Chapter 13

CONDUCT OF OPERATIONS

TABLE OF CONTENTS

Section Page

Chapter 13

CONDUCT OF OPERATIONS

TABLE OF CONTENTS (Continued)

Section Page

Chapter 13

CONDUCT OF OPERATIONS

TABLE OF CONTENTS (Continued)

Section Page

Chapter 13

CONDUCT OF OPERATIONS

LIST OF TABLES

Chapter 13

CONDUCT OF OPERATIONS

LIST OF FIGURES

Chapter 13

CONDUCT OF OPERATIONS

13.1 ORGANIZATION STRUCTURE

The organizational structure of Energy Northwest and the line of responsibility for the operation of Columbia Generating Station (CGS) is in accordance with established administrative and quality standards that apply to this operation. The applicable organization charts are shown in Figures 13.1-1 through 13.1-13.

13.1.1 MANAGEMENT AND TECHNICAL SUPPORT ORGANIZATION

Energy Northwest is a municipal corporation and a joint operating agency of the State of Washington. The management and control of Energy Northwest is vested in the Executive Board.

The Executive Board consists of five members of the Energy Northwest Board of Directors and six outside directors. Three outside directors are selected by the Board of Directors, and three directors are appointed by the Governor of the State of Washington.

The full Board of Directors has members representing each of Energy Northwest's member utilities, and has the authority to select the inside members of the Executive Board and to terminate existing projects or authorize new projects.

Certain responsibilities for day-to-day management of Energy Northwest have been delegated to the Chief Executive Officer (the chief administrative officer).

The staff of Energy Northwest includes senior management level positions, which are responsible to the Chief Executive Officer for performance of specialized work by their respective groups. See Figure 13.1-1 for an organization chart. However, as specified in Technical Specifications, Section 5.2.1, the Chief Executive Officer retains corporate responsibility for overall plant nuclear safety.

13.1.1.1 Technical Support for Operations

Technical support for the nuclear organization is the responsibility of the Chief Nuclear Officer, Plant General Manager, Vice President, Engineering, and Vice President, Operations.

The Plant General Manager is responsible for the safe, reliable, and efficient operation and maintenance of CGS and for providing major services which support plant operation.

Reporting to the Chief Nuclear Officer includes the Vice President, Operations, Vice President, Engineering, and the Quality Manager. The Plant General Manager reports to the Vice President, Operations.

Reporting to the Chief Nuclear Officer are departments that provide support to CGS in the areas of Operations, Engineering, and Quality (see Figure 13.1-2).

Reporting to the Vice President, Engineering are departments which provide technical support in the areas of reactor fuels and engineering.

Reporting to the Vice President, Operations, are the Plant General Manager, the Operations Support General Manager, and the Training Manager. (see Figure 13.1-4). Security reports to the Operations Support Manager or General Manager, if staffed at that level.

The Quality Manager's responsibilities are described in the Energy Northwest Operational Quality Assurance Program Description (OQAPD), EN-QA-004. An organization chart is provided in Figure 13.1-7.

The Vice President, Engineering is responsible for design control of all authorized plant modifications, technical expertise in the fundamental engineering disciplines such as mechanical, electrical, civil, chemical, fuels, as well as specialty areas such as materials, welding, and inservice inspection engineering. In addition, the Vice President, Engineering is responsible for providing technical support in the area of system engineering. An organization chart for Engineering is shown in Figure 13.1-6.

13.1.1.2 Organizational Arrangement

Figures 13.1-1 through 13.1-7 provide the current corporate structure as applicable to CGS support organizations. The number of personnel to be assigned to each of the working level organizations will be determined based on workload and need for pertinent expertise. If the need arises, qualified outside contractors will be used to support the Energy Northwest staff.

13.1.1.3 Qualifications

Qualification requirements for key technical support personnel who fulfill the responsibilities identified in Section 13.1.1.1 shall meet the criteria of Regulatory Guide 1.8, Revision 1, 1977 (see the OQAPD). The personnel qualification and training programs are under continuing review and modification to reflect the changes following the TMI accident. The Vice President Engineering meets the definition and qualifications of "Engineer in Charge."

Any Vice President or Manager listed in Section 13.1.1.1 may authorize deviations from the qualification requirements for subordinate positions when, in their judgment, the combined education, experience, and managerial competency of a particular individual are sufficient to ensure adequate performance of assigned responsibilities. Such exceptions will be documented in writing and will not be used as a means to degrade the overall qualifications of the support staff. Deviations are not authorized for those positions whose qualifications are described in the Technical Specifications and the OQAPD.

13.1.2 OPERATING ORGANIZATION

13.1.2.1 Plant Organization

This section describes the structure, functions, and responsibilities of the onsite organization established to operate and maintain CGS. Figures 13.1-9 through 13.1-13 show the plant organizations that directly operate and maintain CGS. The principal departments that function directly under the supervision of the Plant General Manager are: Operations, Maintenance, Radiological Services, and Chemistry (see Figure 13.1-3).

The Security Force Lieutenant is responsible to the Plant General Manager for day-to-day operation of the Plant Security Program and receives functional supervision from Operations Support management.

Position titles, NRC licenses required, and lines of functional reporting, as well as direct lines of communications, are indicated on the organization charts.

13.1.2.2 Plant Personnel Responsibilities and Authorities

13.1.2.2.1 Plant Management

The Plant General Manager has direct responsibility and authority for all plant activities. The Plant General Manager reports directly to the Vice President, Operations.

The Plant General Manager has the responsibility for management of the following plant departments: Operations, Chemistry, Radiological Services, Planning, Scheduling and Outage, and Maintenance.

A Security Force Lieutenant exercises supervision and authority over the onsite security personnel. The Security Force Lieutenant reports to the Plant General Manager or the designated representative on day shifts and to the Shift Manager during other than normal working hours (i.e., backshifts, weekends, and holidays).

In the event of incapacitation of key plant personnel or unexpected contingencies of a temporary nature, the line of succession of authority and responsibility for all plant activities is as follows:

a. Plant General Manager,
b. Operations Manager,
c. One of the Assistant Operations Managers (see below),
d. Duty Shift Manager.

13.1.2.2.2 Operations Supervision

Operations is under the direction of the Operations Manager. The Operations Manager is responsible for overall plant operation. The Operations Manager directs and manages the activities of operations to ensure safe plant operation and control of plant systems in compliance with licensing documents.

The Operations Manager is responsible for being cognizant of and complying with the OQAPD.

The Operations Manager is responsible for the day-to-day routine as well as the abnormal or emergency operating situations that may arise. The Operations Manager is responsible to see that all operations are carried out in a safe, efficient manner and that the plant is operated in strict conformance to the Operating License, Technical Specifications, and in accordance with approved written procedures. Additionally, the Operations Manager is responsible for operating personnel schedules, development, and periodic review of plant operating procedures and instructions, and the preparation of operating records and reports.

The Operations Crew, Operations Support, Operations Work Control and Operations Training Managers (hereinafter referred to collectively as Assistant Operations Managers (AOMS)) support and assist the Operations Manager in the performance of these duties. The Operations Crew Manager is responsible to the Operations Manager for the immediate supervision of the Operations staff that supports work team and outage activities, and as such, he receives direction from the Operations Manager for the day-to-day routine and supervises implementation. The Operations Support Manager is responsible to the Operations Manager for the immediate supervision of the Operations staff that supplies miscellaneous support to the Operations Department.

The AOMs may be required to maintain a current Senior Reactor Operator (SRO) license. During periods of transition such as promotion, the individual with a current SRO, either the Operations Manager or one of the AOM will have the responsibility for immediate supervision of the Operations staff. In either case, the individual with the SRO may only be relieved by another individual possessing a current SRO. The Operations Manager will designate one of the assistants to assume total responsibility for the Operations Manager's duties (as described in this section) during periods when the Operations Manager is temporarily absent from the plant. See Figure 13.1-9 for an organization chart of the Operations Department.

The plant Fire Marshall assists the Operations Manager in the implementation of the Fire Protection Program. Responsibilities include ensuring that the fire protection systems and components are maintained and that the Fire Brigade is adequately trained and staffed. More detailed information is contained in Section 13.2.2.5.2.

13.1.2.2.3 Operating Shift Crew Supervision

Within the Operations Department are a minimum of five shift crews during normal operations. In some situations, such as refueling outages, these may be reduced to four shift crews. Plant management and technical support will be present or on call at all times to provide advice to the shift personnel.

The Shift Manager holds an SRO license and is directly responsible to the Operations Manager (see Figure 13.1-10 for typical Operations Crew organization chart). The Shift Manager is in charge of all plant operations on shift and is directly in charge of and responsible for the shift crew assigned to his specific shift. The Shift Manager has the authority to institute immediate action in any given situation to shut the plant down, or eliminate difficulties to preclude violation of the Operating License or Technical Specifications, or to avert possible injury or undue radiation exposure of personnel. Additionally, the Shift Manager may at times direct the activities of other personnel during tasks such as backshift maintenance, radiation protection, chemistry control, and security implementation. The Shift Manager also keeps plant management appraised of situations that may affect plant safety and/or constitute a hazard to the general public. During other than normal working hours, the Shift Manager assumes responsibility for all plant operations in the absence of senior plant management personnel.

The Control Room Supervisor holds an SRO license and assists the Shift Manager in the performance of duties and assumes those duties during periods when the Shift Manager is unavailable. The Control Room Supervisor is responsible for supervising the activities of the Control Room Reactor Operators and other assigned personnel (i.e., equipment operators and maintenance support personnel) required to operate the plant safely and efficiently. The Control Room Supervisor is directly responsible to the Shift Manager.

If stationed, the Shift Support Supervisor assists the Shift Manager in the performance of his duties. The Shift Support Supervisor is responsible for the supervision and direction of personnel assigned to perform balance-of-plant (BOP) operating functions such as operations of makeup water treatment system, radwaste processing systems, and other plant support systems. The individual is responsible for performing administrative duties as assigned.

All core alterations are observed and directly supervised by either a licensed SRO, or licensed SRO limited to fuel handling, who has no concurrent responsibilities during the performance of the core alterations.

13.1.2.2.4 Shift Technical Advisor

A Shift Technical Advisor (STA) qualified individual provides engineering expertise on shift pursuant to safe and efficient operation of the plant. The STA function may be staffed by a dedicated individual (licensed or non-licensed), or by an individual filling a dual role as the Control Room Supervisor, Shift Manager or Shift Support Supervisor. The STA qualified individual monitors reactor core operations, and core management and reactivity controls. The STA normally reports to the Shift Manager.

13.1.2.2.5 Licensed Operators

In addition to the licensed supervisors listed above, there are a minimum of two reactor operators on each shift. The reactor operator (RO) holds a reactor operator or senior reactor operator license and is responsible to the Control Room Supervisor for the safe and efficient operation of the plant from the main control room. The RO follows approved procedures in performing work and is responsible for taking the immediate action required to maintain or bring the plant to a safe condition during abnormal and/or emergency conditions. However, if a particular situation is not covered by a procedure, the individual may seek advice from the Control Room Supervisor, or if the situation is critical, may use his or her own judgment to prevent damage to equipment, injury to personnel, or undue radiation exposure of plant personnel and the general public. The RO directs and supports the activities of other operators in the performance of their duties and works cooperatively with all plant service groups that interface with plant operation.

13.1.2.2.6 Nonlicensed Operators

The equipment operators (EO) are responsible to the Control Room Supervisor or Shift Support Supervisor for assisting in the plant operation and performing work assignments from local control stations and all other defined areas outside of the central control room. The EO follows approved procedures in doing work and does not deviate from those procedures except as authorized. The EO performs assigned routine inspections and manipulates equipment without close supervision. The EO also performs special assignments as directed.

13.1.2.2.7 Engineering Management

Reporting to the Vice President, Engineering is the System Engineering Manager, the Technical Services Manager, the Design Engineering Manager, and the Reactor Fuels Manager.

They are responsible for developing and implementing plant programs and procedures which provide proper management control in the above areas and thus ensure compliance with the conditions of the operating license and proper plant safety. They interface with other support organizations to support plant operations.

The engineering organizations are responsible for being cognizant of and complying with the Operational Quality Assurance Program Description.

13.1.2.2.7.1 System Engineering Manager. The System Engineering Manager, with the assistance of direct supervisory reports, is responsible for long-term management of and the health and reliability of systems and components, overall direction of the system engineering program in support of plant operation, maintenance, and chemistry, and developing long range plans for system improvement and performance in the areas of NSSS systems, control/electrical systems, and BOP systems.

The System Engineering Manager is responsible for the development, implementation, and execution of programs to monitor system performance, to conduct inspections, and to perform specialized testing. The objective is to identify potential component degradation, minimize threats to successful operation of systems and the plant, and to identify opportunities for improvement.

The System Engineering Manager is the primary interface with the Design Engineering Manager and Technical Services Manager in support of maintaining plant compliance with design and licensing requirements.

The System Engineering Manager is responsible for implementing performance monitoring of plant systems and critical plant programmatic processes. This includes providing recommendations to plant management for implementation of new program requirements, performing periodic assessments of existing programs, and recommending component or system improvements. The System Engineering Manager is responsible for daily plant support, responding to emergent issues, operability assessments, and providing troubleshooting expertise to operations and maintenance.

System Engineering Supervisors direct the activities of the System Engineering staff in support of plant operation in the functional areas of mechanical engineering, instrumentation and control engineering, and electrical engineering. Activities include initiating engineering design changes, making recommendations for improved operation, supporting operability assessments and providing operating and maintenance support for instrumentation and control systems, mechanical systems, electrical systems, plant water systems, and waste handling systems.

13.1.2.2.7.2 Design Engineering Manager. The Design Engineering Manager is responsible to assist System Engineering for daily plant support, responding to emerging issues, and operability assessments. The Design Engineering Manager is responsible for maintenance of the plant design basis, performance of plant design changes, and design and drafting. This includes non-modification design related activities.

The Design Engineering Manager, with the assistance of direct supervisory reports, manages the various engineering design disciplines including mechanical, civil/stress, structural, electrical, instrumentation and other teams that are formed to address specific design engineering or business needs.

13.1.2.2.7.3 Reactor Fuels Manager. The Reactor Fuels Manager is responsible for fuel design, overall management of the reactor core, and monitoring of core parameters.

The Reactor Fuels Manager, with the assistance of direct supervisory reports, is responsible for providing technical support to Operations in management of refueling floor activities, support to Maintenance in resolving refueling equipment problems, providing technical resources for resolution of vessel hardware problems and concerns with interfacing systems which influence or monitor core reactivity, for maintaining involvement in applicable industry initiatives affecting core reactivity issues and new developments in core operation, providing recommendations to plant management on operating strategies in support of normal and off-normal operating situations, and planned shutdown and startup activities.

The Reactor Fuels Manager ensures sound fuel design philosophy is followed, fuel designs provide no unreasonable challenges to safe plant operation, and probabilistic safety assessments (PSA) are performed for CGS.

The Fuel Design/Reactor Engineering staff are responsible for performing periodic core physics evaluations to monitor the operation, burnup, and thermal/hydraulic performance of the reactor core. They provide and maintain plant operating curves and reactivity data for use by shift operation personnel and are responsible for the onsite accountability of nuclear fuel and special nuclear materials. The Fuel Design/Reactor Engineering staff are responsible for core design, fuel planning, licensing support (e.g., COLR, accident/transient analysis), and analytical work necessary to support cycle operation (e.g., control rod pattern recommendations).

The Safety Analysis/PSA staff provide probabilistic safety assessments for CGS. They provide analytical support for radiation dose analysis, shielding, equipment qualification, ODCM, emergency procedures and primary and secondary containment analyses.

13.1.2.2.7.4 Technical Services Manager, with the assistance of direct supervisory reports, is responsible for plant, code, and component programs. The Technical Services personnel are responsible for Equipment Qualification (EQ), Fire Protection (FP), In Service Test (IST), Thermal Performance (TP), ASME Section XI, ISI, BWRVIP, welding, Appendix J Local Leak Rate Testing (LLRT), pump, valve (AOVs, MOVs, and reliefs), large motor, circuit breaker, relay, and Component Condition Monitoring programs, including vibration analysis, oil analysis, and thermography, and performing engineering needed for special procurement.

13.1.2.2.7.5 Deleted

13.1.2.2.7.6 Deleted

13.1.2.2.7.7 Deleted

13.1.2.2.8 Nuclear Engineering Supervision

See Section 13.1.2.2.7.3.

13.1.2.2.9 Radiological Services Supervision

See Section 12.5.1 for a description of duties, responsibilities, and reporting relationships. See Figure 13.1-11 for an organization chart.

13.1.2.2.10 Chemistry Supervision

Chemistry is under the direction of the Chemistry/Radiological Services Manager, who reports to the Plant General Manager. The group provides plant oversight for system chemistry optimization and control, gaseous, and liquid effluent releases, radwaste processing and chemical control, the Offsite Dose Calculation Manual, the Radiological Environmental Monitoring Program (REMP), and Radiological Effluent Report. See Figure 13.1-12 for an organization chart.

13.1.2.2.11 Maintenance Supervision

Maintenance is under the direction of the Maintenance Manager. The Maintenance Manager is responsible for the Maintenance Program and for the development and implementation of maintenance processes and procedures which will ensure the safe and reliable operation of plant equipment. The Maintenance Manager is responsible for primary component level troubleshooting. The Maintenance Manager reports to the Plant General Manager. The organization is shown in Figure 13.1-13.

The Maintenance Manager, with the assistance of direct managerial reports, manages the following activities: Reactor and Major Maintenance, Maintenance Services, FIN Component Group, Mechanical Component Group, I & C Component Group, Electrical Component Group, and other teams that are formed to address specific maintenance or business needs. Shops and/or teams may be combined as long as supervisory qualifications are maintained as described in Section 13.1.3.4.

All plant modifications are accomplished through this department either directly or through the actions of the Site Support Services contractor. Engineering, Training, and Support Services, as discussed in Section 13.1.1.1, provide support for this department. Other support is provided when needed in the form of vendor representatives for technical guidance on maintenance of major components of the plant.

Maintenance Supervisors are responsible for the day-to-day implementation of the Maintenance Program. They are responsible for maintaining plant electrical, instrumentation, and mechanical systems through preventive and corrective maintenance and surveillance programs.

13.1.2.2.12 Planning, Scheduling and Outage Supervision

This organization is responsible for managing the work process and ensuring work schedule consistency. It is also responsible for the development and oversight of outage preparation and implementation and coordination of outage work.

13.1.2.2.13 Quality Supervision

A description of duties and responsibilities for the Quality organization is contained in the OQAPD.

13.1.2.3 Operating Shift Crews

13.1.2.3.1 Shift Crew Composition

Shift coverage is provided by using a rotating shift schedule depending on operating needs. The schedules are based on a nominal 40-hr work week and shifts are normally of 8 or 12 hr duration (excluding shift turnover time).

During normal operations, a minimum of five crews provide 24 hr/day, 7 day/week coverage. Table 13.1-1, as well as the Technical Specifications and the Emergency Plan, identify the minimum number and type of licensed and unlicensed personnel required to be onsite.

For those operations that involve core alterations, direct supervision of all fuel movements is provided by an individual holding an SRO license. This person has no other concurrent responsibilities during this assignment.

It is CGS's policy to maintain an adequate number of personnel in the Shift Manager, Control Room Supervisor, Shift Support Supervisor, STA (if required), Control Room Reactor Operator, and Equipment Operator positions such that the use of overtime is not routinely required to compensate for inadequate staffing.

13.1.2.3.2 Shift Responsibility for Radiation Protection

A minimum of one Health Physics Technician is assigned to each operating shift to provide radiological surveillance/control (see Table 13.1-1).

All shift personnel are instructed in the fundamentals of health physics such as implementing radiation protection procedures, radiation and contamination surveys, use of protective barriers and signs, use of protective clothing and breathing apparatus, radiation monitoring, and accumulated dose.

Shift personnel are responsible for immediately informing the on-duty Shift Manager if conditions develop that exceed or are likely to exceed preestablished radiation levels or exposure limits or if they believe that unsafe or hazardous conditions exist. The Shift Manager will evaluate the situation and if a radiological condition exists that warrants attention and investigation, the appropriate Health Physics personnel will be called for assistance.

13.1.2.3.3 Shift Maintenance Support

Craftsmen and technicians, as required, are available to provide maintenance support and surveillance testing in the areas of instrumentation and controls and mechanical and electrical equipment.

13.1.2.3.4 Shift Fire Brigade

A Shift Fire Brigade, consisting of a minimum of five members of the nominal shift complement, shall have advanced fire training and be equipped for fire fighting. This select group on each operating shift will have primary response capabilities and will respond to emergencies involving fire and/or emergencies where life threatening danger exists.

The brigade shall not include the minimum shift crew complement required to safely shut down the unit. At a minimum the brigade leader and two brigade members shall have sufficient knowledge of plant fire safe shutdown systems. The balance of the fire brigade shall be composed of Fire Brigade trained support personnel. See Section 13.2.2.5 for the qualification requirements for fire brigade members.

13.1.2.3.5 Shift Chemistry Support

At least one qualified chemistry technician is assigned to each operating shift for the purpose of providing chemistry support in the area of chemical surveillances while the plant is in Modes 1, 2, or 3.

13.1.3 QUALIFICATIONS OF NUCLEAR PLANT PERSONNEL

The minimum educational and experience qualifications for the onsite plant personnel are based on Regulatory Guide 1.8, Revision 1-R, 1977. If an individual who does not meet the minimum qualification criteria is placed in a discipline, it will be specifically pointed out and justification or explanation provided. See Section 13.1.1.3. Personnel qualification and training programs are under continual review and modification to reflect the changes following TMI. The minimum qualification requirements identified in Section 13.1.3.1 will be revised accordingly. The licensed ROs and SROs meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980, NRC letter to all licensees, as modified by NUREG-0737, November 1980, "Clarification of TMI Action Plan Requirements," Enclosure 1, Section 1.A.2.1, "Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications."

13.1.3.1 Plant Management

The Plant General Manager shall have 10 years of responsible power plant experience of which a minimum of 3 years shall be nuclear power plant experience. A maximum of 4 years of the remaining 7 years of experience may be fulfilled by academic training on a one-for-one time basis. This academic training shall be in an engineering or scientific field generally associated with power production. The Plant General Manager shall have acquired the experience and training normally required for examination by the NRC for an SRO license, whether or not the examination is taken. The Plant General Manager should have a recognized baccalaureate or higher degree in an engineering or scientific field generally associated with power production.

13.1.3.2 Operations Department

13.1.3.2.1 Operations Manager

The Operations Manager shall have a minimum of 8 years of responsible power plant experience of which a minimum of 3 years shall be nuclear power plant experience.

A maximum of 2 years of the remaining 5 years of power plant experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis. The Operations Crew Manager shall have qualifications similar to those of the Operations Manager. The Operations Manager or Operations Crew Manager shall hold an SRO license.

13.1.3.2.2 Shift Manager

The Shift Manager shall have a minimum of a high school diploma or equivalent and 4 years of responsible power plant experience of which a minimum of 1 year shall be nuclear power plant experience. At least 6 months of nuclear plant experience will be at CGS. A maximum of 2 years of power plant experience may be fulfilled by academic or related technical training on a one-for-one time basis. The Shift Manager shall hold an SRO license. For NRC license eligibility guidelines (experience, training, and education) for an SRO license, see NUREG-1021, section ES-202.

13.1.3.2.3 Control Room Supervisor

The Control Room Supervisor shall have a minimum of a high school diploma or equivalent and 4 years of responsible power plant experience, of which a minimum of 1 year shall be nuclear power plant experience. At least 6 months of nuclear plant experience will be at CGS. A maximum of 2 years of power plant experience may be fulfilled by academic or related technical training on a one-for-one time basis. The Control Room Supervisor shall hold an SRO license. For NRC license eligibility guidelines (experience, training, and education) for an SRO license, see NUREG-1021, section ES-202.

13.1.3.2.4 Shift Technical Advisor

The STA possesses a bachelor's degree in engineering or science with sufficient courses to provide a sound background for understanding the design and operation of a BWR power plant. The STA shall have a minimum of 2 years of power plant experience with at least 6 months of nuclear plant experience at CGS.

13.1.3.2.5 Shift Support Supervisor

The Shift Support Supervisor shall have a high school diploma or equivalent. The individual shall have 4 years of power plant experience of which 1 year shall be nuclear power plant experience. This position does not require an RO license.

13.1.3.2.6 Reactor Operator

The RO shall have a minimum of a high school diploma or equivalent and two years of power plant experience of which a minimum of 1 year shall be nuclear power plant experience. At least 6 months of the nuclear experience shall be at CGS unless the incumbent has an equal amount of nuclear experience acquired on a similar unit. The individual shall hold an RO license. For NRC license eligibility guidelines (experience, training, and education) for an RO license, see NUREG-1021, section ES-202.

13.1.3.2.7 Equipment Operator

Before assuming the full responsibilities of the position in the plant, the Equipment Operator shall have a minimum of a high school diploma or equivalent and shall have completed the Energy Northwest training program for Equipment Operators. This position does not require an RO license.

13.1.3.3 Engineering

13.1.3.3.1 Engineer in Charge

The "Engineer-in-Charge" described in Section 13.1.1.3 shall have a minimum of a Bachelor's Degree in Engineering or the Physical Sciences and a minimum of 8 years of related technical experience of which 3 years is professional level experience in nuclear services, nuclear plant operation, or nuclear engineering, and the necessary overall nuclear background to determine when to call consultants and contractors for dealing with complex problems beyond the scope of owner-organization expertise.

13.1.3.3.2 Engineering Managers

Engineering Managers shall have a minimum of 8 years of related technical experience of which 1 year should be nuclear power plant experience. A maximum of 4 years of the remaining 7 years may be fulfilled by satisfactory completion of academic training as defined in ANSI N18.1-1971. The Reactor Fuels Manager shall have a bachelor of science degree in engineering or physical sciences suitable to the nuclear power field and a minimum of 2 years of experience in areas such as reactor/core physics and measurements, heat transfer, and physics testing.

Engineering Managers appointed as members of the Plant Operations Committee must also meet the qualification requirements specified in the OQAPD.

13.1.3.3.3 Engineering Supervisors

The Engineering Supervisors shall have a minimum of 5 years of related technical experience of which 1 year shall be nuclear power plant experience. A maximum of 4 years of the required 5 years may be fulfilled by satisfactory completion of academic training. The Reactor Engineering/Fuel Design Supervisor(s) shall have a minimum of 2 years experience in areas such as reactor/core physics and measurements, heat transfer, and physics testing. A Bachelor of Science degree in engineering or physical sciences or the equivalent is required.

The individual(s) responsible for instrumentation and control shall have a minimum of 5 years experience in instrumentation and control, of which a minimum of 6 months shall be in nuclear instrumentation and control. A minimum of 2 of the 5 years of experience should be related technical training. A maximum of 4 of the 5 years of experience may be fulfilled by related technical or academic training as defined by ANSI N18.1-1971.

13.1.3.3.4 Fire Protection Engineer

The qualified Fire Protection Engineer meets the qualifications of professional member in the Society of Fire Protection Engineers or is a registered Fire Protection Engineer.

13.1.3.4 <u>Maintenance</u>

13.1.3.4.1 Maintenance Managers

The Maintenance Manager shall have a minimum of 7 years of responsible power plant experience or applicable industrial experience, a minimum of 1 year of which shall be nuclear power plant experience. A maximum of 2 years of the remaining 6 years of power plant or industrial experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis. He further should have nondestructive testing familiarity, craft knowledge, and an understanding of electrical, pressure vessel, and piping codes.

13.1.3.4.2 Maintenance Supervisors

Maintenance Supervisors shall each have a high school diploma or equivalent and should have a minimum of 4 years experience in the craft or discipline that they supervise in accordance with ANSI 18.1, 1971. In cases where a supervisor does not have a minimum of 4 years of experience in the discipline of the craft being supervised, technical direction for the craft will be given by a qualified supervisor.

13.1.3.5 Chemistry and Radiological Services

13.1.3.5.1 Chemistry/Radiological Services Manager

The Chemistry/Radiological Services Manager shall, in accordance with ANSI N18.1-1971, have a minimum of 8 years in responsible positions, of which 1 year shall be nuclear power plant experience. A maximum of 4 years of the remaining seven years of experience should be fulfilled by satisfactory completion of academic training.

13.1.3.5.2 Deleted

13.1.3.5.3 Radiation Protection Manager

The Chemistry/Radiological Services Manager functions as the Radiation Protection Manager and shall, at a minimum, meet the qualifications defined in Regulatory Guide 1.8, Revision 1-R, May 1977. This individual shall have a bachelor's degree or the equivalent in a science or engineering subject including some formal training in radiation protection. The Radiation Protection Manager shall have at least 5 years of professional experience in applied radiation protection. A master's degree may be considered equivalent to 1 year of professional experience and a doctor's degree may be considered equivalent to 2 years of professional experience where course work related to radiation protection is involved. At least 3 years of this professional experience shall be in applied radiation protection work in a nuclear facility dealing with radiological problems similar to those encountered in nuclear power stations, preferably in an actual nuclear power station. The Radiation Protection Manager is an assigned duty and not a defined position in the organization (see Section 12.5.1).

13.1.3.5.4 Radiological Services Supervisors

Radiological Services Supervisors shall, in accordance with ANSI 18.1-1971, have a high school diploma or equivalent and a minimum of 4 years of related experience.

13.1.3.5.5 Chemistry Supervisors

Chemistry Supervisors who are responsible for directing the actions of technicians shall, in accordance with ANSI N18.1-1971, have a high school diploma or equivalent and a minimum of 4 years related experience.

1.3.1.3.6 Deleted

13.1.3.7 Quality

See the OQAPD for a description of qualification requirements.

Table 13.1-1

Minimum Shift Crew Composition

		Minimum Number of Personnel per Position per Shift	
Position Title[b]	Type of License	Modes 1, 2, and 3[c]	Modes 4 and 5[c]
SM	SRO	1	1
CRS	SRO	1	None
RO	RO	2	1
EO	None	2	1
STA	None	1[d,e]	Note[f]
HP	None	1	1

[a] This table represents the minimum number of personnel required to fill any particular position. It does not provide a total staffing level for an operating shift. Additional staff for safe shutdown and fire brigade must also be satisfied.

Technical Specifications paragraph 5.3.2 was added in LAR 182 to clarify compliance with 10 CFR 55.53 requirements. Energy Northwest may take credit for more than the minimum number of watchstanders required by 10 CFR 50.54(m). However, fulfillment of 10 CFR 55.53(e) and (f) requirements of active performance of operator or senior operator functions requires that Energy Northwest implement administrative controls to assure functions and duties are divided and rotated in a manner which provides each watchstander meaningful and significant opportunity to maintain proficiency in the performance of the functions of an RO and/or SRO.

[b] Position title abbreviations are as follows:

SM	Shift Manager with SRO on Columbia Generating Station
CRS	Control Room Supervisor with SRO on Columbia Generating Station
RO	Reactor Operator with RO or SRO on Columbia Generating Station
EO	Equipment Operator
STA	Shift Technical Advisor
HP	Health Physics Technician

Table 13.1-1

Minimum Shift Crew Composition (Continued)

[c] Modes

1. Power operation
2. Startup
3. Hot shutdown
4. Cold shutdown
5. Refueling

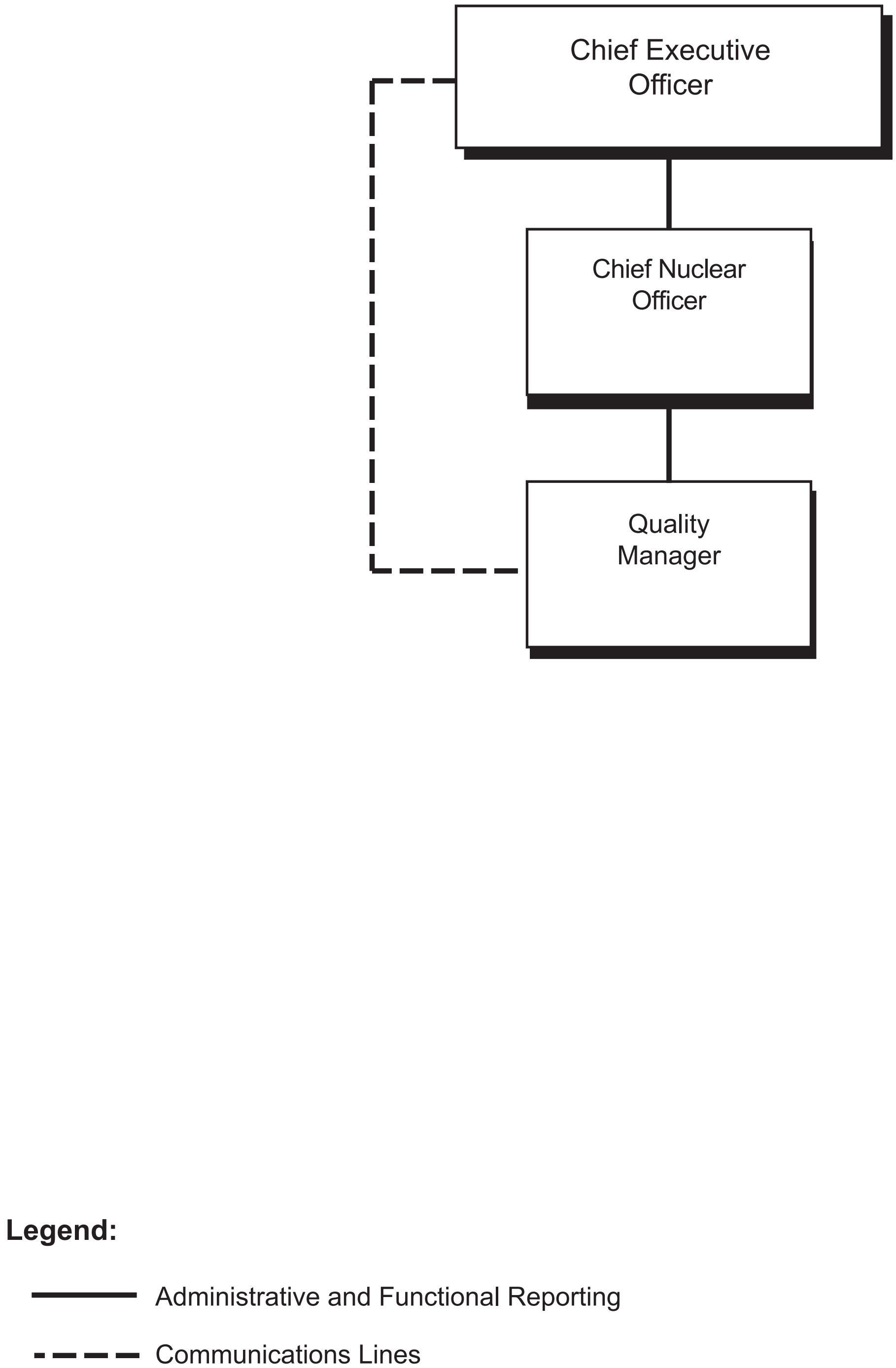
[d] An STA qualified individual shall be on-shift in Modes 1, 2 and 3. The STA qualified individual may be a dedicated individual (licensed or non-licensed) or an individual filling a dual role position as the Control Room Supervisor, Shift Manager or Shift Support Supervisor.

[e] When the STA qualified individual is filling a dual role as the Control Room Supervisor or Shift Manager, another SRO is required to be on-shift to provide independent oversight and emergency response support to the Shift Manager.

[f] Refer to the Emergency Plan for emergency response staffing requirements in Modes 4, 5.

The shift crew composition may be one less than the minimum requirements for a period not to exceed 2 hr to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements. This provision does not permit any shift crew position to be unmanned on shift change due to an oncoming shift crewman being late or absent.

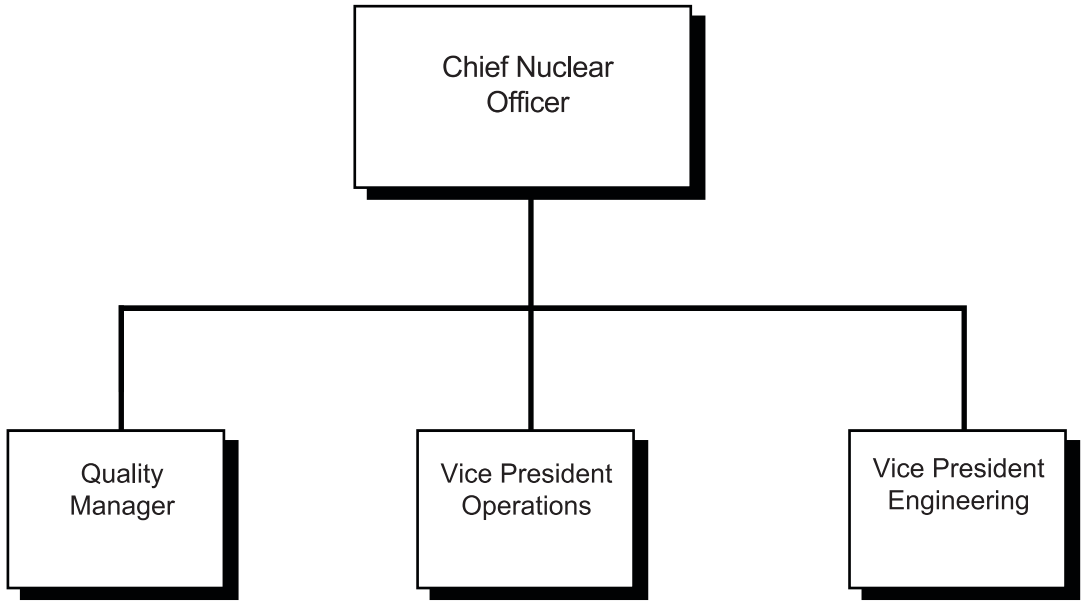
During any absence of the Shift Manager from the control room while the unit is in Operational Condition 1, 2, or 3, an Operations Department individual with a valid SRO license shall be designated to assume the control room command function. During any absence of the Shift Manager from the control room while the unit is in Operational Condition 4 or 5, an individual with a valid SRO license or RO license shall be designated to assume the control room command function.



Columbia Generating Station
Final Safety Analysis Report

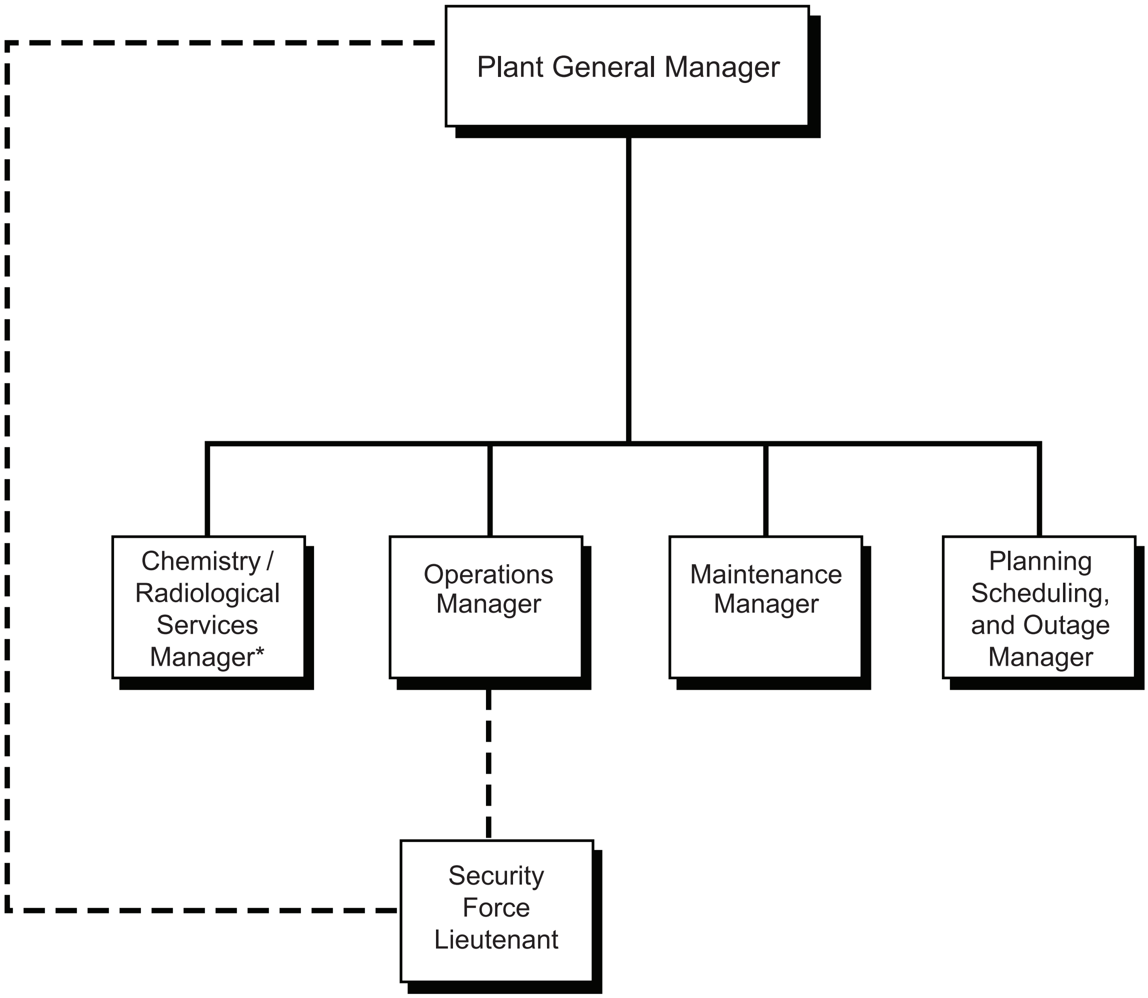
Energy Northwest Organization

Draw. No. 970187.02 | Rev. | Figure 13.1-1



Nuclear Generation Organization

Draw. No. 970187.03 | Rev. | Figure 13.1-2

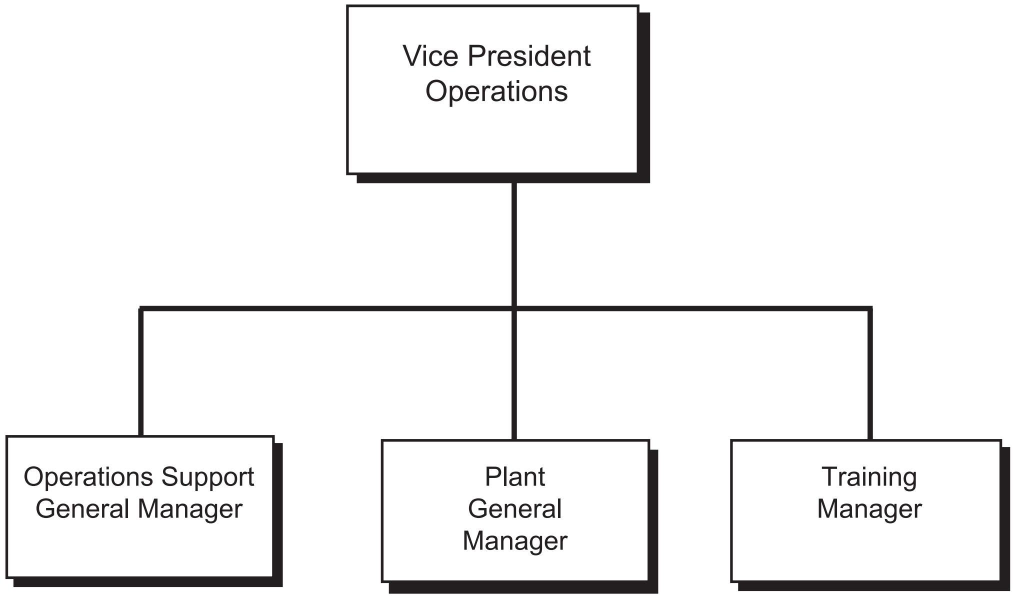


* Also fulfills Radiation Protection Manager function

Columbia Generating Station
Final Safety Analysis Report

Plant General Manager Organization

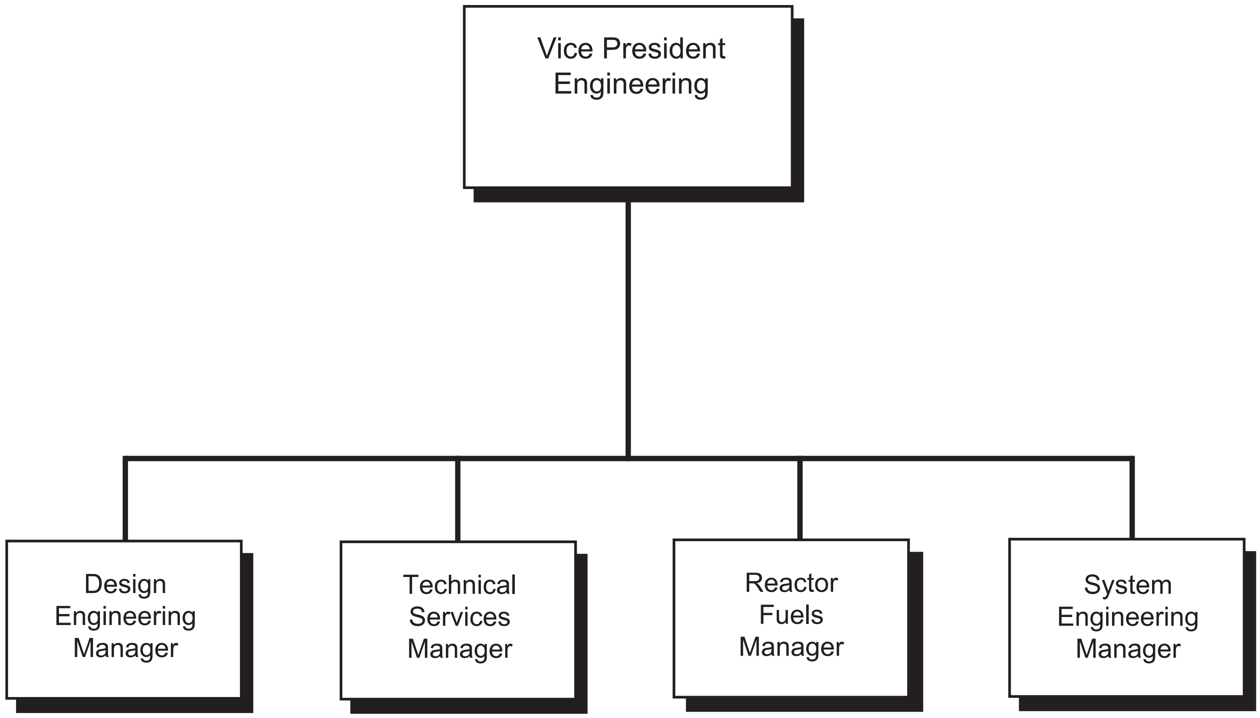
Draw. No. 970187.41	Rev. 3	Figure 13.1-3



Operational Support Organization

Draw. No. 970187.05 | Rev. 4 | Figure 13.1-4

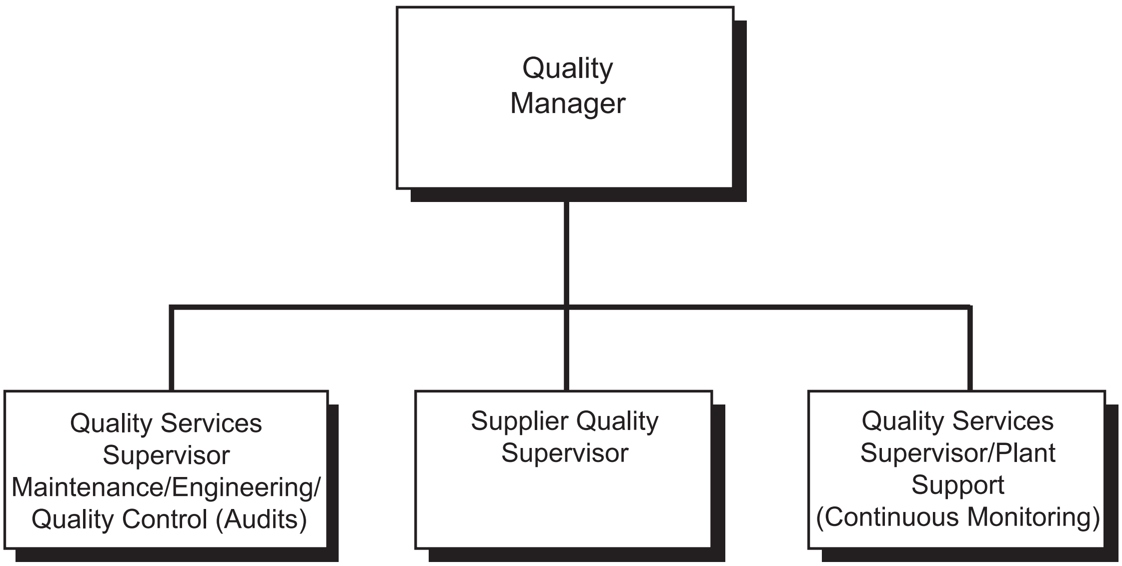
DELETED



Columbia Generating Station
Final Safety Analysis Report

Vice President Engineering Organization

Draw. No. 970187.07 | Rev. | Figure 13.1-6

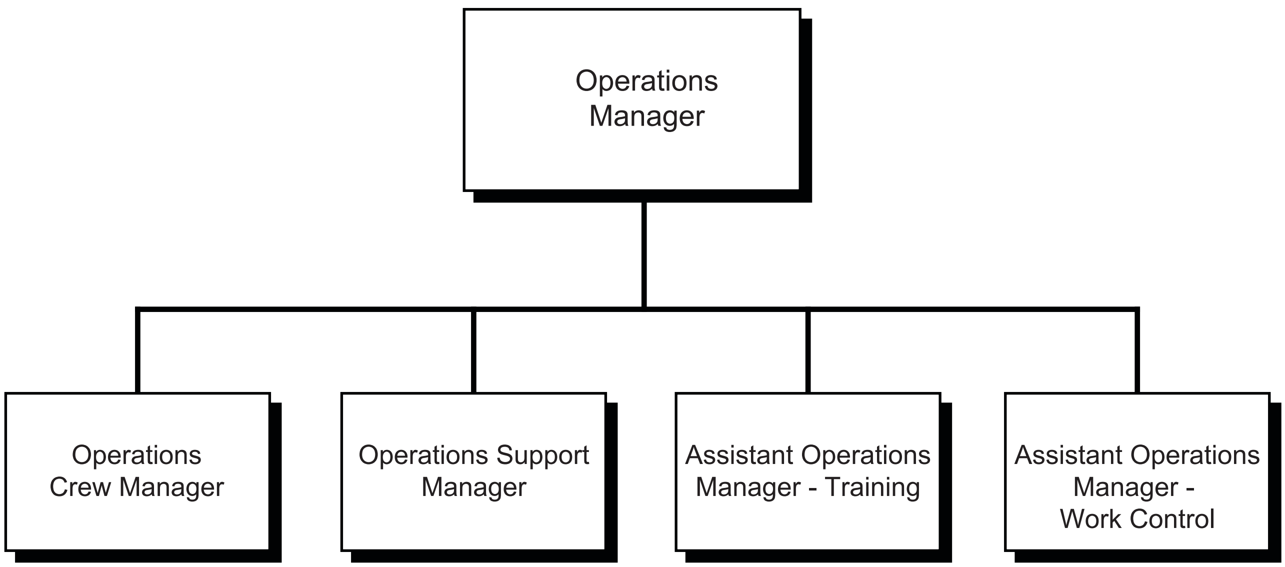


Columbia Generating Station
Final Safety Analysis Report

Quality Organization

Draw. No. 970187.08 | Rev. 1 | Figure 13.1-7

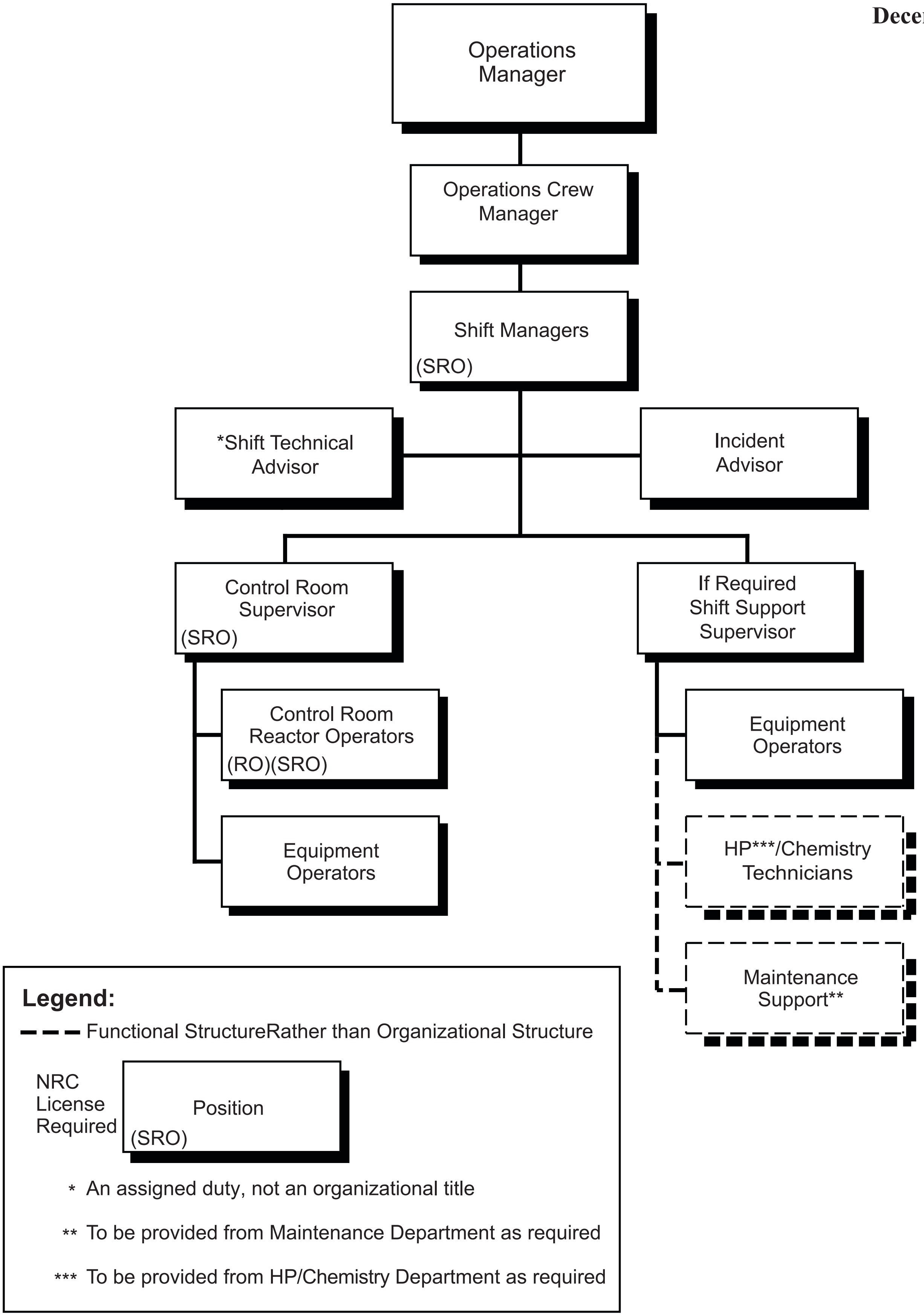
DELETED



Columbia Generating Station
Final Safety Analysis Report

Operations Organization

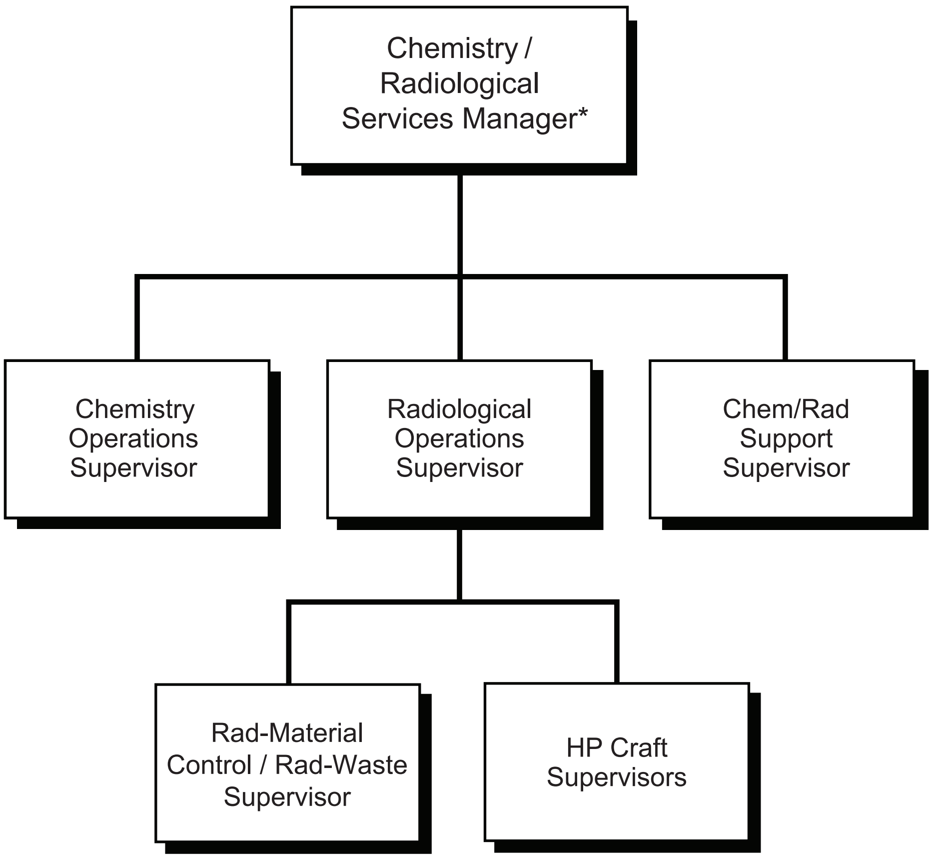
Draw. No. 970187.09	Rev. 2	Figure 13.1-9



Columbia Generating Station
Final Safety Analysis Report

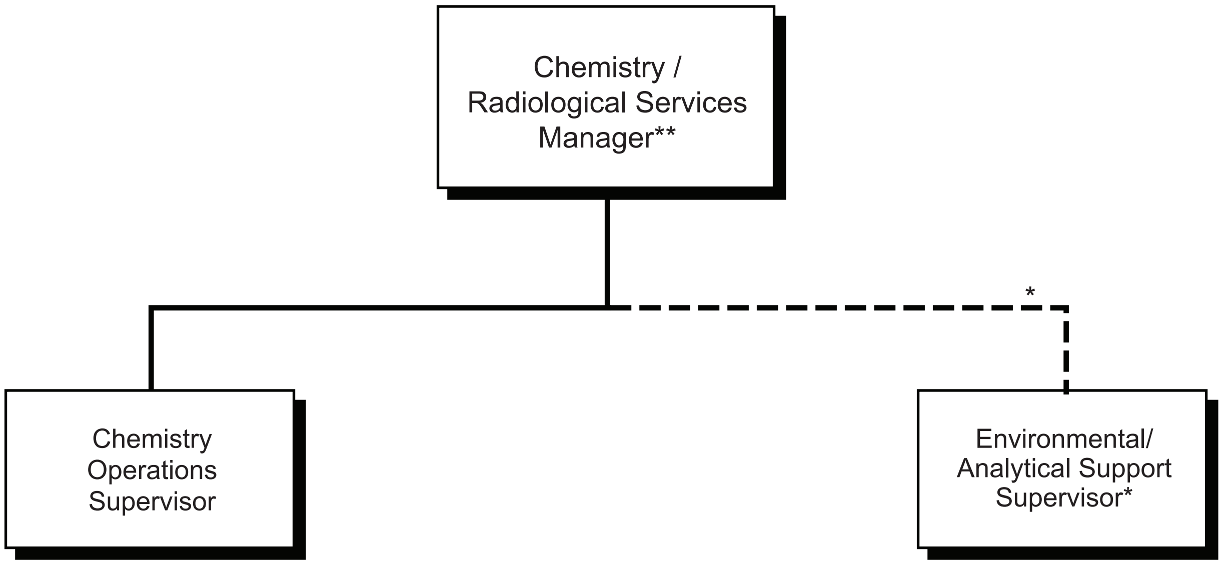
Operations Crew

Draw. No. 970187.10	Rev. 1	Figure 13.1-10



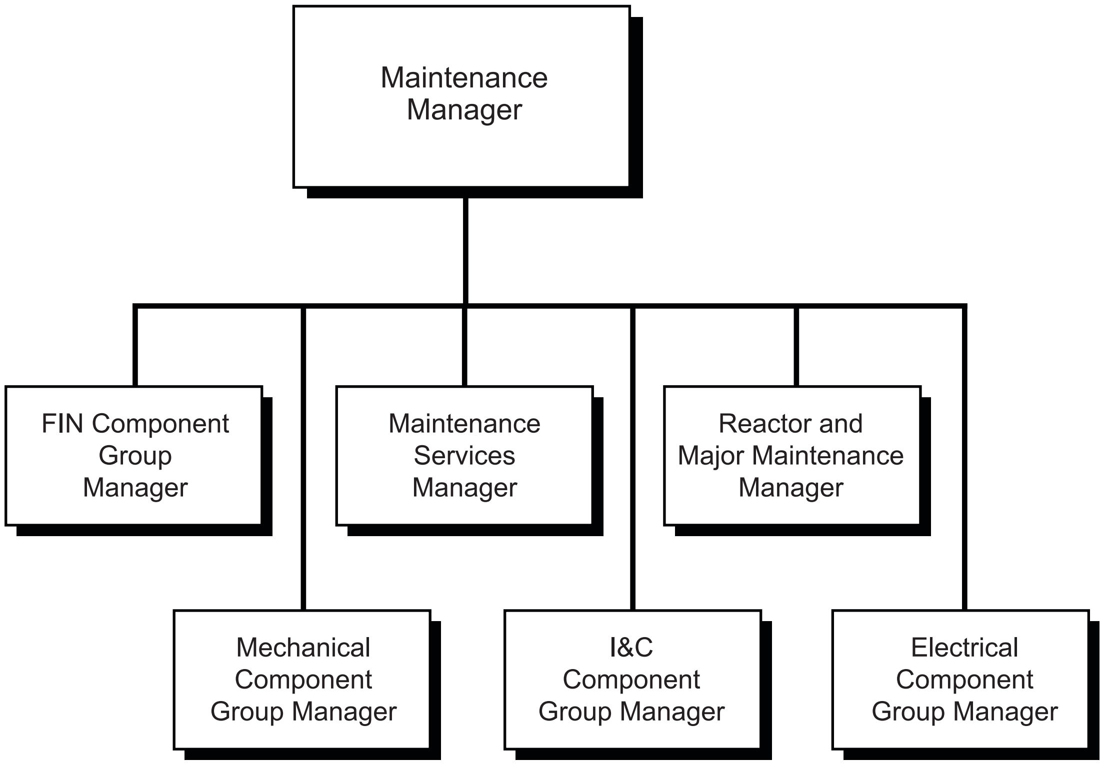
*Also fulfills Radiation Protection Manager function

Columbia Generating Station Final Safety Analysis Report	Radiological Services Organization		
	Draw. No. 970187.11	Rev. 4	Figure 13.1-11



* Dashed line indicates a functional rather than an organizational structure.
** Also fulfills the Chemistry Manager function

Columbia Generating Station **Final Safety Analysis Report**	**Chemistry Organization** Draw. No. **970187.12** Rev. **2** Figure **13.1-12**



Columbia Generating Station
Final Safety Analysis Report

Plant Maintenance Organization

Draw. No. 970187.13 | Rev. 3 | Figure 13.1-13

13.2 TRAINING

13.2.1 PLANT STAFF TRAINING PROGRAM

In accordance with applicable federal guidelines, the Columbia Generating Station (CGS) training program has been designed to provide plant personnel with sufficient knowledge, training, and experience to enable them to safely and efficiently operate and maintain the plant and to protect the health and safety of the public.

The overall training program has been developed and coordinated by Energy Northwest, utilizing courses and programs produced by the nuclear steam supply system (NSSS) supplier, training consultant organizations, the training staff, and other employees of Energy Northwest possessing expertise in related disciplines.

The training program will provide sufficient qualified reactor operators, senior reactor operators, equipment operators, shift technical advisors, maintenance, health physics, chemistry, and engineering support personnel to fully staff CGS.

Initial training programs provide qualified replacement personnel and continuing training programs provide ongoing training for all plant staff commensurate with their area of responsibility and knowledge level.

The Chief Nuclear Officer is responsible for overall conduct and administration of the CGS training program. The development and implementation of that program may be delegated to the Training Organization or other members of the plant staff.

a. General Employee Training - Program Description

   All personnel granted unescorted access to the station will be trained in the following areas:

   1. Appropriate plant security and emergency procedures,
   2. General radiological protection,
   3. Industrial safety,
   4. Fire protection, and
   5. Quality assurance program.

   Written or oral exams will be required for selected classes to determine successful completion.

b. General Employee Training - Fire Protection Program

1. Plant employees

Employees receiving an unescorted security clearance will be provided training to include orientation to the fire protection plans, evacuation signals and procedures, and the procedure for reporting a fire.

2. Contractor personnel

Training will be provided to contractors as part of their access status--escorted or unescorted.

c. Security Personnel Training – Fire Protection Program

Training will be provided to plant security personnel that addresses

1. Entry procedures for offsite fire department,
2. Personnel control during emergency evacuation, and
3. Basic fire hazard recognition.

13.2.2 INITIAL AND CONTINUING TRAINING

13.2.2.1 Licensed Operators

13.2.2.1.1 Initial Training

Under the normal progression of an individual through the various levels of operator qualification, much of the material and experience will have been previously obtained, and hence, the licensed operator replacement training program will emphasize topics pertinent to the control room operator job function and requirements necessary for fulfilling the NRC operator licensing qualifications. Replacement for licensed operators normally come from the ranks of "qualified" nonlicensed operators; however, personnel from other departments or from outside the utility may be trained as control room operators if they meet all requirements for the position.

The CGS Operations Training Manager shall have the responsibility for establishing, supervising, and scheduling the initial licensed operator training program.

In accordance with 10 CFR 55.31(a)(4) the CGS licensed operator initial training program has been reviewed and approved by the Commission and was developed using a systems approach to training.

The licensed operator initial training program has been accredited by the National Academy for Nuclear Training. Accreditation is maintained in accordance with Institute of Nuclear Power Operation (INPO) Guidelines ACAD 02-001, "The Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and ACAD 02-002, "The Process for Accreditation of Training in the Nuclear Power Industry."

13.2.2.1.2 Continuing Training

A requalification training program implementing the requirements of 10 CFR 55.59, will be conducted to maintain the knowledge level and operating proficiency of licensed personnel. The retraining program will be based on a 2-year cycle.

The CGS Operations Training Manager shall have the responsibility for establishing, supervising, and scheduling the retraining program.

In accordance with 10 CFR 55.59(c) the CGS licensed operator requalification training program has been reviewed and approved by the NRC and was developed using a systems approach to training.

The requalification program has been accredited by the National Academy for Nuclear Training. The accreditation is maintained in accordance with INPO Guidelines ACAD 02-001, "The Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and ACAD 02-002, "The Process for Accreditation of Training in the Nuclear Power Industry."

The retraining and replacement program for the unit staff meets the requirements of Section 5.5 of ANSI/ANS N18.1-1971, Appendix A of 10 CFR Part 55, and the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980, NRC letter to all licensees, and includes familiarization with relevant industry operational experience.

13.2.2.2 Nonlicensed Operator Training

13.2.2.2.1 Initial Training

Normally replacements will be required to complete the following training prior to being placed into the equipment operator qualification sequence:

a. Basic fundamentals,
b. Basic boiling water reactor (BWR) systems,
c. Reactor plant equipment and component theory, and
d. Administrative procedures.

The training will emphasize topics pertinent to the equipment operator job function and requirements necessary for qualification.

13.2.2.2.2 Continuing Training Program

Continuing training of nonlicensed operators may be conducted in conjunction with the licensed operator requalification program. Nonlicensed operators shall be required to attend specific lecture topics that pertain to their job level requirements. At a minimum, nonlicensed operators shall participate in periodic reviews of systems and operating procedures for which continuous familiarization is important for safe and efficient operation of the plant. Specifically, the equipment operator retraining program consists of

a. Preplanned lecture series,
b. Update lecture series,
c. Normal/abnormal procedure review, and
d. Examinations/evaluations.

The CGS Operations Training Manager has the responsibility for establishing, supervising, and scheduling the equipment operator training program.

The equipment operator training program has been accredited by the National Academy for Nuclear Training. Accreditation is maintained in accordance with INPO Guidelines ACAD 02-001, "The Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and ACAD 02-002, "The Process of Accreditation of Training in the Nuclear Power Industry."

13.2.2.3 Shift Technical Advisor Training

13.2.2.3.1 Initial Training

The initial shift technical advisor (STA) training program content will normally include training and qualification in the following subject areas:

a. Completion of the SRO replacement operator training program or equivalent
b. Plant transient/accident analysis, and
c. STA job specific training.

13.2.2.3.2 Continuing Training

Continuing training of the STAs is normally conducted in conjunction with the licensed operator requalification training program. The STAs shall be required to attend specific lecture topics that pertain to their job level requirements. At a minimum, STAs shall participate in periodic reviews of systems and operating procedures for which continuous familiarization is important for safe and efficient operation of the plant. Specifically, the STA retraining program consists of

a. Preplanned lecture series,
b. Update lecture series,
c. Normal/abnormal procedure review, and
d. Examinations/evaluations.

The CGS Operations Training Manager has the responsibility for establishing, supervising, and scheduling the STA training program.

The STA training program has been accredited by the National Academy for Nuclear Training. Accreditation is maintained in accordance with INPO Guidelines ACAD 02-001, "The Objectives and Criteria for Accreditation of Training in the Nuclear Power Industry," and ACAD 02-002, "The Process for Accreditation of Training in the Nuclear Power Industry."

13.2.2.4 Other Plant Personnel (Maintenance, Health Physics, Chemistry)

13.2.2.4.1 Initial Training

Replacement personnel, when hired, will be given training commensurate with their job responsibilities as determined necessary by the respective Department Manager and the appropriate Training Supervisor after a review of past experience and training.

13.2.2.4.2 Continuing Training

Continuing training is conducted on a regular basis and consists of pertinent operating experience and designated requalification topics. The continuing training will be commensurate with their assigned job responsibilities as determined necessary by their respective Department Manager and Training Coordinator.

13.2.2.5 Fire Brigade

13.2.2.5.1 Initial and Continuing Training

Each assigned member of the Fire Brigade will complete initial and continuing Fire Brigade training courses to provide the knowledge and skills necessary to accomplish the expected fire fighting activities. The scope of this training will be described and implemented by plant procedures.

One assigned member will be designated as the Fire Brigade leader to direct the actual fire fighting forces. This individual will receive the training necessary to effectively carry out this function.

One assigned member will be designated as the Fire Brigade leader to direct the actual fire fighting forces. This individual will receive the training necessary to effectively carry out this function.

The Fire Brigade leader and two additional members will be knowledgeable of plant fire safe shutdown equipment.

a. Planned meetings

Regular planned meetings for each Fire Brigade member will be held each quarter to review changes in the program and other subjects, as necessary.

During these planned meetings, the initial training program content will be reviewed for all Fire Brigade members over a 2-year period.

b. Practice sessions

Practice sessions will be held for each Fire Brigade member annually on the proper methods of fighting the various types of fires that could occur in a nuclear power plant.

c. Drills

Planned drills will be conducted for practice in responding as a team to areas of the plant site where the Fire Brigade may be required to respond. Each Fire Brigade member will be required to participate in at least two drills per year. Each shift Fire Brigade will be required to participate in quarterly fire drills.

One drill for each shift Fire Brigade per year will be unannounced and one drill for each shift Fire Brigade per year will be on a back shift. The back shift and unannounced drill requirements can be satisfied concurrently for each shift.

13.2.2.5.2 Offsite Fire Department

The offsite fire department that supplements the Fire Brigade will attend familiarization training associated with the CGS plant layout, operational precautions, radiation protection, and special hazards associated with fires at a nuclear power plant. This offsite fire department will participate in at least one fire drill each year.

13.2.3 TRAINING PROGRAM EFFECTIVENESS

The effectiveness of the Training Program will be evaluated by the following methods:

a. Satisfactory job performance as determined by periodic line management evaluations and observations,

b. Satisfactory performance of plant personnel on various oral and or written examinations administered by Energy Northwest or NRC, and

c. Periodic reviews of instructors, programs, and training material as conducted by the Training Department.

13.2.4 PLANT TRAINING RECORDS

The Training Manager maintains complete qualification records on each member of the plant staff.

All records necessary to support requests for NRC reactor operator and senior reactor operator licenses are included in these files. Records to be maintained are as follows:

a. Lecture series attendance,
b. Lecture examinations and answers by the licensees,
c. Annual examinations and answers by the licensees,
d. Simulator performance evaluation results,
e. Control Manipulations Tracking System Form, and
f. Additional training for deficiencies.

13.2.5 OTHER TRAINING DOCUMENTS

For compliance with other applicable documents see Sections 1.8 and 12.5.3.8.

13.3 EMERGENCY PLANNING

The detailed emergency plan is included as a separate volume in the Columbia Generating Station Emergency Plan.

13.4 REVIEW AND AUDIT

The following sections describe the conduct of reviews and audits of operating activities that are important to safety. The review and audit program is consistent with the requirements of ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants."

Periodic reviews of plant operations are performed by the plant operating staff. In addition, Energy Northwest uses a formal onsite committee (see Section 13.4.1) and an independent group (see Section 13.4.2) for review.

The Quality staff has formulated and executed an audit program for the plant activities as defined in the Operational Quality Assurance Program Description (OQAPD).

The organization for review and audit and its relationship to other organizations is shown in Figures 13.1-1, 13.1-2, and 13.1-7.

13.4.1 ONSITE REVIEW

Onsite reviews are consistent with Regulatory Guide 1.33 (see Section 1.8). The plant operating staff provides, as part of the normal duties of plant supervisory personnel, timely and continuing monitoring of operating activities to assist the Plant General Manager in keeping abreast of general plant conditions and to verify that the day-to-day operating activities are conducted safely and in accordance with applicable administrative controls. These continuing monitoring activities are an integral part of the routine supervisory function and are important to the safety of plant operation.

13.4.2 INDEPENDENT REVIEW

In accordance with the OQAPD, the Plant Operations Committee (POC) serves as a review and advisory organization to the Plant General Manager on all matters related to nuclear safety. The Senior Site ALARA Committee (SSAC) serves as a review and advisory organization to the Plant General Manager on radiological safety matters. A specific function of the POC is to implement an independent review program as it relates to all proposed Technical Specification changes, License Amendment Requests, and Emergency Plan changes.

Written administrative procedures describe the responsibility and authority of the POC and SSAC. The POC activities and review are described in the OQAPD. The results of POC and SSAC review activities are documented.

Additionally, in accordance with the OQAPD, the Quality organization is responsible for oversight of the POC and SSAC, which entails evaluating the effectiveness of POC and SSAC reviews, collectively, with regard to nuclear and radiological safety. The Quality manager reports to and advises the Chief Executive Officer on the adequacy and implementation of Energy Northwest nuclear and radiological safety policies and programs.

Documentation defining POC membership, responsibilities, authority, and method of operation is contained in a Site Wide Procedure. Significant organizational features and review responsibilities are also described in the OQAPD. Conclusions of the independent reviews are transmitted to the appropriate members of management.

Independent technical reviews are performed by Quality in accordance with the OQAPD.

The objectivity of Quality is maintained based on a charter and reporting relationship independent of plant line management, without precluding participation in plant activities and tasks.

13.4.3 AUDIT PROGRAM

A comprehensive program of audits is carried out to verify compliance to the OQAPD. These audits are performed by or under the direct cognizance of the Quality staff. Written reports of such audits are reviewed by the POC, Plant General Manager, and other management as appropriate. Timely resolution of any deficiencies noted during audits is required by those organizations having responsibility for the area audited. Details of those areas to be audited are described in the OQAPD.

13.5 PLANT PROCEDURES

The administrative controls and quality assurance program for plant operation are carried out in accordance with approved written procedures. All activities affecting nuclear safety are conducted by written and approved procedures of a type appropriate to the circumstances, and these activities are accomplished in accordance with these procedures.

13.5.1 ADMINISTRATIVE PROCEDURES

13.5.1.1 Conformance With Regulatory Guide 1.33, Revision 2

ANSI N18.7-1976 and Regulatory Guide 1.33 including Appendix A are followed in accordance with the Energy Northwest position discussed in the Operational Quality Assurance Program Description (OQAPD).

13.5.1.2 Preparation of Procedures

The Procedure Program provides the administrative controls necessary to prepare, review, and approve the procedures required for plant operating activities.

The Chief Nuclear Officer has the overall responsibility for the Procedure Program and its implementing procedures. The Plant General Manager is responsible for the procedures that are required by ANSI N18.7-1976 and Regulatory Guide 1.33 and Appendix A. The preparation and review of the procedures are the responsibility of various plant staff personnel. All procedures are approved according to the Procedure Program and the OQAPD.

13.5.1.3 Procedures

The Procedure Program for Administrative Procedures defines the responsibility, methods used, and procedural action required to help ensure that the plant will be managed in a safe and dependable manner.

Administrative Procedures establish rules and instructions pertaining to activities such as procedure preparation, records management, plant reporting requirements, plant personnel responsibilities and authorities, plant modification, corrective and preventive maintenance, clearance orders, temporary changes to approved procedures, reviews of plant documents, surveillance testing and inservice inspection, equipment control, and material control.

Administrative Procedures governing standing orders to shift operations include the reactor operator's authority and responsibilities; the senior reactor operator's authority and responsibilities; the logbook use and control; issuance and updating of special orders; and the plans for meeting the requirements of 10 CFR 50.54(i), (j), (k), (1), and (m). This includes a diagram of the control room that illustrates the area designated as "at the controls."

13.5.2 OPERATING AND MAINTENANCE PROCEDURES

13.5.2.1 Control Room Operating Procedures

Detailed procedures used by the control room operators ensure plant safety and reliability. These procedures are categorized and described as follows:

System Operating Procedures

The System Operating Procedures provide instructions pertinent to the various normal operating modes of startup, operation, and shutdown of each system or subsystem. Checkoff lists are included, where appropriate, with each procedure to delineate the proper equipment lineup that is required.

General Operating Procedures

General Operating Procedures provide the instructions for the integrated operation of plant systems during startup, shutdown, power operations, and power changes. Checkoff lists, as appropriate, are included to ensure that necessary prerequisites to integrated operation have been completed. Checklists may also be used to confirm completion of major steps in the proper sequence.

Abnormal Condition Procedures

Abnormal Condition Procedures specify operator actions for restoring selected equipment or systems to their normal controlled status on a failure or to restore normal operating conditions following a perturbation. These procedures are not emergency procedures but are written to aid the operator in determining if a true emergency exists.

Abnormal Condition Procedures also contain response instructions for annunciator alarms and for abnormal conditions within the major systems covered in System Operating Procedures. Each safety-related annunciator is addressed in a written procedure which contains (1) meaning of annunciator, (2) the source of the signal, (3) the immediate action that is to occur automatically, (4) immediate operator actions, and (5) subsequent operator actions. Those procedures that require the Immediate Operator Action steps to be memorized are given adequate identification.

Emergency Operating Procedures/Severe Accident Guidelines

Emergency Operating Procedures/Severe Accident Guidelines are provided to guide operations during potential emergencies. These procedures specify actions, including manipulation of controls, to avoid further degradation of abnormal conditions or to reduce the consequences of an accident or hazardous condition that has already occurred.

13.5.2.2 Other Procedures

Other safety-related activities conducted in accordance with approved procedures are categorized and described as follows (radioactive waste system operating procedures are covered by System Operating Procedures and the other aspects of radioactive waste management are covered by Health Physics and Chemistry Procedures).

Fuel Handling and Refueling Activities Procedures

Fuel Handling and Refueling Activities Procedures provide instructions for fuel and core component accountability, new fuel handling, refueling operations, defective fuel handling, reactor core component handling, and irradiated fuel shipment.

Surveillance Procedures (both Operational Surveillance and Instrument and Electrical Surveillance)

Surveillance Procedures provide instructions for performing periodic tests to verify and document that safety-related structures, systems, and components continue to function properly to remain in a state of readiness to perform their intended safety functions. Surveillance Procedures cover systems operability tests, logic system functional tests, and instrument and/or electrical functional tests and calibrations for the various surveillance requirements listed in the Technical Specifications.

Operating and Test Procedures

Operating and Test Procedures provide instructions for performing special tests on both safety and non-safety-related systems and components. These procedures contain tests such as power ascension, turbine efficiency, system hydrostatic tests, and reactor steam quality.

Nuclear Performance Evaluation Procedures

The Nuclear Performance Evaluation Procedures provide instructions for Engineering and Operations in the performance of the following types of evaluations: core thermal power evaluations, core thermal-hydraulic evaluations, intermediate range monitor, local power range monitor, and average power range monitor calibration and criticality predictions.

Maintenance Programs and Procedures

Maintenance Procedures provide instructions for performance of maintenance on safety-related equipment or systems and selected non-safety-related equipment and systems. Maintenance procedures cover mechanical, electrical, instrument and control, coatings, and refueling activities.

Health Physics Procedures

Health Physics Procedures establish the administrative and technical controls for the Radiation Protection Program and the implementing procedures for accomplishing the program. Descriptions of the activities covered by these procedures are included in Chapter 12.

Chemistry Procedures

Chemistry Procedures establish the administrative and technical controls for water quality analysis. Chemical and radiochemical determination procedures and associated instrument operation and calibration procedures are provided.

Emergency Plan Implementing Procedures

Detailed procedures prescribe the appropriate course of action necessary to limit or mitigate the consequences for each classification of incidents described in the Emergency Plan. An index of the Emergency Plan Implementing Procedures is included in Appendix II to the Emergency Plan.

Security Programs Implementing Procedures

Detailed security procedures prescribe the course of action necessary for compliance with the policies of the Security Plan. The Security Plan and associated implementing procedures that contain safeguards information are withheld from public disclosure (see Section 13.6).

Fire Protection Procedures

Fire Protection Procedures provide instructions for performing tests, inspections, and scheduled maintenance on fire protection equipment and systems and actions required for degraded systems.

ODCM Implementing Procedures

The ODCM Implementing Procedures prescribe the action necessary to implement the requirements of the Offsite Dose Calculation Manual (ODCM), including effluent monitoring, instrument calibration, and reporting requirements.

Environmental Compliance Procedures

Environmental Compliance Procedures establish the administrative and technical controls for environmental compliance. These procedures provide instructions for the management of solid wastes, pollution prevention and waste minimization, chemical storage and use, and hazardous substance spills and cleanup.

13.6 INDUSTRIAL SECURITY

The Columbia Generating Station Physical Security Plan contains a description of the physical protection program for the facility as required by 10 CFR 50.54(p) and 10 CFR 73.55. The contents of this plan are safeguards information and are withheld from public disclosure pursuant to Section 2.790(a)(3) of 10 CFR Part 2.

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS

Section Page

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Section Page

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Section Page

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Section | Page

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

TABLE OF CONTENTS (Continued)

Chapter 14

INITIAL TEST PROGRAM

LIST OF TABLES

Chapter 14

INITIAL TEST PROGRAM

LIST OF FIGURES

Chapter 14

INITIAL TEST PROGRAM

14.1 SPECIFIC INFORMATION INCLUDED IN PRELIMINARY SAFETY ANALYSIS REPORTS

The initial test program overall test objectives and general prerequisites were previously provided in the Preliminary Safety Analysis Report (PSAR). The technical aspects of the initial test program are described in Section 14.2 in sufficient detail to show that the test program adequately verifies the functional requirements of plant structures, systems, and components such that the safety of the plant will not be dependent on untested structures, systems, or components.

14.2 SYSTEM LINEUP, PREOPERATIONAL, AND INITIAL STARTUP TEST PROGRAM

The italicized information is historical and was provided to support the application for an operating license.

The initial test program consisted of a series of tests categorized as system lineup testing, preoperational, and initial startup tests. The system lineup testing determines correct installation and functional operability of equipment. Preoperational tests are those tests normally conducted prior to fuel loading to demonstrate the capability of plant systems to meet performance requirements. Initial startup tests began with fuel loading and demonstrated the capability of the integrated plant to meet performance requirements.

14.2.1 SUMMARY OF TEST PROGRAM AND OBJECTIVES

14.2.1.1 Initial Test Program Objectives

The objectives of the initial test program are to

a. Ensure that the construction is complete and acceptable,

b. Demonstrate the capability of structures, components, and systems to meet performance requirements,

c. Effect fuel loading in a safe manner,

d. Demonstrate, where practical, that the plant is capable of withstanding anticipated transients and postulated accidents,

e. Evaluate and demonstrate, to the extent possible, plant operating procedures to provide assurance that the operating group is knowledgeable about the plant and procedures and fully prepared to operate the facility in a safe manner, and

f. Bring the plant to rated capacity and sustained power operation.

14.2.1.2 Initial Test Program Summaries

The three categories of tests in the initial test program are summarized below:

a. System lineup tests such as pump and valve tests, mechanical actuation to verify proper installation, and electrical continuity verifications, are those tests which demonstrate that components are correctly installed and operational.

b. Preoperational tests conducted prior to fuel loading to demonstrate that the plant systems have been properly designed and that they meet performance requirements.

c. Startup tests consist of fuel loading, precritical tests, low power tests, and power ascension tests that ensure fuel loading in a safe manner, confirm the design bases, demonstrate where practical that the plant is capable of withstanding the anticipated transients and postulated accidents, and ensure that the plant is safely brought to rated capacity and sustained power operation.

14.2.1.3 Description of System Lineup Tests

Typical system lineup tests generally include but are not limited to the following:

a. Chemical cleaning and flushing of systems, tanks, and vessels,

b. Electrical equipment to test and/or energize, e.g., grounding, relays, circuit breaker operation and controls, continuity, megger, phasing, high potential measurements, and buses,

c. Initial adjustment, bumping, and running of rotating equipment,

d. Checking control and interlock functions of instruments, relays, and control devices,

e. Calibrating instruments and checking or setting initial trip setpoints,

f. Pneumatic testing of instruments and service air system and cleanout of lines,

g. Checking and adjusting relief and safety valves,

h. Complete tests of safety-related motor-operated valves including adjusting torque switches and limit switches, checking all interlocks and controls, measuring motor current and operating speed, and checking leaktightness of stem packing and valve seat during hydrotests; and complete tests of the nuclear steam supply system (NSSS) control systems including checking all interlocks and controls, adjusting limit switches, measuring operating speed, checking leaktightness of pneumatic operators, and checking for proper operation of controllers, pilot solenoids, etc., and

i. Other tests and verifications such as structural, leaktightness, and vibration.

14.2.1.4 Description of Preoperational Tests

A listing of the preoperational tests is provided in Table 14.2-1. The general objectives of the preoperational test phase are as follows:

a. Ensure that test acceptance criteria are met,

b. Provide documentation of the performance and safety of equipment and systems,

c. Provide baseline test and operating data on equipment and systems for future reference,

d. Run-in of a system for a sufficient period so that any design, manufacturing, or installation defects can be detected and corrected,

e. Ensure that plant systems operate together on an integrated basis to the extent possible,

f. Give maximum opportunity to the permanent plant operating staff to obtain practical experience in the operation and maintenance of equipment and systems,

g. Establish safe and efficient normal, abnormal, and emergency operating procedures, to the extent possible,

h. Establish and evaluate surveillance testing procedures, and

i. Demonstrate that systems and safety equipment are operational and that it is possible to proceed to fuel loading and to the Startup Phase.

14.2.1.5 Description of Startup Tests

The Power Ascension Test Phase (PATP) begins after the Preoperational Test Phase has been completed. The Power Ascension Test Phase begins with fuel loading and extends to commercial operation. This phase is subdivided into the following four parts:

a. Open vessel testing (fuel loading and shutdown power level tests),
b. Initial heatup,
c. Power testing, and
d. Warranty demonstration.

The tests conducted during the Power Ascension Test Phase consist of major plant transients (Table 14.2-2), stability tests (Table 14.2-3), and a remainder of tests which are directed *towards demonstrating correct performance of the nuclear boiler and numerous auxiliary plant systems while at power. Certain tests may be identified with more than one class of test. Table 14.2-4 shows the complete Power Ascension Test Program. Figure 14.2-1 provides test conditions region definition.*

The general objectives of the Power Ascension Test Phase are as follows:

a. *Achieve an orderly and safe initial core loading,*

b. *Accomplish all testing and measurements necessary to determine that the approach to initial criticality and subsequent power ascension is safe and orderly,*

c. *Conduct low power physics tests sufficient to ensure that test acceptance criteria have been met,*

d. *Conduct initial heatup and hot functional testing so that hot integrated operation of all systems is shown to meet test acceptance criteria,*

e. *Conduct an orderly and safe power ascension program, with requisite physics and systems testing, to ensure that the plant operating at power meets test acceptance criteria, and*

f. *Conduct a successful warranty demonstration program.*

14.2.2 ORGANIZATION AND STAFFING

14.2.2.1 General

The Energy Northwest Test and Startup Program is administered by two entities with distinct levels of responsibility and two distinct organizations.

For the system lineup test phase and the preoperational test phase, the Test Working Group (TWG) provides review, approval, and planning of general Test and Startup Program activities and the results of those activities. The Test and Startup organization and qualified members of other organizations represented on the TWG provide the necessary development, implementation, and analysis of Test and Startup Program activities at the working level.

For the Power Ascension Test Phase, the Plant Operations Committee (POC) provides review and planning of the test program and evaluates the test results. The Plant Manager approves the procedures and final test reports. The implementation of the PATP is achieved with the normal plant operations crew operating the plant and test engineers under the direction of the Reactor Engineering Supervisor coordinating the test activities.

14.2.2.2 Definitions

The definitions of phrases used in this section and throughout this chapter are as follows:

a. *Test Working Group (TWG) - a project onsite administrative body whose membership consists of personnel representing organizations directly responsible for preparation and performance of testing and startup during the system lineup and preoperational test phases. This group provides review and approval of test preparation and performance activities.*

b. *Power Generation - an Energy Northwest organization within the Operations Directorate with responsibility for development and implementation of the Test and Startup Program.*

c. *Columbia Generating Station (CGS) Test and Startup - a Power Generation division with responsibility for development and implementation of the CGS Test and Startup Program.*

d. *CGS Plant Organization - a Power Generation division with responsibility to startup, operate, and maintain CGS in compliance with Federal, State, local, and owner requirements.*

e. *CGS Plant Operations Committee (POC) - refer to definition in Section 13.4.1. The POC reviews the activities of the Power Ascension Test Phase.*

f. *Test and Startup Manager - the Power Generation Division Manager with responsibility for implementation of the CGS Test and Startup Program.*

g. *Test and Startup Program - the program that encompasses the transition from construction to commercial operation and consists of system lineup testing, preoperational testing, and power ascension testing.*

h. *Test and Startup Program Manual - the manual that defines generic administrative policy and procedures for the initial testing and startup of Energy Northwest nuclear facilities.*

i. *Test and Startup Instructions - the specific instructions required to implement the Test and Startup Program for an individual project.*

j. *Plant Procedure Manual (PPM) - the Plant Manager approved procedures for operating the plant. The PPMs include the test procedures for the PATP.*

14.2.2.3 *Test and Startup Program Organization and the System Lineup and Preoperational Test Program*

14.2.2.3.1 *General*

Power Generation is an organization within the Energy Northwest Operations Directorate. Relative to the Program, Power Generation is responsible for development and administration of plans, policies, and administrative procedures; procurement of test equipment and other test-related resources, and assignment of the CGS Test and Startup Manager. The Power Generation organization and its relationship to other Energy Northwest organizations is shown in Figure 14.2-2.

14.2.2.3.2 *Responsibilities of CGS Test and Startup Division*

CGS Test and Startup is a Division of the Power Generation organization. The CGS Test and Startup Manager manages an organization comprised of Energy Northwest test engineers and test technicians augmented by test personnel from the architect-engineer, the NSSS supplier, and others as contractually established. The CGS Test and Startup Manager is responsible for the development and implementation of the CGS Test and Startup program and those responsibilities are described in Section 14.2.2.3.3. The CGS Test and Startup staff organization is shown in Figure 14.2-3.

14.2.2.3.3 *CGS Test and Startup Department Position Responsibilities*

14.2.2.3.3.1 CGS Test and Startup Manager.

a. *Chairman, TWG;*

b. *Develop plans, schedules, methods, procedures, and data systems for the testing and evaluation of all plant equipment and systems to permit acceptance and licensing;*

c. *Administer and coordinate the testing activities with other organizations involved in the Test and Startup Program;*

d. *Manage and direct assigned test personnel in activities relating to the attainment of Test and Startup Program objectives;*

e. *Manage and direct assigned test personnel to establish qualitative and quantitative acceptance criteria and develop test procedures to direct and guide performance of testing, and* *f.* *Provide recommendations and effect actions to eliminate equipment or system deficiencies as determined by Test and Startup Program criteria which could adversely affect performance of safety-related functions.*

14.2.2.3.3.2 CGS Test Group Manager.

a. *Represent Test and Startup on the TWG;*

b. *Coordinate the activities of Test Group Supervisors and test engineers during the Test and Startup Program;*

c. *Develop, monitor, and coordinate the preparation and implementation of plans, schedules, methods, and procedures for testing and evaluation of plant systems and components for verification of performance and acceptance;*

d. *Maintain surveillance over testing performed by Energy Northwest and others, including system and equipment tests, and calibration of instrumentation;*

e. *Identify problem areas and recommend actions where deficiencies could adversely affect the performance, safety-related functions, or operating efficiency;*

f. *Assist in preparation of program status and other Test and Startup Program related reports, and*

g. *Assume the responsibilities of the Test and Startup Manager as described in the Test and Startup Program Manual (TSPM) during his absence and all other responsibilities specifically delegated.*

14.2.2.3.3.3 CGS Test Group Supervisor. Test Group Supervisors are assigned lead technical responsibility for testing. General Test Group Supervisors' duties are as follows:

a. *Supervise the activities of assigned test engineers;*

b. *Review and, where appropriate, approve test procedures, field changes to procedures and test results, and make recommendations to the Test Group Managers or Startup Manager, as appropriate;*

c. *Set schedules and priorities for assigned Test Engineers and assist them with problem resolution;*

d. With other Test Group Supervisors and the Test Group Manager or Startup Manager, as appropriate, plan and coordinate startup activities and provide assistance;

e. Advise the Test Group Manager or Test and Startup, as appropriate, on all matters concerning testing within their group and if required, attend TWG meetings for this purpose;

f. Act for the Test Group Manager or Test and Startup Manager, as appropriate, when so delegated;

g. Prepare for and perform testing as required to support the Test and Startup Program;

h. Coordinate the identification and documentation of design problems and their resolution, and

i. Advise the Test Group Manager or Test and Startup Manager, as appropriate, regarding current and future manpower requirements impacting the testing effort.

14.2.2.3.3.4 <u>CGS Test Engineers</u>. Test engineers provide for the routine development and implementation of testing. General test engineer duties are as follows:

a. Prepare assigned test procedures,

b. Review tests and inspections prepared by others for application to assigned testing responsibilities,

c. Provide direction during performance of system and component testing, and

d. Identify problem areas and recommend actions where deficiencies could adversely affect performance of safety-related functions or operating efficiency.

14.2.2.4 <u>Plant Operations Organization and the Power Ascension Test Program</u>

The PATP will be carried out by the plant operations organization using test procedures developed and approved according to the requirements of the PPM. The PATP procedures were prepared by members of the plant technical department under the supervision of the Reactor Engineering Supervisor. Technical expertise from other Energy Northwest organizations and from the General Electric Company (GE), the NSSS vendor, was used whenever necessary. Review of these procedures and scheduling of the test activities will be carried out by the POC and approved by the Plant Manager. The Reactor Engineering

Supervisor will direct the PATP test engineers in the completion of testing according to the POC schedule.

14.2.2.5 Test Working Group

14.2.2.5.1 System Lineup and Preoperational Test Program

The purpose of the TWG, a composite of representatives from organizations directly responsible for preparation, performance, and review of Test and Startup Program activities, is to provide a means for a coordinated review of all testing concerns and ensuring all obligations to the Test and Startup Program are met by the organizations represented.

The TWG provides review and approval of all activities proposed and the results thereof as appropriate. All decisions and approvals or recommendations of the group are included in the minutes of the meetings. Matters requiring approval by the TWG includes, but are not limited to

a. System lineup procedures,
b. Preoperational test procedures,
c. Changes to test procedures, and
d. Results of testing.

14.2.2.5.2 Membership and Responsibility of the Test Working Group

The TWG membership consist of organizations that have a direct support function for conduct or development of testing.

The CGS Test and Startup Manager is Chairman of the TWG and is responsible for convening and conducting TWG meetings on the administrative and technical content of program activities.

The Test Group Manager is responsible for providing a technical review of the proposed activities, technical documents, and their results. The Test Group Manager serves as Chairman during the absence of the Test and Startup Manager.

The CGS Plant Manager is responsible for providing an operational review of test documents and for submitting safety-related documents to the POC for review and for communicating the committee's decisions to the TWG. The Plant Manager provides detailed plant operating procedures and surveillance procedures to be used for plant operation and testing during the Test and Startup Program system lineup and preoperational test phase.

The plant quality assurance representative to the TWG shall be responsible for review of proposed activities, test procedures, and test results as required by the Operational Quality Assurance Program Description (OQAPD).

The project engineering representative is responsible for obtaining a technical review of proposed activities and test documents by assigned project engineers and for providing a working relationship with Energy Northwest and architect-engineering organizations to aid resolution of testing concerns.

Conditional Members are representative of any organization having responsibility and/or expertise in the area of the TWG meeting agenda. In this situation the representative will be requested to attend the meeting by the TWG chairman.

14.2.2.6 Plant Organization Functions and Responsibilities During All Testing and Plant Operations

The plant organization has overall responsibility for the safe and efficient operation of plant systems and equipment, from provisional acceptance through commercial operation including responsibility for maintenance and operational control. Plant organization responsibilities in supporting the Test and Startup Program are discussed in Section 14.2.2.7.1.

The responsibility of the plant organization representative to the TWG is defined in Section 14.2.2.5.2.

14.2.2.7 Energy Northwest Support of the Test and Startup Program

14.2.2.7.1 Plant Organization

In addition to the responsibilities described in Section 14.2.2.6, the plant operating, technical, and maintenance sections provide manpower for development, implementation, and review of testing.

14.2.2.7.1.1 Support During Test and Startup Program Development. Assistance during the development of the Test and Startup Program is provided formally through the plant organization's TWG representative and through the POC. Input to test procedures and other testing documentation by the plant staff ensures that

a. *The operational requirements of the test procedures are based on the knowledge and experience of the operating staff,*

b. *The technical considerations receive the review of the Plant Technical Staff, and* *c. Important nuclear and operational safety considerations receive attention by the plant organization.*

14.2.2.7.1.2 <u>Support During Testing</u>. Detailed review and analysis of system lineup and preoperational test results will be performed by the plant technical section and/or plant operations section where their particular expertise is deemed necessary by the plant representative to the TWG to support approvals of completed system lineup and preoperational tests.

Detailed review and analysis of PATP test results will be carried out by the test engineers of the plant operations technical department and will receive final review through the POC and final approval by the Plant Manager.

14.2.2.7.2 CGS Program

The CGS Program Director is responsible for the performance of the organizations involved in the design, procurement, and construction of generating projects. The Program Director supports the Test and Startup Program by providing and implementing project control systems, project engineering services, and engineering support services.

The CGS Program Director supports the Test and Startup Program by maintaining a high level of current status information available to the startup program organizations to ensure that all startup program scheduling and preparation is based on an accurate assessment of the condition of systems and equipment being readied for testing. The Program Director provides liaison with Construction Management for the provision of construction craft support for the implementation of various system lineup and preoperational tests.

14.2.2.7.3 Plant Quality Assurance

The functions of the plant Quality Assurance organization during the Test and Startup Program will be to survey ongoing efforts to determine that the controls required by various regulations, guides, and standards are effectively implemented. The activities of the TWG will be monitored to ensure that the proper degrees of control for safety-related activities are being maintained and that required activities are completed when they are prerequisite to another testing activity.

14.2.2.8 <u>Architect-Engineer Support of the Test and Startup Program</u>

Burns and Roe, Inc., is responsible for providing engineering services required to ensure timely completion of construction testing and equipment turnover for provisional acceptance and system turnover. Burns and Roe also provides system-oriented engineers to assist the CGS Test and Startup Divisions, as requested by Energy Northwest technical direction and/or advice and consultation during system and component testing through preoperational testing.

14.2.2.9 General Electric Support of the Test and Startup Program

General Electric is the supplier of the boiling water reactor (BWR) NSSS for the CGS plant. General Electric is responsible for generic and specific CGS designs and for the supply of the NSSS. During the construction phase of the plant cycle, the GE Resident Site Manager is responsible for all NSSS equipment disposition. When the startup testing phase of the project begins after fuel load, the responsibility of GE-NSSS activities are assigned to the Preoperational and Startup group. The GE Preoperational and Startup staff responsibilities are outlined below.

14.2.2.9.1 Staff Responsibilities

14.2.2.9.1.1 General Electric Operations Manager. The GE Operations Manager is the senior NSSS vendor representative onsite at or near official fuel loading, and is the official site spokesman for GE for preoperational and startup testing concerns and requirements. The Operations Manager coordinates with the Startup Superintendent for the performance of his duties, which are as follows:

a. Reviewing all NSSS test procedures, including changes to test procedures, and test results as a conditional member of TWG and POC,

b. Providing technical direction to the station staff,

c. Managing the activities of the GE site personnel in providing technical direction to CGS personnel in the testing and operation of GE-supplied systems,

d. Providing liaison between the site and the GE San Jose home office to provide rapid and effective solution to problems that cannot be solved onsite,

e. Participating as a conditional member of the TWG when required, and

f. Reviewing test procedures for the POC.

14.2.2.9.1.2 General Electric Operations Superintendent. The GE Operations Superintendent is responsible to the GE Operations Manager for supervising the activities of GE Shift Superintendents. He works directly with the CGS Operations Manager in providing GE technical direction to the operating organization.

14.2.2.9.1.3 General Electric Shift Superintendents. The GE shift superintendents provide technical direction to CGS shift personnel in the testing and operation of GE-supplied systems. They provide 24-hr per day shift coverage as required beginning with fuel loading. They report to the GE Operations Superintendent.

14.2.2.9.1.4 General Electric Lead Engineer - Startup Test, Design, and Analysis. The GE lead engineer - Startup Test, Design, and Analysis, is responsible to the GE Operations Manager for supervising the GE shift engineers and for verifying core physics parameters and characteristics and documenting that performance of the NSSS and components conform to test acceptance criteria.

The lead engineer works with the CGS technical department to coordinate and effect implementation of the PATP instrumentation including special test equipment required to confirm these acceptance criteria.

14.2.2.10 Qualifications of Personnel Supporting the Test and Startup Program

The qualifications described in this section are for those persons having authority to direct testing, review and approve test documentation and results, or otherwise have direct influence on the conduct of testing and quality of acquired data. Although other personnel, specifically GE, Burns and Roe, and Energy Northwest technical specialists, are also involved in these processes, they are under the direction of individuals whose qualifications are described herein and who review and approve all Test and Startup Program activities.

14.2.2.10.1 Test and Startup Program Department Personnel Qualifications

a. *At the time of appointment to the active position, the CGS Test and Startup Manager shall have 10 years of responsible thermal power plant experience such as, but not limited to, managerial, technical, or administrative positions, of which a minimum of 3 years shall be nuclear power plant experience. A maximum of 4 years of the remaining 7 years of experience may be fulfilled by academic training on a one-to-one basis. This academic training shall be in engineering or the individual shall have acquired the experience and training normally required for examination by the NRC for a senior operator license whether or not the examination is taken.*

b. *Minimum qualifications for Test Group Manager are a B.S. degree in engineering or related field and 6 years of applicable experience, at least 3 of which are in testing or operation of nuclear power generation, propulsion, or similar scale test or production facilities. Related experience may be substituted for academic requirements when the candidate's professional background and level of achievement clearly demonstrate capabilities to fill the position. Previous preoperational testing experience is required. A good understanding of quality assurance and regulatory requirements and an ability to effectively communicate with others are necessities. A demonstrated technical leadership in his discipline and necessary work experience at the Test Group Supervisor or equivalent level is evidence of required proficiency.*

c. *Minimum qualifications for Test Group Supervisor are a B.S. degree in engineering or related field and 5 years of applicable experience, at least 2 of which are in testing or operation of nuclear power generation, propulsion, or similar scale test or production facilities. Related experience may be substituted for academic requirements when the candidate's professional background and level of achievement clearly demonstrate capabilities to fill the position. Previous preoperational testing experience is required. A good understanding of quality assurance and regulatory requirements and an ability to effectively communicate with others are necessities. A demonstrated technical leadership in his discipline and necessary work experience at the Senior Test Engineer or equivalent level is evidence of required proficiency.*

d. *Minimum qualifications for a Test Engineer directing preoperational tests are a B.S. degree in engineering or related field or a graduate of a technical or vocational school in an engineering or related field and 2 years of related experience. Related experience above the required minimum may be substituted for academic requirements when the candidate's record for performance clearly indicates the ability to fill the position without question. A good understanding of engineering principles and the ability to understand new concepts and to effectively communicate with others is a necessity.*

   Minimum requirements for a Test Engineer directing startup tests are a B.S. degree in engineering or related field and 2 years of related experience or a graduate of a technical or vocational school in an engineering or related field, and 3 years of related experience. Related experience above the required minimum may be substituted for academic requirements when the candidate's record for performance clearly indicates the ability to fill the position without question. A good understanding of engineering principles and the ability to understand new concepts and to effectively communicate with others is a necessity.

14.2.2.10.2 Plant Organization Personnel Qualifications

Qualifications of some plant personnel are discussed in Section 13.1.3.

14.2.3 TEST PROCEDURES

14.2.3.1 Development of Test Procedures

Test Procedures are developed by the CGS Test and Startup or Plant Operations Department to provide a detailed method to demonstrate the capability of the system to perform its design function under anticipated operating and accident condition.

General Electric Company as supplier of the NSSS provides test program specifications and instructions from which Energy Northwest prepares the preoperational and initial startup test procedures for systems supplied by GE.

Architect-Engineer and Vendors

Technical assistance is provided by Burns and Roe and vendor technical representatives as deemed necessary.

14.2.3.1.1 Incorporation of Plant Procedures

The following program will be implemented at CGS to utilize and qualify plant operating procedures during testing.

a. *Plant procedures required to support testing will have been prepared and approved before preoperational testing begins on the system using the best information available from the principal designer and responsible equipment suppliers.*

b. *Preoperational test procedures will use plant operating and emergency procedures as nearly as possible.*

c. *Using the results of preoperational testing, including the use-testing of plant procedures where practical, the plant procedures required to support startup testing will be updated and revised before startup testing of applicable systems. Exceptions to this program will be those approved plant procedures required to be verified during the startup phase.*

d. *Startup test procedures will be developed using the results of preoperational testing and updated plant procedures.*

14.2.3.1.2 Format of Test Procedures

14.2.3.1.2.1 Preoperational Test Phase. The minimum content requirements for CGS Preoperational test procedures are specified in the Energy Northwest TSPM. The format for CGS test procedures is specified in the CGS TSPM. The resulting format and content is the following:

a. Preoperational Test Procedure Format

1. Purpose

A concise description of the objectives of the test, including such test requirements as component functions to be checked and testing under normal or simulated conditions to verify readiness for system startup and operation, and system tests to confirm that the performance of the system is in compliance with all applicable design requirements.

2. Prerequisites

Provisions necessary for performance of the test. Conditions that should exist prior to start of the test. Instructions given to identify required operational status of the plant and interfacing systems, environmental conditions, and individual component status requirements, including verification of the following:

(a) Components and systems being tested have been turned over and open deficiencies will not affect the performance of the test,

(b) System lineup testing on components, included in the test, is complete,

(c) Necessary support systems are available, and

(d) For control system testing, the other principal control systems are in appropriate operating modes for the given test conditions.

3. Limits and Precautions

Special precautions required for safety of personnel and equipment or needed to ensure a meaningful test and satisfactory performance of testing.

4. Special Equipment

A list of special material and equipment for the performance of the test.

5. Procedure

A step by step procedure for performing the test. Plant operating procedures will be utilized whenever practicable for the operation of *systems and equipment during testing and for returning the system to normal after completion of testing. Abnormal procedures will be utilized as required to supplement normal plant operating procedures. Data collection will be part of the procedure steps.*

6. *Restoration*

   Includes those steps necessary to return the system to a normal operating or tagged status. This may include removal of special test instruments, temporary equipment, electrical jumpers, valve lineups, etc.

7. *Acceptance Criteria*

   The criteria against which the success or failure of the test will be judged must be identified. In some instances, these will be qualitative criteria, e.g., given event does or does not occur. In other cases, quantitative values can be designated as acceptance criteria.

   (a) All quantitative acceptance criteria shall include suitable tolerances, and

   (b) A readily apparent correlation should exist to cross-reference among procedure steps, data, and acceptance criteria.

8. *References*

   A listing of all material required for the preparation and performance of the test. This should include piping and instrumentation drawings, electrical elementary drawings, vendor instruction manuals, applicable FSAR sections, contract specifications, and applicable codes, standards or guides, and applicable plant procedures.

14.2.3.1.2.2 Power Ascension Test Phase. All PATP procedures will be formatted according to the PPM.

14.2.3.2 Review of Test Procedures

Each member of the TWG ensures test procedures will provide for review with respect to that member's organizational area of responsibility. Power ascension test procedures will be reviewed by the POC.

Comments submitted by TWG members will be evaluated by the TWG and the test procedure revised accordingly. After discussion of the resulting version, the decision to reject, accept, or *accept with modification, will be obtained by consensus of the membership of the TWG. In the event the TWG cannot reach a consensus, the Chairman shall provide resolution or a method for resolving the issue to the appropriate division management for review and concurrence.*

The results of the POC review of PATP will be approved by the Plant Manager.

The qualifications of the individuals or organization representatives reviewing test procedures are described in Section 14.2.2.10.

The administrative procedures governing the test procedure review process are contained in the CGS TSPM. These procedures cover the mechanism for review and comment resolution, documentation of this review, and method of indication for the review status of a test procedure.

14.2.3.3 Approval of Test Procedures

Test procedures will be approved by the TWG Chairman by means of consensus of the TWG membership after review of the test procedure as described in Section 14.2.3.2. Power ascension test procedures will be reviewed by the POC in a similar manner.

Individual test procedures will be approved by the chairman of the TWG or POC/Plant Manager, as appropriate. The consensus of the two committees were contained in the meeting minutes.

The administrative procedures governing the exercise of approval of test procedures are contained in the CGS TSPM or the PPM.

14.2.4 CONDUCT OF TEST PROGRAM

14.2.4.1 Administrative Procedures for Preoperational Testing

14.2.4.1.1 Test Performance Authorization

A significant period of time may have elapsed between the time a preoperational test procedure was approved and the time a test is performed. The test procedure is therefore reviewed just prior to initiating the test. Any changes in the system since original approval of the test procedure will be thoroughly researched and the test procedure revised and approved in accordance with Sections 14.2.3.2 and 14.2.3.3. The CGS Test and Startup Manager will then approve the test procedure for performance of the test.

14.2.4.1.2 Preoperational Test Prerequisites

Approval by the Test and Startup Manager to perform a preoperational test also requires consideration of the prerequisite testing required to qualify components and systems for operation. In general, completion of the system lineup testing (see Section 14.2.1.3) will qualify the system for preoperational testing. System lineup testing, as a prerequisite to preoperational testing, includes the following:

a. *Instrumentation and protective relay checks, including calibration, setpoint adjustments, logic verification, and line checks;*

b. *Component operability checks, including valve stroking, motor rotation, ventilation system balancing, rotating equipment run-in and pipe support inspection and adjustment;*

c. *Flushing, including proof flushes, flow instrumentation response, and pump performance and capacity checks;*

d. *Electric component and system checks, including breaker trip setpoints; and*

e. *Hydrostatic or pneumatic pressure tests and systems where dynamic testing, such as pump runs, are required to allow performance of pressure tests. Pressure integrity tests are otherwise performed during construction testing.*

Verification that required system lineup tests have been or can be successfully completed prior to preoperational testing is performed by the respective test group manager prior to recommending turnover of a system or component from a contractor to Energy Northwest. Verification that the system is actually ready for preoperational testing will be performed as described in Section 14.2.4.3.

14.2.4.1.3 Conduct of Preoperational Testing

a. *Implementation responsibilities for scheduling all tests are assigned to the CGS Test and Startup Manager. The TWG will be kept informed of the scheduled activities.*

b. *The satisfaction of prerequisites to commencement of the test, as indicated in the test procedure, will be verified by the test engineer prior to performance of the test.*

c. *The assigned test engineer is responsible for directing the performance of each test. Testing is performed in direct coordination between the test engineer and shift supervision.*

d. *All testing will be conducted in accordance with approved test procedures. If, during the performance of a test the procedure is unacceptable, the test engineer can propose changes by use of a "Test Change Notice" (see Section 14.2.4.4). This provided both documentation of the change and confirmation by the TWG.*

e. *All test data will be entered on or attached to the record copy of the test procedure.*

14.2.4.1.4 Deficiency Reporting

Deficiencies or discrepancies identified during testing will be reported individually as described in Section 14.2.5.2.

Corrective action or satisfactory disposition shall be taken on all deficiencies and discrepancies in equipment and procedures prior to final approval of the preoperational test results. All deficiencies or discrepancies identified during the test, or which have not been resolved on completion of the test, will be recorded in the record copy of the preoperational test.

14.2.4.1.5 Equipment Maintenance and Modifications During Preoperational Testing

Modifications or repair to safety-related systems will be implemented as a result of a formal system of problem and deviation reporting. Disposition of problems requiring mechanical or electrical changes or repairs by contractors will be implemented by work requests.

a. *Startup Problem Reports (SPR), Startup Deficiency Reports (SDR), and Startup Work Requests (SWR) are administered through closed-loop procedural controls to ensure resolutions. A completed SPR, SDR, and SWR is approved for closure by the respective Test Group Manager.*

b. *Startup Problem Reports are used to report design deficiencies and are coordinated by the Energy Northwest project engineering organization for resolution by the responsible design organization or qualified alternate. The SPRs are reviewed by engineering and a Project Engineering Directive (PED) is issued to define plant modifications or changes that are required. An SWR is then issued to perform the plant modification by contractor personnel or an SDR is issued to defer the work or have it performed by startup personnel.*

c. *Startup Deficiency Reports (SDR) are used to report and track non-design-related deficiencies. If required, an SWR will be issued to perform the repair work to resolve the non-design-related deficiency by contractor personnel. Work accomplished by startup personnel can be accomplished by the SDR without issuing an SWR.*

d. *Retest requirements will be identified on the SWR or SDR and attached to, or referenced by the work request number in test files.*

e. *Startup Problem Reports, SDR, SWR, design change documentation, retest results, and procurement records for safety-related systems will be filed in assembled packages or with appropriate cross-referencing for retrievability.*

14.2.4.1.6 Preoperational Test Summary

During the preoperational test, the test engineer will prepare a test report which includes a summary of the conduct of the test, evaluation of the test results with reference to the acceptance criteria, and a description of problems encountered and corrective actions taken or proposed. This report will be attached to the record copy of the test.

14.2.4.1.7 Evaluation of Preoperational Test Data

On completion of the test, a copy of the official test procedure, data, the test summary, and other applicable attachments will be transmitted to each member of the TWG responsible for review.

14.2.4.1.8 Preoperational Test Records

The Test and Startup Manager will maintain all official test records (the copy of the test procedure containing the original test data and signatures and all attachments) until completion of the test program. See Section 14.2.6 for details of the test records handling and retention program.

14.2.4.2 Administrative Procedures for Power Ascension Testing

14.2.4.2.1 Plant Operation During Power Ascension Testing

During initial startup tests and operations, the plant procedures are followed except as specifically modified by approved test procedures. In addition, special safety precautions and limitations are included in the test procedures. Approved test procedures will be used to control test conditions outside of the Technical Specifications limits where allowed for test purposes.

Certain individual tests or power escalations may require authorization by both the POC and the Plant Manager immediately prior to implementation and will be so identified in the applicable test procedure.

The final authority to start or continue a test is the responsibility of the Shift Manager after all previous approvals have been exercised. Testing is performed in direct coordination between the test engineer and Shift Manager.

14.2.4.2.2 Power Ascension Test Scheduling and Sequencing

Scheduling and sequencing of testing during startup is performed under the direction of the Plant Manager by POC.

The startup or power ascension test sequence is described in terms of individual test evolutions and specific power plateaus due to interfaces with other simultaneous tests, requirements for continuous data review, and plant administrative requirements for authorization to proceed or continue. The test sequence identifies hold points for data review and authorization to proceed and establishes the general plant conditions for each group of tests.

14.2.4.2.3 Power Ascension Test Performance

Before starting each test, the assigned shift test engineer will review the test procedure to ensure that prerequisite activities of conditions have been satisfied as described in Section 14.2.4.3.

The test will be stopped or curtailed if it cannot be performed safely or in accordance with the approved test procedure. Required test procedure deviations or changes may be effected in accordance with PPM 1.2.3, "Use of Plant Procedures," as described in Section 14.2.4.4.2.

Should apparent deviations of test results from performance requirements or acceptance criteria be revealed, or should other apparent anomalies develop, the plant will be placed in a safe condition and relevant test data will be reviewed by the test engineer and Shift Manager. If the apparent discrepancy or anomaly is substantiated, the situation will be reviewed by the POC to ascertain if a plant safety question is involved. Control of any identified nonconformance or noncompliance will be in accordance with the plant administrative procedures.

Evaluation of the effect of the discrepancy or anomaly on plant safety will be performed at the appropriate level of review, and appropriate corrective actions will be taken before resumption of the test or test conditions at which the problem was revealed.

At the completion of an entire test procedure, the test engineer will assemble all of the data and supporting information, nonconformance documentation, and test results evaluations for review by the POC. Any data reduction or analysis required will be done as soon after the data is available as is practical so that the results of the analysis may be included in the complete test package.

Test records will be maintained as described in Section 14.2.6.

14.2.4.3 Control of Test Prerequisites

Conditions and activities prerequisite to a given test will be identified in the applicable test procedure. Prior to commencement of the particular test, the test engineer will verify that the identified prerequisites have been satisfied. The verifications will be recorded and retained as part of the test record.

The test engineer will verify that

a. *The test procedure has been approved by the appropriate committee and Plant Manager, Test and Startup Manager, or Startup Superintendent as required. The test procedure is compatible with the latest versions of material referenced in the test procedure;*

b. *The record copy of the test procedure is identical to that contained in the master file or PPM, including the latest TWG/POC approved revisions or test procedure field changes (see Section 14.2.4.4);*

c. *Prerequisite tests have been completed. If TWG and/or Plant Manager approval of a completed test is also a prerequisite, that approval will have been obtained;*

d. *The test procedure has been made available for shift operator review and familiarization. Operator support has been scheduled, as necessary;*

e. *Test equipment is available or in place as required. Calibration or other readiness requirements have been completed. System instrumentation to be used in the test has been calibrated within the required time period established for surveillance testing and/or preventative maintenance; and*

f. *Test and operating personnel involved in the performance of the test have been briefed immediately prior to starting the test.*

14.2.4.4 Modification of Test Procedures During Testing

14.2.4.4.1 System Lineup and Preoperational Test Phase

The TSPM provides a means of controlling modifications to TWG-approved test procedures during testing. This administrative procedure, contained in the CGS TSPM, applies to changes made to an approved test procedure during preoperational and startup testing. The procedure does not apply to revisions made during the preparation of test procedures.

The procedure provides control of revisions which change the intent or the acceptance criteria of the test procedure.

The required changes, when identified by the responsible test engineer, are described on a special form (Test Change Notice/Procedure Deviation Form) which identifies the affected test procedure or plant procedure, justifies the change, and contains spaces for the appropriate approvals. The Test Change Notice forms became a permanent part of the test record.

A Test Change Notice for a preoperational test is reviewed by the TWG and approved by the Test and Startup Manger, TWG Chairman.

14.2.4.4.2 Power Ascension Test Phase

All test procedure details or changes must be made in accordance with PPM 1.2.3, "Use of Plant Procedures." This process requires documentation on the required forms, signatures of authorized individuals, and subsequent full POC review. The PPM 1.2.3 forms became a permanent part of the test record.

14.2.5 REVIEW, EVALUATION, AND APPROVAL OF TEST RESULTS

14.2.5.1 Control of Test Results Review

The individuals responsible for reviewing the results of particular tests will be designated by the POC or the Test and Startup Manager. These reviews will be obtained through TWG or POC members in accordance with their represented areas of responsibility. TWG members will provide names of individuals in their represented organizations who meet the requirements of Regulatory Guide 1.58, Revision 0, for evaluation of inspection and test results.

Based on the recommendations of the qualified reviewers, the completed preoperational test will be approved by the TWG. Plant Operating Committee review and Plant Manager approval of power ascension test results is required.

14.2.5.2 Design Organization Participation in Problem Resolution

Failures of tests to meet acceptance criteria and other problems discovered in the course of testing will be documented as deficiencies in accordance with the requirements of the TSPM for System Lineup and Preoperational Tests and in accordance with PPM 1.3.12, "Plant Nonconformances," for the power ascension tests. Reports of such deficiencies will indicate the parties or organizations deemed responsible for providing an acceptable resolution of the deficiency. The responsible organization will be requested to provide a resolution of the defined problem.

Documentation of the final resolution will include the recommendation of the responsible organization and a description of the measures implemented in accordance with that recommendation. Design problems will require resolution by the appropriate Energy Northwest Technical Division Department, Project Engineering, Plant Technical Staff, or original design organization, depending on the technical nature of the problem.

14.2.5.3 Results Analysis Prerequisites to Continuation of Startup Testing

The POC will establish prerequisites for various tests, test conditions, and test phases in consideration of system or component qualification for subsequent testing. The control or prerequisites to an individual test will be as described in Section 14.2.4.3.

The POC will also require an evaluation of the data acquired during a particular test phase or plateau. The items considered in this evaluation will include, but are not limited to the following:

a. *The need for additional testing or retesting to improve assurance that a particular system or component will perform as required in subsequent testing, especially under more demanding conditions such as higher power levels,*

b. *The need for analysis of certain data to qualify measured variables or parameters for use in subsequent measurements,*

c. *The completeness of testing up to the point in question as evidenced by the documentation of the completed tests, and*

d. *The need for specific reviews and approvals of particular sets of data to satisfy the above.*

14.2.6 TEST RECORDS

14.2.6.1 System Lineup and Preoperational Test Phase

14.2.6.1.1 General

The TSPM contains a generic procedure regarding filing and recordkeeping to be applied to testing documentation. This procedure is intended to ensure compliance of Energy Northwest project startup programs with the applicable provisions of ANS N45.2.9-1974, "Requirements for Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records," as required by Regulatory Guide 1.88, Revision 1, December 1975.

The following sections describe the provisions of the aforementioned procedure, which will be contained in specific detail in the CGS Test and Startup Instructions.

14.2.6.1.2 Test Record Responsibilities

The Test and Startup Manager is responsible for identifying the responsibilities, controls, and requirements for establishing and implementing a Test and Startup Program filing and recordkeeping system, in accordance with 10 CFR 50 Appendix B, ANSI N45.2.9, and the Energy Northwest Quality Assurance Program Manual. The Test and Startup Manager will ensure that adequate procedures are prepared and maintained within the Test and Startup Instructions. The Test and Startup Manager will ensure that trained and qualified personnel maintain the Test and Startup Program files.

14.2.6.1.3 Types of Documents and Records Requiring Test Record File Retention

Documentation and records that will be maintained within Test and Startup Program files are:

a. *Test and Startup program records as specified by ANSI N45.2.9, and*

b. *All records and documents as specified by the Test and Startup Program and instruction manuals.*

Other records, documents, correspondence, etc., may be maintained at the discretion and approval of the Startup Program Manager, provided their access requirements do not compromise the security of the mandatory files.

14.2.6.2 <u>Power Ascension Test Phase</u>

All test records and data shall be kept and filed in accordance with the PPM 1.6 series of procedures which detail the requirements for all plant recordkeeping.

14.2.7 CONFORMANCE OF TEST PROGRAMS WITH REGULATORY GUIDES

14.2.7.1 <u>Conformance with Regulatory Guide 1.68</u>

The CGS Test and Startup Program conforms to the requirements of Regulatory Guide 1.68, Revision 0, "Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors," except where specifically noted otherwise. The Regulatory Guide has been reviewed by Energy Northwest for applicability of individual items in the guide to CGS and its systems. The applicability to this plant has determined the nature and scope of testing to be performed. Actual exceptions to the testing required by this guide have been specifically addressed and are discussed in Section 14.2.7.2. Areas where the guide does not apply are not considered to be exceptions.

14.2.7.2 Exceptions to Regulatory Guide 1.68

The exceptions to Regulatory Guide 1.68 are listed below with an explanation of the justification for the exception.

a. Exception to Format of Test Procedures

The format of the test procedures is different from that found in Appendix C of Regulatory Guide 1.68, but the format difference is not considered an exception to the regulatory guide since the guide specifies required elements of a test procedure while merely implying but not requiring a format.

b. See Section 1.8.2 for a delineation of specific exceptions to the requirements of Regulatory Guide 1.68.

14.2.7.3 Conformance With or Exceptions to Regulatory Guides Other Than 1.68

a. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants" will be complied with for the section that pertains to the Test and Startup Program,

b. Regulatory Guide 1.33, "Quality Assurance Program Requirements" will be complied with in "Quality Assurance During the Operations Phase," Section 17.2, of the FSAR for the Test and Startup Program,

c. All other regulatory guides pertaining to individual testing will be complied with unless noted otherwise in Section 14.2.12, and

d. Regulatory Guide 1.58 "Qualifications of Nuclear Power Plant Inspection, Examination, and Testing Personnel." Energy Northwest Test and Startup personnel involved in testing meet the requirements of Regulatory Guide 1.58.

14.2.8 UTILIZATION OF REACTOR OPERATING AND TESTING EXPERIENCES IN THE DEVELOPMENT OF THE TEST PROGRAM

As a matter of Energy Northwest policy, a continuous program of review of reactor operating experience is coordinated by the Operations Division of Energy Northwest. The sources of information reviewed in compliance with this policy are NRC Information Notices and Bulletins, operating experience reports, preoperational test summaries and startup reports from other plants, administrative and test procedures from other plants' startup programs, personal contacts with other nuclear plant licensees or applicants, and additional information supplied by Energy Northwest Technical and Operations Division members. All available sources are *utilized; relevance to particular Energy Northwest nuclear projects is determined in the review process.*

The information is reviewed by CGS Startup Program personnel for applicability to the CGS Test and Startup Program, for incorporation into test procedures, or for consideration in the administrative control of testing.

14.2.9 TRIAL USE OF PLANT OPERATING AND EMERGENCY PROCEDURES

To the extent practical throughout the preoperational and initial PATP, test procedures utilize operating, emergency, and abnormal procedures where applicable in the performance of tests. The use of these procedures is intended to do the following:

- *a. Prove the specific procedure or illustrate changes which may be required,*
- *b. Provide training of plant personnel in the use of these procedures, and*
- *c. Increase the level of knowledge of plant personnel on the systems being tested.*

Test procedures may use operating, emergency, and abnormal procedures in several ways: the test procedure may reference the procedure directly; the test procedure may extract a series of steps from the procedure; the test procedure may use a combination of the first two methods; or the test procedure may require system and plant conditions that will be obtained by the use of plant operating or emergency procedures.

14.2.10 INITIAL FUEL LOADING AND INITIAL CRITICALITY

14.2.10.1 Fuel Loading and Shutdown Power Level Tests

Fuel loading and initial criticality is conducted in accordance with written procedures after all prerequisite tests are satisfactorily completed and an operating license has been issued. Prior to approving fuel loading, the plant must be verified as ready to load fuel. This verification is accomplished by the following steps, which are performed at the completion of a majority of the preoperational testing.

14.2.10.1.1 Loss of Power Demonstration-Standby Core Cooling Required

This test demonstrates the capability of each emergency diesel generator to start automatically and assumes all of its emergency core cooling loads in a loss of normal auxiliary power.

14.2.10.1.2 Cold Functional Testing

The cold functional testing defined here is an integrated system operation of various plant systems that can be operated as systems prior to fuel loading. The intent is to observe any unexpected operational problems from either an equipment or a procedural source and to *provide an opportunity for operator familiarizations with the system-operating procedures under operating conditions.*

Some of the cold functional testing will be accomplished during the preoperational test program. For example, integrated and simultaneous operation of the following systems may take place during the flush of the total system: condensate system, condensate demineralizer system, low-pressure coolant injection (LPCI) system, core spray system, reactor water cleanup (RWCU) system, service water system, closed cooling water (RCC) system, and others. As required, additional integrated systems performance will be demonstrated prior to fuel loading.

14.2.10.1.3 Routine Surveillance Testing

Because of the interval between completion of a preoperational test on a system and the requirement for that system to be operated may be of considerable length, a number of routine surveillance tests must be performed prior to fuel loading and must be repeated on a routine basis. The Technical Specifications described the test frequency. In general, this Surveillance Test Program (specified in the Technical Specifications) is instituted prior to fuel loading by the plant operating staff.

14.2.10.1.4 Master Startup Checklist

A detailed list of items that must be complete, including the preoperational tests, work requests, design changes, and proper dispositioning of all exceptions noted during preoperational testing listed in Table 14.2-1 is rechecked to verify completion just prior to the final approvals for fuel loading and at each significant new step such as heat up, opening main steam isolation valves (MSIVs), and power operation.

14.2.10.1.5 Initial Fuel Loading

Fuel loading requires the movement of the full core complement of assemblies from the fuel pool to the core, with each assembly identified by number before being placed in the correct coordinate position. The procedure controlling this movement is arranged so that shutdown margin and subcritical checks are made at predetermined intervals throughout the loading, thus ensuring safe loading increments. Specially sensitive invessel neutron monitors that are maintained at the loading face as loading progresses serve to provide indication for the shutdown margin measurements, and also to allow the recording of the core flux level as each assembly is added. A complete check is made of the fully loaded core to ascertain that all assemblies are properly installed, correctly oriented, and are occupying their designated positions.

14.2.10.1.6 Zero Power Level Tests

At this point in the program, a number of tests are conducted which are best described as initial zero power level tests. Chemical and radiochemical tests are made to check the quality of the reactor water before fuel is loaded, and to establish base and background levels required to facilitate later analysis and instrument calibrations. Plant and site radiation surveys are made at specific locations for later comparison with the values obtained at the subsequent operating power levels. Shutdown margin checks are repeated for the fully loaded core, and criticality is achieved with each of the two prescribed rod sequences in turn, the data being recorded for each rod withdrawn. Each rod drive is subjected to scram and performance testing. The initial setting of the intermediate range monitors (IRMs) is at maximum gain.

14.2.10.2 Initial Heatup to Rated Temperature and Pressure

Heatup follows the satisfactory completion of the fuel loading and zero power level tests (Sections 14.2.10.1.5 and 14.2.10.1.6) and further checks are made of coolant chemistry together with radiation surveys at the selected plant locations. All control rod drives (CRDs) are scram-timed at rated temperature and pressure, with selected drives timed at two intermediate reactor pressures and for different accumulator pressures. The process computer checkout continues as more process variables become available for input. The reactor core isolation cooling (RCIC) system will complete controlled starts at low reactor pressure and at rated conditions, with testing in the quick-start mode at 150 psig and 1000 psig. Correlations are obtained between reactor vessel temperatures at several locations and the values of other process variables as heatup continues. The movements of NSSS piping in the drywell mainly as a function of expansion are recorded for comparison with design data.

14.2.10.3 Power Testing From 25% to 100% of Rated Output

The power test phase comprises the following tests, many of which are repeated several times at the different test levels; consequently, see Table 14.2-4 for the series. While a certain basic order of testing is maintained relative to power ascension, there is, nevertheless, considerable flexibility in the test sequence at a particular power level which may be used whenever it becomes operationally expedient. In no instance, however, is nuclear safety compromised.

a. *Coolant chemistry tests and radiation surveys are made at each principal test level to preserve a safe and efficient power increase,*

b. *Selected CRDs are scram-timed at various power levels to provide a correlation with the initial data,*

c. *The effect of control rod movement on other parameters (e.g., electrical output, steam flow, and neutron flux level) is examined for different power conditions,*

d. *Following the first reasonable, accurate heat balance (25% power) the average power range monitors (APRMs) are calibrated and IRMs are reset if necessary,*

e. *At each major power level (25%, 60%, and 100%), the local power range monitors (LPRMs) are calibrated,*

f. *The APRMs are calibrated initially at each new power level and following LPRM calibration,*

g. *Completion of the process computer checkout is made for all variables, and the various options are compared with hand calculations as soon as significant power levels are available,*

h. *Further tests of the RCIC are made with and without injection into the reactor pressure vessel (RPV),*

i. *Collection of data from the system expansion tests is completed for those piping systems which had not previously reached full operating temperatures,*

j. *The axial and radial power profiles are explored fully by means of the traversing in-core probe (TIP) system at representative power levels during the power ascension, and*

k. *Core performance evaluations are made at all test points above the 10% power level and for selected flow transient conditions; the work involves the determination of core thermal power, maximum fuel rod surface heat flux, and minimum critical power ratio (MCPR), and other thermal parameters.*

l. *Overall plant stability in relation to minor perturbations is shown by the following group of tests which are made at selected test points:*

1. *Core power-void mode response,*
2. *Pressure regulator setpoint change,*
3. *Water level setpoint change,*
4. *Turbine valve surveillance, and*
5. *Recirculation flow setpoint change.*

For the first of these tests, a centrally located control rod is moved and the flux response is noted on a selected LPRM chamber. The next two tests require that the changes made should approximate as closely as possible a step change in demand, while for the next test the turbine stop, control, and bypass valves are opened to verify stability and power level for surveillance testing. The remaining test is performed to properly adjust the control loop of the *recirculation system. For all of these tests the plant performance is monitored by recording the transient behavior of numerous process variables, the one of principal interest being neutron flux. Other imposed transients are produced by step changes in demand core flow, partial loss of feedwater heating, and simulating failure of the operating pressure regulator to permit takeover by the backup regulator. Table 14.2-3 shows the power and flow levels at which all these stability tests are performed.*

m. *The category of major plant transients includes full closure of all the MSIVs, fast closure of turbine generator control valves, fast closure of turbine generator stop valves, loss of the main generator and offsite power, tripping a feedwater pump, and several trips of the recirculation pumps. The plant transient behavior is recorded for each test and the results may be compared with the acceptance criteria and the predicted design performance. Table 14.2-2 shows the operating test condition for all the proposed major transients;*

n. *A test is made of the relief valves in which leaktightness and general operability are demonstrated;*

o. *At some major power levels the jet pump flow instrumentation is calibrated;*

p. *The as-built characteristics of the recirculation system are investigated as soon as operating conditions permit full core flow; and*

q. *The local control loop performance, based on the drive pump, jet pumps, and control equipment is checked.*

14.2.11 TEST PROGRAM SCHEDULE

The test program schedule for preoperational and startup tests are indicated in Table 14.2-4 and Figure 14.2-4. These schedules are preliminary and will be adjusted to consider actual construction and testing progress; they are included to provide general information but are not considered to be identical to the schedules in use during the startup program. The test procedures will be made available for review at least 30 days prior to the test date or fuel load.

14.2.12 INDIVIDUAL TEST DESCRIPTIONS

14.2.12.1 Preoperational Test Procedures

The following general descriptions are the specific objectives of each preoperational test. During the final construction phase, it may be necessary to modify the preoperational test methods as operating and preoperational test procedures are developed. Consequently, methods described in the following descriptions are general, not specific.

Specific acceptance criteria for each preoperational test are in accordance with the detailed system and equipment specifications for equipment in those systems. The tests demonstrate that the installed equipment and systems perform within the limits of these specifications.

In addition to the prerequisites listed on each on the following preoperational tests, there will be electrical power available to each of the systems.

Table 14.2-1 lists the preoperational tests anticipated for this facility.

14.2.12.1.1 Reactor Feedwater System Preoperational Test

a. *Purpose*

   To verify the operation of the reactor feedwater system, including pumps, valves, turbines, turbine auxiliaries, and turbine control systems.

b. *Prerequisites*

   The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The condensate system, control air system, and service water system must have a readiness verification.

c. *General Test Methods and Acceptance Criteria*

   The performance of the reactor feedwater system is verified within the limitations of the auxiliary steam supply by the demonstration of the proper operation of the following:

   1. *Valves and related controls, interlocks, and position indicators,*
   2. *Reactor feedwater pumps, turbines, and auxiliaries,*
   3. *Control logic, and*
   4. *Annuciators and protective devices.*

14.2.12.1.2 Condensate System Preoperational Test

a. *Purpose*

   To verify the operation of the condensate system, including pumps, valves, and control systems.

b. <u>Prerequisites</u>

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The condenser, condensate filter demineralizers, feedwater, and control air systems are capable of supporting this test as necessary.

c. <u>General Test Methods and Acceptance Criteria</u>

The performance of the condensate system is verified by the demonstration of the proper operation of the following:

1. *Valves and related controls, interlocks, and positions indicators,*
2. *Condensate pumps, condensate booster pumps and auxiliaries,*
3. *Control logic, and*
4. *Annuciators and protective devices.*

14.2.12.1.3 Fire Protection System Preoperational Test

a. <u>Purpose</u>

To verify the operation of the fire protection system including the diesel engine, pumps, valves, detection and alarm circuits, and control and instrumentation circuits. To verify the location and status of all portable equipment.

b. <u>Prerequisites</u>

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The circulating water system, control and service air system, and electrical distribution system are available to support operation.

c. <u>General Test Methods and Acceptance Criteria</u>

Verification of the fire protection system capability is demonstrated by the proper integrated operation of the following:

1. *Diesel engine and pump operation and related control and logic,*
2. *Fire alarm and detection circuits,*
3. *Fire control panel in the main control room,*
4. *Deluge, wet pipe and preaction sprinkler systems, and*
5. *Carbon dioxide and Halon systems.*

In addition, portable equipment and hose station capability will be verified.

