.1 Perform the following at Hot Shutdown conditions:

3.1.1 Withdraw and insert each CEA to verify proper operation of CEDM.

3.2 Perform the following at hot, zero power conditions:

3.2.1 Withdraw and insert each CEA to verify proper operation of CEDM.

3.2.2 Measure and record drop time for each CEA.

3.2.3 Perform three measurements of drop time for each of those CEAs falling outside the two-sigma limit for similar CEAs.

3.3 Perform the following at any time:

3.3.1 Withdraw and insert each CEA while recording position indications and alarms.

4.0 DATA REQUIRED

4.1 CEA drop time.

4.2 RCS temperature and pressure to be taken during measurement and recording of drop time for each CEA.

4.3 CEA position and alarm indications.

5.0 ACCEPTANCE CRITERIA

5.1 The CEDM/CEAs and their associated position indications operate as described in Section 7.7.1.

5.2 CEA drop times are in agreement with the Technical Specifications.

5.3 CEA insertion and withdrawal times meet design requirements.

14.2.12.2.5 Post-core Reactor Coolant and Secondary Water Chemistry Data

1.0 OBJECTIVE

1.1 To maintain the proper water chemistry for the RCS and steam generators during post-core hot functional testing.

2.0 PREREQUISITES

2.1 Primary and secondary sampling systems are operable.

2.2 Chemicals to support hot functional testing are available.

2.3 The primary and secondary chemical addition system are operable.

2.4 Purification ion exchangers are charged with resin.

3.0 TEST METHOD

3.1 Minimum sampling frequency for the steam generator and RCS will be as specified by the chemistry manual. The sampling frequency will be modified as required to ensure the proper RCS and steam generator water chemistry.

3.2 Perform RCS and steam generator sampling and chemistry analysis after every significant change in plant conditions (i.e., heatup, cooldown, chemical additions).

4.0 DATA REQUIRED

4.1 Plant conditions.

4.2 Steam generator chemistry analysis.

4.3 RCS chemistry analysis.

5.0 ACCEPTANCE CRITERIA

5.1 RCS and steam generator water chemistry can be maintained as described in Sections 9.3.4 and 10.3.5.

5.2 Baseline data for the steam generators and RCS is established.

14.2.12.2.6 Post-core Pressurizer Spray Valve and Control Adjustments

1.0 OBJECTIVE

1.1 To establish the proper settings of continuous spray valves.

1.2 To measure the rate at which Pressurizer pressure can be reduced using Pressurizer spray.

2.0 PREREQUISITES

2.1 The RCS is being operated at nominal hot, zero power conditions.

2.2 All permanently installed instrumentation is available and calibrated.

2.3 Test instrumentation is available and calibrated.

3.0 TEST METHOD

3.1 Adjust continuous spray valves to obtain specified Delta T between the RCS temperature and pressurizer spray line temperature.

3.2 Using various combinations of pressurizer spray valves, measure and record the rate at which the pressurizer pressure can be reduced.

4.0 DATA REQUIRED

4.1 RCS temperature and pressure.

4.2 Spray line temperature.

4.3 Continuous spray valve settings.

4.4 Spray valve combinations.

5.0 ACCEPTANCE CRITERIA

5.1 The Pressurizer performs as described in Sections 7.7.1 and 5.4.10.

14.2.12.2.7 Post-core Reactor Coolant System Leak Rate Measurement

1.0 OBJECTIVE

1.1 To measure the post-core load RCS leakage at hot, zero power conditions.

2.0 PREREQUISITES

2.1 Hydrostatic testing of the RCS and associated systems has been completed.

2.2 The RCS and the CVCS are operating as a closed system.

2.3 The RCS is at hot, zero power conditions.

2.4 All permanently mounted instrumentation is properly calibrated.

3.0 TEST METHOD

3.1 Measure and record the changes in water inventory of the RCS and CVCS for a specified interval of time.

4.0 DATA REQUIRED

4.1 Pressurizer pressure, level, and temperature.

4.2 Volume Control Tank level, temperature, and pressure.

4.3 Reactor Drain Tank level, temperature, and pressure.

4.4 RCS temperature and pressure.

4.5 Safety Injection Tank level and pressure.

4.6 Time interval.

5.0 ACCEPTANCE CRITERIA

5.1 Identified and unidentified leakage shall be within the limits described in the Technical Specifications and as described in Section 5.2.5.

14.2.12.2.8 Post-core In-core Instrumentation Test

1.0 OBJECTIVE

1.1 To measure the leakage resistance of the fixed in-core detectors.

2.0 PREREQUISITES

2.1 All permanently installed instrumentation is properly calibrated.

2.2 Installation and pre-operational checkout of the In-core Instrumentation is completed.

2.3 In-core Instrumentation to the Data Processing System (DPS) has been installed.

2.4 The DPS is operational.

2.5 Special test equipment is available and calibrated.

3.0 TEST METHOD

3.1 Measure and record the leakage resistance of each in-core detector at the nominal, hot zero power condition.

4.0 DATA REQUIRED

4.1 RCS temperature and pressure.

4.2 Leakage resistance measurements.

4.3 Plant Monitoring System readout.

5.0 ACCEPTANCE CRITERIA

5.1 Leakage resistance of the in-core detectors is as described in manufacturer's recommendations.

14.2.12.2.9 Post-core Instrument Correlation

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the PPS, CPC, DPS and DIAS.

2.0 PREREQUISITES

2.1 Core Protection Calculators (CPCs) are in operation.

2.2 DPS, DIAS and COLSS are in operation.

2.3 Permanently installed control room instrumentation for the CPCs, COLSS, PPS, DPS and DIAS systems have been calibrated and is in operation.

3.0 TEST METHOD

3.1 When specified, obtain PPS, CPC, DPS and DIAS readouts.

3.2 Obtain control room instrument readings.

4.0 DATA REQUIRED

4.1 DPS and DIAS readout.

4.2 PPS and CPC data.

4.3 Control room instrument readings.

5.0 ACCEPTANCE CRITERIA

5.1 The DPS, DIAS, PPS, and CPC systems perform as described in Section 7.2 and 7.7.

14.2.12.2.10 Acoustic Leak Monitoring System

1.0 OBJECTIVE

1.1 To obtain baseline data on the Acoustic Leak Monitoring System (ALMS).

1.2 To adjust ALMS alarm setpoints as necessary.

2.0 PREREQUISITES

2.1 Pre-operational tests on ALMS have been completed.

2.2 All ALMS instrumentation have been calibrated are operable.

3.0 TEST METHOD

3.1 Collect baseline data using the ALMS during plant heatup and at normal operation conditions.

4.0 DATA REQUIRED

4.1 Baseline data using ALMS.

4.2 ALMS alarm setpoints.

4.3 RCS temperature and pressure.

5.0 ACCEPTANCE CRITERIA

5.1 ALMS performs as described in Section 7.7.1.6.2.

5.2 The ALMS alarm setpoints have been adjusted as necessary.

14.2.12.2.11 Post-core Ex-core Nuclear Instrumentation System Test

1.0 OBJECTIVE

1.1 To verify the proper functional performance of the Ex-core Nuclear Instrumentation System.

1.2 Verify the proper performance of audio and visual indicators.

2.0 PREREQUISITES

2.1 Construction activities on the Ex-core Nuclear Instrumentation System have been completed.

2.2 Ex-core Nuclear Instrumentation System instrumentation has been calibrated.

2.3 External test equipment has been calibrated and is operational.

2.4 Support systems required for operation of the Ex-core Nuclear Instrumentation System are operational.

2.5 Check source is available.

3.0 TEST METHOD

3.1 Utilizing appropriate test instrumentation, simulate and vary input signals to the startup, safety and control channels of the Ex-core Nuclear Instrumentation System.

3.2 Monitor and record all output signals as a function of variable inputs provided by test instrumentation.

3.3 Record the performance of audio and visual indicators in response to changing input signals.

3.4 Utilizing a check source, verify calibration of the startup, safety and control channels.

4.0 DATA REQUIRED

4.1 Values of input and output signals for correlation purposes, as required.

4.2 Values of all output signals triggering audio and visual alarms.

4.3 Channel response to the check source.

5.0 ACCEPTANCE CRITERIA

5.1 The Ex-core Nuclear Instrumentation System performs as described in Sections 7.2.1 and 7.7.1.

14.2.12.3 Low Power Physics Tests

14.2.12.3.1 Low Power Biological Shield Survey Test

1.0 OBJECTIVE

1.1 To measure radiation in accessible locations of the plant outside of the biological shield.

1.2 To obtain baseline levels for comparison with future measurements of level buildup with operation.

2.0 PREREQUISITES

2.1 Radiation survey instruments calibrated.

2.2 Background radiation levels measured in designated locations prior to initial criticality.

3.0 TEST METHOD

3.1 Measure gamma and neutron dose rates during low power (<5% Reactor Thermal Power (RTP)) operation.

4.0 DATA REQUIRED

4.1 Power level.

4.2 Gamma and neutron dose rates at each specified location.

5.0 ACCEPTANCE CRITERIA

5.1 Baseline neutron and Gamma surveys have been completed.

5.2 The biological shield performs as described in Section 12.3.2.2.

14.2.12.3.2 Isothermal Temperature Coefficient Test

1.0 OBJECTIVE

1.1 To measure the Isothermal Temperature Coefficients (ITCs) for various RCS temperatures, pressures, and CEA configurations.[5]

1.2 To determine the Moderator Temperature Coefficient (MTC) from the measured ITC.

2.0 PREREQUISITES

2.1 The reactor is critical with a stable boron concentration and the desired CEA configuration and RCS temperature and pressure.

2.2 The reactivity computer is operable.

3.0 TEST METHOD

3.1 Changes in RCS temperature are introduced and the resultant changes in reactivity measured.

3.2 Reactivity and power swings are limited by compensation with CEA motion when necessary.

4.0 DATA REQUIRED

4.1 Conditions of the measurement:

4.1.1 Pressurizer pressure

4.1.2 CEA configuration

4.1.3 Boron concentration

4.2 Time dependent information:

4.2.1 Reactivity

4.2.2 CEA position

4.2.3 Temperature

5.0 ACCEPTANCE CRITERIA

5.1 The measured ITCs agree with the predicted values within the acceptance criteria specified in Table 14.2-6 and as described in Sections 4.3.2 and 4.3.3.

5.2 The moderator temperature coefficients (MTC) derived from the measured ITC are in compliance with the Technical Specifications and as described in Sections 4.3.2 and 4.3.3.

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5 For unit, this test will be performed only at normal operating temperature and pressure.

14.2.12.3.3 Shutdown and Regulating CEA Group Worth Test

1.0 OBJECTIVE

1.1 To determine regulating and shutdown CEA group worths necessary to demonstrate adequate shutdown margin.

1.2 To demonstrate that the shutdown margin is adequate.

2.0 PREREQUISITES

2.1 The reactor is critical.

2.2 The reactivity computer is operating.

3.0 TEST METHOD

3.1 Measurement of regulating and shutdown CEA groups:

3.1.1 The CEA group worths will be measured by dilution/boration of the RCS or by using the CEA Exchange Method.

3.1.2 Worths may be determined by CEA drop and/or by use of alternate CEA configurations.

4.0 DATA REQUIRED

4.1 Conditions of the measurement:

4.1.1 RCS temperature

4.1.2 Pressurizer pressure

4.1.3 CEA configuration

4.1.4 Boron concentration

4.2 Time dependent information:

4.2.1 Reactivity variation

4.2.2 CEA positions

5.0 ACCEPTANCE CRITERIA

5.1 The measured CEA group worths agree with predictions within the acceptance criteria specified in Table 14.2-6 and as described in Sections 4.3.2 and 4.3.3.

5.2 Evaluation of the measurements verifies shutdown margin as described in Section 4.3.2.

14.2.12.3.4 Differential Boron Worth Test

1.0 OBJECTIVE

1.1 To measure the differential boron reactivity worth for various CEA configurations.

2.0 PREREQUISITES

2.1 CEA group worth tests are completed.

2.2 Critical configuration boron concentration tests are completed.

3.0 TEST METHOD

3.1 The differential boron worths are determined from the measured boron concentrations associated with state points measured during the CEA group worth tests.

4.0 DATA REQUIRED

4.1 Conditions of the measurement at state points:

4.1.1 RCS temperature

4.1.2 Pressurizer pressure

4.1.3 CEA configuration

4.1.4 Boron concentration

4.2 Integral reactivity changes between state points.

5.0 ACCEPTANCE CRITERIA

5.1 The measured boron worths agree with the predicted values within the acceptance criteria specified in Table 14.2-6 and as described in Sections 4.3.2 and 4.3.3.

14.2.12.3.5 Critical Boron Concentration Test

1.0 OBJECTIVE

1.1 To measure critical boron concentrations for various CEA configurations at appropriate temperatures and associated pressures.

2.0 PREREQUISITES

2.1 The reactor is critical at the test conditions.

3.0 TEST METHOD

3.1 The reactor is critical with the desired CEA configuration (arrived at as endpoints for selected plateaus in the CEA group worth tests).

3.2 Coolant samples are taken and chemically analyzed for boron content until it is established that an equilibrium state has been achieved.

4.0 DATA REQUIRED

4.1 Critical conditions:

4.1.1 Boron concentration

4.1.2 CEA positions

4.1.3 RCS temperature

4.1.4 Pressurizer pressure

5.0 ACCEPTANCE CRITERIA

5.1 The measured critical boron concentrations agree with the predictions within the acceptance criteria specified in Table 14.2-6.

14.2.12.4 Power Ascension Tests

14.2.12.4.1 Variable Tavg (Isothermal Temperature Coefficient and Power Coefficient) Test

1.0 OBJECTIVE

1.1 To measure the Isothermal Temperature Coefficient (ITC) and Power Coefficient of reactivity at selected power levels.

2.0 PREREQUISITES

2.1 The reactor is at the desired power level with equilibrium Xenon and boron concentration and the desired CEA configuration.

3.0 TEST METHOD

3.1 The ITC is measured by changing the core average temperature and using CEA movement to maintain the power essentially constant and/or by balancing temperature against power changes.

3.2 The Power Coefficient is measured by changing the core power using CEA movement to maintain the core average temperature essentially constant.

4.0 DATA REQUIRED

4.1 Conditions of the measurement:

4.1.1 Reactor Thermal Power

4.1.2 CEA configuration

4.1.3 Boron concentration

4.1.4 Core Burnup

4.2 Time dependent data:

4.2.1 Power level

4.2.2 RCS temperature

4.2.3 CEA positions

5.0 ACCEPTANCE CRITERIA

5.1 Measured values agree with predictions within the acceptance criteria specified in Table 14.2-6, as described in Sections 4.3.2 and 4.3.3, and conform with the Technical Specifications.

14.2.12.4.2 Unit Load Transient Test

1.0 OBJECTIVE

1.1 To demonstrate that load changes can be made at the desired rates.

2.0 PREREQUISITES

2.1 The reactor is operating at the desired power level.

2.2 The RRS, FWCS, SBCS, RPCS, MDS, and the pressurizer level and pressure control systems are in automatic operation.

3.0 TEST METHOD

3.1 Load increases and decreases (steps and ramps) in accordance with the ABB-CE Fuel Preconditioning Guidelines and as allowed by the MDS and RRS will be performed at power levels in the 75% to 95% range and in the 25% to 50% power range.

4.0 DATA REQUIRED

4.1 Time dependent data:

4.1.1 Pressurizer level and pressure

4.1.2 RCS temperatures

4.1.3 CEA position

4.1.4 Power level and demand

4.1.5 Steam generator levels and pressures

4.1.6 Feedwater and steam flow

4.1.7 Feedwater temperature.

5.0 ACCEPTANCE CRITERIA

5.1 The step and ramp transients demonstrate that the plant performs load changes allowed by ABB-CE's Fuel Preconditioning Guidelines and data has been taken that will demonstrate the plant's ability to meet unit load swing design transients as described in Sections 3.9.1.1, 4.4.3.4, and 7.7.1.1.

5.2 That no audible noise or significant vibration is observed in the economizer or in the rest of the Feedwater and Emergency Feedwater systems due to water hammer.[6]

14.2.12.4.3 Control Systems Checkout Test

1.0 OBJECTIVE

1.1 To demonstrate that the automatic control systems operate satisfactorily during steady-state and transient conditions.

2.0 PREREQUISITES

2.1 The reactor is operating at the desired conditions.

2.2 The RRS, FWCS, SBCS, RPCS, and the pressurizer level and pressure controls are in automatic operation.

2.3 The Megawatt Demand Setter (MDS) is operational.

3.0 TEST METHOD

3.1 The performance of the control systems including the MDS during steady-state and transient conditions will be monitored to demonstrate that the systems are operating satisfactorily.

6 Acceptance criteria can be satisfied by performing system walkdown when conditions permit entry to containment.

4.0 DATA REQUIRED

4.1 Time dependent data:

4.1.1 Pressurizer level and pressure

4.1.2 RCS temperatures

4.1.3 CEA position

4.1.4 Power level and demand

4.1.5 Steam generator levels and pressures

4.1.6 Feedwater and steam flow

4.1.7 Feedwater temperature

5.0 ACCEPTANCE CRITERIA

5.1 The control systems maintain the reactor power, RCS temperature, pressurizer pressure and level, and steam generator levels and pressures within their control bands during steady-state operation and are capable of returning these parameters to within their control bands in response to transient operation as described in Section 7.7.

14.2.12.4.4 Reactor Coolant and Secondary Chemistry and Radiochemistry Test

1.0 OBJECTIVE

1.1 To conduct chemistry tests at various power levels with the intent of gathering corrosion data and determining activity buildup.

1.2 To verify proper operation of the process radiation monitor.

1.3 To verify the adequacy of sampling and analysis procedures.

2.0 PREREQUISITES

2.1 The reactor is stable at the desired power level.

2.2 Sampling systems for the RCS and CVCS are operable.

3.0 TEST METHOD

3.1 Samples will be collected from the RCS and secondary system at various power levels and analyzed in the laboratory using applicable sampling and analysis procedures.

3.2 Samples will be collected at the process radiation monitor at various power levels, analyzed in the laboratory, and compared with the process radiation monitor to verify proper operation.

4.0 DATA REQUIRED

4.1 Conditions of the measurement:

4.1.1 Power

4.1.2 RCS temperature

4.1.3 Boron concentration

4.1.4 Core average burnup

4.2 Samples for measurement of gross activities and/or isotopic activities.

5.0 ACCEPTANCE CRITERIA

5.1 Measured activity levels are within their limits.

5.2 The Process Radiation Monitors agree with the laboratory analyses within measurement uncertainties as described in Section 9.3.2.

5.3 Samples of reactor coolant and secondary fluids can be obtained from the locations described in Section 9.3.2 and identified in Table 9.3.2-1, and procedures for sample collection and analysis are verified as described in Section 9.3.2.

14.2.12.4.5 Turbine Trip Test

1.0 OBJECTIVE

1.1 To demonstrate that the plant responds and is controlled as designed following a 100% turbine trip without RPCS in service.

2.0 PREREQUISITES

2.1 The reactor is operating above 95% power.

2.2 The MDS, SBCS, FWCS, RRS, and pressurizer pressure and level control systems are in automatic operation.

2.3 The RPCS is in Auto Actuate Out of Service.

3.0 TEST METHOD

3.1 The turbine is tripped.

3.2 The plant behavior is monitored to assure that the RRS, SBCS, FWCS, and pressurizer pressure and level control systems maintain the NSSS within operating limits.

4.0 DATA REQUIRED

4.1 Plant condition prior to trip.

4.2 The following acceptance criteria parameters are monitored prior to and throughout the transient:

4.2.1 Pressurizer pressure and level

4.2.2 RCS hot leg temperatures

4.2.3 SG pressures

4.2.4 CEA drop times

4.3 Additional key plant parameters will be monitored for base line data.

5.0 ACCEPTANCE CRITERIA

5.1 The measured values of the acceptance criteria parameters in Section 4.2 (above) are within the single valued acceptance limits based on test predictions using methodology described in Section 15.0.3.

5.2 The reactor trips on high pressurizer pressure.

5.3 The plant responds as described in Section 15.2.2.

14.2.12.4.6 Unit Load Rejection Test

1.0 OBJECTIVE

1.1 To demonstrate that the plant responds and is controlled as designed following a 100% load rejection with RPCS in service.

2.0 PREREQUISITES

2.1 The reactor is operating above 95% power.

2.2 The MDS, SBCS, FWCS, RRS, CEDMCS, RPCS, and pressurizer pressure and level control are in automatic operation.

3.0 TEST METHOD

3.1 A breaker(s) is tripped so as to subject the turbine to the maximum credible overspeed condition.

3.2 The plant behavior is monitored to assure that the RRS, CEDMCS, SBCS, RPCS, FWCS, and pressurizer pressure and level control systems maintain the monitored parameters.

4.0 DATA REQUIRED

4.1 Plant condition prior to load rejection.

4.2 The following acceptance criteria parameters are monitored prior to and throughout the transient:

4.2.1 Pressurizer pressure and level

4.2.2 RCS hot leg temperatures

4.2.3 SG pressures

4.3 Additional key plant parameters will be monitored for baseline data.

5.0 ACCEPTANCE CRITERIA

5.1 The measured values of the acceptance criteria parameters in Section 4.2 (above) are within the single valued acceptance limits based on test predictions using methodology described in Section 15.0.3.

5.2 A reactor trip does not occur during the test.

5.3 The Reactor Power Cutback System operates as described in Section 7.7.1.1.6.

5.4 The plant responds as described in Section 15.2.1.

14.2.12.4.7 Shutdown from Outside the Control Room Test

1.0 OBJECTIVE

1.1 To demonstrate that the plant can be maintained in Hot Standby from outside the Control Room following a reactor trip.

2.0 PREREQUISITES

2.1 The reactor is operating at ≥ 10% of rated power with plant systems in their normal configuration with the turbine-generator in operation.

2.2 The capability to cool down the plant from the Remote Shutdown Panel (RSP) has been demonstrated during pre- or post-core hot functional tests.

2.3 The Remote Shutdown Panel instrumentation is operating properly.

2.4 The Communication Systems between the Control Room and Remote Shutdown location has been demonstrated to be operational.

2.5 The Remote Shutdown instrumentation controls and systems have been pre-operationally tested.

3.0 TEST METHOD

3.1 The operating crew evacuates the Control Room (standby crew remains in the control room).

3.2 The reactor is tripped from outside the Control Room.

3.3 The reactor is brought to Hot Standby by the minimum shift operating crew from outside the Control Room and is maintained in this condition for at least 30 minutes.

3.4 Transfer of control to the RSP is demonstrated from switches near the MCR exits and at appropriate locations inside the channelized equipment rooms.

3.5 Transfer of control back to MCR from RSP is demonstrated, using the switches provided in the channelized equipment rooms.

4.0 DATA REQUIRED

4.1 Time dependent data:

4.1.1 Pressurizer pressure and level

4.1.2 RCS temperatures

4.1.3 Steam generator pressure and level

4.1.4 CEA drop times

5.0 ACCEPTANCE CRITERIA

5.1 The ability to achieve and control the reactor at Hot Standby from outside the control room is demonstrated as described in Section 7.4.1.1.10.

14.2.12.4.8 Loss of Offsite Power Test

1.0 OBJECTIVE

1.1 To verify that the reactor can be shut down and maintained in Hot Standby in the event of loss of offsite power.

2.0 PREREQUISITES

2.1 Reactor operating at ≥ 10% rated power.

3.0 TEST METHOD

3.1 The plant is tripped in a manner to produce a loss of generator and offsite power.

3.2 The plant is maintained in Hot Standby for at least 30 minutes before restoring power.

4.0 DATA REQUIRED

4.1 Time dependent data:

4.1.1 Steam generator pressure and levels

4.1.2 Pressurizer pressure and level

4.1.3 RCS temperatures

4.1.4 Boron concentration

4.1.5 CEA drop times

5.0 ACCEPTANCE CRITERIA

5.1 The reactor is shut down and maintained in Hot Standby on emergency power for at least 30 minutes during a simulated loss of offsite power as described in Section 15.2.6.

14.2.12.4.9 Biological Shield Survey Test

1.0 OBJECTIVE

1.1 To measure the radiation levels in accessible locations of the plant outside of the biological shield.

1.2 To determine occupancy times for these areas during power operation.

2.0 PREREQUISITES

2.1 Radiation survey instruments have been calibrated.

2.2 Results of the radiation surveys performed at zero power conditions are available.

3.0 TEST METHOD

3.1 Measure gamma and neutron dose rates at 50 and 100% power levels.

4.0 DATA REQUIRED

4.1 Power level.

4.2 Gamma dose rates in the accessible locations.

4.3 Neutron dose rates in the accessible locations.

5.0 ACCEPTANCE CRITERIA

5.1 Accessible areas and occupancy times during power operation have been defined as described in Section 12.3.2.

5.2 The biological shield performs as described in Section 12.3.2.2.

14.2.12.4.10 Steady-State Core Performance Test

1.0 OBJECTIVE

1.1 To determine core power distributions using in-core instrumentation.

1.2 To demonstrate that the core has been assembled as designed.

2.0 PREREQUISITES

2.1 The reactor is operating at the desired power level and CEA configuration with equilibrium xenon.

2.2 The in-core instrumentation system is in operation.

3.0 TEST METHOD

3.1 Selected DPS outputs and CPC outputs are recorded.

3.2 The core power distribution is obtained using the in-core detectors.

4.0 DATA REQUIRED

4.1 Conditions of the test:

4.1.1 Reactor power measurements

4.1.2 CEA positions

4.1.3 Boron concentration

4.1.4 Core average burnup

4.1.5 Selected plant computer outputs and CPC outputs

4.1.6 In-core detector maps

5.0 ACCEPTANCE CRITERIA

5.1 Agreement between the predicted and measured power distributions and core peaking factors are within the acceptance criteria as described in Sections 4.3.2 and 7.7.1.1.8, and specified in Table 14.2-6.

5.2 The measured power of each assembly in a symmetric group is within ±10% of the average powers of the group as described in Sections 4.3.2 and 7.7.1.1.8.

5.3 Quadrant tilt is less than 10% as described in Sections 4.3.2 and 7.7.1.1.8.

14.2.12.4.11 Intercomparison of Plant Protection System, Core Protection Calculator, Data Processing System and Discrete Indicating Alarm System Inputs

1.0 OBJECTIVE

1.1 To verify that process variable inputs/outputs of the Plant Protection System (PPS), the Core Protection Calculator (CPC), the Data Processing System (DPS), the Discrete Indicating Alarm System Inputs (DIAS), and the console instruments are consistent.

2.0 PREREQUISITES

2.1 The plant is operating at the desired conditions.

2.2 All CPCs, CEACs, DPS and the DIAS are operable.

3.0 TEST METHOD

3.1 Process variable inputs/outputs of the PPS, the CPCs, the DIAS, the DPS, and console instruments are read as near simultaneously as practical.

4.0 DATA REQUIRED

4.1 Conditions of the measurement:

4.1.1 Power measurements

4.1.2 Boron concentration

4.1.3 RCS temperatures

4.1.4 Pressurizer pressure and level

4.1.5 Steam generator pressures and levels

4.1.6 RCP speeds and differential pressures

5.0 ACCEPTANCE CRITERIA

5.1 The process variable inputs/outputs from the PPS, the CPCs, the DPS, the DIAS, and the console instruments as described in Sections 7.5.1 and 7.7.1 are within the limits of the uncertainty analysis.

14.2.12.4.12 Verification of Core Protection Calculator Power Distribution Related Constants Test

1.0 OBJECTIVE

1.1 To verify the planar radial peaking, temperature annealing, and CEA shadowing factors, and the shape annealing matrix and boundary point power correlation constants, and to verify the algorithms used in the CPCs to relate ex-core signals to in-core power distribution.

2.0 PREREQUISITES

2.1 The reactor is at the desired power level and CEA configuration with equilibrium xenon.

2.2 The in-core detector system is in operation.

2.3 The safety channels have been properly calibrated.

3.0 TEST METHOD

3.1 Planar radial peaking factors are verified for various CEA configurations by comparison of the CPC values with values measured with the in-core detector system.

3.2 The CEA shadowing factors are verified by comparing ex-core detector responses for various CEA configurations with the unrodded ex-core responses.

3.3 The shape annealing factors are measured by comparing in-core power distributions and ex-core detector responses during a free xenon oscillation.

3.4 The temperature shadowing factors are verified by comparing core power and ex-core detector responses for various RCS temperatures.

4.0 DATA REQUIRED

4.1 Conditions of the measurement:

4.1.1 Power level

4.1.2 Burnup

4.2 Time dependent data:

4.2.1 In-core and ex-core detector readings

4.2.2 CEA position

4.2.3 RCS temperatures

5.0 ACCEPTANCE CRITERIA

5.1 Measured radial peaking factors determined from in-core flux maps are no higher than the corresponding values used in the CPCs as described in Sections 4.3.2, 4.3.3, and 7.7.1.1.8.

5.2 The CEA shadowing factors and temperature shadowing factors used in the CPCs agree within the acceptance criteria specified in the CPC test requirements as described in Section 4.3.3.

5.3 The shape annealing matrix have been measured and the boundary point power correlation constants used in the CPCs are within the limits specified by the test requirements as described in Section 4.3.3.

14.2.12.4.13 Main and Emergency Feedwater Systems Test

1.0 OBJECTIVE

1.1 To demonstrate that the operation of the Main Feedwater, Startup Feedwater, and Emergency Feedwater Systems during Hot Standby, Startup, and other normal operations, transients, and plant trips is satisfactory. A list of transients which require monitoring of the MFW and EFW system performances is provided below:

Evolution	**MFW**	**EFW**
MFW Downcomer to Economizer Transfer	X	
Unit Load Transient Test	X	
Control Systems Checkout Test	X	
Turbine Trip Test	X	
Unit Load Rejection Test	X	
Shutdown From Outside Control Room	X	X
Loss of Offsite Power Test	X	X
RPCS Test	X	

2.0 PREREQUISITES

2.1 The Steam Bypass Control System (SBCS), Feedwater Control System (FWCS), Reactor Regulatory System, Reactor Power Cutback System (RPCS), Control Element Drive Mechanism Control System (CEDMCS) and pressurizer pressure and level controls are operable in either manual or automatic modes.

3.0 TEST METHOD

3.1 Performance of the feedwater systems will be monitored during normal operation, transients, and trips. Specifically, the downcomer to economizer transfer will be monitored for noise or vibration due to water hammer.

3.2 Initiate EFW and throttle the flow to verify the throttle capability over the valve full operating position.

4.0 DATA REQUIRED

4.1 Conditions of the measurement:

4.1.1 Reactor power

4.1.2 RCS temperatures

4.1.3 Pressurizer pressure

4.1.4 Steam generator levels and pressures

4.1.5 Steam and feedwater flows

4.1.6 Feedwater temperature and pressure

4.1.7 CEA position

5.0 ACCEPTANCE CRITERIA

5.1 The Main, Startup and Emergency Feedwater Systems perform as designated by the system description and as described.

5.2 No effects due to water hammer are detected. Check for water hammer noise utilizing appropriately placed personnel or check for water hammer vibration utilizing suitable instrumentation.[6]

5.3 The emergency feedwater flow rate decreases as the feedwater valves are throttled.

14.2.12.4.14 CPC Verification

1.0 OBJECTIVE

1.1 To verify Departure from Nucleate Boiling Rates (DNBR) and Local Power Density (LPD) calculations of the Core Protection Calculators (CPCs).

2.0 PREREQUISITES

2.1 The reactor is at the desired power level and CEA configuration with equilibrium xenon.

2.2 The CPCs are operational.

2.3 The in-core detector system is operational.

3.0 TEST METHOD

3.1 Specified values are recorded from the CPCs.

3.2 The values for LPD and DNBR obtained from the CPCs are compared with the values calculated for the same conditions using the CPC FORTRAN Simulator.

4.0 DATA REQUIRED

4.1 Reactor power.

4.2 CEA positions.

4.3 Boron concentration.

4.4 Specified CPC inputs, outputs, and constants.

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6 Acceptance Criteria can be satisfied by performing system walkdown when conditions permit entry to containment.

5.0 ACCEPTANCE CRITERIA

5.1 The values of DNBR and LPD calculated by the CPCs are consistent with the values calculated by the CPC FORTRAN code as described in Section 7.2.1.

14.2.12.4.15 Atmospheric Dump and Turbine Bypass Valves Capacity Test

1.0 OBJECTIVE

1.1 To demonstrate that the maximum steam flow capacity of each atmospheric steam dump valve upstream of the main steam isolation valves is less than that assumed for the safety analysis.

1.2 To demonstrate the throttling capability of the Atmospheric Dump Valves.

1.3 To measure the capacity of each turbine bypass valve individually to determine that the capacity of each steam bypass valve is less than the value used in the safety analysis.

2.0 PREREQUISITES

2.1 The reactor power is ≥ 15% full power.

2.2 Control systems are in automatic where applicable.

2.3 The operation of the Atmospheric Steam Dump, Turbine Bypass, and Shutdown Cooling System have been demonstrated as part of the Hot Functional testing.

3.0 TEST METHOD

3.1 The individual steam flows through each of the Atmospheric Dump Valves (ADVs) upstream of the Main Steam Isolation Valves (MSIVs) are measured.

3.2 Throttle each ADV over its operating range to verify throttle capability.

3.3 The capacity of each turbine bypass valve is measured.

4.0 DATA REQUIRED

4.1 Reactor power.

4.2 RCS temperatures.

4.3 Pressurizer pressure.

4.4 Steam generator levels and pressure.

4.5 Steam dump and turbine bypass valve positions.

4.6 Feedwater flow rates and feedwater temperatures.

5.0 ACCEPTANCE CRITERIA

5.1 The capacities of the individual atmospheric dump valves are less than the values used in the safety analysis but greater than the values required for a safe cooldown.

5.2 The capacity of each turbine bypass valve has been measured and the capacity of each turbine bypass valve is less than the value used in the safety analysis.

5.3 The ADV flow rate decreases when the valve is throttled.

14.2.12.4.16 In-core Detector Test

1.0 OBJECTIVE

1.1 To verify conversion of the fixed in-core detector signals to voltages for input to the Data Processing System (DPS).

2.0 PREREQUISITES

2.1 The reactor is at the specified power level and conditions.

2.2 The DPS is operable.

3.0 TEST METHOD

3.1 Amplifier output signals are measured.

3.2 Group symmetric instrument signals are measured.

3.3 Background detector signals are recorded.

4.0 DATA REQUIRED

4.1 Reactor power.

4.2 CEA position.

4.3 Boron concentration.

4.4 In-core detector system data.

5.0 ACCEPTANCE CRITERIA

5.1 The DPS input signals for group symmetric instruments are within the measurement and power distribution uncertainties discussed in Section 4.3.3.

5.2 Background detector signals described in Section 7.7.1.1.8 are within tolerances specified by ABB-CE.

14.2.12.4.17 Core Operating Limit Supervisory System Verification

1.0 OBJECTIVE

1.1 To verify Core Operating Limit Supervisory System (COLSS) Secondary Calorimetric, Departure from Nucleate Boiling Rates (DNBR) and Local Power Density (LPD) calculation.

2.0 PREREQUISITES

2.1 The reactor is at the desired power level and CEA configuration with equilibrium xenon.

2.2 The COLSS is operational.

2.3 The in-core detector system is operational.

3.0 TEST METHOD

3.1 Specified values are recorded from the COLSS.

3.2 The values for secondary calorimetric power, LPD and DNBR obtained from the COLSS are compared with independently calculated values using the COLSS algorithms.

4.0 DATA REQUIRED

4.1 Reactor power.

4.2 CEA positions.

4.3 Boron concentration.

4.4 Specified COLSS inputs, outputs, and constants.

4.5 In-core detector maps.

5.0 ACCEPTANCE CRITERIA

5.1 The values of COLSS secondary calorimetric power, DNBR and LPD obtained from the COLSS agree with the independently calculated values within the uncertainties in computer processing contained in the COLSS uncertainty analysis as described in Sections 4.4.2.9 and 7.7.1.8.1.

14.2.12.4.18 Baseline Nuclear Steam Supply System Integrity Monitoring

1.0 OBJECTIVE

1.1 To obtain baseline Internals Vibration Monitoring System (IVMS) data at various power plateaus.

1.2 To obtain baseline Acoustic Leak Monitoring system (ALMS) data at various power plateaus.

1.3 To obtain baseline Loose Parts Monitoring system (LPMS) data at various reactor coolant pump configurations[7] and power plateaus.

1.4 To verify existing, or establish new alarm setpoints as required for the NSSS Integrity Monitoring System.

2.0 PREREQUISITES

2.1 Plant is stable at the applicable power level (0, 20, 50, 80, and 100 percent).

2.2 IVMS, ALMS, LPMS are operational as applicable.

3.0 TEST METHOD

3.1 Collect baseline data at the applicable power levels.

3.2 Collect baseline data with various Reactor Coolant Pump combinations.

4.0 DATA REQUIRED

4.1 Reactor power level, temperature, pressure.

4.2 Baseline data for ALMS, IVMS, LPMS.

5.0 ACCEPTANCE CRITERIA

5.1 Baseline data have been collected for various reactor coolant pump combinations as described in Section 7.7.1.6.

5.2 Baseline data has been collected at 0, 20, 50, 80, and 100 percent power.

5.3 Alarm setpoints have been evaluated for adequacy as described in Section 7.7.1.6.

14.2.12.4.19 Reactor Power Cutback System Test

1.0 OBJECTIVE

1.1 To evaluate system response to a loss of one of two operating feedwater pumps.

1.2 To evaluate system response to a Full Length Control Element Assembly (CEA) drop at power.

2.0 PREREQUISITES

2.1 Plant is operating at >50% RTP.

2.2 RRS, FWCS, SBCS, RPCS, pressurizer level control and pressurizer pressure controls are in automatic.

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[7] Performed at Post-Core Hot Functional tests.

2.3 CEACS are operating (not in INOP).

3.0 TEST METHOD

3.1 Loss of Main Feedwater Pump.

3.1.1. One of the two operating feedwater pumps is tripped.

3.2 CEA Drop.

3.2.1 One ot the two operating feedwater pumps is tripped.

4.0 DATA REQUIRED

4.1 Time dependent data:

4.1.1 Pressurizer level and pressure

4.1.2 RCS temperatures

4.1.3 CEA positions

4.1.4 Power level

4.1.5 Steam generator levels and pressures

4.1.6 Feedwater and steam flows

4.1.7 Feedwater temperatures

5.0 ACCEPTANCE CRITERIA

5.1 The control systems stabilize the plant to normal operating control bands.

5.2 No safety actuation limits are exceeded.

14.2.12.4.20 Cooling Tower Acceptance Test

1.0 OBJECTIVE

1.1 To verify the Cooling Tower is capable of rejecting the design heat load.

2.0 PREREQUISITES

2.1 Construction activities are complete.

2.2 Circulating water system has been flow balanced.

2.3 Permanently installed instrumentation is operable and calibrated.

2.4 Test Instrumentation is properly calibrated and available.

2.5 Plant output is at approximately full power.

3.0 TEST METHOD

3.1 Perform a measurement of the Cooling Tower performance.

4.0 DATA REQUIRED

4.1 Cooling Water temperature and flows.

5.0 ACCEPTANCE CRITERIA

5.1 The Cooling Tower performance meets manufacturers design as described in Section 10.4.5.1.

14.2.12.4.21 Penetration Temperature Survey Test

1.0 OBJECTIVE

1.1 To verify concrete temperatures surrounding hot penetrations do not exceed design allowable temperatures.

2.0 PREREQUISITES

2.1 Plant is stable at the applicable power level.

3.0 TEST METHOD

3.1 Collect data at the applicable power levels.

4.0 DATA REQUIRED

4.1 Penetration sleeve temperature adjacent to shield building concrete.

5.0 ACCEPTANCE CRITERIA

5.1 Concrete temperature does not exceed allowable temperature per ANSI/ACI 349 Code Requirements for Nuclear Safety Related Concrete Structures.

14.2.12.4.22 Ventilation Capability Test

1.0 OBJECTIVE

1.1 To verify that various heating, ventilating, and air conditioning (HVAC) systems for the containment, control building, subsphere building, nuclear annex and areas housing engineered safety systems continue to maintain design temperatures.

2.0 PREREQUISITES

2.1 The plant is operating at or near the desired power.

3.0 TEST METHOD

3.1 Record temperature readings in specified areas while operating with normal ventilation lineups.

3.2 Record temperature readings in specified areas while operating the designed minimum number of HVAC components consistent with existing plant conditions.

3.3 Record temperature readings in specified areas during the loss of offsite power test.

4.0 DATA REQUIRED

4.1 Power levels.

4.2 Temperature data at designated locations.

4.3 Equipment operating data.

5.0 ACCEPTANCE CRITERIA

5.1 Temperature conditions are maintained in the containment, control building, subsphere building, nuclear annex and ESF areas in accordance with Section 9.4.

14.2.12.4.23 Natural Circulation Test

1.0 OBJECTIVE

1.1 To evaluate natural circulation flow conditions.

1.2 To determine that adequate boron mixing can be achieved under natural circulation conditions.

2.0 PREREQUISITES

2.1 The reactor is operating so as to provide a satisfactory heat source after a trip.

3.0 TEST METHOD

3.1 All reactor coolant pumps are secured essentially simultaneously.

3.2 The plant is tripped.

3.3 Reactor Coolant System (RCS) temperatures, pressurizer pressure and level, and steam generator levels and pressures are continuously recorded.

3.4 The natural circulation power-to-flow ratio is calculated at hot standby conditions and at reduced plant pressure and temperature.

3.5 The RCS pressure is lowered using the CVCS auxiliary pressurizer spray.

3.6 The plant is borated using the safety injection pumps. Periodic samples are taken to verify that acceptable mixing of borated water is achieved under natural circulation conditions at reduced plant pressure and temperature and to identify delay time associated with such mixing.

4.0 DATA REQUIRED

4.1 RCS Temperature

4.2 Pressurizer pressure and level.

4.3 Steam generator levels and pressure.

4.4 RCS Boron Concentration

5.0 ACCEPTANCE CRITERIA

5.1 The natural circulation power to flow ratio is less than 1.0 as described in Appendix 5D.

5.2 The RCS can be borated while in natural circulation as described in Appendix 5D.

14.2.12.4.24 Liquid Waste Management System Test

1.0 OBJECTIVE

1.1 To demonstrate that the operation of the Liquid Waste Management System (LWMS) for collection, processing, recycling, and preparation of liquid waste for release to the environment is satisfactory. A list of LWMS subsystems is provided below:

- Low Level Waste Subsystem
- High Level Waste Subsystem
- Laundry and Hot Shower/Chemical Waste Subsystem
- Containment Cooler Subsystem

2.0 PREREQUISITES

2.1 The LWMS equipment, including all subsystem equipment is operable in either manual and/or automatic modes, as desired.

3.0 TEST METHOD

3.1 Performance of the LWMS will be monitored. Specifically, the capability to independently and simultaneously collect and process liquid waste will be verified.

3.2 Verify power-operated valves fail to the position specified in Section 11.2 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Conditions of Measurement.

4.1.1 Reactor Power History and RCS Radioactivity Level.

4.1.2 LWMS Tank Levels.

4.1.3 LWMS Pump Operating Data.

4.1.4 LWMS Ion Exchanger Data.

4.1.5 Effluent Control Monitor Operating Data.

4.1.6 Position response of valves to loss of motive power.

5.0 ACCEPTANCE CRITERIA

5.1 The LWMS equipment performs as described in Section 11.2.

14.2.12.4.25 Gaseous Waste Management System Test

1.0 OBJECTIVE

1.1 To demonstrate that the operation of the Gaseous Waste Management System (GWMS) for collection and processing of radioactive gases vented from plant equipment is satisfactory.

2.0 PREREQUISITES

The GWMS equipment is operable in either manual and/or automatic modes, as designed.

3.0 TEST METHOD

3.1 Performance of the GWMS will be monitored. Specifically the capability to independently and simultaneously collect and process gaseous waste will be verified.

3.2 Verify power-operated valves fail to the position specified in Section 11.3 upon loss of motive power.

4.0 DATA REQUIRED

4.1 Conditions of Measurement.

4.1.1 Reactor Power History and RCS Radioactivity Level.

4.1.2 Containment Temperature and Humidity.

4.1.3 Condenser Operating Data.

4.1.4 Effluent Control Monitor Operating Data.

4.1.5 Gas Analyzer Operating Data.

4.1.6 Gas Transport Times.

4.1.7 Position Response of Valves to Loss of Motive Power.

5.0 ACCEPTANCE CRITERIA

5.1 The GWMS equipment performs as described in Section 11.3.

Table 14.2-1 Pre-operational Tests

Section	Title
14.2.12.1.1	Reactor Coolant Pump Motor Initial Operation
14.2.12.1.2	Reactor Coolant System Test
14.2.12.1.3	Pressurizer Safety Valve Test
14.2.12.1.4	Pressurizer Pressure and Level Control Systems
14.2.12.1.5	CVCS Letdown Subsystem Test
14.2.12.1.6	CVCS Purification Subsystem Test
14.2.12.1.7	Volume Control Tank Subsystem Test
14.2.12.1.8	CVCS Charging Subsystem Test
14.2.12.1.9	Chemical Addition Subsystem Test
14.2.12.1.10	Reactor Drain Tank Subsystem Test
14.2.12.1.11	Equipment Drain Tank Subsystem Test
14.2.12.1.12	Boric Acid Batching Tank Subsystem Test
14.2.12.1.13	Concentrated Boric Acid Subsystem Test
14.2.12.1.14	Reactor Makeup Subsystem Test
14.2.12.1.15	Holdup Subsystem Test
14.2.12.1.16	Boric Acid Concentrator Subsystem Test
14.2.12.1.17	Gas Stripper Subsystem Test
14.2.12.1.18	Boronometer Subsystem Test
14.2.12.1.19	Process Radiation Monitor Subsystem Test
14.2.12.1.20	Gas Stripper Effluent Radiation Monitor Subsystem Test
14.2.12.1.21	Shutdown Cooling System Test
14.2.12.1.22	Safety Injection System Test
14.2.12.1.23	Safety Injection Tank Subsystem Test
14.2.12.1.24	Megawatt Demand Setter System Test
14.2.12.1.25	Engineered Safety Features - Component Control System Test
14.2.12.1.26	Plant Protection System Test
14.2.12.1.27	Ex-core Nuclear Instrumentation System Test
14.2.12.1.28	Fixed In-core Nuclear Signal Channel Test
14.2.12.1.29	Control Element Drive Mechanism Control System Test
14.1.12.1.30	Reactor Regulating System Test

Table 14.2-1 Pre-operational Tests (Cont'd.)

Section	Title
14.2.12.1.31	Steam Bypass Control System Test
14.2.12.1.32	Feedwater Control system Test
14.2.12.1.33	Core Operating Limit Supervisory System Test
14.2.12.1.34	Reactor Power Cutback System Test
14.2.12.1.35	Fuel Handling & Storage System Test
14.2.12.1.36	Emergency Feedwater System Test
14.2.12.1.37	Reactor Coolant System Hydrostatic Test
14.2.12.1.38	CEDM Cooling System Test
14.2.12.1.39	Safety Depressurization System Test
14.2.12.1.40	Containment Spray System Test
14.2.12.1.41	Integrated Engineered Safety Features/Loss of Power Test
14.2.12.1.42	In-containment Water Storage System Test
14.2.12.2.43	Internals Vibrations Monitoring System Test
14.2.12.2.44	Loose Parts Monitoring System Test
14.2.12.1.45	Acoustic Leak Monitoring System Test
14.2.12.1.46	Data Processing System and Discrete Indication and Alarm System Test
14.2.12.1.47	Critical Function Monitoring System Test
14.2.12.1.48	Pre-core Hot Functional Test Controlling Document
14.2.12.1.49	Pre-core Instrument Correlation
14.2.12.1.50	Remote Shutdown Panel
14.2.12.1.51	Alternate Protection System Test
14.2.12.1.52	Pre-core Test Data Record
14.2.12.1.53	Pre-core Reactor Coolant System Expansion Measurements
14.2.12.1.54	Pre-core Reactor Coolant and Secondary Water Chemistry Data
14.2.12.1.55	Pre-Core Pressurizer Performance
14.2.12.1.56	Pre-Core Control Element Drive Mechanism Performance
14.2.12.1.57	Pre-core Reactor Coolant System Flow Measurements
14.2.12.1.58	Pre-core Reactor Coolant System Heat Loss
14.2.12.1.59	Pre-core Reactor Coolant System Leak Rate Measurement
14.2.12.1.60	Pre-core Chemical Volume Control System Integrated Test

Table 14.2-1 Pre-operational Tests (Cont'd.)

Section	Title
14.2.12.1.61	Pre-core Safety Injection Check Valve Test
14.2.12.1.62	Pre-core Boration/Dilution Measurements
14.2.12.1.63	Downcomer Feedwater System Water Hammer Test
14.2.12.1.64	Main Turbine Systems Test
14.2.12.1.65	Main Steam Safety Valve Test
14.2.12.1.66	Main Steam Isolation Valves and MSIV Bypass Valves Test
14.2.12.1.67	Main Steam System Test
14.2.12.1.68	Steam Generator Blowdown System Test
14.2.12.1.69	Main Condenser and Air Removal Systems Test
14.2.12.1.70	Main Feedwater System Test
14.2.12.1.71	Condensate System Test
14.2.12.1.72	Turbine Gland Sealing System Test
14.2.12.1.73	Condenser Circulating Water System Test
14.2.12.1.74	Steam Generator Hydrostatic Test
14.2.12.1.75	Feedwater Heater and Drains System Test
14.2.12.1.76	Ultimate Heat Sink Test
14.2.12.1.77	Chilled Water System Test
14.2.12.1.78	Station Service Water System Test
14.2.12.1.79	Component Cooling Water System Test
14.2.12.1.80	Pool Cooling and Purification System Test
14.2.12.1.81	Turbine Building Cooling Water System Test
14.2.12.1.82	Condensate Storage System Test
14.2.12.1.83	Turbine Building Service Water System Test
14.2.12.1.84	Equipment and Floor Drainage System Test
14.2.12.1.85	Normal and Security Lighting Systems Test
14.2.12.1.86	Emergency Lighting System Test
14.2.12.1.87	Communications Systems Test
14.2.12.1.88	Compressed Air System Test
14.2.12.1.89	Compressed Gas System Test
14.2.12.1.90	Process Sampling System Test

Table 14.2-1 Pre-operational Tests (Cont'd.)

Section	Title
14.2.12.1.91	Heat Tracing System Test
14.2.12.1.92	Fire Protection System Test
14.2.12.1.93	Emergency Diesel Generator Mechanical System Test
14.2.12.1.94	Emergency Diesel Generator Electrical System Test
14.2.12.1.95	Emergency Diesel Generator Auxiliary Systems Test
14.2.12.1.96	Alternate AC Source System Test
14.2.12.1.97	Alternate AC Source Support Systems Test
14.2.12.1.98	Containment Polar Crane Test
14.2.12.1.99	Fuel Building Cranes Test
14.2.12.1.100	Turbine Building Crane Test
14.2.12.1.101	Containment Cooling and Ventilation System Test
14.2.12.1.102	Containment Purge Ventilation System Test
14.2.12.1.103	Control Complex Ventilation System Test
14.2.12.1.105	Turbine Building Ventilation System Test
14.2.12.1.106	Station Service Water Pump Structure Ventilation System Test
14.2.12.1.107	Diesel Building Ventilation System Test
14.2.12.1.108	Fuel Building Ventilation System Test
14.2.12.1.109	Annulus Ventilation System Test
14.2.12.1.110	Radwaste Building Ventilation System Test
14.2.12.1.111	Balance of Control Complex Ventilation System Test
14.2.12.1.112	Hydrogen Mitigation System Test
14.2.12.1.113	Containment Hydrogen Recombiner System Test
14.2.12.1.114	Liquid Waste Management System Test
14.2.12.1.115	Solid Waste Management System Test
14.2.12.1.116	Gaseous Waste Management System Test
14.2.12.1.117	Process and Effluent Radiological Monitoring System Test
14.2.12.1.118	Airborne and Area Radiation Monitoring System Test
14.2.12.1.119	4160 Volt Class 1E Auxiliary Power System Test
14.2.12.1.120	480 Volt Class 1E Auxiliary Power System Test
14.2.12.1.121	Unit Main Power System Test

Table 14.2-1 Pre-operational Tests (Cont'd.)

Section	Title
14.2.12.1.122	13800 Volt Normal Auxiliary Power System Test
14.2.12.1.123	4160 Volt Normal Auxiliary Power System Test
14.2.12.1.124	480 Volt Normal Auxiliary Power System Test
14.2.12.1.125	Non-Class 1E DC Power Systems Test
14.2.12.1.126	Class 1E DC Power Systems Test
14.2.12.1.127	Offsite Power System Test
14.2.12.1.128	BOP Piping Thermal Expansion Measurement Test
14.2.12.1.129	BOP Piping Vibration Measurement Test
14.2.12.1.130	Containment Integrated Leak Rate Test and Structural Integrity Test
14.2.12.1.131	Fuel Transfer Tube Functional Test and Leak Test
14.2.12.1.132	Equipment Hatch Functional Test and Leak Test
14.2.12.1.133	Containment Personnel Airlock Functional Test and Leak Test
14.2.12.1.134	Containment Electrical Penetration Assemblies Test
14.2.12.1.135	Containment Isolation Valves Leakage Rate Test
14.2.12.1.136	Loss of Instrument Air Test
14.2.12.1.137	Mid-Loop Operations Verification Test
14.2.12.1.138	Seismic Monitoring Instrumentation Test
14.2.12.1.139	Auxiliary Steam System Test
14.2.12.1.140	Containment Isolation Valves Test
14.2.12.1.141	Post Accident Monitoring Instrumentation Test
14.2.12.1.142	Component Cooling Water Heat Exchanger Structure(s) Ventilation Systems Test
14.2.12.1.143	Nuclear Annex Ventilation System Test

Table 14.2-2 Post-Core Hot Functional Tests

Section	Title
14.2.12.2.1	Post-core Hot Functional Test Controlling Document
14.2.12.2.2	Loose Parts Monitoring System
14.2.12.2.3	Reactor Coolant System Flow Measurements
14.2.12.2.4	Post-core Control Element Drive Mechanism Performance
14.2.12.2.5	Post-core Reactor Coolant and Secondary Water Chemistry Data
14.2.12.2.6	Post-core Pressurizer Spray Valve and Control Adjustments
14.2.12.2.7	Post-core Reactor Coolant System Leak Rate Measurement
14.2.12.2.8	Post-core In-Core Instrumentation
14.2.12.2.9	Post-core Instrument Correlation
14.2.12.2.10	Post-core Acoustic Leak Monitor System Test
14.2.12.2.11	Post-core Ex-core Nuclear Instrumentation System Test

Table 14.2-3 Low Power Physics Tests

Section	Title
14.2.12.3.1	Low Power Biological Shield Survey Test
14.2.12.3.2	Isothermal Temperature Coefficient Test
14.2.12.3.3	Shutdown and Regulating CEA Group Worth Test
14.2.12.3.4	Differential Boron Worth Test
14.2.12.3.5	Critical Boron Concentration Test

Table 14.2-4 Power Ascension Tests

Section	Title
14.2.12.4.1	Variable Tavg (Isothermal Temperature Coefficient & Power Coefficient) Test
14.2.12.4.2	Unit Load Transient Test
14.2.12.4.3	Control Systems Checkout Test
14.2.12.4.4	RCS and Secondary Chemistry and Radiochemistry Test
14.2.12.4.5	Turbine Trip Test
14.2.12.4.6	Unit Load Rejection Test
14.2.12.4.7	Shutdown From Outside the Control Room Test
14.2.12.4.8	Loss of Offsite Power Test
14.2.12.4.9	Biological Shield Survey Test
14.2.12.4.10	Steady-State Core Performance Test
14.2.12.4.11	Intercomparison of PPS, CPCs, DPS and DIAS Inputs
14.2.12.4.12	Verification of CPC Power Distribution Related Constants Test
14.2.12.4.13	Main and Emergency Feedwater System Test
14.2.12.4.14	CPC Verification
14.2.12.4.15	Atmospheric Dump and Turbine Bypass Valve Test
14.2.12.4.16	In-core Detector Test
14.2.12.4.17	COLSS Verification
14.2.12.4.18	Baseline NSSS Integrity Monitoring
14.2.12.4.19	Reactor Power Cutback System Test
14.2.12.4.20	Cooling Tower Acceptance Test
14.2.12.4.21	Penetration Temperature Survey Test
14.2.12.4.22	Ventilation Capability Test
14.2.12.4.23	Natural Circulation Test
14.2.12.4.24	Liquid Waste Management System Test
14.2.12.4.25	Gaseous Waste Management System Test

Table 14.2-5 Power Ascension Tests

Test Title	Plateau
Variable Tavg (Isothermal Temperature Coefficient & Power Coefficient) Test	50, 100%[1]
Unit Load Transient Test	50, 100%
Control Systems Checkout Test	50, 80%
RCS and Secondary Chemistry and Radiochemistry Test	20, 50, 80, 100%
Turbine Trip Test	100%
Unit Load Rejection Test	100%
Shutdown from Outside the Control Room Test	≥ 10%
Loss of Offsite Power Test	≥ 10%
Biological Shield Survey Test	50, 100%
Steady-State Core Performance Test	20, 50, 80, 100%
Intercomparison of PPS, CPC, DPS and DIAS Inputs	20, 50, 80, 100%
Verification of CPC Power Distribution Related Constants Test	20, 50%
Main and Emergency Feedwater System Test	≥ 10%
CPC Verification	20, 50, 80, 100%
Atmospheric Dump and Turbine Bypass Valve Capacity Test	≥ 15%
In-core Detector Test	20, 50, 80, 100%
COLSS Verification	20, 50, 80, 100%
Baseline NSSS Integrity Monitoring	20, 50, 80, 100%
Reactor Power Cutback System Test	> 50%
Cooling Tower Acceptance Test	100%
Penetration Temperature Survey Test	20, 50, 80, 100%
Ventilation Capability Test	50, 100%
Natural Circulation Test	> 80%
Liquid Waste Management System Test	> 20%
Gaseous Waste Management System Test	> 20%

[1] The temperature and power coefficient measurements are done as close as possible to 100% at a level where CEA motion is practical accounting for margin considerations.

Table 14.2-6 Physics (Steady-State) Test Acceptance Criteria Tolerances

Parameter	Tolerance
Low Power Physics Test	
CEA Group Worths [1]	$\pm$ 10% or 0.05% $\Delta\rho$ Whichever is Greater
Total Worth (Net Shutdown)	$\pm$ 10%
Temperature Coefficient	$\pm 0.3 \times 10^{-4}\ \Delta\rho/°F$
Critical Boron Concentration	$\pm$ 50 ppm
Boron Worth	$\pm$ 15 ppm/%$\Delta\rho$
Power Ascension Physics Test	
Power Distribution (Radial and Axial)	RMS[2] $\leq$3%[3]
Peaking Factors (Fxy, Fr, Fz, Fq)	$\pm$ 7.5%
Temperature Coefficient	$\pm 0.3 \times 10^{-4}\ \Delta\rho/°F$
Power Coefficient	$\pm 0.2 \times 10^{-4}\ \Delta\rho$/% Power

[1] If CEA Exchange methods are used, the acceptance criteria provided in CEN 319 are applicable.

[2] $$RMS = \sqrt{\sum_{1}^{N} \frac{(RPD^{PRED} - RPD^{MEAS})^2}{N}}$$

where N = total number of fuel assemblies in core or number of axial planes, as appropriate.

[3] at 50% power and above

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
RCP Motor Initial Operation			X	X	X	X	X				X	X			X		
Reactor Coolant System Test			X	X	X	X	X	X			X	X			X		
Pressurizer Safety Valve Test[1]																	
Pressurizer Pressure and Level Control Systems Test			X	X	X	X	X										X
Chemical and Volume Control System Letdown Subsystem Test			X	X	X	X	X	X				X	X				
CVCS Purification Subsystem Test			X	X	X	X	X						X				
Volume Control Tank Subsystem Test			X	X	X	X	X	X				X	X				
CVCS Charging Subsystem Test			X	X	X	X	X	X					X			X	
Chemical Addition Subsystem Test			X	X	X	X	X						X				
Reactor Drain Tank Subsystem Test			X	X	X	X	X	X				X	X				
Equipment Drain Tank Subsystem Test			X	X	X	X	X										
Boric Acid Batching Tank Subsystem Test			X				X										
Concentrated Boric Acid Subsystem Test			X	X	X	X	X	X				X	X				
Reactor Makeup Subsystem Test			X	X	X	X	X										
Holdup Subsystem Test			X	X	X	X	X										

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests (Cont'd.)

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
Fuel Handling and Storage System Test							X										
Emergency Feedwater System Test		X	X	X	X	X	X	X		X		X			X	X	
Reactor Coolant System Hydrostatic Test							X										
Control Element Drive Mechanism Cooling System Test			X	X	X	X	X										
Safety Depressurization System Test	X	X		X	X	X		X									
Containment Spray System Test	X	X		X	X	X	X	X		X	X	X		X			
Integrated Engineered Safety Features/Loss of Power Test	X	X		X	X	X	X	X	X	X	X			X			
In-containment Water Storage System Test	X			X	X	X	X										
Internals Vibration Monitoring System Test				X	X	X	X										
Loose Part Monitoring System Test				X	X	X	X										
Acoustic Leak Monitoring System Test				X	X	X	X										
Data Processing System and Discrete Indication and Alarm System Test				X	X	X	X										
Critical Function Monitoring System Test				X	X	X	X										
Pre-core Hot Functional Test Controlling Document[2]																	
Pre-core Instrument Correlation[2]																	
Alternate Protection System Test			X	X	X	X	X										
Pre-core Test Data Record[2]																	

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests (Cont'd.)

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
Pre-core Reactor Coolant System Expansion Measurements[2]																	
Pre-core Reactor Coolant and Secondary Water Chemistry Data[2]																	
Pre-core Pressurizer Performance[2]																	
Pre-core Control Element Drive Mechanism Performance[2]																	
Pre-core Reactor Coolant System Flow Measurements[2]																	
Pre-core Reactor Coolant System Heat Loss[2]																	
Pre-core Reactor Coolant System Leak Rate Measurement[2]																	
Pre-core Chemical and Volume Control System Integrated Test[2]																	
Remote Shutdown Panel Tests[2]																	
Pre-core Safety Injection Check Valve Test[2]																	
Pre-core Boration/Dilution Measurements[2]																	
Downcomer Feedwater System Water Hammer Test[2]																	
Main Turbine Systems Test			X	X	X	X	X				X			X			
Main Steam Safety Valve Test[2]																	
Main Steam Isolation Valves and MSIV Bypass Valves Test[2]																	
Main Steam System Test			X	X	X	X	X					X					
Steam Generator Blowdown System Test			X	X	X	X	X	X									

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests (Cont'd.)

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
Main Condenser and Air Removal Systems Test			X	X	X	X	X										
Main Feedwater System Test				X	X	X	X	X									
Condensate System Test			X	X	X	X	X					X		X			
Turbine Gland Sealing System Test											X						
Condenser Circulating Water System Test			X	X	X	X	X							X			
Steam Generator Hydrostatic Test[2]																	
Feedwater Heater and Drains System Test			X	X	X	X	X					X					
Ultimate Heat Sink Test							X				X						X
Chilled Water System Test						X	X	X			X						X
Station Service Water System Test			X			X	X	X						X			
Component Cooling Water System Test		X	X	X	X	X	X	X			X			X	X		
Pool Cooling and Purification System Test		X	X			X	X				X						
Turbine Building Cooling Water System Test							X				X						X
Condensate Storage System Test							X					X					
Turbine Building Service Water System Test							X							X			
Equipment and Floor Drainage System Test							X										
Normal and Security Lighting Systems Test							X										
Emergency Lighting System Test								X									
Communications Systems Test							X										
Compressed Air Systems Test							X					X					

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests (Cont'd.)

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
Compressed Gas System Test							X										
Process Sampling Systems Test							X										
Heat Tracing System Test							X										
Fire Protection System Test							X										
Emergency Diesel Generator Mechanical System Test							X			X							
Emergency Diesel Generator Electrical System Test		X	X					X		X							
Emergency Diesel Generator Auxiliary Systems Test			X					X		X							
Alternate AC Source System Test				X		X	X		X								
Alternate AC Source Support Systems Test						X		X	X								
Containment Polar Crane Test							X										
Fuel Building Cranes Test							X										
Turbine Building Crane Test							X										
Containment Cooling and Ventilation System Test				X	X	X	X				X						X
Containment Purge Ventilation System Test				X		X	X	X									
Control Complex Ventilation System Test						X	X	X			X						X
Subsphere Building Ventilation System Test						X	X				X						X
Turbine Building Ventilation System Test						X	X				X						
Station Service Water Pump Structure Ventilation System Test						X	X				X						
Diesel Building Ventilation System Test						X	X	X			X						

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests (Cont'd.)

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
Fuel Building Ventilation System Test						X	X				X						X
Annulus Ventilation System Test		X				X	X	X			X						
Radwaste Building Ventilation System Test						X	X				X						X
Balance of Control Complex Ventilation Systems Test						X	X				X						
Hydrogen Mitigation System Test							X										
Containment Hydrogen Recombiner System Test							X										
Liquid Waste Management System Test			X	X		X	X										
Solid Waste Management System Test			X	X		X	X										
Gaseous Waste Management System Test			X	X		X	X										
Process and Effluent Radiological Monitoring System Test						X	X										
Airborne and Area Radiation Monitoring System Test						X	X	X									
4160 Volt Class 1E Auxiliary Power System Test				X	X	X		X									
480 Volt Class 1E Auxiliary Power System Test				X	X	X		X									
Unit Main Power System Test						X	X										
13800 Volt Normal Auxiliary Power System Test				X	X	X	X										
4160 Volt Normal Auxiliary Power System Test				X	X	X	X										
480 Volt Normal Auxiliary Power System Test				X	X	X	X										

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests (Cont'd.)

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
Non-Class 1E DC Power Systems Test				X	X	X	X	X									
Class-1E DC Power Systems Test				X	X	X		X									
Offsite Power System Test				X		X	X										
Balance of Plant Piping Thermal Expansion Measurement Test[2]																	
BOP Piping Vibration Measurement Test[2]																	
Containment Integrated Leak Rate Test and Structural Integrity Test[2]																	
Fuel Transfer Tube Functional Test and Leak Test[1]																	
Equipment Hatch Functional Test and Leak Test[1]																	
Containment Personnel Airlock Functional Test and Leak Test[1]																	
Containment Electrical Penetration Assemblies Test[2]																	
Containment Isolation Valves Leakage Rate Test							X	X									
Loss of Instrument Air Test[2]																	
Mid-Loop Operations Verification Test[2]																	
Seismic Monitoring Instrumentation System Test							X										
Auxiliary Steam System Test[1]						X	X										
Containment Isolation Valves Test		X				X	X	X									
Post Accident Monitoring Instrumentation Test						X	X										
Nuclear Annex Ventilation System Test						X	X	X			X						X

Table 14.2-7 Matrix of Support Systems Recommended for Pre-operational Tests (Cont'd.)

Subject	In-Containment Refueling Water Storage Tank	Component Control System for Engineered Safety Features	Component Control System Process	Data Processing System	Discrete Indication and Alarm System	Main Control Room	Non-1E Power	1E Power	Alternate AC	Diesel Generator	Cooling Water	Compressed Air/Gas	Auxiliary System	Service Water	Emergency Feedwater Tank	Remote Shutdown Panel	Chilled Water
Component Cooling Water Heat Exchanger Structure(s) Ventilation Systems Test							X										

[1] Support Systems not required for testing.
[2] This test requires essentially a mechanically operable plant.

14.3 Certified Design Material

The Certified Design Material is that set of principal design characteristics, site parameters and interfaces, and the inspections, tests, analyses and acceptance criteria that are certified through the rulemaking process of 10 CFR Part 52 and are included in the formal Certification Rule. The selection criteria and processes used to develop the System 80+ Standard Plant Certified Design Material (CDM) are described in this section.

The System 80+ standard plant design information included in the CDM is derived from the more detailed design information presented in the Approved Design Material (ADM). The CDM is the most significant of the design information and reflects the tiered approach to design certification endorsed by the Commission [Staff Review Memorandum 2/15/91 regarding SECY-90-377; 10CFR Part 52 Statement of Considerations, 52 Federal Register 15372, 15377, (1989)]. In addition, the selection of the most significant design information was reviewed by multidiscipline design teams for completeness, accuracy, and consistency with the material in the ADM. Further, separate reviews were conducted by industry representatives and subsequently by combined industry/regulatory representatives in public session to ensure that the CDM met the criteria of "necessary and sufficient" as specified in 10 CFR 52.

The System 80+ standard plant Certified Design Material contains:

- An introduction section which defines terms used in the CDM, general provisions that are applicable to all CDM entries, and acronyms and legends used in the body of the CDM.

- Design descriptions for: a) systems that are fully within the scope of the System 80+ standard plant design certification, and b) the in-scope portion of those systems that are only partially within the scope of the System 80+ standard plant design certification. The intent of the CDM design descriptions is to delineate the principal design features and principal design characteristics that are referenced in the Design Certification Rule. The design descriptions are accompanied by the inspections, tests, analyses and acceptance criteria (ITAAC) required by 10 CFR 52.47(a) (1) (vi) to be part of the design certification application. The ITAAC define verification activities that are to be performed for a plant with specific pre-defined acceptance criteria to be met with the objective of confirming that the plant is built and will operate in accordance with the design certification. Successful completion of these ITAAC, together with the combined license (COL) applicant's ITAAC for the site-specific portions of the plant, will be the basis for NRC authorization to load fuel per the provisions of 10 CFR 52.103.

- Design descriptions and their associated ITAAC for design and construction activities that are applicable to more than one system. Design-related processes have been included in the CDM for aspects of the design that are dependent upon characteristics of as-procured, as-installed systems, structures and components. These characteristics are not available at the time of certification and therefore cannot be used to develop and certify design details. However, the design processes and appropriate acceptance criteria associated with these aspects of the design are contained in the CDM and will be certified and applied at the time of COL application and facility construction.

- Interface requirements as defined by 10 CFR Part 52.47(a) (1) (vii). Interface requirements are those requirements which must be met by the site-specific portions of the complete nuclear power plant that are not within the scope of the certified design. These requirements define characteristics of the site-specific features which must be provided in order for the certified design to comply with certification commitments. Interface requirements are defined for:

a) systems entirely outside the scope of the design certification and b) the out-of-scope portions of those systems that are only partially within the scope of the design certification. The COL applicant will provide ITAAC for the site-specific design features that implement the interface requirements; therefore, the CDM does not include ITAAC for interface requirements.

- Site parameters used as the basis for the System 80+ standard plant design are presented in the ADM. These parameters represent a bounding envelope of site conditions for any license application referencing the System 80+ standard plant design certification. ITAAC are not necessary for the site parameters entries because compliance with site parameters will be verified as part of issuance of a license for a plant that references the System 80+ standard plant design.

The following is a description of the criteria and methods by which specific technical entries for the CDM were selected. The structure of the description is based upon the structure of the CDM.

The criteria and methods that are discussed in the following sections are guidelines only. For some matters, the contents of the CDM may not directly correspond to these guidelines because special considerations related to the matters may have warranted an alternate, but essentially equivalent, approach. For such matters, a case-by-case determination was made regarding how or whether the matters should be addressed in the CDM. These determinations were based upon the principles inherent in Part 52 and its underlying purposes.

14.3.1 CDM Section 1.0: Introduction

Definitions, General Provisions, and Figure Legend and Abbreviations are described in this subsection.

14.3.1.1 CDM Section 1.1: Definitions

Selection Criteria - This Section defines terms which are used throughout the CDM and could (potentially) be subject to various interpretations. Selection of entries was based on the judgement that a particular word/phrase merited definition - with particular emphasis on terms associated with implementation of the ITAAC.

Selection Methodology - The terms defined in the Definition section were selected based on the perceived need to specifically state the context in which the term was to be used. These terms were identified during the preparation and review of the CDM.

Example Entries - Typical terms defined are "as-built," "Division," and "Type Test."

14.3.1.2 CDM Section 1.2: General Provisions

Selection Criteria - This section contains provisions that were selected on the basis that each provision was necessary to either a) define technical requirements applicable to multiple systems in the CDM or to b) provide clarification and guidance for implementation of the CDM.

Selection Methodology - Entries in the General Provisions section also were developed as part of the CDM definition and review process. Each entry is included to clearly state the general requirements, guidelines, and/or interpretations that are intended to be applied to the CDM.

Example Entries - Issues requiring general provisions treatment include guidance on interpretation of figures provided in the body of the CDM and defining the scope of what is included if a system configuration check is specified in an ITAAC entry.

14.3.1.3 CDM Section 1.3: Figure Legend and Abbreviation List

These were included only to aid a user of the CDM.

14.3.2 CDM Section 2.0: System 80+ Certified Design Material

This section of the CDM has the design description and ITAAC material for every system that is either fully or partially within the scope of the System 80+ standard plant design certification. The intent of this comprehensive listing of System 80+ standard plant systems is to define, at the CDM level, the full scope of the certified design.

Since preparation of system design descriptions and the associated ITAAC are sequential, separate processes, they are discussed separately in the next two subsections.

14.3.2.1 Design Descriptions

The Certified Design Description for each System 80+ standard plant system addresses the most significant design features and performance standards which pertain to the safety of the plant and include descriptive text and supporting figures. The intent of the CDM design descriptions is to define the System 80+ standard plant design characteristics which are referenced in the Design Certification Rule as a result of the certification provisions of 10 CFR Part 52.

Selection Criteria - The following criteria were considered in determining which information warranted inclusion in the certified design descriptions:

(1) The information in the certified design descriptions is to be derived only from the technical information presented in the ADM. This reflects the approach that the CDM contains the most significant design information and is based on the Commission directive in the Statement of Considerations for Part 52 (54 FR 15372, 15377 [1989]) that there "be less detail in a certification than in an application for certification." In this context, the "certification" is the CDM and the "application for certification" consists of all the information in the ADM.

(2) The certified design descriptions contain only information from the ADM that is most significant to safety; the ADM contains a wide spectrum of information on various aspects of the System 80+ standard plant design, and not all of this information warrants inclusion in the certified design descriptions. This selection criterion reflects the Commission directive in the Statement of Considerations for Part 52 (54 FR 15372, 15377 [1989]) that the certified design should "encompass roughly the same design features that Section 50.59 prohibits changing without prior NRC approval." In determining what information is most significant to safety, several factors were considered, including the following:

- Whether the feature or function in question is necessary to satisfy the NRC's regulations in Parts 20, 50, 52, 73 and 100.

- Whether the feature or function in question pertains to a safety-related structure, system or component.

- Whether the feature or function in question is specified in the NRC's Standard Review Plan as being necessary to perform a safety-significant function.

- Whether the feature or function in question represents an important assumption or insight from the probabilistic risk assessment.

- Whether the feature or function in question is important in preventing or mitigating severe accidents.

- Whether the feature or function in question has had a significant impact on the safety or operation of existing nuclear power plants.

- Whether the feature or function in question is typically the subject of a provision in the Technical Specifications.

The absence or existence of any one of these factors was not conclusive in determining which information is significant to safety. Instead, these factors, together with the other factors listed in this section, were taken into account in making this determination.

(3) In general, only the safety-related features and functions of structures, systems and components are discussed in the certified design descriptions. Structures, systems, and components that are not classified as safety-related are discussed in the certified design descriptions only to the extent that they perform safety-significant functions or have features to prevent a significant adverse impact upon the safety-related functions of other structures, systems or components. This criterion follows from the principle that only features and functions that are safety-significant warrant treatment in the certified design. Non-safety-significant features and functions of safety-related structures, systems, and components are not generally discussed in the certified design descriptions.

(4) In general, the certified design descriptions for structures, systems, and components are limited to a statement of design features and functions. The design bases of structures, systems, and components, and explanations of their importance to safety, are provided in the ADM and are not included in the certified design descriptions. The purpose of the CDM design descriptions is to define the certified design. Justification that the design meets regulatory requirements is presented in the ADM. For example, the design descriptions for the emergency core cooling systems state the flow capacity of the systems; the descriptions do not provide information that demonstrates these flow capacities are sufficient to maintain post-accident fuel clad temperatures within 10 CFR 50 Appendix K limits.

(5) The certified design descriptions focus on the physical characteristics of the facility. The certified design descriptions do not contain programmatic requirements related to operating conditions or to operations, maintenance, or other programs because these matters are controlled by other means such as the Technical Specifications. For example, the design descriptions do not describe operator actions needed to control systems.

(6) The certified design descriptions in Section 2.0 of the CDM discuss the configuration and performance characteristics that the structures, systems, and components should have after construction is completed.

In general, the certified design descriptions do not discuss the processes that will be used for designing and constructing a plant that references the System 80+ standard plant design certification. This is acceptable because the safety-performance of a structure, system, or component is demonstrated by appropriate inspections, tests and analyses on the as-built structures, systems and components. Exceptions to this criterion include:

- the welding, dynamic qualification (including seismic and other design bases dynamic loads), environmental qualification and valve testing requirements addressed in CDM Section 1.2, and

- the various design and qualification processes defined in CDM Section 3.

In addition, the programmatic aspects of the design and construction processes (training, quality assurance, qualification of welders, etc.) are part of the licensee's programs and are subject to commitments made at the time of COL issuance. Consequently, these issues are not addressed in the CDM.

(7) In general, the certified design descriptions address fixed design features expected to be in place for the lifetime of the facility. This is acceptable because portable equipment and replaceable items are controlled through operational-related programs. Since the CDM pertains to the design, it is not appropriate for it to include a discussion of these items. One exception to this general approach pertains to nuclear fuel, and control element assemblies (CEAs). These components are discussed in the certified design descriptions due to their importance to safety and the desire to control their overall design throughout the lifetime of a plant that references the System 80+ standard plant certified design.

(8) The certified System 80+ standard plant design descriptions do not discuss component types (e.g., valve and instrument types), component internals, or component manufacturers. This approach is based on the premise that the safety function of a particular design element can be performed by a variety of component types and internals from different manufacturers. Consequently, a CDM entry that defines particular component type/manufacturer would have no safety-related benefits and would unnecessarily restrict the procurement options of future applicants and licensees. The CDM does contain exceptions to this general criterion, and these exceptions occur when the type of component is of safety-significance.

(9) The certified design descriptions do not contain any proprietary information.

(10) The CDM design description is intended to be self-contained and does not make direct reference to the ADM, industrial standards, regulatory requirements or other documents. (The ASME Code is an exception and is referenced in some systems, including the reactor pressure vessel, containment, and piping design CDM.) If these sources contain technical information of sufficient safety-significance to warrant CDM treatment, the information has been extracted from the source and included directly in the appropriate system design description. This approach is appropriate because it is unambiguous and it avoids potential confusion regarding how much of a referenced document is encompassed in, and becomes part of, the CDM.

(11) Selection of the technical terminology to be used in the CDM was guided by the principal that the technical terminology should be as consistent as possible with that used in the ADM and the body of regulatory requirements and industrial standards applicable to the nuclear industry. This approach is used to minimize misinterpretations of the intent of the CDM commitments.

The Initial Test Program (ITP) defines testing activities that will be conducted following completion of construction and construction related inspections and tests. The ITP extends through to the start of commercial operation of the facility. The ITP is addressed in Section 2.0 of the CDM and is defined in Chapter 14. The testing specified in Section 2.0 and Section 3.0 of the CDM are a subset of the ITP.

The ITP has been included in the CDM because of the importance of the ITP in defining comprehensive testing in accordance with detailed procedures and administrative controls for the as-built facility to demonstrate compliance with the design certification.

No ITAAC entries are necessary in the CDM for the ITP. This is acceptable because:

- These ITP activities that involve testing with the reactor containing fuel or conducted at various power levels cannot be completed prior to fuel load. (Part 52 requires ITAAC to be completed prior to fuel load.)

- Testing activities specified as part of the ITAAC in the CDM must be performed prior to fuel load. Since the ITAAC addresses the design features and characteristics of key safety significance, additional ITAAC assigned to ITP are not necessary to assure that the as-built plant conforms with the certified design.

Selection Methodology - Using the criteria listed above, design description material was developed for each system by reviewing the ADM material relating to that system.

Of particular importance was the review of those sections of the ADM that document plant safety evaluations showing acceptable plant performance. Specifically, detailed reviews were conducted of the following; the flooding analyses in Chapter 5, the analysis of overpressure protection in Chapter 5, containment analyses in Chapter 6, the core cooling analyses in Chapters 6 and 15, the analysis of fire protection in Chapter 9, the safety analysis of transients and anticipated transients without scram (ATWS) in Chapter 15, the radiological analyses in Chapter 15, the resolution of unresolved or generic safety issues and Three Mile Island issues in Chapters 1 and 20, and the PRA and severe accident information in Chapter 19. These reviews were a key factor in identifying the important, safety-related system design information warranting discussion in the design descriptions.

Example Entries - Because the safety significance of the System 80+ standard plant systems varies considerably, application of the criteria listed above results in a graded treatment of the systems. This leads to considerable variations in the scope of the design description entries. The following lists the types of System 80+ standard plant systems and is a summary of the overall consequences of this graded treatment:

System Type	Scope of Certified Design Description
Safety-related systems that contribute to plant performance during design basis accidents (e.g., emergency core cooling systems).	Major safety-related features and performance characteristics.
Non-safety-related systems involved in beyond-design-basis events (e.g., combustion turbine generator contribution to station blackout event sequence).	Brief discussion of design features and performance characteristics affecting the safety of the plant's response to the event(s).
Non-safety-related systems potentially impacting safety (e.g., potential missiles from the main turbine).	Brief discussions of design features which prevent or mitigate the potential safety concern.
Non-safety-related systems which affect overall plant design (e.g., Chemical and Volume Control System)	Case-by-case evaluation. A brief discussion of the system if warranted by overall standardization goals.
Non-safety-related systems with no relationship to safety or any influence on overall plant design (e.g., Turbine Building Service Water System).	Limited description of system features.

For safety-related systems, application of the above criteria resulted in design description entries which include the following information, as applicable: The name and scope of the system; purpose; safety-related modes of operation; system's classification (i.e., safety-related, seismic category, and ASME Code Class); location; the basic configuration of safety-significant components (usually shown by means of a figure); the type of electrical power provided; the electrical independence and physical separation of divisions within the system; important instruments, controls, and alarms located in the Main Control Room; identification of Class 1E electrical equipment qualified for its intended environment; motor-operated valves that have an active safety-related function; and other functions that are significant to safety.

The certified design descriptions for non-safety-related systems also include the information listed above, but only to the extent that the information is relevant to the system and has a significance to safety. Since much of this information is not relevant to non-safety-related systems, the certified design descriptions for non-safety-related systems are generally substantially less extensive than the descriptions for safety-related systems.

14.3.2.2 Inspections, Tests, Analyses and Acceptance Criteria

A table of Inspections, Tests, Analyses and Acceptance Criteria (ITAAC) entries is generally provided for each system containing design description entries. The intent of these ITAAC is to define activities that will be undertaken to verify the as-built system conforms with the design features and characteristics defined in the corresponding CDM design description for that system. A three-column table format is used to specify the [1] design commitment, [2] inspections, tests, and analyses, and [3] acceptance criteria for each ITAAC. Each design commitment in the left-hand column of the ITAAC has one or more associated inspection, test or analysis (ITA) requirement that is specified in the middle column. The acceptance criteria for the ITA are defined in the right-hand column.

Selection Criteria - The following were considered when determining which information warranted inclusion in the CDM ITAAC entries:

- The scope and content of the ITAAC correspond to the scope and content of the certified design descriptions. There are no ITAAC for those aspects of the design that are not addressed in the design description. This is appropriate because the objective of the ITAAC design certification entries is to verify that the as-built facility has the design features and performance characteristics defined in the design descriptions.

- With only a few special-case exceptions (e.g., initial test program), each System 80+ standard plant system with a design description text has an ITAAC table with one or more entries. This reflects the assessment that, in general, design features meriting a CDM description also merit an ITAAC entry to verify that the feature has been included in the as-built facility.

- One inspection, test, or analysis may verify one or more provisions in the certified design description. In particular, an ITAAC which calls for a system functional test or an inspection of basic configuration may verify a number of provisions in a certified design description. Therefore, there is not necessarily a one-to-one correspondence between the ITAAC and the certified design descriptions. Each COL holder is responsible for demonstrating that the as-built facility complies with the ITAAC. However, in certain circumstances, documentation that verifies compliance of an inspection, test or analysis at one plant may be used as a basis to demonstrate compliance at one or all subsequent plants without repeating that inspection, test or analysis, for example, type testing of valves if the requirements for the valves have not changed.

- As required by 10 CFR 52.103, the inspections, tests, and analyses must be completed (and the acceptance criteria satisfied) prior to fuel loading. Therefore, the ITAAC do not include inspections, tests, or analyses that are dependent upon conditions that only exist after fuel load.

- In general, the ITAAC verify the as-built configuration and performance characteristics of structures, systems and components as identified in the CDM design descriptions. With limited exceptions (e.g., welding), the ITAAC do not address typical construction processes for the reasons discussed in item (6) of Section 14.3.2.1. As necessary, ITAAC coverage of the exceptions is by:

  (1) The provisions of CDM Section 1.2, Items (1) through (4) that are invoked by configuration verification entries in individual system ITAAC tables.

  (2) The ITAAC entries in Section 3 of the CDM.

Selection Methodology - Using the criteria listed above, ITAAC table entries were developed for each system. This was achieved by evaluating the design features and performance characteristics defined in the CDM design description and preparing an ITAAC table entry for each design description entry that satisfied the above selection criteria. As a result of this process, there is a close correlation (although not necessarily one-for-one for the reasons noted in item (2) above) between the left-hand column of the ITAAC table and the corresponding design description entry.

Having established the design features for which ITAAC are appropriate, the ITAAC table was completed by selecting the method to be used for verification (either a test, an inspection or an analysis (ITA) or a combination of inspection, test, and analysis) and the acceptance criteria (AC) against which the as-built feature or functional performance will be measured.

The emphasis when selecting an ITAAC verification method was placed on using in-situ testing in the as-built facility when possible. However, selection of these items was dependent upon the plant feature to be verified but was guided by the following:

Inspection	To be used when verification can be accomplished by visual observations, physical examinations, review of records based on visual observations or physical examinations that compare the as-built structure, system or component condition to one or more design description commitments.
Test	To be used when verification can be accomplished in a practical manner by the actuation or operation, or establishment of specified conditions, to evaluate the performance or integrity of the as-built structures, systems or components. The type of tests identified in the ITAAC tables are not limited to in-situ testing of the completed facility but also include (as appropriate) other activities such as factory testing, special test facility programs, and laboratory testing.
Analysis	To be used when verification can be accomplished by calculation, mathematical computation or engineering or technical evaluations of the as-built structures, systems or components. (In this case, engineering or technical evaluations could include, but are not limited to, comparisons with operating experience or design of similar structures, systems or components.)

The proposed verification activity is identified in the middle column of the ITAAC table. Where appropriate, the ADM provides details regarding implementation of the verification activity. For example, Chapter 14 test abstracts contain specific testing descriptions related to ITAAC. This information is not referenced in the CDM and is not part of the CDM; it is considered as providing only one of potentially several acceptable methods for completing the ITA.

Selection of acceptance criteria (AC) is dependent upon the specific design characteristic being verified by the ITAAC table entry; in most cases, the appropriate AC is based upon the CDM design description. For many of the ITAAC, the AC is a statement that the as-built facility has the design feature or performance characteristic identified in the design description. A central guiding principle for AC preparation is the recognition that the criteria should be objective and unambiguous. The use of objective and unambiguous terms for the AC will minimize opportunities for multiple, subjective (and potentially conflicting) interpretations as to whether an AC has, or has not, been met. In some cases, the ITAAC acceptance criteria contain parameters from the ADM that are not specifically identified in the CDM design descriptions. Also, in some cases, the ADM has identified detailed criteria applicable to the same design feature or function that is the subject of more general acceptance criteria in the ITAAC table. This material is not considered part of the CDM but does provide one of potentially several methods for satisfying the ITAAC. Ranges, limits, and/or tolerances are included for numerical AC. This is necessary and acceptable because:

- specification of a single-value AC is impractical since minute/trivial deviations would represent noncompliance.
- tolerances recognize that as-built variations can occur which do not affect function or performance.
- minor variations within the tolerance bounds have no impact on plant safety.

14.3.3 CDM Section 3.0: Additional Certified Design Material

Entries in this section of the CDM have the same structure as the system material discussed in Section 14.3.2; i.e., design description text and figures and a table of ITAAC entries. The objective of this CDM material is to address selected design and construction activities which are applicable to more than one system and cannot appropriately be covered in the system-by-system information presented in Section 2.0 of the CDM. There are only three entries in Section 3.0 of the CDM: Piping Design, Radiation Protection, and the Design Reliability Assurance Program (see Section 17.3). Selected areas of the design are the subject of rapidly changing technology. These areas include the detailed instrumentation and control designs and the human factors engineering design of the Main Control Room and the Remote Shutdown Room. For these two areas of rapidly changing technology, applicable plans with appropriate acceptance criteria are specified in the CDM in the applicable systems of the System 80+ Standard Design.

The Instrumentation and Controls design is specified as defined systems; e.g., Plant Protection System, in Section 2.0 of the CDM in the same manner as other systems, structures, and components. The I&C system designs including applicable program plans; e.g., the Software Development Plan, have been completed and approved. The aspects of the design which are not completely specified relate to the components to be used in the as-built system. For these aspects, detailed plans have been developed, reviewed, and approved. This includes a software program manual governing verification and validation activities, an equipment qualification plan, and a plan specifying safety system dedication of commercial products. This level of design detail combined with the completion of the required detailed planning documents provides the basis for a positive safety determination and the ability to specify ITAAC to assure that the as-built I&C system conforms to the certified design. Improvements in I&C technology are still readily accommodated into the I&C systems at the component level without affecting the certified design.

Human factors design is incorporated in the design of the Main Control Room (MCR) and the Remote Shutdown Room (RSR) which are contained in Section 2.0 of the CDM. Design details, features, and characteristics, including applicable planning documents are completed such that only human factors verification and validation of the as-built configurations of the MCR and RSR are required to complete specified ITAAC. Design details for the MCR configuration, integrating display (IPSO), and six standard man-machine interface features used throughout the MCR and RSR designs were reviewed and approved. The human factors process review included the eight HFE Program Review model elements. Four PRM elements were completed. Procedures development, the fifth element, is performed by a COL applicant. The remaining three elements were addressed with detailed plan and human factors guidance documents which were reviewed and approved. Consequently, the ITAAC specified in the CDM for the MCR and the RSR relate only to the human factors verification and validation evaluations of the as-built configurations with the detailed evaluation methods and acceptance criteria specified in the ADM and its referenced plans. This level of detail in the design and the completeness of the supporting plans and guidance documents provide the bases for a positive safety determination and the ability to specify ITAAC that would demonstrate conformance with the certified design.

14.3.3.1 Piping Design

The piping design section of the CDM defines the processes by which System 80+ standard plant piping will be designed and evaluated. The material applies to piping systems that are classified as nuclear safety-related.

In general, these piping systems are designated as Seismic Category I and are further classified as ASME Code Section III, Class 1, 2 or 3. The section also addresses the consequential effects of pipe rupture such as jet impingement, potential missile generation, and pressure/temperature effects.

Certification of plant safety-related piping systems via design processes rather than via certification of specific design features is necessitated and justified by the following:

(1) Piping design is based on detailed piping arrangement information as well as the geometry and dynamic characteristics of the as-procured equipment that forms part of the piping system. This detailed plant-specific information is unavailable at the time of design certification and cannot therefore be used to develop detailed design information. This precludes certification of specific piping designs.

(2) An extensive definition of design methodologies is contained in Chapter 3. These methodologies are not considered to be part of the CDM but are one of several methods for executing the design process steps defined in the piping design CDM. In addition, sample design calculations have been performed with these methods to provide confidence that they are complete and yield acceptable design information.

(3) Piping design for nuclear plants is a well-understood process based on straightforward engineering principles. This, together with the methodology definition and sample calculations, provides confidence that future design work by individual applicants/licensees will result in acceptable designs that properly implement the applicable requirements.

The technical material in the piping design CDM entry was selected using the criteria and methodology as discussed above for the Section 2.0 system entries.

14.3.3.2 Radiation Protection

The radiation protection section of the CDM defines the processes by which it will be confirmed that the as-built facility has radiation protection features that maintain exposures for both plant personnel and the general public below allowable limits. The material applies to the radiological shielding and ventilation design of buildings within the scope of the certified design.

Certification of plant radiation protection features via process definition rather than via certification of specific design features is necessitated and justified by the following:

(1) Actual radiological source terms are dependent upon the characteristics of the as-built, as-installed equipment. For example, such parameters as equipment sizes, geometry, and valve stem leakage rates influence source terms. Consequently, final radiological evaluation cannot be completed prior to availability of this as-built data and therefore cannot be used to finalize radiological protection design features at the time of design certification.

(2) Radiological studies using representative design assumptions have been completed and reported in Chapter 12. These preliminary studies show the radiological protection features are such that acceptance criteria related to occupational and general public exposure are met. This provides high confidence that the processes defined in the radiological CDM entry can be successfully executed within the envelope of the certified design. This confidence is based in part on the recognition that technology associated with radiation sources and protection is well understood

and design methodology and protection technology would only improve during the lifetime of the design certification.

Selection of entries in the CDM utilized the same selection criteria and methodology as discussed above for the Section 2.0 system entries.

14.3.4 CDM Section 4.0: Interface Requirements

This section of the CDM provides interface requirements for those structures, systems and components of a complete power-generating facility that are either totally or partially not within the scope of the System 80+ standard plant design as defined in the certification application. For the System 80+ standard plant, these systems are identified in Section 1.9. Generally, structures, systems and components that are part of, or within, the Nuclear Island Structure, Turbine Building, Radwaste Building, Diesel Fuel Storage Building, and Component Cooling Water Heat Exchanger Structure are in the System 80+ standard plant scope. Those portions of the plant outside of these buildings are not generally in the System 80+ standard plant scope. This scope split occurs because design of the plant features located outside the main buildings is dependent upon site-specific characteristics which are not specified at the time of certification (e.g., the source of plant cooling water, the characteristics of the electrical grid to which the plant is connected, etc.). The basis for this interface requirements entry in the CDM is the discussion in 10 CFR 52.47(a) (1) (vii). An applicant for a license that references the System 80+ design certification must provide site-specific systems with design features/characteristics that comply with the interface requirements.

An entry is provided in Section 4.0 of the CDM for each of the systems listed in Section 1.9 that have safety-significant interface requirements; for systems that have no interface requirements of sufficient safety-significance to warrant CDM treatment, there are no entries. For systems that are partially within the scope of the System 80+ standard plant, interface requirements are listed in CDM Section 4.0 and in a separate sub-part of the Section 2.0 entry which addresses the in-scope portion of the system. In all cases, the CDM entries for these systems are limited to defining interface requirements. Conceptual designs for the out-of-scope interfacing systems are required by 10 CFR Part 52.47(a) (1) (ix); these designs are presented in the ADM but are not addressed in the CDM. This is appropriate because the applicant will provide site-specific designs that meet the interface requirements; these site-specific alternate designs may not correspond to the conceptual designs described in the ADM. The CDM does not define any ITAAC associated with the interface requirements. [[This is acceptable because ITAAC for the plant structures, systems, and components outside the scope of the System 80+ standard plant design certification will be provided on a site-specific, design-specific basis by the individual COL applicants who reference the System 80+ standard plant design certification. (Part of the review process at the time of the license application will be to assess compliance of the site-specific designs with the interface requirements.)]][1]

10 CFR Part 52.47(a) (1) (viii) specifies that design certification applications contain justification that the requirements are verifiable through inspection, testing or analysis and that the method to be used for verification be included as part of the ITAAC. The introductory text of CDM Section 4.0 addresses these issues by stating the interface requirements are similar in nature to the design commitments in Section 2.0 for which ITAAC have been developed. This represents justification that a COL applicant will be able to develop ITAAC to verify compliance with the design features or characteristics that implement the interface requirements. The methods to be used for these verifications will be specified in the COL

1 COL information item; see DCD Introduction Section 3.2.

ITAAC and will be similar to the methods in the Section 2.0 ITAAC for comparable/similar design characteristics.

Selection Criteria - The selection criteria listed in Section 14.3.2.1 were used to guide selection of interface requirements defined in Section 4.0 of the CDM (or in the Section 2.0 entries referenced from Section 4.0). The intent is that the interface requirements in the CDM define key, safety-significant design attributes and performance characteristics of the site-specific, out-of-scope portion of the plant which must be provided in order for the certified portions of the System 80+ standard plant to comply with the design commitments in the CDM. It is an objective of this section that it address interfaces between in-scope and out-of-scope portions of the plant that are unique to the System 80+ standard plant design; it is not intended that it be a comprehensive listing of design requirements applicable to the out-of-scope portions of the plant. A discussion of the design feature of out-of-scope portions of the plant will be provided for NRC review when the COL applicant submits a site-specific safety analysis report.

Selection Methodology - The interface requirements included in the CDM were selected from the interface requirements listed in the ADM for fully or partially out-of-scope systems. For example, Section 8.2 defines interface requirements for the Offsite Power Systems. These sections and similar interface requirement sections for other systems were reviewed, and CDM Section 4.0 entries selected using the criteria discussed above.

14.3.5 CDM Section 5.0: Site Parameters

This section of the CDM defines the site parameters which were used as a basis for the design defined in the System 80+ standard plant design certification application. These entries respond to the 10 CFR 52.47(a) (1) (iii) requirement that the design certification documentation include site parameter information. The plant must be designed and built based on the parametric information in Section 5.0. Furthermore, it is intended that applicants referencing the System 80+ standard plant design certification demonstrate that these parameters for the selected site are within the certification envelope.

Site-specific external threats that relate to the acceptability of the design (and not to the acceptability of the site) are not considered site parameters and are addressed as interface requirements in the appropriate system entry (e.g. toxic gas).

Section 5.0 of the CDM does not include any ITAAC and is limited to defining site parameters. This is an appropriate approach because compliance of the site with these parameters must be demonstrated by a COL applicant prior to issuance of the license.

Selection Criteria - Chapter 2, Table 2.0-1 provides the envelope of site design parameters used for the System 80+ standard plant design. The corresponding CDM Section 5.0 is based on using Table 2.0-1 in its entirety except as modified to meet the CDM content criteria previously discussed. For example, references in this table to specific Regulatory Guides have been deleted from the CDM table because of the guideline that the CDM does not contain direct references to codes and standards. Section 5 is limited to a tabular entry; no supporting text material is required.

14.3.6 Elements of Design Material Incorporated into the Certified Design Material

Tables 14.3-1 through 14.3-7 summarize the design material that has been incorporated into the CDM in the areas of 1) Design Bases Accident Analysis, 2) Probabilistic Risk Assessment, 3) Shutdown Risk, 4) Severe Accident Analysis, 5) Flood Protection, 6) Fire Protection, and 7) Anticipated Transients Without Scram (ATWS). PRA assumptions incorporated into these tables encompass elements of the system design and assumptions that were expressly included in Tier 1 due to their importance. Both types of PRA assumptions are included for completeness, but are not distinguished in the tables. CDM falling outside of the seven subject areas are intentionally not incorporated in these tables. However, the referenced ADM sections may contain more information than just that encompassed by these seven subject areas. Each table may also include design information (certified or non-certified) that is not directly related to the particular subject area. Further, the tables are not intended to include all system-specific CDM information that is provided in the ADM system descriptions.

Table 14.3-1 Design Basis Accident Analysis

Paragraph	Assumption/Parameter Description	Value
Table 5.4.13-1	The primary safety valves pass the minimum flow rate of 525,000 lbm/hr-valve (saturated steam at 2575 psia).	
Table 5.4.13-1	Pressurizer Safety Valve: Set Pressure	2500 ±1% psia
Table 5.4.13-1	Pressurizer Safety Valve: Capacity at accumulation Pressure, each Valve	525,000 lb/hr minimum
5.4.13.2	A total MSSV capacity of 19×10^6 lb/hr is required to maintain the peak secondary pressure below 110% of design.	
Table 6.2.1-3	Containment Shell: Containment Atmosphere Design Basis Peak Pressure	53 psia
Table 6.2.1-18	In-Containment Refueling Water Storage Tank: IRWST Water Volume	495,000 gal minimum
Table 6.2.1-19	Runout Flow Per Safety Injection Train	1232 gpm maximum
Table 6.2.1-19	Runout Flow Per Safety Injection Train	980 gpm minimum
Table 6.2.1-19	Containment Spray Pump: Flowrate Per Pump	6500 gpm maximum
Table 6.2.1-19	Containment Spray Pump: Flowrate Per Pump	5000 gpm minimum
Table 6.2.1-19	Containment Spray Heat Exchanger: Number of Heat Exchangers	2
Table 6.2.1-19	Containment Spray Heat Exchanger: Shell Side Flow	8000 gpm minimum
Table 6.2.1-20	Delay Time from CSAS to Spray Delivery	68 sec maximum
6.2.1.3.3	Main Feed Water Isolation Valve: MFIV Design Closure Time	5.0 sec maximum
6.2.1.4	Main Steam Isolation Valve: MSIV Design Closure Time	5.0 sec maximum
6.2.3.2	Annulus Space: Negative Pressure	-0.25 in (water gauge) minimum

Table 14.3-1 Design Basis Accident Analysis (Cont'd.)

Paragraph	Assumption/Parameter Description	Value
6.2.6.1	The integrated containment leakage rate is less than 0.5% volume per day.	
6.2.6.1	Containment Vessel: Leak Rate	0.5 % volume/day maximum
6.3.3.2.2	[1]The Engineered Safety Features System (ESFAS) sends a Safety Injection Actuation Signal (SIAS) to start the SIS pumps and open the SIS valves following a LOCA or transient. The SIAS is generated on low pressurizer pressure or high containment pressure.	
6.3.3.2.2	The SIS consists of four safety injection trains, each consisting of a safety injection pump and a safety injection tank.	
6.3.3.2.2	Diesel generators will provide power on LOCA.	
6.3.3.2.2	There are four direct vessel injection points.	
6.3.3.3.2	Delay Time for SI Flow to Reactor Vessel After SIAS	40 sec maximum
Table 6.3.3.4-1	Emergency Feedwater Storage Tank: Emergency Feedwater Storage Tank Capacity	350,000 gal/tank minimum
6.3.3.4.2	SITs can be vented or isolated.	
6.3.3.4.4	Alignment of SIS for hot and cold injection is possible.	
Table 15.0-3	Reactor Vessel: Coolant Flow Rate (% of 445,600 gpm)	95% minimum
15.1.2.1	Steam Generator: Maximum Auxiliary Feedwater Flow to Each Steam Generator	800 gpm maximum
Table 15.1.5-10	Main Steam Line: Blowdown Area for Each Steam Line	1.283 sq ft maximum
Table 15.1.5-11	Core: 100% Core Power	3914 MWt
Table 15.1.5-12	Atmospheric Dispersion Factor, 0-2 Hrs at EAB for SLBFPD and SLBZPLOPD Events	1.0×10^{-3} sec/m^3
Table 15.1.5-12	Atmospheric Dispersion Factor, 0-8 Hr at LPZ for SLBFPD and SLBZPLOPD Events	1.35×10^{-4} sec/m^3
Table 15.2.3-1	Main Steam Safety Valve: Main Steam Safety Valves - Open	1212 psia

Table 14.3-1 Design Basis Accident Analysis (Cont'd.)

Paragraph	Assumption/Parameter Description	Value
Table 15.2.8-2	Emergency Feedwater Pump: Emergency Feedwater Flow Initiated to the Intact Steam Generators	500 gpm
Table 15.2.8-7	Main Steam Safety Valve: Main Steam Safety Valves - Open	1212 psia
Table 15.2.8-3	Dispersion Data (MDNBR) 2 hr EAB	1.0×10^{-3} sec/m^3
Table 15.2.8-3	Dispersion Data (Over Pressure) 2 hr EAB	1.0×10^{-3} sec/m^3
Table 15.2.8-3	Dispersion Data (MDNBR) 8 hr LPZ	1.35×10^{-4} sec/m^3
Table 15.2.8-3	Dispersion Data (Over Pressure) 8 hr LPZ	1.35×10^{-4} sec/m^3
Table 15.3.1-1	Main Steam Safety Valve: MSSV Opening Pressure Setpoint	1212 psia maximum
15.3.1.3	Each of the EFW pumps can provide 100% of the required EFW flow.	
Table 15.3.3-1	Emergency feedwater is assumed to be automatically actuated on Steam Generator Low Level EFAS.	
Table 15.3.3-1	An isolation valve (block valve) is located upstream of the ADV. The block valve can be closed manually from the control room.	
Table 15.3.3-1	Main Steam Safety Valve: MSSV Opening Pressure Setpoint	1212 psia maximum
15.3.3.1	The ADVs are manually operated from the control room.	
15.3.3.1	Diesel generators provide power to the 4.16 kV safety buses.	
15.3.3.1	An ADV is located downstream of the MSSVs and upstream of the MSIV in each steam line.	
15.3.3.1	Each ADV discharges to the atmosphere.	
15.3.3.3.1	An isolation valve (block valve) upstream of the ADV exists to be closed in case of the stuck open ADV.	
15.3.3.3.1	Reactor trip causes the turbine generator trip.	
Table 15.4.8-1	Main Steam Safety Valve: Main Steam Safety Valves - Open	1212 psia
Table 15.4.8-3	Atmospheric Dispersion Factors - LPZ (30 days)	2.2×10^{-5} sec/m^3

Table 14.3-1 Design Basis Accident Analysis (Cont'd.)

Paragraph	Assumption/Parameter Description	Value
Table 15.4.8-3	Atmospheric Dispersion Factors - LPZ (1-4 days)	5.4×10^{-5} sec/m^3
Table 15.4.8-3	Containment Vessel: Leak Rate	0.5% volume/day maximum
Table 15.4.8-3	Atmospheric Dispersion Factors - EAB (0-2 hr)	1.0×10^{-3} sec/m^3
Table 15.4.8-3	Atmospheric Dispersion Factors - LPZ (0 - 8 hr)	1.35×10^{-4} sec/m^3
Table 15.4.8-3	Atmospheric Dispersion Factors - LPZ (8 - 24 hr)	1.0×10^{-4} sec/m^3
15.5.1.1	A SIAS actuates safety injection pumps and opens the corresponding discharge valves.	
Table 15.5.2-1	Main Steam Safety Valve: MSSV Opening Pressure Setpoint	1212 psia maximum
Table 15.6.2-3	Double-ended letdown line break size is assumed (0.01556 ft^2).	
Table 15.6.2-3	Letdown Line: Letdown Line Double Ended Break Size	0.01556 sq ft
15.6.2.1	Three letdown line isolation valves in series are located within the containment.	
15.6.2.2	The letdown line orifices are located within the containment downstream of the letdown heat exchanger.	
15.6.2.2	The hardware for DIAS (Discrete Indication and Alarm System) is seismically and environmentally qualified.	
Table 15.6.3-7	Main Steam Safety Valve: MSSV Opening Pressure Setpoint	1212 psia maximum
15.6.3.2.2.1	The turbine/generator trips on reactor trip.	
15.6.3.2.2.2	The minimum capacity of each EFW storage tank of 350,000 gallons is more than enough to maintain the plant at hot standby for 8 hours.	
15.6.3.2.2.2	Each EFW storage tank is provided with an atmospheric vent to maintain atmospheric pressure inside the tank.	
15.6.3.2.3.1	Emergency feedwater is actuated automatically to recover steam generator water level.	
15.6.3.3.3.1	The Emergency Feedwater Actuation signal (EFAS) is generated on low SG level.	

Table 14.3-1 Design Basis Accident Analysis (Cont'd.)

Paragraph	Assumption/Parameter Description	Value
15.6.3.3.3.1	The EFW flow is actuated on EFAS to restore the SG level.	
15.6.3.3.3.2	The reactor trip automatically trips the turbine generator.	
15.6.3.3.4	Main Steam Safety Valve: Maximum Allowable Pressure	110% of design pressure maximum
15.6.5.2	Containment Leak Rate, Per Day, (during 1st 24 hours of LOCA) Expressed as a Percentage of Containment Volume Per Day	0.5% nominal
15.6.5.3	Containment Leak Rate, Per Day, (during 1st 24 hours of LOCA) Expressed as a Percentage of Containment Volume Per Day	0.5% nominal
Table 15A-10	Unfiltered Normal Air Intake Rate	2000 cfm maximum
Table 15A-10	Post Accident Iodine Filter: Post Accident Intake and Recirculating Iodine Filter Efficiency - Elemental	95% minimum
Table 15A-10	Post Accident Iodine Filter: Post Accident Intake and Recirculating Iodine Filter Efficiency - Organic	95% minimum
Table 15A-10	Post Accident Iodine Filter: Post Accident Intake and Recirculating Iodine Filter Efficiency - Particulate	99% minimum
Table 15A-10	Control Room: Pressurization	1/8 in (water gauge) Nominal

[1] PRA Assumption

Table 14.3-2 Probability Risk Assessment

Paragraph	Assumption/Parameter Description/Value
19.6.3.1	[1] The main power system consists of the main generator, associated isolated phase buses, generator circuit breakers, three single phase unit main transformers, two unit auxiliary transformers, and two reserve auxiliary transformers.
19.6.3.1	[1] The 4.16 Kv non-Class 1E power system consists of four switchgears and a non-Class 1E alternate AC source. Two of the switchgears (i.e, X - non-safety switchgear and the X - permanent non-safety switchgear) are powered by one of the unit auxiliary transformers, while the other two switchgears (i.e., Y - non-safety switchgear and the Y - permanent non-safety switchgear) are powered by the other unit auxiliary transformer. The permanent non-safety switchgears can also be powered by the reserve auxiliary transformers and the alternate AC source.
19.6.3.1	[1] Each division of the 4.16 Kv Class 1E power has two switchgear. Both switchgears within a division are typically powered from their associated 4.16 Kv permanent non-safety 1E switchgear. Both switchgears can also be powered by the emergency diesel generator of the same division.
19.6.3.1	[1] Each division of the 120 VAC Class 1E power system has three inverters and associated buses. Each inverter within the division is powered from a separate 125 VDC Class 1E bus in the same division of the EDS.
19.6.3.1	[1] Each division of the 125 VDC Class 1E power system has three battery chargers, three batteries, and three distribution centers (buses). Each battery charger is powered from a separate 480 VAC Class 1E motor control center within the same division of the EDS. Each battery is sized to supply its emergency loads for a minimum of 2 hrs without recharging.
19.6.3.1	[1] The emergency diesel generators are physically and electrically isolated from each other.
19.6.3.1	[1] The starting air storage capacity for each emergency diesel generator is sufficient for starting the diesel generator for a minimum of five times.
19.6.3.1	[1] Each emergency diesel generator has a complete and separate fuel oil storage system. The storage system has sufficient fuel that allows the emergency diesel generator to operate supplying post DBA-LOCA loads for a time period of no less than seven days.
19.6.3.1	[1] Each emergency diesel generator is automatically started and loaded by the Engineered Safety Feature - Component Control System (ESF-CCS).
19.6.3.1	[1] Each emergency diesel generator is housed in Seismic Category I structure to guard against earthquakes, fires, and missiles.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.3.1	[1] The onsite EDS has two separate sources of offsite power. Each offsite power source (circuit) terminates at a separate switchyard. The switchyards are physically separated and electrically independent. The lines of the offsite power circuits are routed, to the extent practicable, such that the likelihood of losing both circuits due to a single event is minimized.
19.6.3.1	[1] Each emergency diesel generator is adequately sized to provide power to two 4.16 Kv Class 1E buses within the same division of the EDS.
19.6.3.1	[1] Each of the 4.16 Kv Class 1E switchgears is provided with appropriate incoming feeders from the emergency diesel generator, permanent non-safety switchgear, and the reserve auxiliary transformer. The incoming feed breakers for each 4.16 Kv Class 1E bus are therefore interlocked to prevent more than one breaker from being closed at the same time.
19.6.3.1	[1] If a plant trip occurs and if offsite power is available, offsite power is supplied to plant components by back-feed through the main transformers.
19.6.3.1	[1] The emergency diesel generators are normally in standby mode when offsite power is available. During loss of offsite power events, the emergency diesel generators start automatically by the ESF-CCS. Following a loss of offsite power event, only one of the two emergency diesel generators is required to bring the plant to cold shutdown conditions and to maintain the plant in this shutdown condition.
19.6.3.1	[1] On a LOOP, the AAC automatically starts and is available for automatic connection and loading of the X and/or Y - permanent non-safety loads, if either of the 4.16 Kv permanent non-safety buses becomes de-energized.
19.6.3.1	[1] The RCGVS vent valves are powered from the 125 VDC Class 1E power system.
19.6.3.1	[1] The RDS bleed valves are powered from separate 125 VDC Class 1E buses.
19.6.3.1	[1] Each ADV is powered from a separate 125 VDC Class 1E bus.
19.6.3.1	[1] CCWS components in a division receive electrical power from the Class 1E buses in their division.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
Table 19.6.3.1-1	[1] The CCW pump motors in a division are powered from the 4.16KV Class 1E power system in their division. In a division, one CCW pump is powered from one Class 1E bus in that division and the other CCW pump motor is powered from the other Class 1E bus in that division.
Table 19.6.3.1-1	[1] Each SCS division is electrically powered from its assigned Class 1E bus.
Table 19.6.3.1-1	[1] The SCS pump motor in each division is powered from one of the two Class 1E 4.16 Kv safety buses for that division. Each SCS pump derives its 125 VDC control power from the Class 1E 125 VDC bus associated with the Class 1E 4.16 Kv safety bus that provides its motive power.
Table 19.6.3.1-1	[1] The SCS pump motor in each division is not powered from the same Class 1E 4.16 Kv bus as the CS pump motor in that division.
Table 19.6.3.1-1	[1] The two EFW pump controls in a given EFW division are supplied power from separate 125 VDC buses.
Table 19.6.3.1-1	[1] The EFW steam supply valves in an EFW division are supplied from the same 125 VDC bus.
Table 19.6.3.1-1	[1] The power operated controls for the EFW turbine pumps, turbine supply and bypass line valves, and the EFW Isolation valve to the SG, are powered from the same 125 VDC Class 1E bus.
Table 19.6.3.1-1	[1] The CSS pump motor in each division is powered from one of the two vital Class 1E 4.16 Kv buses for that division. Each CSS pump derives its 125 VDC control power from the Class-1E 125 VDC bus associated with the Class 1E 4.16 Kv bus that provides its motive power.
Table 19.6.3.1-1	[1] The CSS pump motor in each division is not powered from the same Class 1E 4.16 Kv bus as the SCS pump motor in that division.
Table 19.6.3.1-1	[1] The 480 VAC motor power for CSS valves in a division will be derived from the 480 VAC MCCs and LCs associated with the Class 1E 4.16 Kv vital bus that provides power to the pump motor for that division.
Table 19.6.3.1-1	[1] Each SIS division receives emergency 4.16 Kv power from the emergency diesel generator for that division.
Table 19.6.3.1-1	[1] Each SIS pump motor receives 4.16 Kv power from a separate 4.16 Kv bus.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
Table 19.6.3.1-1	[1] The SIS pump control circuit for a given train is powered from the 125 VDC bus associated with the 4.16 Kv bus which provides motive power to the pump motor.
19.6.3.2	[1] The SSWS has two redundant and separate safety related divisions with heat dissipation capacity to achieve and maintain safe shutdown.
19.6.3.2	[1] Each SSWS division has two SSW pumps per division.
19.6.3.2	[1] SSWS components in a division receive electrical power from the Class 1E buses in their division.
19.6.3.2	[1] Manual Start and stop actuation of the SSW pumps is provided from the control room to override automatic actuation.
19.6.3.2	[1] The two SSW divisions are physically separated and protected such that a fire or flood in one division will not affect the SSW pumps in the other division.
19.6.3.3	[1] The CCWS has two redundant and separate safety-related divisions with heat dissipation capacity to achieve and maintain safe shutdown.
19.6.3.3	[1] Each CCWS division has two CCW pumps per division.
19.6.3.3	[1] The ESF Actuation System signals isolate the non-safety related portion of the CCWS following an accident condition, except cooling for the RCPs, charging pump motor coolers, and charging pump miniflow heat exchangers.
19.6.3.3	[1] CCWS components in a division receive electrical power from the Class 1E buses in their division.
19.6.3.3	[1] The CCW pump motors in a division are powered from the 4.16KV Class 1E power system in their division. In a division, one CCW pump is powered from one Class 1E bus in that division and the other CCW pump motor is powered from the other Class 1E bus in that division.
19.6.3.3	[1] Manual start and stop actuation of the CCW pumps is provided from the control room to override automatic actuation.
19.6.3.3	[1] Each CCWS division has two redundant heat exchangers.
19.6.3.3	[1] The two divisions of CCWS are physically separated.
19.6.3.4	[1] Sufficient instrumentation is provided in the control room to monitor and control the IAS.
19.6.3.6	[1] The Safety Injection System (SIS) has four redundant pump trains arranged in two independent divisions.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.3.6	[1] The two SIS divisions are completely physically separated from each other outside containment.
19.6.3.6	[1] Each SIS pump train consists of one SIS pump and its associated valves, piping, and instrumentation.
19.6.3.6	[1] Each SIS division receives emergency 4.16 Kv power from the emergency diesel generator for that division.
19.6.3.6	[1] Each SIS pump motor receives 4.16 Kv power from a separate 4.16 Kv bus.
19.6.3.6	[1] The SIS pump control circuit for a given train is powered from the 125 VDC bus associated with the 4.16 Kv bus which provides motive power to the pump motor.
19.6.3.6	[1] Each SIS pump train has an independent suction line connection to the IRWST.
19.6.3.6	[1] The Engineered Safety Features Actuation System (ESFAS) sends a Safety Injection Actuation Signal (SIAS) to start the SIS pumps and open the SIS valves following a LOCA or transient. The SIAS is generated on low pressurizer pressure or high containment pressure.
19.6.3.7	[1] The Alternate Protection System (APS) provides an alternate means of generating a reactor trip signal and an alternate feedwater actuation signal.
19.6.3.7	[1] The APS monitors the pressurizer pressure and generates a reactor trip signal if the RCS pressure exceeds a predetermined value. Similarly, an alternate feedwater actuation signal is generated if the steam generator level decreases below a predetermined value.
19.6.3.7	[1] The EFWS has two redundant divisions for supplying feedwater to the steam generators for RCS heat removal such that shutdown cooling entry conditions can be met.
19.6.3.7	[1] One EFWS division, including its water source, supplies feedwater to one Steam Generator (SG).
19.6.3.7	[1] Each EFWS division has two EFW pumps, each with a pump driver diverse from the other.
19.6.3.7	[1] In each EFWS division, the two EFW pump discharge pipes are joined together inside containment to a single pipe that connects to the SG downcomer feedwater line.
19.6.3.7	[1] The EFW pumps in one division can supply feedwater to the SG in the other division through a pipe having at least two normally closed isolation valves installed.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.3.7	[1] Each EFW Storage Tank (EFWST) can be supplied by gravity flow from the Condensate Water Storage Tank (CST). This source is isolated by at least two normally closed isolation valves.
19.6.3.7	[1] The EFW turbine-driven pump in each division is supplied with steam from the SG in its division.
19.6.3.7	[1] The valves that control the supply of steam to the EFW turbine pumps fail to the open position upon loss of motive power.
19.6.3.7	[1] The EFWS is actuated by an ESFAS and an APS actuation signal (Low SG Water Level)
19.6.3.7	[1] Each EFW line has a cavitating venturi to prevent runout flow.
19.6.3.7	[1] Upon receipt of an actuation signal, the EFWS: 1. Starts the associated motor-driven pump, 2. De-energizes the solenoid to open the associated turbine steam supply bypass valve, 3. De-energizes the solenoid to open the associated turbine steam supply valve, 4. Opens the associated EFW isolation valves to the appropriate SG, and 5. (EFWS) Opens flow control valves 104 & 106 or 105 & 107.
19.6.3.7	[1] Each EFW division provides at least 500 gpm to either Steam Generator.
19.6.3.7	[1] Installed instrumentation provides the capability to monitor the performance of the system and the major components from the control room.
19.6.3.7	[1] Each EFW pump can deliver EFW flow to the SGs when the SG pressure is at the Main Steam Safety Valve (MSSV) setpoint.
19.6.3.7	[1] Each EFWST has a safety-related volume of at least 350,000 gallons.
19.6.3.7	[1] Each EFW subdivision receives power from its associated Class 1E buses.
19.6.3.7	[1] The two EFW pump controls in a given EFW division are supplied power from separate 125 VDC buses.
19.6.3.7	[1] The EFW steam supply valves in an EFW division are supplied from the same 125 VDC bus.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.3.7	[1] The power operated controls for the EFW turbine pumps, turbine supply and bypass line valves, and the EFW Isolation valve to the SG, are powered from the same 125 VDC Class 1E bus.
19.6.3.7	[1] Each EFW pump can provide 100% of the required EFW flow.
19.6.3.9	[1] The SCS has two separate and redundant divisions, each with heat removal capacity to cool and maintain the RCS in cold shutdown conditions.
19.6.3.9	[1] Each SCS division has one SCS pump and one SCS heat exchanger.
19.6.3.9	[1] The SCS pumps can be aligned to the IRWST.
19.6.3.9	[1] The SCS discharge valves to the RCS are not interlocked on RCS pressure and can be opened when the RCS pressure is less than or equal to the SCS pump shutoff head.
19.6.3.9	[1] The SCS pump in each division can be aligned to back up the Containment Spray (CS) pump in that division for containment spray operation.
19.6.3.9	[1] The valve isolating the SCS pump suction from the IRWST is capable of passing flow in either direction.
19.6.3.9	[1] The CSS pump in each division can be aligned to back up the SCS pump in that division to provide IRWST inventory cooling.
19.6.3.9	[1] Each SCS division is electrically powered from its assigned Class 1E bus.
19.6.3.9	[1] The SCS can be aligned for shutdown cooling operation from the control room.
19.6.3.9	[1] The SCS pump motor in each division is powered from one of the two Class 1E 4.16 Kv safety buses for that division. Each SCS pump derives its 125 VDC control power from the Class 1E 125 VDC bus associated with the Class 1E 4.16 Kv safety bus that provides its motive power.
19.6.3.9	[1] The SCS pump motor in each division is not powered from the same Class 1E 4.16 Kv bus as the CS pump motor in that division.
19.6.3.9	[1] Installed instrumentation provides the capability to monitor the performance of the system and the major components from the control room.
19.6.3.9	[1] The RCS can be brought from hot shutdown to cold shutdown conditions using only one SCS train.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.3.10	[1] The RCGVS has vent valves to vent the pressurizer and the head of the reactor vessel.
19.6.3.10	[1] The vent paths from the pressurizer and reactor vessel are capable of being discharged to the reactor drain tank or the IRWST.
19.6.3.10	[1] The RCGVS vent valves are powered from the 125 VDC Class 1E power system.
19.6.3.10	[1] The Rapid Depressurization System (RDS) or Bleed System has two separate and redundant trains.
19.6.3.10	[1] Each train of the RDS has two bleed valves in series.
19.6.3.10	[1] The RDS bleed valves are powered from separate 125 VDC Class 1E buses.
19.6.3.10	[1] The RDS discharges to the In-Containment Water Storage Tank (IRWST).
19.6.3.10	[1] The RDS is manually initiated from the control room.
19.6.3.10	[1] The SDS valves are remote manually operated.
19.6.3.10	[1] One of the two RDS trains is capable of rapidly depressurizing the RCS.
19.6.3.11	[1] The Reactor Protection System (RPS) has four redundant channels.
19.6.3.11	[1] The RPS communicates with the Reactor Trip Switchgear System and the Engineered Safety Features - Component Control System (ESF-CCS), which enables them to actuate mitigating systems when demanded.
19.6.3.11	[1] Loss of 120 VAC vital power to two RPS channels causes a plant trip to occur.
19.6.3.11	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
19.6.3.11	[1] Instrumentation is provided to adequately monitor plant parameters.
19.6.3.11	[1] A reactor trip signal can be generated using any two of the four RPS channels.
19.6.3.11	[1] The Alternate Protection System (APS) provides an alternate means of generating a reactor trip signal and an alternate feedwater actuation signal.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.3.11	[1] The APS monitors the pressurizer pressure and generates a reactor trip signal if the RCS pressure exceeds a predetermined value. Similarly, an alternate feedwater actuation signal is generated if the steam generator level decreases below a predetermined value.
19.6.3.12	[1] The Engineered Safety Features Actuation System (ESFAS) has at least two redundant trains to generate the following engineered safety feature signal: Safety Injection Actuation Signal (SIAS), Containment Spray Actuation Signal (CSAS), Containment Isolation Actuation Signal (CIAS), Main Steam Isolation Signal (MSIS), Emergency Feedwater Actuation Signal (EFAS).
19.6.3.12	[1] The ESFAS actuates the Engineered Safety Features (ESF) systems when demanded.
19.6.3.13	[1] The Containment Spray System (CSS) has two independent redundant divisions for supplying containment spray flow.
19.6.3.13	[1] Each CSS division has one CSS pump and one CSS heat exchanger.
19.6.3.13	[1] The CSS pump in each division can be aligned to back up the SCS pump in that division for shutdown cooling operation.
19.6.3.13	[1] The crossover valve between the inlet to the CSS heat exchanger and the SCS heat exchanger in a given division is capable of passing flow in either direction.
19.6.3.13	[1] The CSS pump and heat exchanger in each division can be aligned to discharge back to the IRWST to provide cooling for the IRWST inventory.
19.6.3.13	[1] The CSS pump's NPSH is adequate to prevent pump cavitation and failure if the IRWST inventory is saturated.
19.6.3.13	[1] Installed instrumentation provides the capability to monitor CSS flow rates and the performance of major components. This instrumentation provides positive indication that pumps have started and valves have actuated properly.
19.6.3.13	[1] The CSS pump motor in each division is powered from one of the two vital Class 1E 4.16 Kv buses for that division. Each CSS pump derives its 125 VDC control power from the Class 1E 125 VDC bus associated with the Class 1E 4.16 Kv bus that provides its motive power.
19.6.3.13	[1] The CSS pump motor in each division is not powered from the same Class 1E 4.16 Kv bus as the SCS pump motor in that division.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.3.13	[1] The 480 VAC motor power for CSS valves in a division will be derived from the 480 VAC MCCs and LCs associated with the Class 1E 4.16 Kv vital bus that provides power to the pump motor for that division.
19.6.3.13	[1] The CSS pump discharge line in each division has a mini-flow line to prevent damaging the CSS pump in that division by operating it against a closed line. The valves in this line are normally open.
19.6.3.13	[1] The CSS pumps are automatically started and the CSS header valves are automatically opened by CSAS.
19.6.3.13	[1] The CSS can be manually started for spray operation from the control room.
19.6.3.13	[1] Installed instrumentation provides the capability to monitor the performance of the system and the major components from the control room.
19.6.3.13	[1] The CSS pumps are provided with heat exchangers in the mini-flow recirculation lines.
19.6.3.13	[1] Each CSS pump can provide 100% of the required delivery of borated water from the IRWST to the containment spray nozzles.
19.6.3.16	[1] Operator must open the HVT spillway motor-operated valves and the reactor cavity spillway motor-operated valves. This is done from the control room.
19.6.4.1	[1] The SCS has two separate and redundant divisions, each with heat removal capacity to cool and maintain the RCS in cold shutdown conditions.
19.6.4.1	[1] Each SCS division has one SCS pump and one SCS heat exchanger.
19.6.4.1	[1] The SCS pumps can be aligned to the IRWST.
19.6.4.1	[1] The SCS discharge valves to the RCS are not interlocked on RCS pressure and can be opened when the RCS pressure is less than or equal to the SCS pump shutoff head.
19.6.4.1	[1] The SCS pump in each division can be aligned to back up the Containment Spray (CS) pump in that division for containment spray operation.
19.6.4.1	[1] The valve isolating the SCS pump suction from the IRWST is capable of passing flow in either direction.
19.6.4.1	[1] The CSS pump in each division can be aligned to back up the SCS pump in that division to provide IRWST inventory cooling.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.4.1	[1] Each SCS division is electrically powered from its assigned Class 1E bus.
19.6.4.1	[1] The SCS can be aligned for shutdown cooling operation from the control room.
19.6.4.1	[1] The SCS pump motor in each division is powered from one of the two Class 1E 4.16 Kv safety buses for that division. Each SCS pump derives its 125 VDC control power from the Class 1E 125 VDC bus associated with the Class 1E 4.16 Kv safety bus that provides its motive power.
19.6.4.1	[1] The SCS pump motor in each division is not powered from the same Class 1E 4.16 Kv bus as the CS pump motor in that division.
19.6.4.1	[1] Installed instrumentation provides the capability to monitor the performance of the system and the major components from the control room.
19.6.4.1	[1] The RCS can be brought from hot shutdown to cold shutdown conditions using only one SCS train.
19.6.4.2	[1] The SCS has two separate and redundant divisions each with heat removal capacity to cool and maintain the RCS in cold shutdown conditions.
19.6.4.2	[1] Each SCS division has one SCS pump and one SCS heat exchanger.
19.6.4.2	[1] The SCS pumps can be aligned to the IRWST.
19.6.4.2	[1] The SCS discharge valves to the RCS are not interlocked on RCS pressure and can be opened when the RCS pressure is less than or equal to the SCS pump shutoff head.
19.6.4.2	[1] The SCS pump in each division can be aligned to back up the Containment Spray (CS) pump in that division for containment spray operation.
19.6.4.2	[1] The valve isolating the SCS pump suction from the IRWST is capable of passing flow in either direction.
19.6.4.2	[1] The CSS pump in each division can be aligned to back up the SCS pump in that division to provide IRWST inventory cooling.
19.6.4.2	[1] Each SCS division is electrically powered from its assigned Class 1E bus.
19.6.4.2	[1] The SCS can be aligned for shutdown cooling operation from the control room.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.6.4.2	[1] The SCS pump motor in each division is powered from one of the two Class 1E 4.16 Kv safety buses for that division. Each SCS pump derives its 125 VDC control power from the Class 1E 125 VDC bus associated with the Class 1E 4.16 Kv safety bus that provides its motive power.
19.6.4.2	[1] The SCS pump motor in each division is not powered from the same Class 1E 4.16 Kv bus as the CS pump motor in that division.
19.6.4.2	[1] Installed instrumentation provides the capability to monitor the performance of the system and the major components from the control room.
19.6.4.2	[1] The RCS can be brought from hot shutdown to cold shutdown conditions using only one SCS train.
19.6.4.5	[1] The blowdown line containment isolation valves are closed automatically by EFAS, MSIS, CIAS, and AFAS.
19.6.4.6	[1] The MSIVs fail close upon loss of control power. The MSIVs close automatically upon receipt of a Main Steam Isolation Signal (MSIS).
19.6.4.6	[1] Each ADV is powered from a separate 125 VDC Class 1E bus.
19.7.3.1.1	[1] A plant Fire Hazards Analysis considers potential fire hazards.
19.7.3.1.5	[1] A plant Fire Hazards Analysis considers potential fire hazards.
19.7.4.1	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.7.4.1	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.7.4.1	[1] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.
19.7.4.1	[1] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.
19.7.4.1	[1] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.8.1.2	[1] Availability of mitigating equipment following fires can be maximized if separation is maintained between equipment within a quadrant. This will increase the number of success paths available for responding to the event and result in a decrease in risk.
19.8.4.3	[1] Propagation of fires between quadrants is assumed to be impossible based on their separation by three-hour rated fire barriers. Fire doors between quandrants are three-hour rated fire doors and are assumed to be closed during all shutdown operations. These doors specifically include those between Fire Areas 38 and 41 and Fire Areas 39 and 40, as shown in Figure 9.5.1-2.
19.8.4.3	[1] Propagation of fires between divisions is assumed to be impossible based on their separation by three-hour rated fire barriers. The barriers have no communicating openings below 70 feet elevation and all penetrations within the barriers are sealed with assemblies qualified to maintain the integrity of the three-hour rating.
19.8.4.4	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.8.4.4	[1] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.
19.8.4.4	[1] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.
19.8.4.4	[1] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.
Table 1.4-1 of App. 19.8A	[1] Make SCS pumps interchangeable with containment spray pumps to provide further redundancy.
Table 1.4-1 of App. 19.8A	[1] Monitor SCS pump motor current, flowrate, discharge pressure and suction pressure to provide reliable cooling status.
Table 1.4-1 of App. 19.8A	[1] CCW availability improved by two redundant divisions with two pumps each.
Table 1.4-1 of App. 19.8A	[1] Loss of shutdown cooling by compartment flooding and spills reduced by divisional separation.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.8A.2.3.3.2	[1] SCS suction lines do not contain any LOOP seals. The suction piping arrangement allows self venting. This feature allows SCS pumps to be restarted without requiring complicated venting procedures.
19.8A.2.3.3.2	Containment Spray Pump: Number of Pumps = 2
19.8A.2.7.3.1	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.
19.8A.2.7.3.1	[1] The propagation of a fire from one division to the next is prevented by the divisional separation of redundant safety related equipment with a 3-hour fire barrier which is maintained during power operation.
19.8A.2.7.3.1	[1] It was assumed that there are no doors or passageways connecting the divisions of safety related equipment up to elevation 70+0.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS flowrate; Instrument Type - Flowmeter; Instrument Function - Decay heat removal system performance; Range - Bounds SCS pump flow range; Comments - One located in each SCS return line to the RCS. Can be used to measure CSP flow if CSPs are used for SCS.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS pump/CS pump discharge pressure; Instrument Type - Pressure sensor; Instrument Function - Measures individual pump discharge pressures; Comments - One instrument located at the discharge to each pump. Identifies individual pump status.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS pump/CS pump motor current; Instrument Type - Ammeter; Instrument Function - Measure current drawn by pump motor. Fluctuations show air entrainment. Comments - Confirms pump status.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS pump/CS pump suction pressure; Instrument Type - Pressure sensor; Instrument Function - Measure pump suction pressure in each pump. Comment - One instrument located at the suction of each pump. Identifies individual pump status.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCHX inlet and return line temperature; Instrument Type - Temperature sensor; Instrument Function - Measures temperature in the suction and discharge lines of the shutdown cooling heat exchanger; Comments - Temperature indication only available when SCS is operational.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.8A.2.8.3.2.5.2	[1] Individual alarm inputs to the shutdown cooling alarm tiles include: low shutdown cooling pump header pressure, low shutdown cooling flow, higher shutdown cooling heat exchanger outlet temperature, shutdown cooling pump motor current deviation.
19.8A.2.8.3.2.5.3	[1] Discrete indicators are provided on the Nuplex 80+™ (†) control room stations to provide the operator with information that (1) is frequently used to assess system level performance and (2) allows continued operation if the data processing system should become unavailable.
19.8A.2.8.3.2.5.3	[1] Discrete indicator displays to support shutdown cooling for key parameters are on the engineered safety feature panel. These include: Shutdown Cooling System (per train); Inlet Temperature; Outlet Temperature; Heat Exchanger Inlet Temperature; Heat Exchanger Outlet Temperature; Pump Motor Current; Flow; Pump Header Pressure; Reactor Coolant System; Pressurizer Level; Reactor Coolant System Level; Pressure; Core Exit Temperature; Refueling Cavity Level.
19.8A.2.13	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.8A.2.13	[1] Door closed sensors will be provided on flood doors with indications available at a monitored location.
19.8A.2.13.3	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.8A.2.13.3	[1] Door closed sensors will be provided on flood doors with indications available at a monitored location.
19.8A.2.13.3	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.8A.4.1.2	[1] Emergency Feedwater Cavitating Venturi: Emergency Feedwater Flowrate = 800 gpm maximum
19.8A.7.2.7	[1] The integration evident in the Nuplex 80+ displays and Mode dependent alarms contributes to plant safety by reducing the historically common personnel errors during Mode changes and outages.

† Nuplex 80+ is a trademark of Combustion Engineering, Inc.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.11.3.4.2	[1] At least 80 hydrogen ignitors are provided.
19.11.3.6.2	[1] The reactor cavity sump has a minimum thickness of 3 feet.
19.11.3.6.2.6	[1] The reactor cavity sump has a minimum thickness of 3 feet.
19.11.3.8.1	Containment Shell: Containment Atmosphere Design Basis Peak Pressure = 53 psig
19.15.3.2	[1] If a fire occurs inside the main control room and the operator determines that the control room should be evacuated, it is assumed that the operator will trip the reactor and transfer control to the Remote Shutdown Room prior to evacuation.
19.15.3.2	[1] The main control room and the remote shutdown room are located at different elevations and in different fire areas. Since the main control room ventilation system is separate from the ventilation system for the remote shutdown room, and the stairwells connecting these rooms are pressurized, it was assumed that smoke, hot gases, or fire suppressants cannot migrate from one room to the next.
19.15.3.2	[1] Both the remote shutdown room and the main control room are protected by 3-hour fire walls and 3-hour fire doors. It is therefore assumed that a fire that originates in an area outside the main control room area will not threaten the habitability of the control room. Only fires that originate inside the control room may force its evacuation.
19.15.3.2	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.
19.15.3.2	[1] The propagation of a fire from one division to the next is prevented by the divisional separation of redundant safety related equipment with a 3-hour fire barrier which is maintained during power operation.
19.15.3.3	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.15.3.3	[1] It was assumed that there are no doors or passageways connecting the divisions of safety related equipment up to elevation 70+0.
19.15.3.3	[1] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.

Table 14.3-2 Probability Risk Assessment (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.15.3.3	[1] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.
19.15.3.3	[1] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.
19.15.3.3	[1] All safety related structures are designed to withstand the static and dynamic forces of flooding. Therefore, the structural wall between the Nuclear Annex and the Turbine Building will not fail.
19.15.3.4	[1] The System 80+ Class 1E electrical distribution system is provided with protection schemes which conform to the requirements of IEEE STD-741-1986. The protective schemes are designed to isolate faulted equipment from the rest of the system to minimize the effect of the fault and to maximize the availability of the remaining equipment. The basic schemes consist of ground fault protection, instantaneous overcurrent and timed overcurrent protection. In developing the Seismic Margin Assessment models, it was assumed that the seismic failures of equipment in the electrical distribution system were "open circuit" failures. Implicit within this assumption is the assumption that if a "hot short" failure were to occur, the appropriate circuit interrupter(s) would open on overcurrent to prevent "backward" propagation of the fault.

[1] PRA Assumption

Table 14.3-3 Shutdown Risk

Paragraph	Assumption/Parameter Description/Value
19.8.1.2	[I] Availability of mitigating equipment following fires can be maximized if separation is maintained between equipment within a quadrant. This will increase the number of success paths available for responding to the event and result in a decrease in risk.
19.8.4.3	[I] Propagation of fires between quadrants is assumed to be impossible based on their separation by three-hour rated fire barriers. Fire doors between quandrants are three-hour rated fire doors and are assumed to be closed during all shutdown operations. These doors specifically include those between Fire Areas 38 and 41 and Fire Areas 39 and 40, as shown in Figure 9.5.1-2.
19.8.4.3	[I] Propagation of fires between divisions is assumed to be impossible based on their separation by three-hour rated fire barriers. The barriers have no communicating openings below 70 feet elevation and all penetrations within the barriers are sealed with assemblies qualified to maintain the integrity of the three-hour rating.
19.8.4.4	[I] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.8.4.4	[I] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.
19.8.4.4	[I] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.
19.8.4.4	[I] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.
Table 1.4-1 of App. 19.8A	[I] Make SCS pumps interchangeable with containment spray pumps to provide further redundancy.
Table 1.4-1 of App. 19.8A	[I] Monitor SCS pump motor current, flowrate, discharge pressure and suction pressure to provide reliable cooling status.
Table 1.4-1 of App. 19.8A	[I] CCW availability improved by two redundant divisions with two pumps each.
19.8A.2.3.3.2	[I] SCS suction lines do not contain any LOOP seals. The suction piping arrangement allows self venting. This feature allows SCS pumps to be restarted without requiring complicated venting procedures.

Table 14.3-3 Shutdown Risk (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.8A.2.3.3.2	[1] Containment Spray Pump: Number of Pumps = 2
19.8A.2.7.3.1	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.
19.8A.2.7.3.1	[1] The propagation of a fire from one division to the next is prevented by the divisional separation of redundant safety related equipment with a 3-hour fire barrier which is maintained during power operation.
19.8A.2.7.3.1	[1] It was assumed that there are no doors or passageways connecting the divisions of safety related equipment up to elevation 70+0.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS flowrate; Instrument Type - Flowmeter; Instrument Function - Decay heat removal system performance; Range - Bounds SCS pump flow range; Comments - One located in each SCS return line to the RCS. Can be used to measure CSP flow if CSPs are used for SCS.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS pump/CS pump discharge pressure; Instrument Type - Pressure sensor; Instrument Function - Measures individual pump discharge pressures; Comments - One instrument located at the discharge to each pump. Identifies individual pump status.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS pump/CS pump motor current; Instrument Type - Ammeter; Instrument Function - Measure current drawn by pump motor. Fluctuations show air entrainment; Comments - Confirms pump status.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCS pump/CS pump suction pressure, Instrument Type - Pressure sensor; Instrument Function- Measure pump suction pressure in each pump; Comment - One instrument located at the suction of each pump. Identifies individual pump status.
Table 2.8-1 of App. 19.8A	[1] Monitored Parameter - SCHX inlet and return line temperature; Instrument Type - Temperature sensor; Instrument Function - Measures temperature in the suction and discharge lines of the shutdown cooling heat exchanger; Comments - Temperature indication only available when SCS is operational.
19.8A.2.8.3.2.5.2	[1] Individual alarm inputs to the shutdown cooling alarm tiles include: low shutdown cooling pump header pressure, low shutdown cooling flow, higher shutdown cooling heat exchanger outlet temperature, shutdown cooling pump motor current deviation.

Table 14.3-3 Shutdown Risk (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.8A.2.8.3.2.5.3	[1] Discrete indicators are provided on the Nuplex 80+[†] control room stations to provide the operator with information that (1) is frequently used to assess system level performance and (2) allows continued operation if the data processing system should become unavailable.
19.8A.2.8.3.2.5.3	[1] Discrete indicator displays to support shutdown cooling for key parameters are on the engineered safety feature panel. These include: Shutdown Cooling System (per train); Inlet Temperature; Outlet Temperature; Heat Exchanger Inlet Temperature; Heat Exchanger Outlet Temperature; Pump Motor Current; Flow; Pump Header Pressure; Reactor Coolant System; Pressurizer Level; Reactor Coolant System Level; Pressure; Core Exit Temperature; Refueling Cavity.
19.8A.2.13	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.8A.2.13	[1] Door closed sensors will be provided on flood doors with indications available at a monitored location.
19.8A.2.13.3	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.8A.2.13.3	[1] Door closed sensors will be provided on flood doors with indications available at a monitored location.
19.8A.2.13.3	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.8A.4.1.2	Emergency Feedwater Cavitating Venturi: Emergency Feedwater Flowrate = 800 gpm maximum
19.8A.7.2.7	[1] The integration evident in the Nuplex 80+ displays and Mode dependent alarms contributes to plant safety by reducing the historically common personnel errors during Mode changes and outages.

[†] Nuplex 80+ is a trademark of Combustion Engineering, Inc.

[1] PRA Assumption

Table 14.3-4 Severe Accident Analysis

Paragraph	Assumption/Parameter Description/Value
19.6.3.16	[1] Operator must open the HVT spillway motor-operated valves and the reactor cavity spillway motor-operated valves. This is done from the control room.
19.11.3.4.2	[1] At least 80 hydrogen ignitors are provided.
19.11.3.6.2	[1] The reactor cavity sump has a minimum thickness of 3 feet.
19.11.3.6.2.6	[1] The reactor cavity sump has a minimum thickness of 3 feet.
19.11.3.8.1	Containment Shell: Containment Atmosphere Design Basis Peak Pressure = 53 psig

Table 14.3-5 Flood Protection

Paragraph	Assumption/Parameter Description/Value
3.4.1	Maximum Flood Level Below Grade = 1 ft maximum
3.4.2	[1] All safety related structures are designed to withstand the static and dynamic forces of flooding. Therefore, the structural wall between the Nuclear Annex and the Turbine Building will not fail.
3.4.4.1	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
3.4.4.1	[1] Door closed sensors will be provided on flood doors with indications available at a monitored location.
3.4.4.1	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
3.4.4.1	[1] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.
3.4.4.1	[1] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.

[1] PRA Assumption

Table 14.3-5 Flood Protection (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
3.4.4.1	[1] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.
19.7.4.1	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.7.4.1	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.7.4.1	[1] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.
19.7.4.1	[1] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.
19.7.4.1	[1] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.
19.8.4.4	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.8.4.4	[1] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.
19.8.4.4	[1] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.

Table 14.3-5 Flood Protection (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.8.4.4	[1] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.
19.8A.2.13	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.8A.2.13	[1] Door closed sensors will be provided on flood doors with indications available at a monitored location.
19.8A.2.13.3	[1] Flood barriers provide divisional and quadrant separation up to the 70' elevation. Failure of largest storage tank within a division will not flood above the 70' level.
19.8A.2.13.3	[1] Door closed sensors will be provided on flood doors with indications available at a monitored location.
19.8A.2.13.3	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.15.3.3	[1] It was assumed that the primary means of flood control in the Nuclear Annex and Reactor Building is provided by the divisional wall which serves as a barrier between redundant divisions of safety related equipment.
19.15.3.3	[1] It was assumed that there are no doors or passageways connecting the divisions of safety related equipment up to elevation 70+0.
19.15.3.3	[1] The equipment within the Component Cooling Water Heat Exchanger structure was assumed to be divisionally separated by a wall such that a flood in one division will not affect the other division.
19.15.3.3	[1] The divisional flood barrier between redundant divisions of safety related equipment is an important design feature which ensures that flooding of both divisions of safety related equipment will not occur.

Table 14.3-5 Flood Protection (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.15.3.3	[1] The divisional separation of redundant safety related equipment in the Component Cooling Water Heat Exchanger structure and the station service water pump structure is also an important design feature. This ensures that flooding of both divisions of Component Cooling Water Heat Exchangers and station service water pumps will not occur.
19.15.3.3	[1] All safety related structures are designed to withstand the static and dynamic forces of flooding. Therefore, the structural wall between the Nuclear Annex and the Turbine Building will not fail.

Table 14.3-6 Fire Protection

Paragraph	Assumption/Parameter Description/Value
Figure 9.5.1-2	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.
Figure 9.5.1-2	[1] The propagation of a fire from one division to the next is prevented by the divisional separation of redundant safety related equipment with a 3-hour fire barrier which is maintained during power operation.
Figure 9.5.1-2	[1] It was assumed that there are no doors or passageways connecting the divisions of safety related equipment up to elevation 70+0.
Figure 9.5.1-3	[1] The main control room and the remote shutdown room are located at different elevations and in different fire areas. Since the main control room ventilation system is separate from the ventilation system for the remote shutdown room, and the stairwells connecting these rooms are pressurized, it was assumed that smoke, hot gases, or fire suppressants cannot migrate from one room to the next.
Figure 9.5.1-3	[1] Both the remote shutdown room and the main control room are protected by 3-hour fire walls and 3-hour fire doors. It is therefore assumed that a fire that originates in an area outside the main control room area will not threaten the habitability of the control room. Only fires that originate inside the control room may force its evacuation.
Figure 9.5.1-3	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.

[1] PRA Assumption

Table 14.3-6 Fire Protection (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
Figure 9.5.1-3	[1] The propagation of a fire from one division to the next is prevented by the divisional separation of redundant safety related equipment with a 3-hour fire barrier which is maintained during power operation.
Figure 9.5.1-5	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.
Figure 9.5.1-6	[1] The main control room and the remote shutdown room are located at different elevations and in different fire areas. Since the main control room ventilation system is separate from the ventilation system for the remote shutdown room, and the stairwells connecting these rooms are pressurized, it was assumed that smoke, hot gases, or fire suppressants cannot migrate from one room to the next.
Figure 9.5.1-6	[1] Both the remote shutdown room and the main control room are protected by 3-hour fire walls and 3-hour fire doors. It is therefore assumed that a fire that originates in an area outside the main control room area will not threaten the habitability of the control room. Only fires that originate inside the control room may force its evacuation.
9.5.1.1.2	Manual pull stations or individual fire detectors provide fire detection capability and can be used to initiate fire alarms.
9.5.1.7.1	The motor-driven fire pump and the diesel-driven fire pump are separated by a three-hour fire rated barrier.
9.5.1.7.1	The electric motor-driven fire pump is powered from a permanent non-safety bus.
9.5.1.7.1	The diesel and motor-driven fire pumps are designed to meet the largest design demand of any sprinkler, pre-action, or deluge system plus 500 gpm for manual hoses.
9.5.1.7.1	Fire Protection Water Supply Tank: volume = 300,000 gal
9.5.1.7.1	Diesel Driven Fire Pump: fuel supply duration = 8 hr
9.5.1.7.4	The standpipe systems in the Nuclear Annex and Reactor Building, along with their back-up water supply, are classified as Seismic Category I.
9.5.1.7.4	Seismic Fire Water Supply Tank: capacity = 18,000 gal
9.5.1.7.6	Fire Detection Alarm System Power Supply: Battery Backup Duration = 24 hr
9.5.1.12	[1] A plant Fire Hazards Analysis considers potential fire hazards.
19.7.3.1.1	[1] A plant Fire Hazards Analysis considers potential fire hazards.
19.7.3.1.5	[1] A plant Fire Hazards Analysis considers potential fire hazards.

Table 14.3-6 Fire Protection (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
19.8.4.3	[1] Propagation of fires between quadrants is assumed to be impossible based on their separation by three-hour rated fire barriers. Fire doors between quadrants are three-hour rated fire doors and are assumed to be closed during all shutdown operations. These doors specifically include those between Fire Areas 38 and 41 and Fire Areas 39 and 40, as shown in Figure 9.5.1-2.
19.8.4.3	[1] Propagation of fires between divisions is assumed to be impossible based on their separation by three-hour rated fire barriers. The barriers have no communicating openings below 70 feet elevation and all penetrations within the barriers are sealed with assemblies qualified to maintain the integrity of the three-hour rating.
19.8A.2.7.3.1	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.
19.8A.2.7.3.1	[1] The propagation of a fire from one division to the next is prevented by the divisional separation of redundant safety related equipment with a 3-hour fire barrier which is maintained during power operation.
19.8A.2.7.3.1	[1] It was assumed that there are no doors or passageways connecting the divisions of safety related equipment up to elevation 70+0.
19.15.3.2	[1] If a fire occurs inside the main control room and the operator determines that the control room should be evacuated, it is assumed that the operator will trip the reactor and transfer control to the Remote Shutdown Room prior to evacuation.
19.15.3.2	[1] The main control room and the remote shutdown room are located at different elevations and in different fire areas. Since the main control room ventilation system is separate from the ventilation system for the remote shutdown room, and the stairwells connecting these rooms are pressurized, it was assumed that smoke, hot gases, or fire suppressants cannot migrate from one room to the next.
19.15.3.2	[1] Both the remote shutdown room and the main control room are protected by 3-hour fire walls and 3-hour fire doors. It is therefore assumed that a fire that originates in an area outside the main control room area will not threaten the habitability of the control room. Only fires that originate inside the control room may force its evacuation.
19.15.3.2	[1] All fire barriers which provide separation between the two divisions are rated for at least 3 hours. It was assumed that all fire doors and penetrations within the fire barriers are maintained during power operation to prevent the propagation of fire from one area to the next.
19.15.3.2	[1] The propagation of a fire from one division to the next is prevented by the divisional separation of redundant safety related equipment with a 3-hour fire barrier which is maintained during power operation.

[1] PRA assumption

Table 14.3-7 Anticipated Transients Without Scram

Paragraph	Assumption/Parameter Description/Value
7.1.1.1.1	The digital equipment and software used in the PCS/P-CCS are diverse from those used in the PPS and ESF-CCS.
7.1.2.10	Electrical isolation devices are provided at PPS interfaces with the Power Control System, the Discrete Indication and Alarm System - Channel N, and the Data Processing System; and between the signal conditioning equipment and the Discrete Indication and Alarm System - Channel P.
7.1.2.10	Electrical isolation devices are provided between the PCS/P-CCS and the protection system signal conditioning equipment for each protection signal provided to them.
7.1.2.10	The four ESF-CCs divisions are physically separated electrically isolated.
7.1.2.10	Where the ESF-CCS and the process control system interface to the same component, electrical isolation devices are provided between the process control system and the shared component.
7.1.2.10	Electrical isolation devices are provided at ESF-CCS interfaces with the DIAS-N, the DPS, the P-CCS, the control and display interface devices, the master transfer switches; and between the signal conditioning equipment and the DIAS-P.
7.2.1.1	[1] The RPS communicates with the Reactor Trip Switchgear System and the Engineered Safety Features - Component Control System (ESF-CCS), which enables them to actuate mitigating systems when demanded.
7.2.1.1	[1] Instrumentation is provided to adequately monitor plant parameters.
7.2.1.1	[1] A reactor trip signal can be generated using any two of the four RPS channels.
7.2.1.1	The four PPS channels are physically separated and electrically isolated.
7.2.1.1	Upon coincidence of two like signals indicating a condition requiring a reactor trip, the PPS logic initiates a reactor trip.
7.2.1.1	Instrumentation is provided to adequately monitor plant parameters and initiate Reactor Trip and Engineered Safety Features Actuation Signals.
7.2.1.1.1.1	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.2	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.2.1.1.1.3	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.4	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.5	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.6	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.7	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.8	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.9	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.10	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.11	[1] The RPS has the capability of generating an automatic or manual reactor trip signal.
7.2.1.1.1.11	The RTSG can be tripped manually from the Main Control Room or the Remote Shutdown Room.
7.2.1.1.2	The digital equipment and software used in the PCS/P-CCS are diverse from those used in the PPS and ESF-CCS.
7.2.1.1.2.1	Electrical isolation devices are provided between the PCS/P-CCS and the protection system signal conditioning equipment for each protection signal provided to them.
7.2.1.1.3	[1] A reactor trip signal can be generated using any two of the four RPS channels.
7.2.1.1.5	A bistable trip channel bypass can be activated in only one channel at a time.
7.2.1.1.5	The PPS automatically removes an operating bypass if the plant approaches conditions for which the associated trip function is designed to provide protection.
7.2.1.1.7	[1] The Reactor Protection System (RPS) has four redundant channels.
7.2.1.1.8	The digital equipment and software used in the PCS/P-CCS are diverse from those used in the PPS and ESF-CCS.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.2.1.1.9	PPS Interface and Test Processor provides maintenance and test capability.
7.2.1.1.9.2	Bistable trip limit logic can be tested.
7.2.1.1.9.5	Each reactor trip switchgear breaker can be tripped by either an undervoltage or a shunt trip.
7.2.1.1.9.6	Each reactor trip switchgear breaker can be tripped by either an undervoltage or a shunt trip.
7.2.1.1.9.8	The PPS initiates reactor trip and ESF system actuations within allocated response times.
7.2.1.1.10	Each PPS channel is powered from its respective Class 1E bus.
7.2.4	The digital equipment and software used in the PCS/P-CCS are diverse from those used in the PPS and ESF-CCS.
7.3.1.1	The ESF-CCS includes component control logic, signal conditioning equipment, control and display interface devices, master transfer switches, and diverse manual actuation switches. The ESF-CCS interfaces to ESF components and associated sensors, the PPS, the P-CCS, the PCS, the DIAS, and the DPS.
7.3.1.1	Each division of the ESF-CCS has the following elements: - selective 2-out-of-4 logic, - component control logic, - process instrumentation, - signal conditioning equipment, - maintenance and test panel, - control and display interface devices, - master transfer switch.
7.3.1.1	The operator interface devices of the ESF-CCS in the MCR provide for automatic and manual control of ESF systems and components.
7.3.1.1	Each ESF-CCS division's maintenance and test panel provides capability to transfer control from the MCR to the remote shutdown panel for its respective ESF-CCS division and to transfer control back to the MCR for its respective ESF-CCS division.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.3.1.1	Diverse manual actuation switches are provided as an alternate means for manual actuation of ESF components in two divisions of the ESF-CCS as follows: - 2 trains of safety injection, - 1 train of containment spray, - 1 train of emergency feedwater to each steam generator, - 1 main steam isolation valve in each main steam line, - 1 isolation valve in each containment air purge line, - 1 letdown isolation valve.
7.3.1.1	Electrical isolation devices are provided at ESF-CCS interfaces with the DIAS-N, the DPS, the P-CCS, the control and display interface devices, the master transfer switches; and between the signal conditioning equipment and the DIAS-P.
7.3.1.1	Software programmable processors are arranged in primary and standby processor configuration within each ESF-CCS division.
7.3.1.1	ESFAS functions are divided into ESF-CCS distributed segments with two separate multiplexers per segment which receive PPS initiation signals.
7.3.1.1	Separation is provided between safety critical ESFAS processing functions and auxiliary functions of man-machine interfaces, data communications, and automatic testing.
7.3.1.1	Networks exhibit deterministic performance since all data is updated continuously and not dependent on parameter changes of state.
7.3.1.1	Actuation of master transfer switches at either exit of the main control room transfers control capability from the ESF-CCS control and display interface devices depicted in the main control room to those in the remote shutdown room. Indication of the transfer status is provided in the main control room.
7.3.1.1	Prior to transfer of control to the remote shutdown room, control actions in the remote shutdown room do not cause the ESF-CCS to generate the associated control signals.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.3.1.1.2	Each division of the ESF-CCS has the following elements: - selective 2-out-of-4 logic, - component control logic, - process instrumentation, - signal conditioning equipment, - maintenance and test panel, - control and display interface devices, - master transfer switch.
7.3.1.1.2.1	The following ESFAS signals can be manually actuated at the Main Control Room: - Safety Injection Actuation Signal, - Containment Spray Actuation Signal, - Containment Isolation Signal, - Main Steam Isolation Signal, - Emergency Feedwater Actuation Signal.
7.3.1.1.2.2	Each ESF-CCS division receives 4 channels of initiation signals from the PPS which are processed using selective 2-out-of-4 logic to generate actuation signals for the ESF systems controlled by that division.
7.3.1.1.2.2	ESFAS functions are divided into ESF-CCS distributed segments with two separate multiplexers per segment which receive PPS initiation signals.
7.3.1.1.2.3	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following non-ESF systems: - annulus ventilation system, - component cooling water system, - onsite power system, - diesel generators, - control complex ventilation system.
7.3.1.1.2.3	Upon receipt of ESF initiation signals for safety injection, containment spray, or emergency feedwater, the ESF-CCS initiates an automatic start of the diesel generators and automatic load sequencing of ESF loads.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.3.1.1.2.3	Upon detecting loss of power to Class 1E division buses, the ESF-CCS automatically initiates startup of the respective diesel generators, shedding of electrical load, transfer of Class 1E bus connections to the diesel generators, and sequencing to the reloading of safety-related loads to the Class 1E bus.
7.3.1.1.2.3	Upon ESF actuation, the normal load sequence is interrupted, and priority is given to loading the actuated ESF systems and associated safety-related systems.
7.3.1.1.2.3	The diesel loading sequence logic responds to loss of electrical power buses.
7.3.1.1.5	[1] The Engineered Safety Features Actuation System (ESFAS) has at least two redundant trains to generate the following engineered safety feature signal: Safety Injection Actuation Signal (SIAS), Containment Spray Actuation Signal (CSAS), Containment Isolation Actuation Signal (CIAS), Main Steam Isolation Signal (MSIS), Emergency Feedwater Actuation Signal (EFAS).
7.3.1.1.5	Each ESF-CCS division is powered from its respective Class 1E bus.
7.3.1.1.5	Software programmable processors are arranged in primary and standby processor configuration within each ESF-CCS division.
7.3.1.1.6	The digital equipment and software used in the PCS/P-CCS are diverse from those used in the PPS and ESF-CCS.
7.3.1.1.6	Diverse manual actuation switches are provided as an alternate means for manual actuation of ESF components in two divisions of the ESF-CCS as follows: - 2 trains of safety injection, - 1 train of containment spray, - 1 train of emergency feedwater to each steam generator, - 1 main steam isolation valve in each main steam line, - 1 isolation valve in each containment air purge line, - 1 letdown isolation valve.
7.3.1.1.6	The diverse manual actuation switches provide signals to the lowest level in the ESF-CCS digital equipment. Communication of the signals from the switches is diverse from the software used in the higher levels of the ESF-CCS.
7.3.1.1.6	Algorithm execution in Nuplex 80+ control and protection systems is deterministic.
7.3.1.1.6	Actuation of the switches provides a signal which overrides the higher level signals to actuate the associated ESF component or components.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.3.1.1.6	Diverse manual actuations status indication is provided in the MCR.
7.3.1.1.8	Periodic testing to verify operability of the ESF-CCS can be performed with the reactor at power or when shut down without interfering with the protective function of the system.
7.3.1.1.8	Capability is provided for testing all functions from ESF initiating signals received from the PPS through to the actuation of protective system equipment.
7.3.1.1.8.4	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following ESF systems within allocated response times: - safety injection system, - containment isolation system, - containment spray system, - main steam isolation, and - emergency feedwater system.
7.3.1.1.8.5	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following ESF systems within allocated response times: - safety injection system, - containment isolation system, - containment spray system, - main steam isolation, and - emergency feedwater system.
7.3.1.1.8.6	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following ESF systems within allocated response times: - safety injection system, - containment isolation system, - containment spray system, - main steam isolation, and - emergency feedwater system.
7.3.1.1.8.8	The PPS initiates reactor trip and ESF system actuations within allocated response times.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.3.1.1.8.8	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following ESF systems within allocated response times: - safety injection system, - containment isolation system, - containment spray system, - main steam isolation, and - emergency feedwater system.
7.3.1.1.8.9	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following ESF systems within allocated response times: - safety injection system, - containment isolation system, - containment spray system, - main steam isolation, and - emergency feedwater system.
7.3.1.1.10	A SIAS actuates safety injection pumps and opens the corresponding discharge valves.
7.3.1.1.10	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following ESF systems within allocated response times: - safety injection system, - containment isolation system, - containment spray system, - main steam isolation, and - emergency feedwater system.
7.3.1.1.10	The ESF-CCS provides control capability and, upon receipt of initiation signals from the PPS, automatically generates actuation signals to the following non-ESF systems: - annulus ventilation system, - component cooling water system, - onsite power system, - diesel generators, - control complex ventilation system.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.3.1.1.10.1	[I] The ESFAS actuates the Engineered Safety Features (ESF) systems when demanded.
7.3.1.1.10.2	[I] The ESFAS actuates the Engineered Safety Features (ESF) systems when demanded.
7.3.1.1.10.3	[I] The ESFAS actuates the Engineered Safety Features (ESF) systems when demanded.
7.3.1.1.10.4	[I] The ESFAS actuates the Engineered Safety Features (ESF) systems when demanded.
7.3.1.1.10.5	[I] The ESFAS actuates the Engineered Safety Features (ESF) systems when demanded.
7.3.1.1.10.5	The interlock on the EFW isolation valves automatically closes the isolation valves on high SG levels when an Emergency Feedwater Actuation Signal is not present.
7.7.1.1.11	[I] The Alternate Protection System (APS) provides an alternate means of generating a reactor trip signal and an alternate feedwater actuation signal.
7.7.1.1.11	[I] The APS monitors the pressurizer pressure and generates a reactor trip signal if the RCS pressure exceeds a predetermined value. Similarly, an alternate feedwater actuation signal is generated if the steam generator level decreases below a predetermined value.
7.7.1.1.11	[I] The EFWS is actuated by an EFAS and an APS actuation signal (Low SG Water Level).
7.7.1.1.11	The DIAS and DPS provide for monitoring: - safety-related plant process display instrumentation, - reactor trip system status, - engineered safety feature system status, - CEA position, - post-accident monitoring of plant safety functions, - status of plant operating mode-related bypasses, - core cooling status prior to and following an accident, - PPS status information, - ESF-CCS status information, - PCS/P-CCS status information.
7.7.1.1.11	The digital equipment and software used in the PCS/P-CCS are diverse from those used in the PPS and ESF-CCS.