14.2.12.1.4 Reactor Water Cleanup System Preoperational Test

a. Purpose

To verify the operation of the RWCU system, including pumps, valves, and filter/demineralizer equipment.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Filter aid, and anion and cation resin should be available. The RCC system and instrument air system must have readiness verification.

c. General Test Methods and Acceptance Criteria

Verification of the RWCU system capability is demonstrated by the proper integrated operation of the following:

1. *Drain flow regulator flow interlocks,*
2. *System isolation and logic,*
3. *Valve-operating sequence,*
4. *Pump operation and related control and logic,*
5. *Annuciators, and*
6. *Filter/demineralizer system operation.*

14.2.12.1.5 Standby Liquid Control System Preoperational Test

a. Purpose

To verify the operation of the standby liquid control (SLC) system including pumps, tanks, control, logic, and instrumentation.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Valves should be previously bench tested and other precautions relative to positive displacement pumps taken. The reactor vessel should be available for injecting demineralized water.

c. *General Test Methods and Acceptance Criteria*

Verification of the SLC system capability is demonstrated by the proper integrated operations of the following:

1. *SLC system tank level instrumentation,*
2. *Heaters,*
3. *Alarms and logic,*
4. *Relief valves,*
5. *Pumps and related controls and logic, and*
6. *Flow testing with different flow paths.*

14.2.12.1.6 Nuclear Boiler System Preoperational Test

a. *Purpose*

To verify proper operation of the nuclear boiler system including safety/relief valves (SRVs) and related controls and logic.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Verify that all SRVs have been previously bench tested.

c. *General Test Methods and Acceptance Criteria*

Functional and capacity tests of SRVs are not performed; verification of the NSSS capability is demonstrated by the proper integrated operation of the following:

1. *System valves and related sensors and logic,*
2. *Vacuum breaker in relief valve discharge lines,*
3. *Automatic isolation function of reactor water sample isolation valves,*
4. *Isolation and leak detection systems,*
5. *Automatic depressurization system logic,*
6. *Reactor vessel actuators accumulator capacity test,*
7. *Safety/relief valves air piston operation,*
8. *Reactor head seal leak detection, and*
9. *Alarms and annunciators.*

14.2.12.1.7 Residual Heat Removal System Preoperational Test

a. *Purpose*

To verify the operation of the residual heat removal (RHR) system under its various modes of operation: LPCI, shutdown cooling and vessel head spray, containment spray, and suppression pool water cooling.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The RHR service water system must have readiness verification. The reactor vessel and recirculation loops shall be intact and capable of receiving water.

c. *General Test Methods and Acceptance Criteria*

Verification of the RHR system capability is demonstrated by the proper integrated operation of the following:

1. *System isolation valve control and logic tests,*

2. *RHR and RHR service water pump and motor operation, controls, and related logic features,*

3. *Automatic LPCI initiation logic,*

4. *Verification of all flow paths. The time from initiation signal to full flow should be verified, and*

5. *Alarms and annunciators.*

14.2.12.1.8 Reactor Core Isolation Cooling System Preoperational Test

a. *Purpose*

To verify the operation of the RCIC system including turbine, pump, valves, instrumentation, and control.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The turbine, disconnected from the pump, shall be tested. The turbine instruction manual shall be reviewed in detail in order that precautions relative to turbine operation are followed. Then the system shall be tested within the capability of a temporary steam supply with the pump coupled to the turbine.

c. General Test Methods and Acceptance Criteria

1. *All valves and related controls, interlocks, and indicators,*
2. *Manual and automatic initiation,*
3. *Automatic isolation, including leak detection system logic,*
4. *Turbine speed control, trip, mode selection, and test mode,*
5. *Barometric condenser condensate pump, and vacuum pump controls,*
6. *Flow path verification, and*
7. *Annunciators.*

14.2.12.1.9 Reactor Recirculation System and Control Preoperational Test

a. Purpose

To verify the operation of the reactor recirculation system including pumps and their associated motors, valves, instrumentation, and controls. The rated conditions tests will be conducted during the startup testing program.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The RCC system must receive readiness verification. All required testing of equipment up to the operation of the recirculation pump has been completed, including recirculation pump motor (uncoupled) and all control loops.

c. General Test Methods and Acceptance Criteria

After prerequisite testing, verification of system capability is demonstrated by the proper integrated operation of the following:

1. *System valves,*

2. Logic and interlocks,
3. Recirculation pumps, valves, and related controls and interlocks,
4. Annunciators, and
5. Low frequency motor generator (LFMG) set.

14.2.12.1.10 Reactor Manual Control System Preoperational Test

a. Purpose

To verify the operation of the reactor manual control (RMC) system, including relays, control circuitry, switches and indicating lights, and control valves.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The CRD pump will not be operational during this test.

c. General Test Methods and Acceptance Criteria

Verification of RMC system capability is demonstrated by the proper integrated operation of the following:

1. Rod blocks, alarms, and interlocks for all modes of the reactor mode switch,

2. Rod position information system,

3. Rod drift alarm circuit, and

4. Rod directional control valve time sequence for insert and withdraw commands.

14.2.12.1.11 Control Rod Drive Hydraulic System Preoperational Test

a. Purpose

To verify the operation of the CRD hydraulic system including CRD mechanisms, hydraulic control units, hydraulic power supply, instrumentation, and controls.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The CRD manual control system preoperational test must be completed on associated CRDs. The RCC system and instrument air system must receive readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of CRD system capability is demonstrated by the proper integrated operation of the following:

1. *Logic and interlocks,*
2. *CRD pumps and related controls and interlocks,*
3. *Flow controller, pressure control valves, and stabilizer valves,*
4. *Scram discharge level switches and CRD position indication, alarms, and interlocks,*
5. *CRDs functional testing including latching and position indication,*
6. *Scram testing of control rods at atmospheric pressure, and*
7. *Annunciators.*

14.2.12.1.12 Fuel Handling and Vessel Servicing Equipment Preoperational Test

a. *Purpose*

To verify the operation of the fuel handling and vessel servicing equipment including tools used in the servicing of control rods, fuel assemblies, LPRMs and dry tubes, and vacuum cleaning equipment.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the refueling platform, fuel preparation machine, and fuel racks must be installed and operational; all slings and lifting devices must be certified at their design load, at least by the vendor.

c. General Test Methods and Acceptance Criteria

Verification of the fuel handling and vessel servicing equipment is demonstrated by dry operation of the following equipment:

1. *Cell disassembly tools,*

2. *Channel replacement tools,*

3. *Instrument handling tools,*

4. *Vacuum cleaning equipment,*

5. *Interlocks and logic associated with the refueling and service platform are verified, and*

6. *Proper operation of refueling and service platforms are verified.*

14.2.12.1.13 Low-Pressure Core Spray System Preoperational Test

a. Purpose

To verify the operation of the low-pressure core spray system (LPCS), including spray pumps, sparger ring, spray nozzles, controls, valves, and instrumentation.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The reactor vessel must be available and ready to receive water.

c. General Test Methods and Acceptance Criteria

Verification of the LPCS system capability is demonstrated by the proper integrated operation of the following:

1. *Logic and interlocks,*

2. *Low-pressure core spray system pumps, including auto initiation,*

3. *Flow path verification, including determination of system hydraulic performance to verify proper sizing of restricting orifice in LPCS discharge line to vessel (see Section 6.3.2.2.3),*

4. *Annunciators,*

5. *The time for initiation signal to full flow should be verified, and*

6. *Photographs to prove acceptability of core spray patterns.*

14.2.12.1.14 High-Pressure Core Spray System Preoperational Test

a. Purpose

To verify the operation of the high-pressure core spray (HPCS) system, including diesel generator and related auxiliary equipment, pumps, valves, instrumentation, and control.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The HPCS diesel generator must be installed and be operational.

c. General Test Methods and Acceptance Criteria

Verification of HPCS system capability is demonstrated by the proper integrated operation of the following:

1. *Valve controls and interlocks,*

2. *HPCS electrical system tests, including dc and ac,*

3. *HPCS diesel generator functional tests including starting, rated load, load rejection,*

4. *Pump and motor tests with normal power supply and with diesel generator,*

5. *HPCS flow path and flow rate verification,*

6. *Annunciators,*

7. *The time from initiation signal to full flow should be verified, and*

8. *Photographs to prove acceptability of HPCS spray pattern.*

14.2.12.1.15 Fuel Pool Cooling and Cleanup System Preoperational Test

a. *Purpose*

To verify the operation of the fuel pool cooling and cleanup system including the pumps, heat exchangers, controls, valves, and instrumentation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The instrument air, service air, fuel pool emergency makeup, service water, and RHR systems must be available.

c. *General Test Methods and Acceptance Criteria*

Verification of the fuel pool system capability is demonstrated by the integrated operation of the following:

1. *Logic and interlocks,*
2. *Interconnection to RHR system,*
3. *Pump operation and related controls,*
4. *Cleanup subsystem operation, and*
5. *Annunciators.*

14.2.12.1.16 Leak Detection System Preoperational Test

a. *Purpose*

To summarize the test requirements and verify the leak detection test data for each of the nuclear systems.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The prerequisites are included in the preoperational test specifications for each of the nuclear systems listed below.

c. *General Test Methods and Acceptance Criteria*

As an integral part of each of the following system preoperational tests, the nuclear systems leak detection is verified by the proper operation of the leak detection features of the following nuclear systems:

1. *Feedwater control system,*
2. *RWCU system,*
3. *NSSS,*
4. *RHR system,*
5. *RCIC system,*
6. *Recirculation system, and*
7. *Radwaste system.*

14.2.12.1.17 Liquid and Solid Radwaste System Preoperational Test

a. *Purpose*

To verify that the radioactive waste system will perform its design functions of processing liquid and solid radioactive wastes.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. *General Test Methods and Acceptance Criteria*

Testing will demonstrate that the pumps, tanks, controls, and valves including automatic isolation, diversion and protection features, and instrumentation and alarms will operate and function in accordance with design requirements.

Testing will also verify that the CGS Process Control Program results in an acceptable waste form as required by 10 CFR 61. Simulated waste will be verified to form a free-standing monolithic solid with no free liquid prior to implementation of the solidification process on radioactive waste. Liners containing solidified waste will be inspected prior to shipment to the disposal site to verify compliance with 10 CFR 61 requirements.

14.2.12.1.18 Reactor Protection System Preoperational Test

a. Purpose

To verify the proper operation of the reactor protection system (RPS), including sensor logic and their respective scram relays, scram reset time delay, the annunciators, and motor generator set power supply.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. General Test Methods and Acceptance Criteria

Verification of the RPS capability is demonstrated by the proper integrated operation of the following:

1. *Motor generator set performance,*

2. *Sensor logic and scram relay logic,*

3. *Scram reset time delay,*

4. *Sensors input-to-scram trip actuator response time on all channels of each function for which response times are required by the Technical Specifications,*

5. *Annunciators,*

6. *Mode switch tests, and*

7. *Auxiliary sensor operation.*

The ability of the system to scram the reactor within a specified time must be demonstrated in the CRD hydraulic system preoperational test (see Section 14.2.12.1.11).

14.2.12.1.19 Neutron Monitoring System Preoperational Test

a. Purpose

To verify the operation of the neutron monitoring system (NMS) including startup, intermediate, and power range detectors, and their related equipment.

b. Prerequisites

The system lineup tests have been complete, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, all source range monitors (SRMs) and pulse preamplifiers, IRMs and voltage preamplifiers, and APRMs will have been calibrated according to the vendor's instructions.

c. General Test Methods and Acceptance Criteria

Verification of the NMS capability is demonstrated by the proper integrated operation of the following:

1. *All SRM detectors, and their respective insert and retract mechanisms, and cables;*
2. *SRM channel including pulse preamp, remote meter and record, trip logic, logic bypass and related lamps and annunciators, control system interlocks, refueling instrument trips, and power supply;*
3. *All IRM detectors and their respective insert and retract mechanisms and cables;*
4. *IRM channels including voltage preamps, remote recorders, RMC system interlocks, RPS trips, annunciators and lamps, and power supplies;*
5. *All LPRM detectors and their respective cables, and power supplies;*
6. *All APRM channels including trips, trip bypasses, annunciators and lamps, remote recorders, RMC system interlocks, RPS trips, and power supplies;*
7. *Recirculation flow bias signal including flow unit, flow transmitters, and related annunciators, interlocks, and power supplies, and*

8. *Both rod block monitor (RBM) channels including trips, trip bypasses, annunciators and lamps, remote recorders, RMC system interlocks, and power supplies.*

14.2.12.1.20 Traversing In-Core Probe System Preoperational Test

a. *Purpose*

To verify the operation of the traversing in-core probe (TIP) system including the TIP detector, controls and interlocks, containment secure lamp, and containment isolation circuits.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. (Additionally, the TIP detector and dummy detector, ball valve time delay, core top and bottom limits, clutch, x-y recorder, and purge system will have been shown to be operational.)

c. *General Test Methods and Acceptance Criteria*

With the exception of the shear valve, which is not tested, verification of the TIP system is demonstrated by the proper integrated operation of the following:

1. *Indexer cross-calibration interlock,*

2. *Shear valve control monitor lamp, and*

3. *Drive motor manual control and override, automatic control and stop, and low speed control.*

14.2.12.1.21 Rod Worth Minimizer System Preoperational Test

a. *Purpose*

To verify the operation of the rod worth minimizer (RWM) system under its various modes of operation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the *initiation of testing. Additionally, the rod position indication system (RPIS) will have been shown to be operational, rod sequence control (RSC) system bypassed, and computer diagnostic and special tests completed.*

c. General Test Methods and Acceptance Criteria

Verification of the RWM system is demonstrated by the proper integrated operation of the following:

1. *Rod test option,*
2. *System initialization both above and below the low power setpoints, and above and below the low power alarm points,*
3. *RWM program,*
4. *Rod withdrawal and insertion error block, and*
5. *Rod drift scan, and annunciation.*

The RWM program acceptance of an operator-supplied rod position value must be demonstrated.

14.2.12.1.22 Process Radiation Monitoring System Preoperational Test

a. Purpose

To verify the operation of the process radiation monitoring (PRM) system, including the offgas vent, offgas, main steam line, liquid process, and building ventilation radiation monitoring subsystems.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the process radiation monitors, pulse preamplifiers, power supplies, indicator and trip units, are calibrated. Insulation resistance and high potentiometer tests will have been completed.

c. *General Test Methods and Acceptance Criteria*

Verification of the PRM system is demonstrated by the proper integrated operation of the following:

1. *Vent preamps, channels, trip points, annunciators and lamps, sample rack, and check source,*
2. *Offgas vial sampler, log radiation monitor (LRM) and their related annunciators, lamps and recorders, and high/low flow detector,*
3. *Main steam and LRM channels, trip points, and annunciators and lamps, High-High and Inop trip, and recorders,*
4. *Liquid process preamps, channels, trip points, and annunciators and lamps, and recorders,*
5. *Building ventilation system sensors, channels, trip points, and annunciators and lamps, recorders, and SGTS interlock, and*
6. *Control center air monitoring sensors, channels, annunciators, and indicators.*

14.2.12.1.23 Area Radiation Monitoring System Preoperational Test

a. *Purpose*

To verify the operation of the area radiation monitoring (ARM) system, including channels, trip points, alarms, and recorder.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, indicator, trip units, and power supplies are calibrated.

c. *General Test Methods and Acceptance Criteria*

Verification of the ARM system capability is demonstrated by the proper integrated operation of the following:

1. *Monitor channels,*
2. *Channel trip points,*
3. *Alarm annunciators and lights, and*
4. *Recorder.*

14.2.12.1.24 Process Computer Interface System Preoperational Test

a. *Purpose*

To verify the operation of the process computer interface (PCI) system including computer inputs and printout.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, computer diagnostic checks and programming are completed.

c. *General Test Methods and Acceptance Criteria*

Verification of the PCI system is demonstrated by the proper integrated operation of the following:

1. *Analog input signals,*
2. *Computer printout,*
3. *Digital input signals, and*
4. *Digital output signals.*

14.2.12.1.25 Rod Sequence Control System Preoperational Test

a. *Purpose*

To verify the operation of the RSC system under its various modes of operation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the self-test feature of the RSC system is verified.

c. *General Test Methods and Acceptance Criteria*

Verification of the RSC system is demonstrated by the proper integrated operation of the following:

1. *Low power setpoint and low power alarm point tests,*
2. *RSC system status displays and annunciators,*
3. *Reactor mode switch test,*
4. *System diagnostic and data quality tests,*
5. *Rod position data tests,*
6. *Single rod bypass provision,*
7. *Rod sequences tests,*
8. *Rod group assignment,*
9. *Constraints of rod movement tests,*
10. *100% to 75% control rod density tests,*
11. *5% to 50% control rod density tests, and*
12. *0% control rod density to low power setpoint tests.*

14.2.12.1.26 Remote Shutdown Preoperational Test

a. *Purpose*

To verify the feasibility and operability of the shutdown functions from the remote shutdown panel and its ability to bring the reactor to a cold condition in an orderly fashion.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, the control power should be supplied to the remote shutdown panel, and the independence of power supply voltage, and fuses should be verified.

c. General Test Methods and Acceptance Criteria

Verification of the remote shutdown system is demonstrated by the proper integrated operation of the following tests:

1. *Operation of valves, controls, instruments, and pumps on systems available from this panel, and*

2. *Transfer switch operation from the control room panels to the remote shutdown panel.*

14.2.12.1.27 Offgas System Preoperational Test

a. Purpose

To verify the operation of the offgas system including valves, recombiner, condensers, coolers, filters, and hydrogen analyzers.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager (Assistant Plant Manager) has approved the initiation of testing. Additionally, the instrument air system, electrical power, and cooling water should be operational.

c. General Test Methods and Acceptance Criteria

Verification of the offgas system is demonstrated by the following tests:

1. *Valve operation including fail safe and isolation features and valve status lights indicate the correct valve position,*

2. *Pump operation,*

3. *Level and temperature control and indication,*

4. *Recombiner and preheater tests,*

5. *Condenser, cooler, and moisture separator tests,*

6. *Gas dryer and cooler tests,*

7. *Filter efficiency,*

8. Hydrogen analyzer performance test, and

9. Purge and bleed air rate test.

14.2.12.1.28 Environs Radiation Monitoring Preoperational Test

a. Purpose

To verify the operation of the environs radiation monitoring system, including dosimeters, sampling pump, and filter equipment.

b. Prerequisites

System lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Additionally, indicator power supplies are calibrated according to the vendor's instruction manual.

c. General Test Methods and Acceptance Criteria

Verification of the environs radiation monitoring system capability is demonstrated by the proper operation of the following:

1. Air sample equipment, and
2. Thermoluminescent detector (TLD) (passive dosimeters).

14.2.12.1.29 Main Steam System Preoperational Test

a. Purpose

To verify the proper operation of the MSIVs and related controls.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. General Test Methods and Acceptance Criteria

Verification of the main steam system is demonstrated by the proper integrated operation of the following:

1. *Automatic isolation of the MSIVs,*

2. *Minimum closing times are met,*

3. *MSIV accumulator capacity tests are satisfactory, and*

4. *Valves, heaters, blowers, and initiating logic of the MSIV leakage control system.*

14.2.12.1.30 Radwaste Building Heating, Ventilating, and Air Conditioning System Preoperational Test

a. Purpose

To verify that the radwaste building heating, ventilating, and air conditioning (HVAC) system will function in accordance with the design requirements as set forth in the design specifications.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power system, control air supply service air system, and the turbine service water system is capable of supporting this test as necessary.

c. General Test Methods and Acceptance Criteria

Verification of the radwaste building HVAC system is demonstrated by the proper integrated operation of the following:

1. *Ventilation fans and their related controls,*
2. *Filters and instrumentation,*
3. *Dampers and controls, and*
4. *Annunciators and protective devices.*

14.2.12.1.31 Closed Cooling Water System Preoperational Test

a. *Purpose*

To verify the operation of the RCC system including pumps, valves, logic, and annunciator.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems must have received readiness verifications:

1. *Control and service air (CAS/SA),*
2. *Makeup water treatment,*
3. *Essential 480-V ac power, and*
4. *Instrumentation power.*

c. *General Test Methods and Acceptance Criteria*

Verification of the RCC system is demonstrated by the proper integrated operation of the following:

1. *Surge tank level control,*
2. *System pumps and control logic,*
3. *Chemical addition pump and control, and*
4. *Remote-operated valves.*

14.2.12.1.32 Primary Containment Atmospheric Control System Preoperational Test (SYSTEM DEACTIVATED)

a. *Purpose*

To verify the operation of the primary containment atmospheric control (CAC) system including blowers, coolers, valves, instruments, and alarms.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Primary containment, essential 480-V ac power, standby *service water (SW), instrument power, and control air systems must have received readiness verification.*

c. *General Test Methods and Acceptance Criteria*

Verification of the primary CAC system is demonstrated by the proper integrated operation of the following:

1. *Isolation and control valves,*
2. *Blowers,*
3. *Instrumentation,*
4. *Alarms, and*
5. *Recombiner components to the extent that flow paths are verified.*

Primary CAC system hydrogen/oxygen recombining performance capabilities are not demonstrated during the preoperational test.

14.2.12.1.33 Primary Containment Cooling System Preoperational Test

a. *Purpose*

To verify the operation of the primary containment cooling system including fans, dampers, related controls, and instrumentation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power, instrument power, and RCC systems must have received readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the primary containment cooling system is demonstrated by the proper integrated operation of the following:

1. *Fans and control logic,*
2. *Cooling coils,*
3. *Dampers, cooling water flow control valves and related controls,*
4. *Instrumentation,*
5. *Related loss-of-power logic, and*
6. *Annunciators.*

Primary containment cooling system heat removal capabilities are not demonstrated during the preoperational test.

14.2.12.1.34 Primary Containment Instrument Air Preoperational Test

a. Purpose

To verify proper operation of the containment instrument air (CIA) system, including compressors, dryers, valves, and related controls and logic.

b. Prerequisites

The system lineup tests have been completed, and the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The plant service water supply system must receive a readiness classification.

c. General Test Methods and Acceptance Criteria

Verification of the CIA system capability is demonstrated by the proper integrated operation of the following:

1. *Logic and interlocks,*
2. *CIA system air compressors,*
3. *CIA system air dryers,*
4. *System nonreturn check valves,*
5. *Alarms and controls,*
6. *Nitrogen backup supply, and*
7. *Valve/component failure modes for those valves/components supplied by the CIA system to simulated loss of air supply.*

14.2.12.1.35 Primary Containment Atmospheric Monitoring System Preoperational Test

a. Purpose

To verify the capability of the primary containment atmospheric monitoring system to monitor and display containment atmospheric conditions.

b. <u>Prerequisites</u>

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Instrument power is available to system components.

c. <u>General Test Methods and Acceptance Criteria</u>

Verification of the primary containment atmospheric monitoring system capability is demonstrated by the proper integrated operation of the following:

1. *Samples and controls,*
2. *Analyzers,*
3. *Pressure and temperature instrumentation,*
4. *Radiation monitors,*
5. *Indicating/recording instrumentation, and*
6. *Annunciators.*

14.2.12.1.36 Standby Gas Treatment System Preoperational Test

a. <u>Purpose</u>

To verify the reliable operation of the standby gas treatment system (SGTS), including fans, filter trains, and related controls.

b. <u>Prerequisites</u>

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following systems must have readiness verification:

1. *Essential 480-V ac power,*
2. *Instrument power,*
3. *Control air, and*
4. *Reactor building heating and ventilation.*

c. <u>General Test Methods and Acceptance Criteria</u>

Verification of the SGTS is demonstrated by the proper integrated operation of the following:

1. *SGTS fans and control logic,*

2. *Filter trains and related instruments,*

3. *Automatic valves and control logic,*

4. *System interconnections to reactor building heating and ventilation and primary containment atmospheric control system, and*

5. *Annunciators.*

14.2.12.1.37 Loss of Power and Safety Testing Preoperational Test

a. Purpose

To verify the operation of the 230/115-kV, 6.9-kV, 4.16-kV, and 480-V distribution systems.

To verify the integrated ability of the plant electrical distribution and safety systems to operate on normal and standby power sources during accident conditions.

To verify that loss of a single ac or dc distribution system division (exclusive of the HPCS diesel generator and batteries) will not prevent the remaining systems from actuating during an accident condition.

b. Prerequisites

The system lineup tests and the 69/N (N = number of diesels) consecutive starts from the emergency diesel generators have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 125-V dc system and the emergency core cooling systems (ECCS) are available to support testing.

c. General Test Methods and Acceptance Criteria

Verification of the 230/115-kV, 6.9-kV, 4.16-kV, and 480-V distribution systems operability shall be demonstrated by the following:

1. *Demonstration of circuit integrity and integrated operation of circuit breakers, controls and interlocks, instrumentation, automatic transfer features, and protective devices and alarms.*

2. *Demonstration of proper system response to a loss of the 230-kV and 115-kV distribution systems independently and simultaneously both with and without loss-of-coolant accident (LOCA)/containment isolation signals.*

3. *Demonstration of proper system response to a loss of the 230/115-kV distribution systems and one individual standby diesel generator during an ECCS/containment isolation actuation.*

   Signals for these tests shall be simulated from the actual initiating devices when this is practical.

4. *Testing of the diesel generators will include the following:*

   (a) *Sequential loading of each diesel generator unit,*

   (b) *Maintenance of specified frequency and voltage during the loading sequence,*

   (c) *Capability to reject and restart their largest single load any time after the design loading sequence is complete, and*

   (d) *Capability to supply power to vital equipment during loss of station normal power conditions.*

5. *Electrical independence will be verified during testing by*

   (a) *Verifying that operation of the division/equipment being tested and the nonactuation of deenergized buses/equipment does not affect the proper operation of the remaining buses/equipment.*

   (b) *Monitoring of the major distribution buses to ensure absence of voltage.*

   Main power transformers supplying power from the offsite system cannot be full load tested; they are tested according to this procedure to the design emergency load. All other in-plant power sources are load tested in their individual preoperational tests.

14.2.12.1.38 Instrument Power Preoperational Test

a. *Purpose*

To verify the operation of the instrument power systems.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

The 125-V dc and the 480-V ac power systems are energized and capable of supplying power to the instrument power systems.

c. *General Test Methods and Acceptance Criteria*

Verification of the instrument power systems shall be accomplished by demonstrating circuit integrity and integrated operation of

1. *Static inverters, transformers, and buses,*
2. *Controls and interlocks,*
3. *Transfer features,*
4. *Instrumentation, and*
5. *Protective devices and alarms.*

14.2.12.1.39 Emergency Lighting System Preoperational Test

a. *Purpose*

To verify the operation of the emergency lighting system within the design requirements of the system.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 125-V dc system has received a readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the emergency lighting system is to demonstrate proper automatic operation of the system and to provide sufficient lighting during loss of normal lighting.

14.2.12.1.40 Standby Alternating Current Power System Preoperational Test

a. *Purpose*

To verify the operation of the standby ac power system including diesel engines, auxiliaries, generators, controls, and instrumentation.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

The following support systems or components must have received readiness verification:

1. *Standby service water,*
2. *125/250-V dc power,*
3. *Instrument power, and*
4. *Essential 4160-V ac power.*

c. *General Test Methods and Acceptance Criteria*

Verification of the standby ac power system is demonstrated by the proper integrated operation of the following:

1. *The diesel engines and auxiliaries,*
2. *The generators, exciters, and voltage regulators,*
3. *Fuel storage and supply system,*
4. *Start and control logic circuitry and interlocks,*
5. *Protective devices,*
6. *Instrumentation, and*
7. *Annunciators.*

Testing will be performed to demonstrate the following design features.

1. The diesel generator's performance capability to establish frequency, voltage, and load acceptance with a specified time interval on initiation of an automatic start signal under both cold and hot conditions.

2. Specified full- and over-load performance capabilities.

3. The diesel generator's capability to reject the maximum rated load without exceeding speeds or voltage which will cause tripping.

14.2.12.1.41 250-V Direct Current Power System Preoperational Test

a. Purpose

To verify the operation of the 250-V dc power system including batteries, chargers, controls, interlocks, instruments, and protective devices.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Battery room ventilation and 480-V ac power supply to the chargers have received readiness verification.

c. General Test Methods and Acceptance Criteria

Verification of the 250-V dc power system is demonstrated by the proper integrated operation of the following:

1. Battery chargers including capability to recharge the battery in accordance with Section 8.3.2.1.4.3,

2. Batteries (including charge and discharge rate/capacity tests and load profiles described in Table 8.3-14),

3. Protective relays and devices,

4. System control logic,

5. Instrumentation (including ground detection),

6. Breakers, and

7. Annunciators.

14.2.12.1.42 125-V Direct Current Power System Preoperational Test

a. *Purpose*

To verify the operation of the 125-V dc power system including batteries, chargers, controls, interlocks, instruments, and protective devices.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Battery room ventilation and 480-V ac power supply to the chargers have received readiness verification.

c. *General Test Methods and Acceptance Criteria*

Verification of the 125-V dc power system is demonstrated by the proper integrated operation of the following:

1. *Battery chargers including capability to recharge the battery in accordance with Section 8.3.2.1.1.3,*
2. *Batteries (including charge and discharge rate/capacity tests and load profiles described in Tables 8.3-11 and 8.3-12),*
3. *Protective relays and devices,*
4. *System control logic,*
5. *Instrumentation (including ground detection),*
6. *Breakers, and*
7. *Annunciators.*

14.2.12.1.43 24-V Direct Current Power System Preoperational Test

a. *Purpose*

To verify the operation of the 24-V dc power system.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. General Test Methods and Acceptance Criteria

Verification of the 24-V dc power system shall include demonstrations of battery capacity and battery charger capabilities described in Section 8.3.2.1.3.3.

14.2.12.1.44 Plant Service Water System Preoperational Test

a. Purpose

To demonstrate the proper operation of the plant service water system, including pumps, valves, and related controls.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

The following support systems or components must have received readiness verification:

1. *4160-V ac power,*
2. *480-V ac power,*
3. *Instrument power,*
4. *Service water pump house structure,*
5. *Various heat exchangers or coolers utilizing service water, and*
6. *Tower makeup (TMU).*

c. General Test Methods and Acceptance Criteria

Verification of the plant service water system is demonstrated by the proper operation and performance of the service water pumps, the operation of filters, remote-operated valves, related controls, and instrumentation.

14.2.12.1.45 Standby Service Water System Preoperational Test

a. Purpose

To verify the proper operation of the SW system for normal and abnormal plant operating modes.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems or components must have received readiness verification:

1. *Essential 4160-V ac power,*
2. *Instrument power,*
3. *Control air,*
4. *Standby service water pump house structure,*
5. *Various heat exchangers or coolers utilizing SW, and*
6. *Tower makeup (TMU).*

c. General Test Methods and Acceptance Criteria

Verification of this system is demonstrated by the proper integrated operation and performance of the following:

1. *Pumps and related controls,*

2. *Remote-operated valves and controls,*

3. *Automatic-operated valves and control logic,*

4. *Instrumentation,*

5. *Annunciators,*

6. *Standby service water system control logic response to a simulated loss of normal station power event,*

7. *Pumps net positive suction head (NPSH) adequate and no vortexing,*

8. *Proper operation of basin siphon cross connection, and*

9. *The preoperational test program includes tests to confirm the performance characteristics of the spray ponds (see Section 9.2.5).*

14.2.12.1.46 Plant Communications System Preoperational Test

a. *Purpose*

To demonstrate that the plant communications and evacuation alarm system will provide effective communication between various plant locations and to verify proper operation of the emergency evacuation alarm components and system.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. *General Test Methods and Acceptance Criteria*

Proper operation of all the communication system components and the emergency evacuation alarm system and components will be demonstrated.

14.2.12.1.47 Reactor Building Emergency Cooling System Preoperational Test

a. *Purpose*

To demonstrate the proper integrated operation of the reactor building emergency equipment cooling system including fans, cooling coils, instrumentation, and controls.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems or components must have received readiness verification:

1. *Electrical power to motors, control circuits, and instrumentation, and*
2. *Standby service water system.*

c. *General Test Methods and Acceptance Criteria*

Verification of this system is demonstrated by the proper integrated operation of the fan coil units, their associated controls, interlocks, and annunciators.

14.2.12.1.48 *Control, Cable, and Critical Switchgear Rooms Heating, Ventilating, and Air Conditioning System Preoperational Test*

a. *Purpose*

To verify that the control, cable, and critical switchgear rooms HVAC systems will function in accordance with the design requirements as set forth in the design specifications.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following support systems have received readiness verification:

1. *480-V ac power,*
2. *Instrument power, and*
3. *Chilled water.*

c. *General Test Methods and Acceptance Criteria*

Verification of the control, cable, and critical switchgear rooms HVAC system is demonstrated by the proper integrated operation of the following:

1. *Supply and exhaust fans and their related controls,*
2. *Filters, dampers, valves, and related instrumentation and control logic,*
3. *Coolers, and*
4. *Annunciators.*

14.2.12.1.49 *Standby Service Water Pump House Heating and Ventilating System Preoperational Test*

a. *Purpose*

To verify that the SW pump house heating and ventilating system will function in accordance with the design requirements as set forth in the design specifications.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power system must have received readiness verification.

c. General Test Methods and Acceptance Criteria

Verification of the SW pump house heating and ventilating system is demonstrated by the proper integrated operation of the following:

1. *Ventilation fans and their related controls,*
2. *Filters and instrumentation,*
3. *Dampers and controls, and*
4. *Annunciators.*

14.2.12.1.50 Reactor Building Crane Preoperational Test

a. Purpose

To verify the operation of the reactor building crane.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. Construction load tests of 125% static and 100% operational are complete.

Contractor use of the reactor building crane for construction purposes is complete.

c. General Test Methods and Acceptance Criteria

Verification of the reactor building crane is demonstrated by the proper integrated operation of the following:

1. *Crane traverse components,*
2. *Hook traverse and hoist components,*
3. *Controls and indicators,*

4. *Safety devices, and*
5. *Instrumentation.*

14.2.12.1.51 Primary Containment Integrated Leak Rate Preoperational Test

a. *Purpose*

To verify overall primary containment integrity by pressurizing to specified test pressures and conducting integrated leak rate measurements.

b. *Prerequisites*

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following supporting activities, systems, or components must have been completed or received readiness verification:

1. *All type B and C local leak testing completed, documented, and verified as a system lineup test; see Section 6.2.6.1,*

2. *All containment isolation valves fully operable and closed in the normal manner,*

3. *All containment-associated piping hangers, supports, restraints, and anchors have been installed and properly set,*

4. *Residual heat removal and core spray systems preoperational tests complete, and*

5. *A containment area survey completed to locate, isolate, or remove any instrumentation, light bulbs, etc., which may be damaged by high external pressure.*

c. *General Test Methods and Acceptance Criteria*

Verification of primary containment integrity is demonstrated by pressurizing to the required test pressure. See Section 6.2.6.1 for a detailed test description.

The drywell-wetwell leakage test will be performed as part of this test to verify the acceptance criteria described in Section 3.8.3.7.

14.2.12.1.52 Secondary Containment Integrated Leak Rate Preoperational Test

a. Purpose

To verify overall secondary containment integrity by subjecting the reactor building to a specified negative pressure and measuring the inleakage.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The following supporting activities or systems/components must have been completed or received readiness verification:

1. *Reactor building structure complete with personnel and vehicle air lock (railroad bay) doors installed and operable,*

2. *Reactor building conduit, pipe, and other structural penetrations sealed, and*

3. *Standby gas treatment system.*

c. General Test Methods and Acceptance Criteria

Verification of secondary containment integrity is demonstrated by operating the SGTS at a specific capacity while maintaining the reactor building internal structure at a specified negative pressure.

14.2.12.1.53 Diesel Generator Building Heating and Ventilating System Preoperational Test

a. Purpose

To verify that the diesel generator building heating and ventilating system will function in accordance with the design requirements as set forth in the design specifications.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing. The 480-V ac power system must have received readiness verification.

c. General Test Methods and Acceptance Criteria

Verification of the diesel generator building heating and ventilating system is demonstrated by the proper integrated operation of the following:

1. *Ventilation fans and their related controls,*
2. *Filters and instrumentation,*
3. *Dampers and controls, and*
4. *Annunciators.*

14.2.12.1.54 Seismic Monitoring System Preoperational Test

a. Purpose

To verify the operation of the seismic monitoring system.

b. Prerequisites

The system lineup tests have been completed, the TWG has reviewed and approved the procedure, and the Test and Startup Manager has approved the initiation of testing.

c. General Test Methods and Acceptance Criteria

Verification of the seismic monitoring system is demonstrated by the proper integrated operation of the following:

1. *Annunciators, and*
2. *Instrumentation.*

14.2.12.2 General Discussion of Startup Tests

All those tests comprising the startup test phase (Table 14.2-4) are discussed in this section. For each test a description is provided for test purpose, test prerequisites, test description, and statement of test acceptance criteria, where applicable.

In describing the purpose of a test, an attempt is made to identify those operating and safety-oriented characteristics of the plant which are being explored.

Where applicable, a definition of the relevant acceptance criteria for the test is given and is designated either Level 1 or Level 2. A Level 1 criterion normally relates to the value of a process variable assigned in the design of the plant, components, systems, or associated *equipment. If a Level 1 criterion is not satisfied, the plant will be placed in a suitable hold-condition until resolution is obtained. Tests compatible with this hold-condition may be continued. Following resolution, applicable tests must be repeated to verify that the requirements of the Level 1 criterion are now satisfied.*

A Level 2 criterion is associated with expectations relating to the performance of systems. If a Level 2 criterion is not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical techniques used for the predictions would be started.

For transients involving oscillatory response, the criteria are specified in terms of decay ratio (defined as the ratio of successive maximum amplitudes of the same polarity). The decay ratio must be less than unity to meet a Level 1 criterion and less than 0.25 to meet a Level 2 criterion.

14.2.12.3 Startup Test Procedures

14.2.12.3.1 Test Number 1 - Chemical and Radiochemical

14.2.12.3.1.1 Purpose. The principal objectives of this test are to (a) secure information on the chemistry and radiochemistry of the reactor coolant, and (b) determine that the sampling equipment, procedures, and analytic techniques are adequate to supply the data required to demonstrate that the chemistry of all parts of the entire reactor system meet specifications and process requirements.

Specific objectives of the test program include evaluation of fuel performance, evaluations of demineralizer operations by direct and indirect methods, measurements of filter performance, confirmation of condenser integrity, demonstration of proper steam separator-dryer operation, measurement and calibration of the offgas system, and calibration of certain process instrumentation. Data for these purposes is secured from a variety of sources: plant operating records, regular routine coolant analysis, radiochemical measurements of specific nuclides, and special chemical tests.

14.2.12.3.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.1.3 Description. Prior to fuel loading a complete set of chemical and radiochemical samples will be taken to ensure that all required sample stations are functioning properly and to determine initial concentrations. Subsequent to fuel loading during reactor heatup and at each major power level change, samples will be taken and measurements will be made to determine the chemical and radiochemical quality of reactor water and reactor *feedwater, amount of radiolytic gas in the steam, gaseous activities leaving the air ejectors, decay times in the offgas lines and performance of filters and demineralizers.*

Calibrations will be made of monitors in the stack, liquid waste system, and liquid process lines.

14.2.12.3.1.4 Criteria.

Level 1

Chemical factors defined in the Technical Specifications and Fuel Warranty must be maintained within the limits specified.

The activity of gaseous liquid effluents must conform to license limitations.

Water quality must be known at all times and should remain within the guidelines of the Water Quality Specifications.

Level 2

Not applicable.

14.2.12.3.2 Test Number 2 - Radiation Measurements

14.2.12.3.2.1 Purpose. The purposes of this test are to (a) determine the background radiation levels in the plant environs prior to operation for base data on activity buildup, and (b) monitor radiation at selected power levels to ensure the protection of personnel during plant operation.

14.2.12.3.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.2.3 Description. A survey of natural background radiation throughout the plant site will be made prior to fuel loading. Subsequent to fuel loading, during reactor heatup and at nominal power levels of 25%, 60%, and 100% of rated power, gamma dose rate measurements and where appropriate, neutron dose rate measurements will be made at significant locations throughout the plant. All potentially high radiation areas will be surveyed.

14.2.12.3.2.4 Criteria.

Level 1

The radiation doses of plant origin and the occupancy times of personnel in radiation zones shall be controlled consistent with the guidelines of the Standards for Protection Against Radiation outlined in 10 CFR 20 and the NRC General Design Criteria in 10 CFR 50, Appendix A.

Level 2

Not applicable.

14.2.12.3.3 Test Number 3 - Fuel Loading

14.2.12.3.3.1 Purpose. The purpose of this test is to load fuel safely and efficiently to the full core size.

14.2.12.3.3.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Also the following prerequisites will be met prior to commencing fuel loading to ensure that this operation is performed in a safe manner:

- *a. The status of all systems required for fuel loading will be specified and will be in the status required;*
- *b. Fuel and control rod inspections will be complete. Control rods will be installed and tested;*
- *c. At least three movable neutron detectors will be calibrated and operable. At lease three neutron detectors will be connected to the high flux scram trips. They will be located so as to provide acceptable signals during fuel loading;*
- *d. Nuclear instruments will be source checked with a neutron source prior to loading or resumption if sufficient delays are incurred;*
- *e. The status of secondary containment will be specified and established;*
- *f. Reactor vessel status will be specified relative to internal component placement and this placement established to make the vessel ready to receive fuel;*
- *g. Reactor vessel water level will be established and minimum level prescribed;*

h. The standby liquid control system will be operable and in readiness;

i. Fuel handling equipment will have been checked and dry runs completed;

j. The status of protection systems, interlocks, mode switches, alarms, and radiation protection equipment will be prescribed and verified. The high flux trip points will be set for a relatively low power level;

k. Water quality must meet required specifications; and

l. A neutron source will be installed near the center of the core.

14.2.12.3.3.3 Description. Prior to fuel loading, control rods and neutron sources and detectors will be installed and tested. Fuel loading will begin at the center of the core and will proceed radially to the fully loaded configuration.

Control rod functional tests, subcriticality checks, and shutdown margin demonstrations will be performed periodically during the loading.

14.2.12.3.3.4 Criteria.

Level 1

The partially loaded core must be subcritical by at least 0.38% $\Delta k/k$ with the analytically strongest rod fully withdrawn.

Level 2

Not applicable.

14.2.12.3.4 Test Number 4 - Full Core Shutdown Margin

14.2.12.3.4.1 Purpose. The purpose of this test is to demonstrate that the reactor will be subcritical throughout the first fuel cycle with any single control rod fully withdrawn.

14.2.12.3.4.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Also the following prerequisites will be complete prior to performing the full core shutdown margin test:

a. The predicted critical rod position is available,

b. The standby liquid control system is available, *c.* *Nuclear instrumentation is available with neutron count rate of at least 0.5 counts per sec and signal to noise ratio greater than two, and*

d. *High-flux scram trips are set conservatively low.*

14.2.12.3.4.3 Description. This test will be performed in the fully loaded core in the xenon-free condition. The shutdown margin test will be performed by withdrawing the control rods from the all-rods-in configuration until criticality is reached. If the highest worth rod will not be withdrawn in sequence, other rods may be withdrawn providing that the reactivity worth is equivalent. The difference between the measure K_{eff} *and the calculated* K_{eff} *for the in sequence critical will be applied to the calculated value to obtain the true shutdown margin.*

14.2.12.3.4.4 Criteria.

Level 1

The shutdown margin of the fully loaded, cold (68°F or 20°C), xenon-free core occurring at the most reactive time during the cycle must be at least 0.38% $\Delta k/k$ *with the analytically strongest rod (or its reactivity equivalent) withdrawn. If the shutdown margin is measured at some time during the cycle other than the most active time, compliance with the above criterion is shown by demonstrating that the shutdown margin is 0.38%* $\Delta k/k$ *plus an exposure dependent correction factor which corrects the shutdown margin at that time to the minimum shutdown margin.*

Level 2

Criticality should occur within ±1% $\Delta k/k$ *of the predicted critical (predicted critical to be determined later).*

14.2.12.3.5 Test Number 5 - Control Rod Drive System

14.2.12.3.5.1 Purpose. The purposes of the CRD system test are to (a) demonstrate that the CRD system operates properly over the full range of primary coolant temperatures and pressures from ambient to operating, and (b) determine the initial operating characteristics of the entire CRD system.

14.2.12.3.5.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. The RMC system preoperational testing must be completed on CRDs being tested. The reactor vessel, RCC system, condensate supply system, and instrument air system must be operational to the extent required to conduct the test.

14.2.12.3.5.3 Description. The CRD tests performed during the startup test program are designed as an extension of the tests performed during the preoperational CRD system tests. Thus, after it is verified that all CRDs operate properly when installed, they are tested periodically during heatup to ensure that there is not significant binding caused by thermal expansion of the core components.

		Test Conditions Reactor Pressure with Core Loaded psig (kg/cm^2)			
Action	Accumulator Pressure	0	600 (42.2)	800 (56.2)	Rated
Position indication		All			
Normal stroke times insert/withdraw		All			4*
Coupling		All**			4*
Friction		All			4*
Scram	Normal	All	4*	4*	All
Scram	Minimum	4*			
Scram	Zero				4*
Scram	Normal				4***

NOTE: Single CRD scrams should be performed with the charging valve closed. (Do not ride the charging pump head.)

---

* *Refers to four CRDs selected for continuous monitoring based on slow normal accumulator pressure scram times, or unusual operating characteristics, at zero reactor pressure or rated reactor pressure when this data is available. The "four selected CRDs" must be compatible with the RWM, RSC system, and CRD sequence requirements.*

** *Established initially that this check is normal operating procedures.*

*** *Scram times of the four slowest CRDs (based on scram data at rated pressure will be determined at test condition 2, 3, and 6 during planned reactor scram).*

14.2.12.3.5.4 Criteria.

Level 1

a. *Each CRD must have a normal withdraw speed less than or equal to 3.6 in./sec (9.14 cm/sec), indicated by a full 12-ft stroke in greater than or equal to 40 sec.*

b. *The mean scram time of all operable CRDs with functioning accumulators must not exceed the following times (scram time is measured from the time the pilot scram valve solenoids are deenergized):*

Position Inserted From Fully Withdrawn	*Scram Time (sec)*
45	0.430
39	0.868
25	1.936
05	3.497

c. *The mean scram time of the three fastest CRDs in a two-by-two array must not exceed the following times (scram time is measured from the time the pilot scram valve solenoids are deenergized):*

Position Inserted From Fully Withdrawn	*Scram Time (sec)*
45	0.455
39	0.920
25	2.052
05	3.706

Level 2

a. *Each CRD must have normal insert or withdraw speed of 3.0 ± 0.6 in./sec (7.62 ± 1.52 cm/sec), indicated by a full 12-ft stroke in 40 to 60 sec.*

b. *With respect to the CRD friction tests, if the differential pressure variation exceeds 15 psid (1.1 kg/cm^2) for a continuous drive in, a settling test must be performed, in which case the differential settling pressure should not be less than 30 psid (2.1 kg/cm^2) nor should it vary by more than 10 psid (0.7 kg/cm^2) over a full stroke.*

<u>Level 3</u>

a. On receipt of a simulated or actual scram signal (maximum error), the flow control valve must close to its minimum position within 10 sec to 30 sec.

b. The CRD system flow should not change by more than ± 3.0 gpm as reactor pressure varies from 0 to rated pressure.

c. The decay ratio of any oscillatory controlled variable must be ≤0.25 for any flow setpoint changes or for system disturbances caused by the CRDs being stroked.

14.2.12.3.6 Test Number 6 - Source Range Monitor Performance and Control Rod Sequence

14.2.12.3.6.1 <u>Purpose</u>. The purpose of this test is to demonstrate that the operational sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe and efficient manner. The effect of typical rod movements on reactor power will be determined.

14.2.12.3.6.2 <u>Prerequisites</u>. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. The CRD system must be operational.

14.2.12.3.6.3 <u>Description</u>. Source range monitor count-range data will be taken during rod withdrawals to critical and compared with stated criteria on signal count-to-noise count ratio.

A withdrawal sequence has been calculated which completely specifies control rod withdrawals from the all-rods-in condition to the rated power configuration. Critical rod patterns will be recorded periodically as the reactor is heated to rated temperature.

Movement of rods in a prescribed sequence is monitored by the rod control and information system, which will prevent out of sequence withdrawal. Also not more than two rods may be inserted out of sequence.

As the withdrawal of each rod group is completed during the power ascension, the electrical power, steam flow, control valve position, and APRM response will be recorded.

14.2.12.3.6.4 <u>Criteria</u>.

<u>Level 1</u>

There must be a neutron signal-to-noise ratio of at least 2 to 1 on the required operable SRMs or fuel loading chambers.

There must be a minimum count rate of 0.5 counts/sec on the required operable SRMs or fuel loading chambers.

The IRMs must be on scale before the SRMs exceed the rod block setpoint.

Level 2

Not applicable.

14.2.12.3.7 Test Number 7

Not applicable.

14.2.12.3.8 Test Number 8

Not applicable.

14.2.12.3.9 Test Number 9

See test number 16B in Section 14.2.12.3.16.2.

14.2.12.3.10 Test Number 10 - Intermediate Range Monitor System Performance

14.2.12.3.10.1 Purpose. The purpose of this test is to adjust the IRM system to obtain an optimum overlap with the SRM and APRM systems.

14.2.12.3.10.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All SRMs and pulse preamplifiers, IRMs and voltage preamplifiers, and APRMs have been calibrated in accordance with the vendor's instructions.

14.2.12.3.10.3 Description. Initially the IRM system is set to maximum gain. After the APRM calibration, the IRM gains will be adjusted to optimize the IRM overlap with the SRMs and APRMs.

14.2.12.3.10.4 Criteria.

Level 1

Each IRM channel must be on scale before the SRMs exceed their rod block setpoint. Each APRM must be on scale before the IRMs exceed their rod block setpoint.

Level 2

Each IRM channel must be adjusted so that a half decade overlap with the SRMs and one decade overlap with the APRMs are ensured.

14.2.12.3.11 Test Number 11 - Local Power Range Monitor Calibration

14.2.12.3.11.1 Purpose. The purpose of this test is to calibrate the LPRM system.

14.2.12.3.11.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation for calibration has been checked and installed.

14.2.12.3.11.3 Description. The LPRM channels will be calibrated to make the LPRM readings proportional to the neutron flux in the LPRM water gap at the chamber elevation. Calibration factors will be obtained through the use of either an off-line or a process computer calculation that relates the LPRM reading to average fuel assembly power at the chamber height.

14.2.12.3.11.4 Criteria.

Level 1

Not applicable.

Level 2

Each LPRM reading will be within 10% of its calculated value.

14.2.12.3.12 Test Number 12 - Average Power Range Monitor Calibration

14.2.12.3.12.1 Purpose. The purpose of this test is to calibrate the APRM system.

14.2.12.3.12.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation for calibration has been checked and installed.

14.2.12.3.12.3 Description. A heat balance will generally be made each shift and after each major power level change. Each APRM channel reading will be adjusted to be consistent with the core thermal power as determined from the heat balance. During heatup a preliminary calibration will be made by adjusting the APRM amplifier gains so that the APRM readings agree with the results of a constant heatup rate heat balance. The APRMs should be recalibrated in the power range by a heat balance as soon as adequate feedwater indication is *available. Recalibration of the APRM system will not be necessary from safety considerations if at least two APRM channels per RPS trip circuit have readings greater than or equal to core power.*

14.2.12.3.12.4 Criteria.

Level 1

The APRM channels must be calibrated to read equal to or greater than the actual core thermal power.

Technical Specifications and Fuel Warranty Limits on APRM scram and rod block shall not be exceeded.

In the startup mode, all APRM channels must produce a scram at less than or equal to 15% of rated thermal power.

Level 2

If the above criteria are satisfied then the APRM channels will be considered to be reading accurately if they agree with the heat balance or the minimum value required based on peaking factor maximum linear heat generation rate (MLHGR) and fraction of rated power to within (+7, -0)% of rated power.

14.2.12.3.13 Test Number 13 - Process Computer

14.2.12.3.13.1 Purpose. The purpose of this test is to verify the performance of the process computer under plant operating conditions.

14.2.12.3.13.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Computer diagnostic testing has been completed. Construction and construction testing on each input instrument and its cabling has been completed.

14.2.12.3.13.3 Description. Computer system program verifications and calculational program validations at static and at simulated dynamic input conditions will be preoperationally tested at the computer supplier's site and following delivery to the plant site. Following fuel loading, during plant heatup and the ascension to rated power, the NSSS and the balance-of-plant system process variables sensed by the computer as digital or analog signals will become available. Verify that the computer is receiving correct values of NSSS process variables and that the results of performance calculations of the NSSS is correct. At steady-state power conditions the dynamic system test case will be performed.

As discussed in Test 19 the BUCLE offline computation system will be used to evaluate core performance until the process computer performance is verified. A manual computation method is available at the site if both the process computer and BUCLE are not available.

14.2.12.3.13.4 Criteria.

Level 1

Not applicable.

Level 2

Programs OD-1, P1, and OD-6 will be considered operational when

a. *The MCPR calculated by BUCLE and the process computer either*

    1. *Are in the same fuel assembly and do not differ in value by more than 2%, or*

    2. *For the case in which the MCPR calculated by the process computer is in a different assembly than that calculated by BUCLE, for each assembly, the MCPR and CPR calculated by the two methods shall agree within 2%.*

b. *The MLHGR calculated by BUCLE and the process computer either*

    1. *Are in the same fuel assembly and do not differ in value by more than 2%, or*

    2. *For the case in which the MLHGR calculated by the process computer is in a different assembly than that calculated by BUCLE, for each assembly, the MLHGR and LHGR calculated by the two methods shall agree within 2%.*

c. *The maximum average planar linear heat generation rate (MAPLHGR) calculated by BUCLE and the process computer either*

    1. *Are in the same fuel assembly and do not differ in value by more than 2%, or*

    2. *For the case in which the MAPLHGR calculated by the process computer is in different assembly than that calculated by BUCLE, for each*

assembly, the MAPLHGR and APLHGR calculated by the two methods shall agree within 2%.

d. The LPRM gain adjustment factors calculated by BUCLE and the process computer agree to within 2%.

e. The remaining programs will be considered operational on successful completion of the static and dynamic testing.

14.2.12.3.14 Test Number 14 - Reactor Core Isolation Cooling System

14.2.12.3.14.1 Purpose. The purpose of this test is to verify the proper operation of the RCIC system over its expected operating pressure range.

14.2.12.3.14.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing.

14.2.12.3.14.3 Description. The RCIC system test consists of two parts: Injection to the condensate storage tank and injection to the reactor vessel. The initial condensate storage tank (CST) injections consist of manual and automatic starts at 150 psi and at rated reactor pressure. The pump discharge pressure during these tests is throttled to 100 psi above reactor pressure. This initial testing is done to demonstrate system operability and making initial controller adjustments. This is followed by vessel injections beginning with cold RCIC hardware; "cold" being defined as a minimum of 3 days without any kind of RCIC operation.

The vessel injections verify the adequacy of the startup transient and also include steady-state controller adjustments. Five consecutive successful system initiations starting from cold condition and with the same equipment settings are necessary to demonstrate system reliability. Two of these initiations are vessel injection tests with one performed using the controllers on the remote shutdown panel.

After final controller settings are determined, three CST injections at rated pressure and/or 150 psig pressure are done with initially cold RCIC equipment. These runs provide a bench mark for future surveillance testing and provide further assurance of system reliability.

A demonstration of extended operation of 30 minutes of continuous running until pump and turbine oil temperature is stabilized is scheduled at a convenient time during the test program, probably in conjunction with one of the system reliability tests. During this demonstration, automatic RCIC suction transfer from the CST to the suppression pool will be performed to confirm system stability in this configuration.

During vessel injections all reactor steam is routed to the turbine bypass valves. The steam admission valves of the main and feedwater turbines should be closed whenever the moisture carryover threshold is reached.

14.2.12.3.14.4 Criteria.

Level 1

The average pump discharge flow must be equal to or greater than 600 gpm after 30 sec have elapsed from automatic initiation at any reactor pressure between 150 psig and rated.

The RCIC turbine must not trip off or isolate during auto or manual start tests.

If any Level 1 criteria are not met, the reactor operation will be restricted to the power level defined by Figure 14.2-5. This restriction is in addition to any restrictions defined by the Technical Specifications.

Level 2

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The differential pressure switch for the RCIC steam supply line high flow isolation trip shall be adjusted to actuate at the valve specified in the Technical Specifications (about 300%).

The speed and flow control loops shall be adjusted so that the decay ratio of any RCIC system related variable is not greater than 0.25.

To provide an overspeed trip avoidance margin, the transient start first and subsequent speed peaks shall not exceed 5% above the rated RCIC turbine speed.

14.2.12.3.15 Test Number 15

Not applicable.

14.2.12.3.16 Test Numbers 16A and 16B

14.2.12.3.16.1 Test Number 16A - Selected Process Temperatures.

14.2.12.3.16.1.1 Purpose. The purpose of this test is to (a) ensure that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operations, (b) identify any reactor operating modes that cause temperature stratification, (c) determine the proper setting of the low flow control limiter for the recirculation pumps to *avoid coolant temperature stratification in the RPV bottom head region, and (d) familiarize the plant personnel with the temperature differential limitations of the reactor system.*

14.2.12.3.16.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing.

14.2.12.3.16.1.3 Description. The adequacy of bottom drain line temperature sensors will be determined by comparing it with recirculation loop coolant temperature when core flow is 100% of rated.

During initial heatup while at hot standby conditions, the bottom drain line temperature, recirculation loop suction temperature, and applicable reactor parameters are monitored as the recirculation flow is slowly lowered to either minimum stable flow or the low recirculation pump speed minimum valve position, whichever is the greater. The effects of cleanup flow will be investigated as operational limits allow. Using this data it can be determined whether coolant temperature stratification occurs and if so, what minimum recirculation flow will prevent it.

Monitoring the preceding information during planned pump trips will determine if temperature stratification occurs in the idle recirculation loops or in the lower plenum when one or more loops are inactive.

All data will be analyzed to determine if changes in operating procedures are required.

14.2.12.3.16.1.4 Criteria.

Level 1

a. *The reactor recirculation pumps shall not be started nor flow increased unless the coolant temperatures between the steam dome and bottom head drain are within 145°F (81°C).*

b. *The recirculation pump in an idle loop must not be started, active loop flow must not be raised, and power must not be increased unless the idle loop suction temperature is with in 50°F (28°C) of the active loop suction temperature. If two pumps are idle, the loop suction temperature must be within 50°F (28°C) of the steam dome temperature before pump startup.*

Level 2

During two-pump operation at rated core flow, the bottom head temperature as measured by the bottom drain line thermocouple should be within 30°F (17°C) of the recirculation loop temperatures.

14.2.12.3.16.2 Test Number 16B - Water Level Reference Leg Temperature Measurement.

14.2.12.3.16.2.1 Purpose. The purpose of this test is to measure the reference leg temperature and recalibrate the affected level instruments if the measured temperature is different than the value assumed during the initial calibration.

14.2.12.3.16.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All applicable system instrumentation is installed and calibrated.

14.2.12.3.16.2.3 Description. To monitor the reactor vessel water level, five level instrument systems are provided. These are

- a. *Shutdown range level system,*
- b. *Narrow range level system,*
- c. *Wide range level system,*
- d. *Fuel zone level system, and*
- e. *Upset range.*

These systems are used respectively as follows:

- a. *Water level measurement in cold shutdown conditions (shutdown range level system),*
- b. *Feedwater flow and water level control functions in hot operating conditions (narrow range level system),*
- c. *Safety functions in hot operating conditions (wide range level system),*
- d. *Safety functions in cold shutdown conditions (fuel zone level system), and*
- e. *High water level protection, hot operating condition (upset range).*

The test will be done at rated temperature and pressure and under steady-state conditions and will verify that the reference leg temperature of the level instrument is the value assumed during initial calibration. If not, the instruments will be recalibrated using the measured value.

14.2.12.3.16.2.4 Criteria.

Level 1

Not applicable.

Level 2

The indicator readings on the narrow range level system should agree with ± 1.5 in. of the average readings or the reading calculated from the correct reference leg temperatures.

The wide and upset range level system indicators should agree within ± 6 in. of the average readings or the readings calculated from the correct reference leg temperatures.

14.2.12.3.17 Test Number 17 - System Expansion

14.2.12.3.17.1 Purpose. The purpose of this test is to (a) verify that piping systems and components are unrestrained with respect to thermal expansion, (b) verify that suspension components are functioning in the specified manner, (c) provide confirmatory data for the calculated stress levels in nozzles and weldments, (d) perform an inspection to satisfy ASME Section XI, IWF-220 post heatup (shakedown) inspection requirements, and (e) satisfy the inspection requirements for the condensate and feedwater systems according to Regulatory Guide 1.68.1.

14.2.12.3.17.2 Prerequisites. Necessary preoperational tests have been completed. The preheatup examination program relating to component supports as contained in the CGS Preservice Inspection Program Plan has been completed. The POC has reviewed and the Plant Manager has approved the test procedure and initiation of testing. Instrumentation has been installed and calibrated.

14.2.12.3.17.3 Description. A significant mechanical design objective for nuclear piping support systems is to provide for unrestricted thermal expansion of piping and components, from ambient to rated temperature. The combination of visual and remote monitoring of selected piping systems will provide the data necessary to evaluate the support system. The criteria used for system selection is Standard Review Plan Section 3.9.2 and those systems with a normal operating temperature greater than 250°F. The drywell piping systems selected for visual inspection and remote monitoring are the following:

- *a. Reactor recirculation,*
- *b. Main steam,*
- *c. Feedwater,*
- *d. Residual heat removal (shutdown cooling supply and return line),*
- *e. Reactor core isolation cooling (steam supply and head spray line),*

f. Safety/relief valve discharge piping, and
g. Reactor water cleanup.

In addition, visual inspections only of the following drywell systems will be conducted:

a. High-pressure core spray,
b. Low-pressure core spray,
c. Sacrificial shield wall penetrations,
d. Residual heat removal (LPCI) injection lines,
e. Main steam flow instrumentation piping,
f. Main steam drain piping,
g. Reactor head vent piping,
h. Reactor coolant sample piping, and
i. Standby liquid control injection piping.

Piping support system components (hangers, sway struts, boxes, snubbers, and whip restraints) for the systems listed will be visually inspected at ambient (less than or equal to 200°F), during the initial heatup cycle at an intermediate temperature (200°F to 300°F, equivalent to 30 psig reactor pressure) and at normal operating temperature (545°F, equivalent to 1000 psig reactor pressure). Data from the remote monitoring instrumentation will be recorded and evaluated at similar intervals. Exceptions to this are feedwater, main steam relief valve (MSRV) discharge piping, and the reactor head spray and vent piping above the drywell bulkhead. The feedwater piping will attain rated temperatures only at higher reactor power levels, which precludes drywell entry. The MSRV piping is only heated up during valve actuation, which also represents a potential inspection personnel hazard. The area above the bulkhead is considered hazardous due to confinement and high temperatures. The methods used to evaluate these are as follows:

a. Feedwater drywell piping is instrumented and will be evaluated at 25% and 100% reactor power using the data collected by the lanyard potentiometers.

b. Two MSRV lines will be instrumented allowing data evaluation to be applied to all lines during SRV actuation.

c. The piping above the bulkhead will be visually inspected prior to drywell head installation.

Feedwater and the SRV piping systems will also be inspected during the shakedown inspection.

The instrumented nodes will be provided with three sensors to indicate movement in three orthogonal plans. The actual node locations will be selected through a coordinated effort between the CGS Plant Technical and Technology organizations. In this way the analytically best suited node will be coupled with accessible locations. General Electric will provide *locations and acceptance criteria for the recirculation and main steam systems. The Energy Northwest Mechanic's Department will provide similar information for the remainder of the systems tested. The instruments will provide thermal movement and vibration data that will be compared with predicted values. If these measured displacements confirm the calculated values, coupled with acceptable visual inspections, the piping system will be considered to have responded as designed. The type of lanyard potentiometer monitors used enable the collection of thermal movement and vibration data. With the acceptance criteria for all testing based on the system design, conformance to the acceptance criteria indicates adherence to the analytical limits.*

On completion of the startup test, the piping response data and the completed test procedure will be reviewed by the Energy Northwest Engineering Department responsible for the Stress Report Review and GE. The review will determine if the test results indicate the piping responded in a manner consistent with the Stress Report predictions and the ASME Code limits. An Energy Northwest Level 3 inspector and the American Nuclear Insurers (ANI) will sign all data sheets performing ASME Section XI inspections.

The drywell piping testing/inspections will be conducted during the PATP as follows:

- *a. The visual inspections and thermal expansion data will be taken during the initial reactor heatup at thermal equilibrium conditions,*

- *b. During the course of the PATP, data will be collected during steady state and transient conditions for vibration level evaluation, and*

- *c. Near the end of the PATP a final drywell entry and inspection is scheduled.*

Visual inspections will be conducted on selected piping systems outside the drywell during thermal equilibrium, steady-state operation, and selected transient conditions. The systems selected are:

- *a. Main steam,*
- *b. Condensate and feedwater,*
- *c. RCIC steam supply and exhaust,*
- *d. RCIC injection piping,*
- *e. RHR shutdown cooling supply and return,*
- *f. Reactor water cleanup, and*
- *g. Main steam leakage control system.*

14.2.12.3.17.4 Criteria.

Level 1

Thermally induced displacement of system components shall be unrestrained with no evidence of binding or impairment.

Spring hangers shall not be bottomed out or have the spring fully stretched.

Snubbers shall not reach the limits of their travel. The displacements at the established transducer locations used to measure pipe deflections shall not exceed the allowable values. The allowable values of displacement shall be based on not exceeding ASME Section III Code Stress allowables.

Level 2

Spring hangers will be in their operating range (between the hot and cold settings).

Snubber settings must be within their expected operating range.

The displacements at the established transducer locations shall not exceed the expected values.

14.2.12.3.18 Test Number 18 - Core Power Distribution

14.2.12.3.18.1 Purpose. The purpose of this test is to determine the reproducibility of the TIP system readings.

14.2.12.3.18.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. The TIP detector and dummy detector, ball valve time delay, core top and bottom limits, clutch, x-y recorder, and purge system will have been shown to be operational. Instrumentation has been calibrated and installed.

14.2.12.3.18.3 Description. The TIP reproducibility consists of a random noise component and a geometric component. The geometric component is due to variation in the water gap geometry and TIP tube orientation from TIP location to location. Measurement of these components is obtained by taking repetitive TIP readings at a single TIP location, and by analyzing pairs of TIP readings taken at TIP locations which are symmetrical about the core diagonal of fuel loading symmetry.

One set of TIP data will be taken at the 50% power level and at least one other set at 75% power or above.

The TIP data will be taken with the reactor operating with an octant symmetric rod pattern and at steady-state conditions.

The total TIP reproducibility is obtained by dividing the standard deviation of the symmetric TIP pair nodal ratios by two. The nodal TIP ratio is defined as the nodal base value of the TIP in the lower right half of the core divided by its symmetric counterpart in the upper left half. The total TIP reproducibility value that is compared with the test criterion is the average value of the data sets taken.

The random noise uncertainty is obtained from successive TIP runs made at the common hole, with each of the TIP machines making six runs. The standard deviation of the random noise is derived by taking the square root of the average of the variances at nodal levels 5 through 22, where the nodal variance is obtained from the fractional deviations of the successive TIP values about their nodal mean value.

The geometric component of TIP reproducibility is obtained by statistically subtracting the random noise component from the total TIP reproducibility.

14.2.12.3.18.4 Criteria.

Level 1

Not applicable.

Level 2

The total TIP uncertainty (including random noise and geometrical uncertainties) obtained by averaging the uncertainties for all data sets shall be less than 6.0%.

The data acquired for random noise uncertainty does not have specific acceptance criteria value and is used only to aid in the analysis of the TIP uncertainty.

14.2.12.3.19 Test Number 19 - Core Performance

14.2.12.3.19.1 Purpose. The purposes of this test are to (a) evaluate the core thermal power, and (b) evaluate the following core performance parameters are within limits: (a) maximum linear heat generation rate (MLHGR), (b) minimum critical power ratio (MCPR), and (c) maximum average planar linear heat generation rate (MAPLHGR).

14.2.12.3.19.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. System instrumentation has been installed and calibrated, and test instrumentation has been calibrated.

14.2.12.3.19.3 Description. The core performance evaluation is employed to determine the principal thermal and hydraulic parameters associated with core behavior. These parameters are

a. Core flow rate,
b. Core thermal power level,
c. MLHGR,
d. MAPLHGR, and
e. MCPR.

The core performance parameters will be evaluated by manual calculation techniques described in Startup Test Instruction 19 or may be obtained from the process computer.

If the process computer is used as a primary means to obtain these parameters, it must be proven that it agrees with BUCLE within 2% on all thermal parameters (see Test Number 13). If both BUCLE and the process computer are not available, the manual calculation techniques described in Startup Test Instruction 19 can be used for the core performance evaluation.

14.2.12.3.19.4 Criteria.

Level 1

The MLHGR of any rod during steady-state conditions shall not exceed the limit specified by the Technical Specifications.

The steady-state MCPR shall not exceed the minimum limits specified by the Technical Specifications.

The MAPLHGR shall not exceed the limits specified by the Technical Specifications.

Steady-state reactor power shall be limited to the rated MWt and values on or below the design flow control line. Core flow shall not exceed its rated value.

Level 2

Not applicable.

14.2.12.3.20 Test Number 20 - Steam Production

14.2.12.3.20.1 Purpose. The purpose of performing this test is to demonstrate that the NSSS is providing steam sufficient to satisfy all appropriate warranties as defined in the contract.

14.2.12.3.20.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing.

14.2.12.3.20.3 Description. Warranty demonstration consists of recording sufficient data under steady-state conditions to determine the reactor power level, the pressure and quality of the steam, and the steam flow rate from the reactor.

These measurements will include the temperature, pressure, and flow rate of feedwater entering the reactor; the energy added to the reactor water by the recirculation drive pumps; the flow rate through and temperature entering and leaving the reactor cleanup system; the flow rate and temperature of the CRD cooling water; the carryover of reactor water into the steam lines, and the steam pressure outside the drywell near the MSIV.

Each set of measurements shall be taken at frequent intervals, every 5 or 10 minutes as appropriate, for a total test run duration of 4 hr. The average measure quantity, suitably corrected for all calibration factors, is used to determine NSSS output during the test run. Where the contract requires a 100-hr demonstration, two test runs shall be made, one in the first 50 hr and one in the second 50 hr. The demonstrated output is the average of the values from the two test runs. During the balance of the 100-hr demonstration, the NSSS output shall be held constant within ± 5% of the nominal steam flow rate as indicated by the installed plant feedwater instrumentation.

14.2.12.3.20.4 Criteria.

Level 1

a. *The NSSS parameters as determined by using normal operating procedures shall be within the appropriate license restrictions.*

b. *The NSSS will be capable of supplying steam in an amount and quality corresponding to the final feedwater temperature and other conditions shown on the rated steam output curve in the NSSS technical description. The rated steam output curve provides the warrantable reactor vessel steam output as a function of feedwater temperature, as well as warrantable steam conditions at the outboard MSIVs.*

c. *Thermodynamic parameters are consistent with the 1967 ASME steam tables. Correction techniques for conditions that differ from the contracted conditions will be mutually agreed to prior to the performance of the test.*

Level 2

Not applicable.

14.2.12.3.21 Test Number 21 - Core Power-Void Mode

14.2.12.3.21.1 Purpose. The purpose of this test is to measure the stability of the core power-void dynamic response and to demonstrate that its behavior is within specified limits.

14.2.12.3.21.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. System instrumentation has been installed and calibrated, and test instrumentation calibrated.

14.2.12.3.21.3 Description. The core power void loop mode that results from a combination of the neutron kinetics and core thermal hydraulic dynamics is least stable near the natural circulation end of the rated 100% power rod line. A fast change in the reactivity balance is obtained by a pressure regulator step change (see test 22) and by moving a very high worth rod only 1 or 2 notches. Both local flux and total core response will be evaluated by monitoring selected LPRMs during the transient.

14.2.12.3.21.4 Criteria.

Level 1

The transient response of any system-related variable to any test input must not diverge.

Level 2

The decay ratio for each system-related variable containing oscillatory modes must be less than or equal to 0.5.

14.2.12.3.22 Test Number 22 - Pressure Regulator

14.2.12.3.22.1 Purpose. The purposes of this test are to: (a) determine the optimum settings for the pressure control loop by analysis of the transients induced in the reactor pressure control system by means of the pressure regulators, (b) demonstrate the backup capability of the pressure regulators via simulated failure of the controlling pressure regulator and to set the regulating pressure difference between the two regulators at an appropriate value, (c) demonstrate smooth pressure control transition between the control valves and bypass valves when reactor steam generation exceeds steam used by the turbine, and (d) demonstrate that affected parameters are within acceptable limits during pressure-regulator-induced transient maneuvers.

14.2.12.3.22.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.22.3 Description. The pressure setpoint will be decreased rapidly and then increased rapidly by about 10 psi (0.7 kg/cm^2) and the response of the system will be measured in each case. It is desirable to accomplish the setpoint change in less than 1 sec. At specified test conditions the load limit setpoint will be set so that the transient is handled by control valves, bypass valves, and both. The regulators will be tested by simulating a failure of a selected pressure regulator so that the other regulator will take over control. The response of the system will be measured and evaluated and regulator settings will be optimized.

14.2.12.3.22.4 Criteria.

Level 1

The transient response of any pressure control system related variable to any test input must not diverge.

Level 2

a. *Pressure control system variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25,*

b. *The pressure response time from initiation of pressure setpoint change to the turbine inlet pressure peak shall be ≤10 sec,*

c. *Pressure control system deadband, delay, etc., shall be small enough that steady-state limit cycles (if any) shall produce steam flow variations no larger than ± 0.5% of rated steam flow,*

d. *For all pressure regulator transients the peak neutron flux and/or peak vessel pressure shall remain below the scram settings by 7.5% and 10 psi respectively (maintain a plot of power versus the peak variable values along the 100% rod line), and*

e. *The variation in incremental regulation (ratio of the maximum to the minimum valve of the quantity, "incremental change in pressure control signal/incremental change in steam flow," for each flow range) shall meet the following:*

Steam Flow Obtained With Valves Wide Open (%)	*Variation*
0 to 90	*≤4:1*
90 to 97	*≤2:1*
90 to 99	*≤5:1*

Level 3

a. *Additional dynamics of the control system, outside of the regulator compensation filters, shall be equivalent to a time constant no greater than 0.10 sec. This also includes any dead time which may exist,*

b. *Control or bypass valve motion must respond to pressure inputs with deadband (insensitivity) no greater than ± 0.1 psi, and*

c. *Dynamics of both pressure regulators will be essentially identical.*

14.2.12.3.23 Test Number 23 - Feedwater System

14.2.12.3.23.1 23A - Water Level Setpoint and Manual Flow Changes.

14.2.12.3.23.1.1 Purpose. The purpose of this test is to verify that the feedwater system has been adjusted to provide acceptable reactor water level control.

14.2.12.3.23.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.1.3 Description. Reactor water level setpoint changes of approximately 3 in. to 6 in. (8 cm to 15 cm) will be used to evaluate (and adjust if necessary) the feedwater control system settings for all power and feedwater pump modes. The level setpoint changes will also demonstrate core stability to subcooling changes.

14.2.12.3.23.1.4 Criteria.

Level 1

The transient response of any level control system-related variable to any test must not diverge.

<u>*Level 2*</u>

a. *Level control system-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25;*

b. *The open loop dynamic flow response of each feedwater actuator (turbine or valve) to small (< 10%) step disturbances shall be*

1.	*Maximum time to 10% of a step disturbance*	*≤ 1.1 sec*
2.	*Maximum time from 10% to 90% of a step disturbance*	*≤ 1.9 sec*
3.	*Peak overshoot (% of step disturbance)*	*≤ 15%*
4.	*Settling time, 100%, ± 5%*	*≤ 14 sec*

c. *The average rate of response of the feedwater actuator to large (> 20% of pump flow) step disturbances shall be between 10% and 25% rated feedwater flow/sec. This average response rate will be assessed by determining the time required to pass linearly through the 10% and 90% response points; and*

d. *At steady-state generation for the 3/1 element system, the input scaling to be mismatch gain should be adjusted such that level error due to biased mismatch gain output should be within ± 1 in.*

<u>*Level 3*</u>

a. *The dynamic response of each individual level or flow sensor shall be as fast as possible. Band width must be at least 4.0 radians/sec (faster than 0.25 sec equivalent time constant), except for the steam flow sensors which must have band width of at least 1.0 radian/sec (faster than 1.0 sec equivalent time constant);*

b. *Vessel level, feedwater flow, and steam flow sensors must be installed with sufficiently short lines and proper damping adjustment so that no resonances exist;*

c. *Initial settings of the function generators should give a straight line. The function generators must be adjusted so that the change in slope (actual fluid flow change divided by demand change for small disturbances) shall not exceed a factor of 2 to 1 (maximum slope versus minimum slope) over the entire 20% to*

100% feed flow range. Also the function generators should be used to minimize the differences between feedwater actuators (pumps and/or valves); and

d. *All auxiliary controls which have direct impact on reactor level and feedwater control (e.g., feed pump minimum recirculation flow valve control) should be functional, responsive, and stable. The minimum low valve control should be fast enough to avoid pump trips and yet slower than the feedwater startup valve to avoid possible reactor flux scram due to a cold water slug.*

14.2.12.3.23.2 23B - Loss of Feedwater Heating

14.2.12.3.23.2.1 Purpose. The purpose of this test is to demonstrate adequate response to a feedwater temperature loss.

14.2.12.3.23.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.2.3 Description. The condensate/feedwater system will be studied to determine the single failure that will cause the largest loss in feedwater heating. This event will then be performed at between 80% and 90% power with the recirculation flow near its rated value.

14.2.12.3.23.2.4 Criteria.

Level 1

a. *For the feedwater heater loss test, the maximum feedwater temperature decrease due to a single failure case must be ≤100°F. The resultant MCPR must be greater than the fuel thermal safety limit; and*

b. *The increase in simulated heat flux cannot exceed the predicted Level 2 value by more than 2%. The predicted value will be based on the actual test values of feedwater temperature change and power level.*

Level 2

The increase in simulated heat flux cannot exceed the predicted value in the Transient Safety Analysis Design Report referenced to the actual feedwater temperature change and power level.

14.2.12.3.23.3 <u>22C - Feedwater Pump Trip</u>.

14.2.12.3.23.3.1 <u>Purpose</u>. The purpose of this test is to demonstrate the capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump.

14.2.12.3.23.3.2 <u>Prerequisites</u>. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.3.3 <u>Description</u>. One of the two operating feedwater pumps will be tripped and the automatic recirculation runback circuit will act to drop the power to within the capacity of the remaining feedwater pump. Prior to the test a simulation of the feedwater pump trip will be done to verify the runback capability of the recirculation system. This test should be performed after test 23D (limiting pump speeds).

14.2.12.3.23.3.4 <u>Criteria</u>.

<u>Level 1</u>

Not applicable.

<u>Level 2</u>

The reactor shall avoid low water level scram by a 3-in. margin from an initial water level halfway between the high- and low-level alarm setpoints.

14.2.12.3.23.4 <u>23D - Maximum Feedwater Runout Capability</u>.

14.2.12.3.23.4.1 <u>Purpose</u>. This test calibrates the feedwater flow and determines if the maximum feedwater runout capability is compatible with the licensing.

14.2.12.3.23.4.2 <u>Prerequisites</u>. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.23.4.3 <u>Description</u>. The test is divided into two parts: first, the initial calibration of the speed controller and second, verification of calibration by measured data which includes a verification that the maximum feedwater flows do not exceed the flows (different flows at different vessel pressures) in the FSAR.

a. The speed controller calibration is done by first obtaining vendor pump performance curves. The pump performance curves are then used to determine *the turbine speed corresponding to the maximum allowable flow rated vessel pressure specified by the FSAR and the minimum speed that corresponds to 0% flow at 865 psia. Additionally, for good level control system performance it should reach 115% nuclear boiler rated (NBR) flow at 1080 psia and 90% NBR flow at 1024 psi in the one pump tripped condition. Adjustable equipment (i.e., feed pump turbine speed loops, mechanical limiters, and feedwater control system function generator, etc.) are set to prevent the feedwater pumps from exceeding their maximum allowed output and yet allow the desirable performance; and*

b. *During the data collection and verification of calibration portion of the test, pressure, flow, and controller data will be collected between 60%-100% power. Measured data will be compared against expected values to ensure proper calibration. The measured maximum flow will be adjusted to the FSAR pressures using the measured data. The maximum flows stated in the FSAR are used as licensing assumptions; therefore, the FSAR maximum flows should not be exceeded. If, however, the FSAR maximum flows are exceeded two options exist. The system can be adjusted so that the licensing assumption is not exceeded or an additional penalty can be applied to the CPR. The CPR can be revised by applying a 0.01 adder for each 5% of rated feedwater flow difference (between the determined actual maximum flow and the FSAR maximum flow).*

14.2.12.3.23.4.4 Criteria.

Level 1

Maximum speed attained shall not exceed the speeds which will give the following flows with the normal complement of pumps operating.

a. *F% NBR at P psia, and*
b. *[F% + A(P-P rated)] % NBR at P rated, psig*
where: F = 135%, P = 1075 psia, A = 0.2%/psig.

Level 2

The maximum speed must be greater than the calculated speeds required to supply:

a. *With rated complement of pumps -115% NBR at 1075 psi, and*
b. *One feedwater pump tripped condition -68% NBR at 1025 psia.*

NOTE: *Level 1 test criteria are originated from NSSS transient Performance Engineering Unit. Level 2 test criteria are originated from the Control System Design Unit.*

14.2.12.3.24 Test Number 24 - Turbine Valve Surveillance

14.2.12.3.24.1 Purpose. The purpose of this test is to demonstrate the acceptable procedures and maximum power levels for recommended periodic surveillance testing of the main turbine, control, and stop and bypass valves without producing a reactor scram.

14.2.12.3.24.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.24.3 Description. Individual main turbine control and stop and bypass valves are tested routinely during plant operation as required for turbine surveillance testing. At several test points the response of the reactor will be observed. It is recommended that the maximum possible power level for performance of these tests along the 100% load line be established. First, actuation should be between 45% and 65% power and used to extrapolate to the next test point between 75% and 90% power and ultimately to the maximum power test condition with ample margin to scram. Note the proximity to APRM flow bias scram point and preconditioning cladding interim operating management recommendation (PCIOMR) envelope. Each valve test will be manually initiated and reset. The rate of valve stroking and timing of the close-open sequence will be such that the minimum practical disturbance is introduced and that PCIOMR limits are not exceeded.

14.2.12.3.24.4 Criteria.

Level 1

Not applicable.

Level 2

a. *Peak neutron flux must be at least 7.5% below the scram trip setting. Peak vessel pressure must remain at least 10 psi below the high pressure scram setting. Peak heat flux must remain at least 5.0% below its scram trip point; and*

b. *Peak steam flow in each line must remain 10% below the high flow isolation trip setting.*

14.2.12.3.25 Test Number 25 - Main Steam Isolation Valves

14.2.12.3.25.1 25A - Main Steam Isolation Valve Function Tests.

14.2.12.3.25.1.1 Purpose. The purposes of this test are to (a) functionally check the MSIVs for proper operation at selected power levels, (b) determine isolation valve closure times, and (c) determine a maximum power at which full closures of a single valve can be performed without a scram.

14.2.12.3.25.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.25.1.3 Description. At 5% and greater reactor power levels, individual fast closure of each MSIV will be performed to verify their functional performance and to determine closure times. The times to be determined are (a) the time from deenergizing the solenoids until the valve is 100% closed (t_{sol}), and (b) the valve stroke time (t_s) Time t_{sol} equals the interval from deenergizing the solenoids until the valve reaches 90% closed plus 1/8 times the interval from 10% to 90% closure. Time t_s equals the interval from when the valve starts to move until it is 100% closed and is based on the interval from 10% to 90% closure and linear valve travel from 0% to 100% closure.

To determine the maximum power level at which full individual closures can be performed without a scram, first actuation will be performed between 40% to 55% power and used to extrapolate to the next test point between 60% and 85% power and ultimately to the maximum power test condition with ample margin to scram.

14.2.12.3.25.1.4 Criteria.

Level 1

The MSIV stroke time (t_s) shall be not faster than 3.0 sec (average of the fastest valve in each steam line) and for any individual valve 2.5 sec $\leq t_s \leq$5 sec. Total effective closure time for any individual MSIV shall be t_{sol} plus the maximum instrumentation delay time as determined in preoperational test GE-4 and shall be $\leq$5.5 sec.

Level 2

a. *The reactor shall not scram or isolate, and*

b. *During full closure of individual valves, peak valve pressure must be 10 psi (0.7 kg/cm^2) below scram, peak neutron flux must be 7.5% below scram, and* *steam flow in individual lines must be 10% below the isolation trip setting. The peak heat flux must be 5% less than its trip point.*

14.2.12.3.25.2 25B - Full Reactor Isolation.

14.2.12.3.25.2.1 Purpose. The purpose of this test is to determine the reactor transient behavior that results from the simultaneous full closure of all MSIVs.

14.2.12.3.25.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.25.2.3 Description. A test of the simultaneous full closure of all MSIVs will be performed at >75% of rated thermal power. Correct performance of the RCIC and relief valves will be shown. Reactor process variables will be monitored to determine the transient behavior of the system during and following the main steam line isolation.

14.2.12.3.25.2.4 Criteria.

Level 1

a. *Reactor must scram to limit the severity of the neutron flux and simulated fuel surface heat flux transient,*

b. *Feedwater system settings must prevent flooding of the steam lines,*

c. *The recorded MSIV full closure times must meet the previously stated timing specifications (test 25A), and*

d. *The positive change in vessel dome pressure occurring within 30 sec after closure of all MSIV valves must not exceed the Level 2 criteria by more than 25 psi. The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2% of rated value.*

Level 2

a. *The temperature measured by the thermocouples on the discharge side of the SRVs must return to within 10°F of the temperature recorded before the valve was opened. If pressure sensors are available, they shall return to their initial state upon valve closure;*

b. *For the full MSIV closure from full power predicted analytical results based on beginning-of-cycle design basis analysis, assuming no equipment failures and* *applying appropriate parametric corrections, will be used as the basis to which the actual transient is compared.*

c. *Initial action of RCIC and HPCS shall be automatic if low water level (L2) is reached, and system performance shall be within specification, and*

d. *Recirculation pump trip shall be initiated if low water level (L2) is reached. Recirculation pump power will shift to the LFMGs if low water level (L3) is reached.*

14.2.12.3.26 Test Number 26 - Relief Valves

14.2.12.3.26.1 Purpose. The purposes of this test are to (a) verify the proper operation of the main system relief valves, (b) verify that the discharge piping is not blocked, (c) verify their proper seating following operation, (d) obtain signature information of relief valve response for subsequent comparisons, and (e) determine their capacities.

14.2.12.3.26.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.26.3 Description. The main steam relief valves will each be opened using the "manual" control mode so that at any time only one is open. During heatup at 250 psig (17.5 kg/cm^2), each valve will be opened and closed to demonstrate proper functioning. Flow verification of each relief valve will be determined at rate pressure by observing bypass or control valve motion and by observing a change in discharge thermocouple readings. Proper reseating of each relief valve will be verified by observation of temperatures in the relief valve discharge piping. At selected test conditions each valve will be manually actuated and appropriate system parameters recorded during the transient. Data analysis will include a comparison of the system response during each of the valve actuations. Capacity of each relief valve will be determined at rated pressure by the amount of bypass or control valve closure required to maintain reactor pressure.

14.2.12.3.26.4 Criteria.

Level 1

There should be positive indication of steam discharge during the manual actuation of each valve.

The sum of capacity measurements from all relief valves shall be equal to or greater than 15.8 x 10^6 lb/hr at an inlet pressure of 103% at 1205 psig. The total flow capacity of the SRVs used in the automatic depressurization system must be equal to or greater than 4.8 x 10^6 lb/hr *at 1125 psig when the valve having the highest measured capacity is assumed to be out of service.*

Level 2

Relief valve leakage shall be low enough that the temperature measured by the thermocouples in the discharge side of the valves returns to within 10°F (5.6°C) of the temperature recorded before the valve was opened. The thermocouples are expected to be operating properly.

The pressure regulator must satisfactorily control the reactor transient and close the control valves or bypass valves by an amount equivalent to the relief valve discharge. The valve transients recorder signatures for each valve must be returned to GE in San Jose for relative system response comparison.

Each relief valve shall have a capacity between 90% and 122.5% of its expected value corrected to an inlet pressure of 103% at 1205 psig.

No more than 25% of the relief valves may have an individual corrected flow rate that is between 90% and 100% of their expected flow rates.

The transient recorder signatures for each valve must be analyzed for relative system response comparison.

14.2.12.3.27 Test Number 27 - Turbine Trip and Generator Load Rejection

14.2.12.3.27.1 Purpose. The purpose of this test is to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator.

14.2.12.3.27.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All controls and interlocks are checked and instrumentation calibrated. The plant electrical system will be aligned in the normal mode for the operating condition at which the test is performed.

14.2.12.3.27.3 Description. Turbine trip (closure of the main turbine stop valves within 0.1 sec) and generator trip (closure of the main turbine control valves in about 0.1 sec to 0.2 sec) will be performed at selected power levels during the startup test program. At low power levels, reactor protection following the trip is provided by high neutron flux and vessel high pressure scram. For the protective trips occurring at intermediate and higher power levels, reactor will scram by relays, actuated by control or stop valve motion.

A generator trip will be performed at low power level such that nuclear boiler steam generation is just within the bypass valve capacity to demonstrate scram avoidance.

For the trips performed at intermediate power range, reactor scram is most important in controlling the transient peaks.

Above 40% power, the recirculation pump circuit breakers are both automatically tripped, and subsequent transient pressure rise will be limited by the opening of the bypass valves initially and the SRVs if necessary.

14.2.12.3.27.4 Criteria.

Level 1

a. *For turbine and generator trips at power levels greater than 50% NBR, there should be a delay of less than 0.1 sec following the beginning of control or stop valve closure before the beginning of bypass valve opening. The bypass valves should be opened to a point corresponding to greater than or equal to 80% of their capacity within 0.3 sec from the beginning of control or stop valve closure motion;*

b. *Feedwater system settings must prevent flooding of the steam line following these transients;*

c. *The two pump drive flow coastdown transient during the first 6 sec must be equal to or faster than that specified in test 30B (see Figure 14.2-6);*

d. *The positive change in vessel dome pressure occurring within 30 sec after either generator or turbine trip must not exceed the Level 2 criteria by more than 25 psi;*

e. *The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2% of the rated value; and*

f. *The total time delay from start of turbine stop valve motion or control valve motion to the complete suppression of electrical arc between the fully open contacts of the recirculation pump trip (RPT) circuit breakers shall be less than 190 msec.*

Level 2

a. *There shall be no MSIV closure during the first 3 minutes of the transient, and operator action shall not be required during that period to avoid the MSIV trip. (The operator may take action after the first 3 minutes, including switching out of run mode. The operator may also switch out of run mode in the first*

3 minutes if measured data confirms that his action did not prevent MSIV closure);

b. *The positive change in vessel dome pressure and in simulated heat flux which occurs within the first 30 sec after the initiation of either generator or turbine trip must not exceed the predicted values. [Predicted values will be referenced to actual test conditions of initial power life and dome pressure and will use beginning of life (BOL) nuclear data. Worst case design or Technical Specification values of all hardware performance shall be used in the prediction with the exception of control rod insertion time and the delay from beginning of turbine control valve or stop valve motion to the generation of the scram signal. The predicted pressure and heat flux will be corrected for the actual measured values of these two parameters];*

c. *For the generator grip within the bypass valves capacity, the reactor shall not scram for initial thermal power values within that bypass valve capacity;*

d. *The measured bypass capacity (in percent of rated power) shall be equal or greater than that used for the FSAR analysis (3,576,000 lb/hr);*

e. *Recirculation LFMG sets shall take over after the initial recirculation pump trips and adequate vessel temperature difference shall be maintained;*

f. *Feedwater level control shall avoid loss of feedwater due to possible high level (L8) trip during the event;*

g. *Low water level total recirculation pump trip, HPCS, and RCIC shall not be initiated; and*

h. *The temperature measured by thermocouples on the discharge side of the SRVs must return to within 10°F of the temperature recorded before the valve was opened. In addition the acoustical monitors should indicate the valve is closed after the transient is complete.*

14.2.12.3.28 Test Number 28 - Shutdown From Outside the Main Control Room

14.2.12.3.28.1 Purpose. The purpose of this test is to demonstrate that the reactor can be brought down from a normal initial steady-state power level to the point where cooldown is established and under control with reactor vessel pressure and water level controlled from outside the control room.

14.2.12.3.28.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.28.3 Description. The test will be performed at a low power level and will consist of demonstrating the capability to control reactor level and pressure from outside the control room. The reactor will be scrammed and isolated from the control room. Reactor pressure and water level will be controlled using SRVs, RCIC, and RHR from outside the control room during the subsequent cooldown. In addition, the RHR shutdown cooling mode will be placed in service from outside the control room. All other operator actions not directly related to maintaining vessel water level and pressure will be performed in the main control room. Operation from the main control room to protect or secure systems not related to the controlled cooldown of the reactor is permitted during this test. These actions are recorded and later evaluated to determine if they had bearing on the transient.

14.2.12.3.28.4 Criteria.

Level 1

Not applicable.

Level 2

During a simulated main control room evacuation, the reactor must be brought to the point where cooldown can be initiated, and the reactor vessel pressure and water level must be controlled using equipment and controls outside the main control room.

14.2.12.3.29 Test Number 29 - Recirculation Flow Control

14.2.12.3.29.1 29A - Valve Position Control.

14.2.12.3.29.1.1 Purpose. The purpose of this test is to demonstrate the recirculation flow control systems capability while in the valve position (POS) mode.

14.2.12.3.29.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All controls are checked and instrumentation calibrated.

14.2.12.3.29.1.3 Description. The testing of the recirculation flow control system follows a "building block" approach while the plant is ascending from low to high power levels: Components and inner control loops are tested first, followed by drive flow control and plant power maneuvers to adjust and then demonstrate the outer loop controller performance. Preliminary component and valve position loop tests will be run when the plant is in cold *shutdown to visually observe the hydraulic cylinder response. While operating at low power with the pumps using the low frequency power supply, small step changes will input into the position controller and the response recorded.*

14.2.12.3.29.1.4 Criteria.

Level 1

The transient response of any recirculation system related variables to any test input must not diverge.

Level 2

a. *Recirculation system related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25,*

b. *Maximum rate of change of valve position shall be 10 ± 1% sec.*

During TC-3 and TC-6 while operating on the high speed (60 Hz) source, gains and limiters shall be set to obtain the following response,

c. *Delay time for position demand step shall be*

For step inputs of 0.5% to 5% ≤0.15 sec.
For step inputs of 0.2% to 0.5%-

d. *Response time for position demand step shall be*

For step inputs of 0.5% to 5% ≤0.45 sec.
For step inputs of 0.2% to 0.5%-, and

e. *Overshoot after a small position demand input (1% to 5%) step shall be 10% of magnitude of input.*

Level 3

a. *Gains shall be set to give as fast a response as possible for small position demand input within the overshoot criterion (e) and without additional valve duty cycle. (See test 29B, Section 14.2.12.3.29.2, for valve duty cycle measurement.)*

b. *Position loop deadband shall be 0.2% of full valve stroke.*

NOTE: At a minimum, performing tests near the high and low end of the specified range is acceptable for verifying step input response.

14.2.12.3.29.2 29B - Recirculation Flow Loop Control.

14.2.12.3.29.2.1 Purpose. The purposes of this test are to (a) demonstrate the core flow system's control capability over the entire flow control range, including both core flow neutron flux and load following modes of operation, and (b) determine that all electrical compensators and controllers are set for desired system performance and stability.

14.2.12.3.29.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. All controls are checked and instrumentation calibrated.

14.2.12.3.29.2.3 Description. Following the initial position mode tests of 29A the final adjustment of the position loop gains, flow loop gains, and preliminary valves of the flux loop adjustments will be made on the mid-power line. This will be the most extensive testing of the recirculation control system. The core power distribution will be adjusted by control rods to permit broader range of maneuverability with respect to PCIOMR. In general, the controller dials and gains will be raised to meet the maneuvering performance objectives. Thus, the system will be set to be the slowest that will perform satisfactorily to maximize stability margins and to minimize equipment wear by avoiding controller overactivity.

Because of PCIOMR power maneuvering rate restrictions, the fast flow maneuvering adjustments are performed along a mid-power rod line, and extrapolation made to the expected results along the 100% rod line. The utility has the option to decide to

a. Perform the faster power changes on the 100% rod line that are greater than what the PCIOMR allow, or

b. To accept the mid-power load line demonstrations as acceptable proof of maneuverability.

For immediate commercial operation, the flux loop will be set slower and the operator will limit manual mode maneuvers. If PCIOMRs are ever withdrawn, the tested faster auto settings can be inserted onto the controller with only a brief dynamic test, rather than a full startup test.

14.2.12.3.29.2.4 Criteria.

Level 1

The transient response of any recirculation system related variable to any test input must not diverge.

Level 2

a. *The decay ratio of the flow loop response to any test inputs shall be < 0.25,*

b. *The flow loops provide equal flows in the two loops during steady-state operation. Flow loop gains should be set to correct a flow imbalance in less than 25 sec,*

c. *The delay time for flow demand step (≤5%) shall be 0.4 sec or less,*

d. *The response time for flow demand step (≤5%) shall be 1.1 sec or less,*

e. *The maximum allowable flow over shoot for step demand of ≤5% of rated shall be 6% of the demand step, and*

f. *The flow demand step settling time shall be ≤6 sec.*

Level 3

a. *Incremental gain from function generator for valve position demand input to sensed drive flow shall not vary by more than 2 to 1 over the entire flow range, and*

b. *Flow loop upper limit should be checked for proper setting.*

Flux Loop Criteria

Level 1

The flux loop response to test inputs shall not diverge.

Level 2

a. *Flux over shoot to a flux demand step shall not exceed 2% of rated for a step demand of ≤20% of rated,* *b. The delay time for flux response to a flux demand step shall be ≤0.8 sec,*

c. The response time for flux demand stop shall be 2.5 sec, and

d. The flux setting time shall be ≤15 sec for a flux demand step ≤20% of rated.

Scram Avoidance and General Criteria

Level 1

Not applicable.

Level 2

For any one of the above loops test maneuvers, the trip avoidance margins must be at least the following:

a. For APRM ≥7.5%, and
b. For simulated heat flux ≥5.0%.

Flux Estimator Test Criteria

Level 1

Not applicable.

Level 2

a. Switching between estimated and sensed flux should not exceed 5 times/5 minutes at steady state, and

b. During flux step transient there should be no switching to sensed flux or if switching does occur, it should switch back to estimated flux within 20 sec of the transient.

Flux Control Valve Duty Test Criteria

Level 1

Not applicable.

Level 2

The flow control valve duty cycle in any operating mode shall not exceed 0.2% Hz. Flow control valve duty cycle is defined as

$$\frac{\text{Integrated valve movement in percent (\% Hz)}}{\text{2x time span in seconds}}$$

14.2.12.3.30 Test Number 30 - Recirculation System

14.2.12.3.30.1 30A - One Pump Trip.

14.2.12.3.30.1.1 Purpose. The purposes of this test are to (a) obtain recirculation system performance data during the pump trip, flow coastdown, and pump restart, and (b) verify that the feedwater control system can satisfactorily control water level without a resulting turbine trip/scram.

14.2.12.3.30.1.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.1.3 Description. The reactor coolant recirculation system consists of the reactor vessel and two piping loops. Each loop contains a constant speed centrifugal recirculation pump, a flow control valve and two isolation valves located in the drywell, and 10 jet pumps in parallel, situated in the reactor downcomer and discharges through a manifold system to the nozzles of the 10 jet pumps. Here the flow is augmented by suction flow from the downcomer and delivered to the reactor inlet plenum.

A potential threat to plant availability is the high water level turbine trip scram caused by the level upswell that results after an unexpected recirculation one pump trip. The change in core flow and the resultant power decrease causes void formation which the level sensing system senses as a rise in water level. The one-pump trip tests are to prove that the water level will not rise enough to threaten a high level trip of the main turbine or the feedwater pumps.

14.2.12.3.30.1.4 Criteria.

Level 1

The reactor shall not scram during the one-pump trip recovery.

Level 2

The reactor water level margin to avoid a high level trip shall be ≥3.0 in. during the one-pump trip.

NOTE: Margin to trip is defined as

Margin (high level trip < 8 setpoint) - (maximum water level reached ruing test) - (high level alarm < 7 setpoint - initial water level)

a The simulated heat flux margin to avoid a scram shall be ≥5.0% during the one-pump trip and also during the recovery, and

b. The APRM margin to avoid a scram shall be ≥7.5% during the one-pump trip recovery.

14.2.12.3.30.2 30B - Recirculation Trip of Two Pumps.

14.2.12.3.30.2.1 Purpose. The purpose of the test is to record and verify acceptable performance of the recirculation two pump circuit trip system.

14.2.12.3.30.2.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.2.3 Description. In case of higher power turbine or generator trips, there is an automatic opening of circuit breakers in the pump power supply. The result is a fast core flow coastdown that helps reduce peak neutron and heat flow in such events. This two-pump trip test verifies that this flow coastdown is satisfactory prior to the high power turbine/generator trip tests and subsequent operation.

14.2.12.3.30.2.4 Criteria.

Level 1

The two-pump-drive flow coastdown transient during the first 6 sec must be bounded by the limiting curves. (See Figure 14.2-6.)

(The limiting curves will be determined based on measurement of the recirculation flow delta P using the elbow flow meters, transmitter time delay, and time constant.)

Level 2

Not applicable.

14.2.12.3.30.3 30C - System Performance.

14.2.12.3.30.3.1 Purpose. The purpose of this test is to record recirculation system parameters during the power test program.

14.2.12.3.30.3.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.3.3 Description. Recirculation system parameters will be recorded at several power-flow conditions and in conjunction with single pump trip recoveries and internals vibration testing (if applicable).

14.2.12.3.30.3.4 Criteria.

Level 1

Not applicable.

Level 2

a. *The core flow shortfall shall not exceed 5% at rated power,* *

b. *The measured core delta P shall not be 70.6 psi above prediction,* *

c. *The calculated jet pump M ration shall not be 0.2 points below prediction,* *

d. *The drive flow shortfall shall not exceed 5% at rated power,* *

e. *The measured recirculation pump efficiency shall not be 78% points below the vendor tested efficiency, and*

f. *The nozzle and riser plugging criteria shall not be exceeded.*

---

* *The GE Steam Generation System Design Unit will provide predictions for the comparisons for these criteria.*

14.2.12.3.30.4 30D - Recirculation Pump Runback.

14.2.12.3.30.4.1 Purpose. The purpose of this test is to verify the adequacy of the recirculation runback to mitigate a scram on the loss of one feedwater pump.

14.2.12.3.30.4.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.4.3 Description. While operating at near rated recirculation flow, a loss of a feedwater pump will be simulated. The transient and final condition will be studied to determine the adequacy of the system in preventing a scram during the scheduled loss of a single feedwater pump test (test 23C).

14.2.12.3.30.4.4 Criteria.

Level 1

Not applicable.

Level 2

The recirculation flow control valves shall runback on a trip of the runback circuit.

14.2.12.3.30.5 30E - Recirculation System Cavitation.

14.2.12.3.30.5.1 Purpose. The purpose of this test is to verify that no recirculation system cavitation will occur in the operable region of the power-flow map.

14.2.12.3.30.5.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.30.5.3 Description. Both the jet pumps and the recirculation pumps will cavitate at conditions of high flow and low power where NPSH demands are high and little feedwater subcooling occurs. However, the recirculation flow will automatically run back on sensing a decrease in subcooling (as measured by the difference between the steam and recirculation loop temperature), to lower the reactor power. The maximum recirculation flow is limited by approximate stops which will run back the recirculation flow away from the possible cavitation region. It will be verified that these limits are sufficient to prevent operation where recirculation pump or jet pump cavitation is predicted to occur.

The recirculation system flow control valves will cavitate at conditions of high differential pressure and low power (low subcooling). The recirculation flow will automatically run back on sensing a decrease in subcooling (as measured by a low feedwater flow). This limit will be verified to ensure that operation is prevented where flow control valve cavitation may occur.

In both the above cases, flow runback is caused by a shift in the power supply to the recirculation pump motors from normal power to the LFMGs.

14.2.12.3.30.5.4 Criteria.

Level 1

Not applicable.

Level 2

Runback logic shall have settings adequate to prevent operation in areas of potential cavitation.

14.2.12.3.31 Test Number 31 - Loss of Turbine-Generator and Offsite Power

14.2.12.3.31.1 Purpose. This test determines electrical equipment and reactor system transient performance during a loss of auxiliary power.

14.2.12.3.31.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate. The plant electrical system will be aligned in the normal mode for the operating condition at which the test is performed.

14.2.12.3.31.3 Description. The loss of auxiliary power test will be performed at 20% to 30% of rated power. The proper response of reactor plant equipment, automatic switching equipment, and the proper sequencing of the diesel generator load will be verified. Appropriate reactor parameters will be recorded during the resultant transient.

14.2.12.3.31.4 Criteria.

Level 1

a. *Reactor protection system actions shall prevent violation of fuel thermal limits.*

b. *All safety systems, such as the RPS, the diesel generators, and HPCS must function properly without manual assistance. The HPCS and/or RCIC system action, if necessary, shall keep the reactor water level above the initiation level* *of the LPCS, LPCI, automatic depressurization systems, and MSIV closure. Diesel generators shall start automatically and when they reach rated frequency and voltage the diesel breakers will close and restore power to the engineered safety features (ESF) buses.*

Level 2

a. *Proper instrument display to the reactor operator shall be demonstrated, including power monitors, pressure, water level, control rod position, suppression pool temperature, and reactor cooling system status. Displays shall not be dependent on specially installed instrumentation, and*

b. *If SRVs open, the temperature measured by thermocouples on the discharge side of the SRVs must return to within 10°F of the temperature recorded before the valve was opened. If pressure sensors are available, they shall return to their initial state on valve closure.*

14.2.12.3.32 Not Applicable

14.2.12.3.33 Test Number 33 - Piping Vibration

14.2.12.3.33.1 Purpose. The purpose of this test is to verify that the design stress levels due to piping vibration are not exceeded and satisfy the inspection requirements for condensate and feedwater systems according to Regulatory Guide 1.68.1.

14.2.12.3.33.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been installed and calibrated.

14.2.12.3.33.3 Description. This test is an extension of test 17 and has been procedurally combined with the system expansion test. During reactor operation, it is desirable to show that destructive level piping vibrations do not occur during steady-state conditions and during planned transients. Acceptable vibration levels are verified by measurement (using the same sensors used in test 17) and by visual observation during system walkdowns for selected piping systems outside containment. See Section 14.2.12.3.17.2 for systems selected and selection criteria.

14.2.12.3.33.4 Criteria.

Level 1

The measured vibration amplitude (peak-to-peak) of the systems monitored shall not exceed the maximum allowable displacements.

Level 2

The measured amplitude (peak-to-peak) of vibration shall not exceed the expected values.

Visual Inspection Acceptance Criteria

The vibration levels experienced will be evaluated as acceptable if they are too small to be detected by the naked eye with consideration given to the following:

a. *Proximity to sensitive equipment (pumps, valves, motor control centers, control panels, etc.),*

b. *Branch connection behavior, and*

c. *Performance of nearby component supports.*

If an acceptable assessment of the observed deflections cannot be performed and corrective measures are not available, the inspector will then obtain the magnitude and frequency of the vibration using a portable vibration instrument. The information will then be evaluated by the piping design engineer to verify acceptance. Unacceptable vibration levels will be treated as a Level 1 violation.

14.2.12.3.34 Test Number 34 - Reactor Pressure Vessel Internals Vibration

14.2.12.3.34.1 Purpose. The purpose of this test is to provide information needed to confirm the similarity between the reactor internals design and the prototype with respect to flow-induced vibration. Testing is in response to Regulatory Guide 1.20 for a vibration measurement program for nonprototype, Category IV reactor internals, and the GE vibration test specification 22A6601, Revision 0.

14.2.12.3.34.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.34.3 Description. During operation, the reactor structure may be forced into many modes of vibrations. Analytical work indicates that unacceptable level vibrations will not occur.

Detailed descriptions of sensor locations are given in GE Test Specification 22A6601, Revision 0.

Sensors used for the measurements are resistance wire strain gauges and accelerometers with double integrating output signal conditioning. Sensors will be installed in a manner to sense the most probable mode of vibration as indicated by analysis.

The test program consists of at power tests performed with the system at normal operating pressure and temperature.

During the vibration test the vibration engineer will monitor and record vibrating amplitudes and frequencies obtained from the sensors mounted on the various components. The measured amplitudes and frequencies are then compared to the acceptance criteria to ensure that all measured vibration amplitudes are within acceptable levels.

14.2.12.3.34.4 Criteria.

Level 1

The peak stress intensity may exceed 10,000 psi (single amplitude) when the component deformed in a manner corresponding to one of its normal or natural modes, but the fatigue usage factor must not exceed 1.0.

Level 2

The peak stress intensity shall not exceed 10,000 psi (single amplitude) when the component is deformed in a manner corresponding to one of its normal or natural modes. This is the low stress limit which is suitable for sustained vibration in the reactor environment for the design life of the reactor components.

14.2.12.3.35 Test Number 35 - Recirculation System Flow Calibration

14.2.12.3.35.1 Purpose. The purpose of this test is to perform complete calibration of the installed recirculation system flow instrumentation.

14.2.12.3.35.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.35.3 Description. During the testing program at operating conditions, which allow the recirculation system to be operated at rated flow at rated power, the jet pump flow instrumentation will be adjusted to provide correct flow indication based on the jet pump flow. After the relationship between drive flow and core flow is established, the flow biased APRM/RBM system will be adjusted to match this relationship.

14.2.12.3.35.4 Criteria.

Level 1

Not applicable.

Level 2

Jet pump flow instrumentation shall be adjusted such that the jet pump total flow recorder will provide a correct core flow indication at rated conditions.

The APRM/RBM flow-bias instrumentation shall be adjusted to function properly at rated conditions.

The flow control system shall be adjusted to limit maximum core flow to 102.5% of rated by limiting the flow control valve opening position.

14.2.12.3.36 Test Number 70 - Reactor Water Cleanup System

14.2.12.3.36.1 Purpose. The purpose of this test is to demonstrate specific aspects of the mechanical operability of the RWCU system. (This test, performed at rated reactor pressure and temperature, is actually the completion of the preoperational testing that could not be done without nuclear heating.)

14.2.12.3.36.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.36.3 Description. With the reactor at rated temperature and pressure, process variables will be recorded during steady-state operation in three modes as defined by the system process diagram: hot shutdown with loss of RPV recirculation pumps, normal, and blowdown. A comparison of the bottom head flow indicator and the RWCU inlet flow indicator will be made. The RWCU system sample station shall be tested at hot process conditions.

14.2.12.3.36.4 Criteria.

Level 1

Not applicable.

Level 2

The temperature at the tube side outlet of the nonregenerative heat exchangers shall not exceed 130°F (54°C) in the blowdown mode and shall not exceed 120°F in the normal mode.

The pump available NPSH will be 13 ft or greater during the hot shutdown with loss of RPV recirculation pumps mode defined in the process diagrams.

The cooling water supplied to the nonregenerative heat exchangers shall be less than 6% above the flow corresponding to the heat exchanger capacity (as determined from the process diagram) and the existing temperature differential across the heat exchangers. The outlet temperature shall not exceed 180°F.

Recalibrate bottom head flow indicator (R610) against RWCU flow indicator (R609) if the deviation is greater than 25 gpm.

Pump vibration shall be less than or equal to 2 mils peak-to-peak (in any direction) as measured on the bearing housing and 2 mils peak-to-peak shaft vibration as measured on the coupling end.

14.2.12.3.37 Test Number 71 - Residual Heat Removal System

14.2.12.3.37.1 Purpose. The purpose of this test is to demonstrate the ability of the RHR system to remove heat from the reactor system so that the refueling and nuclear system servicing can be performed.

14.2.12.3.37.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.37.3 Description. During the first suitable reactor cooldown, the shutdown cooling mode of the RHR system will be demonstrated. Unfortunately, the decay heat load is insignificant during the startup test period. Use of the mode with low core exposure could result in exceeding the 100°F/hr cooldown rate of the vessel if both RHR heat exchangers are used simultaneously. Late in the test program after accumulating significant core exposure, this demonstration would more adequately demonstrate the heat exchanger capacity.

14.2.12.3.37.4 Criteria.

Level 1

Not applicable.

Level 2

The RHR system shall be capable of operating in the suppression pool cooling and shutdown cooling modes (with each heat exchanger) at the flow rates and temperature differentials determined by the flow rates and temperature differentials indicated on the process diagrams.

14.2.12.3.38 Test Number 72 - Drywell Atmosphere Cooling System

14.2.12.3.38.1 Purpose. The purpose of this test is to verify the ability of the drywell atmosphere cooling system to maintain design conditions in the drywell during operating conditions and post scram conditions.

14.2.12.3.38.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.38.3 Description. During heatup and power operation, data will be taken to ascertain that the drywell atmospheric conditions are within design limits.

14.2.12.3.38.4 Criteria.

Level 1

Not applicable.

Level 2

The drywell cooling system shall maintain drywell air temperatures at or below the design values as specified for the NSSS equipment.

14.2.12.3.39 Test Number 73 - Cooling Water Systems

14.2.12.3.39.1 Purpose. The purpose of the test is to verify that the heat removal performance of the SW system, the reactor building RCC system, and the plant service water (TSW) system is adequate.

14.2.12.3.39.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.39.3 Description. The SW, the RCC, and the TSW systems heat exchanger heat transport capabilities will be verified. Verification will be conducted in the following manner. The system water flow rate through each heat exchanger will be measured. The system water *temperature drop across each heat exchanger will also be measured. From these acquired water flow rates and temperature drop data, the heat transport rates will be calculated. Where available, the calculated heat transport data will be compared directly with design calculations to determine acceptability. For those systems in which no design calculations of the heat transport rate have been directly calculated, the heat removal performance of the particular heat exchanger will be considered acceptable if the components serviced by the cooling system exhibit proper operation. If proper performance is not experienced, adjustments in the heat transport capability (i.e., increased flow to the heat exchanger or increased flow to a particular load) would be made. In addition to the heat exchanger heat transport rate verification, the actual SW pump head will be determined for all three SW pumps. This actual SW pump head will be compared to the design requirements for acceptability.*

14.2.12.3.39.4 Criteria.

Level 1

Not applicable.

Level 2

The system heat transport parameters either meet the requirements of the design specifications, or provide adequate cooling to the components serviced such that they operate satisfactorily.

14.2.12.3.40 Test Number 74 - Offgas System

14.2.12.3.40.1 Purpose. The purposes of this test are to verify the proper operation of the offgas system over its expected operating parameters and to determine the performance of the activated carbon adsorbers.

14.2.12.3.40.2 Prerequisites. The preoperational tests have been completed, reviewed by POC, and the Plant Manager has approved the test procedures and initiation of testing. Instrumentation has been checked or calibrated as appropriate.

14.2.12.3.40.3 Description. The pressure, temperature, relative humidity, system flow, and percentage of radiolytic hydrogen in the offgas are periodically monitored during startup and at steady-state conditions. Prior to initial steam flow to the main condenser, charcoal bed hold-up times will be measure experimentally using a pulsed Krypton-85 gas injection technique. The charcoal bed dynamic adsorption coefficient will then be determined by established analytical methods. The performance of the catalytic recombiner will be compared the catalytic recombiner guaranteed performance curve.

14.2.12.3.40.4 Criteria.

Level 1

The release of radioactive gaseous and particulate effluents must not exceed the limits specified in the Technical Specifications. There shall be no loss of flow of dilution steam to the noncondensing stage when the steam jet air ejectors are pumping.

Level 2

The system flow, pressure, temperature, and relative humidity shall comply with design specifications. The catalytic recombiner, the hydrogen analyzer, the activated carbon bed, and the filters shall be performing their required function.

Table 14.2-1

Preoperational Tests

Section Reference	Title
14.2.12.1.1	Reactor Feedwater System
14.2.12.1.2	Condensate System
14.2.12.1.3	Fire Protection System
14.2.12.1.4	Reactor Water Cleanup System
14.2.12.1.5	Standby Liquid Control System
14.2.12.1.6	Nuclear Boiler System
14.2.12.1.7	Residual Heat Removal System
14.2.12.1.8	Reactor Core Isolation Cooling
14.2.12.1.9	Reactor Recirculation System and Control
14.2.12.1.10	Reactor Manual Control System
14.2.12.1.11	Control Rod Drive Hydraulic System
14.2.12.1.12	Fuel Handling and Vessel Servicing Equipment
14.2.12.1.13	Low Pressure Core Spray System
14.2.12.1.14	High Pressure Core Spray
14.2.12.1.15	Fuel Pool Cooling and Cleanup System
14.2.12.1.16	Leak Detection System
14.2.12.1.17	Liquid and Solid Radwaste System
14.2.12.1.18	Reactor Protection System
14.2.12.1.19	Neutron Monitoring System
14.2.12.1.20	Traversing In-Core Probe System
14.2.12.1.21	Rod Worth Minimizer System
14.2.12.1.22	Process Radiation Monitoring System
14.2.12.1.23	Area Radiation Monitoring System

Table 14.2-1

Preoperational Tests (Continued)

Section Reference	*Title*
14.2.12.1.24	*Process Computer Interface System*
14.2.12.1.25	*Rod Sequence Control System*
14.2.12.1.26	*Remote Shutdown*
14.2.12.1.27	*Offgas System*
14.2.12.1.28	*Environs Radiation Monitoring System*
14.2.12.1.29	*Main Steam System*
14.2.12.1.30	*Radwaste Building Heating, Ventilation, and Air Conditioning System*
14.2.12.1.31	*Closed Cooling Water System*
14.2.12.1.32	*Primary Containment Atmospheric Control System*
14.2.12.1.33	*Primary Containment Cooling System*
14.2.12.1.34	*Primary Containment Instrument Air System*
14.2.12.1.35	*Primary Containment Atmospheric Monitoring System*
14.2.12.1.36	*Standby Gas Treatment System*
14.2.12.1.37	*Loss of Power and Safety Testing*
14.2.12.1.38	*Instrument Power System*
14.2.12.1.39	*Emergency Lighting*
14.2.12.1.40	*Standby Alternating Current Power System*
14.2.12.1.41	*250-V Direct Current Distribution System*
14.2.12.1.42	*125-V Direct Current Distribution System*
14.2.12.1.43	*24-V Direct Current Distribution System*
14.2.12.1.44	*Plant Service Water System*
14.2.12.1.45	*Standby Service Water System*
14.2.12.1.46	*Plant Communication System*

Table 14.2-1

Preoperational Tests (Continued)

Section Reference	Title
14.2.12.1.47	Reactor Building Emergency Cooling System
14.2.12.1.48	Control Cable and Critical Switchgear Rooms Heating, Ventilation, and Air Conditioning System
14.2.12.1.49	Standby Service Water Pump House Heating and Ventilating System
14.2.12.1.50	Reactor Building Crane
14.2.12.1.51	Primary Containment Integrated Leak Rate Test
14.2.12.1.52	Secondary Containment Integrated Leak Rate Test
14.2.12.1.53	Diesel Generator Building Heating and Ventilating System

Table 14.2-2

Major Plant Transients

Test	Title		Test Condition		
		Approximate Power (% rated)	20-25	60-75	95-100
		Approximate Core Flow (% rated)	37	100	100
23C	Feedwater pump trip				X
23B	Loss of feedwater heating				X
25	MSIVs (all valves, full isolation)				X
27	T-G stop valve fast close			X	
27	T-G control valve fast close		X		X
28	Shutdown from outside control room		X		
30	Recirculation pump trips			X	X
31	Loss of generator and offsite power		X		
	Test condition		1, 2	3	6

Table 14.2-3

Stability Tests

Test	Title		Test Condition					
		Approximate Power (% rated)	20	40	60-75	60-75	95-100	40-50
		Approximate Core Flow (% rated)	37	50	100	55	100	NC
21	Core power - void mode response					X		X
22	Pressure regulator setpoint changes		X	X	X	X	X	X
22	Pressure regulator backup regulator		X	X	X	X	X	X
23A	Feedwater system: water level setpoint change		X	X	X	X	X	X
23B	Feedwater system: heater loss						X	
24	Turbine valve surveillance					X[a]	X[b]	
29	Recirculation flow control system		X	X	X	X	X	X
	Test condition		1	2	3	5	6	4

[a] 45-65% Power
[b] 75-90% Power

Table 14.2-4

Power Ascension Test Program

				Test Conditions[a]						
Test	*Name*	*Cold Test or Open RPV*	*Heat Up*	*1*	*2*	*3*	*4*	*5*	*6*	*Warranty*
1	*Chemical and radiochemical*	X	X	X	X	X			X	
2	*Radiation measurements*	X	X	X	X	X			X	
3	*Fuel loading*	X								
4	*Full core shutdown margin*	X								
5	*Control rod drive*	X	X		X[b]	X[b]			X[b]	
6	*SRM performance and control rod sequence*	X	X	X	X			X	X	
7	*Not applicable*									
8	*Not applicable*									
9	*See 16B*									
10	*IRM performance*	X	X	X						
11	*LPRM calibration*		X	X		X			X	

Table 14.2-4

Power Ascension Test Program (Continued)

Test	Name	Cold Test or Open RPV	Heat Up	Test Conditions[a]						
				1	2	3	4	5	6	Warranty
12	APRM calibration		X	X	X	X		X	X	X
13	Process computer	X	X	X[c]						
14	RCIC		X	X						
15	Not applicable									
16A	Selected process temperatures		X	X	X	X	X		X	
16B	Water level reference leg temperature measurement		X	X	X	X	X	X	X	
17	System expansion and piping vibration	X	X	X	X	X			X	
18	Core power distribution					X			X	
19	Core performance			X	X	X	X	X	X	X
20	Steam production									X
21	Core power void mode response						X	X		

Table 14.2-4

Power Ascension Test Program (Continued)

				Test Conditions[a]						
Test	*Name*	*Cold Test or Open RPV*	*Heat Up*	*1*	*2*	*3*	*4*	*5*	*6*	*Warranty*
22	*Pressure regulator: setpoint changes*			*X,BP*	*X,BP*	*X,NO BP,M*	*X,BP*	*X,BP, M*	*X,M, BP*	
	Backup regulator			*X,BP*	*X,BP*	*X,NO BP,M*	*X,BP*	*X,NO, BP,M*	*X,M, BP*	
23	*Feedwater system*									
	C feedwater pump trip								*M*[d]	
	A water level setpoint change			*X*	*X*	*X,M*	*X*	*X*	*X,M*	
	B heater loss								*X*[e]	
	D maximum runout capability		*X*[f]	*X*[f]			*X*	*X*		
24	*Turbine valve surveillance*						*X,*[g,h] *SP*	*X,*[i,j] *SP*		
25	*MSIVs: each valve*		*X*	*X,*[c] *S*						
	one valve						*X,*[g,i,j] *X,*[k] *SP*			

Table 14.2-4

Power Ascension Test Program (Continued)

Test	Name	Cold Test or Open RPV	Heat Up	Test Conditions[a] 1	2	3	4	5	6	Warranty
	full isolation							X,[b] X,[l] SD		
26	Relief valves:									
	Flow demonstration			X[l,m]						
	Operational		X	X[m]						
27	Turbine stop valve					X[b,l]				
	Stop					SD				
	Generator load				X,BP				X[b,l]	
	Rejection								X,[n] SD	
28	Shutdown from outside control room			X					X[o]	

Table 14.2-4

Power Ascension Test Program (Continued)

				Test Conditions[a]						
Test	Name	Cold Test or Open RPV	Heat Up	1	2	3	4	5	6	Warranty
29	Recirculation flow control system	L		L	M,[m] X,[m] L[m]	X,[m] L,[m] M,[m] A[m]	L[g]	M,[g] X[g]	L,[g] X[g]	
30	Recirculation system:									
	Trip one pump					X[l,n]			X[l,n]	
	Trip two pumps					X[l,n]				
	System performance				X	X[l,m]	X[g]		X[l]	
	Runback					X[d]				
	Noncavitation verification					X				
31	Loss of T-G and offsite power				X,[b,l] SD					
32	Not applicable									
33	Not applicable									

Table 14.2-4

Power Ascension Test Program (Continued)

Test	Name	Cold Test or Open RPV	Heat Up	Test Conditions[a]						
				1	2	3	4	5	6	Warranty
34	RPV Internals				X[m]	X[m]		X[g]	X[g]	
36-69	Not applicable									
70	Reactor water cleanup system		X							
71	Residual heat removal system								X	
72	Drywell atmosphere cooling		X		X	X			X	
73	Cooling water system		X						X	
74	Offgas system	X	X	X		X			X	

[a] See Figure 14.2-1 for test conditions region map.

[b] Perform test 5, timing of four slowest control rods in conjunction with these scrams.

[c] Between test conditions 1 and 3.

[d] Demonstrate recirculation system runback feature.

[e] 80%-90% power.

[f] At either heatup or test condition 1.

Table 14.2-4

<u>Power Ascension Test Program</u> (Continued)

[g] *Between or at test conditions 5 and 6.*

[h] *Between 45% and 65% power on 100% load line.*

[i] *Future maximum power test point.*

[j] *Determine maximum power without scram.*

[k] *Between 40% and 55% power on the 100% load line.*

[l] *Do test 17 in conjunction with this test.*

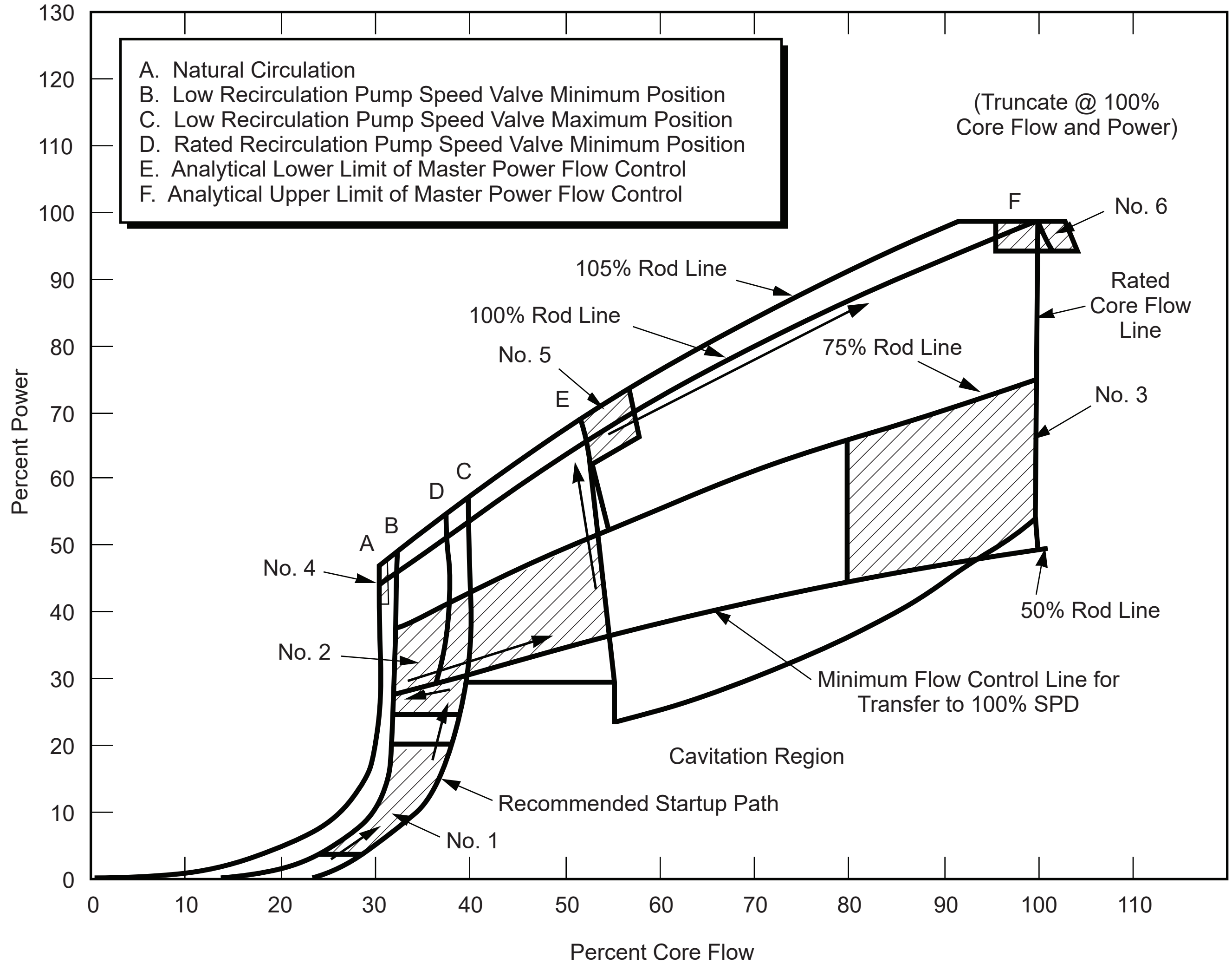
[m] *Between test conditions 2 and 3.*

[n] *Perform test 34 in conjunction with this test.*

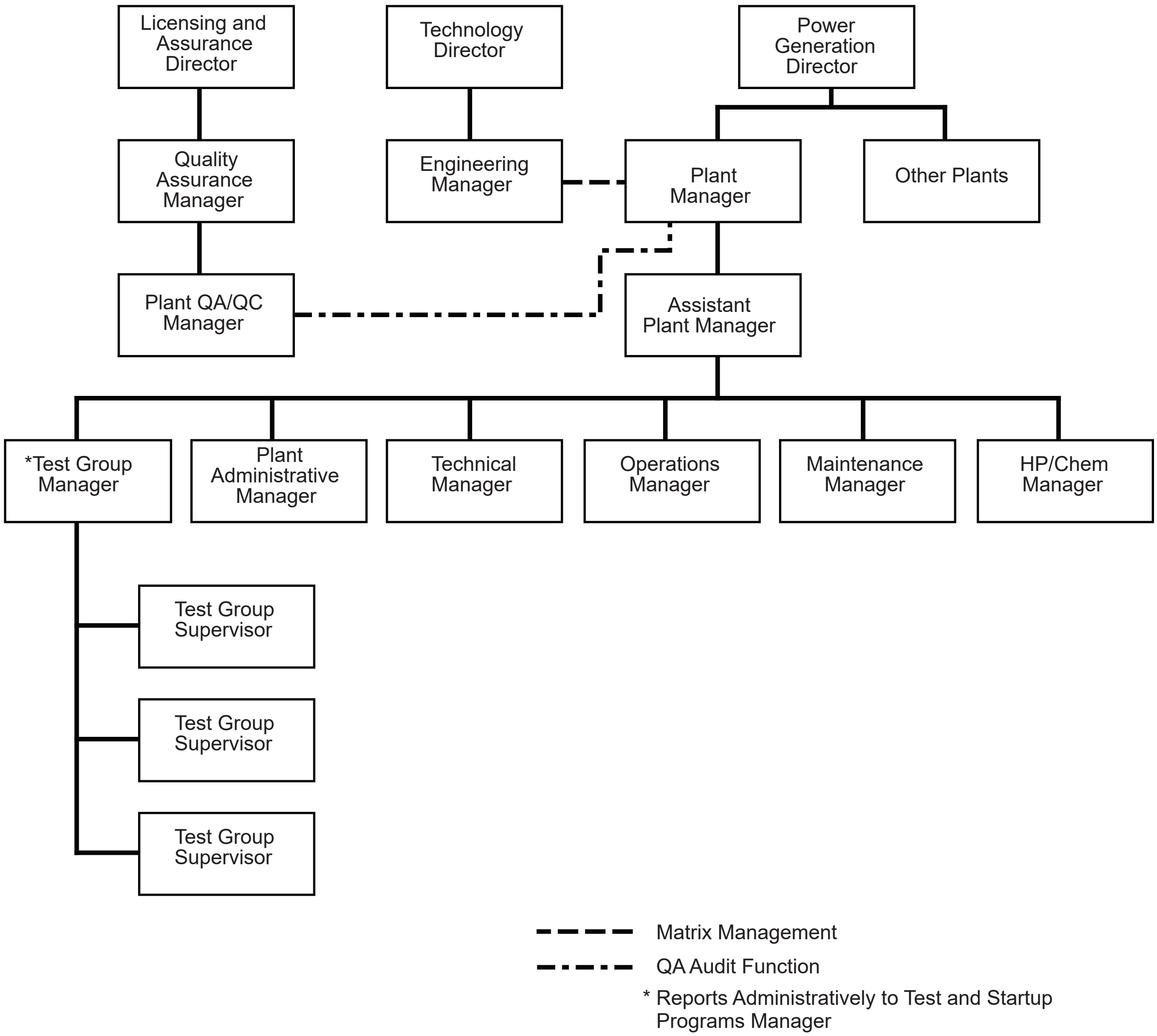
[o] *After one of the scram transients from test condition, during the reactor cooldown, the last part of the shutdown from outside the control room test will be completed by demonstrating the operation of the shutdown cooling mode of RHR from the remote shutdown panel.*

<u>LEGEND</u>

L = Local position command mode operation, POS
M = Flux command mode operation, FLX
X = Combined flow command mode operation, FLO
A = Automatic load following mode operation, ALF
SP = Scram possibility
SD = Scram definite
BP = Bypass valve response

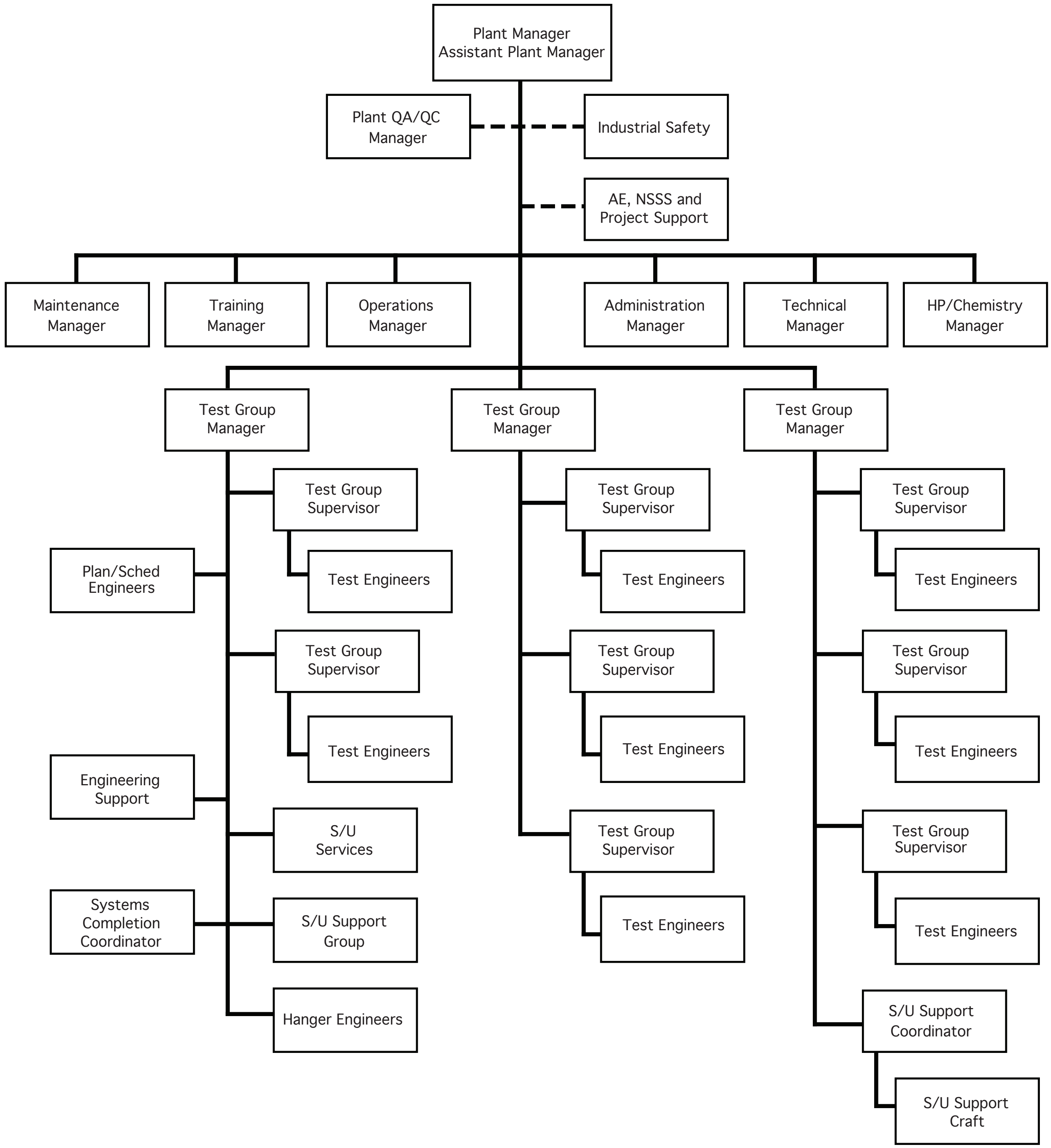


Condition (TC)	
1	Before main generator synchronization and recirc pumps operating on low frequency power supply from approximately 5 to 20 percent thermal power
2	Between 50% and 75% control rod lines, at or below the analytical lower limit of master flow control mode
3	From 50% to 75% control rod lines and core flow between 80% and maximum allowable
4	Natural circulation and within 5% of the intersection with 100% rod line
5	Mid-power range within 5% of 100% control rod line and 0 to +5% core flow of the minimum flow line, for master flow control in manual mode, and for automatic power control in auto mode
6	Within 0 to –5% of rated thermal power, and within 5% of rated core flow rate



Test and Startup Relation to Other Energy Northwest Departments

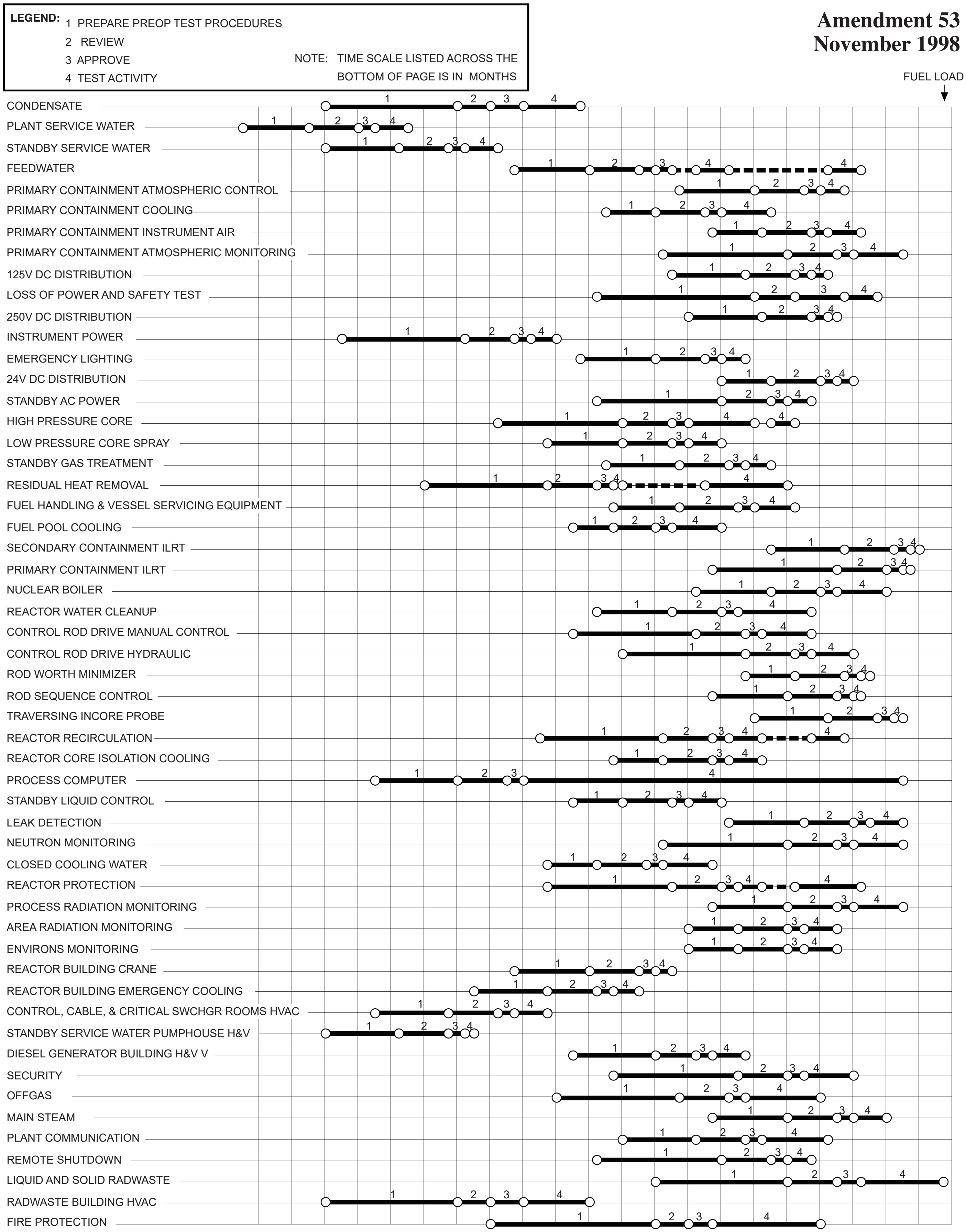
Draw. No. 960222.77 | Rev. | Figure 14.2-2



Columbia Generating Station
Final Safety Analysis Report

CGS Startup Organization

Draw. No. 960222.78 | Rev. | Figure 14.2-3



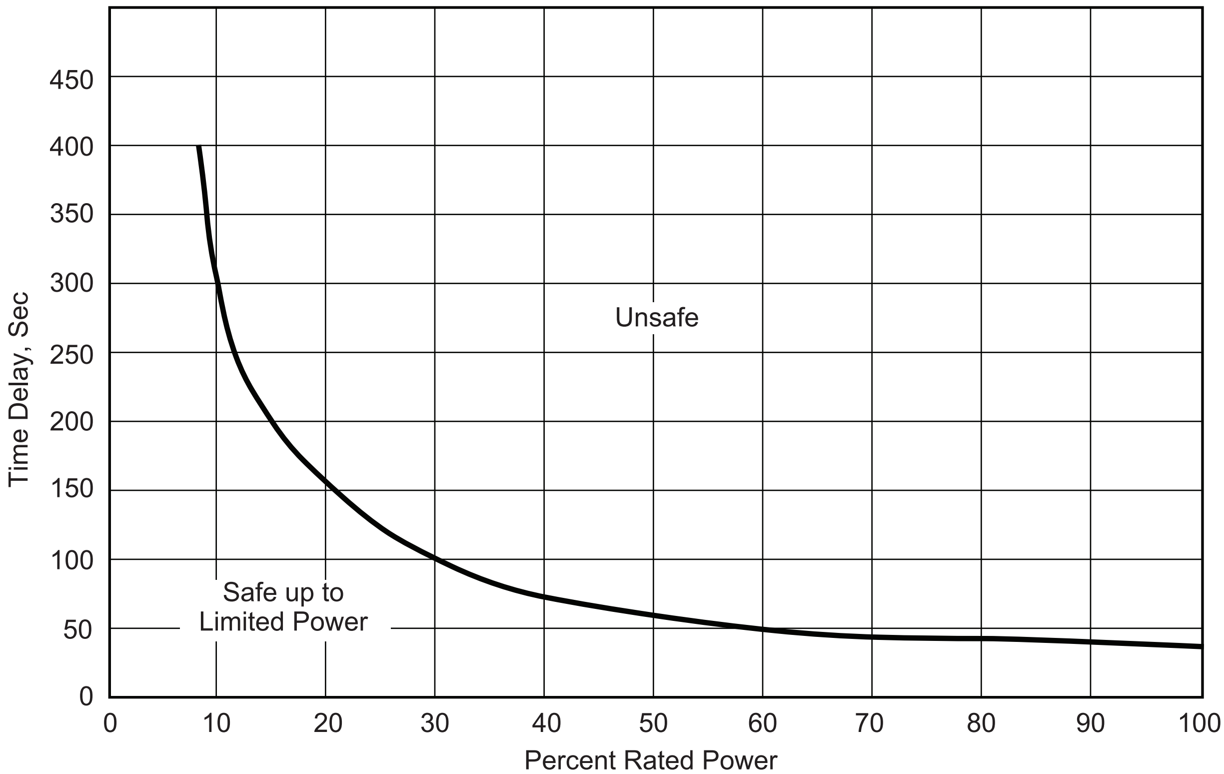
Amendment 53
November 1998

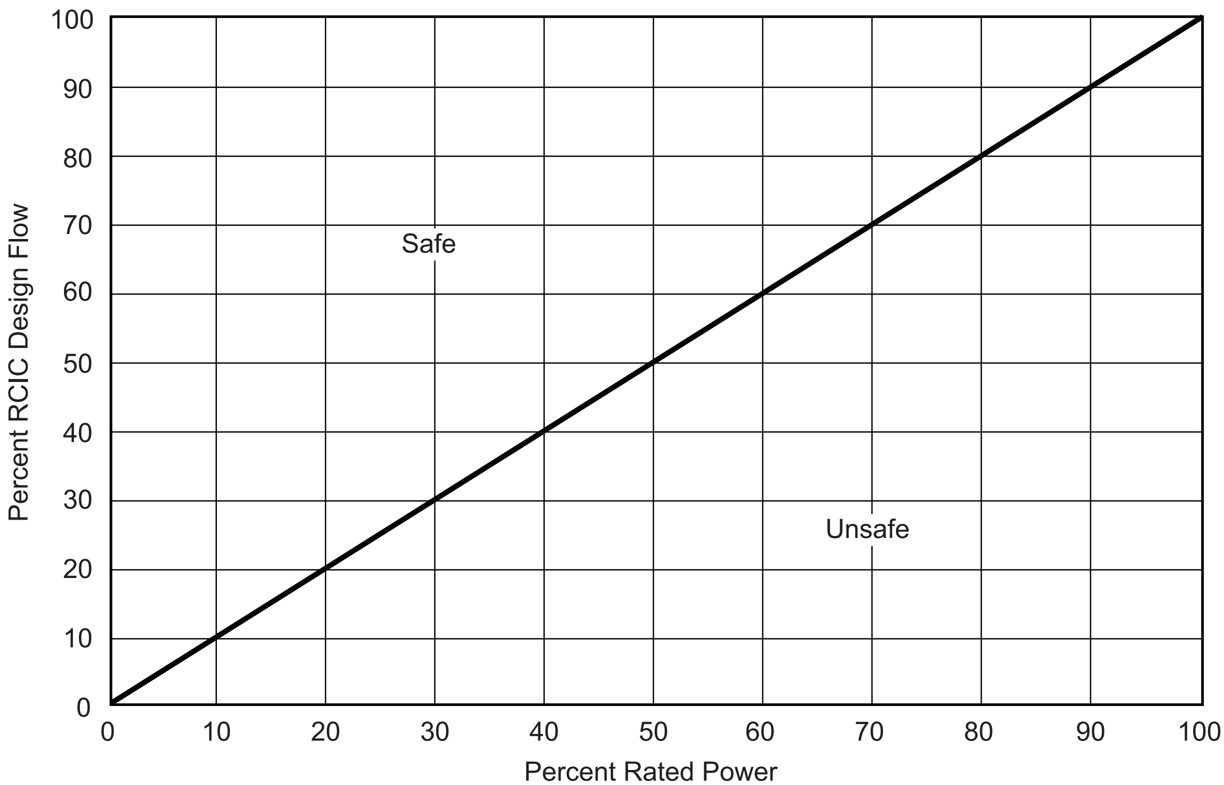
Columbia Generating Station
Final Safety Analysis Report

Preoperational Test Schedule

Draw. No. 960690.83 | Rev. | Figure 14.2-4

Form No. 960690

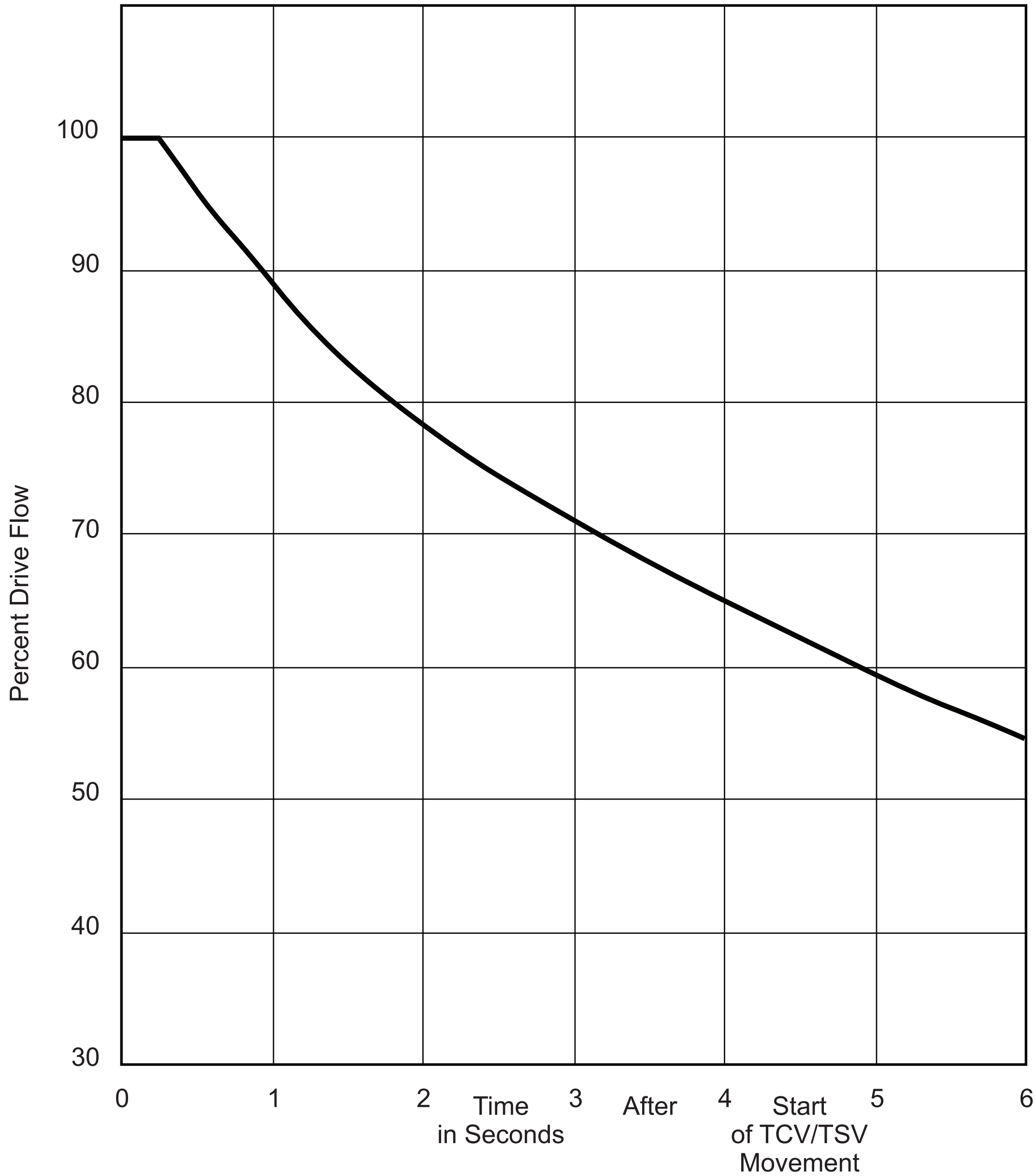




Columbia Generating Station
Final Safety Analysis Report

RCIC Acceptance Criteria Curves for Capacity and Actuation Time

Draw. No. 960690.82	Rev.	Figure 14.2-5



Maximum Acceptable Drive Flow Response

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS

Section | Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section | Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section | Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section | Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section | Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section Page

Chapter 15

ACCIDENT ANALYSES

TABLE OF CONTENTS (Continued)

Section | Page

Chapter 15

ACCIDENT ANALYSES

LIST OF TABLES

Chapter 15

ACCIDENT ANALYSES

LIST OF TABLES (Continued)

Chapter 15

ACCIDENT ANALYSES

LIST OF TABLES (Continued)

Chapter 15

ACCIDENT ANALYSES

LIST OF TABLES (Continued)

Chapter 15

ACCIDENT ANALYSES

LIST OF TABLES (Continued)

Chapter 15

ACCIDENT ANALYSES

LIST OF FIGURES

Chapter 15

ACCIDENT ANALYSES

LIST OF FIGURES (Continued)

Chapter 15

ACCIDENT ANALYSES

LIST OF FIGURES (Continued)

Chapter 15

ACCIDENT ANALYSES

15.0 GENERAL

This chapter discusses the effects of anticipated process disturbances and postulated component failures, their consequences, and the capabilities built into the plant to control or accommodate such failures and events. The analyses have been reviewed and revised, as needed, for the:

- Reactor power uprate
- Installation of the adjustable speed drive for the reactor recirculation pumps
- Implementation of an alternative source term
- APRM/RBM Technical Specification (ARTS) improvement program
- Maximum Extended Load Line Limit Analysis (MELLLA)
- Cycle specific changes

These changes to the plant licensing and design basis and their impact are discussed in this chapter.