Table 14.3-7 Anticipated Transients Without Scram (Cont'd.)

Paragraph	Assumption/Parameter Description/Value
7.7.1.1.11	The PCS/P-CCS provide control interfaces for the following control functions: - reactivity control using control element assemblies, - reactor power cutback, - power change limiter, - pressurizer pressure and level, - main feedwater flow, - steam bypass flow, - boron concentration, - alternate reactor trip actuation, - alternate emergency feedwater actuation.
7.7.1.1.11	The circuits used for alternate actuation of reactor trip, turbine trip and emergency feedwater are independent and diverse from the protection system actuation circuits.
7.7.1.1.11	The PCS/P-CCS provide the following information to the DIAS: - alternate reactor trip status, - alternate feedwater actuation signal status, - pressurizer pressure, and - steam generator 1 and 2 levels.
7.7.1.1.11.1	The digital equipment and software used in the PCS/P-CCS are diverse from those used in the PPS and ESF-CCS.
7.7.1.1.11.1	Electrical isolation devices are provided between the PCS/P-CCS and the protection system signal conditioning equipment for each protection signal provided to them.
7.7.1.1.11.1	Where the ESF-CCS and the process control system interface to the same component, electrical isolation devices are provided between the process control system and the shared component.
7.7.1.1.11.1	Electrical isolation devices are provided at ESF-CCS interfaces with the DIAS-N, the DPS, the P-CCS, the control and display interface devices, the master transfer switches; and between the signal conditioning equipment and the DIAS-P.

[1] PRA Assumption

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Chapter 15 Figures (Cont'd.)

15. Accident Analyses

15.0 Organization and Methodology

This chapter presents analytical evaluations of the System 80+™[†] Nuclear Steam Supply System (NSSS) response to postulated disturbances in process variables and to postulated malfunctions or failures of equipment. Such incidents (or events) are postulated and their consequences analyzed despite the many precautions which are taken in the design, construction, quality assurance, and plant operation to prevent their occurrence. The effects of these incidents are examined to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations.

Evaluations to determine the consequences of these incidents should they occur during shutdown operations are provided in Section 4.0 of Appendix 19.8A.

15.0.1 Classification of Transients and Accidents

15.0.1.1 Format and Content

This chapter is structured according to the format and content suggested by Reference 1 and required by Reference 26.

15.0.1.2 Event Categories

Each postulated initiating event has been assigned to one of the following categories:

- Increased Heat Removal by Secondary System
- Decreased Heat Removal by Secondary System
- Decreased Reactor Coolant Flow
- Reactivity and Power Distribution Anomalies
- Increase in RCS Inventory
- Decrease in RCS Inventory
- Radioactive Release from a Subsystem or Component

The assignment of an initiating event to one of these seven categories is made according to Reference 26.

15.0.1.3 Event Frequencies

Reference 26 subjectively classifies initiating events in the following qualitative frequency groups:

- Moderate Frequency Events

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† System 80+ is a trademark of Combustion Engineering, Inc.

- Infrequent Events
- Accidents

15.0.1.4 Events and Event Combinations

The events and event combinations in this chapter are those identified by Reference 26, and are presented with respect to the event specific acceptance criteria specified therein. For each applicable acceptance criterion in an event category/frequency group, only the limiting event or event combination is presented in analytical detail. Qualitative discussions are provided for all other events or event combinations explaining why they are not limiting.

All event analyses resulting in a turbine generator trip considered the Loss of Offsite Power (LOOP), to comply with GDC-17, while applying the same acceptance criteria for the event with and without LOOP, i.e. without re-classifying the event. In the analyses for which the LOOP is assumed to result from a turbine trip, the time delay between the turbine trip and LOOP is assumed to be zero (except for the steam generator tube rupture event offsite dose analysis in which the assumption of a 3 seconds delay has no significant impact on the analysis results).

For event combinations which require consideration of a single failure, the limiting failure is selected from those listed in Table 15.0-4. Only independent pre-existing failures are considered credible and included in the table. Pre-existing failures are equipment failures existing prior to the event initiation which are not revealed until called upon during the event (e.g., a failure of an emergency feedwater pump). High probability dependent occurrences are always included in the event analysis, if they have an adverse impact (e.g., loss of main feedwater pumps following a loss of electric power). Interactive control system failures are not more limiting than the active failures listed.

10 CFR 50 Appendix A states that a single failure means an occurrence which results in the loss of capacity of a component to perform its intended safety functions. However, failures are considered of not only the safety-related systems whose operation may be required, but also of non-safety related systems whose failure could produce results more severe than failure of a safety system. If a non-safety related system would help to mitigate a transient, then the analysis of that transient assumes the system is in the manual mode of operation. Non-safety related systems are assumed to be in the automatic mode of operation if the system makes the consequences of a transient more adverse.

The purpose of the single failure list is to identify the single failures which could create the most adverse conditions during a given transient, regardless of the safety related status of that component or system. In most cases, the automatic action of safety-related systems overrides the operation of non-safety systems. The justification for choosing the most limiting single failure is explained in the individual analyses of this chapter.

The safety-related components in Table 15.0-4 are the:

Main Feedwater Isolation Valve,

Main Feedwater Back-Flow Check Valve,

Main Steam Isolation Valve,

Atmospheric Dump Valve,

Main Steam Safety Valve,

Emergency Feed Pump (Motor and Steam Driven),

SI Pump, and the

Emergency Diesel Generator.

15.0.1.5 Section Numbering

The incidents analyzed in this chapter are presented in sections in accordance with Reference 26 and are numbered as described in Table 15.0-1. References cited in all sections of Chapter 15 are listed at the end of Section 15.0.

15.0.1.6 Sequence of Events and Systems Operation

The Sequence of Events and Systems Operation section provides, for each limiting event in this chapter, the step-by-step sequence of events from event initiation to the final stabilized condition.

The table in each Sequence of Events and Systems Operation section presents a chronological list of events which occur during the transient and the time at which they occur, from the initiation of the event until the operator takes manual action to initiate plant cooldown. The chronological list of events may be used to trace the actuation of the systems used to mitigate the consequences of each event.

15.0.2 Systems Operation

During the course of any event, various systems may be called upon to function. Some of these systems are described in Chapter 7 and include those electrical, instrumentation, and control systems designed to perform a safety function (i.e., those systems which must operate during an event to mitigate the consequences) and those systems not required to perform a safety function (see Sections 7.2 through 7.6 and 7.7, respectively).

The Reactor Protection System (RPS) is described in Section 7.2. Table 15.0-2 lists the RPS trips for which credit is taken in the analyses discussed in Chapter 15, including the setpoints and the total response times associated with each trip. The analyses take into consideration the response times of actuated devices after the value of the monitored parameter at the sensor equals or exceeds the trip setpoint.

The Reactor Protection System total response time is the sum of the sensor response time and the reactor trip delay time. The sensor response time is defined as the time from when the value of the monitored parameter at the sensor equals or exceeds the reactor protection system trip setpoint until the sensor output equals or exceeds the trip setpoint. The sensor response is modeled by using a transfer function for the particular sensor used. The reactor trip delay time is defined as the elapsed time from the time the sensor output equals or exceeds the trip setpoint to the time the reactor trip breakers are fully open.

The interval between trip breaker opening and the time at which the magnetic flux of the Control Element Assembly (CEA) holding coils has decayed enough to allow CEA motion is conservatively assumed to be 0.50 seconds.

Performance evaluations of the System 80 Control Element Drive Mechanism (CEDM), during reactor scram conditions, have been performed using data obtained during CEDM testing. Testing is conducted using equipment that is identical to that which is installed on the reactor vessel. During a reactor scram the latch coil circuit is discharged. When the coil current decreases sufficiently the mechanical latches spring open and release the CEAs.

Information obtained from actual motor test data as well as from numerical electromechanical modeling of the CEDM motor both indicate that the CEDM latch release time, during reactor scram conditions, is about 0.50 seconds. This is corroborated by field test data on the PVNGS reactor, that the maximum measured drop out or release time was 0.49 seconds.

Finally, a conservative value of 3.50 seconds is assumed for CEA insertion, defined as the elapsed time from the beginning of CEA motion to the time of 90% insertion of the CEAs in the reactor core. Under worst case conditions, the required scram time from electrical power interruption to 90% insertion is 4.0 seconds. This is represented by the acceptance curve in Figure 4B-4 of Appendix 4B. Also, this figure illustrates that the time period between the starting of CEA motion and 90 percent insertion in the reactor core is 3.50 seconds.

90% CEA insertion is used for establishing requirements for rate of insertion (see Section 4.2 and Appendix 4B). However, 100% required shutdown margin corresponds to 100% CEA insertion. Note that the required shutdown margin for the safety analyses conservatively assumes that the highest worth CEA does not insert.

The Engineered Safety Feature Actuation Systems (ESFAS) and electrical, instrumentation, and control systems required for safe shutdown are described in Sections 7.3 and 7.4, respectively. The manner in which these systems function during events is discussed in each event description. The instrumentation which is required to be available to the operator in order to assist him in evaluating the nature of the event and in determining required action is described in Section 7.5. The use of this instrumentation by the operator is discussed in each event description.

Other systems called upon to function are described in Chapters 6 and 9. The utilization of these systems is specified in the appropriate event description.

Systems which may but are not required to perform safety functions are described in Section 7.7. These include various control systems and the Core Operating Limit Supervisory System (COLSS). In general, normal automatic operation of these control systems is assumed unless manual operation would make the consequences of the event more adverse.

15.0.3 Core and System Performance

15.0.3.1 Mathematical Model

The Nuclear Steam Supply System (NSSS) response to various events was simulated using digital computer programs and analytical methods most of which are documented in Reference 2 and have been approved for use by the NRC in Reference 3.

15.0.3.1.1 Loss of Flow Analysis Method

The method used to analyze events which are initiated by failures which cause a decrease in reactor coolant flowrate is identical to that documented in Reference 32 except that the CESEC-III code was used instead of the CESEC-II code to determine the long term response of the NSSS and the CETOP code was used instead of the TORC code to calculate the DNBR transient. The computer codes employed are CESEC-III (Section 15.0.3.1.3), HERMITE (Reference 17) and CETOP (Reference 29).

15.0.3.1.2 CEA Ejection Analysis Method

The method used for analysis of the reactivity and power distribution anomalies initiated by a CEA ejection (Section 15.4) is documented in Reference 16 and approved by the NRC in Reference 47.

15.0.3.1.3 CESEC Computer Program

The CESEC-III computer program is used to simulate the NSSS (unless specified otherwise for an event). CESEC-III is a version of CESEC which incorporates the ATWS model modifications documented in Reference 8 through 12 and includes additional improvements which extend the range of applicability of the models. CESEC-III explicitly models the steam void formation and collapse in the upper head region of the reactor vessel. It also includes a detailed thermal hydraulic model which explicitly simulates the mixing in the reactor vessel from asymmetric transients, an RCS flow model which calculates the time dependent reactor coolant mass flow rate in each loop, a wall heat model, 3-D reactivity feedback model, a safety injection tank model, and a primary-to-secondary heat transfer model which calculates the heat transfer for each generator node rather than for a steam generator as a whole. The CESEC computer code is documented in References 7 and 27 and approved in Reference 45.

CESEC-III computes key system parameters during a transient including core heat flux, pressures, temperatures, and valve actions. A partial list of the dynamic functions included in this NSSS simulation includes: point kinetics neutron behavior, Doppler and moderator reactivity feedback, boron and CEA reactivity effects, multi-node average thermal hydraulics, reactor coolant pressurization and mass transport, reactor coolant system safety valve behavior, steam generation, steam generator water level, turbine bypass, main steam safety and turbine admission valve behavior, as well as alarm, control, protection, and engineered safety feature systems. The steam turbines, condensers and their associated controls are not included in the simulation. Steam generator feedwater enthalpy and flowrate are provided as input to CESEC-III.

During the course of execution, CESEC-III obtains steady-state and transient solutions to the set of equations that mathematically describe the physical models of the subsystems mentioned above. Simultaneous numerical integration of a set of first-order differential equations with time-varying coefficients is carried out by means of a simultaneous solution. As the time variable evolves, edits of the principal systems parameters are printed at prespecified intervals. An extensive library of the thermodynamic properties of uranium dioxide, water, and zircaloy is incorporated into this program. Through the use of CESEC-III, symmetric and asymmetric plant response over a wide range of operating conditions can be determined.

15.0.3.1.4 COAST Computer Program

The COAST computer program is used to calculate the reactor coolant flow coastdown transient for any combination of active and inactive pumps and forward or reverse flow in the hot or cold legs. The program is described in Reference 13 and was referenced in Reference 2. The program was approved in Reference 46.

The equations of conservation of momentum are written for each of the flow paths of the COAST model assuming unsteady one-dimensional flow of an incompressible fluid. The equation of conservation of mass is written for the appropriate nodal points. Pressure losses due to friction, and geometric losses are assumed proportional to the flow velocity squared. Pump dynamics are modeled using a head-flow curve for a pump at full speed and using four-quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

15.0.3.1.5 STRIKIN-II Computer Program

The STRIKIN-II computer program is used to simulate the heat conduction within reactor fuel rods and its associated surface heat transfer. The STRIKIN-II program is described in Reference 14 and was approved in Reference 47.

The STRIKIN-II computer program provides a single, or dual, closed channel model of a core flow channel to calculate the clad and fuel temperatures for an average or hot fuel rod, and the extent of the zirconium water reaction for a cylindrical geometry fuel rod. STRIKIN-II includes:

- Incorporation of all major reactivity feedback mechanisms,
- A maximum of six delayed neutron groups,
- Both axial (maximum of 20) and radial (maximum of 20) segmentation of the fuel element, and
- Control rod scram initiation on high neutron power.

15.0.3.1.6 TORC and CETOP Computer Programs

The TORC computer program is used to simulate the three-dimensional fluid conditions within the reactor core. The TORC program is described in References 18 and 21 and was referenced in Reference 2. The program was approved in Reference 48.

Results from the TORC program include the core radial distribution of the relative channel axial flow rate that is used to calibrate CETOP, described in Reference 29 and approved in Reference 49. Transient core heat flux and thermal-hydraulic conditions from CESEC are input to CETOP which employs the CE-1 critical heat flux correlation described in Reference 19.

15.0.3.1.7 HERMITE Computer Program

The HERMITE program solves the few-group space- and time-dependent neutron diffusion equation including the feedback effects of fuel temperature, coolant temperature, coolant density and control rod motion. The neutronics equations are solved by a model expansion method (2D & 3D) or a finite difference method (1D). The fuel temperature model explicitly represents the pellet, gap and clad. The heat conduction equations are solved by a finite difference method. The coolant temperature and density are determined from the mass and energy conservation equations. The HERMITE program is described in Reference 17 and was approved in Reference 50.

In the generation of axial shapes in support of the process of preliminary safety analysis, the code employs a two-group steady-state finite difference diffusion theory model in which the fluxes are calculated at mesh boundaries and the cross sections are defined over mesh intervals. 1-D HERMITE uses the 1-D neutronics model from the approved code FIESTA (Reference 53).

The code employs macroscopic cross section models with microscopic cross sections for xenon and soluble boron, cross sections or coefficients for thermal-hydraulic and Doppler feedbacks, and macroscopic cross section changes to simulate control rod insertion. The fuel cross sections, including xenon and feedback terms, are derived from 3-D ROCS solutions (References 51 and 52). The rod cross sections which are modeled as changes in group 1 and 2 absorption, are derived by tuning to match ROCS rod worths.

With 1-D HERMITE, separate cross sections (all feedbacks) are derived from ROCS at each axial level. These axially variant cross sections more accurately reflect different radial flux distributions, nuclide distributions, and other conditions at each level of the 3-D ROCS solution.

In 1-D HERMITE the fuel temperature is first calculated as a function of radially averaged linear heat rate and burnup. Fuel cross section changes which include all cross section types for both groups are then calculated as an axial function of the fuel temperature.

The code integrates the power distribution axially from the bottom of the core to the mid-point of each mesh interval to obtain a local enthalpy. The local enthalpy is converted to moderator density and used for computing cross sections. The code models soluble boron as a moderator density dependent absorber.

The code models a pseudo-hot-pin in which the linear heat rate at each level is a multiple, determined from a radial peaking factor, of the core average linear heat rate at that level. In the code the radial peaking factor is adjusted for the presence of control rods.

The thermal-hydraulics calculation models a number of closed, parallel channels. The mesh used for the thermal calculation may be coarser than the mesh used for the neutronics solution. The code solves the one dimensional continuity and conservation of energy equations, along with the equation of state, for each channel. Axial expansion of the coolant and two phase slip flow are modeled. Water and steam properties are determined from tables based on the ASME steam tables. The core pressure, channel inlet temperatures, and channel inlet flow rates are user-specified. The surface heat flux is found using either the Dittus-Boelter correlation for the forced convection regime or the Jens-Lottes correlation for the nucleate boiling regime.

A single channel average fuel rod is modeled for each flow channel. The model defines three regions within a rod: the fuel pellet, the gap, and the cladding. The fuel and clad regions may be divided into any number of radial nodes.

No heat is generated in the gap or clad although a portion may be deposited directly into the coolant. The thermal properties of the fuel and clad are found as a function of temperature. The density of the fuel is assumed not to change. Gap conductance for steady state initialization is found as a function of linear heat rate. For transient calculations the gap conductance may be found as a function of gap temperature.

15.0.3.1.8 Reactor Physics Computer Programs

Numerous computer programs are used to produce the input reactor physics parameters required by the NSSS simulation and reactor core programs previously described. These reactor physics computer programs are described in Chapter 4.

15.0.3.2 Initial Conditions

The events discussed in this chapter have been analyzed over a range of initial values for the principal process variables. The ranges were chosen to encompass all steady state operational configurations (with the exception of part loop operation).

Analysis over a range of initial conditions is compatible with the monitoring function performed by the COLSS which is described in Section 7.7 and the flexibility of plant operation which the COLSS allows. This flexibility is produced by allowing parameter trade-offs by monitoring the principal process variables, synthesizing the margin to fuel thermal design limits, and displaying to the reactor operator the core power operating limit. The range of values of each of the principal process variables that was considered in analyses of events discussed in this chapter is listed in Table 15.0-3.

15.0.3.3 Input Parameters

The parameters described below and used in the analyses are consistent with those described in the preceding section and with values for the first core and projected for future cycles. If different fuel management plans are adopted in the future, the validity of fuel related input data shall be verified to assure conformity with the analyses herein.

15.0.3.3.1 Doppler Coefficient

The effective fuel temperature coefficient of reactivity (Doppler Coefficient) as shown in Section 4.3 is multiplied by a weighing factor to conservatively account for higher feedback effects in the higher power density portions of the core and to account for uncertainties in determining the actual fuel temperature reactivity effects. The Doppler weighing factor, which is specified for each analysis, is 0.85 for cases where a less negative Doppler feedback produces more adverse results and 1.38 for cases where a more negative Doppler feedback produces more adverse results. The Doppler reactivity functions are used in the Chapter 15 analyses are shown in Tables 15.0-5 and 15.0-6.

The effective fuel temperature correlation is discussed in Section 4.3. This correlation relates the effective fuel temperature, which is used to correlate Doppler reactivity, to the core power.

15.0.3.3.2 Moderator Temperature Coefficient

The events analyzed in this Chapter model moderator reactivity as a function of moderator temperature instead of a moderator temperature coefficient. This method is used in order to more accurately calculate reactivity feedbacks due to the large moderator temperature variations which may occur during these events.

The moderator temperature coefficients corresponding to these moderator reactivity functions range from $0.0 \times 10^{-4}\ \Delta\rho/°F$ to $-3.5 \times 10^{-4}\ \Delta\rho/°F$. These values include all uncertainties, and bound the expected moderator temperature coefficients for all power levels, CEA configurations, and boron concentrations.

The most conservative, allowable value for the moderator temperature coefficient is assumed for each individual analysis.

15.0.3.3.3 Shutdown CEA Reactivity

The shutdown reactivity is dependent on the CEA worth available on reactor trip and the axial power distribution. For most transient analyses, conservative total CEA worths of 8.86 percent and 6.5 percent $\Delta\rho$ were used for hot full power (HFP) and hot zero power (HZP), respectively. For some events, more conservative values were used (i.e., less negative). However, in the case of steam line break events a CEA worth of 10% was used for the full power cases. This worth is consistent with the moderator reactivity versus moderator temperature function used in these analyses (see Section 15.1.5). The foregoing values include uncertainties, the most reactive CEA stuck in the fully withdrawn position, and the effect of temperature on CEA worth for events initiated from HZP (Section 4.3.2.4.3).

The shutdown reactivity worth versus position curve which is employed in the majority of Chapter 15 analyses is shown in Figure 15.0-1 and is applicable for an axial shape with an Axial Shape Index (ASI) of +0.3. This shutdown worth versus position curve yields a conservatively slower rate of negative reactivity insertion than is expected to occur during the majority of operations, including power maneuvering. Accordingly, it is a conservative representation of shutdown reactivity insertion rates for reactor trips which occur as a result of the events analyzed. For some events, a dynamic axial power function is utilized based on the HERMITE Code (see Section 15.0.3.1.7).

15.0.3.3.4 Effective Delayed Neutron Fraction

The effective neutron lifetime and delayed neutron fraction are functions of fuel burnup. For each analysis, the values of the neutron lifetime and the delayed neutron fraction are selected consistent with the time in life analyzed.

15.0.3.3.5 Decay Heat Generation Rate

Analyses assume decay heat generation based upon infinite reactor operation at the initial core power level identified for each event.

15.0.4 Radiological Consequences

The objective of the radiological evaluations is to confirm that the calculated doses from postulated accidents lie within the limits described in 10 CFR 100.11 and/or the applicable NUREG-0800 sections. Doses are dependent, in part, upon the assumed values of radiological atmospheric dilution, χ/Q (see Section 2.3). Values assumed for Chapter 15 analyses were determined using meteorological data representative for 80-90% of existing US reactor sites.

Several of the non-LOCA events discussed in Chapter 15 are accompanied by the release of steam or liquid from the reactor coolant system or main steam system. The CESEC computer code (described in Section 15.0.3.1.3), in combination with hand calculations, were used to determine the mass and energy releases as a function of time.

[[The Combined License Applicant for each site will calculate site specific χ/Q using the meteorology, exclusion area boundary and low population zone for that particular site to show that the χ/Qs assumed in the Chapter 15 analyses are bounding.]][2]

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2 COL information item; see DCD Introduction Section 3.2.

These data are used as input to the calculation of radiological release to the atmosphere for determining thyroid and whole body doses at the exclusion area boundary and the low population zone boundary.

Radiation released from the primary coolant may include radiation initially in the coolant and also radiation added to the coolant if the fuel cladding fails. For Chapter 15 design basis events resulting in a violation of the DNBR SAFDL limit, the number of failed rods is calculated by the statistical convolution method described in Reference 4 and approved by the NRC in Reference 54. This method assigns a probability of occurrence of DNB as a function of the DNBR. This statistical convolution technique involves the summation over the reactor core of the number of rods with a specific DNBR times the probability of DNB at that DNBR.

Justification of the applicability of the statistical convolution method to the System 80+™ design is based on the following. The convolution methodology is independent of the core design, however certain inputs to the method do have dependence. These inputs are the Probability of DNB versus DNBR curve, the relationship betw en minimum DNBR and the integrated radial peaking factor, and the pin census i.e. the number of fuel pins in a given interval of integrated radial peaking factor. The probability of DNB versus DNBR curve used in the analyses is based on the ABB 16x16 fuel and fuel grid designs which are also used in the System 80+ design. The minimum DNBR versus integrated radial peaking factor relationship was developed for each Chapter 15 analysis resulting in fuel failure. This relationship was developed using NRC-approved computer codes that utilize the CE-1 Critical Heat Flux Correlation which is applicable to the System 80+ fuel design. Thus, the DNBR versus integrated radial peaking factor relationship was developed specifically for System 80+ events. The pin census applicability is justified since it is part of the plant specific physics input for the System 80+ core design. Therefore, the statistical convolution method is applicable to the System 80+ design.

The methodology utilized for calculation of radiological releases to the atmosphere, and for determining thyroid and whole body doses at the exclusion area boundary and the low population zone boundary as well as control room doses is presented in Appendix 15A.

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Table 15.0-1 Chapter 15 Subsection Designation

Each subsection is identified as 15.W.X.Y, where:		
W =	1	Increase in heat removal by the secondary system
	2	Decrease in heat removal by the secondary system
	3	Decrease in reactor coolant system flow rate
	4	Reactivity and power distribution anomalies
	5	Increase in reactor coolant inventory
	6	Decrease in reactor coolant inventory
	7	Radioactive release from a subsystem or component 1,2, etc.
X =	1, 2, etc.	Event Title from Reference 26
Y =	1	Identification of Event and Causes
	2	Sequence of Events and Systems Operation
	3	Analysis of Effects and Consequences
	4	Conclusions

Table 15.0-2 Reactor Protection System Trips Used in the Safety Analysis

Event	RPS	Analysis Setpoint[1]	Reactor Trip Total Response Times[2]
Events not Mentioned Below	High logarithmic Power Level	0.05%	550 ms
	Variable Overpower	119%[3]	550 ms
	CPC Variable Overpower	115%	550 ms
	High Pressurizer Pressure	2434 psia	1150 ms
	Low Pressurizer Pressure	1705 psia	1150 ms
	Low Steam Generator Pressure	781 psia	1150 ms
	Low Steam Generator Water Level	40.7% wide range[4]	1200 ms
	High Steam Generator Water Level	95% narrow range[5]	1150 ms
	Steam Generator ΔP Low Flow	80%[6]	[8]
	CPC Low RCP Shaft Speed	95%	300 ms
	CPC Coincident Low Pressure/DNBR	2015 psia/1.4[7]	1150 ms
Feedwater and Steam Line Breaks	High Pressurizer Pressure	2475 psia	1150 ms
	Low Pressurizer Pressure	1555 psia	1150 ms
	Low Steam Generator Pressure	719 psia	1150 ms
	Low Steam Generator Water Level	33.7% wide range[4]	1200 ms
	High Steam Generator Water Level	95% narrow range[6]	1150 ms
	CPC Low RCP Shaft Speed	95%	300 ms
	CPC Variable Overpower	115%	550 ms

[1] Some Chapter 15 analyses assumed more conservative setpoints for specific events.

[2] Reactor Protection System response time testing is discussed in Section 7.2.

[3] See discussion in Section 7.2.

[4] Percent of distance between the wide range instrument taps. See chapter 5 for details. Setpoint is valid at full power only (i.e., 100-102% power).

[5] Percent of distance between the narrow range instrument taps. See Chapter 5 for details.

[6] Percent of hot leg flow.

[7] Trip credited for 15.6.2 and 15.6.3 events.

[8] 1.2 seconds from time of occurrence of low flow trip condition until the reactor trip breakers open.

Table 15.0-3 Initial Conditions

Parameter	Units	Range
Core Power	% of 3914 MWt	0 - 102
Axial Shape Index	--	$-0.3 \leq \text{ASI} \leq +0.3$[1]
Reactor Vessel Inlet Coolant Flow Rate	% of 445600 gpm	95 - 116
Pressurizer Water Level	% distance (between upper tap and lower tap) above lower tap	26 to 60
Core Inlet Coolant Temperature <90% Power 90%-100% Power	 °F °F	 543 - 561 550 - 561
Pressurizer Pressure	psia	2175 - 2325
Steam Generator Water Level Low Level High Level	 % Wide Range[2] % Narrow Range[3]	 33.7[4] 40.7 95.0

Notes:

[1] ASI = $(A - B) \div C$
where: A = Area under axial shape in lower half of core
B = Area under axial shape in upper half of core
C = Total area under axial shape

[2] Percent of distance between the wide range instrument taps. See Chapter 5 for details.

[3] Percent of distance between the narrow range instrument taps. See Chapter 5 for details.

[4] For steam and feedwater line breaks only.

Table 15.0-4 Single Failures

Steam Bypass Control System	
1.	Failure to Modulate Open
2.	Failure to Quick Open
3.	One Bypass Valve Fails to Quick Close
4.	Excessive Steam Bypass Flow
5.	Failure to Generate Automatic Withdrawal Prohibit Signal During Steam Bypass Operation
6.	Failure to Generate the Reactor Power Cutback Signal
Reactivity Control Systems	
7.	Regulating Group(s) Fail(s) to Insert or Withdraw
8.	A Single CEA Stuck[1]
9.	A CEA Subgroup Stuck[1]
10.	Failure to Initiate or Execute the Reactor Power Cutback
11.	CEAs Withdraw upon Automatic Withdrawal Prohibit and/or CEA Withdrawal Prohibit
Feedwater Control System	
12.	Failure of Reactor Trip Override
13.	Failure of High Level Override
Turbine-Generator Control System	
14.	Setback w/o Cutback
15.	Failure to Modulate the Turbine Control Valves
16.	Failure to Setback Given a Cutback (100% $\geq$ Initial Power > 75%)
17.	Failure to Setback (75% $\geq$ Initial Power $\geq$ 60%)
18.	Failure to Runback (60% > Initial Power)
19.	Failure to Trip the Turbine

[1] Control Element Drive Mechanism does not respond to control signal. Release of CEA(s) on trip is not inhibited.

Table 15.0-4 Single Failures (Cont'd.)

Pressurizer Pressure Control System (PPCS)	
20.	Failure of Spray Control Valves to Open
21.	Failure of Spray Control Valves to Close
22.	Failure of Backup Heaters to Turn On
23.	Failure of Backup Heaters to Turn Off
24.	Failure of Proportional Heaters to Turn Off
Pressurizer Level Control System	
25.	Charging Flow Control Valve Fails to Open
26.	Charging Flow Control Valve Fails to Close
27.	Letdown Flow Control Valve Fails to Close
28.	Letdown Flow Control Valve Fails to Open
Main Feedwater System	
29.	One MFIV Fails to Close
30.	One Back-flow Check Valve Fails to Close
Main Steam System	
31.	One MSIV Fails to Close
32.	One Atmospheric Dump Valve Fails to Open
33.	One MSSV Closes Below Blowdown Pressure
34.	One Atmospheric Dump Valve Fails to Reclose
Emergency Feedwater System	
35.	Failure of Any One Emergency Feed Pump to Start
Safety Injection System	
36.	Failure of One SI Pump
Electrical Power Sources	
37.	Failure of One Emergency Generator to Start, Run, or Load (Two SI pumps are powered from one Emergency Generator.)
Interactive Control System Failures	
38.	Loss of CEDMC Reactor Tripped Signal

Table 15.0-5 Reactivity versus Fuel Temperature Corresponding to Least Negative Doppler Coefficient

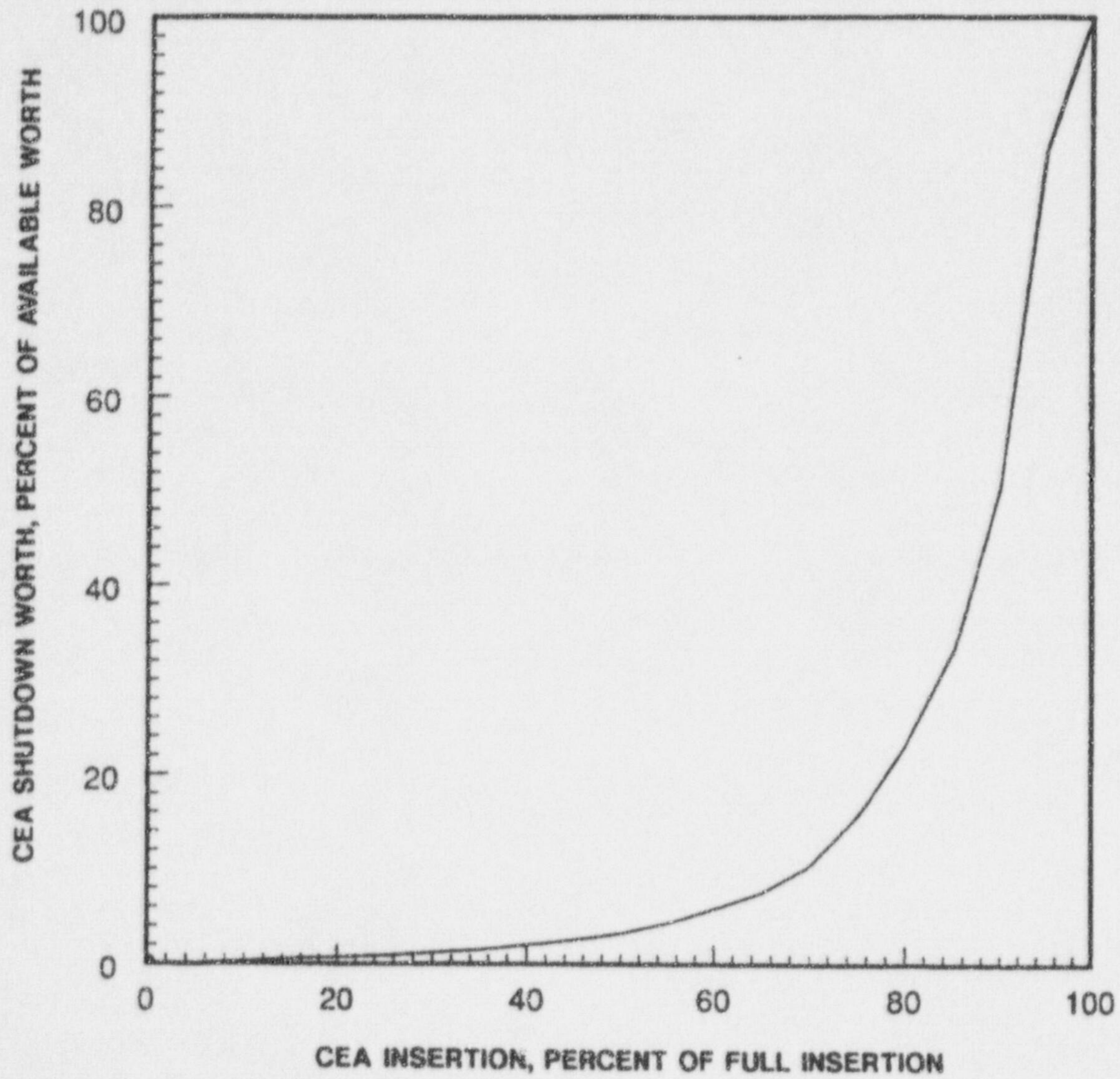
Fuel Temperature (°F)	Reactivity [1] (% $\Delta\rho$)
100	1.736
300	1.355
500	1.003
1000	0.235
1056	0.157
1500	-0.411
2000	-0.978
2500	-1.511
3000	-2.053

Table 15.0-6 Reactivity versus Fuel Temperature Corresponding to Most Negative Doppler Coefficient

Fuel Temperature (°F)	Reactivity[2] (% $\Delta\rho$)
100	0.548
300	0.059
500	-0.381
1000	-1.320
1056.07	-1.414 @ 100% Power
1500	-2.113
2000	-2.870
2500	-3.700
3000	-4.714

[1] For least negative with bias and uncertainty, multiply % $\Delta\rho$ by 0.85.

[2] For most negative with bias and uncertainty, multiply % $\Delta\rho$ by 1.38.



CEA Shutdown Worth vs. CEA Position	Figure 15.0-1

15.1 Increase in Heat Removal by the Secondary System

15.1.1 Decrease in Feedwater Temperature

15.1.1.1 Identification of Event and Causes

A decrease in feedwater temperature may result from a loss of feedwater heaters. The feedwater heaters may be lost due to isolation of one of the high pressure feedwater heater trains. The maximum feedwater temperature decrease due to a failure in the main feedwater system is less than 100°F.

15.1.1.2 Sequence of Events and Systems Operation

A decrease in feedwater temperature causes a decrease in the temperature of the reactor coolant, an increase in reactor power due to the negative moderator temperature coefficient, and a decrease in the reactor coolant system (RCS) and steam generator pressures. Detection of these conditions is accomplished by the RCS and steam generator low pressure alarms and the high linear power alarm. If the transient were to result in an approach to specified acceptable fuel design limits, trip signals generated by the core protection calculators would assure that low departure from nucleate boiling ratio (DNBR) or high local power density limits are not exceeded.

15.1.1.3 Analysis of Effects and Consequences

Analysis of the most adverse decrease in feedwater temperature event shows that the minimum transient DNBR for this event and for this event with a loss of offsite power concurrent with reactor/turbine trip is greater than that for the inadvertent opening of a steam generator atmospheric dump valve (IOSGADV) event and for the IOSGADV event with a loss of offsite power concurrent with reactor/turbine trip, respectively, which are presented in Section 15.1.4. Likewise, these events in combination with the limiting single failure result in events less limiting than the IOSGADV event and the IOSGADV event with a loss of offsite power in combination with the limiting single failure, respectively, which are also presented in Section 15.1.4.

All increased heat removal events analyzed in this section are characterized by decreasing RCS pressure due to the cooldown of the primary system. Thus, the events of this section will result in an insignificant increase in RCS pressure.

15.1.1.4 Conclusions

The decreased feedwater temperature events result in DNBRs greater than 1.24 throughout the transient. Also, the RCS pressures remain well below 2750 psia, and the steam generator pressures remain below 1320 psia.

15.1.2 Increase in Feedwater Flow

15.1.2.1 Identification of Event and Causes

An increase in main feedwater flow could be caused by the further opening of a feedwater control valve or an increase in feedwater pump speed. The maximum increase at full power is less than 60% above nominal for the main feedwater system.

In addition, an increase in feedwater flow could be caused by the inadvertent actuation of an emergency feedwater pump. The maximum flow of 800 gpm, however, is equivalent to less than a 10% increase in main feedwater flow, including the effect of the lower enthalpy of the emergency feedwater.

15.1.2.2 Sequence of Events and Systems Operation

An increase in feedwater flow causes a decrease in the temperature of the reactor coolant, an increase in reactor power due to the negative moderator temperature coefficient, a decrease in the RCS and steam generator pressures and an increase in steam generator water level. Detection of these conditions is accomplished by the RCS low pressure alarm and steam generator low pressure and high water level alarms. Protection against the violation of specified acceptable fuel design limits, as a consequence of an increase in feedwater flow, is provided by the CPC variable overpower and the high steam generator water level trips. Protection against high steam generator water level is provided by the high steam generator water level trip.

15.1.2.3 Analysis of Effects and Consequences

Analysis of the spectrum of possible excess feedwater flows shows that the minimum transient DNBR for this event and for this event with a loss of offsite power concurrent with reactor/turbine trip is greater than that for the inadvertent opening of a steam generator atmospheric dump valve (IOSGADV) event and for the IOSGADV event with a loss of offsite power concurrent with a reactor/turbine trip, respectively, which are presented in Section 15.1.4. Likewise, these events in combination with the limiting single failure result in events less limiting than the IOSGADV event and the IOSGADV event with a loss of offsite power in combination with the limiting single failure, respectively, which are also presented in Section 15.1.4.

All increased heat removal events analyzed in this section are characterized by decreasing RCS pressure due to the primary system cooldown. Thus, the events of this section will result in an insignificant increase in RCS pressure.

15.1.2.4 Conclusions

The increased feedwater flow events result in DNBRs greater than 1.24 throughout the transient. Also, the RCS pressure remains below 2750 psia, and the steam generator pressures remain below 1320 psia.

15.1.3 Increased Main Steam Flow

15.1.3.1 Identification of Event and Causes

An increase in main steam flow may be caused by an inadvertent increased opening of the turbine admission valves. This may be caused by operator error or turbine load limit malfunctions and will result in no more than a 10% increase over the nominal full power steam flow rate. An increase in main steam flow can also result from the inadvertent opening of a turbine bypass valve or an atmospheric dump valve; however, these events are discussed separately in Section 15.1.4.[1]

15.1.3.2 Sequence of Events and Systems Operation

An increase in main steam flow causes a decrease in the temperature of the reactor coolant, an increase in core power and heat flux, and a decrease in reactor coolant system and steam generator pressures. Detection of these conditions is accomplished by the RCS and steam generator low pressure alarms and the high reactor power alarm. If the transient were to result in an approach to specified acceptable fuel design limits, trip signals generated by the core protection calculators would assure that low departure from nucleate boiling ratio (DNBR) or high local power density limits are not exceeded.

15.1.3.3 Analysis of Effects and Consequences

A comparison of the RCS temperatures shows that the maximum RCS temperature decrease for the increased main steam flow event is identical to that for the inadvertent opening of a steam generator atmospheric dump valve (IOSGADV) event. This is due to the fact that both events cause an increase in main steam flow of no more than 11%. Thus, the resultant power increase and the subsequent DNBR transient are also identical. Therefore, the systems operation described above will be similar to the IOSGADV event presented in Section 15.1.4. Also, the systems operation for the Increased Main Steam Flow event with a loss of offsite power will be similar to the IOSGADV event with a loss of offsite power, presented in Section 15.1.4. These events in combination with the limiting single failure are no more severe than the IOSGADV event and the IOSGADV with loss of offsite power event, combined with the limiting single failure, respectively, which are also presented in Section 15.1.4.

All increased heat removal events analyzed in this section are characterized by decreasing RCS pressure due to the cooldown of the primary system. Thus, the events of this section will show an insignificant increase in RCS pressure.

15.1.3.4 Conclusions

The increased main steam flow events result in DNBR greater than 1.24 throughout the transient. Also, the RCS pressure remains well below 2750 psia, and the steam generator pressures remain below 1320 psia.

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1 Two incidents at an operating plant in which multiple inservice turbine bypass valves opened due to a single failure resulted from the electrical cross-connection of multiple instrument signal loops in the Balance of Plant (BOP) portion of the instrumentation system. NSSS interface requirements documents required that independent signals be input to the Steam Bypass Control system (SBCS). In both cases, a common connection between input signals existed, which was not consistent with the NSSS interface requirements. The System 80+ design scope includes the portions of instrument signal loop interfaces which were BOP scope for System 80. Common connections do not exist in the System 80+ design. Hence, there is no need for analysis of a postulated fail open event of all turbine bypass valves due to a single malfunction in the electrical system.

15.1.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

15.1.4.1 Identification of Event and Causes

An atmospheric dump valve (ADV) or a turbine bypass valve may be inadvertently opened by the operator or may open due to a failure of the control system which operates the valve. A steam generator safety valve will remain open only as a result of a valve failure. The opening of any of these valves will result in similar consequences because they relieve steam at the same maximum flow rate (no more than 11% of full power turbine flow rate). The inadvertent opening of a steam generator atmospheric dump valve (IOSGADV) is presented here to illustrate these events. As discussed in the previous sections, the consequences of the IOSGADV event bound those of the increased main steam flow, decrease in feedwater temperature, and increase in feedwater flow events. For the events of this section, the major parameter of concern is the minimum hot channel DNBR. This parameter establishes whether a fuel design limit has been violated and thus whether fuel cladding degradation might be anticipated. Those factors which cause a decrease in local DNBR are:

- Increasing coolant temperature
- Decreasing coolant pressure
- Increasing local heat flux (including radial and axial power distribution effects)
- Decreasing coolant flow

The single failure (SF) which yields the minimum transient hot channel DNBR is the SF which combines the greatest decrease in DNBR after initiation of a reactor trip signal with the lowest possible pre-trip DNBR.[2] An evaluation of the SFs listed in Table 15.0-4 shows that the limiting SF for the event of this section is the loss of the Feedwater Control System (FWCS) reactor trip override (RTO). As a result, the feedwater flow is not reduced after reactor trip. This single failure results in the most severe DNBR transient for this event.

In addition, it is assumed that the most reactive CEA is held in the fully withdrawn position following reactor trip.

The earlier analysis of the ISOGADV event considered LOOP as a single failure. The final analysis was performed in compliance with GDC-17 and considered LOOP in addition to a SF. The LOOP is assumed to result due to the turbine generator trip and occurs with no time delay.

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[2] The determination of a single failure is based upon the failure which creates the most limiting scenario for the given transient, regardless of whether the system is safety related or not. Thus, in consideration of the inadvertent opening of a steam generator ADV with a single failure event, the most limiting single failure is as noted here.

15.1.4.2 Sequence of Events and Systems Operation

Ca: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power

The opening of a steam generator ADV increases the rate of heat removal by the steam generators, causing cooldown of the RCS. Due to the negative moderator temperature coefficient, core power increases from the initial value of 102% of rated core power, reaching a new stabilized value of 115%. The feedwater control system, which is assumed to be in the automatic mode, supplies feedwater to the steam generators such that steam generator water levels are maintained. Acting upon the large power mismatch between the reactor and turbine and the audible indication of steam blowdown, the reactor operator recognizes that the plant is in an abnormal state and manually trips the reactor. The analysis presented herein assumes this initial operator action is delayed until after 30 minutes following the first indication of the event. It is also conservatively assumed that a loss of offsite power (LOOP) occurs immediately upon turbine trip. The reactor coolant pumps are therefore assumed to begin coasting down at the time of turbine trip.

Following the generation of a turbine trip on reactor trip and concurrent LOOP, normal feedwater flow is terminated. Since the steam bypass control system is assumed to be in the manual mode with all bypass valves closed, the main steam safety valves (MSSVs) open to limit secondary system pressure and remove heat stored in the core and RCS. The water level of both steam generators decreases following reactor trip and falls below the point for emergency feedwater flow initiation. The secondary system pressure then decreases due to the cooldown caused by flow through the MSSVs and the ADV and the MSSVs close. The secondary system pressure continues to decrease to the point where a main steam isolation signal (MSIS) is generated. This causes one steam generator to be isolated from the flow path through the open ADV and causes main feedwater flow to be terminated. During the period of blowdown following reactor trip, reactor coolant temperatures and pressure decrease slowly. After dryout of the affected steam generator, decay heat and heat addition from the walls and structure of the primary coolant system cause a gradual increase in reactor coolant temperatures and pressure. Relief of steam by the safety valves on the unaffected steam generator provides cooling which limits reactor coolant temperatures. Reactor coolant pressure is limited by the pressurizer safety valves.

Subsequent to tripping the reactor, the operator manually closes the ADV which had been inadvertently opened, terminating steam release to the atmosphere from the affected steam generator. In the analysis presented herein it is conservatively assumed that this action to close the ADV is delayed 20 minutes beyond the operator's initial action to trip the reactor, or a total of 50 minutes after event initiation. RCS heat removal for plant stabilization and cooldown is accomplished by using the ADV valves. The operator is assumed to initiate plant cooldown 30 minutes after he manually trips the reactor.

Case 2: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve with Loss of Feedwater Control System Reactor Trip Override (IOSGADV + SF) and with a Loss of Offsite Power.

Up until the time of the assumed reactor trip, the transient due to the IOSGADV is identical with or without SF. For the IOSGADV + SF, the reactor is manually tripped 30 minutes following the first indication of the event. It is also conservatively assumed that a loss of offsite power (LOOP) occurs immediately upon turbine trip. The reactor coolant pumps are therefore assumed to begin coasting down at the time of turbine trip. Due to the single failure assumed the feedwater control system does not receive the reactor trip override (RTO) signal to cut back feedwater flow. Therefore, primary and secondary pressures continue to decrease and the MSSVs do not open. Primary pressure and temperatures decrease more rapidly following trip with the SF and main steam isolation also occurs earlier, terminating feedwater flow. However, shortly thereafter, emergency feedwater flow is initiated. During the period of blowdown following reactor trip, reactor coolant temperatures and pressure decrease slowly until the safety injection setpoint is reached. Safety injection delivery collapses the reactor vessel upper head (RVUH) void and refills the pressurizer, gradually increasing the reactor coolant pressure. Relief of steam by the safety valves on the unaffected steam generator provides cooling which in turn maintains natural circulation flow through the core and limits reactor coolant temperatures. Reactor coolant pressure is limited by the pressurizer safety valves.

Acting upon a variety of indications--including the initial large power mismatch between the reactor and turbine, the steady decrease in steam generator pressures and water levels after reactor trip, the continued decrease in pressure and level in the affected steam generator after MSIS, the low steam generator pressure and water level alarms, and the audible indication of steam blowdown--the reactor operator diagnoses the incident and manually closes the ADV which had been inadvertently opened, terminating steam release to the atmosphere from the affected steam generator. The analysis presented herein assumes that this initial operator action to close the open ADV is delayed until 20 minutes beyond the operator's initial action to trip the reactor, or a total of 50 minutes after event initiation. RCS heat removal for plant stabilization and cooldown is accomplished by manual control of the ADVs on the unaffected steam generator. The operator is assumed to initiate plant cooldown 30 minutes after he manually trips the reactor.

15.1.4.3 Analysis of Effects and Consequences

- Mathematical Model

The nuclear steam supply steam (NSSS) response to the IOSGADV and the IOSGADV + SF with and without loss of offsite power were simulated using the CESEC-III computer program described in section 15.0.3. The time-dependent thermal margins on DNBR in the reactor core were calculated using the CETOP-D computer program (see Section 15.0.3.1.6) which uses the CE-1 critical heat flux correlation described in Reference 19 of Section 15.0.

- Input Parameters and Initial Conditions

Table 15.1.4-3 lists the assumptions and initial conditions used for these analyses in addition to those discussed in section 15.0. The initial conditions for the principal process variables were varied to determine the set of initial conditions which would produce the greatest overpower condition caused by the increase in steam flow. If core power increases to more than 115%, the Core Protection Calculators (CPC) will initiate a reactor trip and there will be no further degradation in thermal margin.

- Results

Case 1: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power.

The dynamic behavior of the salient NSSS parameters following the IOSGADV is presented in Figures 15.1.4-1.1 through 15.1.4-1.15. Table 15.1.4-1 summarizes the major events, times and results for this transient.

The opening of an ADV increases the rate of heat removal by the steam generators causing cooldown of the RCS. Due to the negative moderator reactivity coefficient, core power increases from 102% of rated core power, reaching a new, stabilized value of 115%. The feedwater control system, which is assumed to be in the automatic mode supplies feedwater to the steam generators such that the steam generator water levels are maintained.

During the IOSGADV transient, a DNBR of 1.36 occurs just before the operator manually trips the reactor at 1800 seconds. At 1800.22 seconds the steam generator water level reaches the emergency feedwater actuation setpoint and emergency feedwater delivery begins within 60 seconds. At 1800.55 seconds the trip breakers open, turbine trip is initiated, loss of offsite power is assumed to occur and the RCPs begin to coast down. Due to the RCPs coastdown, the transient DNBR decreases, reaching a minimum value of 1.30 at 1801.96 seconds and then rapidly increases as shown in Figure 15.1.4-1.15. From 1805 seconds to 1845 seconds the MSSVs release steam. At 1919.46 seconds a void begins to form in the RV upper head.

At 2050.4 seconds the steam generator pressure drops below the MSIS setpoint of 719 psia. The MFIVs and MSIVs close by 2056.75 seconds. Safety injection is initiated at 2115.5 seconds. The affected steam generator dries out at 2154.6 seconds. At 3000 seconds the operator manually closes the open ADV. The operator initiates plant cooldown at 3600 seconds.

Case 2: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve with Loss of the Feedwater Control System Reactor Trip Override (IOSGADV + SF) and with Loss of Offsite Power.

The dynamic behavior of the salient NSSS parameters following IOSGADV with loss of offsite power and with loss of the Feedwater Control System Reactor Trip Override is presented in Figures 15.1.4-2.1 through 15.1.4-2.15. Table 15.1.4-2 summarizes the major events, times and results for this transient.

The opening of an ADV increases the rate of heat removal by the steam generators causing cooldown of the RCS. Due to the negative moderator reactivity coefficient core power increases from 102% of rated core power, reaching a new, stabilized value of 115%. The feedwater control system, which is assumed to be in the automatic mode, supplies feedwater to the steam generators such that the steam generator water levels are maintained.

During the IOSGADV + SF transient the operator manually trips the reactor at 1800 seconds, at which time the DNBR is 1.36. At 1800.55 seconds the trip breakers open, turbine trip is initiated, loss of offsite power is assumed to occur and the RCPs begin to coast down. At 1800.6 seconds the steam generator water level reaches the emergency feedwater actuation setpoint and emergency feedwater delivery begins within 60 seconds. Due to the RCPs coastdown, the transient DNBR decreases, reaching a minimum value of 1.29 at 1802.15 seconds and then rapidly increases as shown in Figure 15.1.4-2.15. The IOSGADV event plus the limiting SF does not result in fuel pins in DNB. Voids begin to form in the upper head of the reactor vessel at 1829.76 seconds.

At 1841.8 seconds the steam generator pressure drops below the MSIS setpoint of 719 psia. The MFIVs and the MSIVs close by 1848.15 seconds. Safety injection is initiated at 1913.4 seconds.

At 3000 seconds the operator manually closes the open ADV. The operator initiates plant cooldown at 3600 seconds.

15.1.4.4 Conclusions

The IOSGADV events result in a DNBR greater than 1.24 throughout the transient. These events in combination with the limiting SF (IOSGADV + SF), also do not result in any fuel pins being predicted to be in DNB. For all cases, the RCS pressure remains well below 2750 psia, ensuring that the integrity of the RCS is maintained, and the steam generator pressure remains below 1320 psia ensuring that the integrity of the secondary system is maintained.

15.1.5 Steam System Piping Failures Inside and Outside Containment

15.1.5.1 Identification of Event and Causes

A steam line break (SLB) is defined as a pipe break in the main steam system. SLB cases are chosen to maximize potential for a post-trip return to power, to maximize potential for degradation in fuel cladding performance, and to maximize dose at the site Exclusion Area Boundary. The results show that fission power levels remain sufficiently low following reactor trip to preclude degradation in fuel performance as a result of post-trip return to power, that there is no degradation in fuel performance prior to trip, that the core will remain in place and intact with no loss of core cooling capability, and that doses are within 10 CFR 100 guidelines. The steam line breaks presented are:

- Cases chosen to maximize potential for a post-trip return to power:

    1. A large steam line break inside containment during full power operation with concurrent loss of offsite power in combination with a single failure and a stuck CEA (SLBFPLOP).

2. A large steam line break inside containment during full power operation with offsite power available in combination with a single failure and a stuck CEA (SLBFP).

3. A large steam line break inside containment during zero power operation with concurrent loss of offsite power in combination with a single failure and a stuck CEA (SLBZPLOP).

4. A large steam line break inside containment during zero power operation with offsite power available in combination with a single failure and a stuck CEA (SLBZP).

- Cases chosen to maximize potential for degradation in fuel performance and dose at the site Exclusion Area Boundary:

5. A steam line break outside of containment upstream of the main steam isolation valve (MSIV) during full power operation with loss of offsite power concurrent with reactor/turbine trip in combination with a single failure, Technical Specification steam generator tube leakage, and a stuck CEA (SLBFPLOPD).

6. A steam line break outside of containment upstream of the MSIV during zero power operation with concurrent loss of offsite power in combination with a single failure, Technical Specification steam generator tube leakage, iodine spike, and a stuck CEA (SLBZPLOPD).

Steam line breaks outside of containment upstream of the main steam isolation valve (MSIV) during full power operation with concurrent loss of offsite power or with no loss of offsite power in combination with a single failure, steam generator tube leakage at the allowable limit of the Technical Specifications, and a stuck CEA are not presented because the event consequences are bounded by the full power event which is presented (case 5). The case with loss of offsite power concurrent with reactor/turbine trip bounds all other cases because it presents the greatest degradation of DNBR and, hence, the greatest potential for large radiological doses.

A steam line break outside of containment upstream of the MSIV during zero power operation with offsite power available in combination with a single failure, steam generator tube leakage at the allowable limit of the Technical Specifications and a stuck CEA produced the same radiological dose results as the corresponding case without offsite power (case 6). Both cases resulted in doses which are a small fraction of 10CFR100 guidelines. In addition, the zero power cases are bounded by the full power SLB outside of containment case.

The largest possible steam line break size is the double ended rupture of a steam line upstream of the MSIV. In the System 80+ Standard Design, an integral flow restrictor exists in each steam generator outlet nozzle. The largest effective steam blowdown area for each steam line, which is limited by the flow restrictor throat area, is approximately 30% of the steam line cross-section area, or 1.28 square feet.

These SLB events are analyzed in two ways. The first set of analyses maximizes post-trip degradation in DNBR. The second set maximizes pre-trip degradation in DNBR. For the first set (SLB cases 1 through 4), the initial conditions are adjusted to maximize the post-trip degradation in fuel performance (i.e., near the time of maximum reactivity, which occurs several minutes after reactor trip). For these cases, there is no post-trip return to power and as a result, the DNBR during this time interval of maximum reactivity does not approach the DNBR limit. However, there is a potential for violating the transient DNBR limit during the pretrip time period. However, the second set of SLB analyses yield more adverse results since the initial conditions are adjusted to maximize the event consequences at that time. The second set of analyses are the pre-trip cases. These are specifically analyzed to maximize the potential for fuel damage near the time of reactor trip.

The earlier analysis of the pre-trip case considered the scenarios of the event with and without the loss of offsite power (LOOP). The limiting scenario was determined to be the one without LOOP. The analysis scenario with LOOP assumed the LOOP to occur coincidentally with the steam pipe break.

The final pre-trip analysis was performed in compliance with GDC-17, i.e. considering the event with and without LOOP. The limiting case analysis presented assumes that LOOP which results from turbine generator trip occurs with no time delay (see Section 15.0.1.4).

In the final post-trip analysis it is additionally assumed that the turbine admission and turbine control valves fail to close for the full power case with offsite power available (case 2), resulting in an increased steam flow from the intact steam generator.

15.1.5.2 Sequence of Events and Systems Operation

Steam line breaks are characterized as cooldown events due to the increased steam flow rate, which causes excessive energy removal from the steam generators and the reactor coolant system (RCS). This results in a decrease in reactor coolant temperatures and in RCS and steam generator pressure. The cooldown causes an increase in core reactivity due to the negative moderator and Doppler reactivity coefficients.

Detection of the cooldown is accomplished by the pressurizer and steam generator low pressure alarms, by the high reactor power alarm and by the low steam generator water level alarm. Reactor trip as a consequence of a steam line break is provided by one of several available reactor trip signals including low steam generator pressure, low RCS pressure, low steam generator water level, high reactor power, low DNBR trip initiated by the core protection calculators and, for inside containment breaks, high containment pressure. For a SLB that occurs with a concurrent loss of offsite power, the events of turbine stop valve closure, termination of feedwater to both steam generators and coastdown of the reactor coolant pumps are assumed to be initiated simultaneously. Following reactor trip, the most reactive control rod is conservatively assumed to be held in the fully withdrawn position. To maximize the primary system cooldown, it is assumed that emergency feedwater is immediately activated to both steam generators.[3] The depressurization of the affected steam generator results in the actuation of a main steam isolation signal (MSIS). This closes the MSIVs, isolating the unaffected steam generator from blowdown and closes the main feedwater isolation valves (MFIVs), terminating main feedwater flow to both steam generators. The pressurizer pressure decreases to the point where a Safety Injection Actuation Signal (SIAS) is initiated. The introduction of safety injection boron upon SIAS causes core reactivity to decrease. The operator, via the appropriate emergency procedures, may initiate plant cooldown by manual control of the atmospheric steam dump valves, or, in the event that offsite power is available, by using the MSIV bypass valves associated with the unaffected steam generator and the turbine bypass valves.

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[3] A manually actuated emergency feedwater (EFW) isolation system was selected for System 80+, as opposed to automatic system actuation on high steam generator differential pressure, after a design reassessment, prompted by Generic Safety Issue (GSI) 125.II.-07 in NUREG-0933, was conducted. A manual isolation system significantly simplifies the EFW actuation logic and was found to have an acceptable effect on the safety analyses. A discussion of the effects of this design change is provided in Chapter 20.

The analysis presented herein conservatively assumes operator action is delayed until 30 minutes after first indication of the event. The plant is then cooled to 350°F and 330 psia, at which point shutdown cooling is initiated.

Table 15.1.5-11 provides the results of a parametric study of single failures that would have an adverse impact on the SLB. This table demonstrates that the failure of one of the emergency diesel generators to start on loss of offsite power and the consequent loss of two safety injection (SI) pumps following SIAS has the most adverse effect for the full and zero power cases with concurrent loss of offsite power (Cases 1 and 3). Consequently, two SI pumps are conservatively assumed to fail for these cases. The evaluation shows that for the full and zero power SLB without loss of offsite power (Cases 2 and 4) the most adverse effect is caused by failure of a MSIV on one of the steam lines on the intact generator to close following MSIS. Consequently for these cases steam is assumed to continue to be released from the intact steam generator after MSIS.

For full power Case 2 the turbine admission and turbine control valves are also assumed to fail to close. The analysis conservatively assumes, therefore, that flow continues from the intact steam generator through the full area of the steam generator outlet nozzle for one steam line (1.28 square feet).

For zero power Case 4 the turbine admission and control valves are closed prior to event initiation and the flow from the intact steam generator is assumed to be at a rate consistent with the interface requirement of a maximum of 11% design steam flow rate non-isolable steam flow. This open flow path is represented by an effective flow area for steam blowdown from the intact steam generator of 0.2663 square feet.

For Case 5 (SLBFPLOPD), there is no single failure which increases the potential for degradation in fuel cladding performance or which increases the offsite dose. The radiological consequences of the SLB outside containment upstream of the MSIV would not be affected by the failure of a main steam isolation valve in the intact steam generator. The radiological consequences for this event conservatively assume that after the ruptured steam generator blowdown ends, the plant heats up to hot standby (561°F) after which the operator initiates an orderly cooldown to shutdown cooling entry conditions by releasing steam to the environment through the ADVs. If an MSIV in the intact steam generator were to fail, then the steam releases to the environment would be less than those calculated without the failure since the plant would not heat back up to hot standby conditions. Therefore, the sensible heat to be removed from the RCS to achieve shutdown cooling conditions would be lower. Hence, the radiological consequences would be reduced. Further, if the turbine were to fail to trip (i.e. the turbine stop valves were to fail to close) there would be no initiator for the loss of offsite power which is assumed to occur due to and coincident with the turbine trip. Without a loss of offsite power, the transient minimum DNBR would be higher and the event consequently less adverse.

The steam generator level for Case 5 is initially at the low steam generator level trip. If the feedwater control system is in the automatic mode, the plant would be at the normal water level, consequently, with a larger steam generator inventory, the rate of steam generator depressurization and RCS cooldown rates would be decreased, resulting in a slower increase in core power and hence higher minimum DNBRs.

High energy line break interactive failures in the steam bypass control system do not impact steam line break cases prior to the main steam isolation valve closure on low steam generator pressure as the flow exiting both steam generators is choked at both nozzles. The only case where the potential for more adverse results exists for a steam bypass system failure is in the post trip return to power cases with AC power available and a failure in the intact steam generator MSIV. An additional failure in the steam bypass control system was not considered for zero power cases, since it is less limiting than the full power case with stuck open MSIV and turbine stop and control valves, due to the initially higher average core temperature assumed for the full power cases.

The sequence of events for Cases 1 through 5 above are presented in Tables 15.1.5-1 through 15.1.5-5, respectively. The sequence of events for Case 6 is the same as for Case 3.

15.1.5.3 Analysis of Effects and Consequences

- Mathematical Models

  The mathematical models and data transfer between codes used in the SLB analysis are identical to those presented in Reference 33 of Section 15.0, except that an emergency feedwater model specific to the System 80+ Standard Design is used in place of the Palo Verde specific auxiliary feedwater model described in the reference. U.S. Nuclear Regulatory Commission approval of these methods is provided in Reference 34. As was done in Reference 33, the System 80+ specific model assumes that emergency feedwater is actuated instantaneously to both steam generators at the time of the reactor trip even though the steam generators inventories are greater than the value at which emergency feedwater would normally be actuated. The maximum value of 800 gpm emergency feedwater flow is assumed to be delivered to both steam generators until the operator takes manual action to isolate emergency feedwater to the ruptured steam generator and begin an orderly cooldown to the shutdown cooling entrance conditions.

- Input Parameters and Initial Conditions

  The initial conditions assumed in the analysis of the NSSS response to Cases 1 through 5 are presented in Tables 15.1.5-6 through 15.1.5-10, respectively. The initial conditions for Case 6 are the same as those for Case 3. Justification of the selection of the initial conditions and input parameters follows.

  1. Post-Trip Return to Power (R-t-P) Cases

     The ranges of the parameters given in Table 15.0-3 were considered in establishing the most adverse initial plant state for R-t-P. For the System 80+ Standard Design, this most adverse state has been found to be the maximum core power, most positive ASI, minimum core flowrate, maximum pressurizer water level, maximum core inlet coolant temperature, maximum reactor coolant system pressure, and maximum water level in the steam generators. If a post-trip R-t-P were to occur for the steam line break transient, a conservative three dimensional peaking factor of approximately 150 would be used to bound all possible power distributions.[4]

     Maximizing the core power and core inlet temperature and minimizing the core flow impact the R-t-P adversely via their effect of maximizing RCS average temperature and

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[4] The three-dimensional peaking factor (F_q) of 150 used for the Steam Line Break analysis was chosen to be substantially larger than the maximum peaking factor that has been calculated for any ABB-CE plant. typical calculated values for the maximum F_q in operating ABB-CE plants obtained using the ROCS/MC design methodology range from 25 to 75. This includes a broad range of fuel management schemes, various burnable absorbers, and conditions ranging to N-1 (all rods in with the most reactive out) at 68°F. Therefore, an F_q of 150 is significantly conservative with respect to the peaking factor that would occur during a Steam Line Break event.

core outlet temperature. Maximizing RCS average temperature maximizes the rate of cooldown since it maximizes steam generator pressure. Maximizing RCS (core) average temperature also causes the cooldown to occur over a more adverse portion of the moderator reactivity function, i.e., the portion having the greatest rate of change of reactivity with temperature. Maximizing core outlet temperature maximizes the energy stored in the water and metal of the upper head region of the reactor vessel and also maximizes the saturation pressure of the water in this region. As the RCS pressure falls below the saturation pressure of the liquid in the upper head region, the stored energy provides the energy necessary to vaporize this liquid, resulting in a low rate of decrease of RCS pressure below the saturation pressure of the liquid in the upper head. This in turn minimizes the safety injection boron reactivity at the time of R-t-P, since the safety injection actuation signal is delayed and the safety injection pump flow is impeded by the higher transient pressures.

Use of the most positive ASI maximizes the delay in insertion of CEA reactivity following trip. This has little effect on the R-t-P. Maximizing pressurizer water level and pressure maximizes the energy stored in the pressurizer. This maximizes transient RCS pressures, delaying and impeding safety injection flow.

Maximizing steam generator water level in the affected steam generator maximizes the amount of cooldown, thus maximizing the moderator reactivity. Maximizing the water level in the unaffected steam generator maximizes the amount of steam blowdown from that steam generator before MSIS, since a higher initial steam generator water level results in a lower rate of decrease of steam generator pressure causing a lower rate of decrease in steam blowdown flow rate. Thus, increasing the initial water level in the unaffected steam generator also increases the cooldown due to steam blowdown from this steam generator.

Use of the most negative moderator and Doppler coefficients maximizes the reactivity feedbacks obtained during the cooldown, thereby causing the closest approach to a post trip R-t-P. Figure 15.1.5-0 presents the moderator reactivity as a function of moderator temperature which was used for the SLB analyses. As noted in this figure, the moderator reactivity function used for the analyses is appreciably more conservative than the most adverse function expected for SLBs. The curve for the most adverse moderator reactivity function is for an all rods in, most reactive rod fully withdrawn, end of cycle state corresponding to the most negative moderator temperature coefficient allowed by the Technical Specifications (-3.5×10^{-4} $\Delta\rho/°F$). This curve includes both moderator temperature and density effects and the loss of rod worth with temperature, and is based on constant fuel temperature and xenon distributions. The Doppler reactivity function is presented in Table 15.0-6. The minimum scram rod worth at each power level (10% $\Delta\rho$ at full power, 6.5% $\Delta\rho$ at zero power) is assumed. These values assume the most reactive CEA is stuck in the fully withdrawn position. This minimizes the negative reactivity available to prevent a potential post-trip R-t-P.

The control rod worth of 10% $\Delta\rho$ was used in the SLB analysis. This value is increased from 8.86% $\Delta\rho$, as used for other analyses in Chapter 15.

The change in CEA worth used in the full power steam line break (SLBFP) analyses to 10% $\Delta\rho$ results from an analysis of the apportionment of conservative margins to the values of the reactivity components of the SLB analysis for potential post-trip return to power. Figure 15.1.5-0 is useful in discussing this. As a reference point, a CEA worth of 10% $\Delta\rho$ used together with the moderator cooldown function represented by the lower curve of Figure 15.1.5-0 results in post-trip reactivity values which are typical of those appropriate to SLB analyses (assuming the usual conservatisms such as end of fuel cycle).

Decreasing the CEA worth in conjunction with this curve or using a CEA worth of 10% $\Delta\rho$ together with a more adverse (more negative slope) curve will increase the conservatism of the analysis results. The CEA worth of 10% $\Delta\rho$ used together with the moderator cooldown function employed in the SLB analyses (upper curve of Figure 15.1.5-0) yields results which are appreciably more conservative than the most adverse expected for System 80+. Employing both a value of 8.86% $\Delta\rho$ CEA worth and the upper curve would produce an extreme, excessively conservative bound for the expected post-trip reactivity change.

The comparison of available CEA worths and allowances presented in Table 4.3-7 is based on ROCS/DIT calculations for an equilibrium 18 month cycle core design for System 80+. The results of these calculations show that the worth available from the CEAs with all CEAs inserted except the most reactive CEA is 10.7%$\Delta\rho$. The net CEA worth of 10.7%$\Delta\rho$ is the difference between the total worth of CEAs inserted (15.3%$\Delta\rho$) and the stuck rod worth (4.6%$\Delta\rho$). The calculated net CEA worth exceeds the 10%$\Delta\rho$ CEA worth assumed in the SLB analyses. Therefore, the CEA worth used in the SLB analysis is conservative with respect to the actual reactivity available from the CEAs.

The increase in the net CEA worth used in the SLB analysis from 8.86%$\Delta\rho$ for the 3800 MWt core power level to 10%$\Delta\rho$ for the 3914 MWt core power level is due to a change in the fuel management for the System 80+ core from out-in to low-leakage. In a low-leakage fuel management scheme, the fresh fuel assemblies are placed in the interior of the core rather than on the core periphery. As a result, a larger percentage of the fresh fuel assemblies are covered by CEAs, and the N-1 condition results in uncovery of fewer contiguous fresh fuel assemblies than is the case for an out-in fuel management scheme, leading to an increase in net CEA worth. Another contributing factor to the increase in net CEA worth is the change from B_4C to erbium for the burnable absorber material. Use of erbium permits better control of the power distribution peaking than is the case with B_4C, which in turn allows a lower leakage fuel management and thus a greater net CEA worth.

2. Pre-Trip Degradation in Fuel Performance Cases

For the purposes of analyzing the pre-trip portion of the steam line break event, the initial conditions chosen for RCS pressure, temperature, core flow, and power are such as:

- to make the initial state near a power operating limit for the values of ASI and radial peaking factors used, and
- to minimize the transient minimum DNBR.

The value of ASI and radial peaking factor, F_R, are chosen to maximize the fraction of fuel pins calculated to experience DNB. Assumptions concerning initial pressurizer water level have little or no impact on the transient DNBR.

The initial steam generator mass inventory is reduced to its minimum value to maximize the RCS cooldown during the first 10 seconds of the transient. This lower initial inventory leads to a more rapid steam generator depressurization and temperature reduction. The lower secondary temperatures cause a corresponding more rapid decrease in the RCS temperatures.

Note that the reason for different steam generator (SG) liquid inventories between SLB inside and outside containment analyses is due to the different objectives of these analyses. For a SLB inside containment, the objective is to maximize the possibility of post-trip return to power. For a SLB outside containment, the objective is to maximize pre-trip degradation in DNBR. For the latter case this is achieved through minimizing SG liquid inventory. As stated in the previous paragraph, the impact of reduced SG inventory during a SLB maximizes the initial rate of SG depressurization and temperature reduction, which in turn maximizes RCS cooldown rate. The maximum cooldown rate of the RCS creates the most rapid power increase due to reactivity feedback. This results in a more rapid decrease in DNBR and, hence, a greater potential for fuel damage. Since the dose is driven by the radioactivity transported from the primary to the secondary by the Technical Specification tube leak, this scenario is the most limiting for doses to the environment following a SLB outside the containment.

The minimum scram rod worth minimizes the rate of reactivity insertion upon reactor trip and, therefore, maximizes the delay in core power decrease. The most negative moderator temperature coefficient (MTC) conservatively maximizes positive reactivity insertion. Also, the least negative Doppler reactivity coefficient minimizes the insertion of negative reactivity during fuel heatup. Therefore, use of the minimum rod worth and of the least negative Doppler coefficient (Table 15.0-5) and most negative moderator coefficient ($-3.5 \times 10^{-4}\ \Delta\rho/°F$) maximizes the core heat flux and minimizes the DNBR prior to and shortly after the reactor trip.

- Results

Case 1: Large Steam Line Break During Full Power Operation with Concurrent Loss of Offsite Power (SLBFPLOP)

The dynamic behavior of the salient NSSS parameters following the SLBFPLOP is presented in Figures 15.1.5-1.1 through 15.1.5-1.13. Table 15.1.5-1 summarizes the major events, times, and results for this transient.

Concurrent with the steam line break, a loss of offsite power occurs. At this time an actuation signal for the emergency diesel generators is initiated. Due to decreasing core flow following loss of power to the reactor coolant pumps, conditions exist for a low DNBR trip. At 0.83 second the reactor coolant pump (RCP) reaches the Core Protection Calculator (CPC) low shaft speed setpoint. At 0.98 seconds, the CPC generates a low RCP shaft speed trip signal. At 1.13 second the reactor trip breakers open. At 9.7 seconds voids begin to form in the upper head of the reactor vessel. At 10.22 seconds the steam generator pressure drops below the MSIS setpoint of 719 psia. The MFIVs and MSIVs close by 16.57 seconds. At 79.3 seconds the pressurizer empties. At 176.4 seconds the pressurizer pressure has dropped below 1555 psia initiating safety injection.

Within 40.6 seconds, the operable SI pumps are loaded on the diesels and reach full speed and the SI valves are fully open.

At 350 seconds the maximum core reactivity (- 1.03% $\Delta\rho$) occurs. Safety injection boron begins to reach the core at 296.2 seconds. Since there is no return to power the values of DNBR remain above those for which fuel damage would be indicated. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves, assuming that offsite power has not been restored. Shutdown cooling is initiated when the RCS reaches 350°F and 330 psia.

Case 2: Large Steam Line Break During Full Power Operation with Offsite Power Available (SLBFP)

The dynamic behavior of the salient NSSS parameters following the SLBFP is presented in Figures 15.1.5-2.1 through 15.1.5-2.13. Table 15.1.5-2 summarizes the major events, times, and results for this transient.

At 7.49 seconds the CPC Variable Overpower Trip (VOPT) condition of 115% power is reached. The CPC VOPT signal is generated at 7.89 seconds.

At 8.04 seconds the reactor trip breakers open. Opening of the reactor trip breakers generates a turbine trip signal which will close the turbine stop valves. However, it is conservatively assumed that these valves as well as the turbine control valves do not close, leaving a path for the full steam flow from the unaffected steam generator, through an assumed faulted (stuck open) MSIV in that steam generator, to the condenser. At 14.52 seconds voids begin to form in the upper head of the reactor vessel. At 16.10 seconds the steam generator pressure drops below the MSIS setpoint of 719 psia. The MFIVs and the operable MSIVs close by 22.45 seconds. At 46.4 seconds the pressurizer empties. At 69.5 seconds the pressurizer pressure drops below 1555 psia, initiating safety injection. Within 40.6 seconds, the SI pumps reach full speed and the SI valves are fully open. Safety injection boron begins to reach the core at 168.6 seconds. At 230 seconds the maximum core reactivity (-0.81% $\Delta\rho$) occurs. Since there is no return to power, the values of DNBR remain above those for which fuel damage would be indicated. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves or the MSIV bypass valves and the turbine bypass valves. If it is not possible to close either the turbine stop or control valves, the operator would break condenser vacuum and use manual control of the atmospheric dump valves to release steam as necessary. Shutdown cooling is initiated when the RCS reaches 350°F and 330 psia.

Case 3: Large Steam Line Break During Zero Power Operation with Concurrent Loss of Offsite Power (SLBZPLOP)

The dynamic behavior of the salient NSSS parameters following the SLBZPLOP is presented in Figures 15.1.5-3.1 through 15.1.5-3.13. Table 15.1.5-3 summarizes the major events, times, and results for this transient.

Concurrent with the steam line break, a loss of offsite power occurs. At this time an actuation signal for the emergency diesel generators is initiated. Due to decreasing core flow following loss of power to the reactor coolant pumps, conditions exist for a low DNBR trip. At 0.83 second the reactor coolant pump (RCP) reaches the Core Protection Calculator (CPC) low shaft speed setpoint. At 0.98 seconds, the CPC generates a low RCP shaft speed trip signal. At 1.13 second the reactor trip breakers open. At 11.86 seconds the steam generator pressure drops below the MSIS setpoint of 719 psia. The MFIVs and MSIVs close by 18.21 seconds.

At 68.6 seconds the pressurizer empties. At 72.2 seconds the pressurizer pressure drops below 1555 psia initiating safety injection. Within 40.6 seconds, the operable SI pumps are loaded on the diesels and reach full speed and the SI valves are fully open. At 93.8 seconds voids begin to form in the upper head of the reactor vessel. Safety injection boron begins to reach the core at 140 seconds. At 187 seconds the maximum core reactivity ($-1.43\%\Delta\rho$) occurs.

Since there is no return to power, the values of DNBR remain above those for which fuel damage would be indicated. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves, assuming that offsite power has not been restored. Shutdown cooling is initiated when the RCS reaches 350°F and 330 psia.

Case 4: Large Steam Line Break Zero Power Operation with Offsite Power Available (SLBZP)

The dynamic behavior of the salient NSSS parameters following the SLBZP is presented in Figures 15.1.5-4.1 through 15.1.5-4.13. Table 15.1.5-4 summarizes the major events, times, and results of this transient.

At 12.6 seconds after initiation of the steam line break, the steam generator pressure drops below the low steam generator pressure trip and MSIS setpoint of 719 psia. At 13.75 seconds the reactor trip breakers open. The MFIVs and MSIVs close by 18.95 seconds. At 62.3 seconds the pressurizer empties. At 64.7 seconds the pressurizer pressure drops below 1555 psia initiating safety injection. Within 40.6 seconds, the operable SI pumps reach full speed and the SI valves are fully open. At 78.1 seconds voids begin to form in the upper head of the reactor vessel. Safety injection boron begins to reach the core at 132.5 seconds. At 171 seconds the maximum core reactivity ($-1.50\%\Delta\rho$) occurs. Since there is no return to power, the values of DNBR remain above those for which fuel damage would be indicated. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the MSIV bypass valves associated with the unaffected steam generator and turbine bypass valves. Shutdown cooling is initiated when the RCS reaches 350°F and 330 psia.