The scope of the situations analyzed includes anticipated (expected) operational occurrences, off-design abnormal (unexpected) transients that induce system operating condition disturbances, postulated accidents of low probability, and hypothetical events of extremely low probability. For each reload, the events are evaluated by the fuel vendor(s). The events identified as limiting during the evaluation are analyzed and the sections are revised.

The plant was originally licensed at 3323 MWt. In 1995, an amendment to the plant Operating License authorized an increase in power to 3486 MWt. The power uprate analysis was performed in accordance with the NRC-approved General Electric Company (GE) generic power uprate program for boiling water reactors (BWRs).

A Measurement Uncertainty Recapture (MUR) uprate design change was performed per EC 14942 in 2016 to increase rated thermal power to 3544 MWt. The power uprate analysis was performed in accordance with the NRC-10CFR50, Appendix K approved methodology.

The postulated events in this chapter have been analyzed for power uprate conditions. The only exceptions to using uprated power are some non-limiting single loop operation (SLO) transients that were not reanalyzed as part of the GE power uprate transient analysis. Their text and figures are clearly marked with ORIGINAL POWER designation. Limiting events in terms of setting the fuel operating limits (e.g., Loss of Feedwater Heating, Generator Load Rejection Without Bypass) are reanalyzed on a cycle specific basis and therefore, may include fuel vendor results and references.

The events in this chapter have been analyzed for application of the adjustable speed drives (ASD) in place of the former reactor recirculation control system that used flow control valves

(FCV). The uprated power for Columbia Generating Station is 3544 MWt which is 6.65% higher than the original licensed power of 3323 MWt. All transient initial conditions are specified in Table 15.0-2, 15.0-2A, 15.0-2B or the individual transient event description sections. Several performance improvement packages have been included in the analysis:

1. Final Feedwater Temperature Reduction (FFWTR) and Feedwater Heaters Out-Of-Service (FWHOOS) - Analyses were performed at a reduced feedwater temperature at rated thermal power for operations at end-of-cycle and during the cycle for limiting transients.

2. Increased Core Flow (ICF) – Increased core flow allows for operation at 106% of the rated core flow. The limiting transients were performed for the end-of-cycle with control rods fully withdrawn. This envelopes the operation at increased core flow condition throughout the cycle.

3a. Extended Load Line Limit Analysis (ELLLA) - The consequences of the transients were evaluated to determine if operating limit adjustments are necessary for operation in the extended operating domain and compared with the evaluation at rated thermal power and increased core flow region. This comparison ensures bounding of the results at the extended operating domain.

3b. Maximum Extended Load Line Limit Analysis (MELLLA) – The consequences of the transients were evaluated to determine if operating limit adjustments are necessary for operation in the maximum extended operating domain and compared with the evaluation at rated thermal power and increased core flow region. This comparison ensures bounding of the results at the maximum extended operating domain.

4. Single Loop Operation (SLO) - Limiting transients were re-analyzed for operation at SLO. Using adjustable speed drives (ASD), GE determined the maximum active loop's recirculation flow at 105% of rated pump speed with resultant analyzed power and core flow conditions of 73.8% UP and 57% of rated core flow for SLO. Prior to power uprate, a comprehensive SLO analysis was performed. For non-limiting events, this analysis has been retained for completeness and historical purposes. These analyses are clearly marked with ORIGINAL POWER designation.

5. End-of-Cycle RPT Out-of-Service (RPT OOS) - The recirculation pump trip (RPT) mitigates several transients that are more severe at end-of-cycle. The limiting transients were re-analyzed with RPT OOS at various power/flow conditions.

6. Turbine Bypass Out-of-Service - Limiting transient events have been analyzed with turbine bypass valves out-of-service at limiting power and flow conditions.

7. Average Power Range Monitor, Rod Block Monitor Technical Specifications (ARTS) – The ARTS improvement program improves fuel thermal limits protection at off-rated conditions with a more rigorous application of power and flow dependent

Minimum Critical Power Ratio (MCPR) and Linear Heat Generation Rate (LHGR) limits. The ARTS improvement program eliminates the Technical Specification requirement for total peaking factor setdown at off-rated conditions. The ARTS program includes modification of the Rod Block Monitor (RBM), from flow-based to power-based setpoints, to improve the rod movement flexibility at less than rated power conditions, and establish an optimized configuration that improves the system response with respect to bundle power.

Additional updates address the implementation of the use of alternative source terms (AST) as described in the Regulatory Guide 1.183, July 2000, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors." This methodology is based on the advances that have been made in understanding the timing, magnitude, and the chemical form of fission product releases from severe nuclear power plant accidents. The accidents that were reanalyzed by Energy Northwest with the AST:

- Loss of coolant accident (LOCA)
- Fuel handling accident (FHA)
- Control rod drop accident (CRDA)
- Main steam line break, outside containment, accident (MSLB)

The radiological consequences of these accidents were determined based on AST approved for use under 10 CFR 50.67. In accordance with the guidance provided in Regulatory Guide 1.183, the licensing and design basis are revised to reflect the application of full scope AST methodology (with the exception that the TID-14844 will continue to be used as the basis for equipment qualification (EQ) and radiation zone maps/shielding calculations). The accidents analyzed as part of the implementation of AST are subject to the limits specified in 10 CFR 50.67 and guidelines of Regulatory Guide 1.183.

15.0.1 ANALYTICAL OBJECTIVE

The spectrum of postulated initiating events is divided into categories based on the type of disturbance and the expected frequency of the initiating occurrence. The limiting events in each combination of category and frequency are quantitatively analyzed.

15.0.2 ANALYTICAL CATEGORIES

Transient and accident events contained in this report are provided in individual categories as specified by Regulatory Guide 1.70, Revision 2. The results of the events are summarized in Table 15.0-1. Events evaluated are assigned to one of the following applicable categories:

a. Decrease in reactor coolant temperature:

   Reactor vessel water (moderator) temperature reduction results in an increase in core reactivity. This could lead to fuel-cladding damage.

b. Increase in reactor pressure:

Nuclear system pressure increases threaten to rupture the reactor coolant pressure boundary (RCPB). Increasing pressure also collapses the voids in the core-moderator, thereby increasing core reactivity and power level that could threaten fuel cladding due to overheating.

c. Decrease in reactor coolant system flow rate:

A reduction in the core coolant flow rate could overheat the cladding as the coolant becomes unable to adequately remove the heat generated by the fuel.

d. Reactivity and power distribution anomalies:

Transient events included in this category are those that could cause rapid increases in power due to increased core flow disturbance events. Increased core flow reduces the void content of the moderator increasing core reactivity and power level.

e. Increase in reactor coolant inventory:

Increasing coolant inventory could result in excessive moisture carryover to components such as the main turbine, feedwater turbines, etc.

f. Decrease in reactor coolant inventory:

Reductions in coolant inventory could threaten the fuel as the coolant becomes less able to remove heat generated in the core.

g. Radioactive release from subsystems and components:

Loss of integrity of a radioactive containment component is postulated.

h. Anticipated transients without scram:

To determine the capability of plant design to accommodate an extremely low probability event, a multi-system maloperation situation is postulated.

15.0.2.1 Single Loop Operation (SLO)

Operation with one recirculation loop results in a maximum power output that is 20% to 30% below that which is attainable for two-pump operation. Therefore, the consequences of abnormal operation transients from one-loop operation will be considerably less severe than those analyzed from a two-loop operational mode because of the associated reduction in operation power level.

For pressurization, flow decrease, and cold water increase transients, results presented bound both the thermal and overpressure consequences of one-loop operation. The consequences of flow decrease transients are also bounded by the full power analysis. A single pump trip from one-loop operation is less severe than a two-pump trip from full power because of the reduced initial power level.

Cold water increase transients can result from either recirculation flow controller failure or introduction of colder water into the reactor vessel by events such as loss of feedwater heater. For the former, the flow-dependent MCPR values are derived assuming both recirculation loop controllers fail. This condition produces the maximum possible power increase and, hence, maximum ΔMCPR for transients initiated from less than rated power and flow. When operating with only one recirculation loop, the flow and power increase associated with this failure with only one recirculation loop will be less than that associated with both loops; therefore, the MCPR values derived with the two-pump assumption are conservative for SLO. The latter event, loss of feedwater heating, is generally the most severe cold water increase event with respect to increase in core power. This event is caused by positive reactivity insertion from core inlet subcooling and it is relatively insensitive to initial power level. A generic statistical loss of feedwater heater analysis using different initial power levels and other core design parameters concluded one-pump operation with lower initial power level is conservatively bounded by the full power two-pump analysis. Inadvertent restart of the idle recirculation pump has been analyzed and is applicable for SLO.

From the above discussions, the transient consequence from SLO is bounded by previously submitted full power analyses. The maximum power level that can be attained with one-loop operation is only restricted by the MCPR and overpressure limits established from a full-power analysis.

The following most limiting transients of coldwater increase, pressurization and flow decrease events are analyzed for SLO and the results are shown in Table 15.0-1A:

a. Feedwater flow controller failure (maximum demand),
b. Generator load rejection with bypass failure, and
c. One pump seizure accident.

15.0.3 EVENT EVALUATION

15.0.3.1 Identification of Causes and Frequency Classification

Situations and causes that lead to the initiating event analyzed are described within the analytical categories. The frequency of occurrence of each event is summarized based on operating plant history for the transient event. Events for which inconclusive data exist are discussed separately within each event section.

Each initiating event within the major groups is assigned to one of the following frequency groups:

a. Incidents of moderate frequency - these are incidents that may occur during a calendar year to once per lifetime. This event is referred to as an "anticipated (expected) operational transient."

b. Infrequent incidents - these are incidents that may occur during the life of the particular plant. This event is referred to as an "abnormal (unexpected) operational transient."

c. Limiting faults - these are occurrences that are not expected to occur but are postulated because their consequences may result in the release of significant amounts of radioactive material. This event is referred to as a "design basis (postulated) accident."

15.0.3.1.1 Unacceptable Results for Incidents of Moderate Frequency [Anticipated (Expected) Operational Transients]

The following are unacceptable safety results for incidents of moderate frequency:

a. Release of radioactive material to the environs that exceeds the limits of 10 CFR 20,

b. Reactor operation induced fuel cladding failure,

c. Nuclear system stresses in excess of that allowed for the transient classification by applicable industry codes, and

d. Containment stresses in excess of that allowed for the transient classification by applicable industry codes.

15.0.3.1.2 Unacceptable Results for Infrequent Incidents [Abnormal (Unexpected) Operational Transients]

The following are unacceptable safety results for infrequent incidents:

a. Release of radioactivity that results in dose consequences that exceed a small fraction of 10 CFR 50.67 values,

b. Fuel damage that would preclude resumption of normal operation after a normal restart,

c. Generation of a condition that results in consequential loss of function of the reactor coolant system, and

d. Generation of a condition that results in a consequential loss of function of a necessary containment barrier.

15.0.3.1.3 Unacceptable Results for Limiting Faults [Design-Basis (Postulated) Accidents]

The following are unacceptable safety results for limiting faults:

a. Radioactive material release that results in dose consequences that exceed the requirements of 10 CFR 50.67,

b. Failure of fuel cladding that would cause changes in core geometry such that core cooling would be inhibited,

c. Nuclear system stresses in excess of those allowed for the accident classification by applicable industry codes,

d. Containment stresses in excess of those allowed for the accident classification by applicable industry codes when containment is required, and

e. Radiation exposure to plant operations personnel in the main control room in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident.

15.0.3.2 Sequence of Events and Systems Operation

Each transient or accident is discussed and evaluated in terms of

a. A step-by-step sequence of events from initiation to final stabilized condition (e.g., termination of the accident),

b. The extent to which normally operating plant instrumentation and controls are assumed to function,

c. The extent to which plant and reactor protection systems are required to function,

d. The credit taken for the functioning of normally operating plant systems,

e. The operation of engineered safety systems that is required, and

f. The effect of a single failure or an operator error on the event.

The transient or accident discussion is specific to the event in that it is limited to the events and system operations related to the reactor core performance and postulated damage. In general, the step-by-step description ends when the analysis has demonstrated that the core performance results are within established limits. The stabilized condition does not imply that all actions to stabilize plant parameters or to recover from the transient or accident have been completed by plant personnel. In the stabilized condition, either the core has demonstrated compliance with requirements or the postulated or deterministic damage is complete. At this point, the transient or accident is terminated. After termination of the event, the operator actions or system operations are not event specific. The required actions and expected system operations, needed to establish cold shutdown or to initiate recovery actions, are symptom based and described in procedures. The events associated with a radiological release and radiological consequences of the transient or accident are also discussed.

15.0.3.2.1 Single Failures or Operator Errors

15.0.3.2.1.1 General. The events considered in this section were evaluated and are provided in this chapter in accordance with Regulatory 1.70, Revision 2.

15.0.3.2.1.2 Initiating Event Analysis.

a. The undesired opening or closing of any single valve (a check valve is not assumed to close against normal flow),

b. The undesired starting or stopping of any single component,

c. The malfunction or maloperation of any single control device,

d. Any single electrical component failure, or

e. Any single operator error.

Operator error is defined as an active deviation from written operating procedures or nuclear plant standard operating practices. The set of actions is limited as follows:

a. Those actions that could be performed by one person,

b. Those actions that would have constituted a correct procedure had the initial decision been correct, and

c. Those actions that are subsequent to the initial operator error and have an effect on the designed operation of the plant, but are not necessarily directly related to the operator error.

Examples of single operator errors are as follows:

a. An increase in power above the established flow control power limits by control rod withdrawal in the specified sequences,

b. The selection and complete withdrawal of a single control rod out of sequence,

c. An incorrect calibration of an average power range monitor (APRM), and

d. Manual isolation of the main steam lines as a result of operator misinterpretation of an alarm or indication.

15.0.3.2.1.3 Single Active Component Failure or Single Operator Error Analysis.

a. The undesired action or maloperation of a single active component, or

b. Any single operator error where operator errors are defined as in Section 15.0.3.2.1.2.

15.0.3.3 Core and System Performance

Fuel thermal and hydraulic design are described in Section 4.4.

The fuel cladding integrity safety limit is set so that no fuel damage is calculated to occur if the limit is not violated. Exceeding unacceptable results criteria for fuel cladding integrity for anticipated operational transients is avoided by meeting the following criteria provided in the NRC Standard Review Plan (NUREG-0800) Section 4.4:

a. The expected number of fuel rods in boiling transition should not exceed 0.1% of the fuel rods in the core. This criterion is met by ensuring that the MCPR for any anticipated operational transient is calculated to be not less than the safety limit MCPR values given in the cycle-specific Core Operating Limits Report (COLR).

b. No fuel centerline melting nor uniform total cladding strain in excess of 1% will occur. This criterion is met by compliance with the operating limits for LHGR given in the cycle-specific COLR.

The operating limit for MCPR is developed as follows:

The MCPR calculated during the transient is compared to the safety limit. The MCPR safety limit is established using the critical power evaluation methods and includes consideration of the operating domain and manufacturing uncertainties and a conservative core power distribution as inputs. The operating limit MCPR is established such that the transient ΔCPR for the dynamic anticipated operational occurrences and quasi steady-state anticipated operational occurrences are included in the evaluation. Thus, the operating limit MCPR is specified to maintain an adequate margin to boiling transition.

The MCPR operating limit is the maximum of (a) the applicable exposure dependent, full power and full flow MCPR limit, (b) the applicable exposure and power dependent MCPR limit, and (c) the flow dependent MCPR limit as specified in the cycle-specific COLR. This stipulation ensures that the safety limit MCPR will not be violated throughout the CGS operating regime. Full power MCPR limits are specified to define operating limits at rated power and a range of flow conditions that support extended load line operation. Power dependent MCPR limits are specified to define operating limits at other than rated power conditions. A flow dependent MCPR limit is specified to define operating limits at other than rated flow conditions.

With implementation of ARTS, the APRM total peaking factor setdown requirement is eliminated and power-dependent LHGR limits are substituted to ensure adherence to the fuel thermal mechanical design bases. Flow dependent LHGR limits are added to ensure adherence to all fuel thermal mechanical design bases during recirculation flow increase events.

ELLLA operation extends the power and flow operating regime for CGS above the rated rod line for SLO and two-loop recirculation pump operation (TLO). MELLLA further extends the power and flow operating regime but only for TLO. The COLR defines the ELLLA boundary for SLO and MELLLA boundary for TLO. The cycle specific Supplemental Reload Licensing Report (Reference 15.0-1) documents the reload analyses.

The CGS cycle-specific COLR provides the average planar linear heat generation rate (APLHGR) limits, the MCPR limits, and the linear heat generation rate (LHGR) limits as required by the Technical Specifications.

15.0.3.3.1 Mathematical Model

Unless otherwise stated in the Mathematical Model description for the event being discussed, the following mathematical model was used to perform the Chapter 15 transient analyses.

Transients are analyzed using the transient analysis models described in Reference 15.0-5. The three-dimensional transient analysis model TRACG was used to analyze transients involving significant reactor pressurization (i.e., limiting events). The point-kinetics transient analysis model REDY and the one-dimensional transient analysis model ODYN were used for transients not involving significant reactor pressurization (i.e., non-limiting events). The transient analysis model determines the transient pressure, power, heat flux, and average core flow which are required as input to both the hot channel analysis and to the transient critical power methodology. The TRACG transient analysis model also calculates the transient peak reactor vessel pressure to demonstrate conformance to the reactor pressure vessel safety limit, which is based on the reactor pressure vessel design pressure.

TRACG is a best-estimate code for analysis of BWR transients (Reference 15.0-5). It is based on a multi-dimensional, two-fluid model for the reactor thermal-hydraulics, and a three-dimensional neutron kinetics model for the reactor core. TRACG has a modular structure and flexible geometry capability. It contains a set of basic thermal-hydraulic components, such as vessel, channel, pipe, and tee components which are used as the building blocks to construct the system simulation. In addition to the basic thermal-hydraulic component models, TRACG contains a set of component models for the recirculation pumps, jet pumps, fuel channels, steam separators, and dryers. TRACG also contains a control system model capable of simulating major BWR control systems.

The input data to the transient analysis model come from two sources: (1) the plant model or base deck, and (2) the BWR three-dimensional simulator PANACEA. The plant model provides the necessary input data for the simulation of the plant, including the plant and control systems performance characteristics. The BWR three-dimensional simulator supplies the core state, the neutron kinetics cross sections, and other data necessary to characterize the reactor core.

The TRACG analysis process begins by performing channel grouping and selecting limiting (hot) channels from the PANACEA wrapup file. After updating the TRACG Basedeck with any cycle specific OPL-3 changes, a TRACG Steady-State Initialization case, restarting from the PANACEA wrapup, is then run to establish initial conditions for the subsequent transient case. The Steady-State Initialization includes key parameters such as core power, core flow, vessel steam flow, core inlet subcooling, reactor dome pressure, vessel narrow range water level, steamline pressure drop, and turbine control valve initial position. These TRACG calculated steady state parameters are then compared with the corresponding PANACEA heat balance value or the cycle specific OPL-3 form to confirm that the steady state results are within methodology defined acceptance criteria. A TRACG Null Transient case is then run to establish the TRACG flux convergence criterion. Finally, the TRACG transient cases are run to calculate the limiting (hot) channel ΔCPR/ICPR, pressure margins, and Limiting (hot) channel power and nodal integrated powers.

The GESAM SLMCPR calculational process, which includes the GEXL correlation, is then used to calculate the OLMCPR, based on plant specific transient bias and uncertainty inputs, the cycle specific SLMCPR, and the TRACG calculated ΔCPR/ICPR. The limiting hot channel power and nodal integrated powers are then normalized and used for input to perform the plant/cycle/event specific fuel rod thermal/mechanical evaluation, which is a separate calculation.

The above mathematical models describe the models used in the introduction of GNF2 fuel. Cycle specific analyses are performed using vendor specific models for the vendor supplying the reload fuel for the current cycle as described elsewhere in this chapter.

15.0.3.3.2 Input Parameters and Initial Conditions for Analyzed Events

This section discusses the important input parameters used in the analysis for the event discussed. In some cases, the discussion references Table 15.0-2 (or 2A or 2B).

15.0.3.3.3 Consideration of Uncertainties

Except for total core flow and TIP reading, the uncertainties used in the statistical analysis to determine the MCPR fuel cladding integrity safety limit are not dependent on whether coolant flow is provided by one or two recirculation pumps. Uncertainties used in the two-loop operation analysis are documented in the FSAR. A 6% core flow measurement uncertainty has been established for single loop operation (compared to 2.5% for two-loop operation). This value conservatively reflects the one standard deviation (one sigma) accuracy of the core flow measurement system documented in Reference 15.0-2. In SLO, measurement and prediction uncertainties for radial power distribution and axial power distribution also increase. In the current methodology, axial power uncertainty is not an important parameter. The net effect of these revised uncertainties is an incremental increase in the required MCPR fuel cladding integrity safety limit. The MCPR safety limit for SLO is given in the cycle specific COLR.

15.0.3.3.3.1 Core Flow Uncertainty Analysis

The uncertainty analysis procedure used to establish the core flow uncertainty for one-pump operation is essentially the same as for two-pump operation, with some exceptions. The core flow uncertainty analysis is described in Reference 15.0-2. The analysis of one-pump core flow uncertainty is summarized below.

For SLO, the total core flow can be expressed as follows (see Figure 15.0-2):

$$W_C = W_A - W_I$$

where:

W_C = total core flow

W_A = active loop flow, and

W_I = inactive loop (true) flow.

By applying the "propagation of errors" method to the above equation, the variance of the total flow uncertainty can be approximated by:

$$\sigma^2_{W_C} = \sigma^2_{W_{sys}} + \left[\frac{1}{1-a}\right]^2 \left(\sigma^2_{W_{A_{rand}}}\right) + \left[\frac{a}{1-a}\right]^2 \left(\sigma^2_{W_{I_{rand}}} + \sigma^2_C\right)$$

where:

σ_{W_C} = uncertainty of total core flow;

$\sigma_{W_{sys}}$ = uncertainty systematic to both loops;

$\sigma_{W_{A_{rand}}}$ = random uncertainty of active loop only;

$\sigma_{W_{I_{rand}}}$ = random uncertainty of inactive loop only;

σ_C = uncertainty of "C" coefficient; and

a = ratio of inactive loop flow (WI) to active loop flow (WA).

From an uncertainty analysis, the conservative, bounding values of

$$\sigma_{W_{sys}}, \sigma_{W_{A_{rand}}}, \sigma_{W_{I_{rand}}}, \text{ and } \sigma_C$$

are 1.6%, 2.6%, 3.5% and 2.8% respectively. Based on the above uncertainties and a bounding value of 0.36* for "a", the variance of the total flow uncertainty is approximately:

$$\sigma^2_{W_C} = (1.6)^2 + \left[\frac{1}{1-0.36}\right]^2 (2.6)^2 + \left[\frac{0.36}{1-0.36}\right]^2 \left((3.5)^2 + (2.8)^2\right) = (5.0\%)^2$$

When the effect of 4.1% core bypass flow split uncertainty at 12% (bounding case) bypass flow fraction is added to the above total core flow uncertainty, the active coolant flow uncertainty is:

$$\sigma^2 \text{active coolant} = (5.0\%)^2 + \left[\frac{0.12}{1-0.12}\right]^2 (4.1\%)^2 = (5.1\%)^2$$

which is less than the 6% core flow uncertainty assumed in the statistical analysis.

In summary, core flow during one-pump operation is measured in a conservative way and its uncertainty has been conservatively evaluated.

15.0.3.3.4 Results

This section discusses the results, in terms of core and system performance, of the event analyzed. The COLR provides operating limits that are the results of analytical evaluations that impact core operating parameters for the current cycle. In addition, critical parameters for the complete set of transients analyzed are shown in Table 15.0-1. From the data in Table 15.0-1, an evaluation of the limiting event for that particular category and parameter can

* This flow split ratio varies from about 0.13 to 0.36. The 0.36 value is a conservative bounding value. The analytical expected value of the flow split ratio for CGS is ~0.23.

be made. The limiting events are reanalyzed for the current operating cycle. Table 15.0-3 provides a summary of accidents that may have radiological consequences.

15.0.3.4 Barrier Performance

This section addresses the performance of the RCPB and the containment system during transients and accidents.

During transients that occur with no release of coolant to the containment, only RCPB performance is considered. If release to the containment occurs as in the case of limiting faults, then challenges to the containment are evaluated as well.

Piping systems within the secondary containment structure (i.e., the reactor building) have been analyzed for pipe break effects including jet impingement, jet reaction, pipe whip, and subcompartment pressurization. Where necessary, these loads were included in the design of the structure to ensure that the secondary containment can perform its required functions as defined in Section 6.2.3.

15.0.3.5 Radiological Consequences

This section addresses the radiological release consequences during the incidents of moderate frequency (anticipated operational transients), infrequent incidents (abnormal operational transients), and limiting faults (design basis accidents [DBA]) events. For all events where consequences are limiting a detailed quantitative evaluation is presented. For nonlimiting events, a qualitative evaluation is presented or the results are referenced from a more limiting or enveloping case or event.

For limiting faults (DBA), conservative assumptions considered to be acceptable to the NRC for the purpose of worst case bounding of the event and determining the adequacy of the plant design to meet 10 CFR 50.67 requirements are assumed. This is referred to as the "design basis analysis."

The atmospheric dispersion coefficients are presented in Tables 15.0-4 and 15.0-5. Reference will be made to these tables in the discussion of the analyses.

15.0.4 REFERENCES

15.0-1 Supplemental Reload Licensing Report for Columbia (most recent version referenced in COLR).

15.0-2 General Electric Company, General Electric BWR Thermal Analysis Basis (GETAB); Data, Correlation, and Design Application, NEDO-10958-A, January 1977.

15.0-3 GE Nuclear Energy, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, Revision 0, September 1993 (Proprietary).

15.0-4 GE-Hitachi Report, "Evaluation of Steam Flow Induced Error Impact on the L3 Setpoint Analysis Limit," GEH-NE-0000-0077-4603, December 2007.

15.0-5 General Electric Company, "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A, and supplement for United States, NEDE-24011-P-A-US (most recent approved version referenced in COLR).

15.0-6 GE-Hitachi Nuclear Energy, "Safety Analysis Report for Columbia Generating Station Thermal Power Optimization," NEDC-33853P, March 2016.

LDCN-16-005

Table 15.0-1

Results Summary of Transient Events Applicable to Columbia Generating Station[a]

Paragraph I.D.	Figure I.D.	Description	Maximum Neutron Flux (%NBR)[e]	Maximum Dome Pressure (psig)	Maximum Vessel Pressure (psig)	Maximum Steam Line Pressure (psig)	Maximum Core Average Surface Heat Flux (% of Initial)	DCPR[b,c,e]	Frequency Category
15.1		DECREASE IN REACTOR COOLANT TEMPERATURE							
15.1.1		Loss of Feedwater Heating, Manual Flow Control						0.12[k]	(d)
15.1.2	15.1-1	Feedwater Controller Failure, Max Demand	297	1191	1218	1189		0.31[k]	(d)
15.1.3	15.1-2	Pressure Regulator Fail-Open	129	1151	1172	1151	100	<0.01	
15.1.4		Inadvertent Opening of Safety or Relief Valve	102	1020	1061	1012	100	<0.01	(d)
15.1.6		RHR Shutdown Cooling Malfunction Decreasing Temperature	See text						(d)
15.2		INCREASE IN REACTOR PRESSURE							
15.2.1		Pressure Regulator Fail-Closed	160	1188	1220	1187	106	n/a	(d)
15.2.2	15.2-1	Generator, Load Rejection, Bypass-On[f]	See text						(d)
15.2.2	15.2-2	Generator Load Rejection, Bypass-Off	325	1245	1271	1241		0.32[k]	(d)
15.2.3	15.2-3	Turbine Trip, Bypass-On[f]	See text						(d)
15.2.3	15.2-4	Turbine Trip, Bypass-Off	308	1242	1268	1238		0.31[k]	(d)
15.2.4	15.2-5	Inadvertent MSIV Closure	203	1200	1234	1198	100	0.022	(d)
15.2.5	15.2-6	Loss of Condenser Vacuum	194	1173	1199	1166	111	0.12	(d)
15.2.6	15.2-7	Loss of Auxiliary Power Transformers	104[h]	1169	1185	1166	100	<0.01	(d)
15.2.6	15.2-8	Loss of All Grid Connections	193	1173	1196	1166	106	0.079	(d)
15.2.7	15.2-9	Loss of all Feedwater Flow	104[h]	1142	1152	1142	100	<0.01	(d)
15.2.8		Feedwater Piping Break	See Section 15.6.6						
15.2.9		Failure of RHR Shutdown Cooling	See text						

Table 15.0-1

Results Summary of Transient Events Applicable to Columbia Generating Station[a] (Continued)

Paragraph I.D.	Figure I.D.	Description	Maximum Neutron Flux (%NBR)[e]	Maximum Dome Pressure (psig)	Maximum Vessel Pressure (psig)	Maximum Steam Line Pressure (psig)	Maximum Core Average Surface Heat Flux (% of Initial)	DCPR[b,c,e]	Frequency Category
15.3		DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE							
15.3.1	15.3-1	Trip of One Recirculation Pump Motor	104[h]	1020	1059	1012	100	<0.01	(d)
15.3.1	15.3-2	Trip of Both Recirculation Pump Motors	104[h]	1077	1088	1076	100	<0.01	(d)
15.3.2	15.3-3	Speed Decrease of One Main Recirc Motor	104[h]	1020	1059	1012	100	<0.01	(d)
15.3.2	15.3-4	Speed Decrease of Two Main Recirc Motors	104[h]	1061	1072	1061	100	<0.01	(d)
15.3.3	15.3-5	Seizure of One Recirculation Pump	104[h]	1099	1110	1098	100	<0.01	(i)
15.3.4		Recirc Pump Shaft Break	See 15.3.3						
15.4		REACTIVITY AND POWER DISTRIBUTION ANOMALIES							
15.4.1.1		RWE - Refueling	See text						(j)
15.4.1.2		RWE - Startup	See text						(j)
15.4.2		RWE - At Power	See text						(d)
15.4.3		Control Rod Misoperation	See Sections 15.4.1 and 15.4.2						
15.4.4	15.4-1	Abnormal Startup of Idle Recirculation Loop	122[c]	1004	1026	998	190	0.53	(d)
15.4.5	15.4-2	Speed Increase of One Main Recirc Motor	134[c]	990	1009	986	127	0.15	(d)
15.4.5		Speed Increase of Both Main Recirc Motors	150[c]	1006	1033	1001	149	0.27	(d)
15.4.7		Misplaced Bundle Accident	See text						(j)
15.4.9		Rod Drop Accident							(i)
15.5		INCREASE IN REACTOR COOLANT INVENTORY							
15.5.1	15.5-1	Inadvertent HPCS Pump Start[f]	100[h]	1020	1052	1012	100	<0.01[g]	(d)
15.5.3		BWR Transients	See appropriate events in Sections 15.1 and 15.2						

[a] Results reflect GE14 fuel introduction, and updates from GNF2 introduction some of which are dependent on fuel design and core loading pattern. Compliance with the event acceptance criteria is demonstrated by cycle-dependent analysis of potentially limiting events just prior to the operation of that cycle. The results are reported in the Supplemental Reload Licensing Report (Reference 15.0-1).

LDCN-16-005

Table 15.0-1

Results Summary of Transient Events Applicable to Columbia Generating Station[a] (Continued)

[b] MCPR operating limits are based on the delta-CPR (DCPR) results from the limiting transient event and the MCPR safety limit defined in the Technical Specifications.

[c] Option B DCPR results are reported.

[d] Moderate frequency.

[e] For Measurement Uncertainty Recapture (MUR), non-limiting events are not re-analyzed, but reported results are scaled from 3486 MWt to 3544 MWt rated, unless otherwise indicated.

[f] Non-limiting event under power uprate conditions (event not reanalyzed).

[g] ODYN results without the adjustment factors delineated in the ODYN Report NEDO-24154, NEDC-24154P.

[h] No increase from initial value.

[i] Limiting fault.

[j] Infrequent incident.

[k] This value is only for the more limiting GNF2 fuel and does not include plant specific TRACG bias and uncertainty.

Table 15.0-1A

Summary of Transient Peak Value Results
Single-Loop Operation

Paragraph/ Figure	Description	Maximum Neutron Flux (% NBR)	Maximum System Pressure (psig)	Frequency Category
	Initial condition	73.8	1020	N/A
15.1.2/ 15.1-3	Feedwater flow controller failure (maximum demand) uprated power	87.5	1118	(a)
15.2.2	Generator load rejection - uprated power	129	1184	(a)
15.3.3/ 15.3-6	Seizure of active recirculation pump	73.8	1017	(b)

[a] Moderate frequency incident.
[b] Limiting fault.

Table 15.0-2

Input Parameters and Initial Conditions for Transients

		REDY (ASD Events)	REDY	ODYN
1.	Thermal power level, MWt[a]			
	Rated value	3486	3323	3486
	Analysis value	3702	3464	3629
2.	Steam flow, lbs/hr analysis value	16.09×10^6	14.98×10^6	15.73×10^6
3.	Core flow, lbs/hr	108.5×10^6	108.36×10^6	$95.5\text{-}115.0 \times 10^6$
4.	FW flow rate, lb/sec analysis value	4471	4161	4362
5.	Feedwater temperature, °F	426	424	426
6.	Vessel dome pressure, psig	1020	1020	1020
7.	Vessel core pressure, psig	1031	1031	1031
8.	Turbine bypass capacity, %NBR	22.7	25	22.7
9.	Core coolant inlet enthalpy, Btu/lb	528.3	529.3	529.6
10.	Turbine inlet pressure, psig	992	975	997
11.	Fuel lattice	8 x 8/9 x 9	8x8	Simulated 8x8/9x9
12.	Core average fuel cladding gap conductance, Btu/sec-ft^2-°F	0.3608	0.1667	Fuel specific
13.	Core leakage flow, %	10.20	11.84	Cycle specific
14.	Required MCPR operating limit	(b)	1.24	(c)
15.	MCPR safety limit	(b)	1.06	(c)
16.	Doppler coefficient (-)¢/°			
	Nominal EOC-1	0.311	0.227	(d)
	Analysis data ASD events			
	1. Increase power	0.295	0.215	
	2. Decrease power	0.327		
17.	Void coefficient (-)¢/% Rated			
	Nominal EOC-1		7.48	(d)
	Analysis data for power increase events	15.93	12.70	(d)
	Analysis data for power decrease events	12.10	7.065	(d)
18.	Core average rated void fraction, % (Steady state)	41.24	41.32	43.1
19.	Scram reactivity, $k analysis data	Figure 15.0-1	Figure 15.0-1	(d)
20.	Control rod drive speed, position versus time	Figure 15.0-1	Figure 15.0-1	Figure 15.0-1
21.	Jet pump ratio, M	2.36	2.41	2.39

Table 15.0-2

Input Parameters and Initial Conditions for Transients (Continued)

		REDY (ASD Events)	REDY	ODYN
22.	Safety/relief valve capacity, % NBR safety valve capacity @ 1241 psig	108.6	111.5	108.6
	Relief valve capacity @ setpoint values in item 25 of this table	@ 1121 psig 98.3	101.8	98.3
		@ 1131 psig 99.1	102.8	99.1
		@ 1141 psig 100.0	103.7	100
		@ 1151 psig 100.9	104.6	100.9
		@ 1161 psig 101.7	105.5	101.7
	Manufacturer		Crosby	Crosby
	Quantity installed		18	18
23.	Relief function delay, sec	0.4	0.4	0.4
24.	Relief function response, sec	0.15	0.1	0.15
25.	Setpoints for safety/relief valves			
	Safety function, psig	1200, 1210 1221, 1231 1241	1177, 1187, 1197, 1207, 1217	1200, 1210 1221, 1231 1241
	Relief function, psig	1121, 1131 1141, 1151 1161	1091, 1101, 1111, 1121, 1131	1121, 1131 1141, 1151 1161
26.	Number of valve groupings simulated			
	Safety function, number		5	5
	Relief function, number		5	5
27.	High flux trip analysis setpoint (123 x 1.041), % NBR	128.0	126.20	128[e]
28.	High pressure scram setpoint, psig	1086	1071	1086
29.	Vessel level trips, inches with respect to dryer skirt bottom			
	Level 8 - (L8), in.	59.5	55.5	59.5
	Level 4 - (L4), in.		31.5	30
	Level 3 - (L3), in.	7.5[i]	12.5[i]	(f)
	Level 2 - (L2), in.		(-38)	(f)
30.	APRM thermal trip analysis setpoint			
	(117 x 1.041)% NBR @ 100% core flow	121.8	122.030	121.8[e]
31.	Recirculation pump trip delay, sec	0.190	0.140	0.190
32.	Recirculation pump trip inertia time constant for analysis, sec	6[g]	6[g]	6[g]
33.	RPS response time delay	(h)	(h)	(h)

Table 15.0-2

Input Parameters and Initial Conditions for Transients (Continued)

[a] Defines rated thermal power associated with the analysis. REDY values reflect original rated thermal power, REDY ASD Events and ODYN values reflect the 3486 MWt reactor power uprate. %NBR values correspond to the rated thermal power values. Measure Uncertainty Recapture power uprate valuves are in Table 15.0-2B. Reported results are scaled to 3544 MWt, unless otherwise indicated.

[b] See COLR.

[c] Not applicable to reload 7/cycle 8 simulation.

[d] ODYN values are calculated within the code.

[e] The thermal multiplier (1.041 = 3629/3486) is used to give a conservative margin that is proportional to the core power.

[f] Parameter not used in the analysis.

[g] The inertia time constant is defined by the expression:

$$t = \frac{2 \pi J_O n}{g T_O}$$

where

t = inertia time constant (sec)
J_o = pump motor inertia ($lb\text{-}ft^2$)
n = rated pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (lb-ft)

[h] The "maximum overall response time" as addressed in the LCS is utilized for each scram encountered in the Chapter 15 events.

[i] The impact of steam flow induced error on the analytical limit does not impact event descriptions or conclusions (Reference 15.0-4).

Table 15.0-2A

Input Parameters and Initial Conditions for Transients and Accidents for Single-Loop Operation

		Original Rated Power	Uprated Power
1.	Thermal power analysis value (MWt)	2596.9	2615
2.	Flow		
	Steam (1b/hr)	10.79×10^6	10.76×10^6
	Core (lb/hr)	59.0×10^6	61.85×10^6
	Core bypass (lb/hr)	5.88×10^6	6.22×10^6
	Feedwater (lb/hr)	10.79×10^6	10.76×10^6
	Turbine bypass (lb/hr)	5.88×10^6	N/A
	Turbine bypass (% rated)	N/A	23%
3.	Core Inlet Enthalpy (Btu/lb)	510.8	513.7
4.	Pressure		
	Vessel dome (psia)	1020	1008
	Vessel core (psia)	1029.7	1017.7
	Turbine inlet (psia)[a]	960.5	1000
5.	Jet pump ratio (M)	3.2	3.4
6.	Safety/relief valve capacity		
	% NBR @ 1,164 psig	107.1	N/A
	Manufacturer	Crosby	Crosby
	Quantity installed	18	18
	% NBR @ 1241 psig	N/A	108.6
7.	Relief function		
	Delay (sec)	0.4	0.4
	Response (sec)	0.1	0.15

Table 15.0-2A

Input Parameters and Initial Conditions for Transients and Accidents for Single-Loop Operation (Continued)

		Original Rated Power	Uprated Power
8.	Setpoints for safety/relief valves		
	Safety function (psig)	1177, 1187, 1197, 1207, 1217	1200, 1210, 1221, 1231, 1241
	Relief function (psig)	1106, 1116, 1126, 1136, 1146	1121, 1131, 1141, 1151, 1161
9.	Number of valve groupings simulated		
	Safety function (number)	5	5
	Relief function (number)	5	5
10.	Setpoints		
	High flux trip analysis (1.21 x 1.043) (% NBR)	126.2	128
	High pressure scram (psig)	1071	1086
	APRM thermal trip (% NBR @ 100% core flow)	122.03	121.8
11.	Vessel level trips (ft above instrument zero)		
	Level 8 - (L8) (ft)	4.542	
	Level 4 - (L4) (ft)	2.625	
	Level 3 - (L3) (ft)	1.083[b]	
	Level 2 - (L2) (ft)	(-)4.167	
12.	RPT delay (sec)	0.19	0.19
13a.	RPT inertia for analysis (lb/ft^2)	24,500	N/A
13b.	RPT inertia time constant (sec)	N/A	6

[a] Pressure specified at rated power condition. Off-rated power pressure drop is calculated by transient analysis code.

[b] The impact of steam flow induced error on the analytical limit does not impact event descriptions or conclusions (Reference 15.0-4).

Table 15.0-2B

Input Parameters and Initial Conditions for
ARTS/MELLLA, MUR and GNF Reload Transient Analyses

Parameter	ARTS/MELLLA	MUR/Reload
1. Thermal power level, MWt	3486	3544
2. Steam flow, lbs/hr analysis value	15.01×10^6	15.28×10^6
3. Core flow, lbs/hr	$87.6 - 115.0 \times 10^6$	$89.7 - 115.0 \times 10^6$
4. FW flow rate, lb/sec analysis value	4161.6	4236.9
5. Feedwater temperature, °F	421.2	422.1
6. Vessel dome pressure, psig	1020	
7. Vessel core pressure, psig	1032	
8. Turbine bypass capacity, %NBR	23.75	23.33
9. Core coolant inlet enthalpy, Btu/lb (rated flow)	527.2	528.5
10. Turbine inlet pressure, psig	990	
11. Fuel lattice	10 x 10 mixed core	
12. Required MCPR operating limit	See COLR	
13. MCPR safety limit	See COLR	
14. Control rod drive speed, position versus time[a]		
15. Jet pump ratio, M	2.285	
16. Safety/relief valve capacity, % NBR safety valve capacity	See Table 5.2-3	
Manufacturer	Crosby	
Quantity installed	18	
17. Relief valve function		
delay, sec	0.4	
response, sec	0.15	
18. Safety valve function		
delay, sec	0.0	
response, sec	0.3	

Table 15.0-2B

Input Parameters and Initial Conditions for GNF Reload Transient (Continued)

Parameter	Value	
19. Setpoints for safety/relief valves	# in Group	Setpoint
Safety function, psig	2[b]	1200
	4[b]	1210
	4	1221
	4	1231
	4	1241
Relief function, psig	2[b]	1156
	4[b]	1166
	4	1176
	4	1186
	4	1196
20. Number of valve groupings simulated		
Safety function, number (actual/credited)	5 / 3	
Relief function, number (actual/credited)	5 / 3	
21. High flux trip analysis setpoint, % NBR	123.0	
22. High pressure scram setpoint, psig	1086	
23. Vessel level trips, inches with respect to instrument zero		
Level 8 – (L8), in.	59.5	
Level 4 – (L4), in.	30	
Level 3 – (L3), in.	2.5[c]	
Level 2 – (L2), in.	-90 LOCA -70 Non LOCA	
24. APRM thermal trip analysis setpoint	Not credited	
25. Recirculation pump trip delay, sec	0.200	
26. RPS response time delay	See LCS	

[a] See Section 4.6.1.1.2.5.3.
[b] Valve group function not credited in safety analyses.
[c] This allows the correction due to steam flow induced error (Reference 15.0-4).

Table 15.0-3

Summary of Accidents

Paragraph I.D.	Title	Failed Fuel Calculated Value
15.3.3	Seizure of one recirculation pump	None
15.3.4	Recirculation pump shaft break	None
15.4.9	Rod drop accident	850 rods
15.6.2	Instrument line break	None
15.6.4	Steam system pipe break outside containment	None
15.6.5	Loss-of-coolant accident within RCPB	100%
15.6.6	Feedwater line break	None
15.7.1	Main condenser gas treatment system failure	N/A
15.7.3	Liquid radwaste tank failure	N/A
15.7.4	Fuel handling accident	250 rods
15.8	Anticipated transients without scram	None

Table 15.0-4

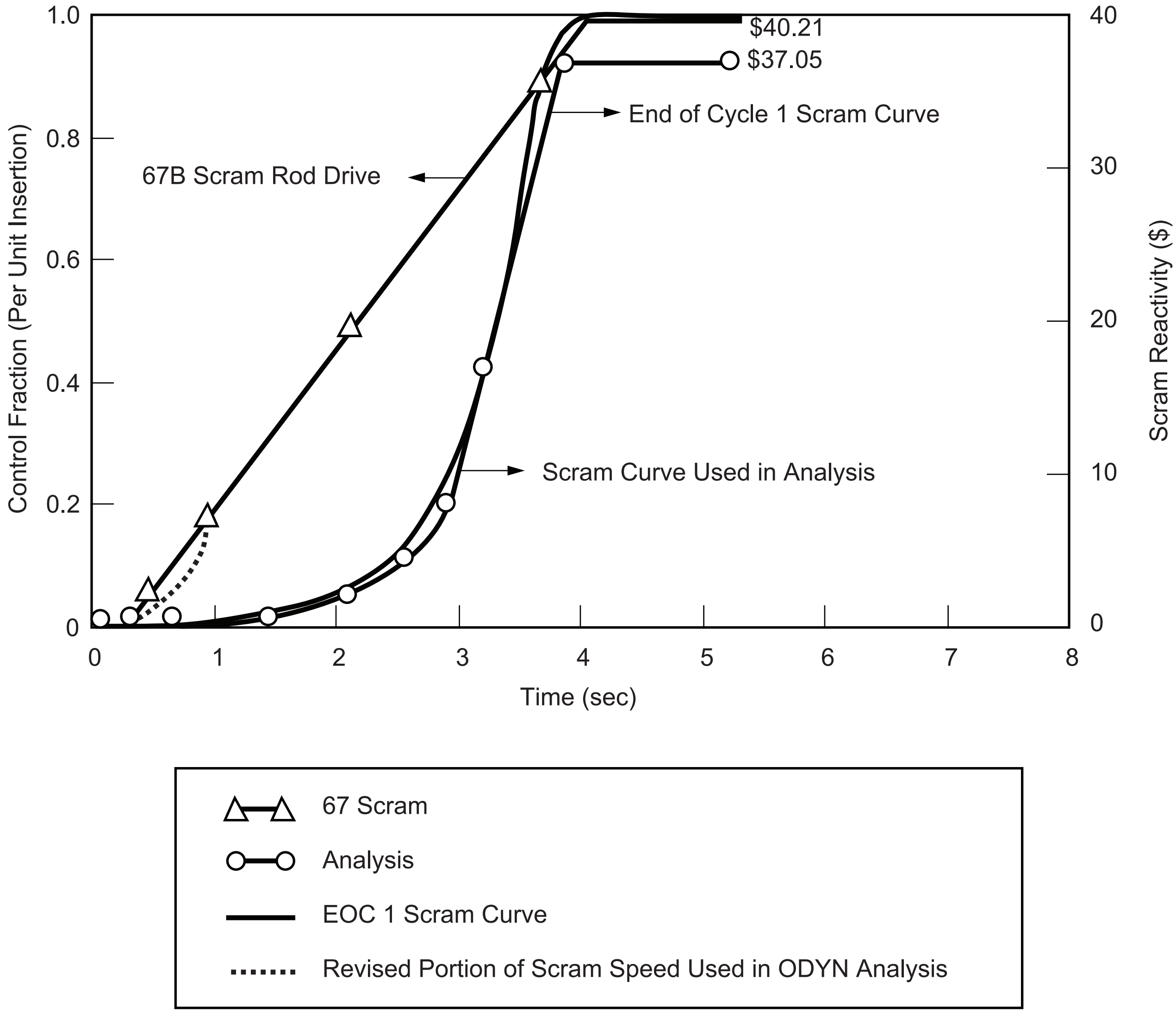
χ/Q (s/m^3) values for the EAB and LPZ

Time Period	EAB χ/Q (s/m^3)	LPZ χ/Q (s/m^3)
0 - 2 hrs	1.81 E-4	4.95 E-5
2 - 8 hrs		4.95 E-5
8 - 24 hrs		3.69 E-5
1 - 4 d		1.95 E-5
4 - 30 d		7.81 E-6

Table 15.0-5

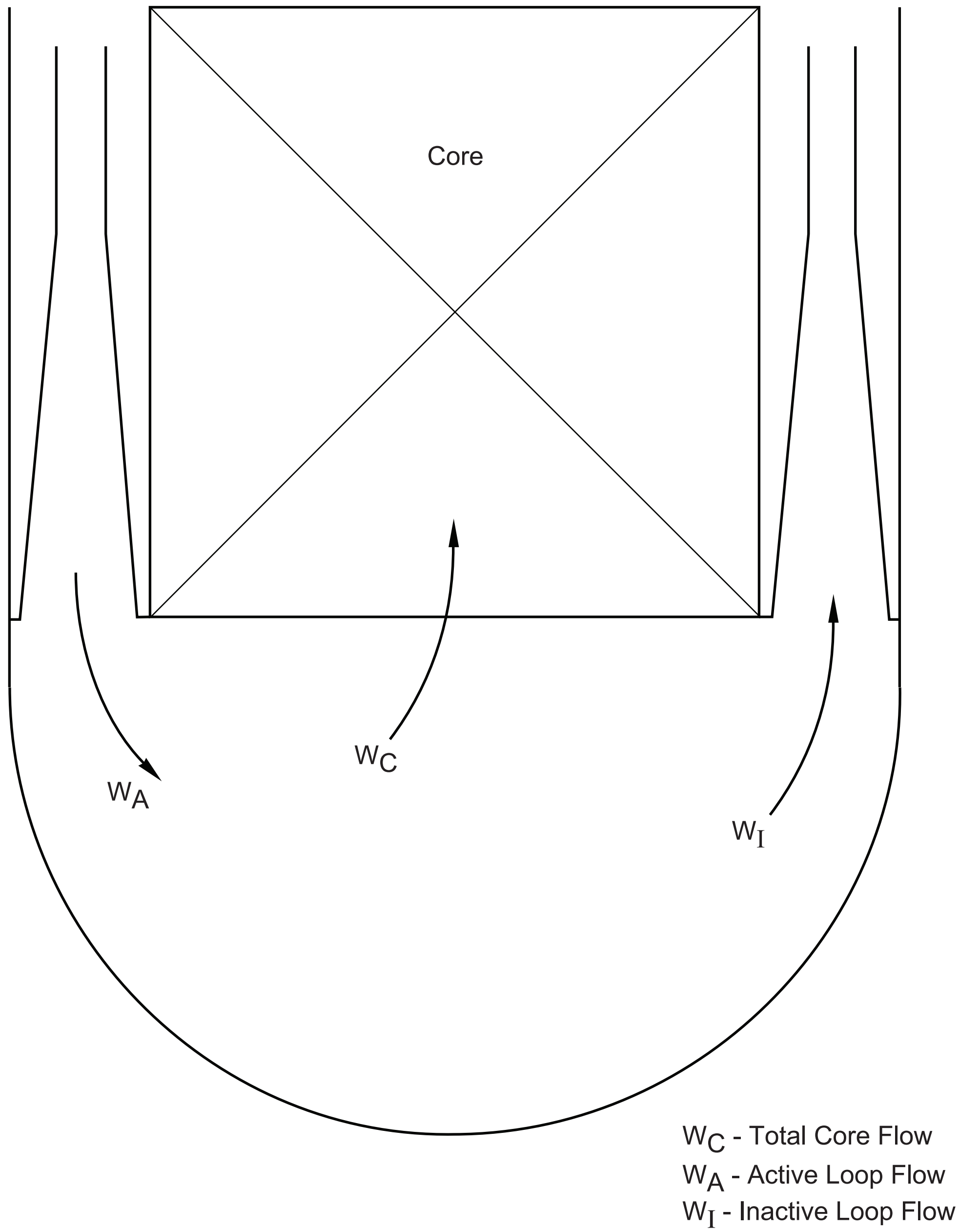
Control Room Atmospheric Dispersion Factors
(sec/m^3)

	Hours	Turbine Building	Secondary Containment	SGT System Release
Filtered Intake Release Path	0 - 2	8.81E-4	2.82E-4	1.43E-4
	2 - 8	3.75E-4	2.17E-4	1.05E-4
	8 - 24	1.93E-4	8.77E-5	4.14E-5
	24 - 96	1.50E-4	7.42E-5	3.52E-5
	96 - 720	1.44E-4	6.40E-5	3.03E-5
Unfiltered Intake Release Path	0 - 2	4.70E-3	7.02E-4	6.95E-4
	2 - 8	2.00E-3	3.19E-4	3.36E-4
	8 - 24	1.03E-3	1.30E-4	1.28E-4
	24 - 96	8.01E-4	1.05E-4	9.72E-5
	96 - 720	7.69E-4	9.00E-5	7.69E-5



Scram Position and Reactivity Characteristics

Draw. No. 900547.61 | Rev. | Figure 15.0-1



Columbia Generating Station Final Safety Analysis Report	**Illustration of Single Recirculation Loop Operation Flows**
	Draw. No. 910402.42 Rev. Figure 15.0-2

15.1 DECREASE IN REACTOR COOLANT TEMPERATURE

15.1.1 LOSS OF FEEDWATER HEATING

15.1.1.1 Identification of Causes and Frequency Classification

15.1.1.1.1 Identification of Causes

A feedwater heater can be lost in at least two ways:

a. Steam extraction line to heater is closed, and
b. Steam is bypassed around heater.

The first case produces a gradual cooling of the feedwater. In the second case, the steam bypasses the heater and no heating of that feedwater occurs. In either case, the reactor vessel receives cooler feedwater. The maximum number of feedwater heaters that can be tripped or bypassed by a single event represents the most severe transient for analysis considerations. This event has been conservatively estimated to incur a loss of up to 100°F of the feedwater heating capability of the plant and causes an increase in core inlet subcooling. This increases core power due to the negative void reactivity coefficient.

15.1.1.1.2 Frequency Classification

This event is considered to be an incident of moderate frequency and is analyzed under worst case conditions of a 100°F loss at full power.

15.1.1.2 Sequence of Events and Systems Operation

The loss of feedwater heating leads to a gradual decrease in the temperature of the feedwater entering the reactor vessel. The decrease in feedwater temperature results in an increase in the core inlet subcooling which collapses voids, and increases the core average power. The gradual power change allows fuel thermal response to maintain pace with the increase in neutron flux. For this analysis, it was assumed that the initial feedwater temperature dropped 100°F.

In establishing the expected sequence of events and simulating the plant performance, it was assumed that normal functioning occurred in the plant instrumentation and controls, plant protection, and reactor protection systems. Engineered safety feature (ESF) system initiation is not anticipated or required to prevent or mitigate the transient.

The Average Power Range Monitor (APRM) Simulated Thermal Power trip setpoint provides protection against transients such as the Loss of Feedwater Heating where thermal power increases slowly. While the sequence of events may produce sufficiently high flux levels to initiate an APRM reactor protection system trip, no credit is taken for a reactor trip in the analysis of the event. A description of the APRM system and operation is provided in Sections 7.2.1.1.1.2 and 7.6.1.4.3.

15.1.1.2.1 The Effect of Single Failures and Operator Errors

The loss of feedwater heating generally leads to an increase in reactor power level. The APRM system is the mitigating system and is designed to be single failure proof. Therefore, single failures are not expected to result in a more severe event than analyzed.

15.1.1.3 Core and System Performance

15.1.1.3.1 Mathematical Model

The analytical dynamic behavior has been determined using the steady state boiling water reactor (BWR) simulator code PANACEA (Reference 15.1-2). This code does not provide plots of the dynamic behavior of basic parameters as a function of time nor does it provide information for a sequence of events table. Therefore, no figures or tables are available. Reference 15.1-6 approves the use of PANACEA for modeling the Loss of Feedwater Heating event.

The loss of feedwater heating (LFWH) event analysis supports an assumed 100°F decrease in the feedwater temperature. The result is an increase in core inlet subcooling, which collapses voids, thereby, increasing the core power and shifting the axial power distribution toward the bottom of the core. As a result of the axial power shift and increased core power, voids begin to build up at the bottom of the core, acting as negative feedback to the void collapse process. The negative feedback moderates the core power increase. The PANACEA code is used to determine the change in minimum critical power ratio (MCPR) during the event. Analyses were performed for a range of cycle exposures to ensure that appropriate limits are set. Although there is a substantial increase in core thermal power during the event, the increase in steam flow is much less because a large part of the added power is used to overcome the increase in inlet subcooling. The increase in steam flow is accommodated by the pressure control system by the turbine control (governor) valves or the turbine bypass valves, so no pressurization occurs (Reference 15.1-3).

15.1.1.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2B.

15.1.1.3.3 Results

The LFWH transient is analyzed for each reload core to quantify the reduction in thermal margins. The results of the analysis are provided in the cycle specific Supplemental Reload Licensing Report (Reference 15.1-3).

15.1.1.3.4 Considerations of Uncertainties

Factors such as exposure and magnitude of feedwater temperature change are assumed to be at the worst configuration so that any deviations seen in the actual plant operation reduce the severity of the event.

15.1.1.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.1.1.5 Radiological Consequences

Since this event does not result in any additional fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.1.2 FEEDWATER CONTROLLER FAILURE - MAXIMUM DEMAND

15.1.2.1 Identification of Causes and Frequency Classification

15.1.2.1.1 Identification of Causes

This event is postulated on the basis of a single failure of a control device, specifically one that can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe applicable event is a feedwater controller failure (FWCF) during maximum flow demand. The feedwater controller is forced to its upper limit at the beginning of the event. The event is evaluated for both single and two reactor recirculation loop operations. Because the two-loop operation event is bounding, the core performance analysis is limited to the feedwater controller failure during two-loop operation. However, the MCPR operating limit for single loop operation (SLO) is obtained by adding the ΔCPR from two-loop operation to the MCPR safety limit (SLMCPR) for SLO.

15.1.2.1.2 Frequency Classification

This event is considered to be an incident of moderate frequency.

15.1.2.2 Sequence of Events and Systems Operation

The increase in feedwater flow, due to a failure of the feedwater control system to maximum demand, results in an increase in the water level and a decrease in the coolant temperature at the core inlet. The increase in core inlet subcooling causes an increase in core power. As the feedwater flow continues at maximum demand, the water level continues to rise and eventually reaches the high water level trip setpoint. The initial water level is conservatively assumed to be at the low level normal operating range of 30 inches above instrument zero to delay the high-level trip and maximize the core inlet subcooling that results from the FWCF. The high water level trip causes the turbine throttle (stop) valves to close in order to prevent damage to the turbine from excessive liquid inventory in the steam line. The valve closures create a compression wave that travels to the core causing a void collapse and subsequent rapid power excursion. In addition to the turbine throttle valve closure, the turbine governor valves also close in the fast closure mode. The closure of the governor (control) turbine valves initiates a reactor scram and a recirculation pump trip. Because of the partially opened initial position of the governor valves, they will close faster than the throttle valves and initiate the pressurization portion of the event. The turbine bypass valves are assumed operable and provide some pressure relief. The core power excursion is mitigated in part by the pressure relief, but the primary mechanisms for termination of the event are reactor scram and revoiding of the core.

The high-pressure core spray (HPCS) system and reactor core isolation cooling (RCIC) system initiate on a low reactor water level (L2) to maintain long-term water level control following tripping of feedwater pumps. The analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection and reactor protection systems.

Table 15.1-1 lists the sequence of events for Figure 15.1-1. The figure shows the changes in variables during this transient.

15.1.2.2.1 Sequence of Events and Systems Operation – Single Loop Operation

The simulated feedwater controller transient is shown in Figure 15.1-3 for the case of 73.8% power, 57% core flow. The high-water level turbine trip and feedwater pump trip are initiated at approximately 8.4 sec. A scram occurs simultaneously with the turbine trip and limits the neutron flux peak and fuel thermal transient so no fuel damage occurs.

Table 15.1-1A lists the sequence of events for Figure 15.1-3. The figures show the changes in important variables during this transient.

Identification of Operator Actions

a. Observe high feedwater pump trip has terminated the failure event,

b. Switch the feedwater controller from auto to manual control to try to regain a correct output signal, and

c. Conduct follow-up assessment.

15.1.2.2.2 The Effect of Single Failures and Operator Errors

The first sensed event to initiate corrective action to the transient is the vessel high water level (L8) trip. Multiple level sensors are used to sense and detect when the water level reaches the L8 setpoint. At this point in the logic, a single failure will not initiate or prevent a turbine trip signal. Turbine trip signal transmission, however, is not built to single failure criterion. The result of a failure at this point would have the effect of delaying, but not impacting, the pressurization “signature.”

Scram trip signals from the turbine are designed such that a single failure will neither initiate nor impede a reactor scram trip initiation.

15.1.2.3 Core and System Performance

15.1.2.3.1 Mathematical Model

The predicted dynamic behavior has been determined using a computer simulated, analytical model of a direct-cycle BWR. This model is described in detail in Reference 15.1-3. Results from the two-loop operation bound the SLO event. Therefore, the discussion of core and system performance is limited to the description of the analysis for two-loop operation.

The nonlinear computer simulated analytical model is designed to predict associated transient behavior of the reactor. Some of the significant features of the model are the following:

a. An integrated three-dimensional neutron kinetics core model is assumed which includes a detailed description of hydraulic feedback effects, axial power shape changes, and reactivity feedbacks;

b. The fuel is represented by a separate channel grouping scheme based on the distinct characteristics of the fuel bundles in the core;

c. The four physical steam lines are modeled as two steam lines, one a single steam line and the other as three lumped steam lines. The modeled steam lines are connected with a tee component and another tee connected downstream which is connected to a valve component modeling the Turbine Bypass Valves (TBVs). Also associated with these steam lines are valve components modeling the inboard and outboard main steam isolation valves, the Safety/Relief valves, and the Turbine Control Valves. Pressure boundary condition components are connected to the downstream sides of the S/RVs, and the TBVs. A flow boundary condition component represents the steam mass flow rate through the TCVs. This mass flow rate is calculated by the TRACG control system logic. The open area fraction of the S/RVs and TBVs is determined by the TRACG control system logic. TRACG control systems are used extensively in modeling plant component and system behavior.;

d. The code is based on a multi-dimensional two-fluid model for the reactor thermal hydraulics. The basic two-phase, two-fluid model consists of the volume and time averaged conservation equations for mass, momentum, and energy for each phase. Thus, the model does not assume thermal or mechanical equilibrium between the phases;

e. A control system model capable of simulating major BWR controls systems, such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand; and

f. The ability to simulate necessary reactor protection system functions is provided.

15.1.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed with the plant conditions in Table 15.0-2B.

All rods out scram characteristics are assumed. The safety/relief valve (SRV) action is conservatively assumed to occur with higher than nominal setpoints. The transient is simulated by programming an upper limit failure in the feedwater system such that 139% feedwater flow occurs at the nominal reactor operating pressure of 1035 psia.

An increase in feedwater flow will cause a corresponding drop in feedwater temperature. However, the relatively large time constant of the feedwater heaters (order of minutes) plus the flow transport time (10 sec from heaters to vessel and 3 sec from sparger to core) would preclude any effect of temperature reduction on the transient since the transient is essentially over in about 20 sec. Therefore, feedwater temperature is assumed to remain constant.

15.1.2.3.3 Results

The simulated feedwater controller transient is shown in Figure 15.1-1. The high water level turbine trip and feedwater pump trip are initiated as stated in Table 15.1-1. Results reflect GNF2 fuel introduction, some of which are dependent on fuel design and core loading pattern. Compliance with the event acceptance criteria is demonstrated by cycle-dependent analysis of potentially limiting events just prior to the operation of that cycle. The results are reported in the Supplemental Reload Licensing Report (Reference 15.1-3).

Because the total change in feedwater flow is greatest from reduced power conditions, the feedwater controller failure (FWCF) transient was analyzed for several reduced power states. The power dependent MCPR limits are established to protect the fuel during the FWCF event.

15.1.2.3.4 Consideration of Uncertainties

All systems used for protection in this event were assumed to have the most conservative response characteristics. Therefore, actual plant behavior is expected to lead to a less severe transient.

15.1.2.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.1.2.5 Radiological Consequences

The consequence of this event does not result in fuel failure. It does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation, which is contained in the primary containment. This event does not result in an uncontrolled release to the environment, so the plant operator can choose to hold the activity in containment or discharge it when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.1.3 PRESSURE REGULATOR FAILURE - OPEN

15.1.3.1 Identification of Causes and Frequency Classification

15.1.3.1.1 Identification of Causes

The total steam flow rate to the main turbine resulting from a pressure regulator malfunction in the Digital Electro-Hydraulic (DEH) control system is limited by a maximum flow limiter imposed at the turbine controls. This limiter is set to limit maximum steam flow demand to approximately 130% NBR.

If the triple redundant DEH control system fails such that the turbine control (governor) valves fully open and the turbine bypass valves partially open, the maximum steam flow is established.

15.1.3.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.1.3.2 Sequence of Events and Systems Operation

15.1.3.2.1 Sequence of Events

Table 15.1-2 lists the sequence of events for Figure 15.1-2. Figure 15.1-2 depicts how the high water level turbine trip and isolation valve closure stops vessel depressurization and produces a normal shutdown of the reactor.

15.1.3.2.2 Systems Operation

Depressurization results in formation of voids in the reactor coolant and causes a decrease in reactor power almost immediately. In this simulation, the depressurization rate is large enough such that water level swells to the sensed level trip setpoint (L8), initiating main turbine and feedwater turbine trips. Position switches on the turbine stop (throttle) valves initiate a reactor scram and RPT and shut down the reactor. After the turbine trip, the failed DEH control system signals the bypass to open to full bypass flow of 25% NBR steam flow. After the pressurization resulting from the turbine stop (throttle) valve closure, the pressure increase opens the relief valves and pressure drops and continues to drop until turbine inlet pressure is below the low turbine pressure isolation setpoint when main steam line isolation limits the duration and severity of the depressurization.

In order to properly simulate the expected sequence of events, the analysis of this event assumed normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems except as otherwise noted.

Initiation of HPCS and RCIC system functions will occur when the vessel water level reaches the L2 setpoint although this is not included in the analysis. Normal startup and actuation can take up to 30 sec before effects are realized. If these events occur, they will follow some time after the primary concerns of fuel thermal margin and overpressure effects have occurred and are expected to be less severe than those already experienced by the system.

15.1.3.2.3 The Effect of Single Failures and Operator Errors

This transient leads to a loss of pressure control such that the increased steam flow demand causes a depressurization. Instrumentation for pressure sensing of the turbine inlet pressure is designed to be single failure proof for initiation of MSIV closure.

Reactor scram sensing, originating from limit switches on the MSIVs, is designed to be single failure proof. It is, therefore, concluded that the basic phenomenon of pressure decay is adequately terminated.

15.1.3.3 Core and System Performance

15.1.3.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 is used to simulate this event.

15.1.3.3.2 Input Parameters and Initial Conditions

This transient is simulated by setting the DEH control system demand signal to a high value, which causes the turbine control (governor) valves to open fully and the turbine bypass valves to open partially. A DEH control failure with 130% steam flow demand signal was simulated as a worst case since 130% is the normal maximum flow limit in order to conform with Table 15.1-2.

A 5-sec isolation valve closure is assumed when the turbine pressure decreases below the turbine inlet low pressure setpoint for main steam line isolation initiation.

Reactor scram is initiated when the isolation valves reach the 10% closed position. This is the maximum travel from the full open position allowed by specification.

This analysis has been performed, unless otherwise noted, with the plant conditions listed in Table 15.0-2.

15.1.3.3.3 Results

Results are summarized in Table 15.0-1.

No significant reductions of fuel thermal margins occur. No significant thermal stresses are imposed on the reactor coolant pressure boundary (RCPB).

15.1.3.3.4 Consideration of Uncertainties

If the maximum flow limiter were set higher or lower than normal, a faster or slower loss in nuclear steam pressure would result. The rate of depressurization may be limited by the bypass capacity, but it is unlikely. For example, the turbine valves will open to the valves-wide-open state admitting slightly more than the rated steam flow, and with the limiter in this analysis set to fail at 130%, it is expected that less than 25% would be bypassed. This is, therefore, not a limiting factor for the plant. If the rate of depressurization does change, it will be terminated by the low turbine inlet pressure trip setpoint.

Depressurization rate has a proportional effect upon the voiding action in the core and the flashing in the vessel bulk water regions. If the rate is low enough, the water level may not swell to the high water level trip setpoint and the isolation will occur earlier when pressure at the turbine decreases below 795 psig. The reactor will scram as a result of the MSIV closure. Since power is being depressed as the pressure decreases (due to additional voiding in the core), this transient is less severe when a slower depressurization rate is assumed. Therefore, the assumed L8 trip provides the most restrictive margins on MCPR and peak vessel pressure.

15.1.3.4 Barrier Performance

Barrier performance analyses were not required since the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which fuel, pressure vessel, or containment are designed. Peak pressure in the bottom of the vessel is below the ASME code upset limit for the RCPB.

15.1.3.5 Radiological Consequences

The consequence of this event does not result in fuel failure. It does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation, which is contained in the primary containment. This event does not result in an uncontrolled release to the environment, so the plant operator can choose to hold the activity in containment or discharge it when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.1.4 INADVERTENT SAFETY/RELIEF VALVE OPENING

The event is defined as the inadvertent opening of an SRV which stays in the "open" position. It was determined that this event is not limiting from a core performance standpoint.

15.1.4.1 Identification of Causes and Frequency Classification

15.1.4.1.1 Identification of Causes

Cause of inadvertent opening is attributed to malfunction of the valve or an operator initiated opening. Opening and closing circuitry at the individual valve level (as opposed to groups of valves) is subject to a single failure impact. It is therefore simply postulated that a failure occurs and the event is analyzed accordingly. Detailed discussion of the valve is provided in Section 5.2.2.

15.1.4.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.1.4.2 Sequence of Events and Systems Operation

15.1.4.2.1 Sequence of Events

Table 15.1-3 lists the sequence of events.

15.1.4.2.2 Systems Operation

In this transient, the analysis assumes normal functioning of plant instrumentation and controls, specifically, the relief valve discharge line temperature sensors and the suppression pool temperature sensors and reactor pressure vessel level control systems. The opening of an SRV allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient. The pressure regulator senses the nuclear system pressure decrease and within a few seconds closes the turbine control (governor) valve far enough to stabilize reactor vessel pressure at a slightly lower value and reactor power settles at nearly the initial power level. Additionally, although not credited in the analysis to mitigate the consequences of this transient, minimum reactor and plant protection systems, emergency core cooling system flow, and RHR suppression pool cooling, are available.

15.1.4.2.3 The Effect of Single Failures and Operator Errors

From a core performance standpoint, a single failure or operator error would simply activate the reactor protection system resulting in a plant shutdown. A single failure or operator error cannot increase the severity of this event.

The instrumentation which detects and audibly alarms the resulting suppression pool temperature rise, and the RHR containment heat removal system are designed to meet the single failure criteria. The operator must manually initiate suppression pool cooling.

15.1.4.3 Core and System Performance

15.1.4.3.1 Mathematical Model

The one-dimensional ODYN model described in Section 15.0.3.3.1 is used to simulate this event.

15.1.4.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2, the ODYN column. A discussion of the SRV is provided in Section 5.2.2.

15.1.4.3.3 Results

Thermal margins decrease only slightly through the transient, and no fuel damage results from the transient. The MCPR is essentially unchanged and, therefore, the safety limit margin is unaffected.

15.1.4.4 Barrier Performance

The transient resulting from a stuck open relief valve is a mild depressurization which is within the range of normal load following. Therefore, there is no significant effect on RCPB and containment design pressure limits.

Since quenchers are used as steam discharge devices on the steam relief lines, no unstable condensation oscillations are expected which could damage the containment vessel. This is discussed in Appendix 3A.

Therefore, barrier integrity and function is maintained.

15.1.4.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment there will be no exposures to operating personnel. Since this event does not result in an uncontrolled release to the environment the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.1.5 SPECTRUM OF STEAM PIPING FAILURES INSIDE AND OUTSIDE OF CONTAINMENT IN A PRESSURIZED WATER REACTOR

This event is not applicable to BWR plants.

15.1.6 INADVERTENT RESIDUAL HEAT REMOVAL SHUTDOWN COOLING OPERATION

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.1.6.1 Identification of Causes and Frequency Classification

15.1.6.1.1 Identification of Causes

At design power conditions no conceivable malfunction in the shutdown cooling system could cause temperature reduction.

In startup or cooldown operation, where the reactor is at or near critical, a very slow increase in reactor power could result. A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for the RHR heat exchangers. The resulting temperature decrease would cause a slow insertion of positive reactivity into the core. If the operator did not act to control the power level, a high neutron flux reactor scram would terminate the transient without violating fuel thermal limits and without any measurable increase in nuclear system pressure.

15.1.6.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.1.6.2 Sequence of Events and Systems Operation

15.1.6.2.1 Sequence of Events

A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for RHR heat exchangers. The resulting temperature decrease causes a slow insertion of positive reactivity into the core. Scram will occur before any thermal limits are reached if the operator does not take action. The sequence of events for this event is shown in Table 15.1-4.

15.1.6.2.2 System Operation

A shutdown cooling malfunction causing a moderator temperature decrease must be considered in all operating states. However, this event is not considered while at power operation since pressure is too high to permit operation of RHR shutdown cooling.

No unique safety actions are required to avoid unacceptable safety results for transients as a result of a reactor coolant temperature decrease induced by misoperation of the shutdown cooling heat exchangers. In startup or cooldown operation, where the reactor is at or near critical, the slow power increase resulting from the cooler moderator temperature would be controlled by the operator in the same manner normally used to control power in the source or intermediate power ranges.

15.1.6.2.3 Effect of Single Failures and Operator Action

No single failures can cause this event to be more severe.

If the operator takes action, the slow power rise will be controlled in the normal manner. If no operator action is taken, a scram will terminate the power increase before thermal limits are reached.

15.1.6.3 Core and System Performance

The increased subcooling caused by misoperation of the RHR shutdown cooling mode could result in a slow power increase due to the reactivity insertion. This power rise would be terminated by a flux scram before fuel thermal limits are approached. Therefore, only a qualitative description is provided here.

15.1.6.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.1.6.5 Radiological Consequences

Since this event does not result in any fuel failures, no analysis of radiological consequences is required for this event.

15.1.7 REFERENCES

15.1-1 For Power Uprate: GE Nuclear Energy, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, September 1993 (Proprietary).

15.1-2 NEDE-30130-P-A, "Steady State Nuclear Methods," April 1985.

15.1-3 Supplemental Reload Licensing Report for Columbia (most recent version referenced in COLR).

15.1-4 NEDC-24154-P-A, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," Volumes 1, 2, 3 and 4, February 2000.

15.1-5 GE Nuclear Energy, "WNP-2 Power Uprate Project NSSS Engineering Report," GE-NE-208-17-0993, Revision 1, December 1994.

15.1-6 "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A and "Supplement for United States," NEDE-24011-P-A-US (most recent approved revision referenced in COLR).

15.1-7 NEDE-32906P-A, "TRACG Application for Anticipated Operational Occurrences Transient Analyses," Revision 3, September 2006.

Table 15.1-1

Typical Sequence of Events for Figure 15.1-1

Feedwater Controller Failure
100% Reactor Power / 106% Core Flow

Time (sec)	Event
0	Initiate simulated failure of 139% upper limit on feedwater flow.
10.06	L8 vessel level setpoint trips main turbine and feedwater pumps. Turbine bypass operation initiated.
10.16	Turbine control (governor) or stop (throttle) valves fully closed.
10.08	Reactor scram trip actuated from main turbine control (governor) valve fast closure.
10.16	Turbine bypass valves start to open.
10.27	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.

Table 15.1-1A

Sequence of Events for Figure 15.1-3

Feedwater Controller Failure
Single Loop Operation
73.8% Power / 57% Flow

Time (sec)	Event
0	Initiate an upper limit failure of 146% of rated feedwater flow.
8.39	L8 vessel level setpoint trips main turbine and feedwater pumps.
8.39	Recirculation pump trip (RPT) actuated by stop valve position switches.
8.40	Reactor scram trip actuated from main turbine stop valve position switches.
8.49	Turbine stop valves closed and main turbine bypass valves start to open.
8.58	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.

Table 15.1-2

Sequence of Events for Figure 15.1-2

Pressure Regulator Failure - Open Uprated Power

Time (sec)	Event
0	Simulate maximum limit on steam flow, (130%) to main turbine.
0.2[a]	Main turbine bypass valves open.
3.31	Vessel water level (L8) trip initiates turbine and feedwater trips.
3.32	Main turbine stop valves reach 90% open position initiating a reactor scram.
3.50	Both recirculation pumps trip.
6.15	Feedwater recirculation valves trip.
6.95	Group 3 relief valves actuated.
7.40	Group 4 relief valves actuated.
10[a]	Pressure relief valves closed.
57.98	Main steam line isolation valves closed on turbine inlet pressure (795 psig).
77	High-pressure core spray and RCIC system initiation on low level (L2).

[a] Approximately.

Table 15.1-3

Sequence of Events for Inadvertent
Safety/Relief Valve Opening

Uprated Power

Time	Event
0	Initiate opening of one SRV which remains open throughout the event.
1[a]	Reactor dome pressure decreases.
3[a]	DEH turbine control system pressure regulator initiates closure of the turbine control (governor) valves to stabilize reactor vessel pressure.
8+	Reactor power settles near the initial power level.

[a] Approximately.

Table 15.1-4

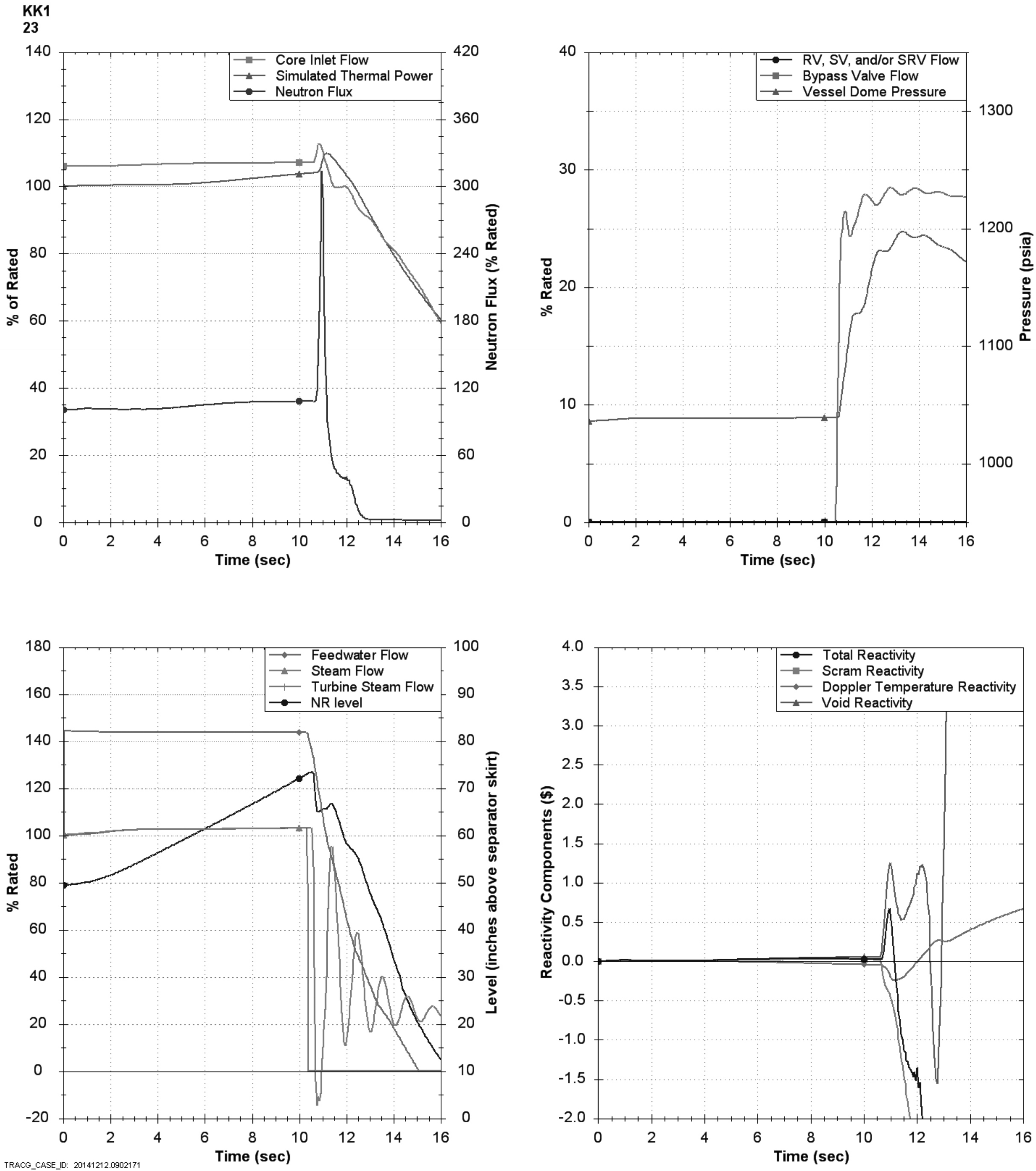
Sequence of Events for Inadvertent
Residual Heat Removal Shutdown Cooling Operation

Original Rated Power

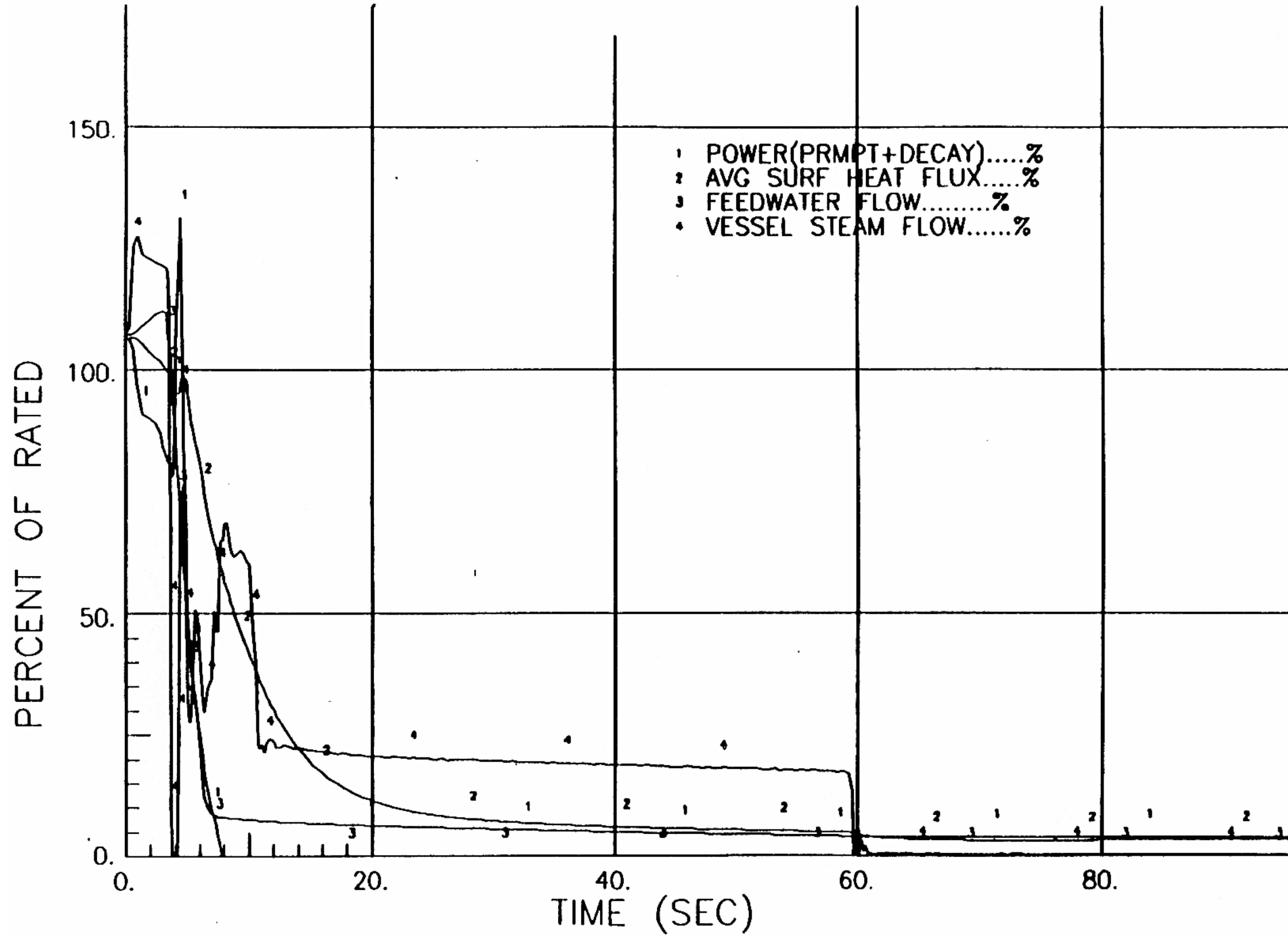
Time[a]	Event
0	Residual heat removal shutdown cooling inadvertently activated.
0-10 minutes	Slow rise in reactor power.
+10 minutes	Operator may take action to limit power rise. Flux scram will occur if no action is taken.

[a] Approximately.

FWCF
ICF_TNM1-EIS



Columbia Generating Station Final Safety Analysis Report	Feedwater Controller Failure, Maximum Demand System Response 100% Power, 106% Flow
	Draw. No. 910402.34 / Rev. 1 / Figure 15.1-1.1



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

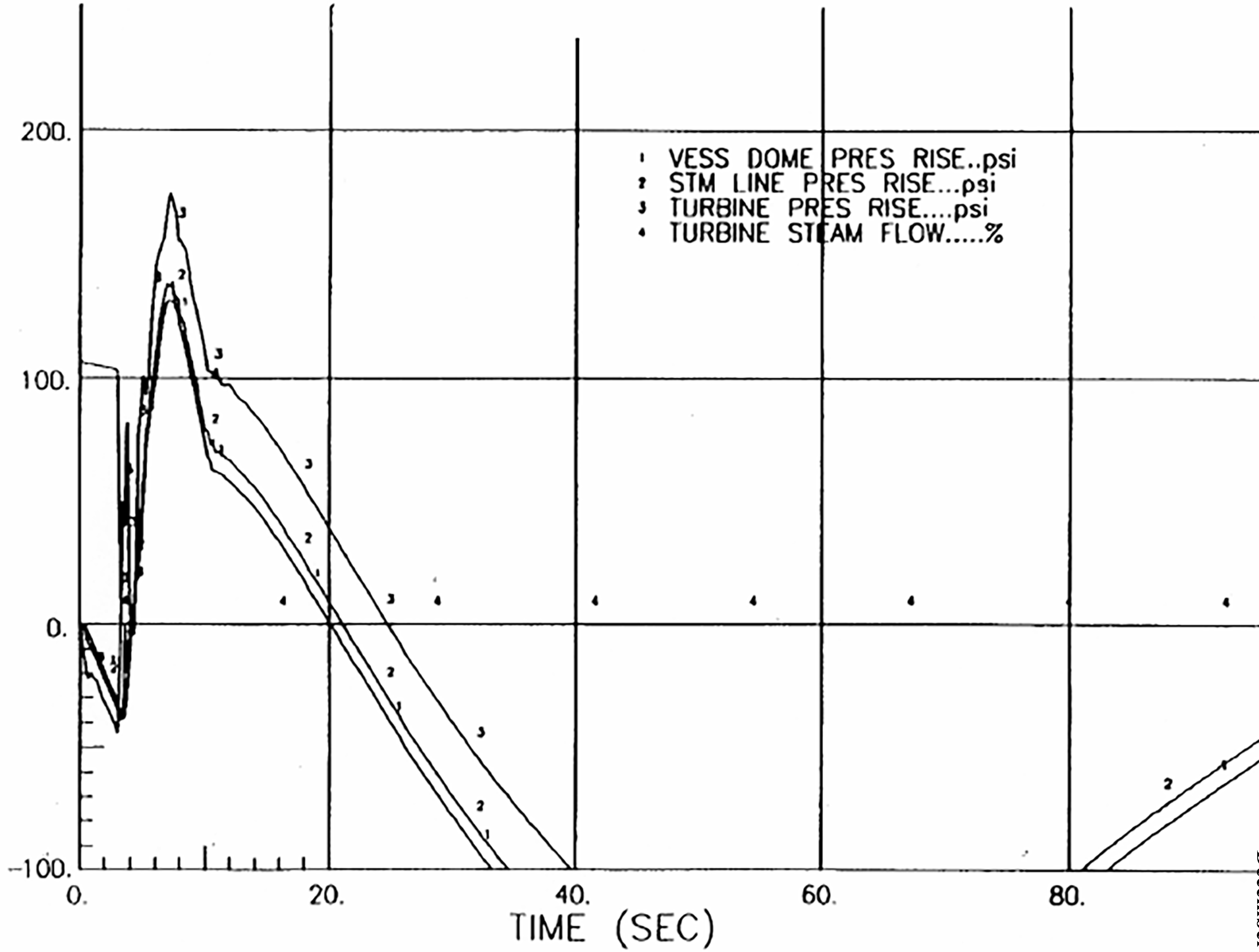
**Pressure Regulator Failure - Open at 104.5*%
Uprated Power, 100% Flow**

Draw. No. 02036l.57

Rev.

Figure 15.1-2.1

Form No. 960690
LDCN-16-005

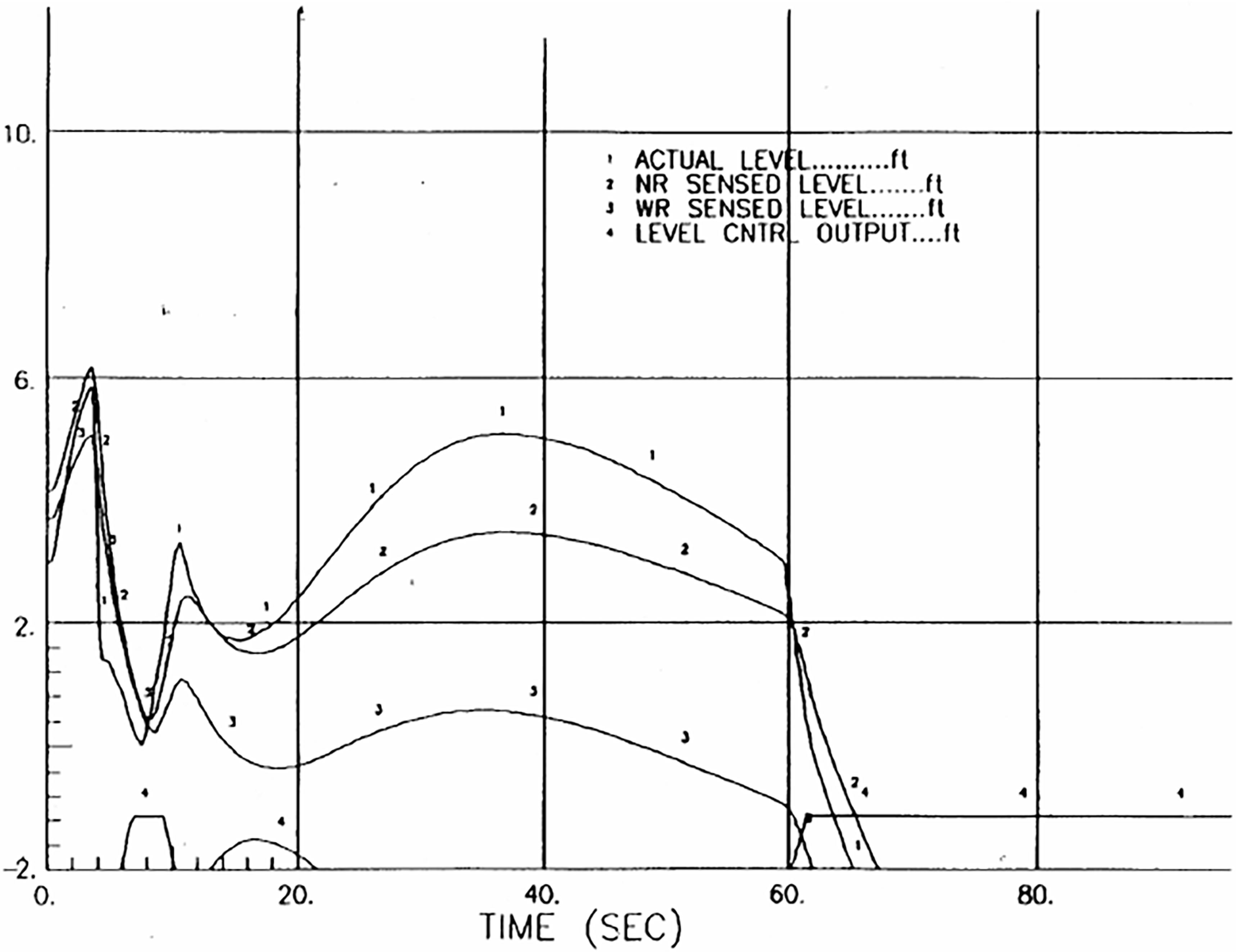


*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Pressure Regulator Failure - Open at 104.5*%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
020361.58		15.1-2.2

Form No. 960690
LDCN-16-005



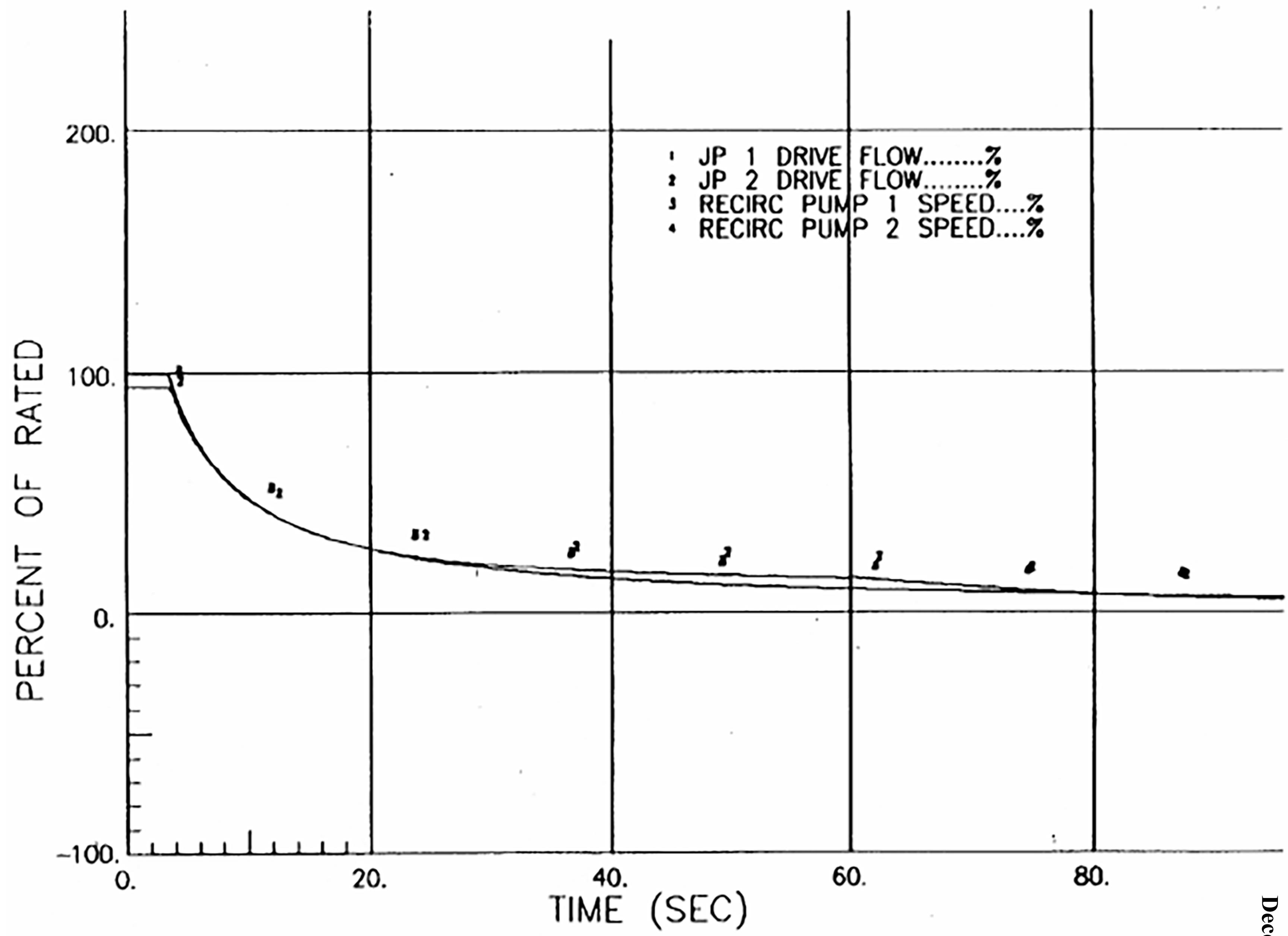
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486.MWt.

Columbia Generating Station
Final Safety Analysis Report

Pressure Regulator Failure - Open at 104.5*% Uprated Power, 100% Flow

Draw. No. 02036I.59	Rev.	Figure 15.1-2.3

Columbia Generating Station
Final Safety Analysis Report



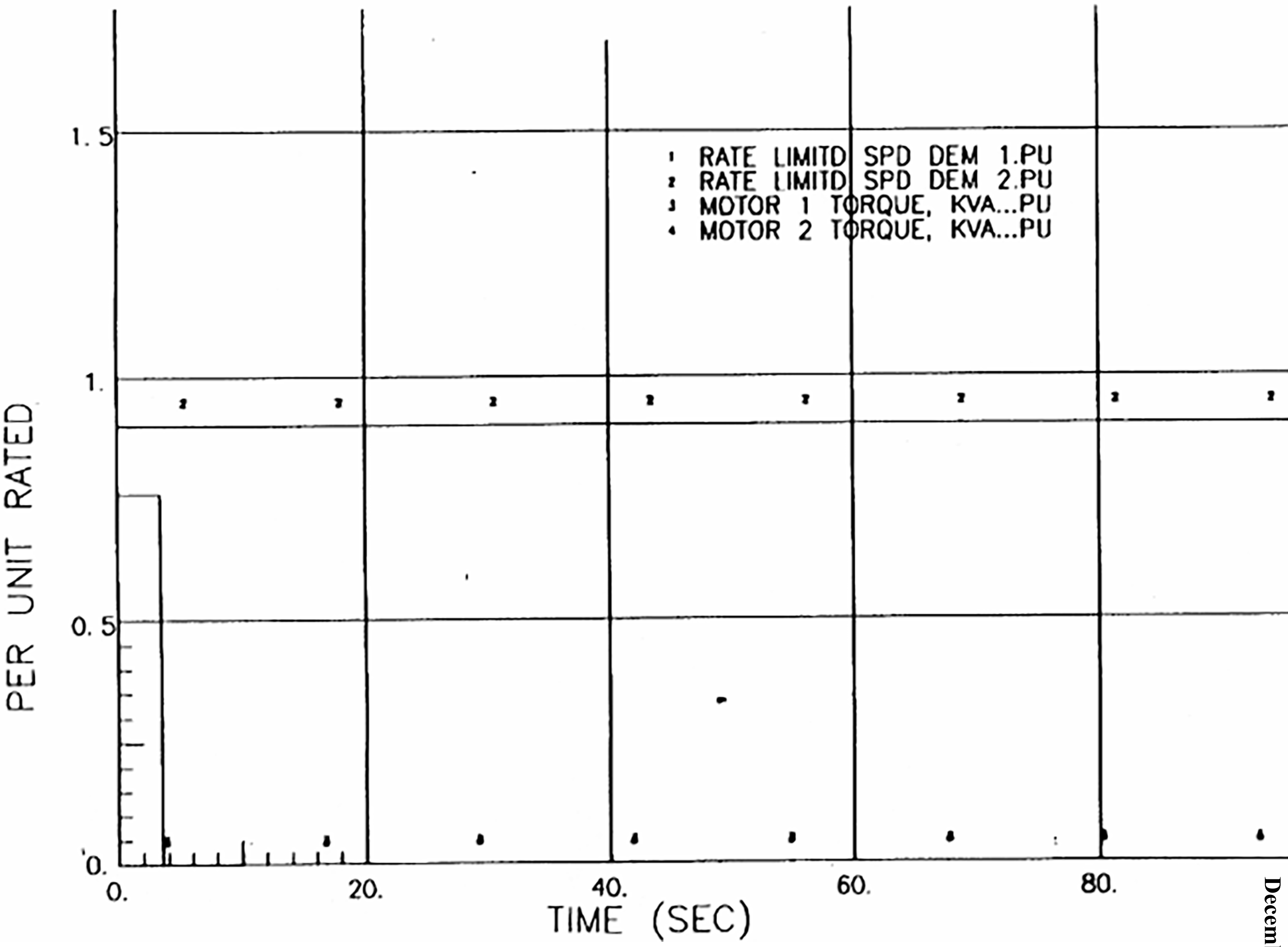
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Pressure Regulator Failure - Open at 104.5*% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
02036I.60		15.1-2.4

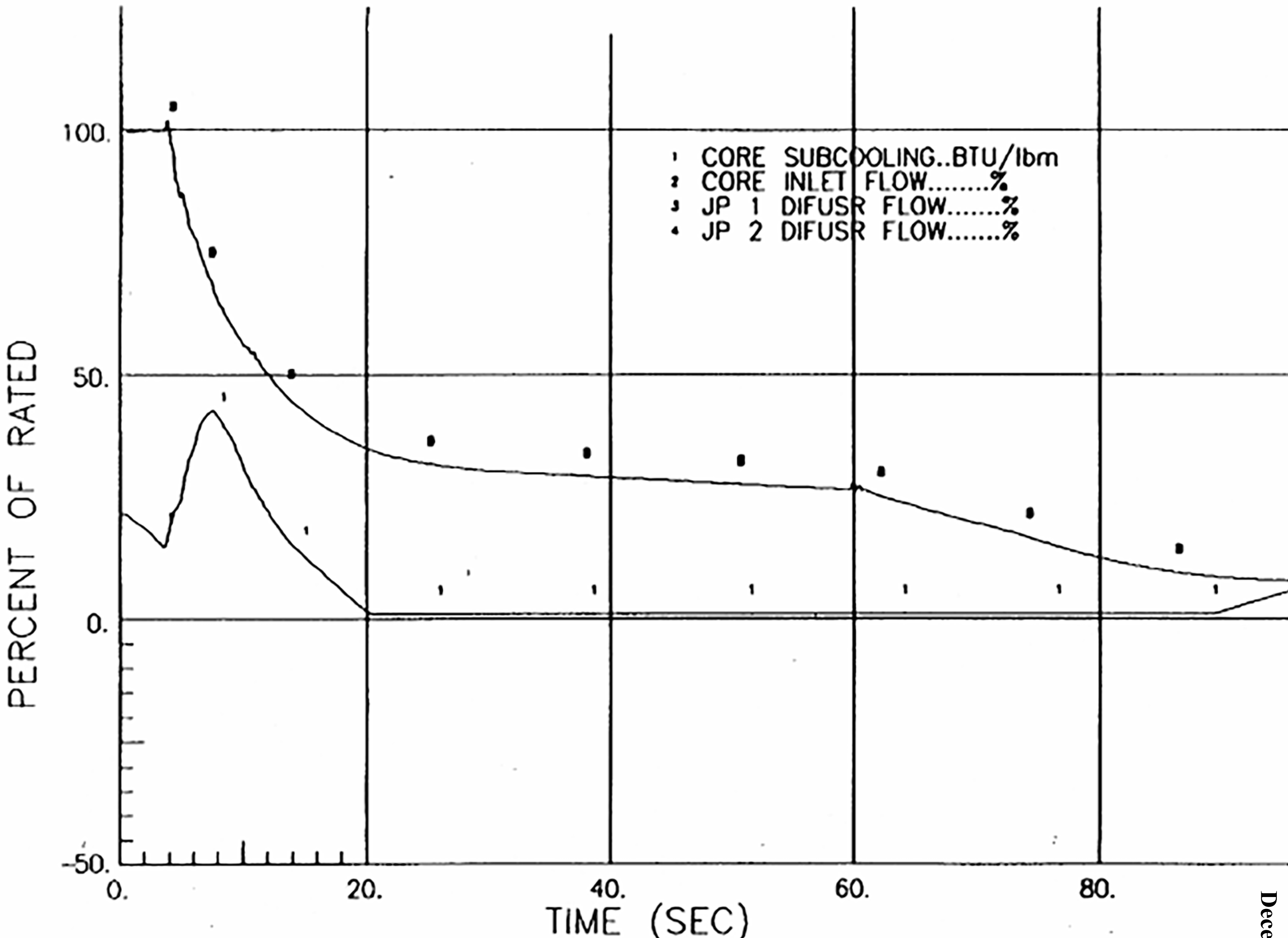
Form No. 960690
LDCN-16-005

*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.



Pressure Regulator Failure - Open at 104.5*%
Uprated Power, 100% Flow

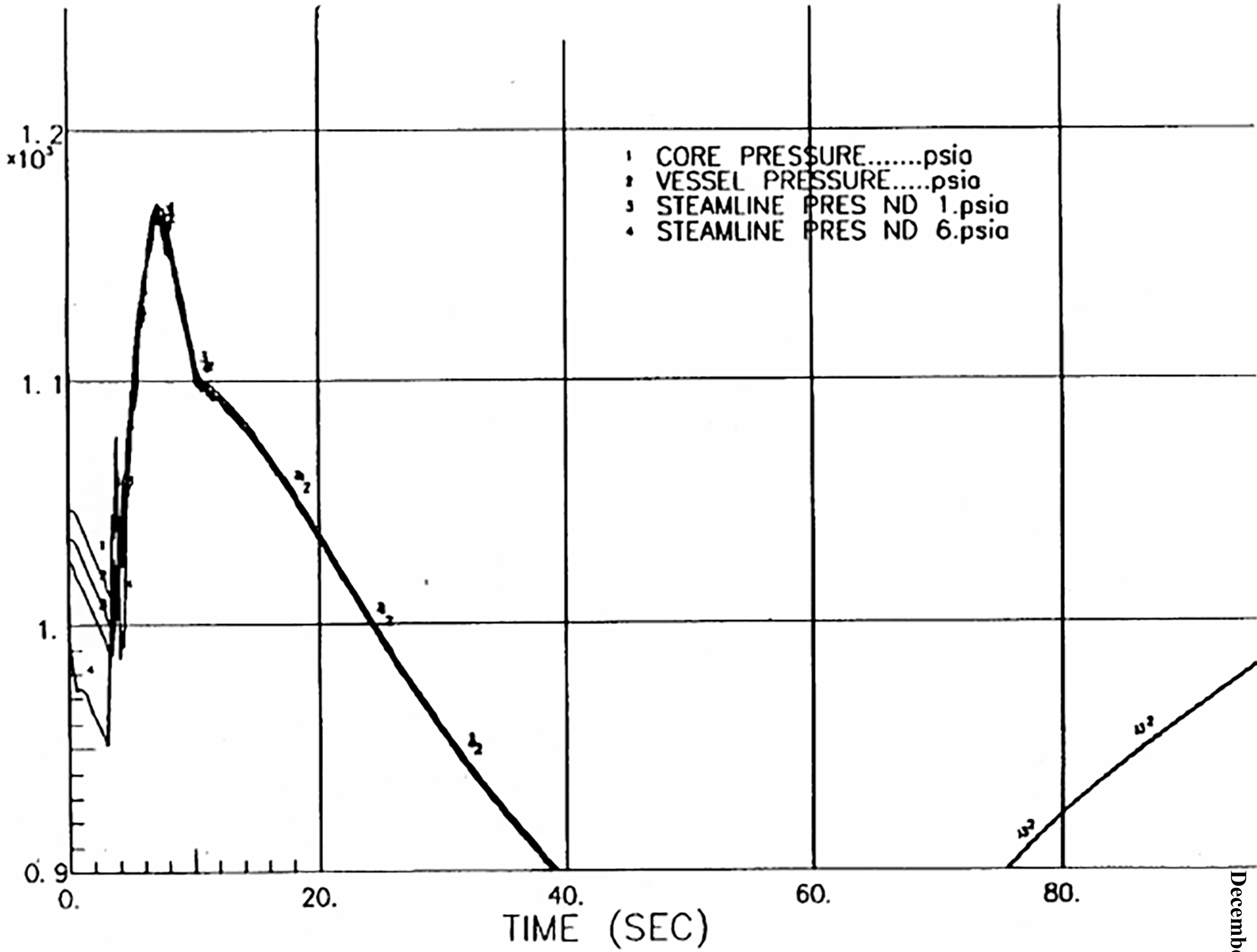
Draw. No.	Rev.	Figure
020361.61		15.1-2.5



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Pressure Regulator Failure - Open at 104.5*% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
020361.62		15.1-2.6



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

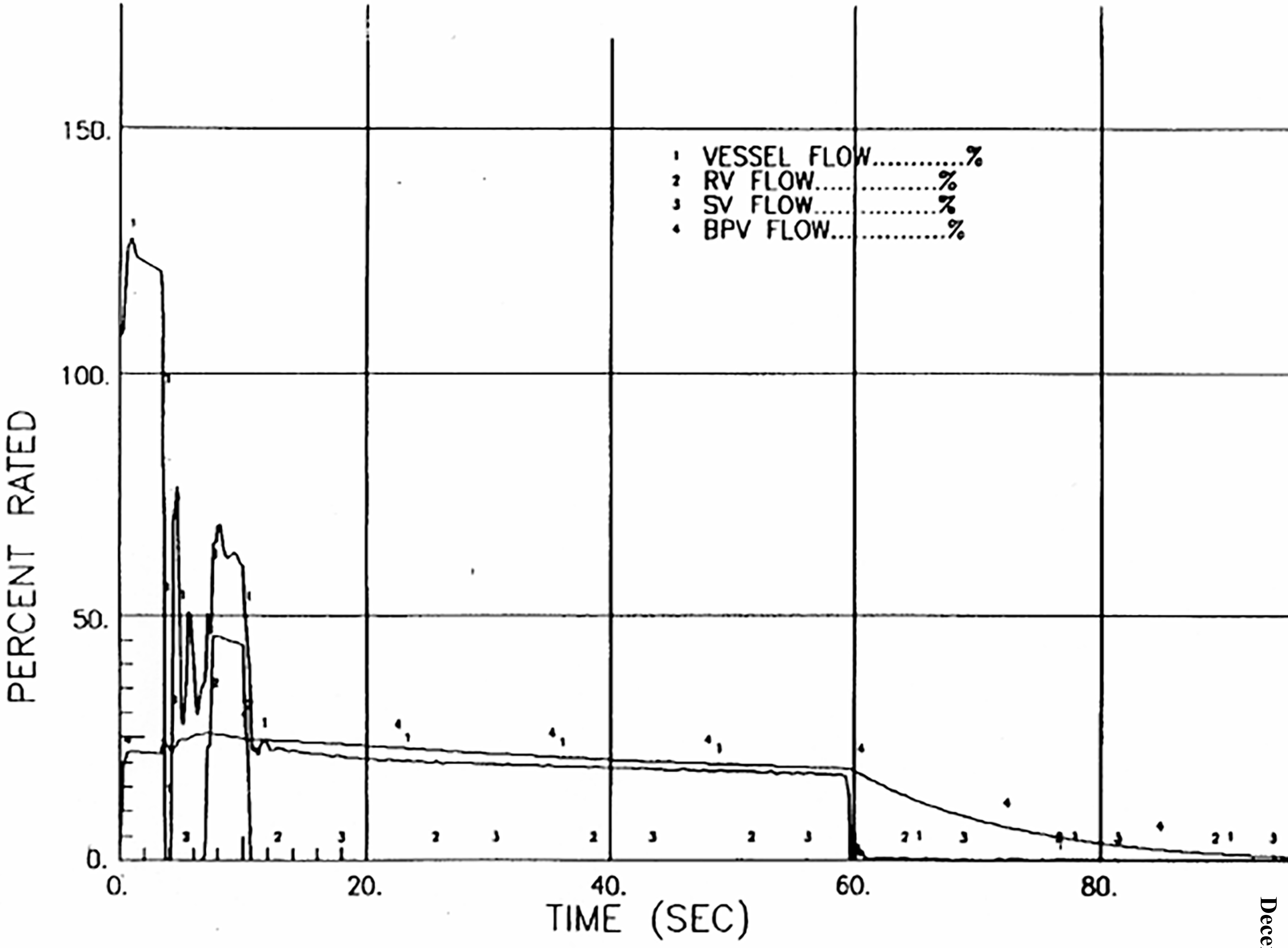
Pressure Regulator Failure - Open at 104.5*%
Uprated Power, 100% Flow

Draw. No. 020361.63

Rev.

Figure 15.1-2.7

Form No. 960690
LDCN-16-005



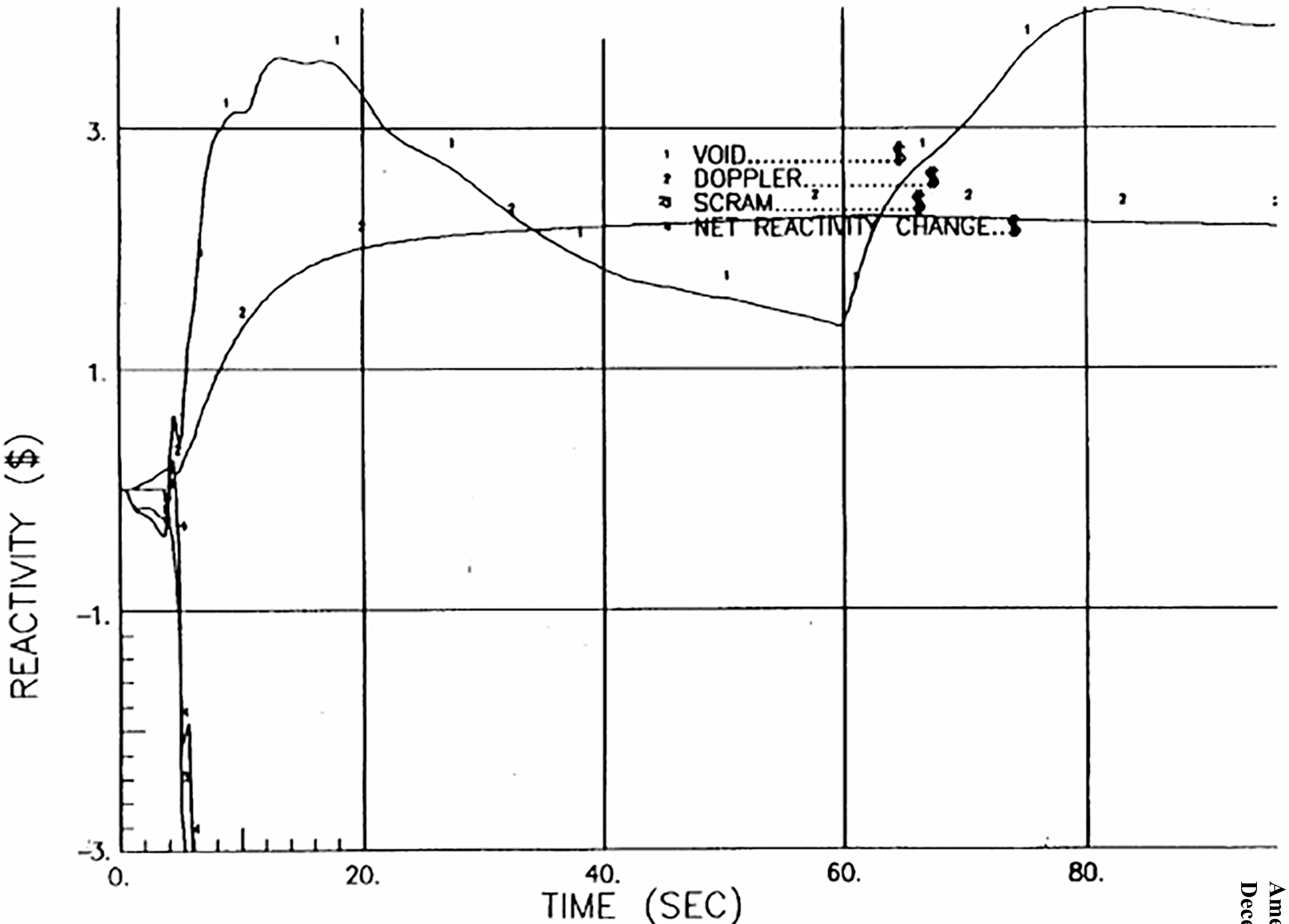
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Pressure Regulator Failure - Open at 104.5*%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
020361.64		15.1-2.8

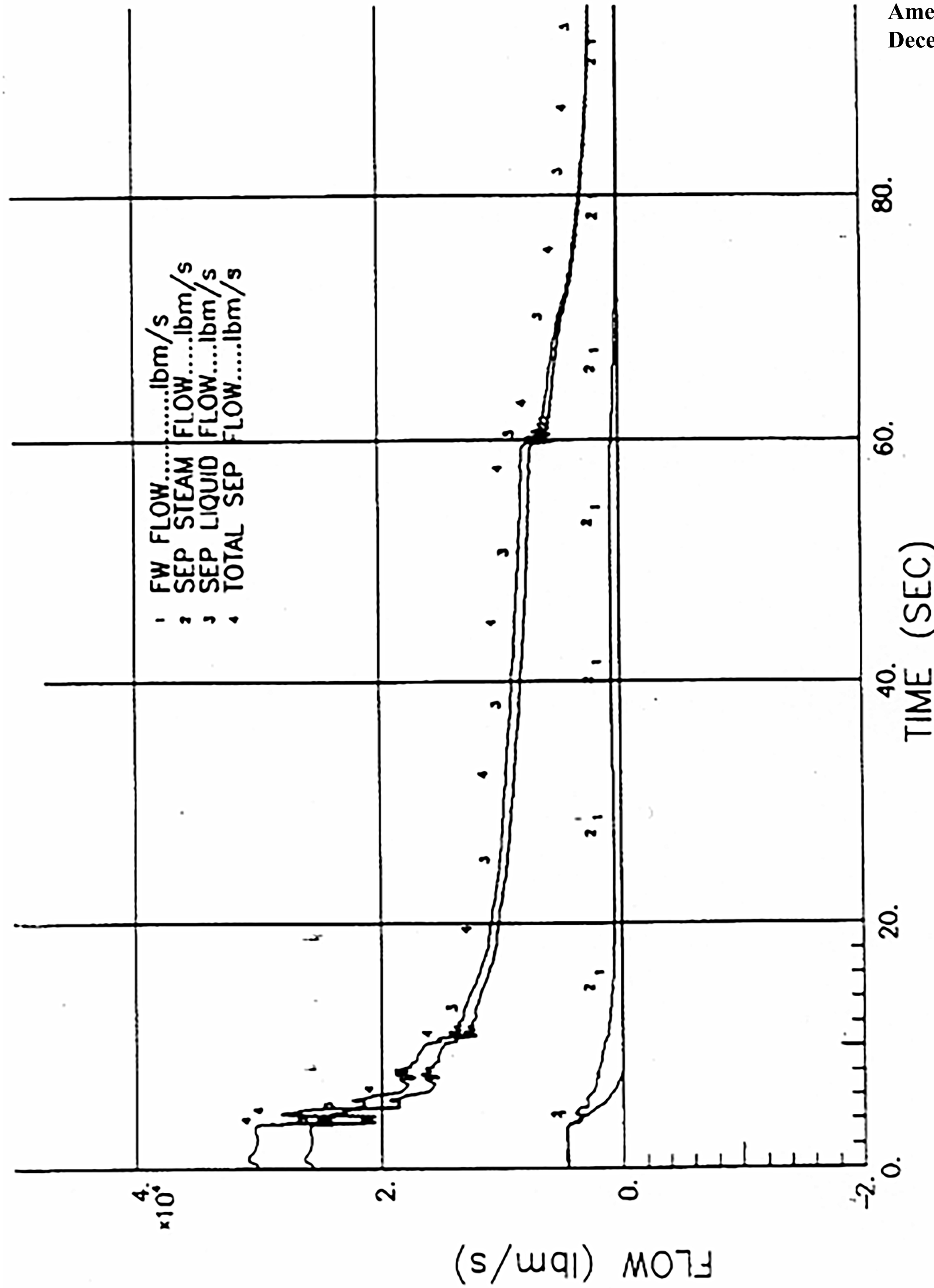
Amendment 64
December 2017



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

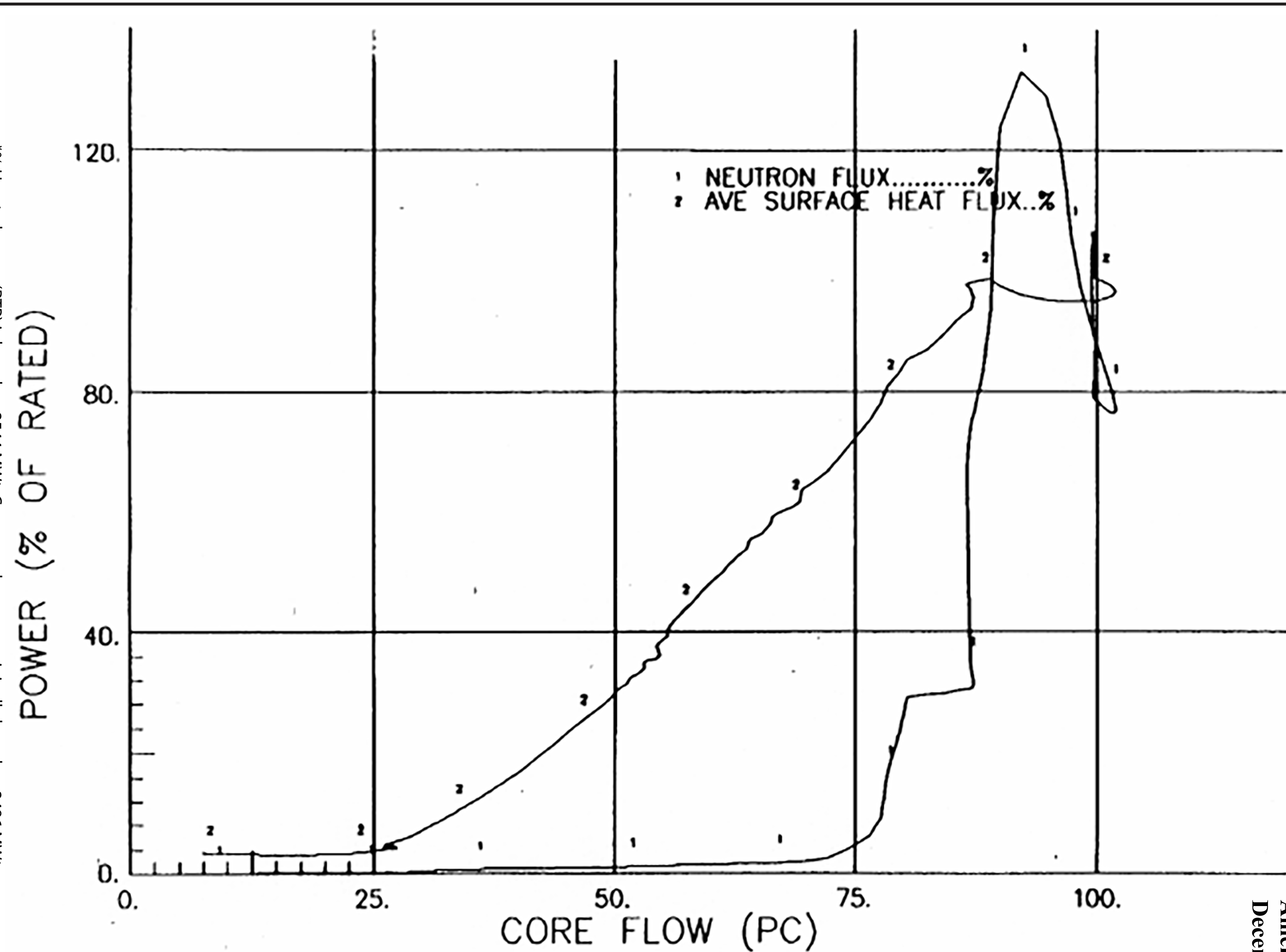
Pressure Regulator Failure - Open at 104.5*%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
020361.65		15.1-2.9



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Pressure Regulator Failure - Open at 104.5*% Uprated Power, 100% Flow	
	Draw. No. 020361.66	Rev.	Figure 15.1-2.10



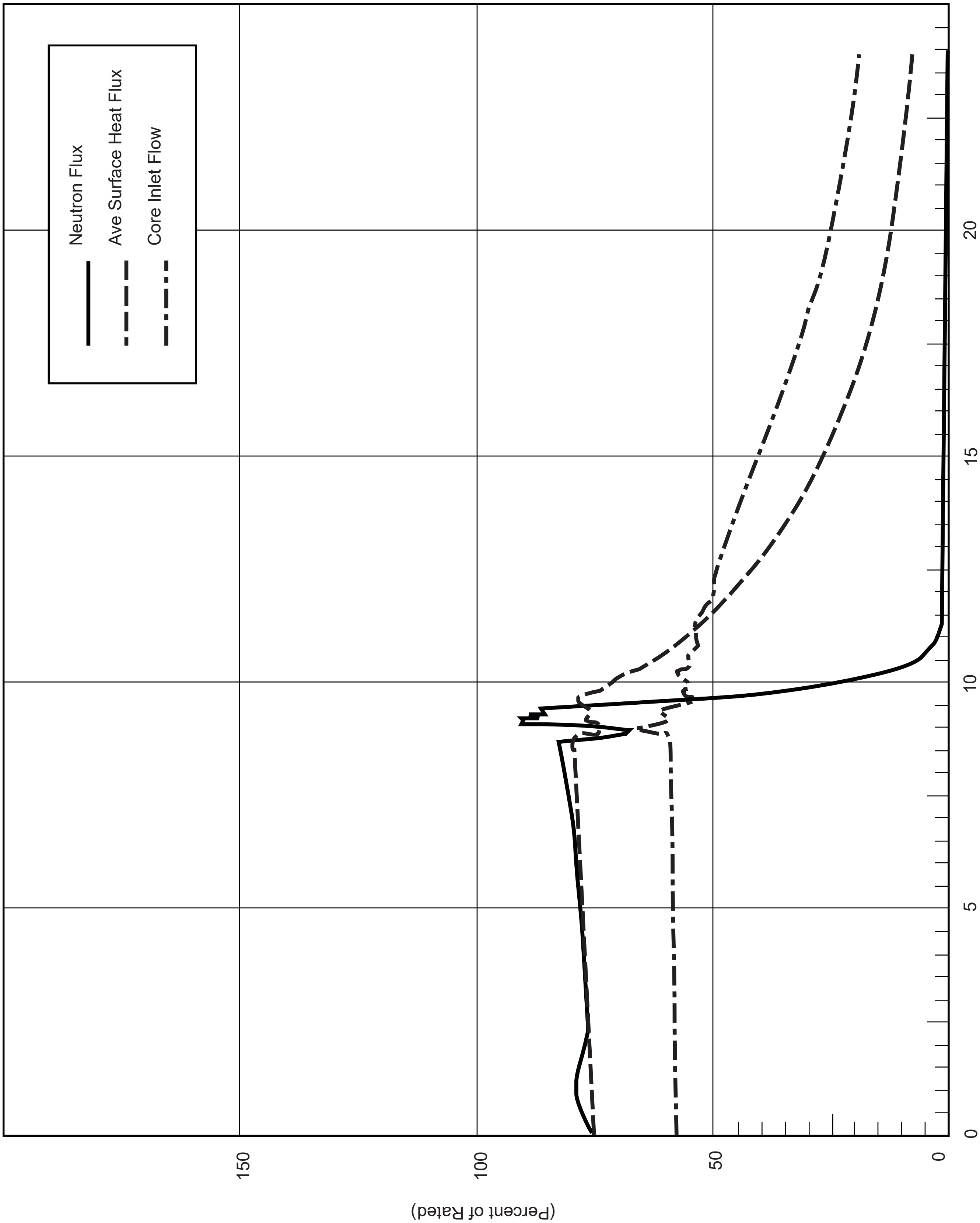
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Pressure Regulator Failure - Open at 104.5*%
Uprated Power, 100% Flow

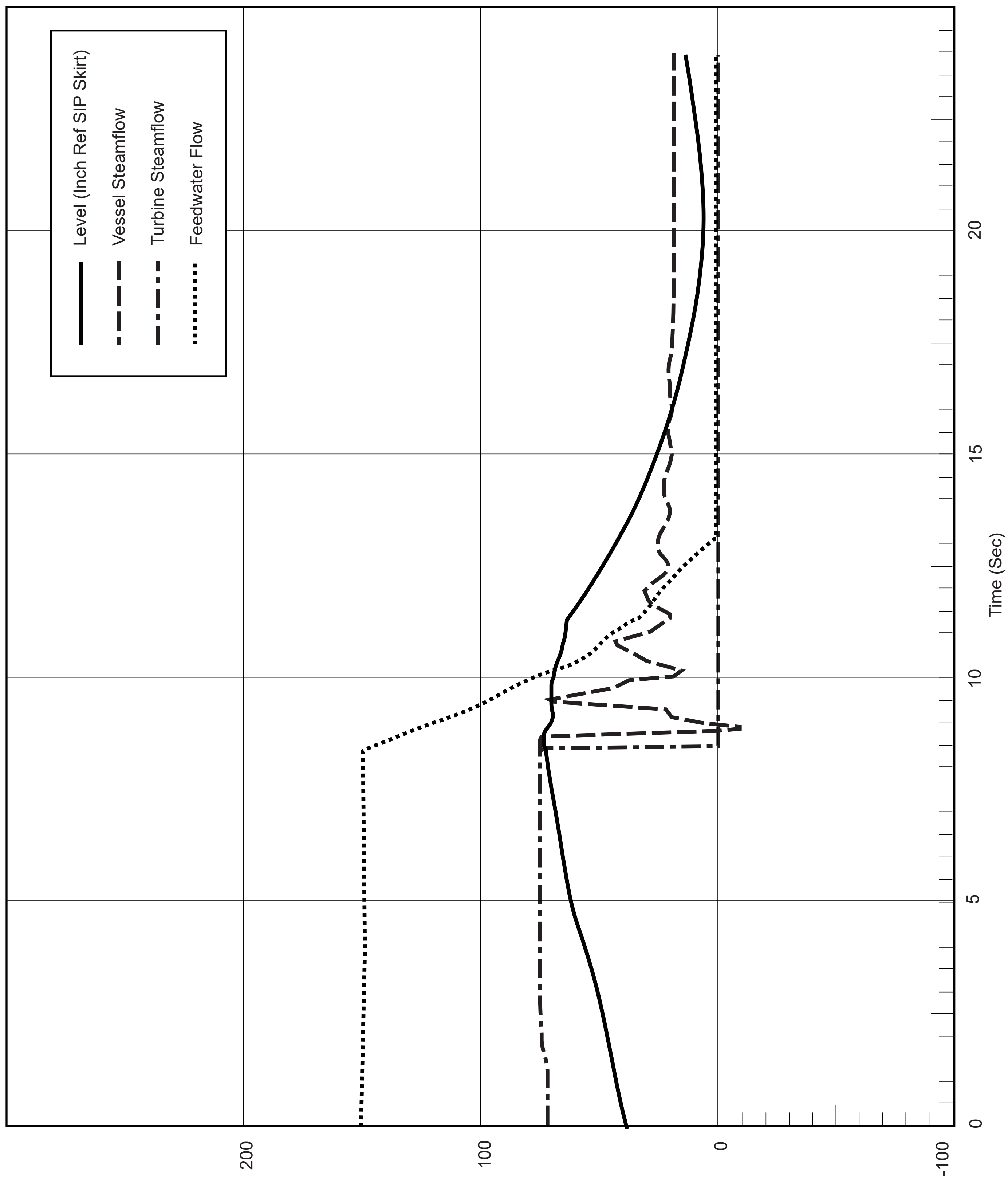
Draw. No. 020361.67	Rev.	Figure 15.1-2.11

Form No. 960690
LDCN-16-005



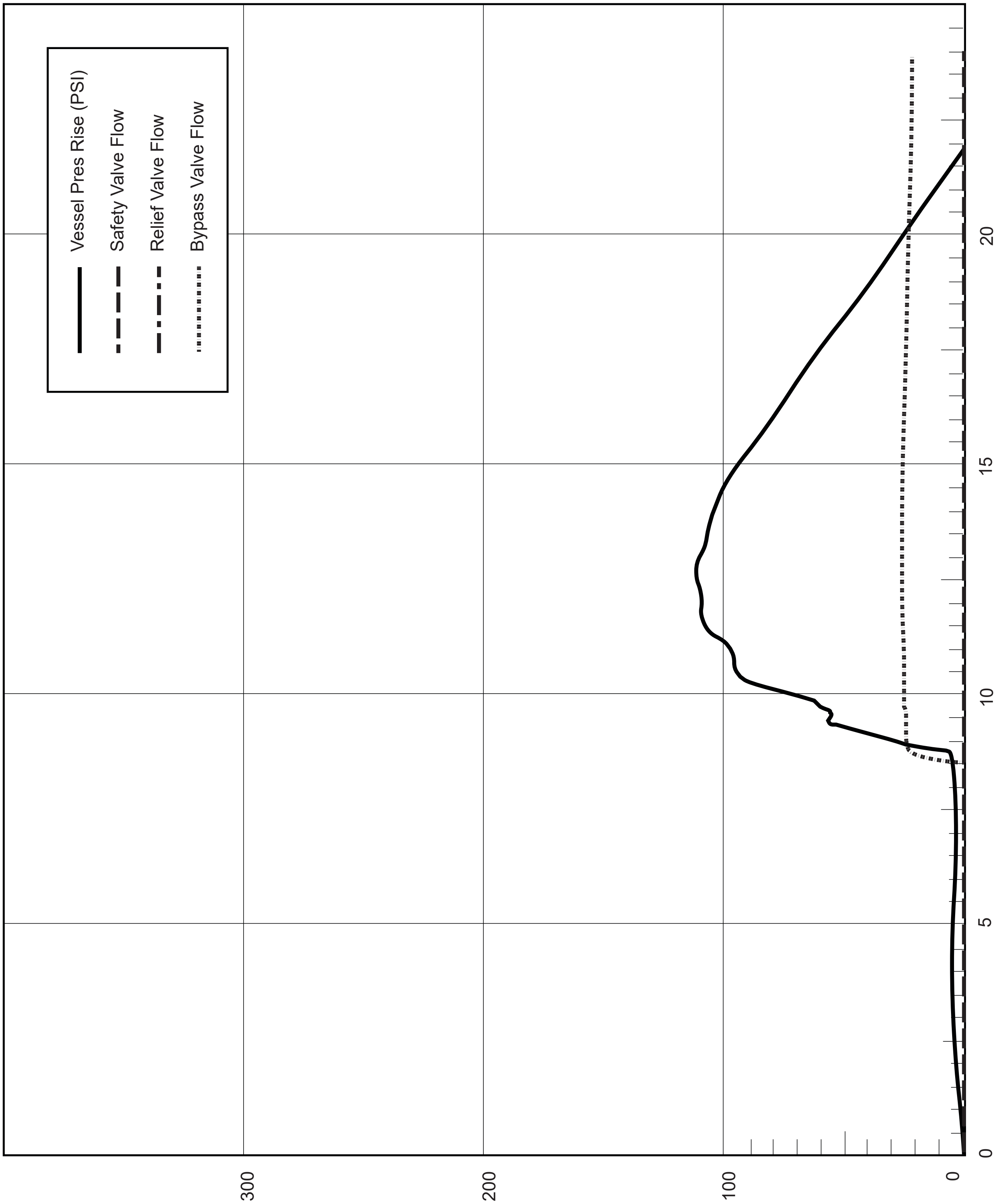
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Feedwater Controller Failure, Maximum Demand, EOC RPT OOS, Single Loop Operation and 73.8*% Uprated Power, 57% Flow	
	Draw. No. 910402.41	Rev.	Figure 15.1-3.1



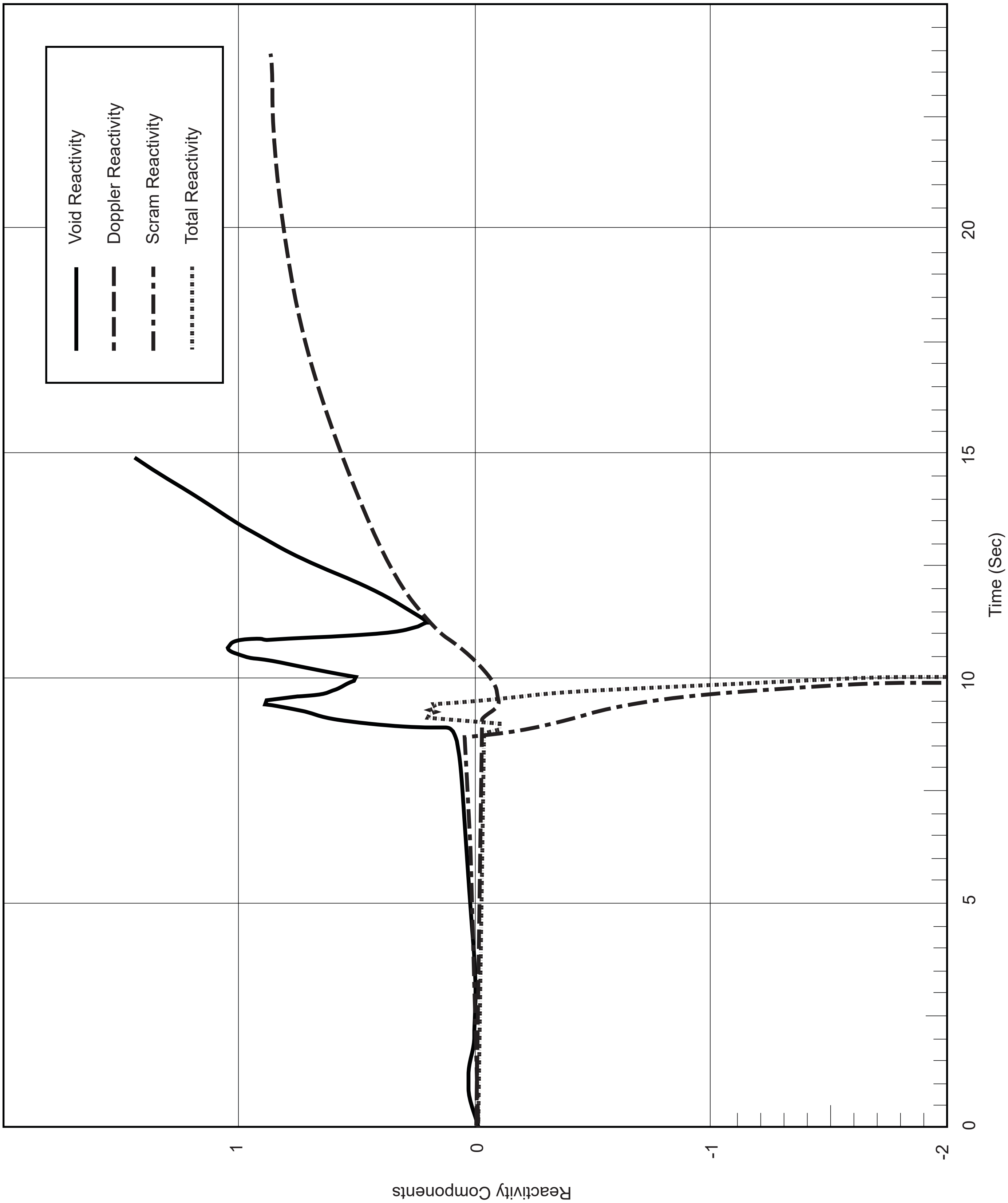
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Feedwater Controller Failure, Maximum Demand, EOC RPT OOS, Single Loop Operation and 73.8*%Uprated Power, 57% Flow
	Draw. No. 910402.40 | Rev. | Figure 15.1-3.2



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Feedwater Controller Failure, Maximum Demand, EOC RPT OOS, Single Loop Operation and 73.8*% Uprated Power, 57% Flow		
	Draw. No. 910402.39	Rev.	Figure 15.1-3.3



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Feedwater Controller Failure, Maximum Demand, EOC RPT OOS, Single Loop Operation and 73.8*% Uprated Power, 57% Flow
	Draw. No. 910402.38 / Rev. / Figure 15.1-3.4

15.2 INCREASE IN REACTOR PRESSURE

15.2.1 PRESSURE REGULATOR FAILURE - CLOSED

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, cycle specific analyses are not performed for this event. The analysis results presented in the section are based on uprated power conditions and a representative reload core (Cycle 8) as documented in Reference 15.2-5.