Case 5: Steam Line Break Outside Containment During Full Power Operation with Loss of Offsite Power Concurrent with Reactor/Turbine Trip (SLBFPLOPD)

The dynamic behavior of the salient NSSS parameters following a typical limiting SLBFPLOPD is presented in Figures 15.1.5-5.1 through 15.1.5-5.9. Table 15.1.5-5 summarizes the major events, times and results for this transient.

The consequences of this transient are approximately the same as those for SLBFPLOPDs for a spectrum of break sizes, due to the protective action of the Core Protection Calculators (CPCs). The largest break size yields the minimum DNBR. Therefore the transient presented here is that which results from the double ended break of a main steam line.

Not later than 7.21 seconds after initiation of the steam line break, a trip signal is initiated by the CPCs on variable overpower. At 7.36 seconds the reactor trip breakers open. At 8.88 seconds a minimum transient DNBR of 1.25 is calculated to occur, after which DNBR rapidly increases, as shown in Figure 15.1.5-5.9, At 12.82 seconds voids begin to form in the upper head of the reactor vessel. At 13.0 seconds the steam generator pressure drops below the MSIS setpoint of 719 psia. The MFIVs and the MSIVs close by 19.35 seconds. At 182.2 seconds the maximum core reactivity (-1.75%$\Delta\rho$) occurs.

Subsequently, the events of this transient follow a sequence similar to those of the SLBFPLOP (Case 1). Since the cooldown is less severe due to the smaller initial steam generator inventory the potential for post-trip degradation in fuel cladding performance is less for this case (SLBFPLOPD) than for Case 1 (SLBFPLOP). At a maximum of 30 minutes the operator, using the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves assuming that offsite power has not been restored. Shutdown cooling is initiated when the RCS reaches 350°F and 330 psia.

At the point of the minimum transient DNBR none of the fuel rods are predicted to experience DNB. To provide a bounding valve for potential offsite dose calculations, however, 0.5% of the fuel rods are assumed to fail. All of the activity in the fuel gap for fuel rods that are assumed to fail is assumed to be uniformly mixed with the reactor coolant. The activity in the fuel clad gap is assumed to be 5% of the iodines, cesiums, and rubidiums and 5% of the noble gases accumulated in the fuel at the end of core life, assuming continuous full power operation. Assuming one gpm steam generator tube leakage, during a period of two hours after initiation of the SLBFPLOPD, the integral leakage from the RCS through the affected steam generator is 1001 lbm, which is assumed to be released to the atmosphere with a DF of 1.

The total steam released from the affected steam generator is 390,050 lbm. The affected steam generator will empty in two hours; therefore all the mass release from the affected steam generator to the atmosphere has a DF of 1.

Less than 74,000 lbm of steam from the unaffected steam generator will be released through the steam line break. During the SLBFPLOPD the MSIVs will isolate the unaffected steam generator and prevent it from emptying. Therefore, a DF of 100 is assumed in calculating iodine, cesium, and rubidium activity released from the unaffected steam generator.

The doses are calculated by the methods outlined in Appendix 15A. Table 15.1.5-12 presents the major assumptions, parameters, and radiological consequences for this transient. SLBFPLOPD offsite doses are summarized in Table 15.1.5-13. Control room doses are provided in Section 6.4.3.

Case 6: Large Steam Line Break Outside Containment from Zero Power Operation with Loss of Offsite Power (SLBZPLOPD)

Case 6 is included in Case 3, since the break of the latter can be either inside or outside of containment. The Figures, Tables, and Discussion for Case 3 apply to Case 6. Assuming a one gpm steam generator tube leakage, during a period of two hours after initiation of the SLBZPLOPD the integral leakage from the RCS through the affected steam generator is 1001 1bm, which is assumed to be released to the atmosphere with a DF of 1. This mass release results in a contribution to the inhalation thyroid doses at the EAB of:

- 14.1 rem, assuming a pre-existing iodine spike; or
- 8.8 rem, assuming an event-induced iodine spike.

The total steam released from the affected steam generator is 571,000 1bm. The affected steam generator will empty in two hours; therefore all the mass release from the affected steam generator to atmosphere has a DF of 1. The calculated inhalation thyroid dose is 13.3 rem for the blowdown steam originating from the initial steam generator mass inventory.

Less than 1,352,000 1bm of steam from the unaffected steam generator will be released through the atmospheric steam dump valves and through the steam line break within two hours. During the SLBZPLOPD the MSIVs will isolate the unaffected steam generator and prevent it from emptying. Therefore, a DF of 100 is assumed in calculating iodine activity released from the unaffected steam generator. The resulting contribution to the inhalation thyroid dose at the EAB is 0.32 rem.

The doses are calculated by the methods outlined in Appendix 15A. Table 15.1.5-12 presents the major assumptions and parameters used in evaluating the radiological consequences for this transient. The resultant offsite radiological consequences are given in Table 15.1.5-13. Control room doses are provided in Section 6.4.3.

In summary, the total two-hour inhalation thyroid dose at the EAB as a consequence of the SLBZPLOPD is no more than 28 rem.

15.1.5.4 Conclusions

For the large steam line break in combination with a single failure and stuck CEA, with or without a loss of offsite power, no post-trip return to power occurs, thereby precluding fuel damage.

For a large steam line break during zero power operation in combination with a loss of offsite power and Technical Specification tube leakage, the two-hour inhalation thyroid dose at the EAB is a small fraction of 10 CFR 100 guidelines:

- 28 rem, assuming a pre-existing iodine spike; or
- 23 rem, assuming an event-induced iodine spike.

The maximum potential for radiological releases due to fuel failure occurs for steam line breaks outside containment with loss of offsite power in combination with a stuck CEA. For these cases the maximum potential for degradation in fuel cladding performance occurs prior to and during reactor trip. With the assumption of one gallon per minute steam generator tube leakage and with the assumed maximum of 0.5% fuel failure, the two-hour inhalation thyroid dose at the EAB is calculated to be no more than 70 rem, which is within the 10 CFR 100 guidelines.

The System 80+ design ensures that structural integrity of the NSSS is not challenged by the thermal shock due to a steam line break (see Chapter 3).

Table 15.1.4-1 Sequence of Events for Full Power Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power

Time (sec)	Event	Setpoint or Value
0.0	One atmospheric dump valve opens fully	--
1800	Hot channel DNBR	1.36
1800	Operator initiates manual trip	--
1800.22	Steam generator water level reaches emergency feedwater actuation analysis setpoint, %WR	19.9
1800.4	Manual reactor trip signal generated	--
1800.55	Reactor trip breakers open/Turbine Trip/ Loss of Offsite Power/RCPs begin to coastdown	--
1801.96	Minimum Transient DNBR	1.30
1805	Main steam safety valves open, psia	1212
1845	Main steam safety valves close, psia	1151
1860.22	Emergency feedwater delivered to generator	--
1919.46	Void begins to form in RV upper head	--
2050.4	Steam generator pressure reaches main steam isolation signal (MSIS) analysis setpoint, psia	719
2056.75	MFIVs close completely	--
2056.75	MSIVs close completely	--
2074.9	Pressurizer pressure reaches low pressurizer safety injection actuation analysis setpoint, psia	1555
2115.5	Safety injection pumps reach full speed	--
2154.6	Affected steam generator dries out	--
3000	Operator manually closes ADV	--
3600	Operator initiates plant cooldown	--

Table 15.1.4-2 Sequence of Events for Full Power Inadvertent Opening of a Steam Generator Atmospheric Dump Valve with Loss of the Feedwater Control System Reactor Trip Override (IOSGADV+SF) and with Loss of Offsite Power

Time (sec)	Event	Setpoint or Value
0.0	One atmospheric dump valve opens fully	--
1800	Hot channel DNBR	1.36
1800	Operator initiates manual trip	--
1800.4	Manual reactor trip signal generated	--
1800.55	Reactor trip breakers open/Turbine Trip/ Loss of Offsite Power/RCPs begin to coastdown	--
1800.6	Steam generator water level reaches emergency feedwater actuation analysis setpoint, %WR	19.9
1802.15	Minimum transient DNBR	1.29
1829.76	Void begins to form in RV upper head	--
1841.80	Steam generator pressure reaches main steam isolation signal (MSIS) analysis setpoint, psia	719
1848.15	MFIVs close completely	--
1848.15	MSIVs close completely	--
1860.6	Emergency feedwater delivered to generator	--
1872.8	Pressurizer pressure reaches low pressurizer pressure safety injection actuation analysis setpoint, psia	1555
1913.4	Safety injection pumps reach full speed	--
3000	Operator manually closes ADV	--
3600	Operator initiates plant cooldown	--

Table 15.1.4-3 Assumptions and Initial Condition For Full Power Inadvertent Opening of An Atmospheric Dump Valve Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV and IOSGADV + SF) with Loss of Offsite Power

Parameter	Value
Initial Core Power Level, MWt	3992
Initial Core Inlet Coolant Temperature, °F	561
Initial Core Mass Flow rate, 10^6 lbm/hr	152.2
Initial Pressurizer Pressure, psia	2325
Initial Pressurizer Water Volume, ft^3	500
Initial Steam Generator Pressure, psia	1076.5
Initial Steam Generator Inventory, lbm per SG	110,438
CEA Worth on Trip, 10^{-2} $\Delta\rho$	-8.8
Moderator Temperature Coefficient, $\Delta\rho$/°F	-3.5×10^{-4}
Core Burnup	End of Cycle
ASI	-0.3
Maximum Radial Peaking Factor	1.50
Doppler Reactivity	Table 15.0-5

Table 15.1.5-1 Sequence of Events for a Large Steam Line Break During Full Power Operation with Concurrent Loss of Offsite Power (SLBFPLOP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break and Loss of Offsite Power Occur	--
0.83	Reactor Coolant Pump Reaches CPC Low Shaft Speed Setpoint, Fraction	0.95
0.98	CPC Low RCP Shaft Speed Trip Signal Generated	--
1.13	Reactor Trip Breakers Open	--
9.7	Voids Begin to Form in RV Upper Head	--
10.22	Steam Generator Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint, psia	719
16.57	MFIVs Close Completely	--
16.57	MSIVs Close Completely	--
79.3	Pressurizer Empties	--
176.4	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia	1555
217.0	Safety Injection Flow Begins	--
296.2	Safety Injection Boron Begins to Reach Reactor Core	--
350	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-1.03
1800	Operator Initiates Cooldown	--

Table 15.1.5-2 Sequence of Events for a Large Steam Line Break During Full Power Operation with Offsite Power Available (SLBFP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
7.49	CPC Variable Overpower Trip Condition Reached (% Power)	115
7.89	CPC Variable Overpower Trip Signal Generated	--
8.04	Reactor Trip Breakers Open	--
14.52	Voids Begin to Form in RV Upper Head	--
16.10	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	719
22.45	MFIVs Close Completely	--
22.45	MSIVs Close Completely	--
46.4	Pressurizer Empties	--
69.5	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1555
110.1	Safety Injection Flow Begins	--
168.6	Safety Injection Boron Begins to Reach Reactor Core	--
230	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-0.81
1800	Operator Initiates Cooldown	--

Table 15.1.5-3 Sequence of Events for a Large Steam Line Break During Zero Power Operation with Concurrent Loss of Offsite Power (SLBZPLOP and SLBZPLOPD)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break and Loss of Offsite Power Occur	--
0.83	Reactor Coolant Pump Reaches CPC Low Shaft Speed Setpoint, Fraction	0.95
0.98	CPC Low RCP Shaft Speed Trip Signal Generated	--
1.13	Reactor Trip Breakers Open	--
11.86	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	719
18.21	MFIVs Close Completely	--
18.21	MSIVs Close Completely	--
68.6	Pressurizer Empties	
72.2	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1555
93.8	Voids Begin to Form in RV Upper Head	--
112.8	Safety Injection Flow Begins	--
140.0	Safety Injection Boron Begins to Reach Reactor Core	--
187	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-1.43
1800	Operator Initiates Cooldown	--

Table 15.1.5-4 Sequence of Events for a Large Steam Line Break During Zero Power Operation with Offsite Power Available (SLBZP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
12.60	Steam Generator Pressure Reaches Reactor Trip Analysis Setpoint, psia	719
12.60	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	719
13.60	Low Steam Generator Pressure Reactor Trip Signal Generated	--
13.75	Trip Breakers Open	--
18.95	MFIVs Close Completely	--
18.95	MSIVs Close Completely	--
62.3	Pressurizer Empties	--
64.7	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1555
78.1	Voids Begin to Form in RV Upper Head	--
105.3	Safety Injection Flow Begins	--
132.5	Safety Injection Boron Begins to Reach Reactor Core	--
171	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-1.50
1800	Operator Initiates Cooldown	--

Table 15.1.5-5 Sequence of Events for a Steam Line Break Outside Containment During Full Power Operation with Loss of Offsite Power Concurrent with Reactor/Turbine Trip (SLBFPLOPD)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
6.81	CPC Variable Overpower Trip Condition Reached	115
6.81	EFW Initiated to Both Steam Generators	--
7.21	CPC Variable Overpower Trip Signal Generated	--
7.36	Reactor Trip Breakers Open/Turbine Trip/Loss of Offsite Power/RCPs Begin to Coastdown	--
8.88	Minimum Transient DNBR	1.25
12.82	Voids Begin to Form in RV Upper Head	--
13.0	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	719
19.35	MFIVs Close Completely	--
19.35	MSIVs Close Completely	--
182.2	Maximum Post-trip Transient Reactivity, $10^{-2}\ \Delta\rho$	-1.75
331.2	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia	1555
371.8	Safety Injection Flow Begins	--
483.1	Safety Injection Boron Begins to reach Reactor Core	--
1800	Operator Initiates Cooldown	--

Table 15.1.5-6 Assumptions and Initial Conditions for a Large Steam Line Break During Full Power Operation with Concurrent Loss of Offsite Power (SLBFPLOP)

Parameter	Assumed Value
Initial Core Power Level, MWt	3992
Initial Core Inlet Coolant Temperature, °F	561
Initial Core Mass Flow Rate, 10^6 lbm/hr	152.3
Initial Pressurizer Pressure, psia	2325
Initial Pressurizer Water Volume, ft^3	1350
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-10.0
Initial Steam Generator Liquid Inventory, lbm	256,429
Two Trains of Safety Injection Pumps	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

Table 15.1.5-7 Assumptions and Initial Conditions for a Large Steam Line Break During Full Power Operation with Offsite Power Available (SLBFP)

Parameter	Assumed Value
Initial Core Power Level, MWt	3992
Initial Core Inlet Coolant Temperature, °F	561
Initial Core Mass Flow Rate, 10^6 lbm/hr	152.3
Initial Pressurizer Pressure, psia	2325
Initial Pressurizer Water Volume, ft^3	1350
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-10.0
Initial Steam Generator Liquid Inventory, lbm	256,429
One Main Steam Isolation Valve on Intact Steam Generator	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

Table 15.1.5-8 Assumptions and Initial Conditions for a Large Steam Line Break During Zero Power Operation with Concurrent Loss of Offsite Power (SLBZPLOP AND SLBZPLOPD)

Parameter	Assumed Value
Initial Core Power Level, MWt	10
Initial Core Inlet Coolant Temperature, °F	561
Initial Core Mass Flow Rate, 10^6 lbm/hr	152.3
Initial Pressurizer Pressure, psia	2325
Initial Pressurizer Water Volume, ft^3	1350
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-6.5
Initial Steam Generator Liquid Inventory, lbm	414,386
Two Trains of Safety Injection Pumps	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

Table 15.1.5-9 Assumptions and Initial Conditions for a Large Steam Line Break During Zero Power Operation with Concurrent Loss of Offsite Power (SLBZP)

Parameter	Assumed Value
Initial Core Power Level, MWt	10
Initial Core Inlet Coolant Temperature, °F	561
Initial Core Mass Flow Rate, 10^6 lbm/hr	152.3
Initial Pressurizer Pressure, psia	2325
Initial Pressurizer Water Volume, ft^3	1350
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-6.5
Initial Steam Generator Liquid Inventory, lbm	414386
One Main Steam Isolation Valve or Intact Steam Generator	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

Table 15.1.5-10 Assumptions and Initial Conditions for the Steam Line Break Outside Containment During Full Power Operation with Loss of Offsite Power Concurrent with Reactor/Turbine Trip (SLBFPLOPD)

Parameter	Assumed Value
Initial Core Power Level, MWt	3992
Initial Core Inlet Coolant Temperature, °F	561
Initial Core Mass Flow Rate, 10^6 lbm/hr	152.3
Initial Pressurizer Pressure, psia	2400
Initial Pressurizer Water Volume, ft^3	1350.0
Radial Peaking Factor, F_R	1.52
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-8.86
Initial Steam Generator Liquid Inventory, lbm	86219
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

Table 15.1.5-11 Effect of Single Failure of MSIV or One SI Pump on Maximum Post-Trip Reactivity and Core Average Power for Double-Ended Guillotine Main Steam Line Breaks With a Stuck CEA

			Maximum Post-Trip:	
Initial Power Level	Offsite Power	Single Failure	Reactivity (%$\Delta\rho$)	Core Average Power (% of 3914 MWt)
Full	Loss of	One Diesel Generator	-1.03	No R-t-P
		MSIV	-1.73	No R-t-P
	Available	One SI Pump	-1.14	No R-t-P
		MSIV	-0.81	No R-t-P
Zero	Loss of	One Diesel Generator	-1.43	No R-t-P
		MSIV	-1.60	No R-t-P
	Available	One SI Pump	-1.60	No R-t-P
		MSIV	-1.50	No R-t-P

Table 15.1.5-12 Parameters Used in Evaluating the Radiological Consequences of Steam Line Breaks Outside Containment Opstream of MSIV

Parameter	Value	
	SLBFPLOPD (Case 5)	SLBZPLOPD (Case 6)
A. Data and Assumptions Used to Evaluate the Radioactive Source Term		
1. Power Level, MWt	3992	10
2. Burnup, MWD/MT	28,000	28,000
3. Percent of Fuel Assumed to Experience DNB, %	0.5	0
4. Reactor Coolant Activity Before Event (based on 3992 MWt),	Tech Spec Appendix 15A	Tech Spec 3.4.15[1] Appendix 15A
5. Secondary System Activity Before Event	Tech Spec Appendix 15A	Tech Spec 3.7.6 Appendix 15A
6. Primary System Liquid Inventory, lbm	638,000	638,000
7. Steam Generator Inventory, lbm		
- Affected Steam Generator	108,640	414,386
- Intact Steam Generator	108,640	414,386
B. Data and Assumptions Used to Estimate Activity Released from the Secondary System		
1. Primary to Secondary Leak Rate, gpm	1.0 (total)	1.0 (total)
2. Total Mass Release from the Affected Steam Generator, lbm (0-30 min)	390,050	570,520
3. Total Mass Release from the Intact Steam Generator	1,350,990 (2 hrs) 2,885,400 (8 hrs)	1,351,950 (2 hrs) 2,885,440 (8 hrs)
4. Percent of Core Inventory of Volatile Fission Products Assumed in the Gap	5	N/A
5. Iodine/Cesium/Rubidium Decontamination Factor in the Affected Steam Generator	1.0	1.0

[1] Except for cases assuming pre-existing and concurrent iodine spike.

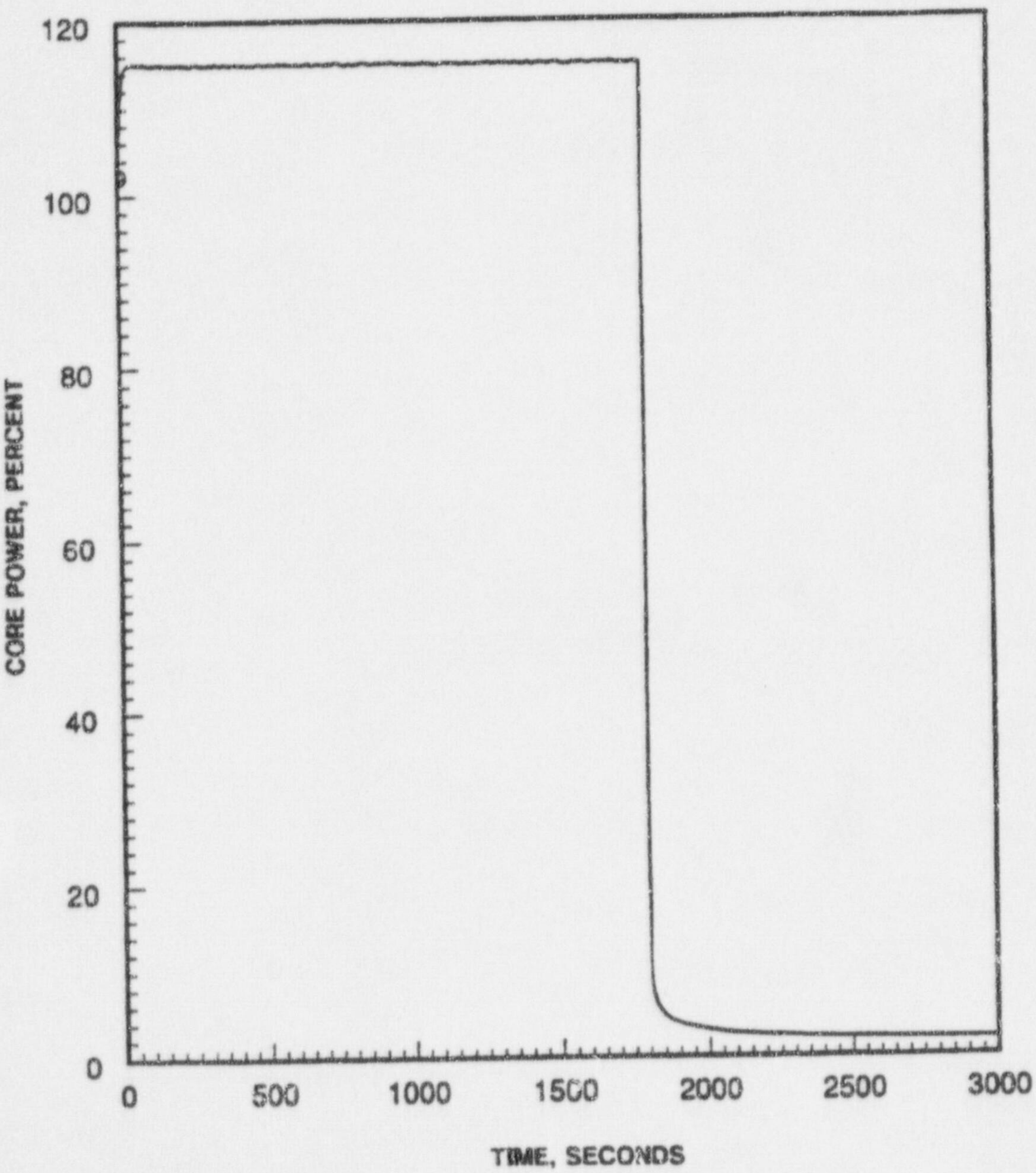
Table 15.1.5-12 Parameters Used in Evaluating the Radiological Consequences of Steam Line Breaks Outside Containment Opstream of MSIV (Cont'd.)

Parameter	Value	
	SLBFPLOPD (Case 5)	SLBZPLOPD (Case 6)
6. Iodine/Cesium/Rubidium Decontamination Factor in the Intact Steam Generator	100	100
7. Peaking Factor	1.58	N/A
8. Credit for Radioactive Decay in Transit to Dose Point	No	No
9. Loss of Offsite Power	Yes	Yes
C. Atmospheric Dispersion Data	Table 2.3-1	Table 2.3-1
D. Dose Data		
1. Method of Dose Calculation	Appendix 15A	Appendix 15A
2. Dose Conversion Assumptions	Appendix 15A	Appendix 15A

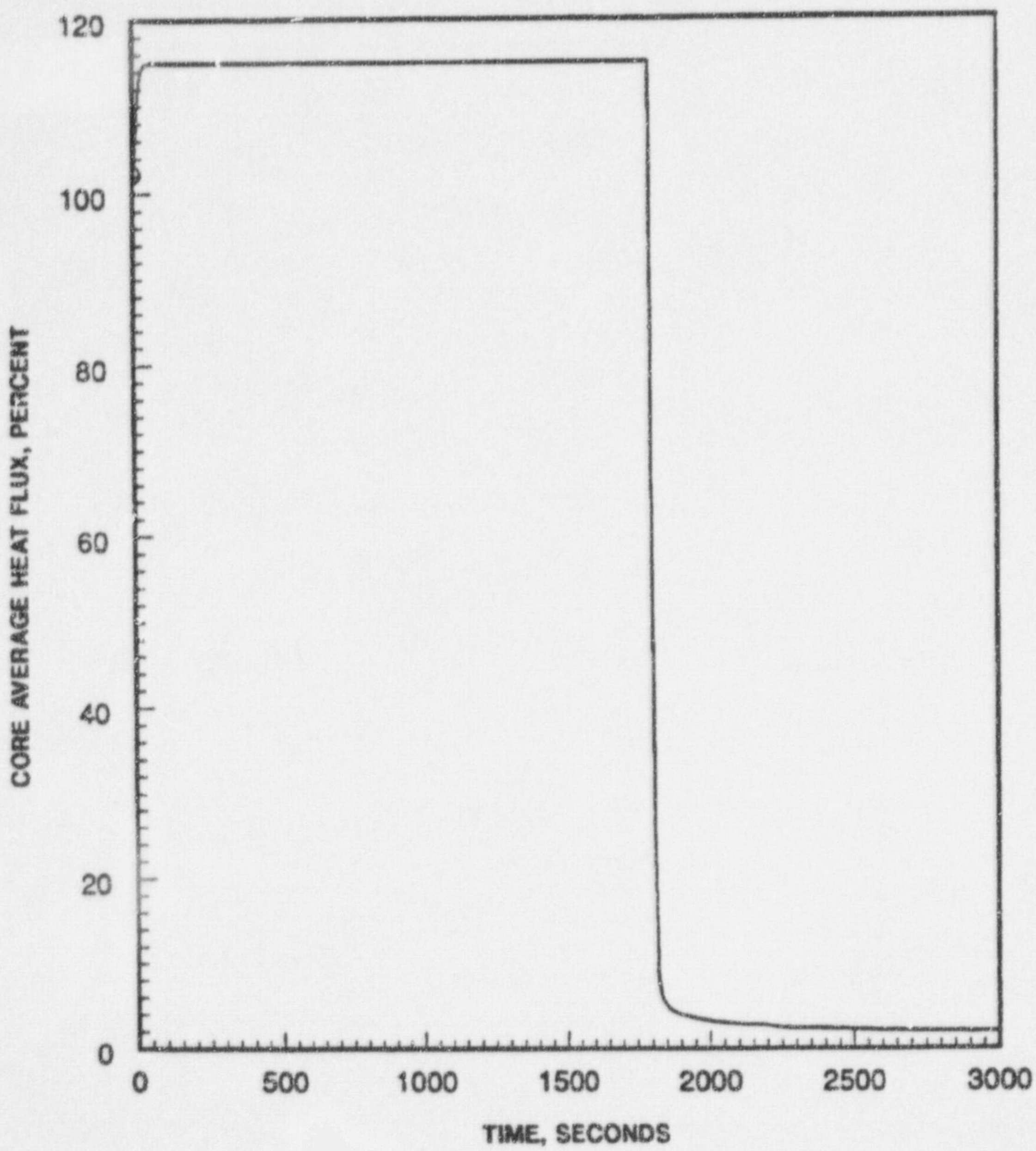
Table 15.1.5-13 Radiological Consequences of Steam Line Breaks Outside Containment Upstream of MSIV

Location	Offsite Doses (rem)	
	SLBFPLOPD (Case 5)	SLBZPLOPD (Case 6)
1. Exclusion Area Boundary (0-2 hours)		
a. Thyroid	70	28[1] (PIS)
		23[1] (GIS)
b. Whole-Body	0.3	0.06 (PIS)
		0.06 (GIS)
2. Low Population Zone (0-8 hours)		
a. Thyroid	34	9.5 (PIS)
		20.6 (GIS)
b. Whole-Body	0.08	0.014 (PIS)
		0.016 (GIS)

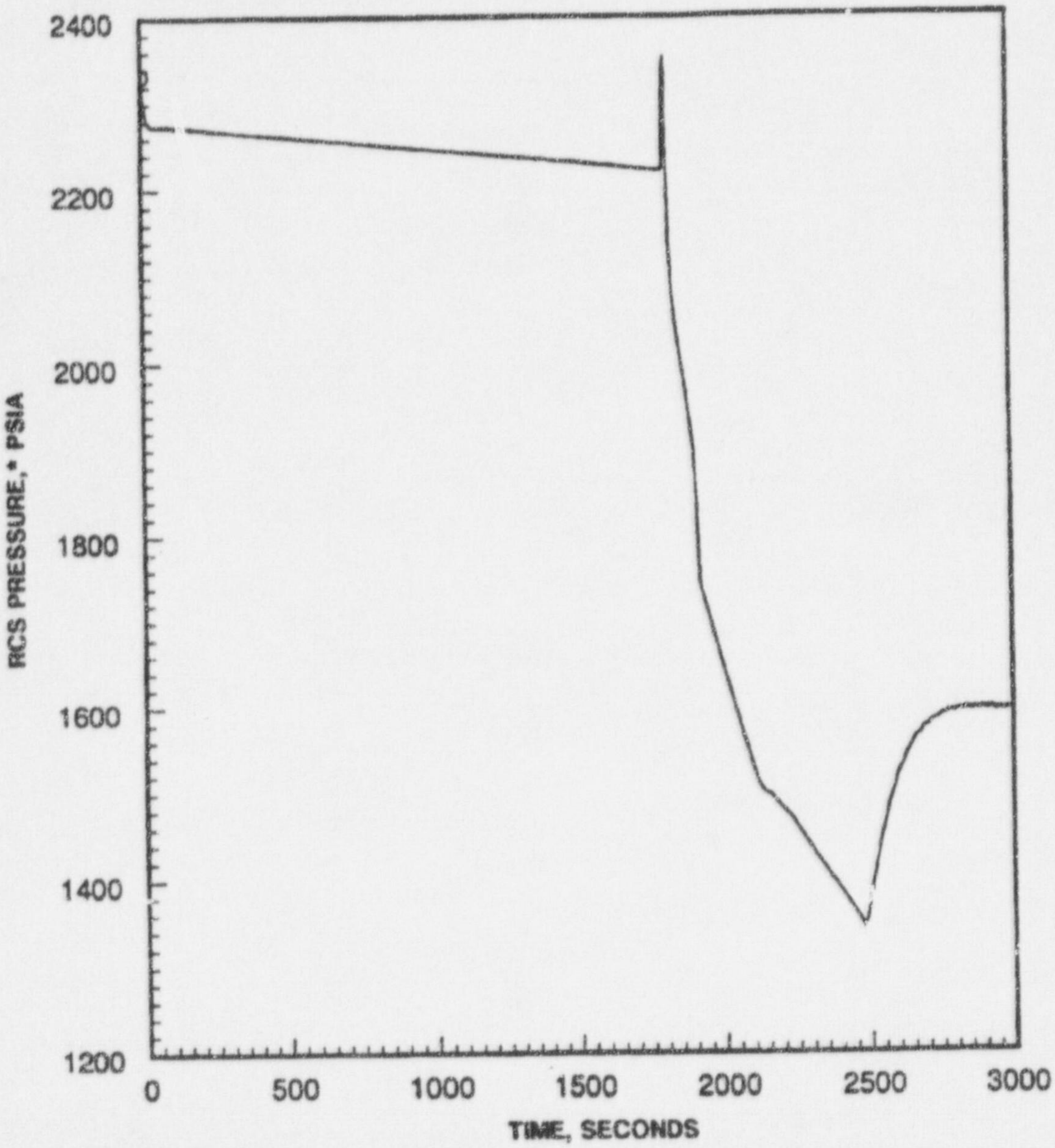
[1] Values are provided for a Pre-existing Iodine Spike (PIS) and for an event Generated Iodine Spike (GIS).



Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Core Power vs. Time	Figure 15.1.4-1.1

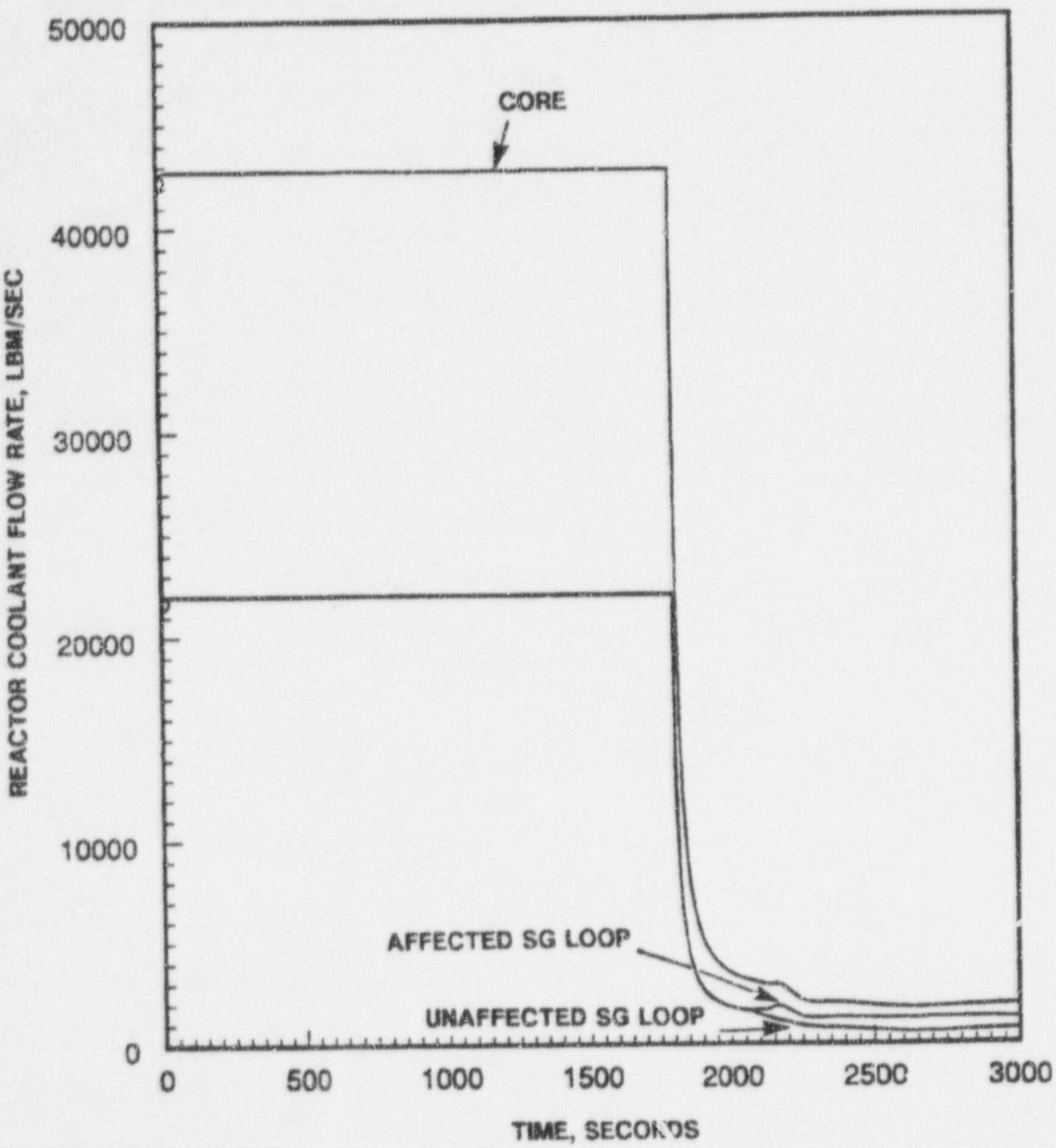


Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Core Power Average Heat Flux vs. Time	Figure 15.1.4-1.2

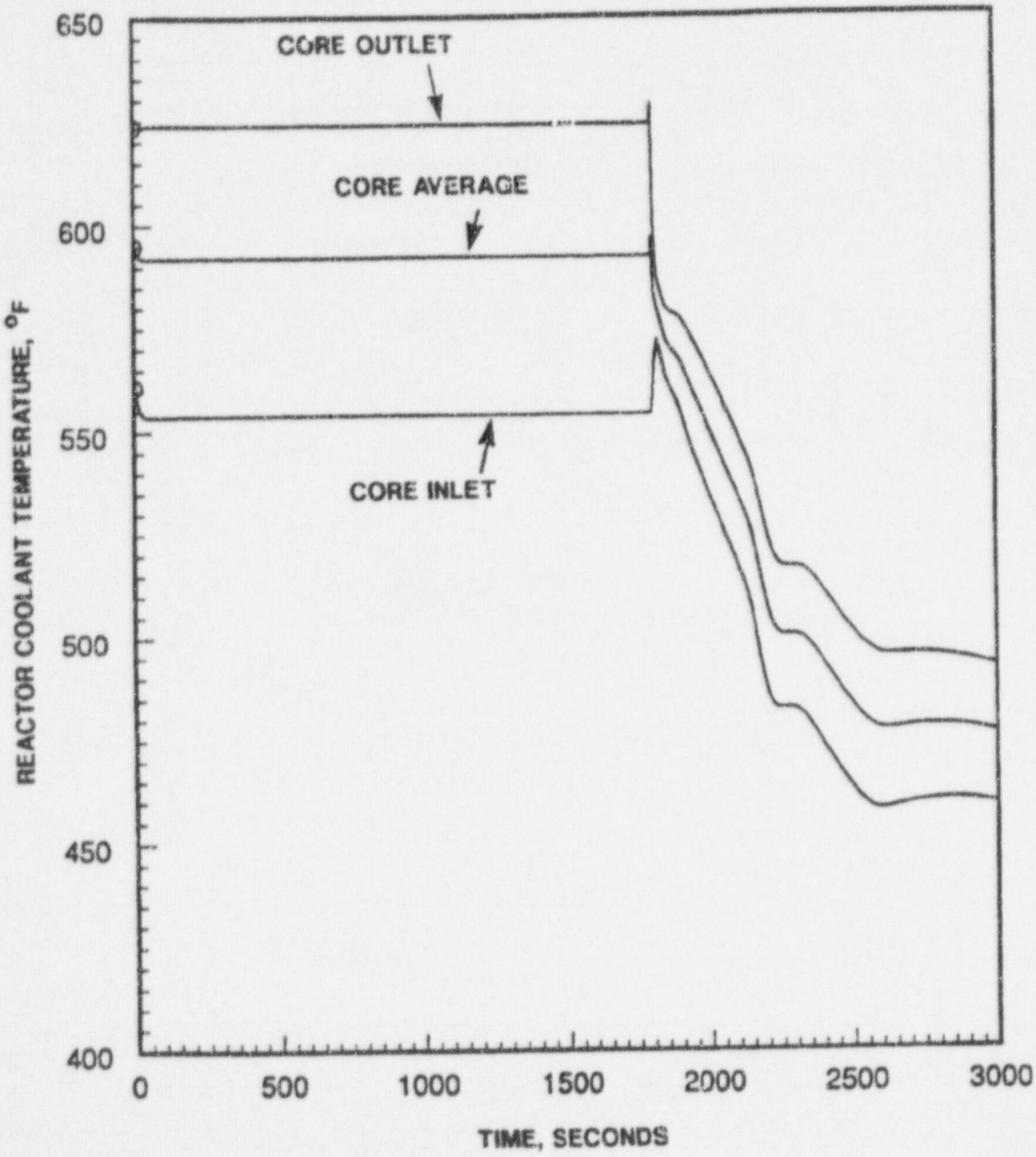


*THIS PRESSURE DOES NOT INCLUDE THE PRESSURE DIFFERENCE BETWEEN THE COLD LEG AT RCP DISCHARGE AND THE SURGE LINE

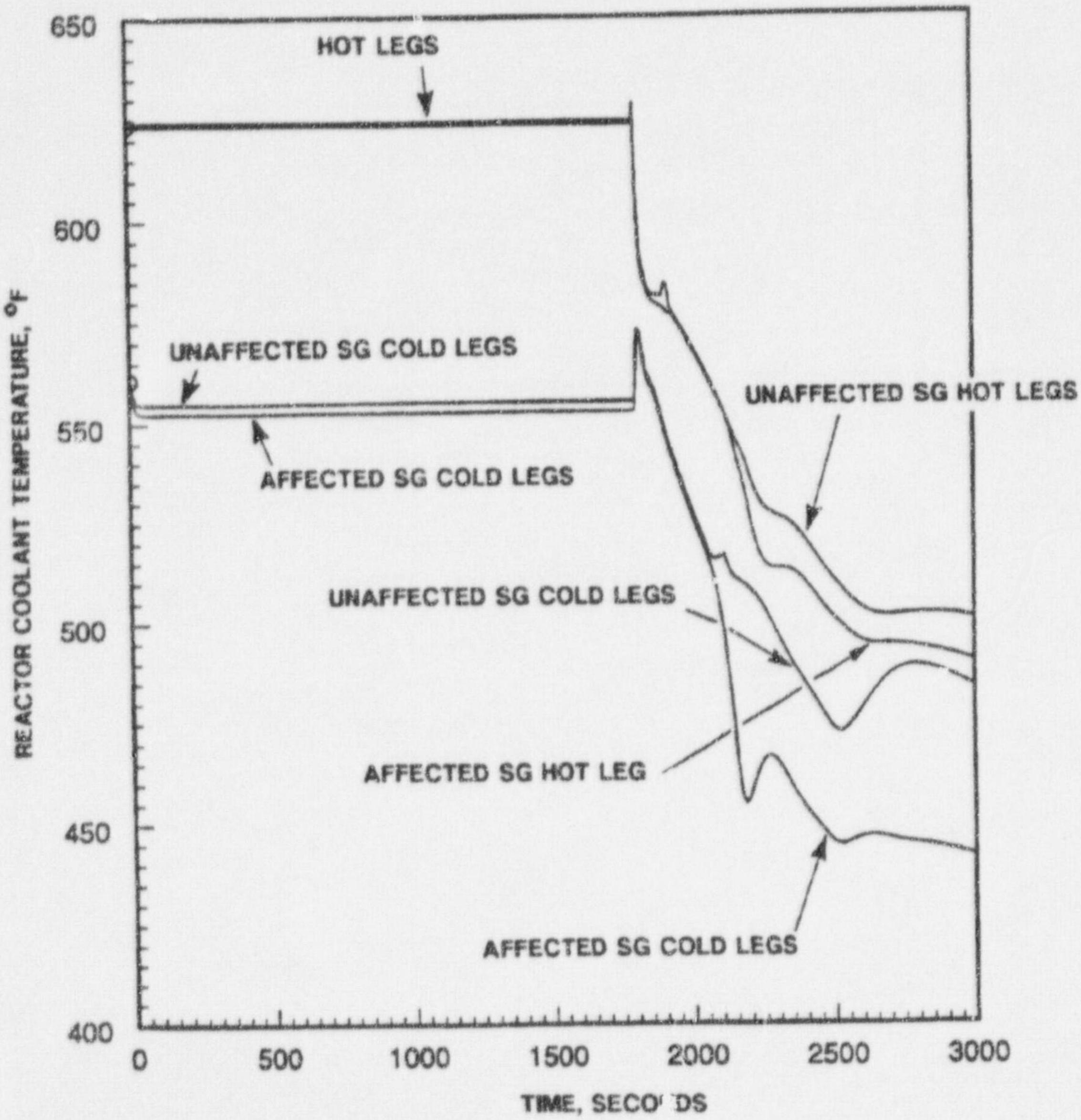
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Reactor Coolant System Pressure vs. Time	Figure 15.1.4-1.3



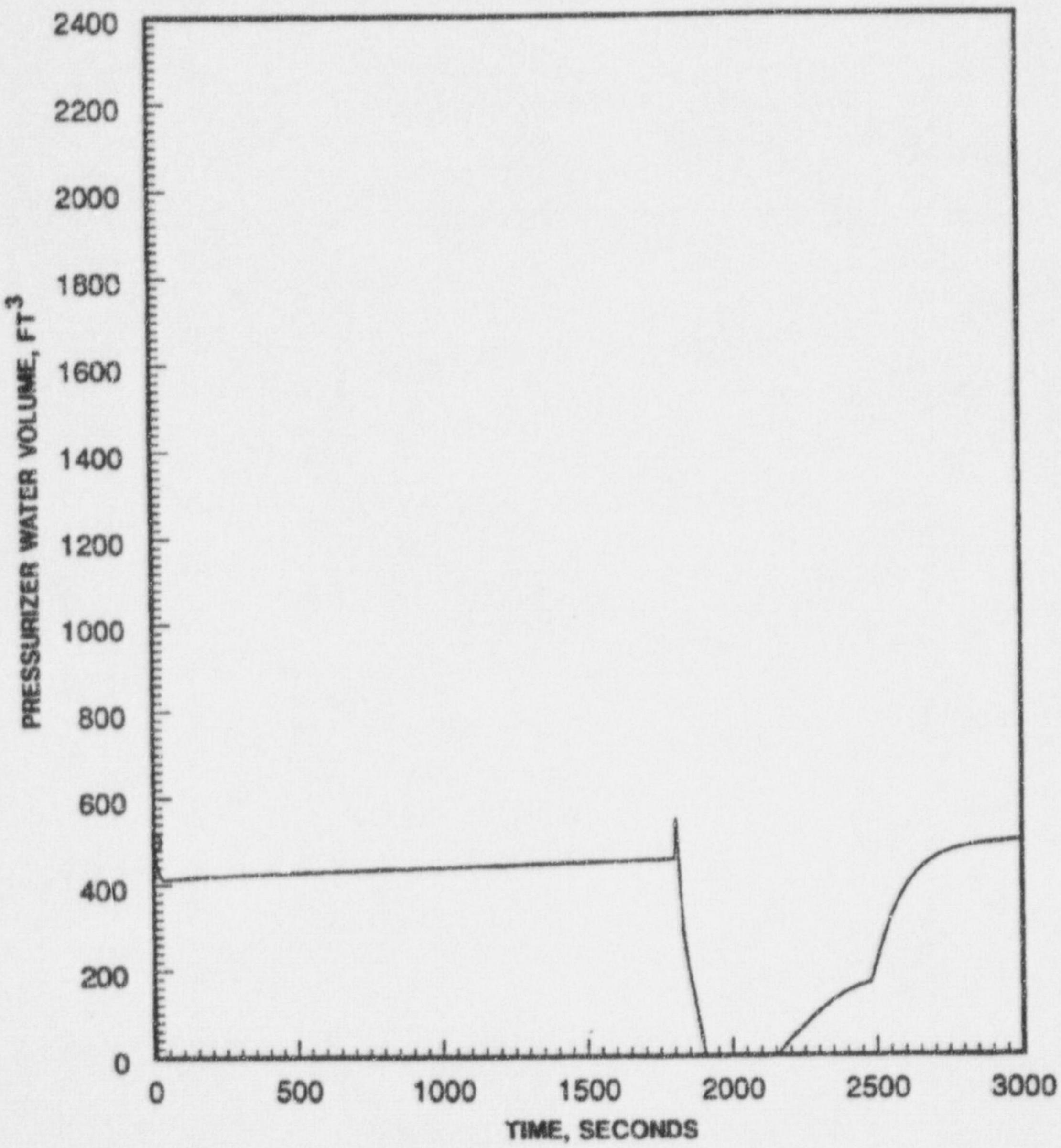
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Reactor Coolant Flow Rates vs. Time	Figure 15.1.4-1.4



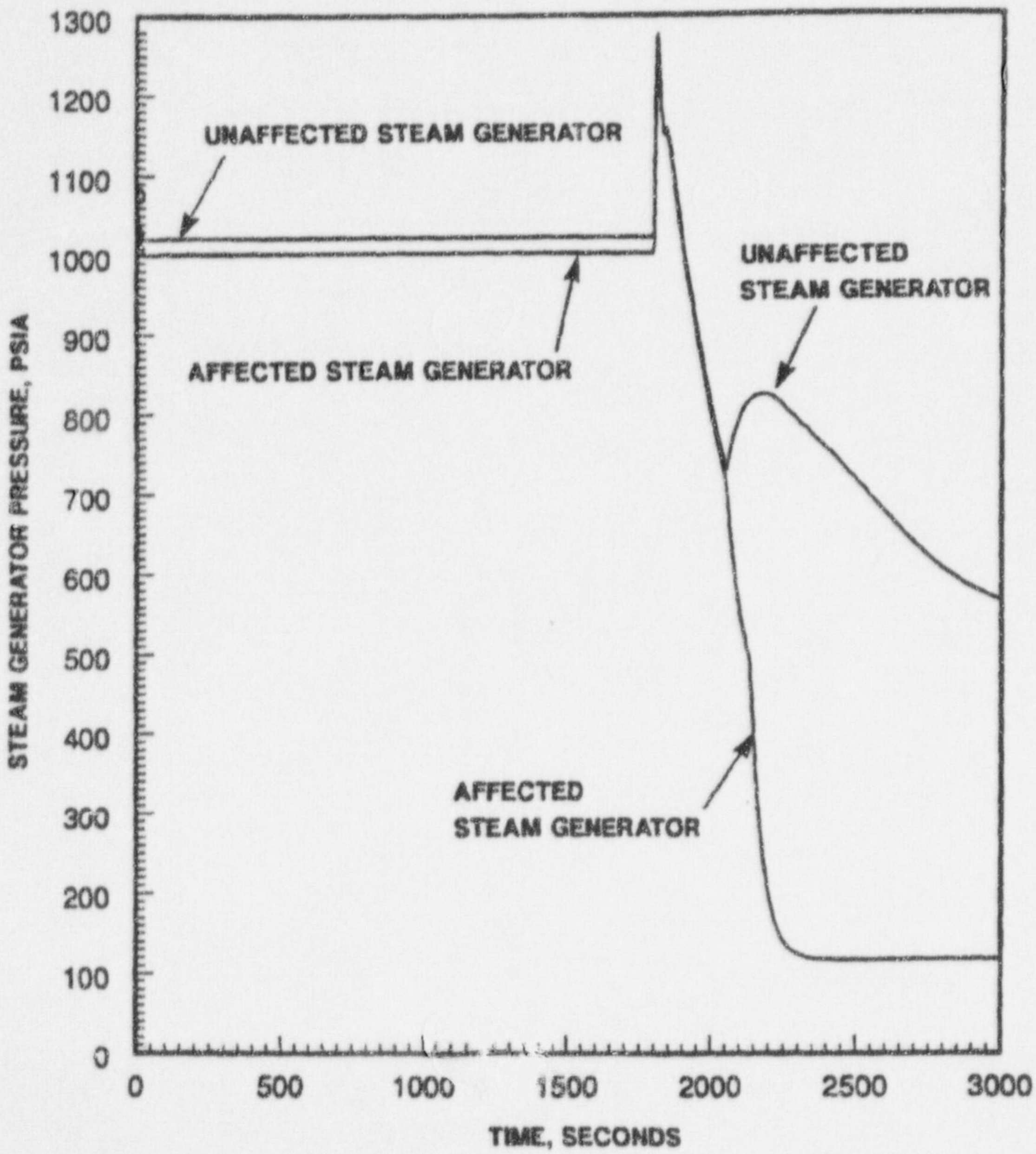
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Reactor Coolant Temperatures (A) vs. Time	Figure 15.1.4-1.5A



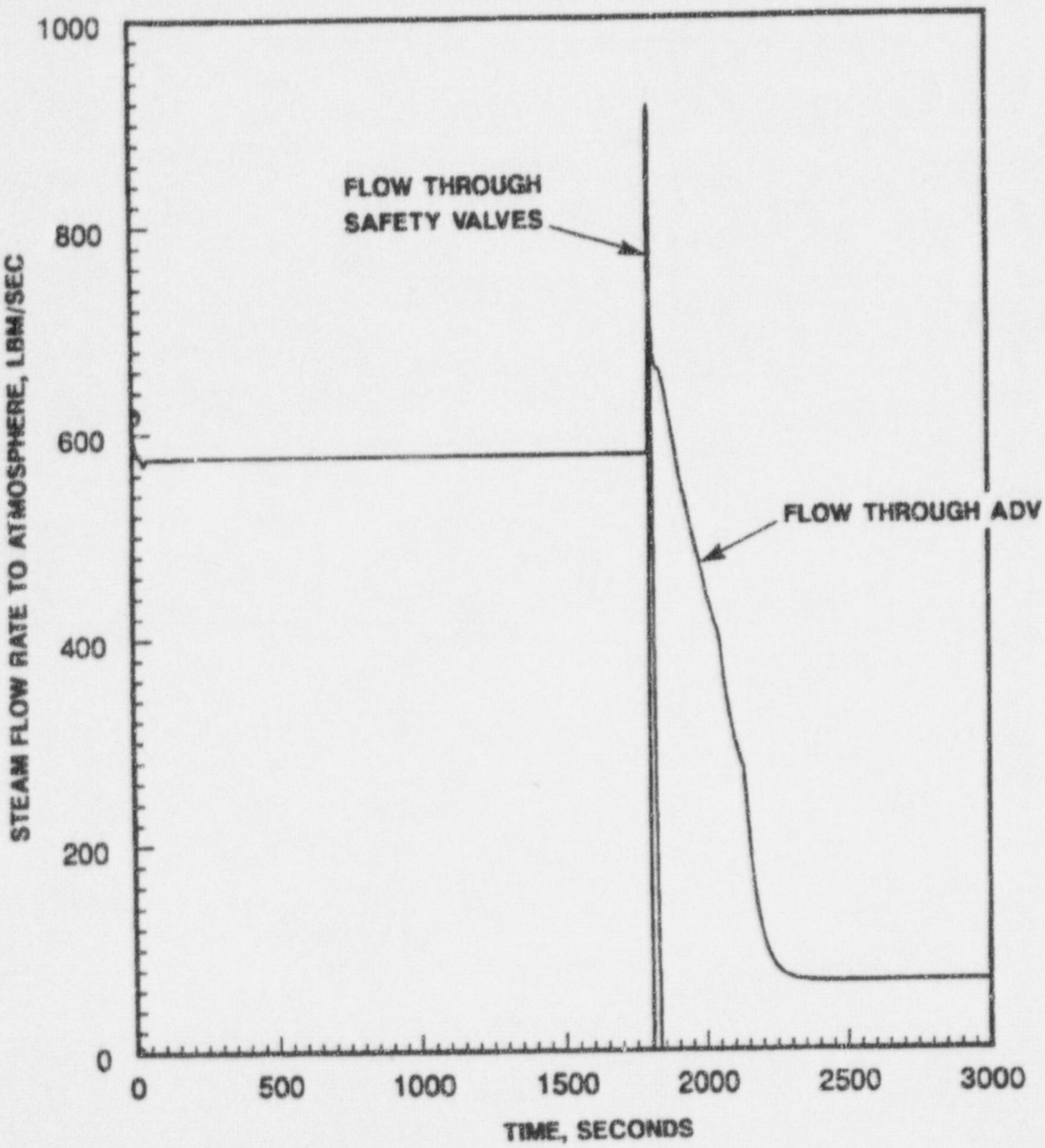
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Reactor Coolant Temperatures (B) vs. Time	Figure 15.1.4-1.5B



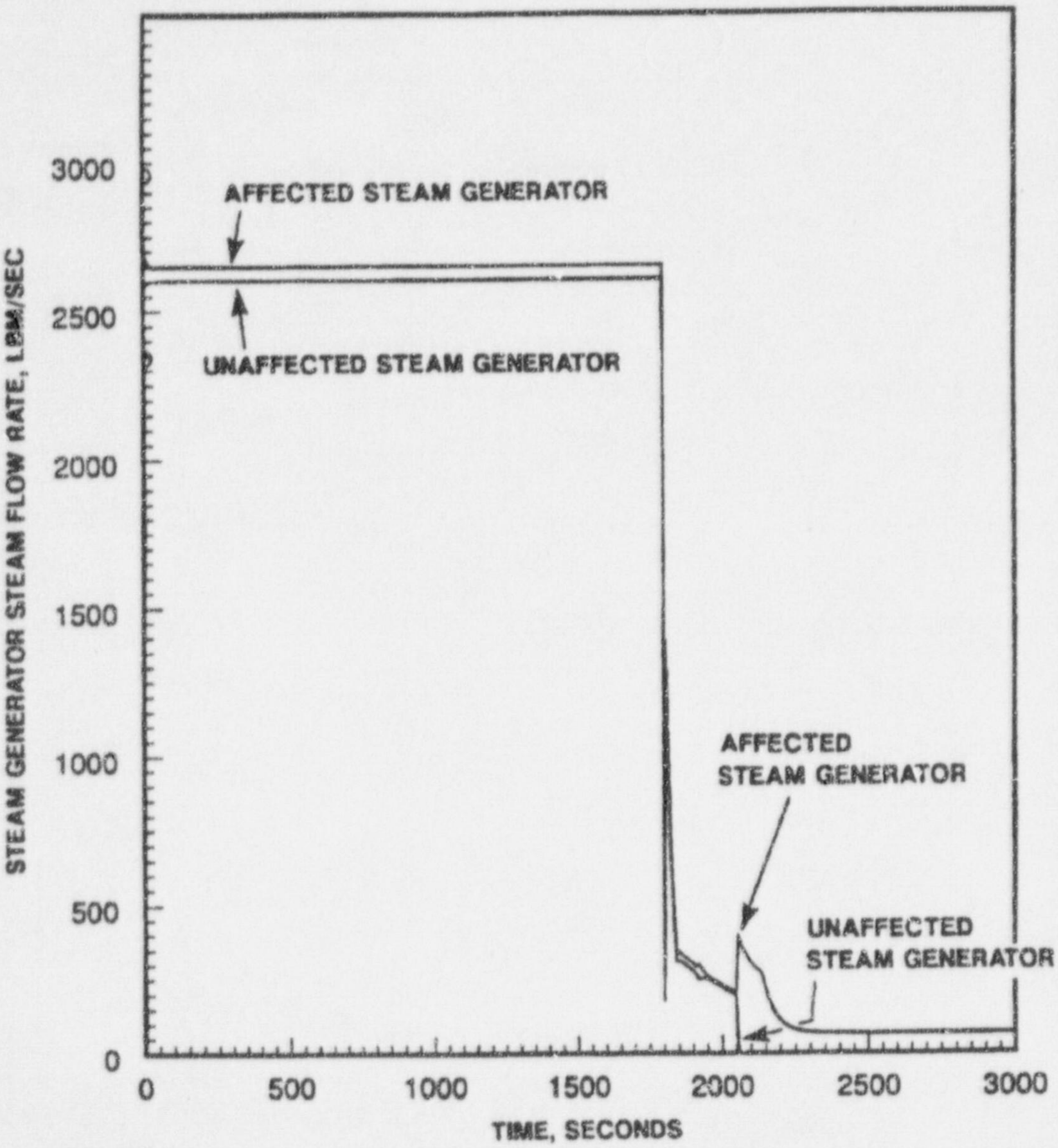
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Pressurizer Water Volume vs. Time	Figure 15.1.4-1.6



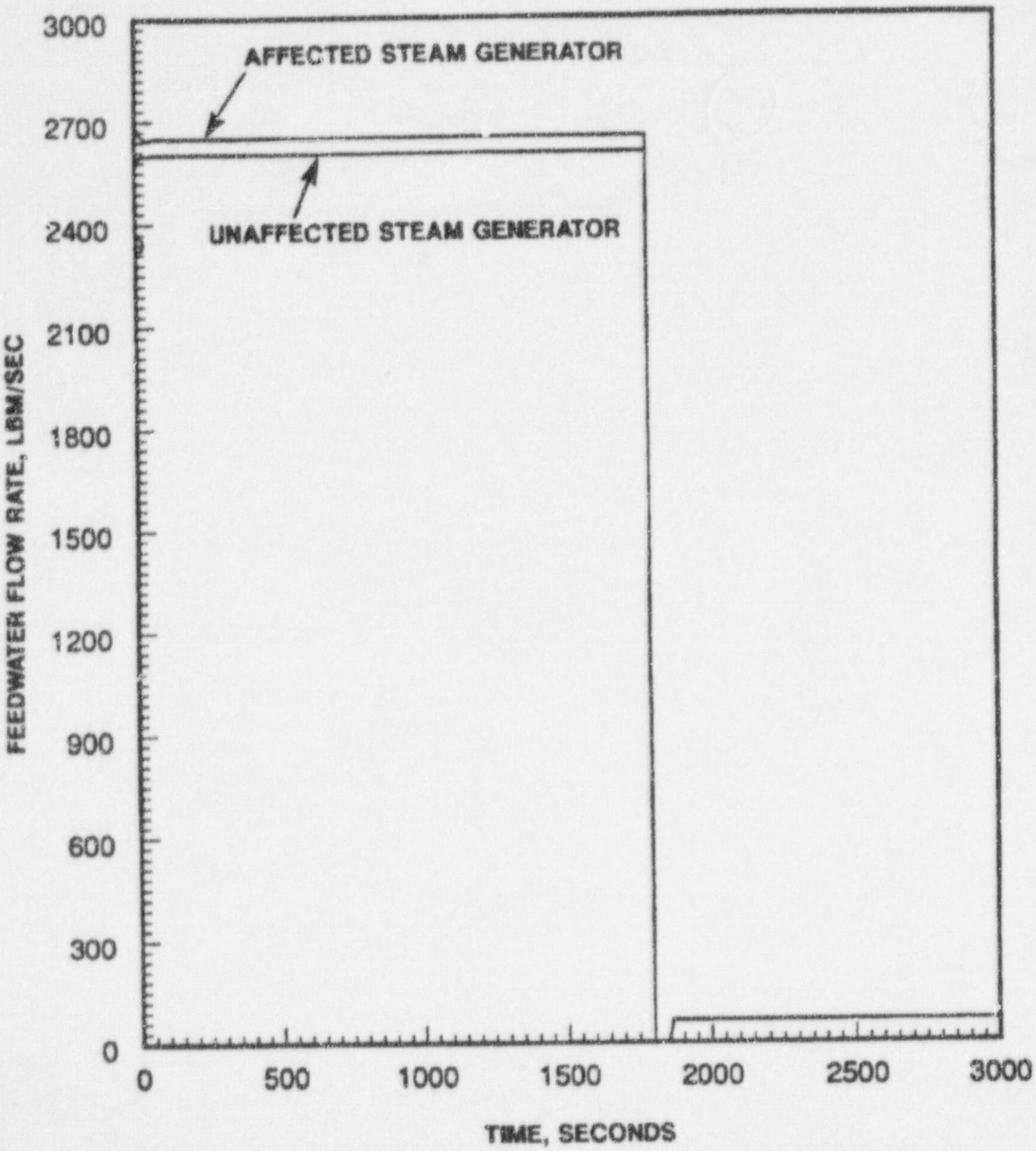
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Steam Generator Pressures vs. Time	Figure 15.1.4-1.7



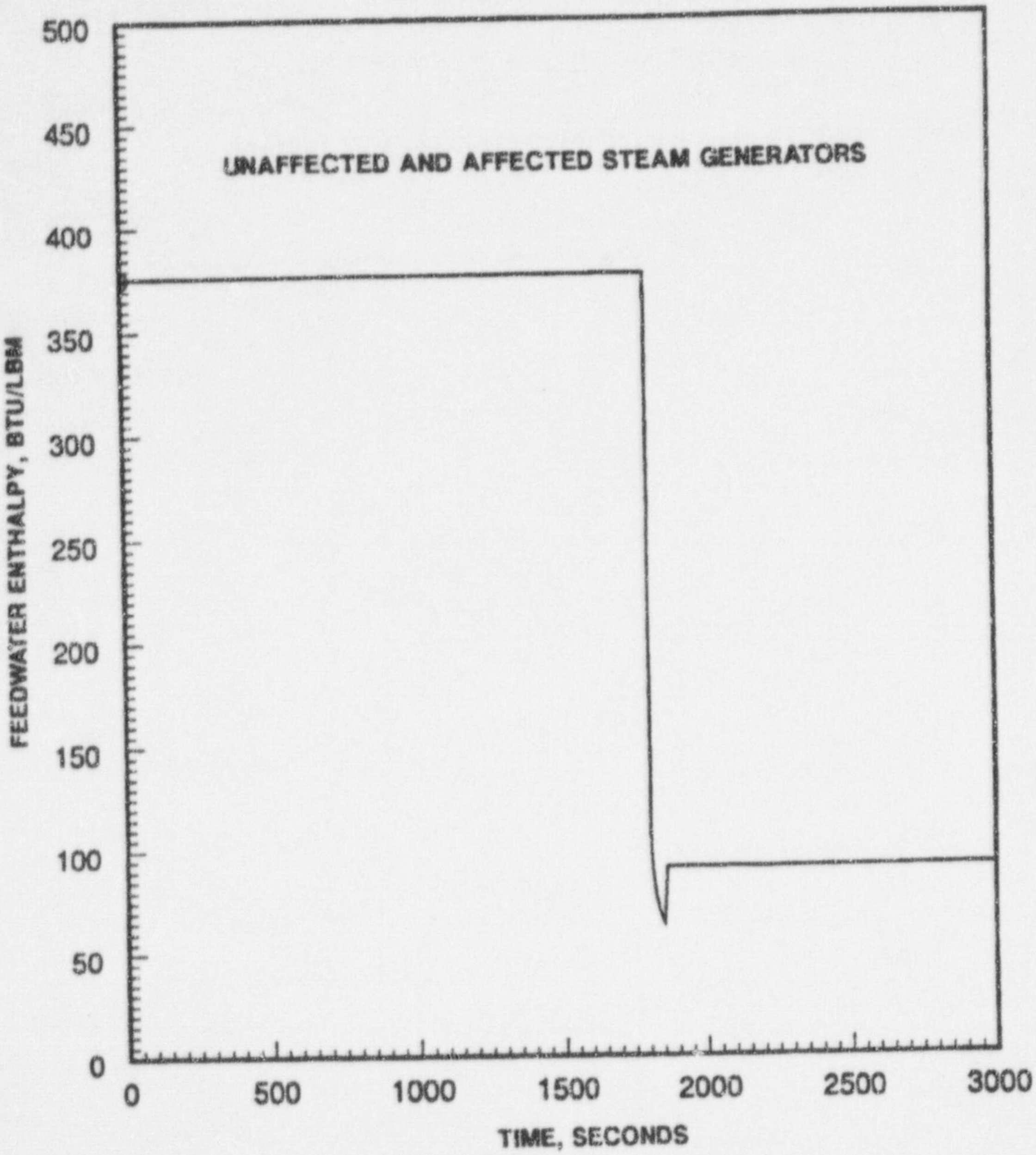
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Steam Flow Rates to Atmosphere vs. Time	Figure 15.1.4-1.8



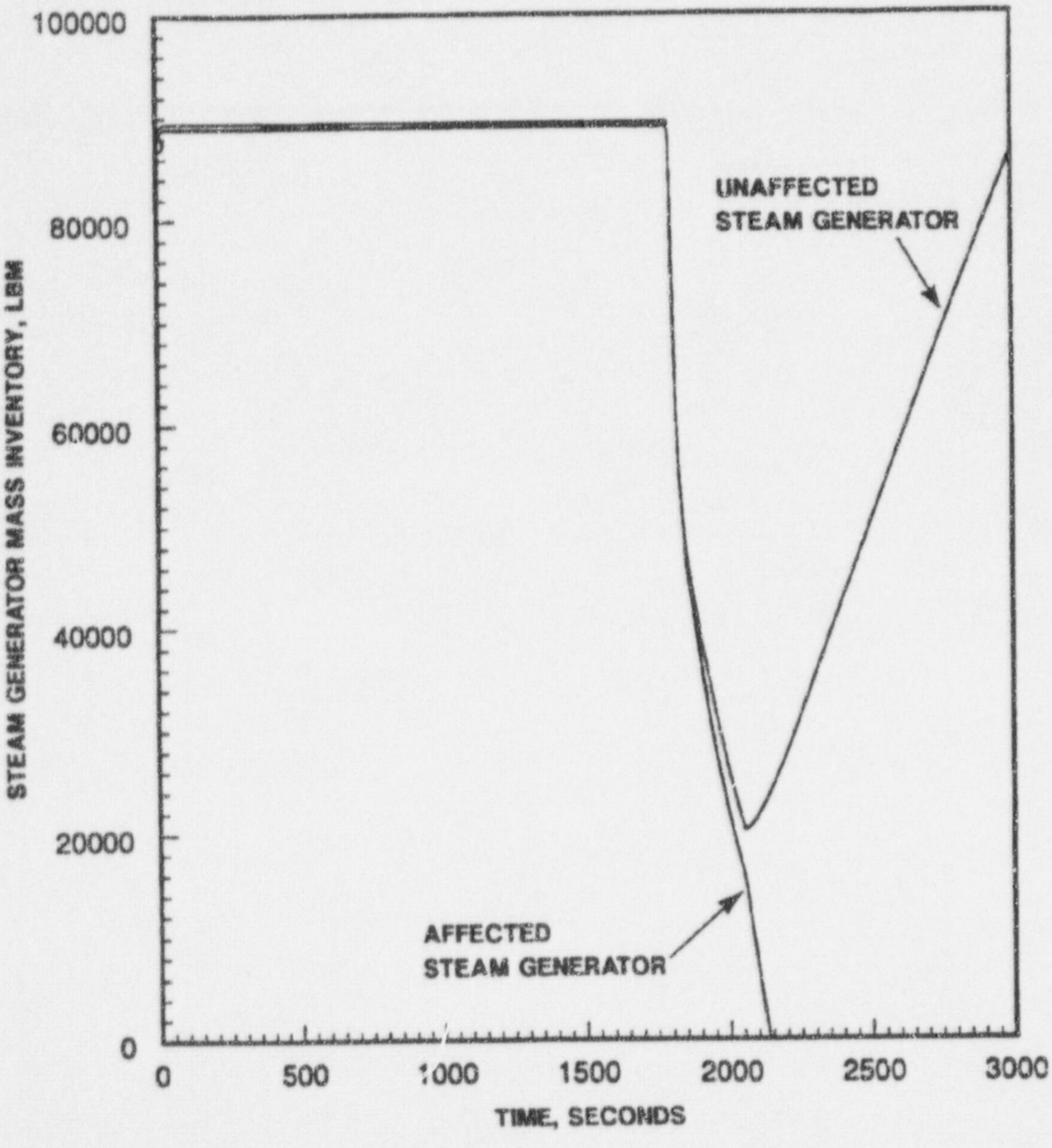
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Steam Generator Steam Flow Rates vs. Time	Figure 15.1.4-1.9



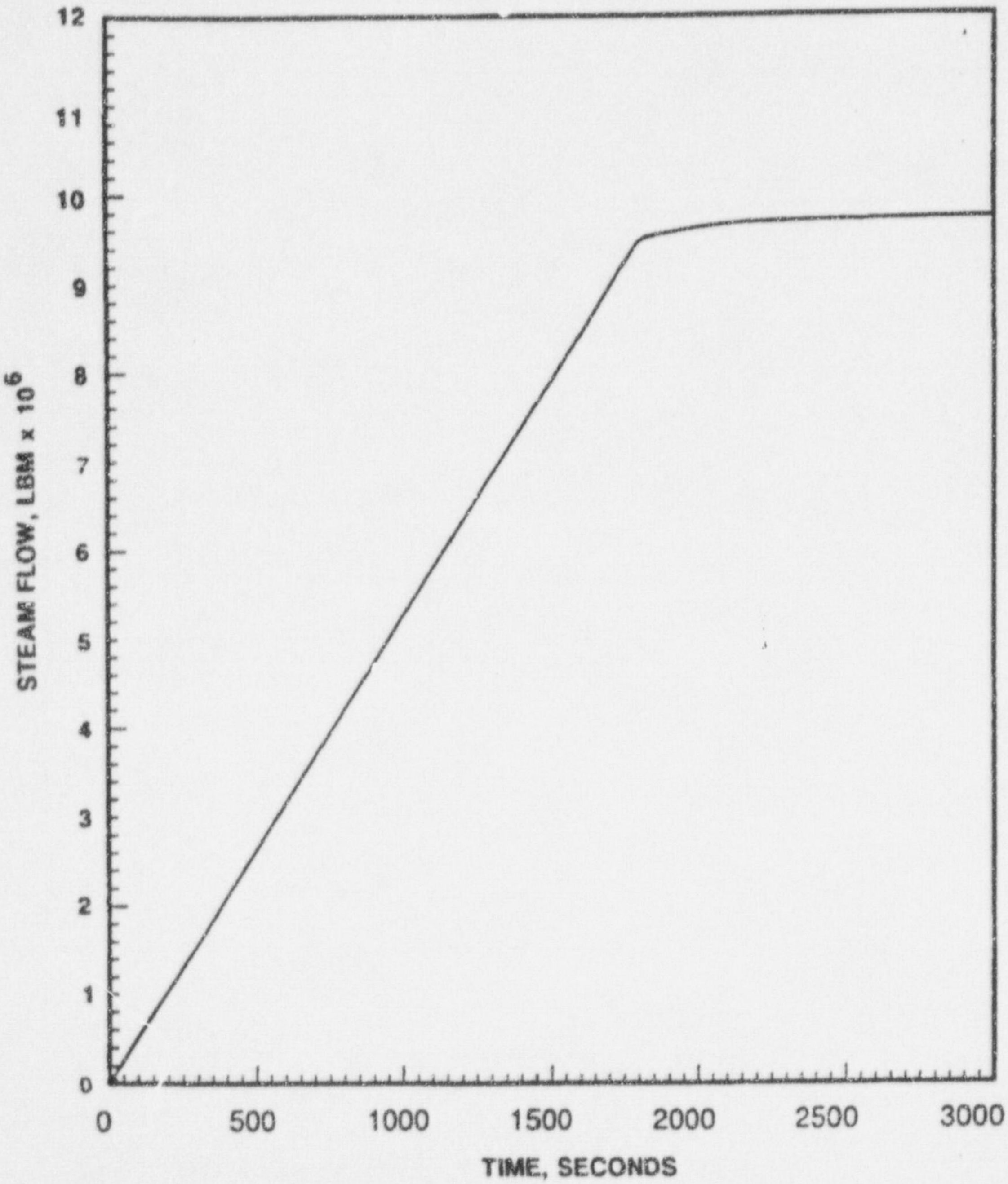
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Feedwater Flow Rates vs. Time	Figure 15.1.4-1.10



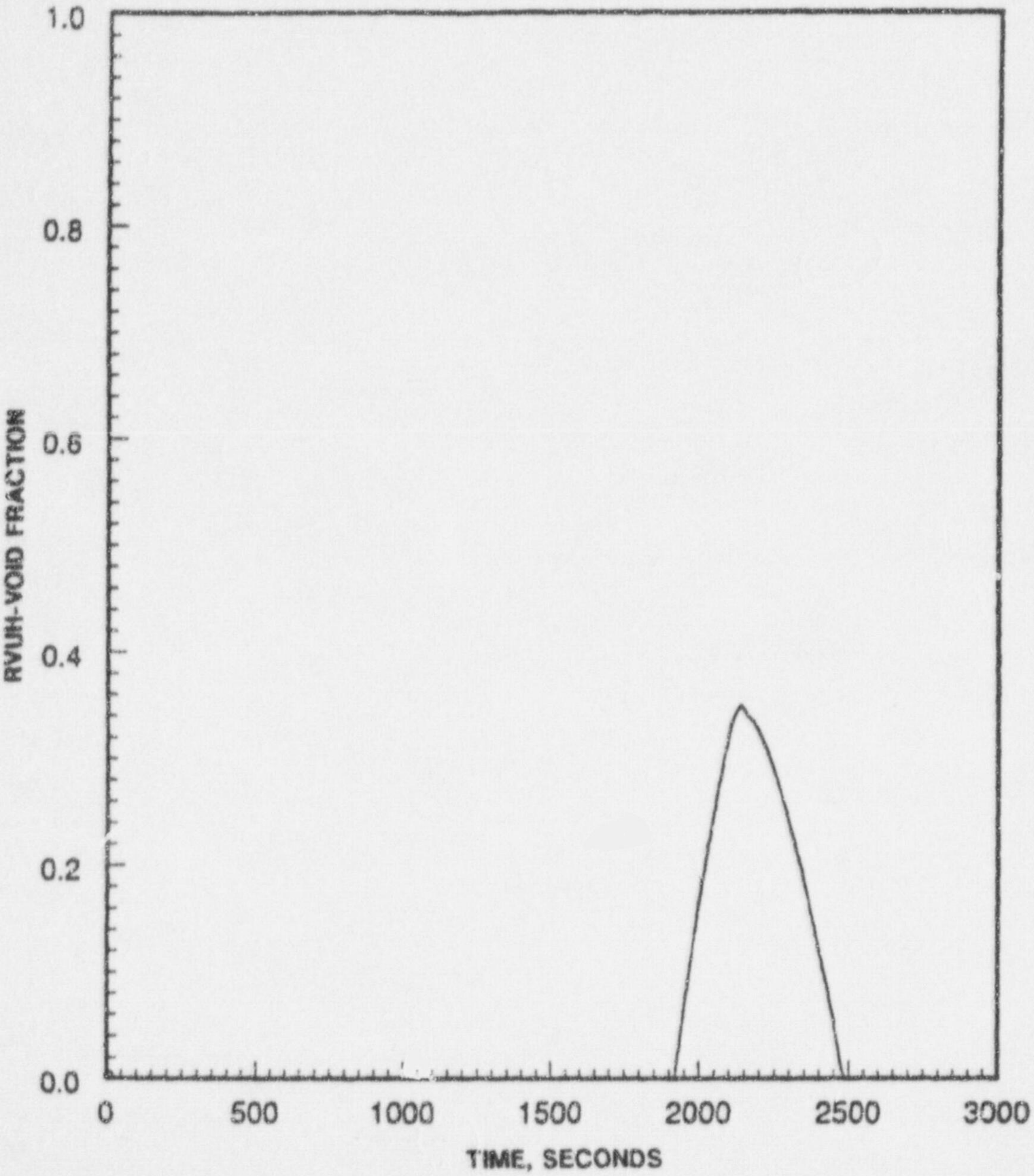
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Feedwater Enthalpies vs. Time	Figure 15.1.4-1.11



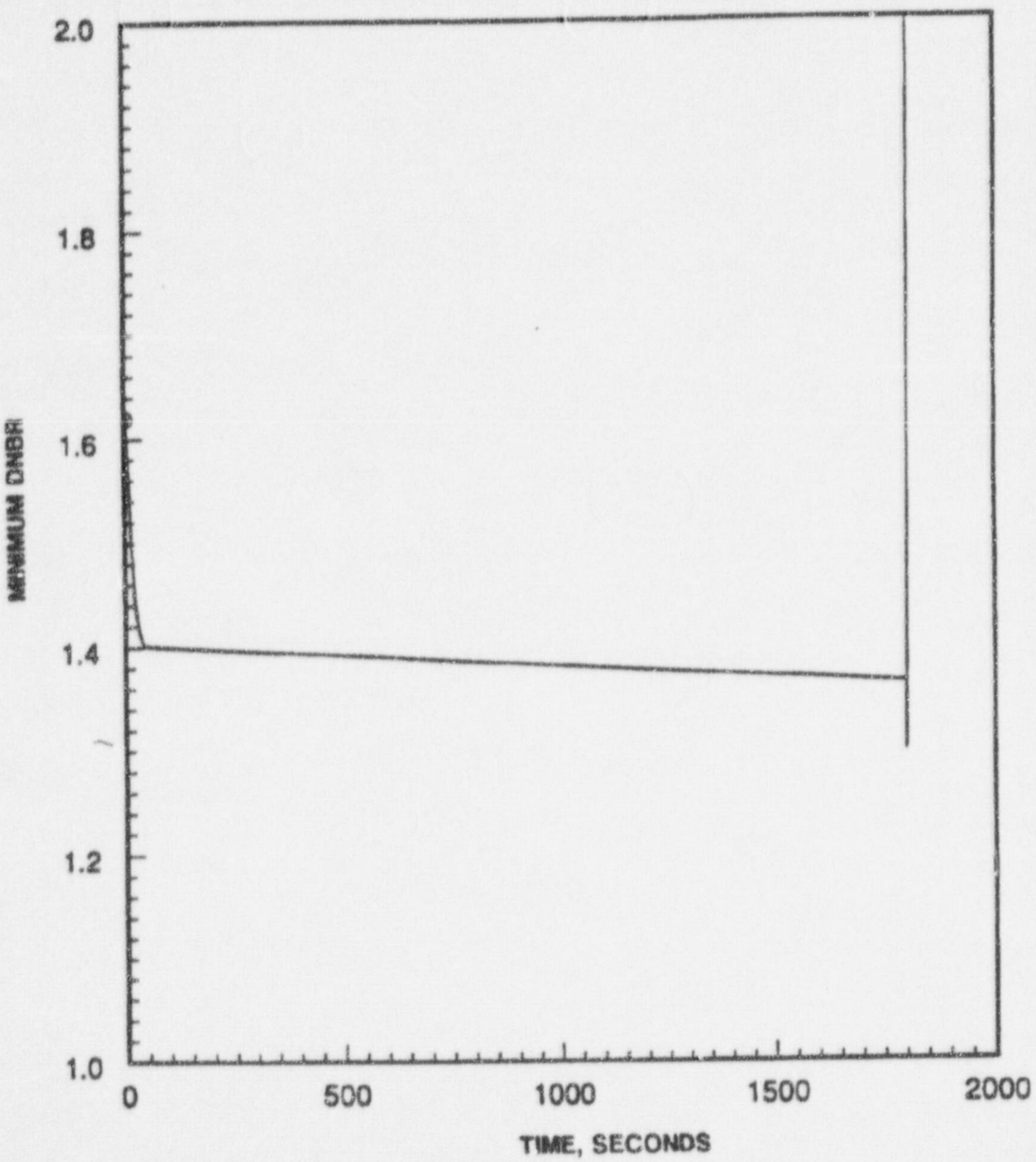
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Steam Generator Mass Inventories vs. Time	Figure 15.1.4-1.12