15.2.1.1 Identification of Causes and Frequency Classification

15.2.1.1.1 Identification of Causes

A triple redundant control system is provided to maintain primary system pressure control. The pressure upstream of the main turbine stop (throttle) valves is sensed by three redundant throttle pressure transmitters and the control system uses a median select logic to determine which pressure transmitter is used to control throttle pressure. The pressure control system compares the detected throttle pressure to a pressure setpoint to control the position of the main turbine control (governor) valves in order to control pressure.

It is assumed for purposes of this transient analysis that a single failure occurs on the controlling pressure transmitter which erroneously causes the DEH control system to close the turbine control (governor) valves and thereby increases reactor pressure. If this occurs, the self diagnostics ability and triple redundant control system is available.

15.2.1.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.1.2 Sequence of Events and Systems Operation

15.2.1.2.1 Sequence of Events

A failure of a DEH control system component that causes the turbine control (governor) valves or turbine bypass valves to move towards the closed position will momentarily result in an initial pressure increase because the reactor is still generating the initial steam flow. The DEH control system is self diagnostic. It will detect the faulty component and disable it. The control system is redundant and will continue to perform its functions, and will restore steady state operation.

For a failure that causes the DEH turbine control pressure regulator to initiate a demand signal to close the turbine control (governor) valves (requires multiple component failures), there will be an increase in system pressure and reactor power. A scram will be initiated when the high neutron flux scram setpoint is reached. The pressure rises to the pressure relief setpoint, part of the relief valves open, discharging steam to the suppression pool. The plant response is given in Table 15.2-1.

15.2.1.2.2 Systems Operation

Normal plant instrumentation and control is assumed to function except for the pressure regulator failure. The event is analyzed from 102.4% uprated power and 106% of rated core flow. The event results in a high flux trip initiated by the reactor protection system.

15.2.1.2.3 The Effect of Single Failures and Operator Errors

The first assumed failure produces a slight pressure increase in the reactor until the DEH control system adjusts to the single failure and gains control. No other action is significant in restoring normal operation. If subsequent failures occur such that the DEH control system further closes the turbine control (governor) valves the reactor pressure could rise to the point where a flux or pressure scram trip would be initiated to shutdown the reactor. This event is less severe than the turbine trip for the following reasons:

a. For the DEH control system failure-closure event the reactor scrams on high neutron flux or pressure but the recirculation pumps do not trip. As a result, core flow remains at 100% or greater throughout the critical portion of the transient with respect to the critical power ratio (CPR). This provides improved heat transfer capability in relation to the turbine trip transient; and

b. Since the turbine control (governor) valves close in response to a pressure error signal, their closure rate is not as fast as the turbine stop (throttle) or control (governor) valve response to a trip signal. This produces a slower pressurization rate for the DEH control system failure relative to the turbine trip event. This in turn results in a lower peak neutron flux and therefore a lower peak surface heat flux than the turbine trip event.

15.2.1.3 Core and System Performance

15.2.1.3.1 Mathematical Model

The one-dimensional ODYN model described in Section 15.0.3.3.1 is used to simulate this event.

15.2.1.3.2 Input Parameters and Initial Conditions

The analyses have been performed with plant conditions at 102.4% of uprated power and 106% of rated core flow. The input parameters are given in detail in Table 15.0-2 under the ODYN column.

15.2.1.3.3 Results

The closure of the turbine governor (control) valves results in a rise in reactor pressure, collapsing the coolant voids which in turn increases the neutron flux. One sec after the initiation of the event the neutron flux increases to the high flux setpoint signal and initiates a reactor scram. Two sec into the event the pressure in the reactor reaches the ATWS high pressure trip setpoint, initiating a recirculation pump trip signal. As the pressure in the reactor system continues to rise, the relief valves begin to open starting with Group 3. The maximum pressure is reached at 3.25 sec and is calculated to be 1220 psig at the bottom of the reactor vessel. Table 15.2-1 provides the sequence of events and Figure 15.2-1 depicts the plant parameters responses. Key transient peak values are presented in Table 15.0-1. This event is nonlimiting in that the pressurization event is less severe than the Generator Load Rejection with Bypass Failure and Turbine Trip with Bypass Failure events.

15.2.1.3.4 Consideration of Uncertainties

The uncertainties included in the initial power and flow considerations maximize the consequences of the plant response. The independent pressure regulators normally respond such that failure of one would be compensated by the other regulator with plant not experiencing a trip.

15.2.1.4 Barrier Performance

The consequences of this event do not result in any temperature or pressure transient (see Table 15.0-1) in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.2.1.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.2.2 GENERATOR LOAD REJECTION

15.2.2.1 Identification of Causes and Frequency Classification

15.2.2.1.1 Identification of Causes

Fast closure of the turbine control (governor) valves (TCVs) is initiated whenever electrical grid disturbances occur which result in significant loss of electrical load on the generator. The TCVs are required to close as rapidly as possible to prevent excessive overspeed of the turbine-generator rotor. Closure of the main TCVs will cause a sudden reduction in steam flow which results in an increase in system pressure, which may cause a reactor shutdown due to a high flux or high steam pressure condition.

15.2.2.1.2 Frequency Classification

15.2.2.1.2.1 Generator Load Rejection. This event is categorized as an incident of moderate frequency.

15.2.2.1.2.2 Generator Load Rejection with Bypass Failure. This event is categorized as a moderate frequency event.

15.2.2.2 Sequence of Events and System Operation

The generator load rejection with bypass failure event is the most limiting (with respect to thermal margin) of the class of transients characterized by rapid vessel pressurization, including load rejection with the bypass valves operating. The generator load rejection causes a TCV (governor valve) fast closure, which initiates a reactor scram and a recirculation pump trip (RPT). The compression wave produced by the TCV fast closure travels through the steam lines into the vessel and pressurizes the reactor vessel and core. Bypass flow to the condenser, which would mitigate the pressurization effect, is conservatively not allowed. The excursion of core power due to void collapse is primarily terminated by reactor scram and void growth due to RPT. The recirculation pump speed remains constant until tripped by the RPT system.

Events caused by low water level trips, including closure of main steam line isolation valves (MSIVs), and initiation of high-pressure core spray (HPCS) and reactor core isolation cooling (RCIC) are not included in the simulation. Should these events occur, they will follow after the primary concerns of fuel thermal margin and overpressure effects have occurred, and are expected to be less severe than those already experienced by the system.

15.2.2.2.1 Sequence of Events

15.2.2.2.1.1 Generator Load Rejection - Turbine Control Valve Fast Closure. This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, the original rated power (3323 MWt) analysis has not been updated.

A loss of generator electrical load from high power conditions produces the sequence of events listed in Table 15.2-2.

15.2.2.2.1.2 Generator Load Rejection with Failure of Bypass. A loss of generator electrical load at 3544 MWt with bypass failure produces the sequence of events listed in Table 15.2-3.

15.2.2.2.2 System Operation

15.2.2.2.2.1 Generator Load Rejection with Bypass. To properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection, reactor pressure vessel (RPV) safety/relief valves (SRV), and reactor protection systems (RPS) unless stated otherwise. The bypass valve opening characteristics reflect the specified delay together with the specified opening characteristic required for bypass system operation.

Turbine control valve fast closure initiates a scram trip signal for power levels greater than 29.5% nuclear boiler rated (NBR). In addition, recirculation pump trip (RPT) is initiated. Both of these trip signals satisfy single failure criterion and credit is taken for these protection features.

The pressure relief system, which operates the SRVs independently when system pressure exceeds relief valve instrumentation setpoints is assumed to function normally during the time period analyzed.

15.2.2.2.2.2 Generator Load Rejection with Failure of Bypass. Same as Section 15.2.2.2.2.1 except that failure of the main turbine bypass valves is assumed for the entire transient. In addition, the pressure relief system, which operates the SRVs independently when system pressure exceeds relief valve instrumentation setpoints, fails to operate. Pressure relief is provided by the safety function of the SRVs.

15.2.2.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase, the basic nature of this transient, is accomplished by the RPS functions. Turbine control valve trip scram and RPT are designed to satisfy the single failure criterion. An evaluation of the most limiting single failure (i.e., failure of the bypass system) was considered in this event.

15.2.2.3 Core and System Performance

15.2.2.3.1 Mathematical Model

15.2.2.3.1.1 Generator Load Rejection with Bypass. The predicted dynamic behavior for the generator load reject with bypass valves operable has been determined using a computer simulated, analytical model of a generic direct-cycle BWR. This model is described in detail in Reference 15.2-4.

The nonlinear computer simulated analytical model is designed to predict associated transient behavior of the reactor. Some of the significant features of the model are the following:

a. A point kinetic model is assumed with reactivity feedbacks from control rods (absorption), voids (moderation), and Doppler (capture) effects.

b. The fuel is represented by three four-node cylindrical elements, each enclosed in a cladding node. One of the cylindrical elements is used to represent core average power and fuel temperature conditions, providing the source of Doppler feedback. The other two are used to represent "hot spots" in the core, to simulate peak fuel center temperature and cladding temperature.

c. Four primary system pressure nodes are simulated. The nodes represent the core exit pressure, vessel dome pressure, steam line pressure (at a point representative of the safety/relief valve location), and turbine inlet pressure.

d. The active core void fraction is calculated from a relationship between core exit quality, inlet subcooling, and pressure. This relationship is generated from multimode core steady-state calculations. A second-order void dynamic model, with the void boiling sweep time calculated as a function of core flow and void conditions, is also utilized.

e. Principal controller functions such as feedwater flow, recirculation flow, reactor water level, pressure and load demand are represented together with their dominant nonlinear characteristics.

f. The ability to simulate necessary reactor protection system functions is provided.

15.2.2.3.1.2 Generator Load Rejection with Bypass Failure. The predicted dynamic behavior for the load rejection with bypass inoperable has been determined using a computer simulated, analytical model of a direct-cycle BWR that is discussed in Section 15.1.2.3.1. This model is described in detail in Reference 15.2-10.

15.2.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2 for the load rejection with bypass and in Table 15.0-2B for load rejection with bypass failure.

The turbine digital electrohydraulic control system power/load imbalance device detects load rejection before a measurable speed change takes place.

The closure characteristics of the TCVs are assumed such that the valves operate in the full arc (FA) mode and have a full stroke closure time, from fully open to fully closed, of 0.15 sec. In FA mode, at 100% power, the TCVs are not fully open, so the analysis assumes a closure time that is a fraction of the full stroke time proportional to the TCV initial position.

15.2.2.3.3 Results

Analyses were performed to analyze combinations of RPT operable/inoperable and Option A and Option B scram speeds (Reference 15.2-3). The excursion of core power due to void collapse is primarily terminated by reactor scram and void growth due to RPT.

15.2.2.3.3.1 Generator Load Rejection with Bypass. Figure 15.2-2.1 shows the results of the generator trip from original rated power. Peak neutron flux rises 147% above NBR conditions.

The average surface heat flux peaks at 102.9% of the initial value and minimum critical power ratio (MCPR) does not significantly decrease below its initial value.

15.2.2.3.3.2 Generator Load Rejection with Failure of Bypass. Figure 15.2-2.2 shows that, for the case of bypass failure, peak neutron flux reaches about 325% power. Results reflect GNF2 fuel introduction, some of which are dependent on fuel design and core loading pattern. Compliance with the event acceptance criteria is demonstrated by cycle-dependent analysis of potentially limiting events just prior to the operation of that cycle. The results are reported in the Supplemental Reload Licensing Report (Reference 15.2-3). As discussed in Section 15.0.2.1, when this event is initiated during single loop operation, the consequences are less severe than the consequences analyzed for the two loop operation.

15.2.2.3.4 Consideration of Uncertainties

The full stroke closure time of the TCV of 0.15 sec is conservative. Typically, the actual closure time is closer to 0.2 sec. The less time it takes to close, the more severe the pressurization effect.

All systems used for protection in this event were assumed to have the poorest allowable response. Expected plant behavior is, therefore, expected to reduce the actual severity of the transient.

15.2.2.4 Barrier Performance

15.2.2.4.1 Generator Load Rejection

Peak pressure remains within normal operating range and no threat to the barrier exists.

15.2.2.4.2 Generator Load Rejection with Failure of Bypass

The peak dome pressure reaches 1244 psig. The peak reactor coolant pressure boundary (RCPB) pressure reaches 1270 psig. The peak pressure remains well below the nuclear barrier transient pressure limit of 1375 psig.

15.2.2.5 Radiological Consequences

While the consequences of this event do not result in fuel failures, the result includes the discharge of normal coolant activity to the suppression pool by means of safety/relief valve (SRV) operation. Since this activity is contained in the primary containment, there will be no exposure to the public. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or filter the discharge prior to release to the environment when conditions permit in accordance with established requirements.

15.2.3 TURBINE TRIP

15.2.3.1 Identification of Causes and Frequency Classification

15.2.3.1.1 Identification of Causes

A variety of turbine or nuclear system malfunctions will initiate a turbine trip. Some examples are moisture separator high levels, operator lockout, loss of control fluid pressure, low condenser vacuum, and reactor high water level.

15.2.3.1.2 Frequency Classification

15.2.3.1.2.1 Turbine Trip. This event is categorized as an incident of moderate frequency. In defining the frequency of this event, turbine trips which occur as a by-product of other transients such as loss of condenser vacuum or reactor high level trip events are not included. However, spurious low vacuum or high level trip signals which cause an unnecessary turbine trip are included in defining the frequency.

15.2.3.1.2.2 Turbine Trip with Failure of Bypass. This transient disturbance is categorized as a moderate frequency incident.

15.2.3.2 Sequence of Events and Systems Operation

15.2.3.2.1 Sequence of Events

15.2.3.2.1.1 Turbine Trip. This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, the original rated power (3323 MWt) analysis has not been updated. Turbine trip at high power produces the sequence of events listed in Table 15.2-4.

15.2.3.2.1.2 Turbine Trip with Failure of Bypass. Turbine trip at high power with bypass failure produces the sequence of events listed in Table 15.2-5.

15.2.3.2.2 Systems Operation

15.2.3.2.2.1 Turbine Trip. All plant control systems maintain normal operation unless specifically designated to the contrary.

Turbine stop (throttle) valve closure initiates a reactor scram trip by means of valve position signals to the protection system.

Turbine stop valve closure initiates RPT thereby terminating the jet pump drive flow.

The pressure relief system, which operates the relief valves independently when system pressure exceeds relief valve instrumentation setpoints, is assumed to function normally during the time period analyzed.

The severity of turbine trips from lower initial power levels decreases to the point where a scram can be avoided if auxiliary power is available from an external source and the power level is within the bypass capability.

15.2.3.2.2.2 Turbine Trip with Failure of Bypass. Same as Section 15.2.3.2.2.1 except that failure of the main turbine bypass system is assumed for the entire transient time period analyzed. During the transient the SRVs open and close sequentially as the stored energy is dissipated until the pressure falls below the valve setpoints.

15.2.3.2.2.3 Turbine Trip at Low Power with Failure of Bypass. Same as Section 15.2.3.2.2.1 except that failure of the main turbine bypass system is assumed.

Below 29.5% NBR power level, a main stop valve scram trip inhibit signal derived from the first stage pressure of the turbine is activated. This is done to eliminate the stop valve scram trip signal from scramming the reactor provided the bypass system functions properly. In other words, the bypass would be sufficient at this low power to accommodate a turbine trip without the necessity of shutting down the reactor. All other protection system functions remain functional as before and credit is taken for those protection system trips.

15.2.3.2.3 The Effect of Single Failures and Operator Errors

15.2.3.2.3.1 Turbine Trips at Power Levels Greater Than 29.5% Nuclear Boiler Rated. Mitigation of pressure increase, the basic nature of this transient, is accomplished by the RPS functions. Main stop valve closure scram trip and RPT are designed to satisfy single failure criterion.

15.2.3.2.3.2 Turbine Trips at Power Levels Less Than 29.5% Nuclear Boiler Rated. Same as Section 15.2.3.2.3.1 except RPT and stop valve closure scram trip is normally inoperative. Since protection is still provided by high flux, high pressure, etc., these will continue to function and scram the reactor should a single failure occur.

15.2.3.3 Core and System Performance

15.2.3.3.1 Mathematical Model

15.2.3.3.1.1 Turbine Trip with Bypass. The predicted dynamic behavior for the turbine trip has been determined using a computer simulated, analytical model of a generic direct-cycle BWR, as discussed in Section 15.2.2.3.1. This model is described in detail in Reference 15.2-4.

15.2.3.3.1.2 Turbine Trip with Bypass Failure. The three-dimensional TRACG model described in Section 15.0.3.3.1 is used to simulate this event.

15.2.3.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2 for the turbine trip with bypass and Table 15.0-2B for the turbine trip with bypass failure.

The turbine trip analysis was performed at the 105% of the original rated steam flow. The turbine trip with bypass failure was analyzed at an initial condition of 100% rated power (3544 MWt) and 106% rated core flow.

Turbine stop (throttle) valves full stroke closure time is 0.1 sec.

A reactor scram is initiated by position switches on the stop valves when the valves are 90% open or less. This stop valve scram trip signal is automatically bypassed when the reactor is below 29.5% NBR power level.

Reduction in core recirculation flow is initiated by position switches on the main stop valves, which actuate trip circuitry which trips the recirculation pumps.

15.2.3.3.3 Results

15.2.3.3.3.1 Turbine Trip. The results of a turbine trip with the bypass system operating normally are shown in Figure 15.2-3.

Neutron flux increases rapidly because of the void reduction caused by the pressure increase. However, the flux increase is limited to 138% of rated by the stop valve scram and the RPT system. Peak fuel surface heat flux does not exceed 101.7% of its initial value.

15.2.3.3.3.2 Turbine Trip with Failure of Bypass. The results of a turbine trip with failure of the bypass system are shown in Figure 15.2-4.

The peak neutron flux reaches 308% of its rated value, and peak surface heat flux reaches 111% of its initial value.

Results reflect GE14 fuel introduction, some of which are dependent on fuel design and core loading pattern. The event was analyzed for GNF2 introduction, however the results were not reported because the event was not limiting. Compliance with the event acceptance criteria is demonstrated by cycle-dependent analysis of potentially limiting events just prior to the operation of that cycle. The results are reported in the Supplemental Reload Licensing Report (Reference 15.2-3) if the event is limiting.

15.2.3.3.3.3 Turbine Trip with Bypass Valve Failure, Low Power. This transient is less severe than a similar one at high power. Below 29.5% of rated power, the turbine stop valve closure and TCV (governor valve) closure scrams are automatically bypassed. At these lower power levels, turbine first stage pressure is used to initiate the scram logic bypass. The scram which terminates the transient is initiated by high vessel pressure. The bypass valves are assumed to fail; therefore, system pressure will increase until the pressure relief setpoints are reached. At this time, because of the relatively low power of this transient event, relatively few relief valves will open to limit reactor pressure. Peak pressures are not expected to greatly exceed the pressure relief valve setpoints and will be significantly below the reactor coolant pressure boundary (RCPB) transient limit of 1375 psig. Peak surface heat flux and peak fuel center temperature remain at relatively low values and MCPR remains well above the GETAB safety limit.

15.2.3.3.4 Considerations of Uncertainties

Uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed,
b. Scram worth shape for all-rod-out conditions is assumed,
c. Minimum specified valve capacities are utilized for overpressure protection, and
d. Setpoints of the SRVs include errors and uncertainties (high) for all valves.

15.2.3.4 Barrier Performance

15.2.3.4.1 Turbine Trip

Peak pressure in the bottom of the vessel reaches 1163 psig, which is below the American Society of Mechanical Engineers (ASME) Code limit of 1375 psig for the RCPB. Vessel dome pressure does not exceed 1136 psig.

15.2.3.4.2 Turbine Trip with Failure of Bypass

The peak steam line pressure reaches 1235 psig. The peak reactor coolant pressure boundary (RCPB) pressure reaches 1260 psig. The peak pressure remains well below the nuclear barrier transient pressure limit of 1375 psig.

15.2.3.4.2.1 Turbine Trip with Failure of Bypass at Low Power. Qualitative discussion is provided in Section 15.2.3.3.3.3.

15.2.3.5 Radiological Consequences

The consequence of this event does not result in fuel failure. It does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation, which is contained in the primary containment. This event does not result in an uncontrolled release to the environment, so the plant operator can choose to hold the activity in containment or discharge it when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.4 MAIN STEAM LINE ISOLATION VALVE CLOSURES

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, cycle specific analyses are not performed for this event. The analysis results presented in the section are based on uprated power conditions and a representative reload core (Cycle 8) as documented in Reference 15.2-5.

15.2.4.1 Identification of Causes and Frequency Classification

15.2.4.1.1 Identification of Causes

Various steam line and nuclear system malfunctions, or operator actions, can initiate MSIV closure. Examples are low-steam line pressure, high-steam line flow, low-water level, or manual action.

15.2.4.1.2 Frequency Classification

15.2.4.1.2.1 Closure of All Main Steam Line Isolation Valves. This event is categorized as an incident of moderate frequency. To define the frequency of this event as an initiating event and not the byproduct of another transient, only the following contribute to the frequency: Manual action (purposely or inadvertent); spurious signals such as low pressure, low reactor water level, and low condenser vacuum; and equipment malfunctions such as faulty valves or operating mechanisms. A closure of one MSIV may cause an immediate closure of all the other MSIVs depending on reactor conditions. If this occurs, it is also included in this category. During the MSIV closure, position switches on the valves provide a reactor scram when the valves in three or more main steam lines are less than 90% open (except for interlocks which permit proper plant startup). Protection system logic permits the test closure of one valve without initiating scram from the position switches.

15.2.4.1.2.2 Closure of One Main Steam Line Isolation Valve. This event is categorized as an incident of moderate frequency. One MSIV at a time may be manually closed for testing purposes. Operator error or equipment malfunction may cause a single MSIV to be closed inadvertently. If reactor power is greater than about 75% when this occurs, a high flux or high steam line flow condition may result in a scram. If all MSIVs close as a result of the single event, the event is considered as a closure of all MSIVs. The results presented for this event assume all MSIVs close as a result of an unspecified initiating event.

15.2.4.2 Sequence of Events and Systems Operation

15.2.4.2.1 Sequence of Events

Table 15.2-6 lists the sequence of events for Figure 15.2-5. When the MSIV's reach their 85% open position, a reactor scram is initiated by the reactor protection system. The valve closure results in a system pressure increase which in turn results in a spike in reactor neutron flux. The reactor vessel pressure increase also results in an ATWS recirculation pump trip (RPT). As the pressure increases, the relief valves begin to open terminating the pressure increase.

15.2.4.2.2 Systems Operation

15.2.4.2.2.1 Closure of All Main Steam Line Isolation Valves. The MSIV closures initiate a reactor scram trip by means of position signals to the protection system. Credit is taken for successful operation of the protection system.

The pressure relief system which initiates opening of the relief valves when system pressure exceeds relief valve instrumentation setpoints is assumed to function normally during the time period analyzed.

All plant control systems maintain normal operation unless specifically designated to the contrary.

15.2.4.2.2.2 Closure of One Main Steam Line Isolation Valve. A closure of a single MSIV will not initiate a reactor scram by means of the position signal to the protection system. This is because the valve position scram trip logic is designed to accommodate single valve operation and testability during normal reactor operation at limited power levels. Credit is taken for the operation of the pressure and flux signals to initiate a reactor scram.

All plant control systems maintain normal operation unless specifically designated to the contrary.

15.2.4.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase is accomplished by initiation of the reactor scram by means of MSIV position switches and the protection system. Relief valves also operate to limit system pressure. All of these aspects are designed to single failure criterion and additional single failures would not alter the results of this analysis.

Failure of a single relief valve to open is not expected to have any significant effect. Such a failure is expected to result in less than a 5 psi increase in the maximum vessel pressure rise. The peak pressure will still remain considerably below 1375 psig.

15.2.4.3 Core and System Performance

15.2.4.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 is used to simulate these transient events.

15.2.4.3.2 Input Parameters and Initial Conditions

It is assumed the closure of all MSIVs occurs with the plant operating at 104.5% of uprated power and 100% core flow. The input parameters are defined with the plant conditions tabulated in Table 15.0-2 for power uprate.

The MSIVs close in 3 to 5 sec. The worst case, the 3-sec closure time, is assumed in this analysis.

Position switches on the valves initiate a reactor scram when the valves are less than 90% open as described in Section 7.2 (85% is assumed in the analysis). Closure of these valves inhibits steam flow to the feedwater turbines terminating feedwater flow.

Valve closure indirectly causes a trip of the main turbine and generator.

Because of the loss of feedwater flow, water level within the vessel decreases sufficiently to initiate trip of the recirculation pump and to initiate the HPCS and RCIC systems.

15.2.4.3.3 Results

15.2.4.3.3.1 Closure of All Main Steam Line Isolation Valves. The reactor scram is initiated at 0.45 sec when the MSIVs reach 85% open position. The nuclear system relief valves begin to open at 3.08 sec after the start of isolation. The valves close sequentially as the stored heat is dissipated but continue to discharge the decay heat intermittently. Table 15.2-6 provides the sequence of events and Figure 15.2-5 depicts the plant parameters responses. Key transient peak values are presented in Table 15.0-1. This event is non-limiting in that the pressurization event and change in CPR margin is less severe than the Generator Load Rejection with Bypass Failure and Turbine Trip with Bypass Failure events.

15.2.4.3.3.2 Closure of One Main Steam Line Isolation Valve. Only one isolation valve is permitted to be closed at a time for testing purposes to prevent scram. Normal test procedure requires an initial power reduction to approximately 65% to 70% of design conditions to avoid high-flux scram, high-pressure scram, or full isolation from a high-steam flow condition in the open steam lines. With a 3-sec closure of one MSIV during 105% of original rated power conditions, the steam flow disturbance raises vessel pressure and reactor power enough to initiate a high neutron flux scram. This transient is considerably milder than closure of all MSIVs at full power. No quantitative analysis is furnished for this event. No significant change in thermal margins is experienced and no fuel damage occurs. Peak pressure remains below SRV setpoints.

Inadvertent closure of one or all of the isolation valves while the reactor is shut down will produce no significant transient. Closures during plant heatup will be less severe than the maximum power cases (maximum stored and decay heat).

15.2.4.3.4 Considerations of Uncertainties

Uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed,

b. Scram worth shape for all-rod-out conditions is assumed,

c. Minimum specified valve capacities are used for overpressure protection, and

d. Setpoints of the SRVs are assumed to be 15 psi higher than the valve's nominal setpoint.

15.2.4.4 Barrier Performance

15.2.4.4.1 Closure of All Main Steam Line Isolation Valves

The nuclear system relief valves begin to open at approximately 3.1 sec after the start of isolation. The valves close sequentially as the stored heat is dissipated but continue to discharge the decay heat intermittently. Peak pressure at the vessel bottom reaches 1234 psig, clearly below the pressure limits of the RCPB. Peak pressure in the main steam line is 1198 psig.

15.2.4.4.2 Closure of One Main Steam Line Isolation Valve

No significant effect is imposed on the RCPB, since if closure of the valve occurs at a high operating power level a flux or pressure scram will result. The main turbine bypass system will continue to regulate system pressure by means of the other three steam lines.

15.2.4.5 Radiological Consequences

While the consequence of this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via SRV operation. Since this activity is contained in the primary containment, there will be no exposure to the public. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.5 LOSS-OF-CONDENSER VACUUM

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, cycle specific analyses are not performed for this event. The analysis results presented in the section are based on uprated power conditions and a representative reload core (Cycle 8) as documented in Reference 15.2-5.

15.2.5.1 Identification of Causes and Frequency Classification

15.2.5.1.1 Identification of Causes

Various malfunctions can cause a loss-of-condenser vacuum. The causes and estimated vacuum decay rates include failure or isolation of steam jet air ejectors (<1 in. Hg/mm), loss of sealing steam shaft gland seals (1 to 2 in. Hg/minute), opening of vacuum breaker valves (2 to 12 in. Hg/minute), and loss of one or more circulating water pumps (4 to 24 in. Hg/minute).

15.2.5.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.5.2 Sequence of Events and Systems Operation

15.2.5.2.1 Sequence of Events

Table 15.2-7 lists the sequence of events for Figure 15.2-6.

15.2.5.2.2 Systems Operation

It is conservatively assumed that condenser vacuum is lost at a rate of 2 inches of Hg per second. The bypass system is signaled to close approximately 10 inches of Hg less than the stop (throttle) valve closure vacuum setpoint level which means the bypass is available for approximately 5 sec before the turbine stop (throttle) valves close. The loss of vacuum initiates a main turbine trip and feedwater turbine trip. Upon reaching 90% close, the turbine throttle (stop) valves closure results in a reactor scram. As the reactor pressure increases, the relief valves will open. Subsequently, this results in the main steam line isolation valves to close. However, the effect of the MSIV closure is minimal since the turbine stop (throttle) valve and bypass valve closure have already terminated main steam line flow.

Tripping functions incurred by sensing main turbine condenser vacuum are designated in Table 15.2-8.

15.2.5.2.3 The Effect of Single Failures and Operator Errors

Single failure will not effect the vacuum monitoring and turbine trip devices which are redundant. The protective sequences of the anticipated operational transient are shown to be single failure proof.

15.2.5.3 Core and System Performance

15.2.5.3.1 Mathematical Model

The one-dimensional ODYN model described in Section 15.0.3.3.1 was used to simulate this transient event.

15.2.5.3.2 Input Parameters and Initial Conditions

This analysis was performed with plant conditions tabulated in Table 15.0-2 and at 102.4% of uprated power and 100% core flow. Turbine stop (throttle) valves full stroke closure time used in this analysis is 0.1 second and a reactor scram is initiated by position switches on the stop valves when the valves are less than 90% open. The 2 inches of Hg per second assumed in the analysis is conservative with respect to normal loss of vacuum and no operator actions are assumed.

Thus, the bypass system is available for several seconds since the bypass is signaled to close at a vacuum level of about 10 in. Hg less than the stop valve closure.

15.2.5.3.3 Results

The loss of condenser vacuum initiates a main turbine trip, which then initiates turbine bypass operation. The bypass is available for approximately 5 sec until both the turbine bypass valves and the main steam line isolation valves receive a signal to close on low condenser vacuum. The effect of MSIV closure tends to be minimal since the closure of main turbine stop valves and subsequently the bypass valves have already shut off the main steam line flow. Figure 15.2-6 shows the transient expected for this event. It is assumed that the plant is initially operating at 105% of uprated NBR steam flow conditions. Peak neutron flux reaches 252% of NBR power while average fuel surface heat flux reaches 111% of rated value. The SRVs open to limit the pressure rise then sequentially reclose as the stored energy is dissipated.

15.2.5.3.4 Consideration of Uncertainties

The reduction or loss of vacuum in the main turbine condenser will sequentially trip the main and feedwater turbines and close the MSIVs and turbine bypass valves. While these are the major events occurring, other resultant actions will include scram (from stop valve closure) and bypass opening with the main turbine trip. Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is dependent upon the rate at which the vacuum is lost. Normal loss of vacuum due to loss-of-cooling water pumps or steam jet air ejector problem produces a very slow rate of loss of vacuum (minutes, not seconds). If corrective actions by the reactor operators are not successful, then simultaneous trips of the main and feedwater turbines, and ultimately complete isolation by closing the bypass valves (opened with the main turbine trip) and the MSIVs, will occur.

A faster rate of loss of the condenser vacuum would reduce the anticipatory action of the scram and the overall effectiveness of the bypass valves since they would be closed more quickly.

Other uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed,

b. Scram worth shape for all-rod-out conditions is assumed,

c. Minimum specified valve capacities are utilized for overpressure protection, and

d. Setpoints of the SRVs are assumed to be 15 psi higher than the valve's nominal setpoint.

15.2.5.4 Barrier Performance

The maximum calculated pressure for this event as presented in Table 15.0-1 is below the ASME Code limit of 1375 psig for the RCPB and the ASME Service Level C of 1500 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.2.5.5 Radiological Consequences

While the consequence of this event does not result in fuel failures, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no exposure to the public. Since this event does not result in an uncontrolled release to the environment, the plant operator can choose to hold the activity in containment or discharge it to the environment when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.6 LOSS OF ALTERNATING CURRENT POWER

This transient considers the loss of AC power to the plant from both an onsite cause (loss of auxiliary power transformer) and an offsite cause (loss of all grid connections).

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, cycle specific analyses are not performed for this event. The analysis results presented in the section are based on uprated power conditions and a representative reload core (Cycle 8) as documented in Reference 15.2-5.

15.2.6.1 Identification of Causes and Frequency Classification

15.2.6.1.1 Identification of Causes

15.2.6.1.1.1 Loss of Auxiliary Power Transformers. Causes for interruption or loss of the auxiliary power transformers can arise from normal operation or malfunctioning of transformer protection circuitry. These can include high transformer oil temperature, reverse of high current operation, and operator error which trips the transformer breakers.

15.2.6.1.1.2 Loss of All Grid Connections. Loss of all grid connections can result from major shifts in electrical loads, loss of loads, lightning, storms, wind, etc., which contribute to electrical grid instabilities. These instabilities will cause equipment damage if unchecked. Protective relay schemes automatically disconnect electrical sources and loads to mitigate damage and regain electrical grid stability.

15.2.6.1.2 Frequency Classification

15.2.6.1.2.1 Loss of Auxiliary Power Transformers. This event is categorized as an incident of moderate frequency.

15.2.6.1.2.2 Loss of All Grid Connections. This event is categorized as an incident of moderate frequency.

15.2.6.2 Sequence of Events and Systems Operation

15.2.6.2.1 Sequence of Events

15.2.6.2.1.1 Loss of Auxiliary Power Transformers. Table 15.2-9 lists the sequence of events for Figure 15.2-7.

15.2.6.2.1.2 Loss of All Grid Connections. Table 15.2-10 lists the sequence of events for Figure 15.2-8.

15.2.6.2.2 Systems Operation

15.2.6.2.2.1 Loss of Auxiliary Power Transformers. This event, unless otherwise stated, assumes and takes credit for normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems.

The reactor is subjected to a complex sequence of events when the plant loses all auxiliary power. Estimates of the responses of the various reactor systems (assuming loss of the auxiliary transformers) provide the following simulation sequence:

a. Recirculation pumps and condenser circulatory water pumps trip off at time = 0. A 4 sec recirculation pump trip inertia time constant is assumed for this analysis;

b. Reactor scram and MSIV closure is initiated at 2 sec due to loss of power to the scram and MSIV relay solenoids; and

c. Feedwater turbines trip off at 4 sec due to MSIV closure at 2 sec.

Operation of the HPCS and RCIC are not simulated in this analysis. Their operation occurs at a time beyond the primary concerns of fuel thermal margin and overpressure effects of this analysis.

15.2.6.2.2.2 Loss of All Grid Connections. Same as Section 15.2.6.2.2.1 with the following additional concern.

The loss of all grid connections would add a generator load rejection to the above sequence at time, t=0. The load rejection immediately causes the TCVs (governor valves) to close, causes a scram, and initiates RPT [already tripped at reference time t = 0].

15.2.6.2.3 The Effect of Single Failures and Operator Errors

Loss of the auxiliary power transformers in general leads to a reduction in power level due to rapid pump coastdown with pressurization effects due to MSIV closure resulting from loss of power to the solenoids. Additional failures of the other systems assumed to protect the reactor would not result in an effect different from those reported. Failures of the protection systems have been considered and satisfy single failure criteria and, as such, no change in analyzed consequences is expected.

15.2.6.3 Core and System Performance

15.2.6.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 was used to simulate this event.

15.2.6.3.2 Input Parameters and Initial Conditions

15.2.6.3.2.1 Loss of Auxiliary Power Transformers. It is assumed the loss of the auxiliary power transformer occurs with the plant operating at 104.5% of uprated power and 100% core flow. The input parameters are defined with the plant conditions tabulated in Table 15.0-2 except as noted below.

a. The recirculation pump trip inertia time constant is 4 sec.

b. The relay-type Reactor Trip System (RTS) circuitry generates a reactor scram and Main Steam Isolation Valves (MSIV) closure signal due to loss of power to the scram and MSIV solenoids. This occurs 2 sec after the loss of offsite power.

c. The feedwater pumps trip due to MSIV closure 2 sec after the MSIV begin to close as a result of the loss of power to the MSIV solenoids.

15.2.6.3.2.2 Loss of All Grid Connections. It is assumed the loss of all grid connections occurs with the plant operating at 102.4% of uprated power and 100% core flow. The input parameters are defined with the plant conditions tabulated in Table 15.0-2 except as noted below.

a. The recirculation pump trip inertia time constant is 4 sec.

b. The relay-type Reactor Trip System (RTS) circuitry generates a Main Steam Isolation Valves (MSIV) closure signal due to loss of power to the MSIV solenoids. This occurs 2 sec after the loss of offsite power.

c. The feedwater pumps trip due to MSIV closure 2 sec after the MSIV begin to close as a result of the loss of power to the MSIV solenoids.

15.2.6.3.3 Results

15.2.6.3.3.1 Loss of Auxiliary Power Transformers. Initially the offsite power is cutoff causing both recirculation pumps to trip. The loss of power to the scram and MSIV solenoids causes a reactor scram, MSIV isolation and a feedwater pump trip 2 sec after the MSIV isolation. Subsequently, the feedwater recirculation valves trip and the relief valves begin to open due to the rising pressure caused by the main steam line isolation. Table 15.2-9 provides the sequence of events and Figure 15.2-7 depicts the plant parameters responses. Key transient peak values are presented in Table 15.0-1. This event is non-limiting in that the pressurization event and change in MCPR margin are less severe than the Generator Load Rejection with Bypass Failure and Turbine Trip with Bypass Failure events.

15.2.6.3.3.2 Loss of All Grid Connections. Loss of all grid connections is a more general form of loss of auxiliary power. It essentially takes on the characteristic response of the standard full load rejection discussed in Section 15.2.2. Initially the offsite power is cutoff to the grid causing the turbine-generator to detect a loss of electrical load, and a power-load unbalance. The turbine generator overspeed protection control (OPC) initiates a control (governor) valve fast closure, turbine bypass valves opening and a reactor scram. At the same time both recirculation pump motors trip. Subsequently, MSIV isolation occurs and both feedwater pumps trip. The rising pressure due to the isolation of the steam line causes the relief valves to open. Table 15.2-10 provides the sequence of events and Figure 15.2-8 depicts the plant parameter responses. Key transient peak values are presented in Table 15.0-1. This event is non-limiting in that the pressurization event and change in MCPR margin are less severe than the Generator Load Rejection with Bypass Failure and Turbine Trip with Bypass Failure events.

15.2.6.3.4 Consideration of Uncertainties

The most conservative characteristics of protection features are assumed. Any actual deviations in plant performance are expected to make the results of this event less severe.

Operation of the HPCS and RCIC systems are not included in the simulation of the first 50 sec of this transient. Startup of the pumps occurs in the latter part of this time period but the system has no significant effect on the results of this transient.

Following main steam line isolation and prior to RHR initiation the reactor pressure is expected to increase until the SRV setpoints are reached. During this time the valves operate in a cyclic manner to discharge decay heat to the suppression pool.

15.2.6.4 Barrier Performance

15.2.6.4.1 Loss of Auxiliary Power Transformers

Safety/relief valves open in the pressure relief mode of operation as the pressure increases beyond their setpoints. The pressure in the dome is limited to a maximum value of 1169 psig well below the vessel pressure limit of 1375 psig.

15.2.6.4.2 Loss of All Grid Connections

Safety/relief valves open in the pressure relief mode of operation as the pressure increases beyond their setpoints. The pressure in the dome is limited to a maximum value of 1173 psig well below the vessel pressure limit of 1375 psig.

15.2.6.5 Radiological Consequences

The consequence of this event does not result in fuel failure. It does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation, which is contained in the primary containment. This event does not result in an uncontrolled release to the environment, so the plant operator can choose to hold the activity in containment or discharge it when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.7 LOSS-OF-FEEDWATER FLOW

This transient is classified as a nonlimiting event for both original and uprated power conditions. Therefore, cycle specific analyses are not performed for this event. The analysis results presented in the section are based on uprated power conditions and a representative reload core (Cycle 8) as documented in Reference 15.2-5. The analysis has not been updated for the change in MSIV isolation setpoint from Level 2 to Level 1 because the analysis is bounding and conclusions of the analysis are not affected (Reference 15.2-8).

15.2.7.1 Identification of Causes and Frequency Classification

15.2.7.1.1 Identification of Causes

A loss of feedwater flow could occur from pump failures, feedwater controller failures, operator errors, or reactor system variables such as a high vessel water level (L8) trip signal.

15.2.7.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.7.2 Sequence of Events and Systems Operation

15.2.7.2.1 Sequence of Events

Feedwater flow terminates at approximately 5 sec. Subcooling decreases causing a reduction in core power level and pressure. As power level is lowered, the turbine steam flow starts to drop off. Water level continues to drop until the vessel level (L3) scram trip setpoint is reached, whereupon the reactor is shut down.

Main steam line isolation initiation occurs due to vessel water dropping to the L2 trip. Also at this time, the recirculation system is tripped and HPCS and RCIC operation is initiated. Operation of the HPCS and RCIC systems is not included in the simulation of the first 50 seconds of this transient since startup of the pumps occurs in the latter part of this time period. Therefore, the system has no significant effects on the results of this transient.

Table 15.2-11 lists the sequence of events for Figure 15.2-9.

15.2.7.2.2 Systems Operation

Loss of feedwater flow results in a proportional reduction of vessel inventory causing the vessel water level to drop. The first corrective action is the low level (L3) scram trip actuation. Reactor protection system responds after this trip to scram the reactor. The low level (L3) scram trip function meets single failure criterion.

Vessel water level (L2) trip initiates main steam line isolation, recirculation pump trip and HPCS/RCIC system operation (not simulated). The recirculation pump motor circuit breakers then open causing decrease in core flow to natural circulation.

15.2.7.2.3 The Effect of Single Failures and Operator Errors

The nature of this event results in a lowering of vessel water level. Key corrective efforts to shut down the reactor are automatic and designed to satisfy single failure criterion. Therefore, any additional failure in these shutdown methods would not aggravate or change the simulated transient.

The potential exists for a single relief valve failing to close once it is opened. This would result in a complete depressurization of the reactor. Either the RCIC or the HPCS system is capable of maintaining adequate core coverage and will provide long-term inventory control. For the complete loss of feedwater flow event, operation of RCIC or HPCS is sufficient to avoid initiation of ADS on low vessel level (L1).

15.2.7.3 Core and System Performance

15.2.7.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 was used to simulate this event.

15.2.7.3.2 Input Parameters and Initial Conditions

The simultaneous trip of both feedwater pumps is assumed to occur while the plant is operating at 104.5% uprated power and 100% core flow. These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

15.2.7.3.3 Results

Table 15.2-11 provides the sequence of events and Figure 15.2-9 depicts the plant parameter responses. Key transient peak values are presented in Table 15.0-1. This event is non-limiting in that the pressurization event and change in MCPR are less severe than the Generator Load Rejection with Bypass Failure and Turbine Trip with Bypass Failure events.

15.2.7.3.4 Consideration of Uncertainties

End-of-cycle scram characteristics are assumed.

This transient is most severe from high power conditions, because the rate of level decrease is greatest and the amount of stored decay heat to be dissipated is highest.

15.2.7.4 Barrier Performance

Peak pressure in the bottom of the vessel reaches 1152 psig, which is below the ASME Code limit of 1375 psig for the RCPB. Vessel dome pressure does not exceed 1142 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function are maintained.

15.2.7.5 Radiological Consequences

The consequence of this event does not result in fuel failure. It does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation, which is contained in the primary containment. This event does not result in an uncontrolled release to the environment, so the plant operator can choose to hold the activity in containment or discharge it when conditions permit. If purging of the containment is chosen the release will be in accordance with established requirements.

15.2.8 FEEDWATER LINE BREAK

See Section 15.6.6.

15.2.9 FAILURE OF RESIDUAL HEAT REMOVAL SHUTDOWN COOLING

This transient is classified as a nonlimiting event for both original and uprated power conditions.

Normally, in evaluating component failures associated with the RHR shutdown cooling mode of operation, active pumps or instrumentation (all of which are redundant for the safety related portions of the RHR system) would be assumed to be the component failure. For purposes of a worst case analysis, a valve on the single recirculation suction line to the otherwise redundant RHR shutdown cooling loops is assumed to fail. Manual attempts to open the valve are assumed unsuccessful. Discovery is conservatively assumed to occur at 100 psig. This envelops discovery at normal RHR shutdown cooling operating limits (see Section 5.4.7). This failure disables the shutdown cooling mode but does not affect the remaining RHR modes of operation. Reference 15.2-1 establishes additional assumptions.

15.2.9.1 Identification of Causes and Frequency Classification

15.2.9.1.1 Identification of Causes

The plant is operating at 105% of original NBR steam flow when an event occurs, e.g., a long-term loss of offsite power, causing a plant shutdown. Reactor vessel depressurization is initiated to bring the reactor pressure to approximately 100 psig. Concurrent with the loss of offsite power a failure of a valve in the shutdown cooling suction line occurs which prevents the operator from establishing the normal shutdown cooling path through the RHR shutdown cooling lines. An additional failure is assumed which completely disables the RHR equipment in one division. The operator then establishes a shutdown cooling path for the vessel through the SRV valves.

15.2.9.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.2.9.2 Sequence of Events and Systems Operation

15.2.9.2.1 Sequence of Events

The sequence of events for this event is shown in Table 15.2-12.

15.2.9.2.1.1 Identification of Operator Actions. For the early part of the transient, the operator actions are to restore and maintain reactor water level. The operator should reestablish reactor cooling by one or more of the following:

a. Maintain reactor water inventory with the RCIC (when single failure is not assumed to be a loss of Division 1 dc power) and HPCS systems,

b. At approximately 10 minutes into the transient, initiate suppression pool cooling, it is assumed that only one RHR heat exchanger is available,

c. Initiate RPV shutdown depressurization by manual actuation of the SRVs,

d. Attempts to open one of the two RHR shutdown cooling suction valves are assumed unsuccessful (reactor pressure is approximately 100 psig), and

e. Continue RPV depressurization by opening SRVs and establish a reactor cooling path as described in the notes for Figure 15.2-10.

Time required to initiate the necessary steps to maintain reactor pressure and level control is approximately 10 minutes.

15.2.9.2.2 Systems Operation

Plant instrumentation and control is assumed to be functioning normally except as noted. In this evaluation credit is taken for the plant and reactor protection systems and/or the ESF used.

15.2.9.2.3 The Effect of Single Failures and Operator Errors

The worst case single failure (loss of division power) has already been analyzed in this event. Therefore, no single failure or operator error can increase the consequences of this event.

15.2.9.3 Core and System Performance

The earliest time the shutdown cooling system can be actuated is 2 to 3 hr after shutdown is initiated. During this time MCPR remains high and nucleate boiling heat transfer is not exceeded at any time. Therefore, the core thermal safety margin remains essentially unchanged. The 10-minute time period approximated for operator action is an estimate of how long it would take the operator to initiate the necessary actions. It is not a time by which action must be initiated.

The transient behavior of the core during this event has been evaluated in Section 15.2.6.

15.2.9.4 Results

For most single failures that could result in loss of shutdown cooling, no unique safety actions are required. In these cases, shutdown cooling is simply reestablished using the redundant shutdown cooling loop. In cases where the RHR shutdown cooling suction line valves cannot be opened, alternate paths are available to accomplish the shutdown cooling function (Figure 15.2-11). An evaluation has been performed assuming a failure that disables the RHR shutdown cooling suction line valves.

This evaluation demonstrates the capability to safely transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded.

The alternate cooldown path chosen to accomplish the shutdown cooling function uses the RHR and ADS or normal relief valve systems (see Reference 15.2-1 and Figure 15.2-10). The alternate shutdown systems are capable of performing the function of transferring heat from the reactor to the environment using only safety systems. The systems are capable of bringing the reactor to a cold shutdown in approximately 36 hr or less after the transient occurs.

The systems have suitable redundancy in components such that even for onsite electrical power operation (offsite power is not available), the safety function of the systems can be accomplished assuming an additional single failure. The systems can be fully operated from the main control room.

The design evaluation is divided into two phases: (a) full power operation to approximately 100 psig vessel pressure, and (b) approximately 100 psig vessel pressure to cold shutdown (14.7 psia 200°F) conditions.

15.2.9.4.1 Full Power to Approximately 100 psig

Independent of the event that initiated plant shutdown (whether it be a normal plant shutdown or a forced plant shutdown), the reactor is normally brought to approximately 100 psig using either the main condenser or, in the case where the main condenser is unavailable, the HPCS and RCIC systems together with the nuclear boiler pressure relief system and the RHR heat exchanger in the suppression pool cooling mode.

For evaluation purposes, however, it is assumed that plant shutdown is initiated by a transient event (loss of offsite power) which results in relief valve actuation and subsequent suppression pool heatup. For this postulated condition, the reactor is shut down and the reactor vessel pressure is reduced to approximately 100 psig. Manual operation of the SRVs is used to depressurize the reactor vessel. Reactor vessel makeup water is automatically provided by means of the RCIC (until reduced vessel pressure is reached) and HPCS systems. While in this condition, the RHR system (suppression pool cooling mode) is used to maintain the suppression pool temperature within shutdown limits.

These systems are designed to routinely perform their functions for both normal and forced plant shutdown. Since the HPCS and RHR systems are divisionally separated and the HPCS and RCIC systems are divisionally separated, no single failure together with the loss of offsite power, is capable of preventing reaching the 100 psig level.

15.2.9.4.2 Approximately 100 psig to Cold Shutdown

The following assumptions are used for the analyses of the procedures for attaining cold shutdown from a pressure of approximately 100 psig:

a. The vessel is at 100 psig and saturated conditions,

b. A worst-case single failure is assumed to occur (i.e., loss of a division of emergency power), and

c. There is no offsite power available.

In the event that the RHRs shutdown suction line is not available because of single failure, the first action to be taken will be to control reactor pressure. If a single electrical failure caused the suction line to fail in the closed position, a hand wheel is provided on the valve to allow manual operation. If for some reason the normal shutdown cooling suction line cannot be restored to service, the capabilities described below will satisfy the normal shutdown cooling requirements and thus fully comply with GDC 34.

The RHR shutdown cooling line valves are in two divisions (Division 1 - the outboard valve, and Division 2 - the inboard valve) to satisfy containment isolation criteria. For evaluation purposes, the worst-case failure is assumed to be the loss of a division of emergency power, since this also prevents electrical actuation of one shutdown cooling line valve. Engineered safety features equipment and safe shutdown RCIC equipment (until reduced reactor pressure is reached) available for accomplishing the shutdown cooling function include (for the selected path):

ADS (dc Division 1 and dc Division 2)

RHR Loop A (Division 1)

HPCS (Division 3)

RCIC (dc Division 1)

LPCS (Division 1)

Since availability or failure of Division 3 equipment does not affect the normal shutdown mode, normal shutdown cooling is easily available through equipment powered from only Divisions 1 and 2. It should be noted that, HPCS is always available for coolant injection if either of the other two divisions fails. For failure of Division 1 or 2, the following systems are assumed functional:

a. Division 1 Fails, Division 2 and 3 Functional

Failed Systems	Functional Systems
RHR Loop A	HPCS
LPCS	ADS
RCIC	RHR Loops B and C

Assuming the single failure is a failure of Division 1 emergency power, the safety function is accomplished by establishing one of the cooling loops described in Activity C1 of Figure 15.2-10.

b. Division 2 Fails, Division 1 and 3 Functional

Failed Systems	Functional Systems
RHR Loop B and C	HPCS ADS RHR Loop A LPCS RCIC (until reduced reactor pressure is reached)

Assuming the single failure is the failure of Division 2, the safety function is accomplished by establishing one of the cooling loops described in Activity C2 of Figure 15.2-10. Figures 15.2-12 through 15.2-15 show RHR loops A, B, and/or C (simplified).

15.2.9.4.3 Temperature Response – 3462 MWt

The reactor vessel temperature and pressure response versus time for the core conditions defined in Table 15.2-13 (105% of original rated steam flow, 3462 MWt rated power) are presented in Figures 15.2-16 and 15.2-17. Figure 5.2-16 presents the results for

Activity C1.b.1 or C2 described in Figure 15.2-10. Figure 5.2-17 presents the results for Activity C1.b.2. The bulk suppression pool temperature responses from the same analysis are presented in Figures 15.2-18 and 15.2-19. Figure 5.2-18 presents the results for Activity C1.b.1 or C2 and Figure 5.2-19 presents the results for Activity C1.b.2.

15.2.9.4.4 Temperature Response – 3702 MWt

Reference 15.2-7 analyzed the same two scenarios (Activities C2 and C1.b.2) for 104.5% of power uprate conditions (3702 MWt) to determine the peak bulk suppression pool temperature and the time required to cool the reactor vessel to cold shutdown (14.7 psia and 200°F). The analysis at power uprate conditions calculated a relative 4°F increase in the peak bulk pool temperature due to the power uprate. However, the peak temperature calculated was lower than the temperatures presented in this section due to the use of more realistic assumptions. These assumptions include a more realistic decay heat model, lower initial suppression pool temperature (90°F), and more realistic treatment of pump heat addition.

15.2.9.5 Barrier Performance

As noted above, the consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Release of coolant to the containment occurs by means of SRV actuation.

15.2.9.6 Radiological Consequences

The consequence of this event does not result in fuel failure. It does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation, which is contained in the primary containment. This event does not result in an uncontrolled release to the environment, so the plant operator can choose to hold the activity in containment or discharge it when conditions permit. If purging of the containment is chosen, the release would be in accordance with established requirements.

15.2.10 REFERENCES

15.2-1 Letter - R. S. Boyd to I. F. Stuart; dated November 12, 1975. Subject: Requirements delineated for RHRS - Shutdown Cooling System - Single Failure Analysis.

15.2-2 NEDC-24154-P-A, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," Volumes 1, 2, 3 and 4, February 2000.

15.2-3 Supplemental Reload Licensing Report for Columbia (most recent version referenced in COLR).

15.2-4 R. B. Linford, "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor," NEDO 10802, April 1973.

15.2-5 For Power Uprate: GE Nuclear Energy, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, September 1993 (Proprietary).

15.2-6 Deleted.

15.2-7 GE Nuclear Energy, "WNP-2 Power Uprate Project NSSS Engineering Report," GE-NE-208-17-0993, Revision 1, December 1994 (Proprietary).

15.2-8 AREVA NP, Inc., "Columbia Generating Station MSIV Closure Level Setpoint Change - Loss of Feedwater Flow Transient Analysis," 51-9084418-000, July 2008.

15.2-9 GE Hitachi Nuclear Energy, "License Amendment Request for Proposed Changes to Columbia Technical Specifications: Changing Group 1 Isolation Valves' Low Reactor Water Level Isolation Signal from the Current Level 2 to Level 1," 0000-0081-6730-R1, July 2008.

15.2-10 NEDE-32906P-A, "TRACG Application for Anticipated Operational Occurrences Transient Analyses," Revision 3, September 2006.

Table 15.2-1

Sequence of Events for Figure 15.2-1

Pressure Regulator Failure - Closed
102.4% Uprated Power - 106% Flow

Time (sec)	Event
0	Failure of the pressure regulator causes closure of the turbine control valves.
1.0	Scram signal initiated at high neutron flux.
2.0	Recirculation pump motor circuit breakers open causing decrease in core flow to the natural circulation.
2.56	Group 3 relief valves actuated.
2.67	Group 4 relief valves actuated.
2.77	Group 5 relief valves actuated.
2.84	Turbine control valves close.

Table 15.2-2

Sequence of Events for Figure 15.2-2.1

Generator Load Rejection with Bypass On
Original Rated Power

Time (sec)	Event
(-)0.015[a]	Turbine generator detection of loss of electrical load.
0	Turbine generator overspeed protection control (OPC) devices trip to initiate turbine control (governor) valve fast closure.
0	Turbine generator OPC trip initiates main turbine bypass system operation.
0	Fast control valve closure initiates scram trip.
0	Fast control valve closure initiates an RPT.
0.07	Turbine control valves closed.
0.11	Turbine bypass valves start to open.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
1.70	Group 1 relief valves actuated.
1.86	Group 2 relief valves actuated.
2.01	Group 3 relief valves actuated.
2.27	Group 4 relief valves actuated.

[a] Approximately.

Table 15.2-3

Typical Sequence of Events for Figure 15.2-2.2

Generator Load Rejection with Bypass Failure
100% Power 106% Flow

Time (sec)	Event
(-)0.003[a]	Turbine generator detection of loss of electrical load.
0	Turbine generator OPC devices trip to initiate turbine control (governor) valve fast closure.
0	Turbine bypass valves fail to operate.
0.03	Time of scram trip.
0.15	Turbine control valves fully closed.
0.20	Time of RPT trip.
0.28	Start of control blade motion.
(b)	Group 1 MSRVs actuated (safety function).
(b)	Group 2 MSRVs actuated (safety function).
2.83	Group 3 MSRVs actuated (safety function).
3.17	Group 4 MSRVs actuated (safety function).

[a] Approximately.

[b] Not used - out of service for this analysis.

Table 15.2-4

Sequence of Events for Figure 15.2-3

Turbine Trip, Trip Scram - Bypass and RPT On
Original Rated Power

Time (sec)	Event
0	Turbine trip initiates closure of main stop (throttle) valves.
0	Turbine trip initiates bypass operation.
0.01	Main turbine stop valves reach 90% open position and initiate reactor scram trip.
0.01	Main turbine stop valves reach 90% open position and initiate an RPT.
0.10	Turbine stop valves closed.
0.10	Turbine bypass valves start to open to regulate pressure.
0.20	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
1.63	Group 1 relief valves actuated.
1.78	Group 2 relief valves actuated.
1.94	Group 3 relief valves actuated.
2.14	Group 4 relief valves actuated.
2.50	Group 5 relief valves actuated.
4.67	Feedwater turbines trip on L8 high water level.
5.1[a]	Group 5 relief valves start to close.
7.2[a]	All relief groups closed.
31.0	Turbine bypass starts to close.
32.3[a]	Turbine bypass closed.
39.7	Turbine bypass reopens on pressure increase at turbine inlet.
45.3	Main steam line isolation[b], HPCS system initiation, and RCIC system initiation on low level (L2) (not included in simulation).
50+	Group 1 relief valves cycle open and close on pressure.

[a] Estimated.

[b] The analysis has not been updated for the change in MSIV isolation setpoint from Level 2 to Level 1 because the analysis is bounding and conclusions of the analysis are not affected (Reference 15.2-9).

Table 15.2-5

Sequence of Events for Figure 15.2-4

Turbine Trip with Bypass Failure
at 100% Power/106% Core Flow

Time (sec)	Event
0	Turbine trip initiates closure of main stop (throttle) valves.
0	Turbine bypass valves fail to operate.
0.01	Main turbine stop valves reach 90% open position and initiate reactor scram trip.
0.10	Turbine stop valves closed.
0.20	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
(a)	Group 1 relief valves actuated.
(a)	Group 2 relief valves actuated.
2.83	Group 3 relief valves actuated.
3.18	Group 4 relief valves actuated.

[a] Not used - out of service for this analysis.

Table 15.2-6

Sequence of Events for Figure 15.2-5

Main Steam Line Isolation Valve Closure
104.5% Uprated Power, 100% Rated Flow

Time (sec)	Event
(-) 0.003 (approximately)	Turbine-Generator detection of loss of electrical load.
0	Initiate closure of all main steam line valves.
0.45	MSIVs reach 85% opening initiating a position valve scram.
2.0	Loss of feedwater begins as turbine loses steam supply.
2.53	Both recirculation pumps trip due to high pressure.
3.0	All MSIVs closed.
3.08	Groups 3 relief valves actuated.
3.16	Groups 4 relief valves actuated.
3.24	Groups 5 relief valves actuated.
11 (approx.)	All pressure relieve valves closed.
18.23	Groups 3 relief valves begin to cycle.

Table 15.2-7

Sequence of Events for Figure 15.2-6

Loss of Condenser Vacuum
102.4% Uprated Power, 100% Rated Flow

Time (sec)	Event
(-)5.0 (approximately)	Initiate simulated loss of condenser vacuum at 2 in. of Hg per second.
0.00	Low condenser vacuum main turbine trip and feedwater turbine trips initiated.
0.00	Main turbine trip initiates turbine bypass operation.
0.01	Main turbine stop valves reach 90% open position and initiate reactor scram.
0.19	Both recirculation pumps trip.
2.15	Group 3 relief valves actuated.
2.28	Group 4 relief valves actuated.
2.42	Group 5 relief valves actuated.
2.91	Feedwater recirculation valve is tripped.
5.00	Low condenser vacuum initiates turbine bypass valve closure and MSIV closure.
5.6 (approx.)	All relief valves closed.
6.0 (approx.)	Main steam isolation valves closed.
7.90	Group 3 relief valves reactuated.
8.35	Group 4 relief valves reactuated.
24.01	Group 5 relief valves reactuated.

Table 15.2-8

Trip Signals Associated with Loss-of-Condenser Vacuum

Vacuum[a]	Protective Action Initiated
27 to 30	Normal vacuum range.
20 to 23	Main turbine trip and feedwater turbine trip (stop valve closures).
7 to 10	Main steam line isolation valve closure and bypass valve closure.

[a] Inches of Hg.

Table 15.2-9

Sequence of Events for Figure 15.2-7

Loss of Auxiliary Power Transformers
104.5% Uprated Power, 100% Rated Flow

Time (sec)	Event
0.00	Loss of auxiliary power transformers occurs.
0.00	Recirculation system pump motors are tripped.
2.00	Reactor scram due to loss of power to the scram solenoid.
2.00	Main steam line isolation valves begin to close due to loss of power to MSIV solenoids.
4.00	Feedwater pumps are tripped due to MSIV closure.
5.98	Group 3 relief valves actuated.
6.15	Group 4 relief valves actuated.
6.34	Group 5 relief valves actuated.

Table 15.2-10

Sequence of Events for Figure 15.2-8

Loss of All Grid Connections
102.4% Uprated Power, 100% Rated Flow

Time (sec)	Event
0.00	Loss of grid causes turbine-generator to detect a loss of electrical load.
0.00	Turbine-generator PLU devices trip to initiate TCV fast closure and turbine bypass system operation.
0.00	Recirculation pumps trip.
0.00	Fast control valve closure initiates reactor scram.
2.00	Main steam line isolation is initiated due to loss of power to the solenoids.
2.12	Group 3 relief valves actuated.
2.25	Group 4 relief valves actuated.
2.37	Group 5 relief valves actuated.
4.00	Feedwater pump tripped due to MSIV closure.

Table 15.2-11

Sequence of Events for Figure 15.2-9

Loss of All Feedwater Flow
104.5% Uprated Power, 100% Rated Flow

Time (sec)	Event
0	Initiate trip of all feedwater pumps.
3.91	Recirculation runback initiated with narrow range sensed level less than L4 and feedwater pumps off.
7.38	Vessel water level (L3) trip initiates scram trip.
32.32	Vessel water level (L2) trip initiates main steam line isolation[a], recirculation pump trip and HPCS/RCIC system operation (not simulated).
32.51	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.

[a] The analysis has not been updated for the change in MSIV isolation setpoint from Level 2 to Level 1 because the analysis is bounding and conclusions of the analysis are not affected (Reference 15.2-8).

Table 15.2-12

Sequence of Events for Failure of Residual Heat Removal Shutdown Cooling

Original Rated Power

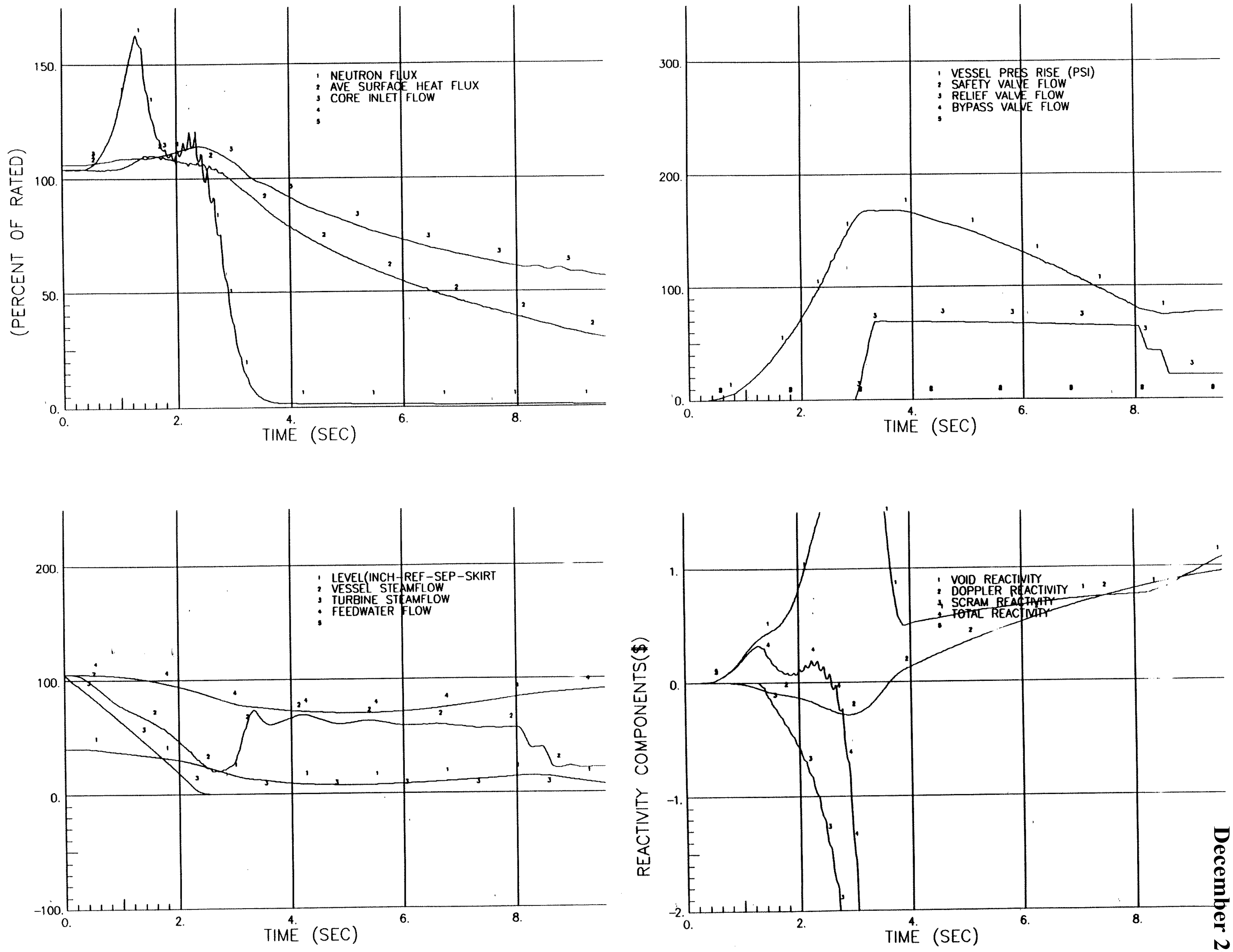
Time[a]	Event
0	Reactor is operating at 105% NBR steam flow when LOP transient occurs initiating plant shutdown.
0	Concurrently loss of division power occurs (i.e., loss of one diesel generator).
0	Initial suppression pool temperature at 95°F.
10 minutes	Suppression pool cooling initiated to prevent overheating from SRV actuation.
10 minutes	Controlled blowdown initiated.
2-3 hr	Blowdown to 100 psi completed.
2-3 hr	Personnel are sent in to open RHR shutdown cooling suction valve and fail.
2.5-3.5 hr	Complete blowdown to suppression pool by opening SRVs.
2.5-3.5 hr	Redirect RHR pump discharge from pool to vessel by means of the LPCI line. Alternate cooling path now established.
7 hr	Maximum suppression pool temperature attained.

[a] Approximately.

Table 15.2-13

Evaluation of Failure of Residual Heat Removal
Shutdown Cooling

Parameter	Value
Initial power corresponding	105% original rated steam flow
To suppression pool mass (lbm)	8.52 E6
Residual heat removal (KHX value) (Btu/sec/°F)	289
Initial vessel condition	
Pressure (psia)	1055
Temperature (°F)	550.7
Initial primary fluid inventory (lbm)	7.016 E5
Initial pool temperature (°F)	95
Service water temperature (°F)	87
Vessel heat capacity (Btu/lbm/°F)	0.123
High-pressure core spray on-off water level (ft)	
HPCS ON	40.8
HPCS OFF	47
High-pressure core spray flow rate (lbm/sec)	868
Low-pressure coolant injection flow rate (lbm/sec)	982



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

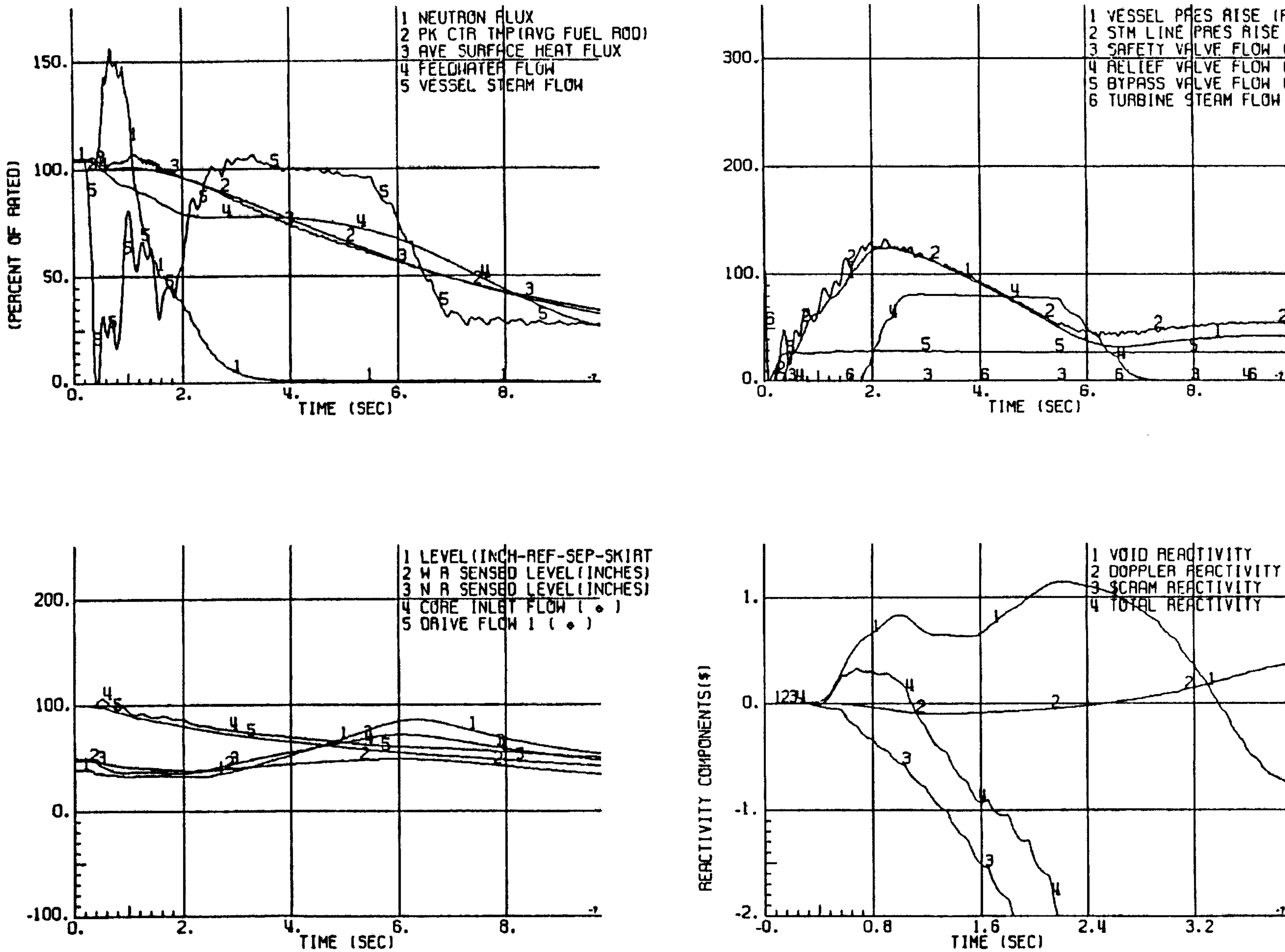
Amendment 64
December 2017

Columbia Generating Station
Final Safety Analysis Report

Pressure Regulator Failure - Down Scale Failure at 102.4*% Uprated Power, 106% Flow

Draw. No. 060108.06	Rev.	Figure 15.2-1

Form No. 960690
LDCN-16-005



Columbia Generating Station
Final Safety Analysis Report

Generator Load Rejection with Bypass On -
Original Rated Power

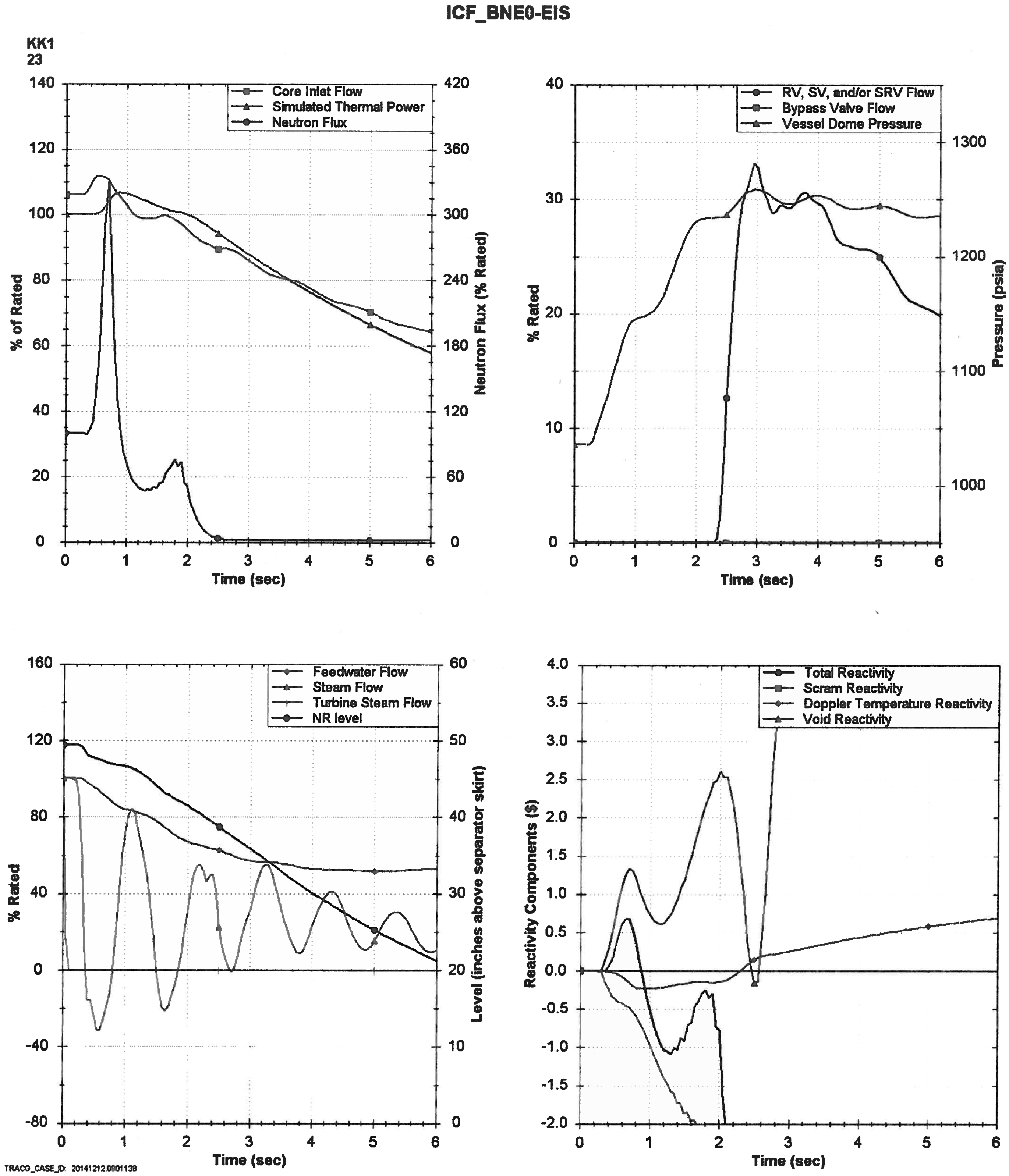
Draw. No. 020361.68

Rev.

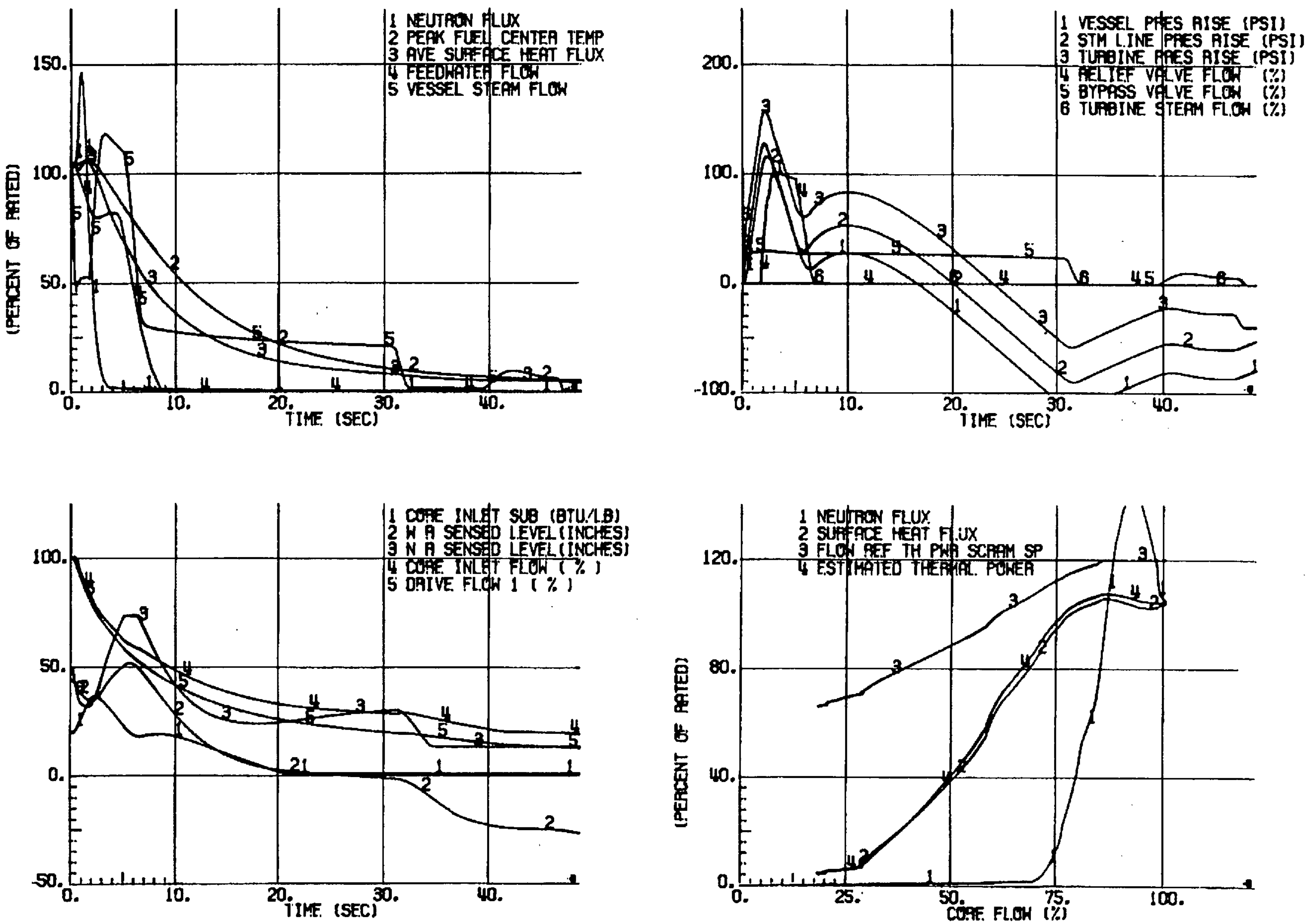
Figure 15.2-2.1

Amendment 59
December 2007

Form No. 960690
LDCN-07-011

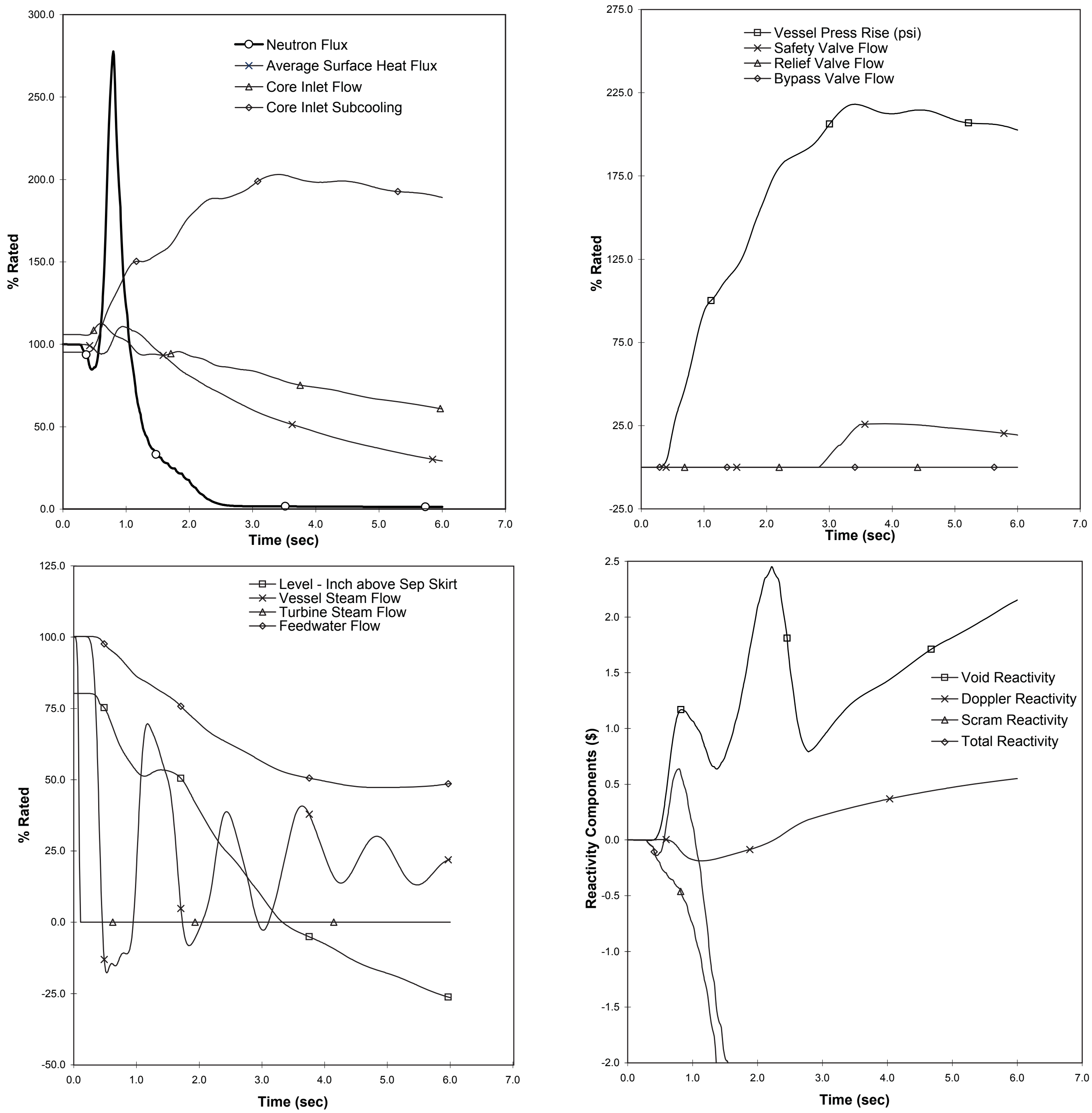

ICF_BNE0-EIS
KK1
23
Core Inlet Flow
Simulated Thermal Power
Neutron Flux
% of Rated
Neutron Flux (% Rated)
Time (sec)
RV, SV, and/or SRV Flow
Bypass Valve Flow
Vessel Dome Pressure
% Rated
Pressure (psia)
Time (sec)
Feedwater Flow
Steam Flow
Turbine Steam Flow
NR level
% Rated
Level (inches above separator skirt)
Time (sec)
TRACG_CASE_ID: 20141212.0801138
Total Reactivity
Scram Reactivity
Doppler Temperature Reactivity
Void Reactivity
Reactivity Components ($)
Time (sec)

Columbia Generating Station
Final Safety Analysis Report



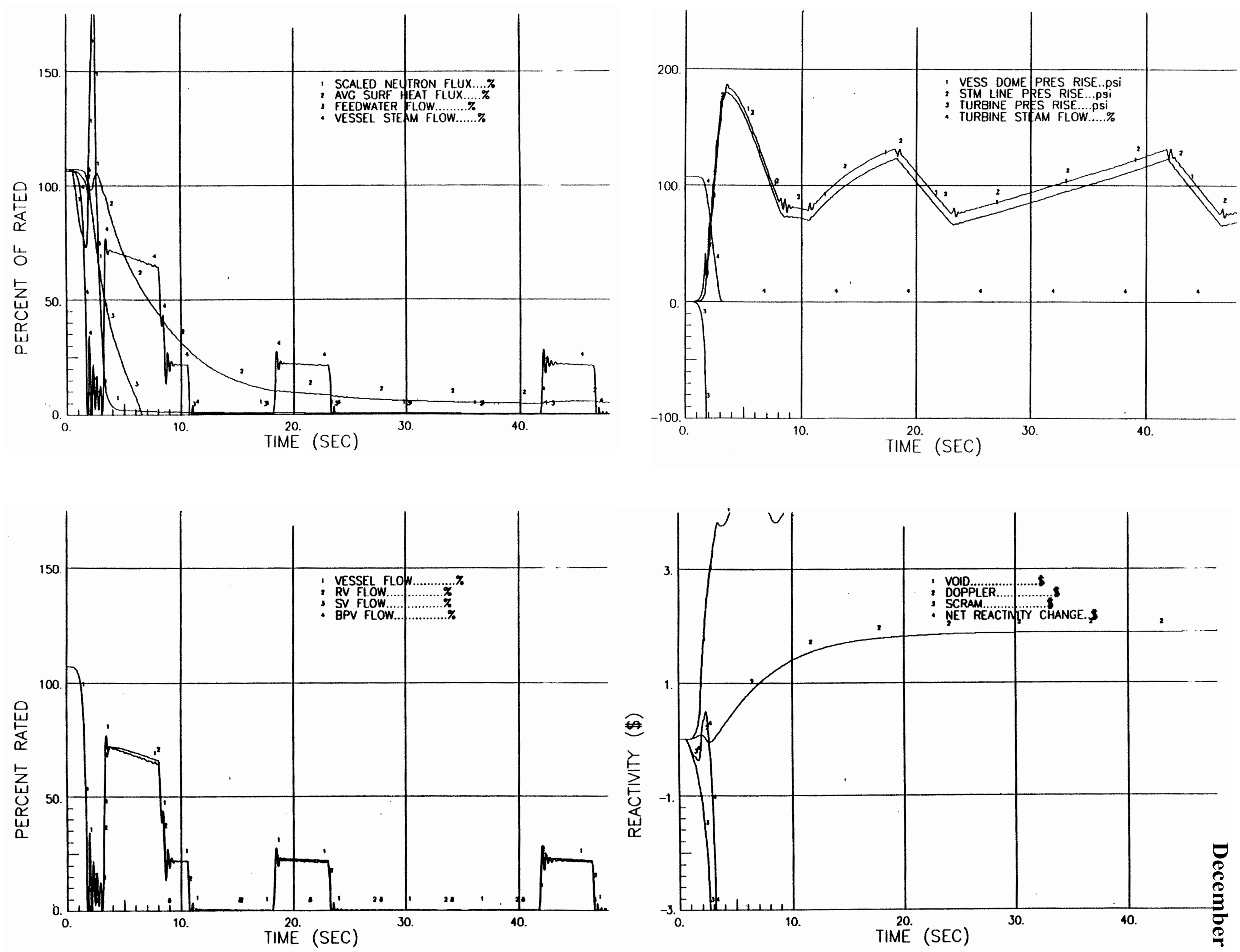
Turbine Trip, Trip Scram, Bypass and RPT - On

Draw. No. 020361.70	Rev.	Figure 15.2-3



Columbia Generating Station Final Safety Analysis Report	Turbine Trip with Bypass Failure	
	Draw. No. 020361.71	Rev.	Figure 15.2-4

Form No. 960690
LDCN-16-005



*% uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Main Steam Line Isolation Valve Closure at 104.5*% Uprated Power, 100% Rated Flow

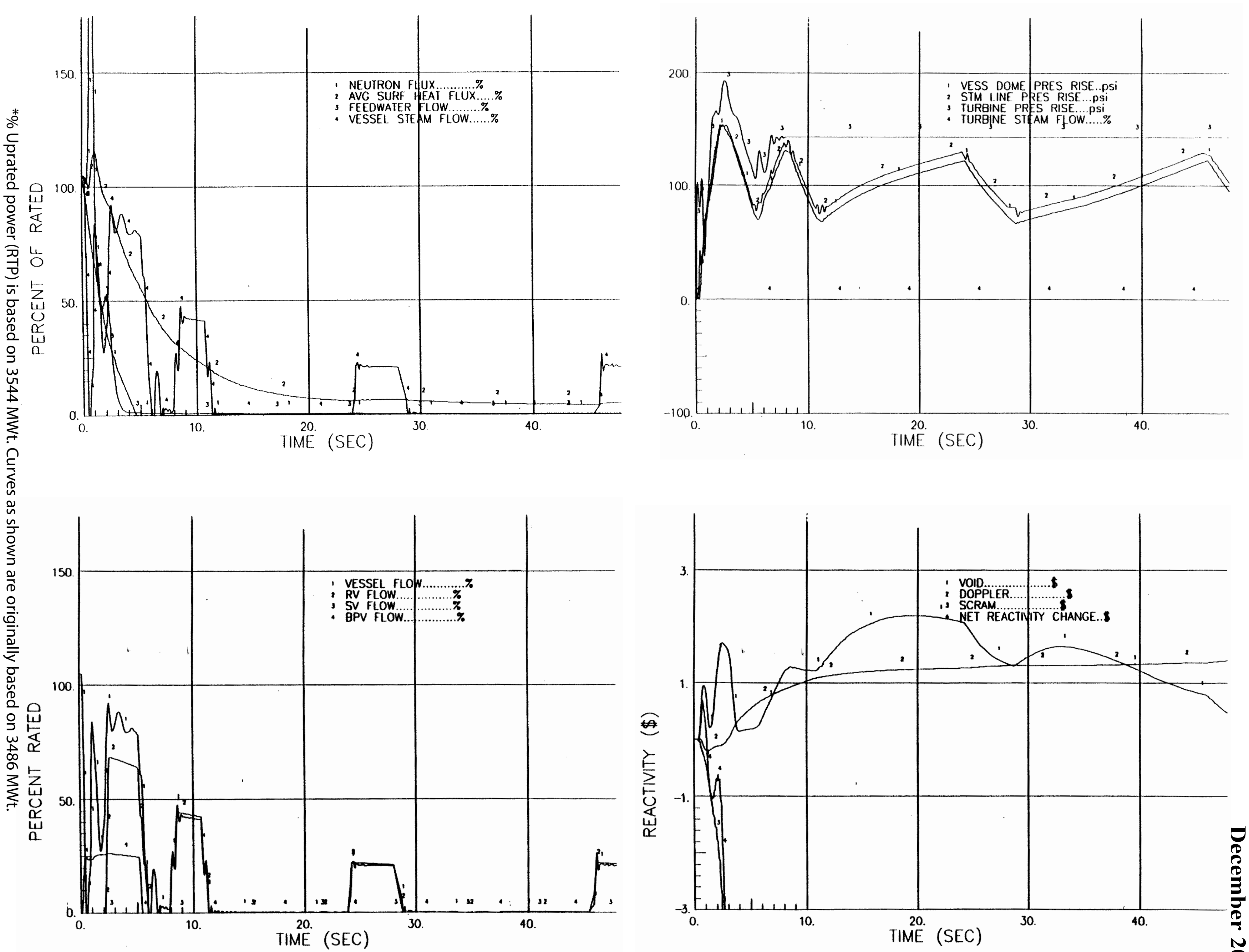
Draw. No. 020361.72	Rev.	Figure 15.2-5

Amendment 64
December 2017

Form No. 960690
LDCN-16-005

Columbia Generating Station
Final Safety Analysis Report

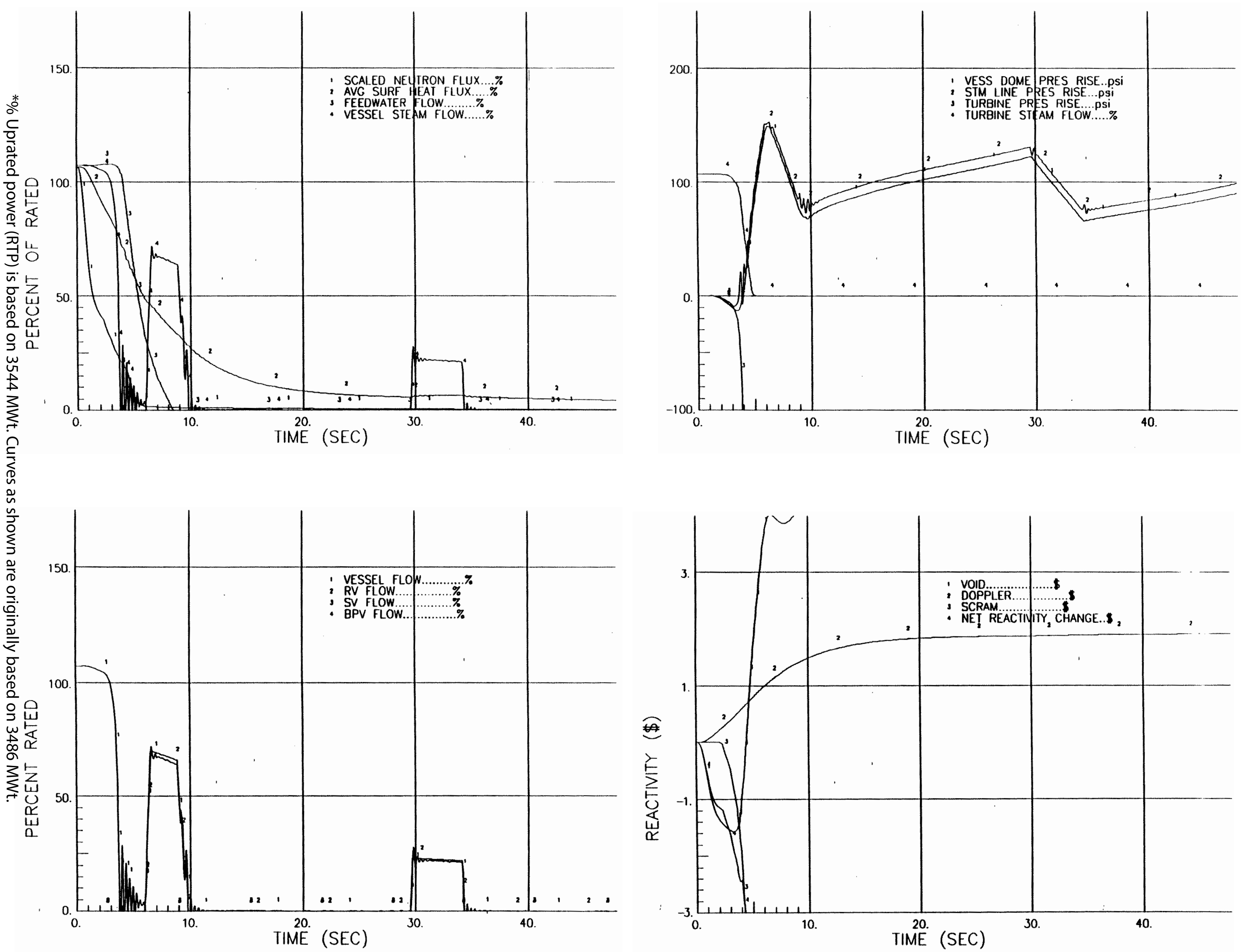
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.



Loss of Condenser Vacuum
at 102.4*% Uprated Power, 100% Rated Flow

Draw. No. 020361.73	Rev.	Figure 15.2-6

Amendment 64
December 2017



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Amendment 64
December 2017

Columbia Generating Station
Final Safety Analysis Report

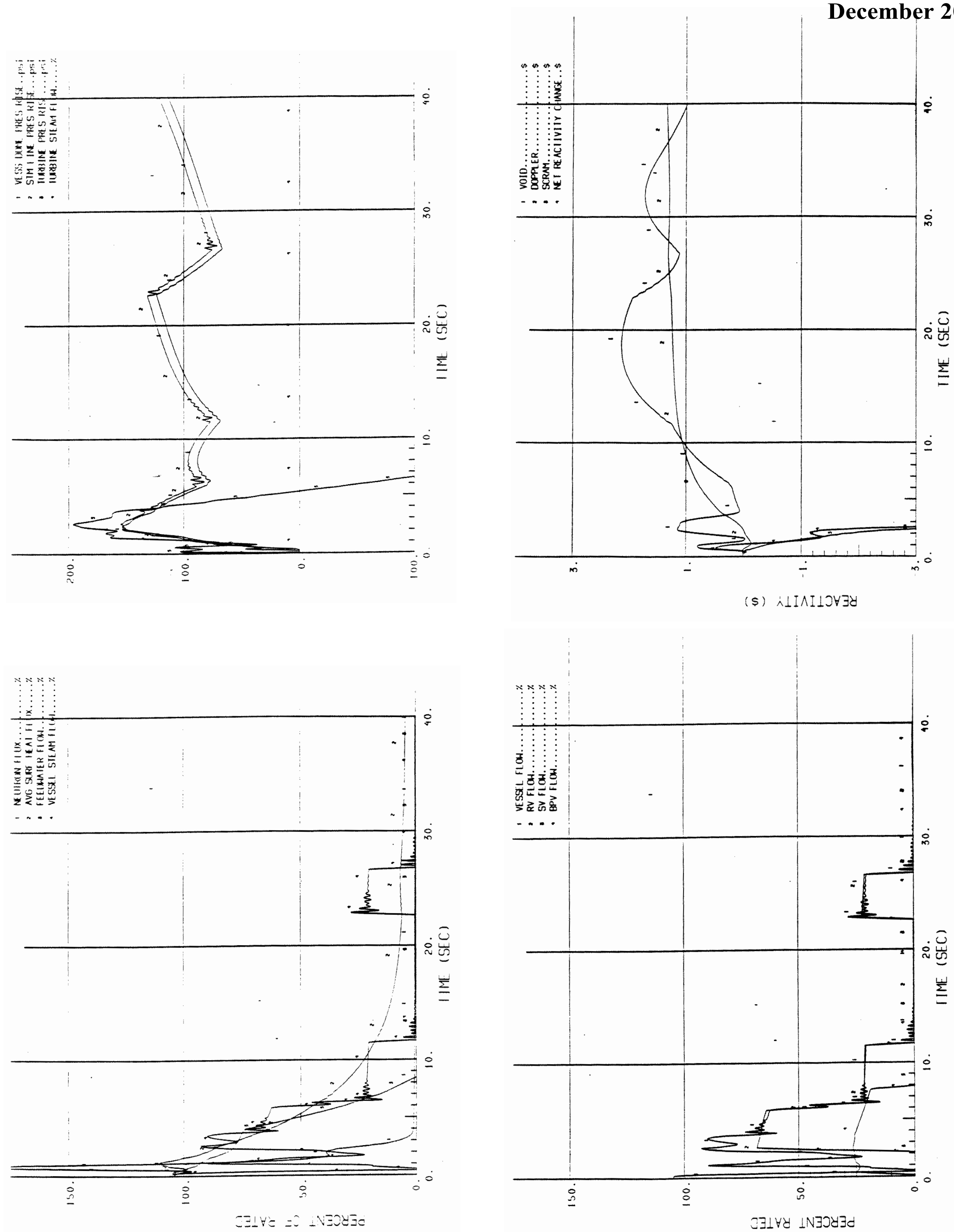
Loss of Auxiliary Power Transformers - at 104.5*% Uprated Power, 100% Rated Flow

Draw. No. 020361.74

Rev.

Figure 15.2-7

Form No. 960690
LDCN-16-005



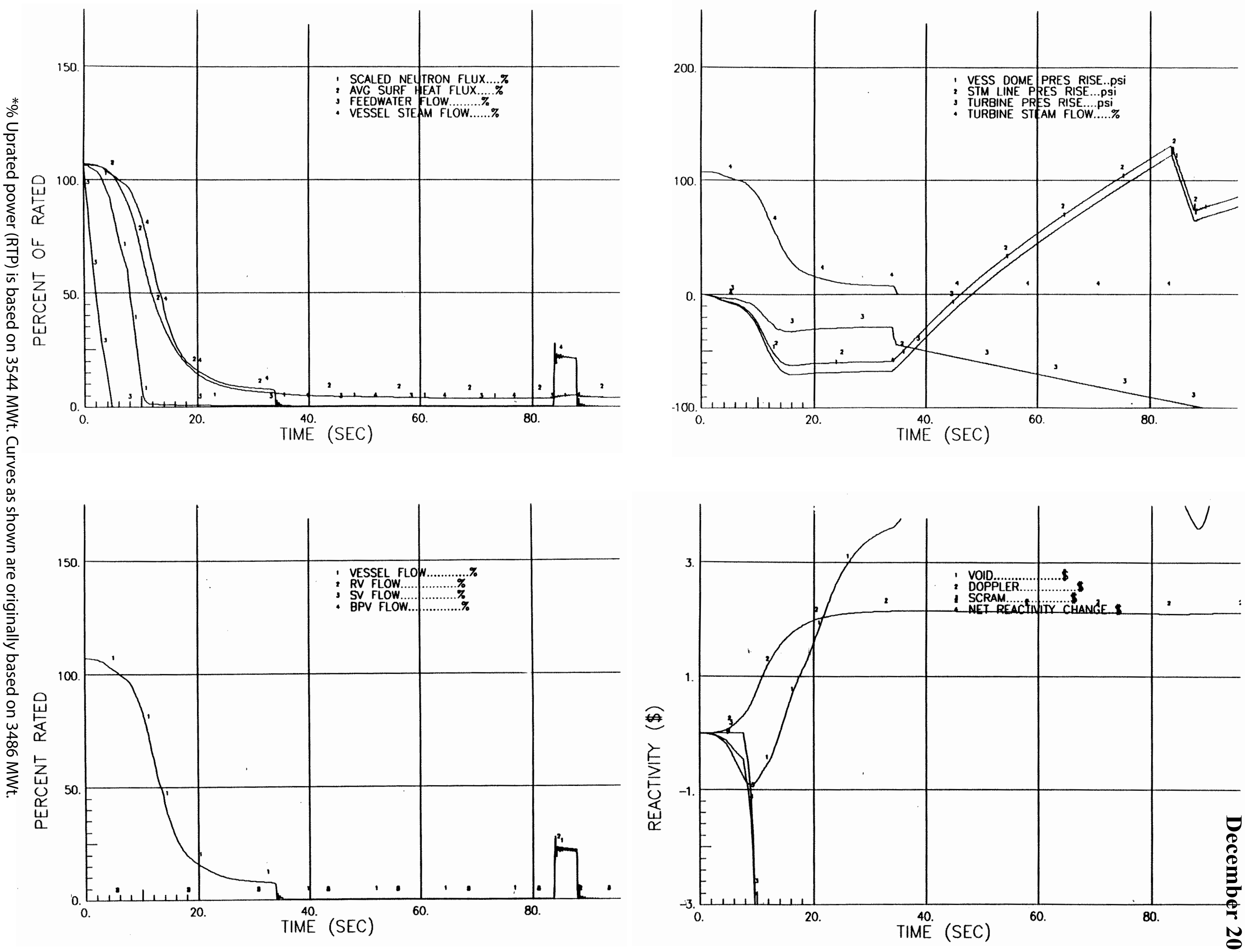
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Loss of All Grid Connections -
102.4*% Uprated Power, 100% Rated Flow

Draw. No. 020361.75	Rev.	Figure 15.2-8

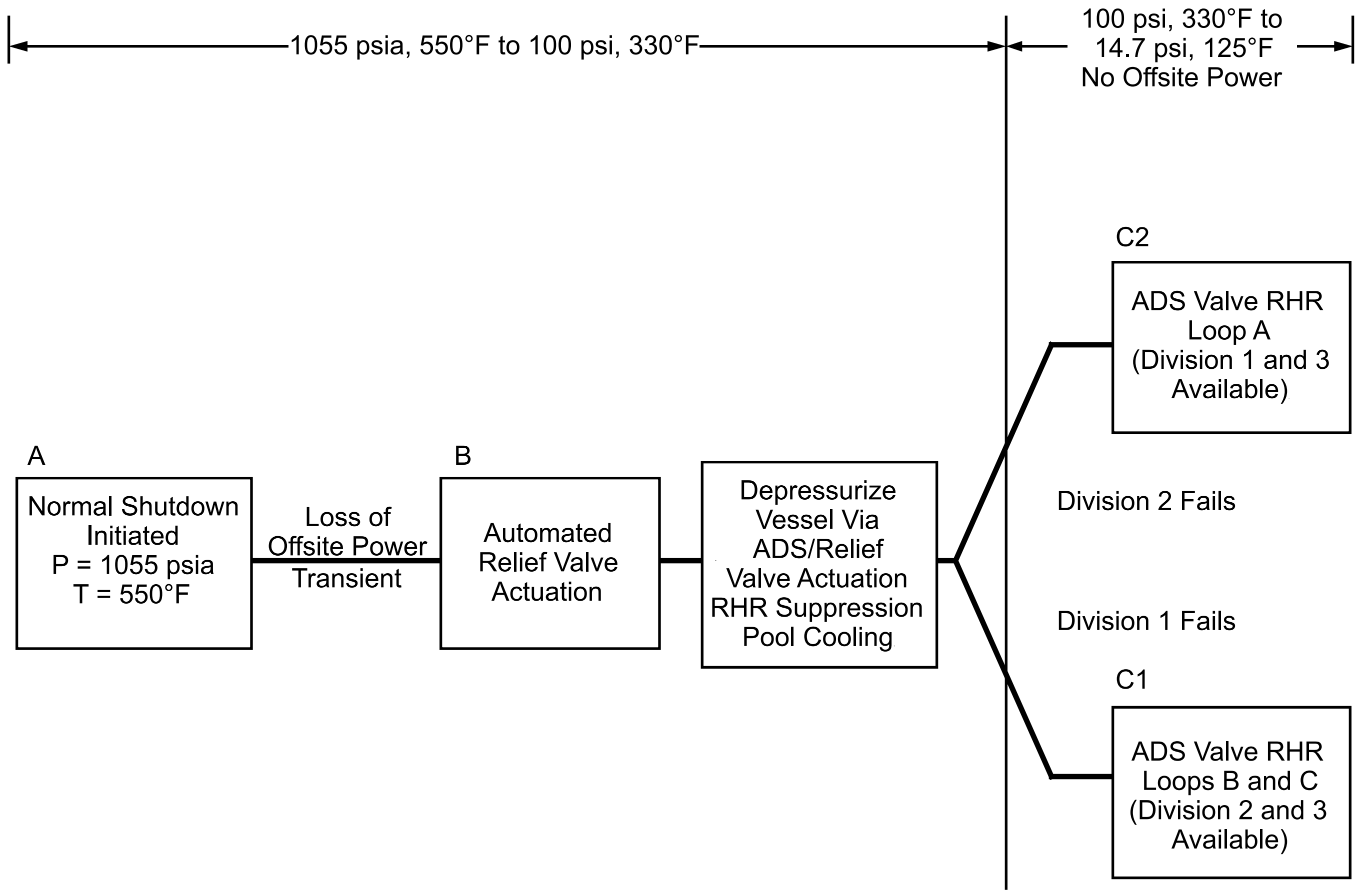
Columbia Generating Station
Final Safety Analysis Report



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Loss of All Feedwater Flow - 104.5*% Uprated Power, 100% Rated Flow

Draw. No. 020361.76 | Rev. | Figure 15.2-9



Columbia Generating Station Final Safety Analysis Report	Automatic Depressurization System/Residual Heat Removal Cooling Loops
Draw. No. 900547.63	Rev. / Figure 15.2-10.1

NOTES

ACTIVITY A
Initial pressure =1055 psia
Initial temperature = 550°F
For purpose of this analysis, the following worst-case conditions are assumed to exist:

a. The reactor is assumed to be operating at 105% of original NBR steam flow,
b. A loss of power transient occurs,
c. A simultaneous loss of onsite power (Division 1 or Division 2), and
d. Operator unable to open one of the RHR shutdown cooling line suction valves.

ACTIVITY B
Initial system pressure =1055 psia
Initial system temperature = 550°F

Operator Actions
During approximately the first 30 minutes, reactor decay heat is passed to the suppression pool by the automatic operation of the reactor relief valves. Reactor water level will be returned to normal by the HPCS and RCIC systems automatic operation.

After approximately 10 minutes, the operator initiates depressurization of the reactor vessel to control vessel pressure. Controlled depressurization procedure consists of controlling vessel pressure and water level by using the SRV or HPCS and/or RCIC systems. After approximately 15 minutes, it is assumed one RHR heat exchanger is placed in the suppression pool cooling mode to remove decay heat. At this time, the suppression pool will be 121°F.

When the reactor pressure approaches 100 psig, the operator would normally prepare for operation of the RHR system in the shutdown cooling mode. At this time (121 minutes), the suppression pool will be 186°F.

ACTIVITY C1 (Division 1 fails, Division 2 available)
System pressure =100 psig
System temperature = 330°F

Operation Actions

The operator establishes a closed cooling path as follows:

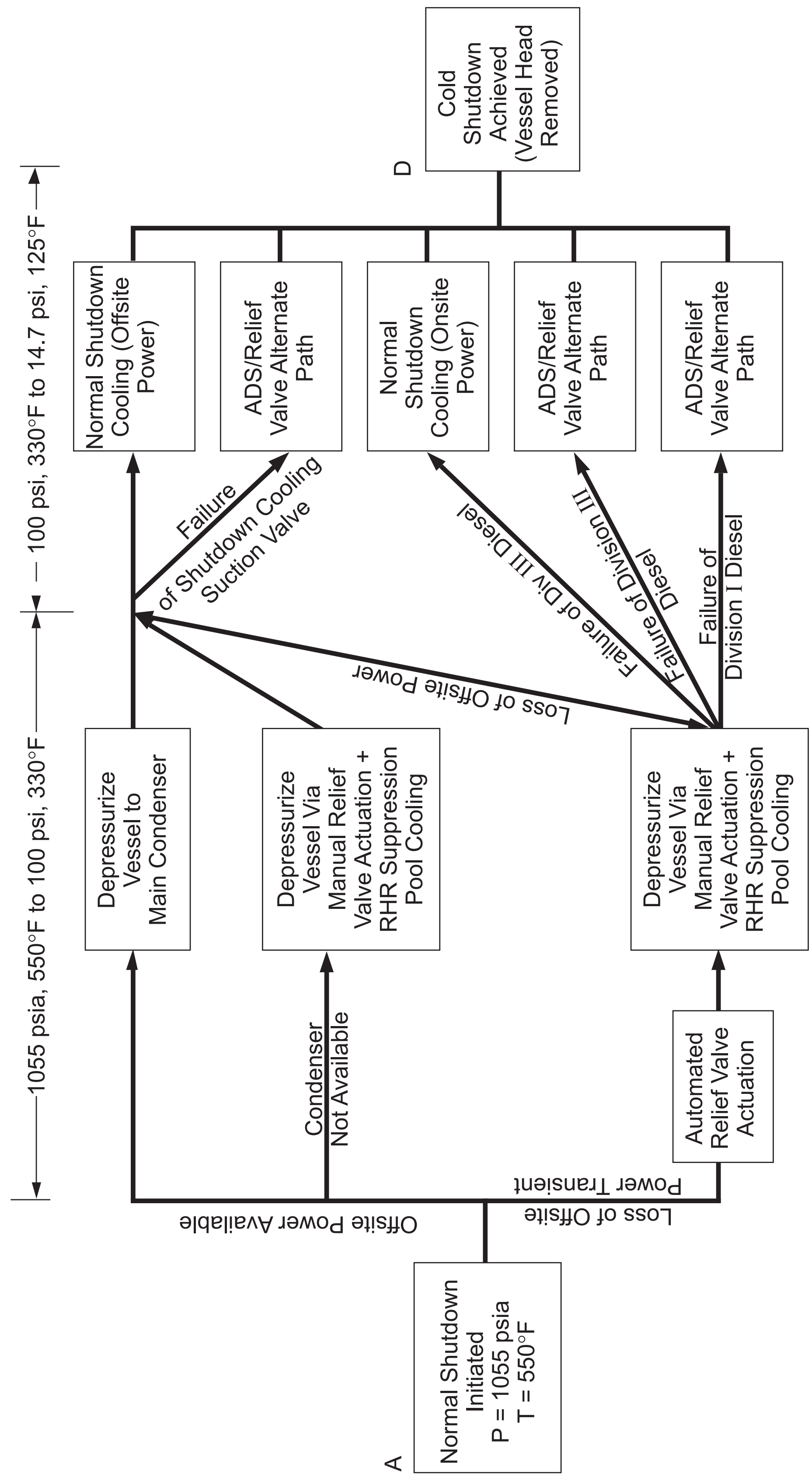
a. A minimum of two ADS valves (dc Division 2) are powered open.
b. Either of the following cooling paths are established:
    1. Using RHR loop B, water from the suppression pool is pumped through the RHR heat exchanger (where a portion of the decay heat is removed) into the reactor vessel. The cooled suppression pool water flows through the vessel (picking up a portion of the decay heat) out the ADS valves and back to the suppression pool. This alternate cooling path is shown in Figure 15.2-12.
    2. Using RHR loops B and C together, water is taken from the suppression pool and pumped directly into the reactor vessel. The water passes through the vessel (picking up decay heat) and out the ADS valves returning to the suppression pool as shown in Figure 15.2-13. Suppression pool water is then cooled by operation of RHR loop B in the pool cooling mode (see Figure 15.2-14). In this alternate cooling path, RHR loop C is used for injection and RHR loop B for cooling. Cold shutdown is achieved approximately 36 hr after the transient occurs.

ACTIVITY C2 (Division 2 fails, Division 1 available) (Figure 15.2-15)
System pressure =100 psig
System temperature = 330°F

Operator Actions

The operator establishes a closed cooling path as follows:

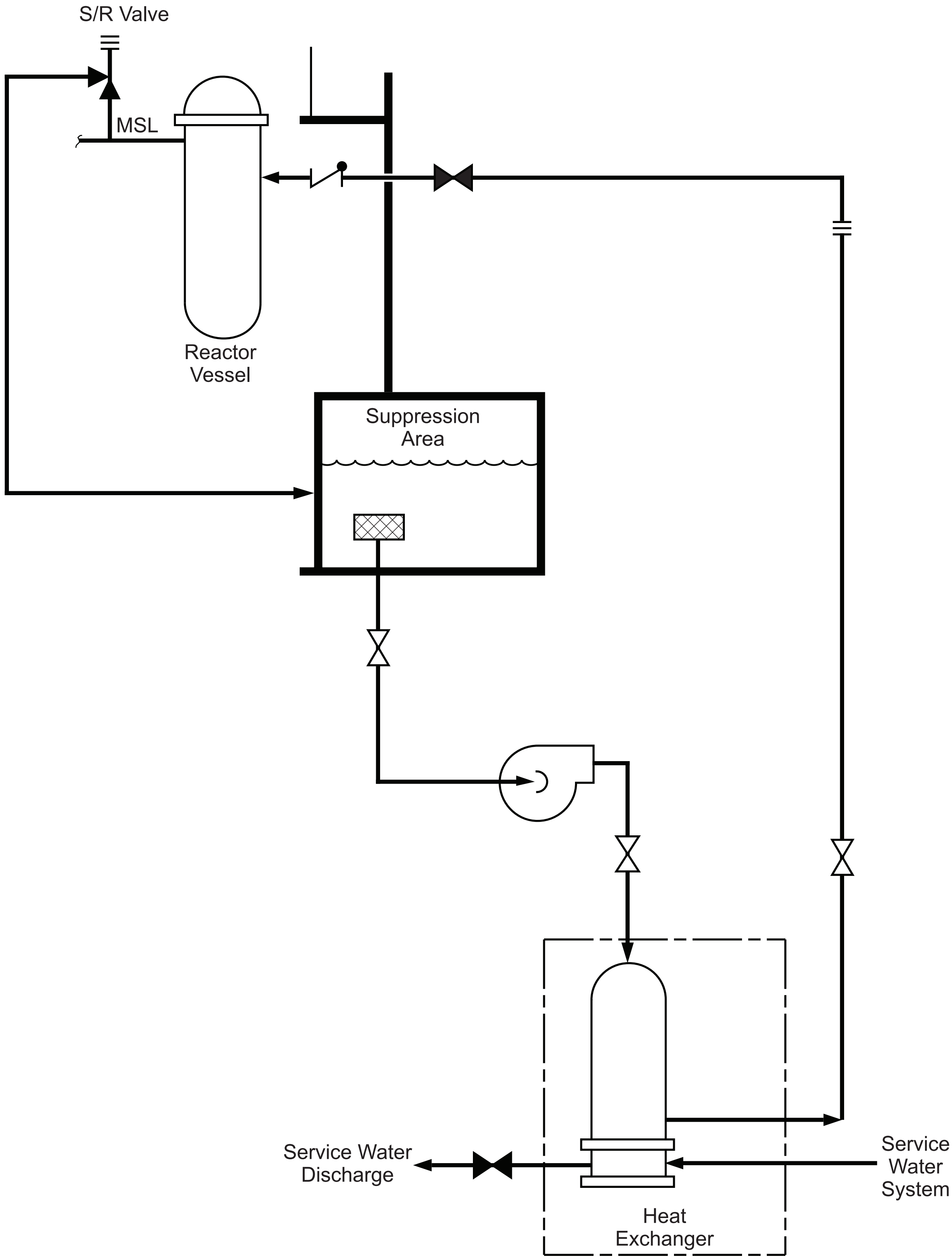
a. A minimum of two ADS valves (dc Division 1) are powered open, and
b. Using RHR loop A instead of loop B, an alternate cooling path is established as shown in Activity C1. Cold shutdown is reached in approximately 15 hr.