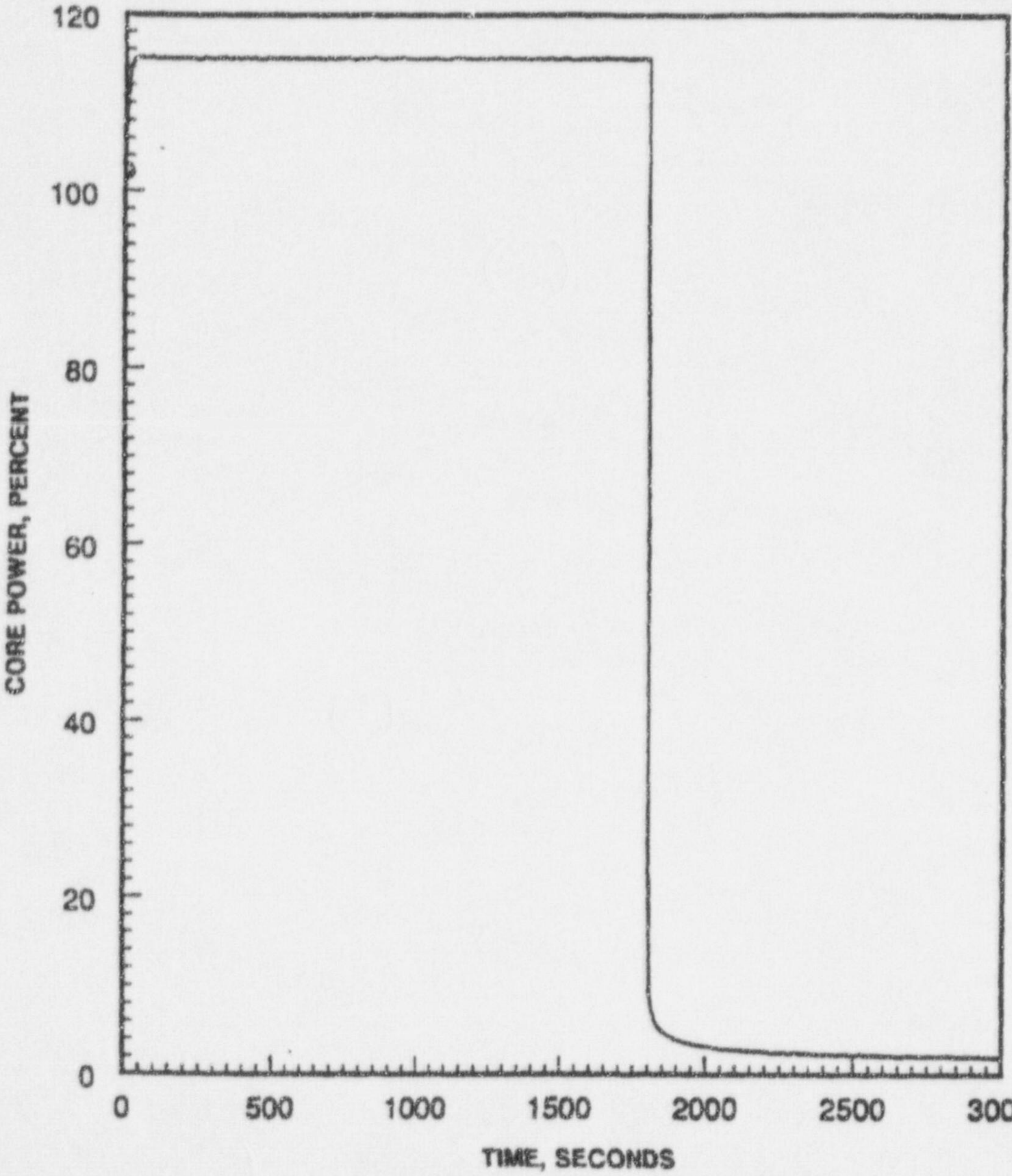
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Steam Flow to Atmosphere vs. Time	Figure 15.1.4-1.13



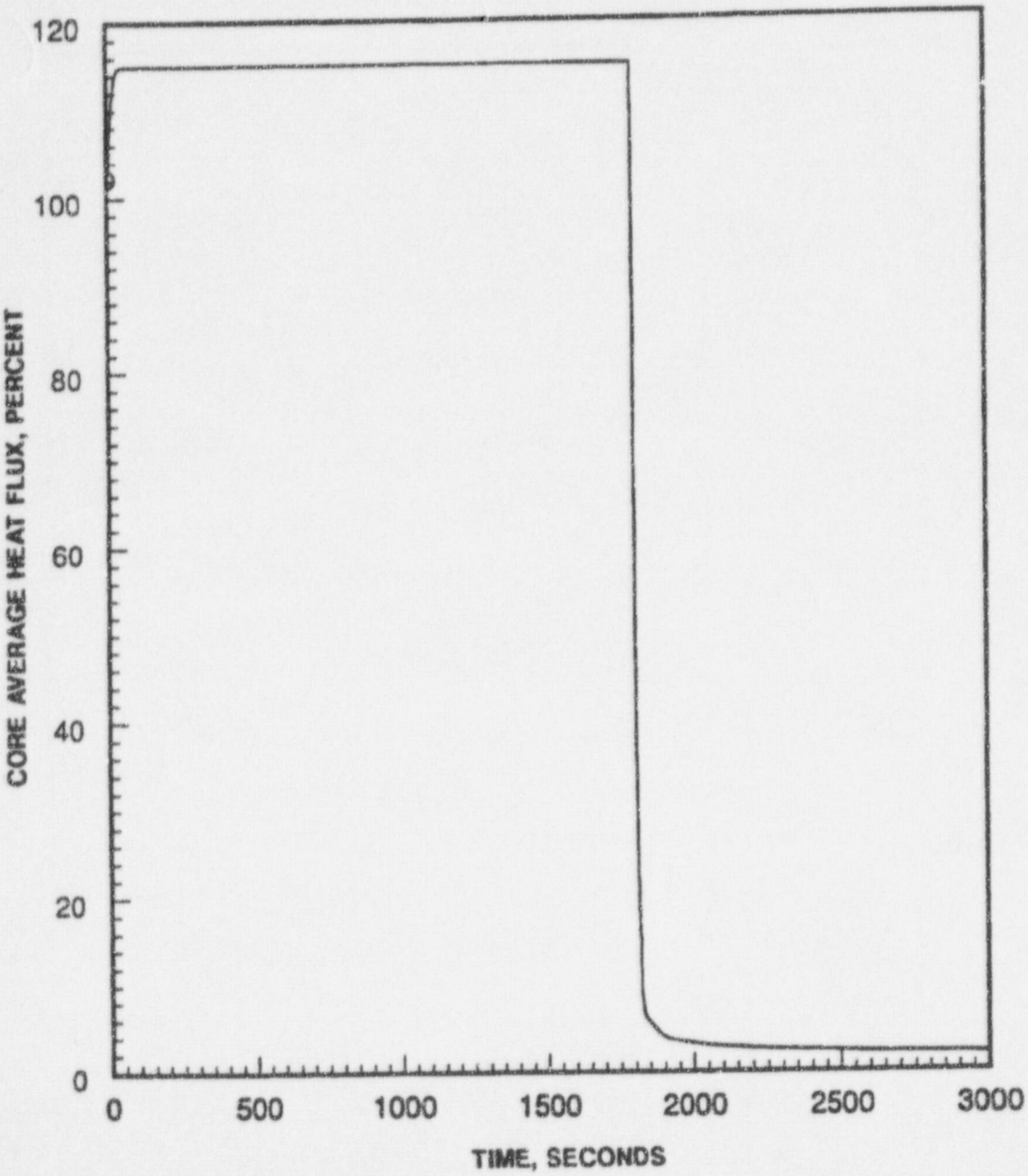
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Reactor Vessel Upper Head Steam Void Fraction	Figure 15.1.4-1.14



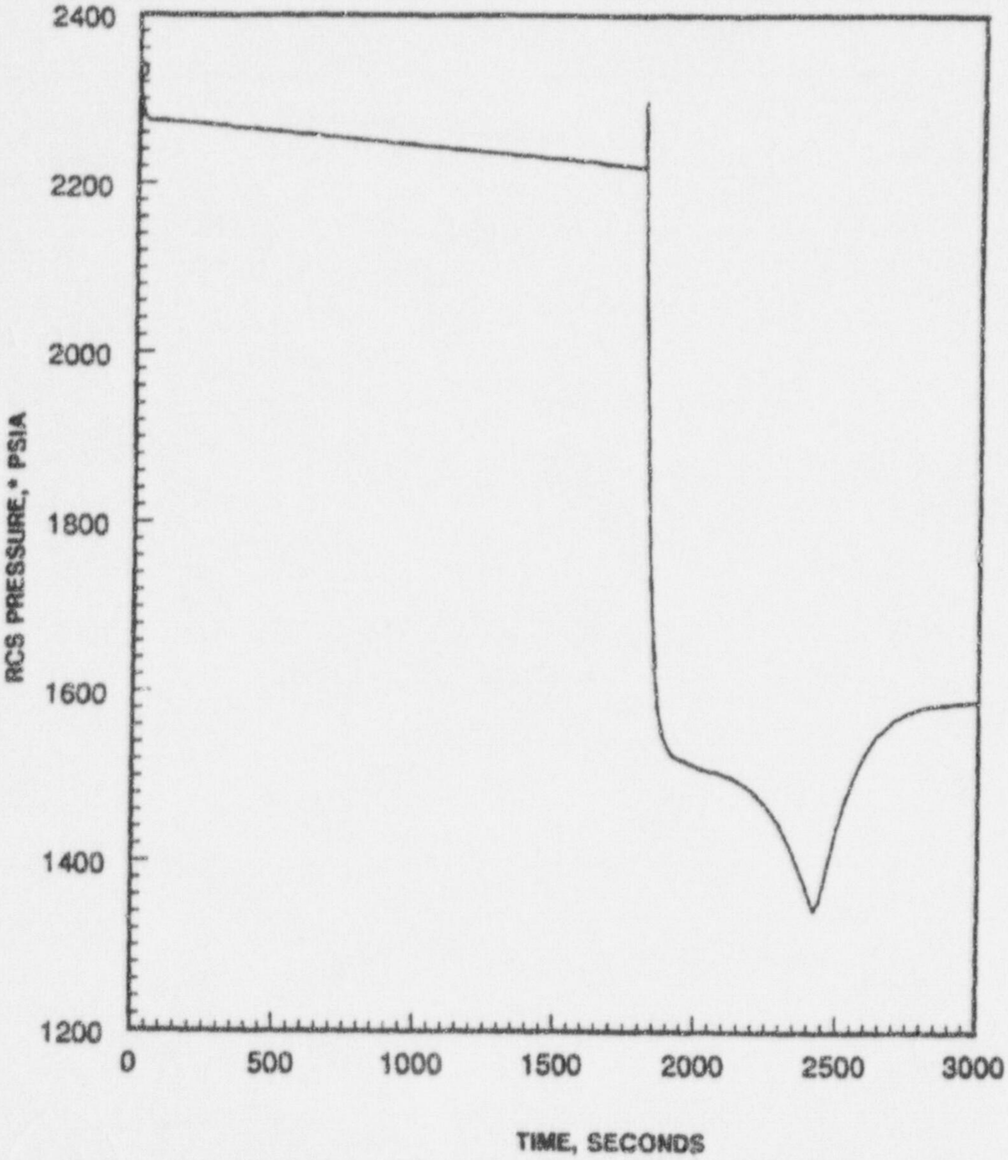
Inadvertent Opening of an Atmospheric Dump Valve (IOSGADV) with Loss of Offsite Power; Minimum DNBR vs. Time	Figure 15.1.4-1.15



IOSGADV with Single Failure and LOOP; Core Power Vs. Time	Figure 15.1.4-2.1

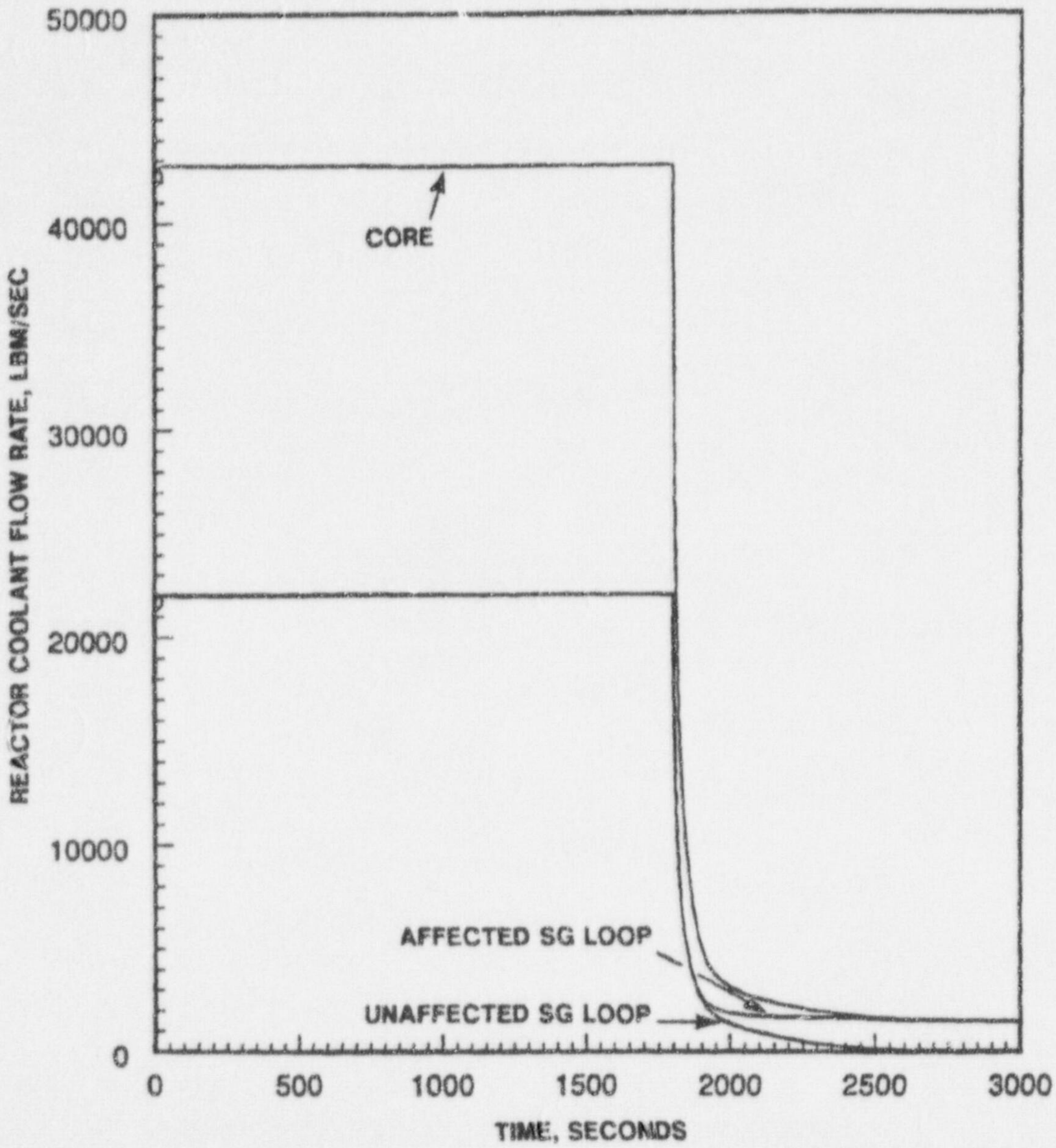


IOSGADV with Single Failure and LOOP; Core Average Heat Flux vs. Time	Figure 15.1.4-2.2

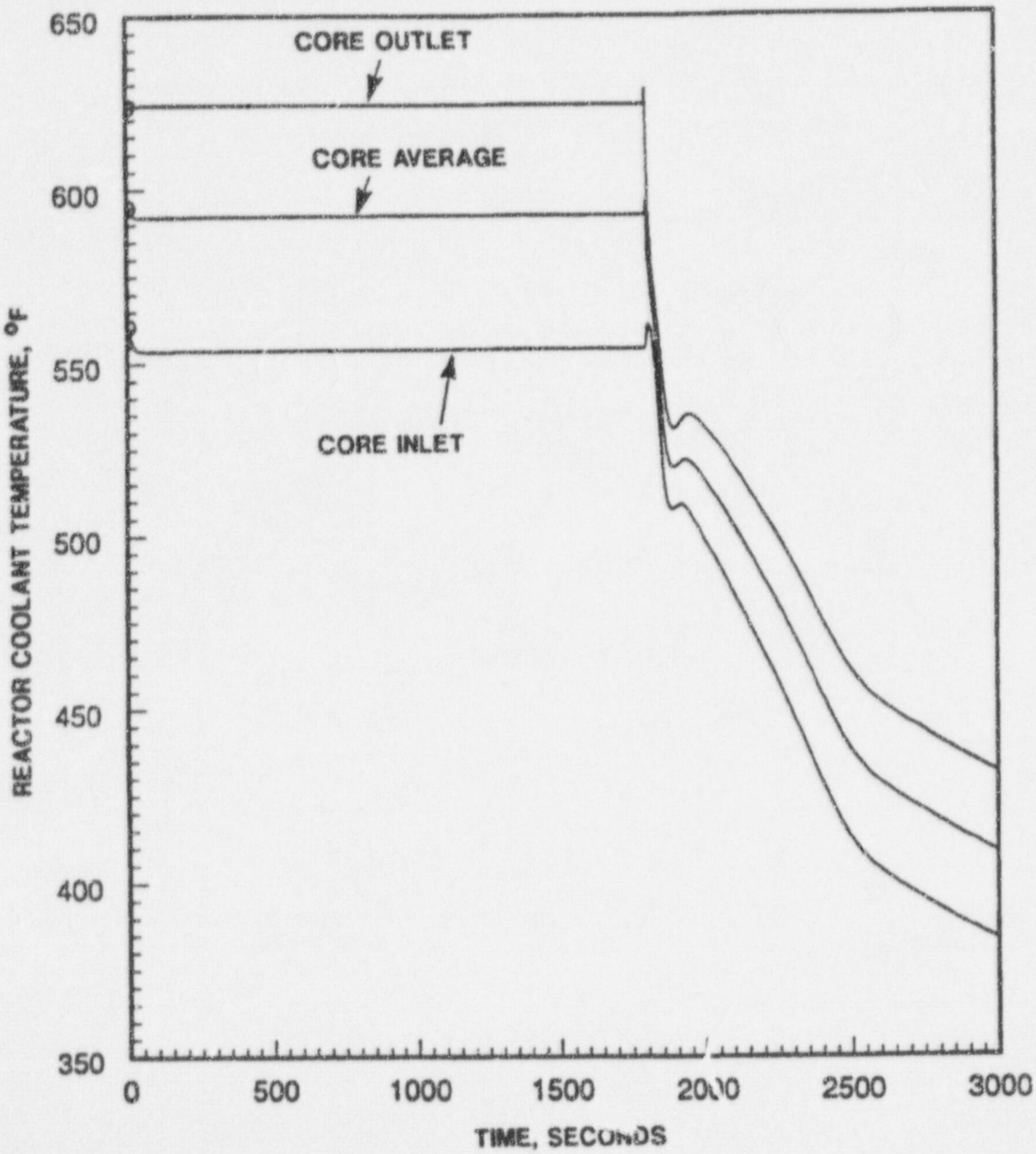


*THIS PRESSURE DOES NOT INCLUDE THE PRESSURE DIFFERENCE BETWEEN THE COLD LEG AT RCP DISCHARGE AND THE SURGE LINE

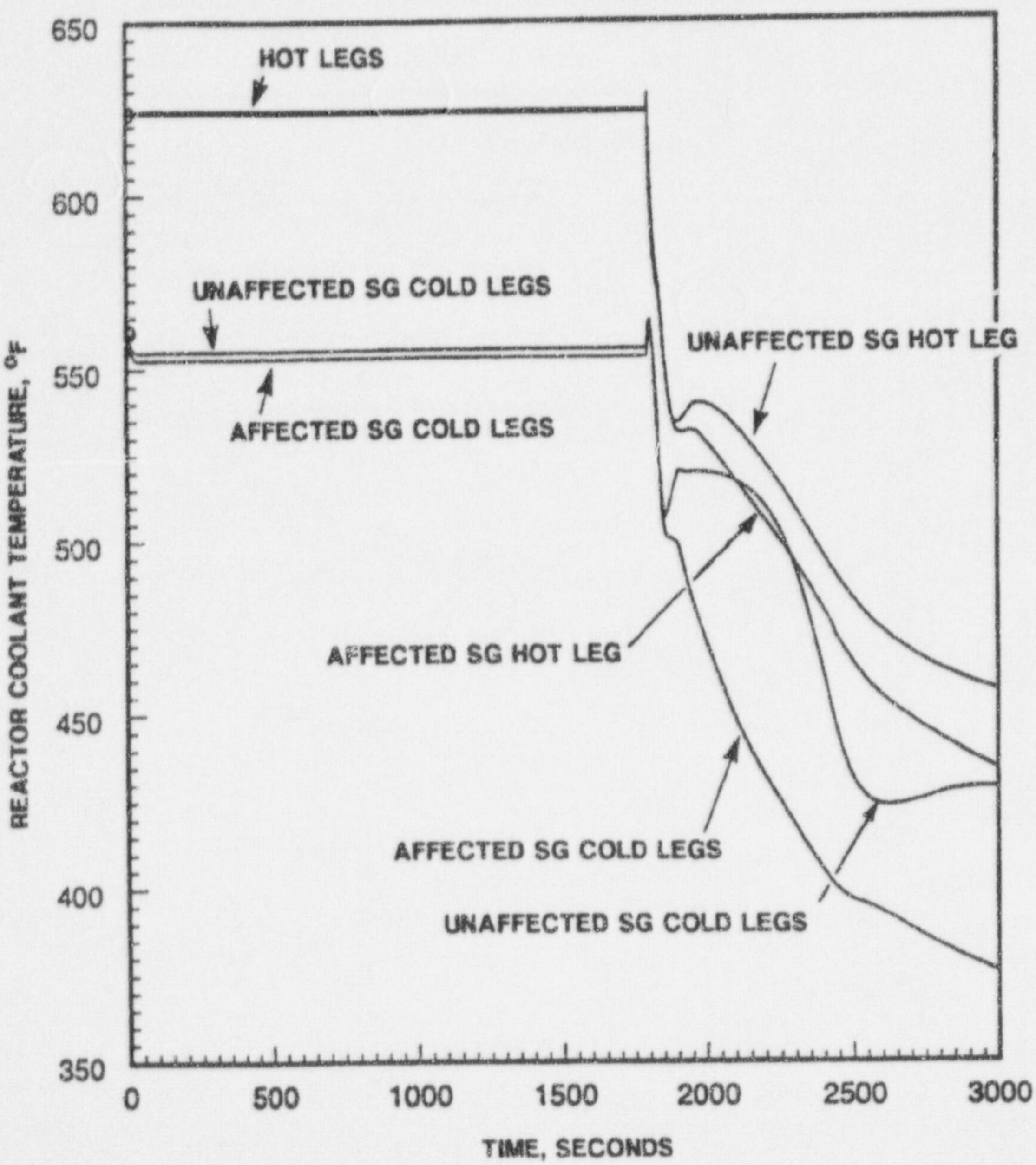
IOSGADV with Single Failure and LOOP; Reactor Coolant System Pressure vs. Time	Figure 15.1.4-2.3



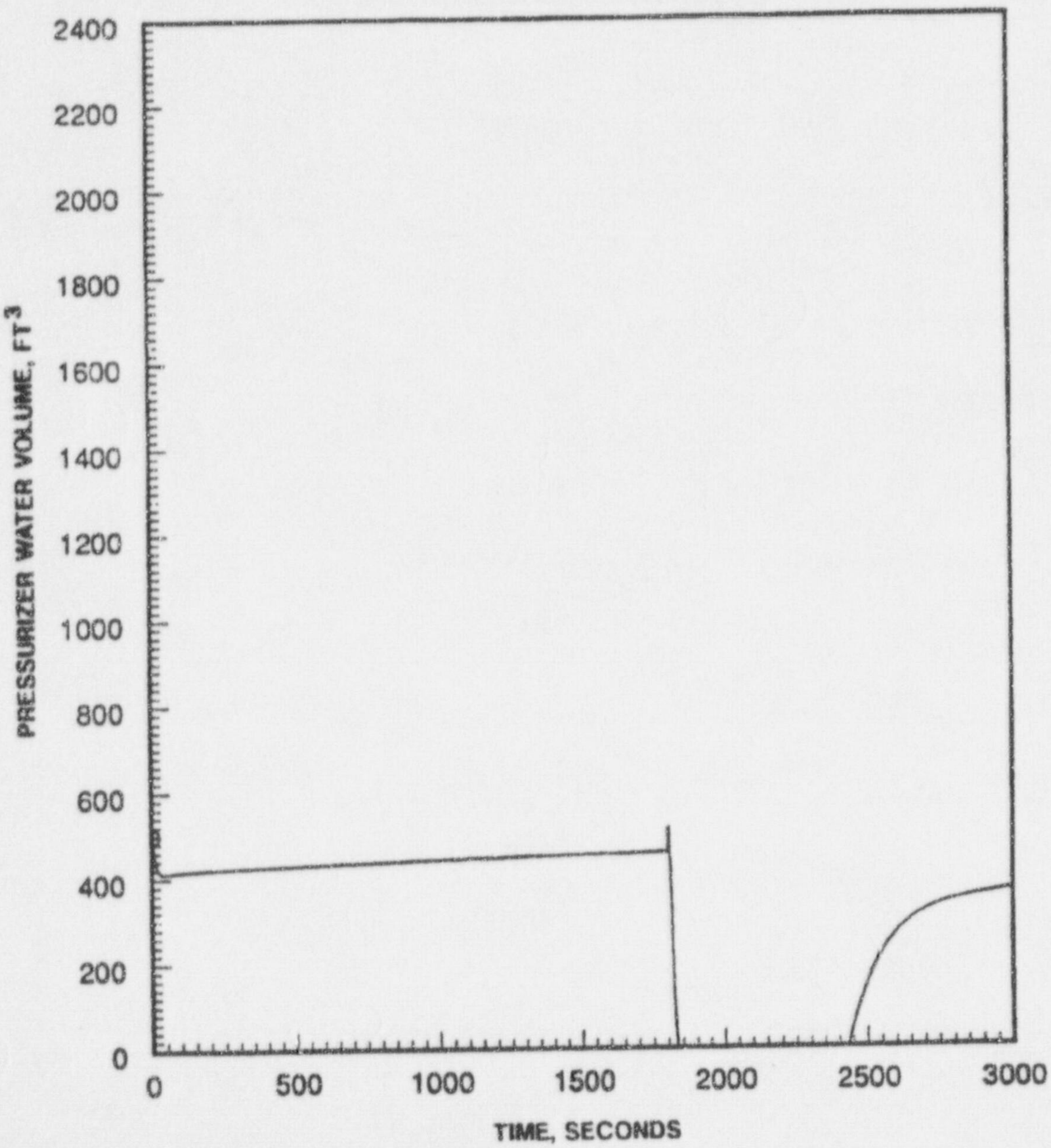
IOSGADV with Single Failure and LOOP; Reactor Coolant Flow Rates vs. Time	Figure 15.1.4-2.4



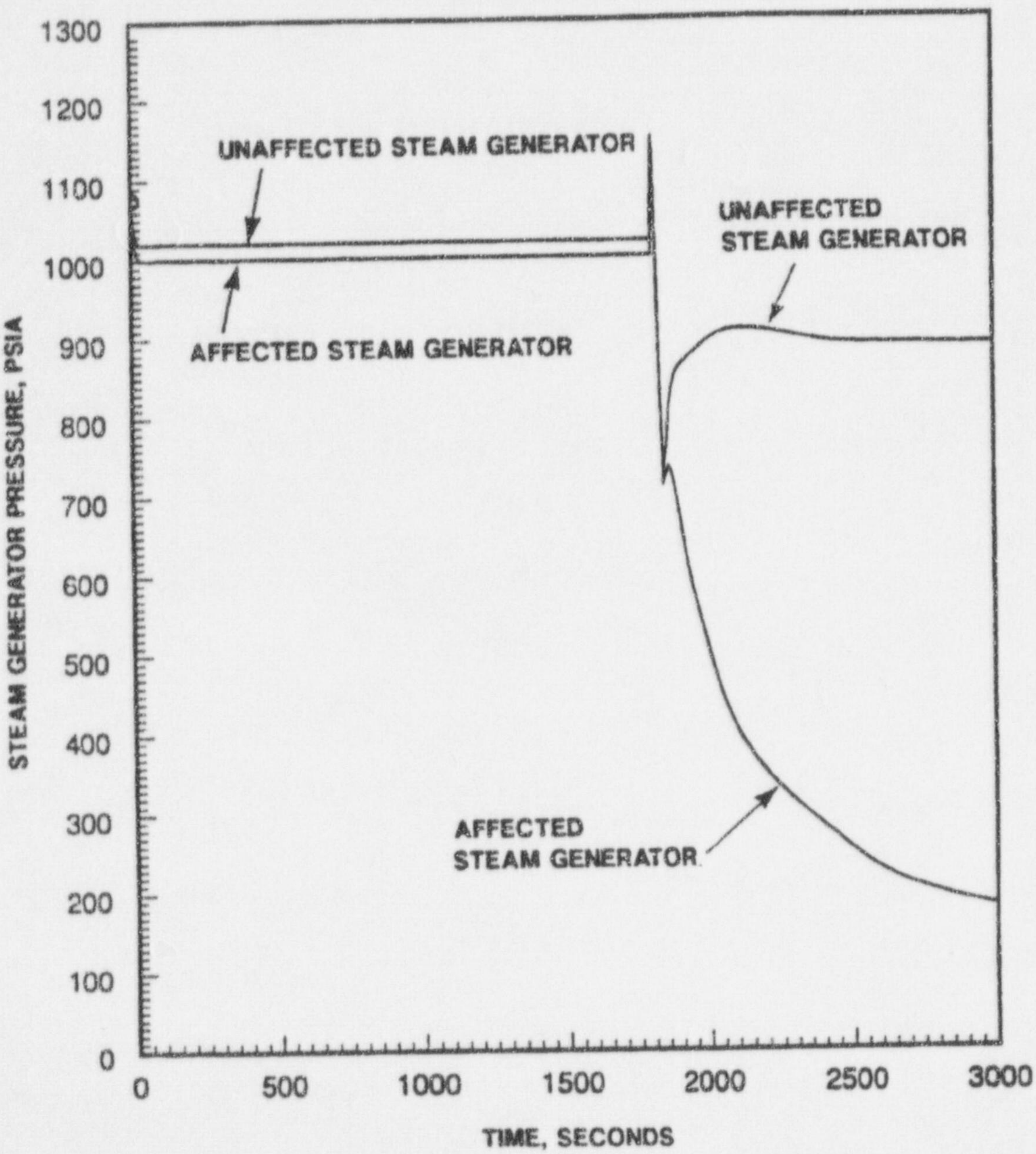
IOSGADV with Single Failure and LOOP; Reactor Coolant Temperatures (A) vs. Time	Figure 15.1.4-2.5A



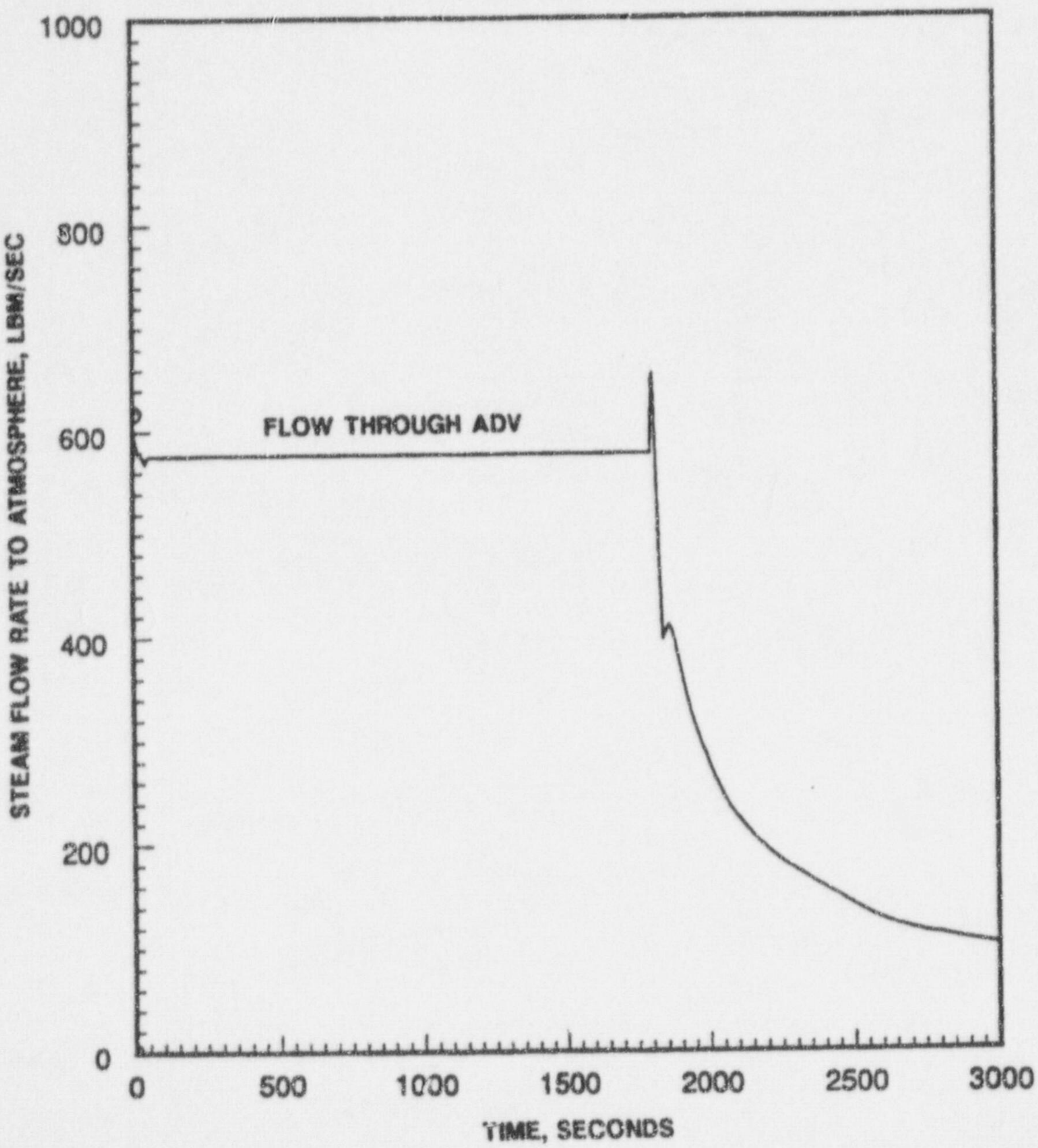
IOSGADV with Single Failure and LOOP; Reactor Coolant Temperatures (B) vs. Time	Figure 15.1.4-2.5B



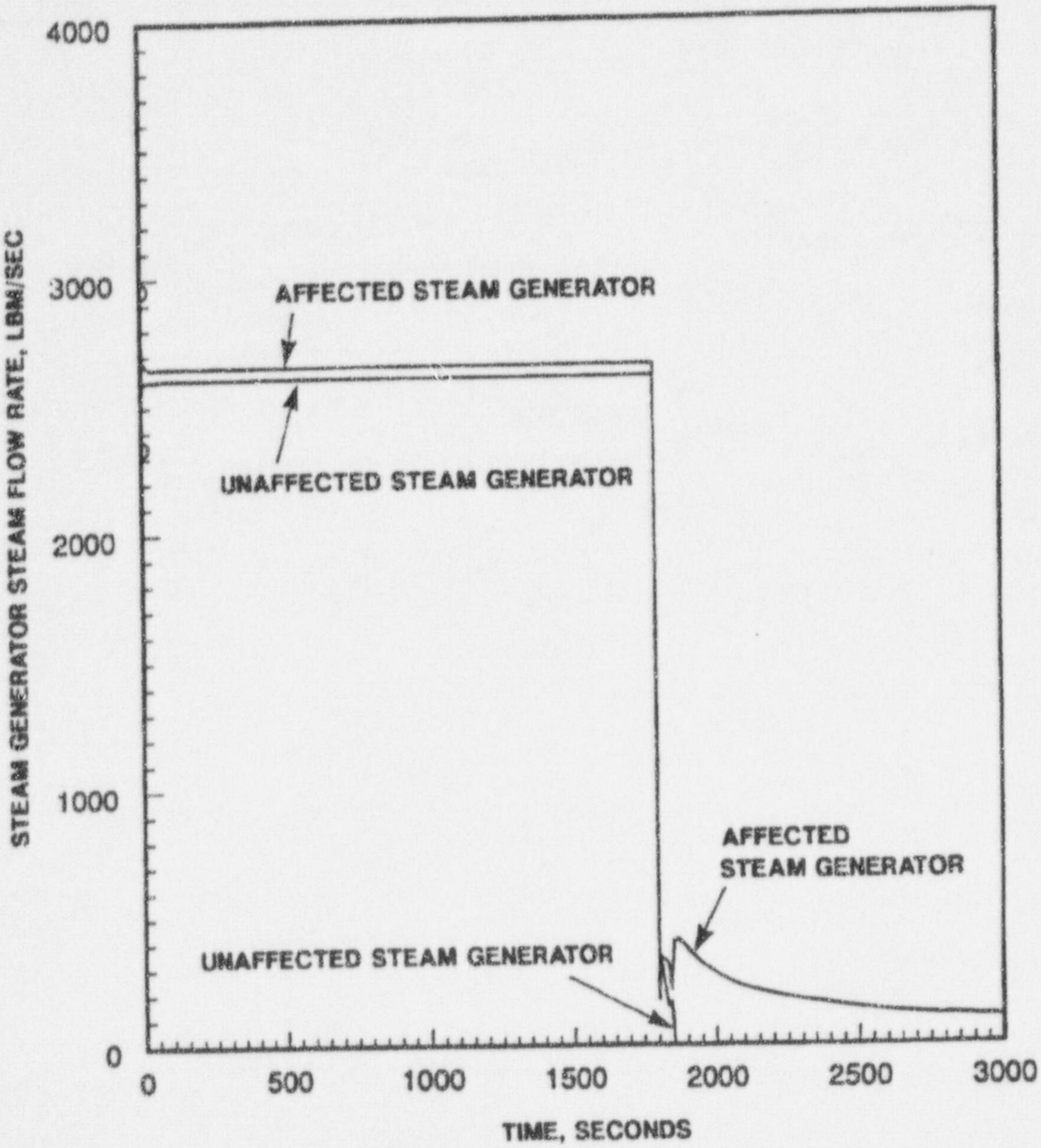
IOSGADV with Single Failure and LOOP; Pressurizer Water Volume vs. Time	Figure 15.1.4-2.6



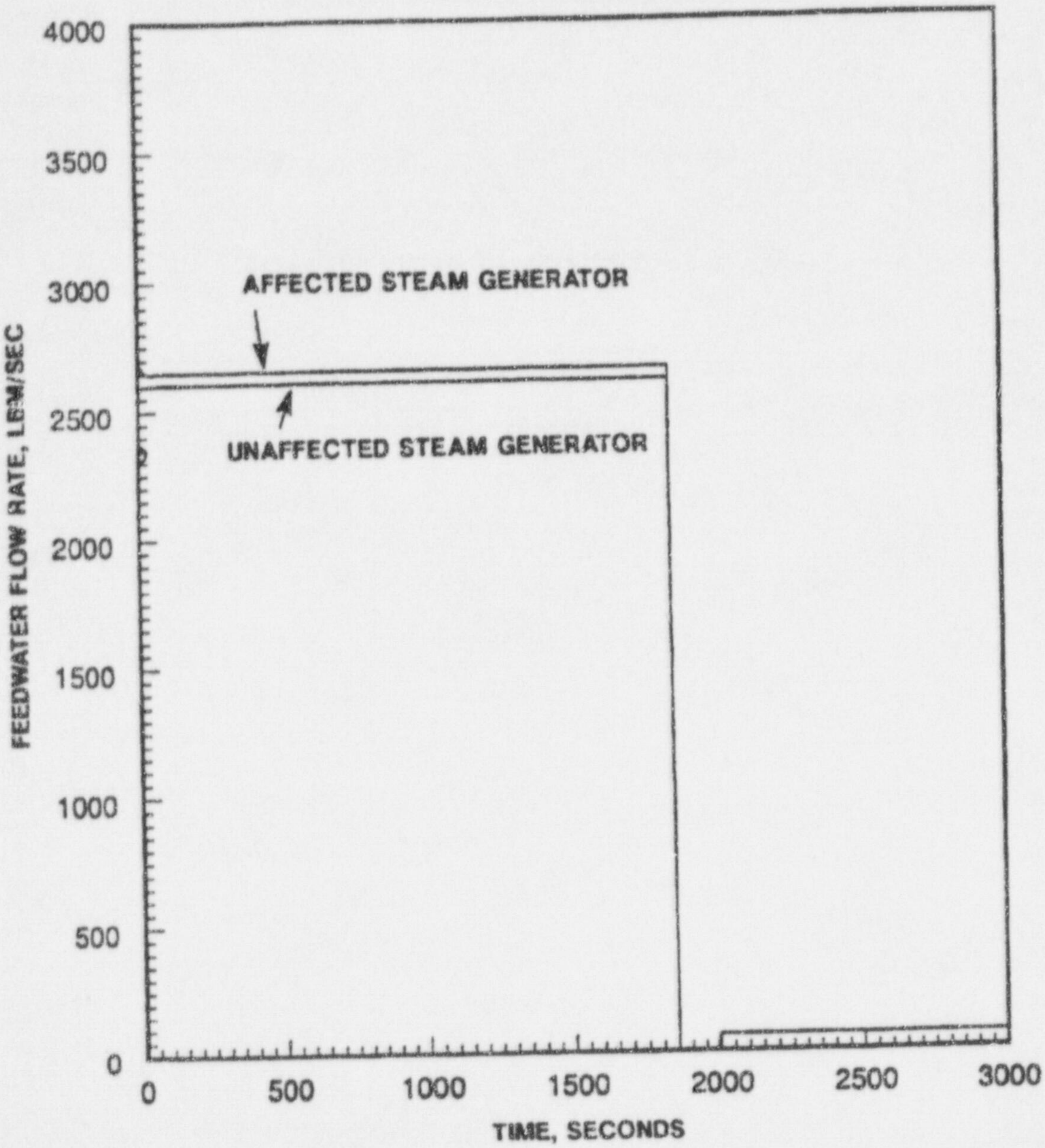
IOSGADV with Single Failure and LOOP; Steam Generator Pressures vs. Time	Figure 15.1.4-2.7



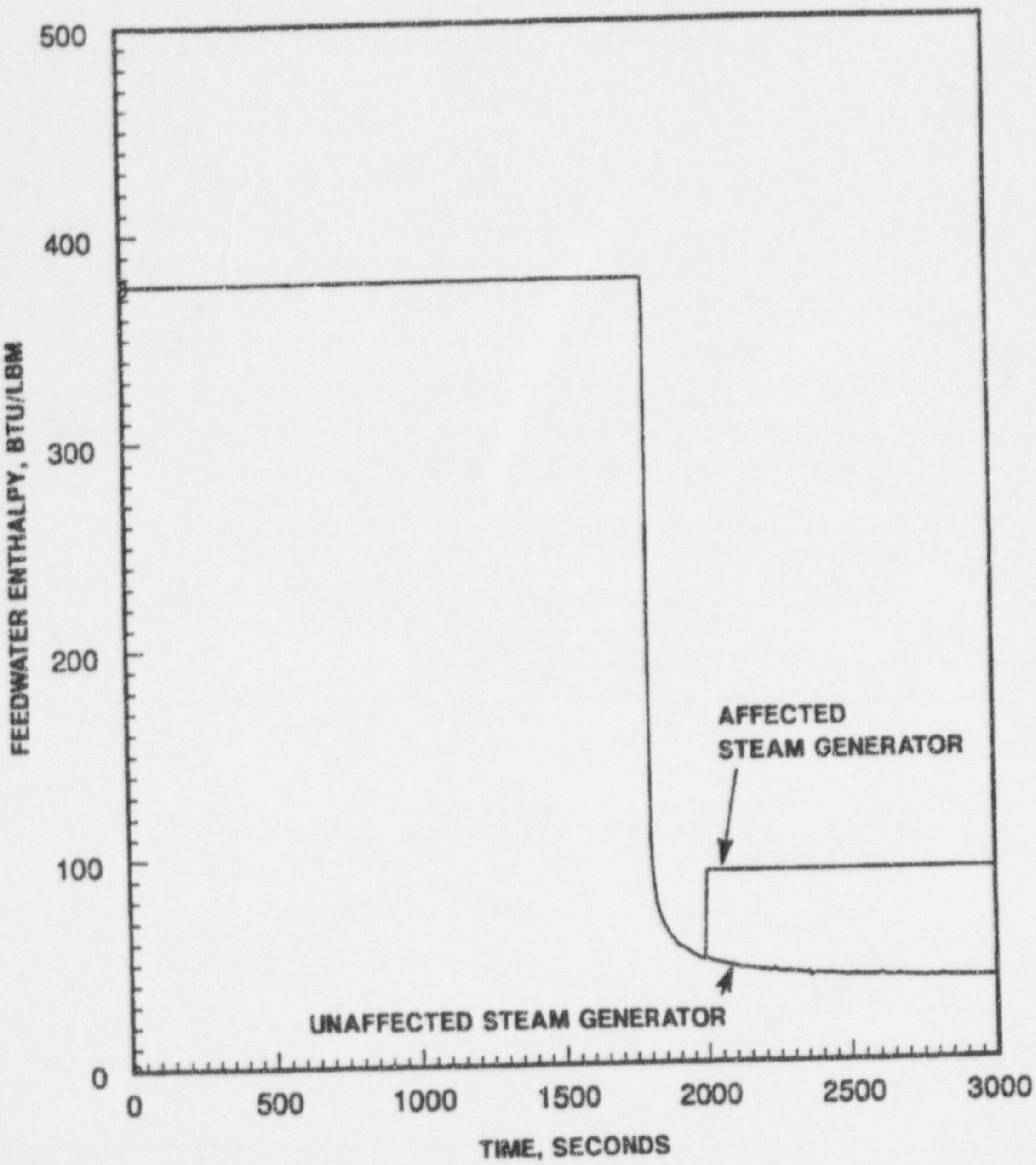
IOSGADV with Single Failure and LOOP; Steam Flow to Atmosphere vs. Time	Figure 15.1.4-2.8



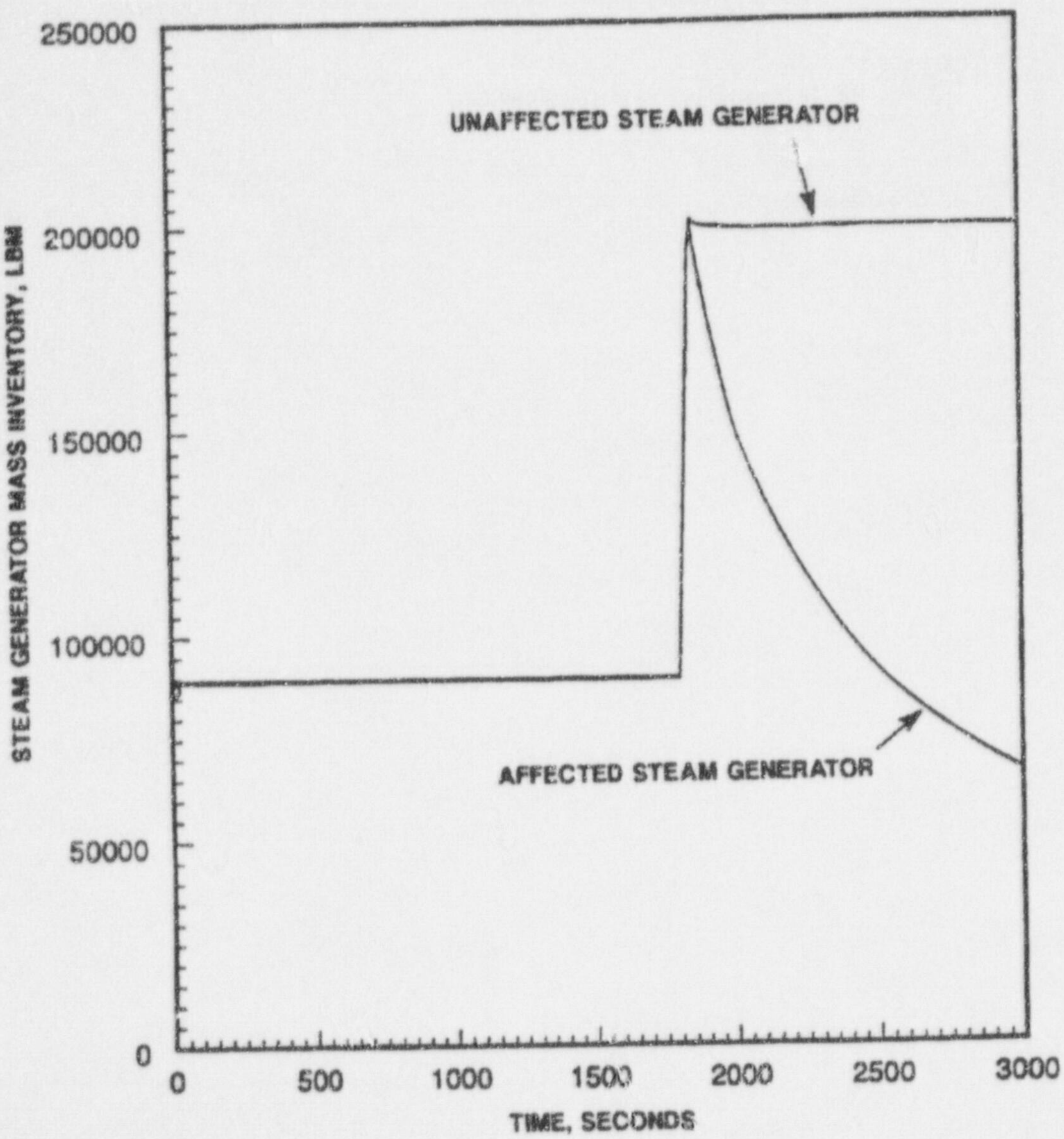
IOSGADV with Single Failure and LOOP; Steam Generator Steam Flow Rates vs. Time	Figure 15.1.4-29



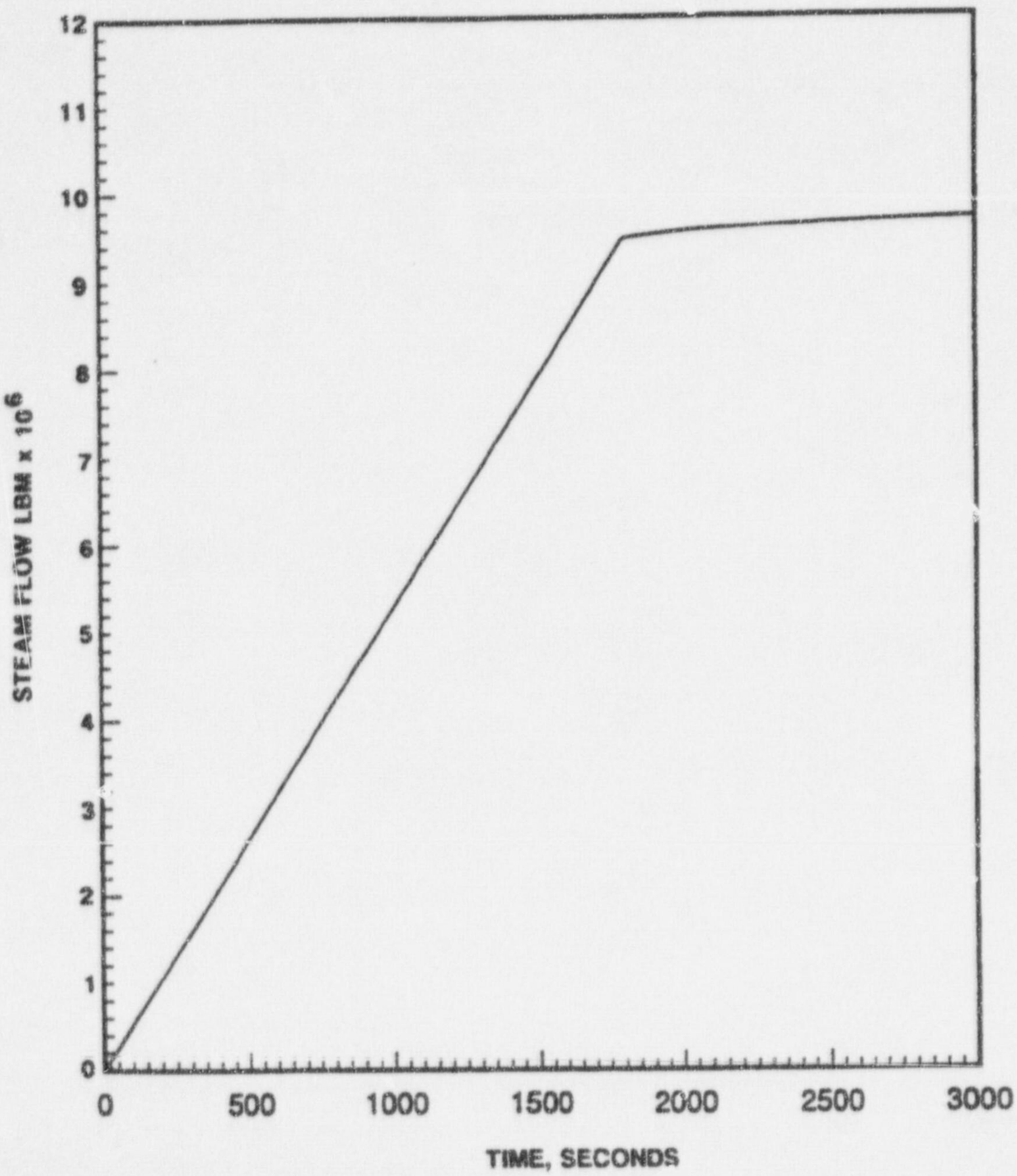
IOSGADV with Single Failure and LOOP; Feedwater Flow Rates vs. Time	Figure 15.1.4-2.10



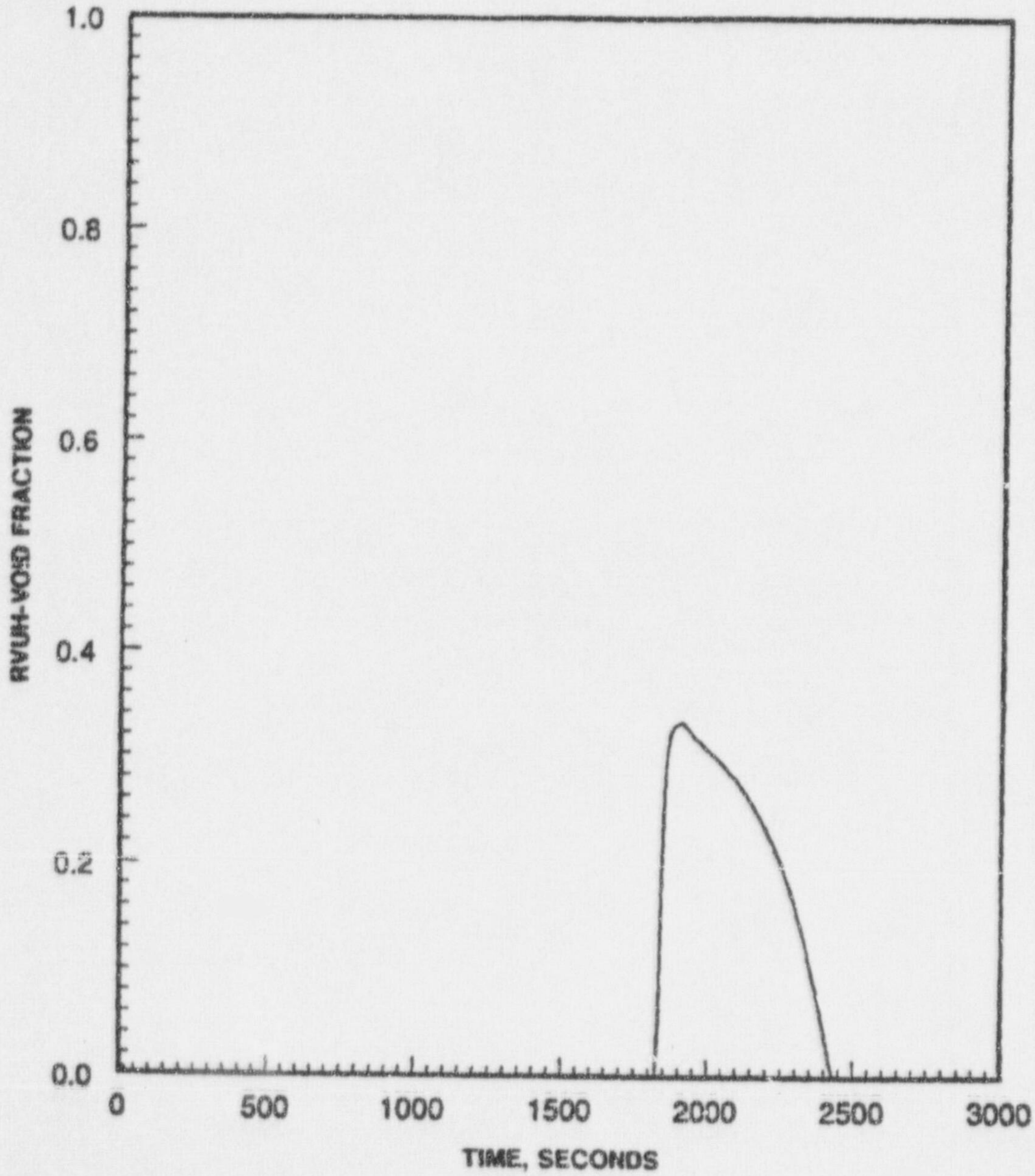
IOSGADV with Single Failure and LOOP; Feedwater Enthalpies vs. Time	Figure 15.1.4-2.11



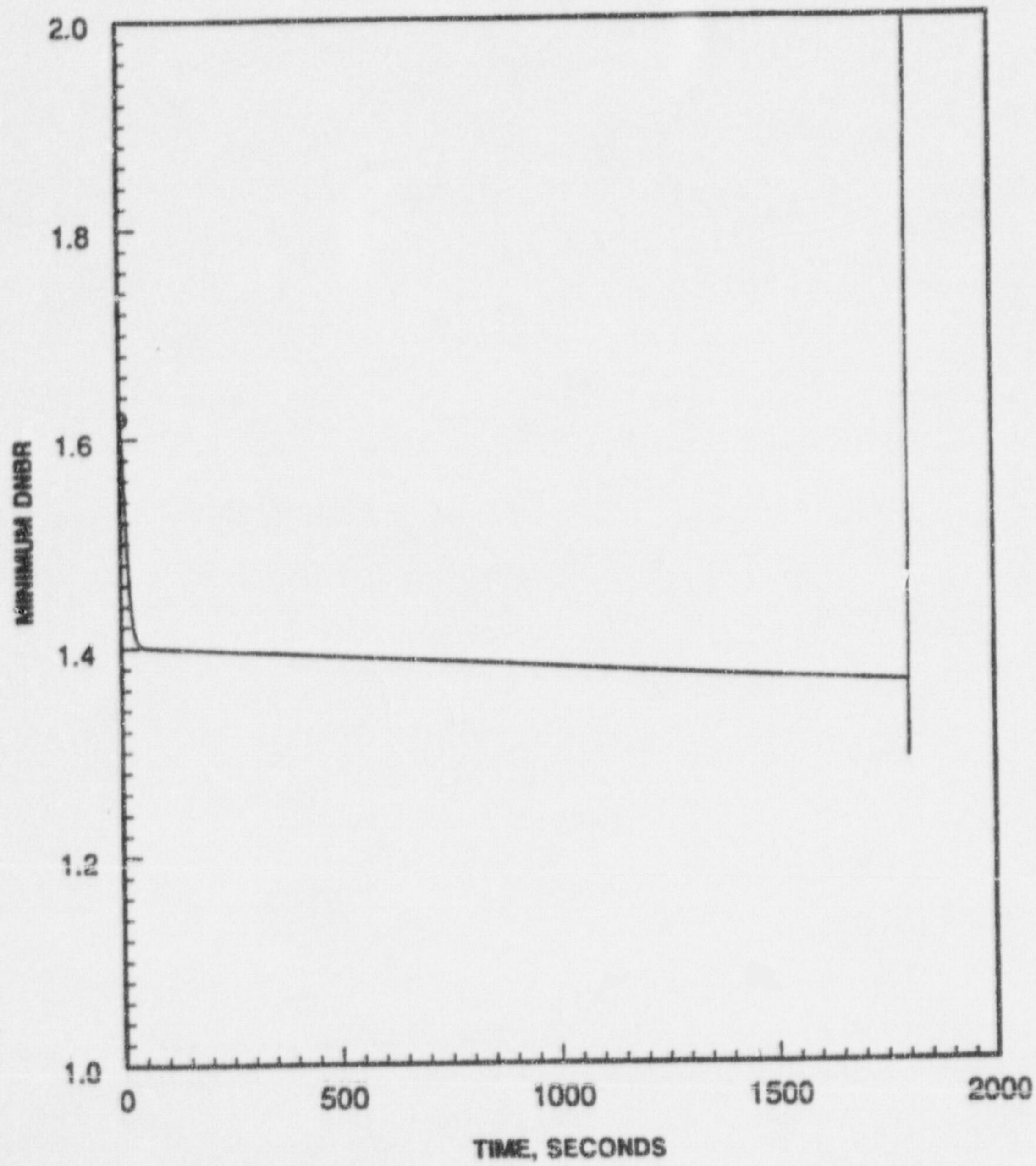
IOSGADV with Single Failure and LOOP; Steam Generator Mass Inventories vs. Time	Figure 15.1.4-2.12



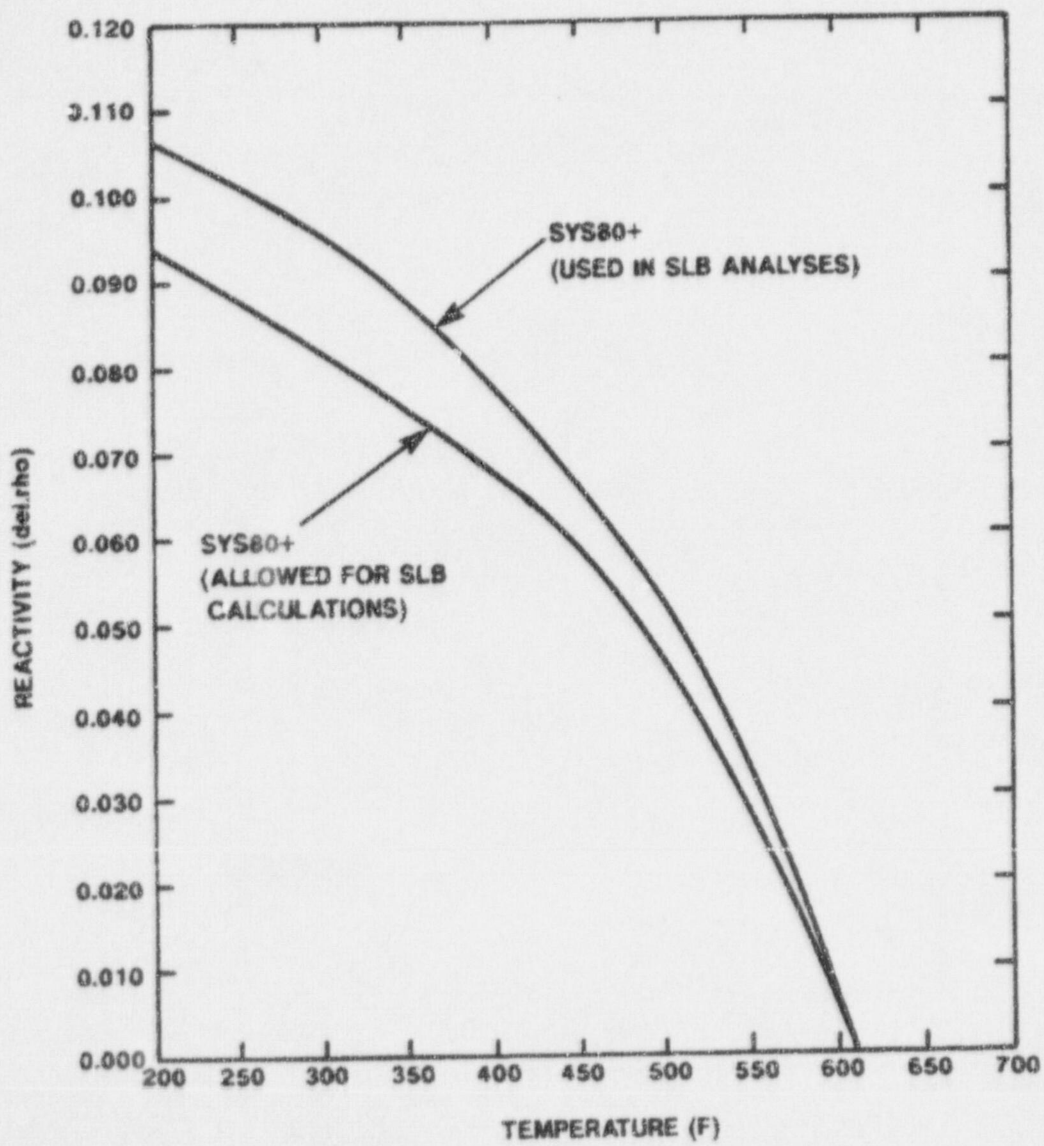
IOSGADV with Single Failure and LOOP; Steam Flow Rates to Atmosphere vs. Time	Figure 15.1.4-2.13



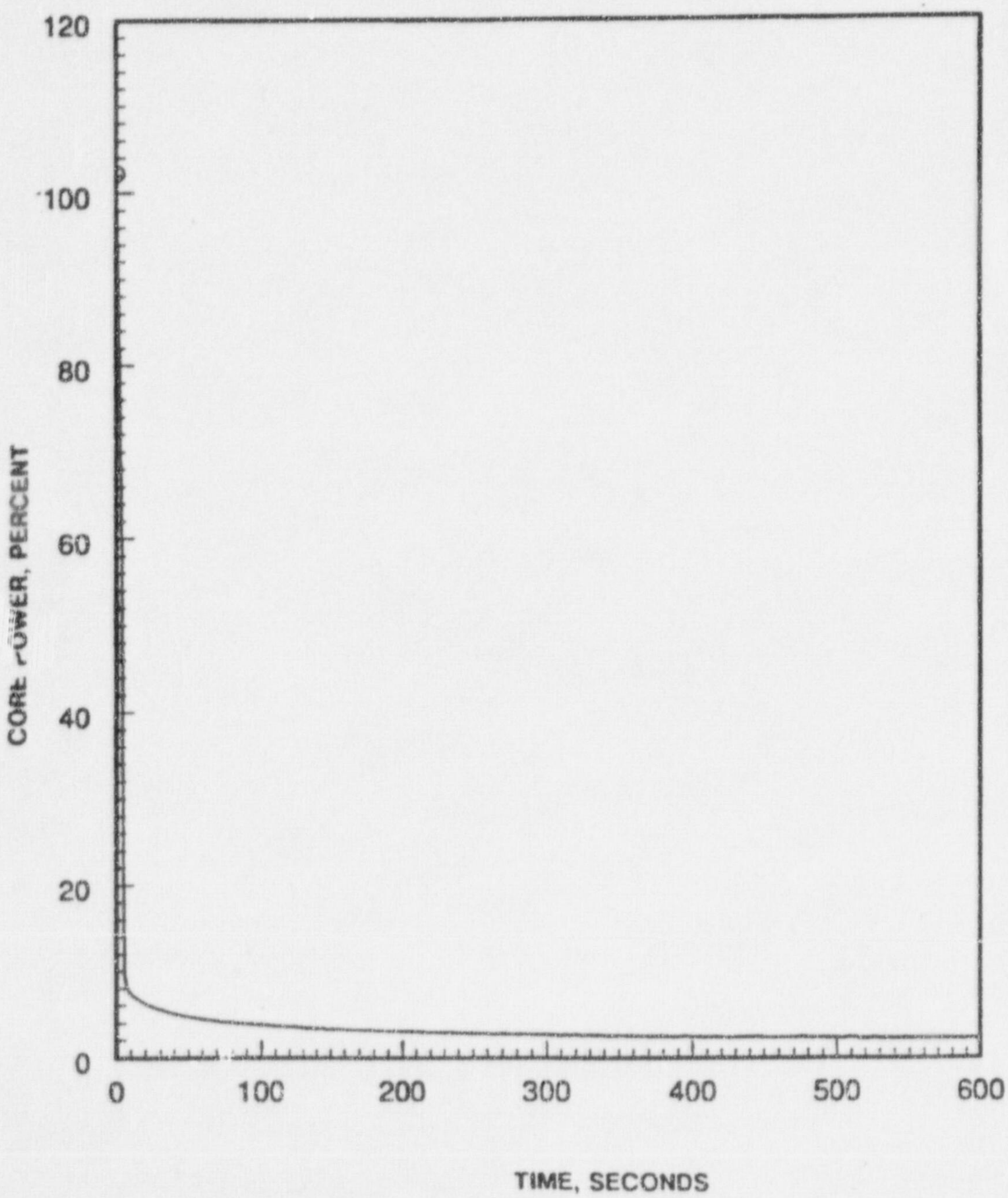
IOSGADV with Single Failure and LOOP; Reactor Vessel Upper Head Steam Void Fraction vs. Time	Figure 15.1.4-2.14



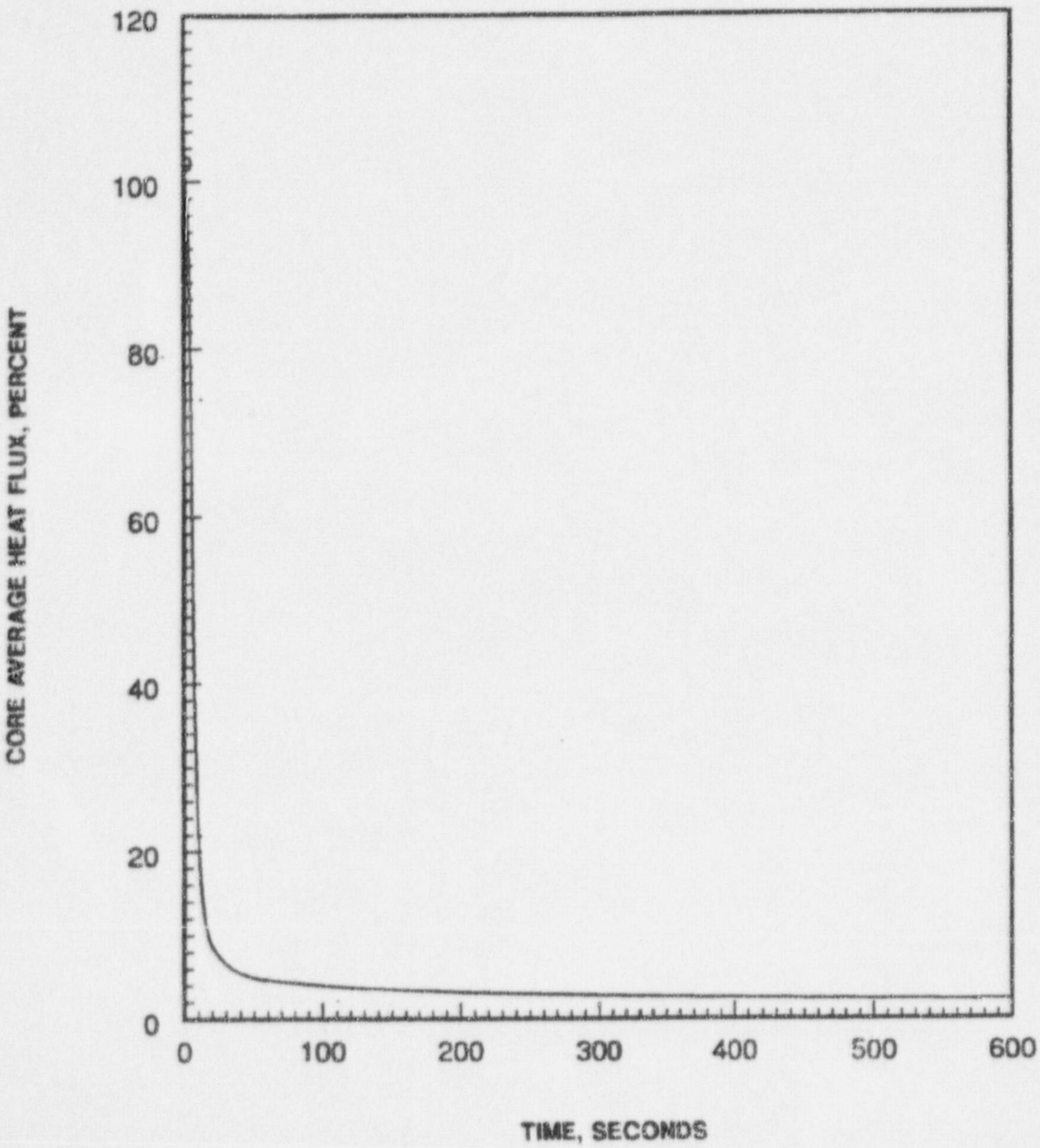
IOSGADV with Single Failure and LOOP; Minimum DNBR vs Time	Figure 15.1.4-2.15



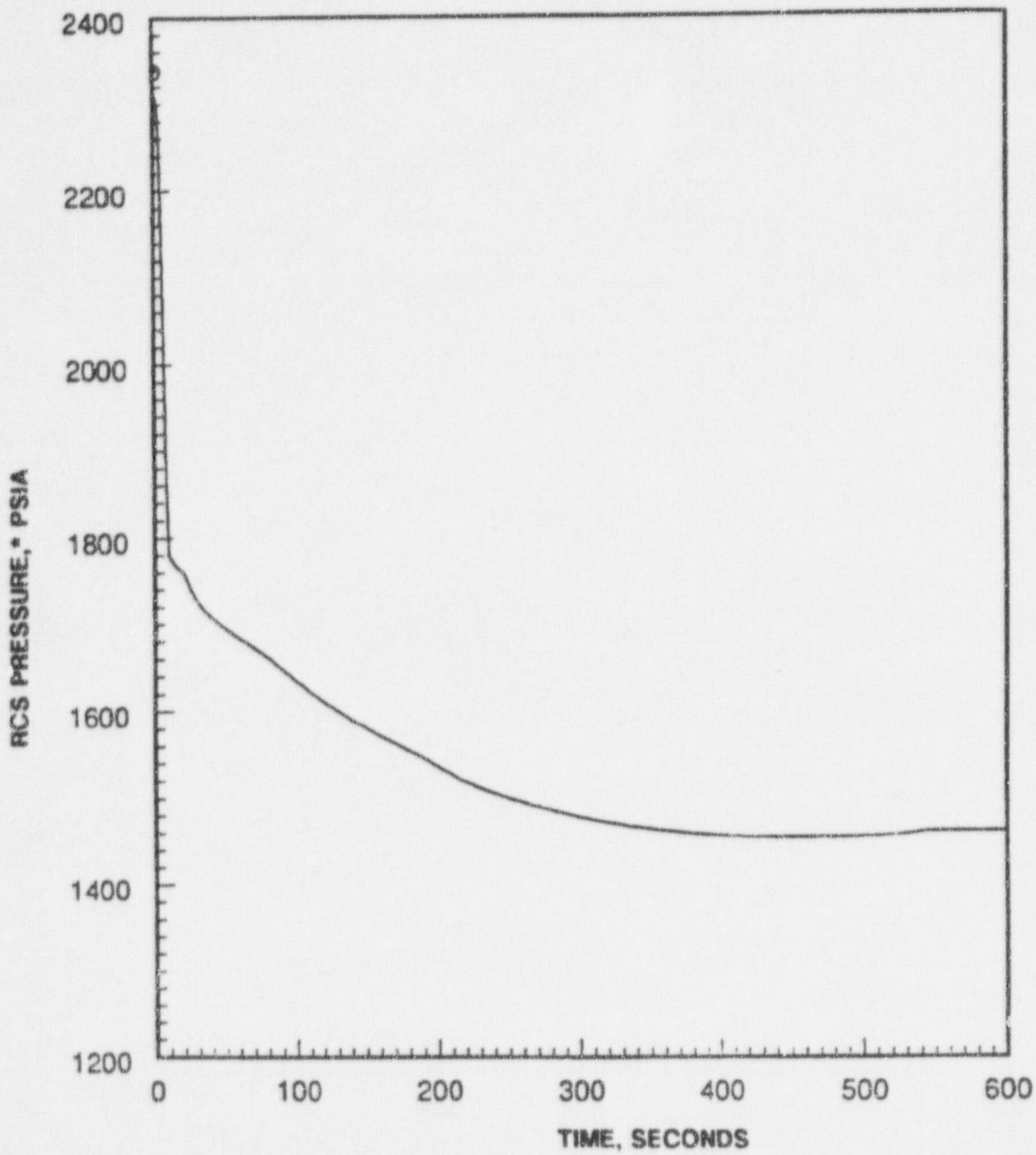
Moderator Reactivity vs. Temperature	Figure 15.1.5-0



Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Core Power vs. Time	Figure 15.1.5-1.1

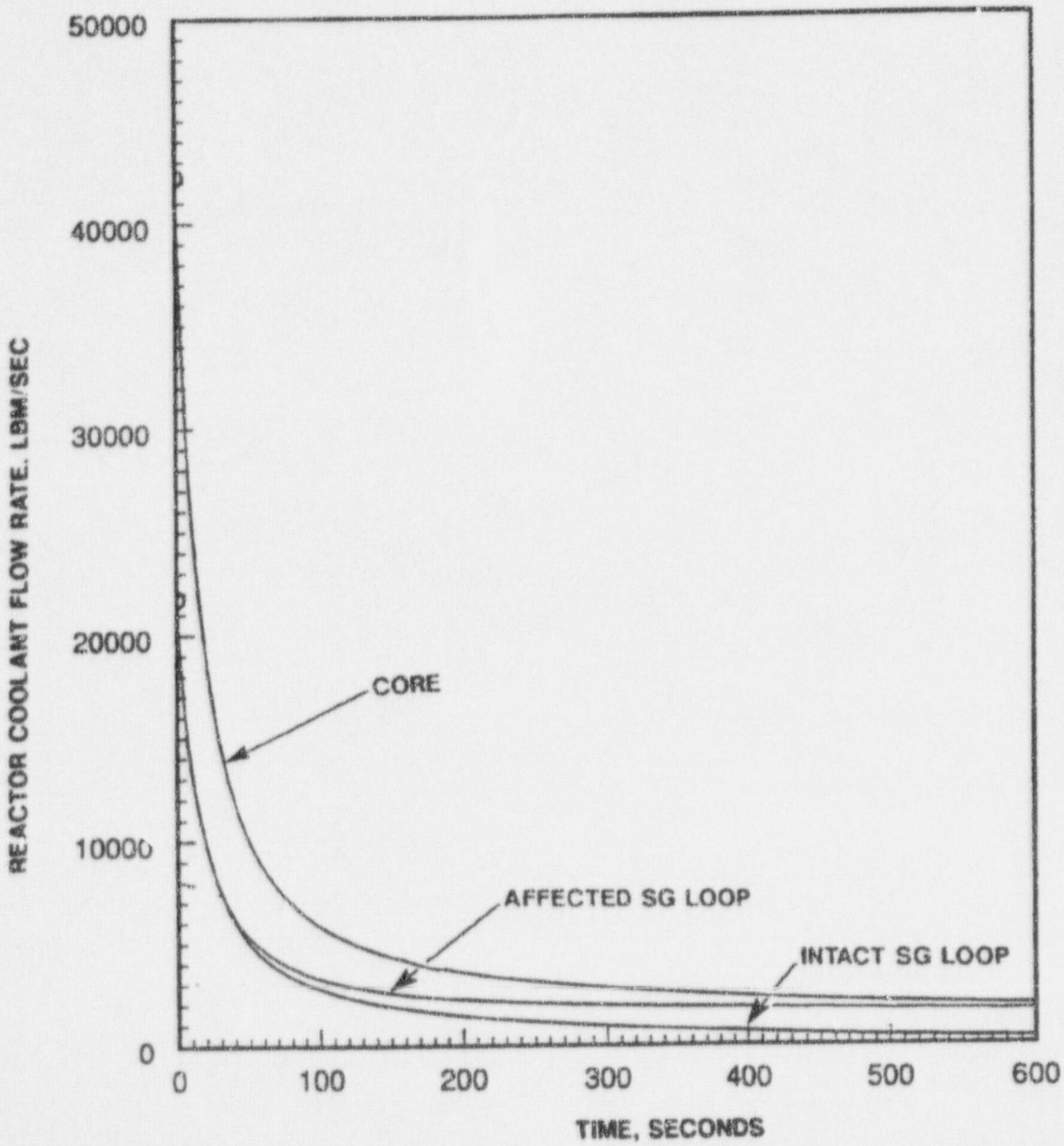


Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Core Average Heat Flux vs. Time	Figure 15.1.5-1.2