Columbia Generating Station
Final Safety Analysis Report

Summary of Paths Available to Achieve Cold Shutdown

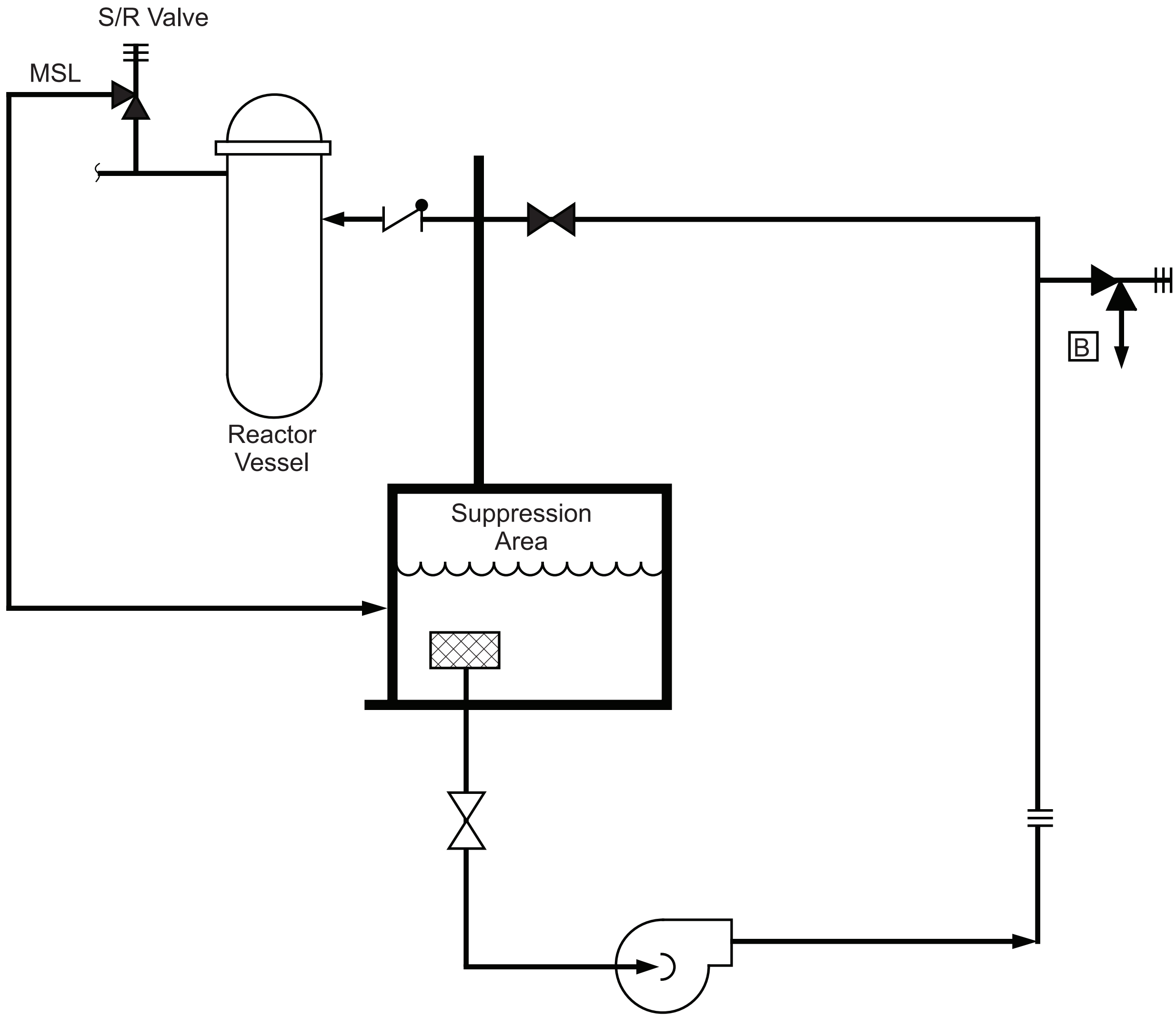
Draw. No. **900547.64** Rev. Figure **15.2-11**



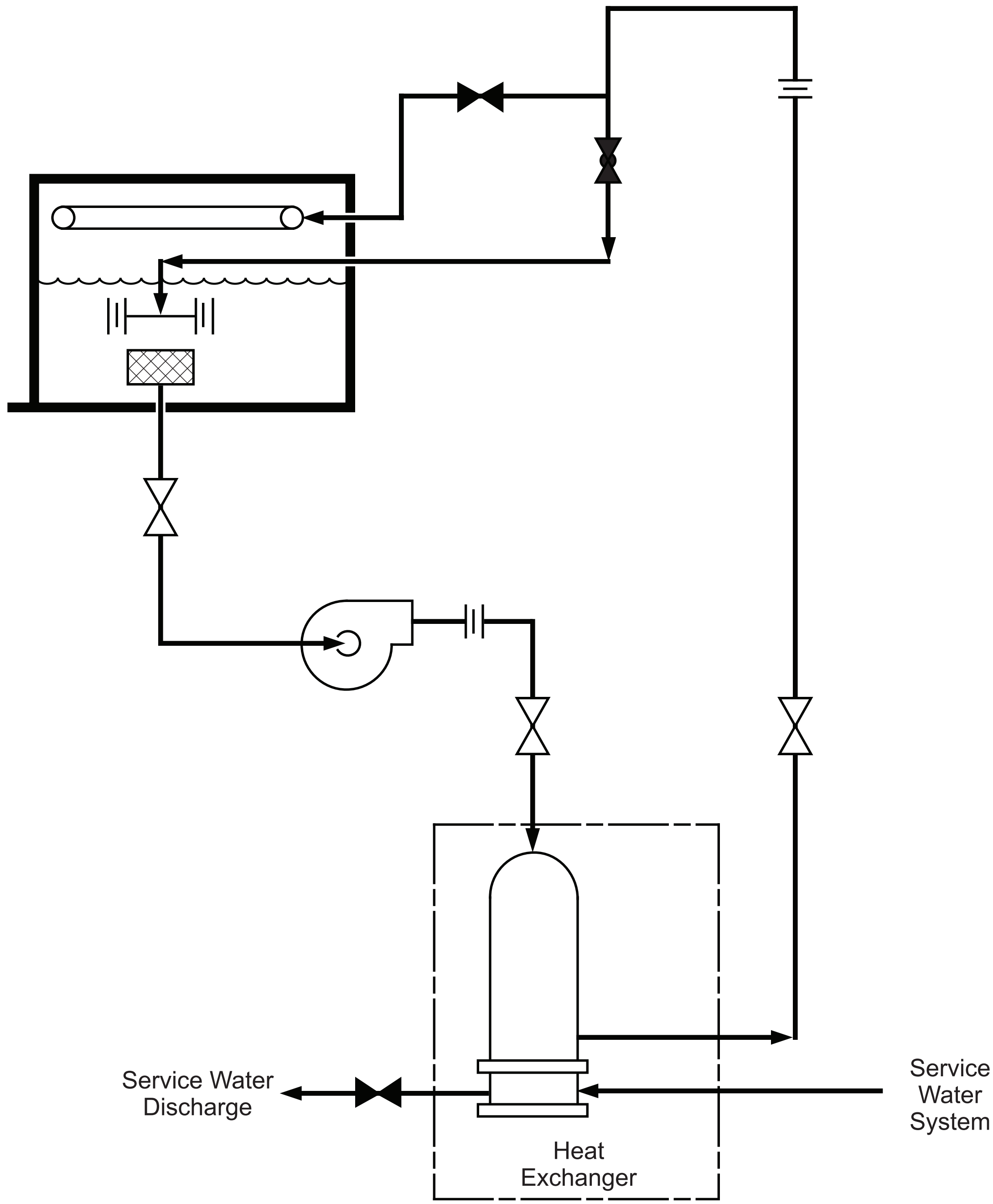
Columbia Generating Station
Final Safety Analysis Report

Activity C1 Alternate Shutdown Cooling Path
Utilizing Residual Heat Removal Loop B

Draw. No. 900547.65	Rev.	Figure 15.2-12



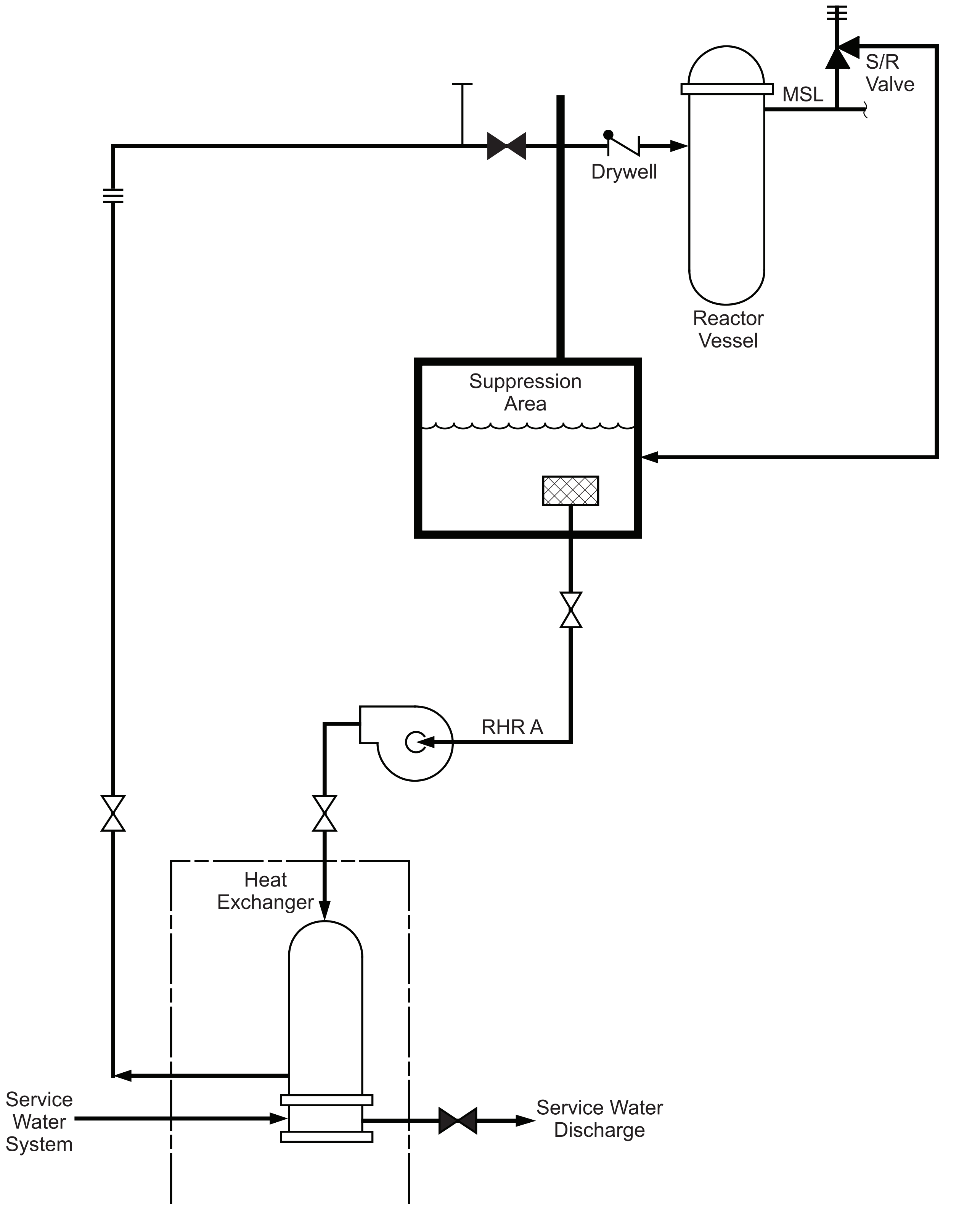
Residual Heat Removal Loop C



Columbia Generating Station
Final Safety Analysis Report

Residual Heat Removal Loop A(B) (Suppression Pool Cooling/ Rated Pump Flow Test Mode)

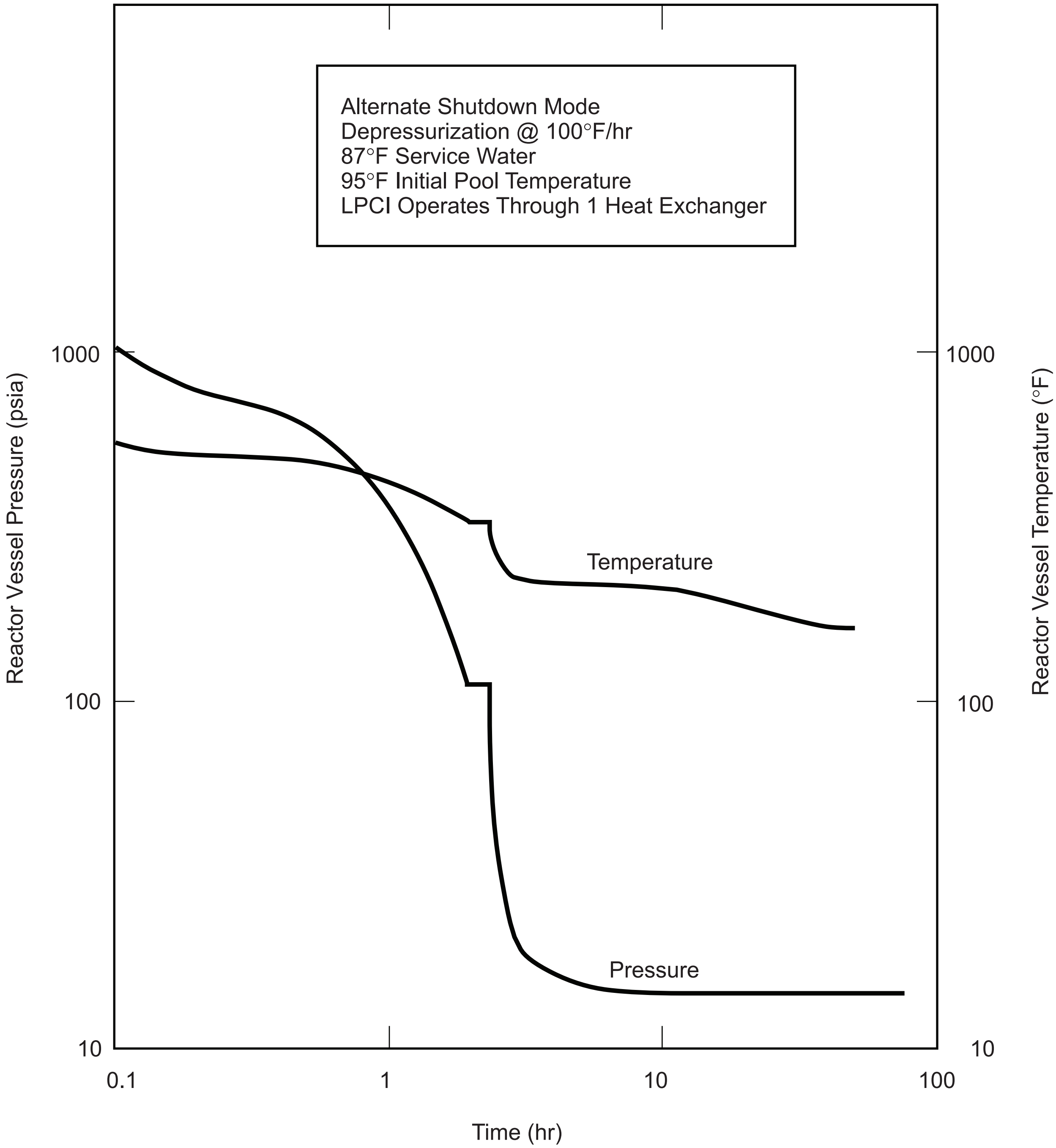
Draw. No. 900547.67 | Rev. | Figure 15.2-14



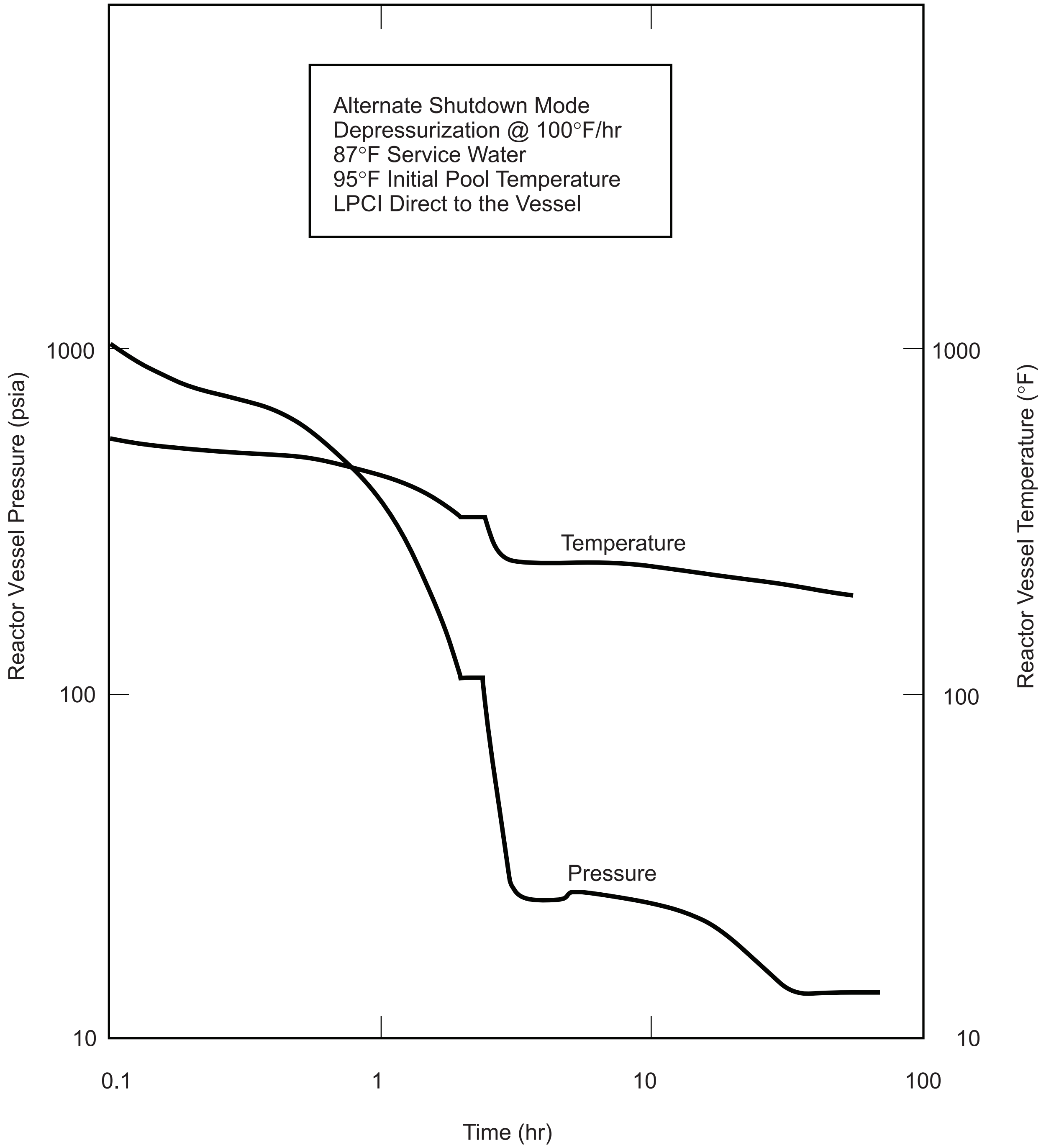
Columbia Generating Station
Final Safety Analysis Report

Activity C2 Alternate Shutdown Cooling Path Utilizing Residual Heat Removal Loop A

Draw. No. 900547.68 | Rev. | Figure 15.2-15

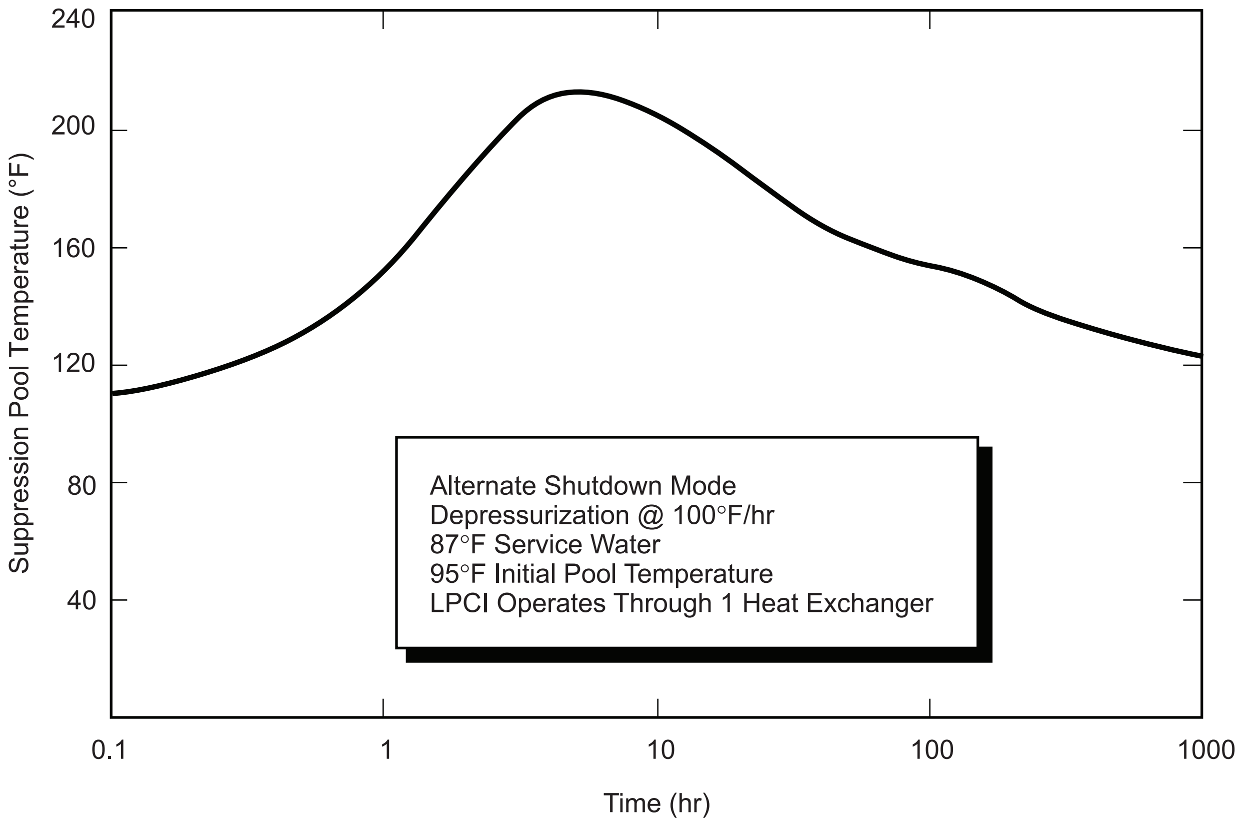


Vessel Temperature and Pressure Versus Time
(Activity C1.b.1 or C2)



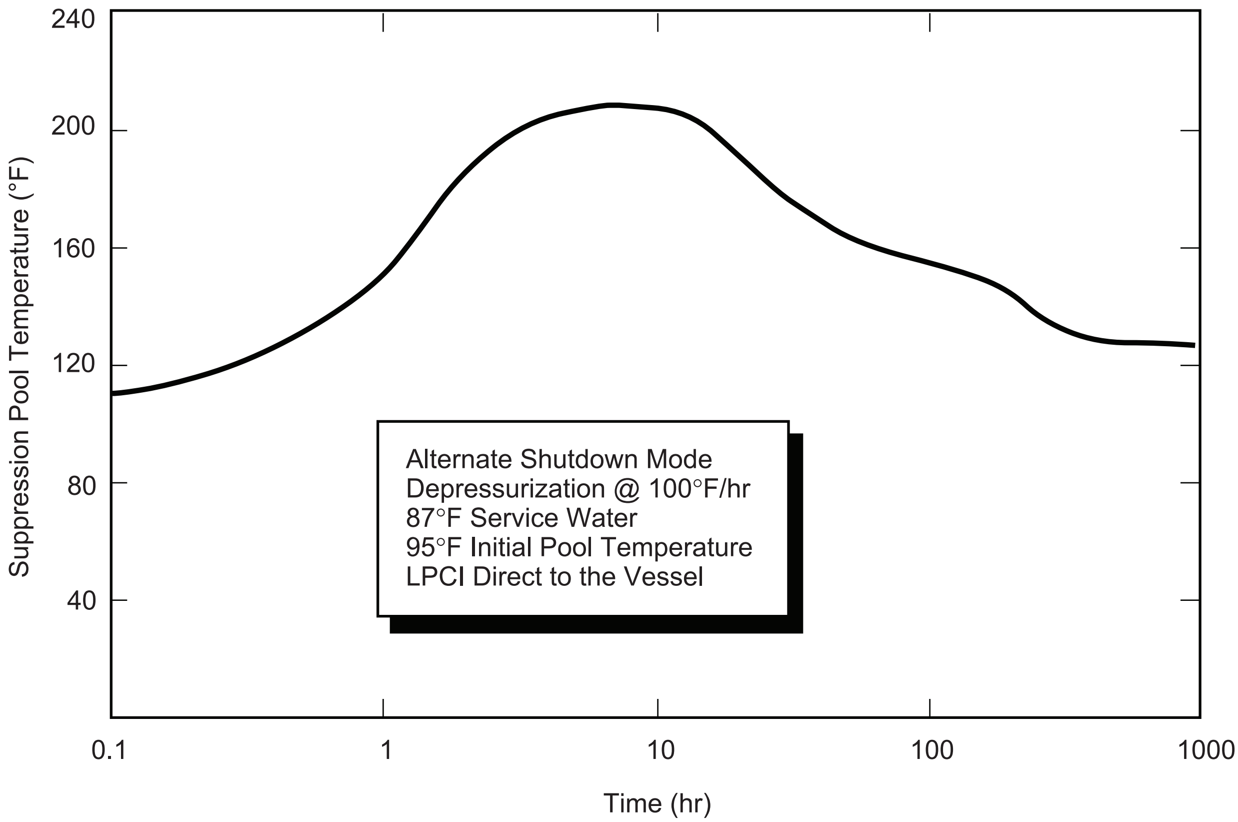
Vessel Temperature and Pressure Versus Time (Activity C1.b.2)

Draw. No. 900547.70 Rev. Figure 15.2-17



Columbia Generating Station Final Safety Analysis Report	Suppression Pool Temperature Versus Time (with 87°F Service Water Temperature) (Activity C1.b.1 or C2)	
Draw. No. 900547.71	Rev.	Figure 15.2-18

Form No. 960690



Columbia Generating Station
Final Safety Analysis Report

Suppression Pool Temperature Versus Time (with 87°F Service Water Temperature) (Activity C1.b.2)

Draw. No. 900547.72 | Rev. | Figure 15.2-19

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

15.3.1 RECIRCULATION PUMP TRIP

The events for two-recirculation pump operation are not limiting, therefore, the analyses have not been updated since the reactor power uprate analyses.

15.3.1.1 Identification of Causes and Frequency Classification

15.3.1.1.1 Identification of Causes

Recirculation pump motor operation can be tripped by design and by random operational failures. Design tripping will occur in response to:

a. Reactor vessel water level L2 setpoint trip,
b. Turbine control (governor) valve fast closure or stop (throttle) valve closure,
c. Failure to scram high pressure setpoint trip,
d. Motor branch circuit over-current protection,
e. Motor overload protection, and
f. Suction block valve not fully open.

Random tripping will occur in response to:

a. Operator error,

b. Loss of electrical power source to the pumps, and

c. Equipment or sensor failures and malfunctions which initiate the above intended trip response.

15.3.1.1.2 Frequency Classification

15.3.1.1.2.1 Trip of One Recirculation Pump. This event is categorized as an incident of moderate frequency.

15.3.1.1.2.2 Trip of Two Recirculation Pumps. This event is categorized as an incident of moderate frequency.

15.3.1.2 Sequence of Events and Systems Operation

15.3.1.2.1 Sequence of Events

15.3.1.2.1.1 Trip of One Recirculation Pump. Table 15.3-1 lists the sequence of events for Figure 15.3-1.

15.3.1.2.1.2 Trip of Two Recirculation Pumps. Table 15.3-2 lists the sequence of events for Figure 15.3-2.

15.3.1.2.2 Systems Operation

15.3.1.2.2.1 Trip of One Recirculation Pump. Tripping a single recirculation pump requires no protection system or safeguard system operation. This analysis assumes normal functioning of plant instrumentation and controls.

15.3.1.2.2.2 Trip of Two Recirculation Pumps. Analysis of this event assumes normal functioning of plant instrumentation and controls and plant and reactor protection systems.

Specifically, this transient takes credit for vessel level (L8) instrumentation to trip the turbine. Reactor shutdown relies on scram trips from the turbine stop (throttle) valves. High system pressure is limited by the pressure relief valve system operation.

15.3.1.2.3 The Effect of Single Failures and Operator Errors

15.3.1.2.3.1 Trip of One Recirculation Pump. None

15.3.1.2.3.2 Trip of Two Recirculation Pumps. Table 15.3-2 lists the vessel level (L8) trip event as the first response to initiate corrective action in this transient and it is intended to prohibit moisture carryover to the main turbine. Multiple level sensors are used to sense and detect when the water level reaches the L8 setpoint. At this point, a single failure will neither initiate nor impede a turbine trip signal. Turbine trip signal transmission circuitry, however, is not built to single failure criterion. At this point the transient event is functionally over.

Scram trip signals from the turbine are designed such that a single failure will neither initiate nor impede a reactor scram trip initiation.

15.3.1.3 Core and System Performance

15.3.1.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 is used to simulate this event.

15.3.1.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions in Table 15.0-2.

Pump motors and pump rotors are simulated with minimum specified rotating inertias.

15.3.1.3.3 Results

15.3.1.3.3.1 Trip of One Recirculation Pump. Figure 15.3-1 shows the response of the reactor system following the trip of one recirculation pump motor. Initially a recirculation pump is tripped in one loop, causing the core inlet flow to decrease, while the other recirculation loop flow increases. Subsequently jet pump diffuser flow reverses in the tripped recirculation loop. At approximately 45 sec the reactor reaches a new equilibrium operating point, at approximately 73.8% power and 57% core flow. During the transient, level swell is not sufficient to cause turbine trip.

15.3.1.3.3.2 Trip of Two Recirculation Pumps. Figure 15.3-2 shows the response of the reactor system following the trip of both recirculation pump motors. Initially both recirculation pumps are tripped, causing the core inlet flow to decrease, while vessel level rises until both main and feedwater turbines trip on high level (L8). A reactor scram is subsequently initiated at 90% turbine stop valve position. Shortly after the scram is initiated the stop valves close and the bypass valves open to regulate pressure. At this point the transient event is functionally over.

15.3.1.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force analytical results to be more severe than expected under actual plant conditions.

Actual pump and pump-motor drive line rotating inertias are expected to be somewhat greater than the minimum design values assumed in this simulation. Actual plant deviations regarding inertia are expected to lessen the severity as analyzed. Minimum design inertias were used as well as the least negative void coefficient since these maximize the flow reduction.

15.3.1.4 Barrier Performance

15.3.1.4.1 Trip of One Recirculation Pump

Figure 15.3-1 results indicate a basic reduction in system pressures from the initial conditions. Therefore, the reactor coolant pressure boundary (RCPB) barrier is not impacted.

15.3.1.4.2 Trip of Two Recirculation Pumps

The results shown in Figure 15.3-2 indicate peak pressures stay well below the limit allowed by the applicable American Society of Mechanical Engineers (ASME) code. Therefore, the RCPB barrier is not impacted.

15.3.1.5 Radiological Consequences

The consequence of this event does not result in fuel failure. It does result in the discharge of normal coolant activity to the suppression pool by means of safety/relief valve (SRV) operation, which is contained in the primary containment. This event does not result in an uncontrolled release to the environment, so the plant operator can choose to hold the activity in containment or discharge it when conditions permit. If purging of the containment is chosen, the release will be in accordance with established requirements.

15.3.2 RECIRCULATION FLOW CONTROL FAILURE - DECREASING FLOW

15.3.2.1 Identification of Causes and Frequency Classification

15.3.2.1.1 Identification of Causes

A postulated failure of the input demand signal, which is used in both loops, can decrease core flow at the maximum ramp demand rate established by the adjustable speed drive (ASD) control. Failure within either loop controller can result in a maximum ramp demand rate as limited by the ASD control.

15.3.2.1.2 Frequency Classification

This event is categorized as an incident of moderate frequency.

15.3.2.2 Sequence of Events and Systems Operation

15.3.2.2.1 Sequence of Events

15.3.2.2.1.1 Speed Decrease of One Recirculation Pump. Table 15.3-3 lists the sequence of events for Figure 15.3-3.

15.3.2.2.1.2 Speed Decrease of Two Recirculation Pumps. Table 15.3-4 lists the sequence of events for Figure 15.3-4.

15.3.2.2.2 Systems Operation

15.3.2.2.2.1 Speed Decrease of One Recirculation Pump. The most severe control system disturbance is a failure that causes the ASD internal controller to move at its maximum rate. Such transients may be obtained by instantaneous failure of a controller output into its upper or lower limits. Originally the recirculation flow was controlled by valve motion. For the current analysis the recirculation flow control valves have been locked at the full open position, and ASD units have been implemented to provide the necessary flow control.

15.3.2.2.2.2 Speed Decrease of Two Recirculation Pumps. The most severe control system disturbance is a failure that causes the ASD internal controller to move at its maximum rate. Such transients may be obtained by instantaneous failure of a controller output into its upper or lower limits. The independent and simultaneous failure of each individual loop controller would be highly improbable.

Thus, for the two loop controller failure event, the ASD internal controller is assumed to move at its maximum rate in both recirculation loops. Originally the recirculation flow was controlled by valve motion. For the current analysis the recirculation flow control valves have been locked at the full open position, and ASD units have been implemented to provide the necessary flow control.

15.3.2.2.3 The Effect of Single Failures and Operator Errors

The single failure and operator considerations for this event are essentially the same as in Section 15.3.1.2.3.2. The speed decrease of two instead of one recirculation pump would be the envelope case for the additional single component failure or operator error.

15.3.2.3 Core and System Performance

15.3.2.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 is used to simulate these transient events.

15.3.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions listed in Table 15.0-2.

15.3.2.3.2.1 Speed Decrease of One Recirculation Pump. For the simulation of this event, a controller malfunction causes a zero demand signal to be sent to one of the recirculation ASD units, while the plant is operating at 104.5% uprated power and 100% core flow. A control demand error (low) signal causes the ASD to adjust the recirculation pump speed demand rate limit downward at an assumed rate of 25%/sec for one loop failure. The ensuing transient is similar to a recirculation pump trip.

15.3.2.3.2.2 Speed Decrease of Two Recirculation Pumps. For the simulation of this event, a controller malfunction causes a zero demand signal to be sent to both of the recirculation ASD units, while the plant is operating at 104.5% uprated power and 100% core flow. A control demand error (low) can cause the ASD units to adjust the recirculation pump speed downward in both loops at the 5%/sec pump speed rate limit.

15.3.2.3.3 Results

15.3.2.3.3.1 Speed Decrease of One Recirculation Pump. Figure 15.3-3 shows the response of the plant for this transient. Initially a negative recirculation pump speed demand is sent to the ASD due to a postulated controller failure. The negative pump speed demand causes the diffuser flow to decrease, and eventually reverse, in the failed loop. At the same time the active loop increases flow to compensate for the failed recirculation loop. At approximately 45 sec the reactor reaches a new equilibrium operating point, at approximately 72.8% power and 57% core flow. During the transient, level swell is not sufficient to cause turbine trip which would result in a reactor scram.

15.3.2.3.3.2 Speed Decrease of Two Recirculation Pumps. Figure 15.3-4 shows the response of the plant to this transient using the 5%/sec pump speed demand rate limit. Initially, a negative recirculation pump speed demand is sent to both ASD units due to a postulated controller failure. The negative pump speed demand causes the diffuser flows to decrease in the failed loops. During the transient, level swell is not sufficient to cause turbine trip which would result in a reactor scram.

15.3.2.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force analytical results to be more severe than expected under actual plant conditions.

These analyses are unaffected by deviations in pump/pump motor and driveline inertias since it is the ASD controller that causes rapid recirculation decreases.

15.3.2.4 Barrier Performance

15.3.2.4.1 Speed Decrease of One Recirculation Pump

The pressure in the vessel dome is well below the vessel pressure limit. The event does not result in a temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.3.2.4.2 Speed Decrease of Two Recirculation Pumps

The pressure in the vessel dome is well below the vessel pressure limit. The event does not result in a temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed and these barriers maintain their integrity and function as designed.

15.3.2.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment there are no radiological consequences associated with this event.

15.3.3 RECIRCULATION PUMP SEIZURE

The pump seizure accident for single loop operation (SLO) is analyzed for the introduction of GNF2 fuel into the Columbia reactor core.

15.3.3.1 Identification of Causes and Frequency Classification

The case of recirculation pump seizure represents the extremely unlikely event of instantaneous stoppage of the pump motor shaft of one recirculation pump. This event produces a very rapid decrease of core flow as a result of the large hydraulic resistance introduced by the stopped rotor. The sudden decrease in core coolant flow while the reactor is at full power results in a degradation of core heat transfer which could result in fuel damage.

The event is categorized as an infrequent incident when operating with two recirculation pumps in service. For single loop operation, this event is considered to be a limiting fault, but is analyzed as an incident of moderate frequency for Global Nuclear Fuel reloads.

15.3.3.2 Sequence of Events and Systems Operation

15.3.3.2.1 Sequence of Events

Table 15.3-5 lists the sequence of events for Figure 15.3-5, for two loop operation. Table 15.3-6 lists the typical sequence of events for the recirculation pump seizure accident during SLO.

Identification of Operator Actions

The operator must verify that the reactor scrams with the turbine trip resulting from reactor water level swell. The operator should regain control of reactor water level through RCIC operation or by restart of a feedwater pump, and must monitor reactor water level and pressure control after shutdown.

15.3.3.2.2 Systems Operation

In order to properly simulate the expected sequence of events, the analysis of this event assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems.

Operation of safe shutdown features, including operation of the HPCS and RCIC systems though not included in this simulation, may be used to maintain adequate water level.

15.3.3.2.3 The Effect of Single Failures and Operator Errors

Single failures in the scram logic originating by means of the high vessel level (L8) trip are similar to the considerations in Section 15.3.1.2.3.2.

15.3.3.3 Core and System Performance

15.3.3.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 is used to simulate this event for two loop operation. The computer model described in Reference 15.3-2 was used to simulate this event for SLO.

15.3.3.3.2 Input Parameters and Initial Conditions

This analysis has been performed for two loop operation, unless otherwise noted, with plant conditions tabulated in Table 15.0-2, column "REDY (ASD Events)". For the simulation of the event while in two loop operation, one recirculation pump was seized instantaneously (pump speed set to zero) while the plant is operating at 104.5% uprated power and 100% core flow.

For single loop operation, the analysis has been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2A, column "Original Rated Power". For the purpose of evaluating consequences to the fuel thermal limits, this transient event is assumed to occur as a consequence of an unspecified, instantaneous stoppage of the active recirculation pump shaft while the reactor is operating at 73.8% NBR power under SLO. Also, the reactor is assumed to be operating at thermally-limiting conditions. The void coefficient is adjusted to the most conservative value, that is, the least negative value in Table 15.0-2A.

15.3.3.3.3 Results

Figure 15.3-5 presents the results of the accident for two loop operation. Table 15.3-5 shows the sequence of events for this transient. Initially a recirculation pump is seized in one loop causing the flow in the seized loop to reverse and the flow in the active loop to increase. As the flow in the seized loop decreases, the vessel level rises until a turbine trip is initiated on high level, L8. Once L8 is reached, both feedwater pumps trip. A reactor scram is subsequently initiated due to 90% turbine stop (throttle) valve position. Shortly after the turbine trip is initiated the stop valves close and the bypass valves open to regulate pressure. Simultaneously the active recirculation loop trips due to the turbine trip. The MCPR does not decrease significantly before fuel surface heat flux begins dropping enough to restore greater thermal margins. After the time at which MCPR occurs, heat flux decreases more rapidly than the rate at which heat is removed by the coolant and the ΔCPR is less than 0.01.

Figure 15.3-6 presents the results of the event in SLO. Core coolant flow drops rapidly, reaching a minimum value of 25% rated at about 2.0 sec.

The RRC pump seizure while in SLO is more limiting than the RRC pump seizure in two loop operation. See Table 15.0-1A.

15.3.3.3.3.1 Considerations of Uncertainties. Considerations of uncertainties are included in the analysis.

15.3.3.4 Barrier Performance

The bypass valves open to limit the pressure well within the range allowed by the ASME vessel code. The RCPB is not impacted by overpressure. Therefore, barrier integrity and function is maintained.

15.3.3.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment there are no radiological consequences associated with this event.

15.3.4 RECIRCULATION PUMP SHAFT BREAK

15.3.4.1 Identification of Causes and Frequency Classification

The breaking of the shaft of a recirculation pump is considered a design basis accident event. It has been evaluated as a mild accident in relation to other design basis accidents such as the loss-of-coolant accident. The analysis has been conducted with consideration to a single or two loop operation. Two loop operation represents the worst case since single loop operation is limited to approximately 73.8% power.

This postulated event is bounded by the more limiting case of recirculation pump seizure.

15.3.4.1.1 Identification of Causes

The case of recirculation pump shaft breakage represents the unlikely event of rapid stoppage of the pump operation of one recirculation pump. This event produces a rapid decrease of core flow.

15.3.4.1.2 Frequency Classification

This event is categorized as an incident of infrequent frequency.

15.3.4.2 Sequence of Events and Systems Operation

15.3.4.2.1 Sequence of Events

A postulated instantaneous break of the pump motor shaft of one recirculation pump as discussed in Section 15.3.4.1.1 will cause the core flow to decrease rapidly resulting in water level swell in the reactor vessel. When the vessel water level reaches the high water level setpoint (Level 8), a main turbine trip and feedwater pump trip will be initiated.

A reactor scram and the remaining recirculation pump trip will be initiated due to the turbine trip. Eventually the vessel water level will be controlled by HPCS and/or RCIC flow.

15.3.4.2.2 Systems Operation

Normal operation of plant instrumentation and control is assumed. This event takes credit for vessel water level (Level 8) instrumentation to scram the reactor and trip the main turbine and feedwater pumps. High system pressure is limited by the pressure relief system operation.

Operation of HPCS and/or RCIC is expected in order to maintain adequate water level control.

15.3.4.2.3 The Effect of Single Failures and Operator Errors

Effects of single failures in the high vessel level (L8) trip are similar to the considerations in Section 15.3.1.2.3.2.

Assumption of single component failure or operator error in other equipment has been examined and this has led to the conclusion that no other credible failure exists for this event. Therefore, the bounding case has been considered.

15.3.4.3 Core and System Performance

The pump shaft break event is bounded by the pump seizure event. Since this event is less limiting than that event, only qualitative evaluation is provided. Therefore, no discussion of mathematical model, input parameters, and consideration of uncertainties, etc., is necessary.

15.3.4.3.1 Qualitative Results

If this unlikely event occurs, core coolant flow will drop rapidly. The level swell produces a trip of the main and feedwater turbines. A scram is initiated due to turbine trip. Since heat flux decreases more rapidly than the rate at which heat is removed by the coolant, there is no impact on thermal limits. Additionally, the bypass valves and the potential for a momentary opening of some of the SRVs limit the pressure well within the range allowed by the ASME vessel code. Therefore, the RCPB is not impacted by overpressure.

The severity of this pump shaft break event is bounded by the pump seizure event. In either of these two events, the recirculation drive flow of the affected loop decreases rapidly.

In the case of the pump seizure event, the loop flow decreases faster than the normal flow coastdown as a result of the large hydraulic resistance introduced by the stopped rotor. For the pump shaft break event, the hydraulic resistance caused by the broken pump shaft is less than that of the stopped rotor for the pump seizure event. Therefore, the core flow decrease following a pump shaft break effect is slower than the pump seizure event. Thus, it can be concluded that the potential effects of the hypothetical pump shaft break accident are bounded by the effects of the pump seizure event.

15.3.4.4 Barrier Performance

The bypass valves and momentary opening of some of the SRVs limit the pressure well within the range allowed by the ASME vessel code. Therefore, the RCPB is not impacted by overpressure.

15.3.4.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment there are no radiological consequences associated with this event.

15.3.5 REFERENCES

15.3-1 General Electric Company, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, September 1993.

15.3-2 NEDC-24154-P-A, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," Volumes 1, 2, 3 and 4, February 2000.

15.3-3 Advanced Nuclear Fuels Corporation, "WNP-2 Single Loop Operation Analysis," ANF-87-119, September 1987.

Table 15.3-1

Sequence of Events for Figure 15.3-1

Trip of One Recirculation Pump Motor
Uprated Power

Time (sec)	Event
0	Trip of one recirculation pump initiated.
9	Jet pump diffuser flow reverses in the tripped loop.
45[a]	Core flow and power level stabilize at new equilibrium conditions.

[a] Approximately.

Table 15.3-2

Sequence of Events for Figure 15.3-2

Trip of Both Recirculation Pump Motors
Uprated Power

Time (sec)	Event
0	Trip of both recirculation pumps initiated.
5.66	Vessel water level (L8) trip initiates turbine trip.
5.66	Feedwater pumps are tripped off.
5.67	Main turbine stop (throttle) valves reach 90% open position and initiate reactor scram trip.
5.76	Turbine bypass valves open.

Table 15.3-3

Sequence of Events for Figure 15.3-3

Recirculation Flow Control Failure
Decreasing Flow in One Loop
Uprated Power

Time (sec)	Event
0	Initiate fast down scale of recirculation pump speed in one loop.
4[a]	Jet pump diffuser flow reverses in the affected loop.
45[a]	Core flow and power level stabilize at new equilibrium conditions.

[a] Approximately.

Table 15.3-4

Sequence of Events for Figure 15.3-4

Recirculation Flow Control Failure
Decreasing Flow in Both Loops (5%/sec)
Uprated Power

Time (sec)	Event
0	Initiate 5%/sec down scale of recirculation pump speed in both loops.
85[a]	Core flow and power level stabilize at new equilibrium conditions.

Table 15.3-5

Sequence of Events for Figure 15.3-5

One Recirculation Pump Seizure
Uprated Power

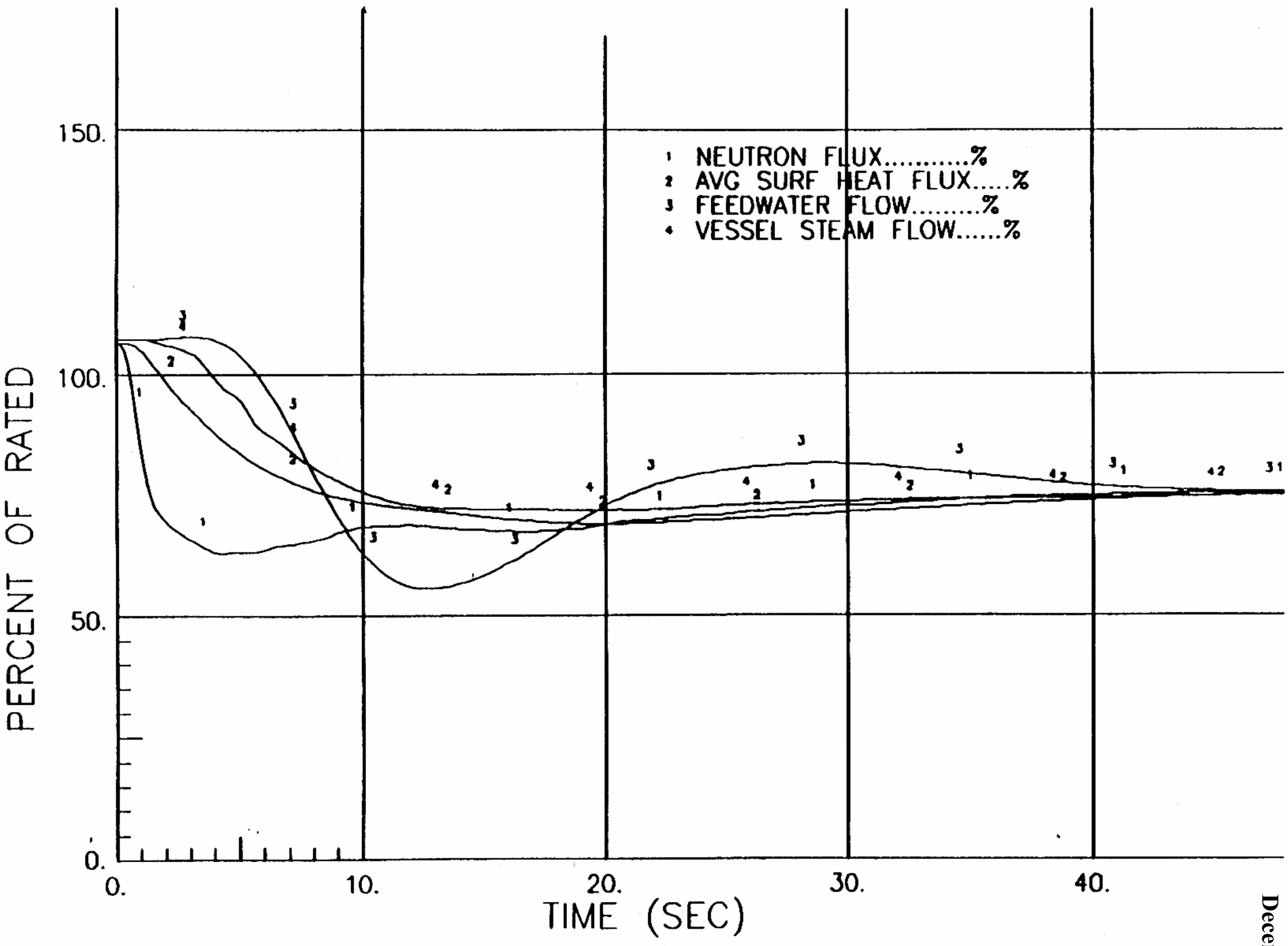
Time (sec)	Event
0	Seizure of one recirculation pump initiated.
1[a]	Jet pump diffuser flow reverses in the seized loop.
4.40	Vessel water high level (L8) trip initiates a turbine trip.
4.40	Feedwater pumps are tripped off.
4.41	Main turbine stop (throttle) valves reach 90% open position and initiate reactor scram.
4.59	Active recirculation loop trips due to previous turbine trip.

[a] Approximately.

Table 15.3-6

Sequence of Events for Pump Seizure
(for Single Loop Operation)

Time (sec)	Event
0.0	Recirculation pump motor trip off complete Single pump seizure was initiated; core flow decreases
~1.9	Reverse flow ceases in the idle loop
~6.0	Power and flow stabilize



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

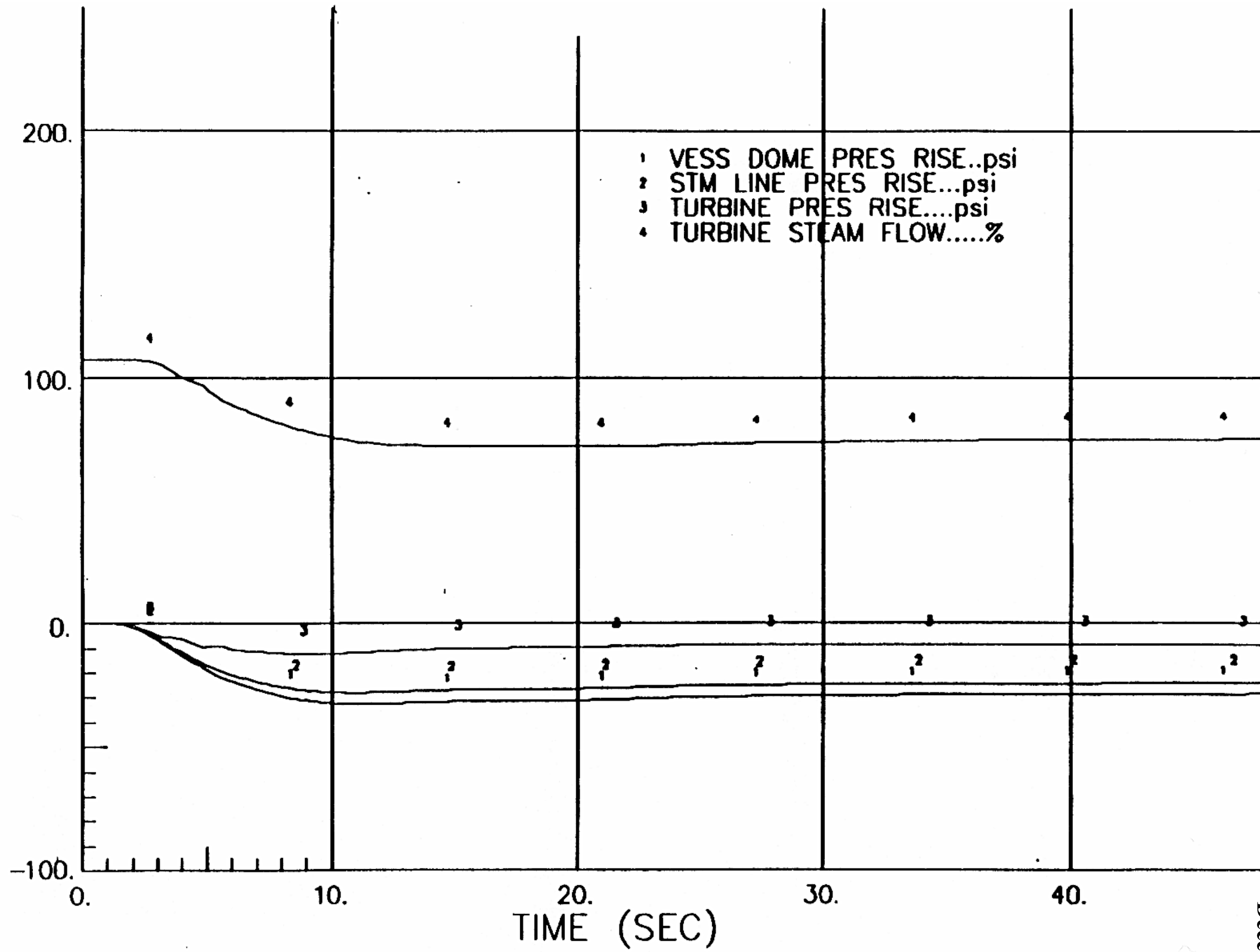
Columbia Generating Station
Final Safety Analysis Report

One Recirculation Pump Trip at 104.5*%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
02036I.77		15.3-1.1

Amendment 64
December 2017

Form No. 960690
LDCN-16-005



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

One Recirculation Pump Trip at 104.5*%
Uprated Power, 100% Flow

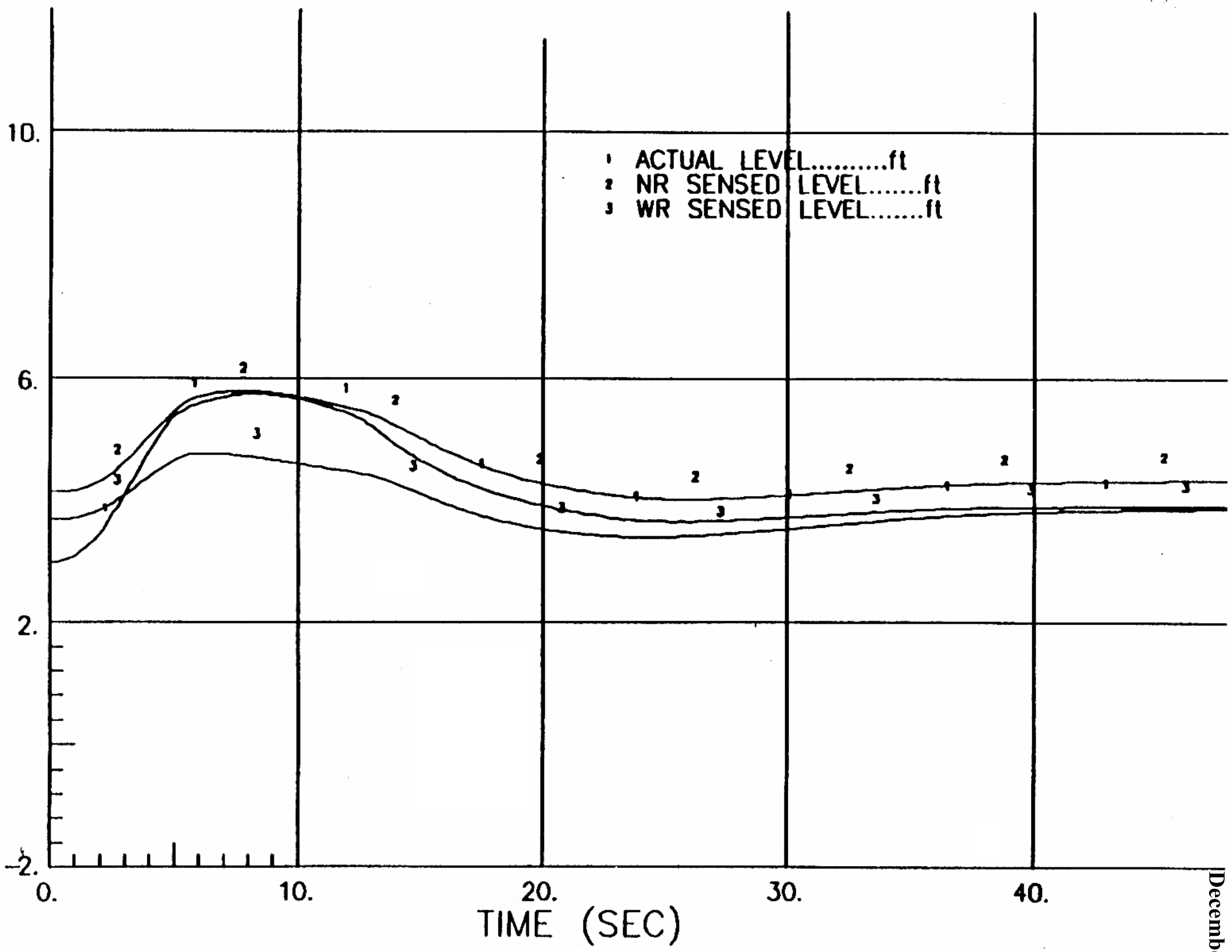
Draw. No.	Rev.	Figure
020361.78		15.3-1.2

Form No. 960690
LDCN-16-005

Form No. 960690
LDCN-16-005

Columbia Generating Station
Final Safety Analysis Report

*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

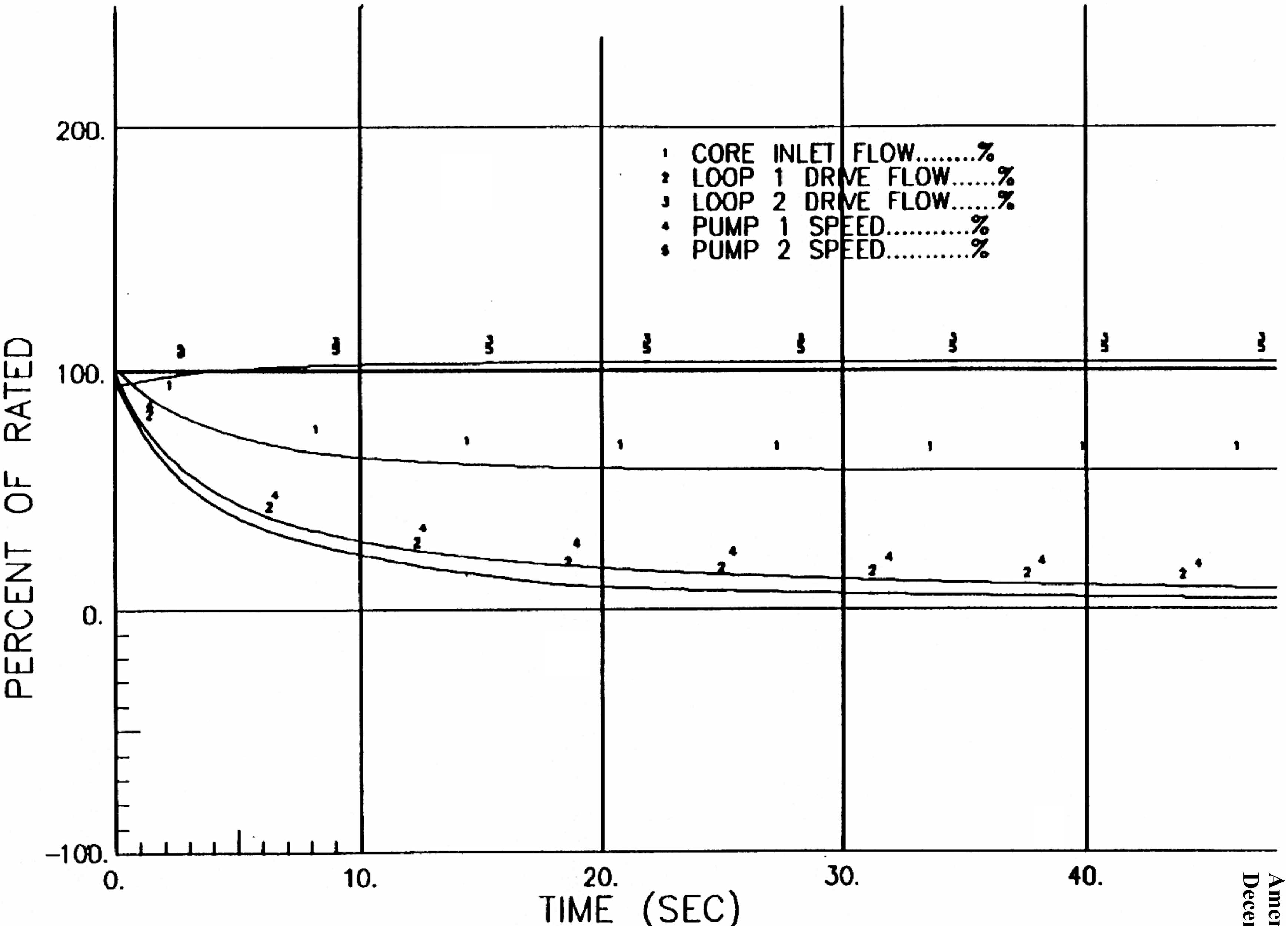


One Recirculation Pump Trip at 104.5*%
Uprated Power, 100% Flow

Draw. No. 020361.79

Rev.

Figure 15.3-1.3

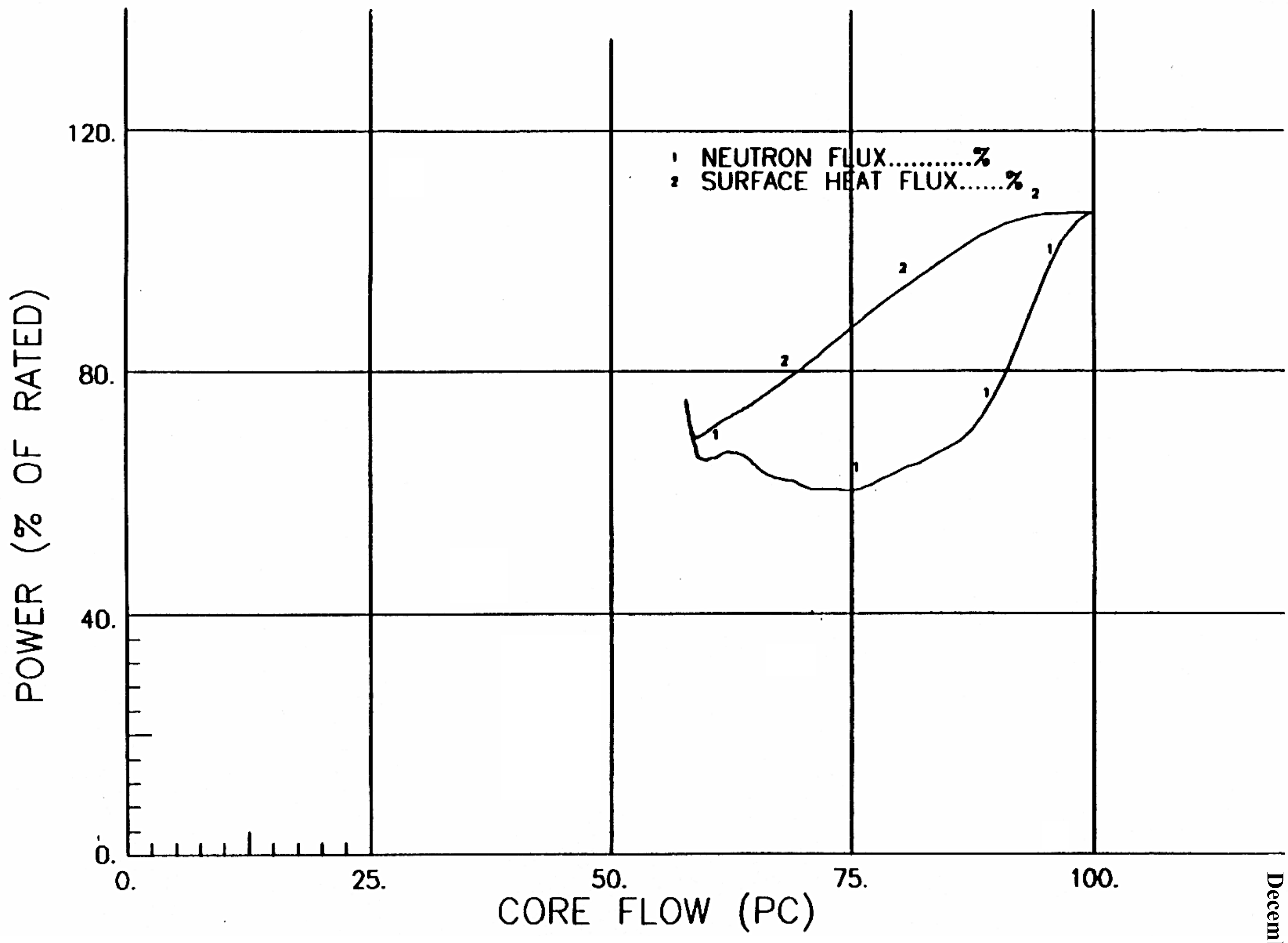


*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

One Recirculation Pump Trip at 104.5*% Uprated Power, 100% Flow

Draw. No. 020361.80 | Rev. | Figure 15.3-1.4

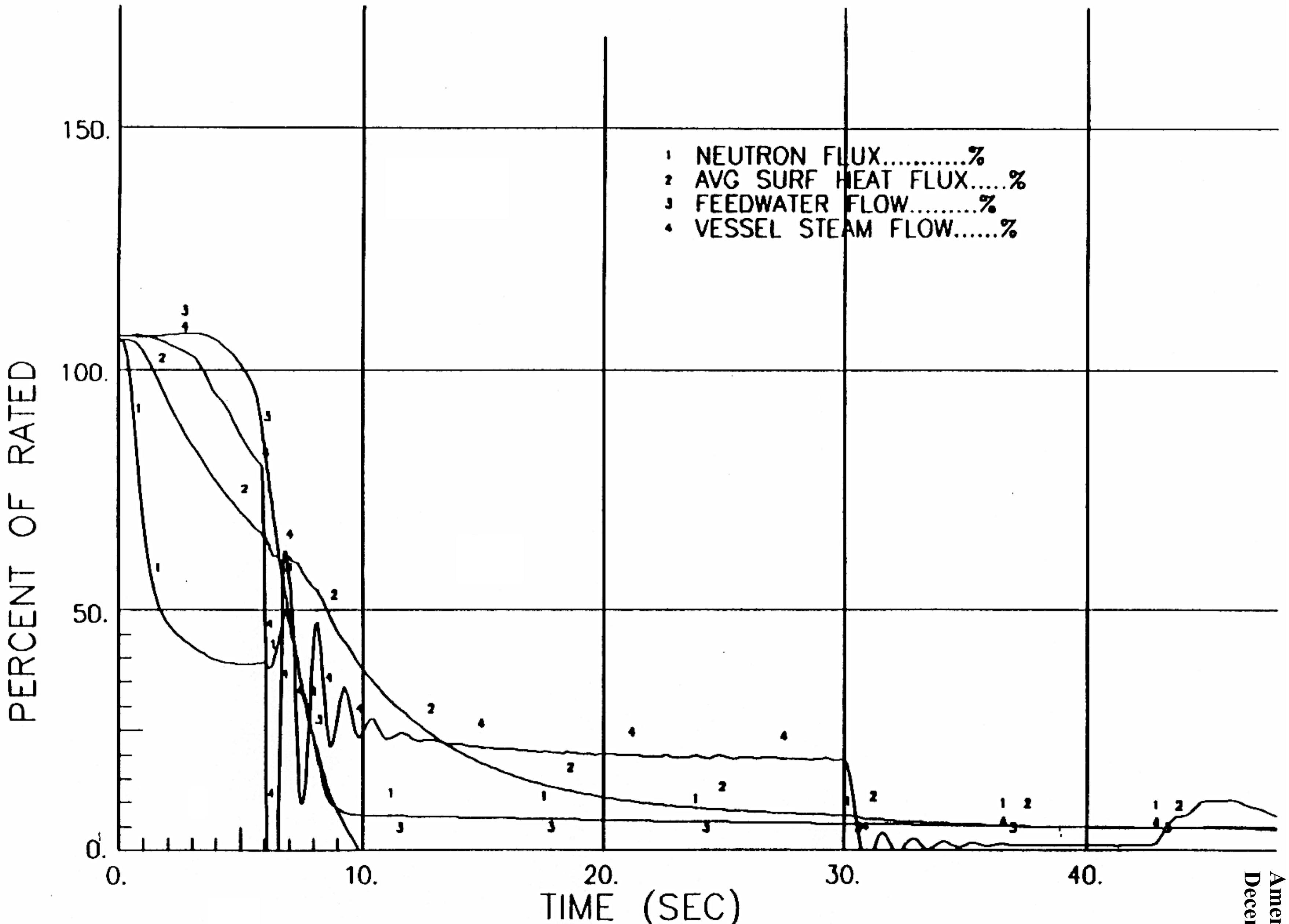


*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

One Recirculation Pump Trip at 104.5*%
Uprated Power, 100% Flow

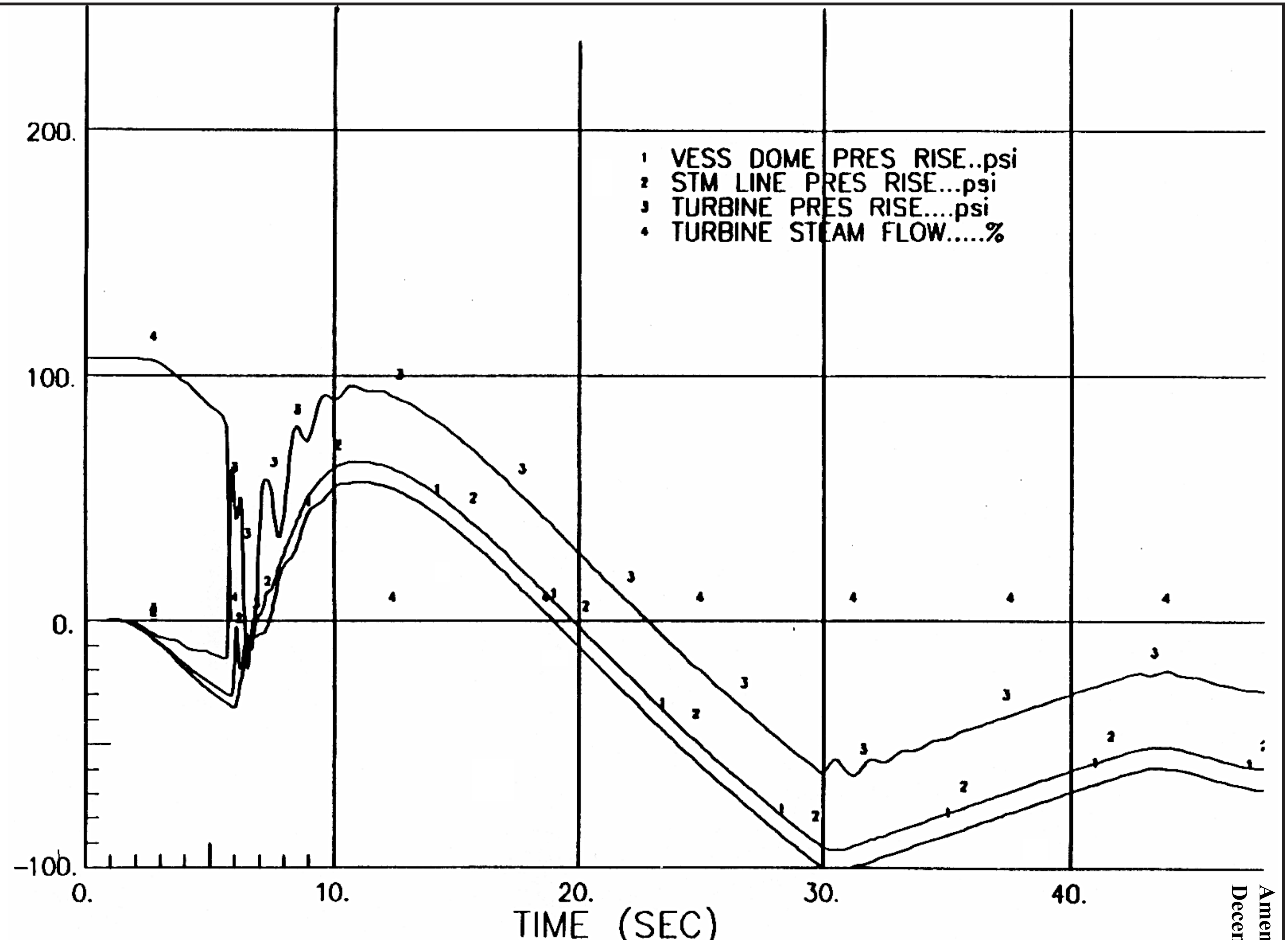
Draw. No. 020361.81 | Rev. | Figure 15.3-1.5



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Two Recirculation Pump Trip at 104.5*%
Uprated Power, 100% Flow

Draw. No. 020361.82	Rev.	Figure 15.3-2.1



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

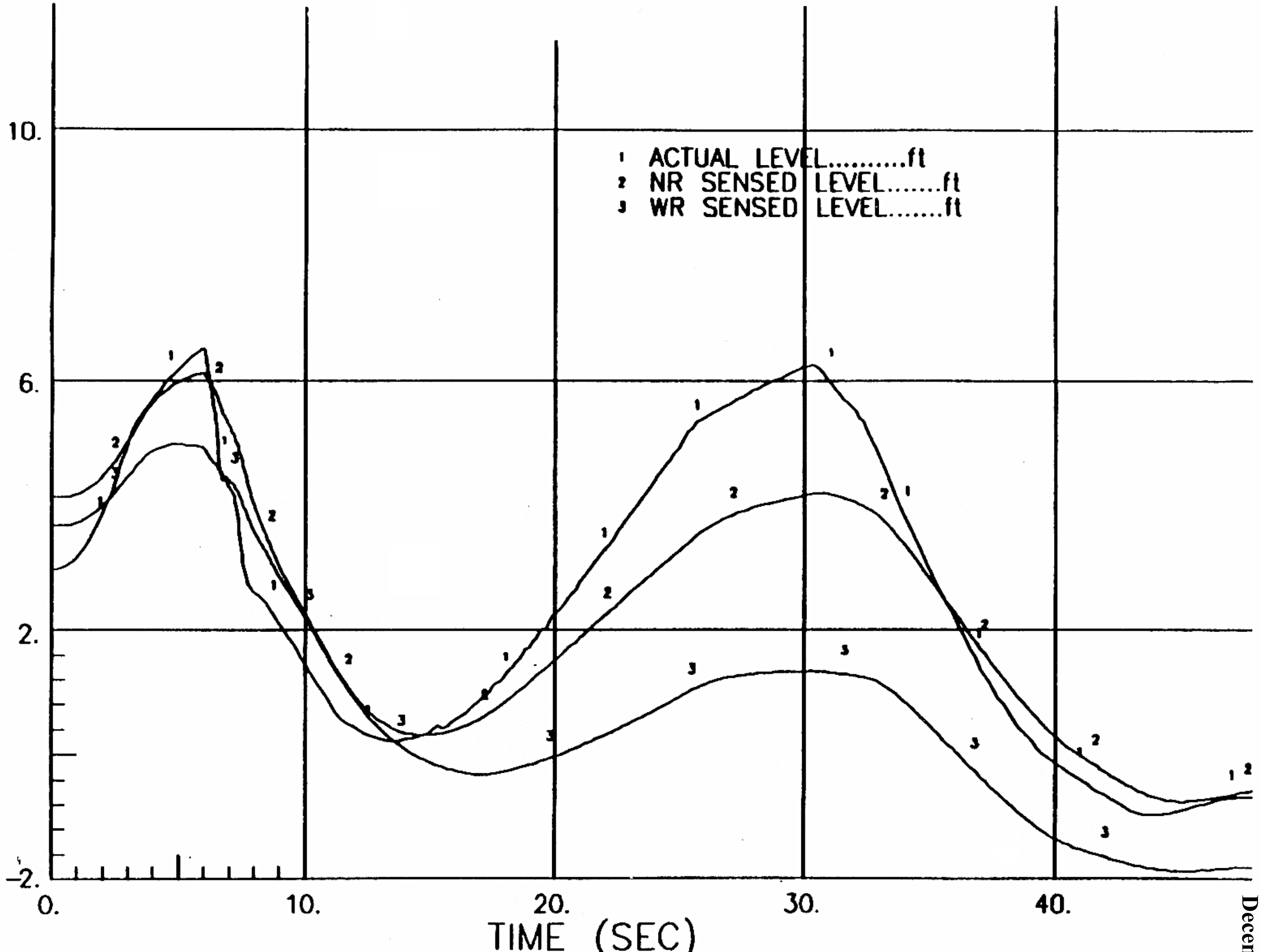
Columbia Generating Station
Final Safety Analysis Report

Two Recirculation Pump Trip at 104.5*% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
020361.83		15.3-2.2

Form No. 960690
LDCN-16-005

Columbia Generating Station
Final Safety Analysis Report



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Two Recirculation Pump Trip at 104.5*% Uprated Power, 100% Flow

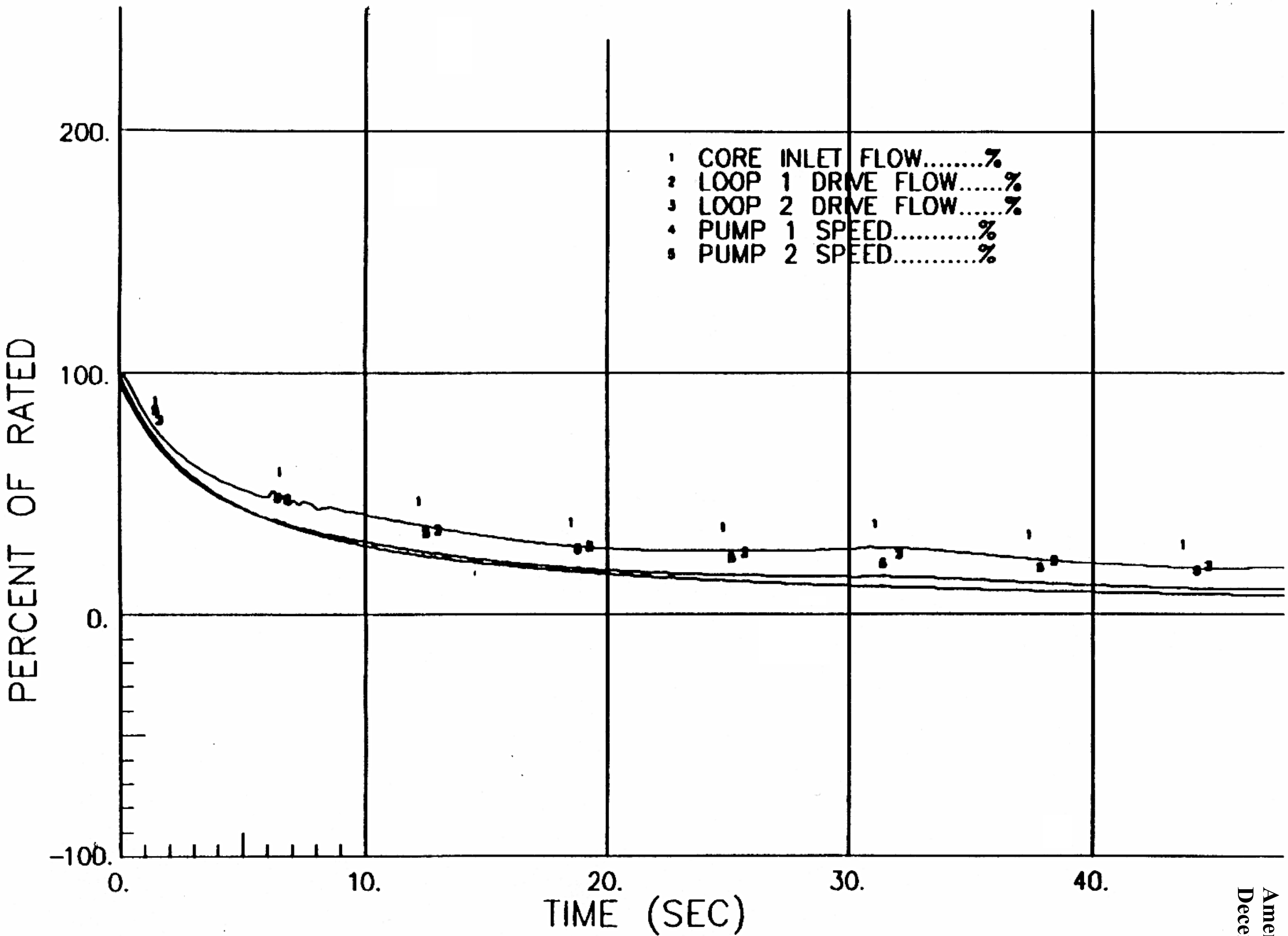
Draw. No. 020361.84

Rev.

Figure 15.3-2.3

Form No. 960690
LDCN-16-005

Columbia Generating Station
Final Safety Analysis Report

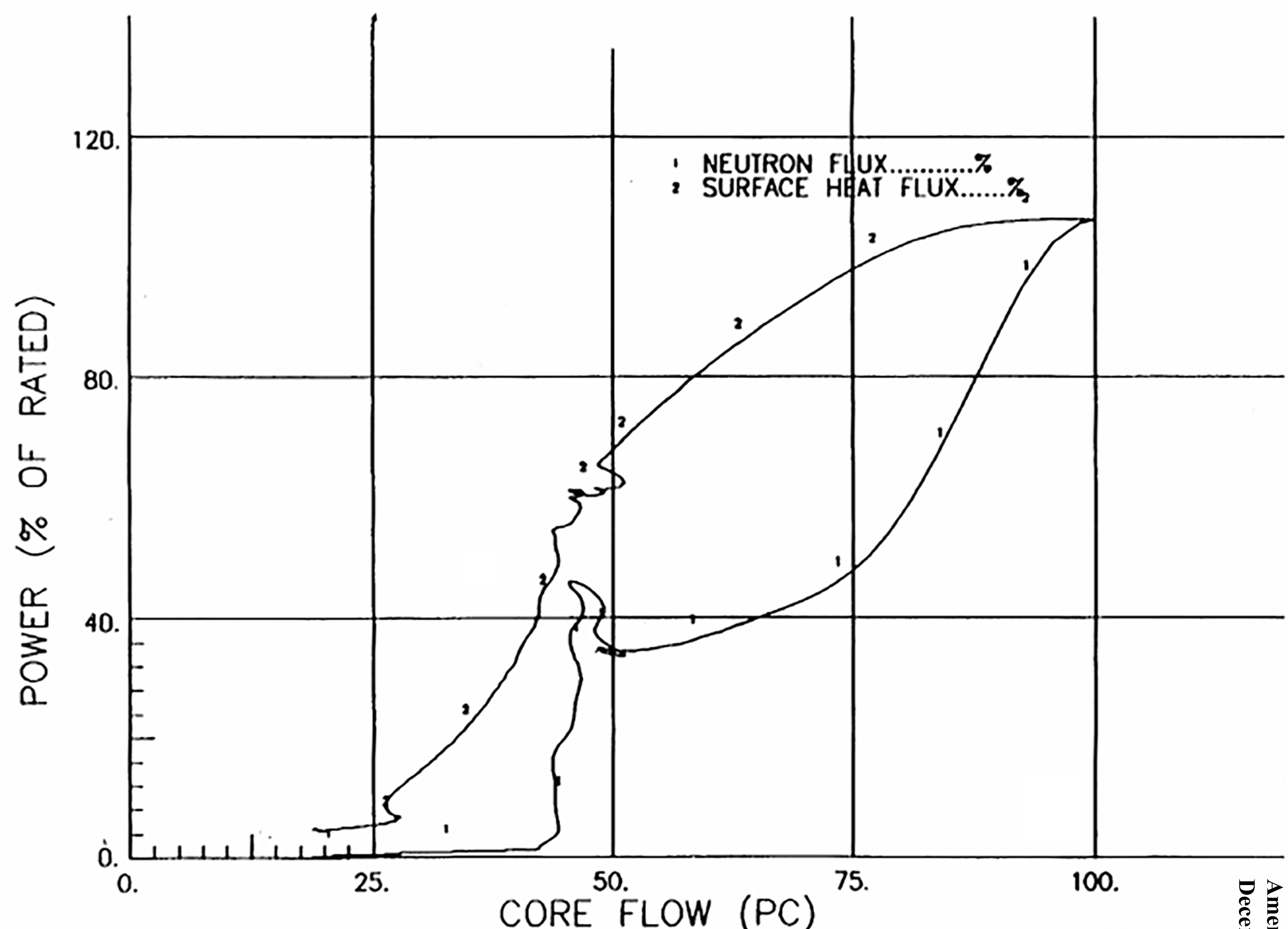


*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Two Recirculation Pump Trip at 104.5*%
Uprated Power, 100% Flow

Draw. No. 020361.85	Rev.	Figure 15.3-2.4

Amendment 64
December 2017



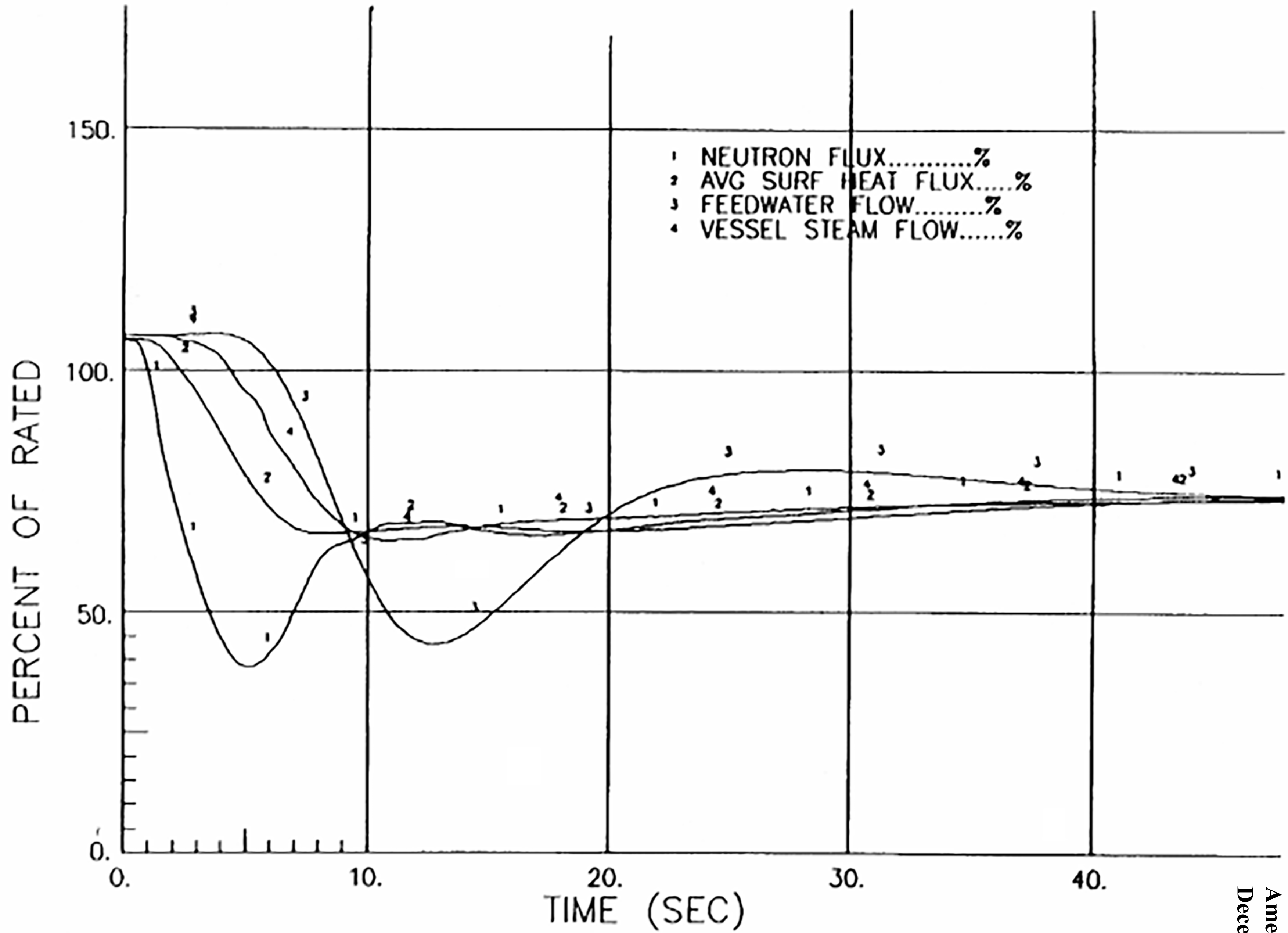
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Two Recirculation Pump Trip at 104.5*% Uprated Power, 100% Flow

Draw. No. 020361.86 | Rev. | Figure 15.3-2.5

Form No. 960690
LDCN-16-005

Amendment 64
December 2017



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Amendment 64
December 2017

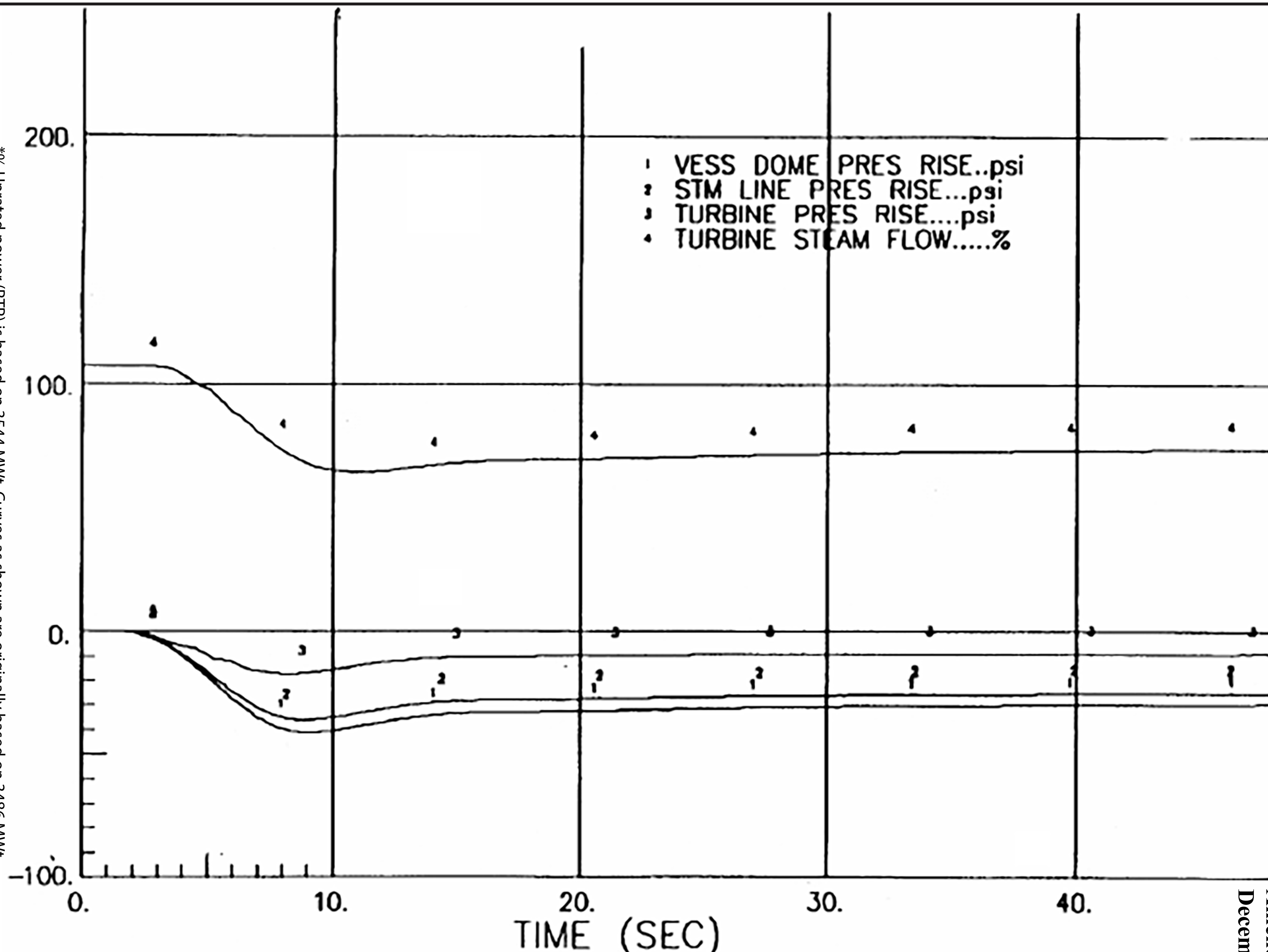
Recirculation Flow Control Failure - Decreasing Flow in One Loop at 104.5*% Uprated Power, 100% Flow

Draw. No. 020361.87

Rev.

Figure 15.3-3.1

Form No. 960690
LDCN-16-005



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

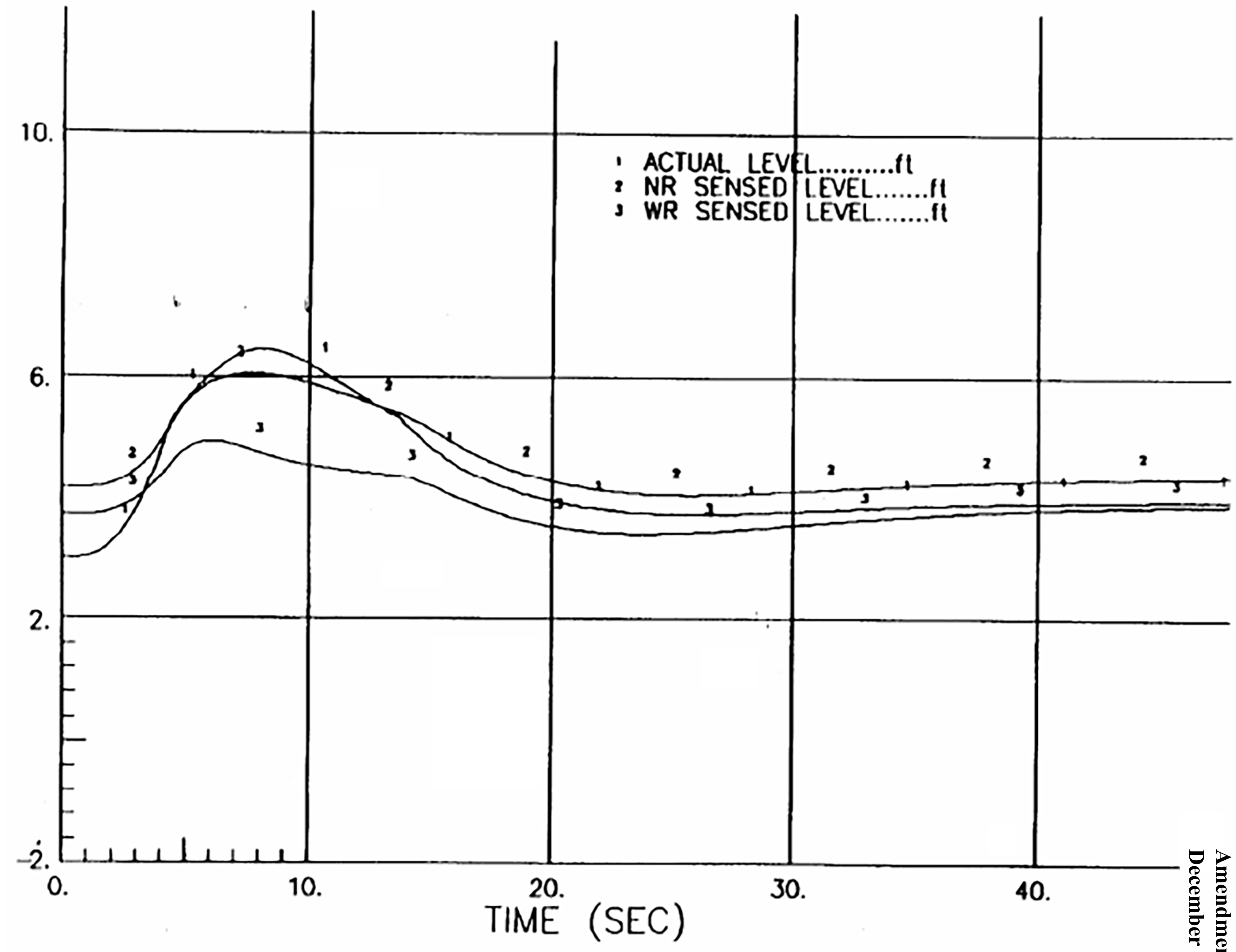
Columbia Generating Station
Final Safety Analysis Report

Recirculation Flow Control Failure - Decreasing Flow in One Loop at 104.5*% Uprated Power, 100% Flow

Draw. No. 020361.88	Rev.	Figure 15.3-3.2

Amendment 64
December 2017

Form No. 960690
LDCN-16-005



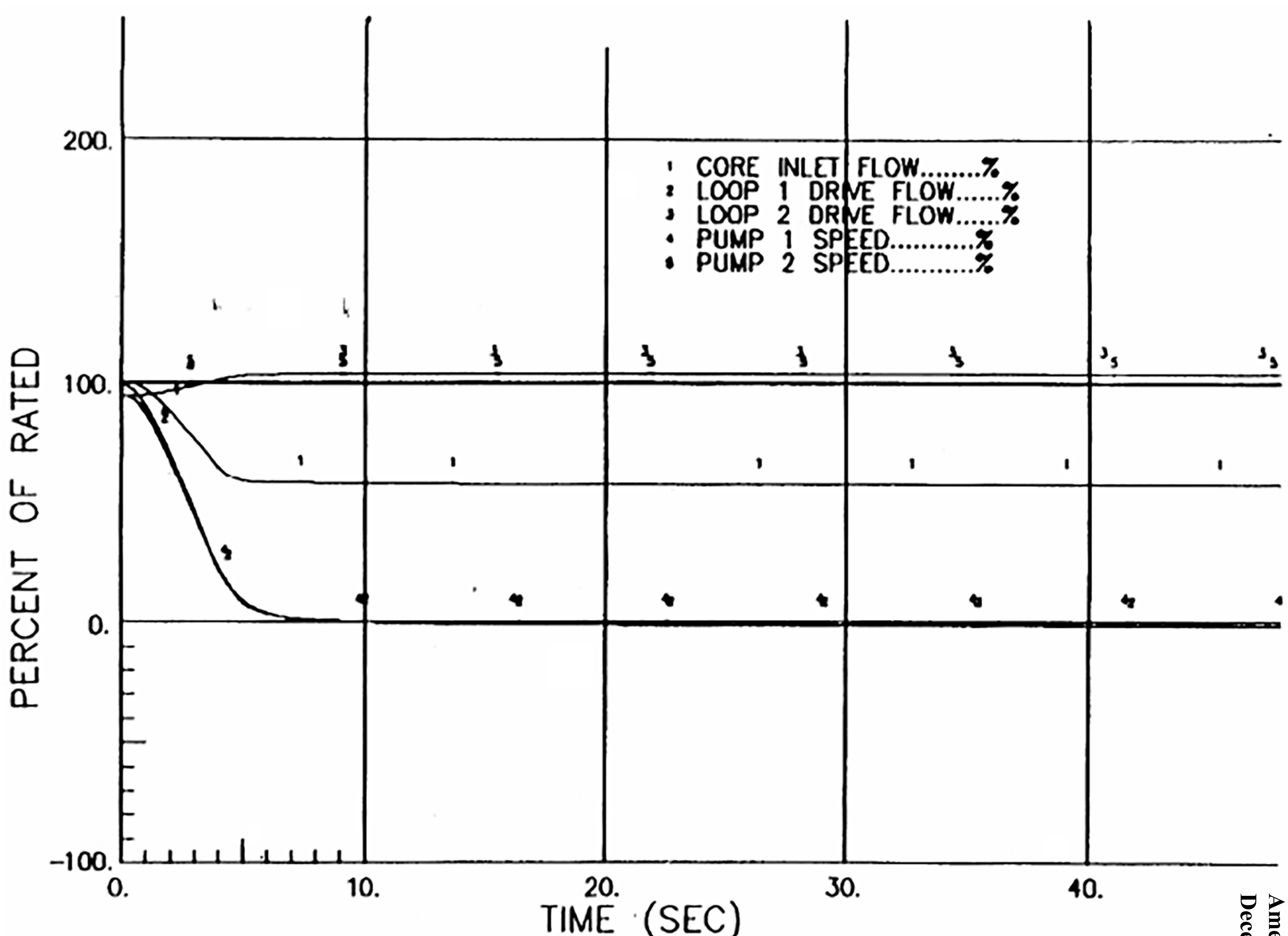
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Recirculation Flow Control Failure - Decreasing Flow in One Loop at 104.5*% Uprated Power, 100% Flow

Draw. No. 020361.89

Rev.

Figure 15.3-3.3



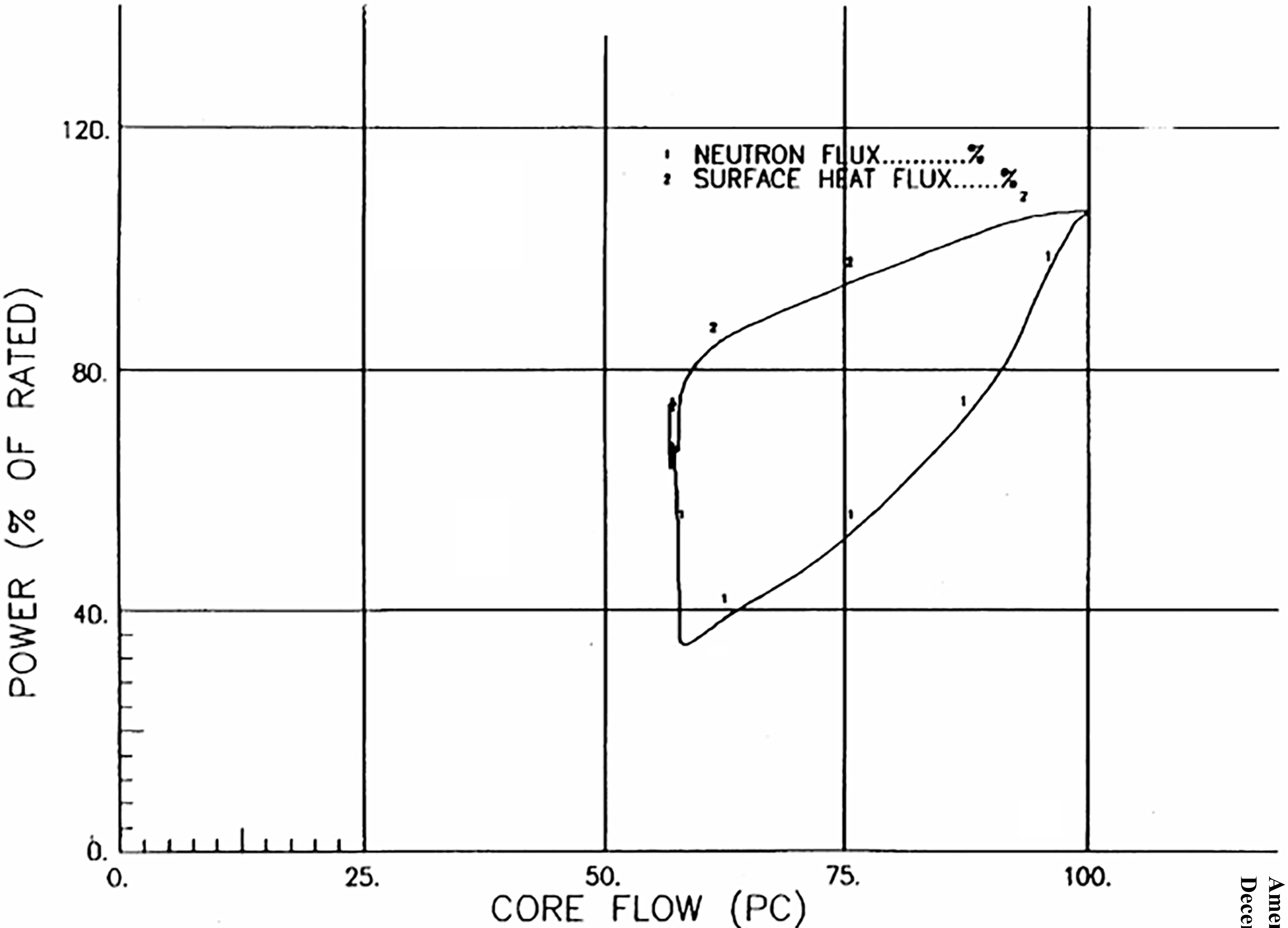
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Recirculation Flow Control Failure - Decreasing Flow in One Loop at 104.5*% Uprated Power, 100% Flow

Draw. No. 02036190	Rev.	Figure 15.3-3.4

Amendment 64
December 2017

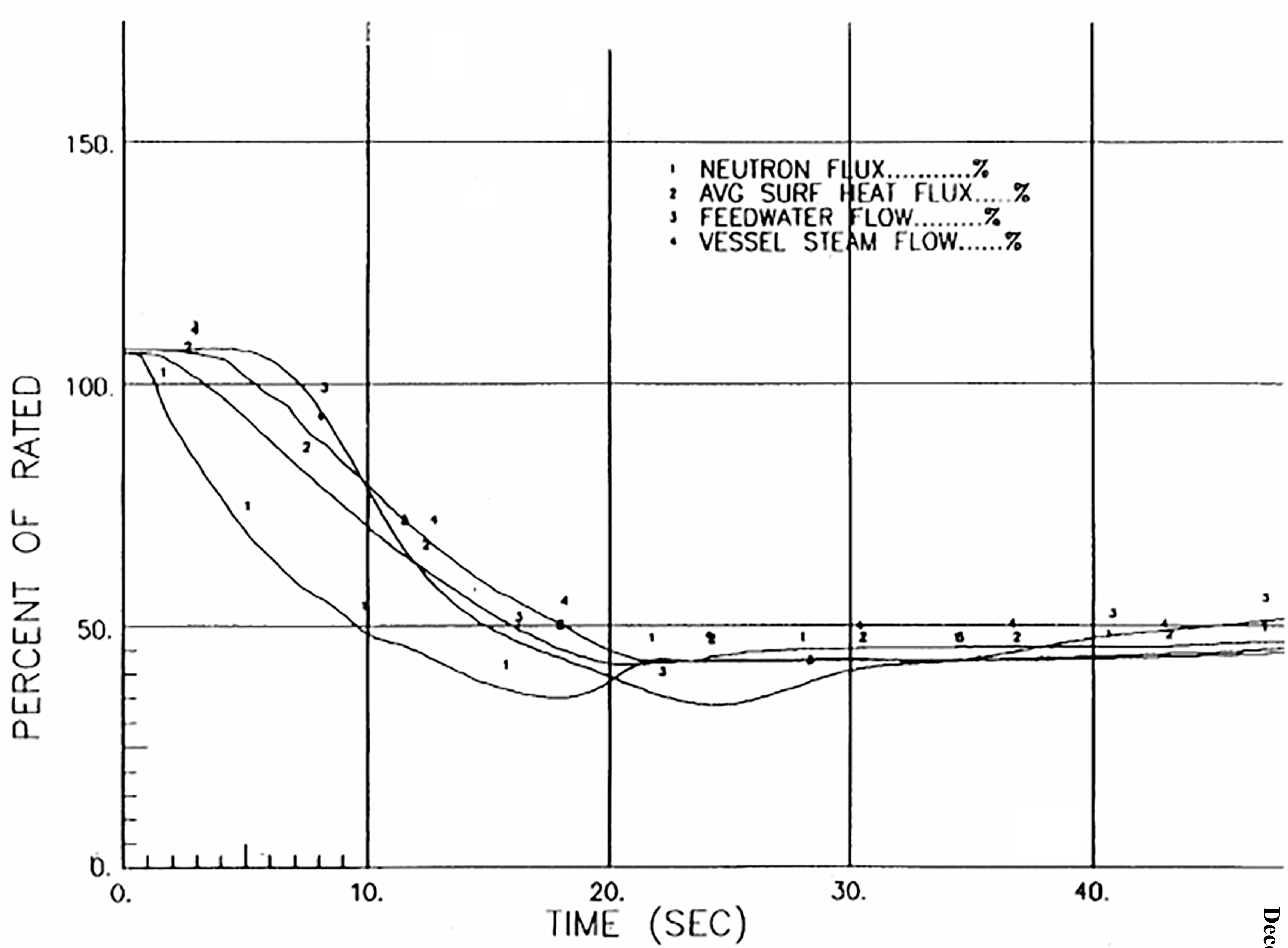


*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Recirculation Flow Control Failure - Decreasing Flow in One Loop at 104.5*% Uprated Power, 100% Flow

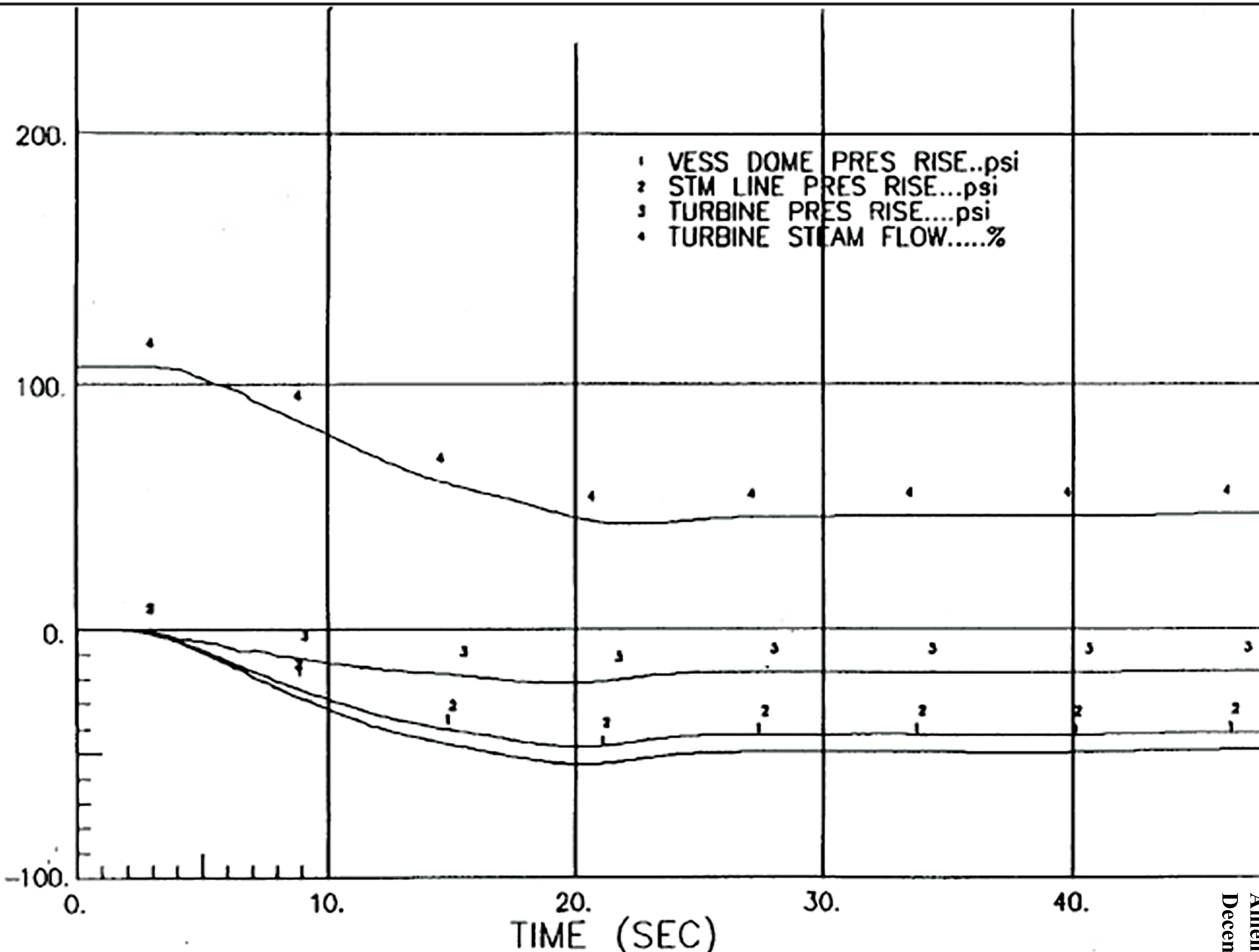
Draw. No. 02036I.91	Rev.	Figure 15.3-3.5



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 104.5*% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
02036192		15.3-4.1



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 104.5*% Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
02036l.93		15.3-4.2

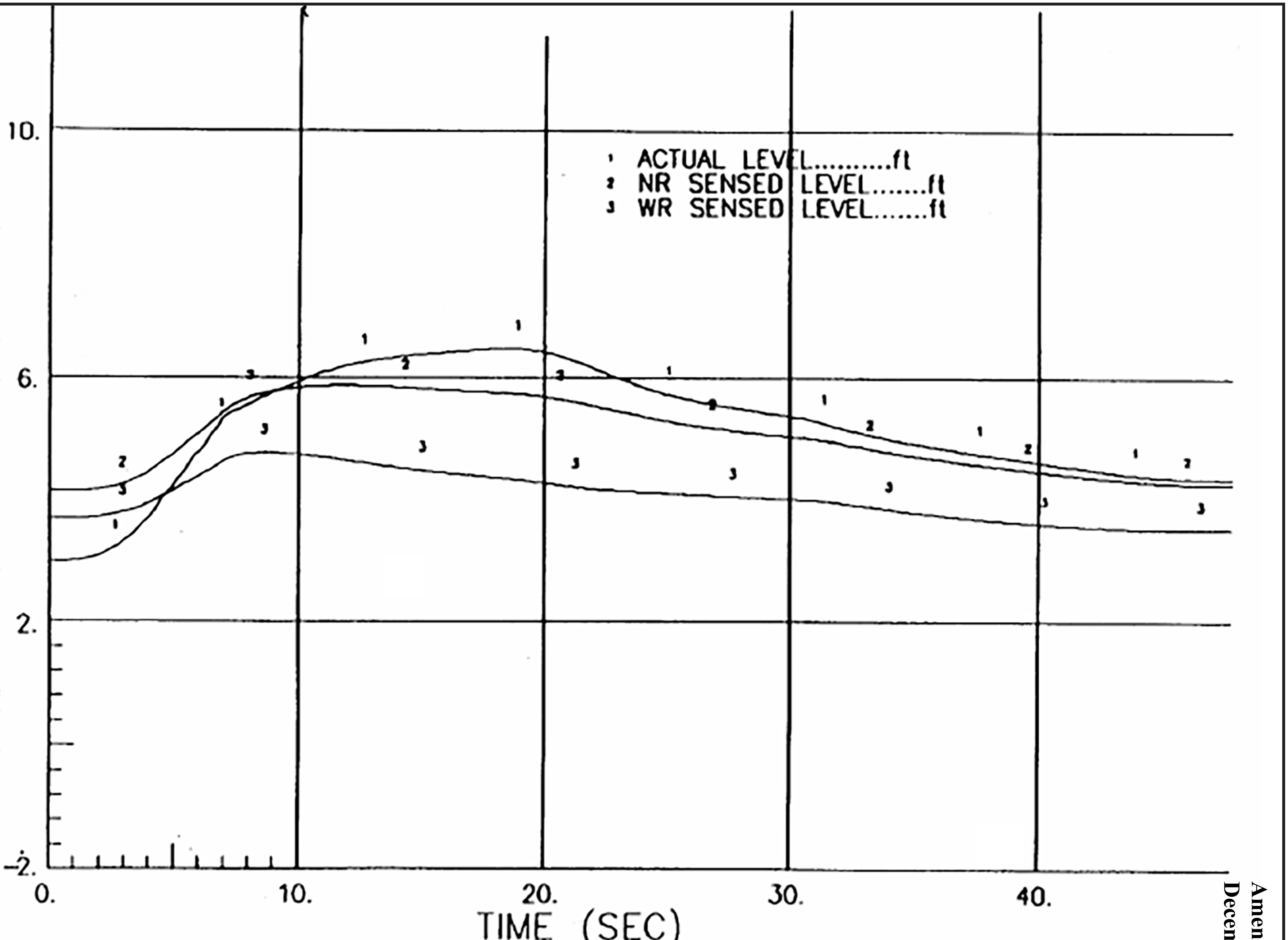
Amendment 64
December 2017

Form No. 960690
LDCN-16-005

Form No. 960690
LDCN-16-005

Columbia Generating Station
Final Safety Analysis Report

*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.



Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 104.5*% Uprated Power, 100% Flow

Draw. No. 02036I.94

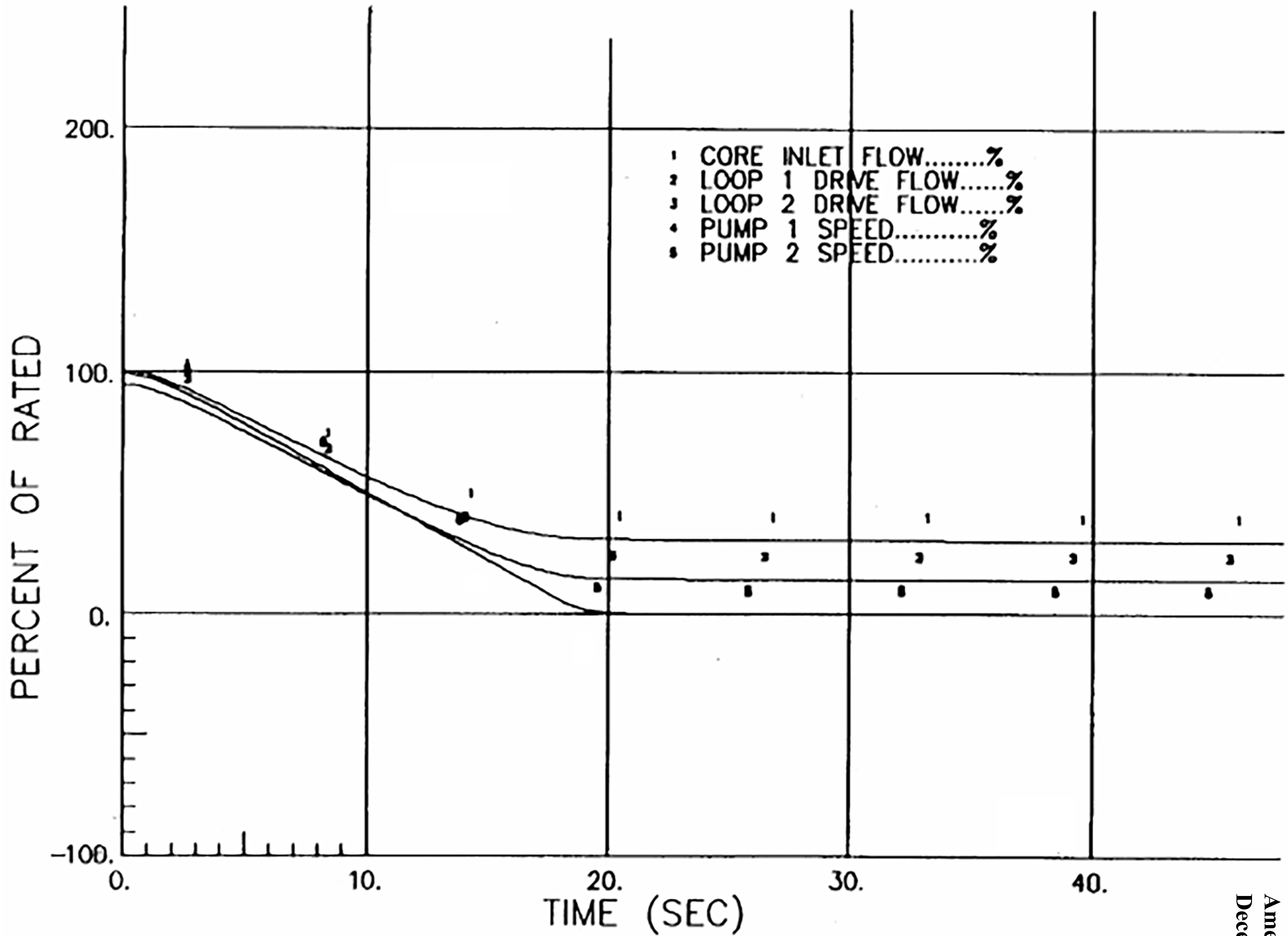
Rev.

Figure 15.3-4.3

Amendment 64
December 2017

Form No. 960690
LDCN-16-005

Columbia Generating Station
Final Safety Analysis Report

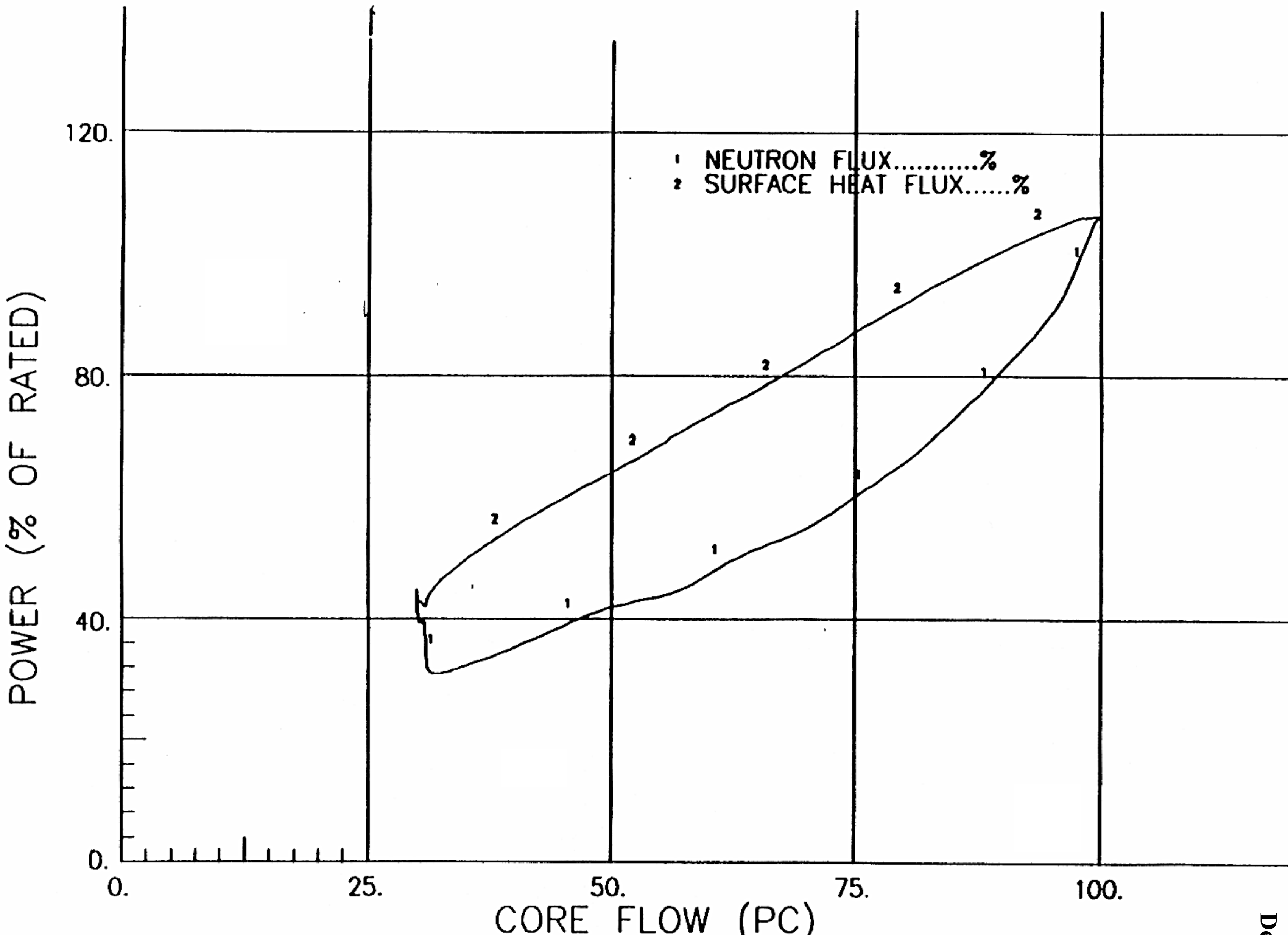


*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 104.5*% Uprated Power, 100% Flow

Draw. No. 02036195	Rev.	Figure 15.3-4.4

Amendment 64
December 2017



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

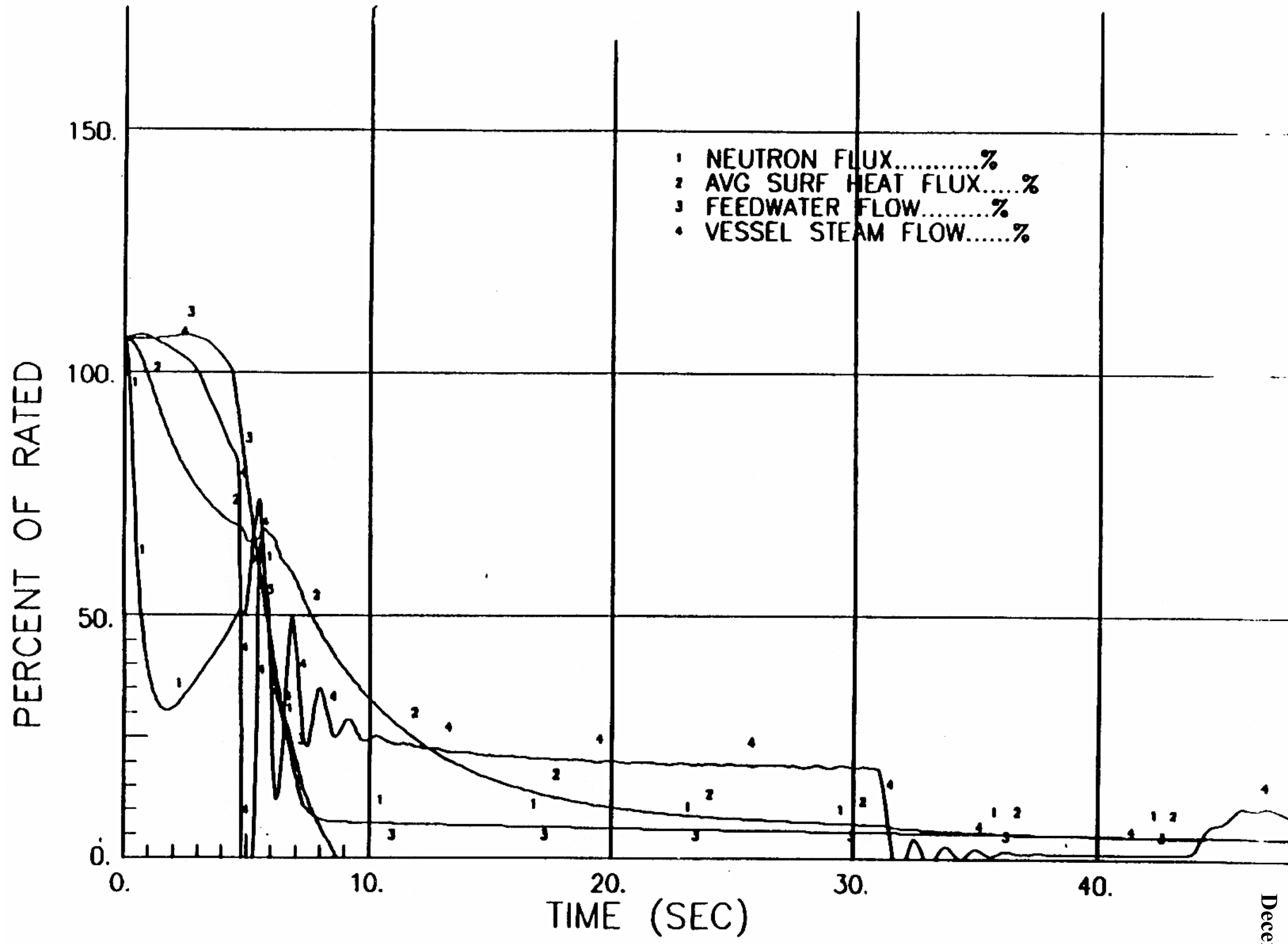
Columbia Generating Station
Final Safety Analysis Report

Recirculation Flow Control Failure - Decreasing Flow in Two Loops, (5%/Sec Ramp) at 104.5*% Uprated Power, 100% Flow

Draw. No. 02036l.96	Rev.	Figure 15.3-4.5

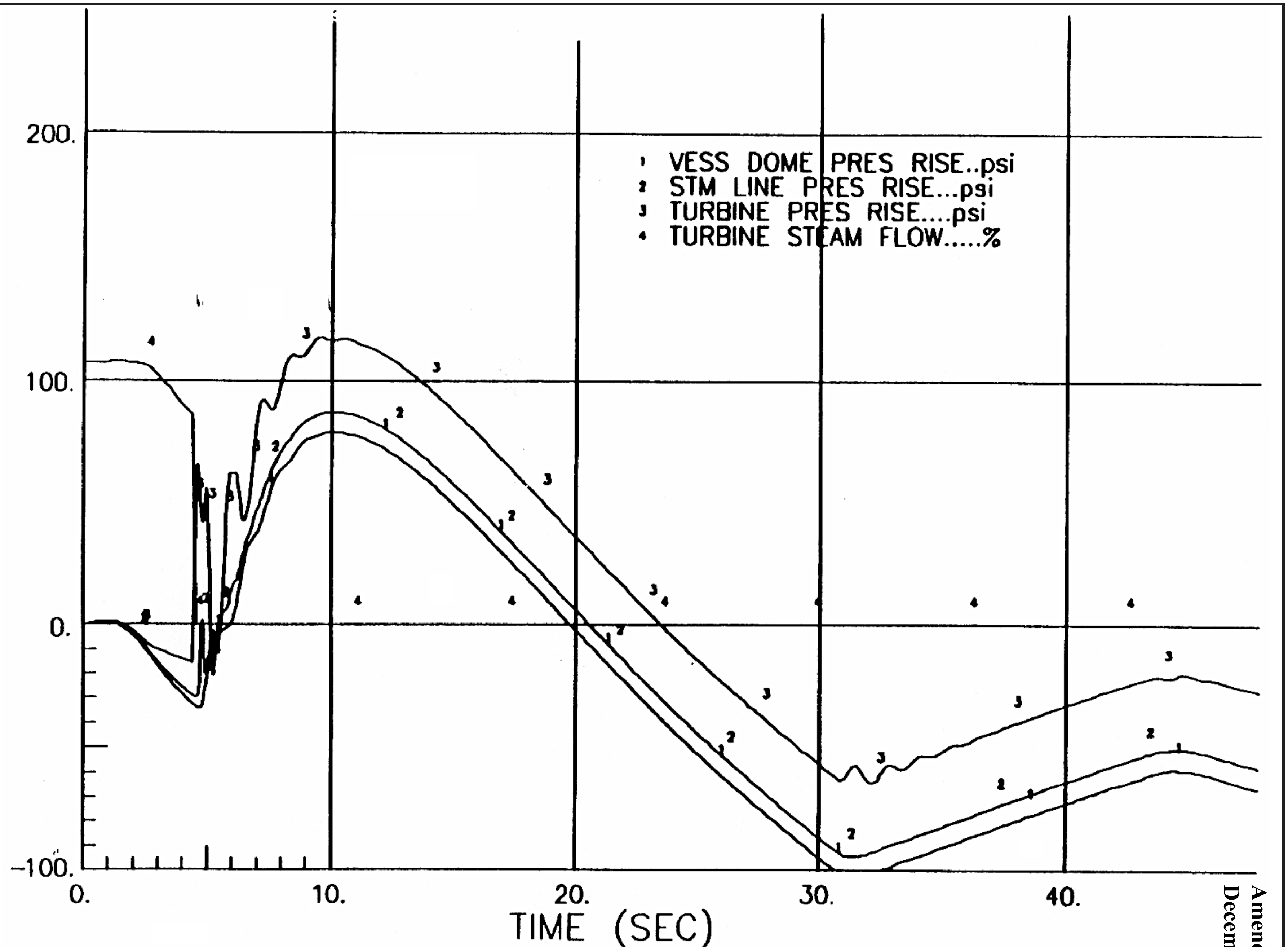
Columbia Generating Station
Final Safety Analysis Report

*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.



Recirculation Pump Seizure at 104.5*%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
020361.97		15.3-5.1



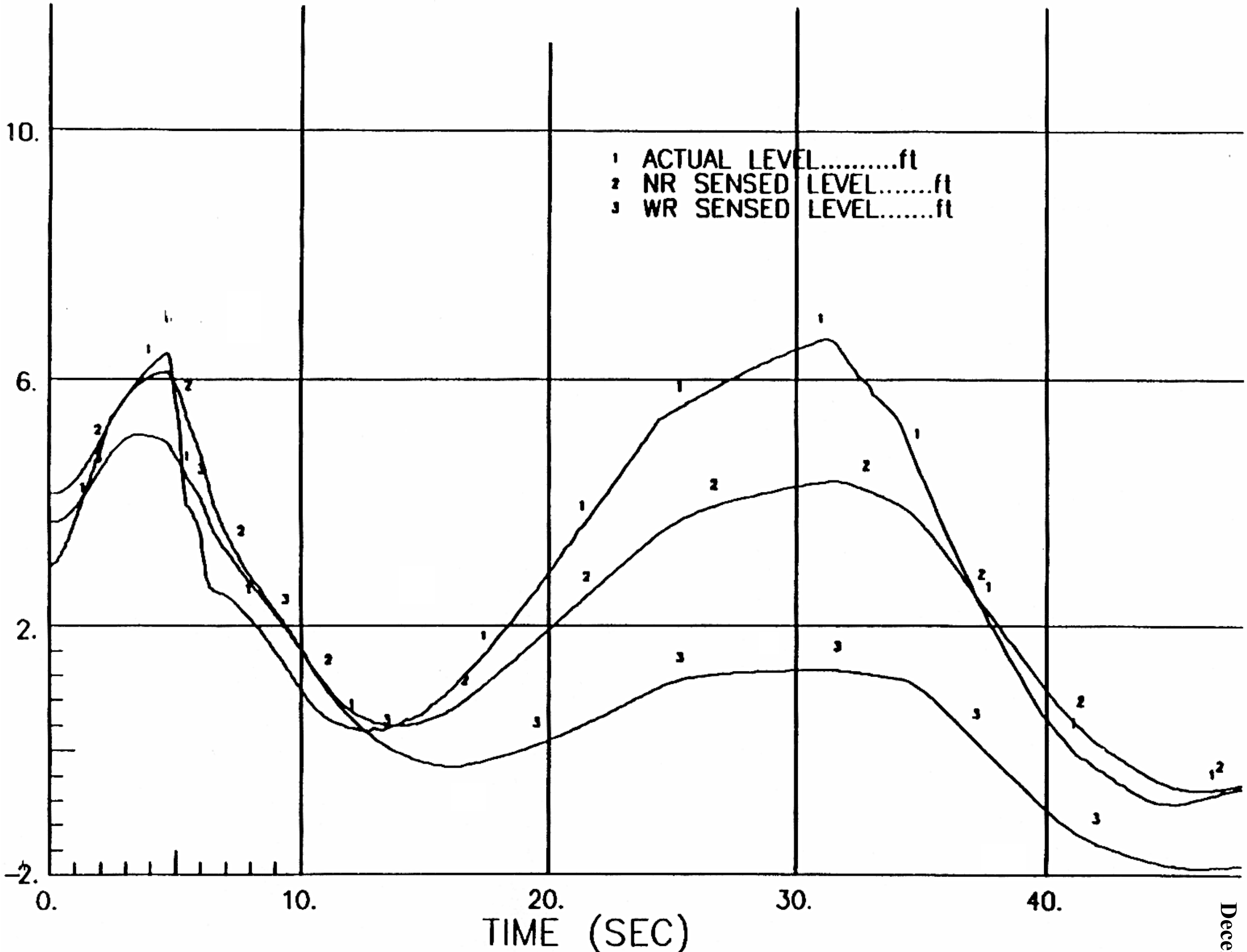
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Recirculation Pump Seizure at 104.5*% Uprated Power, 100% Flow

Draw. No. 02036l.98

Rev.

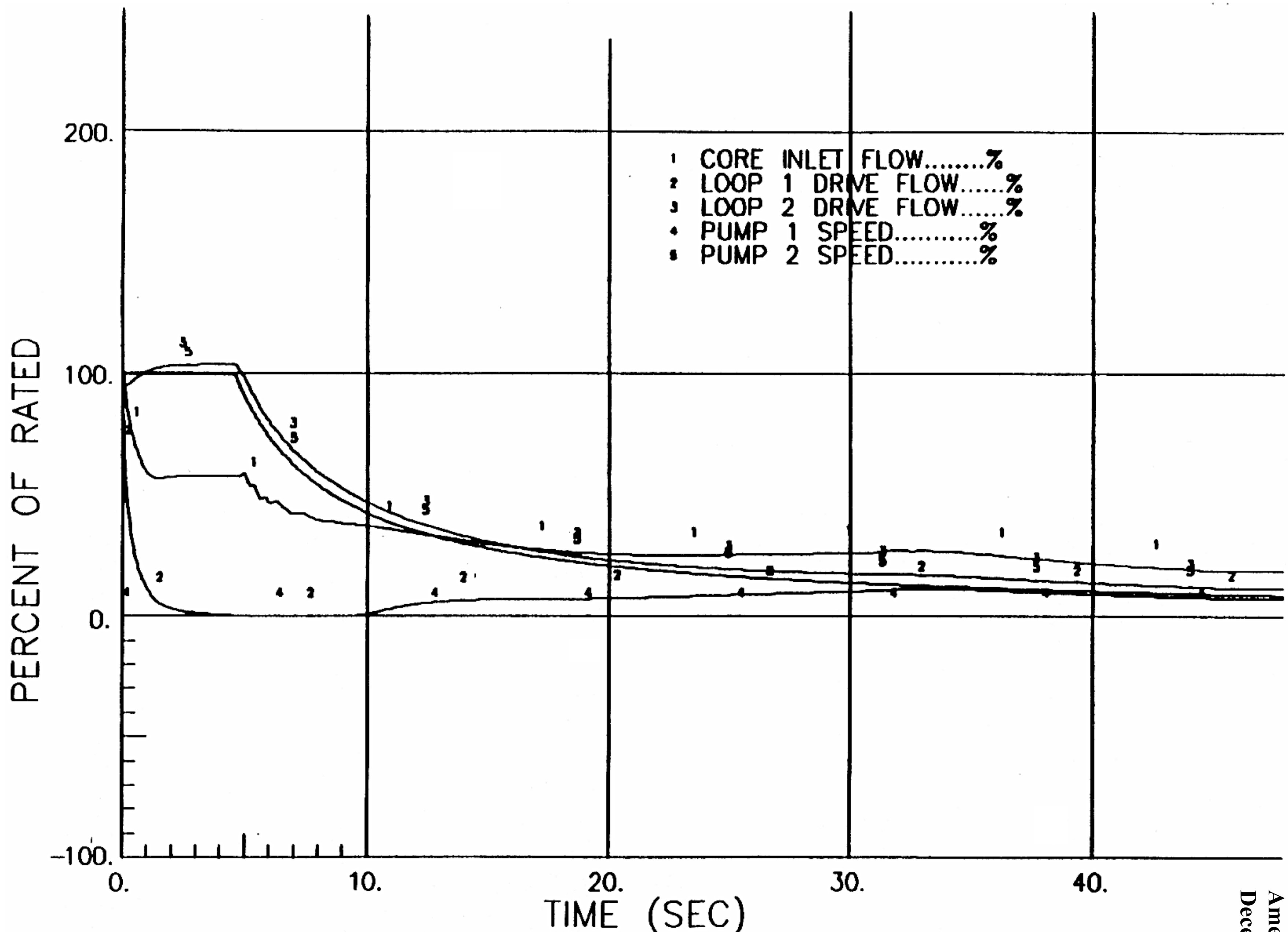
Figure 15.3-5.2



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Recirculation Pump Seizure at 104.5*% Uprated Power, 100% Flow

Draw. No. 02036l.99 | Rev. | Figure 15.3-5.3



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Recirculation Pump Seizure at 104.5*%
Uprated Power, 100% Flow

Draw. No. 020002.01

Rev.

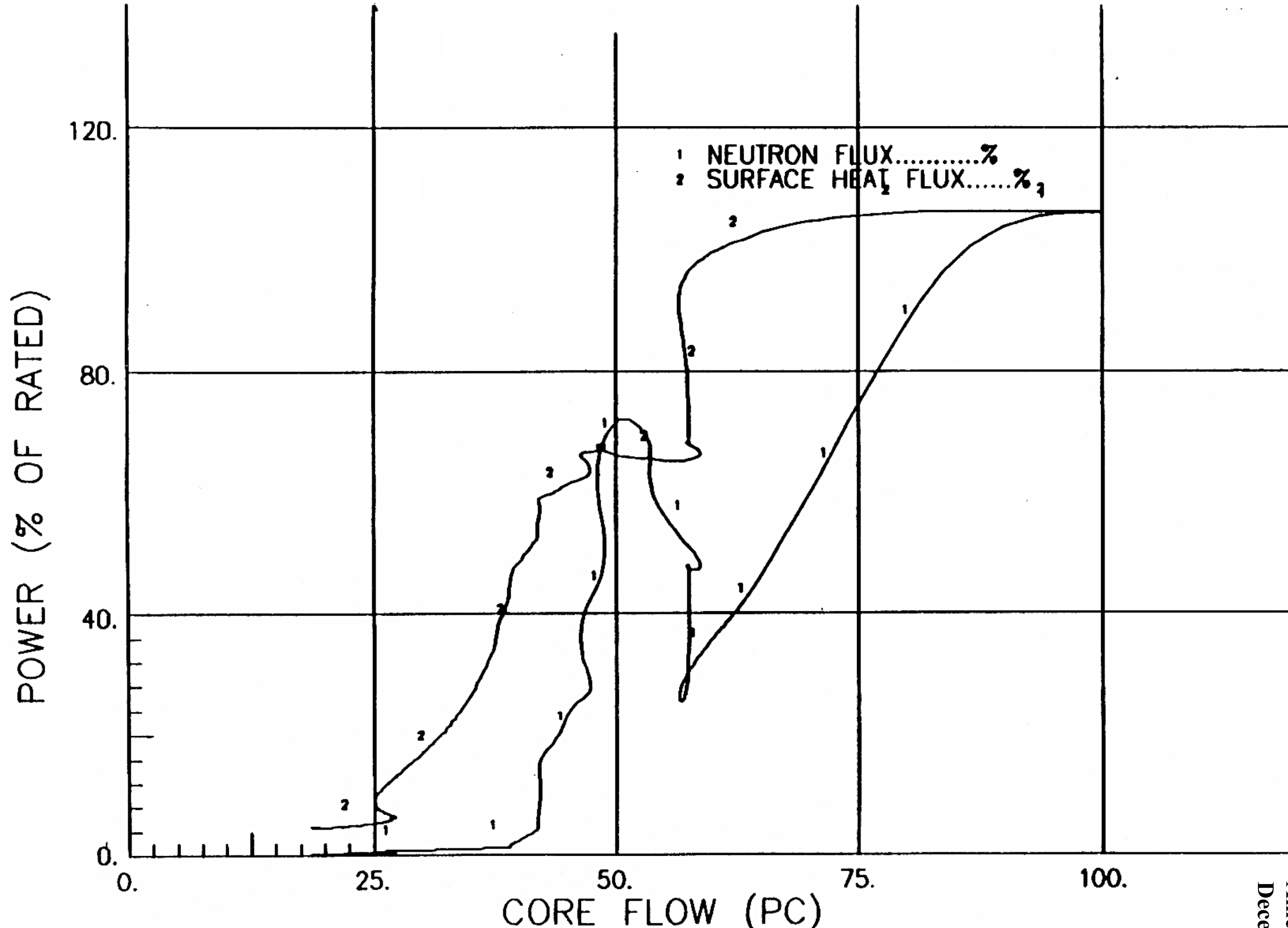
Figure 15.3-5.4

Form No. 960690
LDCN-16-005

Form No. 960690
LDCN-16-005

Columbia Generating Station
Final Safety Analysis Report

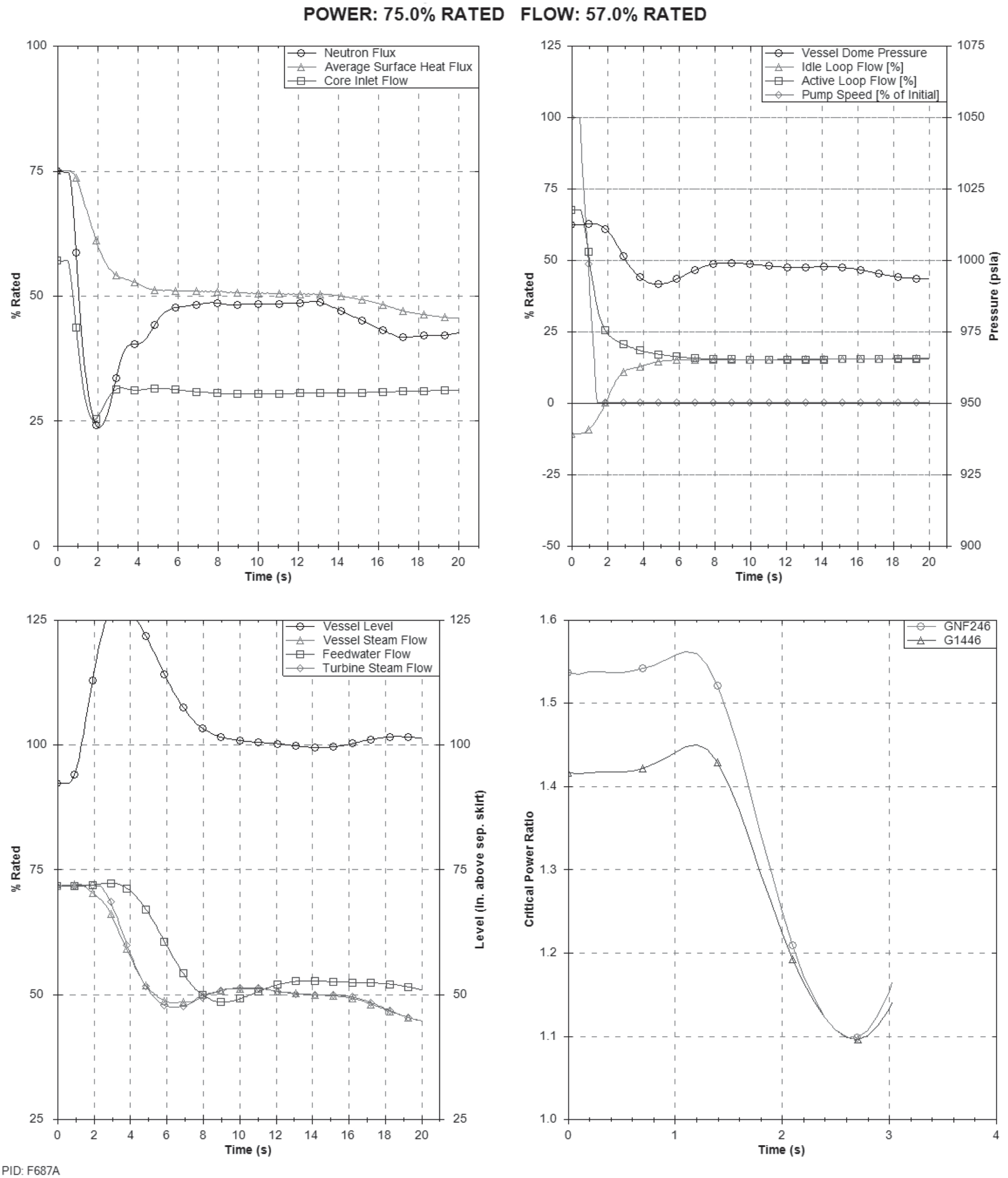
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.



Recirculation Pump Seizure at 104.5*%
Uprated Power, 100% Flow

Draw. No.	Rev.	Figure
020002.02		15.3-5.5

Amendment 64
December 2017



Columbia Generating Station
Final Safety Analysis Report

SLO Recirculation Pump Seizure Results

Draw. No. 910402.37 | Rev. 1 | Figure 15.3-6

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15.4.1 ROD WITHDRAWAL ERROR - LOW POWER

This transient is classified as a nonlimiting event for both original and uprated power conditions. Furthermore, the low power Rod Withdrawal Error (RWE) is not affected by power uprate and therefore, the following qualitative analysis is valid for power uprate.

15.4.1.1 Control Rod Removal Error During Refueling

15.4.1.1.1 Identification of Causes and Frequency Classification

The event considered is inadvertent criticality due to the complete withdrawal or removal of the most reactive rod during refueling. The probability of the initial causes alone is considered low enough to warrant its being categorized as an infrequent incident since there is no postulated set of circumstances which results in an inadvertent control rod withdrawal error (RWE) while in the refuel mode.

15.4.1.1.2 Sequence of Events and Systems Operation

15.4.1.1.2.1 Initial Control Rod Removal. During refueling operations, safety system interlocks provide assurance that inadvertent criticality does not occur because a control rod was removed or is withdrawn in coincidence with another control rod.

15.4.1.1.2.2 Fuel Insertion With Control Rod Removed. To minimize the possibility of loading fuel into a cell containing no control rod, it is required that all control rods are fully inserted when fuel is being loaded into the core. This requirement is backed up by refueling interlocks on rod withdrawal and movement of the refueling platform. When the mode switch is in the "REFUEL" position, the interlocks prevent the platform from being moved over the core if a control rod is withdrawn and fuel is on the hoist. Likewise, if the refueling platform is over the core and fuel is on the hoist, control rod motion is blocked by the interlocks.

15.4.1.1.2.3 Second Control Rod Removal. When the platform is not over the core (or fuel is not on the hoist) and the mode switch is in the "REFUEL" position, only one control rod can be withdrawn. Any attempt to withdraw a second rod results in a rod block by the refueling interlocks.

Since the core is designed to meet shutdown requirements with the highest worth rod withdrawn, the core remains subcritical even with one rod withdrawn.

15.4.1.1.2.4 Control Rod Removal Without Fuel Removal. The design of the control rod, incorporating the velocity limiter, does not physically permit the upward removal of the control rod without the simultaneous or prior removal of the four adjacent fuel bundles. This precludes any hazardous condition.

15.4.1.1.2.5 Effect of Single Failure and Operator Errors. If any one of the operations involved in initial failure or error is followed by any other single equipment failure or single operator error, the necessary safety actions are taken (e.g., rod block or scram) automatically prior to violation of any limits.

15.4.1.1.3 Core and System Performances

Since the probability of inadvertent criticality during refueling is precluded, the core and system performances were not analyzed. The withdrawal of the highest worth control rod during refueling will not result in criticality. This is verified experimentally by performing shutdown margin checks. Additional reactivity insertion is precluded by interlocks. As a result, no radioactive material is released from the fuel, making it unnecessary to assess any radiological consequences.

No mathematic models are involved in this event. The need for input parameters or initial conditions is not required as there are no results to report. Consideration of uncertainties is not appropriate.

15.4.1.1.4 Barrier Performance

An evaluation of the barrier performance was not made for this event since it is a highly localized event and does not result in any change in the core pressure or temperature.

15.4.1.1.5 Radiological Consequences

An evaluation of the radiological consequences was not made for this event since no radioactive material is released from the fuel.

15.4.1.2 Continuous Rod Withdrawal During Reactor Startup

15.4.1.2.1 Identification of Causes and Frequency Classification

This event is categorized as an infrequent incident. The probability of further development of this event is low because it is contingent upon the failure of the rod worth minimizer (RWM) system or failure of a second licensed operator (or technically qualified member of the technical staff) observing the out-of-sequence rod selection concurrent with a high worth rod, out-of-sequence rod selection contrary to procedures, and operator disregard of continuous alarm annunciations prior to safety system actuation.

15.4.1.2.2 Sequence of Events and Systems Operation

15.4.1.2.2.1 Sequence of Events. Control RWEs are not considered credible in the startup and low power ranges. The RWM or second licensed operator (or other technically qualified member of the technical staff) prevents the operator from selecting and withdrawing an out-of-sequence control rod.

Continuous control RWEs during reactor startup are precluded by the RWM or second qualified person. The RWM or second qualified person prevents the withdrawal of an out-of-sequence control rod from 100% control rod density to 10% of rated thermal power.

15.4.1.2.2.2 Effects of Single Failure and Operator Errors. If any one of the operations involved in the initial failure or error is followed by another single component failure or single operator error, the necessary safety actions are automatically taken to preclude violation of any limits.

15.4.1.2.3 Core and System Performance

The performance of the RWM or second licensed operator (or technically qualified member of the technical staff) prevents erroneous selection and withdrawal of an out-of-sequence control rod. Thus, core and system performance is not affected by such a single operator error.

No mathematical models are involved in this event. The need for input parameters or initial conditions is not required as there are no results to report. Consideration of uncertainties is not applicable.

15.4.1.2.4 Barrier Performance

An evaluation of the barrier performance was not performed for this event since there is no postulated set of circumstances for which this error could occur.

15.4.1.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released.

15.4.2 ROD WITHDRAWAL ERROR - AT POWER

15.4.2.1 Identification of Causes and Frequency Classifications

15.4.2.1.1 Identification of Causes

While operating in the power range in a normal mode of operation, the reactor operator makes a procedural error and withdraws the maximum worth control rod until the rod block monitor (RBM) system inhibits further withdrawal.

15.4.2.1.2 Frequency Classification

The probability of this event is considered low enough to warrant its being categorized as an infrequent incident. However, because of the lack of sufficient frequency database, this event is considered an incident of moderate frequency.

15.4.2.2 Sequence of Events and Systems Operation

15.4.2.2.1 Sequence of Events

The sequence of events for this transient is presented in Table 15.4-1.

15.4.2.2.2 Systems Operation

The focal point of this event is localized to a small portion of the core; therefore, although reactor control and instrumentation is assumed to function normally, credit is taken only for the RBM system.

While operating in the power range in a normal operational mode, the reactor operator makes a procedural error and withdraws the maximum worth control rod until the RBM system inhibits further withdrawal.

Under normal operating conditions the nearest local power range monitor (LPRM) would detect the peak linear power exceeding design limits and alarm. The operator would acknowledge the alarm and take appropriate action.

If the RWE is severe, the RBM system would alarm, at which time the operator would acknowledge the alarm and take corrective action. Even for conditions such as highly abnormal control rod patterns, operator disregard of all alarms and warnings, and continuous control rod withdrawal, the RBM system will block further withdrawal of the control rod before the fuel reaches the point of boiling transition or the 1% plastic strain limit imposed on the clad.

15.4.2.2.3 Effect of Single Failure and Operator Errors

Operator errors do not impact the consequences of this event due to the single failure proof design of the RBM system.

15.4.2.3 Core and System Performance

15.4.2.3.1 Mathematical Model

The control RWE transient is classified as a "slow transient." A slow transient is a power increase transient that is sufficiently slow so that the assumption that steady-state conditions are achieved at each time step is either realistic or conservative. Using this assumption, this transient is calculated using a steady state, three dimensional, coupled nuclear thermal hydraulics computer program PANACEA. All spatial effects are included in the calculation. A detailed discussion of the code is presented in Reference 15.4-4.

The control RWE analysis has been performed to estimate the minimum critical power ratio (MCPR) and maximum linear heat generation rate (LHGR) in such a transient. A starting control rod pattern is established for the typical BWR reactor and a central control rod is withdrawn from the fully inserted position. Rod withdrawal results in an increase of the LHGR and decrease of the critical power ratio (CPR). The computed maximum LHGR and minimum CPR are compared to values of other transients to establish operating limits for the reactor. The analysis determines the transient MCPR as a function of the rod block monitor setpoint.

15.4.2.3.2 Input Parameters and Initial Conditions

The number of possible RWE transients is large due to the number of control rods and the wide range of exposures and power levels. In order to encompass all of the possible RWEs which could conceivably occur, a limiting analysis is defined such that a conservative assessment of the consequences is provided. These conditions bound the effects of the RWE at lower power or flow conditions, including operation with only one reactor recirculation pump.

a. The assumed error is a continuous withdrawal of the maximum worth rod at its maximum drive speed;

b. The core is assumed to be operating at rated conditions;

c. The reactor is presumed to be in its most reactive state and devoid of all xenon. This ensures that the amount of reactivity is a maximum;

d. It is assumed that the operator has fully inserted the maximum worth rod prior to its removal and selected the remaining control rod pattern in such a way as to approach thermal limits in the fuel bundles in the vicinity of the rod to be withdrawn (this control rod configuration would only be achieved by deliberate operator action or by numerous operator errors);

e. The operator is assumed to ignore all warnings during the transient;

f. Each RBM channel is analyzed and within each channel, LPRM failures are considered such that the worst case LPRM failures (a minimum of 4 LPRMs are required for the channel to be operable) for the least responsive RBM channel is considered when calculating the ΔCPR for each RBM setpoint. The channel with the greatest response is assumed to be bypassed.

15.4.2.3.2.1 Rod Block Monitor System Operation. The RBM system minimizes the consequences of a RWE by blocking motion of the control rod before the safety limits are exceeded.

When the operator selects a control rod, the RBM signals (associated LPRM input) are calibrated to a fixed (constant) reference signal. The upscale trip levels are set at a fixed level above the reference and will vary as step functions of APRM simulated thermal power. The analytical limits are specified in References 15.4-17 and 15.4-18. This will allow longer withdrawals at low powers where thermal margins are high and allow only short withdrawals at high power. Once tripped, recalibration is allowed only by deselecting the rod, typically accomplished by selecting another rod, and reselecting the rod. Reselection will result in recalibration to the reference signal. The operator verifies adequate thermal margin before continuing rod withdrawal following an RBM upscale trip.

15.4.2.3.3 Results

At certain core exposures and power/flow conditions, this limiting transient may be a control RWE. The fuel thermal-mechanical limit (i.e., 1% plastic strain) criterion is met. Results reflect GE14 fuel introduction, some of which are dependent on fuel design and core loading pattern. Compliance with the event acceptance criteria is demonstrated by cycle-dependent analysis of potentially limiting events just prior to the operation of that cycle. The results are reported in the Supplemental Reload Licensing Report (Reference 15.4-16).

15.4.2.3.4 Considerations of Uncertainties

The conservative assumptions which ensure that this event has been conservatively analyzed have been previously discussed in Section 15.4.2.3.2.

15.4.2.4 Barrier Performance

An evaluation of the barrier performance was not made for this event since this is a localized event with very little change in the gross core characteristics. Typically, an increase in total core power is less than 6% and the changes in pressure are negligible.

15.4.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released from the fuel.

15.4.3 CONTROL ROD MALOPERATION (SYSTEM MALFUNCTION OR OPERATOR ERROR)

This event is covered with the evaluation cited in Sections 15.4.1 and 15.4.2.

15.4.4 STARTUP OF IDLE RECIRCULATION PUMP

15.4.4.1 Identification of Causes and Frequency Classification

This event is not analyzed for reload cores. This event is bounded by the off-rated power and flow dependent limits. The slow flow runout analysis of two recirculation loops and the associated limits bounds this event because the heat flux change associated with two pumps increasing flow to the maximum bounds the heat flux change associated with a single pump startup. For the application of ARTS, the analysis basis is that there is an initial 50°F ΔT between the idle and operating loops. This is an appropriate assumption for the thermal limits calculations and it is consistent with Technical Specification requirements. The analysis basis is not expanded into the MELLLA domain because single loop operation is not expanded beyond the ELLLA domain. (Reference 15.4-17)

The event is not analyzed for power uprate to 3544 MWt (Reference 15.4-18).

15.4.4.1.1 Identification of Causes

This action results directly from the operator's manual action to initiate pump operation. It assumes that the remaining loop is already operating.

15.4.4.1.2 Frequency Classification

15.4.4.1.2.1 Normal Restart of Recirculation Pump at Power. This event is categorized as an incident of moderate frequency.

15.4.4.1.2.2 Abnormal Startup of Idle Recirculation Pump. This event is categorized as an incident of moderate frequency.

15.4.4.2 Sequence of Events and Systems Operation

15.4.4.2.1 Sequence of Events

Table 15.4-2 lists the sequence of events for Figure 15.4-1.

15.4.4.2.2 Systems Operation

This event assumes and takes credit for normal functioning of plant instrumentation and controls. No protection systems action is anticipated. No engineered safety feature (ESF) action occurs as a result of the event.

15.4.4.2.3 The Effect of Single Failures and Operator Errors

Attempts by the operator to start the pump at higher power levels will result in a reactor scram on flux.

15.4.4.3 Core and System Performance

15.4.4.3.1 Mathematical Model

The point-kinetics REDY model described in Section 15.0.3.3.1 is used to simulate this event.

15.4.4.3.2 Input Parameters and Initial Conditions

This analysis has been performed while the plant is operating with a single recirculation loop, at 57% uprated power and 34% core flow. Conservatively, the water in the idle loop is assumed to have a minimum temperature of 100°F. The average enthalpy is based on saturated water temperature at the suction inlet with a linear enthalpy gradient to the discharge outlet water temperature of 100°F.

The active recirculation loop is operating with a pump speed that produces about 45% of normal rated jet pump diffuser flow in the active jet pumps. The inactive recirculation loop jet pumps are forward flowing at about 2% of normal jet pump diffuser flow because of natural circulation affects. The core is receiving about 34% of its normal rated flow.

The idle recirculation pump suction and discharge block valves are open. Normal procedure requires leaving an idle loop in this condition to maintain the loop temperature within the required limits for restart.

15.4.4.3.3 Results

The transient response to the incorrect startup of a cold idle recirculation loop is shown in Figure 15.4-1. Shortly after the pump begins to move, the flow from the started jet pump diffusers causes the core inlet flow to increase. The pump startup demand is conservatively assumed to ramp at a rate of 3.3% until maximum pump speed is achieved. The diffuser flows on the started side of the reactor increase ultimately to about 144% of rated while the flow rate of the opposite loop diffusers decreases and eventually reverses to about -8% of rated. As the inactive loop pump increases speed the cold fluid is pumped out of the recirculation loop piping and is mixed with hot downcomer fluid and the mixture flows to the core with a resulting increase of the core inlet subcooling.

A moderate-duration neutron flux peak to just above 122% of NB rated is produced as the colder, increasing core flow reduces the void volume. Surface heat flux follows the slower response of the fuel and peaks at 108% of rated before decreasing after the cold water is washed out of the loop at about 30 sec. No damage occurs to the fuel barrier as the MCPR remains substantially above the safety limit.

15.4.4.3.4 Consideration of Uncertainties

This particular transient is analyzed for a maximum pump speed demand signal causing the ASD to adjust the recirculation pump speed upward at a nominal speed demand rate limit. A conservative idle loop temperature is assumed and no other uncertainties were included.

15.4.4.4 Barrier Performance

No evaluation of barrier performance is required for this event since no significant pressure increases are incurred during this transient. See Figure 15.4-1.

15.4.4.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.4.5 RECIRCULATION FLOW CONTROL FAILURE WITH INCREASING FLOW

15.4.5.1 Identification of Causes and Frequency Classification

15.4.5.1.1 Identification of Causes

An upscale failure of the master manual setpoint station can cause an increase in the core coolant flow rate. Upscale failure of an individual remote manual setpoint station or manual demand loop can also cause an increase in core coolant flow rate.

15.4.5.1.2 Frequency Classification

This event is an incident of moderate frequency.

15.4.5.2 Sequence of Events and Systems Operation

The increase in recirculation flow results in an increase in core flow. The increase in core flow causes an increase in core power level and shifts the power toward the top of the core by reducing the void fraction in the top of the core.

The rate and magnitude of the power increase are dependent on the rate and magnitude of the flow increase. The operator would be expected to control a slow or small increase through normal operating procedures. However, a rapid or significant increase in neutron flux could exceed the high flux scram setpoint and initiate a scram.

This analysis assumes a relatively gradual flow increase that challenges the thermal limits but does not initiate plant protective systems prior to operator action to terminate the transient. The turbine control (governor) valves and possibly the bypass valves open to control reactor pressure. Core power increases until a steady state power level is reached at the maximum recirculation flow. The operator then regains control of the flow control system and returns the plant to a normal operating condition.

The analysis of this event assumes and takes credit for normal functioning of plant instrumentation and controls, and the reactor protection system (RPS). Operation of ESF is not expected.

15.4.5.2.1 The Effect of Single Failures and Operator Errors

The greatest challenge to the thermal limits is the gradual flow increase without actuation of the RPS. The transient is terminated by operator action but not until the maximum core flow of 108.5% rated flow is reached. No actions, either automatic or manual, occur to mitigate the transient prior to event termination at the maximum core flow.

15.4.5.3 Core and System Performance

15.4.5.3.1 Mathematical Model

The core is assumed to be in a pseudo steady state condition in which all plant thermal hydraulics are in equilibrium. The feedwater inlet temperature is assumed to be at its equilibrium value at all power levels during the event. The flow control line used to define the power/flow points represents the steepest attainable during normal reactor operation. The core radial and axial peaking distributions are assumed not to change during the event. The MCPR hot channel analysis along the flow ascension path is calculated with ISCOR (References 15.4-4 and 15.4-14).

Only potentially MCPR limiting fuel is evaluated. Potentially limiting is defined as within 0.10 of the core MCPR for the nominal rated power rodded depletion (typically only fresh and once burnt fuel). ISCOR is run at the power/flow level corresponding to the plant/cycle specific maximum flow and iterations are performed on the potentially MCPR limiting fuel channel radial peaking factor(s) such that the hot channel MCPR is equal to the MCPR safety limit (SLMCPR) ±0.005. ISCOR is then run along the specified flow control line at a range of core flows from 30% to 100% to obtain the potentially MCPR limiting fuel MCPR value(s) for each case. The results of this analysis determine the flow-dependent MCPR limits to assure that the MCPR will not fall below the SLMCPR for a flow increase event. These analyses bound final feedwater temperature reduction (FFWTR) as well as normal feedwater temperature conditions. The LHGR along the flow ascension path is calculated using PANACEA (References 15.4-4 and 15.4-14) to perform a power search at 10% flow increments from 30% up to the maximum runout flow at various core exposures. Only bundles which could exceed the steady state LHGR limits after the event are considered in the statistical sample. A statistically based overpower or a bounding overpower is used in confirming the LHGR reduction factors. LHGR reduction factors are determined to ensure that 1% plastic strain and fuel centerline melt limits are not exceeded (Reference 15.4-17).

15.4.5.3.2 Input Parameters and Initial Conditions

The gradual increase in recirculation flow provides the greatest challenge to thermal limits. The final point in the transient is a power below the high flux scram setpoint at maximum flow. Maximum flow is the maximum flow that can be attained by a credible controller failure initiated from a given low flow starting point. A spectrum of initial, low flow starting points is analyzed at various points throughout the cycle. The analysis assumes that the event is quasi-steady state and that a flow biased scram does not occur. Table 15.4-3 contains a listing of the important input parameters and initial conditions.

15.4.5.3.3 Results

The reduced flow MCPR was calculated at discrete flow points. The reduced flow MCPR operating limit curve is shown in the cycle specific Core Operating Limits Report (COLR) for all cycle exposures, including FFWTR operation. The reduced flow LHGR was calculated at discrete flow points. The reduced flow LHGR operating limit is shown in the COLR.

15.4.5.3.4 Considerations of Uncertainties

The conservative nature of the analysis approach bounds the uncertainties in void reactivity and power distribution characteristics expected for actual plant conditions.

15.4.5.4 <u>Barrier Performance</u>

The reduced flow MCPR is established so that the event does not challenge the safety limit MCPR. Therefore, no fuel damage is predicted as a result of this event.

15.4.5.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released.

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTIONS

This event is not applicable to boiling water reactor (BWR) plants.

15.4.7 MISPLACED BUNDLE ACCIDENT

The fuel loading error considers the consequences of either of two possible events: misorientation or mislocation of a fuel assembly. Further, the assumption is made that the error is not discovered during core verification. The purpose of the analysis is to determine the change in the minimum CPR and increase in LHGR between the correctly loaded core and the misloaded core. A combination of the misorientation and mislocation is not considered because of the very low probability of occurrence.

15.4.7.1 Identification of Causes and Frequency Classification

15.4.7.1.1 Identification of Causes

The event discussed in this section is the improper loading of a fuel bundle and subsequent operation of the core. For the mislocation of a fuel bundle, three errors must occur during the initial core loading. First, a bundle must be misloaded into a wrong position in the core. Second, the bundle that was supposed to be loaded where the mislocation occurred would have to be placed in an incorrect location. Third, the misplaced bundles would have to be overlooked during the core verification performed following core loading. For the misorientation of a fuel bundle, the bundle is loaded 180° from the correct orientation and this error is overlooked during the core verification.

A fuel loading error would place a fuel assembly in an incorrect location in the core, potentially placing several highly reactive assemblies in close proximity. If a relatively high reactivity assembly is placed in a location not directly monitored by the LPRM/core monitoring system (i.e., unmonitored location), this incorrectly located assembly will operate at higher powers with reduced thermal margins relative to the symmetric monitored assembly. The incorrectly located assembly may violate operating limits if the symmetric, monitored assembly is operated close to limits. If the incorrect location is a directly monitored cell, the change in the local power readings may not be sufficient to either alert the operators of the loading error or to completely account for the reduction in thermal margin. In this situation, the incorrectly located assembly may violate operating limits while being treated by the monitoring system as if it were correctly loaded.

15.4.7.1.2 Frequency of Occurrence

This event is categorized as an infrequent incident but is analyzed for GNF reloads consistent with Section 15.3.3.1 as an incident of moderate frequency.

15.4.7.2 Sequence of Events and Systems Operation

A fuel bundle is misloaded (incorrect location or orientation) into the core and the error is not identified during the core verification process. The core is operated through the cycle at the conditions assumed for the reference core (the specified core load) with the control rod sequence developed for the reference core. At some point during the cycle, the control rod sequence places the limiting assembly (being monitored by the core monitoring system as a correctly loaded assembly) at the MCPR operating limit. Potentially, this causes the misloaded assembly to be operated below the MCPR operating limit curve and above the design LHGR limit curve. Because the operator may be unable to detect the error, the core operation continues throughout the cycle.

Fuel loading errors, undetected by in-core instrumentation following fueling operations, may result in undetected reductions in thermal margins during power operations. No detection is assumed, and therefore, no corrective operator action or automatic protection system functioning occurs.

15.4.7.2.1 Effect of Single Failure and Operator Errors

This analysis already represents the worst case (i.e., operation with a misplaced bundle requires multiple equipment failures or operator errors).

15.4.7.3 Core and System Performance

15.4.7.3.1 Mathematical Model

A three-dimensional BWR simulator model is used to calculate the core performance resulting from this event. This model is described in detail in Reference 15.4-4 and Sections S.2.2.1.8 and S.2.2.1.9 of Reference 15.4-5.

15.4.7.3.2 Input Parameters and Initial Conditions

Initial input parameters and conditions are cycle specific. Sections S.2.2.1.8 and S.2.2.1.9 of Reference 15.4-5 describe the input parameters and initial conditions applied to the mislocated and misoriented bundle events. For both the mislocated and misoriented bundle events, the fuel loading error is undetected throughout the cycle by the core monitoring system.

15.4.7.3.3 Results

The results of the analyses for the fuel loading errors show that the resulting MCPR does not challenge the SLMCPR. No rods are expected to exceed the LHGR limits. Results reflect GE14 fuel introduction, some of which are dependent on fuel design and core loading pattern.

Compliance with the event acceptance criteria is demonstrated by cycle-dependent analysis of potentially limiting events just prior to the operation of that cycle. The results are reported in the Supplemental Reload Licensing Report (Reference 15.4-16).

15.4.7.3.4 Considerations of Uncertainties

A sufficient number of mislocated assembly cases are considered to assure that the limiting case is evaluated. The mislocated assemblies are loaded into positions that could produce limiting results. For the misoriented assembly case, the gap sizes resulting from the rotation are selected to assure a conservative estimate of the impact on MCPR.

15.4.7.4 Barrier Performance

An evaluation of the barrier performance was not made for this event since it is a mild and highly localized event. No perceptible change in the core pressure would be observed.

15.4.7.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this event since no radioactive material is released from the fuel.

15.4.8 SPECTRUM OF ROD EJECTION ASSEMBLIES

This event is not applicable to BWR plants.

15.4.9 CONTROL ROD DROP ACCIDENT

15.4.9.1 Identification of Causes and Frequency Classification

15.4.9.1.1 Identification of Causes

The control rod drop accident (CRDA) is the result of a high worth control rod decoupled from the drive mechanism, dropping out of the core. The subsequent insertion of positive reactivity causes a localized power excursion. This is not an anticipated event because of the system failures and personnel errors that would have to occur in combination to present the reactivity required at the same time that the coupling failed. The control rod patterns are controlled in accordance with the banked position withdraw sequence (BPWS) to preclude situations in which rod drops would have sufficient reactivity to cause the damage postulated by the power excursion.

Detailed discussions of the rod drop analysis and BPWS are given in Reference 15.4-3 and 15.4-7.

15.4.9.1.2 Frequency Classification

The CRDA is categorized as a limiting fault because it is not expected to occur during the lifetime of the plant. However, postulated consequences include the potential for the release of radioactive material.

For reactivity anomalies, the CRDA is the limiting event.

15.4.9.2 Sequence of Events and Systems Operation

The CRDA assumptions include:

1. At some time, a fully inserted control rod becomes decoupled from its drive and sticks in the fully inserted position.

2. During the start up sequence, the rod patterns employed are permitted by the constraints on rod movements by technical specifications and the rod sequence control hardware, including the maximum allowable number of bypassed rods. At some time under critical reactor conditions, the rod pattern causes the decoupled rod to have the maximum worth from fully inserted to the position of its drive. The rod worth minimizer is not functioning. The rod drops at that time.

3. The reactor goes on a positive period, and the fuel temperature reactivity feedback terminates the initial power burst.

4. The reactor scrams on the APRM high flux scram signal.

5. All withdrawn rods, except for the decoupled rod, scram at the technical specification rate.

6. The scram terminates the accident.

7. If the mechanical vacuum pump (MVP) is maintaining condenser vacuum (e.g., the plant was operating at 5% power or less) and the main steam line radiation (MSLR) monitors detected radiation levels above the setpoint, the MSLR monitors would trip the MVP to reduce the fission product release from the condenser.

Although other normal plant instrumentation and controls are assumed to function, no credit for their operation is taken in the analysis of this event. No operator actions are required to terminate this event. Subsequent to reactor scram which terminates the event, normal vessel inventory makeup systems will be used as available.

15.4.9.2.1 Effect of Single Failures and Operator Errors

As discussed, the event is terminated, and therefore mitigated, by the APRM high flux scram signal to RPS. The RPS design meets the single failure criteria. The event is further mitigated by an initial control rod configuration that complies with the BPWS. The withdrawal (or insertion) sequence is implemented by the operator and enforced by the RWM. An operator error in control rod movement will be detected and stopped by the RWM. If the RWM system is not operable, rod movement can only continue with a backup for the operator verifying compliance with the BPWS sequence. Failure of the RWM concurrent with an operator error of moving an out-of-sequence rod, contrary to procedures would be required to result in a potentially more limiting event. Therefore, sufficient redundancy exists such that termination of this transient within the limiting criteria is assured.

At low power levels, the MVP trip maintains the condenser leak rates within the analytical assumptions. The MSLR monitor design meets the single failure criteria and no active failure would prevent the trip signal (Section 11.5.2.1).

15.4.9.3 Core and System Performance

15.4.9.3.1 Mathematical Model

The analytical methods, assumptions and conditions for evaluating the excursion aspects of the CRDA are described in detail in References 15.4-1, 15.4-3, 15.4-13. To limit the worth of the postulated dropped rod, the rod pattern control systems are programmed to follow the BPWS, which is generically defined in Reference 15.4-7.

15.4.9.3.2 Input Parameters and Initial Conditions

The data presented in Reference 15.4-7 shows that BPWS reduces the control rod worths to the degree that the detailed analyses presented in References 15.4-1, 15.4-3, 15.4-13 or the bounding analyses presented in Reference 15.4-11 do not need to be performed each cycle.

15.4.9.3.3 Results

Control rod drop accident results from BPWS plants have been statistically analyzed and documented in Reference 15.4-12. The results show that, in all cases, the peak fuel enthalpy in a CRDA would be much less than the 280 cal/gm design limit even with a maximum incremental rod worth corresponding to 95% probability at the 95% confidence level. Based on these results, it was proposed to the NRC, and subsequently found acceptable, to delete the CRDA from the standard GE BWR reload package for the BPWS plants.

The US Supplement to Reference 15.4-5 reports the results of radiological analyses for initial cores that are orders of magnitude below those identified in 10 CFR 100. The radiological consequences of the CRDA, assuming a full core of more recent GE/GNF fuel designs, are discussed in Reference 15.4-5. With implementation of Alternative Source Term (AST), the radiological release acceptance criterion becomes 10 CFR 50.67. An evaluation of fuel damage was performed because the maximum deposited fuel rod enthalpy exceeded 170 cal/gm, which is the enthalpy limit assumed for eventual cladding perforation. The number of fuel rods predicted to fail (Reference 15.4-15) are bounded by the number assumed in the radiological consequences analysis for this event.

The total energy deposited and the associated increase in reactor system pressure during a rod drop event is not high relative to other events such as turbine trip without bypass or main steam line isolation valve closure, both of which are quantitatively analyzed. As such, the increase in reactor system pressure is not anticipated to result in penetration of the stress limits defined in Section III of the ASME boiler and pressure code.

15.4.9.4 Barrier Performance

An evaluation of the barrier performance was not made for this accident since this is a localized event with no significant change in the gross core temperature or pressure.

15.4.9.5 Radiological Consequences

The radiological analysis is based on the AST described in Reference 15.4-8. Specific models, assumptions, and the program used for computer evaluation are described in Reference 15.4-6. Specific parametric values used in the evaluation are presented in Table 15.4-4. The radiological consequences remain bounding because cycle specific analyses have confirmed that the number of fuel rods with an enthalpy greater than the threshold for fuel failure are well below the number assumed in the analysis.

15.4.9.5.1 Fission Product Release from Fuel

The failure of 1.8% of the core was assumed for this analysis. The mass fraction of the fuel in the damaged rods which reaches or exceeds the initiation temperature of fuel melting (taken as 2804°C) is assumed to be 0.0077.

Fuel reaching melt condition is assumed to release 100% of the noble gas inventory and 50% of the iodine inventory. The remaining fuel rods with clad damage only (no melting), will undergo a gap release which is assumed to release 10% of noble gases and 10% of iodine inventories.

The core inventory of fission products is based on a plant-specific ORIGEN 2 run for pre-power uprate basis of 3489 MW with 1000 days of exposure, adjusted as follows:

- A scale factor of 1.0528 to bound the dose impact of power level to 3556 MWt,
- A correction to increase by 25 percent short-lived krypton values (based on comparisons to other core inventory tables), and
- An increase by 60% in the activity of longer lived isotopes to bound longer plant operation at a higher burnup rate.

The assumed core power of 3556 MWt is the rated power plus power measurement uncertainties. These adjustments resulted in a conservative source term (in terms of activity available). A peaking factor of 1.7 is assumed and no delay time is considered between departure from that power condition and the initiation of the accident.

15.4.9.5.2 Fission Product Transport to the Environment

The transport pathway consists of a release from the core to the coolant, carryover with steam to the turbine condenser and leakage from the condenser to the environment. The release fractions are given in Reference 15.4-6 and are consistent with Reference 15.4-8. No credit is taken for mixing in the turbine building or filtration by the CREF.

Of the activity reaching the condenser, 100% of the noble gases, and 10% of the iodine (due to partitioning and plate-out) and 1% of the particulates remain airborne and are available for release to the environment. The activity airborne in the condenser leaks to the environment as a ground level release at a rate of 1% of condenser volume per day. Release from the condenser is assumed to terminate 24 hours following the onset of the accident. Radioactive decay is accounted for during residence in the condenser; however, it is neglected after release to the environment. If the condenser is not isolated from the offgas system, the activity is processed through the offgas system. In this case, radioactive decay is accounted for during the residence in the offgas system. Response of the offgas system to elevated radiation levels is described in Section 11.3.2.4.5.

The activity airborne in the condenser is presented in Table 15.4-5. The cumulative release of activity to the environment is presented in Table 15.4-6.

15.4.9.5.3 Results

The calculated exposures from the design basis analysis are presented in Table 15.4-7 and are within the limits of 10 CFR 50.67.

15.4.10 REFERENCES

15.4-1 Stirn, R. C., "Rod Drop Accident Analysis for Large Boiling Water Reactors," NEDO-10527, March 1972.

15.4-2 GE Nuclear Energy, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, September 1993 (Proprietary).

15.4-3 Stirn, R. C., "Rod Drop Accident Analysis for Large BWRs," Supplement 1, NEDO-10527, July 1972.

15.4-4 "Steady -State Nuclear Methods," NEDE-30130-P-A, April 1985.

15.4-5 "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A and "Supplement for United States," NEDE-24011-P-A-US (most recent approved version referenced in COLR).

15.4-6 Energy Northwest, "Columbia Generating Station Alternative Source Term," CGS-FTS-0168, Revision 2, June 2011.

15.4-7 Paone, C. J., "Bank Position Withdrawal Sequence," NEDO-21231.

15.4-8 NRC Regulatory Guide 1.183, "Alternative Source Term for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.

15.4-9 Deleted.

15.4-10 General Electric, "Safety Evaluation for Eliminating the Boiling Water Reactor Main Steam Isolation Valve Closure Function and Scram Function of the Main Steam Line Radiation Monitor," NEDO-31400A, Class I, October 1992.

15.4-11 "GE BWR Generic Reload Application for 8x8 Fuel," Supplement 3 to Revision 1, NEDO-20360.

15.4-12 Letter from R. E. Engel (GE) to D. M. Vassallo (NRC), "Elimination of Control Rod Drop Accident Analysis for Banked Position Withdrawal Sequence Plants," February 24, 1982.

15.4-13 Stirn, R. C., "Rod Drop Accident Analysis for Large Boiling Water Reactors Addendum No. 2 Exposed Cores," Supplement 2, NEDO-10527, January 1973.

15.4-14 Letter from D. G. Eisenhut (NRC) to R. L. Gridley (GE), "Safety Evaluation for the General Electric Topical Report, Generic Reload Fuel Application (NEDE-24011-P)," May 12, 1978, MFN-212-78.

15.4-15 "GE14 Compliance with Amendment 22 of NEDE-24011-P-A (GESTAR II)," NEDC-32868P, Revision 4, January 2012.

15.4-16 Supplemental Reload Licensing Report for Columbia (most recent version referenced in COLR).

15.4-17 "Energy Northwest Columbia Generating Station APRM/RBM/Technical Sepcifications/Maximum Extended Load Line Limit Analysis (ARTS/MELLLA)," NEDC-33507P, Revision 0, April 2010.

15.4-18 GE-Hitachi Nuclear Energy, "Safety Analysis Report for Columbia Generating Station Thermal Power Optimization," NEDC-33853P, March 2016.

Table 15.4-1

Sequence of Events - Rod Withdrawal Error in Power Range

Time[a]	Event
(1)	Event begins; operator selects the maximum worth control rod, acknowledges any alarms and withdraws the rod at the maximum rod speed.
(2)	Core average power and local power increase causing LPRM alarm.
(3)	Event ends – rod block by RBM

[a] The RWE event is analyzed with a three-dimensional core simulator. This is a conservative steady state analysis for the determination of the appropriate power distribution limits during the event. Since it is not a dynamic simulation, no timed sequence of events is available.

Table 15.4-2

Sequence of Events for an Abnormal Startup
of an Idle Recirculation Loop

Time (sec)	Event
0.00	Plant operating with one recirculation loop only.
5.00	Start idle recirculation loop pump motor.
29.6	Peak value of core inlet subcooling.
29.6	Peak thermal power. Estimated APRM thermal power approximately 1% below APRM thermal power setpoint.
45.7	Pump motor at full speed.
80+	Reactor reaches new equilibrium condition.

Table 15.4-3

Reactor Recirculation Pump Flow Increase
Input Parameters and Initial Conditions

Parameter	Value
Reactor Power/Core Flow	Flow increase is initiated from several power/flow points and terminates at 109% rated power, 108.5%rated flow
Power Distribution	The MCPR equals the safety limit at the final power/flow condition
Reactivity	The results are applicable from Beginning of Cycle to End of Cycle for nominal and reduced feedwater temperatures
Control Rod Configuration	The control rod pattern is the same at the initial and final points.

Table 15.4-4

Control Rod Drop Accident Evaluation Parameters

I.	Data and assumptions used to estimate radioactive source from postulated accidents.		
	A.	Power level	Section 15.4.9.5.1
	B.	Burnup	Section 15.4.9.5.1
	C.	Fuel damaged	1.8% of core
	D.	Release of activity by nuclide	Table 15.4-6
	E.	Iodine fractions	
		(1) Organic	0.0015
		(2) Elemental	0.0485
		(3) Particulate	0.95
	F.	Reactor coolant activity before the accident.	N/A
II.	Data and assumptions used to estimate activity released.		
	A.	Condenser leak rate (%/day)	1.0
	B.	Turbine building leak rate (%/day)	N/A
	C.	Valve closure time (sec)	N/A
	D.	Adsorption and filtration efficiencies	
		(1) Organic iodine	N/A
		(2) Elemental iodine	N/A
		(3) Particulate iodine	N/A
		(4) Particulate fission products	N/A
	E.	Recirculation system parameters	
		(1) Flow rate	N/A
		(2) Mixing efficiency	N/A
		(3) Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)	N/A

Table 15.4-4

Control Rod Drop Accident Evaluation Parameters (Continued)

	G.	Containment volumes	N/A
	H.	All other pertinent data and assumptions	None
III.	Dispersion data		Table 15.0-4
IV.	Dose data		
	A.	Method of dose calculation	Reference 15.4-6
	B.	Dose conversion assumptions	Reference 15.4-6
	C.	Peak activity concentrations in condenser	Table 15.4-5
	D.	Doses	Table 15.4-7

Table 15.4-5

Control Rod Drop Accident
Activity Airborne in the Condenser (Curies)

3556 MWth

	1 m	30 m	2 hrs	8 hrs	12 hrs	24 hrs
Kr83m	4.12E+04	3.43E+04	1.96E+04	2.06E+03	4.61E+02	5.13E+00
Kr85m	8.50E+04	7.88E+04	6.21E+04	2.40E+04	1.27E+04	1.90E+03
Kr85	4.77E+03	4.77E+03	4.76E+03	4.75E+03	4.74E+03	4.72E+03
Kr87	1.54E+05	1.18E+05	5.20E+04	1.95E+03	2.18E+02	3.05E-01
Kr88	2.19E+05	1.95E+05	1.34E+05	3.03E+04	1.12E+04	5.72E+02
Kr89	2.05E+05	3.71E+02	1.14E-06	6.96E-18	1.01E-16	7.70E-18
Xe131m	3.24E+03	3.23E+03	3.22E+03	3.16E+03	3.13E+03	3.02E+03
Xe133m	1.93E+04	1.91E+04	1.88E+04	1.74E+04	1.65E+04	1.41E+04
Xe133	6.30E+05	6.28E+05	6.23E+05	6.01E+05	5.87E+05	5.47E+05
Xe135m	1.23E+05	3.40E+04	6.24E+02	7.12E-05	1.68E-09	2.52E-16
Xe135	1.52E+05	1.46E+05	1.31E+05	8.30E+04	6.13E+04	2.47E+04
Xe137	4.52E+05	2.62E+03	2.99E-04	4.13E-18	3.26E-17	2.41E-17
Xe138	4.00E+05	1.22E+05	3.11E+03	1.30E-03	7.24E-08	2.47E-18
Total noble gases	2.49E+06	1.39E+06	1.05E+06	7.68E+05	6.97E+05	5.96E+05
I-131*	3.06E+05	2.64E+05	1.83E+05	8.50E+04	6.15E+04	2.47E+04
I-132	6.71E+05	1.98E+05	1.34E+05	3.03E+04	1.12E+04	5.72E+02
I-133	6.05E+05	1.22E+05	3.11E+03	1.30E-03	7.24E-08	1.02E-17
I-134	3.24E+03	3.23E+03	3.22E+03	3.16E+03	3.13E+03	3.02E+03
I-135	2.51E+06	1.41E+06	1.07E+06	7.85E+05	7.14E+05	6.10E+05
Total Iodine	4.09E+06	1.99E+06	1.39E+06	9.03E+05	7.90E+05	6.38E+05

* The isotopic iodine activity is the sum of the elemental and organic iodines with 97% elemental and 3% organic.
The particulate iodine comprise 0%.

Table 15.4-5

Control Rod Drop Accident
Activity Airborne in the Condenser (Curies) (Continued)

3556 MWth

	1 m	30 m	2 hrs	8 hrs	12 hrs	24 hrs
Rb86	5.87E-02	5.86E-02	5.84E-02	5.77E-02	5.73E-02	5.60E-02
Cs134	8.23E+00	8.23E+00	8.22E+00	8.20E+00	8.18E+00	8.14E+00
Cs136	1.82E+00	1.82E+00	1.81E+00	1.79E+00	1.77E+00	1.71E+00
Cs137	6.63E+00	6.63E+00	6.62E+00	6.61E+00	6.59E+00	6.56E+00
Sb127	1.38E-02	1.38E-02	1.36E-02	1.30E-02	1.26E-02	1.14E-02
Sb129	3.95E-02	3.66E-02	2.88E-02	1.10E-02	5.84E-03	8.61E-04
Te127m	1.95E-03	1.95E-03	1.94E-03	1.94E-03	1.93E-03	1.91E-03
Te127	1.38E-02	1.38E-02	1.38E-02	1.36E-02	1.34E-02	1.25E-02
Te129m	5.81E-03	5.80E-03	5.79E-03	5.75E-03	5.72E-03	5.63E-03
Te129	3.72E-02	3.74E-02	3.43E-02	1.52E-02	8.10E-03	1.20E-03
Te131m	1.75E-02	1.73E-02	1.67E-02	1.45E-02	1.32E-02	9.97E-03
Te132	1.67E-01	1.66E-01	1.64E-01	1.55E-01	1.49E-01	1.33E-01
Ba137m	1.54E+00	6.62E+00	6.62E+00	6.61E+00	6.59E+00	6.56E+00
Ba139	7.82E-02	6.14E-02	2.90E-02	1.43E-03	1.94E-04	4.75E-07
Ba140	7.65E-02	7.64E-02	7.61E-02	7.49E-02	7.41E-02	7.17E-02
Mo99	1.02E-02	1.02E-02	1.00E-02	9.39E-03	8.99E-03	7.90E-03
Tc99m	9.06E-03	9.12E-03	9.27E-03	9.45E-03	9.33E-03	8.55E-03
Ru103	9.81E-03	9.81E-03	9.79E-03	9.72E-03	9.68E-03	9.55E-03
Ru105	7.21E-03	6.69E-03	5.33E-03	2.14E-03	1.16E-03	1.87E-04
Ru106	4.26E-03	4.26E-03	4.26E-03	4.24E-03	4.23E-03	4.21E-03
Rh105	6.83E-03	6.83E-03	6.80E-03	6.42E-03	6.04E-03	4.87E-03
Y90	3.50E-05	6.38E-05	1.52E-04	4.90E-04	7.02E-04	1.28E-03
Y91	4.56E-04	4.66E-04	4.95E-04	5.82E-04	6.22E-04	6.87E-04
Y92	6.39E-04	4.76E-03	1.26E-02	1.28E-02	7.81E-03	1.10E-03
Y93	5.94E-04	5.74E-04	5.18E-04	3.42E-04	2.59E-04	1.13E-04
Zr95	7.13E-04	7.13E-04	7.12E-04	7.08E-04	7.06E-04	6.98E-04
Zr97	7.23E-04	7.09E-04	6.66E-04	5.21E-04	4.42E-04	2.70E-04

Table 15.4-5

Control Rod Drop Accident
Activity Airborne in the Condenser (Curies) (Continued)

3556 MWth

	1 m	30 m	2 hrs	8 hrs	12 hrs	24 hrs
Nb95	7.13E-04	7.13E-04	7.13E-04	7.11E-04	7.10E-04	7.06E-04
La140	8.08E-04	1.43E-03	3.33E-03	1.04E-02	1.46E-02	2.54E-02
La141	7.26E-04	6.66E-04	5.10E-04	1.75E-04	8.58E-05	1.01E-05
La142	6.91E-04	5.55E-04	2.81E-04	1.84E-05	3.00E-06	1.29E-08
Pr143	6.31E-04	6.32E-04	6.35E-04	6.44E-04	6.49E-04	6.58E-04
Nd147	2.86E-04	2.85E-04	2.84E-04	2.79E-04	2.76E-04	2.66E-04
Am241	1.28E-07	1.28E-07	1.28E-07	1.28E-07	1.27E-07	1.27E-07
Cm242	2.91E-05	2.91E-05	2.90E-05	2.89E-05	2.89E-05	2.87E-05
Cm244	2.36E-06	2.35E-06	2.35E-06	2.35E-06	2.34E-06	2.33E-06
Ce141	1.85E-03	1.85E-03	1.85E-03	1.83E-03	1.82E-03	1.80E-03
Ce143	1.67E-03	1.66E-03	1.60E-03	1.40E-03	1.28E-03	9.85E-04
Ce144	1.36E-03	1.36E-03	1.36E-03	1.35E-03	1.35E-03	1.34E-03
Np239	2.93E-02	2.91E-02	2.85E-02	2.64E-02	2.51E-02	2.15E-02
Pu238	3.99E-06	3.99E-06	3.99E-06	3.98E-06	3.97E-06	3.95E-06
Pu239	7.89E-07	7.89E-07	7.89E-07	7.87E-07	7.85E-07	7.82E-07
Pu240	1.30E-06	1.30E-06	1.30E-06	1.29E-06	1.29E-06	1.29E-06
Pu241	3.70E-04	3.70E-04	3.69E-04	3.68E-04	3.68E-04	3.66E-04
Sr89	3.37E-02	3.37E-02	3.37E-02	3.35E-02	3.33E-02	3.29E-02
Sr90	5.58E-03	5.58E-03	5.57E-03	5.56E-03	5.55E-03	5.52E-03
Sr91	4.32E-02	4.17E-02	3.74E-02	2.42E-02	1.81E-02	7.54E-03
Sr92	5.01E-02	4.41E-02	2.97E-02	6.14E-03	2.15E-03	9.15E-05

Table 15.4-6

Control Rod Drop Accident
Activity Airborne to the Environment (Curies)

3556 MWth

	1 m	0.5 hr	2 hrs	8 hrs	12 hrs	24 hrs
Kr83m	2.78E-01	7.86E+00	2.43E+01	4.38E+01	4.56E+01	4.61E+01
Kr85m	5.74E-01	1.71E+01	6.09E+01	1.61E+02	1.91E+02	2.19E+02
Kr85	3.21E-02	9.92E-01	3.97E+00	1.59E+01	2.38E+01	4.75E+01
Kr87	1.04E+00	2.83E+01	7.87E+01	1.17E+02	1.18E+02	1.18E+02
Kr88	1.48E+00	4.31E+01	1.45E+02	3.20E+02	3.52E+02	3.69E+02
Kr89	1.54E+00	8.07E+00	8.08E+00	8.08E+00	8.08E+00	8.08E+00
Xe131m	2.18E-02	6.73E-01	2.69E+00	1.07E+01	1.59E+01	3.13E+01
Xe133m	1.30E-01	4.00E+00	1.58E+01	6.10E+01	8.92E+01	1.66E+02
Xe133	4.24E+00	1.31E+02	5.22E+02	2.05E+03	3.04E+03	5.88E+03
Xe135m	8.48E-01	1.48E+01	2.00E+01	2.01E+01	2.01E+01	2.01E+01
Xe135	1.02E+00	3.10E+01	1.18E+02	3.80E+02	5.00E+02	7.01E+02
Xe137	3.32E+00	2.09E+01	2.10E+01	2.10E+01	2.10E+01	2.10E+01
Xe138	2.75E+00	5.00E+01	7.03E+01	7.08E+01	7.08E+01	7.08E+01
Total Noble Gases	1.73E+01	3.58E+02	1.09E+03	3.28E+03	4.50E+03	7.70E+03
I-131*	4.08E-01	1.19E+01	4.01E+01	1.05E+02	1.35E+02	2.12E+02
I-132	4.81E+00	1.48E+02	5.83E+02	2.21E+03	3.23E+03	6.10E+03
I-133	8.80E-01	1.58E+01	2.40E+01	3.60E+01	4.39E+01	6.76E+01
I-134	2.06E+00	5.93E+01	1.97E+02	4.97E+02	6.18E+02	8.19E+02
I-135	4.80E+00	6.40E+01	1.66E+02	3.41E+02	3.73E+02	3.90E+02
Total Iodine	1.30E+01	2.99E+02	1.01E+03	3.19E+03	4.40E+03	7.59E+03

* The isotopic iodine activity is the sum of the elemental and organic iodines with 97% elemental and 3% organic.
The particulate iodine comprise 0%.

Table 15.4-6

Control Rod Drop Accident
Activity Airborne to the Environment (Curies) (Continued)

3556 MWth

	1 m	0.5 hr	2 hrs	8 hrs	12 hrs	24 hrs
Rb86	3.95E-07	1.22E-05	4.88E-05	1.94E-04	2.90E-04	5.73E-04
Cs134	5.54E-05	1.71E-03	6.86E-03	2.74E-02	4.11E-02	8.19E-02
Cs136	1.23E-05	3.79E-04	1.52E-03	6.02E-03	8.99E-03	1.77E-02
Cs137	4.47E-05	1.38E-03	5.52E-03	2.21E-02	3.31E-02	6.60E-02
Sb127	9.31E-08	2.87E-06	1.14E-05	4.47E-05	6.60E-05	1.26E-04
Sb129	2.66E-07	7.92E-06	2.83E-05	7.46E-05	8.82E-05	1.01E-04
Te127m	1.31E-08	4.05E-07	1.62E-06	6.48E-06	9.70E-06	1.93E-05
Te127	9.31E-08	2.88E-06	1.15E-05	4.58E-05	6.83E-05	1.33E-04
Te129m	3.91E-08	1.21E-06	4.83E-06	1.93E-05	2.88E-05	5.72E-05
Te129	2.50E-07	7.77E-06	3.04E-05	9.08E-05	1.10E-04	1.28E-04
Te131m	1.18E-07	3.63E-06	1.43E-05	5.33E-05	7.65E-05	1.34E-04
Te132	1.12E-06	3.46E-05	1.38E-04	5.35E-04	7.88E-04	1.49E-03
Ba137m	5.43E-06	1.21E-03	5.35E-03	2.19E-02	3.29E-02	6.58E-02
Ba139	5.29E-07	1.45E-05	4.15E-05	6.44E-05	6.55E-05	6.56E-05
Ba140	5.15E-07	1.59E-05	6.36E-05	2.53E-04	3.77E-04	7.41E-04
Mo99	6.89E-08	2.12E-06	8.44E-06	3.27E-05	4.80E-05	9.02E-05
Tc99m	6.11E-08	1.89E-06	7.65E-06	3.12E-05	4.69E-05	9.18E-05
Ru103	6.61E-08	2.04E-06	8.17E-06	3.26E-05	4.88E-05	9.69E-05
Ru105	4.86E-08	1.45E-06	5.19E-06	1.39E-05	1.66E-05	1.93E-05
Ru106	2.87E-08	8.87E-07	3.55E-06	1.42E-05	2.13E-05	4.24E-05
Rh105	4.60E-08	1.42E-06	5.68E-06	2.23E-05	3.27E-05	6.00E-05
Y90	2.33E-10	1.02E-08	7.78E-08	8.86E-07	1.88E-06	6.88E-06
Y91	3.07E-09	9.60E-08	3.97E-07	1.75E-06	2.76E-06	6.06E-06
Y92	3.78E-09	5.63E-07	6.33E-06	4.33E-05	6.04E-05	7.81E-05
Y93	4.00E-09	1.22E-07	4.63E-07	1.52E-06	2.02E-06	2.90E-06

Table 15.4-6

Control Rod Drop Accident
Activity Airborne to the Environment (Curies) (Continued)

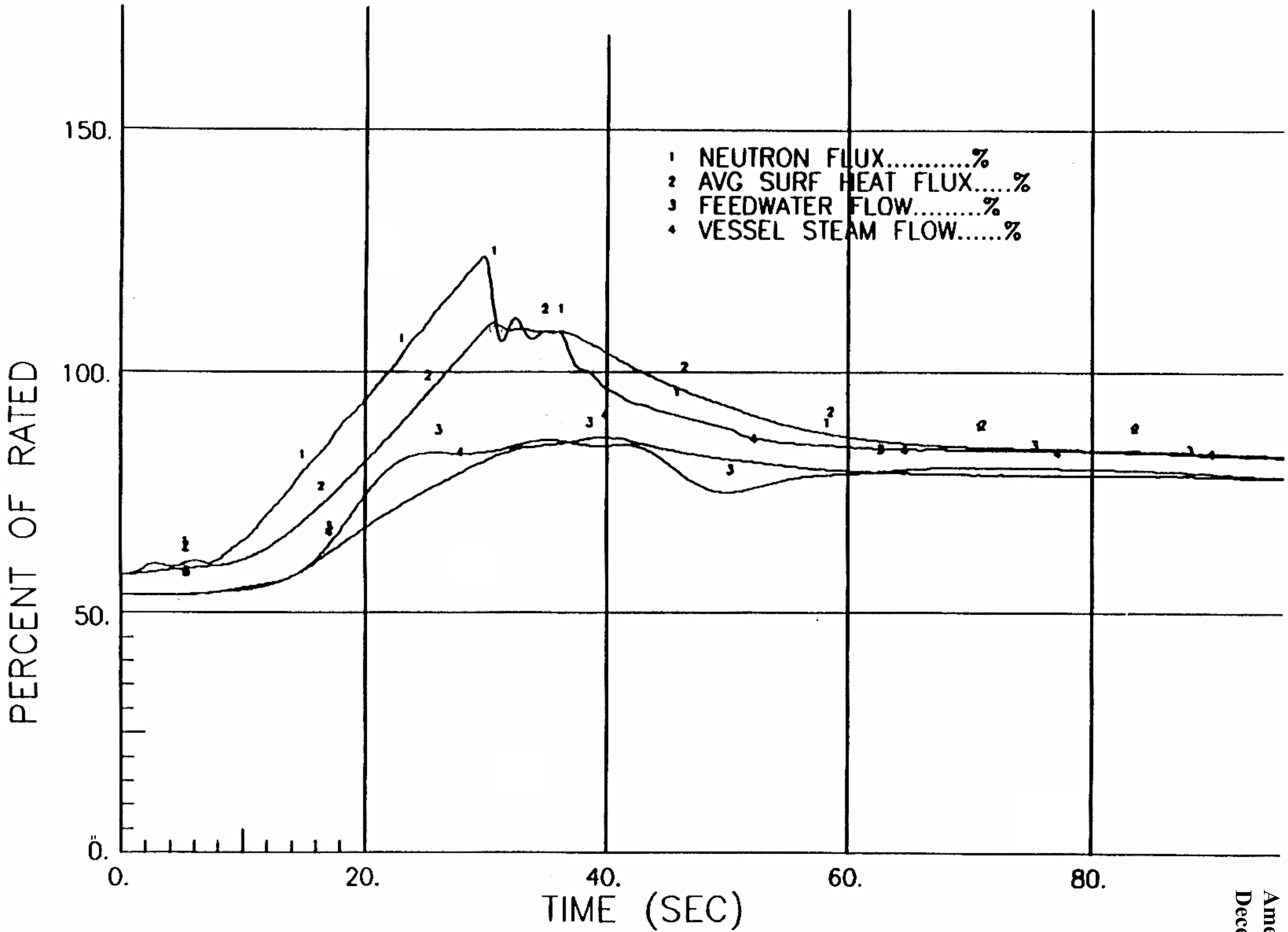
3556 MWth

	1 m	0.5 hr	2 hrs	8 hrs	12 hrs	24 hrs
Zr95	4.81E-09	1.48E-07	5.94E-07	2.37E-06	3.55E-06	7.06E-06
Zr97	4.87E-09	1.49E-07	5.79E-07	2.06E-06	2.86E-06	4.60E-06
Nb95	4.81E-09	1.48E-07	5.94E-07	2.38E-06	3.56E-06	7.10E-06
La140	5.37E-09	2.31E-07	1.72E-06	1.91E-05	4.00E-05	1.41E-04
La141	4.90E-09	1.45E-07	5.11E-07	1.29E-06	1.50E-06	1.68E-06
La142	4.67E-09	1.30E-07	3.81E-07	6.23E-07	6.37E-07	6.40E-07
Pr143	4.25E-09	1.32E-07	5.28E-07	2.13E-06	3.21E-06	6.48E-06
Nd147	1.92E-09	5.94E-08	2.37E-07	9.42E-07	1.40E-06	2.76E-06
Am241	8.63E-13	2.67E-11	1.07E-10	4.27E-10	6.39E-10	1.28E-09
Cm242	1.96E-10	6.05E-09	2.42E-08	9.67E-08	1.45E-07	2.89E-07
Cm244	1.59E-11	4.90E-10	1.96E-09	7.84E-09	1.18E-08	2.34E-08
Ce141	1.25E-08	3.85E-07	1.54E-06	6.15E-06	9.20E-06	1.83E-05
Ce143	1.13E-08	3.47E-07	1.37E-06	5.12E-06	7.36E-06	1.30E-05
Ce144	9.15E-09	2.83E-07	1.13E-06	4.52E-06	6.77E-06	1.35E-05
Np239	1.97E-07	6.07E-06	2.41E-05	9.28E-05	1.36E-04	2.52E-04
Pu238	2.69E-11	8.31E-10	3.33E-09	1.33E-08	1.99E-08	3.98E-08
Pu239	5.32E-12	1.64E-10	6.58E-10	2.63E-09	3.94E-09	7.86E-09
Pu240	8.75E-12	2.70E-10	1.08E-09	4.33E-09	6.48E-09	1.29E-08
Pu241	2.49E-09	7.69E-08	3.08E-07	1.23E-06	1.85E-06	3.68E-06
Sr89	2.27E-07	7.02E-06	2.81E-05	1.12E-04	1.68E-04	3.34E-04
Sr90	3.76E-08	1.16E-06	4.65E-06	1.86E-05	2.78E-05	5.55E-05
Sr91	2.91E-07	8.84E-06	3.36E-05	1.09E-04	1.44E-04	2.05E-04
Sr92	3.38E-07	9.81E-06	3.26E-05	7.00E-05	7.63E-05	7.96E-05

Table 15.4-7

Control Rod Drop Accident
Radiological Effects (rem)

Area	Time	TEDE Dose
Exclusion area (1950 m)	2 hr	0.03
Low population zone (4827 m)	30 days	0.03
Control Room	30 days	0.7



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Abnormal Startup of an Idle Recirculation Loop at *56.95% Uprated Power, 34.1% Flow

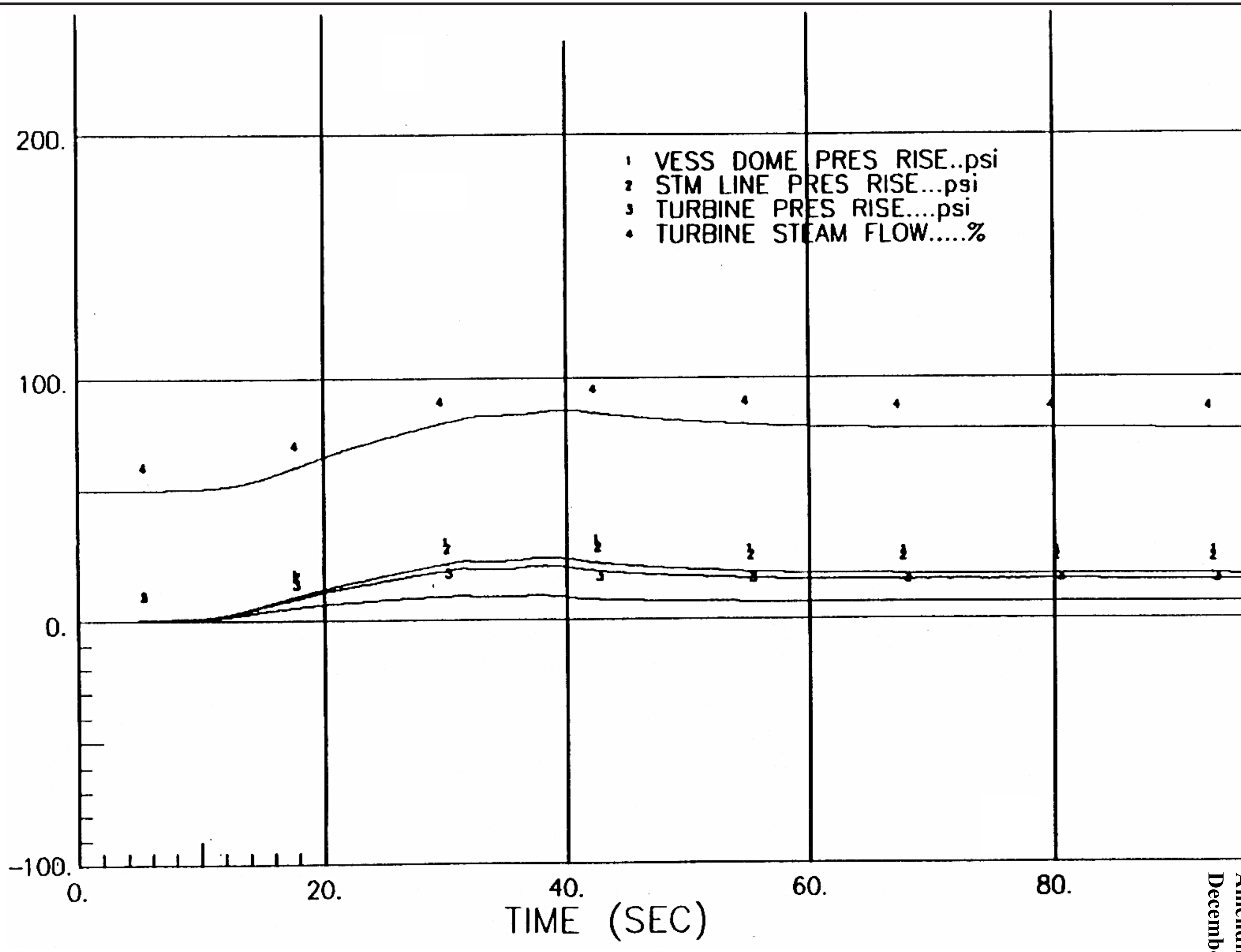
Draw. No. 02002.03

Rev.

Figure 15.4-1.1

Amendment 64
December 2017

Form No. 960690
LDCN-16-005

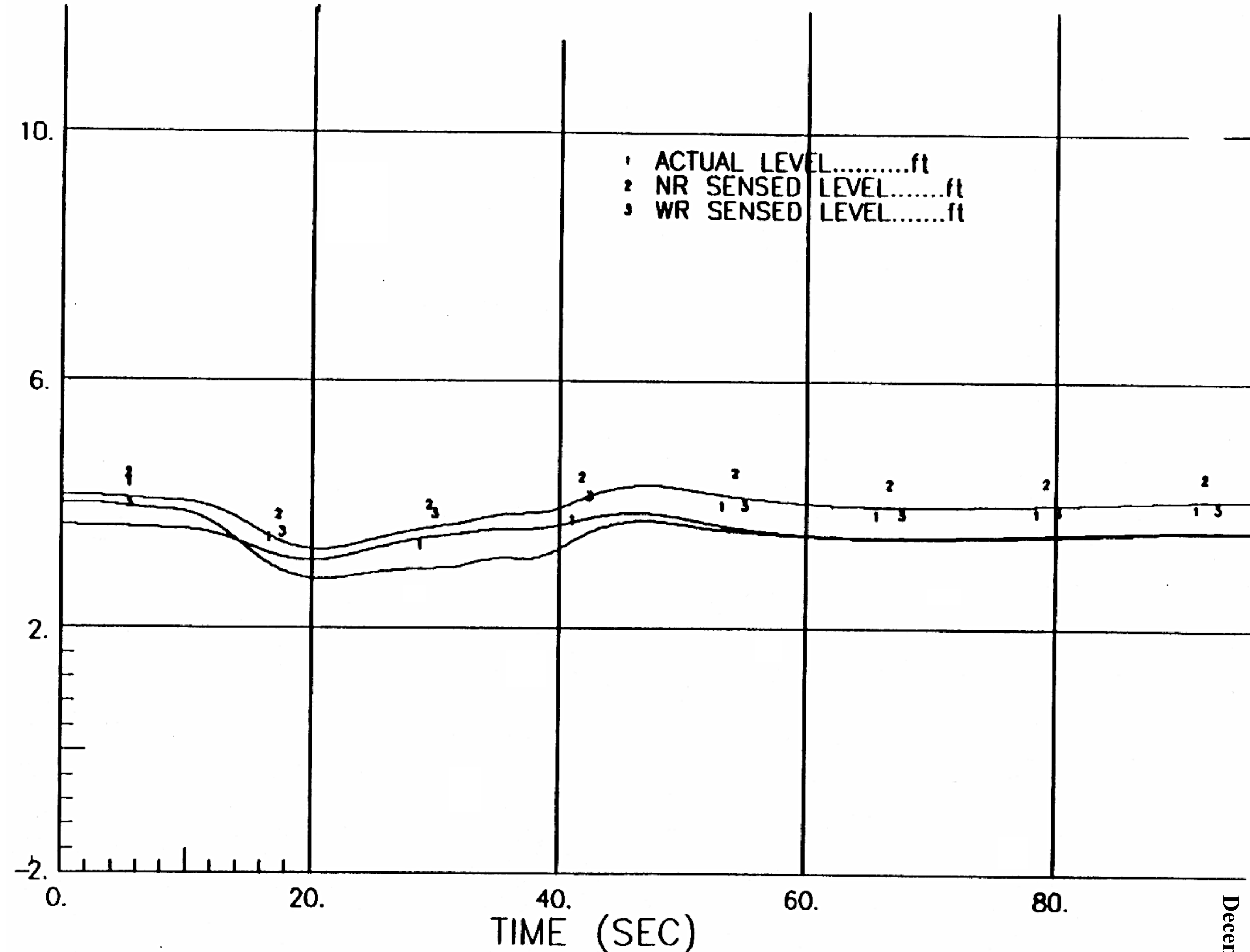


*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Abnormal Startup of an Idle Recirculation Loop at *56.95% Uprated Power, 34.1% Flow

Draw. No.	Rev.	Figure
020002.04		15.4-1.2



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

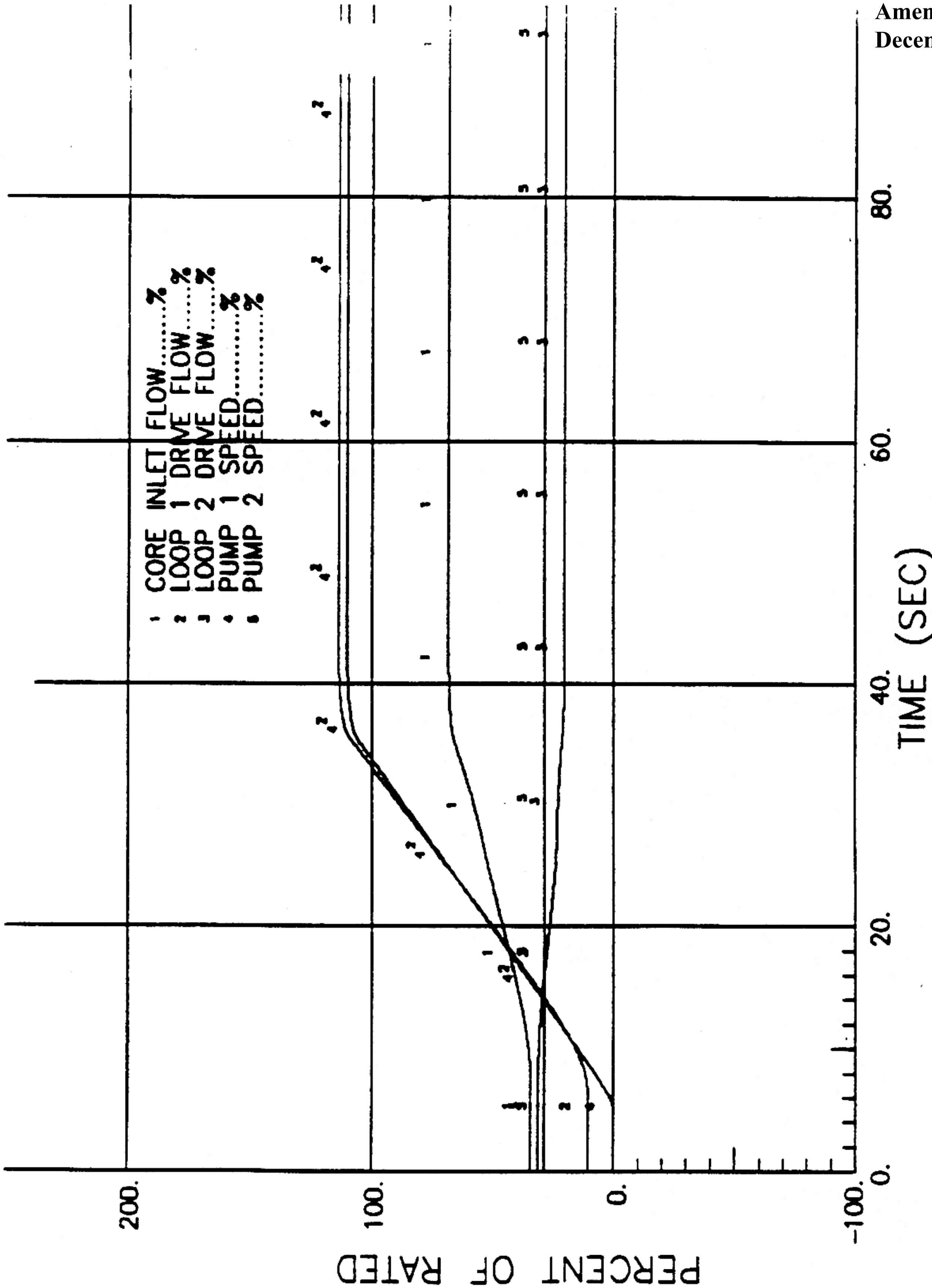
Columbia Generating Station
Final Safety Analysis Report

Abnormal Startup of an Idle Recirculation Loop at 56.95*% Uprated Power, 34.1% Flow

Draw. No. 02002.05

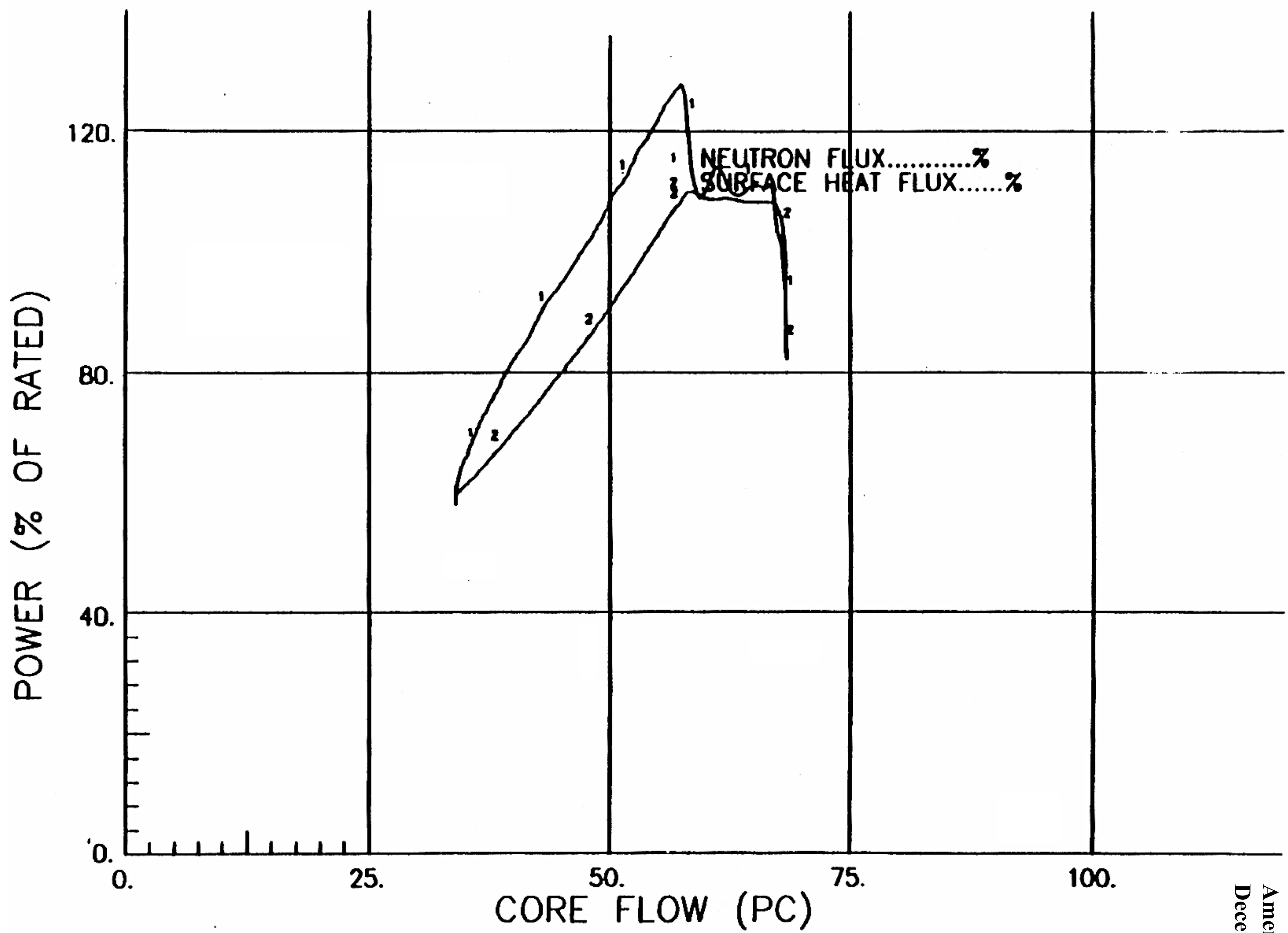
Rev.

Figure 15.4-1.3



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Abnormal Startup of an Idle Recirculation Loop at 56.95*% Uprated Power, 34.1% Flow		
	Draw. No. 020002.06	Rev.	Figure 15.4-1.4



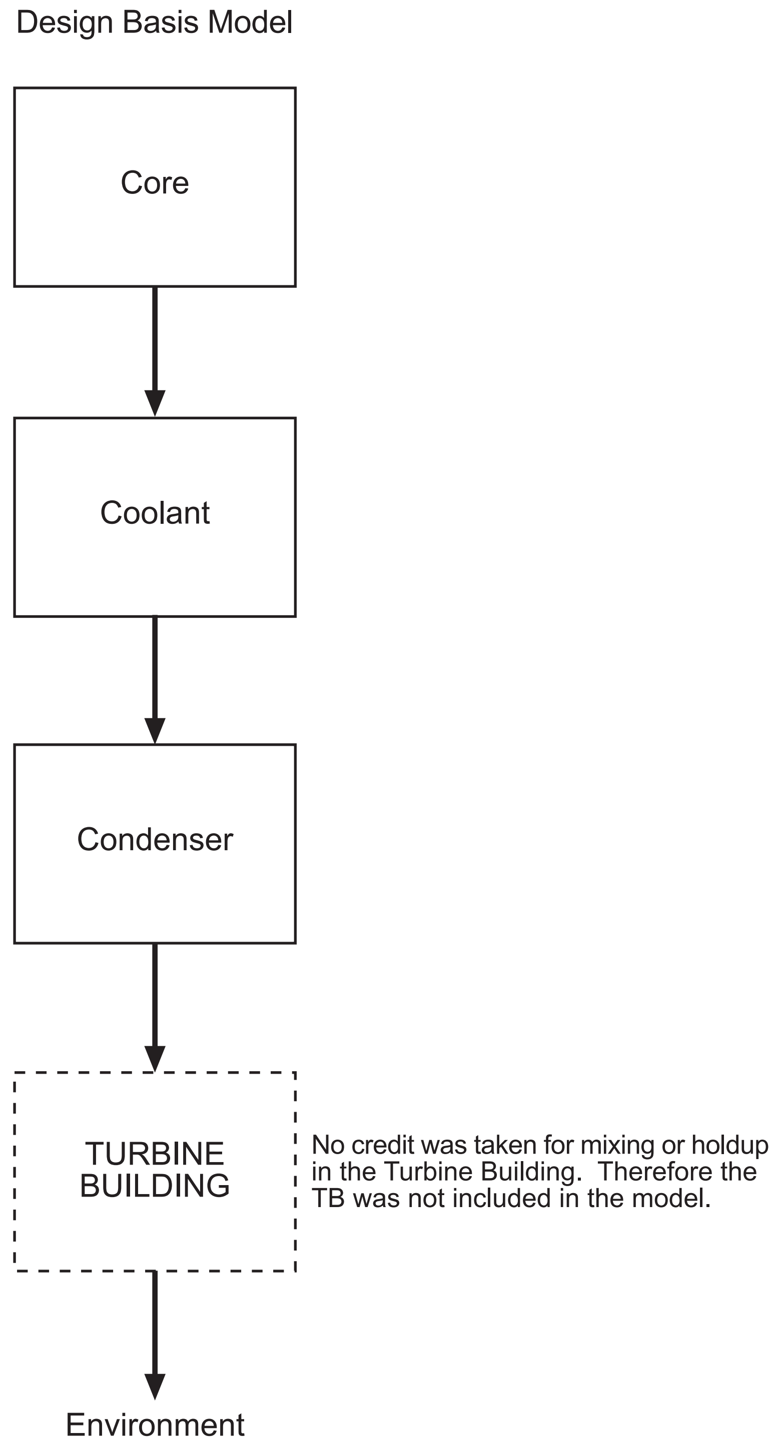
*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Abnormal Startup of an Idle Recirculation Loop at 56.95*% Uprated Power, 34.1% Flow

Draw. No.	Rev.	Figure
02002.07		15.4-1.5

Amendment 64
December 2017



Columbia Generating Station
Final Safety Analysis Report

Leakage Path Model for Rod Drop Accident

Draw. No. 960222.71 | Rev. | Figure 15.4-2

15.5 INCREASE IN REACTOR COOLANT INVENTORY

15.5.1 INADVERTENT HIGH-PRESSURE CORE SPRAY STARTUP

This transient is classified as a nonlimiting event for both original and uprated power conditions. The transient is not analyzed for each reload, but was analyzed for the GE14 New Fuel Introduction. Inadvertent startup of the high-pressure core spray (HPCS) system was analyzed because it provides the greatest auxiliary source of cold water into the vessel.

15.5.1.1 Identification of Causes and Frequency Classification

15.5.1.1.1 Identification of Causes

Manual startup (i.e., operator error) and continued injection of the HPCS system is postulated for this analysis.

15.5.1.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.5.1.2 Sequence of Events and Systems Operation

The HPCS system is manually initiated and injects into the reactor vessel, reaching full flow in approximately one second. The addition of the cooler water to the upper plenum causes a reduction in steam flow. This causes some reactor pressure decrease as the turbine control system responds to the event. As the steam flow decreases, the feedwater system responds by decreasing flow. In less than a minute, the reactor and the auxiliary steam systems stabilize at a new, lower power level. The analysis assumes normal functioning of plant instrumentation and controls. No engineered safety feature (ESF) function is expected in response to this transient. Plant parameter responses are shown in Figure 15.5-1.

15.5.1.2.1 The Effect of Single Failures and Operator Errors

Inadvertent operation of the HPCS system results in a mild depressurization. Level control and pressure regulator actuation are expected to establish a new stable operating state. The effect of a single failure in the DEH control system will have no effect on the transient because of its redundant design.

The effect of a single failure in the level control system has rather straightforward consequences including level rise or fall by improper control of the feedwater system. Increasing level will trip the turbine and automatically stop injection by the HPCS system. Decreasing level will automatically initiate a scram at the L3 level trip.

15.5.1.3 Core and System Performance

15.5.1.3.1 Mathematical Model

The one-dimensional ODYN transient analysis model described in Reference 15.5-1 was used to simulate this transient.

15.5.1.3.2 Input Parameter and Initial Conditions

The important parameters are shown in Table 15.5-1.

15.5.1.3.3 Results

The calculated uncorrected ΔCPR for the simulated bundles is less than 0.01 (Reference 15.5-2). A summary of transient key peak values is found in Table 15.0-1.

15.5.1.3.3.1 Consideration of Uncertainties. Important analytical factors including reactivity coefficient and feedwater temperature change have been assumed to be at the worst conditions so that any deviations in the actual plant parameters will produce a less severe transient.

15.5.1.4 Barrier Performance

Figure 15.5-1 indicates only a slight pressure reduction from initial conditions; therefore, reactor coolant pressure boundary pressure margins are not impacted.

15.5.1.5 Radiological Consequences

Since this event does not result in any fuel failures or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this event.

15.5.2 CHEMICAL VOLUME CONTROL SYSTEM MALFUNCTION (OR OPERATOR ERROR)

This event is not applicable to boiling water reactor plants.

15.5.3 BOILING WATER REACTOR TRANSIENTS WHICH INCREASE REACTOR COOLANT INVENTORY

These events are discussed in Sections 15.1 and 15.2.

15.5.4 REFERENCES

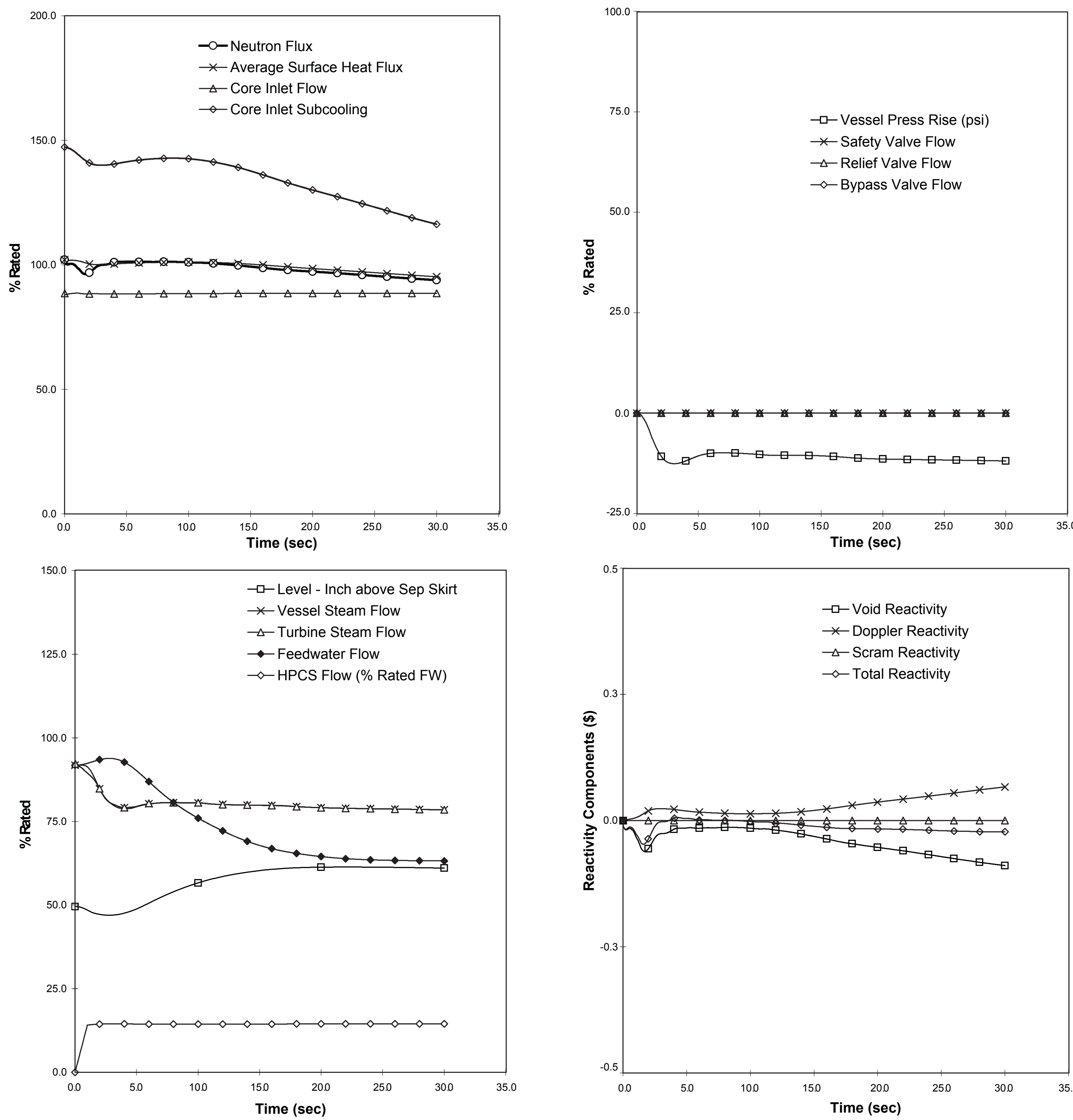
15.5-1 "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," Volumes 1, 2, 3 and 4, NEDC-24154-P-A, February 2000.

15.5-2 GE Hitachi Nucear Energy, "Inadvertent High Pressure Core Spray Startup Analysis," 0000-0098-5369-R0, March 2009.

Table 15.5-1

Input Parameters and Initial Conditions
HPCS Injection

Parameter	Value
Reactor power	100.34% (3556 MWth)
Core flow	106% ICF and 88% ELLLA
HPCS water source	Suppression pool
HPCS source pressure	14.7 psia
HPCS source temperature	40° F
HPCS source enthalpy	11.0 Btu/lbm
HPCS pump flow	12.6 % of rated feedwater flow (3800 gal/min)
Vessel-to-suppression pool differential pressure	1020 psid



*% Uprated power (RTP) is based on 3544 MWt. Curves as shown are originally based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Inadvertent Start of High Pressure Core Spray Pump at 100.34*% Uprated Power, 88% Flow		
	Draw. No. 020002.18	Rev.	Figure 15.5-1

15.6 DECREASE IN REACTOR COOLANT INVENTORY

15.6.1 INADVERTENT SAFETY/RELIEF VALVE OPENING

This event is discussed in Section 15.1.4.

15.6.2 INSTRUMENT LINE PIPE BREAK

This faulted condition is not a limiting event for either original or uprated power conditions. Therefore, the uprated power analysis for the accident has not been updated.

This event involves the postulated pipe break in a small steam or liquid line that is connected to the reactor coolant pressure boundary (RCPB) and is located in the reactor building. If the break were inside primary containment, the event would be bounded by the steam line break inside containment (LOCA) (see Section 15.6.5). That event is bounding because the instrument line sizes are bounded by the spectrum of breaks considered in the LOCA analysis.

15.6.2.1 Identification of Causes and Frequency Classification

15.6.2.1.1 Identification of Causes

There is no specific event or circumstance identified which results in the failure of an instrument line. These lines are designed to specific engineering specifications and standards, and seismic and environmental requirements. However, for the purpose of evaluating the consequences of this event, the failure of an instrument line is assumed to occur.

15.6.2.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.2.2 Sequence of Events and Systems Operation

The instrument line ruptures (complete circumferential break) and releases reactor coolant into the secondary containment. The analysis assumes that the reactor coolant activity is at the Technical Specification limit corresponding to an iodine spike of 4μCi/g dose equivalent ^{131}I and that the break cannot be isolated. The operators have a variety of methods to detect the leak such as monitoring plant area temperatures and radiation levels, system pressures, or sump inventories, or during operator rounds. It is assumed that the reactor operators identify the break after 20 minutes and initiate a reactor scram.

Using available plant systems, the operators maintain reactor water level and cool down and depressurize the reactor within 5 hr, at a rate less than or equal to the 100°F/hr limit in the Technical Specifications. Examples of plant systems or components the operators can use for inventory and temperature controls include HPCS, RCIC, SRVs, RHR, or the condensate feed system. No credit is taken for the automatic initiation of the RPS or ESF.

15.6.2.2.1 The Effect of Single Failures and Operator Errors

The event is handled by operator actions. Assuming additional single equipment failure or single operator error occurrences, adequate equipment would be available to respond to the loss of reactor coolant.

15.6.2.3 Core and System Performance

The inventory loss is within the capacity of the make up systems available and the shutdown and the cool down are controlled evolutions. Therefore, no fuel damage will occur and no other barriers are challenged.

15.6.2.3.1 Qualitative Summary - Results

Since instrument line breaks result in a slower rate of coolant loss and are bounded, the results are qualitative rather than quantitative. Since the rate of coolant loss is slow, an orderly reactor system depressurization follows reactor scram and the primary system is cooled down and maintained without ECCS actuation. No fuel damage or core uncovery occurs as a result of this event.

15.6.2.4 Barrier Performance

15.6.2.4.1 General

The release of primary coolant through the orificed instrument line would not result in an increase in secondary containment pressure.

15.6.2.5 Radiological Consequences

The radiological consequences are based on the following assumptions and methods:

a. The broken instrumentation line contains a 0.5-in. diameter flow restricting orifice inside the drywell.

b. Flow is critical at the orifice and is determined using the GOTHIC computer program (Reference 15.6-1) that employs the Henry model for subcooled liquid and the Moody model for saturated and superheated vapors (Reference 15.6-4).

c. The total integrated mass of fluid released by means of the break during the blowdown is 121,000 lb. Of this total, 29,800 lb flash to steam.

d. The specific models, assumptions and the program used for the radiological analysis is in Reference 15.6-3. Specific values of parameters used in the evaluation are presented in Table 15.6-1. The leakage path used in these calculations is shown in Figure 15.6-1.

e. The activity released from the instrument line break is based on the iodine spike concentration of 4μCi/g dose equivalent ^{131}I and is assumed to not mix or be held up within the secondary containment and is released to the environment at a flow rate of 80,000 cfm without SGT filtration.

f. The activity released to the secondary containment and the environment is presented in Table 15.6-2.

15.6.2.5.1 Results

The calculated exposures are presented in Table 15.6-3.

15.6.3 STEAM GENERATOR TUBE FAILURE

This event is not applicable to boiling water reactor (BWR) plants.

15.6.4 STEAM SYSTEM PIPING BREAK OUTSIDE CONTAINMENT

This event involves the postulation of a large steam line pipe break outside the primary containment. The analysis assumes that a main steam line instantaneously and circumferentially breaks at a location downstream of the outboard isolation valve. The plant is designed to immediately detect such an occurrence, initiate isolation of the broken line, and actuate the necessary protective features. The main steam line was selected for analysis because the postulated event envelops evaluation of steam line failures outside containment.

15.6.4.1 Identification of Causes and Frequency Classification

15.6.4.1.1 Identification of Causes

A main steam line break is postulated without the cause being identified. These lines are designed to specific engineering codes and standards, and seismic and environmental requirements. However, for the purpose of evaluating the consequences of a postulated large steam line rupture, the failure of a main steam line is assumed to occur.

15.6.4.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.4.2 Sequence of Events and Systems Operation

15.6.4.2.1 Sequence of Events

When the steam line breaks, steam flow through the failed line will rapidly increase, initiating the high main steam line flow trip that initiates the signal to close the main steam isolation valves (MSIVs). The closing MSIVs initiate a reactor protection (RPS) signal, scramming the reactor. The analysis assumes that the MSIVs are fully closed 6 seconds after the break. Performance of the engineered safety feature (ESF) systems in response to the loss of coolant is discussed in Chapter 6.

The sequence of events and approximate time required to reach the event is given in Table 15.6-4.

15.6.4.2.2 Systems Operation

A postulated guillotine break of one of the four main steam lines outside the containment results in mass loss from both ends of the break. The flow from the upstream side is initially limited by the flow restrictor upstream of the inboard isolation valve. Flow from the downstream side is initially limited by the total area of the flow restrictors in the three unbroken lines. Initially, only steam will issue from the broken end of the steam line. The flow in each line is limited by critical flow at the limiter to a maximum of 200% of rated flow for each line. Rapid depressurization of the RPV causes the water level to rise resulting in a steam-water mixture flowing from the break until the valves are closed. Mass loss (steam and water) is reduced and finally terminated (except for leakage) as the MSIVs close.

15.6.4.2.3 The Effect of Single Failures and Operator Errors

The effect of single failures has been considered in analyzing this event. All of the protective sequences for this event are capable of single equipment failure or single operator error accommodation and yet still complete the necessary safety action.

15.6.4.3 Core and System Performance

The temperature and pressure transients resulting as a consequence of this accident are insufficient to cause fuel damage.

15.6.4.3.1 Input Parameters and Initial Conditions

See Section 6.3 for initial conditions.

15.6.4.3.2 Results

There is no fuel damage as a consequence of this accident.

See Section 6.3 for ECCS analysis.

15.6.4.3.3 Considerations of Uncertainties

Discussions of the uncertainties associated with the ECCS performance and the containment isolation systems are discussed in Sections 6.3 and 7.3, respectively.

15.6.4.4 Barrier Performance

Since this break occurs outside the primary containment, barrier performance within the containment envelope is not applicable. There are sufficient vent openings in the steam tunnel to ensure that the secondary containment structure will not be damaged.

15.6.4.5 Radiological Consequences

The radiological analysis is based on NRC Regulatory Guide 1.183 (Reference 15.6-5). The dispersion of the plume is based on the puff model given in Regulatory Guide 1.194 (Reference 15.6-6).

The specific models, assumptions, and the program used for computer evaluation are described in Reference 15.6-3. Specific values of parameters used in the evaluation are presented in Table 15.6-5. There is no fuel damage as a result of this accident. The only activity available for release from the break is that which is present in the reactor coolant and steam lines prior to the break. The iodine inventories and the subsequent exposures are based on the equilibrium conditions and maximum reactor coolant activity for an iodine spiking event as allowed by the Technical Specifications. The analysis assumes all the activity in this discharge becomes airborne and released directly and unfiltered to the environment. The release of activity to the environment is presented in Table 15.6-6.

The following assumptions and conditions are used in determining the mass loss from the primary system from the inception of the break to full closure of the MSIVs:

a. The reactor is operating at the power level associated with maximum mass release,

b. Nuclear system pressure is 1060 psia and remains constant during closure,

c. An instantaneous circumferential break of the main steam line occurs,

d. Isolation valves start to close at 0.5 sec on high flow signal and are fully closed at 6 sec,

e. The Moody critical flow model (Reference 15.6-4) is applicable, and

f. The flow limiters allow up to 200% of rated flow through the MSIVs, and

g. Level rise time is conservatively assumed to be one second. Mixture quality is conservatively taken to be a constant 7% (steam weight percentage) during mixture flow.

The total integrated mass leaving the RPV through the steam line break is 130,000 lb of which 105,000 lb is liquid and 25,000 lb is steam. Only the liquid portion of the discharged coolant is assumed to carry the iodine activity of 4 μCi/gm dose-equivalent of I-131. The entire amount of activity in the liquid is assumed to be released to the environment.

The transport pathway is a direct unfiltered release to the environment and an unfiltered entrance to the control room as presented in Figure 15.6-2.

15.6.4.5.1 Results

The calculated doses for the design basis analysis are presented in Table 15.6-7. The doses are within the limits of 10 CFR 50.67.

15.6.5 LOSS-OF-COOLANT ACCIDENTS (RESULTING FROM SPECTRUM OF POSTULATED PIPING BREAKS WITHIN THE REACTOR COOLANT PRESSURE BOUNDARY) - INSIDE CONTAINMENT

Accidents that could result in the release of radioactive fission products directly into the containment are the results of postulated breaks in the reactor coolant system pressure boundary (RCPB). The analysis postulates that the most severe pressurization transient to the primary containment is caused by a complete circumferential break of the suction line of one of the two recirculation loops. Flow through the break transports the reactor vessel contents to the suppression pool.

The loss-of-coolant accident (LOCA) postulates the break of any of the spectrum of piping systems that form the RCPB. The plant and operator responses to the spectrum of breaks are presented in Chapter 6. Chapter 6 demonstrates that fuel, core, and barrier performance requirements are met for the spectrum of breaks. The bounding radiological analysis for the LOCA event detailed in this section reflects an inadequate core cooling accident that degrades to complete core damage. The event assumed for the analysis is the break inside containment of one of the main steam lines. The radiological analysis assumptions presented in

Section 15.6.5 are separate and distinct and are not mechanistically tied to the pipe break analyzed in Chapter 6.

15.6.5.1 Identification of Causes and Frequency Classification

15.6.5.1.1 Identification of Causes

There are no realistic, identifiable events that would result in a pipe break inside the containment of the magnitude required to cause the fuel damage sufficient to release the source terms assumed in this section. The piping is designed to specific engineering codes and standards and for severe seismic and environmental conditions. However, since such an accident provides an upper limit estimate of the dose consequences for the limiting faulted condition, it is evaluated without the causes being identified.

15.6.5.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.5.2 Sequence of Events and Systems Operation

The sequence of events and system operations are discussed in Chapter 6. The effect of single failures and operator errors is discussed in Chapter 6.

15.6.5.3 Core and System Performance

For the plant response to the LOCA and the evaluation of the system and core performance, see Chapter 6.

15.6.5.4 Radiological Consequences

The radiological consequences are based on the guidance provided in Regulatory Guide 1.183 (Reference 15.6-5) for the purpose of determining adequacy of the plant design to meet 10 CFR 50.67 limits.

A schematic of the transport pathway is shown in Figure 15.6-3.

15.6.5.4.1 Design Basis Analysis

The specific models, assumptions, and computer code used to evaluate the radiological consequences of the bounding LOCA based on the above criteria are presented in Reference 15.6-3. Specific values of parameters used in this evaluation are presented in Table 15.6-8.

15.6.5.4.1.1 Fission Product Release from Fuel. It is assumed that 100% of the noble gases and 30% of the iodine are released from an equilibrium core operating at a power level of 3556 MWt for 1000 days prior to the accident. Of this release, 100% of the noble gases become airborne. Some of the iodine is removed by plate-out and filtration; therefore, it is not available for airborne release to the environment. The activity airborne in the containment is presented in Table 15.6-9.

15.6.5.4.1.2 Fission Product Transport to the Environment. The fission product transport to the environment consists of two basic pathways. One transport pathway consists of leakage from the containment to the secondary containment by several different mechanisms and is discharged to the environment through the SGT system at an elevated location. Of the secondary containment flow, 50 cfm bypasses the SGT filters. The second transport pathway consists of leakage from the containment directly to the environment through piping systems that originate in containment and terminate outside the reactor building. The individual mechanisms for leakage from the primary containment are:

a. Containment leakage - Leakage from primary containment to the secondary containment. Prior to the completion of secondary containment drawdown this leakage is assumed to be a direct release to the environment; however, when drawdown is complete, 20 minutes post accident, this leakage is treated by the SGT system before it is released to the environment. No credit is taken for forced mixing and holdup within the secondary containment.

b. ESF leakage - Leakage from engineered safety feature (ESF) components outside the primary containment (all ESF equipment which circulates primary coolant or suppression pool water during the course of the postulated accident) to the secondary containment. This leakage is treated in a manner similar to the containment leakage described above.

c. Hydrogen purge - No hydrogen purge is required or assumed throughout the postaccident period.

d. MSIV leakage - Leakage from the primary containment (or the RPV) through the main steam isolation valves (MSIVs) to the turbine building. Iodine is assumed to plate-out in three of the four main steam lines. Plate-out in the broken fourth main steam line is not credited. In that line it is assumed one MSIV fails open (single failure), whereas all MSIVs in the other three steam lines are assumed to close.

e. Bypass leakage - Leakage from the primary containment that bypasses the secondary containment and is released, untreated, directly to the environment.

Fission product activities in secondary containment and those released to the environment based on the above assumptions are given in Tables 15.6-10 and 15.6-11, respectively.

15.6.5.4.1.3 Suppression Pool pH Control. The suppression pool pH is maintained above 7.0 for the duration of the accident as a result of the standby liquid control system injection of sodium pentaborate solution. The solution is assumed to be injected and fully mixed with the suppression pool water within 8 hours post-LOCA.

15.6.5.4.1.4 Results. The calculated doses for the design basis analysis are presented in Table 15.6-12 and are within the limts of 10 CFR 50.67.

15.6.6 FEEDWATER LINE BREAK - OUTSIDE CONTAINMENT

In order to evaluate large liquid process line pipe breaks outside containment, the failure of a feedwater line is assumed to evaluate the response of the plant design to this postulated event. The postulated break of the feedwater line, representing the largest liquid line outside the containment, provides the envelope evaluation relative to this type of occurrence. The break is assumed to be instantaneous, circumferential, and outboard of the outermost isolation valve. The analysis has not been updated for the change in MSIV isolation setpoint from Level 2 to Level 1 because the analysis remains bounded by the recirculation line break LOCA (Reference 15.6-9).

15.6.6.1 Identification of Causes and Frequency Classification

15.6.6.1.1 Identification of Causes

A feedwater line break is assumed without the cause being identified. The subject piping is designed to specific engineering codes and standards.

15.6.6.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.6.6.2 Sequence of Events and Systems Operation

15.6.6.2.1 Sequence of Events

The sequence of events is shown in Table 15.6-13.

15.6.6.2.2 Systems Operation

It is assumed that the normally operating plant instrument and controls are functioning. Credit is taken for the actuation of the reactor isolation system and ECCS. The RPS (SRVs, ECCS, and control rod drives) and plant protection system (RHR heat exchanger) are assumed to function. The ESF system is assumed to operate normally. Although not an ECCS and not credited nor required for mitigation of this event, RCIC will also be used if available for maintaining vessel level as it initiates at approximately the same low reactor vessel level as HPCS.

15.6.6.2.3 The Effect of Single Failures and Operator Errors

The feedwater line outside the containment is a special case of the general LOCA break spectrum considered in Section 6.3. The general single-failure analysis for LOCAs is discussed in Section 6.3.3.3. For the feedwater line break outside the containment, since the break is isolable, the HPCS can provide adequate flow to the vessel to maintain core cooling and prevent fuel rod cladding failure. A single failure of the HPCS would require actuation of ADS and the low-pressure core cooling systems to keep the core covered with water.

15.6.6.3 Core and System Performance

15.6.6.3.1 Qualitative Summary

The accident evaluation qualitatively considered in this section is considered to be conservative and to envelope assessment of the consequences of the postulated failure of one of the feedwater piping lines external to the containment. The accident is postulated to occur at the input parameters and initial conditions given in Table 6.3-2a, 6.3-2b, and 6.3-2c.

15.6.6.3.2 Qualitative Results

The feedwater line break outside the containment is less limiting than the steam line break outside the containment or the LOCA inside the containment.

The reactor vessel is isolated on low-low water level and the HPCS would restore the reactor water level to the normal elevation. The fuel is covered throughout the event and there are no pressure or temperature transients sufficient to cause fuel damage.

15.6.6.3.3 Consideration of Uncertainties

This event was conservatively analyzed and uncertainties were adequately considered (see Section 6.3 for details).

15.6.6.4 Barrier Performance

A break spectrum analysis for the complete range of reactor conditions indicates that the limiting fault event for breaks outside the containment is a complete severance of one of the main steam lines. The feedwater system piping break is less severe than the main steam line break.

15.6.6.5 Radiological Consequences

The specific models, assumptions, and the program used for computer evaluation are described in Reference 15.6-2. Specific values of parameters used in the evaluation are presented in Table 15.6-14. A diagram of the leakage path for this accident is shown in Figure 15.6-4.

15.6.6.5.1 Fission Product Release

Fission product release is assumed to occur from two pathways: activity being pumped from the condenser hotwell and activity returning to the feedwater system from the reactor water cleanup (RWCU) system. The activity in both of these sources is based on the Technical Specification coolant limit.

Noble gas activity in the condensate is negligible since the air ejectors remove most of the noble gas from the condenser.

15.6.6.5.2 Fission Product Transport to the Environment

The transport pathway consists of liquid release from the break, carryover to the turbine building atmosphere due to flashing and partitioning and unfiltered release to the environment through the turbine building ventilation system.

Of the 860,000 lb of condensate released from the break, 86,000 lb flashes to steam with assumed iodine carryover of 100%. Of the activity remaining in the unflashed liquid, 5% is assumed to become airborne. Normally, all feedwater reaching the break location will have passed through condensate demineralizers which have a 90% iodine removal efficiency. However, as a result of the increased feedwater flow caused by the break, differential pressure across the demineralizers is assumed to initiate flow through the demineralizer bypass line. This bypass line then carries 15% of the total flow resulting in an effective iodine removal efficiency for all flow of 76.5%. In addition, it is also assumed that 2771 lb of liquid returning from the RWCU are released prior to isolation of the RWCU. The activity concentration in this return steam is 1% of the RPV coolant concentration.

Taking no credit for holdup, decay, or plate-out during transport through the turbine building, the release of activity to the environment is presented in Table 15.6-15. The release is assumed to take place within 2 hr of the occurrence of the break.

15.6.6.5.3 Results

The calculated exposures for the realistic analysis are presented in Table 15.6-16 and are a small fraction of 10 CFR 100 guidelines.

15.6.7 REFERENCES

15.6-1 GOTHIC Containment Analysis Package, Technical Manual, Version 4.0, Numerical Applications, Inc., NA18907-06, Revision 3.

15.6-2 Nguyen, D., “Realistic Accident Analysis for General Electric Boiling Water Reactor - The RELAC Code and User’s Guide,” (NEDO-21142).

15.6-3 Energy Northwest, “Columbia Generating Station Alternative Source Term,” CGS-FTS-0168, Revision 2, June 2011.

15.6-4 Moody, F. J, “Maximum Two-Phase Vessel Blowdown from Pipes,” ASME Paper Number 65-WA/HT-1, March 15, 1965.

15.6-5 Regulatory Guide 1.183, Revision 0, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” July, 2000.

15.6-6 Regulatory Guide 1.194, Revision 0, “Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants,” July, 2003.

15.6-7 Federal Guidance Report 11, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion and Ingestion,” Oak Ridge National Laboratory, 1988.

15.6-8 Federal Guidance Report 12, “External Exposure to Radionuclides in Air, Water and Soil,” Oak Ridge National Laboratory, 1993.

15.6-9 GE Hitachi Nuclear Energy, “License Amendment Request for Proposed Changes to Columbia Technical Specifications: Changing Group 1 Isolation Valves’ Low Reactor Water Level Isolation Signal from the Current Level 2 to Level 1,” 0000-0081-6730-R1, July 2008.

Table 15.6-1

Instrument Line Break Accident - Parameters Tabulated for Postulated Accident Analyses

Parameters			Design Basis Assumptions
I.	Data and assumptions used to estimate radioactive source from postulated accidents		
	A.	Power level	N/A
	B.	Burnup	N/A
	C.	Fuel damaged	None
	D.	Airborne activity by nuclide	Table 15.6-2
	E.	Iodine fractions	
		(1) Organic	0.15%
		(2) Elemental	4.85%
		(3) Particulate	95%
	F.	Initial reactor coolant activity with iodine spike	4 µci/g
		^{131}I	1.6 µci/g
		^{132}I	14.8 µci/g
		^{133}I	11.0 µci/g
		^{134}I	30.0 µci/g
		^{135}I	16.0 µci/g
II.	Data and assumptions used to estimate activity released		
	A.	Primary containment leak rate (%/day)	N/A
	B.	Secondary containment effluent rate (cfm)	80,000[a]
	C.	Valve movement times	N/A
	D.	Adsorption and filtration efficiencies	
		(1) Organic iodine	N/A
		(2) Elemental iodine	N/A
		(3) Particulate iodine	N/A
		(4) Particulate fission products	N/A
	E.	Recirculation system parameters	
		(1) Flow rate	N/A
		(2) Mixing efficiency	N/A
		(3) Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)	N/A
	G.	Containment volumes	N/A
	H.	All other pertinent data and assumptions	None

Table 15.6-1

Instrument Line Break Accident - Parameters
Tabulated for Postulated Accident Analyses (Continued)

		Parameters	Design Basis Assumptions
III.	Dispersion data		
	A.	Offsite	See Table 15.0-4
	B.	Control Room	See Table 15.0-5
IV.	Dose data		
	A.	Method of dose calculation	Reference 15.6-5
	B.	Dose conversion assumptions	Reference 15.6-7
	C.	Peak activity released from secondary containment	Table 15.6-2
	D.	Doses	Table 15.6-3

[a] No forced mixing in secondary containment is considered.

Table 15.6-2

Instrument Line Failure

Activity Airborne in Secondary Containment (Ci)					
	2 hr	5 hr	8 hr	1 day	30 days
^{133}Xe	7.02E-07	2.60E-07	0.00E+00	0.00E+00	0.00E+00
^{135}Xe	1.22E-05	3.67E-06	0.00E+00	0.00E+00	0.00E+00
Total	1.29E-05	3.93E-06	0.00E+00	0.00E+00	0.00E+00
^{131}I	2.00E-02	8.09E-03	0.00E+00	0.00E+00	0.00E+00
^{132}I	1.03E-01	1.72E-02	0.00E+00	0.00E+00	0.00E+00
^{133}I	1.29E-01	4.80E-02	0.00E+00	0.00E+00	0.00E+00
^{134}I	7.60E-02	2.80E-03	0.00E+00	0.00E+00	0.00E+00
^{135}I	1.64E-01	4.93E-02	0.00E+00	0.00E+00	0.00E+00
Total	4.92E-01	1.25E-01	0.00E+00	0.00E+00	0.00E+00

Activity Airborne in the Environment (Ci)					
	2 hr	5 hr	8 hr	1 day	30 days
^{133}Xe	1.90E-03	3.93E-03	4.91E-03	6.06E-03	6.08E-03
^{135}Xe	3.56E-02	6.76E-02	8.02E-02	9.06E-02	9.06E-02
Total	3.75E-02	7.15E-02	8.51E-02	9.67E-02	9.67E-02
^{131}I	4.87E+01	8.46E+01	8.72E+01	8.72E+01	8.72E+01
^{132}I	3.51E+02	4.81E+02	4.86E+02	4.86E+02	4.86E+02
^{133}I	3.26E+02	5.51E+02	5.65E+02	5.65E+02	5.65E+02
^{134}I	4.91E+02	5.52E+02	5.53E+02	5.53E+02	5.53E+02
^{135}I	4.46E+02	7.06E+02	7.22E+02	7.22E+02	7.22E+02
Total	1.66E+03	2.37E+03	2.41E+03	2.41E+03	2.41E+03

Table 15.6-3

Instrument Line Failure
Radiological Effects

Area	Total Effective Dose Equivalent (rem)	Limit (rem TEDE)
Control Room	1.58	5
Exclusion area (1950 m) (2 hr)	0.36	2.5
Low population zone (4827 m) (30 days)	0.16	2.5

Table 15.6-4

Sequence of Events for Steam Line Break
Outside Containment

Time	Event
0	Guillotine break of one main steam line outside primary containment.
0.5[a]	High steam line flow signal initiates closure of MSIV.
<1.0	Reactor begins to scram.
≥ 6.0	Main steam line isolation valves fully closed.
10	Safety/relief valves open on high vessel pressure. The valves open and close to maintain vessel pressure at approximately 1100 psi.
600	Operator initiates ADS or manually controls relief valves. Vessel depressurizes rapidly.
750	High-pressure core spray initiates on low water level.
1270	Core effectively reflooded. No fuel rod failure.

[a] Approximately.

Table 15.6-5

Steam Line Break Accident - Parameters
Tabulated for Postulated Accident Analyses

Parameters	Design Basis Assumptions
I. Data and assumptions used to estimate radioactive source from postulated accidents.	
A. Power level	N/A
B. Burnup	N/A
C. Fuel damaged	None
D. Release of activity by nuclide	Table 15.6-6
E. Iodine fractions[1]	
(1) Organic	N/A
(2) Elemental	N/A
(3) Particulate	N/A
F. Reactor coolant activity before the accident corresponds to the iodine spike of 4 µci/gm dose-equivalent I-131	4 µci/gm
II. Data and assumptions used to estimate activity released.	
A. Primary containment leak rate (%/day)	N/A
B. Secondary containment leak rate (%/day)	N/A
C. Isolation valve closure time (sec)	6
D. Adsorption and filtration efficiencies	
(1) Organic iodine[1]	N/A
(2) Elemental iodine	N/A
(3) Particulate iodine	N/A
(4) Particulate fission products	N/A

[1] Since no filtration is credited, speciation of iodines is not applicable.

Table 15.6-5

Steam Line Break Accident - Parameters
Tabulated for Postulated Accident Analyses (Continued)

Parameters				Design Basis Assumptions
	E.	Recirculation system parameters		N/A
		(1)	Flow rate	N/A
		(2)	Mixing efficiency	N/A
		(3)	Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)		N/A
	G.	Containment volumes		N/A
	H.	All other pertinent data and assumptions		None
III.	Dispersion data			
		(1)	Offsite	Table 15.0-4
		(2)	Control Room	8.19 E-4 sec/m^3
IV.	Dose data			
	A.	Method of dose calculation		Reference 15.6-3
	B.	Dose conversion assumptions		Reference 15.6-7
	C.	Peak activity concentrations in containment		N/A
	D.	Doses		Table 15.6-7

Table 15.6-6

Steam Line Break Accident
Activity Release to Environment (Curies)

Isotope	Activity Released
^{131}I	1.91E 02

Table 15.6-7

Steam Line Break Accident
Radiological Effects of a Puff Release

Area	TEDE (rem)
Exclusion area (1950 m)	0.40
Low population zone (4827 m)	0.11
Control Room	1.8

Table 15.6-8

Loss-of-Coolant Accident - Parameters
Tabulated for Postulated Accident Analysis

Parameters				Design Basis Assumptions
I.	Data and assumptions used to estimate radioactive source from postulated accidents			
	A.	Power level		3556
	B.	Burnup		N/A
	C.	Fuel damaged		100%
	D.	Airborne activity by nuclide		Table 15.6-10 and 15.6-11
	E.	Iodine fractions		
		(1)	Organic	0.0015
		(2)	Elemental	0.0485
		(3)	Particulate	0.95
	F.	Reactor coolant activity before the accident		N/A
II.	Data and assumptions used to estimate activity released			
	A.	Primary containment leak rate includes MSIV leakage (% volume/day)		0 – 24 hrs 0.5 24 – 720 hrs 0.25
	B.	Secondary containment leak rate (%/day)		N/A
	C.	Drawdown period (minutes)		20
	D.	Adsorption and filtration efficiencies (%)		
		(1)	Organic iodine	98%
		(2)	Elemental iodine	98%
		(3)	Particulate iodine	98%
		(4)	Particulate fission products	98%

Table 15.6-8

Loss-of-Coolant Accident - Parameters
Tabulated for Postulated Accident Analysis (Continued)

		Parameters		Design Basis Assumptions	
	E.	Secondary containment volumetric flow rate bypassing SGT filters[1], cfm		50	
	F.	Secondary containment bypass leakage		0 – 24 hrs 24 – 720 hrs	0.04% volume per day 0.02% volume per day
	G.	Recirculation system parameters			
		(1)	Flow rate (cfm)	N/A	
		(2)	Mixing efficiency	N/A	
		(3)	Filter efficiency	N/A	
	H.	Containment spray removal rates		Time (hr) 0 0.25 2.44 24.0	Removal Rate (1/hr) 0.0 6.20 0.62 0.0
	I.	Containment volumes		Table 6.2-1	
	J.	MSIV leak rate per steam line		0 – 24 hrs 24 – 720 hrs	16 scfh 8 scfh
	K.	ESF leakage into secondary containment		2 gpm	
	L.	CREF bypass leakage		50 cfm	
III.	Dispersion data				
		(1)	Offsite	Table 15.0-4	
		(2)	Control room	Table 15.0-5	

[1] SGT filter bypass will reduce SGT filter efficiency from 99% to 98%.

Table 15.6-8

Loss-of-Coolant Accident - Parameters
Tabulated for Postulated Accident Analysis (Continued)

		Parameters	Design Basis Assumptions
IV.	Dose data		
	A.	Method of dose calculation	Reference 15.6-5
	B.	Dose conversion assumptions	Reference 15.6-7, 15.6-8
	C.	Peak activity concentrations in containment	Table 15.6-9
	D.	Doses	Table 15.6-12

Table 15.6-9

Loss-of-Coolant Accident
Primary Containment[1] Activity (Curies)

Isotope	0.25 hr	0.5 hr	0.8 hr	1.0 hr	2.0 hr	4.0 hr	8.0 hr	24.0 hr	30 day
^{131}I	2.15E+06	1.72E+06	2.42E+06	2.63E+06	2.69E+06	3.93E+05	1.25E+05	4.09E+04	3.03E+03
^{132}I	2.82E+06	2.10E+06	2.75E+06	2.79E+06	2.15E+06	2.17E+05	3.57E+04	1.12E+02	1.03E-01
^{133}I	4.16E+06	3.30E+06	4.62E+06	4.97E+06	4.95E+06	6.82E+05	1.92E+05	3.92E+04	3.25E-06
^{134}I	3.81E+06	2.49E+06	2.87E+06	2.55E+06	1.18E+06	3.47E+04	4.52E+02	4.13E-04	0
^{135}I	3.78E+06	2.94E+06	4.05E+06	4.29E+06	3.97E+06	4.77E+05	1.02E+05	6.80E+03	0
Total iodines	1.67E+07	1.26E+07	1.67E+07	1.72E+07	1.49E+07	1.80E+06	4.55E+05	8.71E+04	3.03E+03
^{83m}Kr	2.51E+05	4.92E+05	1.80E+06	3.02E+06	5.87E+06	2.84E+06	6.34E+05	1.58E+03	0
^{85m}Kr	5.45E+05	1.13E+06	4.35E+06	7.71E+06	1.86E+07	1.39E+07	7.36E+06	5.84E+05	0
^{85}Kr	3.17E+04	6.82E+04	2.74E+05	5.05E+05	1.43E+06	1.46E+06	1.46E+06	1.45E+06	1.29E+06
^{87}Kr	9.02E+05	1.69E+06	5.92E+06	9.53E+06	1.56E+07	5.33E+06	5.97E+05	9.35E+01	0
^{88}Kr	1.38E+06	2.79E+06	1.05E+07	1.82E+07	4.03E+07	2.51E+07	9.29E+06	1.76E+05	0
^{89}Kr	6.47E+04	5.31E+03	8.12E+02	5.71E+01	3.42E-04	1.60E-15	3.36E-38	5.95E-129	0
^{131m}Xe	2.15E+04	4.63E+04	1.86E+05	3.42E+05	9.66E+05	9.81E+05	9.71E+05	9.30E+05	1.56E+05
^{133m}Xe	1.28E+05	2.74E+05	1.10E+06	2.01E+06	5.63E+06	5.60E+06	5.33E+06	4.33E+06	6.17E+02
^{133}Xe	4.19E+06	9.00E+06	3.61E+07	6.64E+07	1.87E+08	1.89E+08	1.86E+08	1.72E+08	3.52E+06
^{135m}Xe	4.40E+05	4.87E+05	1.00E+06	9.51E+05	1.88E+05	9.29E+02	2.18E-02	0	0
^{135}Xe	1.02E+06	2.23E+06	8.57E+06	1.56E+07	4.20E+07	4.21E+07	3.82E+07	1.79E+07	0
^{137}Xe	2.50E+05	3.75E+04	1.05E+04	1.35E+03	8.99E-02	5.09E-11	1.59E-29	1.52E-103	0
^{138}Xe	1.50E+06	1.75E+06	3.81E+06	3.82E+06	9.34E+05	7.13E+03	3.98E-01	3.87E-18	0
Total noble gases	1.07E+07	2.00E+07	7.36E+07	1.28E+08	3.19E+08	2.86E+08	2.50E+08	1.97E+08	4.97E+06
Alkali metals	9.84E+05	7.85E+05	9.21E+05	9.62E+05	9.72E+05	1.29E+05	3.05E+04	9.57E+01	7.73E+01
Te-group	2.83E+05	2.31E+05	2.04E+06	2.49E+06	2.41E+06	3.09E+05	6.56E+04	1.72E+02	5.34E+01
Noble metals	0.00E+00	0.00E+00	1.55E+05	1.97E+05	1.99E+05	2.57E+04	5.82E+03	1.60E+01	3.99E+00
La-group	0.00E+00	0.00E+00	2.40E+04	3.19E+04	3.17E+04	9.64E+03	3.11E+03	1.33E+01	1.00E+01
Ce-group	0.00E+00	0.00E+00	1.15E+05	1.46E+05	1.52E+05	1.98E+04	4.49E+03	1.18E+01	1.05E+00

[1]Primary Containment includes the Dry Well & the Wet Well Air-Space

Table 15.6-10

Loss-of-Coolant Accident
Secondary Containment Activity (Curies) - 20 Minute Drawdown

Isotope	0.25 hr	0.5 hr	0.75 hr	1 hr	2 hr	4 hr	8 hr	24 hr	30 day
^{131}I	0	6.89E+00	9.90E+00	1.15E+01	1.50E+01	7.11E+00	6.08E+00	5.47E+00	4.11E-01
^{132}I	0	8.38E+00	1.13E+01	1.22E+01	1.19E+01	3.26E+00	8.84E-01	6.86E-03	1.79E-07
^{133}I	0	1.32E+01	1.89E+01	2.17E+01	2.75E+01	1.23E+01	9.36E+00	5.24E+00	0
^{134}I	0	9.98E+00	1.18E+01	1.12E+01	6.54E+00	6.29E-01	2.20E-02	5.53E-08	0
^{135}I	0	1.18E+01	1.65E+01	1.88E+01	2.21E+01	8.61E+00	4.95E+00	9.08E-01	0
Total iodines	0	5.02E+01	6.84E+01	7.54E+01	8.29E+01	3.19E+01	2.13E+01	1.16E+01	4.11E-01
^{83m}Kr	0	1.65E+00	5.88E+00	1.02E+01	2.02E+01	9.84E+00	2.20E+00	5.47E-03	0
^{85m}Kr	0	3.77E+00	1.42E+01	2.59E+01	6.40E+01	4.81E+01	2.55E+01	2.03E+00	0
^{85}Kr	0	2.28E-01	8.97E-01	1.70E+00	4.91E+00	5.06E+00	5.06E+00	5.03E+00	2.24E+00
^{87}Kr	0	5.66E+00	1.94E+01	3.21E+01	5.36E+01	1.85E+01	2.07E+00	3.25E-04	0
^{88}Kr	0	9.33E+00	3.44E+01	6.13E+01	1.38E+02	8.69E+01	3.22E+01	6.10E-01	0
^{89}Kr	0	1.78E-02	2.66E-03	1.92E-04	1.17E-09	5.56E-21	1.17E-43	0	0
^{131m}Xe	0	1.55E-01	6.08E-01	1.15E+00	3.32E+00	3.40E+00	3.37E+00	3.22E+00	2.70E-01
^{133m}Xe	0	9.17E-01	3.59E+00	6.78E+00	1.93E+01	1.94E+01	1.85E+01	1.50E+01	1.07E-03
^{133}Xe	0	3.01E+01	1.18E+02	2.24E+02	6.43E+02	6.59E+02	6.49E+02	6.06E+02	6.47E+00
^{135m}Xe	0	1.63E+00	3.29E+00	3.20E+00	6.44E-01	3.22E-03	7.58E-08	0	0
^{135}Xe	0	7.70E+00	2.87E+01	5.35E+01	1.50E+02	1.61E+02	1.57E+02	8.24E+01	0
^{137}Xe	0	1.25E-01	3.43E-02	4.53E-03	3.09E-07	1.77E-16	5.52E-35	0	0
^{138}Xe	0	5.87E+00	1.25E+01	1.28E+01	3.21E+00	2.47E-02	1.38E-06	0	0
Total noble gases	0	6.72E+01	2.42E+02	4.33E+02	1.10E+03	1.01E+03	8.95E+02	7.14E+02	8.98E+00
Alkali metals	0	2.75E+00	3.18E+00	3.33E+00	3.38E+00	4.51E-01	1.07E-01	3.34E-04	1.34E-04
Te-group	0	8.69E-01	6.92E+00	8.69E+00	8.45E+00	1.08E+00	2.29E-01	5.99E-04	9.28E-05
Noble metals	0	0.00E+00	5.18E-01	6.76E-01	6.92E-01	8.96E-02	2.03E-02	5.60E-05	6.92E-06
La-group	0	0.00E+00	8.11E-02	1.12E-01	1.12E-01	3.36E-02	1.09E-02	4.65E-05	1.74E-05
Ce-group	0	0.00E+00	3.82E-01	5.04E-01	5.30E-01	6.92E-02	1.57E-02	4.11E-05	1.81E-06

Table 15.6-11

Loss-of-Coolant Accident
Activity Released to the Environment (Curies) - 20 Minute Drawdown

Isotope	0.25 hrs	0.5 hrs	0.75 hrs	1 hrs	2 hrs	4 hrs	8 hrs	24 hrs	30 d
^{131}I	6.59E+01	1.39E+02	1.80E+02	2.31E+02	4.48E+02	5.49E+02	6.37E+02	8.35E+02	3.03E+03
^{132}I	8.83E+01	1.82E+02	2.31E+02	2.89E+02	5.27E+02	7.45E+02	1.13E+03	2.52E+03	1.15E+04
^{133}I	1.28E+02	2.69E+02	3.47E+02	4.44E+02	8.49E+02	1.03E+03	1.17E+03	1.42E+03	1.67E+03
^{134}I	1.23E+02	2.45E+02	2.99E+02	3.53E+02	4.98E+02	5.25E+02	5.28E+02	5.28E+02	5.28E+02
^{135}I	1.17E+02	2.44E+02	3.13E+02	3.97E+02	7.35E+02	8.74E+02	9.63E+02	1.05E+03	1.06E+03
Total iodines	5.22E+02	1.08E+03	1.37E+03	1.71E+03	3.06E+03	3.72E+03	4.43E+03	6.35E+03	1.78E+04
^{83m}Kr	1.09E+01	4.59E+01	1.47E+02	3.80E+02	2.19E+03	4.92E+03	6.81E+03	7.35E+03	7.35E+03
^{85m}Kr	2.34E+01	1.02E+02	3.43E+02	9.21E+02	6.15E+03	1.67E+04	2.99E+04	4.36E+04	4.42E+04
^{85}Kr	1.34E+00	6.00E+00	2.09E+01	5.82E+01	4.33E+02	1.37E+03	3.25E+03	1.07E+04	1.64E+05
^{87}Kr	3.98E+01	1.62E+02	5.03E+02	1.25E+03	6.46E+03	1.27E+04	1.55E+04	1.59E+04	1.59E+04
^{88}Kr	5.95E+01	2.55E+02	8.42E+02	2.22E+03	1.40E+04	3.49E+04	5.53E+04	6.71E+04	6.73E+04
^{89}Kr	9.01E+00	1.13E+01	1.16E+01	1.16E+01	1.16E+01	1.16E+01	1.16E+01	1.16E+01	1.16E+01
^{131m}Xe	9.12E-01	4.07E+00	1.42E+01	3.94E+01	2.93E+02	9.28E+02	2.18E+03	7.06E+03	5.55E+04
^{133m}Xe	5.42E+00	2.41E+01	8.40E+01	2.33E+02	1.72E+03	5.38E+03	1.24E+04	3.71E+04	9.18E+04
^{133}Xe	1.77E+02	7.92E+02	2.76E+03	7.66E+03	5.68E+04	1.80E+05	4.22E+05	1.35E+06	6.45E+06
^{135m}Xe	2.28E+01	6.80E+01	1.40E+02	2.36E+02	4.35E+02	4.58E+02	4.59E+02	4.59E+02	4.59E+02
^{135}Xe	4.33E+01	1.98E+02	6.85E+02	1.86E+03	1.34E+04	4.24E+04	9.96E+04	2.67E+05	3.33E+05
^{137}Xe	2.69E+01	3.79E+01	3.99E+01	4.04E+01	4.04E+01	4.04E+01	4.04E+01	4.04E+01	4.04E+01
^{138}Xe	7.66E+01	2.35E+02	5.02E+02	8.78E+02	1.74E+03	1.87E+03	1.87E+03	1.87E+03	1.87E+03
Total noble gases	4.97E+02	1.94E+03	6.09E+03	1.58E+04	1.04E+05	3.02E+05	6.49E+05	1.81E+06	7.23E+06
Alkali metals	2.99E+01	6.16E+01	7.76E+01	9.54E+01	1.68E+02	1.96E+02	2.10E+02	2.14E+02	2.16E+02
Te-group	6.96E+00	1.64E+01	3.87E+01	8.25E+01	2.70E+02	3.38E+02	3.71E+02	3.81E+02	3.82E+02
Noble metals	0	0	1.54E+00	4.94E+00	2.01E+01	2.56E+01	2.84E+01	2.93E+01	2.94E+01
La-group	0	0	2.30E-01	7.72E-01	3.23E+00	4.56E+00	5.82E+00	6.30E+00	6.65E+00
Ce-group	0	0	1.13E+00	3.66E+00	1.51E+01	1.94E+01	2.15E+01	2.22E+01	2.22E+01

Table 15.6-12

Loss-of-Coolant Accident
(Design Basis Analysis)
Radiological Effects

Total Effect	TEDE (rem)
Exclusion area (1950 m) (2 hr)	4.1
Low population zone (4827 m) (30 days)	4.0
Control Room (30 days)	3.5

Table 15.6-13

Sequence of Events for Feedwater Line Break
Outside Containment

Time	Event
0	One feedwater line breaks.
0+	Feedwater line check valves isolate the reactor from the break.
<30 sec	At low reactor water level, reactor scram would initiate and, at low-low reactor water level, HPCS and MSIV closure[b] would initiate and recirculation pumps would trip.
2 minutes[a]	The SRVs open and close and maintain the reactor vessel pressure at approximately 1100 psig.
1 to 2 hr	Normal reactor cooldown established.

[a] Approximately.

[b] The analysis has not been updated for the change in MSIV isolation setpoint from Level 2 to Level 1 because it remains bounded by the recirculation line break LOCA (Reference 15.6-9).

Table 15.6-14

Feedwater Line Break Accident - Parameters
Tabulated for Postulated Accident Analysis

Parameter	Value
I. Data and assumptions used to estimate radioactive source from postulated accidents	
A. Power level	N/A
B. Burnup	N/A
C. Fuel damaged	None
D. Release of activity by nuclide	Table 15.6-15
E. Iodine fractions	
(1) Organic	0
(2) Elemental	1%
(3) Particulate	0
(4) Reactor coolant activity before the accident	Section 15.6.6.5.1
II. Data and assumptions used to estimate activity released	
A. Primary containment leak rate (%/day)	N/A
B. Secondary containment leak rate (%/day)	N/A
C. RWCU total isolation valve closure time (sec)	75
D. Adsorption and filtration efficiencies	
(1) Organic iodine	N/A
(2) Elemental iodine	N/A
(3) Particulate iodine	N/A
(4) Particulate fission products	N/A
E. Recirculation system parameters	N/A
(1) Flow rate	N/A
(2) Mixing efficiency	N/A
(3) Filter efficiency	N/A
F. Containment spray parameters (flow rate, drop size, etc.)	N/A
G. Containment volumes	N/A
H. All other pertinent data and assumptions	None

Table 15.6-14

Feedwater Line Break Accident - Parameters
Tabulated for Postulated Accident Analysis (Continued)

Parameter			Value
III.	Dispersion data		
	A.	Boundary and LPZ distance (m)	1950/4827
	B.	χ/Qs for time intervals of 0-2 hr - EAB/LPZ	2.62×10^{-4}/1.06×10^{-4}
IV.	Dose data		
	A.	Method of dose calculation	Reference 15.6-2
	B.	Dose conversion assumptions	Reference 15.6-2
	C.	Peak activity concentrations in containment	N/A
	D.	Doses	Table 15.6-16

Table 15.6-15

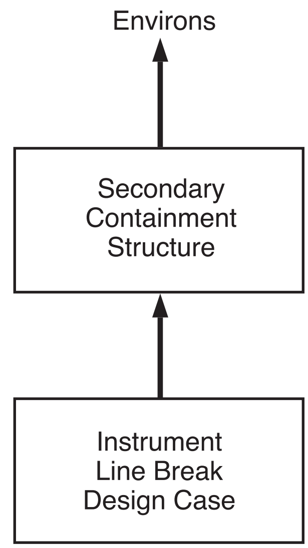
Feedwater Line Break Accident
Activity Release to Environment (Curies)

Isotope	Activity
^{131}I	2.22×10^{-2}
^{132}I	2.05×10^{-1}
^{133}I	1.52×10^{-1}
^{134}I	4.45×10^{-1}
^{135}I	2.22×10^{-1}
Total	1.04×10

Table 15.6-16

Feedwater Line Break Accident
Biological Effects of a Puff Release

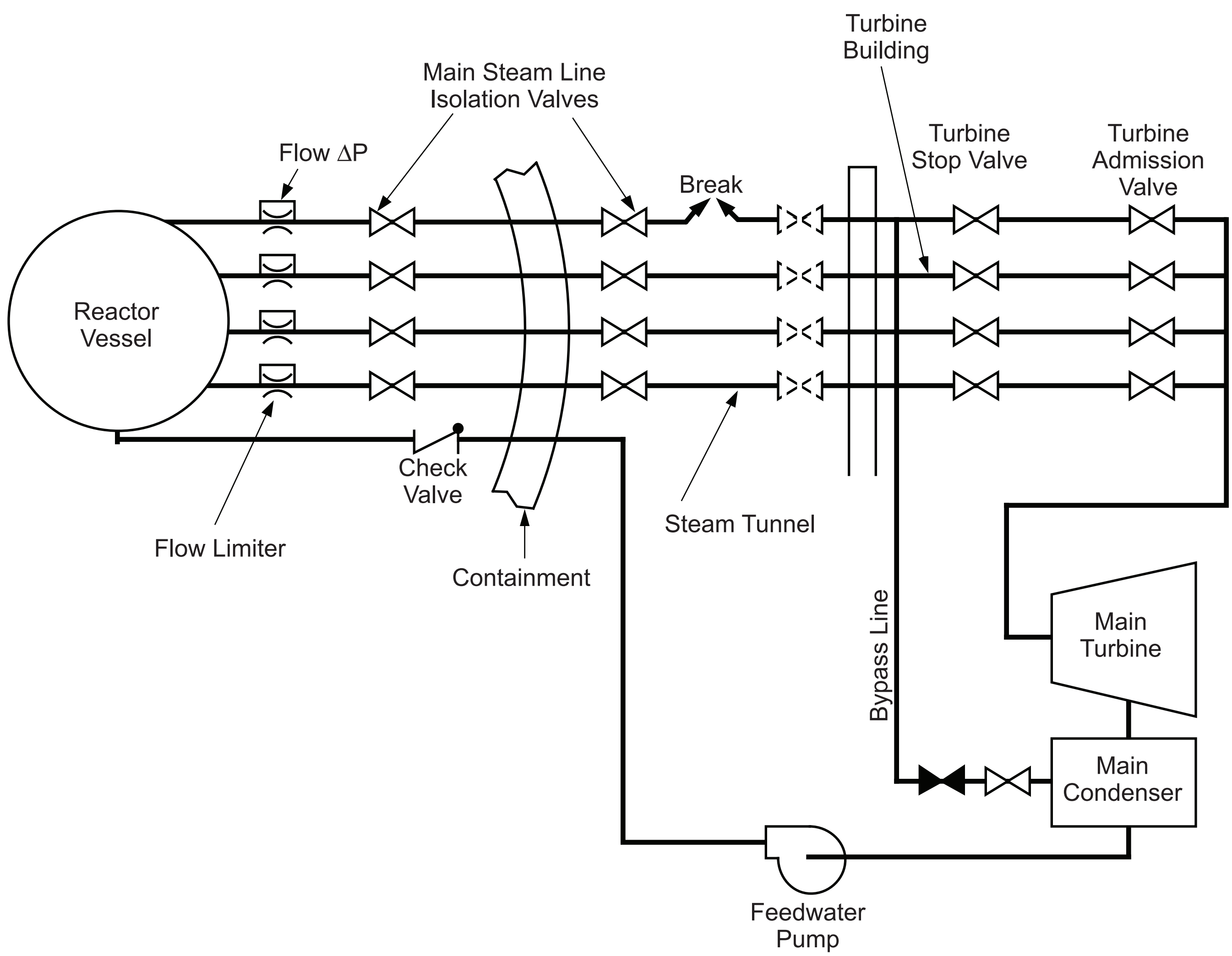
Area	Whole Body Dose (rem)	Thyroid Dose (rem)
Exclusion area (1950 m)	1.37×10^{-4}	5.47×10^{-3}
Low population zone (4827 m)	5.53×10^{-5}	2.21×10^{-3}



Columbia Generating Station
Final Safety Analysis Report

Leakage Path for Instrument Line Break

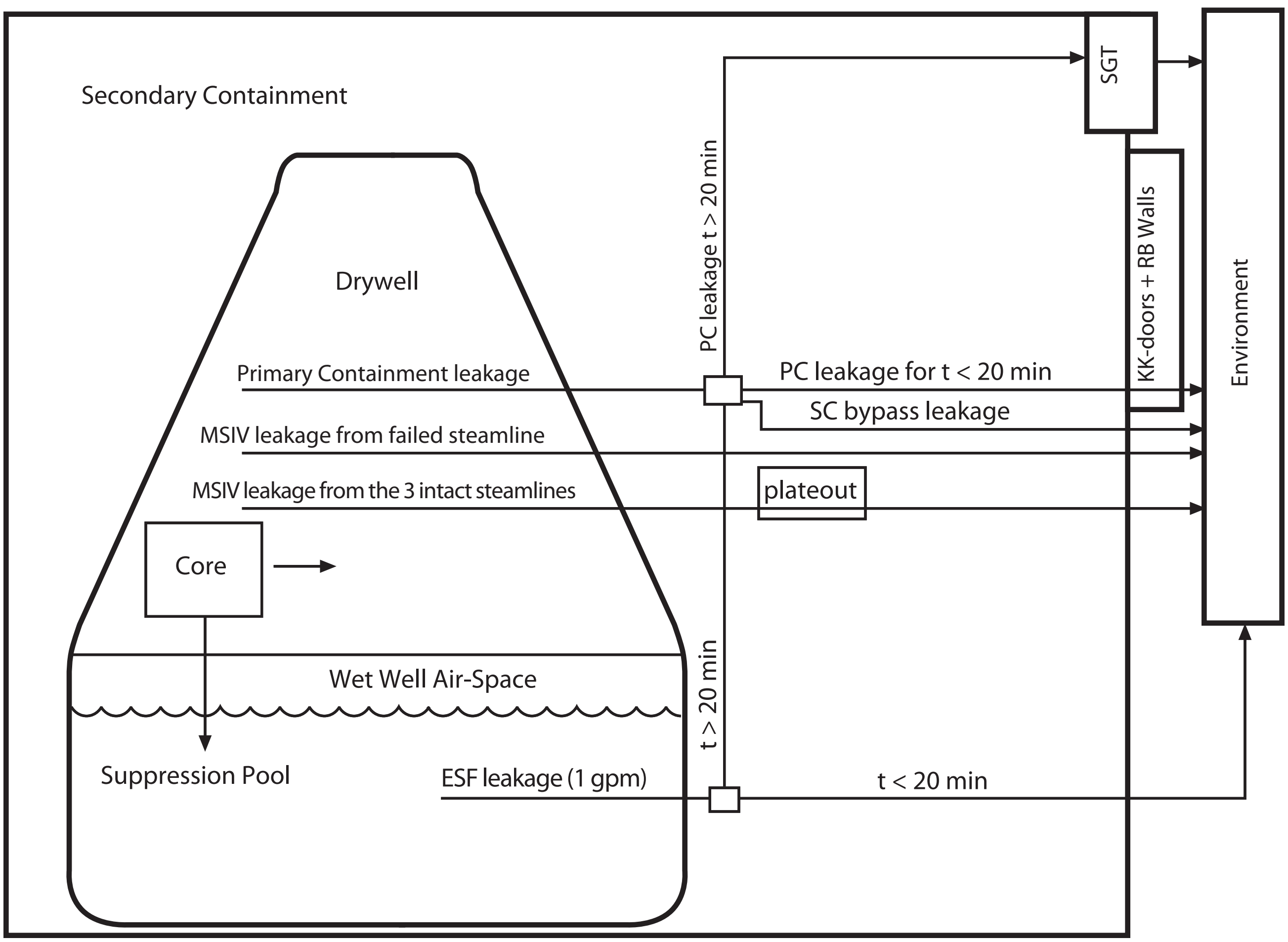
Draw. No. 900547.73 | Rev. | Figure 15.6-1



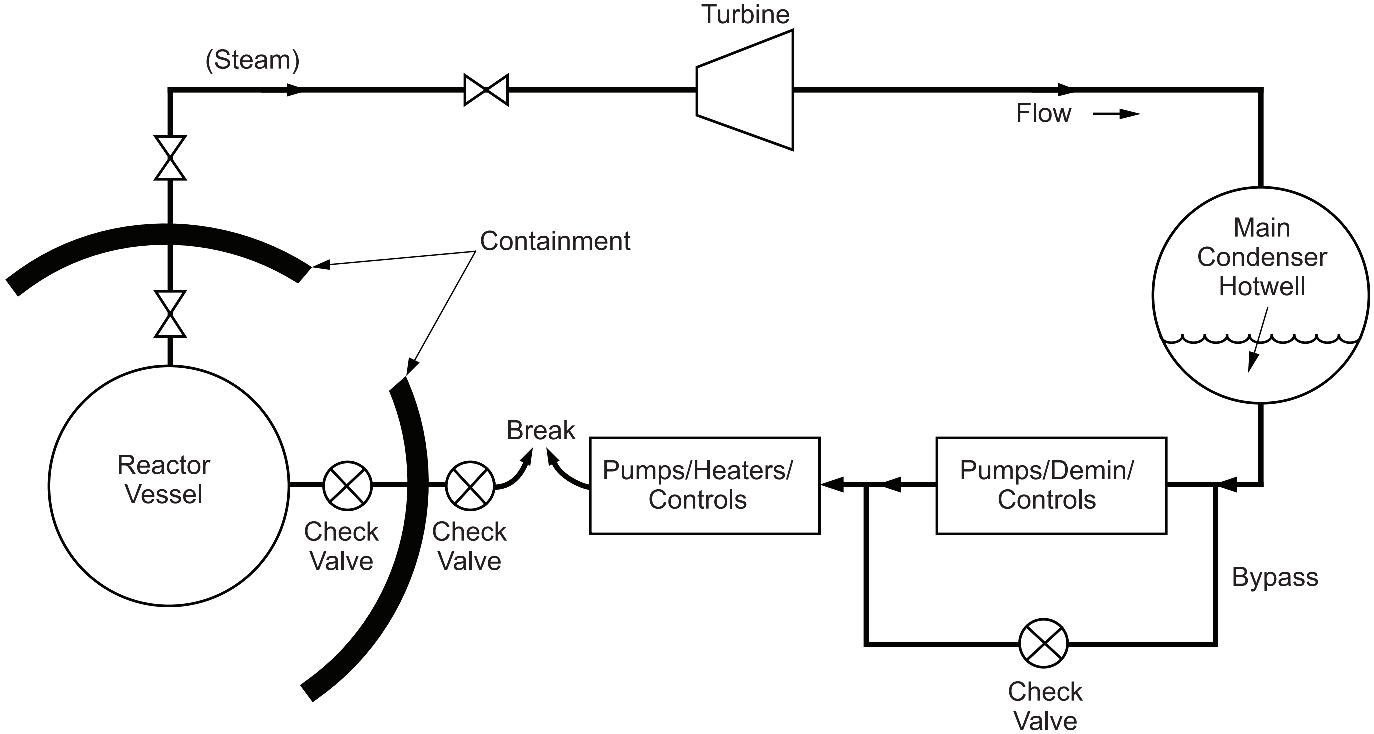
Columbia Generating Station
Final Safety Analysis Report

Steam Flow Schematic for Steam Break
Outside Containment

Draw. No. 900547.74 | Rev. | Figure 15.6-2



Leakage Path for LOCA



Leakage Path for Feedwater Line Break
Outside Containment

15.7 RADIOACTIVE RELEASE FROM SUBSYSTEMS AND COMPONENTS

These events are classified as nonlimiting events for both original and uprated power conditions. Therefore, no further analysis has been performed.