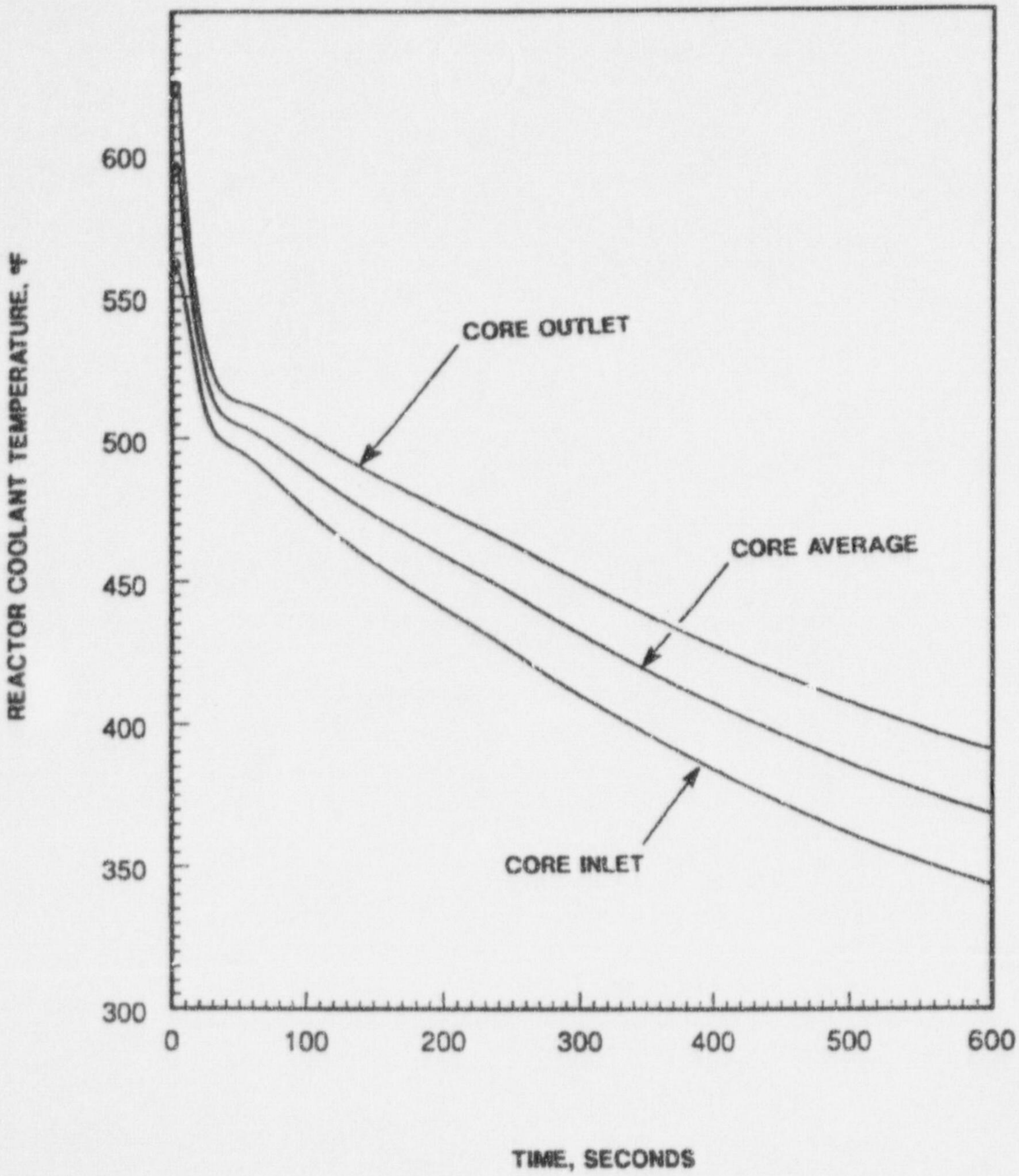


*THIS PRESSURE DOES NOT INCLUDE THE PRESSURE DIFFERENCE BETWEEN THE COLD LEG AT RCP DISCHARGE AND THE SURGE LINE

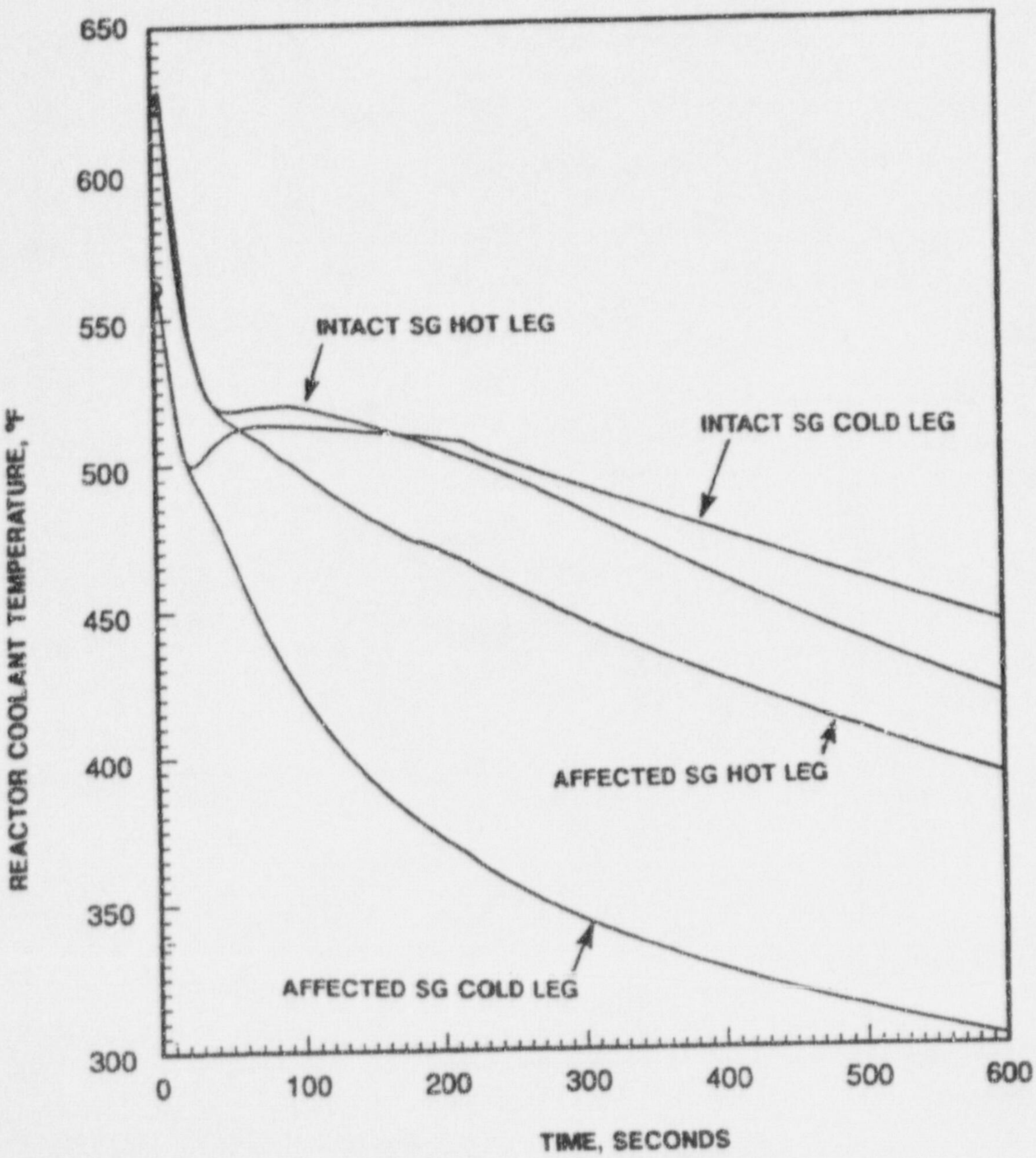
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Coolant System Pressure vs. Time	Figure 15.1.5-1.3



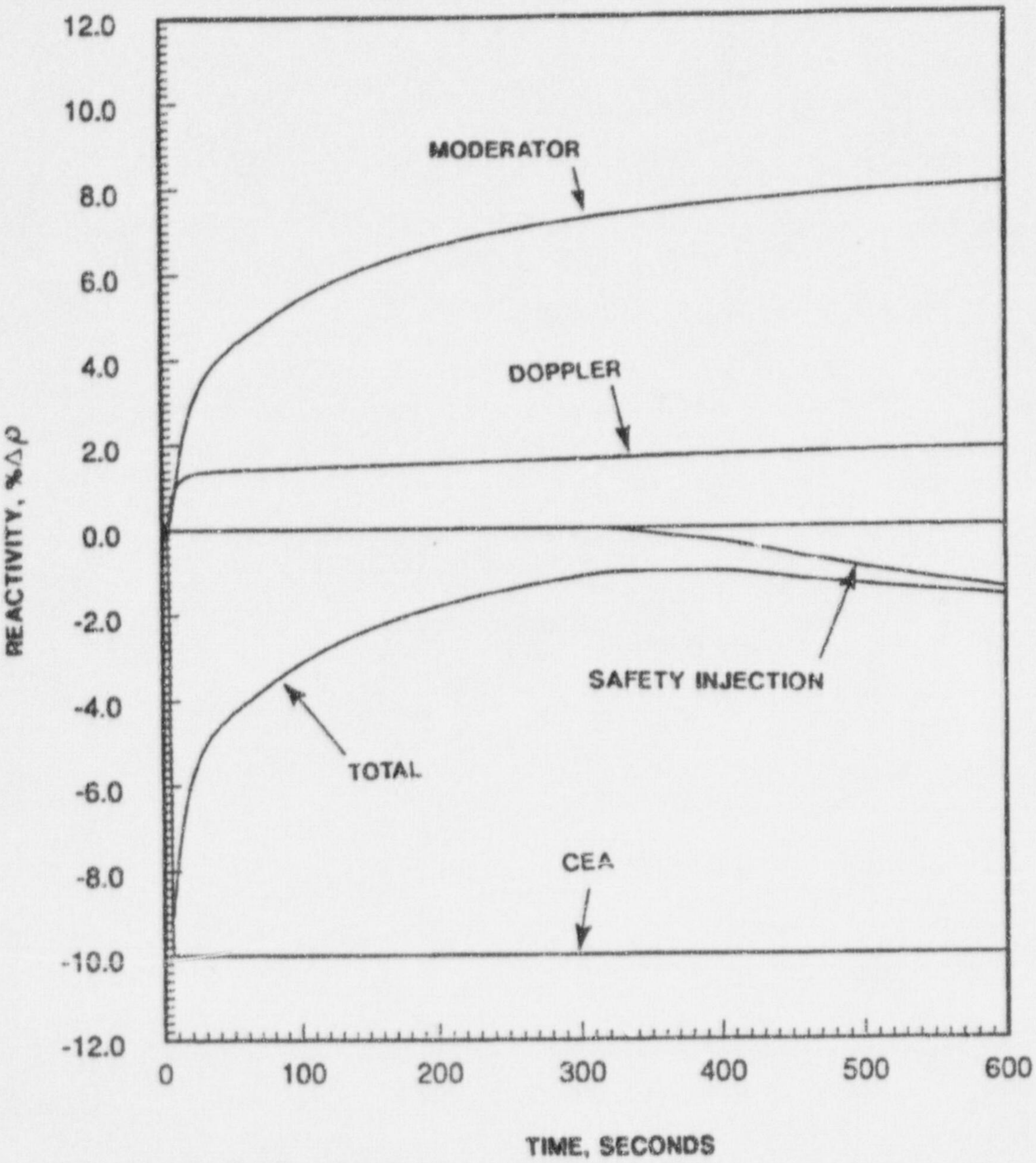
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Coolant Flow Rates vs. Time	Figure 15.1.5-1.4



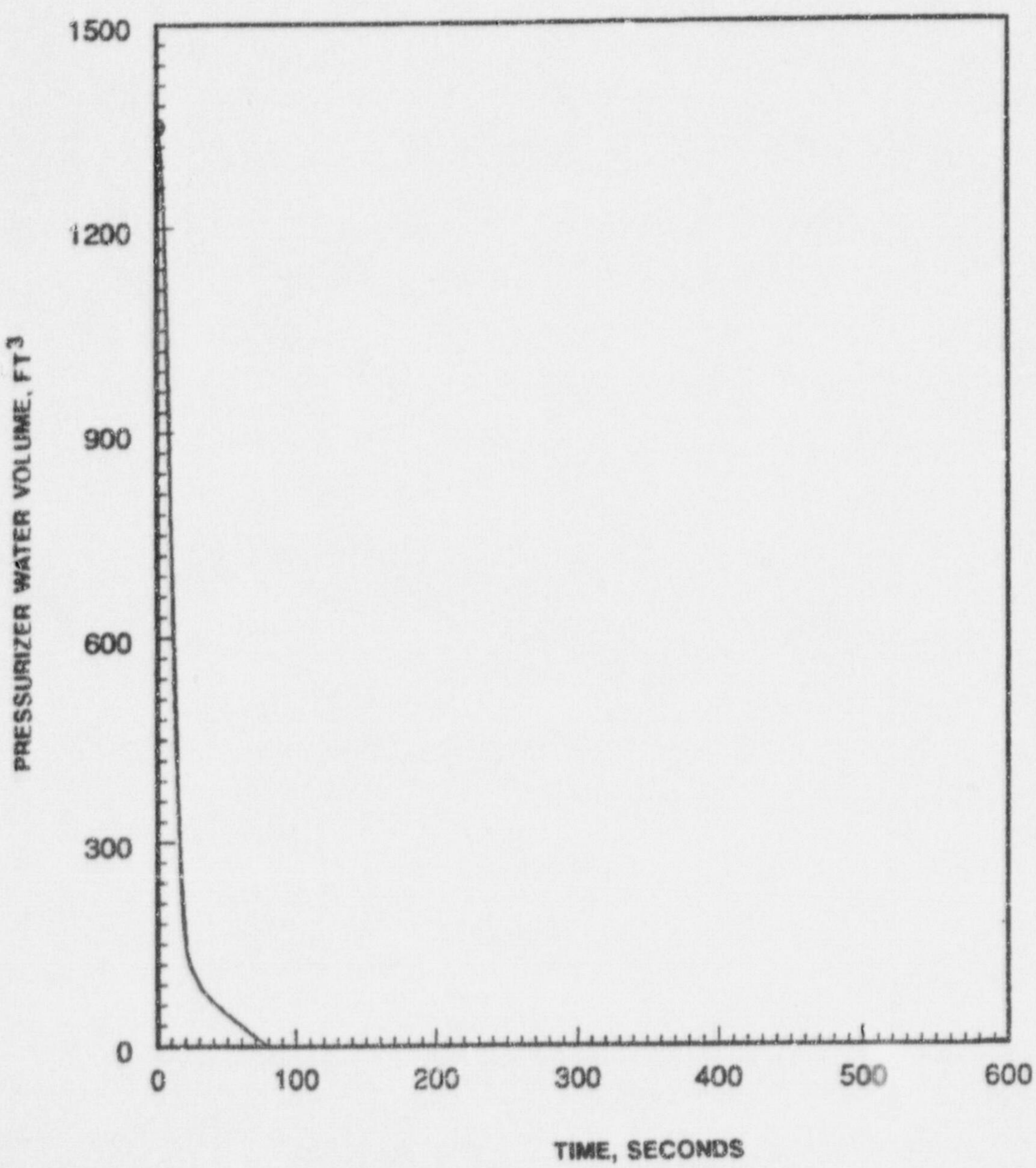
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Coolant Temperatures (A) vs Time	Figure 15.1.5-1.5A



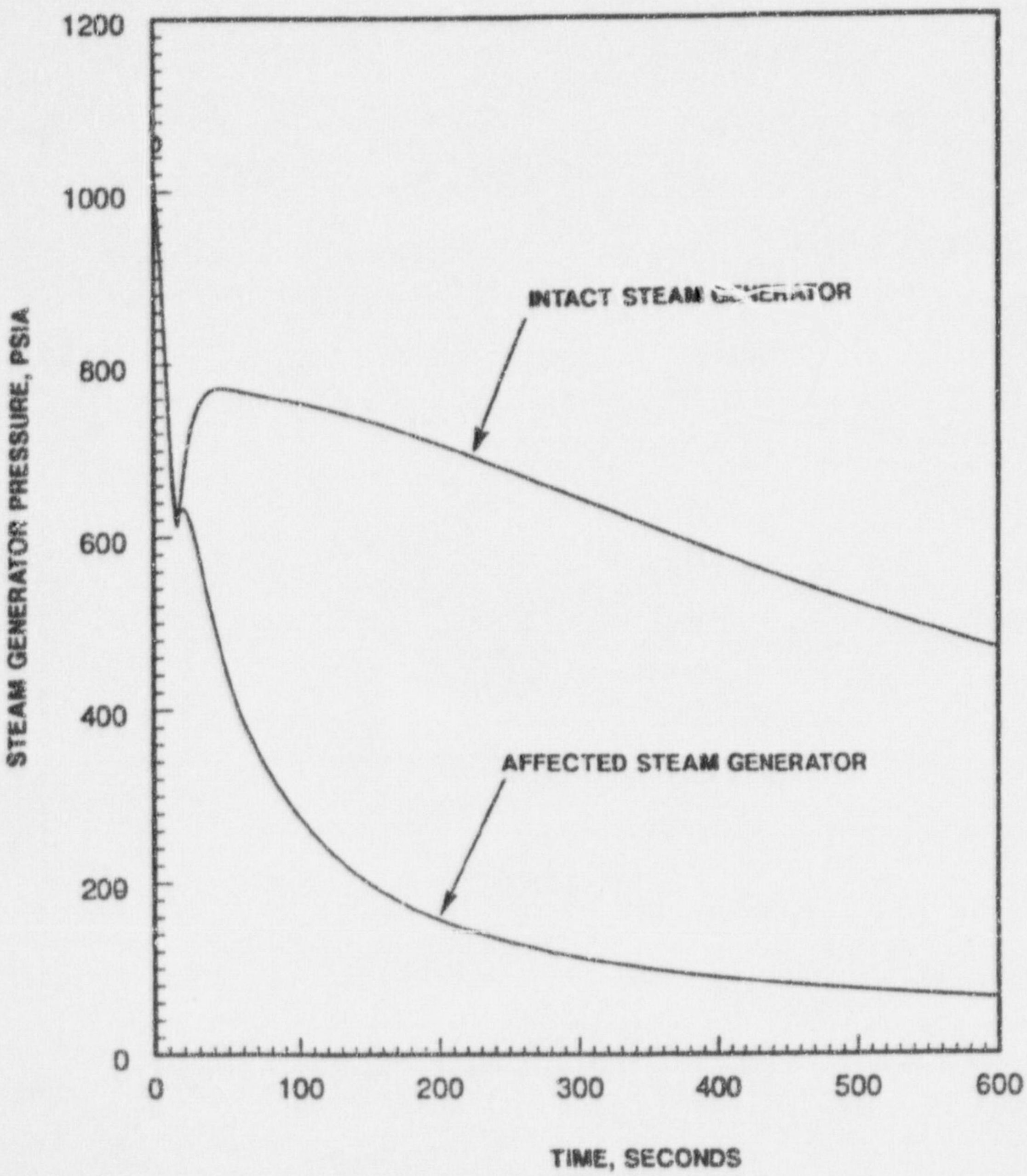
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Coolant Temperatures (B) vs Time	Figure 15.1.5-1.5B



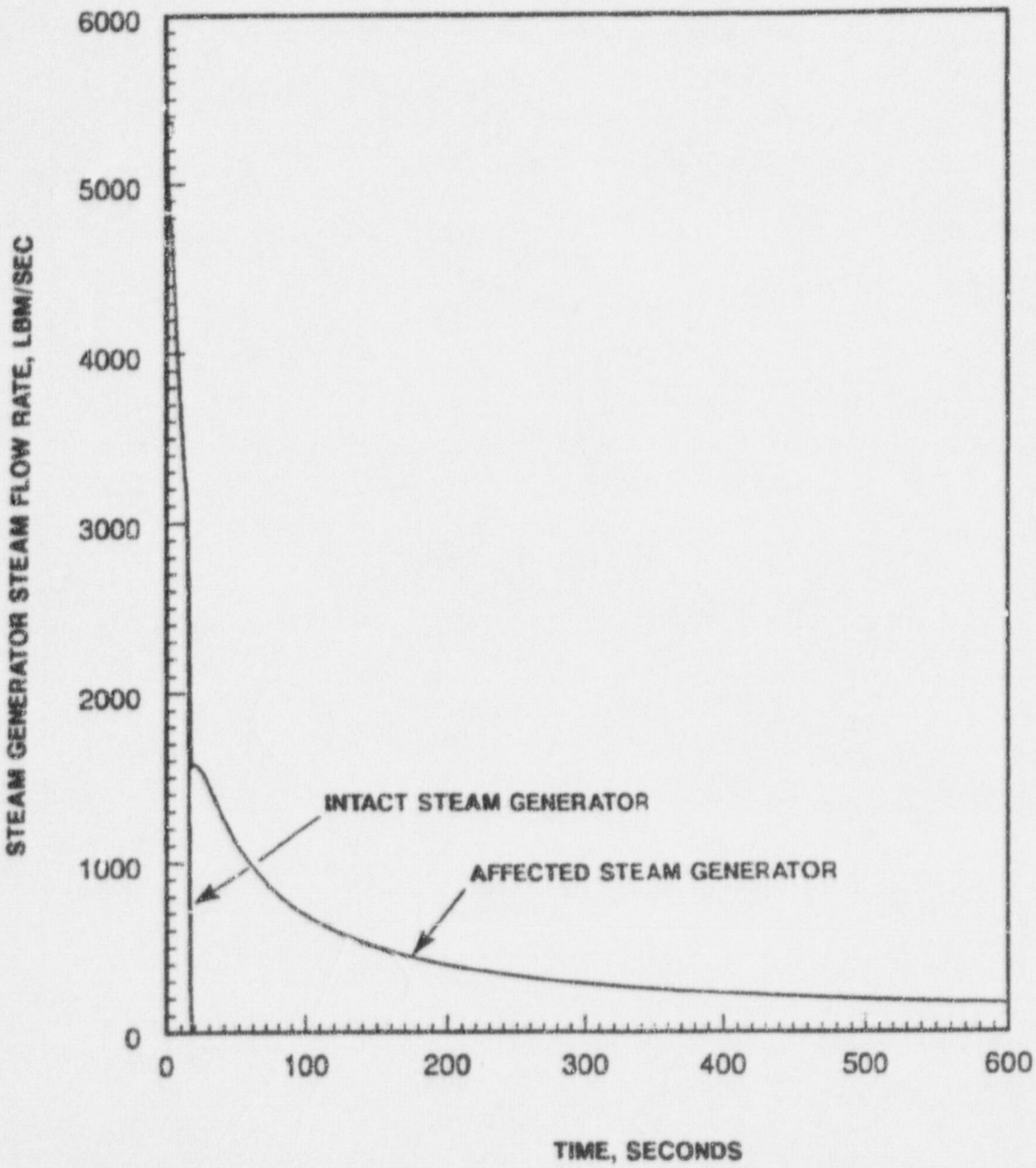
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactivity vs Time	Figure 15.1.5-1.6



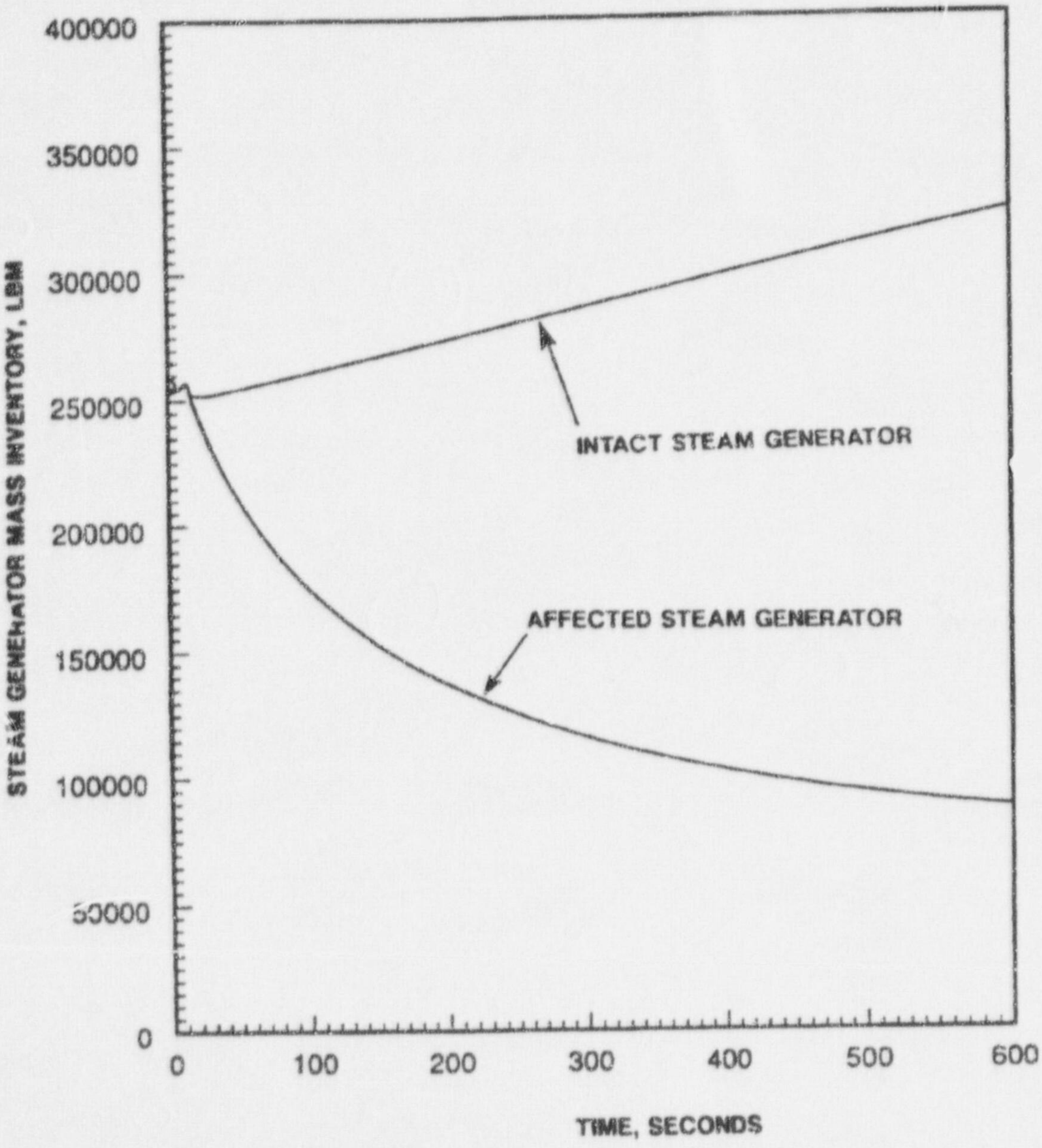
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Pressurizer Water Volume vs Time	Figure 15.1.5-1.7



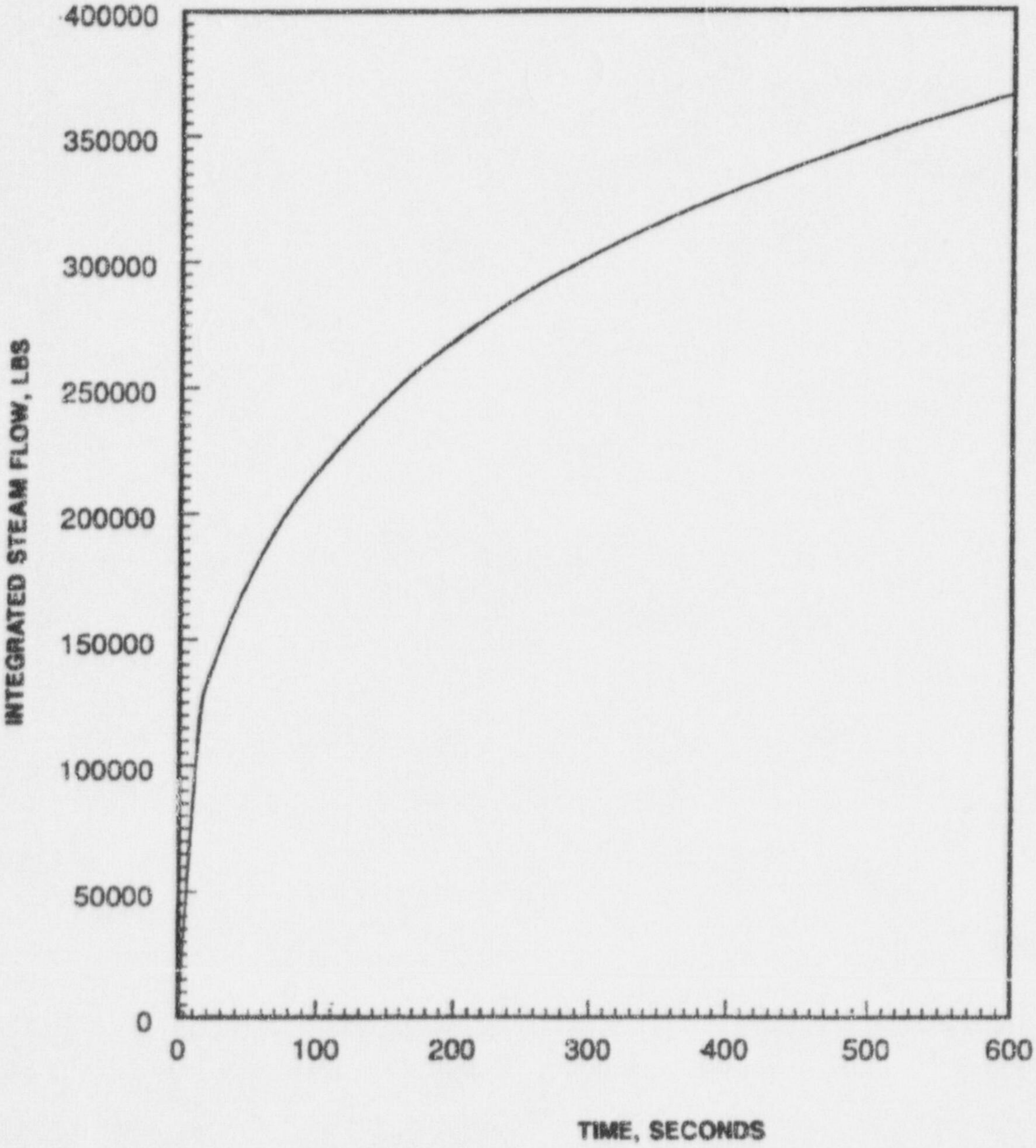
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Steam Generator Pressures vs Time	Figure 15.1.5-1.8



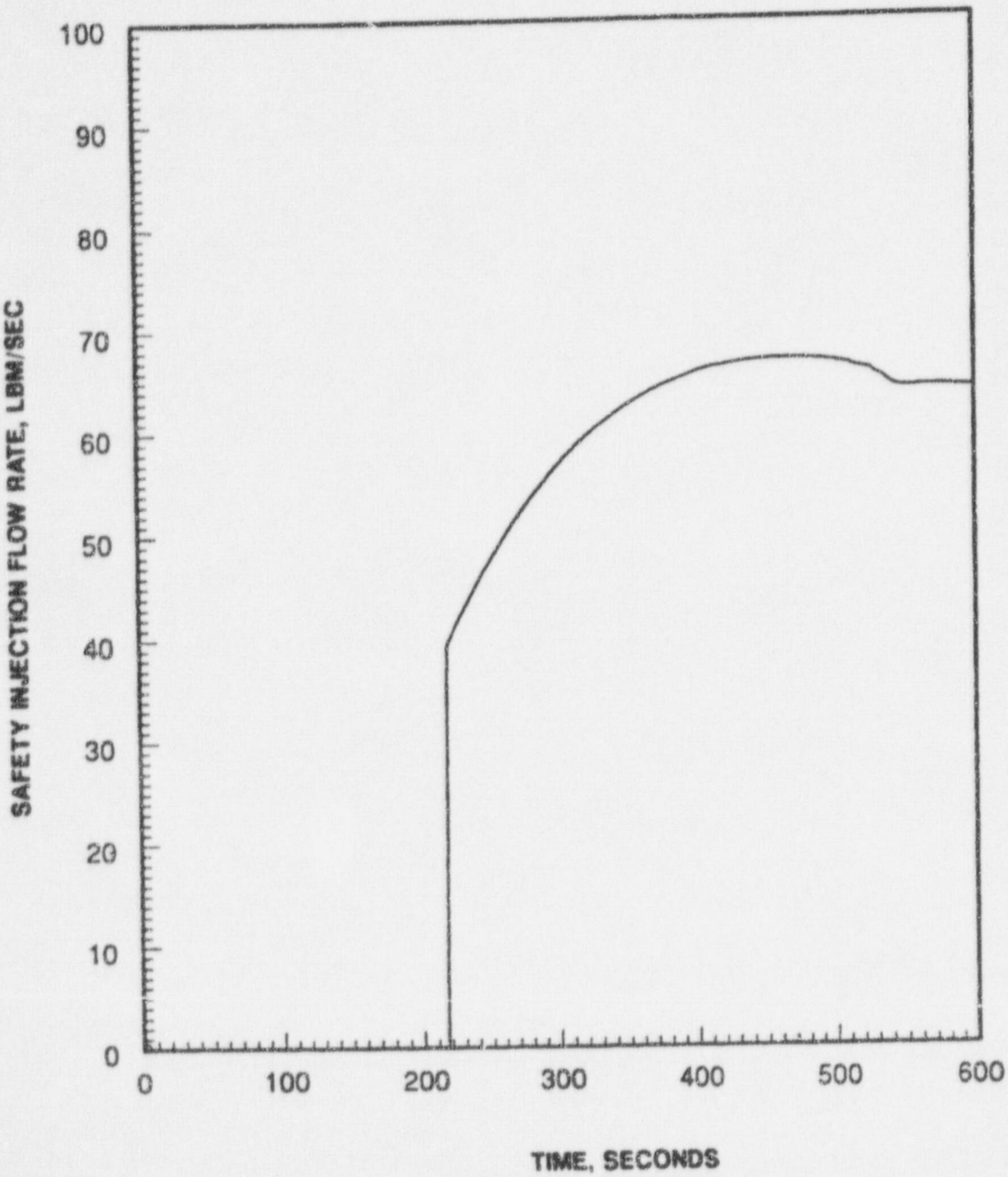
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Steam Generator Flow Rates vs Time	Figure 15.1.5-1.9



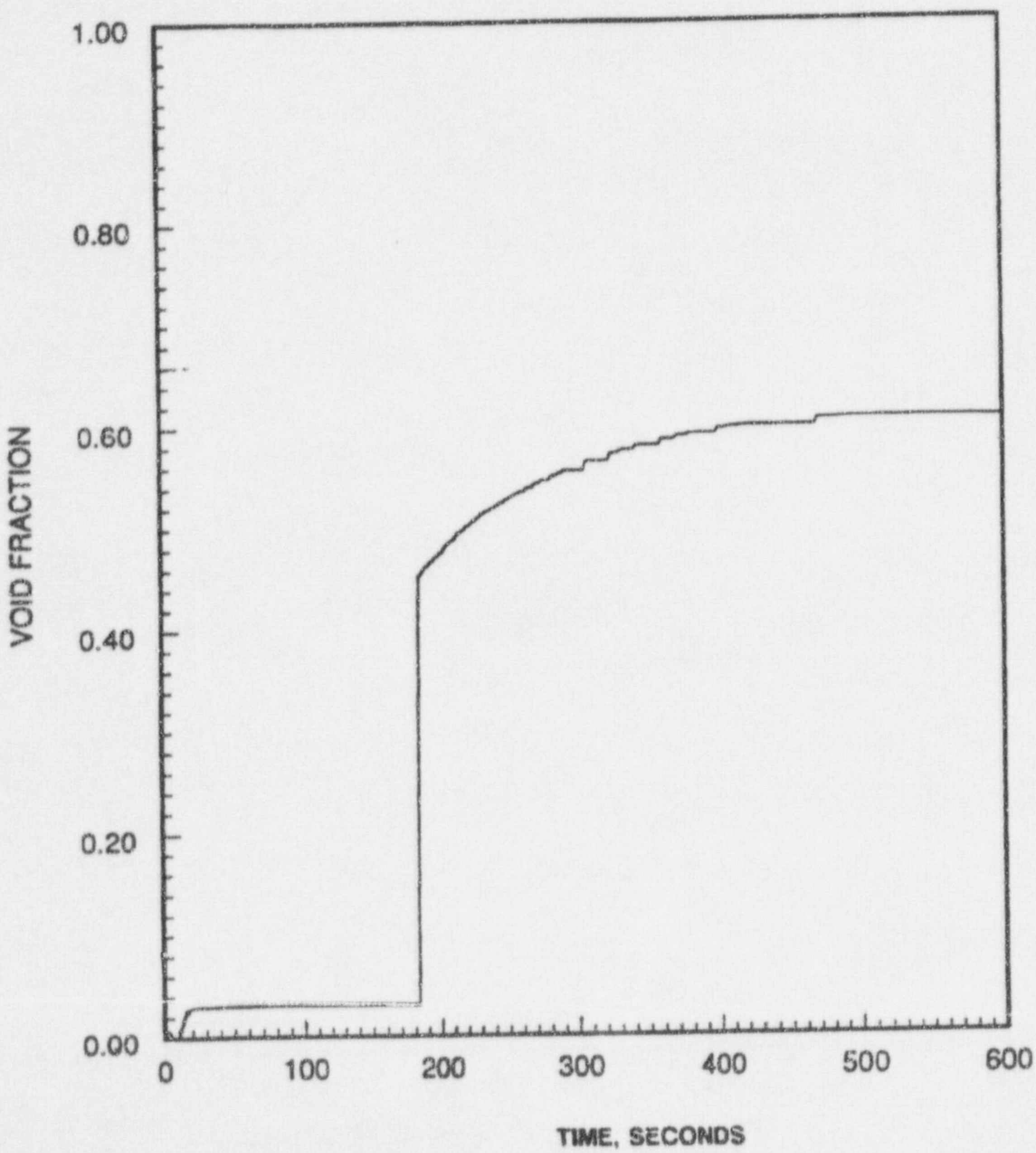
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Steam Generator Mass Inventories vs Time	Figure 15.1.5-1.10



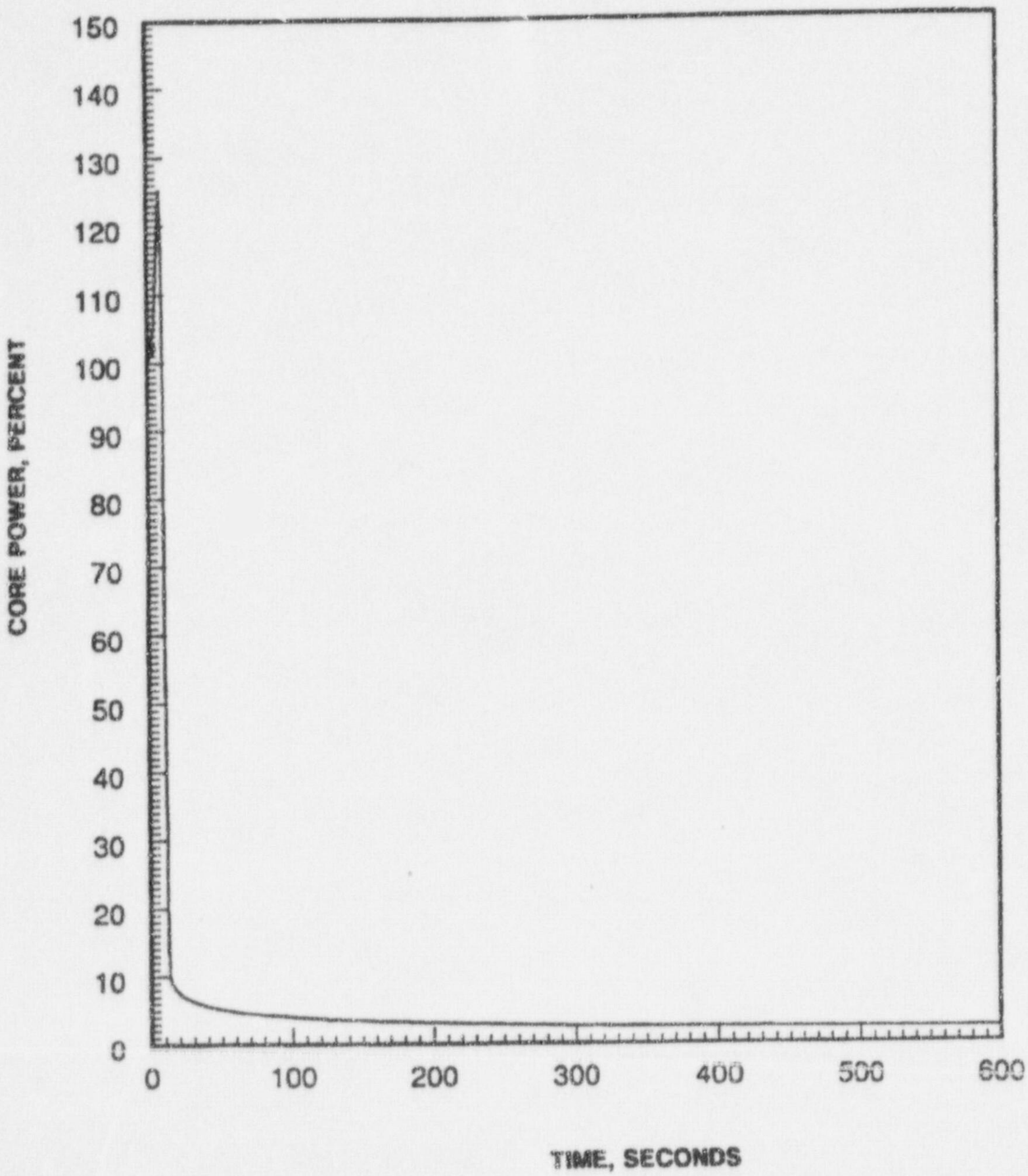
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Integrated Steam Mass Release Through Break vs. Time	Figure 15.1.5-1.11



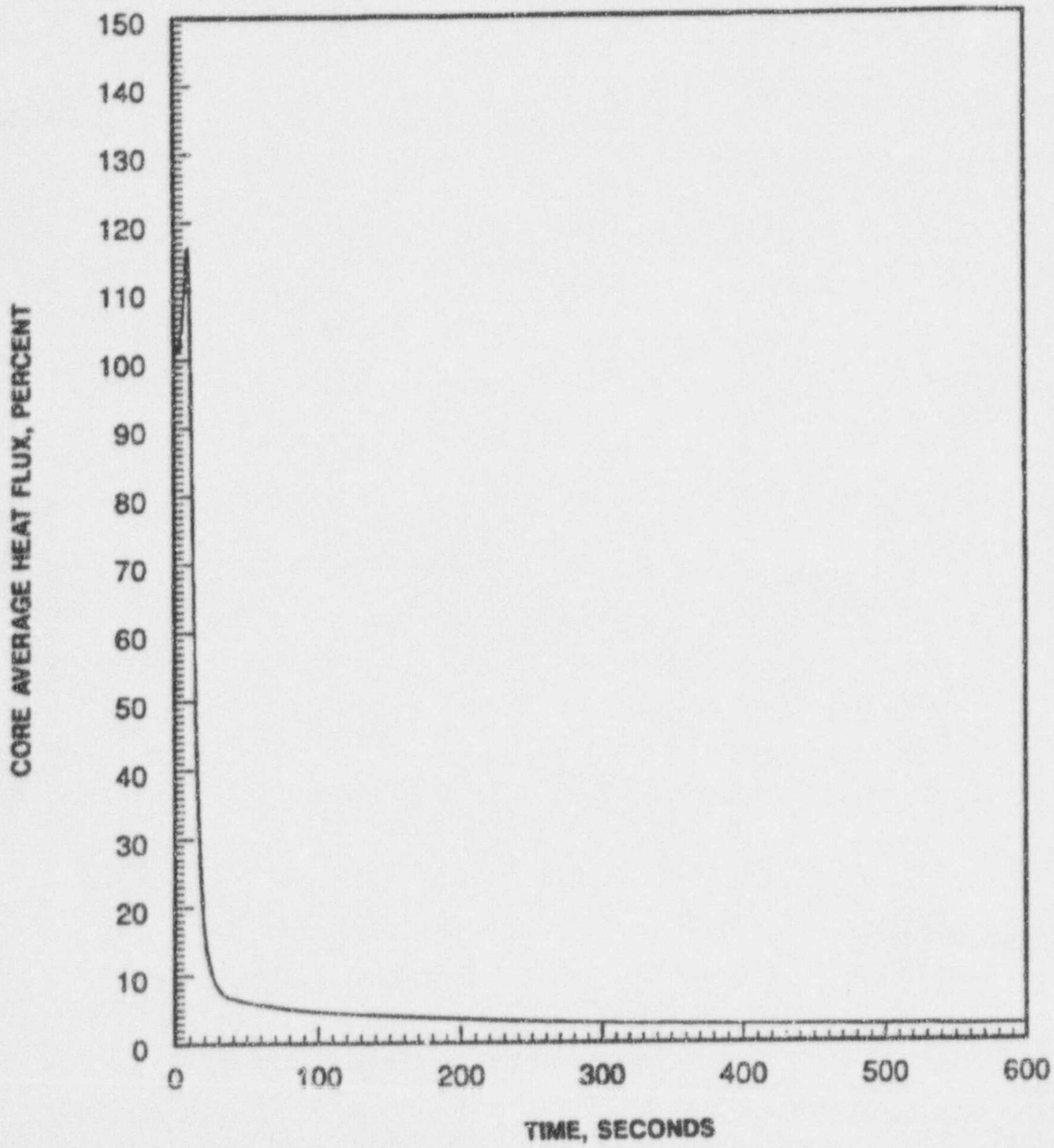
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Safety Injec'ion Flow Rate vs. Time	Figure 15.1.5-1.12



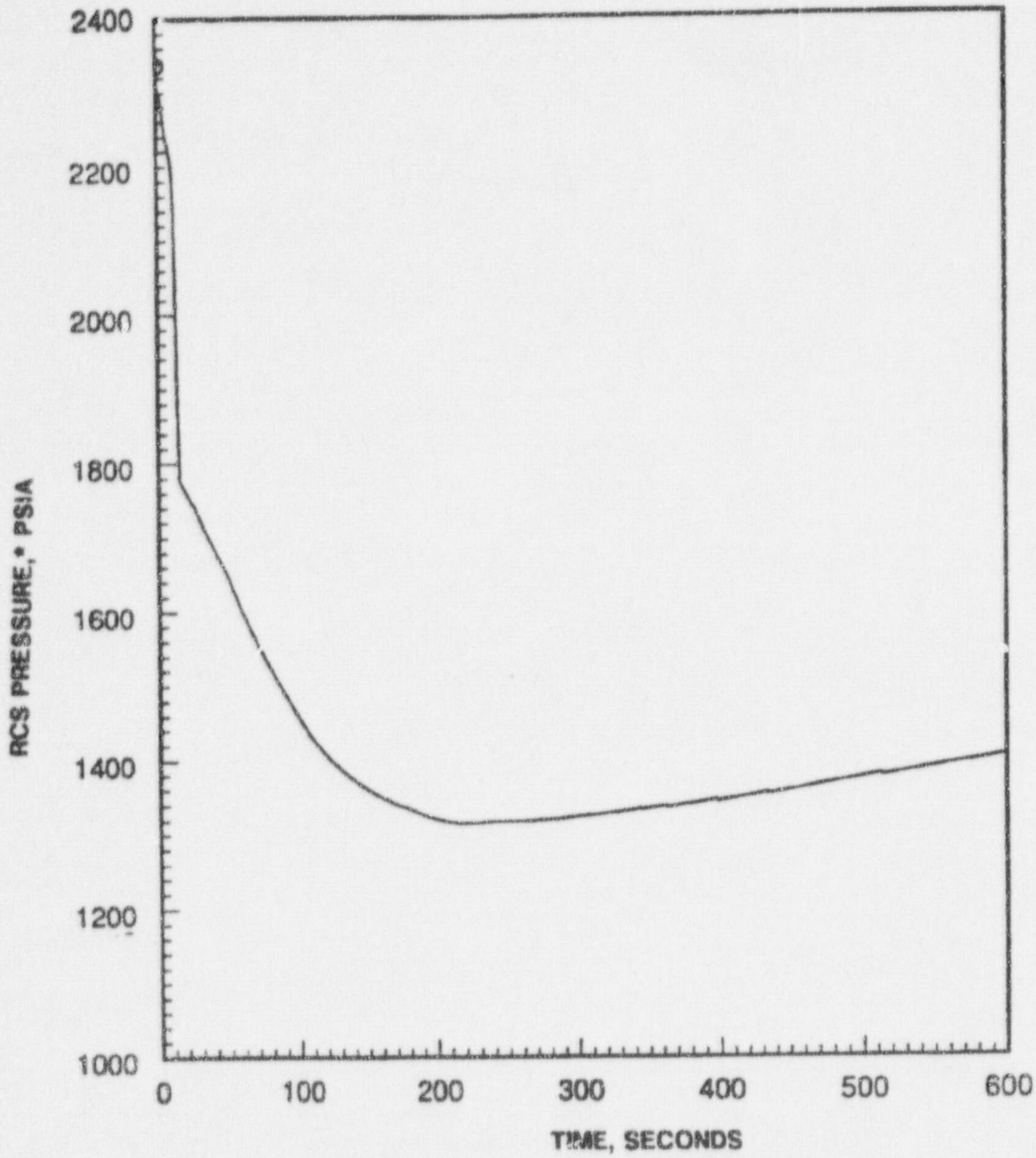
Full Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Vessel Upper Head Steam Void Fraction vs. Time	Figure 15.1.5-1.13



Full Power Large Steam Line Break with Offsite Power Available; Core Power vs. Time	Figure 15.1.5-2.1

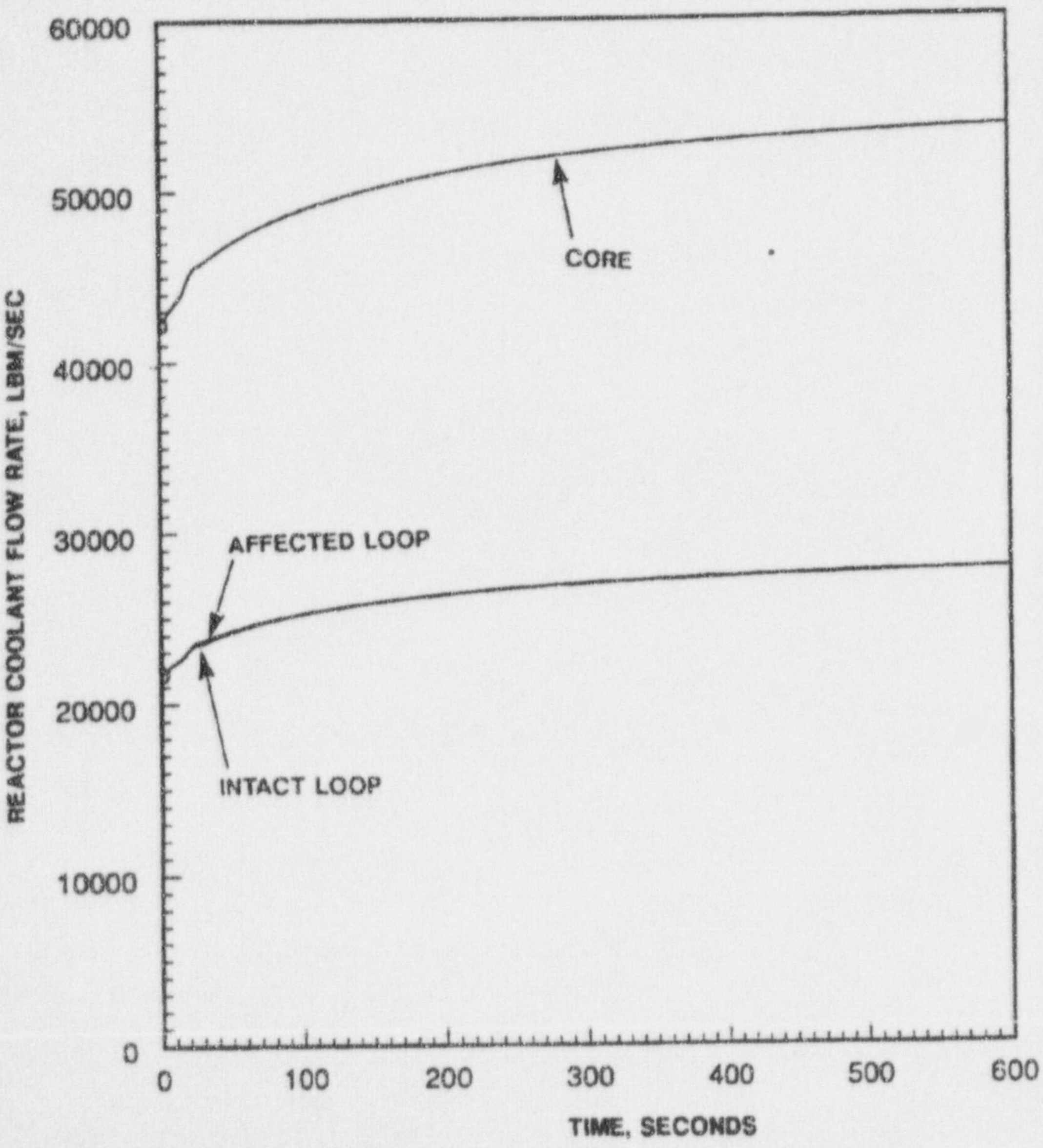


Full Power Large Steam Line Break with Offsite Power Available; Core Average Heat Flux vs. Time	Figure 15.1.5-2.2

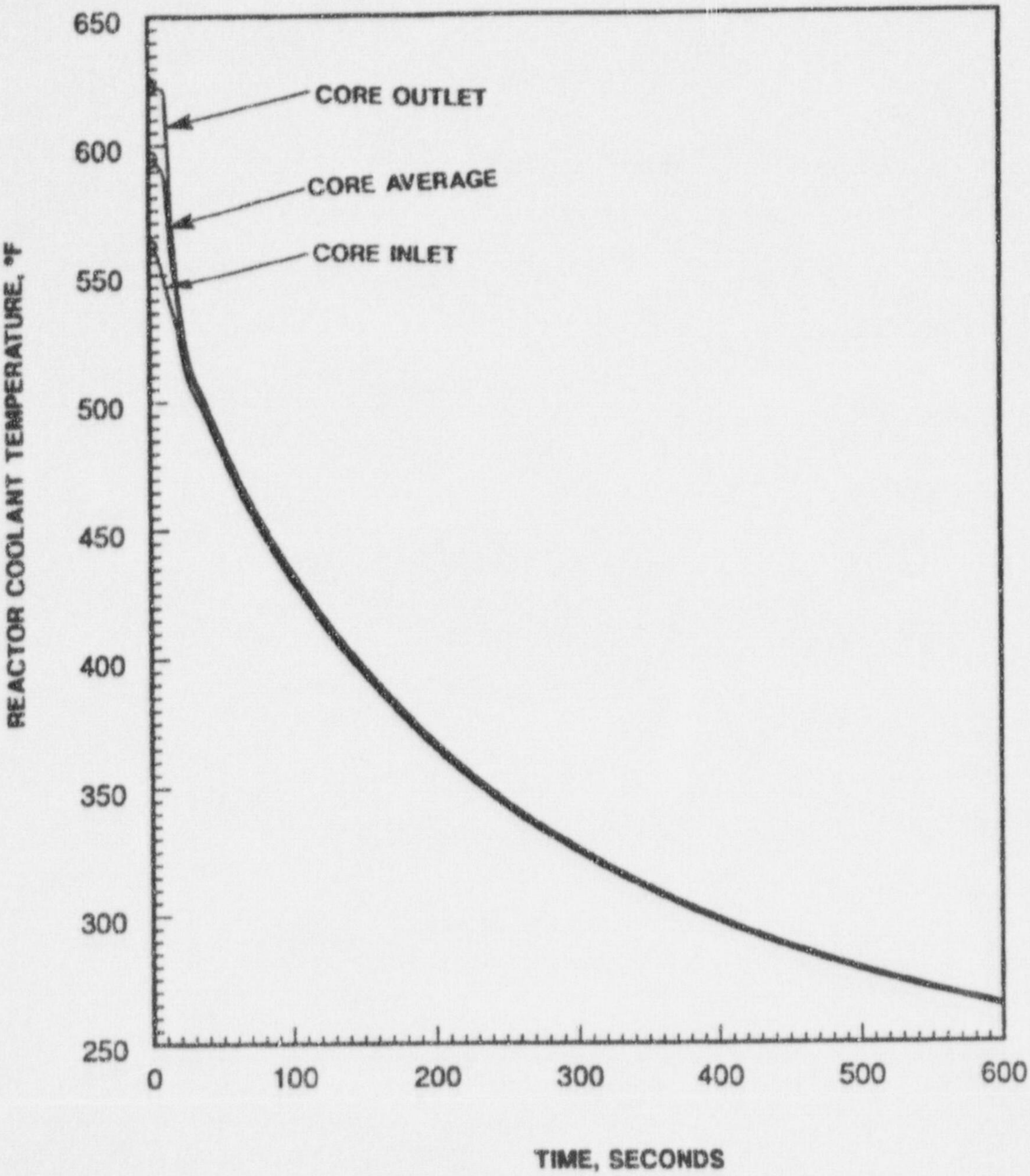


*THIS PRESSURE DOES NOT INCLUDE THE PRESSURE DIFFERENCE BETWEEN THE COLD LEG AT RCP DISCHARGE AND THE SURGE LINE

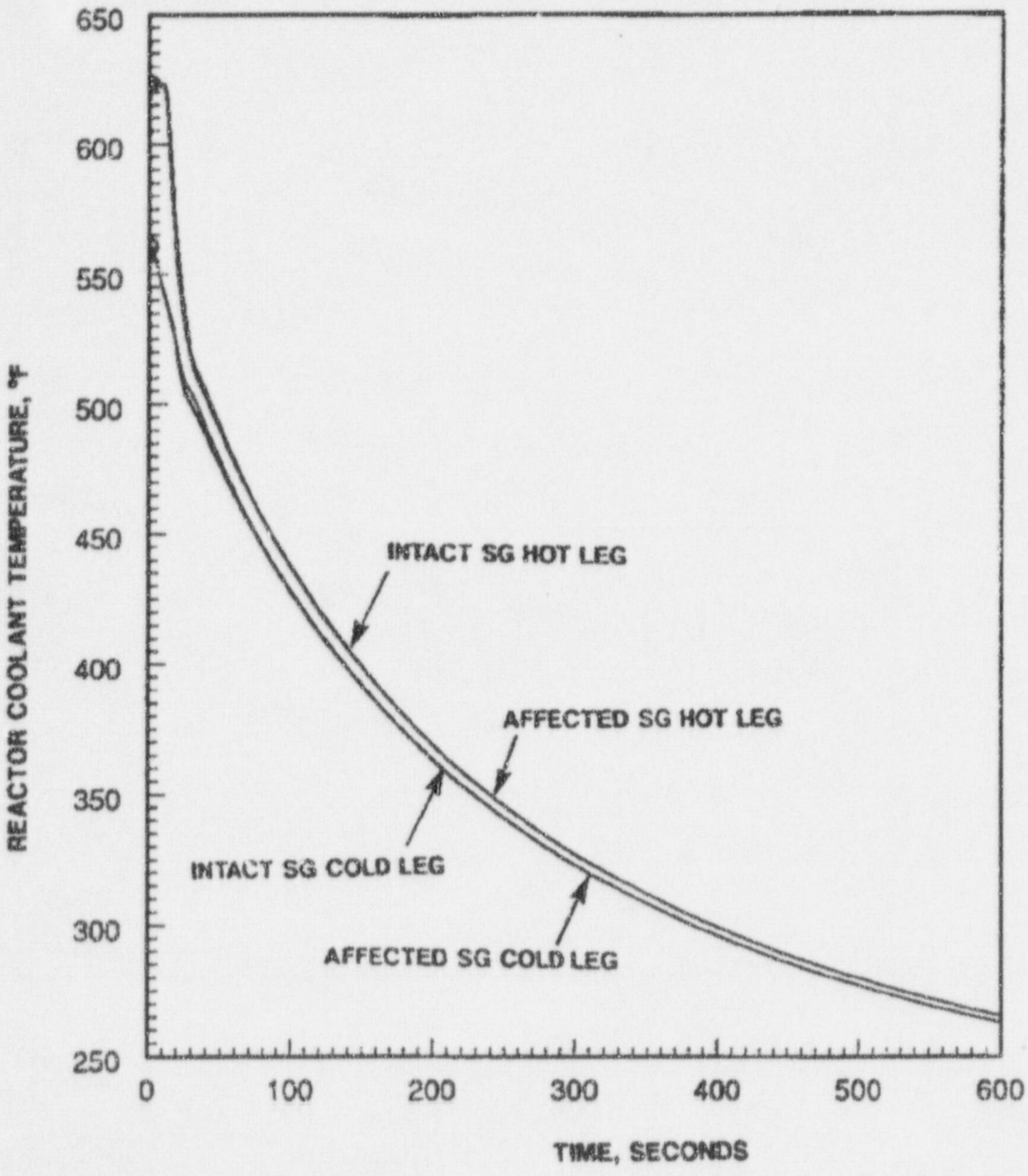
Full Power Large Steam Line Break with Offsite Power Available; Reactor Coolant System Pressure vs. Time	Figure 15.1.5-2.3



Full Power Large Steam Line Break with Offsite Power Available; Reactor Coolant Flow Rates vs. Time	Figure 15.1.5-2.4



Full Power Large Steam Line Break with Offsite Power Available; Reactor Coolant Temperatures (A) vs. Time	Figure 15.1.5-2.5A



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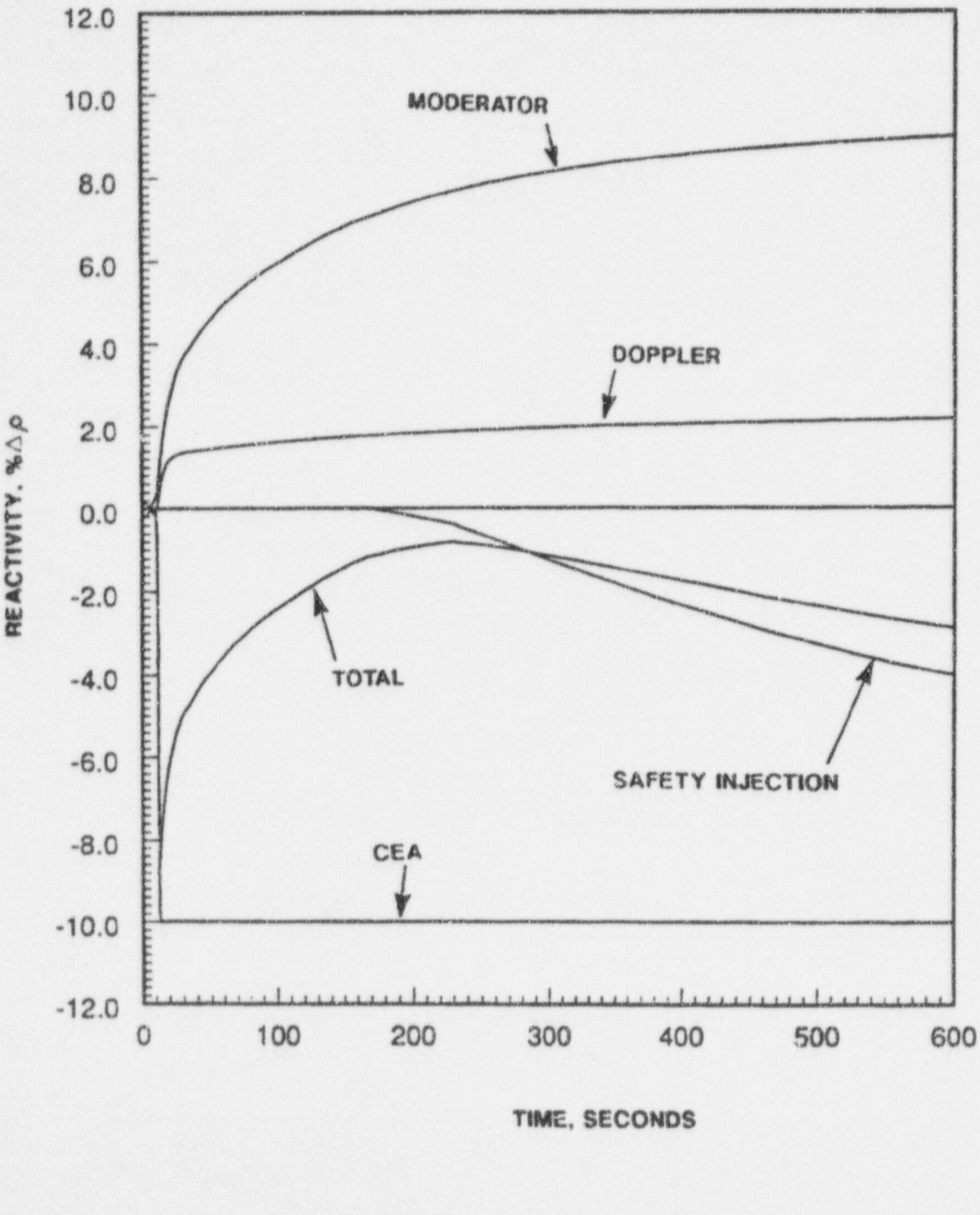

Full Power Large Steam Line Break with Offsite Power Available; Reactivity vs. Time	Figure 15.1.5-2.6

2

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

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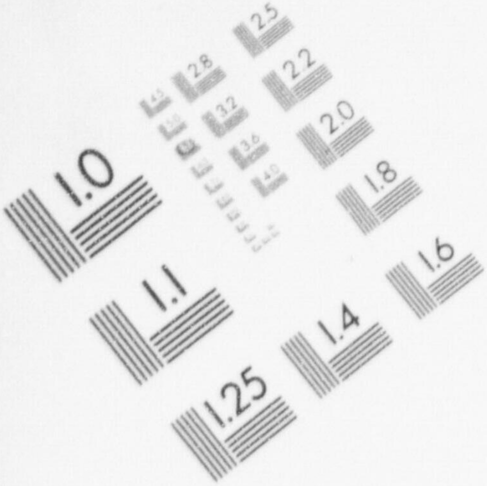
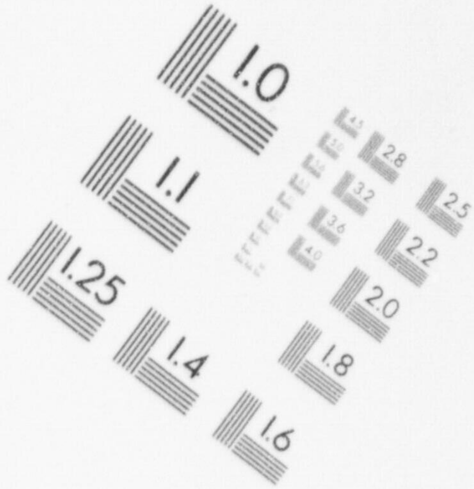
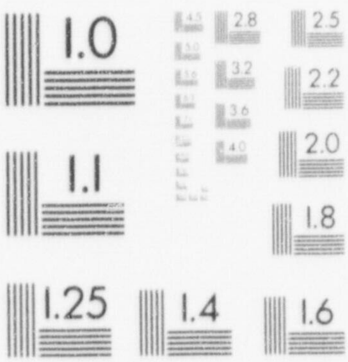
2

IMAGE EVALUATION TEST TARGET (MT-3)







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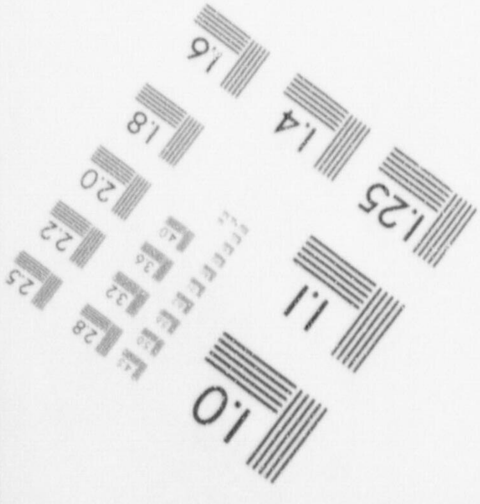

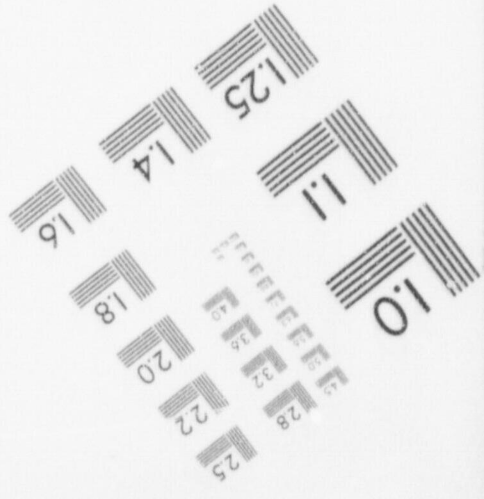

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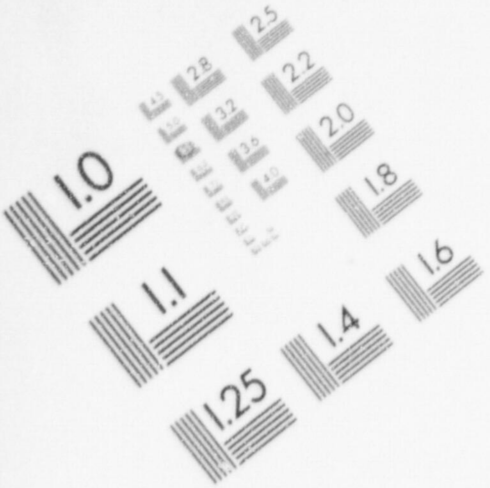
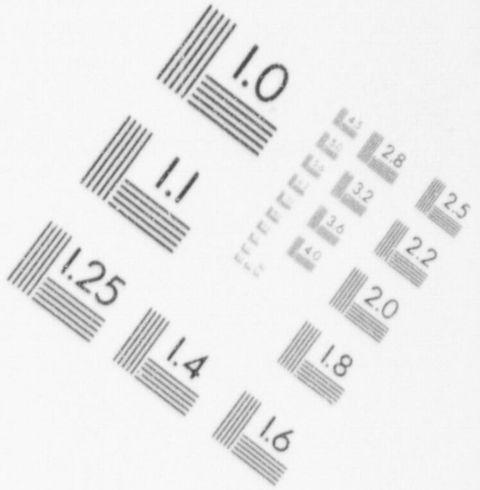
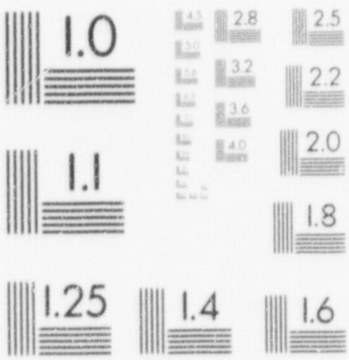

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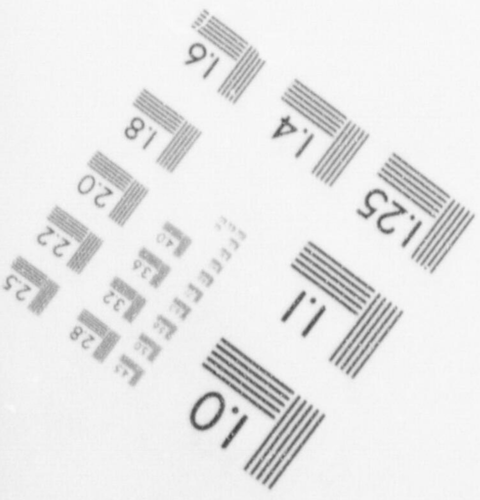
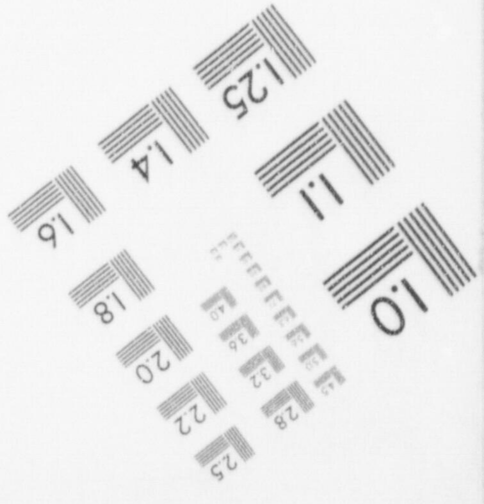

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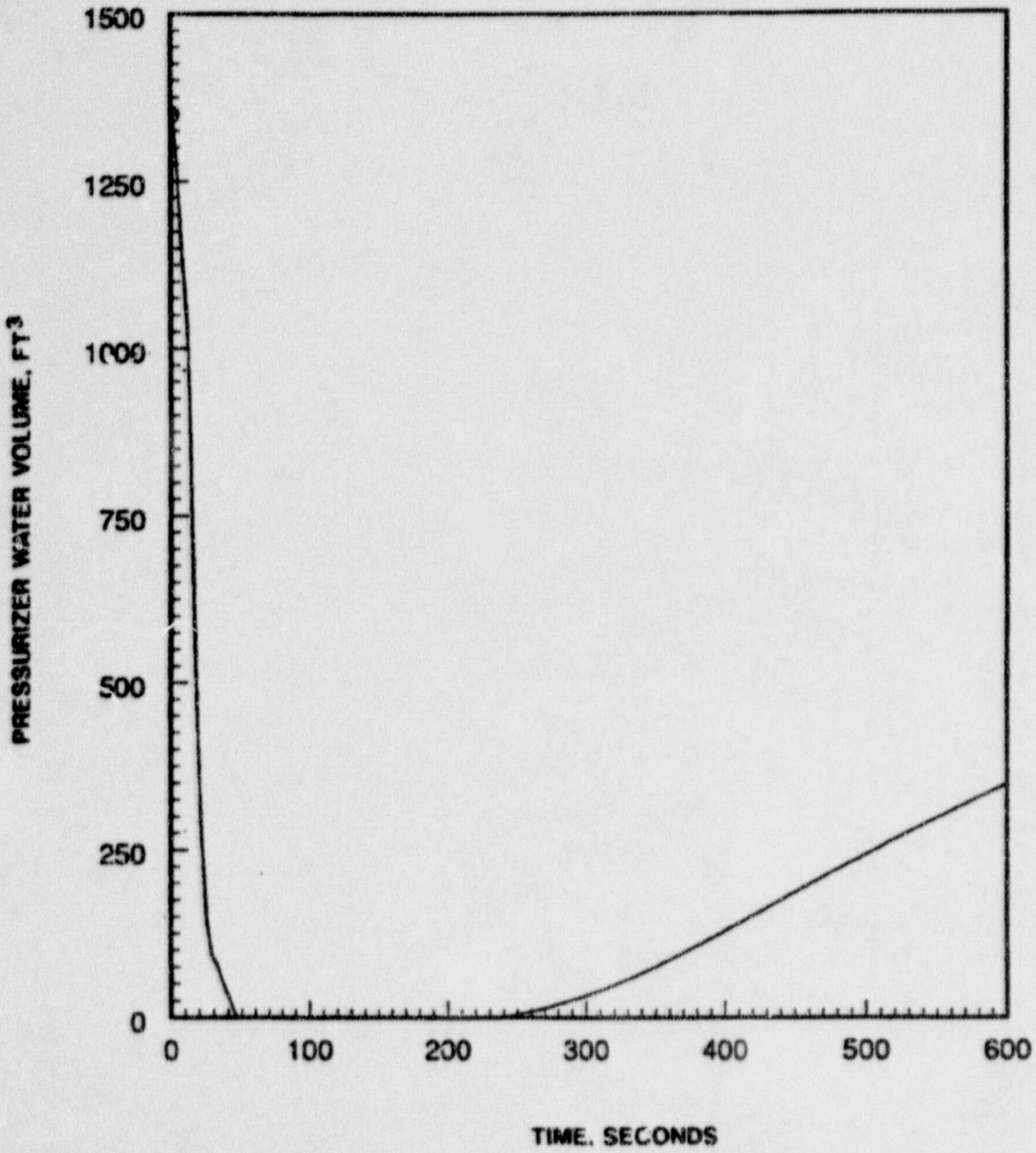
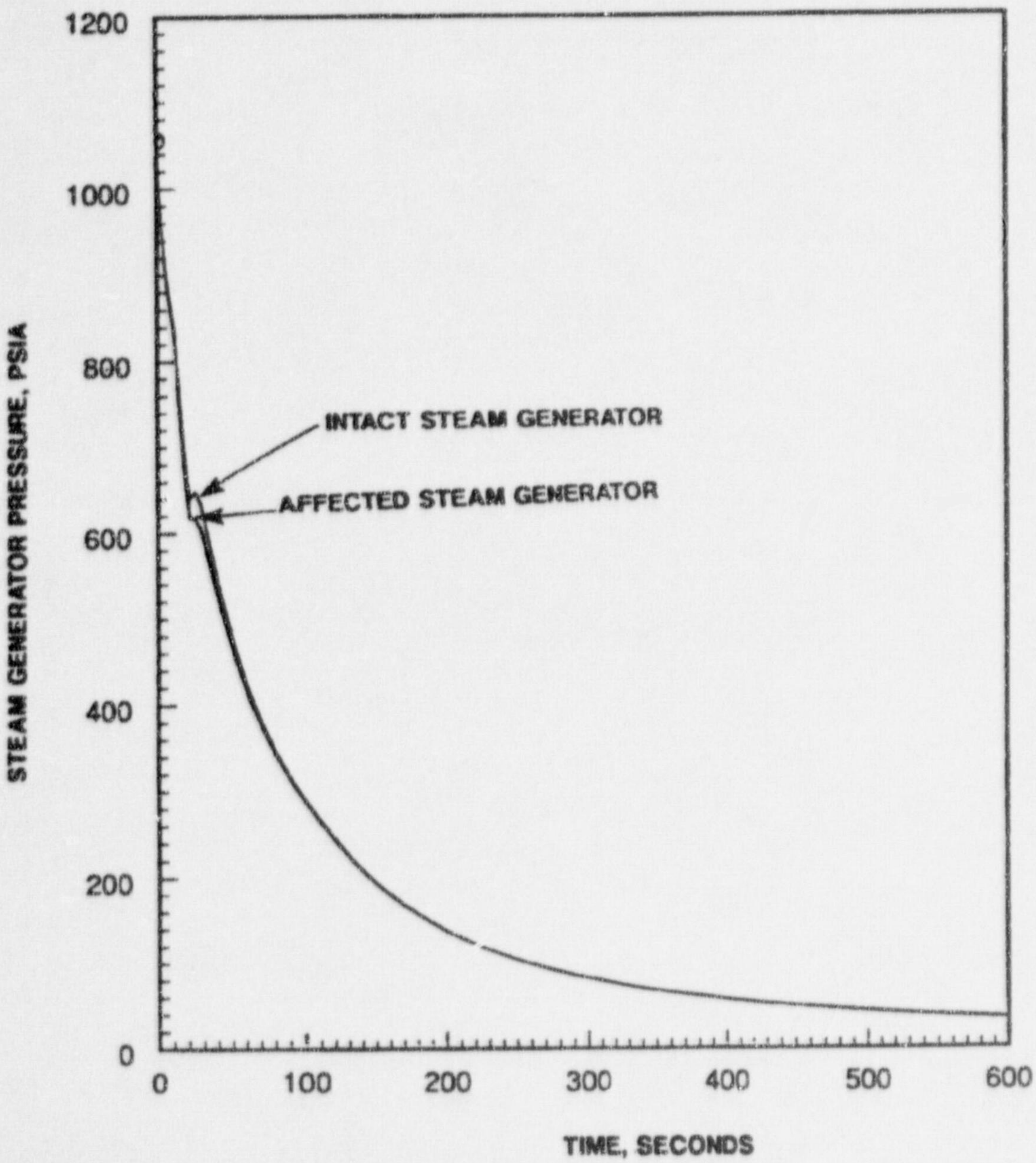
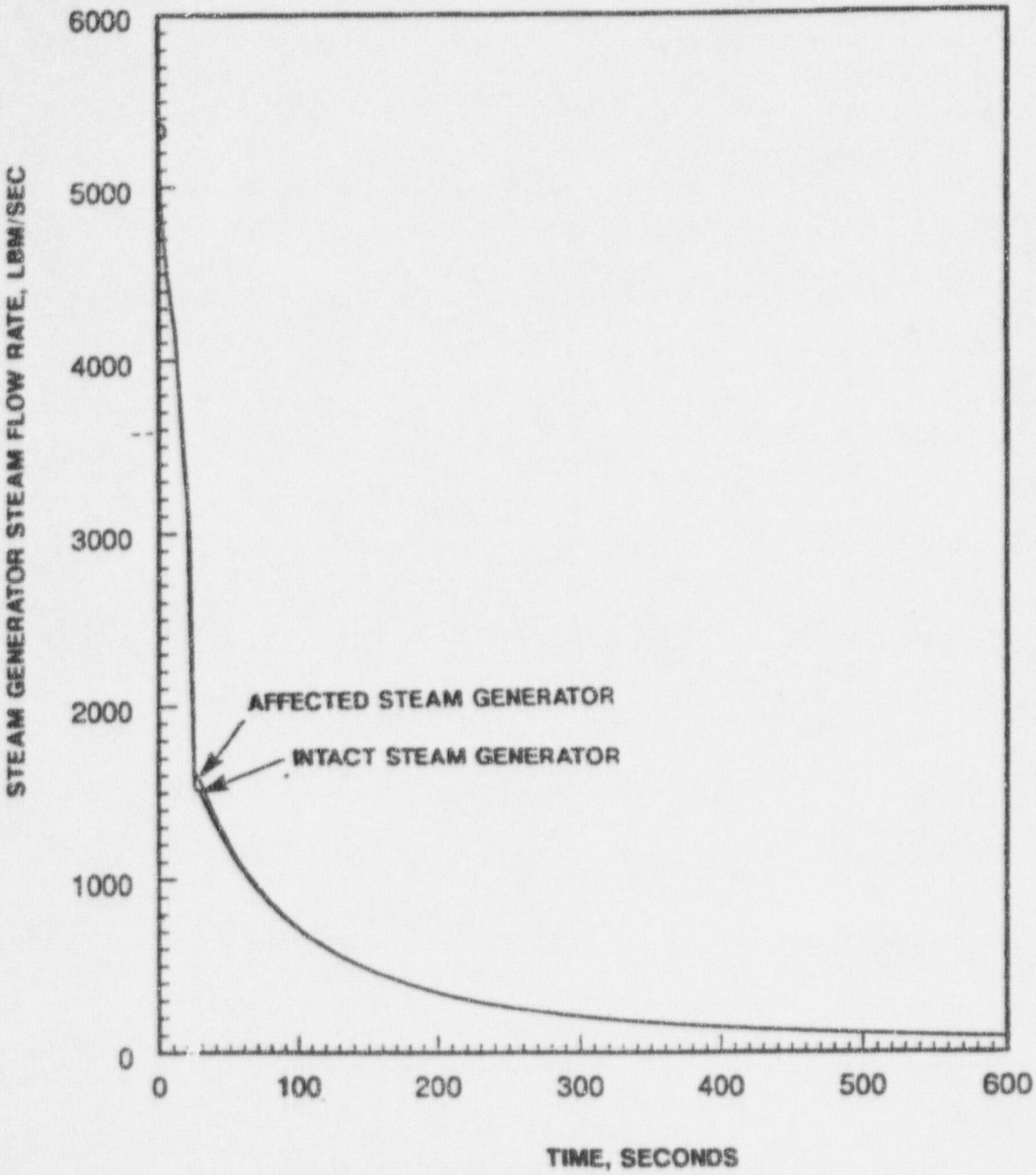