15.7.1 RADIOACTIVE GAS WASTE SYSTEM LEAK OR FAILURE

Not applicable.

15.7.2 LIQUID RADIOACTIVE SYSTEM FAILURE

Not applicable.

15.7.3 POSTULATED RADIOACTIVE RELEASES DUE TO LIQUID RADWASTE TANK FAILURE

15.7.3.1 Identification of Causes and Frequency Classification

15.7.3.1.1 Identification of Causes

The liquid radwaste tanks are constructed to specific engineering codes and standards and to the uniform building code seismic requirements. These tanks operate at atmosphere pressure and low temperatures. A positive action interlock system is provided to prevent inadvertent opening of a drain valve because of operator error. Accordingly, the possibility of a complete tank failure or drainage is considered small.

An unspecified event is postulated to cause the complete release of the average radioactivity inventory in the tank containing the largest quantities of significant radionuclides in the liquid radwaste system. The tank postulated to rupture is one of the two decontamination solution concentrated waste tanks (see Figure 11.2-1).

15.7.3.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.7.3.2 Sequence of Events and Systems Operation

15.7.3.2.1 Sequence of Events

The sequence of events expected to occur is as follows:

Sequence of Events - Liquid Radwaste Tank Failure

Events	Time
Event begins-failure occurs	0
Area radiation alarms alert plant personnel	~ 1 minute
Operator action begins	~ 10 minute

15.7.3.2.2 Systems Operation

Failure of a concentrated waste tank does not require a shutdown nor does it impair a safe shutdown. It will lead to limited operation of the concentrated waste system using the remaining tank.

The liquid contents of this tank will also be contained by the building walls and an unlined, 18-in. high concrete dike around the radwaste tank area. Floor drain sump pumps would receive a high water level alarm, activate automatically, and remove the spilled liquid.

15.7.3.2.3 The Effects of Single Failures and Operator Errors

This event has been analyzed without taking credit for any expected operator action or system operation; therefore, a discussion of single equipment failure or single operator error is not applicable.

15.7.3.3 Core and System Performance

The failure of this liquid radwaste system component does not directly affect the nuclear steam supply system (NSSS). It will lead to decoupling of NSSS with the subject system.

This failure has no applicable effect on the reactor core or the NSSS safety performance. Specific assumptions and parameters are presented in Table 15.7-1.

15.7.3.4 Barrier Performance

This event does not involve any containment barrier integrity except the tank itself and the radwaste building. The dike and walls of the radwaste building surrounding the tanks are built to Seismic Category I criteria. In the analysis of spill consequences, no credit is taken for the dike or radwaste building in recontaining the spilled liquid.

15.7.3.5 Radiological Consequences

The entire volume (700 gal) of concentrator waste tank assumed to spill with isotope inventory given in Table 11.2-1. Tritium concentration is assumed to be 0.01 µCi/ml (Environmental Report, Operating License Section 3.5.1).

The hypothetical radwaste tank failure was evaluated using conservative assumptions such as no containment in the radwaste building and unimpeded flow vertically through 50-60 ft of sand and gravel.

The following offsite concentration data for the radionuclides of interest are provided for the WNP-1/4 wells and at the Columbia River:

Radionuclide	Concentration at WNP-1/4 Wells (µCi/ml)	Concentration at Columbia River (µCi/ml)	Concentration Limit (µCi/ml)
^{3}H	1.0×10^{-7}	1.3×10^{-8}	1×10^{-3}
^{90}Sr	1.7×10^{-4}	4.2×10^{-7}	5×10^{-7}
^{137}Cs	2.2×10^{-10}	1.4×10^{-27}	1×10^{-6}

The calculations show the strontium concentration exceeding the unrestricted area limitation at the WNP-1/4 wells. These wells are a temporary water supply and are under the control of Energy Northwest. Should a spill occur there will be ample time to assess the severity and extent of contamination.

Concentration at the river bank will be diluted by the river flow. The nearest surface water users are several miles downstream.

15.7.4 FUEL HANDLING ACCIDENT

15.7.4.1 Identification of Causes and Frequency Classification

15.7.4.1.1 Identification of Causes

The fuel handling accident is assumed to occur as a consequence of a failure of the fuel assembly lifting mechanism resulting in dropping a raised irradiated fuel assembly onto other fuel bundles seated in the reactor pressure vessel (RPV). The event was selected as the bounding event because it considers the maximum height and weight, while assuming a minimum water level above the damaged fuel.

15.7.4.1.2 Frequency Classification

This event is categorized as a limiting fault.

15.7.4.2 Sequence of Events and Systems Operation

The following sequence of events is assumed in the analysis.

No fuel movement will take place in the first 24 hr following shutdown. At 24 hr post-shutdown fuel movement starts and the fuel handling equipment is assumed to fail dropping the fuel grapple and an irradiated fuel bundle onto the irradiated fuel bundles seated in the RPV. Fuel is damaged and fission products are released to the reactor coolant, then to the reactor building atmosphere, and finally to the environment over a 2-hr period. No credit is taken for holdup or mixing in the reactor building, nor is credit taken for filtration by the standby gas treatment (SGT).

15.7.4.2.1 The Effects of Single Failures and Operator Errors

No systems or operator actions are credited to mitigate a fuel handling accident.

15.7.4.3 Core and System Performance

15.7.4.3.1 Mathematical Model

Because of the complex nature of the impact and the resulting damage to fuel assembly components, a rigorous prediction of the number of failed rods is not possible. For this reason, a simplified energy approach was taken and numerous conservative assumptions were made to ensure a conservative estimate of the number of failed rods.

The kinetic energy acquired by a falling fuel assembly may be dissipated in one or more impacts. The energy absorption on successive impacts is estimated by considering a plastic impact.

The energy transferred in the dropped assembly is considered in two phases. First, the fuel assembly is expected to impact on the reactor core at a small angle from the vertical, inducing a bending mode of failure on the fuel rods of the dropped assembly. The kinetic energy of the fall is dissipated in the impact. The analysis assumes that the energy of the dropped assembly is absorbed by only the cladding and other core structures. The assumption that no energy is absorbed by the fuel material results in considerable conservatism in the mass-energy calculations. Half of the energy is dissipated in the structure of the dropped assembly, failing all the rods in the assembly. The remaining half is allocated evenly across the structural mass of the impacted assemblies. The energy dissipated by the cladding is calculated by multiplying the impacted assembly energy by the cladding mass fraction and dividing by the energy required to fail a rod (based on 1% uniform plastic deformation).

The second phase considers the kinetic energy developed by the irradiated fuel assembly and lifting mechanism tipping over and impacting the core horizontally. The kinetic energy developed is equal to the initial potential energy of the assembly relative to the top of the core. Again, half of the energy is absorbed by the dropped assembly and half by the impacted assemblies. The number of failed rods in the impacted assemblies is determined using the cladding mass fraction and the energy required to fail a rod.

15.7.4.3.2 Input Parameters and Initial Conditions

The parameters and conditions used to determine the number of failed rods are listed below:

a. The fuel assembly is dropped from a height of 34 ft. The maximum height allowed by the fuel handling equipment is less than 34 ft;

b. The dropped mass consists of a fuel assembly (600 lb bounding analyzed wet weight for GNF2 10 x 10 fuel, 586 lb bounding analyzed wet weight for GE14 10 x 10 fuel, 617 lb wet weight for GE 8 x 8 fuel and 665 lb dry weight for ATRIUM-10) and the fuel grapple (350 lb wet weight);

c. The energy required to fail a fuel rod is approximately 157 ft-lb for GNF2 10 x 10 fuel, 175 ft-lb for GE14 10 x 10 fuel, 250 ft-lb for GE 8 x 8 fuel and 205 ft-lb for ATRIUM-10; see Reference 15.7-3 for SVEA-96.

15.7.4.3.3 Results

Based on a core of GE 8 x 8 fuel, the calculation predicts 124 failed fuel rods; 62 rods in the dropped assembly, 43 rods in the first impact, and 19 additional rods in the second impact. Westinghouse analysis predicts a maximum of 123 failed rods (Reference 15.7-3) and AREVA NP calculated that up to 156 rods could fail (Reference 15.7-4). Analysis of the GE14 10 x 10 fuel estimates that a total of 151 fuel rods will fail (Reference 15.7-5). Analysis of GNF2 10 x 10 fuel estimates that a total of 172 fuel rods will fail.

15.7.4.4 <u>Barrier Performance</u>

The reactor coolant pressure boundary, primary containment and secondary containment are open at the time of the accident. However, a similar event could occur in the spent fuel pool (SFP), during spent fuel transfer from the RPV to, or handling in, the SFP. Assuming a drop height of 4 ft, the number of failed rods as a result of a GE 8 x 8 bundle (unchanneled) drop in the SFP was calculated and found to be 90 rods; the number for channeled GE 8 x 8 is less than that. The dose analysis for a drop of a bundle over the core, which assumes 250 failed rods, bounds a drop of a bundle in the SFP.

15.7.4.5 Radiological Consequences

The fission product inventory is based on a plant-specific ORIGEN 2 run for pre-power uprate basis of 3489 MW with 1000 days exposure adjusted as described in Section 15.4.9.5.1. The release is based on damage to 250 fuel rods. A 24-hr period for decay from the power condition is assumed. Figure 15.7-1 indicates the leakage flow path for this accident.

15.7.4.5.1 Design Basis Analysis

Specific values of parameters used in the evaluation are presented in Table 15.7-2. The dispersion coefficients used to determine offsite doses are presented in Table 15.0-4.

15.7.4.5.1.1 Fission Product Release From Fuel. The fission product inventory of a core average exposure fuel rod is adjusted by a peaking factor of 1.7 to establish the inventory of each damaged rod. Five percent of the noble gases inventory (10% for ^{85}Kr) and 5% of the iodine inventory (8% for ^{131}I), and 12% of the alkali metals inventory are assumed to be released to the reactor well. The activity airborne in the secondary containment is presented in Table 15.7-3.

15.7.4.5.1.2 Fission Product Transport to the Environment. The transport pathway consists of mixing in the reactor well water, migration from the reactor well to the secondary containment atmosphere, and release to the environment without passing through the SGT. All of the noble gas, 0.5% of the iodines, and 0% of the alkali metals are assumed to become airborne in the secondary containment (Reference 15.7-1).

From the activity airborne in the reactor building, 99% is released to the environment in 2 hr.

The release of activity to the environment is presented in Table 15.7-4.

15.7.4.5.1.3 Results. The calculated doses for the design basis analysis are presented in Table 15.7-5 and are within the limits of 10 CFR 50.67.

15.7.5 SPENT FUEL CASK DROP ACCIDENT

The spent fuel cask is equipped with ANSI N14.6 (Reference 15.7-2) compliant lifting lugs and a lifting yoke compatible with the reactor building crane main hook. The reactor building crane is provided with sufficient redundancy such that no credible postulated failure of any crane component required to lift, hold, and move loads, will result in the dropping of the fuel cask. Therefore, an analysis of the spent fuel cask drop is not required.

15.7.6 REFERENCES

15.7-1 Energy Northwest, "Columbia Generating Station Alternative Source Term," CGS-FTS-0168, Revision 2, June 2011.

15.7-2 "Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More," ANSI N14.6-1993, June 1993.

15.7-3 ABB/Combustion Engineering, "Fuel Assembly Mechanical Design Report for WNP-2," CE NPSD-792-P, May 1996.

15.7-4 AREVA NP, "Columbia Generating Station Cycle 19 Reload Analysis," ANP-2602, Revision 0, March 2007.

15.7-5 GEH-0000-0075-4920, "GE14 Fuel Design Cycle-Independent Analyses for Energy Northwest Columbia Generating Station" (most recent version referenced in the COLR).

Table 15.7-1

Liquid Radwaste Tanks Failure – Parameters and Concentrations

Parameter			Value
I.	Data and assumptions used to estimate radioactive source		Entire volume (700 gal) of concentrator waste tank assumed to spill with isotope inventory given in Table 11.2-1. Tritium concentration assumed to be 0.01 mCi/ml from the CGS ER-OL.
II.	Data and assumptions used to estimate activity released		
	A.	Containment leak rate (%/day)	N/A
	B.	Secondary containment leak rate (%/day)	N/A
	C.	Valve movement times	N/A
	D.	Absorption and filtration efficiencies	N/A
		(1) Organic iodine	N/A
		(2) Elemental iodine	N/A
		(3) Particulate iodine	N/A
		(4) Particulate fission products	N/A
	E.	Recirculation system parameters	N/A
		(1) Flow rate	N/A
		(2) Mixing efficiency	N/A
		(3) Filter efficiency	N/A
	F.	Containment spray parameters (flow rate, drop size, etc.)	N/A
	G.	Containment volumes	N/A
	H.	Other pertinent data and assumptions	See Section 2.4.13.3
III.	Concentration data		

Radionuclide	@ Col. R (μCi/ml)	@ WNP-1/4 Wells (μCi/ml)	Conc. Limit[a] (μCi/ml)
^{3}H	1.0×10^{-7}	1.3×10^{-8}	1×10^{-3}
^{90}Sr	1.7×10^{-4}	4.2×10^{-7}	5×10^{-7}
^{137}Cs	2.2×10^{-10}	1.4×10^{-27}	1×10^{-6}

[a] From 10 CFR Part 20.

Table 15.7-2

Fuel Handling Accident Parameters Tabulated for Postulated Accident Analysis

				Parameters	Design Basis Assumptions
I.	Data and assumptions used to estimate radioactive source from postulated accidents				
	A.	Power level			3556
		Fuel decay period			24 hrs
	B.	Radial peaking factor			1.7
	C.	Assumed fuel damaged			250 rods
		Bundles in the core			764
		Rods per bundle			62
	D.	Release of activity from the gap to the reactor well water			Figure 15.7-1
	E.	Iodine species fractions released			Figure 15.7-1
		(1)	Organic		
		(2)	Elemental		
		(3)	Particulate		
	F.	Reactor coolant activity before the accident			N/A
II.	Data and assumptions used to estimate activity released				
	A.	Primary containment leak rate (%/day)			N/A
	B.	Secondary containment release rate			99% of the activity in 2 hr with a flow rate of 2.3 SC volumes per hr
	C.	Valve movement times			N/A
	D.	SGT filtration			N/A
	E.	Scrubbing by reactor well water			Figure 15.7-1
		(1)	Organic iodine		
		(2)	Elemental iodine		
		(3)	Particulate iodine		
		(4)	Particulate alkali metals		

Table 15.7-2

Fuel Handling Accident Parameters Tabulated
for Postulated Accident Analysis (Continued)

Parameters	Design Basis Assumptions
F. Recirculation system parameters	
(1) Flow rate	N/A
(2) Mixing efficiency	N/A
(3) Filter efficiency	N/A
G. Containment spray parameters (flow rate, drop size, etc.)	N/A
H. Containment volumes	N/A
I. Other pertinent data and assumptions	
(1) SGT filtration	None
(2) CREF filtration	None
(3) Holdup in reactor building	None
(4) Mixing in reactor building	None
III. Dispersion data (for duration of release, 0 – 2 hr)	
(1) Offsite	Table 15.0-4
(2) Control room	8.69E-4 sec/m^3
IV. Dose data	
A. Method of dose calculation	Regulatory Guide 1.183
B. Dose conversion assumptions	Regulatory Guide 1.183
C. Peak activity concentrations in containment	N/A
D. Doses	Table 15.7-5

Table 15.7-3

Fuel Handling Accident
Activity Airborne in Secondary Containment (Curies)

Isotope	6 minutes	12 minutes	0.5 hr	1 hr	2 hr	4 hr	8 hr	1 day	4 days	30 days
^{131}I	2.64E+02	2.10E+02	1.05E+02	3.31E+01	3.29E+00	3.26E+00	3.22E+00	3.04E+00	2.35E+00	2.51E-01
^{132}I	1.95E-01	1.50E-01	6.87E-02	1.87E-02	1.39E-03	7.65E-04	2.33E-04	1.98E-06	9.73E-16	6.23E-20
^{133}I	1.58E+02	1.25E+02	6.19E+01	1.93E+01	1.86E+00	1.74E+00	1.52E+00	8.96E-01	8.21E-02	8.31E-11
^{134}I	1.54E-06	1.13E-06	4.44E-07	9.40E-08	4.21E-09	8.45E-10	3.40E-11	8.99E-17	6.50E-19	1.25E-36
^{135}I	2.72E+01	2.14E+01	1.04E+01	3.11E+00	2.80E-01	2.28E-01	1.51E-01	2.91E-02	1.75E-05	1.10E-22
Total iodine	4.49E+02	3.56E+02	1.77E+02	5.55E+01	5.43E+00	5.23E+00	4.90E+00	3.97E+00	2.43E+00	2.51E-01
^{83m}Kr	5.55E-01	4.25E-01	1.90E-01	4.98E-02	3.42E-03	1.62E-03	3.62E-04	9.06E-07	1.78E-18	7.63E-20
^{85m}Kr	2.10E+02	1.64E+02	7.85E+01	2.29E+01	1.95E+00	1.42E+00	7.57E-01	6.04E-02	6.91E-07	5.85E-21
^{85}Kr	1.06E+03	8.42E+02	4.22E+02	1.33E+02	1.33E+01	1.33E+01	1.33E+01	1.33E+01	1.33E+01	1.32E+01
^{87}Kr	3.24E-02	2.43E-02	1.03E-02	2.49E-03	1.44E-04	4.81E-05	5.39E-06	8.50E-10	9.87E-22	1.21E-30
^{88}Kr	6.26E+01	4.85E+01	2.26E+01	6.30E+00	4.91E-01	2.99E-01	1.11E-01	2.11E-03	3.80E-11	4.03E-22
^{89}Kr	6.66E-19	1.43E-19	1.54E-21	1.49E-23	1.56E-24	2.38E-20	3.88E-19	4.10E-20	1.19E-19	4.03E-51
^{131m}Xe	3.39E+02	2.70E+02	1.35E+02	4.26E+01	4.24E+00	4.22E+00	4.18E+00	4.02E+00	3.38E+00	7.55E-01
^{133m}Xe	1.58E+03	1.25E+03	6.26E+02	1.97E+02	1.94E+01	1.89E+01	1.80E+01	1.47E+01	5.95E+00	2.34E-03
^{133}Xe	6.73E+04	5.34E+04	2.68E+04	8.50E+03	9.24E+02	1.30E+03	1.98E+03	3.78E+03	4.60E+03	1.62E+02
^{135m}Xe	1.92E-20	1.17E-20	2.64E-21	2.22E-22	1.88E-24	1.85E-26	4.61E-28	1.38E-20	1.72E-21	7.32E-53
^{135}Xe	1.67E+04	1.32E+04	6.58E+03	2.14E+03	3.64E+02	1.02E+03	1.71E+03	1.39E+03	1.22E+01	5.37E-20
^{137}Xe	6.42E-21	1.76E-21	3.71E-23	2.48E-25	6.80E-27	4.31E-24	1.39E-19	1.11E-20	1.01E-20	8.74E-51
^{138}Xe	1.73E-20	1.07E-20	2.58E-21	2.42E-22	2.50E-24	2.92E-26	4.76E-28	1.83E-21	2.69E-22	3.34E-52
Total noble gases	8.73E+04	6.92E+04	3.47E+04	1.10E+04	1.33E+03	2.36E+03	3.73E+03	5.20E+03	4.63E+03	1.76E+02

Table 15.7-4

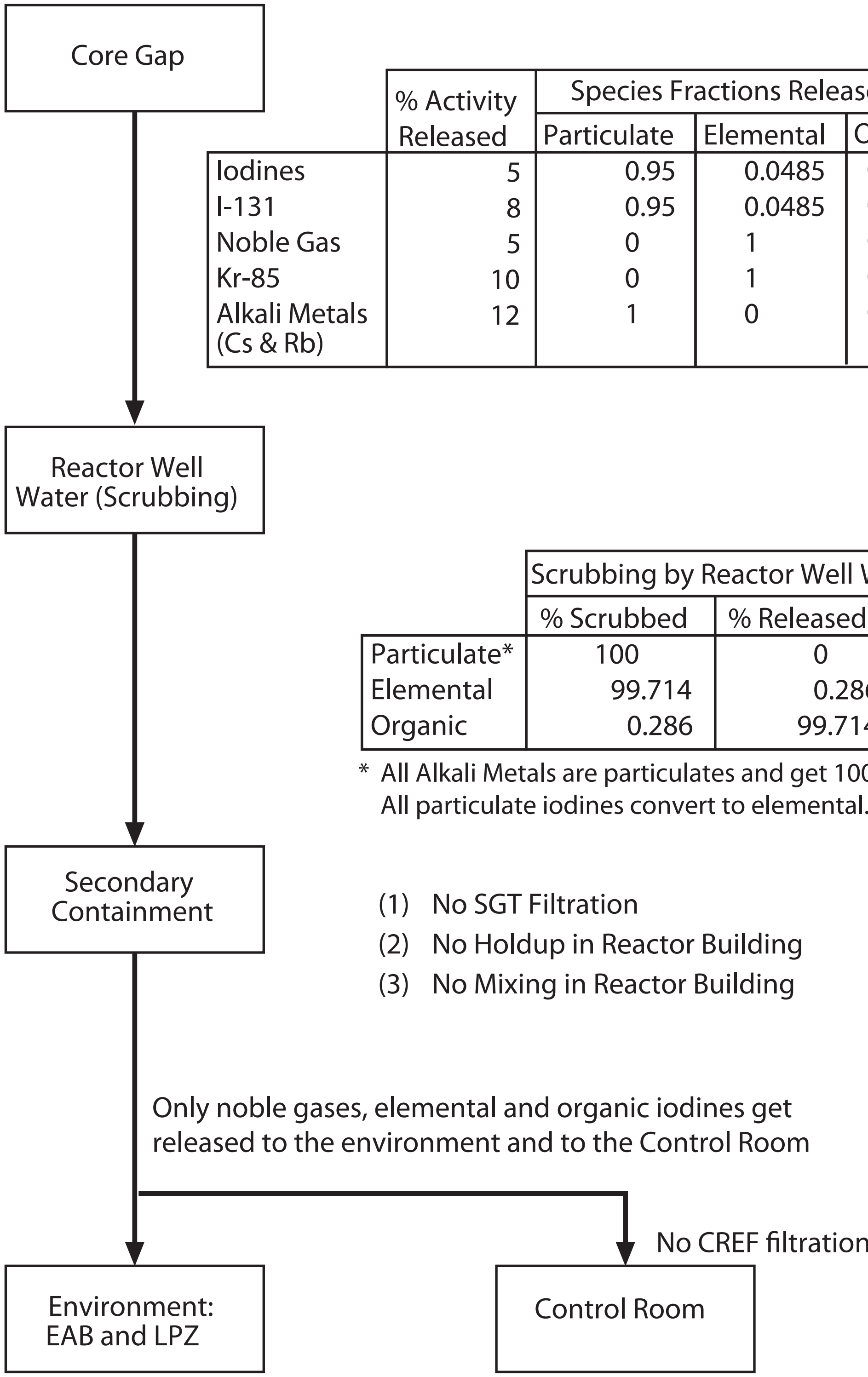
Fuel Handling Accident
Activity Released to the Environment (Curies)

Isotope	6 minutes	12 minutes	0.5 hr	1 hr	2 hr	4 hr	8 hr	1 day	4 days	30 days
^{131}I	6.84E+01	1.23E+02	2.28E+02	2.98E+02	3.28E+02	3.28E+02	3.29E+02	3.29E+02	3.29E+02	3.29E+02
^{132}I	5.12E-02	9.07E-02	1.63E-01	2.07E-01	2.23E-01	2.23E-01	2.23E-01	2.23E-01	2.23E-01	2.23E-01
^{133}I	4.09E+01	7.33E+01	1.35E+02	1.77E+02	1.95E+02	1.95E+02	1.95E+02	1.95E+02	1.95E+02	1.95E+02
^{134}I	4.16E-07	7.21E-07	1.23E-06	1.49E-06	1.56E-06	1.56E-06	1.56E-06	1.56E-06	1.56E-06	1.56E-06
^{135}I	7.07E+00	1.26E+01	2.31E+01	3.01E+01	3.28E+01	3.28E+01	3.28E+01	3.28E+01	3.28E+01	3.28E+01
Total iodine	1.16E+02	2.09E+02	3.86E+02	5.06E+02	5.56E+02	5.56E+02	5.57E+02	5.57E+02	5.57E+02	5.57E+02
^{83m}Kr	1.47E-01	2.59E-01	4.61E-01	5.81E-01	6.21E-01	6.21E-01	6.21E-01	6.21E-01	6.21E-01	6.21E-01
^{85m}Kr	5.49E+01	9.78E+01	1.78E+02	2.30E+02	2.50E+02	2.50E+02	2.50E+02	2.50E+02	2.50E+02	2.50E+02
^{85}Kr	2.75E+02	4.93E+02	9.13E+02	1.20E+03	1.32E+03	1.32E+03	1.32E+03	1.32E+03	1.32E+03	1.32E+03
^{87}Kr	8.63E-03	1.51E-02	2.64E-02	3.28E-02	3.47E-02	3.47E-02	3.47E-02	3.47E-02	3.47E-02	3.47E-02
^{88}Kr	1.64E+01	2.92E+01	5.26E+01	6.73E+01	7.26E+01	7.26E+01	7.26E+01	7.26E+01	7.26E+01	7.26E+01
^{89}Kr	3.64E-19	4.43E-19	4.64E-19	4.64E-19	4.64E-19	4.64E-19	4.65E-19	4.78E-19	4.38E-16	1.27E-13
^{131m}Xe	8.80E+01	1.58E+02	2.92E+02	3.85E+02	4.23E+02	4.23E+02	4.23E+02	4.23E+02	4.23E+02	4.23E+02
^{133m}Xe	4.10E+02	7.35E+02	1.36E+03	1.79E+03	1.96E+03	1.96E+03	1.96E+03	1.96E+03	1.96E+03	1.96E+03
^{133}Xe	1.74E+04	3.13E+04	5.79E+04	7.63E+04	8.40E+04	8.40E+04	8.40E+04	8.40E+04	8.40E+04	8.40E+04
^{135m}Xe	5.74E-21	9.23E-21	1.34E-20	1.46E-20	1.47E-20	1.47E-20	1.47E-20	1.47E-20	9.44E-18	1.02E-13
^{135}Xe	4.34E+03	7.78E+03	1.44E+04	1.89E+04	2.10E+04	2.10E+04	2.10E+04	2.10E+04	2.10E+04	2.10E+04
^{137}Xe	3.03E-21	3.86E-21	4.16E-21	4.17E-21	4.17E-21	4.17E-21	4.31E-21	2.95E-20	8.44E-16	1.27E-13
^{138}Xe	5.10E-21	8.26E-21	1.22E-20	1.34E-20	1.35E-20	1.35E-20	1.35E-20	1.35E-20	5.69E-18	1.05E-13
Total noble gases	2.26E+04	4.06E+04	7.51E+04	9.89E+04	1.09E+05	1.09E+05	1.09E+05	1.09E+05	1.09E+05	1.09E+05

Table 15.7-5

Fuel Handling Accident (Design Basis Analysis)
Radiological Effects

Area	TEDE (rem)
Exclusion area (1950 m) (2 hr)	1.0
Low population zone (4827 m) (30 day)	0.3
Control room (30 day)	3.7



	% Activity Released	Species Fractions Released		
		Particulate	Elemental	Organic
Iodines	5	0.95	0.0485	0.0015
I-131	8	0.95	0.0485	0.0015
Noble Gas	5	0	1	0
Kr-85	10	0	1	0
Alkali Metals (Cs & Rb)	12	1	0	0

	Scrubbing by Reactor Well Water		
	% Scrubbed	% Released	DF
Particulate*	100	0	∞
Elemental	99.714	0.286	350
Organic	0.286	99.714	1

* All Alkali Metals are particulates and get 100% scrubbed, All particulate iodines convert to elemental.

(1) No SGT Filtration
(2) No Holdup in Reactor Building
(3) No Mixing in Reactor Building

Only noble gases, elemental and organic iodines get released to the environment and to the Control Room

Leakage Path for Fuel Handling Accident

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

15.8.0 CAPABILITIES OF PRESENT DESIGN TO ACCOMMODATE ANTICIPATED TRANSIENTS WITHOUT SCRAM

The anticipated transients without scram (ATWS) events described in this section are not design basis events for Columbia Generating Station (CGS). A proposed method for minimizing the effects of failure-to-scram is described in References 15.8-1 and 15.8-2.

The recirculation pump trip (RPT), alternate rod insertion (ARI), and two pump standby liquid control (SLC) system operation features are utilized at CGS to provide protection against failure to scram. Due to the CGS design feature utilizing SLC system injection through the high-pressure core spray (HPCS) header, a plant-unique analysis was performed to demonstrate ATWS protection and mitigation at pre-power uprate conditions.

The ATWS acceptance criteria are established in Reference 15.8-3 as:

a. The reactor coolant pressure boundary (RCPB) remains below emergency pressure limits,

b. The containment pressure remains below design limits. The suppression pool temperature remains below local saturation temperature limits as defined in Reference 15.8-3,

c. A coolable geometry is maintained,

d. Radiological releases are maintained within 10 CFR 100 allowable limits. With implementation of Alternate Source Term (AST), the radiological release acceptance criterion becomes 10 CFR 50.67, and

e. Equipment necessary to mitigate the postulated ATWS event are evaluated to provide a high degree of assurance (assurance of function) that it will function in the environment (pressure, temperature, humidity, and radiation) predicated to occur as a result of the ATWS event.

The ATWS analysis, performed in conformance with NEDE-24222, did not include a SLCS pump suction valve delay in the SLCS injection time. To determine the impact of the 35 sec opening time for the suction valves upstream of the SLCS pumps, the limiting ATWS event for peak suppression pool temperature (i.e., MSIVC) was analyzed with the 35 sec delay in SLC system injection time. The results presented for the hot shutdown time, peak suppression pool temperature, and peak containment pressure for MSIVC in Table 15.8-3 include the effects of the 35 sec delay.

Section 15.8.9 shows that for the ATWS event with the most severe heat flux transient, fuel related applicable limits were met with considerable margins. In addition, Reference 15.8-3 concludes that maximum peak cladding temperature will not exceed 2200°F and the maximum local oxidation will be much less than 17%. Thus, criteria 3 and 4 are shown to be satisfied by the plant specific and generic analyses. Sections 15.8.7 and 15.8.9 show that resulting primary system pressures will be less than emergency pressure limit and that suppression pool temperature increase and peak pressure are within design limits. Reference 15.8-3 concludes that the safety/relief valve (SRV) air clearing loads will be bounded by the design loads. Thus criteria 1 and 2 are satisfied. In Reference 15.8-5, Energy Northwest concluded that ATWS equipment had been determined to be qualified by (a) materials analysis of agreeable components including test reports when available, (b) existing qualification to other accident profiles (LOCA, HELB) that encompass the ATWS profile, or (c) location in a mild environment that is not affected by the ATWS accident environment. This satisfies criterion 5.

Power Uprate Evaluation

The ATWS events were analyzed at power uprate operating conditions to demonstrate protection and mitigation of the consequences of these events. These analyses were performed at 3629 MWt power level and bound operation at uprate power level of 3544 MWt. The selection of critical events which were analyzed were guided by Reference 15.8-3.

For power uprate evaluation, it was conservatively assumed that ARI has failed, thus, requiring SLC system injection to achieve reactor shutdown.

The analysis presented herein are applicable to application of flow control valve (FCV) or adjustable speed drive to reactor recirculation system (RRC). A summary of ATWS results are shown in Table 15.8-3. The analysis results presented in this section are based on a representative reload core at the time of the analysis (Cycle 8). Power uprate ATWS analyses were performed with Extended Load Line Limit Analysis (ELLLA) operating conditions. These analyses show that performance at the power uprate condition is within vessel maximum pressure, fuel temperature and containment pressure limits for the most severe ATWS transients (Reference 15.8-6).

Maximum Extended Load Line Limit Analysis (MELLLA)

The ATWS events were analyzed at MELLLA operating conditions to demonstrate protection and mitigation of the consequences of these events. These analyses were performed at 3486 MWt power level. The selection of critical events which were analyzed was guided by References 15.8-8, 15.8-10 and 15.8-11.

It was conservatively assumed that ARI has failed, thus requiring SLC system injection to achieve reactor shutdown. ATWS mitigation is achieved with one or two subsystems of SLC provided the SLC solution is enriched to 44 atom percent Boron-10.

A summary of ATWS results are shown in Table 15.8-3. The analysis results presented in this section are based on a representative reload core at the time of the analysis (Cycle 20) (Reference 15.8-12). The analysis was dispositioned for GNF2 fuel introduction (reference 15.8-13).

The analysis was dispositioned for power uprate to 3544 MWt (Reference 15.8-14).

15.8.1 INADVERTENT CONTROL ROD WITHDRAWAL

This transient is bounded by assumptions in the GE licensing topical reports and the other transients analyzed in this section.

15.8.2 LOSS OF FEEDWATER

15.8.2.1 Identification of Causes and Frequency Classification

15.8.2.1.1 Identification of Causes

Section 15.2.7 provides identification of causes for loss of feedwater event. The loss of feedwater event with failure to scram will initiate an ATWS event.

15.8.2.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.2.2 Sequence of Events and System Operation

15.8.2.2.1 Sequence of Events

Table 15.8-4 lists the sequence of events for Figure 15.8-1.

15.8.2.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed.

a. Allow automatic operation of the HPCS and reactor core isolation cooling (RCIC),

b. Begin boron injection at two minutes following ATWS high-pressure trip or at boron injection initiation temperature (BIIT), whichever is later, and

c. Switch residual heat removal (RHR) to suppression pool cooling mode 11 minutes following initiation of the transient.

The emergency operating procedures provide operator actions for an ATWS event.

15.8.2.2.2 System Operation

For the loss of feedwater ATWS event, a complete failure to scram is postulated to occur for all reactor protection system (RPS) scram signals. All other plant control systems maintain normal operation. The relief valves are all assumed to function at the specified setpoints. Loss of feedwater flow results in a proportional reduction of vessel inventory causing the vessel water level to drop. The first corrective action is the initiation of HPCS and RCIC on Level 2. For this event, a complete failure of ARI is postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.2.2.3 The Effect of Single Failure and Operator Errors

This ATWS event is based on the assumed complete failure of all control rods to scram. This is a multiple equipment failure. For the conservative assumption of failure of the ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. This event is less limiting compared with other ATWS events analyzed at power uprate condition.

15.8.2.3 Core and System Performance

15.8.2.3.1 Mathematical Model

Reference 15.8-7 describes the generic evaluation methodology for the ATWS event evaluated at uprated power conditions. Additional plant specific analyses were performed for a bounding 10% power uprate using the same methodology.

15.8.2.3.2 Input Parameters and Initial Conditions

The initial operating conditions and equipment performance characteristics are given in Tables 15.8-1 and 15.8-2, respectively. MSIV closure occurs on low-low-low water level (L1) but is analyzed based on low-low water level (L2), conservatively overpredicting suppression pool heatup. The HPCS/RCIC flow rates are conservatively high and water level setpoints represent nominal values. The ATWS high pressure setpoint was set at the upper analytical limit. The SRV setpoints were set using a statistical spread of the analytical setpoint limits for the first opening of each value and reset to a statistical spread of the nominal setpoints for all remaining SRV openings during the transient event.

15.8.2.3.3 Results

The results of this ATWS event simulation are shown in Figure 15.8-1. Feedwater pump trip is assumed to occur at the onset of the event. Upon the loss of the feedwater flow, reactor pressure, water level, and neutron flux begin to fall. Once reactor water level reaches low-low water level (L2), the protection system trips the recirculation pumps, initiates HPCS and RCIC and signals closure of main steam line isolation valves (MSIVs). Reactor pressure begins to rise due to closure of MSIVs. The relief valves begin to open due to reactor pressure increase. It is conservatively assumed the operator manually initiates SLC system 2 minutes after the ATWS setpoint has been reached.

15.8.2.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analysis assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

15.8.2.4 Barrier Performance

The calculated peak vessel bottom head pressure is 1202 psig, which is below the American Society of Mechanical Engineers (ASME) Code Limit of 1375 psig for the RCPB and well below the ASME service level C of 1500 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Therefore, barrier integrity and function is maintained.

15.8.2.5 Radiological Consequences

While this event does not result in fuel failure it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.3 LOSS OF ALTERNATE CURRENT POWER

This transient is bounded by the other transients analyzed in this section.

15.8.4 LOSS OF ELECTRICAL LOAD

This transient is bounded by assumptions in the GE licensing topical reports and the other transients analyzed in this section. (Reference 15.8-11)

15.8.5 LOSS OF CONDENSER VACUUM

This transient is bounded by assumptions in the GE licensing topical reports and the other transients analyzed in this section.

15.8.6 TURBINE TRIP

This event was analyzed at pre-power uprate condition for low power and full power (corresponding to 3323 MWt) operation. At uprated conditions, the event is bounded by the other transients analyzed in this section. The selection of critical events were guided by Reference 15.8-3.

15.8.7 CLOSURE OF MAIN STEAM LINE ISOLATION VALVES

15.8.7.1 Identification of Causes and Frequency Classification

15.8.7.1.1 Identification of Causes

Various steam line and nuclear system malfunctions, or operator actions, can initiate MSIV closure. These are detailed in Section 15.2.4. The MSIV closure event with failure to scram will initiate an ATWS event.

15.8.7.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.7.2 Sequence of Events and System Operation

15.8.7.2.1 Sequence of Events

Table 15.8-5 lists the sequence of events for Figure 15.8-2.

15.8.7.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed:

a. Allow automatic operation of RCIC, inhibit HPCS consistent with Emergency Operating Procedures,

b. Begin boron injection at 2 minutes following ATWS high-pressure trip or at BIIT, whichever is later, and

c. Switch RHR to suppression pool cooling mode 11 minutes following initiation of the transient.

Emergency Operating Procedures provide operator actions for an ATWS event.

15.8.7.2.2 System Operation

For the MSIV closure ATWS event, a complete failure to scram is postulated to occur for all RPS scram signals. All other plant control systems maintain normal operation. The relief valves are all assumed to function at the specified setpoints. The RPT occurs at the ATWS high pressure trip setpoint. For this event, a complete failure of ARI is postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.7.2.3 The Effect of Single Failures and Operator Errors

For the conservative assumption of failure of ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. Relief valves operate to limit system pressure. All of these aspects are designed to single failure criterion. Analyses have been performed for dual and single SLC pump operation with natural of 44 atom percent Boron-10 enrichment, respectively. The single pump SLC transport time delay accounts for the reduced flow rate in the system.

15.8.7.3 Core and System Performance

15.8.7.3.1 Mathematical Model

References 15.8-8, 15.8-11 and 15.8-12 describes the generic evaluation methodology for the ATWS event under MELLLA conditions.

15.8.7.3.2 Input Parameters and Initial Conditions

The initial operating conditions and equipment performance characteristics are given in Table 15.8-1A. The ATWS high pressure setpoint was set at the upper analytical limit. The SRV setpoints were set using a statistical spread of the analytical setpoint limits for the first opening of each value and reset to a statistical spread of the nominal setpoints for all remaining SRV openings during the transient event.

15.8.7.3.3 Results

The results of this ATWS event simulation are shown in Table 15.8-3 and Figure 15.8-2. The MSIVs close within a nominal 4 sec stroke time. Once the MSIVs reach the 85% open position, a reactor scram is initiated. The scram was assumed to fail to insert any control rods. The rapid increase in reactor pressure generates rapid increase in reactor core power due to collapsing core voids. The relief valves begin to open responding to reactor pressure rise. Upon reaching the ATWS high-pressure setpoint, the RPT occurs and reduces core power. It is conservatively assumed the operator manually initiates SLC system 2 minutes after the ATWS setpoint has been reached.

The peak calculated vessel bottom head pressure is below the ASME Service Level C limit of 1500 psig.

The calculated peak suppression pool temperature of the event is below the containment design limit. The calculated peak containment pressure is also below the containment design limit.

15.8.7.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analyses assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

c. A 35 sec opening time for the suction values upstream to the SLCS pumps was modeled increasing the SLCS initiation time.

15.8.7.4 Barrier Performance

The calculated peak vessel bottom head pressure is below the ASME Service Level C limit of 1500 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containments are designed. Therefore, these barrier integrity and function is maintained.

15.8.7.5 Radiological Consequences

While this event does not result in fuel failure it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.8 INADVERTENT OPENING OF RELIEF VALVE

15.8.8.1 Identification of Causes and Frequency Classification

15.8.8.1.1 Identification of Causes

This event assumes that a SRV may "open" and stick in the "open" position. These events are detailed in Section 15.1.4. The inadvertent opening of relief valve (IORV) event with failure to scram will initiate an ATWS event.

15.8.8.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.8.2 Sequence of Events and System Operation

15.8.8.2.1 Sequence of Events

The analysis has not been updated for the change in MSIV isolation setpoint from Level 2 to Level 1 because the analysis is bounding and conclusions of the analysis are not affected (Reference 15.8-9).

Table 15.8-7 lists the sequence of events for Figure 15.8-4.

15.8.8.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed:

a. Initiate boron injection 2 minutes after BIIT,
b. Disable HPCS, RCIC, and low level MSIV closure,
c. Use feedwater to manually control the water level at the top of active fuel, and
d. Manually trip the recirculation pumps.

15.8.8.2.1.2 System Operation. For the IORV ATWS event, a complete failure to scram is postulated to occur for all RPS scram signals. All other plant control systems maintain normal operation. For this event, a complete failure of ARI is also postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.8.2.2 The Effect of Single Failures and Operator Errors

For the conservative assumption of failure of ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. This is a multiple equipment failure event. All of these aspects are designed to single failure criterion.

The instrumentation, which detects and audibly alarms the resulting suppression pool temperature rise, and the RHR containment heat removal system are designed to meet the single failure criteria. The operator must, however, manually initiate suppression pool cooling.

15.8.8.3 Core and System Performance

15.8.8.3.1 Mathematical Model

Reference 15.8-7 describes the generic evaluation methodology for the ATWS event evaluated at uprated power conditions. Additional plant specific analyses were performed for a bounding 10% power uprate using the same methodology.

15.8.8.3.2 Input Parameters and Initial Conditions

The initial operating conditions and equipment performance characteristics are given in Tables 15.8-1 and 15.8-2, respectively. The HPCS/RCIC flow rates are conservatively high and water level setpoints represent nominal values. The ATWS high pressure setpoint was set at the upper analytical limit. The SRV setpoints were set using a statistical spread of the analytical setpoint limits for the first opening of each value and reset to a statistical spread of the nominal setpoints for all remaining SRV openings during the transient event.

15.8.8.3.3 Results

The results of this ATWS event simulation are shown in Figure 15.8-4. The opening of a SRV allow steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient.

Discharge of steam into the suppression pool increases the suppression pool temperature. The operator initiates SLC system 2 minutes after the suppression pool temperature reaches 110°F, trips the recirculation pumps, and initiates feedwater runback to lower the reactor water level to top of active fuel (TAF). Suppression pool cooling begins 11 minutes after the initiation of the event. The operator disables HPCS and RCIC level 2 initiation. The MSIV Level 2 closure is also disabled. Turbine steam flow is terminated upon closure of the MSIVs due to low steam line pressure.

15.8.8.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analysis assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

15.8.8.4 Barrier Performance

The IORV ATWS event is a mild depressurization which has no significant effect on RCPB. During the event, the suppression pool is continually heated due to SRV discharge. The peak suppression pool temperature and pressure are within the design criteria of the containment.

15.8.8.5 Radiological Consequences

While this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.9 PRESSURE REGULATOR FAILURE - OPEN (PREGO)

15.8.9.1 Identification of Causes and Frequency Classification

15.8.9.1.1 Identification of Causes

The causes for this event is detailed in Section 15.1.3. The PREGO event with failure to scram will initiate an ATWS event.

15.8.9.1.2 Frequency Classification

This event is of extremely low probability and is categorized as a limiting fault.

15.8.9.2 Sequence of Events and System Operation

15.8.9.2.1 Sequence of Events

Table 15.8-8 lists the sequence of events for Figure 15.8-5.

15.8.9.2.1.1 Identification of Operator Actions. For the simulation purpose, the following operator actions have been assumed.

a. Allow automatic operation of RCIC, inhibit HPCs consistent with Emergency Operating Procedures,

b. Begin boron injection at 2 minutes following ATWS high-pressure trip or at BIIT, whichever is later, and

c. Switch RHR to suppression pool cooling mode 11 minutes following initiation of the transient.

The emergency operating procedures provide operator actions for an ATWS event.

15.8.9.2.1.2 System Operation. For the PREGO ATWS event, a complete failure to scram is postulated to occur for all RPS scram signals. All other plant control systems maintain normal operation. For this event, a complete failure of ARI is also postulated. The operator must manually initiate SLC system to inject boron into the reactor vessel for reactor shutdown.

15.8.9.2.3 The Effect of Single Failures and Operator Errors

For the conservative assumption of failure of ARI system, the ATWS event is terminated by boron injection through operator activation of the SLC system. This is a multiple equipment failure event. All of these aspects are designed to single failure criterion.

The instrumentation, which detects and audibly alarms the resulting suppression pool temperature rise, and the RHR containment heat removal system are designed to meet the single failure criteria.

15.8.9.3 Core and System Performance

15.8.9.3.1 Mathematical Model

References 15.8-8, 15.8-11 and 15.8-12 describe the generic evaluation methodology for the ATWS event under MELLLA conditions.

15.8.9.3.2 Input Parameters and Initial Conditions

The initial operating conditions an equipment performance characteristics are given in Table 15.8-1A. The ATWS high pressure setpoint was set at the upper analytical limit. The SRV setpoints were set using a statistical spread of the analytical setpoint limits for the first opening of each value and reset to a statistical spread of the nominal setpoints for all remaining SRV openings during the transient event.

15.8.9.3.3 Results

The results of this ATWS event simulation are shown in Table 15.8-3 and Figure 15.8-5. The DEH control system failure with 130% steam flow demand signal is assumed to occur. Ensuing reactor depressurization results in formation of voids in the reactor coolant and causes a decrease in reactor power almost immediately. The MSIV closure occurs due to trip signal from low steam line pressure. Reactor pressure rises to the relief setpoints and the recirculation pumps trip on the high pressure ATWS setpoint.

Discharge of steam into the suppression pool increases the suppression pool temperature. The operator initiates feedwater runback to lower the reactor water level to TAF after the suppression pool temperature reaches 110°F. The HPCS and RCIC systems are initiated at low reactor water level. The SLC system is manually initiated 2 minutes after the ATWS high pressure setpoint was reached.

15.8.9.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system setpoints, system capacities, and system response times. For ATWS transient analyses, best estimated values are used when possible. Examples of conservative bounding values which were used to cover uncertainties are as follows:

a. For conservatism, the analysis assumed the highest probable ATWS high-pressure trip setpoint, and

b. Boron injection is the later time of BIIT or 2 minutes following ATWS high-pressure trip.

15.8.9.4 Barrier Performance

The calculated peak vessel bottom head pressure is below the ASME Service Level C limit of 1500 psig. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel pressure vessel or containment are designed. Therefore, barrier integrity and function is maintained.

15.8.9.5 Radiological Consequences

While this event does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool by means of SRV operation. Since this activity is contained in the primary containment, there will be no uncontrolled release to the environment.

15.8.10 SINGLE REACTOR RECIRCULATION SYSTEM PUMP OPERATION

The following discussion is based on pre-uprate power level of 3323 MWt. Thus, the 100% rod line corresponds to 3323 MWt power at rated core flow.

For pre-uprate condition, it was shown that operation of the plant with only a single RRC pump and the resulting transient conditions which could occur while in this mode are bounded by the other transients analyzed in this section, and the parametric studies performed in Reference 15.8-4. This conclusion was based on evaluating the effects of power, void reactivity worth and doppler worth at both 100% conditions, and at conditions present under single RRC pump operation.

Sensitivity studies presented in Reference 15.8-4 compare the turbine trip at 100% power condition with the turbine trip at lower power conditions, such as one would have under single RRC pump.

The rod line for single RRC pump operation for pre-uprate condition was normally maintained between 100% and 104.25% power level. At less than 100% power the average void in the core was slightly higher for operation on the 104.25% rod line than for operation on the 100% rod line. In addition, the doppler worth at lower power conditions is higher than at 100% power. The presence of higher voids and the increased doppler worth when operating at the 104.15% rod line is bounded by the parametric analyses in Reference 15.8-4. These parametric analyses determined the sensitivity of plant response between the MSIV closure at 100% power and the MSIV closure with higher reactivity coefficients at 100% power. The void worth assumed in the higher reactivity coefficient case gives a much higher effect than the increased average void present in the single RRC pump operation mode at the 104.25% rod line, which bounds this case. The doppler reactivity worth used in the MSIV closure with higher reactivity coefficients is representative of the doppler reactivity worth found at lower power conditions such as those present in the single RRC pump operation mode.

15.8.11 REFERENCES

15.8-1 Hatch Unit 1 FSAR. Amendment 10, Appendix L, "Failure-to-Scram Analysis," October 27, 1971.

15.8-2 Michelotti, L. A., "Analysis of Anticipated Transients Without Scram," NEDO-10349.

15.8-3 NEDE-24222, "Assessment of BWR Mitigation of ATWS, Volume II (NUREG-0460 Alternate No. 3)."

15.8-4 EI International, Inc., "Final Report, Anticipated Transients Without Scram Analysis for the WNP-2 Nuclear Power Plant," SA-JAD-087-90, December 1989.

15.8-5 Supply System Letter G02-90-116, G. C. Sorensen (Supply System) to NRC, "Nuclear Plant No. 2. Operating License (NPF-21 Resolution of Anticipated Transient Without Scram (ATWS) for WNP- 2," dated June 29, 1990.

15.8-6 GE Nuclear Energy, "WNP-2 Power Uprate Project NSSS Engineering Report," GE-NE-208-17-0993, Revision 1, December 1994.

15.8-7 GE Nuclear Energy, "Generic Evaluations of General Electric Boiling Water Reactor Power Uprate," Licensing Topical Report NEDC-31984P, July 1991 and Supplements 1 & 2.

15.8-8 "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32424P-A, February 1999 (ELTR-1).

15.8-9 GE Hitachi Nuclear Energy, "License Amendment Request for Proposed Changes to Columbia Technical Specifications: Changing Group 1 Isolation Valves' Low Reactor Water Level Isolation Signal from the Current Level 2 to Level 1," 0000-0081-6730-R1, July 2008.

15.8-10 "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32523P-A, February 2000 (ELTR-2) and Supplement 1, Volume 1, February 1999 and Volume II, April 1999.

15.8-11 "Constant Pressure Power Uprate," NEDC-33004P-A, Revision 4, July 2003.15.8-12"Project Task Report ENERGY NORTHWEST Columbia Generating Station ARTS/MELLLA Task T0902: Anticipated Transients Without Scram," 0000-0101-1095-R2, May 2010.

15.8-13 002N3439, GNF2 Fuel Design Cycle-Independent Analyses for Energy Northwest Columbia Generating Station, (most recent version referenced in the COLR).

15.8-14 GE-Hitachi Nuclear Energy, "Safety Analysis Report for Columbia Generating Station Thermal Power Optimization," NEDC-33853P, March 2016.

Table 15.8-1

Anticipated Transients Without Scram Analysis
Initial Conditions

Parameters	Value
Reactor dome pressure (psig)	1020
Vessel core flow (Mlb/hr)	108.5
Vessel steam flow (Mlb/hr)	15.728
Reactor thermal power (MWt)	3629
Initial vessel and recirculation piping inventory (lbm)	609,600
Narrow range sensed initial water level (ft above separator skirt)	4.13
Initial core average void fraction (%)	41.8
Void reactivity coefficient (¢/%)	-12.937
Doppler coefficient (%/F)	-0.31087
Feedwater enthalpy (Btu/lb)	403.1
Sodium penetaborate solution concentration (% by weight)	13.6
Suppression pool liquid volume (ft^3)	112,197
Suppression pool temperature (°F)	90
Service water temperature (°F)	90

Table 15.8-1A

Anticipated Transients Without Scram Analysis for MELLLA
Initial Conditions and Equipment Performance Characteristics

Parameter	Value
Dome Pressure (psia)	1035
MELLLA Core Flow (Mlbm/br / % rated)	87.6 / 80.7
Core Thermal Power (MWt / %CLTP)	3486 / 100.0
Steam / Feed Flow (Mlbm/hr / %NBR)	15.013 / 100
Sodium Pentaborate Solution Concentration in the SLCS Storage Tank (% by weight)	13.6
Boron 10 Enrichment (atom %)	19.8*
SLCS Injection Location	HPCS
Number of SLCS Pumps Operating	2
SLCS Injection Rate (gpm)	82.4*
SLCS Liquid Transport Time (sec)	321
Initial Suppression Pool Liquid Volume (ft^3)	112197
Initial Suppression Pool Temperature (°F)	90
RHR Heat Exchanger Design Effectiveness per Loop (BTU/sec°F)	289
Number of RHR Heat Exchanger Loops	2
RHR Heat Exchanger Design Effectiveness during LOOP (BTU/sec°F)	289
Number of RHR Heat Exchanger Loops Available for LOOP Event	2
RHR Service Water Temperature (°F)	90
Transient time at which the RHR suppression pool cooling is established (seconds)	660
High Dome Pressure ATWS-RPT Setpoint (psig)	1170
SRV Capacity — per valve (lbm/hr) / Reference Pressure (psig) / Accumulation (%)	876500/ 1165 / 3
SRV Configuration	18 SRV (4 OOS)

* Values for two SLC pumps injection. For single pump injection, flow rate is 41.2 gpm and Boron-10 enrichment is 44 atom %.

Table 15.8-2

Anticipated Transients Without Scram Analysis
Equipment Performance Characteristics

Parameter	Value
Main steam line isolation valve nominal closure time (sec)	4
Relief valve system capacity (%NBR steam flow at 1144 psia)	93.7
Number of SRVs	18
Relief valve and sensor time delay (sec)	0.4
Relief valve opening time (sec)	0.15
Relief valve closure time delay (sec)	0.3
Standby liquid control system injection rate (gpm)	86.0
High-pressure core spray/RCIC low water level initiation nominal setpoint (ft above separator skirt)	-3.04 (L2)
High-pressure core spray/RCIC high water level shutoff setpoint (ft above separator skirt)	5.667 (L8)
High-pressure core spray flow rate (gpm at 1035 psia)	3875
Reactor core isolation cooling flow rate (gpm)	600
Anticipated transients without scram high pressure UAL setpoint (psia)	1186
Anticipated transients without scram dome pressure sensor and logic time delay (sec)	0.53
Total bypass capacity (Mlb/hr)	3.565
Total bypass capacity (% of uprate steam flow)	22.3*
Pump inertia constant (sec)	5.4729
Residual heat removal pool cooling capacity (Btu/sec-°F)	578

*23.3 for MELLLA

Table 15.8-3

Summary of Anticipated Transients
Without Scram Results

Parameter	ATWS Event			
	PREGO[d]	MSIVC[d]	LOFW	IORV
Maximum neutron flux (%)	292.1[d]	261	277.45	114.7
Time (sec)	19.2	4.1	22.36	7.96
Maximum average fuel heat flux (%)	150	136	101.2	101.45
Time (sec)	22.6	5	0.49	0.69
Maximum bottom pressure (psig)	1364[d]	1349	1202.2	1061.4
Time (sec)	28.7	9.9	23.62	0.19
Peak suppression pool temperature (°F)	178.9	179.6[c]	161.06	165.29
Peak containment pressure (psig)	9.6	9.8[c]	5.97	6.87
Time (sec)	3146	3056	8400	6600
Peak cladding temperature (°F)	1572	N/A	N/A	N/A
Time (sec)[b]				
Min. water level (ft above sep. skirt)[b]			-11.24	-10.66
Time (sec)[b]			91.38	975.4
Time of hot shutdown[a] (sec)	895	898	977	1524.6
Time of reaching ATWS setpoint (sec)	22.1	4.4	17.5	N/A
Time of BIIT (sec)	64	47	170	554

[a] Hot shutdown is defined as generated power remaining below 1% NBR. For MELLLA, hot shutdown is defined as Neutron Flux remains < 0.1%.

[b] Values not reported for MELLLA.

[c] Results for two SLC pump operation. For single pump operation, suppression pool temperature is 187°F and containment pressure is 12 psig.

[d] Noted parameters for PREGO are beginning of Cycle 20 under MELLLA conditions. All other PREGO and MSIVC results are end of Cycle 20.

Table 15.8-4

Sequence of Events for Loss of Feedwater

Time	Event
0 sec	Feedwater pump trip.
17.5 sec	High-pressure core spray and RCIC initiated on Level 2.
17.5 sec	Main steam line isolation valve closure on Level 2 (see Section 15.8.2.3.2) - scram fails.
17.5 sec	Recirculation pump tripped on Level 2 (ATWS setpoint reached, ARI fails).
22.9 sec	Relief valves lift.
23.6 sec	Vessel pressure peaks.
2 minutes 18 sec	Operator initiates SLCS (2 minutes after ATWS setpoint reached).
3 minutes 3 sec	Liquid control flow enters the core.
16 minutes	Hot shutdown achieved.
140 minutes	Suppression pool temperature and containment pressure peak.

Table 15.8-5

Sequence of Events for Main Steam Line
Isolation Valve Closure
(Long Term Transient)

Event	EOC MELLLA (sec)
MSIV Isolation Initiated	0.0
MSIVs Fully Closed	4.0
High Pressure ATWS Setpoint	4.4
Peak Neutron Flux	4.1
Opening of the First Relief Valve	4.6
Recirculation Pumps Trip	4.9
Peak Heat Flux	5.0
Peak Vessel Pressure	9.9
Feedwater Reduction Initiated	30.0
BIIT Reached	47.0
SLCS Pumps Start	124
Hot Shutdown Achieved (Neutron Flux Remains $<0.1\%$)	898
RHR Cooling established	660
Peak Suppression Pool Temperature	3056

Table 15.8-6

DELETED

Table 15.8-7

Sequence of Events for Inadvertent Open Relief Valve

Time	Event
0 sec	Relief valve with the lowest opening setpoint opens.
9 minutes 14 sec	Operator initiates SLCS 2 minutes after suppression pool temperature = 110°F (scram and ARI fail).
9 minutes 14 sec	Operator trips recirculation pumps.
9 minutes 14 sec	Operator initiates feedwater runback to bring level to TAF.
11 minutes	Suppression pool cooling begins.
13 minutes	Operator disables HPCS, RCIC Level 2 initiation and MSIV Level 2 closure[a].
14 minutes	Liquid control flow enters the core.
25 minutes	Hot shutdown achieved.
29 minutes	Main steam line isolation valve closure on low pressure.
110 minutes	Suppression pool temperature and containment pressure peak.

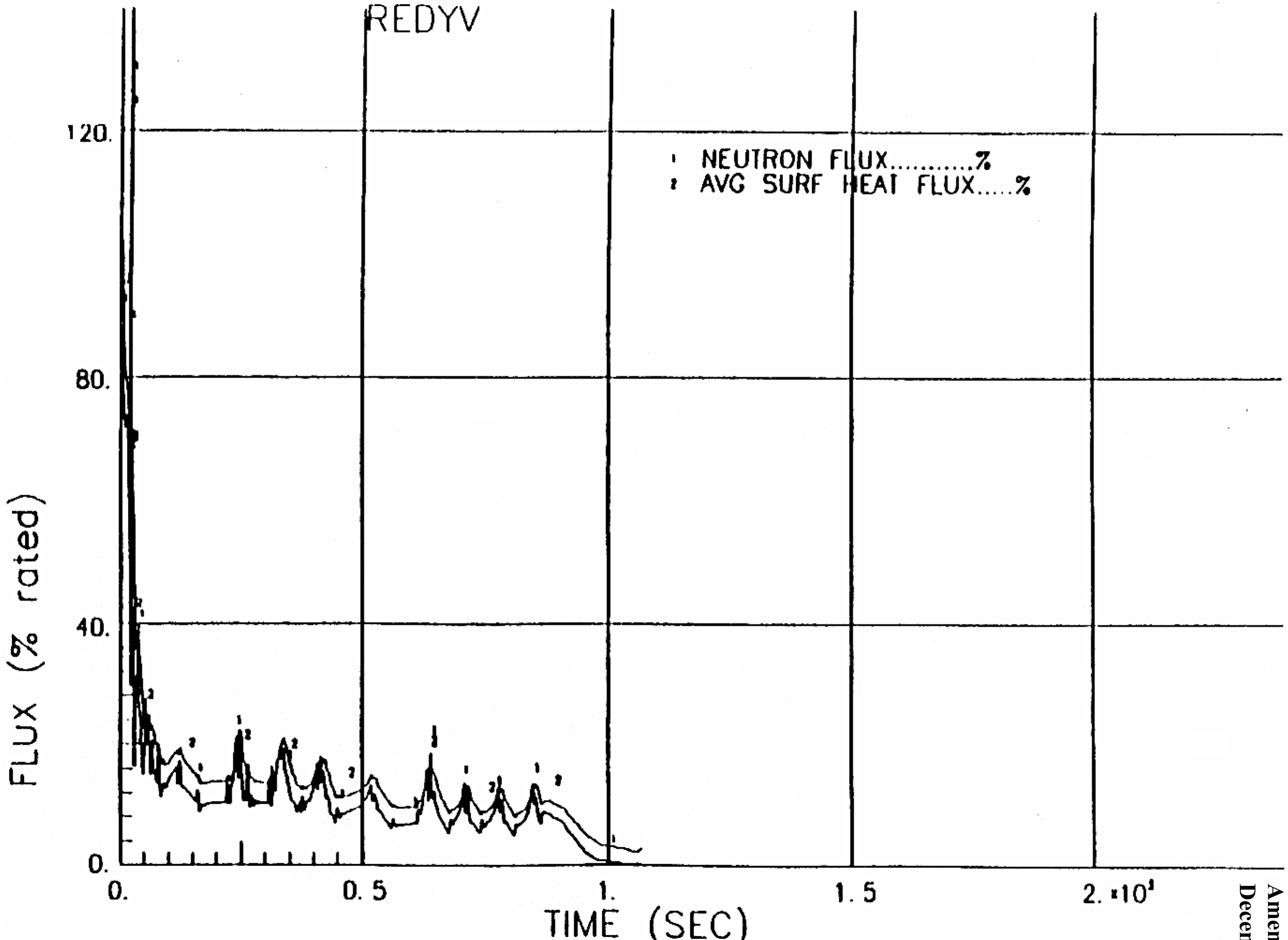
[a] The analysis has not been updated for the change in MSIV isolation setpoint from Level 2 to Level 1 because the analysis is bounding and conclusions of the analysis are not affected (Reference 15.8-9).

Table 15.8-8

Sequence of Events for Pressure Regulator
Failure Open (Long Term Transient)

Event	BOC MELLLA (sec)	EOC MELLLA (sec)
TCV and Bypass Valves Start Open	0.1	0.1
MSIV Closure Initiated by Low Steamline Pressure	15.0	14.2
MSIVs Fully Closed	19.0	18.2
Peak Neutron Flux	19.2	18.4
High Pressure ATWS Setpoint	22.6	22.1
Opening of the First Relief Valve	22.8	22.2
Recirculation Pumps Trip	23.2	22.6
Peak Heat Flux	23.2	22.6
Peak Vessel Pressure	28.7	27.9
Feedwater Reduction Initiated	45.8	45.8
BIIT Reached	64.0	64.0

% Rated is based on 3486 MWt.



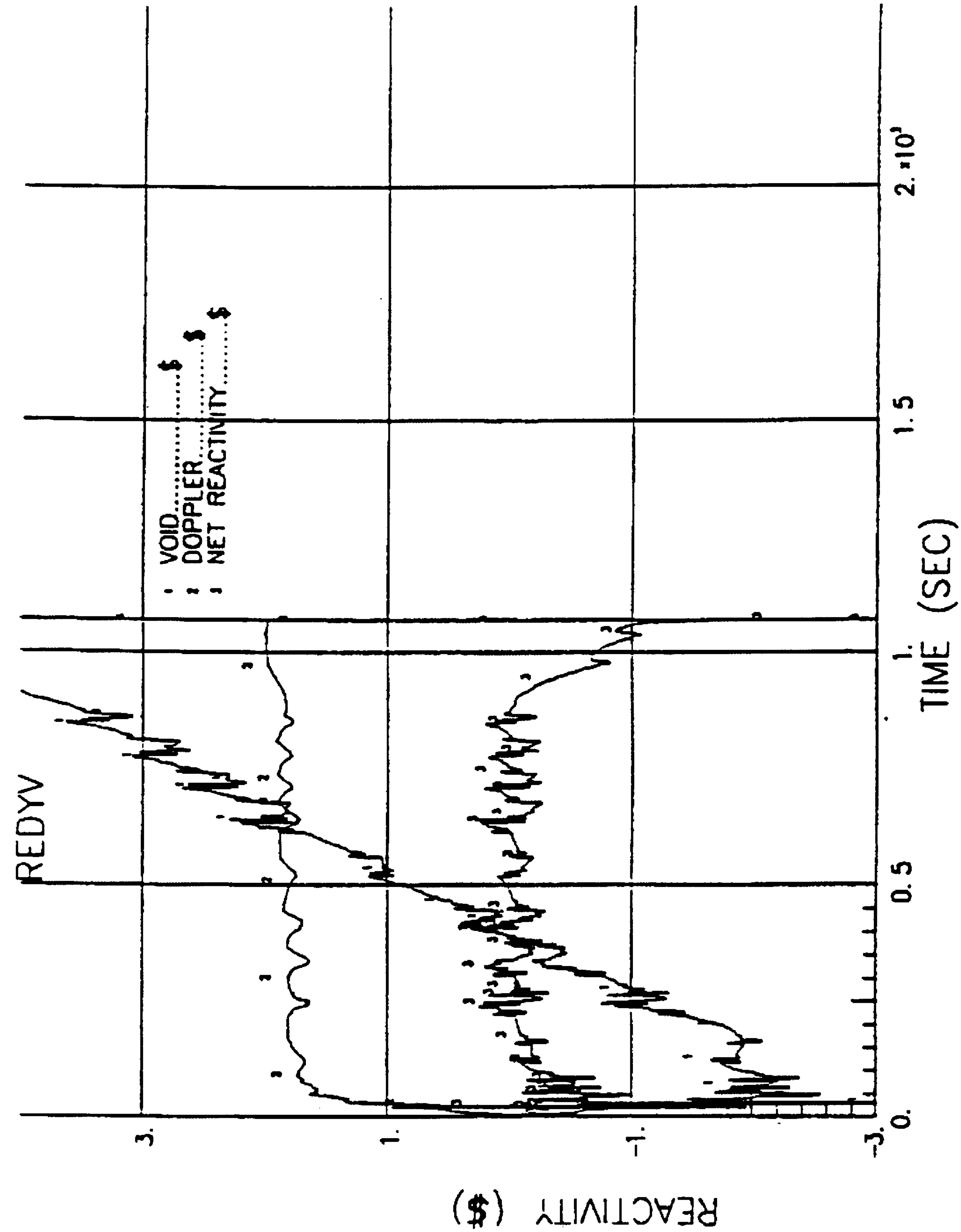
Columbia Generating Station
Final Safety Analysis Report

Loss of Feedwater Event

Draw. No. 020002.29

Rev.

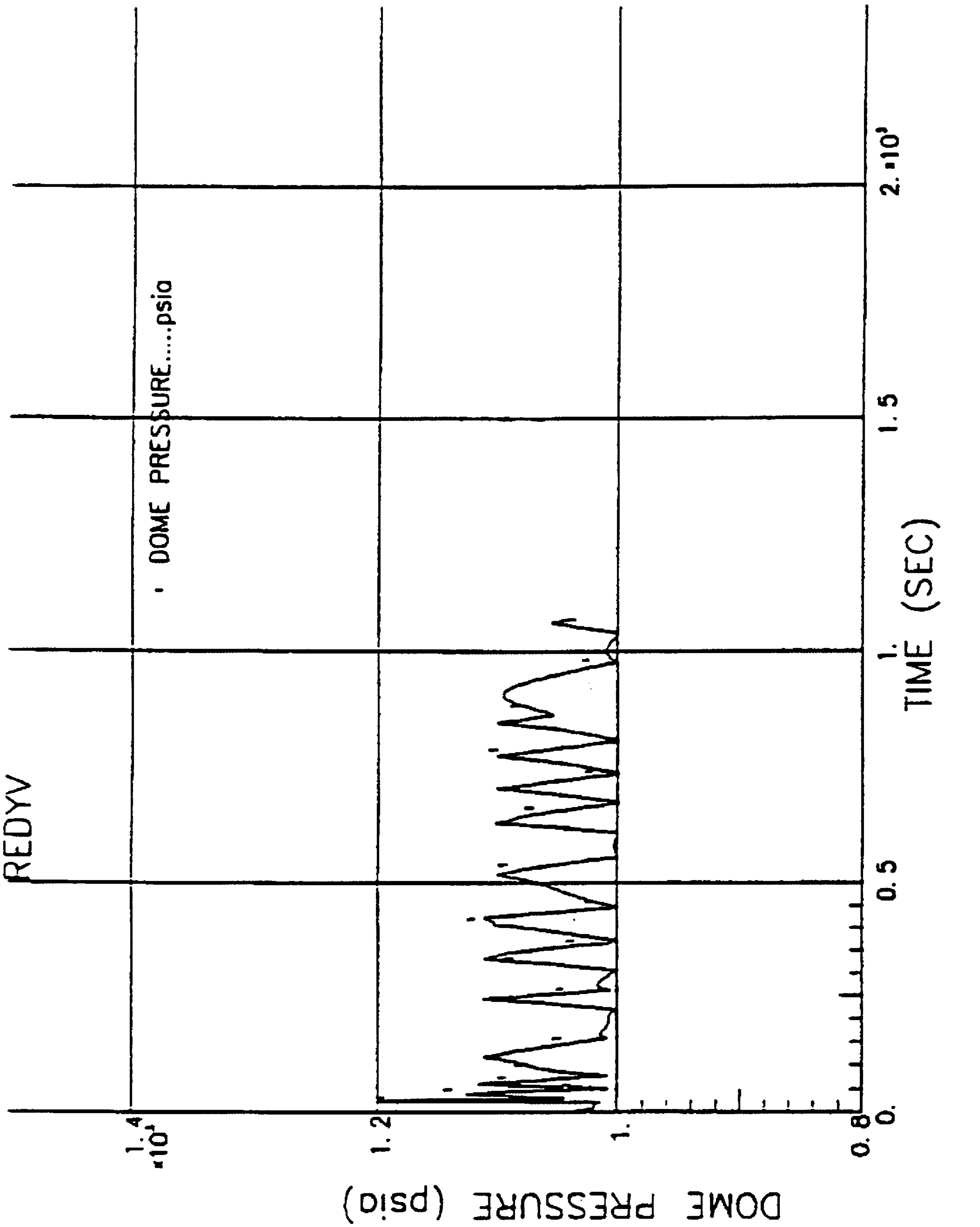
Figure 15.8-1.1



Columbia Generating Station
Final Safety Analysis Report

Loss of Feedwater Event

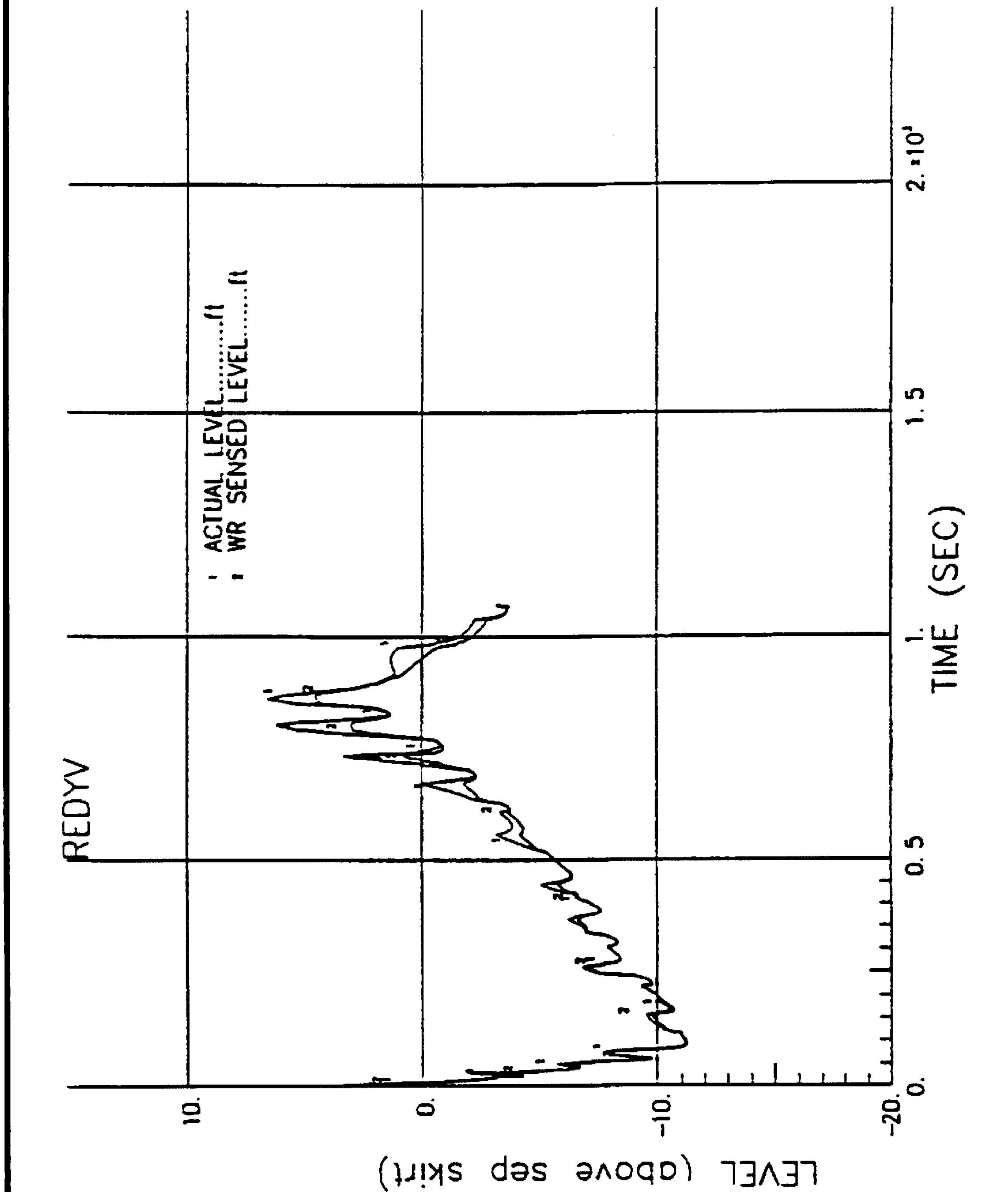
Draw. No. 020002.30	Rev.	Figure 15.8-1.2



Columbia Generating Station
Final Safety Analysis Report

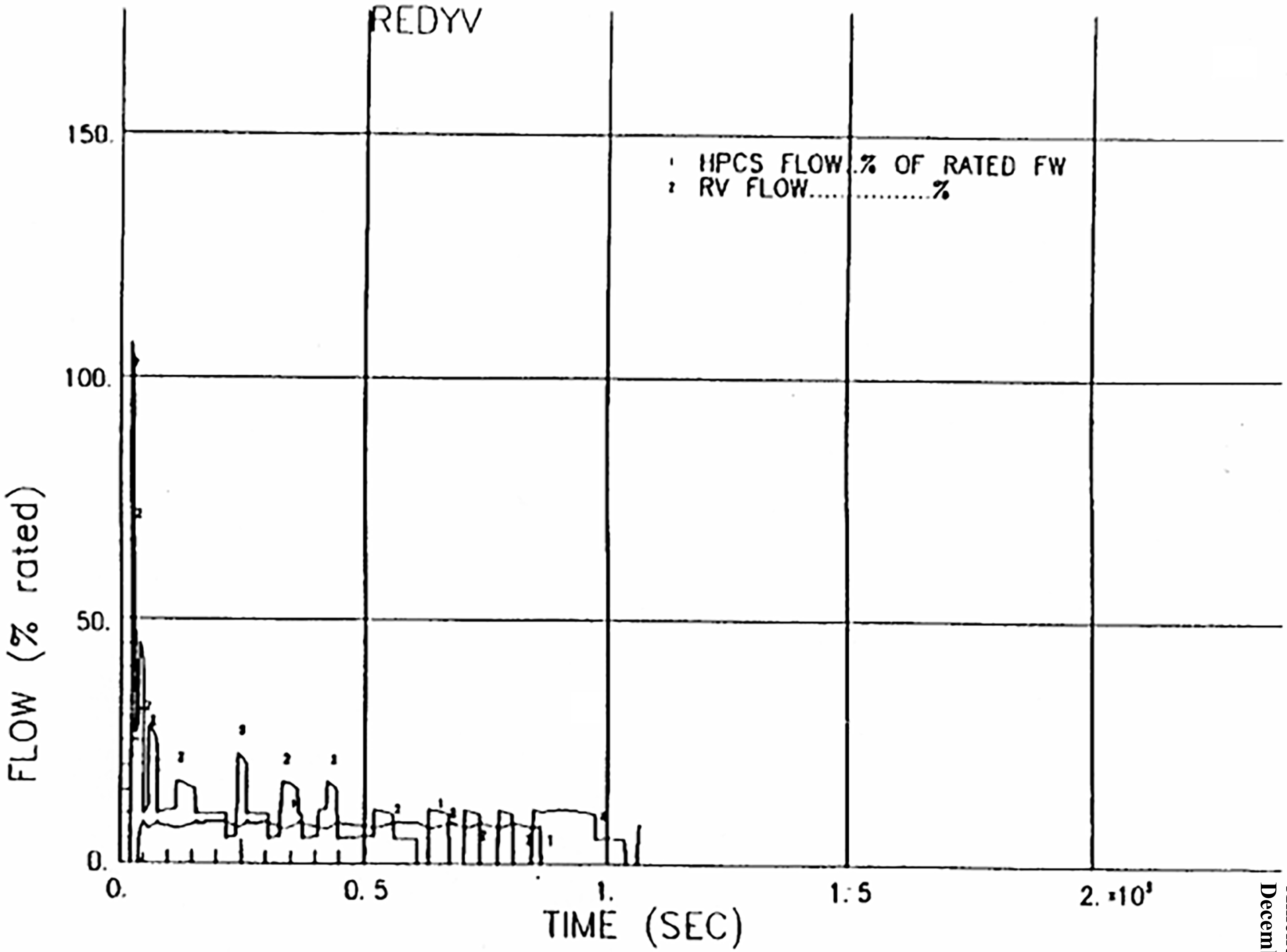
Loss of Feedwater Event

Draw. No. 020002.31	Rev.	Figure 15.8-1.3



Columbia Generating Station Final Safety Analysis Report	Loss of Feedwater Event		
	Draw. No. 020002.32	Rev.	Figure 15.8-1.4

Columbia Generating Station
Final Safety Analysis Report



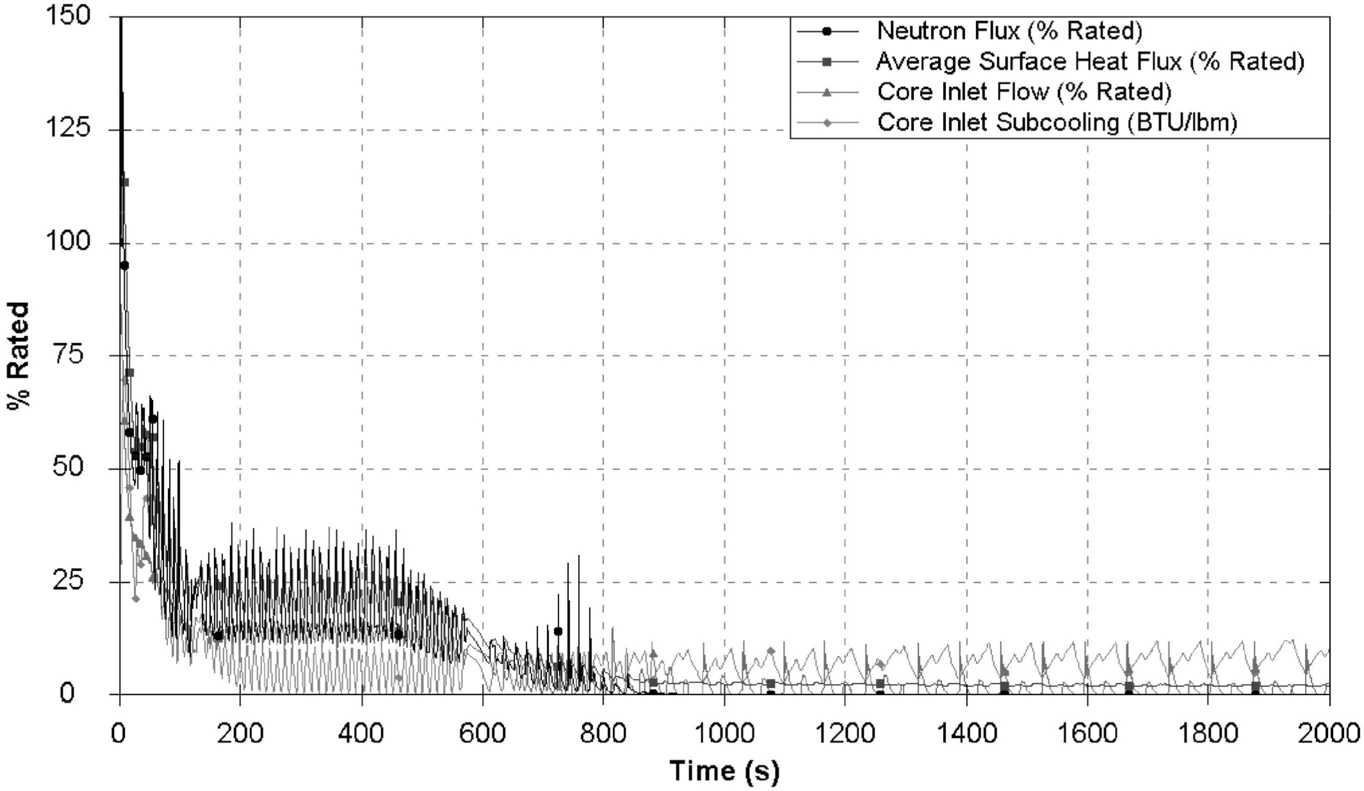
% rated is based on 3486 MWt.

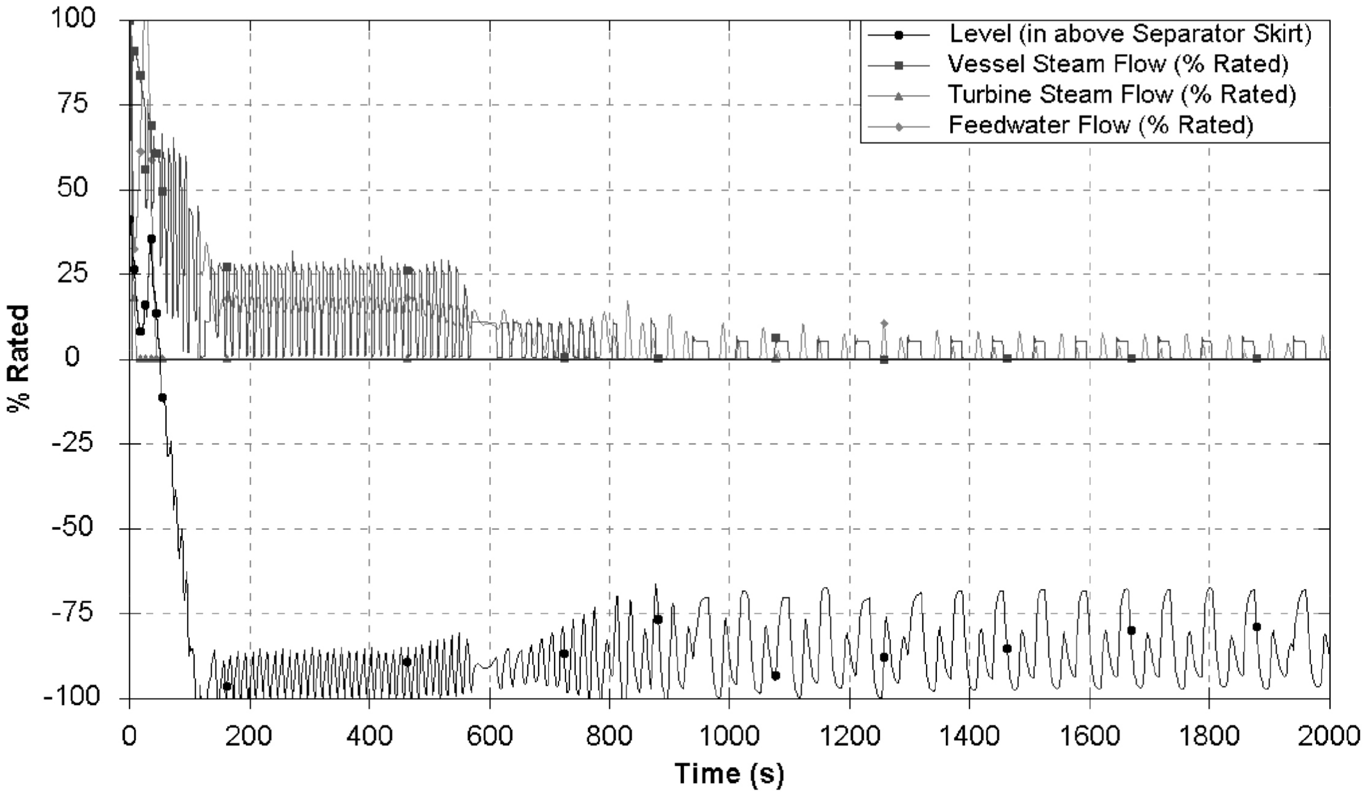
Loss of Feedwater Event

Draw. No. 020002.33

Rev.

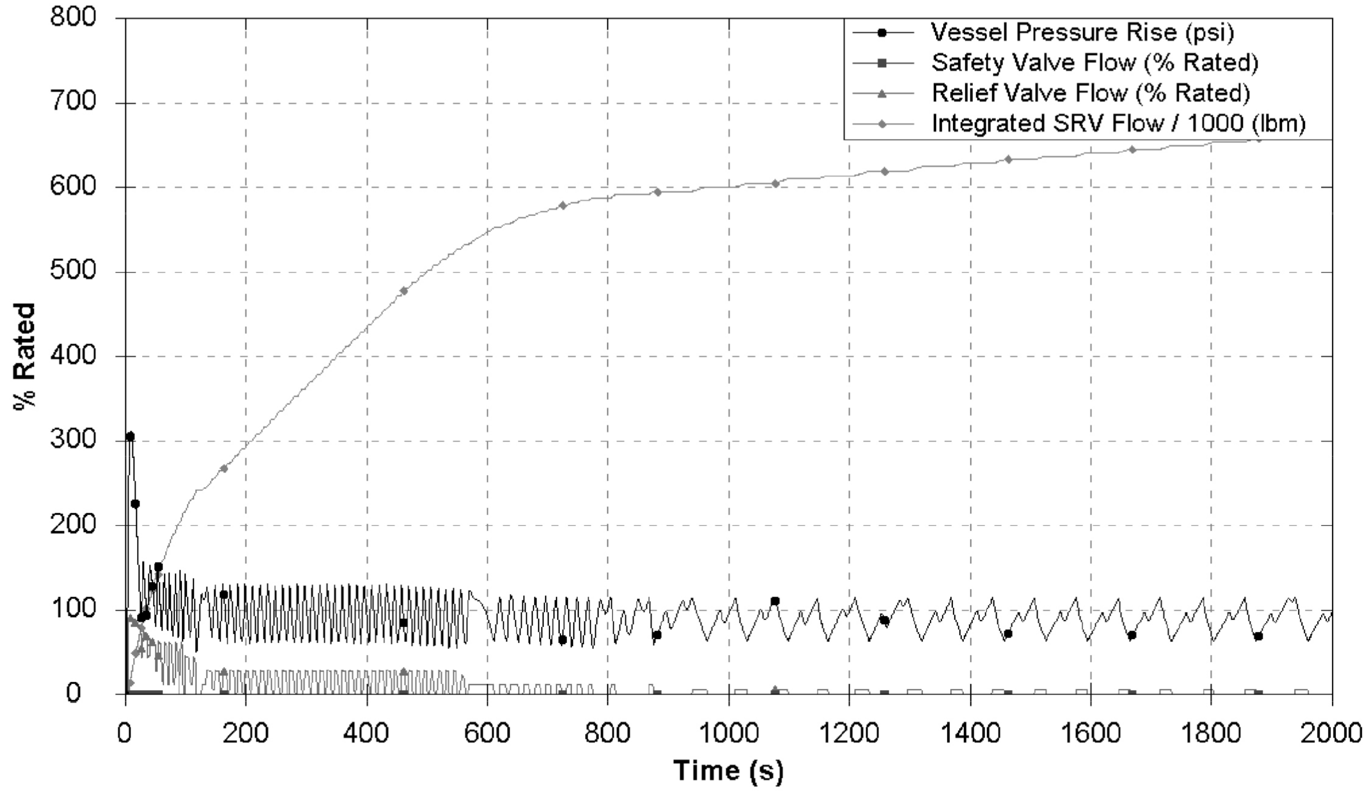
Figure 15.8-1.5





% Rated is based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Main Steam Isolation Valve Closure Event		
	Draw. No. 020002.34	Rev.1	Figure 15.8-2.1

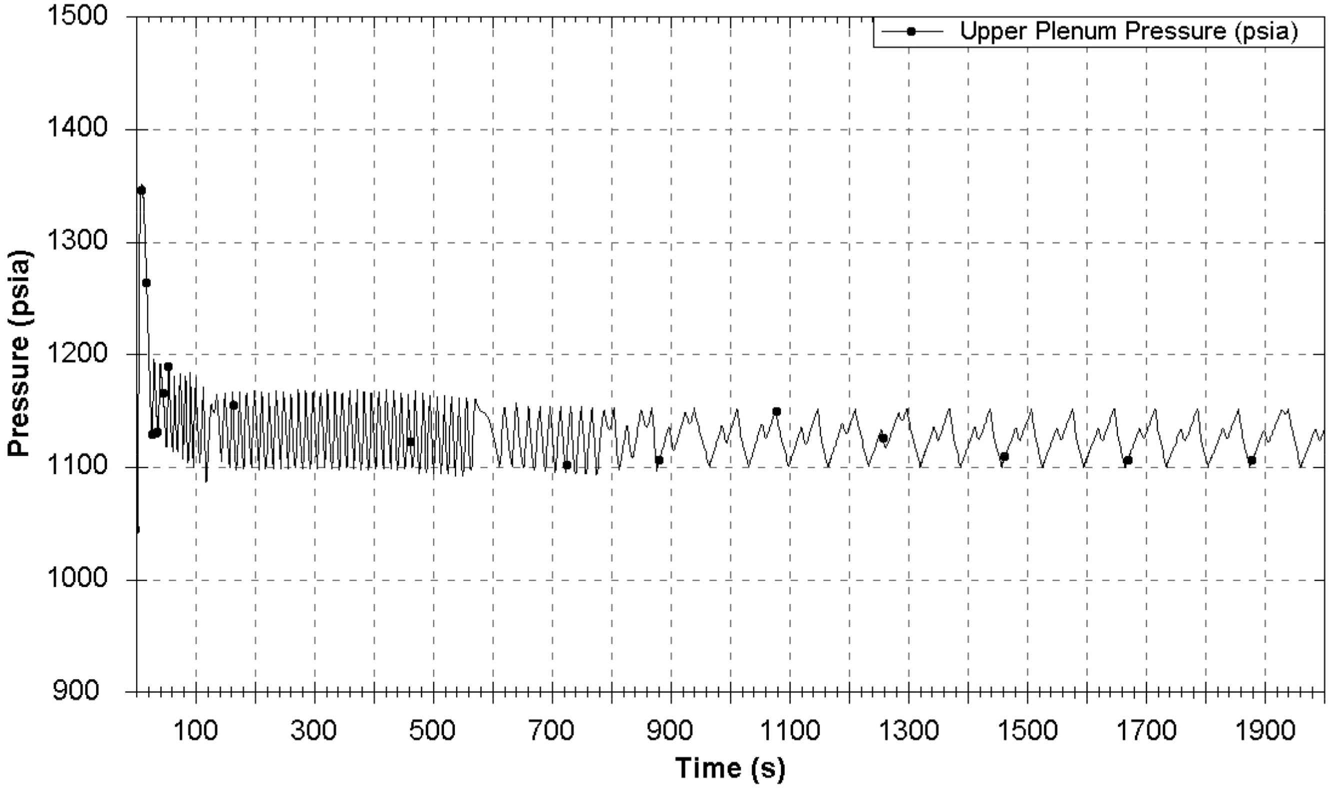


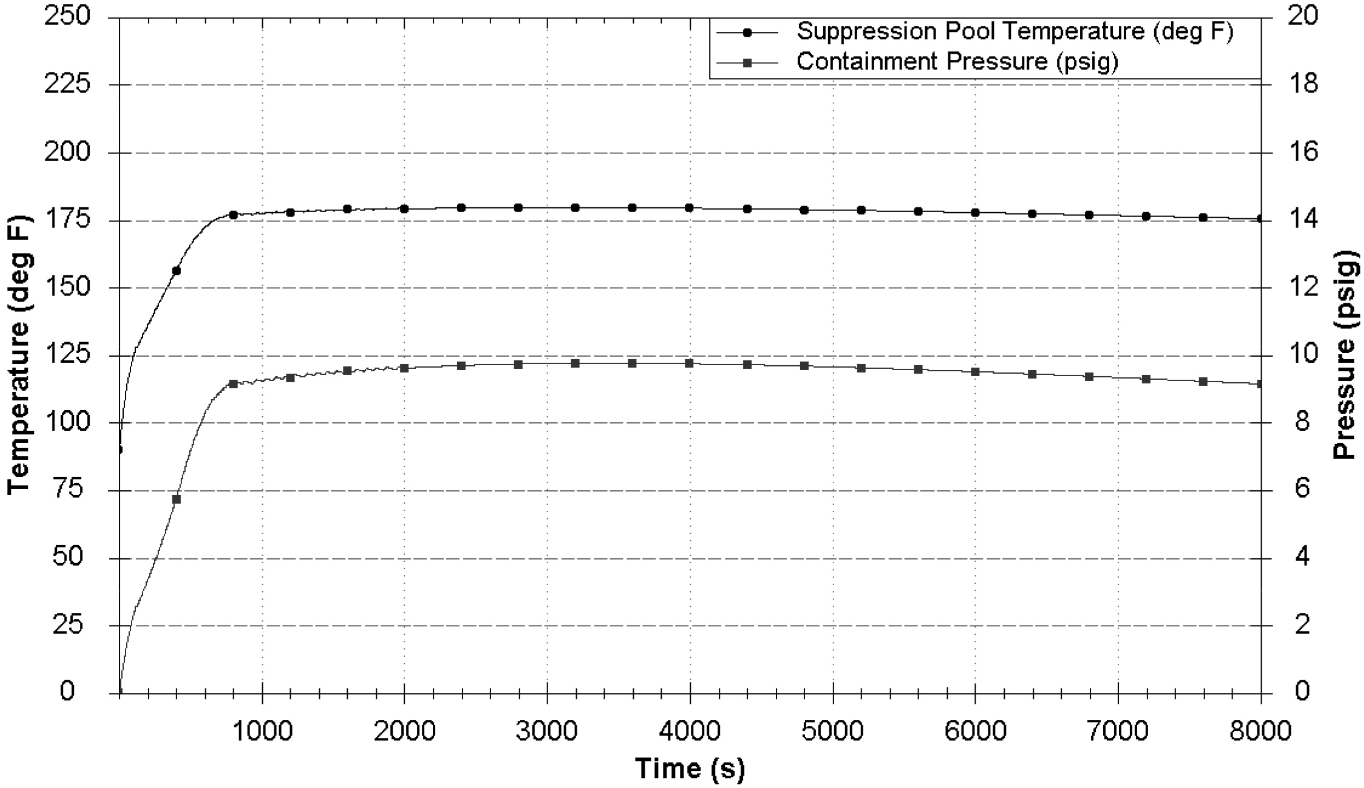
% Rated is based on 3486 MWt.

Columbia Generating Station
Final Safety Analysis Report

Main Steam Isolation Valve Closure Event

Draw. No. 020002.35	Rev. 1	Figure 15.8-2.2





Columbia Generating Station Final Safety Analysis Report	Main Steam Isolation Valve Closure Event		
	Draw. No. 020002.36	Rev. 1	Figure 15.8-2.3

DELETED

DELETED

DELETED

Columbia Generating Station
Final Safety Analysis Report

Main Steam Isolation Valve Closure Event with 4 SRVs Out-of-Service

Draw. No.	Rev.	Figure
960222.40		15.8-3.1

DELETED

Columbia Generating Station
Final Safety Analysis Report

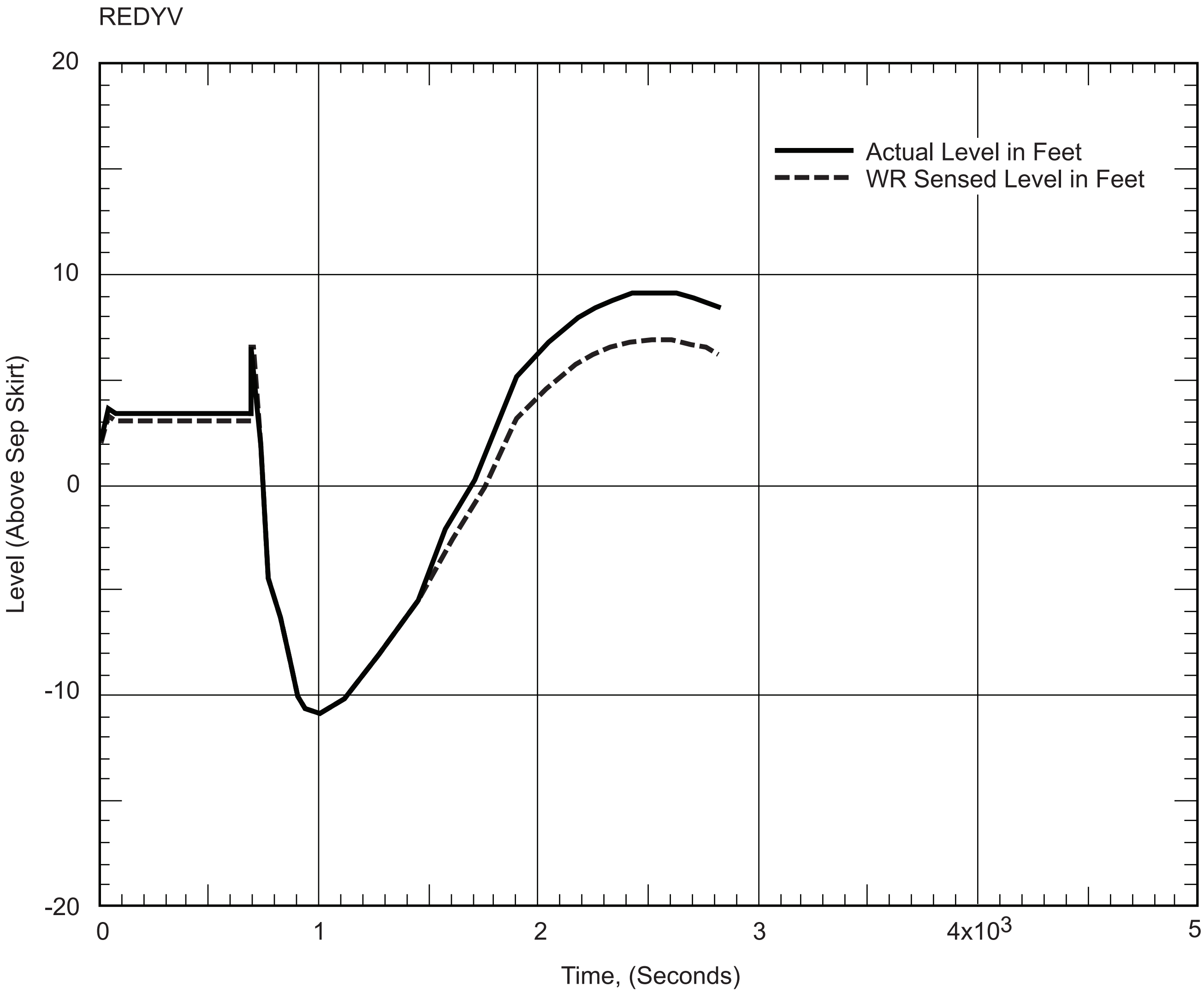
Main Steam Isolation Valve Closure Event with
4 SRVs Out-of-Service

Draw. No. 960222.41 | Rev. | Figure 15.8-3.2

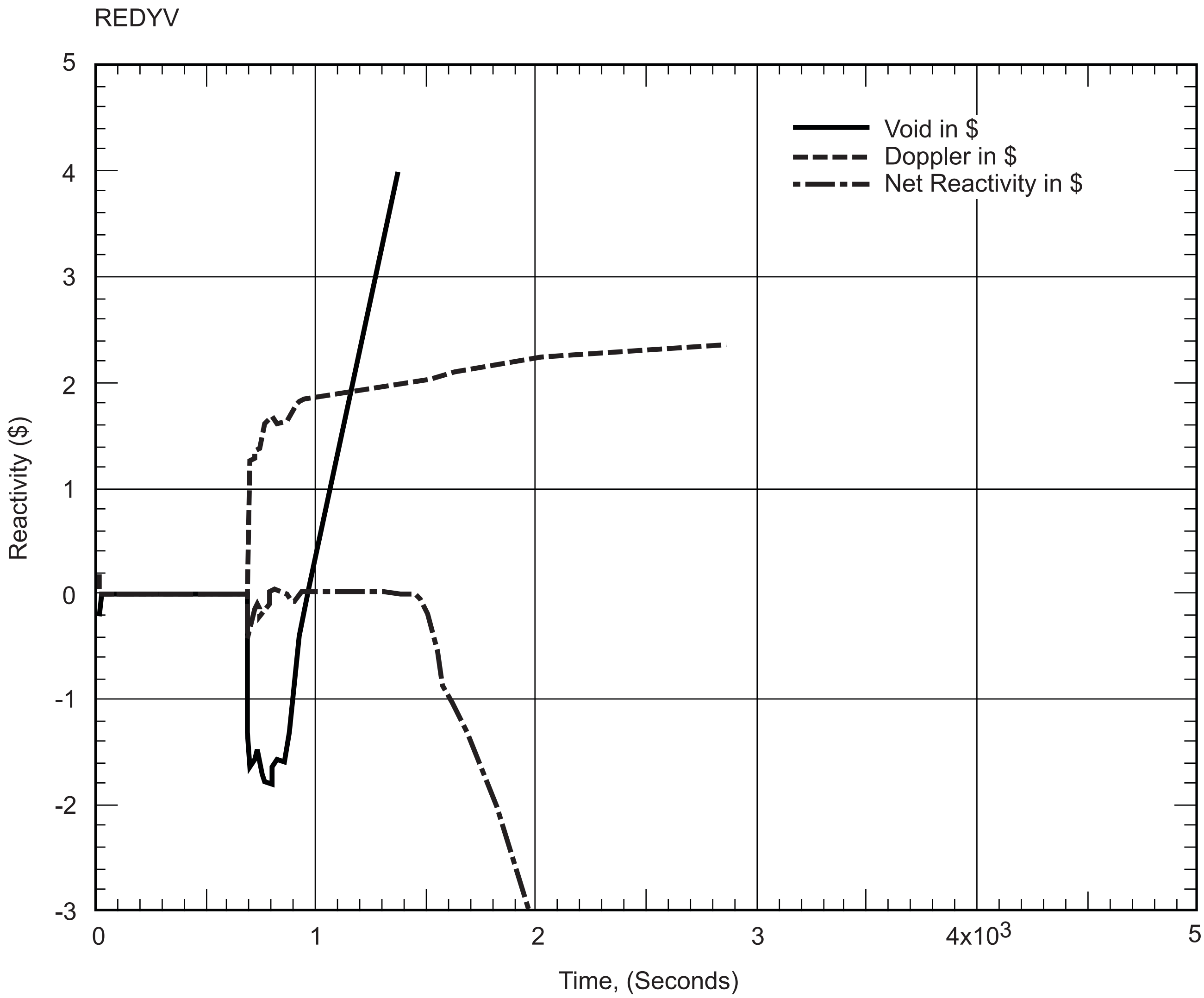
DELETED

DELETED

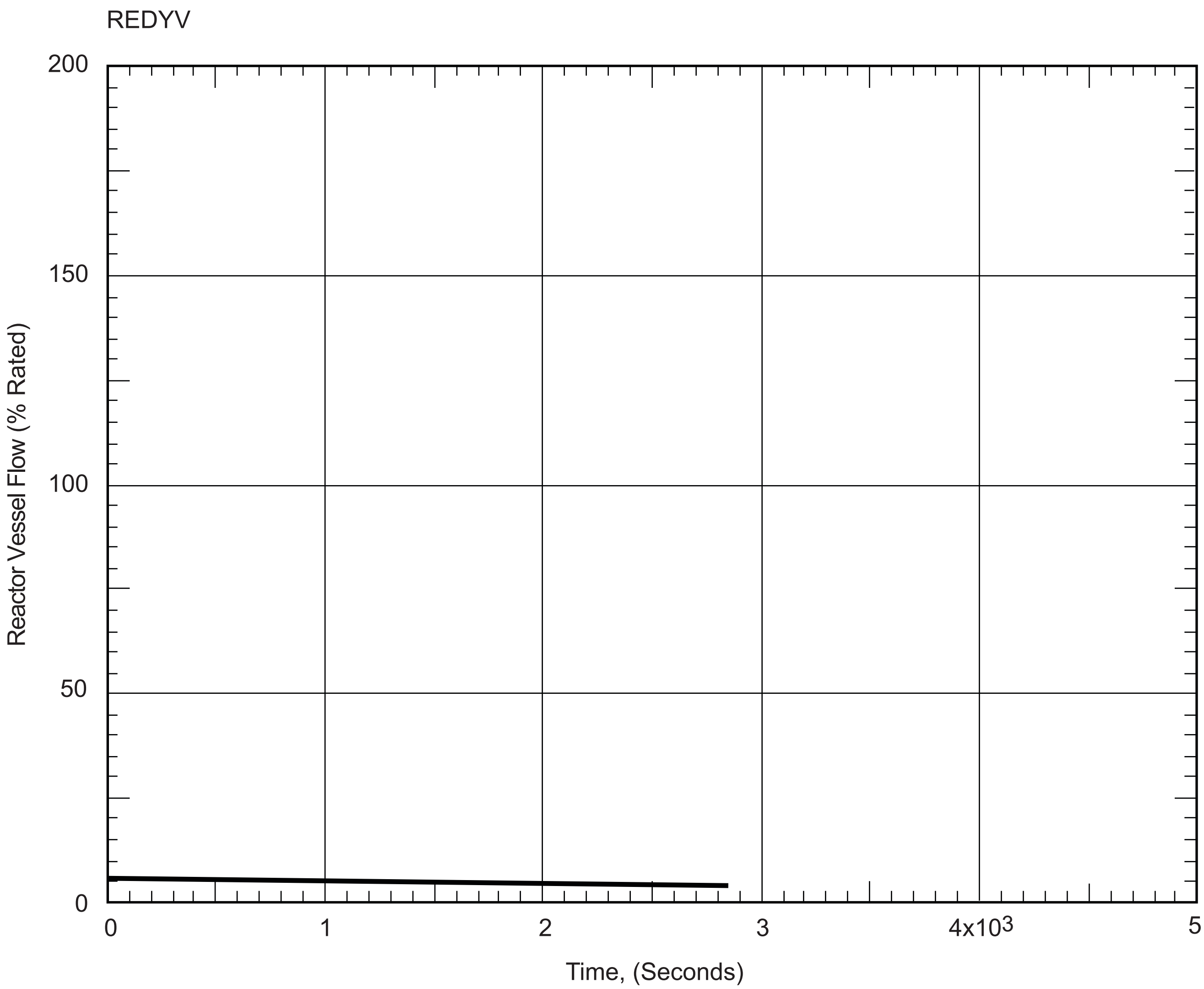
DELETED



Inadvertent Opening of Relief Valve Event



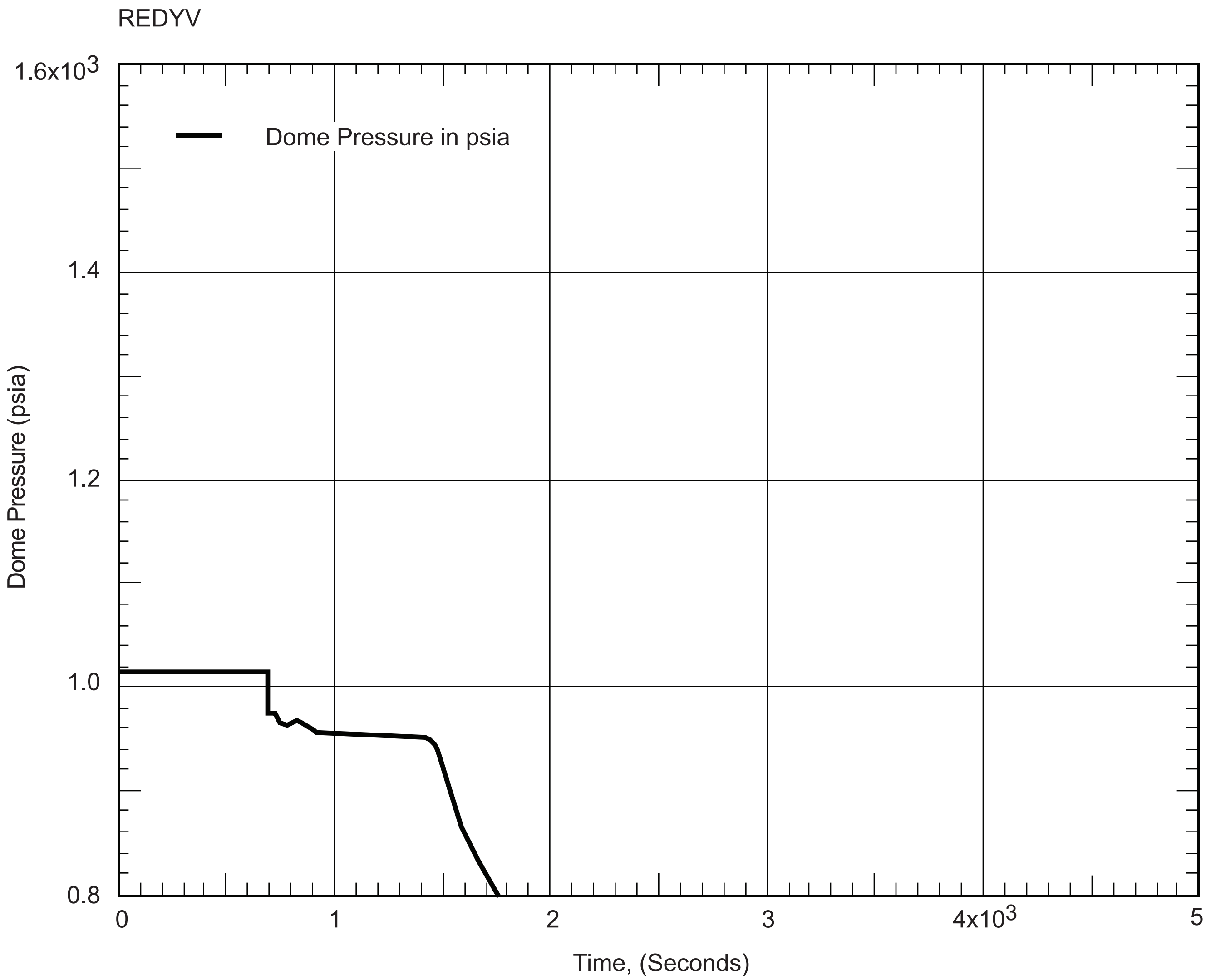
Columbia Generating Station **Final Safety Analysis Report**	**Inadvertent Opening of Relief Valve Event**
	Draw. No. **960222.48** | Rev. | Figure **15.8-4.2**



% Rated is based on 3486 MWt.

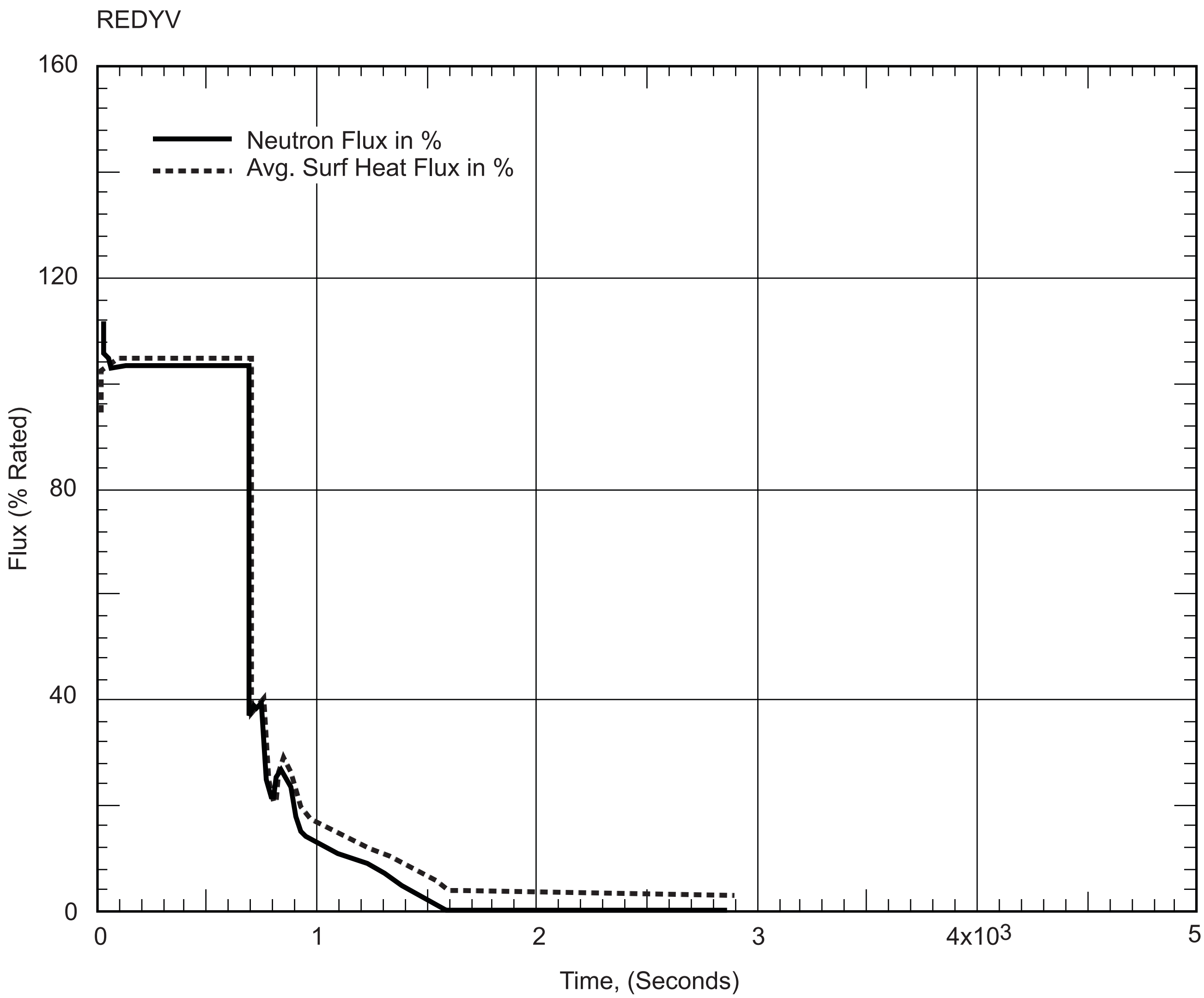
Inadvertent Opening of Relief Valve Event

Draw. No. 960222.46 | Rev. | Figure 15.8-4.3



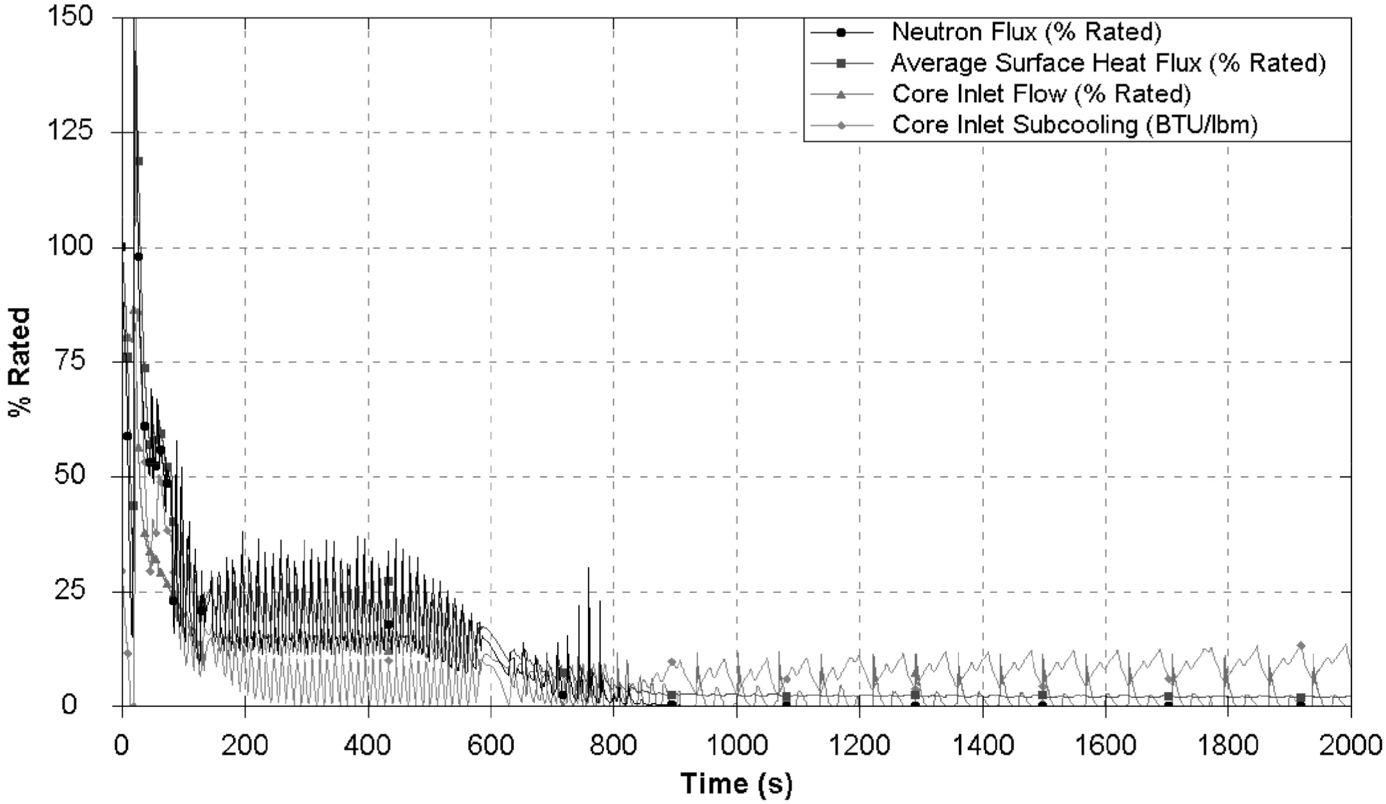
Inadvertent Opening of Relief Valve Event

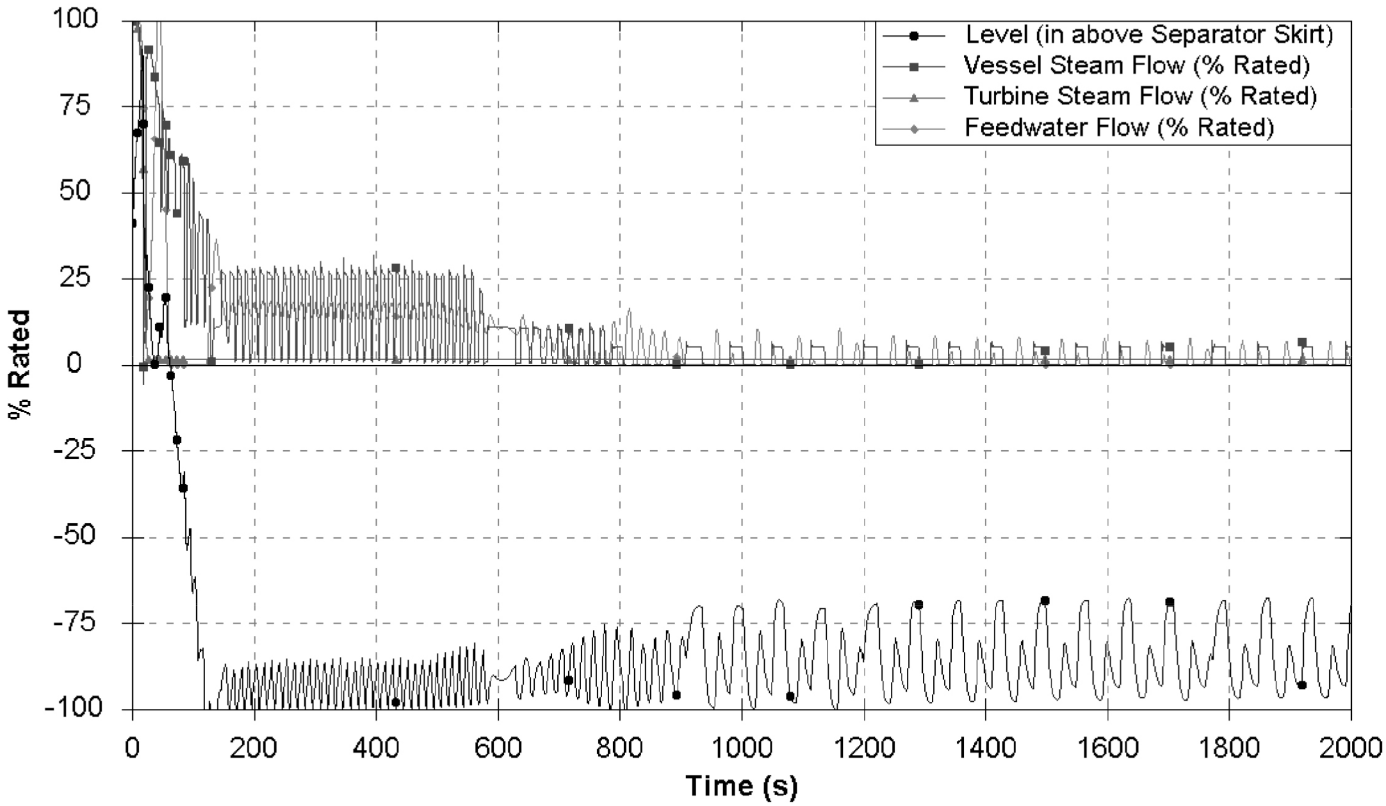
Draw. No. 960222.47 | Rev. | Figure 15.8-4.4



% Rated is based on 3486 MWt.

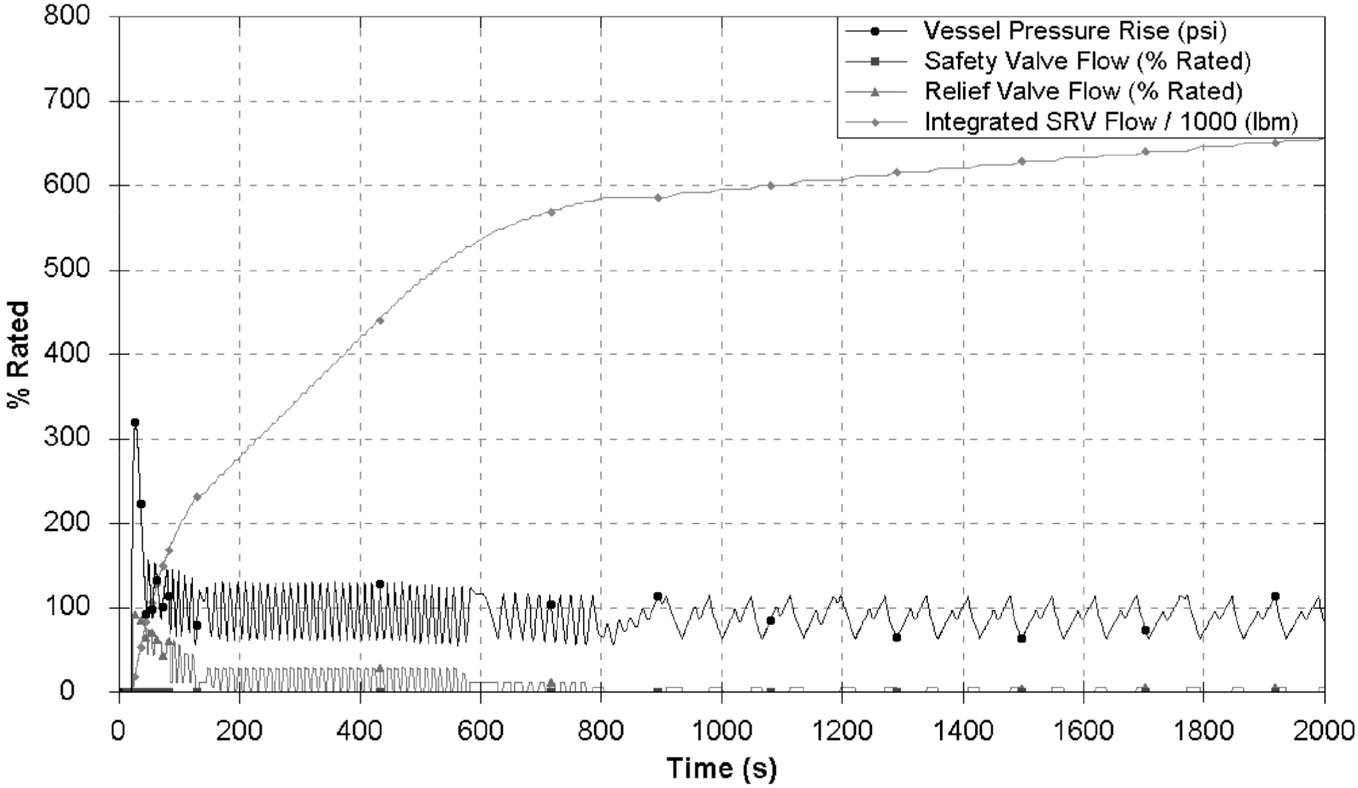
Columbia Generating Station Final Safety Analysis Report	Inadvertent Opening of Relief Valve Event
	Draw. No. 960222.49 | Rev. | Figure 15.8-4.5





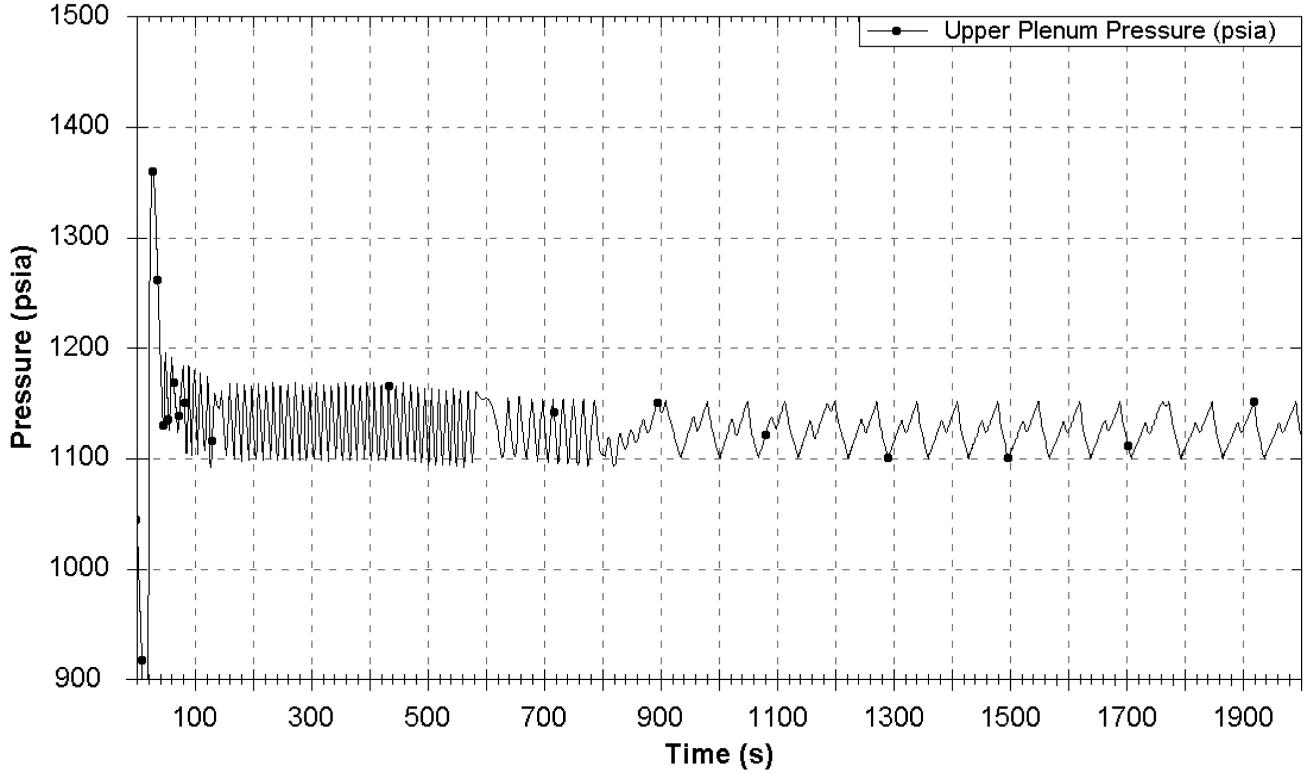
% Rated is based on 3486 MWt.

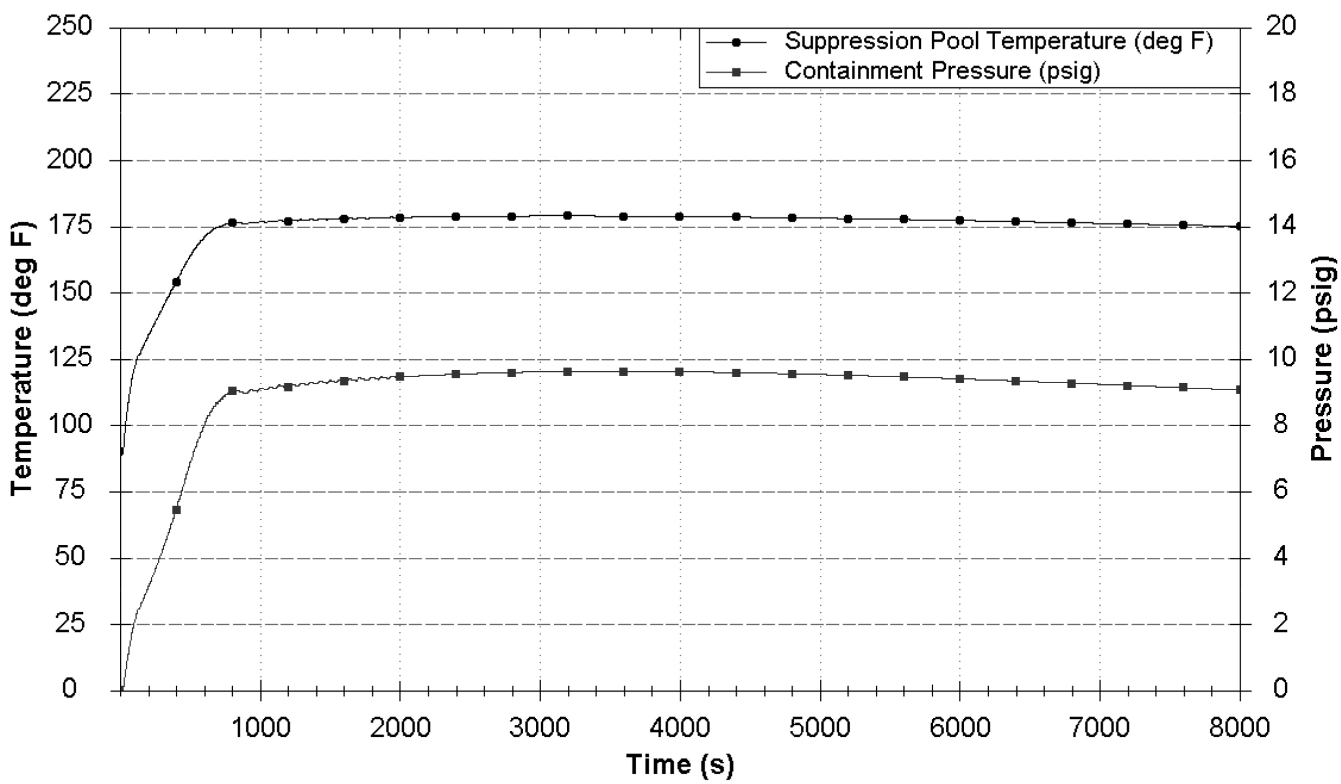
Columbia Generating Station Final Safety Analysis Report	Pressure Regulator Failure - Open Event		
	Draw. No. 020002.39	Rev. 1	Figure 15.8-5.1



% Rated is based on 3486 MWt.

Columbia Generating Station Final Safety Analysis Report	Pressure Regulator Failure - Open Event		
	Draw. No. 020002.40	Rev.	Figure 15.8-5.2





Columbia Generating Station Final Safety Analysis Report	Pressure Regulator Failure - Open Event		
	Draw. No. 020002.41	Rev. 1	Figure 15.8-5.3

DELETED

Columbia Generating Station
Final Safety Analysis Report

Pressure Regulator Failure - Open Event

Draw. No. 020002.42	Rev.	Figure 15.8-5.4

DELETED

Chapter 16

TECHNICAL SPECIFICATIONS

(See Operating License Appendix A)

TECHNICAL SPECIFICATION BASES

(Separate Volume)

LICENSEE CONTROLLED SPECIFICATIONS

(Separate Volume)

Chapter 17

QUALITY ASSURANCE

TABLE OF CONTENTS

Chapter 17

QUALITY ASSURANCE

TABLE OF CONTENTS (Continued)

Chapter 17

QUALITY ASSURANCE

LIST OF TABLES

Chapter 17

QUALITY ASSURANCE

LIST OF FIGURES

Chapter 17

QUALITY ASSURANCE

17.1 QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

The quality assurance requirements during design and construction were defined in the FSAR and were revised through Amendment 30 in June 1983. This section is no longer applicable since these phases are completed.