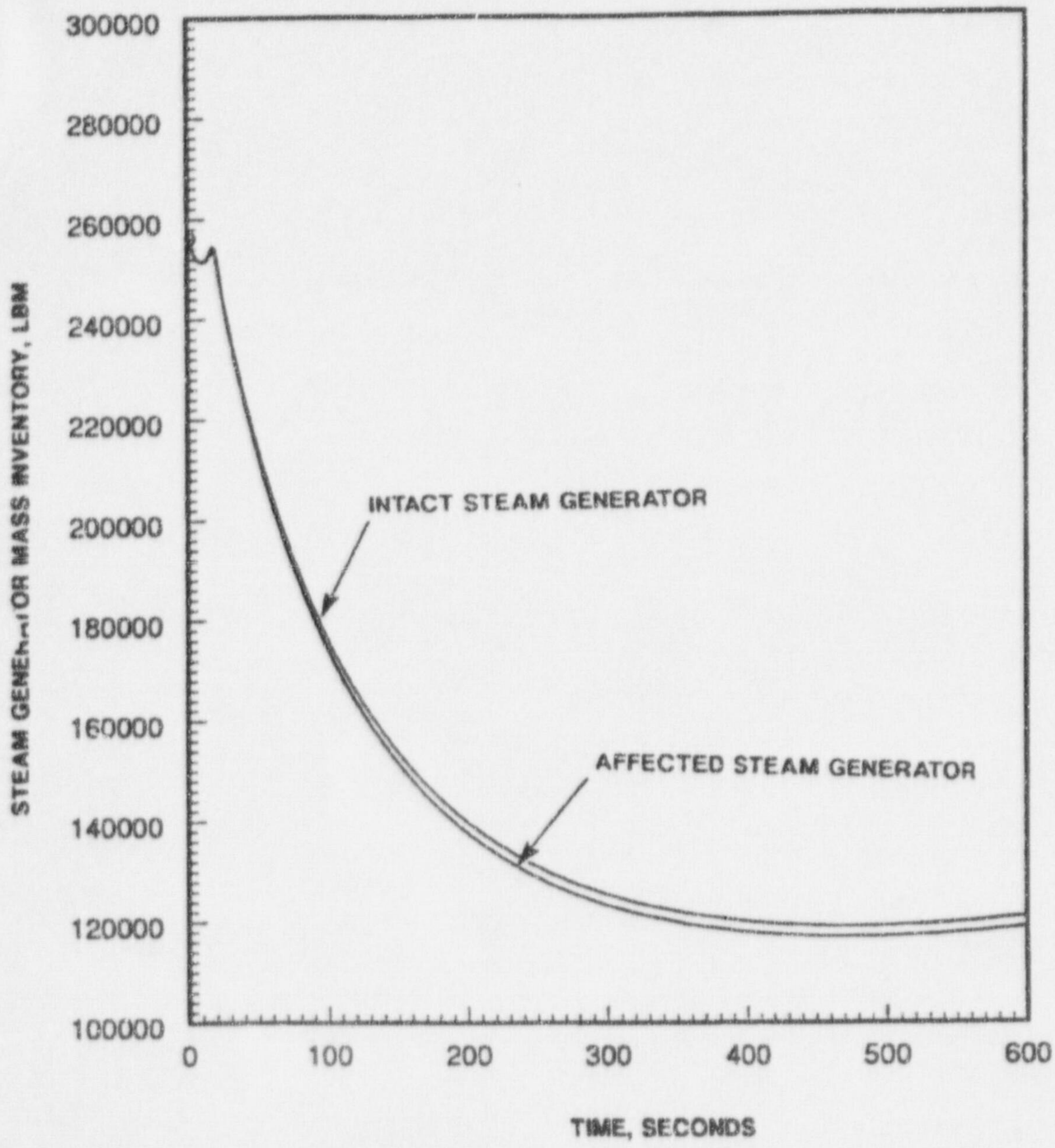
Full Power Large Steam Line Break with Offsite Power Available; Pressurizer Water Volume vs. Time	Figure 15.1.5-2.7



Full Power Large Steam Line Break with Offsite Power Available; Steam Generator Pressures vs. Time	Figure 15.1.5-2.8



Full Power Large Steam Line Break with Offsite Power Available; Steam Generator Steam Flow Rates vs. Time	Figure 15.1.5-2.9



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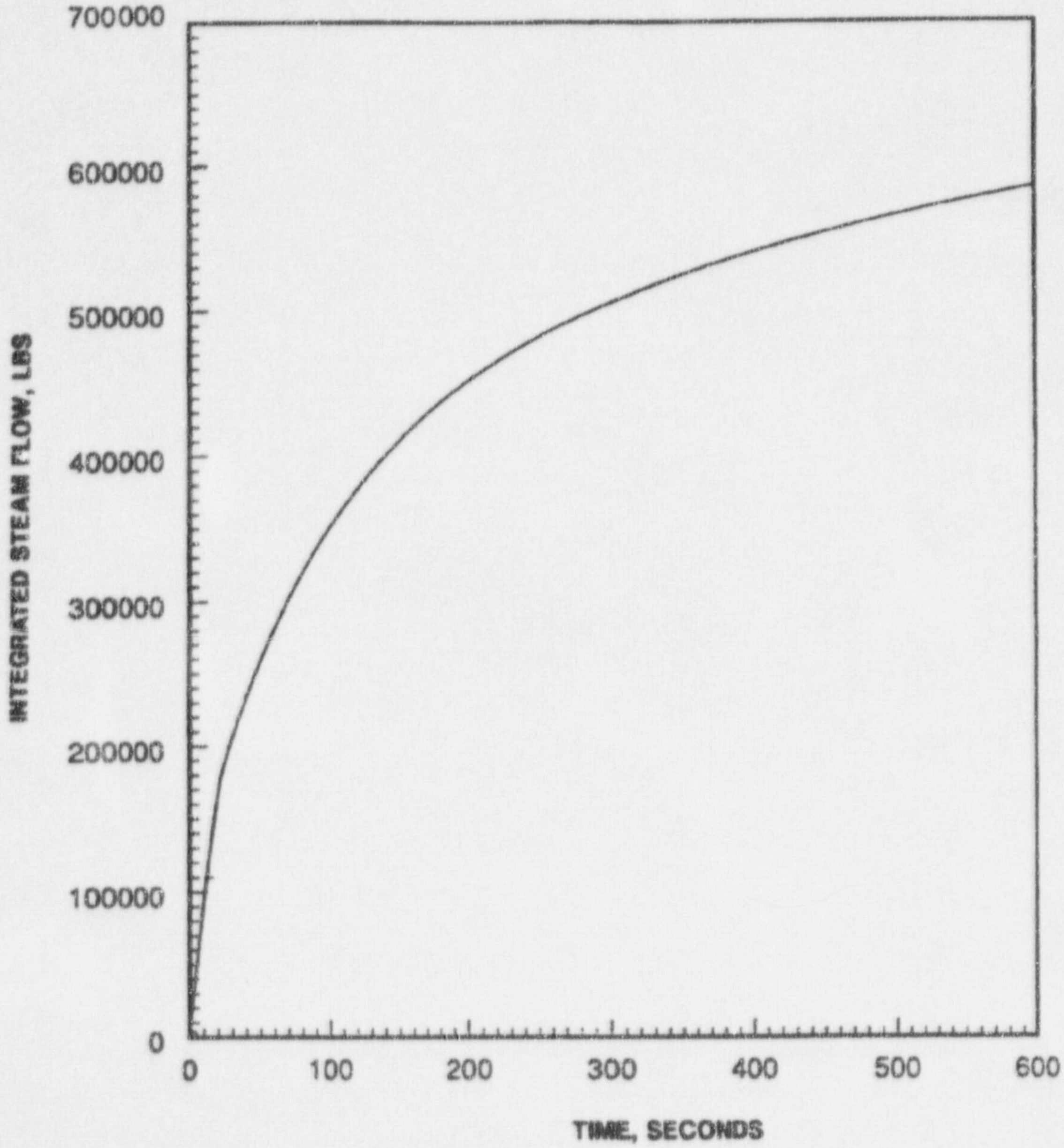
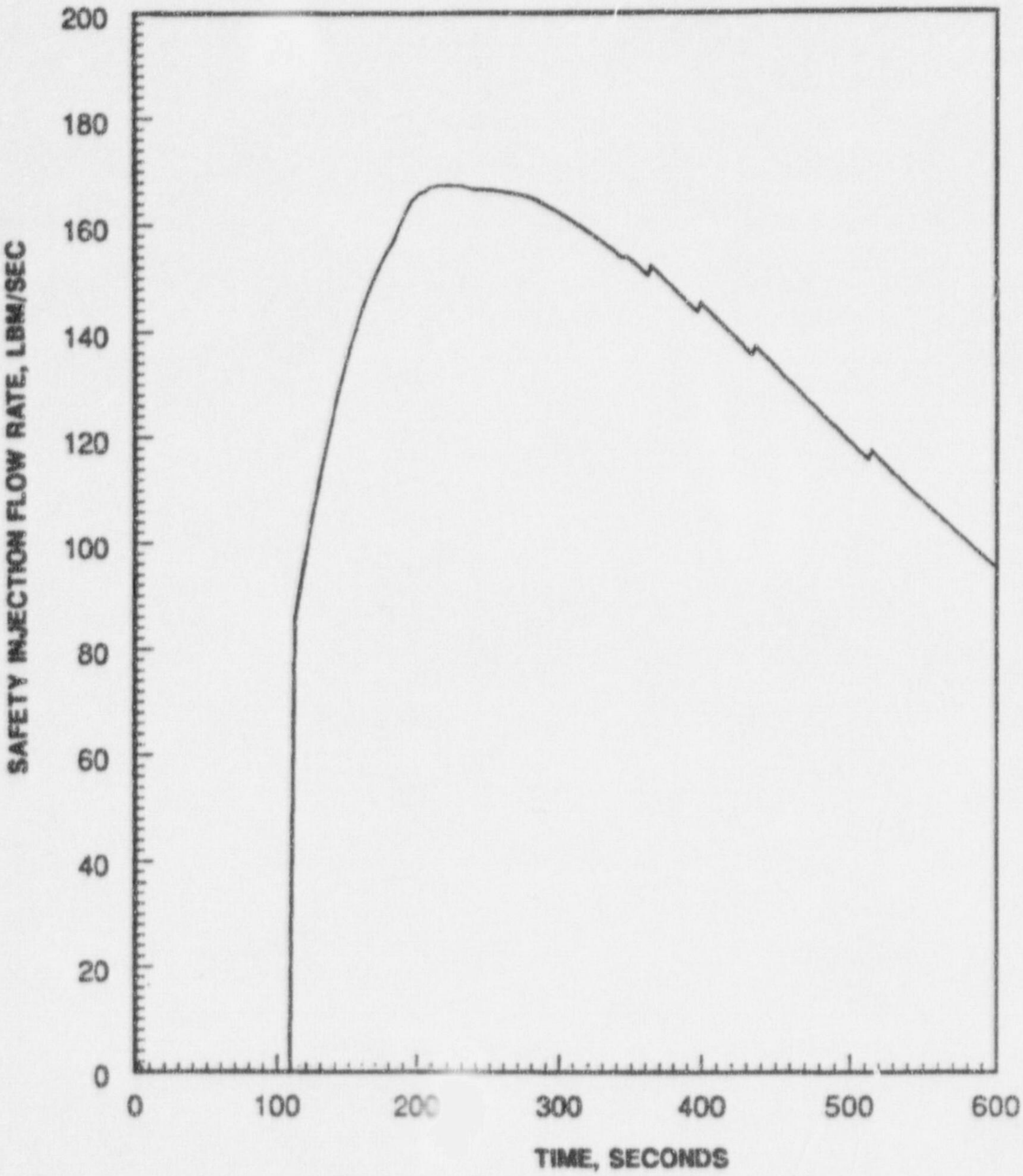
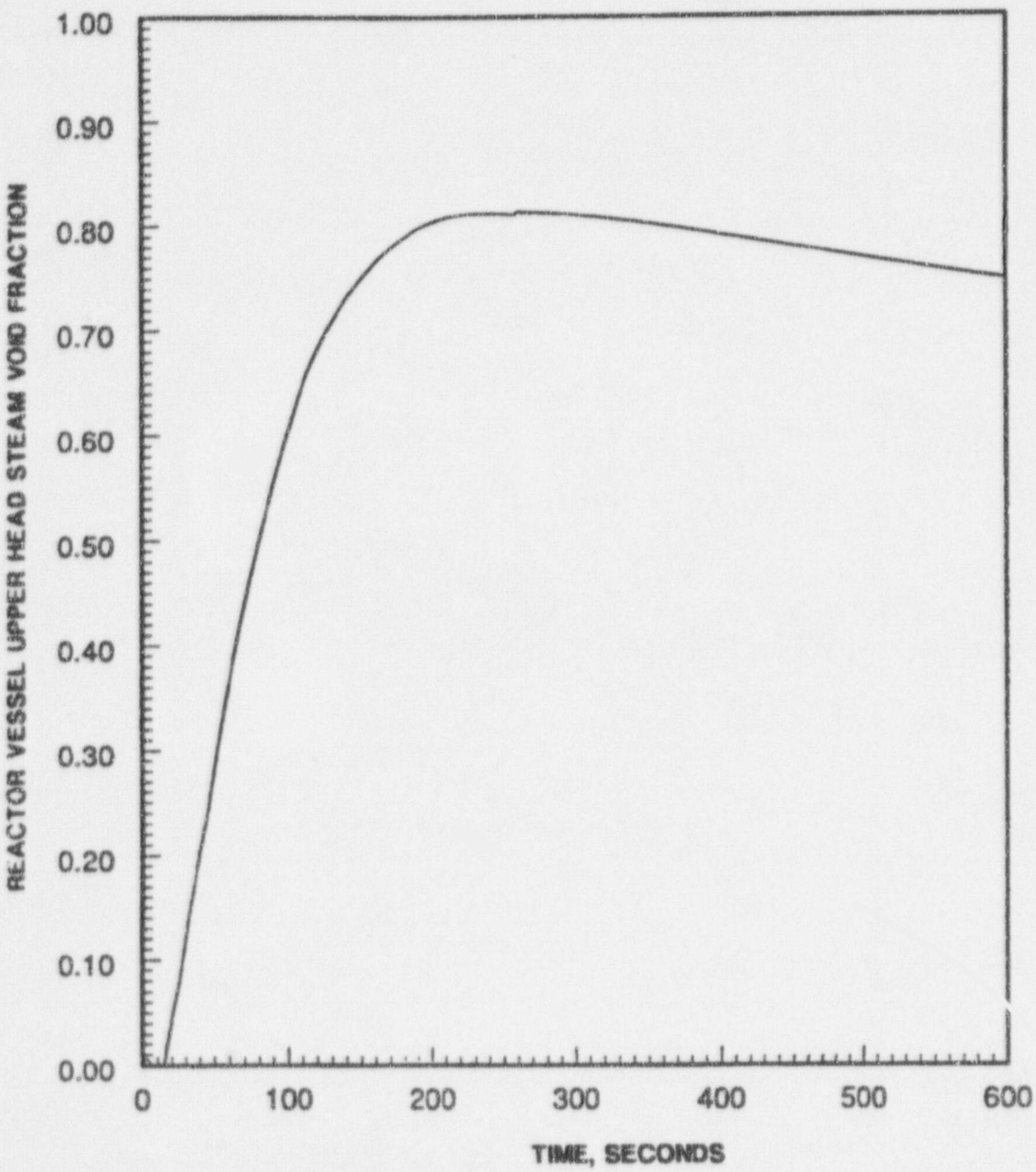


Full Power Large Steam Line Break with Offsite Power Available; Integrated Steam Release vs. Time	Figure 15.1.5-2.11



Full Power Large Steam Line Break with Offsite Power Available; Safety Injection Flow Rate vs. Time	Figure 15.1.5-2.12



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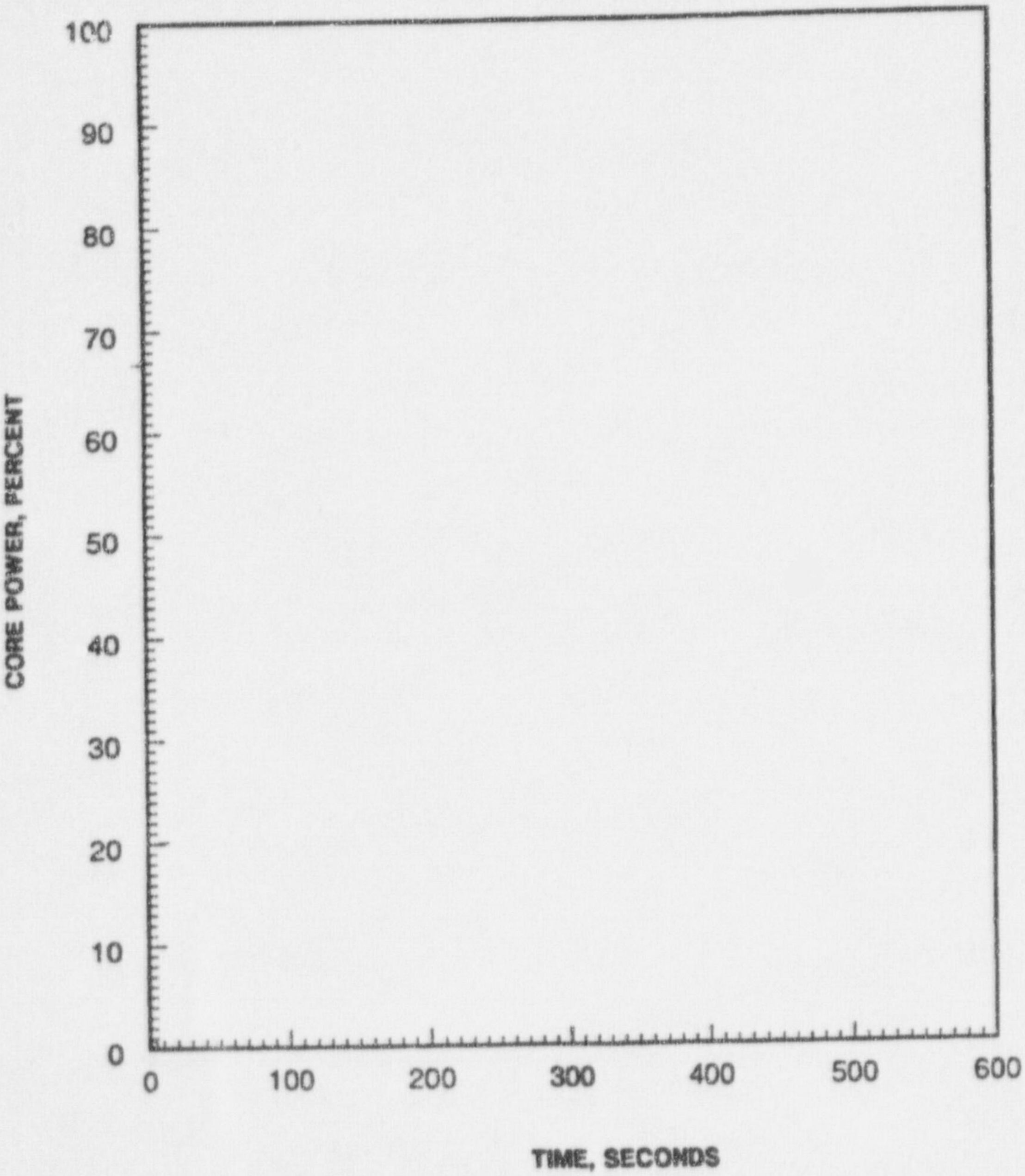
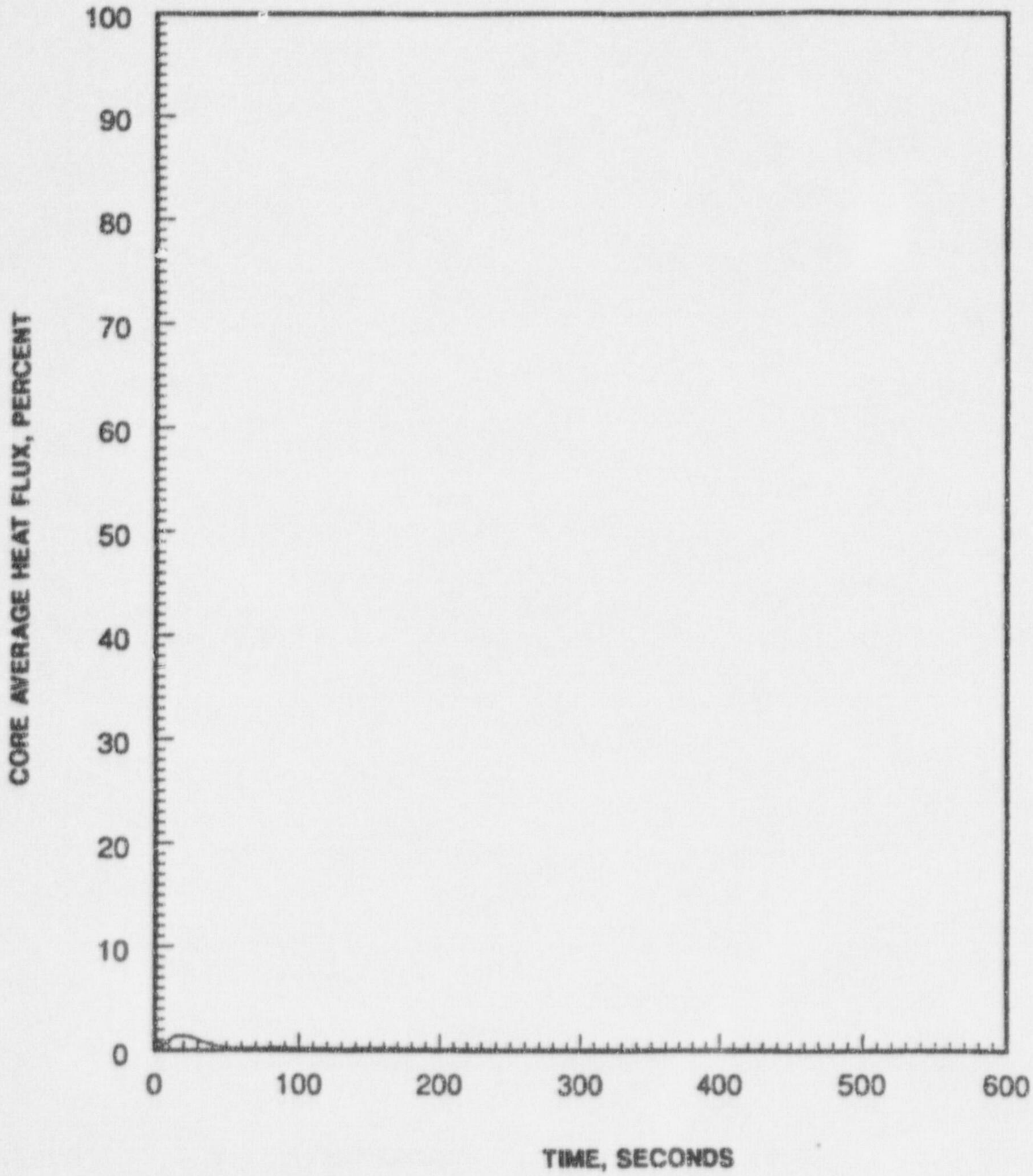


Zero Power Large Steam Line Break with Concurrent Loss of Offsite Power; Core Power vs. Time	Figure 15.1.5-3.1



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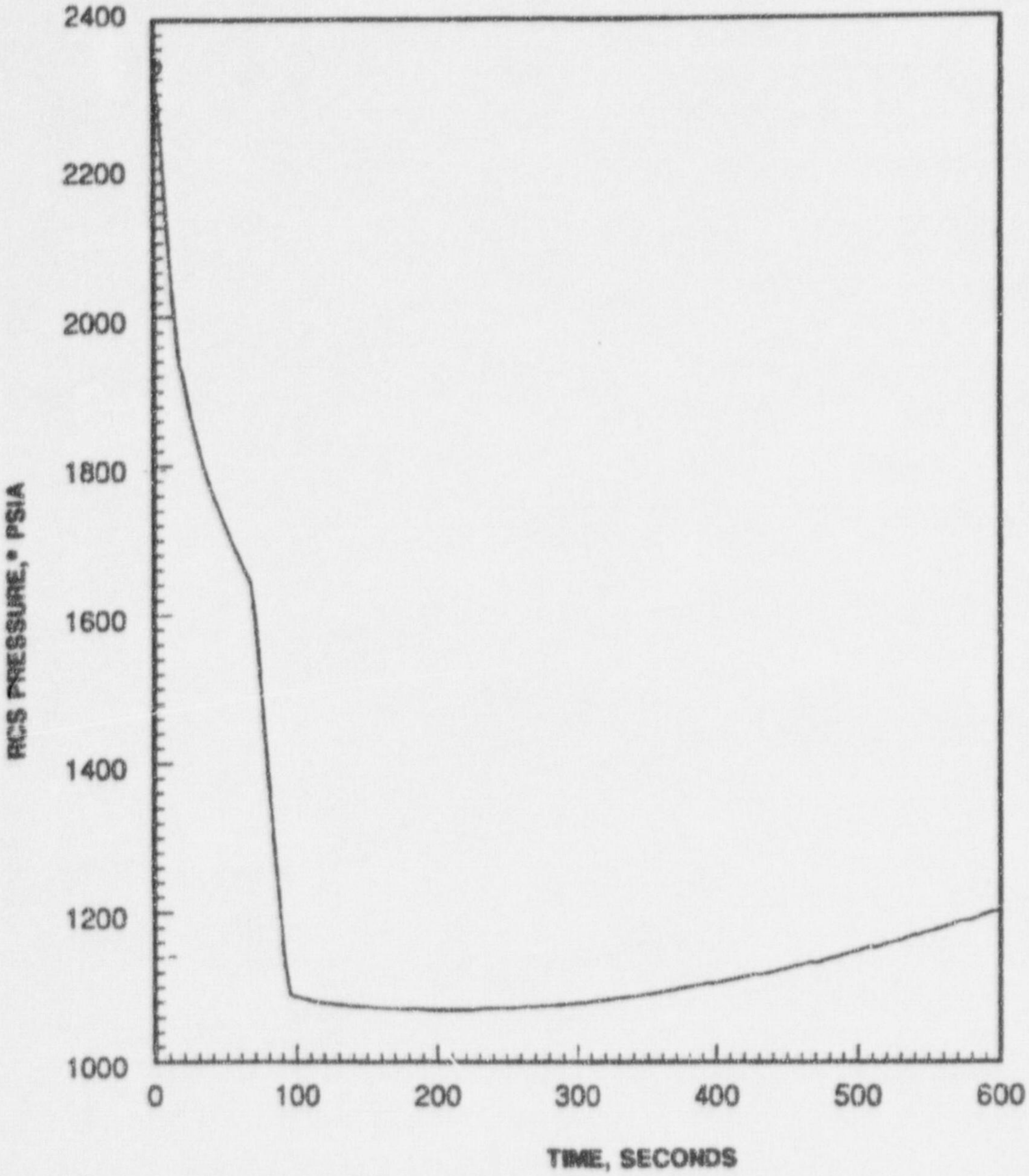
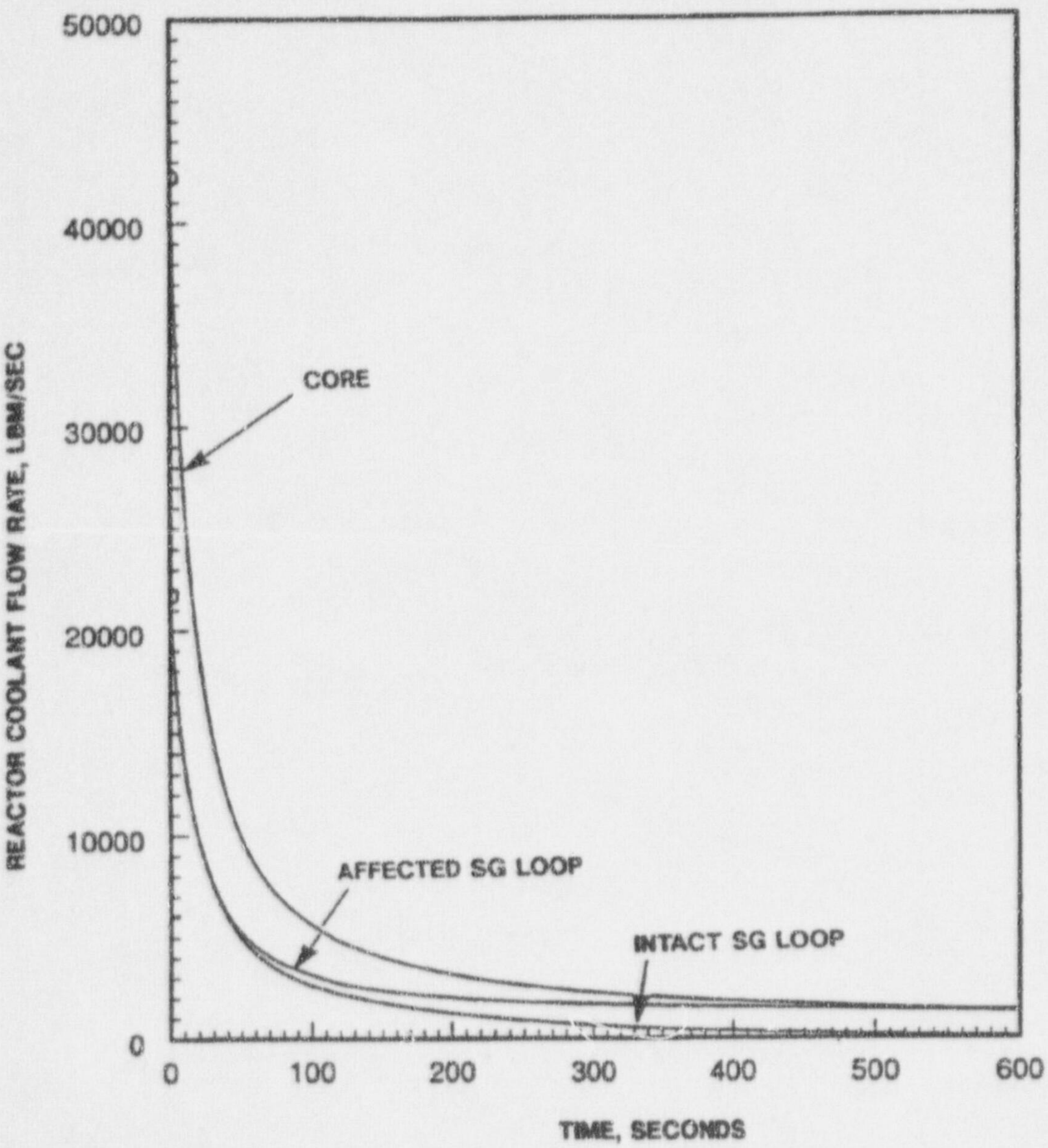


*THIS PRESSURE DOES NOT INCLUDE THE PRESSURE DIFFERENCE BETWEEN THE COLD LEG AT RCP DISCHARGE AND THE SURGE LINE

Zero Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Coolant System Pressure vs. Time	Figure 15.1.5-3.3



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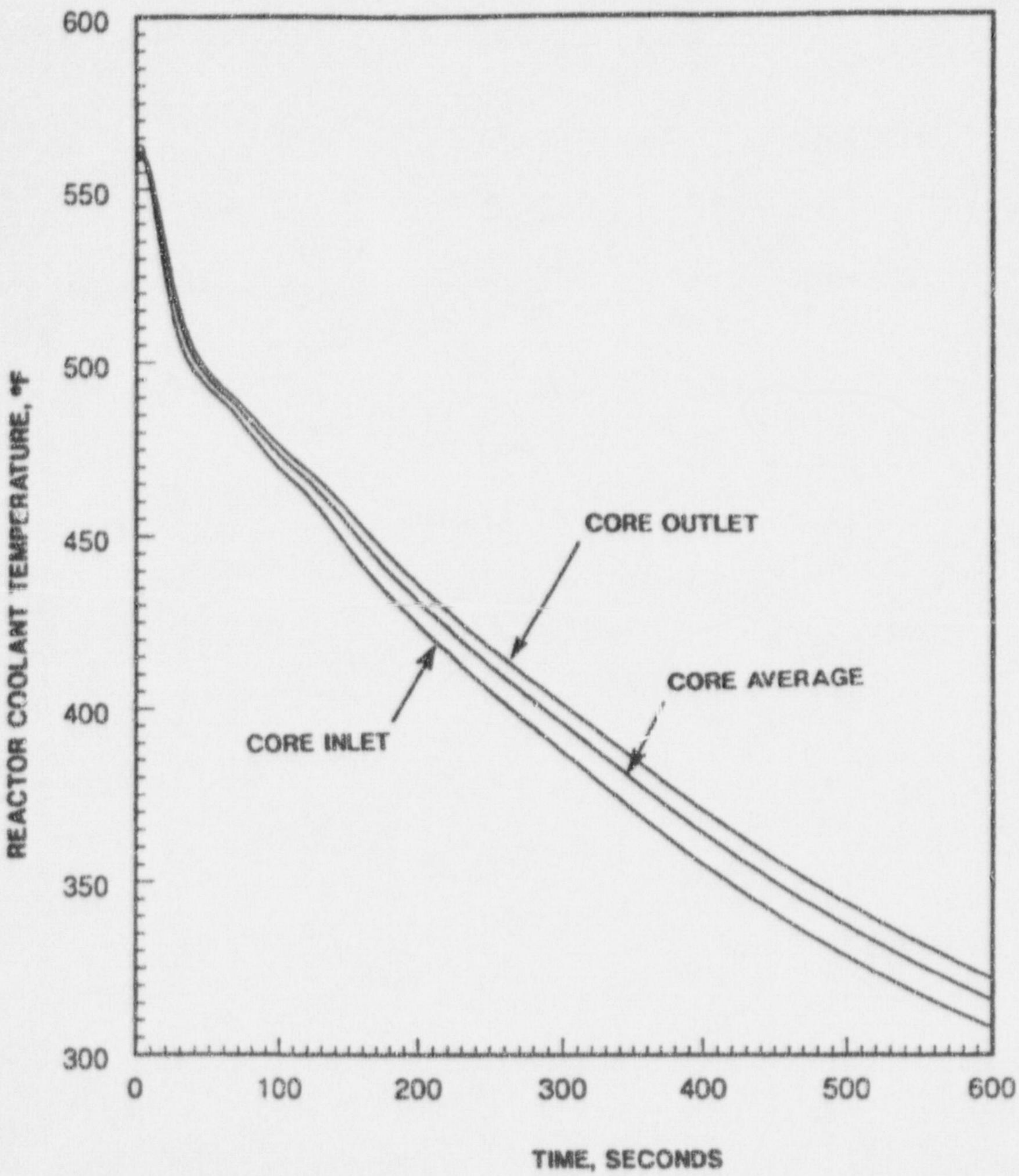
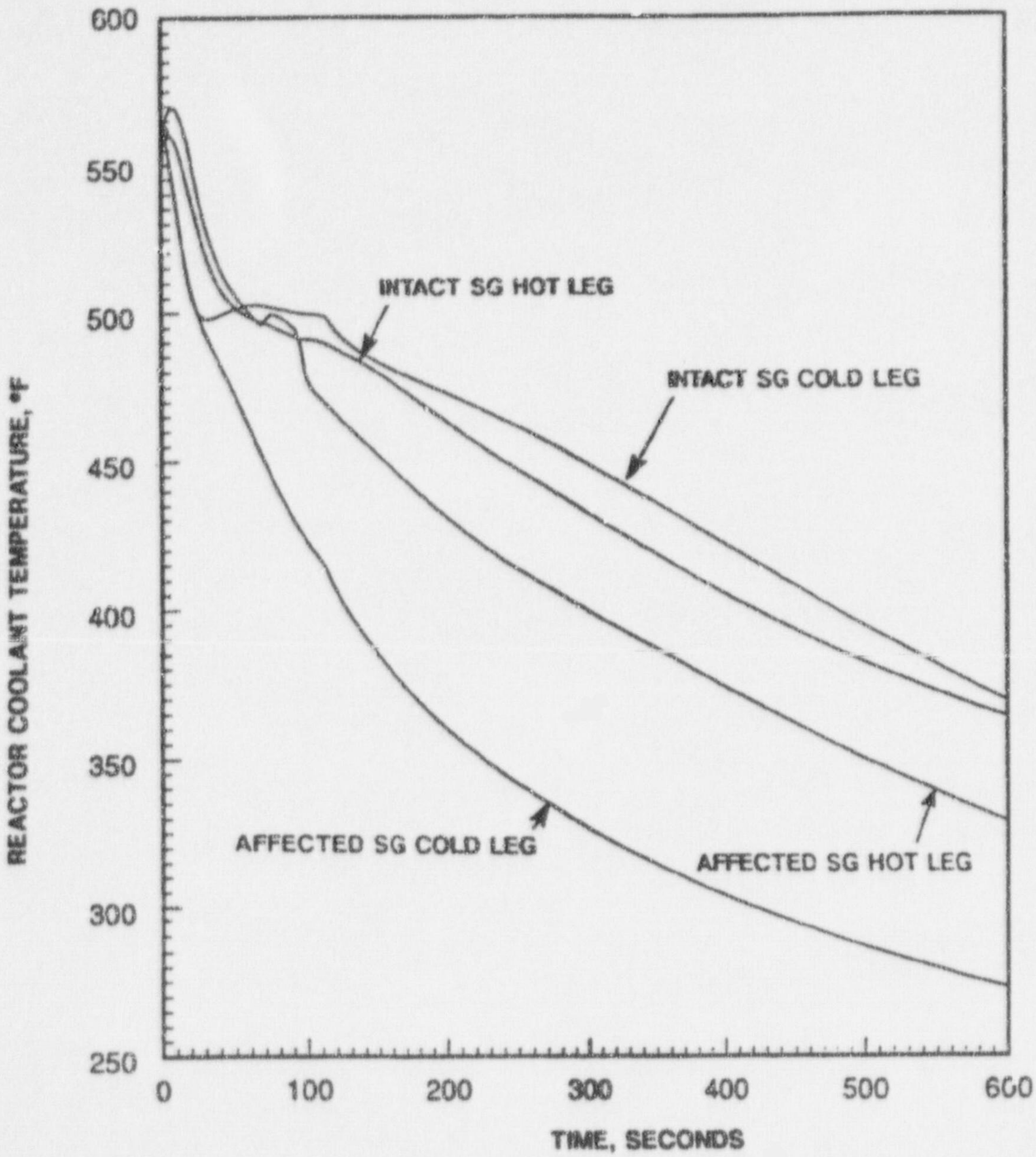
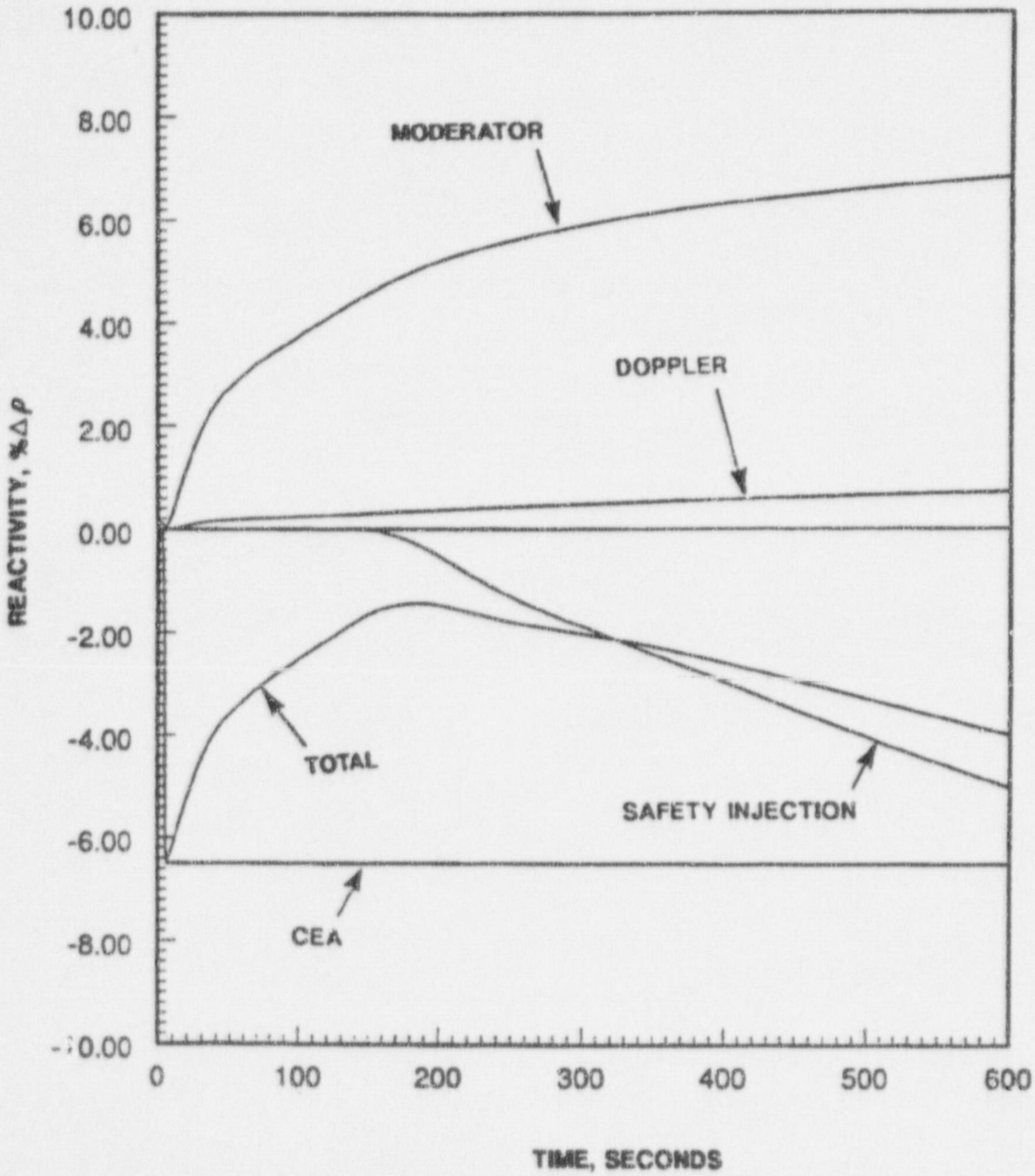


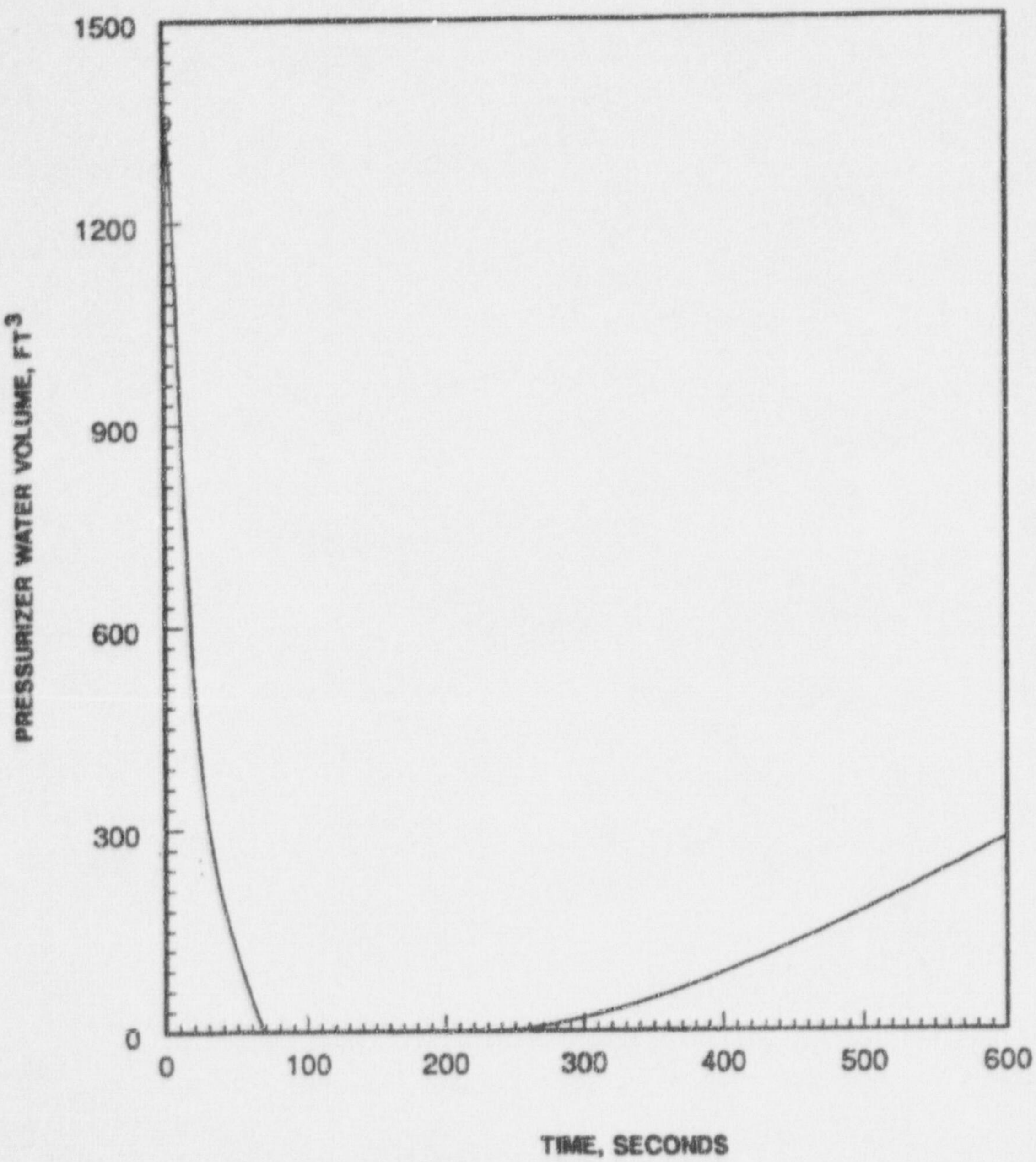
Zero Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Coolant Temperatures (A) vs. Time	Figure 15.1.5-3.5A



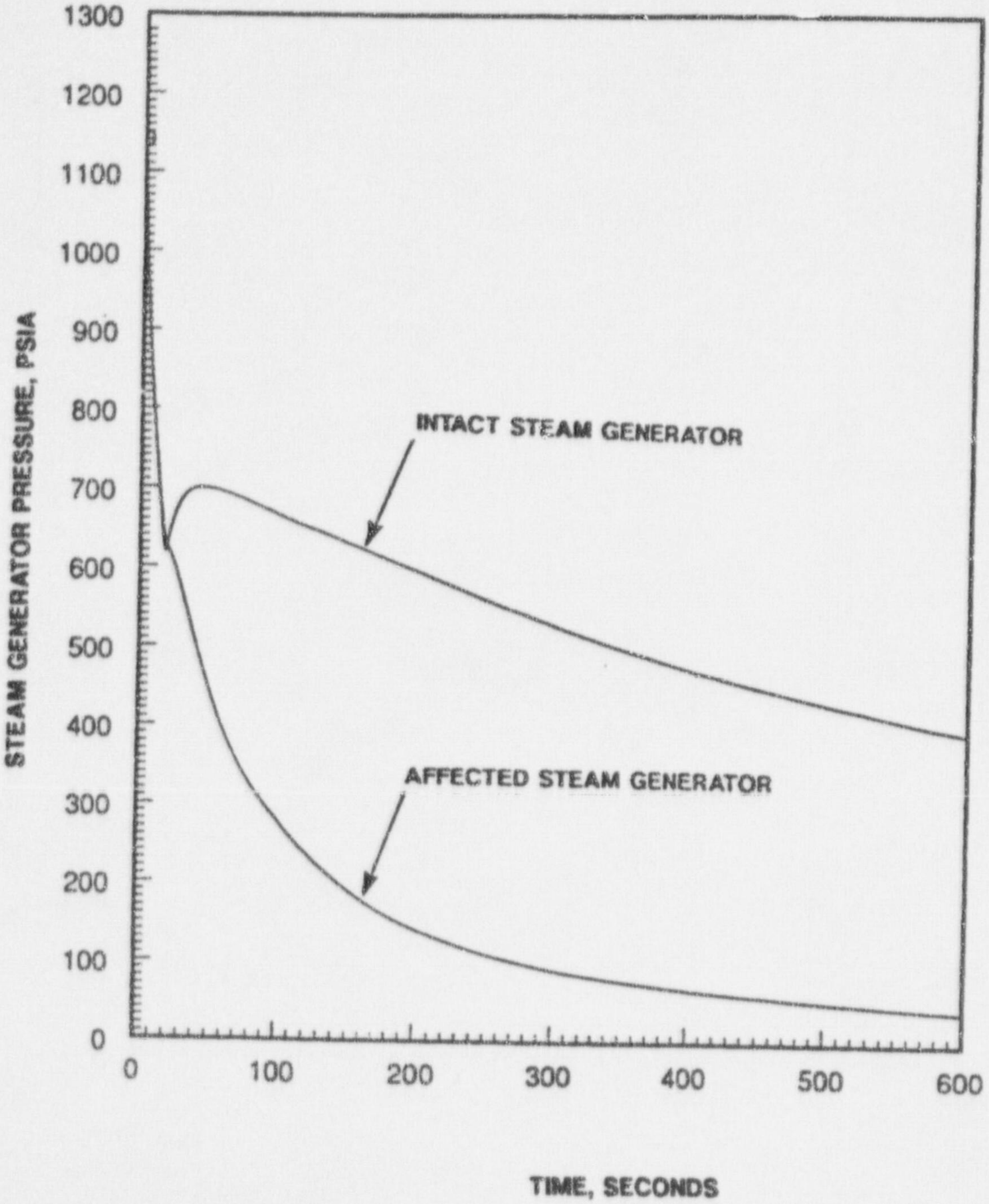
Zero Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Coolant Temperatures (B) vs. Time	Figure 15.1.5-3.5B



Zero Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactivity vs. Time	Figure 15.1.5-3.6



Zero Power Large Steam Line Break with Concurrent Loss of Offsite Power; Pressurizer Water Volume vs. Time	Figure 15.1.5-3.7



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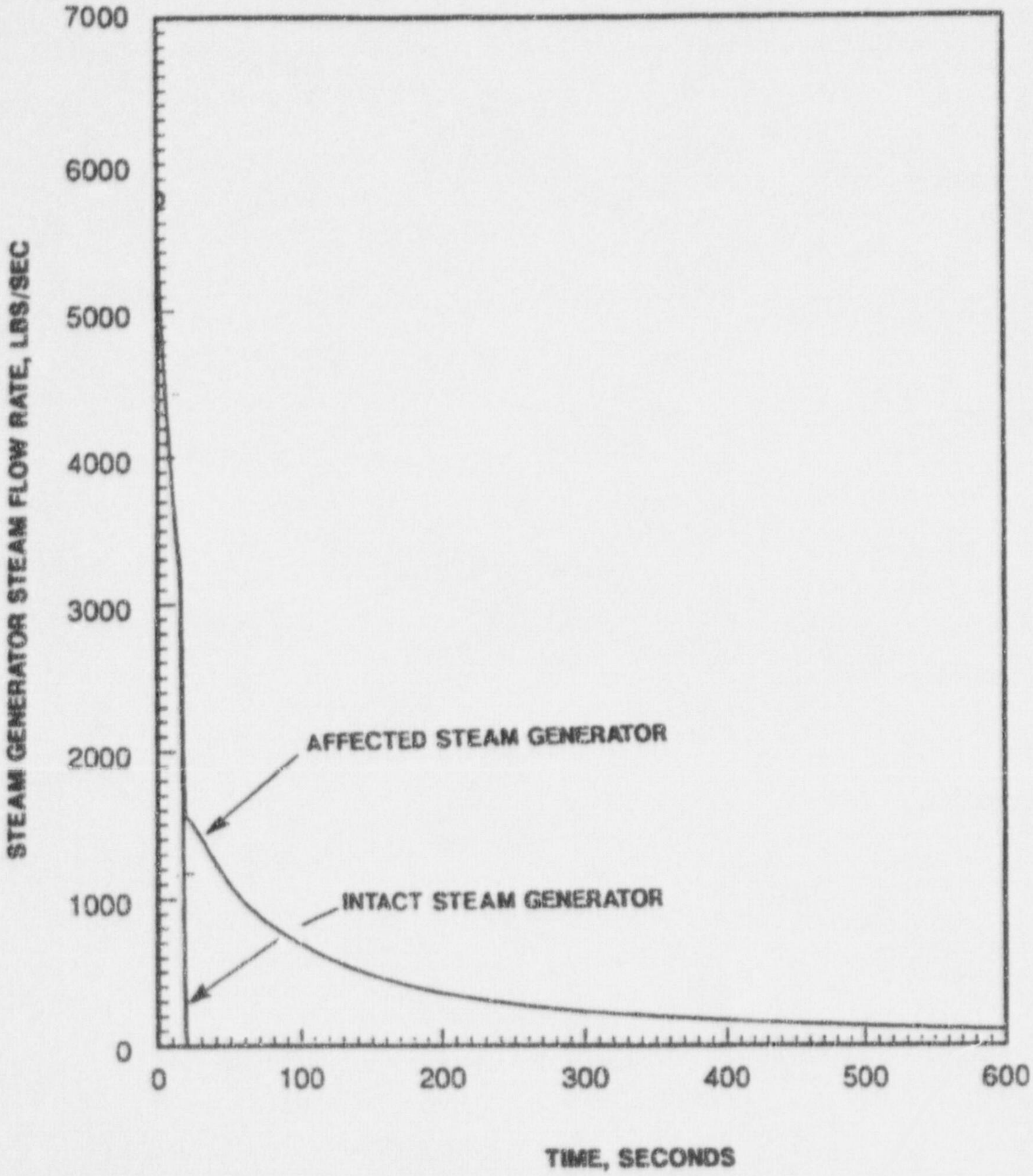

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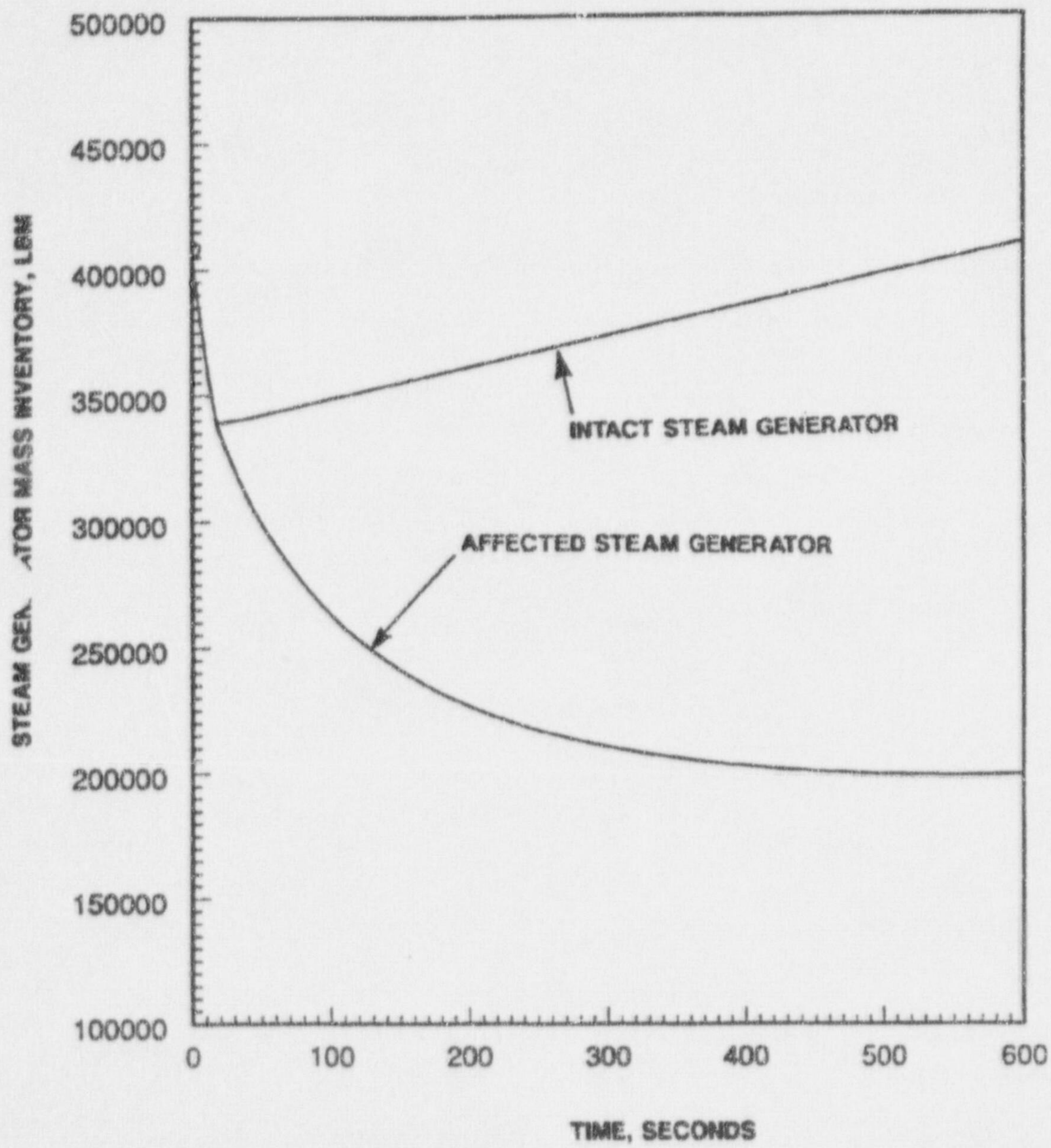

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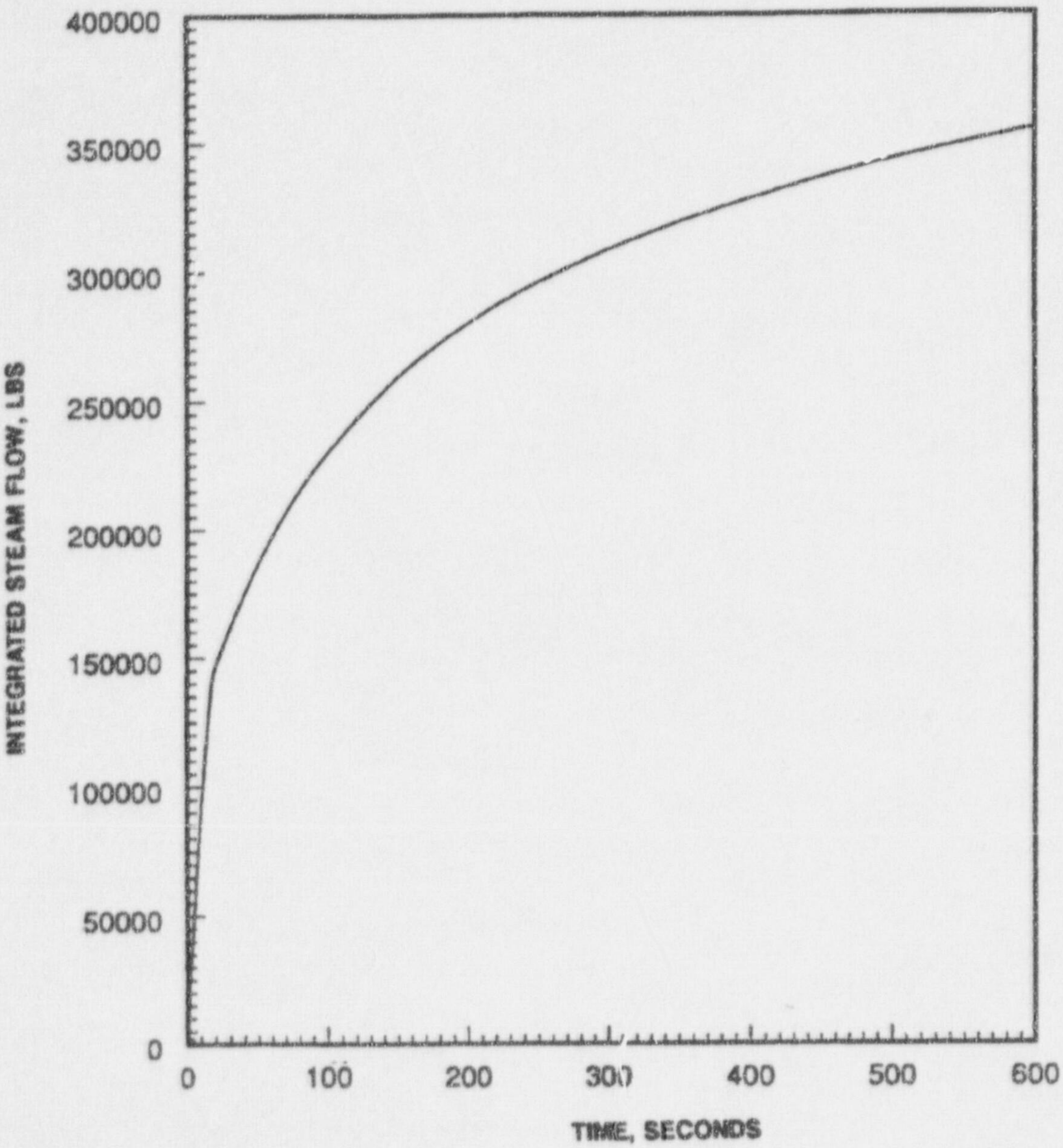

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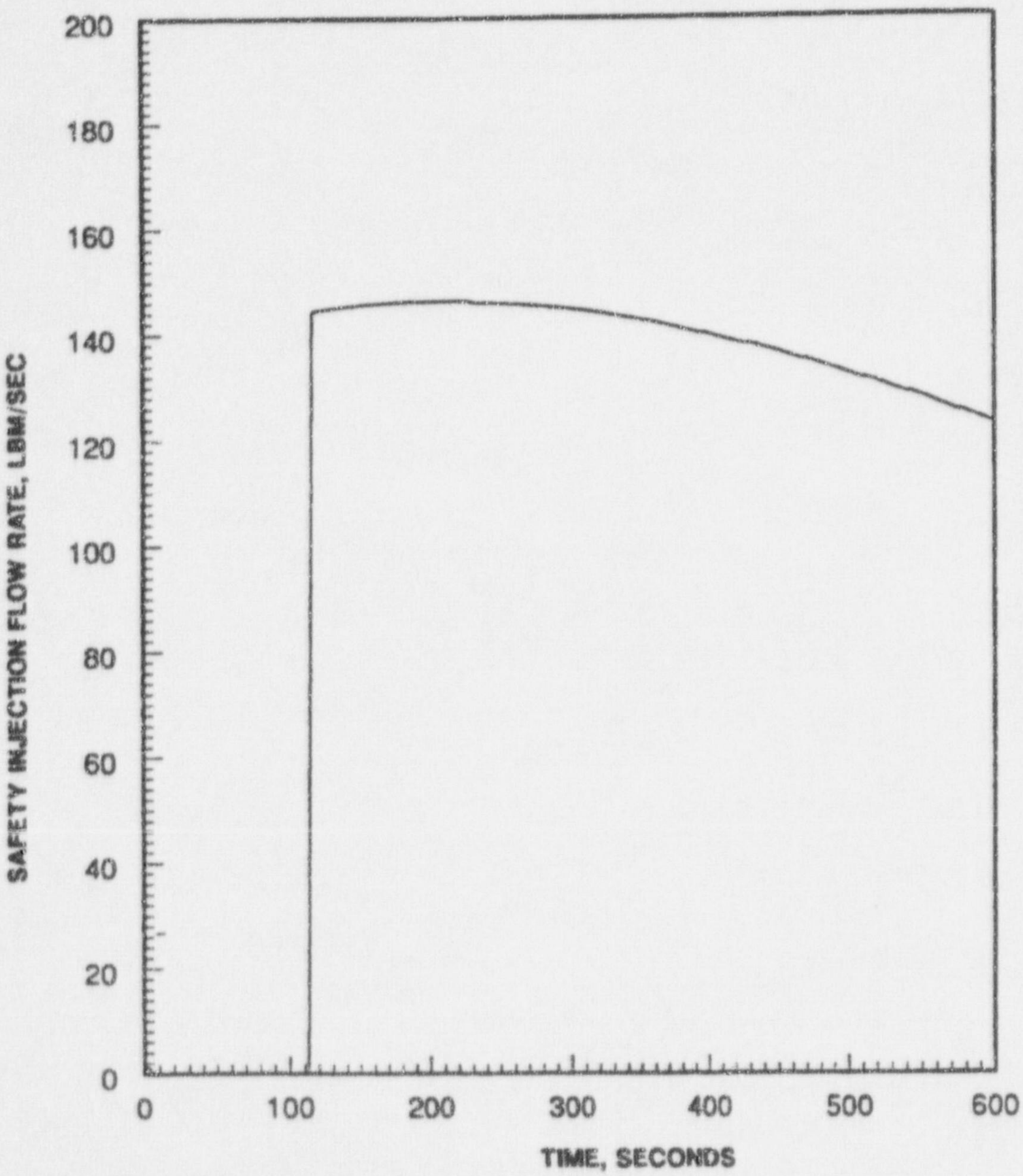

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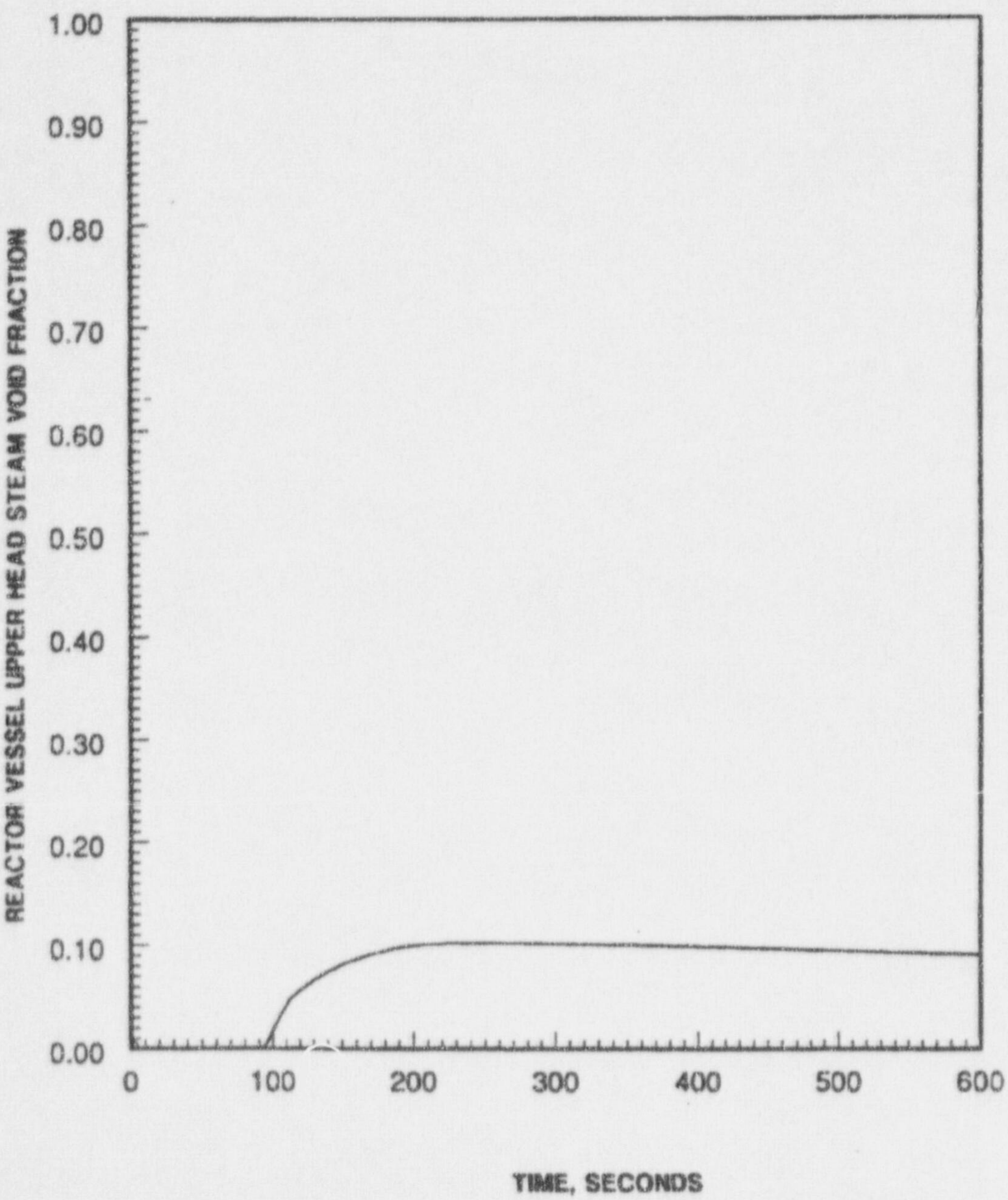
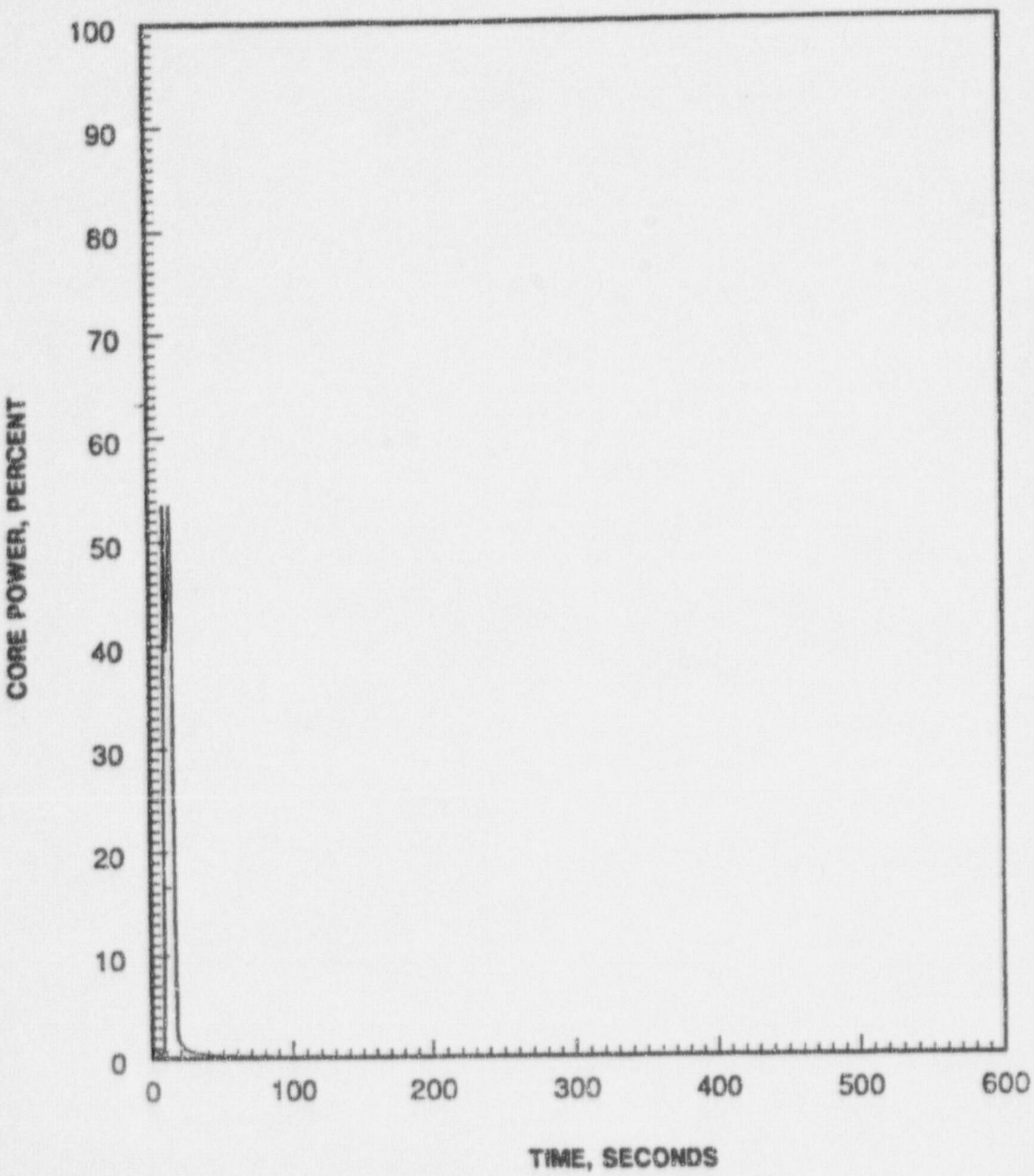
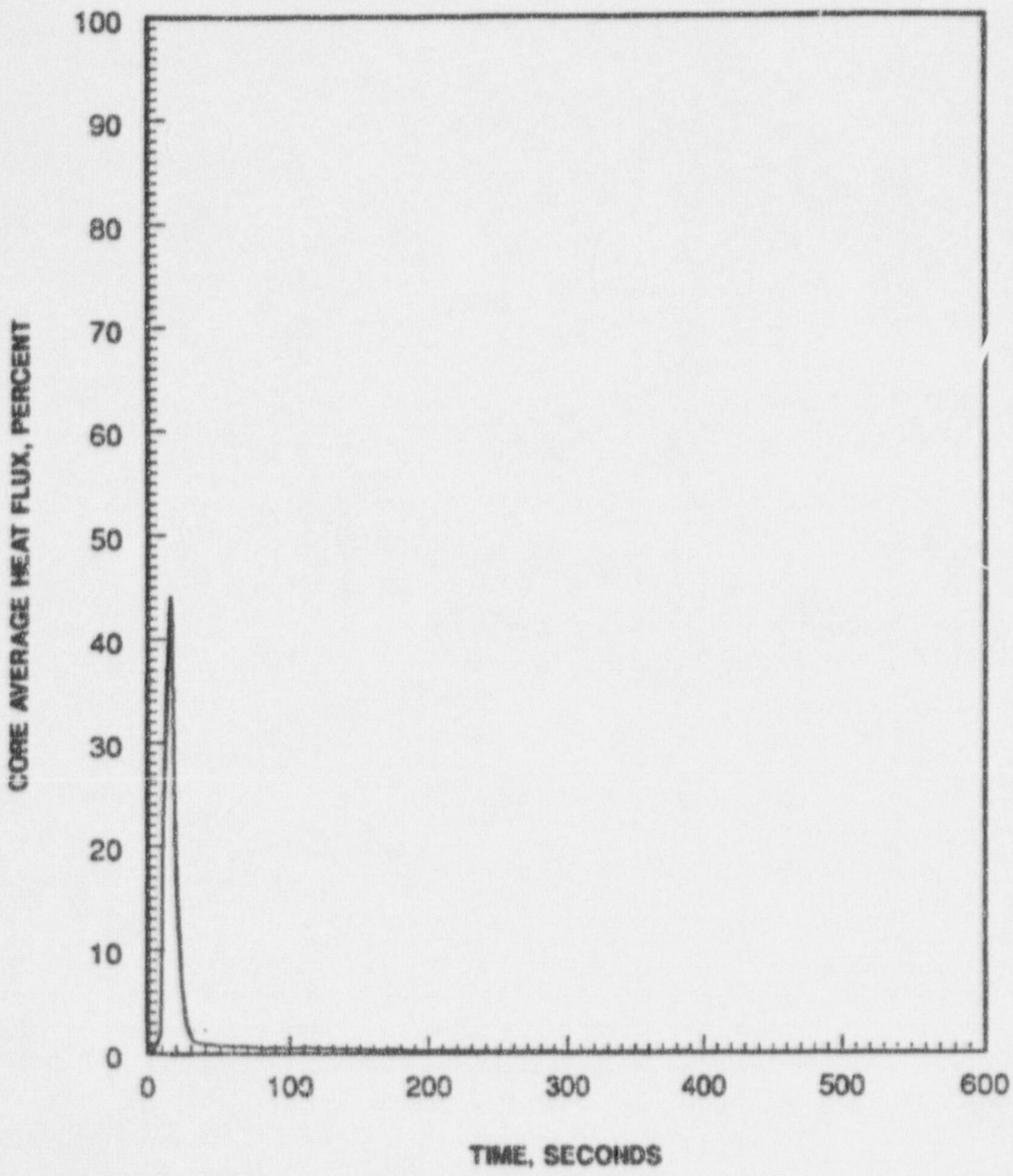


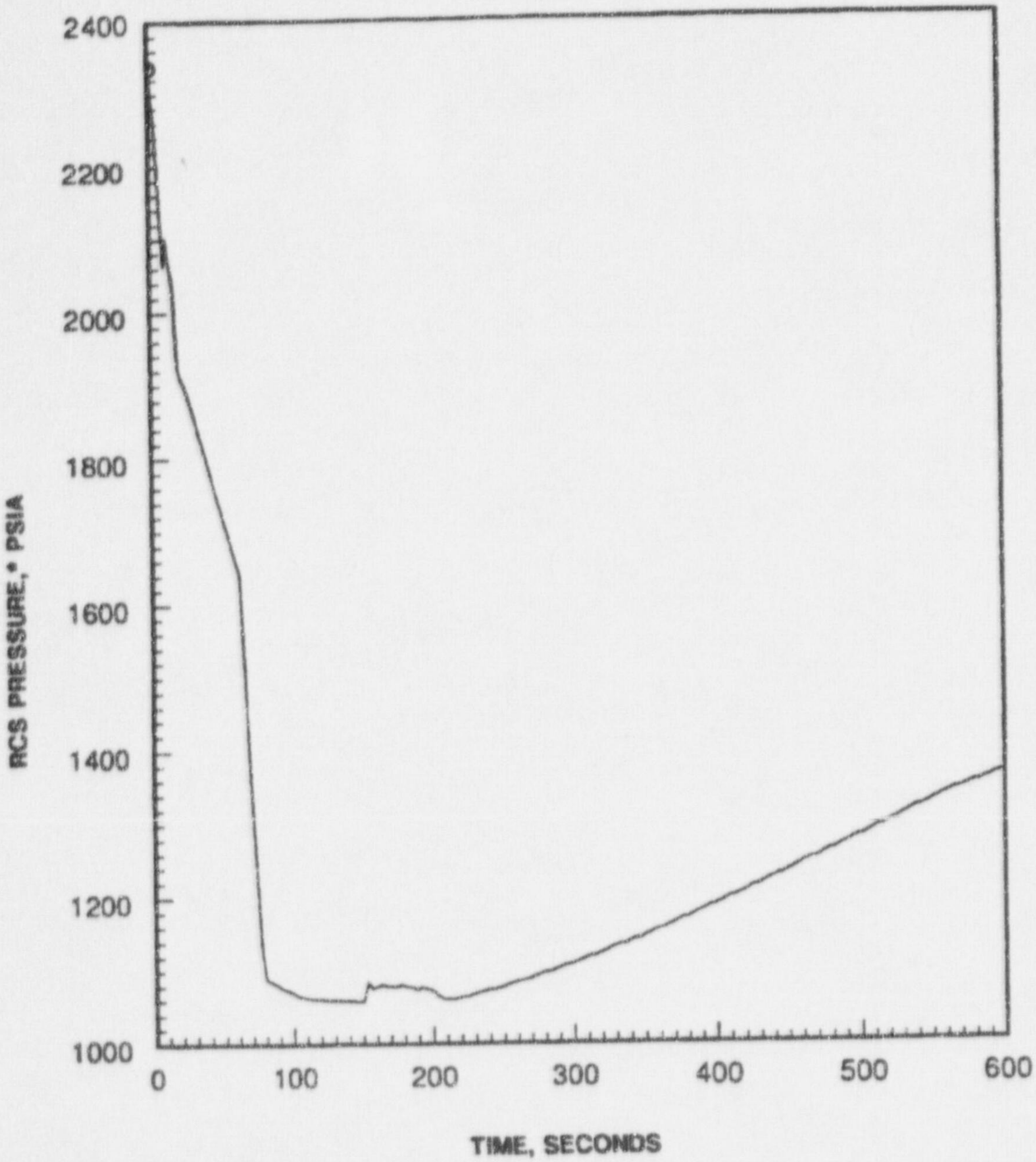
Zero Power Large Steam Line Break with Concurrent Loss of Offsite Power; Reactor Vessel Upper Head Steam Void Fraction vs. Time	Figure 15.1.5-3.13



Zero Power Large Steam Line Break with Offsite Power Available; Core Power vs. Time	Figure 15.1.5-4.1



Zero Power Large Steam Line Break with Offsite Power Available; Core Average Heat Flux vs. Time	Figure 15.1.5-4.2



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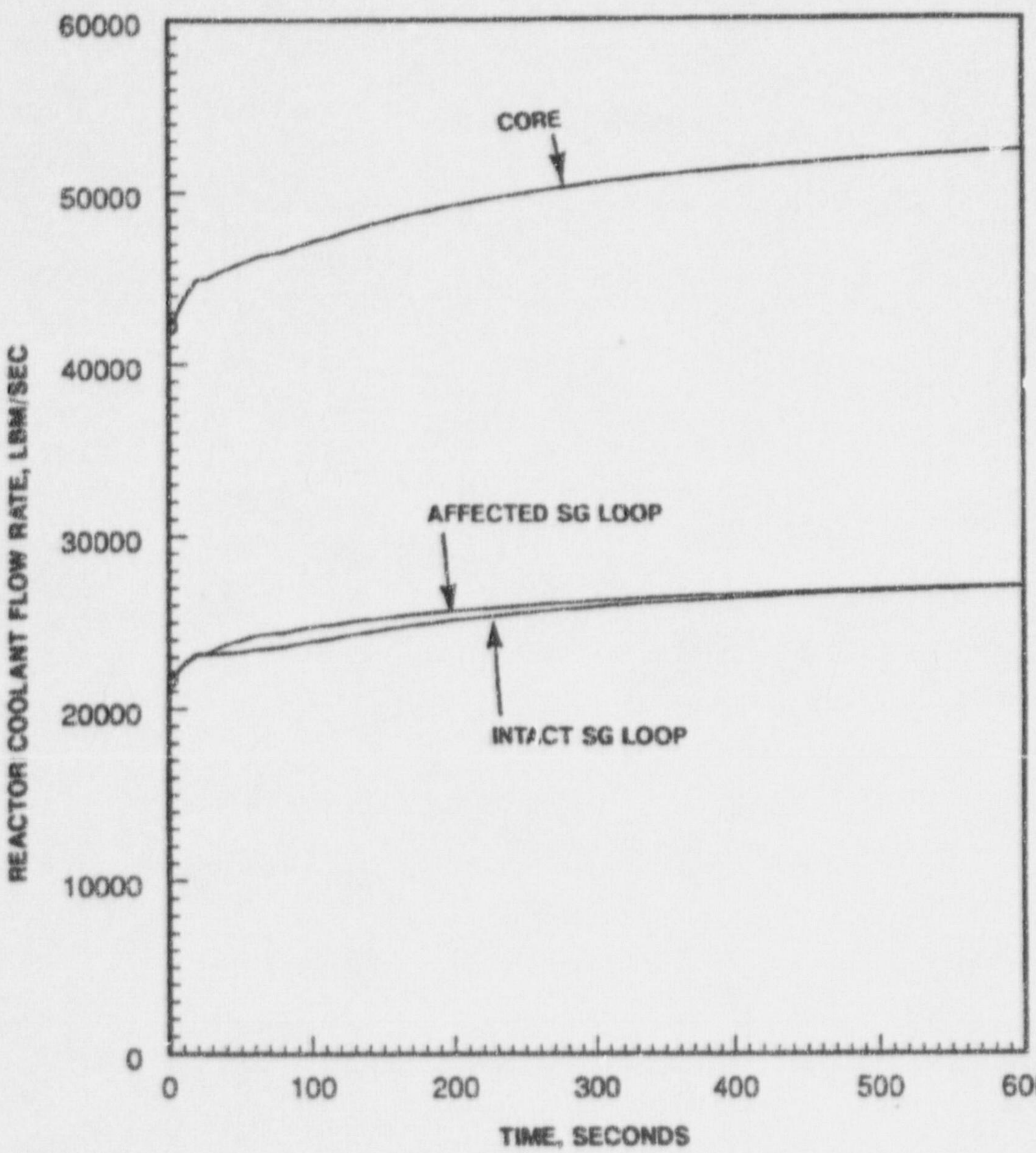
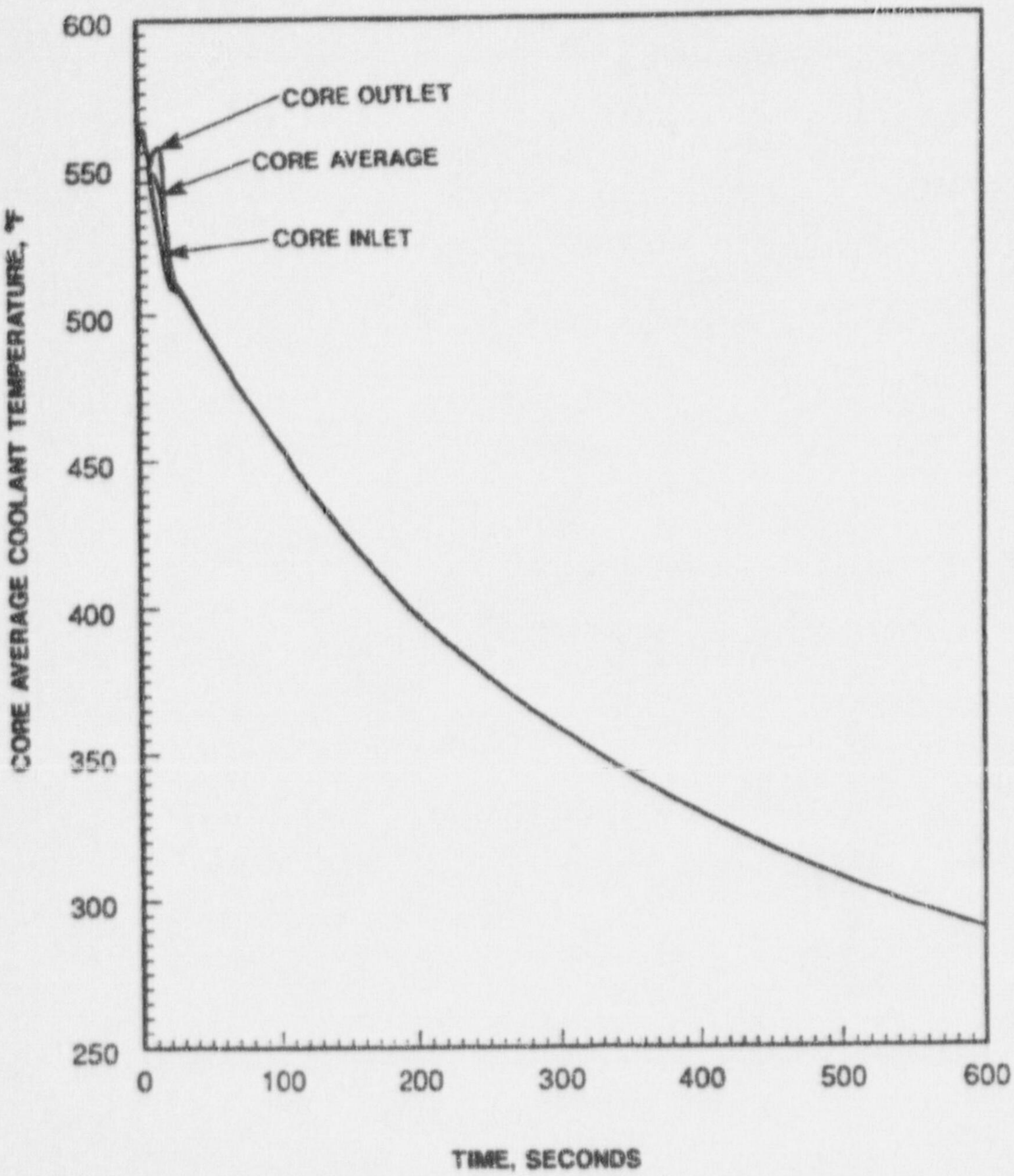
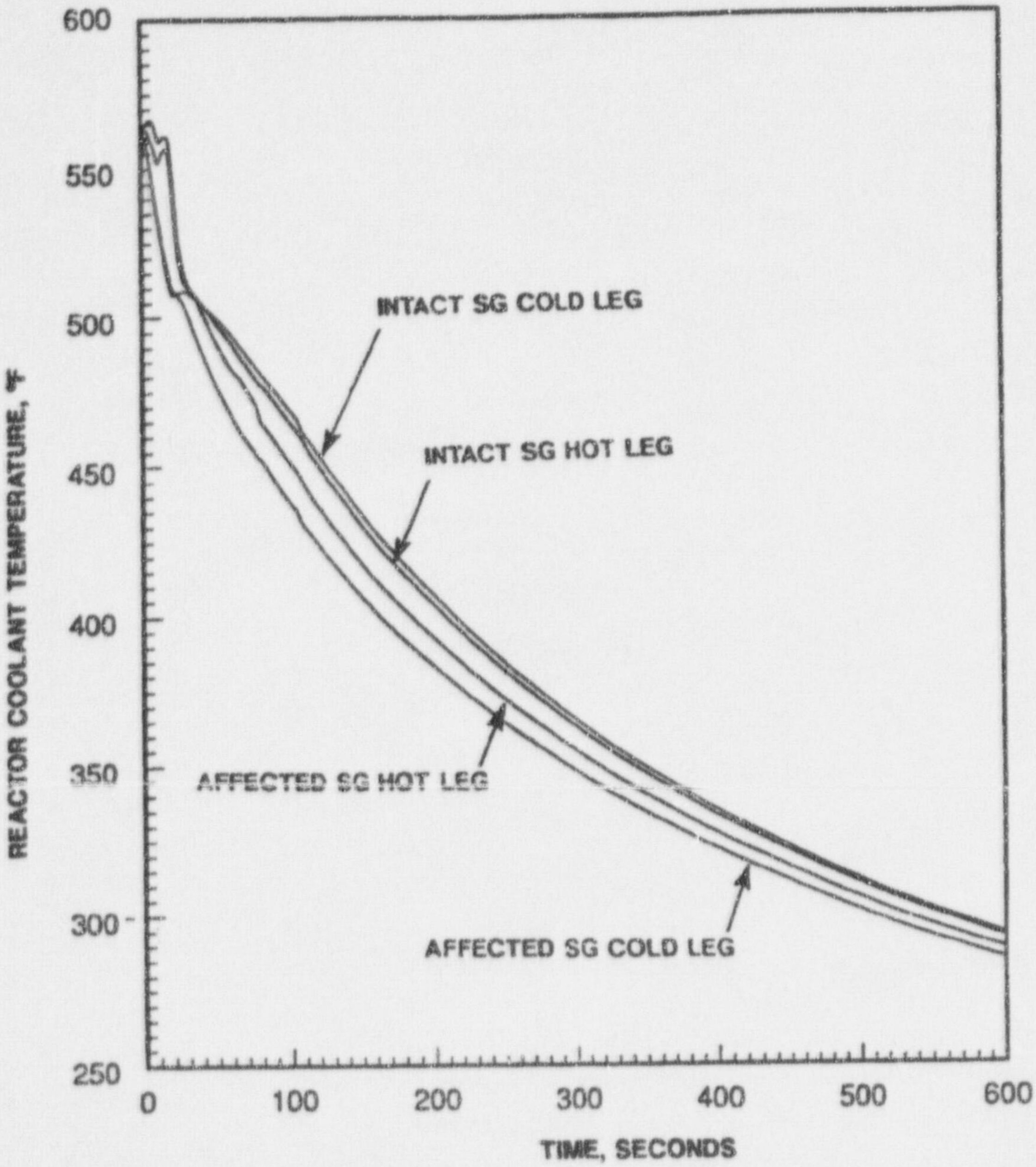
Zero Power Large Steam Line Break with Offsite Power Available; Reactor Coolant System Pressure vs. Time	Figure 15.1.5-4.3



Zero Power Large Steam Line Break with Offsite Power Available; Reactor Coolant Flow Rates vs. Time	Figure 15.1.5-4.4



Zero Power Large Steam Line Break with Offsite Power Available; Core Average Coolant Temperatures (A) vs. Time	Figure 15.1.5-4.5A



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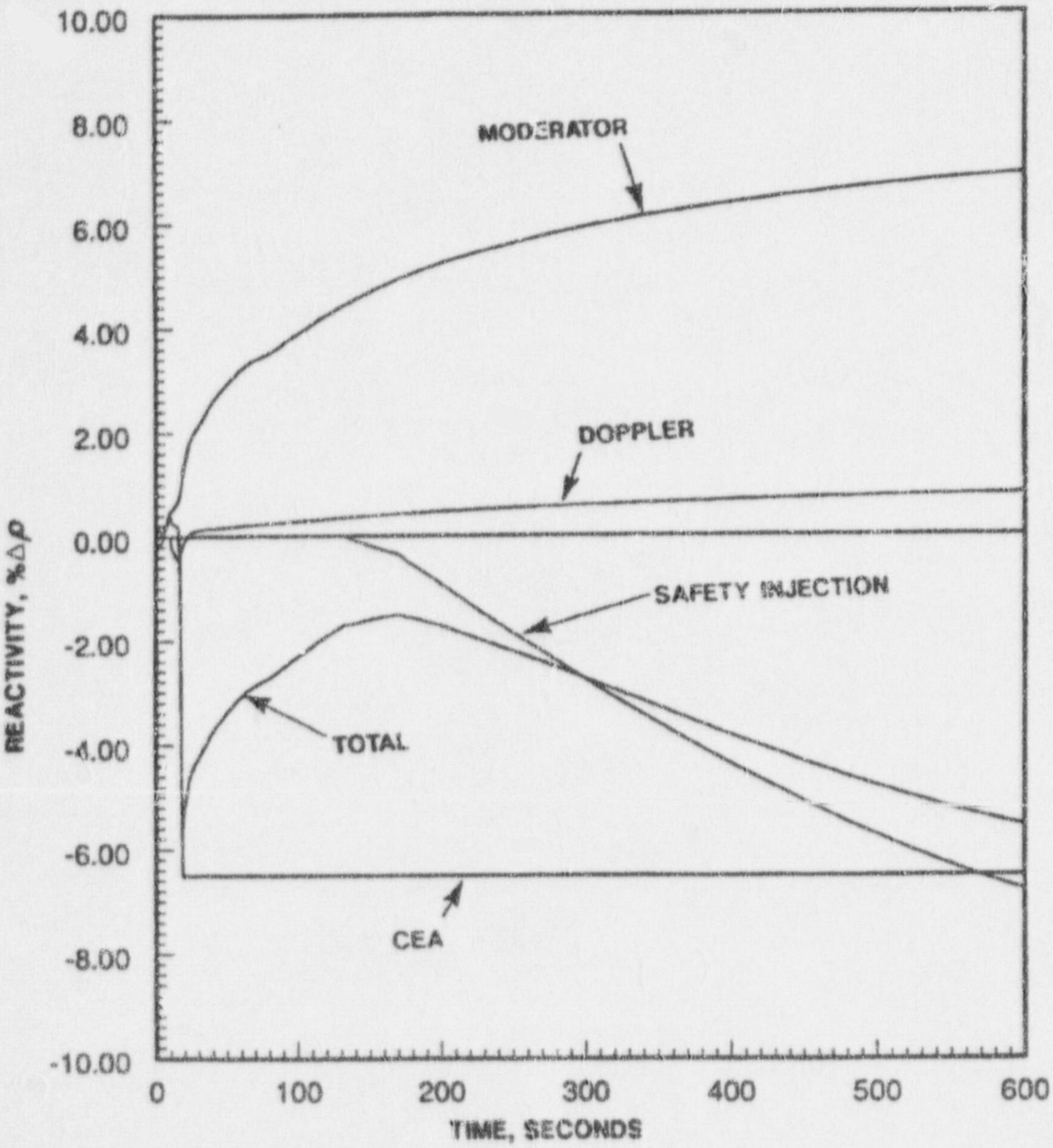
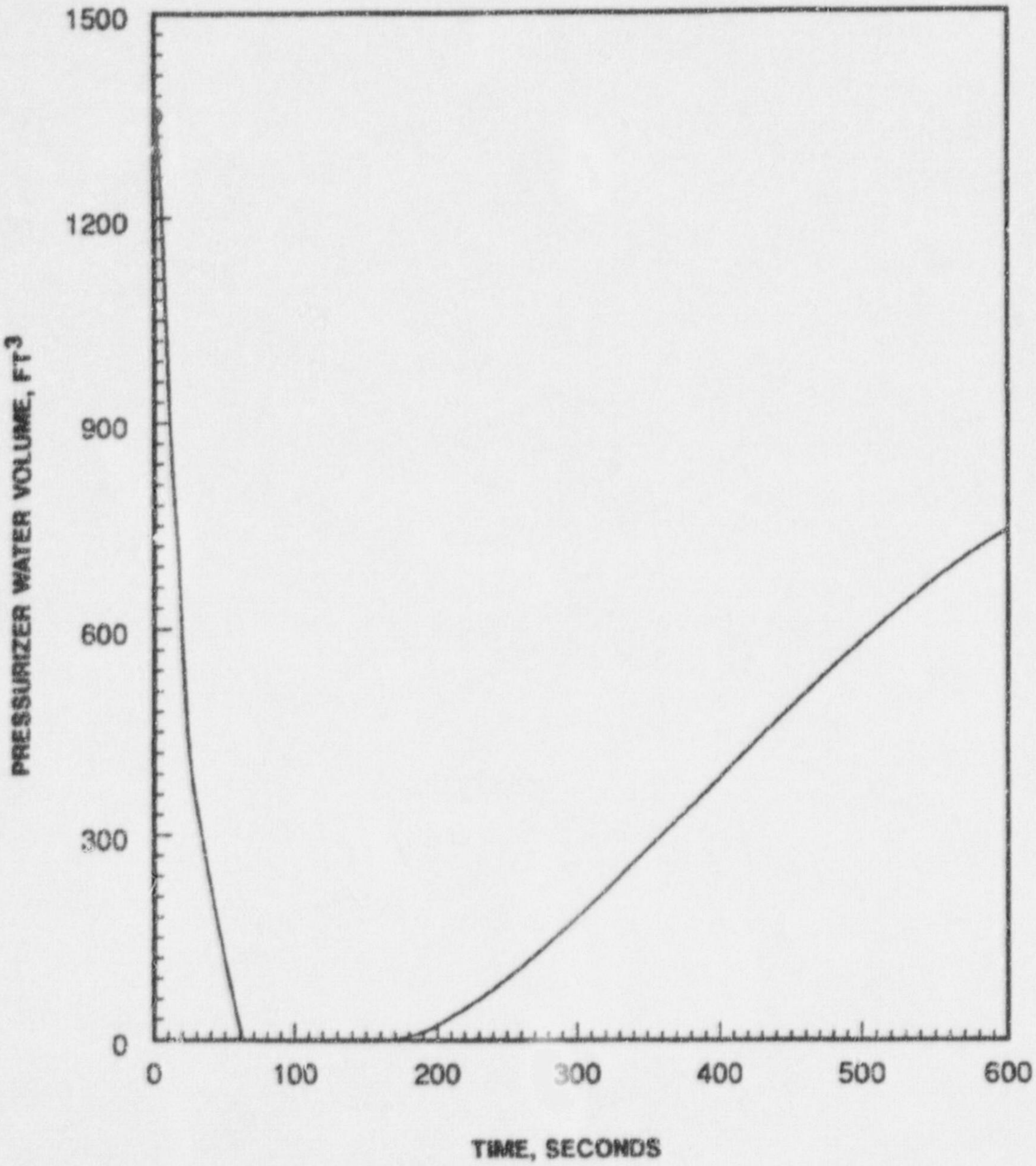
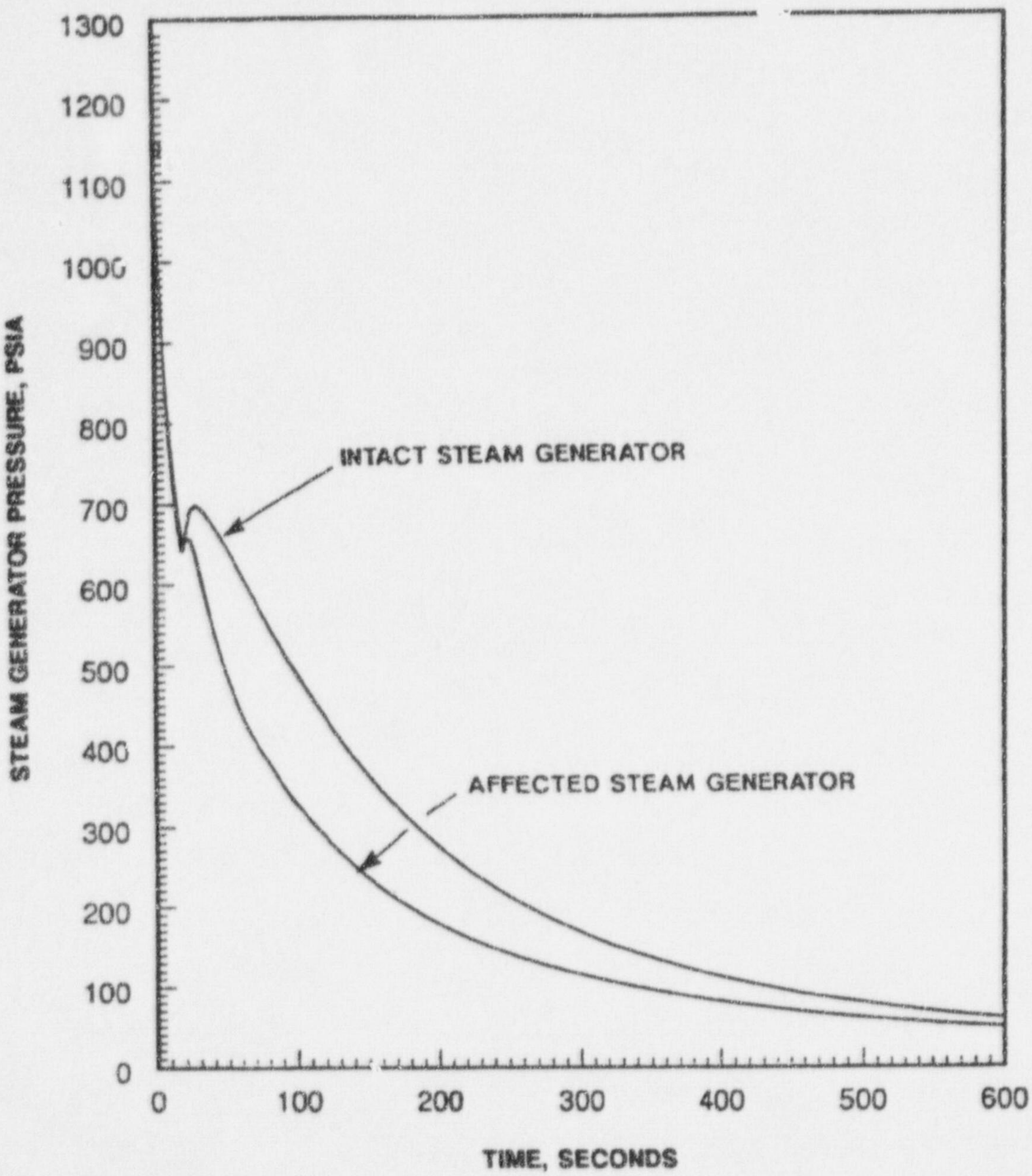


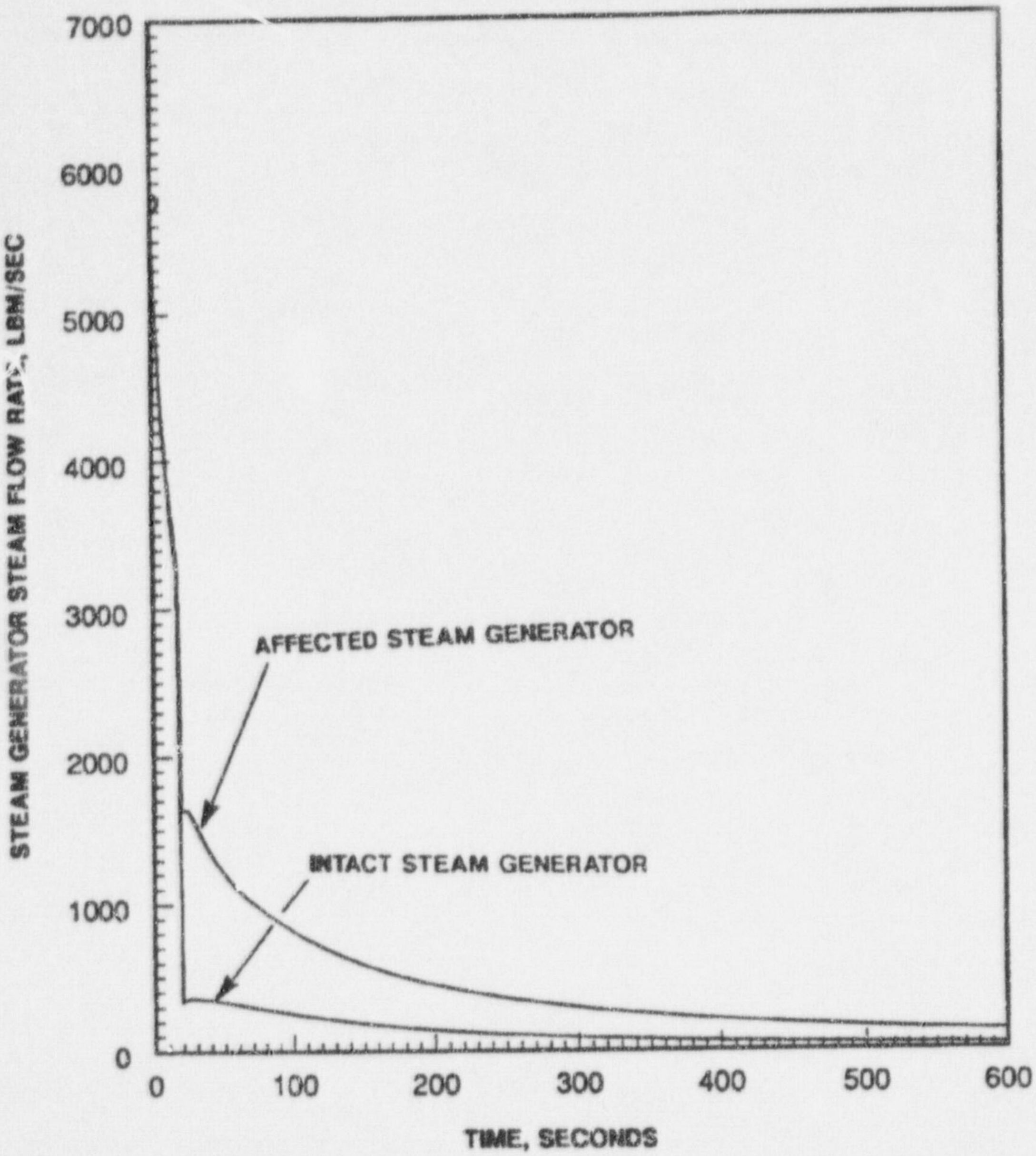
Zero Power Large Steam Line Break with Offsite Power Available; Reactivity vs. Time	Figure 15.1.5-4.6



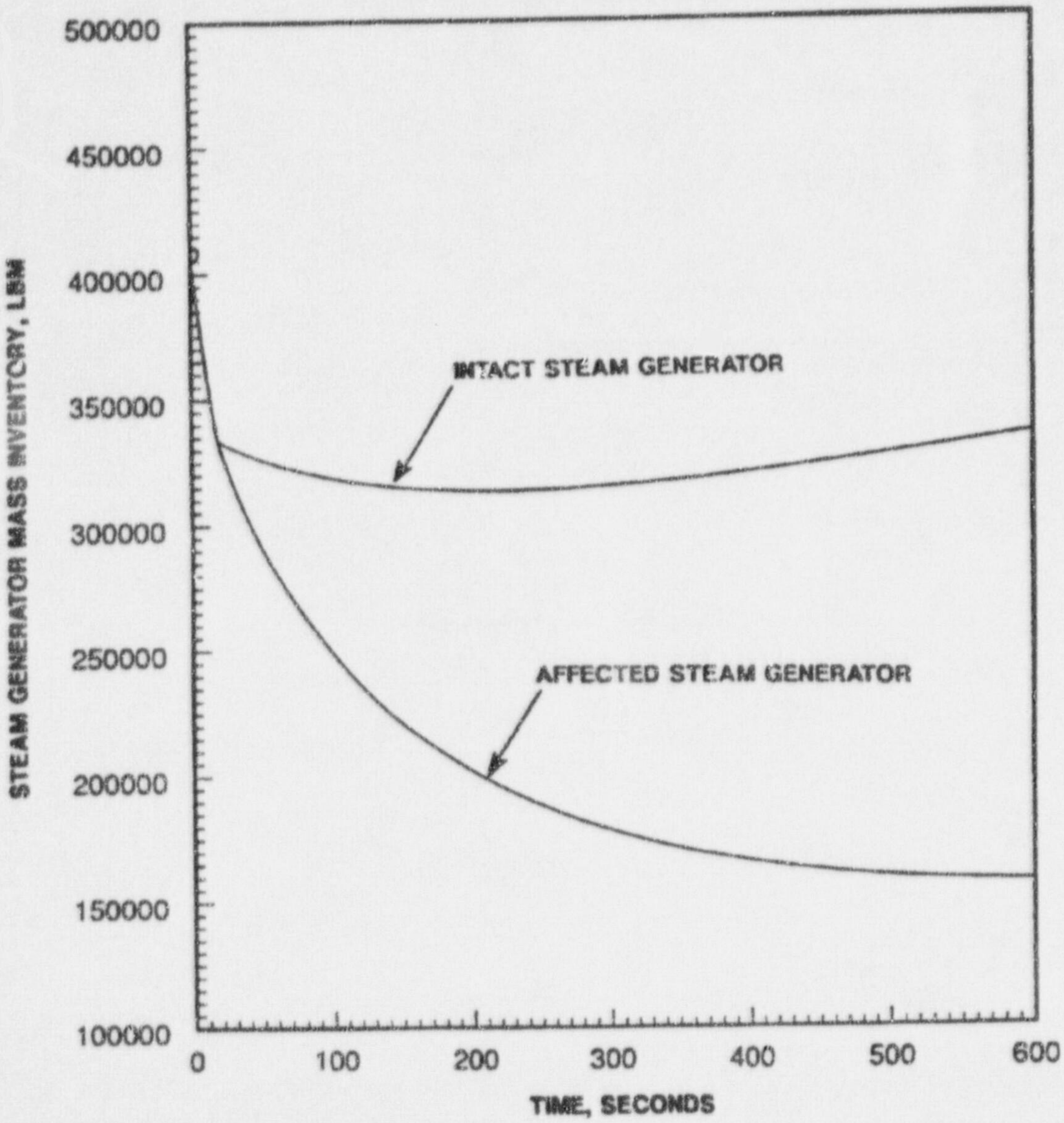
Zero Power Large Steam Line Break with Offsite Power Available; Pressurizer Water Volume vs. Time	Figure 15.1.5-4.7



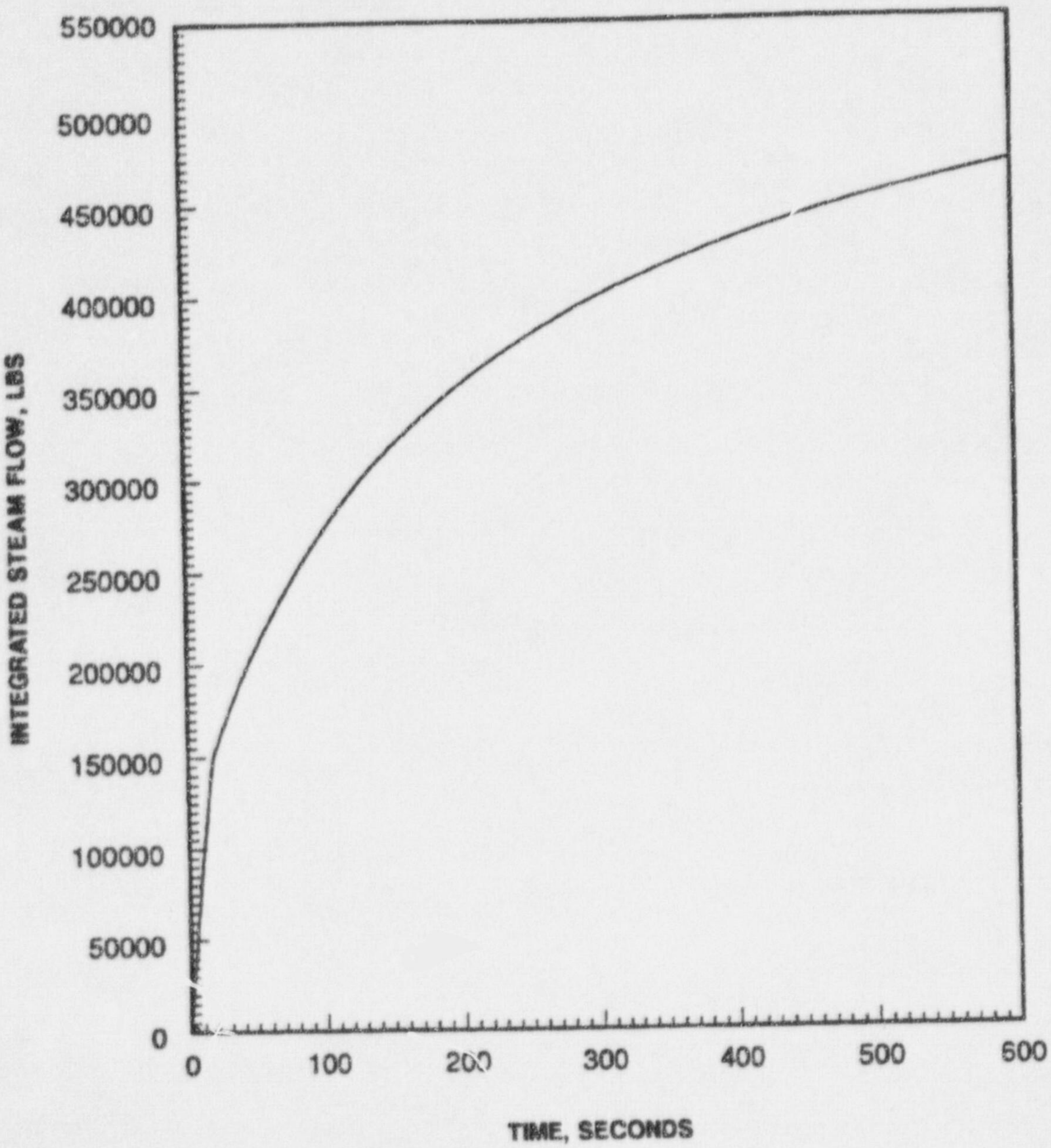
Zero Power Large Steam Line Break with Offsite Power Available; Steam Generator Pressures vs. Time	Figure 15.1.5-4.8



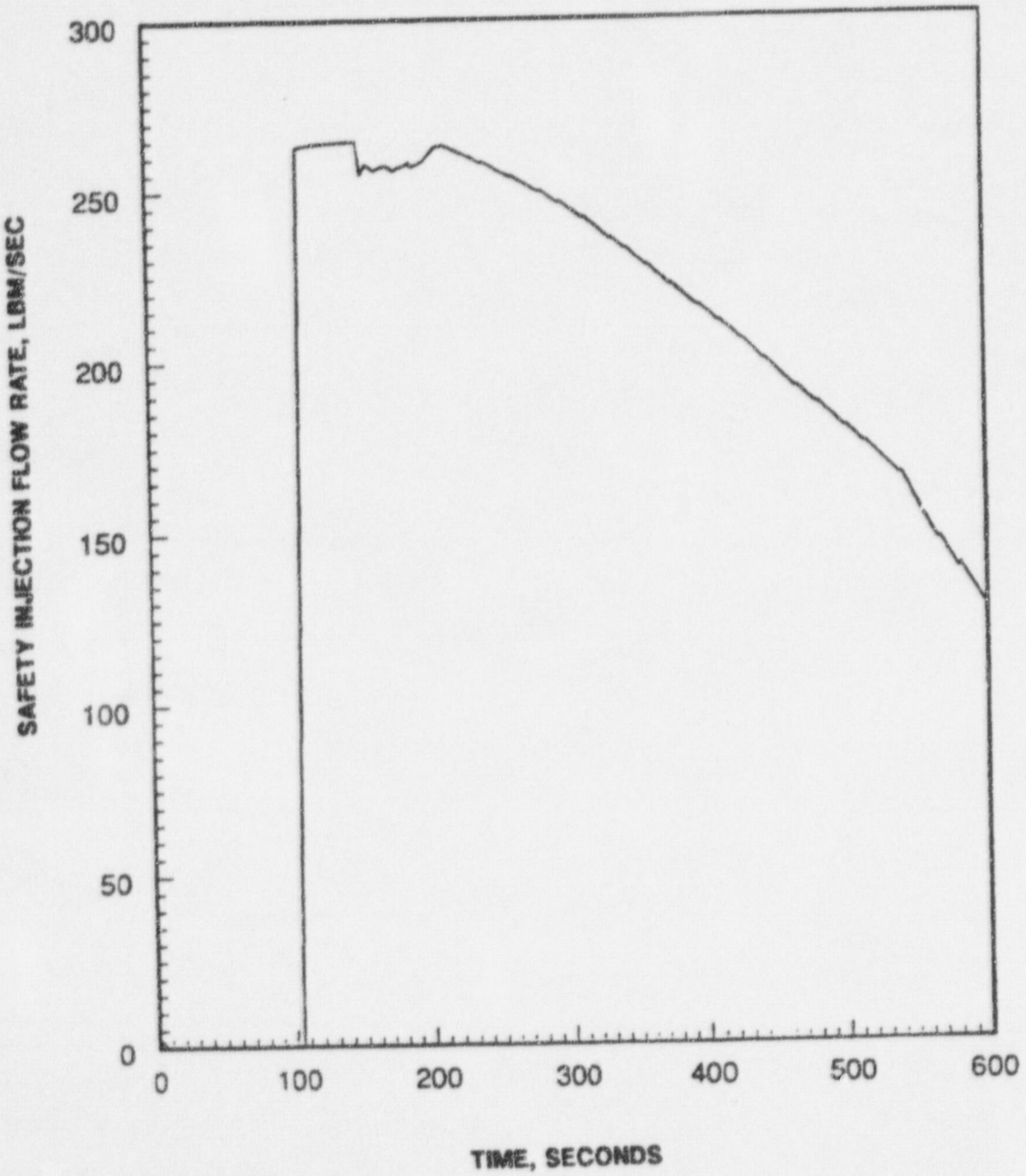
Zero Power Large Steam Line Break with Offsite Power Available; Steam Generator Steam Flow Rates vs. Time	Figure 15.1.5-4.9



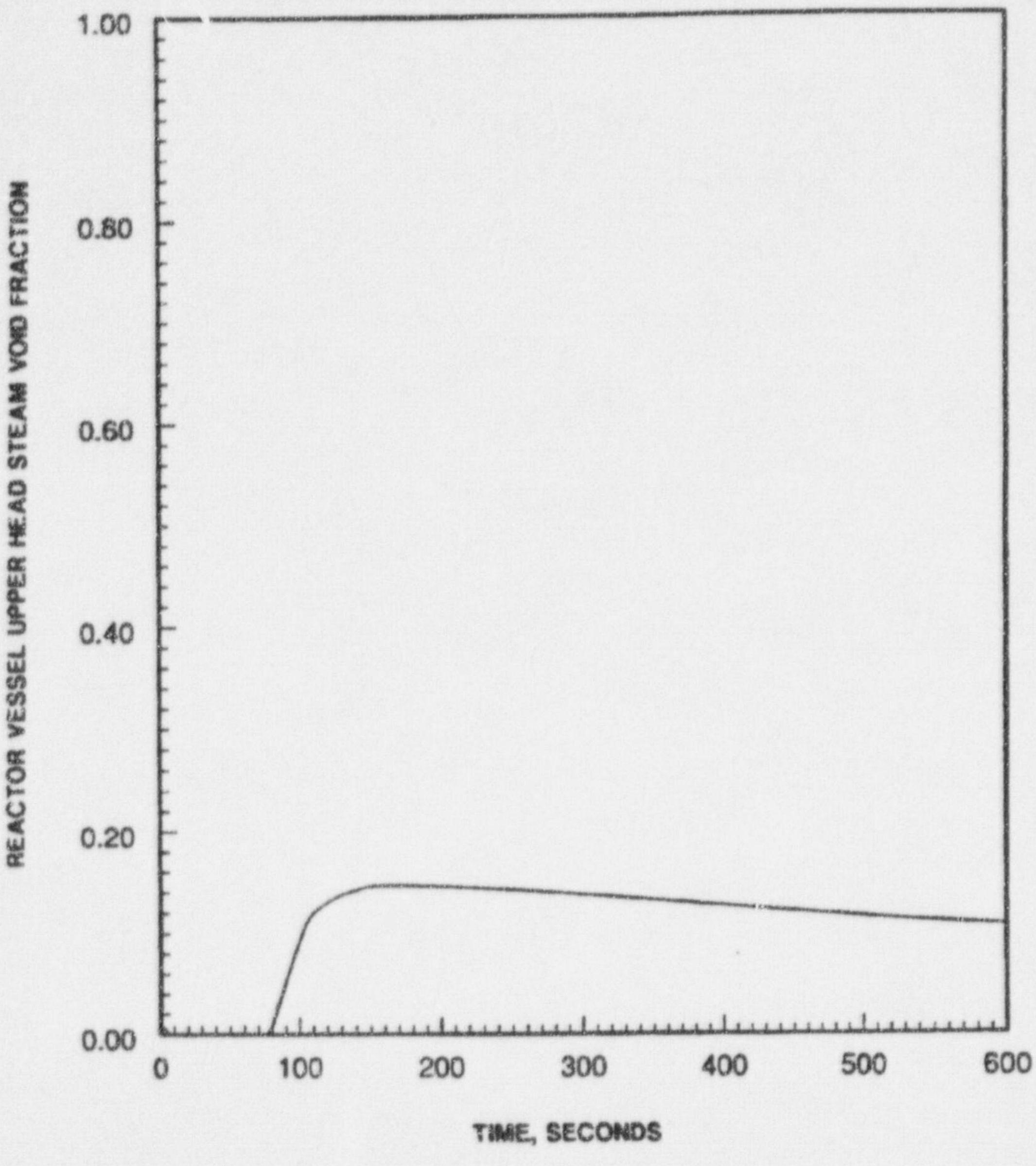
Zero Power Large Steam Line Break with Offsite Power Available; Steam Generator Mass Inventories vs. Time	Figure 15.1.5-4.10



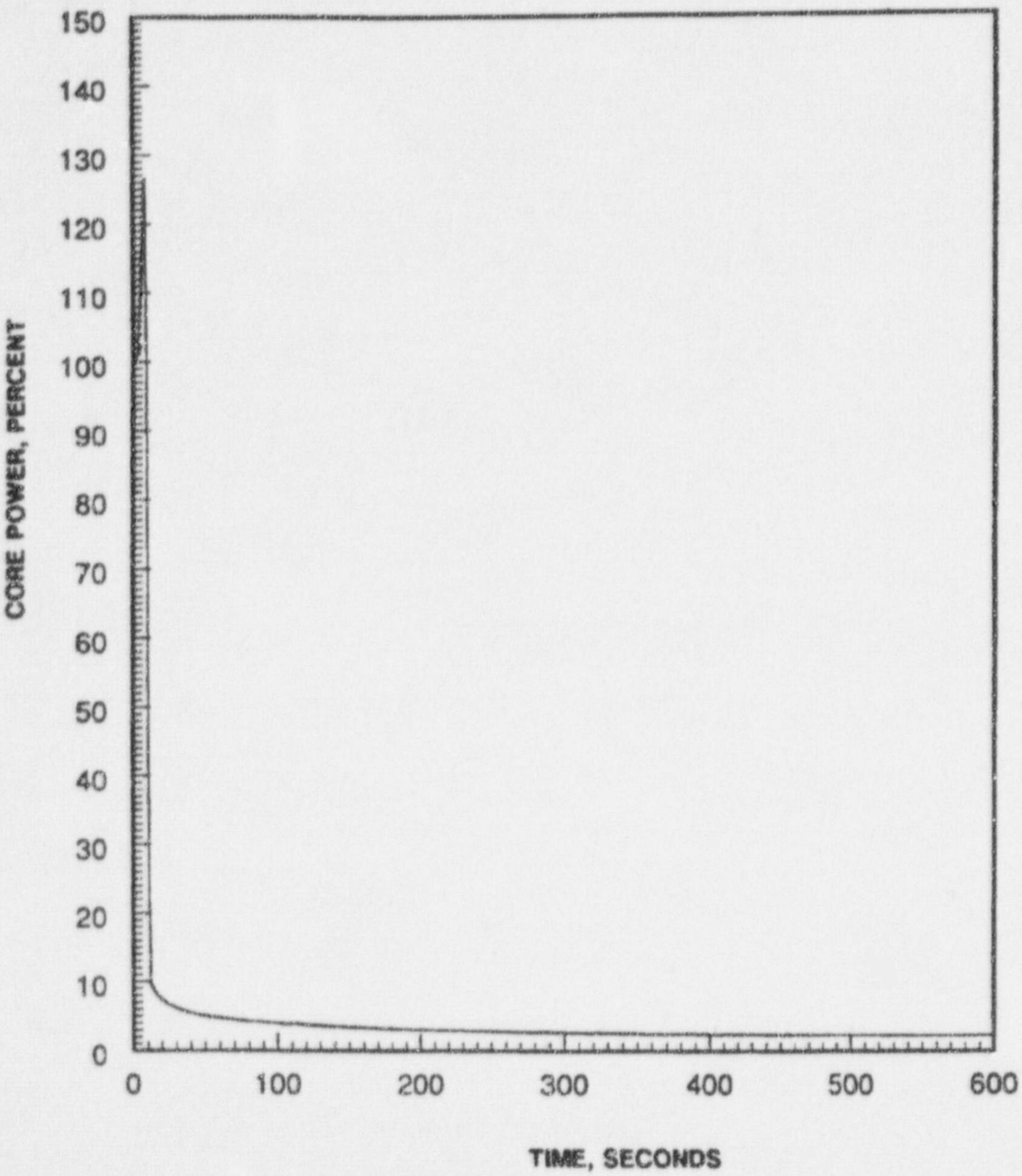
Zero Power Large Steam Line Break with Offsite Power Available; Integrated Steam Mass Release Through Break vs. Time	Figure 15.1.5-4.11



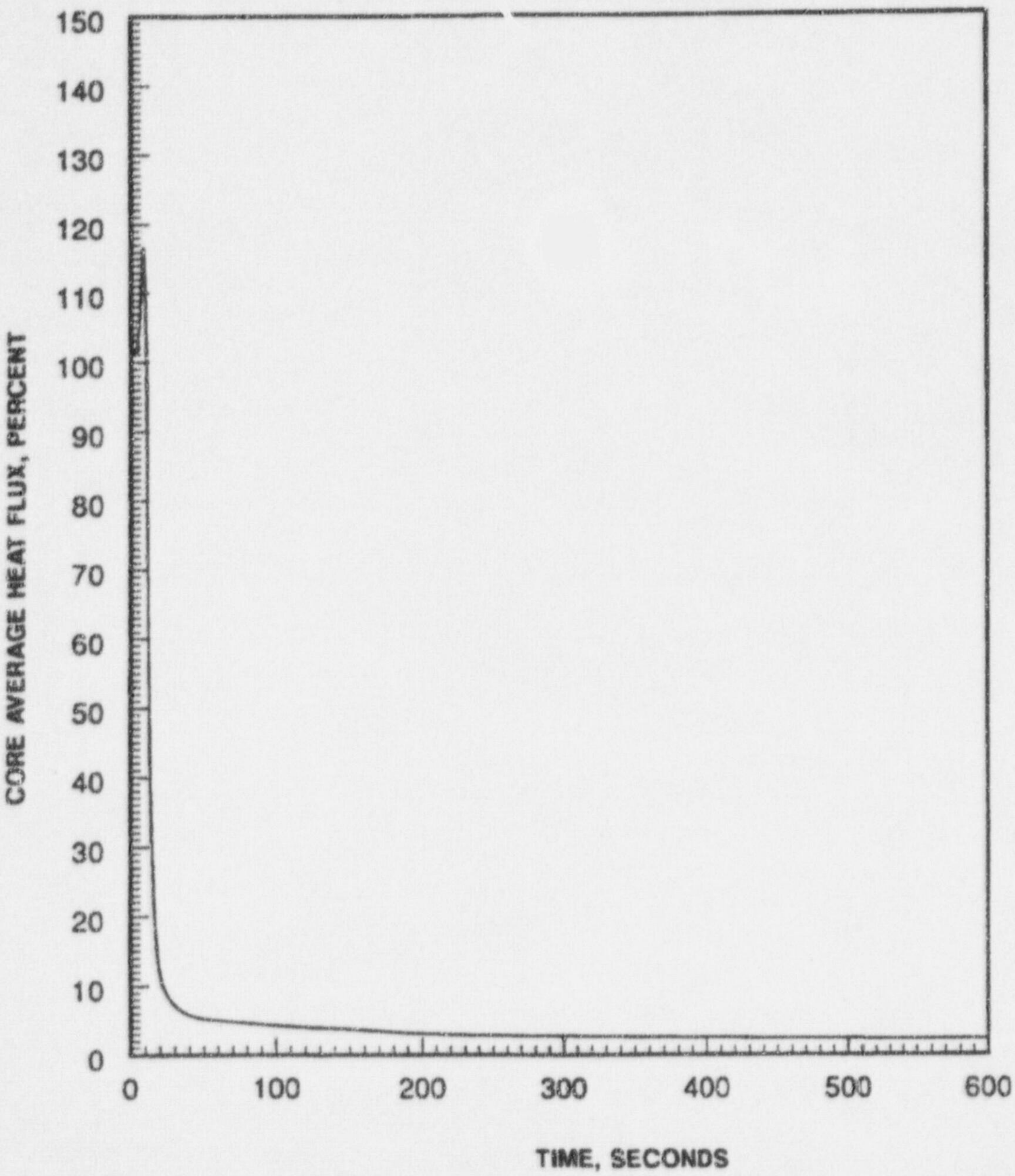
Zero Power Large Steam Line Break with Offsite Power Available; Safety Injection Flow Rate vs. Time	Figure 15.1.5-4.12



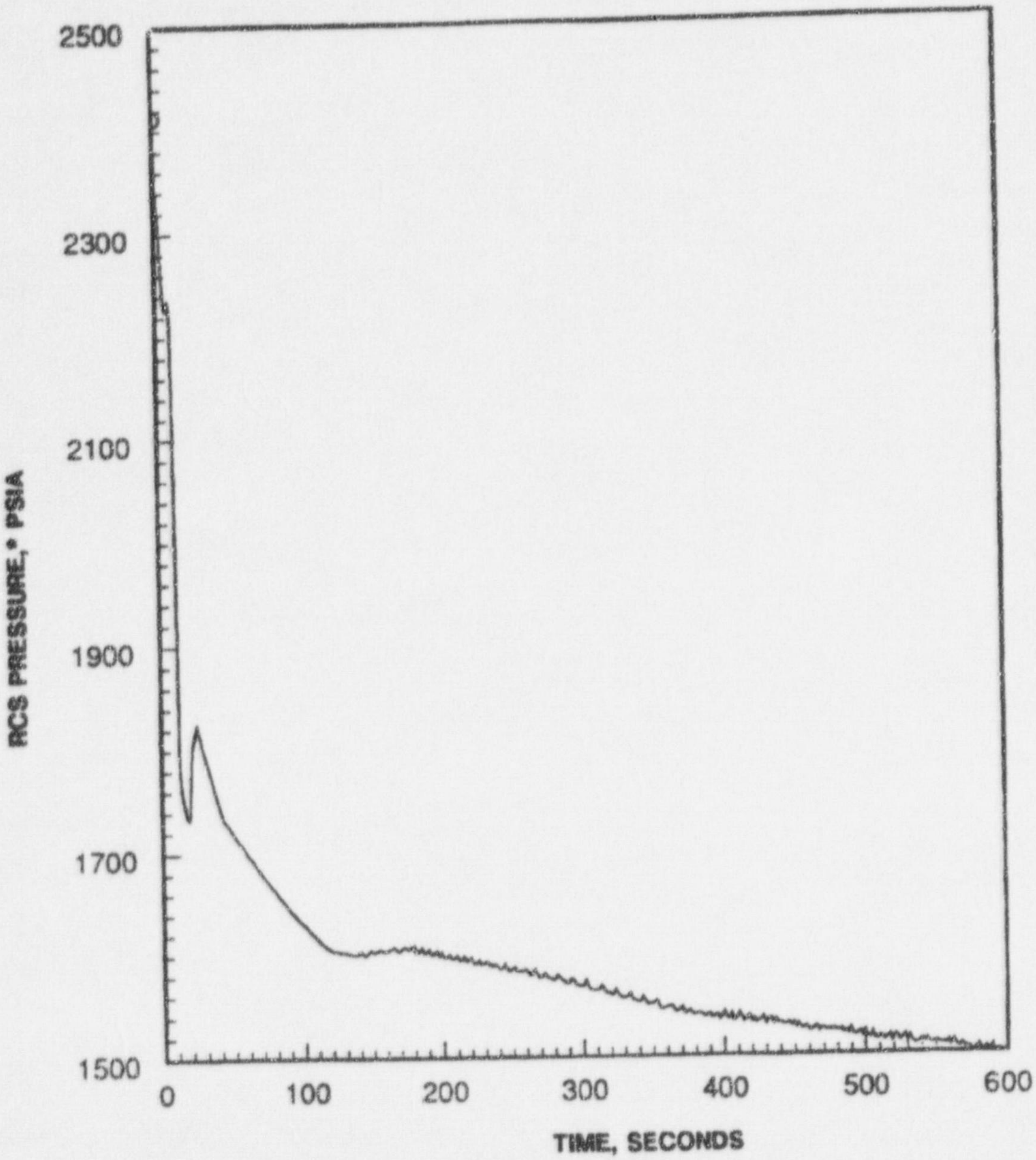
Zero Power Large Steam Line Break with Offsite Power Available; Reactor Vessel Upper Head Steam Void Fraction vs. Time	Figure 15.1.5-4.13



Full Power Steam Line Break with Loss of Offsite Power; Core Power vs. Time	Figure 15.1.5-5.1

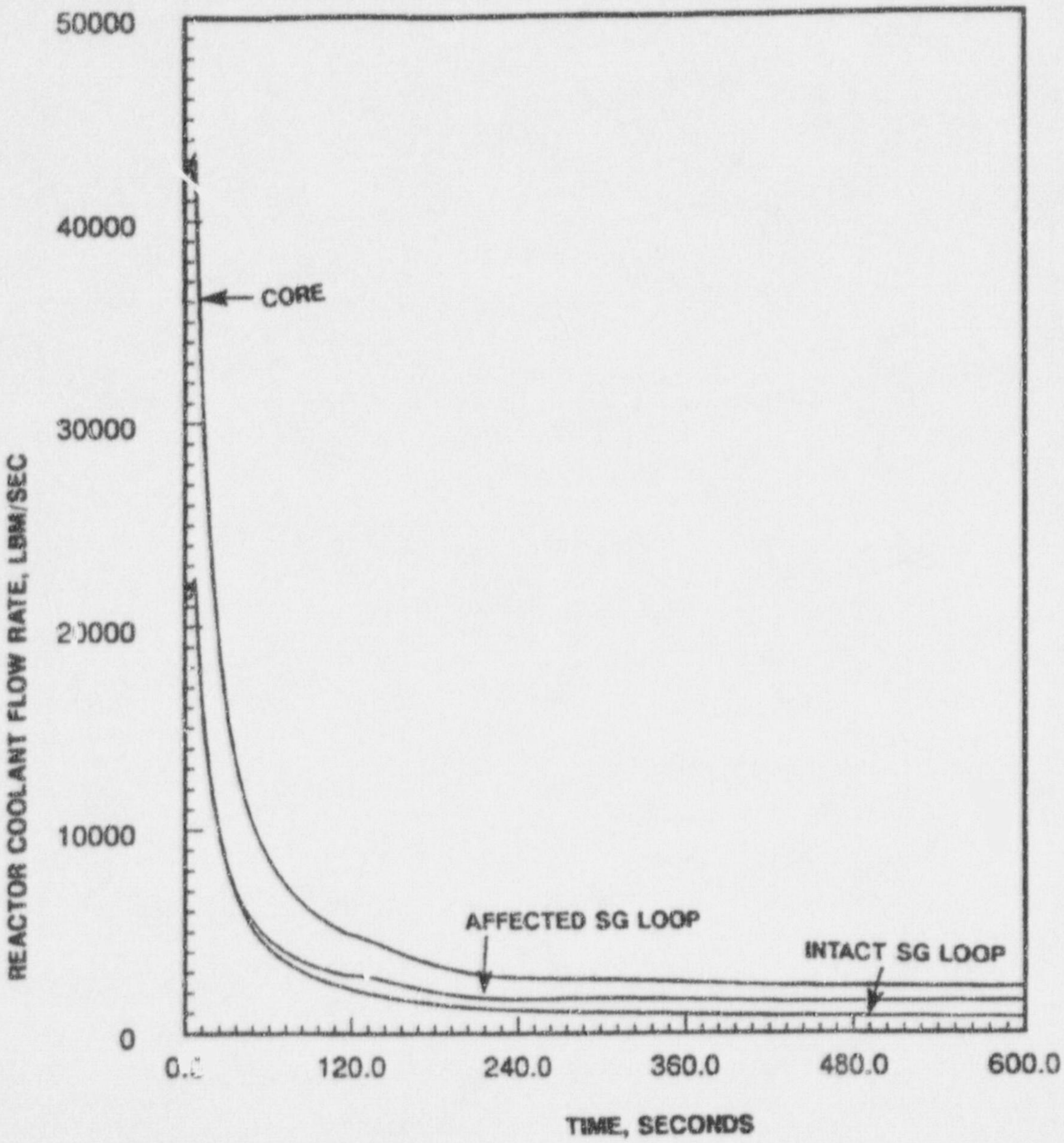


Full Power Steam Line Break with Loss of Offsite Power; Core Average Heat Flux vs. Time	Figure 15.1.5-5.2

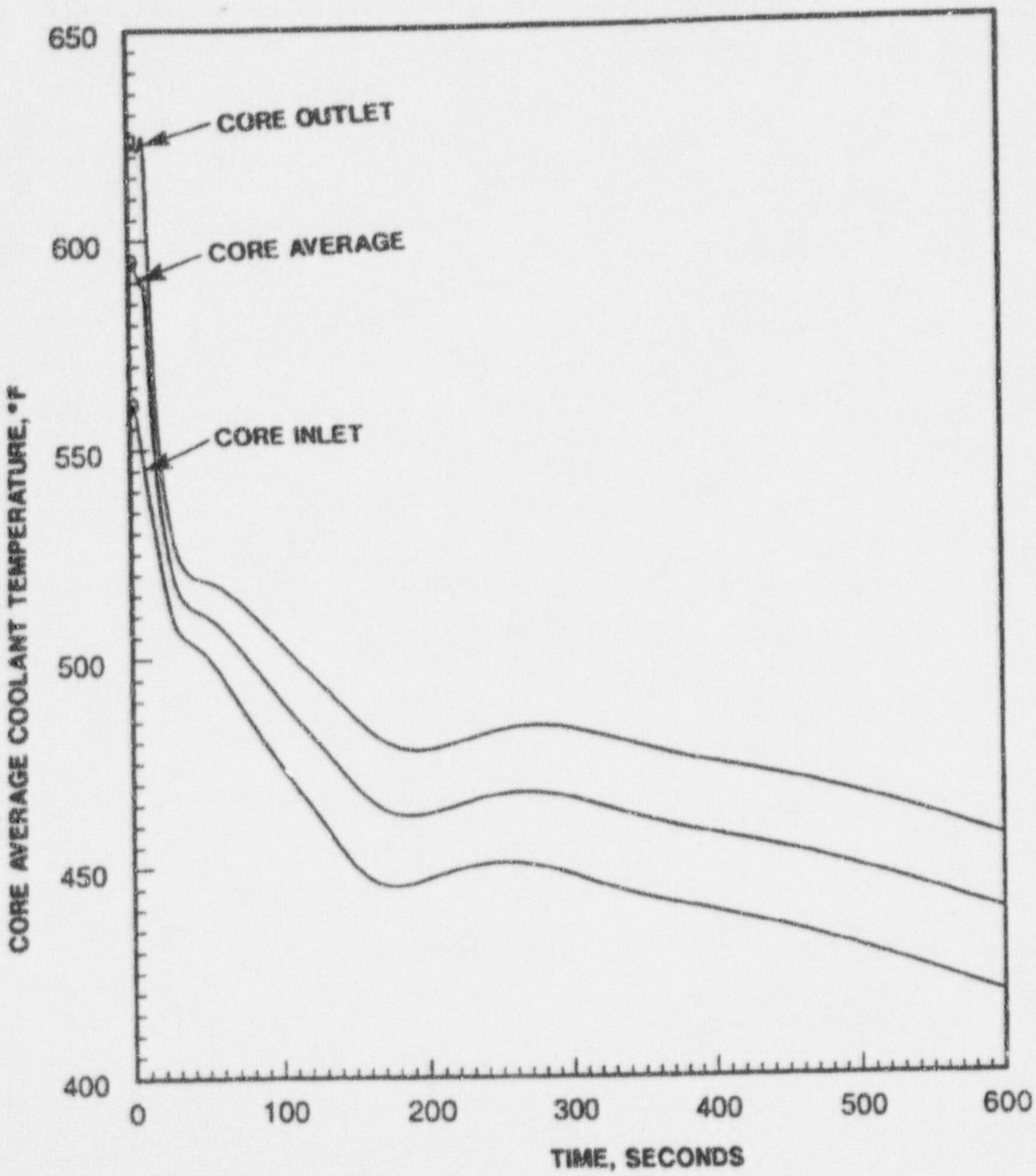


*THIS PRESSURE DOES NOT INCLUDE THE PRESSURE DIFFERENCE BETWEEN THE COLD LEG AT RCP DISCHARGE AND THE SURGE LINE

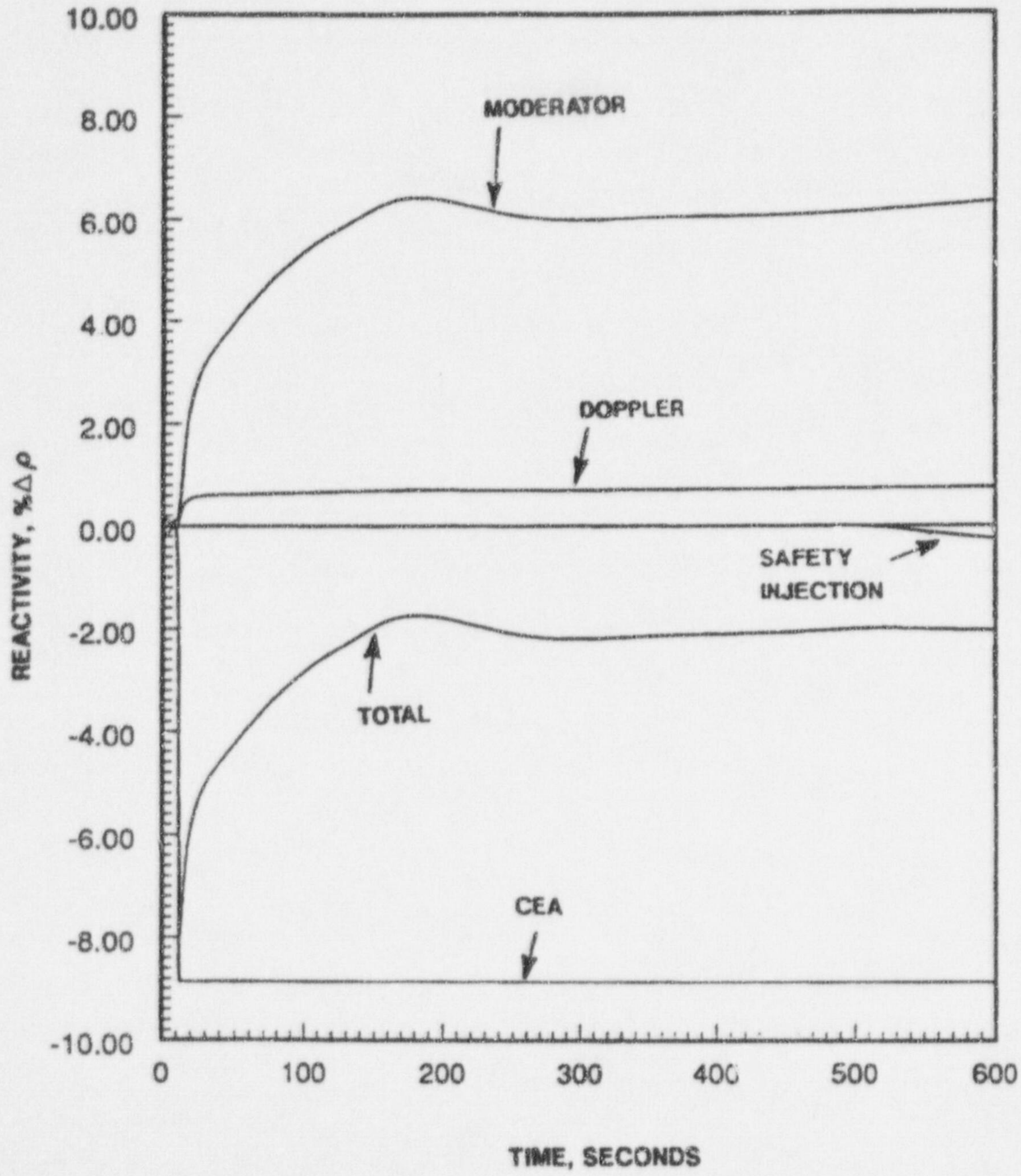
Full Power Steam Line Break with Loss of Offsite Power; Reactor Coolant System Pressure vs. Time	Figure 15.1.5-5.3



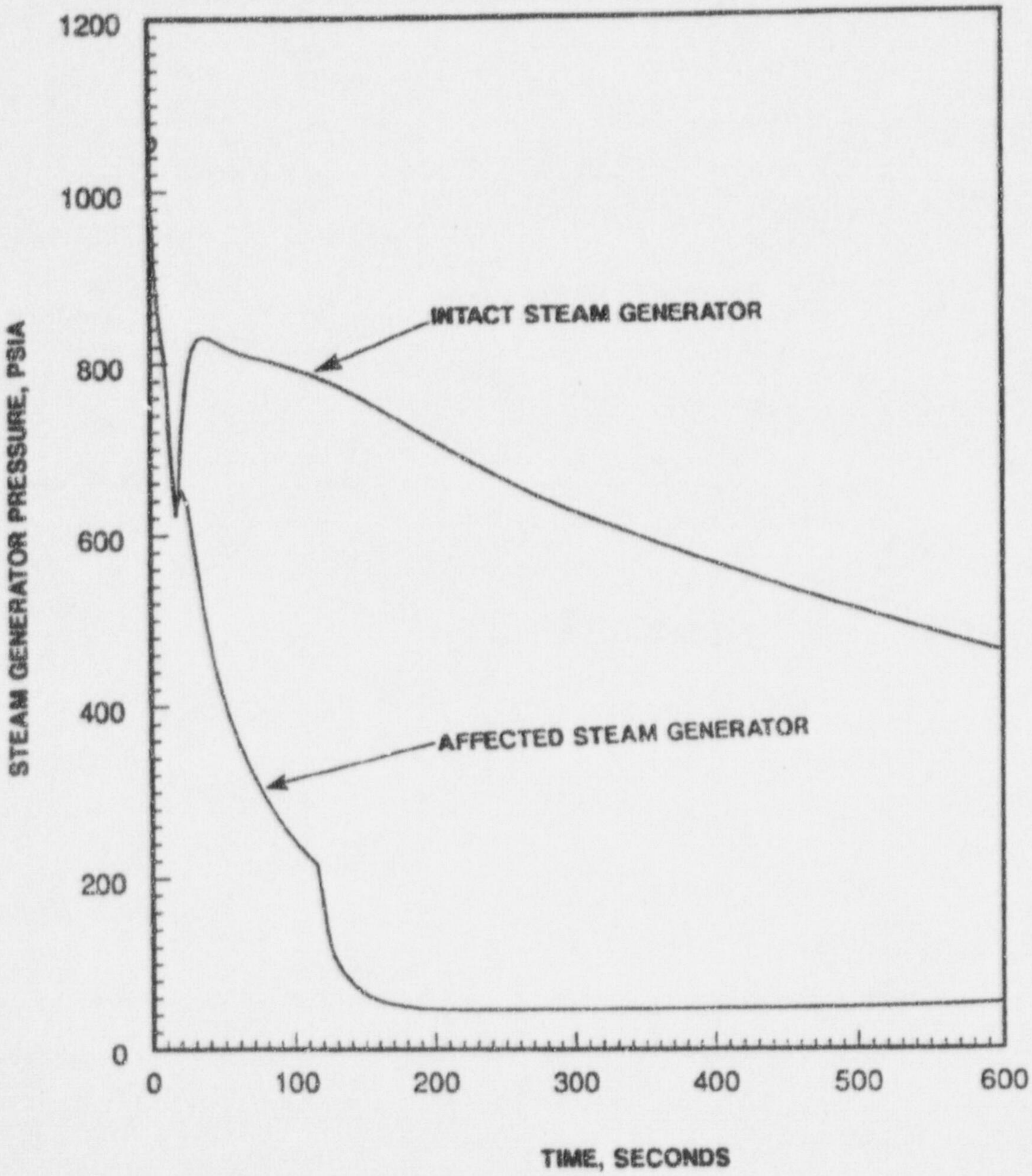
Full Power Steam Line Break with Loss of Offsite Power; Reactor Coolant Flow Rates vs. Time	Figure 15.1.5-5.4



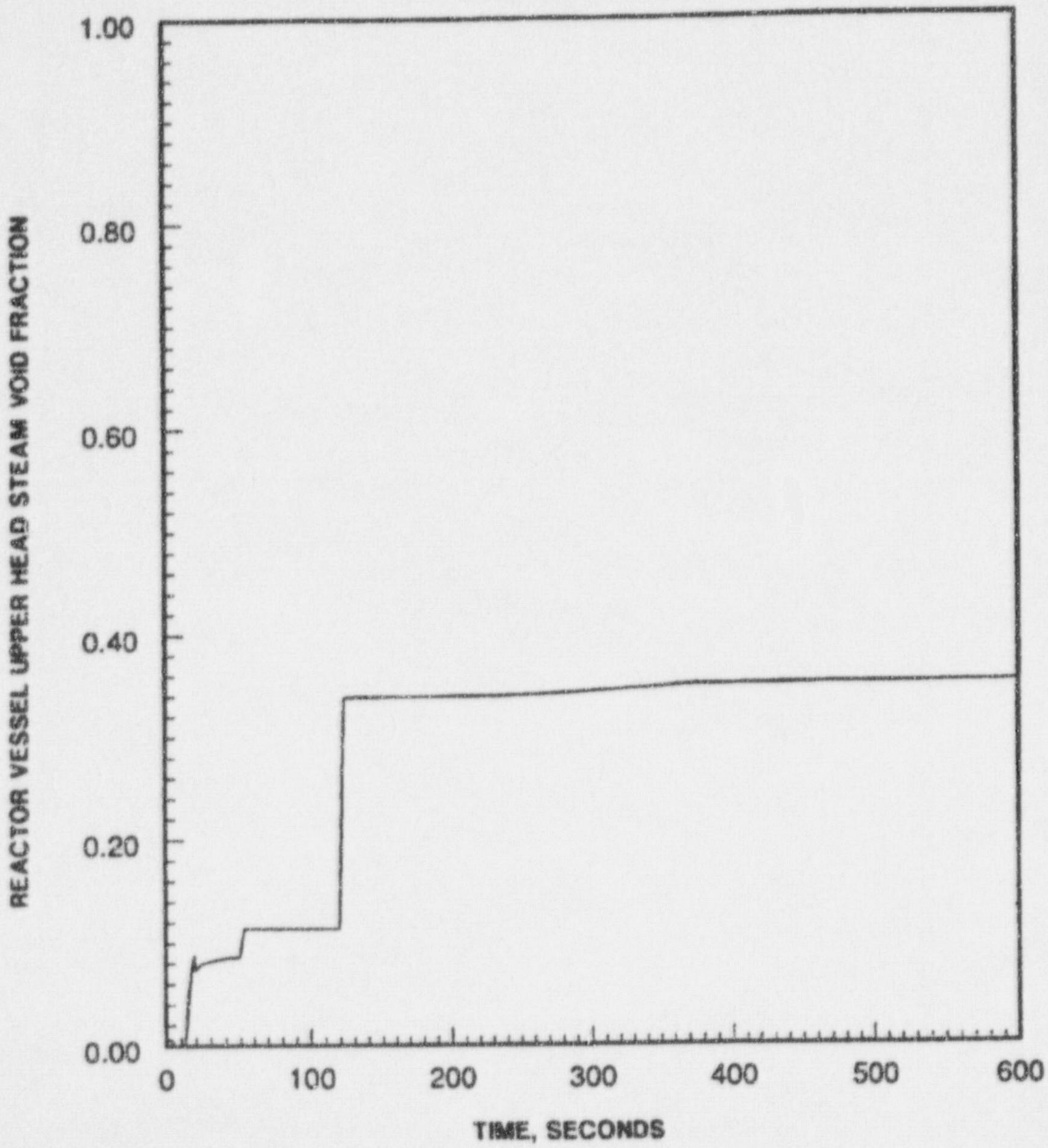
Full Power Steam Line Break with Loss of Offsite Power; Core Average Coolant Temperatures vs. Time	Figure 15.1.5-5.5



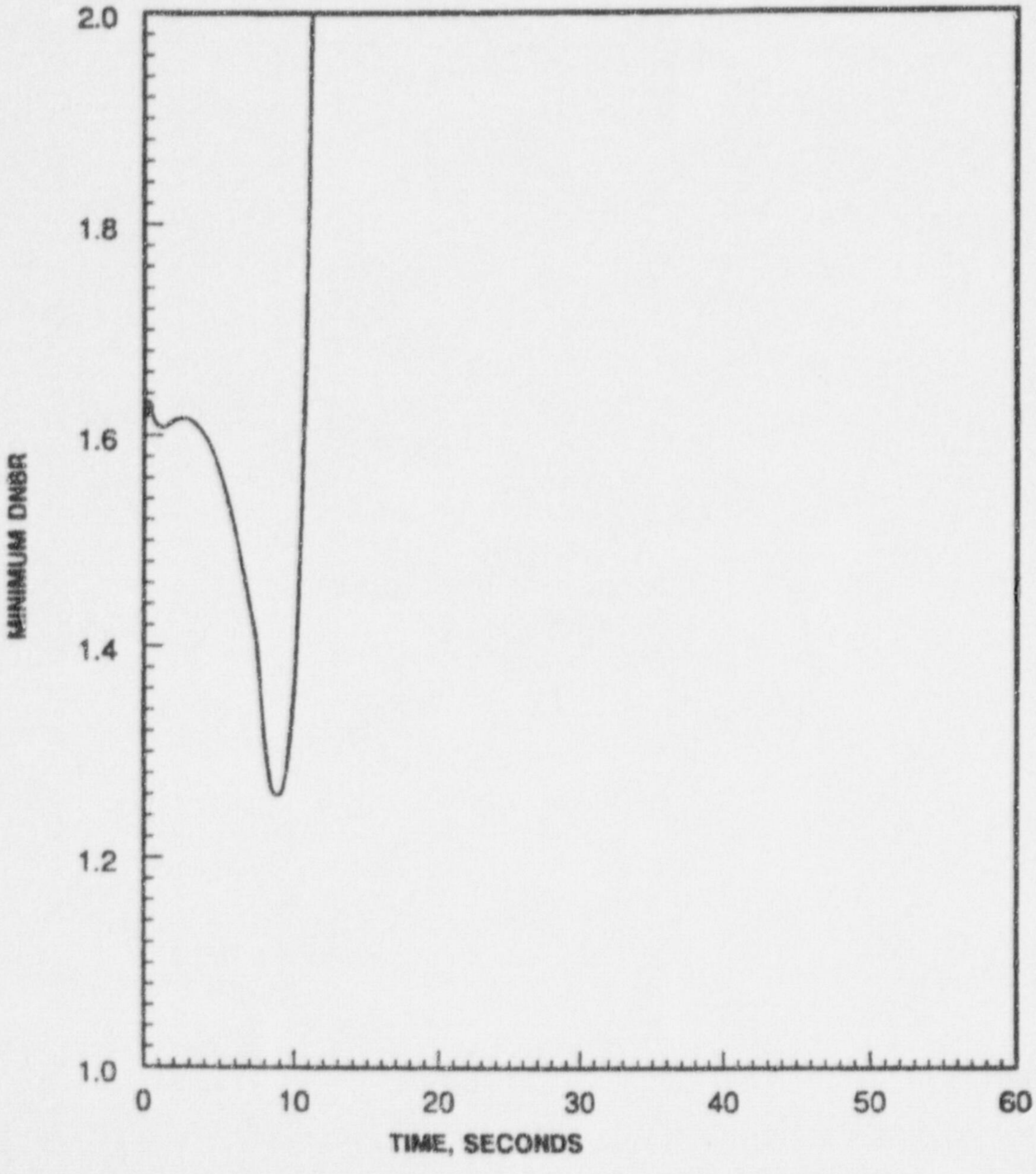
Full Power Steam Line Break with Loss of Offsite Power; Reactivity vs. Time	Figure 15.1.5-5.6



Full Power Steam Line Break with Loss of Offsite Power; Steam Generator Pressures vs. Time	Figure 15.1.5-5.7



Full Power Steam Line Break with Loss of Offsite Power; Reactor Vessel Upper Head Steam Void Fraction vs. Time	Figure 15.1.5-5.8



Full Power Steam Line Break with Loss of Offsite Power; Minimum DNBR vs. Time	Figure 15.1.5-5.9