There are four principal participants in Columbia Generating Station (CGS) design and construction quality programs. They are the Owner, Energy Northwest; the Architect/Engineer (AE), Burns and Roe, Inc. (B&R); the Nuclear Steam Supply System (NSSS) Supplier, General Electric Company (GE); and the Construction Manager (CM), Bechtel Power Corporation.

a. *Energy Northwest, as the owner and Licensee, has overall responsibility for assuring that the plant is designed and constructed in accord with approved Quality Assurance Programs (QAPs). The Energy Northwest CGS Project Quality Assurance organization provides management overview of the other elements of the site QAPs. Section 17.1.1 describes the Energy Northwest CGS QAP.*

b. *Burns and Roe, Inc. provides Architect/Engineer and related services for CGS. Section 17.1.2 describes the B&R QAP.*

c. *The General Electric Company (GE) provides NSSS design, fabrication, and erection/construction services for CGS. Section 17.1.3 describes the GE QAP.*

d. *The Bechtel Power Corporation provides construction management services for CGS. This service consists primarily of direction and coordination of site contractor activities and includes related Quality Assurance/QC services. Section 17.1.4 describes the Bechtel QAP.*

17.1.1 ENERGY NORTHWEST QUALITY ASSURANCE PROGRAM

Energy Northwest has implemented a QAP for the design, procurement, and construction of Energy Northwest Columbia Generating Station (CGS). This QAP has been implemented in accordance with requirements of Appendix B to 10 CFR 50. The applicable requirements of Appendix B, 10 CFR 50 are applied to those items classified as Energy Northwest Quality Class I due to their relationship to a nuclear safety function.

As the license applicant, Energy Northwest is responsible for the plant. Therefore, the Energy Northwest CGS QAP and its implementation has been structured to assure that design, *procurement, and construction activities are accomplished in accordance with sound engineering principles and practices. Systems, components, and structures that are safety-related, in the context of 10 CFR 20, 10 CFR 50, and 10 CFR 100, are required to be designed, specified, fabricated, installed, and tested in accordance with applicable regulatory requirements, codes, standards, specifications, and procedures.*

The description of the Energy Northwest CGS Design and Construction QAP which follows is of the program as it currently exists. This program evolved from the original quality program which first appeared in Appendix D.O of the PSAR. The changes involved in this evolution process include: NRC requested changes; updates in organization responsibilities and authorities; and the incorporation of new requirements.

17.1.1.1 Organization

Energy Northwest Managing Director is responsible to the Board of Directors for the overall management of Energy Northwest activities, including the establishment and implementation of policies. The Managing Director resolves issues involving quality brought to his attention because of failure to reach resolution at lower levels of management. Overall Energy Northwest organization is shown on Figure 17.1-1.

The Managing Director has the ultimate responsibility for the QAP. The Managing Director shall ensure that the program is implemented and maintained by assigning the appropriate authority and responsibility to the Director of Licensing and Assurance.

The Deputy Managing Director has the authority to implement the policies of the Managing Director. The Deputy Managing Director is accountable to the Managing Director and is responsible for:

a. *Coordinating and integrating the activities of Energy Northwest organizations,*

b. *Supporting and advising the Managing Director on the performance of Energy Northwest functions and evaluation of such, and*

c. *Acting for the Managing Director, as required.*

The Director of Licensing and Assurance reports and is accountable to the Managing Director for the overall development, implementation, and verification of the Energy Northwest Quality Assurance and Nuclear Safety and Regulatory programs to ensure compliance with regulations, codes, and standards. These responsibilities include:

a. *Determining the adequacy and effectiveness of program implementation,* *b. Maintaining cognizance of changing regulatory requirements and providing controlled interface between Energy Northwest and regulatory agencies,*

c. Exercising authority to stop nonconforming work of any Energy Northwest Contractor or Supplier organization, and

d. Administering corporate and project Quality Assurance and Nuclear Safety and Regulatory program activities.

The Director of Licensing and Assurance operates through the Manager of Construction Quality Assurance, the Manager of Audits, and the Manager of Nuclear Safety and Regulatory Programs.

The Director of Operations reports and is accountable to the Managing Director for development and implementation of policies and programs supporting the design, construction, and operational phases of Nuclear Power projects WNP-1, CGS, and WNP-3, and the extended construction delay of WNP-4/5. The Director of Operations carries out his responsibilities through the Director of Generation; the Director of Technology; and the Program Directors of WNP-1, CGS, and WNP-3.

The Director of Power Generation reports to the Director of Operations and is responsible for ensuring that the calibration of measuring and test equipment is performed in accordance with approved procedures which establish calibration frequencies, procedures used, recall methods, identification requirements, tolerances and records required to establish equipment history and calibration data.

The Director of Power Generation carries out his responsibilities through the Manager, Generation Services; the Manager, Generation Maintenance; and the Supervisor of Instrumentation Maintenance and Calibration. The Plant Manager and Test and Startup also report to the Director of Power Generation. Startup activities are conducted in accordance with the Operational QAP, Topical Report EN-QA-004, as referenced in Section 17.2.

The Director, Technology reports to the Director of Operations and is responsible for:

a. Providing technical and engineering support to the project,

b. Assisting the project engineering organization in providing technical direction to the Architect Engineer,

c. Assisting the project in performing technical overview of Energy Northwest activities,

d. ASME Code consultation to the project, including interfacing with ASME, *e. Performing and managing selected technical programs, having applicability to several projects, including preoperational environmental monitoring, and geology,*

f. Providing independent technical evaluations when requested by the Director of Operations, and

g. Overall Energy Northwest records management policy. Implementation of the policy with regard to functions described in this manual is the responsibility of all Directorates, as applicable.

To accomplish this role, the Director of Technology operates through the Assistant Directors, Technology for Systems Engineering, Generation Engineering, CGS Plant Engineering, and Fuel and Environment.

The Director of Support Services reports to the Managing Director and is responsible for the development and implementation of policies and programs which support design, construction, and operation of Energy Northwest plants in the areas of safety and security. Areas in which the Director of Support Services provides support for the projects include industrial safety and fire protection, technical training, administration, and security. To accomplish this role, the Director of Support Services operates through the Manager, Technical Training Programs; the Manager, Administration; the Manager, Health and Safety Programs; and the Manager, Security Programs.

The Chief Financial Officer reports to the Managing Director and is responsible, through the Manager of Central Materials and Procurement, for the development of corporate material management and procurement policy, and the procurement and control of corporate, multiple-project and specialized materials and related services required to support the design and construction of Energy Northwest nuclear power plants.

The Program Director is directly accountable to the Director of Operations and is responsible for the safe, successful, and timely completion of construction of the nuclear plant (including those responsibilities assigned to the Owner by Section III of the ASME Code). The Program Director accomplishes Project responsibilities by managing and directing the AE who performs the design; the CM who manages the construction on the Project; and Project Energy Northwest personnel. See Figures 17.1-2, 17.1-4, and 17.1-5.

The Deputy Program Director reports to the Program Director and is responsible for managing and directing the completion of the design, construction, and turnover to Operations of the power plant in accordance with established requirements. These responsibilities include:

a. Monitoring AE/CM internal performance and also monitoring their management of other Contractor's performance against established requirements; determines corrective measures and/or gives direction and advice, as necessary,

b. Ensuring necessary licenses and permits are obtained, and

c. Providing Project-level reviews and reports, as necessary or directed.

The manager of each CGS department or organization, as well as the manager of each Energy Northwest home office support organization, is responsible for:

a. Identifying those activities within his organization which are quality-related,

b. Establishing and clearly defining the duties and responsibilities of personnel within his organization who execute those quality-related activities, and

c. Ensuring that quality-related activities are accomplished by qualified personnel in accordance with approved procedures, as required.

The principal CGS project organizations are shown on Figures 17.1-2 and 17.1-3. A description of the primary quality-related functions follows.

The project Engineering Manager reports to the Program Director and is responsible for the timely completion of design for effective field engineering support of the construction effort and for the direction of the AE. Included in his responsibilities are:

a. Managing the design activities of the Project and ensuring its technical adequacy. This includes all actions necessary to ensure a plant design which is constructable, which conforms to all regulatory requirements and corporate commitments that are necessary to receive and retain an operating license, and which is safe and efficient to operate;

b. Those engineering activities which provide solutions and prevention of technical construction restraints which ensure the technical adequacy of the completed construction. In addition, the project Engineering Manager is responsible for dispositioning Energy Northwest-originated nonconformances; and

c. Continuous review of the plant design as it applies to NRC commitments and safety requirements.

The project CM is responsible to the program Director for construction activities at the project, including the direction of the CM. Included in his responsibilities are:

a. *Providing the necessary management, monitoring, control, and reporting elements that are necessary to ensure performance of the CM.*

b. *Overview of CM for receiving, storage, issuance, and maintenance of Energy Northwest prepurchased equipment and material from the time of receipt at the project (or release from the Contractor) until it is transferred to the final control of the Energy Northwest.*

The Site Administration Manager is responsible to the program Director for providing support services which include management of project facilities, services, personnel services, budget control, procedure development and control; and

a. *Shall be responsible for establishing, developing, implementing, and maintaining procedures/instructions for controlling the receipt, distribution, encoding, retention, and disposition of prepurchased equipment, Energy Northwest, AE, CM, and Contractor quality assurance records.*

b. *Shall be responsible for the receipt, control, preservation, and retrieval of project construction records.*

These responsibilities are carried out through the Manager, Records Management, and the Facilities/General Services Supervisor.

The Business Manager reports to the program Director. The Business Manager ensures that Corporate Contract Management policies and procedures are implemented which include management of contract administration, procurement, materials management, and materials control.

a. *Supervisor, Contract Administration provides contract administration support including construction contract administration, claims management, contract data reporting, bid preparation, evaluation, and award processing;*

b. *Manager, project procurement provides purchasing, renting, leasing, or otherwise obtaining materials, equipment, supplies, services, and related phases of contract administration including preparation, award of contracts, and administration;*

c. *Manager, project Material Control provides receiving, handling, warehousing, excess materials, and storage until installed; and*

d. *Materials Management provides Project inventory control support, coordination of material, identifies material needed, startup, and operations support.*

The Manager, Program Control reports to the Program Director CGS, and is responsible for:

a. *Overall administration and coordination of the Project budget, including analyses of Owner's cost, construction management forecasts, and AE estimates,*

b. *Overall analysis and reporting for the performance measurement system,*

c. *Financial verification and processing of payments to contractors and vendors, and*

d. *Coordination and administration of the change management system.*

The Manager of Project Licensing reports directly to the Manager, Regulatory Programs and is matrixed to the Program Director. The Manager, Project Licensing is responsible for:

a. *Providing coordinated Project-level management of licensing activities,*

b. *Developing and implementing Project licensing policies consistent with Corporate policies, and*

c. *Ensuring technical adequacy of licensing submittals.*

The Manager, Construction Quality Assurance reports to the Director, Licensing and Assurance and is responsible for the development and implementation of the QAP during the Nuclear Power Plant Design and Construction phases. He is also responsible for Procurement QA; plant modifications; qualification and certification of Energy Northwest nondestructive examination and inspection personnel, and other personnel requiring certification; surveillance of nondestructive examination and inspection activities.

The Manager of Procurement Quality Assurance reports to the Manager of Construction Quality Assurance and is primarily responsible for the definition and implementation of the source surveillance/audit program for verification of activities performed by Energy Northwest vendors (including the NSSS vendors). The Manager of Procurement Quality Assurance is specifically responsible for:

a. *Review of and concurrence with procurement documents for items and services (other than nuclear fuel) initiated by Corporate personnel,*

b. *Performance of preaward surveys/evaluations of vendors/suppliers, and maintaining and distributing an updated listing of those approved,* *c.* *Planning, coordination, and performance of source surveillances, source inspections, and source audits to verify implementation of Energy Northwest direct-purchase Supplier QA/QC Programs,*

d. *Review and/or approval of offsite Energy Northwest-administrated vendor/supplier quality assurance/ quality control procedures and programs,*

e. *Perform receipt-inspection of items received at the Corporate Warehouse and Corporate extensions,*

f *Verify that received items are handled and stored correctly,*

g. *Ensure training of receiving inspectors,*

h. *Provide program overview of AE vendor surveillance activities,*

i. *Quality assurance vendor surveillance of offsite Supplier activities,*

j. *Audits, surveillances, and/or surveys of suppliers of items, materials, or services who do not have ASME Certification, and*

k. *Provide overview of NSSS vendors.*

The Project Quality Assurance Manager reports to the Manager, Construction Quality Assurance and is matrixed to the Program Director. The Project Quality Assurance Manager is responsible for:

a. *Verification of the implementation of Quality Assurance Requirements Manual,*

b. *Verifying adequate implementation of an approved stop work authority program and directing a stop work order should conditions so dictate,*

c. *Assurance of a program for identification and reporting of nonconformances,*

d. *Verification, by audits and surveillances, that the AE, CM, selected contractors, and other Project organizations are implementing applicable quality requirements,*

e. *Ensuring that adequate staffing is obtained to implement the QAPs at the Project,*

f. *The assignment of adequately trained an qualified/certified personnel to perform quality verification activities,* *g. Overview of AE/CM approval of Contractor procedures and instructions,*

h. Reporting significant conditions adverse to quality to the Program Director and the Director, Licensing and Assurance, and

i. Reporting quality problems and trends to the Manager, Construction Quality Assurance for use in developing standards for Licensing and Assurance management systems to preclude repetition of quality assurance problems.

The Manager of Audits reports to the Director, Licensing and Assurance and is responsible for maintaining an organization of qualified auditors responsible for verifying implementation of the QAP as follows:

a. Performing quality assurance audits of internal Energy Northwest organizations and external organizations (e.g., AE/CM); except for Management Audits,

b. Developing audit and surveillance schedules and selecting qualified personnel to perform the activities of this function,

c. Certification of Audit Team Leaders,

d. Training of audit personnel,

e. Participating in audits and providing overview of AE activities,

f. Periodic review of Corporate and project audit reports to identify any quality trends which may constitute a need for corrective action, and

g. Maintenance of audit records.

The Manager of Nuclear Safety and Regulatory programs reports to the Director of Licensing and Assurance and is responsible for the development and implementation of policies and programs which support design, construction, and operation of Energy Northwest plants in the areas of Nuclear Safety and Regulatory Programs. Areas in which the Manager of Nuclear Safety and Regulatory Programs provides support for the Projects include nuclear safety assurance, environmental compliance, and licensing. The Manager, Nuclear Safety and Regulatory Programs is responsible for establishment and maintenance of Energy Northwest/ regulatory interfaces and ensuring that nuclear licensing transmittals receive an adequate, competent, and timely review prior to making commitments. To accomplish this role, the Manager, Nuclear Safety and Regulatory Programs operates through the Manager, Regulatory Programs and the Manager, Programs and Safety Performance.

17.1.1.2 Quality Assurance Program

Energy Northwest has established and implemented a QAP for the design, procurement, and construction phase of the CGS facility. The QAP is based on the assignment of quality classifications which impose applicable quality requirements to structures, systems, and components.

The Energy Northwest QAP and the supporting procedures and instructions comply with the requirements of Appendix B to 10 CFR Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", and applicable regulatory guides as specified in Section 1.8.2 of the FSAR.

Energy Northwest's design and construction activities at CGS are performed in accordance with the policies established by the Energy Northwest QAP Manual for Design and Construction.

A matrix of the Energy Northwest QAP procedures and the corresponding criteria of 10 CFR 50, Appendix B, appears in the table below followed by description of the scope covered by these procedures.

10 CFR 50, Appendix B Criteria	*Supply System QAR*
Organization	*QAR-1*
Quality Assurance Program	*QAR-2*
Design Control	*QAR-3*
Procurement Document Control	*QAR-4*
Instructions, Procedures and Drawings	*QAR-5*
Document Control	*QAR-6*
Control of Purchased Materials, Equipment and Services	*QAR-7*
Identification and Control of Material, Parts and Components	*QAR-8*
Control of Special Processes	*QAR-9*

Inspection	*QAR-10*
Test Control	*QAR-11*
Control of Measuring and Test Equipment	*QAR-12*
Handling, Storage and Shipping	*QAR-13*
Inspection, Test and Operating Status	*QAR-14*
Nonconforming Materials, Parts or Components	*QAR-15*
Corrective Action	*QAR-16*
Quality Assurance Records	*QAR-17*
Audits	*QAR-18*

a. Organization - QAR-1

Establishes an organizational structure that will direct the resources of Energy Northwest and its contractors to engineer, design, procure, fabricate, manufacture, install, construct, and test the Energy Northwest Nuclear projects to maximize safety, reliability, and efficiency.

b. Program - QAR-2

Defines the QAP established by Energy Northwest for design and construction. Included in this program is a system for classifying structures, systems, components, design characteristics, and procurement documents to determine the Quality Assurance activities associated with each item.

c. Design Control - QAR-3

Establishes a system of independent reviews to ensure applicable quality regulatory, code, and design basis requirements are properly translated into design and procurement documents for each structure, system, and component. The documented review provides a check for design adequacy, inspectability, and compatibility with intended usage.

d. Procurement Document Control - QAR-4

Establishes a system to ensure that procurement documents and changes thereto incorporate the technical and quality assurance requirements necessary to ensure the quality and integrity of procured material, equipment, and services.

e. Instructions, Procedures, and Drawings - QAR-5

Establishes system defining the requirements and responsibilities controlling the preparation, review, approval, and release of instructions, procedures, and drawings which implement quality requirements.

f. Document Control - QAR-6

Establishes a system to control the issuance of documents, including changes thereto, which prescribe activities affecting quality.

g. Control of Purchased Material, Equipment, and Services - QAR-7

Establishes a system to ensure material, equipment and services are procured in accordance with the requirements specified in the procurement documents.

h. Identification and Control of Materials, Parts and Components - QAR-8

Establishes a system for the identification and control of material, parts, components, equipment and partially-completed assemblies to ensure that items incorporated into the plant are of proper configuration and, when necessary, traceable to all supporting quality assurance documentation.

i. Control of Special Processes - QAR-9

Establishes a system for the control of special processes.

j. Inspection - QAR-10

Establishes a system which ensures the program requirements for inspection are delineated in the specifications and contracts and ensures that inspection and surveillance activities are performed in accordance with predetermined requirements delineated in written instructions in a planned and systematic manner.

k. Test Control - QAR-11

Establishes a system to ensure that plant testing activities are performed in accordance with predetermined requirements, approved, and delineated in written instructions.

l. Control of Measuring and Test Equipment - QAR-12

Establishes a system for the control, calibration, and adjustment of tools, gauges, instruments, and other inspection, measuring, testing, and maintenance devices at specified periods to ensure the usage of proper type, range, and accuracy necessary to verify conformance to established requirements.

m. Handling, Storage, and Shipping - QAR-13

Establishes system to control the handling, storage, shipping, cleaning, and preservation of material, parts, components, and equipment in accordance with written and approved procedures, instructions and recommendations, to ensure that the designed integrity and functionality of the item are maintained.

n. Inspection, Test, and Operating Status - QAR-14

Establishes a system to indicate the inspection, test, and operating status for all structures, systems, or components to preclude the inadvertent bypassing of their inspection and test requirements and to prevent their inadvertent operation.

o. Nonconforming Material, Parts, or Components - QAR-15

Establishes a system to ensure that nonconformances are identified, documented, segregated or otherwise controlled, prevented from inadvertent use or installation and that notification of actions taken is transmitted to the affected parties.

p. Corrective Action - QAR-16

Establishes a system to ensure that significant conditions adverse to quality are identified, the cause determined, documented, brought to the attention of upper management, corrected as soon as possible, and that measures are taken to preclude repetition.

q. Quality Assurance Records - QAR-17

Establishes a system for the control and maintenance of all records sufficient and necessary to provide objective evidence of the activities affecting quality.

r. Audits - QAR-18

Establishes a system of audits to be performed in a planned and systematic manner to verify compliance and effectiveness of the Energy Northwest QAP.

The CGS Project Management Instructions (PMI) Manual delineates the responsibilities of and interfaces between project organizations. Each project organization is responsible for developing and using implementing procedures/instructions for their assigned functions.

Quality Assurance Instructions, Project Procurement Manuals, and other procedures or instructions pertinent to specific departmental functions describe the measures used to implement the provisions of the programs.

The Energy Northwest Quality Assurance Manager assigned to the CGS Project is responsible for establishing and administering the CGS Quality Assurance policies, goals, and objectives of the QAP and verifying adequate implementation.

The CGS Quality Assurance personnel have the authority and responsibility to perform the necessary actions, including provisions for stop work authority, to accomplish their assignments.

To ensure that CGS Project personnel who perform quality-related activities are cognizant of the quality requirements, they are provided training and indoctrination as prescribed by the Project Training Program. The initial indoctrination includes discussions as to the purpose of applicable codes and standards and familiarization with Appendix B, 10 CFR Parts 50, 50.55(e), and 10 CFR Part 21. The training phase includes instructions on the Project QA policies and instructions on specific quality activities directly related to individual job functions. Personnel whose activities require specific qualifications such as nondestructive testing, audit, inspection, and testing are suitably evaluated, trained as appropriate, and certified.

Training sessions are an ongoing activity and are appropriately documented. Nondestructive test, audit, test, and inspection personnel qualification records are maintained.

The CGS QAP is audited on a regular basis by the Home Office Energy Northwest Audit Section.

Contractors who perform safety-related work include the AE, NSSS Supplier, and CM. These contractors are required to establish and implement QAPs consistent with the applicable requirements of 10 CFR Part 50, Appendix B. These programs are reviewed for adequacy by CGS Project personnel. The AE, NSSS Supplier, and Construction Management Contractor quality-related functions are controlled in accordance with the programs described in Sections 17.1.2, 17.1.3, and 17.1.4, respectively.

17.1.1.3 Design Control

Burns and Roe, as AE, is responsible for specifying the overall design of the project, except that GE is responsible for design of the NSSS system. Design by other project organizations (contractors) is performed in accordance with an approved QAP. The details of the Burns and Roe and GE CGS QAPs are described in Sections 17.1.2 and 17.1.3 respectively.

Design control is performed by project organizations in accordance with approved procedures and/or instructions.

Design input, such as design bases, performance requirements, regulatory requirements, appropriate quality standards, and industry codes and standards are properly identified, documented, and translated into design documents, such as drawings and specifications.

Procedures describe the controls established for the review, approval, release, distribution, and revision of design documents involving design interfaces.

Changes in design, including field changes, and the reason for changes, are documented, controlled, and reviewed in accordance with measures commensurate with those applied to the original activity.

Computer programs for quality affecting activities are controlled, in accordance with quality program requirements of the user organization.

17.1.1.4 Procurement Document Control

Procurement of material, equipment, and services for the Project is accomplished through procurement specifications contracts, or purchase orders which are prepared, reviewed, and approved by cognizant personnel. Procedures require that procurement documents incorporate the applicable quality assurance, regulatory code, and design requirements. The procurement documents require that bidders submit a QAP or plan for major contracts describing their policies, procedures, and systems to be utilized in the control of quality throughout the applicable phases of production, from design to final shipment, erection, or installation.

Procurement documents provide requirements for suppliers to submit or make available for review applicable documents such as drawings, specifications, procedures, instructions, *inspection and test records, and quality assurance records to the Project for review and/or approval.*

Procurement documents require suppliers to provide measures for retention, control, and maintenance of their Quality Assurance records procurement documents specify the appropriate records to be delivered to the Project prior to or with delivery.

When source surveillance is required ,procurement documents require suppliers to provide right of access to their facilities, procedures, and records for inspection and audit by Project personnel. Procurement documents issued after January 1978 require the supplier to establish measures for reporting 10 CFR Part 21 reportable deficiencies and disposition of nonconformances from procurement document requirements. Procurement documents require that the supplier retain the responsibility for monitoring and evaluating their sub-tier suppliers' performance to specified requirements.

Procurement documents for spare or replacements contain original, equivalent, or improved technical requirements including codes and standards and current applicable QAP requirements.

Changes and revisions to procurement documents are subject to the same or equivalent review/approval requirements as the original document.

17.1.1.5 Instructions, Procedures, and Drawings

Activities affecting quality are described in procedures, instructions, and drawings and the activities are conducted in accordance with these documents.

Procedures, instructions, and drawings include adequate quantitative and qualitative acceptance criteria to ascertain that the prescribed activities have been satisfactorily accomplished.

Procedures, instructions, and drawings are subject to review to assure that applicable codes, standards, and acceptance/rejection criteria are included. Review, approval, or information requirements are included in contract documents.

17.1.1.6 Document Control

A document control system is implemented by the Project. The requirements ensure that documents, including changes, are reviewed, approved, and released in a timely manner to the locations where the activity is being performed. The Project prepares procedures, instructions, and drawings as necessary to ensure that activities such as design, procurement, manufacturing, construction and installation, testing, inspection, auditing, calibration, and special processes are adequately prescribed and the necessary quality requirements are stated.

Changes to these documents require review and/or approval commensurate to that performed on the original document.

Contractors/subcontractors involved in activities affecting quality are required to establish measures for document control which satisfy project requirements.

Changes to specifications and drawings require approval of the cognizant Engineering personnel. As required by Procurement Documents, changes to supplier and contractor drawings and procedures are reviewed and approved by the Project Organization. Changes to documents such as specifications and drawings are indicated by a revision, change order, or equivalent documented methods.

Project drawings and specifications, supplier and contractor drawings, current revisions, addenda, and changes in design and engineering change notices are released in a controlled manner.

To preclude the inadvertent use of obsolete or superseded documents, a Project drawing/specification status report is periodically issued. These reports indicate the current revision to AE drawings and specifications and related changes, addenda, and design and engineering change notices. Site contractors are required to establish measures to ensure that obsolete or superseded documents are controlled to prevent their inadvertent use.

17.1.1.7 Control of Purchased Material, Equipment, and Services

Prior to award of contract, Quality Assurance, Engineering, and other personnel, as required, perform an evaluation of accepted bids to determine the supplier's capability to meet procurement requirements. The evaluation may consist of a direct survey of the prospective supplier's facility and personnel or, a review and evaluation of the implementation of his QAP, or evaluation of the supplier's history of providing satisfactory products to the project, or evaluation of the supplier's current records supported by objective evidence.

Surveillance of suppliers, as required, during fabrication, inspection, testing, and shipment of materials, equipment, and components is performed to provide assurance that material, equipment, and services conform to procurement document requirements. Surveillances are conducted by qualified personnel in accordance with established plans and to procedures that identify the attributes or processes to be witnessed and/or verified and the acceptance criteria. Those items which are simple and standard in design, manufacture, and test, or where quality characteristics can be verified by standard inspections or tests after delivery, are accepted during receiving inspection with no source surveillance. Receiving inspection is performed in accordance with written procedures or instructions.

Measures are established to provide for delivery of documentation from the supplier to the site, prior to or with delivery. These documents provide objective evidence:

a. That the items conform to the procurement quality requirements such as specifications, codes, and standards,

b. That the required tests, examinations, and inspections have been performed, and

c. That nonconformances have been dispositioned as required.

17.1.1.8 <u>Identification and Control of Materials, Parts, and Components</u>

Measures are established to identify and control materials, parts, and components including partially completed subassemblies. Requirements for identification and traceability are determined during initiation of design documents and are specified in procurement specifications and on drawings.

These measures require that items important to the safety of the Project are identified in a manner (i.e., heat/lot number, part number, serial number, etc.) that can be traced to the appropriate documentation, or group of documents, such as drawings, specifications, purchase orders, material certifications, etc. The identification is maintained and verified, as required, throughout fabrication, installation, and use of the item.

Implementation of these measures is accomplished by the responsible contractors in accordance with approved procedures.

Verification that items are properly identified is performed during vendor surveillance and receiving inspection activities.

During receipt inspection, materials, parts, and components are identified as acceptable or unacceptable. Where practicable, unacceptable items are physically segregated from acceptable items. Items identified as unacceptable may be released for installation provided the following conditions are met:

a. Traceability and identification is maintained,

b. The item can be brought to an acceptable condition without damage to associated equipment or structures, and

c. Controls are established to ensure retrievability and, when applicable, limit the use of the item.

17.1.1.9 Control of Special Processes

Measures are established for the procedural control of special processes that require interim in-process controls in addition to that inspection and/or examination to ensure achievement of required quality. Examples of these processes are coating/plating, heat treating, welding material cleaning, and nondestructive testing (NDT).

Special processes specified in fabrication/construction documents are controlled and are performed by qualified personnel using approved procedures and equipment evaluated to ensure compliance in accordance with applicable codes, standards, and specifications. Special processes delineated in the procurement documents may require that the applicable contractors submit procedures for review and approval.

17.1.1.10 Inspection

Measures are established to assure that an inspection program is planned and scheduled.

Equipment manufacturers, installers, and constructors are required by procurement documents to perform the inspection necessary to verify that items conform to established criteria. Procurement documents also require that inspection activities are performed in accordance with documented instructions, procedures, and drawings, as applicable.

Measures are implemented to ensure that inspections and/or tests are performed on work operations as necessary to verify quality, that personnel performing inspections are independent of the individual or group performing the activity being inspected and are qualified to the requirements of the applicable codes, standards, and company programs. Records of certification of qualification are maintained in a current status. Inspection planning provides measures to identify mandatory inspection hold points for contractor inspection personnel. Where appropriate, procedures, instructions, and checklists used in performing inspections, include as a minimum:

a. *Identification of characteristics and activities to be inspected,*

b. *Identification of the individuals or groups responsible for inspection,*

c. *Acceptance/rejection criteria,*

d. *Inspection method, and*

e. *Inspection reports attesting to the completion of inspection and the identity of the inspector or data recorded.*

The inspection program provides that modification, repairs, and replacements are inspected in accordance with the original design and inspection requirements or acceptable alternatives.

Construction inspection, and receiving inspection at the Project Site is performed by Construction Management Contractor Quality Control and/or installing contractor Quality Control personnel for those activities within the scope of their responsibility. Construction Management Contractor Quality Control personnel perform receiving inspection functions on project supplied materials, parts and components. Construction Management Quality Assurance personnel perform surveillance/audit functions on these activities to ensure compliance with project requirements.

The Energy Northwest Project Quality Assurance performs surveillance/audit functions on the preceding activities.

17.1.1.11 Test Control

A test program is established to specify the requirements and to provide for identification of the testing necessary to demonstrate that structures, systems, and components perform satisfactorily in service.

Testing as addressed in this section pertains to tests performed on prepurchased equipment and materials and, tests performed by the contractors on installed equipment, components, structures, and systems.

The necessary testing requirements are specified in written procedures which incorporate or reference the acceptance limits contained in design and procurement documents and provide that:

- *a. Calibrated test instrumentation and equipment is available,*
- *b. Tests are performed under suitable environmental conditions with adequate test methods,*
- *c. Tests are conducted by appropriately trained and qualified personnel,*
- *d. Items which are modified, repaired, and replaced are tested in accordance with the same requirements which were applied to the original items or an approved alternate, and*
- *e. Test results are documented and evaluated to ensure that test requirements have been satisfied.*

17.1.1.12 Control of Measuring and Test Equipment

Measures are established to ensure that tools, gauges, instruments, and other measuring and testing devices are identified, controlled, adjusted, and calibrated at intervals necessary to maintain accuracy within specified limits.

Suppliers and site contractors whose activities are quality affecting are required to implement control of measuring and test equipment in accordance with approved procedures. These procedures contain provisions that:

a. *Devices are adjusted and calibrated at prescribed intervals against certified standards having valid relationships to nationally recognized standards, or, if no national standard exists, the basis for calibration is documented.*

b. *Measuring and test equipment is calibrated at specific intervals based on the required accuracy, purpose, extent of use, stability characteristics, and other conditions affecting measurement control.*

c. *Measuring and test equipment is calibrated against reference standards. Records are maintained and equipment adequately identified to indicate calibration status and usage.*

d. *When measuring and test equipment is found to be out of calibrations written procedures describe provisions for documenting and evaluating the validity of previous inspections and tests and, for repeating the original inspection or test using calibrated equipment where necessary to establish acceptability of suspect items.*

e. *Supplier and contractor procedures specified in procurement documents are reviewed and approved prior to starting work.*

17.1.1.13 Handling, Storage, and Shipping

Measures are established to control the handling, storage, shipping, cleaning, and preservation of material and equipment to prevent damage or deterioration. Appropriate procedures are prepared in accordance with design specification requirements and manufacturer's instructions to provide for special handling, storage, maintenance, cleaning, and preservation. These activities are accomplished in accordance with approved procedures or instructions.

Where required, procedures address requirements for special protective environments such as inert gas atmosphere, moisture content levels, and temperature levels and require that:

a. Procurement documents establish requirements for handling, shipping, storage, preservation, and maintenance.

b. Items are stored in accordance with their classifications as delineated in Project instructions.

c. Storage areas are monitored to assure that the required storage integrity is maintained.

17.1.1.14 Inspection, Test, and Operating Status

Measures are established to indicate that inspections and tests performed on structures, systems and components are known throughout fabrication, installation and test. Indicators such as tags, stamps, labels, travelers, or other suitable means are utilized to indicate the status of the item. Where required, structures, systems and components such as valves, switches, electrical, and rotating equipment are tagged or locked out to prevent inadvertant use.

Project organizations and contractors involved in inspection, test, and operation of equipment, components, and systems are required to prepare and implement procedures for the control of these items and activities. Procedures include requirements that specified inspections and tests are performed, that application and removal of status indicators are controlled, that bypassing of quality affecting tests and inspections are controlled, and that systems containing inoperative, malfunctioning or nonconforming items, structures, or components are identified and controlled to prevent inadvertant operation.

17.1.1.15 Nonconforming Materials, Parts, or Components

Measures are established for the control of material, parts, components, or services that do not conform to specified requirements.

To prevent inadvertent use or installation, the QAPs of the Project organization, site contractors, subcontractors, and suppliers establish control for identification, documentation, segregation, review, disposition, and notification to affected organizations of non-conforming materials, parts, components, or services.

Written procedures contain provisions:

a. For the handling, processing and dispositioning of nonconforming materials, parts, components, or services,

b. For the identity of the individuals or groups with the authority and responsibility for the review, disposition and approval of nonconforming items, *c.* *That nonconforming items are identified as such, by the appropriate status indicator and are physically segregated where practical from acceptable items until dispositioned,*

d. *That rework or repair of nonconforming items be subject to the same, or an equal test or inspection as was originally imposed, or an approved alternate, and the inspection, testing, rework and/or repair activities are documented,*

e. *That nonconformance reports are reviewed for potential 10 CFR 50.55(e) and Part 21 reportability,*

f. *For identification and control of conditional released items,*

g. *That measures are established in procurement documents to require offsite vendors and suppliers to include their nonconformance reports, which deviate from procurement documents, as a part of their Quality Assurance records, and*

h. *That site contractors and subcontractors document deviations from contract requirements, and nonconformances dispositioned "use-as-is" or "repair" are submitted to the project for review and/or concurrence.*

Nonconformance documentation identifies the nonconforming item, describes the nonconformance and the disposition of the nonconformance, identifies any special inspection requirements and the completion of inspection, and contains required signatures/approvals.

Construction Management Contractor Quality Assurance is responsible for the review of these nonconformance reports to ascertain that they have been dispositioned, approved, and closed out.

Reviews include trend studies, corrective action adequacy, and reporting to appropriate levels of management.

The AE is responsible to provide acceptance of disposition for those conditions for which they have assigned technical responsibility. When technical responsibility has not been assigned to the AE, or another design contractor, or when technical requirements are not affected or technical responsibility has been assumed by Energy Northwest, Energy Northwest will provide acceptance of disposition.

17.1.1.16 Corrective Action

Measures are established to provide for the prompt identification, evaluation, and correction of conditions adverse to quality such as nonconformances, failures, malfunctions, deficiencies, deviations, defective material, and equipment.

The QAPs for the project organization and onsite contractors are required to establish provisions:

a. *That corrective action is implemented in accordance with procedures,*

b. *That corrective action for significant conditions adverse to quality identify the cause and include actions to preclude recurrence,*

c. *That follow-up is performed to verify implementation and close out of corrective action,*

d. *That for significant conditions adverse to quality, the cause and the corrective action taken are reported to cognizant management levels, and*

e. *That Corrective Action Reports are reviewed for potential 10 CFR 50.55(e) and Part 21 reportability.*

17.1.1.17 Quality Assurance Records

Measures are established to assure that sufficient records are maintained to provide documentary evidence of the quality of items and the activities affecting quality.

Quality Assurance records include:

a. *Test logs,*
b. *Results of reviews of inspection, tests, audits, and material analysis,*
c. *Surveillance and audit documents,*
d. *Qualification of personnel, procedures and equipment,*
e. *Drawings, as-built drawings and specifications,*
f. *Procurement documents,*
g. *Calibration procedures and reports, and*
h. *Nonconformance and corrective action reports.*

Inspection and test records contain as applicable:

a. *Type of inspection, test, or examination,*
b. *Identity of inspector or data recorded,*
c. *Date and results of inspection/test,*
d. *Acceptability,*
e. *Action taken relative to deficiencies noted, and*
f. *Identification with the applicable item or activity.*

Suppliers, vendors, and contractors are required to furnish Quality Assurance records prior to or on delivery of equipment, supplies, structures, or systems, or retain them if required by contractual agreement.

Procedures are established and contain provisions for the identification of individuals or groups responsible for record transmittals, retention, and maintenance, and provisions for ensuring that records are identifiable and retrievable.

Record storage facilities are constructed, located and secured to prevent destruction by fire, flooding, theft, and deterioration by extremes in temperature and humidity.

17.1.1.18 Audits

Measures are established to provide a system for conducting audits to verify compliance with all aspects of the QAP and to determine the effectiveness of the program. All aspects include activities associated with:

- *a. Indoctrination and training programs,*
- *b. Interface control between Energy Northwest and the principal Contractors,*
- *c. Corrective action, calibrating, and nonconformance control systems, and*
- *d. SAR commitments.*

The project organizations and principal contractors have established and implemented an audit system which includes objective evaluations of quality-related practices, procedures, activities, and records. The system ensures that the necessary audit functions are performed to preestablished written procedures or checklists, in a planned and systematic manner, and are conducted by trained and qualified personnel who do not have direct responsibility in the areas being audited.

The audit system provides for external audits to be performed, as appropriate, by the home office, project organization, and principal contractors on their suppliers, vendors, and contractors, and internal audits to be performed within each organization.

Audits are planned and scheduled on the basis of the status and safety importance of the activities being performed. They are initiated early enough and performed at regular intervals to ensure the QAP is effectively implemented during design, procurement, manufacture, construction, and installation.

Audits are documented and reviewed with the level of management responsible for the area audited and, where required, follow-up action including reaudit of the deficient areas is performed.

Audit data is evaluated to assure that the QAP is effective and properly implemented and the results are reported to management for review and assessment.

The Energy Northwest CGS quality affecting activities are audited on a scheduled basis by the Energy Northwest home office audit group.

17.1.2 THE BURNS AND ROE, INC. QUALITY ASSURANCE PROGRAM

17.1.2.1 Introduction

The Burns and Roe, Inc. (B&R) QAP for the Energy Northwest Columbia Generating Station (CGS) has evolved during the design and construction of CGS. The original B&R QAP was described in the Atomic Energy Commission accepted Preliminary Safety Analysis Report (PSAR) for CGS, Appendix D.O. This QAP was implemented until February 1978, when Energy Northwest assumed responsibility for Construction Management, Site Quality Assurance, and Vendor Surveillance of selected prepurchased equipment contracts. The B&R QAP was implemented during this phase of the CGS PSAR Deviation Request No. 15 WP. In this phase, B&R was responsible for the AE scope of the engineering and design of CGS and provided experienced Quality Assurance personnel to carry out Energy Northwest's assumed responsibilities. On June 1, 1981 B&R implemented their Quality Assurance Topical Report, B&ROE-COM4-1-NP-2A, approved by the Nuclear Regulatory Commission, with documented exceptions for the B&R engineering and design and procurement activities for CGS.

17.1.2.2 The Burns & Roe, Inc. Quality Assurance Topical Report

The QAP for CGS was implemented by B&R on June 1, 1981 and is based on the B&R Quality Assurance Topical Report with documented exceptions, CGS Final Safety Analysis Report (FSAR) commitments, Energy Northwest direction and the B&R contractual responsibilities for the design and construction of CGS. The B&R responsibilities for the CGS Project are engineering and design, and procurement activities for assigned prepurchased equipment contracts. The exceptions to the Quality Assurance Topical Report are identified in the following subparagraphs.

17.1.2.3 Exceptions to the Burns & Roe, Inc. Quality Assurance Topical Report

17.1.2.3.1 Chapter I - Organization

Paragraph 4.1.2

The B&R CGS Project Organization chart is shown as Figure 17.1-4.

Paragraph 4.3

Construction Management is not within B&R scope of services.

17.1.2.3.2 Chapter II - Quality Assurance Program

Paragraph 2.1

The US NRC Regulatory Guides applicable to CGS are identified in Section 1.8.3 of the CGS FSAR.

Paragraph 4.6

Under the B&R CGS QAP, satisfactory accomplishment of the following quality affecting functions shall be verified:

a. *The design process is accomplished in accordance with established procedures.*

b. *Specifications contain appropriate quality requirements.*

c. *For those prepurchased equipment contracts for which Burns and Roe performs the vendor surveillance function:*

    1. *Contractors' QAPs and procedures are adequate,*

    2. *Nonconformances are identified and dispositions provided, and*

    3. *Material receiving, inspection, and storage functions are performed in accordance with established procedures.*

d. *Surveillance of the activities performed by Contractors whose sole function is to provide engineering and design services.*

e. *Audits of the quality affecting activities described above are performed on a scheduled basis.*

17.1.2.3.3 Chapter III - Design Control

Paragraph 2.1

10 CFR 50, Appendix B and ANSI N45.2 are the basis for the B&R design control program.

<u>Paragraph 4.1</u>

The detailed design effort is based only on an approved project criteria document.

<u>Paragraph 5</u>

Additional design reviews/verifications have been performed on a sampling of previously issued system designs by the performance of special design reviews in accordance with project procedure WNP-2-ED-013.

Burns & Roe, Inc. procedures for design control have been upgraded to verify that future issued designs and modifications comply with applicable codes, standards, and design requirements.

17.1.2.3.4 Chapter IV - Procurement Document Control

<u>Paragraph 3.4</u>

Records to be retained, controlled and maintained by a supplier are not identified in the specification.

<u>Paragraph 4</u>

The appropriate commercial requirements are established by Energy Northwest and/or B&R and may be incorporated during the initial preparation of the technical specification. Energy Northwest prepares the potential bidders list.

<u>Paragraph 5</u>

Award is determined by Energy Northwest using the bid evaluation prepared by B&R.

<u>Paragraph 6</u>

Technical specifications are not normally conformed. When technical specifications are conformed, the changes are reviewed and approved in accordance with the same procedure used for the original technical specification.

<u>Paragraph 7</u>

Later procurement of spare or replacement parts shall be to the original or improved technical requirements. Impositions of Quality Assurance requirements will be in accordance with the Quality Assurance requirements of the existing specification for procurement of components *which are added to existing contracts. The latest CGS Project Quality Programs are imposed on new procurements.*

17.1.2.3.5 Chapter V - Instructions, Procedures, and Drawings

Paragraph 2.2

Burns and Roe, Inc. review of Quality Assurance plans required by procurement documents is limited to those prepurchased contracts for which B&R performs the vendor surveillance function.

Paragraph 2.5

Burns and Roe verification of the implementation of instructions, procedures, and drawing programs is limited to those prepurchased contracts for which B&R performs the vendor surveillance function.

17.1.2.3.6 Chapter VI - Document Control

Paragraph 2.1

The B&R CGS QAP, in regard to document control, does not govern the following:

a. *Procurement documents, except for prepurchased equipment contracts for which B&R performs the vendor surveillance function,*

b. *Quality Assurance plans, except for the B&R Quality Assurance Plan and the quality assurance plans prepared by prepurchased equipment contracts for which B&R performs the vendor surveillance function,*

c. *Contractor manufacturing, inspection, and testing procedures, except for those prepared by prepurchased equipment contracts for which B&R performs the vendor surveillance function,*

d. *Construction and operational test procedures, and*

e. *Nonconformance reports, except for those prepared by prepurchased equipment contracts for which B&R performs the vendor surveillance function.*

Paragraph 2.3

Changes to documents listed in Paragraph 2.1 may be made and implemented prior to the official revision of the document provided an advance change system exists and is controlled by approved project instruction and/or procedures.

Paragraphs 2.6 and 2.7

Burns and Roe verification of Contractor's document control programs is limited to those prepurchased contracts for which B&R performs the vendor surveillance function.

17.1.2.3.7 Chapter VII - Control of Purchased Material, Equipment, and Services

Paragraph 3

Recommended bidder lists are not prepared by B&R.

Paragraph 4.2

Quality Assurance audits are performed after contract award.

Paragraph 4.3

Recommendations for award are made by project management to Energy Northwest and Energy Northwest approves and makes the award.

Paragraph 4.4

Records of B&R bid evaluations and recommendation are only maintained by B&R for the supplier selection process.

Paragraphs 5 and 6

Surveillance plans are approved by the Manager of Vendor Surveillance and are subject to Project Quality Assurance review.

Paragraphs 6.3 and 7

Not applicable to B&R CGS QAP.

17.1.2.3.8 Chapter VIII - Identification and Control of Material Parts and Components

Paragraph 2.1

Verification of identification of components, assemblies and subassemblies is performed by B&R only on prepurchased contracts for which B&R performs a final inspection prior to shipment.

17.1.2.3.9 Chapter IX - Control of Special Processes

Paragraphs 2.5 and 2.6

Only when performing the function of vendor surveillance on prepurchased contracts does B&R evaluate and verify a Contractor's special process control program.

17.1.2.3.10 Chapter X - Inspection

Paragraph 2.1

The applicability of US NRC Regulatory Guides is as committed in Section 1.8.3 of the CGS FSAR. Mandatory hold points for prepurchased contracts are established after contract award and are contained in the Vendor Surveillance Plan for each Contract.

Paragraph 2.4

Verification that the contractor's inspection program is being effectively implemented is accomplished by a series of surveillances and audits performed by quality assurance personnel for those prepurchase contracts which Burns and Roe has retained the vendor surveillance function.

17.1.2.3.11 Chapter XI - Test Control

Paragraph 2.1

The applicability of US NRC Regulatory Guides are as committed in Section 1.8.3 of the CGS FSAR.

Paragraph 2.6

Verification of the implementation of a Prepurchase Contractor's test control program is performed by B&R for prepurchased contracts when B&R performs the vendor surveillance function.

17.1.2.3.12 Chapter XII - Control of Measuring and Test Equipment

Paragraph 2.3

Selected prepurchase contractor programs for the control of measuring and test equipment are subject to engineering review and approval by B&R.

Paragraph 2.4

Verification that the program for the control of measuring and test equipment is being effectively implemented is ensured by a series of surveillances and audits performed by quality assurance personnel for those prepurchase contracts which Burns and Roe has retained the vendor surveillance function.

17.1.2.3.13 Chapter XIII - Handling, Storage, and Shipping

Paragraph 2.3

Only selected prepurchase contractor programs for the control of handling, preservation, storage, cleaning, packaging, and shipping of items are subject to review and approval by Burns and Roe, Inc. personnel. This procedurally controlled and documented review is the responsibility of the cognizant system or component engineer and includes review by a quality assurance engineer. Project management, based on comments generated during the review, makes an approval determination.

Paragraph 2.4

Not applicable to B&R CGS QAP.

Paragraphs 2.5, 2.6, and 2.7

These requirements are applicable to those prepurchased contracts for which B&R performs the vendor surveillance function.

Paragraph 2.8

Verification of the implementation of Contractor programs for handling, storage, and shipping is performed by B&R only for prepurchased contracts when B&R performs the vendor surveillance function.

17.1.2.3.14 Chapter XIV - Inspection, Test, and Operating Status

Paragraph 2.3

Not applicable to B&R CGS QAP.

Paragraph 2.4

Selected prepurchase contractor programs for inspection, test, and operating status are subject to engineering review and approval by B&R, for prepurchased contracts which B&R has retained by vendor surveillance function.

Paragraph 2.5

Verification that the inspection, test, and operating status program is being effectively implemented is ensured by a series of surveillances and audits performed by quality assurance personnel for prepurchased contracts which B&R has retained the vendor surveillance function.

17.1.2.3.15 Chapter XV - Nonconforming Materials, Parts, or Components

Paragraph 2.2

Nonconformance reports are not included in final data packages forwarded to B&R. Nonconformance reports on the CGS Project are not issued or analyzed for quality trends by B&R.

Paragraph 2.3

Selected prepurchase contractor nonconformance control programs are subject to engineering review and approval by B&R.

Paragraph 2.4

All nonconformance reports for those conditions for which B&R has the assigned technical responsibility require engineering review and approval by B&R. Such dispositioned nonconformance reports must be concurred in by the B&R Quality Assurance Manager or designated Quality Assurance Engineers.

Paragraph 2.5

Not applicable to the B&R CGS QAP.

17.1.2.3.16 Chapter XVI - Corrective Action

No deviations.

17.1.2.3.17 Chapter XVII - Quality Assurance Records

No deviations.

17.1.2.3.18 Chapter XVIII - Audits

Paragraph 2.10

Not applicable to B&R CGS QAP.

Paragraph 2.11

The audit program on material and equipment suppliers applies only to those prepurchased contracts for which B&R performs the vendor surveillance function.

17.1.3 GENERAL ELECTRIC COMPANY QUALITY ASSURANCE PROGRAM

The applicable QAP and detailed procedures of the CGS NSSS and fuel have evolved during the design and construction phases of the CGS plant. The original GE program for CGS was implemented in 1968 and is described in the PSAR, Appendix D. The program at that time was in accordance with the Nuclear Energy Division (NED) quality objectives for safety and reliable systems and components as set forth in the "Blue Book" issued August 20, 1968. On October 1, 1969, the "Blue Book" was replaced with the "Green Book", Revision 0, which incorporated the intent of the then "Proposed Atomic Energy Commission (AEC) Quality Assurance (QA) Criteria." The "Green Book" has proceeded through several revisions since 1969. The latest revision is NEDO-11209-04A, dated October 1980. Table 17.1-1 is a matrix showing the entire evolutionary process which the GE program has undergone since August 1968 and identifies related NRC and industry standards that were applied. The actual version in effect at any point in time controlled the QA measures applied to CGS by GE for work when it was initiated, consistent with any necessary contractual adjustments to update from the 1970 base date of the contract with Energy Northwest. For example, any work initiated after March 1978, applies the criteria represented by "Green Book" (NEDO-11209-04A). Note that those portions dealing with the Standard Reactor Island (STRIDE) are not applicable to CGS in that CGS is not provided a STRIDE by GE.

In so far as the NSSS is concerned, GE positions and commitments to regulatory guides and ANSI Standards, as made in the applicable revisions of NEDO-11209, take precedence over the positions and commitments described in the FSAR Chapter 3.

17.1.4 BECHTEL POWER CORPORATION QUALITY ASSURANCE PROGRAM

17.1.4.1 Quality Assurance Topical Report

The Bechtel QAP Plan for use by the Bechtel Power Corporation during Construction Management and System Completion of Energy Northwest Project CGS is described in the NRC-approved Bechtel Topical Report BQ-TOP-1, Revision 3A, Bechtel Quality Assurance Program for Nuclear Power Plants.

17.1.4.2 Scope of Responsibility

This section describes Bechtel responsibilities for providing quality-related services in Construction Management and Systems Completion to Energy Northwest on the CGS Project. The scope of responsibility differs from that indicated in BQ-TOP-1 in that Bechtel does no function as the responsible design engineering organization. Therefore, those provisions in BQ-TOP-1 associated with design engineering do not apply.

Bechtel will have an engineering management group under the direction of the Project Engineering Manager. This group will provide engineering management staff support capability to Energy Northwest. Engineering personnel will assist in developing the scope and relative priority of remaining engineering activities and will interface with Energy Northwest licensing personnel. Bechtel may perform engineering design assignments on a task basis. Such design tasks will meet design requirements established by the AE (B&R) and will be performed to the applicable requirements of BQ-TOP-1.

Bechtel will perform construction in the completion of systems, structures, components as assigned by Energy Northwest, utilizing materials provided by Energy Northwest.

Construction Management provisions for quality-related services include:

a. *Receiving, including receipt inspection of Energy Northwest purchased items,*

b. *Storage and maintenance of Energy Northwest purchased items,*

c. *Contractor/vendor QA documentation review, retention, and turnover to the Energy Northwest,*

d. *Review and approval of onsite contractor quality-related procedures and manuals,*

e. *QA/QC audit and surveillance inspection over onsite contractor activities,*

f. *Administration of the project program for controlling nonconforming items,*

g. *Administration of the project program for control of design documents, and*

h. *Procurement services, including procurement supplier quality services, in support of construction activities.*

17.1.4.3 Project-Unique Modification to BQ-TOP-1, Revision 3A

a. *Introduction, Page 3 - Replace Regulatory Guide 1.58 (August 1973) with Regulatory Guide 1.58, Revision 1 (September 1980).*

b. *Introduction, Page 3 - Add Regulatory Guide 1.146 "Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants" (Revision 0, 1978). See Section 1.8.3 for compliance statement.*

c. *Introduction, Page 3 - Replace ANSI Standard N45.2.12-1974 with Regulatory Guide 1.144, "Auditing of Quality Assurance Programs for Nuclear Power Plants" (Revision 1, 1980). See Section 1.8.3 for compliance statement.*

d. *Section 1, Organization, Subsection 1.5.1, Page 10 - Replace Subsection 1.5.1 with Attachment 1.*

e. *Section 1, Organization, Subsection 1.5.2, Page 10 - Replace Subsection 1.5.2 with Attachment 2.*

f. *Section 1, Organization, Subsection 1.5.4, Page 11- Replace Subsection 1.5.4 with Attachment 3.*

g. *Section 2, Quality Assurance Program (Subparagraphs 2 and 4), Page 23 - Change Regulatory Guide 1.58 (August 1973) to Regulatory Guide 1.58, Revision 1 (September 1980).*

h. *Section 2, Quality Assurance Program (Subparagraph 3), Page 23 - Change ANSI N45.2.12 to ANSI N45.2.23.*

i. *Change "Project Engineer" to "Project Engineering Manager" throughout.*

j. *Table 1, "Bechtel Quality Program Documents", Page 57 and 58 - Add to Table 1 the Project Documents shown on Attachment 4.*

k. *Add Figure 15, Bechtel Projects Management Organization, Attachment 5.*

l. *Add Figure 16, Quality Assurance/Quality Control Organization, Attachment 6.*

m. *Appendix A, Bechtel Position on QA NRC Regulatory Guides and ANSI Standards - Delete 5th paragraph (A-7) on Page A-1; Delete pages A-7 through A-13 entirely. Delete 11th paragraph (A-22) on Page A-1; delete Pages A-22 and A-23 entirely.*

n. *Appendix B, Division Quality Policies, Scope, and Relationship to 10 CFR 50, Appendix B - Add Project Nuclear Quality Assurance Manual as shown by Attachment 7.*

ATTACHMENT 1

The Manager of Projects (Attachment 5) is the senior Bechtel representative assigned to the CGS Project. The Manager of Projects reports to the Division Manager of Project Operations and is responsible for providing overall project direction to ensure the consistent and coordinated application of Bechtel policies and skills for the benefit of the CGS Project. The Manager of Project's staff includes a Deputy Manager of Projects and other managers to coordinate activities in labor relations, the quality program, and administrative services.

ATTACHMENT 2

QUALITY ASSURANCE

The SFPD QA Manager (SFHO) is independent of the other managers within the division and has the authority to carry out the responsibilities listed below in directing the Division QAP. He is assisted by a staff of Quality Assurance Managers (SFHO) assigned to functional areas of Program, Technical Services, Training, Project QA, and Audit. The SFPD QA Manager's (SFHO) functions for the CGS Project include:

a. *Provide technical guidance and concurrence for the CGS Project QAP for conformance with the requirements of 10 CFR 50, Appendix B;*

b. *Formulate and approve Division Quality Assurance Department Procedures which define responsibilities, authority, and functions of SFPD home office staff Quality Assurance Department personnel. Review and concur with the CGS PQAM and revisions;*

c. *Maintain an awareness of CGS project status, through management audit and day-to-day contact with the Manager of Quality, and provide assistance to the Manager of Quality to ensure timely and effective implementation of the CGS QAP;*

d. *Formulate and conduct management QA audits to assure compliance with the CGS Nuclear Quality Assurance Manual (NQAM) and implementing procedures, and identify quality problems; identify the need for corrective action and initiate, recommend, coordinate or provide solutions; and verify implementation of solutions and corrective actions;*

e. *Provide and maintain a qualified and suitably trained staff of Quality Assurance Engineers to carry out required project and staff functions. Assign Quality Assurance Engineer(s) to the CGS project and provide them with administrative direction through the QA Manager - Projects (SFHO);*

f. *Formulate and implement programs to provide indoctrination and training of Quality Assurance Department Personnel to ensure that suitable proficiency is maintained; and*

g. *From information supplied by the Manager of Quality, provide quarterly reports to the Division Manager and Manager of Quality Assurance, evaluating the status and adequacy of the WNP-BPC QAP, and advising of any problems requiring program revision or special attention including recommendations for corrective actions. At least annually, a meeting is held with the Division*

Manager (SFHO) and his staff on the subject of status and adequacy of the Division QAP. The Manager of Quality participates in this meeting to cover the status and adequacy of the CGS QAP.

MANAGER OF QUALITY

The Manager of Quality receives administrative, technical, and project direction from the Manager of Projects, and is responsible for the project and technical direction of the CGS QAP. The Manager of Quality receives technical guidance for QA and QC from the SFPD QA Manager (SFHO) and Chief Construction Quality Control Engineer (SFHO) respectively. He is assisted by, and provides project and technical direction to the Project Quality Assurance Engineer and Project Construction Quality Control Engineer (Attachment 6). The Manager of Quality is independent of the other line managers within the Project Management organization and has the authority to carry out the responsibilities listed below in directing the QAP including authority to stop work or control further processing. The Manager of Quality's functions include:

a. *Provide technical and project direction to Quality Assurance Engineers assigned to the Energy Northwest projects;*

b. *Formulate and approve, after review and concurrence by the SFPD QA Manager (SFHO) the Energy Northwest Projects SAR and QAPs as defined in the Energy Northwest Project's NQAMs. The NQAMs shall be in conformance with the requirements of 10 CFR 50, Appendix B, the TPO Quality Program Policy Manual, and the appropriate Project SAR;*

c. *Formulate and approve, after review and concurrence by the SFPD QA Manager (SFHO) the revisions to the Energy Northwest Projects SARS and NQAMs. Coordinate revisions to implementing procedures to improve effectiveness of the QAP and update the program;*

d. *Formulate and approve, after review and concurrence by the SFPD QA Manager (SFHO) the Project Quality Assurance Department Procedures and revisions for Energy Northwest Projects which define responsibilities, authority, and functions of Energy Northwest Projects Quality Assurance personnel;*

e. *Review quality-related procedures and manuals prepared by centralized support functions outside of the Division (e.g., Procurement, C&S, M&QS) to verify conformance with requirements of the Energy Northwest Projects NQAMs and approve, through the Manager of Quality Assurance BPC, for use as part of the QAP on the Energy Northwest projects;*

f. *Maintain an awareness of project status, through contact with the Manager of Projects and ensure timely and effective implementation of the QAP;*

g. *Direct the performance of project audits to ensure compliance with Energy Northwest projects NQAMs and implementing procedures, and to identify quality problems; identify the need for corrective action and initiate, recommend, coordinate or provide solutions; and verify implementation of solutions and corrective actions;*

h. *Provide quarterly reports to the SFPD QA Manager (SFHO) evaluating the status and adequacy of the Energy Northwest projects QAP and advising of any problems requiring program revision or special attention, including recommendations for corrective actions;*

i. *Review Division standard criteria for specifying QAP requirements applicable to contractors and subcontractors, and approve for use on the Energy Northwest projects; and*

j. *Coordinate the Quality Assurance and Quality Control functions for the Energy Northwest Projects with the Division groups having quality functions, and with groups outside the Division having quality functions, e.g., M&QS, C&S, and PSQD.*

ATTACHMENT 3

DIVISION CONSTRUCTION

The Manager of Division Construction provides technical and administrative direction of the Construction Department personnel. The Manager of Division Construction (SFHO) is assisted by CMs (SFHO), Chief Construction Engineers (SFHO), where assigned, and the Chief Construction Quality Control Engineer (SFHO). Construction Managers (SFHO) are responsible for the management and technical direction of assigned projects, and for ensuring that construction projects are provided with appropriate personnel and are following prescribed division practices and procedures for conduct of construction activities. Chief Construction Engineers (SFHO) are responsible for providing division standard work procedures to the projects.

Formal quality verification inspection and onsite contractor surveillance inspection activities performed by Bechtel are the responsibility of Construction Quality Control. The Chief Construction Quality Control Engineer (SFHO) is responsible for providing administrative direction to the Construction Quality Control Engineers assigned to the CGS Project. The Chief Construction Quality Control Engineer's functions include:

a. *Provide administrative direction to the Project Construction Quality Control Engineer,*

b. *Assign quality control engineers to the project,*

c. *Assist with the training and qualification of construction quality control engineers, and*

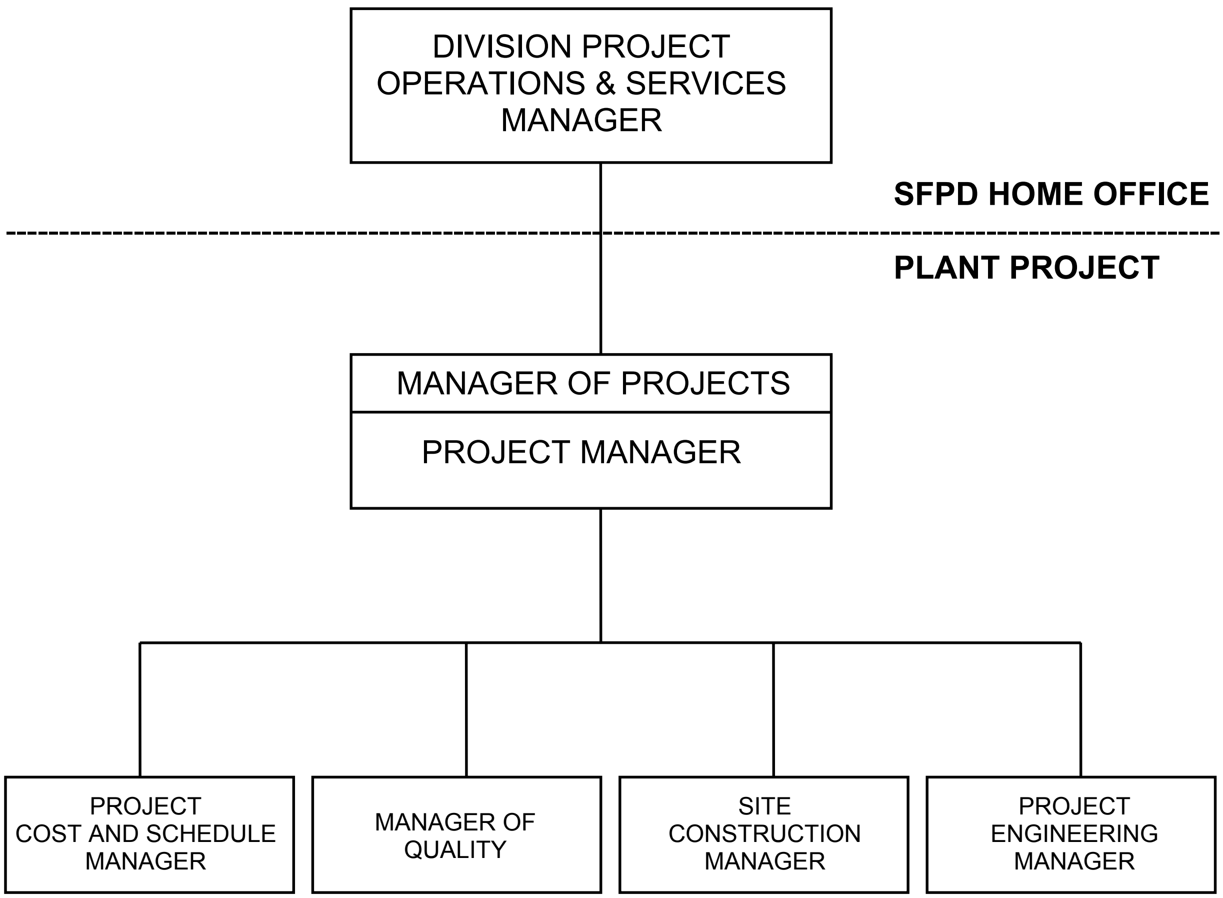
d. *Provide technical guidance to the Manager of Quality for the preparation of quality control procedures and instructions.*

ATTACHMENT 4

PROJECT QUALITY PROGRAM DOCUMENTS

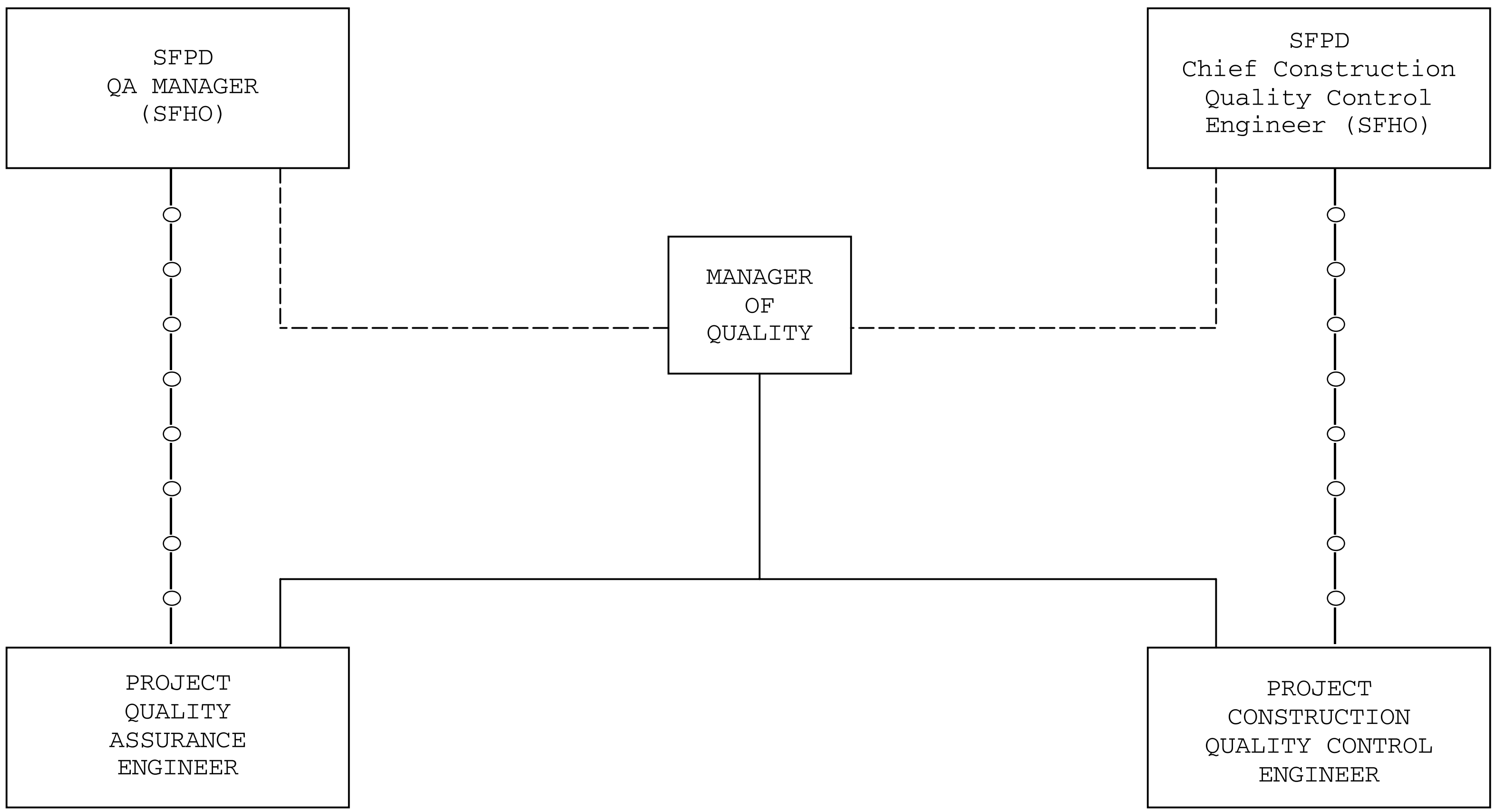
Documents	*Originating Authority*	*Review for QA Policy and Program Requirements*	*Authorizing Approval*	*Contents*
Nuclear Quality Assurance Manual (NQAM)	*Project QA Engineer*	*SFPD QA Manager (SFHO)*	*Manager of Quality*	*Quality program policy. Based on Division policy as contained in SFPD Standard NQAM*
Project QA manual (PQAM)	*Project QA Engineer*	*SFPD QA Manager (SFHO)*	*Manager of Quality*	*Procedures for conducting Project QA activities*
Construction Quality Control Manual (CQCM)	*Project Construction*	*Project QA Engineer*	*Manager of Quality*	*Responsibilities and procedures for construction QC activities*
Construction Procedures	*Project Field Engineer*	*Project QA Engineer*	*Chief Construction Engineer (SFHO)*	*Responsibilities and requirements for construction site activities*
Bechtel Quality Assurance Manual ASME Nuclear Components	*Manager of Codes and Standards*	*Manager of Quality and SFPD - QA Manager (SFHO)*	*President - BPC and appropriate authorized code inspection agency*	*Policies and procedures for overall Bechtel Program applicable to ASME work*
Engineering Department Project Instructions	*Project Engineering Manager*	*Project QA Engineer*	*SFPD Engineering Manager*	*Responsibilities and requirements for engineering departments activities*
Field Procurement Procedures [individual jobsite instructions (IJI)]	*Project Field Procurement Manager*	*Project QA Engineer*	*Manager of Field Procurement*	*Responsibilities and requirements for field procurement activities*
Procurement Supplier Quality Manual	*Manager Procurement Supplier Quality*	*Manager QA - BPC*	*Manager Procurement Supplier Quality*	*Procedures for procurement, supplier quality activities*
Field Procurement	*Manager Field Procurement*	*Manager QA - BPC*	*Manager Field Procurement*	*Procedures for field procurement activities*

ATTACHMENT 5



ATTACHMENT 6

QUALITY ASSURANCE/QUALITY CONTROL ORGANIZATION



LEGEND AND NOTE

——————— PROJECT AND TECHNICAL DIRECTION

– – – – – TECHNICAL GUIDANCE AND COORDINATION

—O—O— ADMINISTRATIVE DIRECTION

NOTE: The SFPD QA Manager (SFHO) is responsible for performing management QA audits of the Plant Project Quality Assurance/Quality Control Organization

ATTACHMENT 7

APPENDIX B
DIVISION QUALITY POLICIES, SCOPE, AND RELATIONSHIP
TO 10 CFR 50, APPENDIX B
NUCLEAR QUALITY
ASSURANCE MANUAL

SAN FRANCISCO POWER DIVISION

10CFR50 APP. B CRIT.	SUBJECT	SECTION 0: 1 Table of contents	2 QA Program Applicability	3 QA Program Definition	4 Definitions	5 Fire Protection QA Program	6 Radwaste Management System QA Program	7 Seismic II/I QA Program	8 Matrix	SECTION I: 1 Organization Charts	2 SFPD Organization	3 Project QA Team	4 Project Management Team	5 Project Engineering Team	6 Project Construction Team	7 Project Organization Charts	8 Procurement Department	9 Materials & Quality Services Department	10 Bechtel Power Corporation	11 Construction Department
I	ORGANIZATION		●	●	●					●	●	●	●	●	●	●	●	●	●	●
II	QUALITY ASSURANCE PROGRAM		●	●						●										
III	DESIGN CONTROL																			
IV	PROCUREMENT DOCUMENT CONTROL																			
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS			●																
VI	DOCUMENT CONTROL			●																
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES																			
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS																			
IX	CONTROL OF SPECIAL PROCESSES																			
X	INSPECTION																			
XI	TEST CONTROL																			
XII	CONTROL OF MEASURING AND TEST EQUIPMENT																			
XIII	HANDLING, STORAGE AND SHIPPING																			
XIV	INSPECTION, TEST, AND OPERATING STATUS																			
XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS																			
XVI	CORRECTIVE ACTION																			
XVII	QUALITY ASSURANCE RECORDS																			
XVIII	AUDITS																			

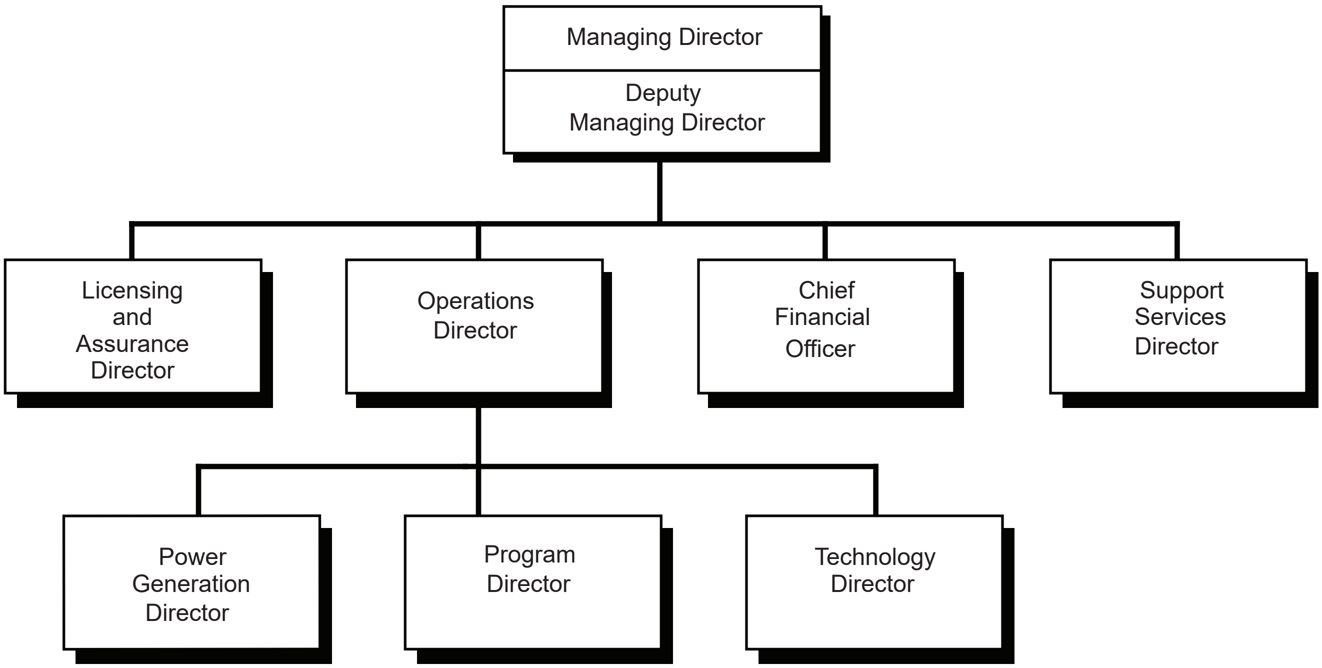
10CFR50 APP. B CRIT.	SUBJECT	SECTION II: 1 Design Control Procedures	2 Design Process and Change Control	3 Design Verification	4 Design Interface	5 Specialty Group Design Control	SECTION III: 1 Supplier Evaluation	2 Field Procurement	3 Supplier Control & Source Surveillance	4 Supplier Document Processing	SECTION IV: 1 Construction Site Quality Program	2 Mat'l Rec, Stor, Maint, Hand, & Cont.	3 Field Inspection and Test	4 Nonconforming Materials	5 Control of Measuring and Test Equipment	6 System T/O for Preoperational Testing	7 Field Contractor/Subcontractor Control	8 Control of Special Processes
I	ORGANIZATION																	
II	QUALITY ASSURANCE PROGRAM	●									●	●	●		●			●
III	DESIGN CONTROL	●	●	●	●	●												
IV	PROCUREMENT DOCUMENT CONTROL						●	●										
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS	●									●							
VI	DOCUMENT CONTROL	●									●							
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES						●	●	●			●	●	●			●	
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS											●		●				
IX	CONTROL OF SPECIAL PROCESSES																	●
X	INSPECTION								●	●			●				●	●
XI	TEST CONTROL			●									●			●		
XII	CONTROL OF MEASURING AND TEST EQUIPMENT														●			
XIII	HANDLING, STORAGE AND SHIPPING										●	●					●	
XIV	INSPECTION, TEST, AND OPERATING STATUS												●			●		
XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS													●				
XVI	CORRECTIVE ACTION	●												●				
XVII	QUALITY ASSURANCE RECORDS									●								
XVIII	AUDITS																	

10CFR50 APP. B CRIT.	SUBJECT	SECTION V: 1 NQAM Policies and Revisions	2 Quality Assurance Procedures	3 Indoctrination, Training & Qualification	4 Management Corrective Action	5 Stop Work	6 Procedure Control	7 Quality Assurance Records	8 Quality Action Requests	9 Status and Adequacy Review	SECTION VI: 1 Quality Audit System
I	ORGANIZATION										
II	QUALITY ASSURANCE PROGRAM	●	●	●						●	
III	DESIGN CONTROL										
IV	PROCUREMENT DOCUMENT CONTROL										
V	INSTRUCTIONS, PROCEDURES, AND DRAWINGS	●	●				●				
VI	DOCUMENT CONTROL						●				
VII	CONTROL OF PURCHASED MATERIAL, EQUIPMENT, AND SERVICES										
VIII	IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS										
IX	CONTROL OF SPECIAL PROCESSES										
X	INSPECTION										
XI	TEST CONTROL										
XII	CONTROL OF MEASURING AND TEST EQUIPMENT										
XIII	HANDLING, STORAGE AND SHIPPING										
XIV	INSPECTION, TEST, AND OPERATING STATUS										
XV	NONCONFORMING MATERIAL, PARTS OR COMPONENTS					●					
XVI	CORRECTIVE ACTION				●				●		
XVII	QUALITY ASSURANCE RECORDS							●			
XVIII	AUDITS			●							●

Table 17.1-1

General Electric Quality Assurance Evolutionary Process

Date of Effectiveness	*NED Quality Objectives - Safe and Reliable Systems and Components*	*Intent of Proposed AEC QA Criteria*	*Intent of 10 CFR 50 Appendix B (proposed)*	*10 CFR 50 Appendix B*	*ANSI N45.2*	*AEC Regulatory Guide 1.28*	*ASME B&P Code*	*QA Related Regulatory Guide and ANSI Standards*
8/20/68	*Blue Book*							
10/1/69	*Green Book Rev. 0*	*X*						
5/1/70	*Green Book Rev. 1*	*X*						
9/15/71	*Green Book Rev. 2*		*X*					
6/1/72	*Green Book Rev. 3*			*X*	*X*			
3/1/73	*Green Book Rev. 4 (NEDO-11209)*			*X*	*X*			
5/7/74	*Green Book Rev. 5 (NEDO-11209-01)*			*X*	*X*	*X*	*X*	*X*
12/12/75	*Green Book (NEDO-11209-02)*			*X*	*X*	*X*	*X*	*X*
11/76	*Green Book (NEDO-11209-03A)*			*X*	*X*	*X*	*X*	*X*
3/31/78	*Green Book (NEDO-11209-04A)*			*X*	*X*	*X*	*X*	*X*
10/80	*Green Book (NEDO-11209-04A)*			*X*	*X*	*X*	*X*	*X*

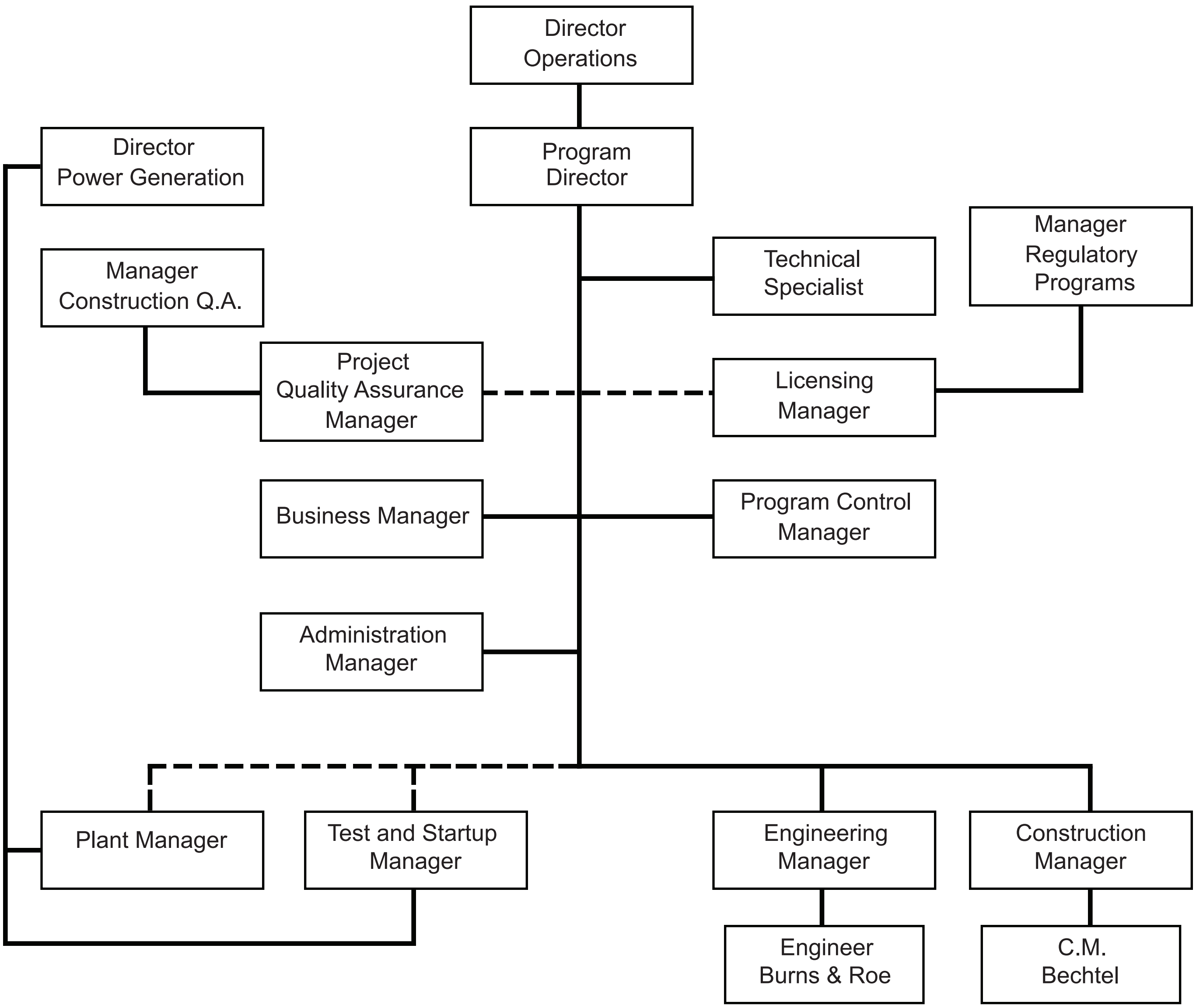


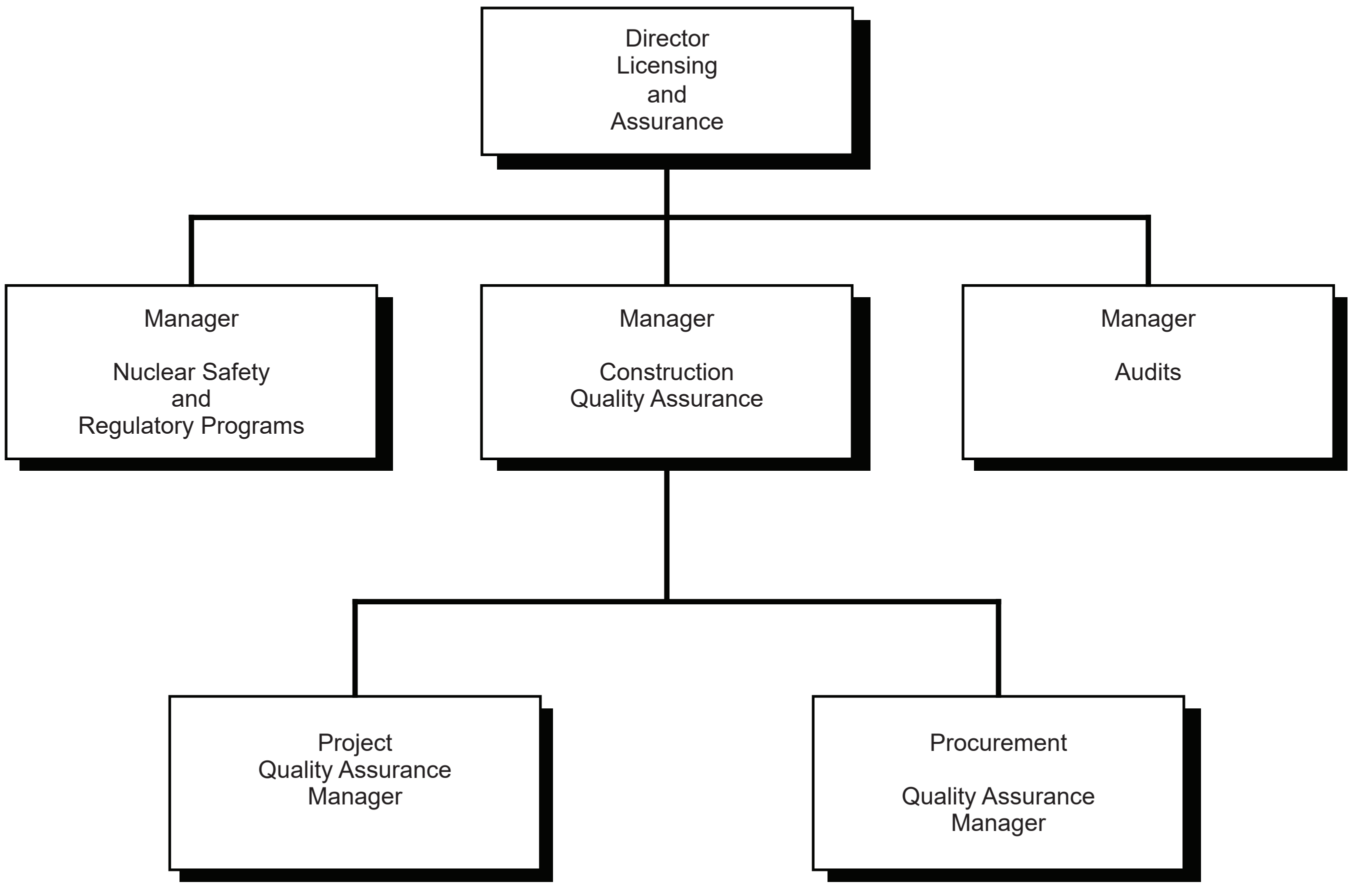
Columbia Generating Station
Final Safety Analysis Report

Energy Northwest Organization Chart

Draw. No. 960222.79 | Rev. | Figure 17.1-1

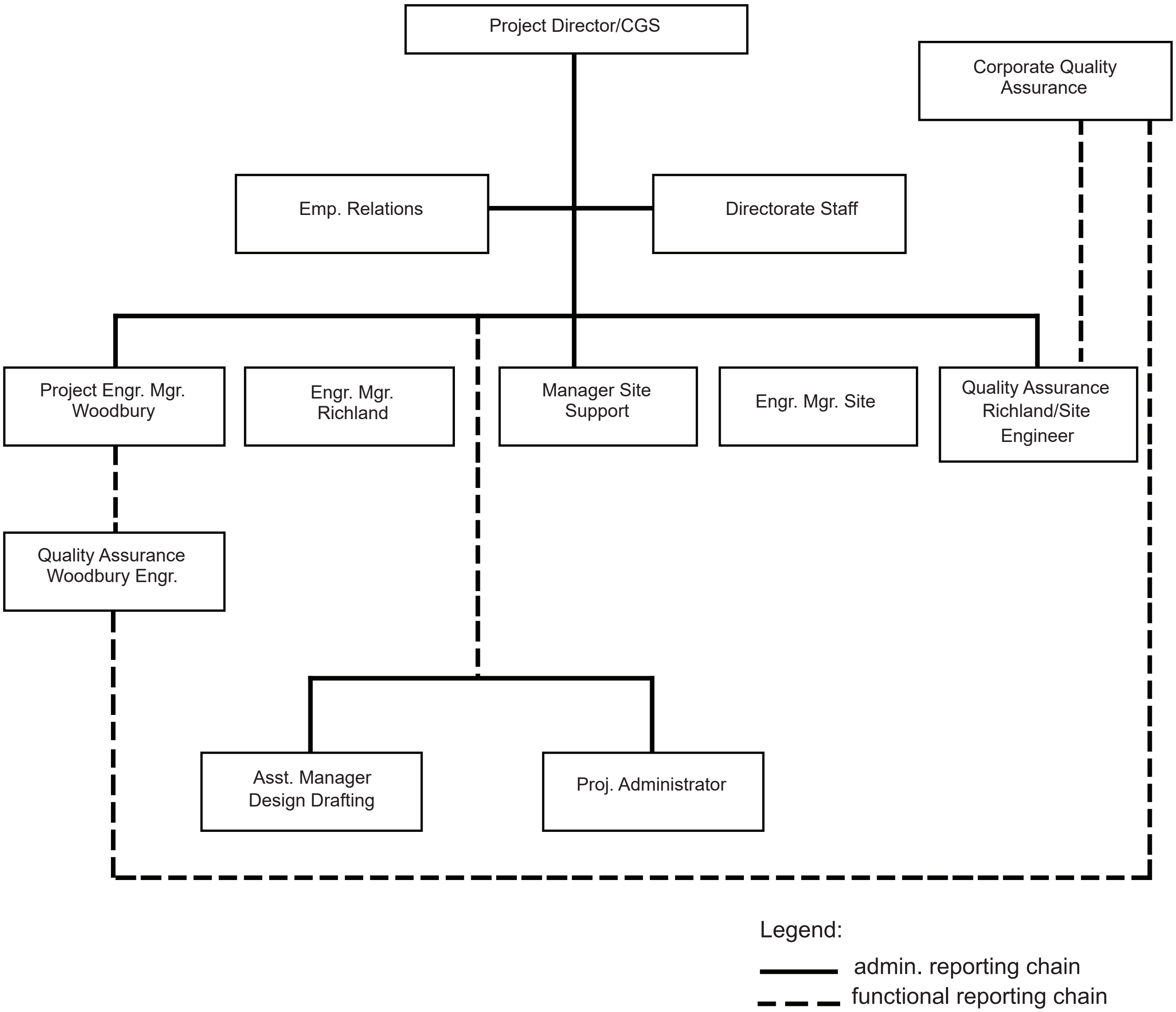
Form No. 960690


Director
Operations
Director
Power Generation
Program
Director
Technical
Specialist
Manager
Regulatory
Programs
Manager
Construction Q.A.
Project
Quality Assurance
Manager
Licensing
Manager
Business Manager
Program Control
Manager
Administration
Manager
Plant Manager
Test and Startup
Manager
Engineering
Manager
Construction
Manager
Engineer
Burns & Roe
C.M.
Bechtel

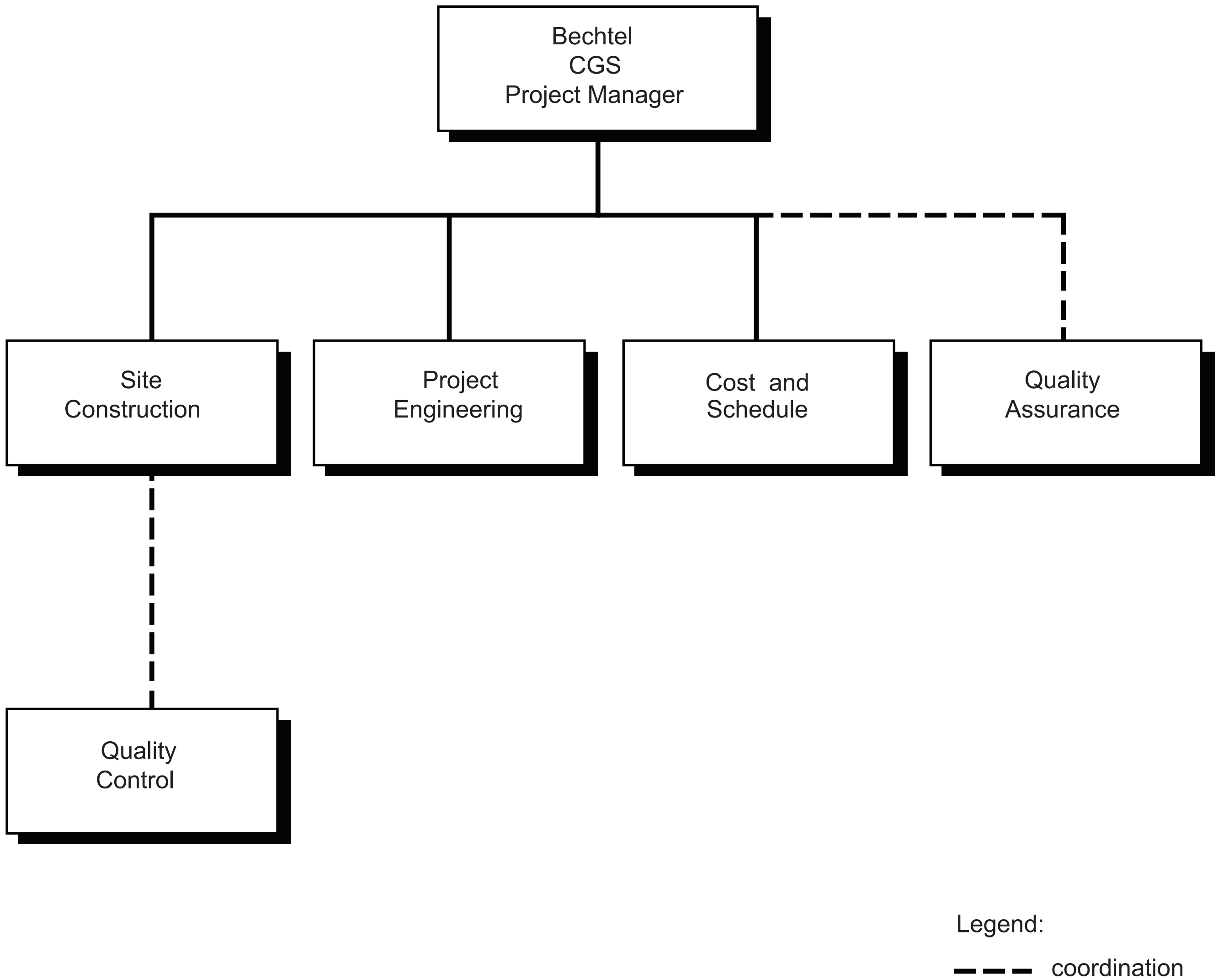


CGS Project Management Organization Chart

Draw. No. 960222.81 | Rev. | Figure 17.1-3



Columbia Generating Station Final Safety Analysis Report	Burns and Roe, Inc. CGS Organization Chart		
	Draw. No. 960222.82	Rev.	Figure 17.1-4



Bechtel CGS Organization Chart

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

The CGS program for quality assurance during the operations phase is provided separately in the Energy Northwest Operational Quality Assurance Program Description (EN-QA-004).

Appendix A

SUPPLEMENT
AGING MANAGEMENT PROGRAMS AND ACTIVITIES
CREDITED FOR COLUMBIA LICENSE RENEWAL

TABLE OF CONTENTS

Appendix A

SUPPLEMENT
AGING MANAGEMENT PROGRAMS AND ACTIVITIES
CREDITED FOR COLUMBIA LICENSE RENEWAL

TABLE OF CONTENTS (continued)

Appendix A

SUPPLEMENT
AGING MANAGEMENT PROGRAMS AND ACTIVITIES
CREDITED FOR COLUMBIA LICENSE RENEWAL

TABLE OF CONTENTS (continued)

APPENDIX A

SUPPLEMENT AGING MANAGEMENT PROGRAMS AND ACTIVITIES CREDITED FOR COLUMBIA LICENSE RENEWAL

A.0 FINAL SAFETY ANALYSIS REPORT SUPPLEMENT

A.1 INTRODUCTION

This appendix provides the information submitted for the Final Safety Analysis Report (FSAR) Supplement as required by 10 CFR 54.21(d) for the License Renewal Application (LRA). The programs and activities credited to manage the effects of aging are described in LRA Appendix B. Section 4 of the LRA documents the evaluations of time-limited aging analyses for the period of extended operation. LRA Section 3, Section 4, and Appendix B have been used to prepare the program and activity descriptions that are contained in this appendix.

A.2 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

The license renewal integrated plant assessment identified existing and new aging management programs (AMPs) necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This section describes the aging management programs and activities identified during the integrated plant assessment. The aging management programs will be implemented prior to the period of extended operation. One-time inspections will be conducted within the 10-year period prior to beginning the period of extended operation. The aging management programs identified as necessary in association with the evaluation of time-limited aging analyses (TLAAs) are described in Section A.2.2.

Three elements of an effective aging management program that are common to each of the aging management programs are corrective actions, confirmation process, and administrative controls. These elements are included in the Operational Quality Assurance Program Description (OQAPD) for Columbia, which implements the requirements of 10 CFR 50, Appendix B.

Prior to the period of extended operation, the elements of corrective actions, confirmation process, and administrative controls in the OQAPD will be applied to required aging management programs for both safety-related and non-safety related structures and components determined to require aging management during the period of extended operation.

The existing Corrective Action Program and the Operating Experience Program ensure, through the continual review of both plant-specific and industry operating experience, that the license renewal aging management programs are effective to manage the aging effects for which they are credited. The aging management programs are either enhanced or new programs are developed when the review of operating experience indicates that the aging management programs may not be effective. For each aging management program listed in this section, operating experience is reviewed on a continuing basis.

The processes and procedures for the review of operating experience address the following points:

- All operating experience is screened for aging of long lived passive structures or components and further evaluation as applicable is performed by personnel trained in the requirements of license renewal scoping, screening, and aging management reviews (aging effects and mechanisms). The evaluation is completed and prioritized commensurate with the potential significance of the issue. Such evaluations are documented and retained in an auditable and retrievable form.

- Periodic training for system engineers, equipment operators and maintenance personnel specific to identifying aging issues.

- The License Renewal program lead is trained in the requirements of license renewal scoping, screening, and aging management reviews (aging effects and mechanisms).

- Aging management program owners are trained in the requirements of license renewal scoping, screening, and aging management reviews (aging effects and mechanisms) associated with their particular aging management program.

- When it is determined that enhancements are necessary to adequately manage the effects of aging, the enhancements are entered into and implemented consistent with the plant corrective action program or operating experience program, as applicable. Enhancements can include, as appropriate, modifications to aging management programs or the creation and implementation of new AMPs.

- Operating experience that is related to aging of long lived passive structures or components is keyword tagged “Aging.”

- The processes are adequate so as to not preclude the consideration of operating experience related to aging management. The processes appropriately gather information on all structures and components within the scope of license renewal, and their materials, environments, aging effects, and aging mechanisms. In addition, the processes include the AMPs credited for managing the effects of aging, and the activities under these AMPs (e.g., inspection methods, preventive actions, evaluation techniques, etc.).

- While the programs and procedures may specify reviews of certain sources of information, such as NRC generic communications and Institute of Nuclear Power Operations reports, they allow for any potential source of relevant plant specific or industry operating experience information.

- AMP owners review data collected by the AMPs, utilize the corrective action program for any conditions that are unsatisfactory to ensure they will be addressed and corrected, maintain required records for the program and maintain the program current and implement revisions as needed based on program results and internal or external operating experience.

- Provide guidance on sharing internal operating experience related to license renewal issues with the industry.

A.2.1 AGING MANAGEMENT PROGRAMS

A.2.1.1 ABOVEGROUND STEEL TANKS INSPECTION

The Aboveground Steel Tanks Inspection detects and characterizes the conditions on the bottom surfaces of the condensate storage tanks. The inspection provides direct evidence through volumetric examination as to whether, and to what extent, a loss of material due to corrosion has occurred in inaccessible areas (i.e., tank base and bottom surface).

The Aboveground Steel Tanks Inspection is a new inspection program that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.2 AIR QUALITY SAMPLING PROGRAM

The Air Quality Sampling Program is an existing prevention and condition monitoring program that manages loss of material due to corrosion for Diesel Starting Air (DSA) components that contain compressed air through periodic sampling of the air for hydrocarbons, dewpoint, and particulates and periodic ultrasonic inspection of the DSA System air receivers. In addition, the Air Quality Sampling Program ensures that the Control Air System remains dry and free of contaminants, such that no aging effects require management.

The Air Quality Sampling Program is supplemented by the Diesel Starting Air Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging in the DSA System dryers and the downstream piping and components (excluding the DSA System air receivers).

A.2.1.3 APPENDIX J PROGRAM

The Appendix J Program is an existing monitoring program that detects degradation of the Primary Containment and systems penetrating the Primary Containment, which are the containment shell and primary containment penetrations including (but not limited to) the personnel airlock, equipment hatch, control rod drive hatch, and drywell head. The Appendix J Program provides assurance that leakage from the Primary Containment will not exceed maximum values for containment leakage.

A.2.1.4 BOLTING INTEGRITY PROGRAM

The Bolting Integrity Program is a combination of existing activities that, in conjunction with other credited programs, address the management of aging for the bolting of mechanical components and structural connections within the scope of license renewal. The Bolting Integrity Program relies on manufacturer and vendor information and industry recommendations for the proper selection, assembly, and maintenance of bolting for pressure-retaining closures and structural connections. The Bolting Integrity Program includes, through the Inservice Inspection (ISI) Program, Inservice Inspection (ISI) Program – IWF, Structures Monitoring Program, and External Surfaces Monitoring Program, the periodic inspection of bolting for indications of degradation such as leakage, loss of material due to corrosion, loss of pre-load, and cracking due to stress corrosion cracking (SCC) and fatigue.

A.2.1.5 BURIED PIPING AND TANKS INSPECTION PROGRAM

The Buried Piping and Tanks Inspection Program manages the effects of loss of material due to corrosion on the external surfaces of metallic piping and tanks that are buried or underground. The program also manages the effects of cracking, loss of material (and loss of pre-load) for bolting that is buried. In addition, the program also verifies that aging degradation is not occurring for concrete and polymer piping that is buried. The Buried Piping and Tanks Inspection Program is a combination of a mitigation program (consisting of protective coatings. cathodic protection, and backfill quality) and a condition monitoring program (consisting of electrochemical verification of cathodic protection, confirmation of backfill quality, visual inspections of pipe or tank external surfaces, and non-destructive evaluation of pipe or tank wall thickness as needed).

Inspection of buried and underground piping will be performed within the 10-year period prior to entering the period of extended operation. Additional inspections of buried and underground piping and buried tanks will be performed within 10 years after entering the period of extended operation, and in each 10 year period thereafter.

The Buried Piping and Tanks Inspection Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.6 BWR FEEDWATER NOZZLE PROGRAM

The BWR Feedwater Nozzle Program is an existing program that manages cracking due to stress corrosion cracking and intergranular attack (SCC/IGA) and flaw growth of the feedwater nozzles. The BWR Feedwater Nozzle Program is in accordance with ASME Section XI and NRC augmented requirements.

The BWR Feedwater Nozzle Program consists of: (a) enhanced inservice inspection in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB 2500-1 (2001 edition including the 2002 and 2003 Addenda) and the recommendations of General Electric report NE-523-A71-0594-A (Reference A.3-1), and (b) system modifications, as described in FSAR Section 5.3.3.1.4.5, to mitigate cracking. The program specifies periodic ultrasonic inspection of critical regions of the feedwater nozzles.

The BWR Feedwater Nozzle Program credits portions of the Inservice Inspection (ISI) Program.

A.2.1.7 BWR PENETRATIONS PROGRAM

The BWR Penetrations Program is an existing condition monitoring program that manages cracking due to SCC or intergranular stress corrosion cracking (IGSCC) of reactor vessel instrument penetrations, jet pump instrument penetrations, control rod drive penetrations, and incore instrument penetrations. The BWR Penetrations Program detects and sizes cracks in accordance with the guidelines of approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) documents and the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the vessel components.

The program credits portions of the Inservice Inspection (ISI) Program and the BWR Vessel Internals Program.

A.2.1.8 BWR STRESS CORROSION CRACKING PROGRAM

The BWR Stress Corrosion Cracking Program is an existing condition monitoring program that manages cracking due to SCC/IGA for stainless steel and nickel alloy reactor coolant pressure boundary piping, nozzle safe ends, nozzle thermal sleeves, valve bodies, flow elements, and pump casings.

The BWR Stress Corrosion Cracking Program consists of (a) preventive measures to mitigate SCC/IGA, and (b) inspection and flaw evaluation to monitor SCC/IGA and its effects. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term mitigation of SCC/IGA. The program includes the scope of the Generic Letter 88-01 program, as modified by the staff-approved BWRVIP-75 report.

The program credits portions of the Inservice Inspection (ISI) Program and the BWR Water Chemistry Program.

A.2.1.9 BWR VESSEL ID ATTACHMENT WELDS PROGRAM

The BWR Vessel ID Attachment Welds Program is an existing program that manages cracking due to SCC/IGA of the welds for internal attachments to the reactor vessel. The BWR Vessel ID Attachment Welds Program performs examinations and inspections as required by ASME Section XI, augmented by BWRVIP-48-A. These inspections include enhanced visual inspections with resolution to the guidelines in BWRVIP-03. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the vessel internal attachment welds.

The BWR Vessel ID Attachment Welds Program credits portions of the BWR Vessel Internals Program and the Inservice Inspection (ISI) Program.

A.2.1.10 BWR VESSEL INTERNALS PROGRAM

The BWR Vessel Internals Program is an existing condition monitoring program that manages cracking due to stress corrosion cracking and irradiation assisted stress corrosion cracking (SCC/IASCC), SCC/IGA, flaw growth, and flow-induced vibration for various components and subcomponents of the reactor vessel internals. The BWR Vessel Internals Program consists of mitigation, inspection, flaw evaluation, and repair in accordance with the guidelines of BWRVIP reports and the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the vessel internal components.

In addition, this program provides screening criteria to determine the susceptibility of cast austenitic stainless steels (CASS) reactor vessel internals to thermal aging and neutron fluence. For "potentially susceptible" components, the program considers loss of fracture toughness due to neutron or thermal aging embrittlement and directs augmented inspections as necessary. The additional screening and inspections will be implemented prior to the period of extended operation.

The BWR Vessel Internals Program credits portions of the Inservice Inspection (ISI) Program.

A.2.1.11 BWR WATER CHEMISTRY PROGRAM

The BWR Water Chemistry Program is an existing program that mitigates degradation of components that are within the scope of license renewal and contain or are exposed to treated water, treated water in the steam phase, reactor coolant, or treated water in a sodium pentaborate solution. The program manages the relevant conditions that could lead to the onset and propagation of a loss of material due to corrosion or erosion, cracking due to SCC, or reduction in heat transfer due to fouling through proper monitoring and control of chemical concentrations consistent with BWRVIP water chemistry guidelines.

The BWR Water Chemistry Program is supplemented by the Chemistry Program Effectiveness Inspection and the Heat Exchangers Inspection, to provide verification of the effectiveness of the program in managing the effects of aging. Additionally, the BWR Water Chemistry Program is supplemented by the BWR Feedwater Nozzle Program, BWR Stress Corrosion Cracking Program, BWR Penetrations Program, BWR Vessel ID Attachment Welds Program, BWR Vessel Internals Program, Inservice Inspection (ISI) Program, and Small Bore Class 1 Piping Program to provide verification of the program's effectiveness in managing the effects of aging for reactor pressure vessel, reactor vessel internals, and reactor coolant pressure boundary components.

A.2.1.12 CHEMISTRY PROGRAM EFFECTIVENESS INSPECTION

The Chemistry Program Effectiveness Inspection detects and characterizes the condition of materials in representative low flow and stagnant areas of systems with water chemistry controlled by the BWR Water Chemistry Program or the Closed Cooling Water Chemistry Program, and with fuel oil chemistry controlled by the Fuel Oil Chemistry Program. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred. The inspection also determines whether cracking due to SCC of susceptible materials in susceptible locations has occurred. The Chemistry Program Effectiveness Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.13 CLOSED COOLING WATER CHEMISTRY PROGRAM

The Closed Cooling Water Chemistry Program mitigates degradation of components that are within the scope of license renewal and contain closed cooling water. The program manages the relevant conditions that could lead to the onset and propagation of a loss of material due to corrosion or erosion, cracking due to SCC, or reduction in heat transfer due to fouling through proper monitoring and control of corrosion inhibitor concentrations consistent with EPRI closed cooling water chemistry guidelines.

The Closed Cooling Water Chemistry Program includes corrosion rate measurement in reactor building closed cooling water locations and is supplemented by the one-time Chemistry Program Effectiveness Inspection and Heat Exchangers Inspection, which provide verification of the effectiveness of the program in managing the effects of aging.

The Closed Cooling Water Chemistry Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.14 COOLING UNITS INSPECTION PROGRAM

The Cooling Units Inspection Program manages the effect of loss of material for aluminum, steel, copper alloy, and stainless steel cooling unit components that are exposed to condensation. The inspection also manages the effects of a reduction in heat transfer due to fouling of heat exchanger tubes and fins, or cracking due to SCC of aluminum components exposed to condensation.

The Cooling Units Inspection is a new program that will be implemented via baseline inspection of a sample population followed by opportunistic inspections when components are opened for periodic maintenance, repair, and surveillance activities when surfaces are made available for inspection. These inspections ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. Inspection of a sample population will be conducted within the 10-year period prior to the period of extended operation and serve as a baseline for future inspections.

A.2.1.15 CONTROL ROD DRIVE RETURN LINE NOZZLE PROGRAM

The Control Rod Drive Return Line (CRDRL) Nozzle Program is an existing mitigation and condition monitoring program that manages cracking due to flaw growth of the control rod drive return line nozzle, safe end, cap, and connecting welds. The CRDRL Nozzle Program consists of a) mitigation activities, and b) inspection, flaw evaluation, and repair in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, Table IWB

2500-1 (2001 Edition through 2003 Addenda) and the recommendations of NUREG-0619. System modifications were implemented by the original equipment manufacturer prior to initial startup to mitigate cracking. The BWR Water Chemistry Program monitors and controls reactor coolant water chemistry in accordance with BWRVIP guidelines to ensure the long-term integrity and safe operation of the critical regions of the CRDRL nozzle.

The CRDRL Nozzle Program credits portions of the Inservice Inspection (ISI) Program.

A.2.1.16 DIESEL STARTING AIR INSPECTION

The Diesel Starting Air Inspection detects and characterizes the condition of materials for the DSA System air dryers and downstream piping and components (excluding the DSA System air receivers). The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Diesel Starting Air Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.17 DIESEL SYSTEMS INSPECTION PROGRAM

The Diesel Systems Inspection Program manages the effects of the loss of material due to corrosion and cracking due to stress corrosion cracking of materials for the interior of the steel and stainless steel exhaust piping for the Division 1, 2, and 3 diesels in the Diesel Engine Exhaust System, including the loop seal drains from the exhaust piping. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Diesel Systems Inspection is a new program that will be implemented via baseline inspection of a sample population followed by opportunistic inspection when components are opened for periodic maintenance, repair, or surveillance activities when surfaces are made available for inspection. These inspections ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. Inspection of a sample population will be conducted within the 10-year period prior to the period of extended operation and will serve as a baseline for future inspections.

A.2.1.18 DIESEL-DRIVEN FIRE PUMPS INSPECTION PROGRAM

The Diesel-Driven Fire Pumps Inspection Program manages the effects of the loss of material, due to corrosion or erosion, and reduction in heat transfer of the interior of the Fire Protection

System diesel engine exhaust piping, and of Fire Protection System diesel heat exchangers exposed to a raw water environment. The inspection also manages cracking due to SCC of susceptible materials.

The Diesel-Driven Fire Pumps Inspection is a new program that will be implemented via baseline inspection of a sample population followed by opportunistic inspection when components are opened for periodic maintenance, repair, or surveillance activities when surfaces are made available for inspection. These inspections ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. Inspection of a sample population will be conducted within the 10-year period prior to the period of extended operation and will serve as a baseline for future inspections.

A.2.1.19 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS PROGRAM

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is an inspection program that detects degradation of electrical cables and connections that are not environmentally qualified and are within the scope of license renewal. The program provides for periodic visual inspection of accessible, non- environmentally qualified cables and connections in order to determine if age-related degradation is occurring, particularly in plant areas with adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified design or bounding plant environment for the general area.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Program is a new aging management program that will be implemented prior to the period of extended operation. The inspection frequency of the program will be once every 10 years, with the initial inspection to be performed prior to the period of extended operation.

A.2.1.20 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS PROGRAM

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a monitoring program that detects degradation of electrical cables and connections that are not environmentally qualified and used in circuits with sensitive, low-current applications (such as radiation monitoring and nuclear instrumentation loops). The program provides for a review of calibration records for the low-current instruments, in order to detect and identify degradation of the cable system insulation resistance. The program retains the option to perform direct cable testing.

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program is a new aging management program that will be implemented prior to the period of extended operation. The frequency of the program will be once every 10 years, with the initial review to be performed prior to the period of extended operation.

A.2.1.21 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS INSPECTION

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection detects and characterizes the material condition of metallic electrical connections within the scope of license renewal. The inspection uses thermography (augmented by contact resistance testing) to detect loose or degraded connections that lead to increased resistance for a representative sample of metallic electrical connections in various plant locations.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.22 EQ PROGRAM

Environmental qualification (EQ) analyses for electrical components with a qualified life of 40 years or greater are identified as TLAAs; therefore, the effects of aging must be addressed for license renewal.

NRC regulation 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," requires licensees to identify electrical equipment covered under this regulation and to maintain a qualification file demonstrating that the equipment is qualified for its application and will perform its safety function up to the end of its qualified life. The EQ Program is an existing program that implements the requirements of 10 CFR 50.49 (as further defined by the Division of Operating Reactor Guidelines, NUREG-0588, and Regulatory Guide 1.89 Revision 1).

In accordance with 10 CFR 54.21(c)(1)(iii), the EQ Program will be used to manage the effects of aging on the intended functions of the components associated with EQ TLAAs for the period of extended operation, because equipment will be replaced prior to reaching the end of its qualified life. Reanalysis addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions if acceptance criteria are not met. Reanalysis of aging evaluations to extend the qualification of components is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of the Columbia EQ Program.

A.2.1.23 EXTERNAL SURFACES MONITORING PROGRAM

The External Surfaces Monitoring Program consists of observation and surveillance activities intended to detect degradation resulting from loss of material due to corrosion and cracking due to SCC for mechanical components, as well as hardening and loss of strength for elastomers. The External Surfaces Monitoring Program is a condition-monitoring program.

The External Surfaces Monitoring Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.24 FATIGUE MONITORING PROGRAM

Fatigue evaluations for mechanical components are identified as TLAAs; therefore, the effects of fatigue have been addressed for license renewal.

Energy Northwest monitors fatigue of various components (including ASME Class 1 reactor coolant pressure boundary, high energy line break locations, and Primary Containment) via the Fatigue Monitoring Program, which tracks transient cycles and calculates fatigue usage. Energy Northwest has assessed the impact of the reactor coolant environment on the sample of critical components identified in NUREG/CR-6260 and other limiting components beyond those locations identified in NUREG/CR-6260. Calculation of fatigue usage values is not required for non-Class 1 SSCs. Instead, stress intensification factors and lower stress allowables are used to ensure components are adequately designed for fatigue.

In accordance with 10 CFR 54.21(c)(1)(iii), the Fatigue Monitoring Program will be used to manage the effects of aging due to fatigue on the intended functions of the components associated with fatigue TLAAs for the period of extended operation.

The Fatigue Monitoring Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.25 FIRE PROTECTION PROGRAM

The Fire Protection Program is an existing program, described in Appendix F of the FSAR, that detects degradation of components in the scope of license renewal that have fire barrier functions. Periodic visual inspections and functional tests are performed of fire dampers, fire barrier walls, ceilings and floors, fire-rated penetration seals, fire wraps, fire proofing, and fire doors to ensure that functionality and operability are maintained. In addition, the Fire

Protection Program supplements the Fuel Oil Chemistry Program and External Surfaces Monitoring Program through performance monitoring of the diesel-driven fire pump fuel oil supply components and testing and inspection of the halon and carbon dioxide suppression systems, respectively. The Fire Protection Program is a condition monitoring program, comprised of tests and inspections based on National Fire Protection Association (NFPA) recommendations.

A.2.1.26 FIRE WATER PROGRAM

The Fire Water Program (sub-program of the overall Fire Protection Program) is described in Appendix F of the FSAR, and is credited with managing loss of material due to corrosion, erosion, macrofouling, and selective leaching, cracking due to SCC/IGA of susceptible water-based fire suppression components in the scope of license renewal. Periodic inspection and testing of the water-based fire suppression systems provides reasonable assurance that the systems will remain capable of performing their intended function. Periodic inspection and testing activities include hydrant and hose station inspections, fire main flushing, flow tests, and sprinkler inspections. The Fire Water Program is a condition monitoring program, comprised of tests and inspections based on NFPA recommendations.

The Fire Water Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.27 FLEXIBLE CONNECTION INSPECTION PROGRAM

The Flexible Connection Inspection Program manages degradation, including the effects of the loss of material due to wear and hardening and loss of strength of elastomer components exposed to treated water, dried air, gas, and indoor air environments.

The Flexible Connection Inspection Program is a new plant-specific program that will be implemented via baseline inspection of a sample population followed by opportunistic inspection when components are opened for periodic maintenance, repair, or surveillance activities when surfaces are made available for inspection. These inspections ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. Inspection of a sample population will be conducted within the 10-year period prior to the period of extended operation and will serve as a baseline for future inspections.

A.2.1.28 FLOW-ACCELERATED CORROSION (FAC) PROGRAM

The Flow-Accelerated Corrosion (FAC) Program manages loss of material for steel and gray cast iron components located in the treated water environment of systems that are susceptible to

FAC, also called erosion-corrosion. The FAC Program combines the elements of predictive analysis; inspections (to baseline and monitor wall-thinning), industry experience, station information gathering and communication, and engineering judgment to monitor and predict FAC wear rates. The program is a condition monitoring program that implements the recommendations of NRC Generic Letter 89-08, and follows the guidance and recommendations of EPRI NSAC-202L (Reference A.3-2), to ensure that the integrity of piping systems susceptible to FAC is maintained.

The FAC Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.29 FUEL OIL CHEMISTRY PROGRAM

The Fuel Oil Chemistry Program is an existing program that maintains fuel oil quality in order to mitigate degradation of the storage tanks and associated components containing fuel oil that are within the scope of license renewal. The program includes diesel fuel oil testing for emergency diesel generator and diesel-driven fire pump fuel. The Fuel Oil Chemistry Program manages the relevant conditions that could lead to the onset and propagation of loss of material due to corrosion, or cracking due to SCC of susceptible copper alloys, through proper monitoring and control of fuel oil contamination consistent with plant technical specifications and American Society for Testing and Materials (ASTM) standards for fuel oil. The relevant conditions are specific contaminants such as water or microbiological organisms in the fuel oil that could lead to corrosion of susceptible materials. Exposure to these contaminants is minimized by verifying the quality of new fuel oil before it enters the emergency diesel generator storage tanks and by periodic sampling to ensure that both the emergency diesel generator tanks and fire protection tanks are free of water and particulates. The Fuel Oil Chemistry Program is a mitigation program.

The Fuel Oil Chemistry Program is supplemented by the Chemistry Program Effectiveness Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging.

A.2.1.30 HEAT EXCHANGERS INSPECTION

The Heat Exchangers Inspection detects and characterizes the surface conditions with respect to fouling of heat exchangers and coolers that are in the scope of the inspection and exposed to indoor air or to water with the chemistry controlled by the BWR Water Chemistry Program or the Closed Cooling Water Chemistry Program. The inspection provides direct evidence as to whether, and to what extent, a reduction of heat transfer due to fouling has occurred on the heat transfer surfaces of heat exchangers and coolers.

The Heat Exchangers Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.31 HIGH-VOLTAGE PORCELAIN INSULATORS AGING MANAGEMENT PROGRAM

The High-Voltage Porcelain Insulators Aging Management Program is an existing program that manages the build-up of contamination (hard water residue) on the surfaces of the 115-kV high-voltage insulators located in the transformer yard and the 230-kV high voltage insulators located in the Ashe substation. The program provides for periodic cleaning or recoating of insulators and visual inspection of the coating (if present) on the high-voltage station post insulators between the 115-kV backup transformer and circuit breaker E-CB-TRB located in the station transformer yard. Testing for contamination, and cleaning if required, is conducted on the high voltage station post insulators between the 230-kV overhead line running to Columbia and circuit breaker E-CB-TRS, located in the Ashe substation.

The High-Voltage Porcelain Insulators Aging Management Program is a preventive maintenance program consisting of activities to mitigate potential degradation of the insulation function due to hard water deposits. Uncoated insulators located in the transformer yard are inspected and cleaned every two years. Coated insulators are visually inspected for damage every two years and are re-coated every 10 years. The program requires enhancement prior to the period of extended operation to have the insulators located in the Ashe substation tested for contamination, and cleaned if required, every 8 years.

A.2.1.32 INACCESSIBLE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 EQ REQUIREMENTS PROGRAM

The Inaccessible Power Cables Not Subject to 10 CFR 50.49 EQ Requirements Program will manage the aging of in-scope, power cables (≥ 400V) exposed to significant moisture. First tests or first inspection for license renewal will be completed before the period of extended operation. These cables will be tested at least once every 6 years to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2 (Reference A.3-3), or other testing that is state-of-the-art at the time the test is performed. Significant moisture is defined as periodic exposures that last more than a few days (e.g., cable in standing water). Periodic exposures that last less than a few days (e.g., normal rain and drain) are not significant. In addition, inspection for water collection in electrical manholes will be performed based on actual plant experience with water accumulation in the manholes. However, the inspection frequency will be at least annually. Manhole inspection will also be performed periodically, in response to event-driven occurrences (such as heavy rain or flooding). The inspection will include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and sump pump systems and associated alarms operate properly. In addition, sump pumps will be inspected and operation verified prior to any known or predicted heavy rain or flooding events which could require the sump pump to operate.

A.2.1.33 INSERVICE INSPECTION (ISI) PROGRAM

The Inservice Inspection (ISI) Program is an existing condition monitoring program that manages cracking due to SCC/IGA and flaw growth of multiple reactor coolant system pressure boundary components, including the reactor vessel, a limited number of internals components, and the reactor coolant system pressure boundary. The Inservice Inspection (ISI) Program also manages loss of material due to corrosion for reactor vessel internals components and reduction of fracture toughness due to thermal embrittlement of cast austenitic stainless steel pump casings and valve bodies.

The Inservice Inspection (ISI) Program details the requirements for the examination, testing, repair, and replacement of components specified in ASME Section XI for Class 1, 2, or 3 components. The Inservice Inspection (ISI) Program complies with the ASME Code requirements.

The program scope has been augmented to include additional requirements, and components, beyond the ASME requirements. Examples include the augmentation of ISI to expand reactor vessel feedwater nozzle examinations, examinations of high energy line piping systems that penetrate containment, examinations per Generic Letter 88-01, and examinations of shroud support plate access hole covers per BWRVIP guidance. Such augmentation is consistent with the ISI program description in NUREG-1801, Section XI.M1.

A.2.1.34 INSERVICE INSPECTION (ISI) PROGRAM – IWE

The Inservice Inspection (ISI) Program – IWE is an existing program that establishes responsibilities and requirements for conducting IWE inspections as required by 10 CFR 50.55a. The Inservice Inspection (ISI) Program – IWE includes visual examination of all accessible surface areas of the steel containment and its integral attachments, and containment pressure-retaining bolting in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE.

The inservice examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC. This is consistent with NRC statements of consideration for 10 CFR 54 associated with the adoption of new editions and addenda of the ASME Code in 10 CFR 50.55a.

A.2.1.35 INSERVICE INSPECTION (ISI) PROGRAM – IWF

The Inservice Inspection (ISI) Program – IWF is an existing program that establishes responsibilities and requirements for conducting IWF Inspections for ASME Class 1, 2, and 3 component supports as required by 10 CFR 50.55a. The Inservice Inspection (ISI) Program – IWF performs visual examination of supports based on sampling of the total support population. The sample size varies depending on the ASME Class. The largest sample size is specified for the most critical supports (ASME Class 1 and those other than piping supports (Class 1, 2, 3, and MC)). The sample size decreases for the less critical supports (ASME Class 2 and 3). The primary inspection method employed is visual examination. Degradation that potentially compromises support function or load capacity is identified for evaluation. Supports requiring corrective actions are re-examined during the next inspection period in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWF.

The inservice examinations conducted throughout the service life of Columbia will comply with the requirements of the ASME Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC. This is consistent with NRC statements of consideration for 10 CFR 54 associated with the adoption of new editions and addenda of the ASME Code in 10 CFR 50.55a.

A.2.1.36 LUBRICATING OIL ANALYSIS PROGRAM

The Lubricating Oil Analysis Program manages loss of material due to corrosion or selective leaching of susceptible materials and reduction of heat transfer due to fouling for plant components that are within the scope of license renewal and exposed to a lubricating oil environment. The Lubricating Oil Analysis Program is a mitigation program.

The Lubricating Oil Analysis Program is supplemented by the Lubricating Oil Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging.

The Lubricating Oil Analysis Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.37 LUBRICATING OIL INSPECTION

The Lubricating Oil Inspection detects and characterizes the condition of materials in systems and components for which the Lubricating Oil Analysis Program is credited with aging management. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion or selective leaching has occurred. The inspection also determines whether a reduction in heat transfer due to fouling has occurred.

The Lubricating Oil Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.38 MASONRY WALL INSPECTION

The Masonry Wall Inspection consists of inspection activities to detect cracking of masonry walls within the scope of license renewal. Masonry walls that perform a fire barrier intended function are also managed by the Fire Protection Program. The Masonry Wall Inspection is implemented as part of the Structures Monitoring Program. The Masonry Wall Inspection performs visual inspection of external surfaces of masonry walls.

The Masonry Wall Inspection is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.39 MATERIAL HANDLING SYSTEM INSPECTION PROGRAM

The Material Handling System Inspection Program manages loss of material for cranes (including bridge, trolley, rails, and girders), monorails, and hoists within the scope of license renewal. The Material Handling System Inspection Program is based on guidance contained in ANSI B30.2 for overhead and gantry cranes, ANSI B30.11 for monorail systems and underhung cranes, and ANSI B30.16 for overhead hoists.

A.2.1.40 METAL-ENCLOSED BUS PROGRAM

The Metal-Enclosed Bus Program is an inspection program that detects degradation of metal-enclosed bus within the scope of license renewal. The program provides for the visual inspection of interior sections of bus, and an inspection of the elastomeric seals at the joints of the duct sections. The program also makes provision for thermographic inspection of bus bolted connections.

The Metal-Enclosed Bus Program is a new aging management program that will be implemented prior to the period of extended operation. The thermography portion of the program will be performed once every 10 years, with the initial inspections to be performed prior to the period of extended operation. The visual inspection portion of the program will also be performed once every 10 years, with the first inspections to be performed prior to the period of extended operation.

A.2.1.41 MONITORING AND COLLECTION SYSTEMS INSPECTION PROGRAM

The Monitoring and Collection Systems Inspection Program manages the effects of the loss of material due to corrosion or erosion for the internal surfaces of subject mechanical components that are exposed to equipment or area drainage water and other potential contaminants and fluids. The inspection also manages cracking due to SCC of susceptible materials.

The Monitoring and Collection Systems Inspection Program is a program that will be implemented via baseline inspection of a sample population followed by opportunistic inspection when components are opened for periodic maintenance, repair, or surveillance activities when surfaces are made available for inspection. These inspections ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. Inspection of a sample population will be conducted within the 10-year period prior to the period of extended operation and will serve as a baseline for future inspections.

A.2.1.42 OPEN-CYCLE COOLING WATER PROGRAM

The Open-Cycle Cooling Water Program manages loss of material due to corrosion and erosion for components located in the Standby Service Water and Plant Service Water systems, and for components connected to or serviced by those systems. The program manages fouling due to particulates (e.g., corrosion products) and biological material (micro- or macro-organisms) resulting in reduction in heat transfer for heat exchangers (including condensers, coolers, cooling coils, and evaporators) within the scope of the program. The Open-Cycle Cooling Water Program also manages loss of material for components associated with the feed-and-bleed mode for emergency makeup water to the spray pond.

The Open-Cycle Cooling Water Program consists of inspections, surveillances, and testing to detect the presence, and assess the extent of fouling and loss of material. The inspection activities are combined with chemical treatments and cleaning activities to minimize the effects of aging. The program is a combination condition monitoring and mitigation program that implements the recommendations of NRC Generic Letter 89-13 for safety-related equipment in the scope of the program. The scope of the program also includes non-safety related components containing either service water or spray pond makeup water.

The Open-Cycle Cooling Water Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.43 POTABLE WATER MONITORING PROGRAM

The Potable Water Monitoring Program is a mitigation program that, by means of chemical water treatment, manages loss of material due to corrosion and erosion for components that contain potable water.

The Potable Water Monitoring Program is an existing program that requires enhancement prior to the period of extended operation. At least one inspection will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.44 PREVENTIVE MAINTENANCE – RCIC TURBINE CASING

Preventive Maintenance – RCIC Turbine Casing is an existing program that manages loss of material due to corrosion for the reactor core isolation cooling (RCIC) pump turbine casing and associated piping components downstream from the steam admission valve. These components are exposed to steam during RCIC system operation and testing, but are empty during normal plant operating conditions. Preventive Maintenance – RCIC Turbine Casing is a condition monitoring program comprised of periodic inspection and surveillance activities to detect aging and age-related degradation.

A.2.1.45 REACTOR HEAD CLOSURE STUDS PROGRAM

The Reactor Head Closure Studs Program is an existing program that manages cracking due to SCC and loss of material due to corrosion for the reactor head closure stud assemblies (studs, nuts, washers, and bushings). The Reactor Head Closure Studs Program examines reactor vessel stud assemblies in accordance with the examination and inspection requirements specified in the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB (edition and addenda described in the Inservice Inspection (ISI) Program), Table IWB 2500-1. The Reactor Head Closure Studs Program includes preventive measures in accordance with Regulatory Guide 1.65 to mitigate cracking.

The Reactor Head Closure Studs Program credits portions of the Inservice (ISI) Inspection Program.

A.2.1.46 REACTOR VESSEL SURVEILLANCE PROGRAM

The Reactor Vessel Surveillance Program is an existing condition monitoring program that manages reduction of fracture toughness due to radiation embrittlement for the low alloy steel reactor vessel shell and welds in the beltline region. The Reactor Vessel Surveillance Program incorporates the BWRVIP Integrated Surveillance Program (ISP), as described in reports BWRVIP-86-A and BWRVIP-116.

Energy Northwest follows the requirements of the BWRVIP ISP and applies the ISP data to Columbia. The NRC has approved the use of the BWRVIP ISP in place of a unique plant program for Columbia.

The provisions of 10 CFR 50 Appendix G require Columbia to operate within the currently licensed pressure-temperature (P-T) limit curves, and to update these curves as necessary. The P-T limit curves, as contained in plant technical specifications, will be updated as necessary through the period of extended operation as part of the Reactor Vessel Surveillance Program. Reactor vessel P-T limits will thus be managed for the period of extended operation.

A.2.1.47 SELECTIVE LEACHING INSPECTION

The Selective Leaching Inspection detects and characterizes the conditions on internal and external surfaces of subject components exposed to raw water, treated water, fuel oil, soil, and moist air (including condensation) environments. The inspection provides direct evidence through a combination of visual examination and hardness testing, or NRC-approved alternative, as to whether, and to what extent, a loss of material due to selective leaching has occurred.

The Selective Leaching Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted no earlier than 5 years prior to the period of extended operation.

A.2.1.48 SERVICE AIR SYSTEM INSPECTION PROGRAM

The Service Air System Inspection Program manages the effects of the loss of material due to corrosion of steel piping and valve bodies exposed to an “air (internal)” (i.e., compressed air) environment within the license renewal boundary of the Service Air System.

The Service Air System Inspection Program is a new plant-specific program that will be implemented via baseline inspection of a sample population followed by opportunistic inspection when components are opened for periodic maintenance, repair, or surveillance activities when surfaces are made available for inspection. These inspections ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. Inspection of a sample population will be conducted within the 10-year period prior to the period of extended operation and will serve as a baseline for future inspections.

A.2.1.49 SMALL BORE CLASS 1 PIPING PROGRAM

The Small Bore Class 1 Piping Program will detect and characterize cracking of small bore Class 1 piping components that are exposed to reactor coolant. This periodic program will provide physical evidence as to whether, and to what extent, cracking due to SCC or to thermal or mechanical loading has occurred in small bore Class 1 piping components. The Small Bore Class 1 Piping Program will be a condition monitoring program with no actions to prevent or mitigate aging effect. The program will include visual and volumetric inspection of a representative sample of small bore Class 1 piping, including butt welds and socket welds.

The Small Bore Class 1 Piping Program is a new program that will be implemented prior to the period of extended operation. Inspection activities will start during the fourth 10-year inservice inspection interval and continue through the period of extended operation. The Small Bore Class 1 Piping Inspection will credit portions of the Inservice Inspection (ISI) Program. The Small Bore Class 1 Piping Inspection will verify the effectiveness of the BWR Water Chemistry Program in mitigating cracking of small bore piping and piping components.

A.2.1.50 STRUCTURES MONITORING PROGRAM

The Structures Monitoring Program manages age-related degradation of plant structures and structural components within its scope to ensure that each structure or structural component retains the ability to perform its intended function. Aging effects are detected by visual inspection of external surfaces prior to the loss of the structure's or component's intended function. The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection and the Masonry Wall Inspection. This program implements provisions of the Maintenance Rule, 10 CFR 50.65, that relate to structures, masonry walls, and water control structures. Concrete and masonry walls that perform a fire barrier intended function are also managed by the Fire Protection Program.

The Structures Monitoring Program is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.51 SUPPLEMENTAL PIPING/TANK INSPECTION

The Supplemental Piping/Tank Inspection detects and characterizes the material condition of steel, gray cast iron, and stainless steel components exposed to moist air environments. The inspection provides direct evidence as to whether, and to what extent, a loss of material due to corrosion has occurred.

The Supplemental Piping/Tank Inspection is a new one-time inspection that will be implemented prior to the period of extended operation. The inspection activities will be conducted within the 10-year period prior to the period of extended operation.

A.2.1.52 THERMAL AGING AND NEUTRON EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

The Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) is managed under the BWR Vessel Internals Program, see FSAR A.2.1.10.

A.2.1.53 WATER CONTROL STRUCTURES INSPECTION

The Water Control Structures Inspection, implemented as part of the Structures Monitoring Program, consists of inspection activities to detect aging and age-related degradation. The Water Control Structures Inspection ensures the structural integrity and operational adequacy of the spray ponds, standby service water pump houses, circulating water pump house (including circulating water basin), makeup water pump house, cooling tower basins, and those structural components within the structures.

The Water Control Structures Inspection is an existing program that requires enhancement prior to the period of extended operation.

A.2.1.54 BORON CARBIDE MONITORING PROGRAM

The Boron Carbide Monitoring Program detects degradation of the Boron Carbide (B_4C) neutron absorbers in the spent fuel storage racks by monitoring spent fuel racks for potential off-gassing, by in situ testing of the spent fuel racks, and by inspecting the B_4C coupons.

From the monitoring data, the stability and integrity of Boron Carbide in the storage cells are assessed. Periodic monitoring of B_4C coupons permits early determination of aging degradation.

A.2.1.55 SERVICE LEVEL 1 PROTECTIVE COATINGS PROGRAM

The Service Level 1 Protective Coating Program monitors the performance of Service Level 1 coatings inside containment through periodic coating examinations, condition assessments, and remedial actions, including repair or testing. The program establishes roles, responsibilities, controls and deliverables for the Service Level 1 Protective Coatings Program. This program also ensures the Design Basis Accident (DBA) analysis limits with regard to coating will not be exceeded for the suction strainers.

A.2.2 EVALUATION OF TIME-LIMITED AGING ANALYSES

In accordance with 10 CFR 54.21(c), an application for a renewed operating license requires an evaluation of TLAAs for the period of extended operation. The following TLAAs have been identified and evaluated to meet this requirement.

A.2.2.1 REACTOR VESSEL NEUTRON EMBRITTLEMENT

Neutron embrittlement is the change in mechanical properties of reactor vessel materials resulting from exposure to fast neutron flux ($E > 1.0$ MeV) in the beltline region of the reactor core. The most pronounced material change is a reduction in fracture toughness. As fracture toughness decreases with cumulative fast neutron exposure, the material's resistance to crack propagation decreases. Fracture toughness is also dependent on temperature. The reference temperature for nil-ductility transition (RT_{NDT}) is the temperature above which the material behaves in a ductile manner and below which the material behaves in a brittle manner. As fluence increases, RT_{NDT} increases, and higher temperatures are required for the material to continue to act in a ductile manner.

Requirements associated with fracture toughness, pressure-temperature limits, and material surveillance programs for the reactor coolant pressure boundary are contained in Appendices G and H of 10 CFR 50.

The analyses associated with evaluation of the effect of neutron embrittlement on the reactor pressure vessel for 40 years are TLAAs. Neutron fluence, upper shelf energy, adjusted reference temperature (ART), and vessel P-T limits are time dependent parameters associated with fracture toughness (embrittlement) of reactor vessel materials.

A.2.2.1.1 Neutron Fluence

EFPY Projection

To evaluate the effects of radiation on reactor pressure vessel material embrittlement, the results of analyses were projected to determine neutron fluence out to 54 effective full power years (EFPY). Using actual reactor core power histories through 2007 and conservative estimates of future core designs, extended operation to 60 years was determined to be bounded by 54 EFPY.

Fluence Projection

Analyzed fluence values at 51.6 EFPY of reactor operation are addressed in FSAR Section 4.3.2.8 and FSAR Table 4.3-1. These fluence analyses are based on the original licensed thermal power of 3323 mega-watt thermal (MWt) through fuel cycle 10, the previous licensed thermal power uprated to 3486 MWt from cycle 11 through cycle 23, and the current licensed thermal power uprated to 3544 MWt from cycle 24 through the end of life. These fluence analyses use NRC-approved methodology based on the guidance of Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." The fluence analyses were projected to 54 EFPY for the extended operating period of 60 years.

Beltline Evaluation

For the extended operating period, all ferritic materials for vessel beltline shells, welds, nozzles and the associated nozzle to vessel welds, and assembly components are required to be evaluated for neutron irradiation embrittlement if high energy neutron fluence is greater than a threshold value of 1E+17 n/cm^2 (E >1 MeV) at the end of the 60 years. The only vessel assembly items, other than the shells and welds of the beltline region that would experience neutron fluence greater than 1E+17 n/cm^2 during the period of extended operation are instrumentation nozzle N12 and residual heat removal/low pressure coolant injection (RHR/LPCI) nozzle N6 (and the associated nozzle-to-vessel welds).

Instrumentation nozzle N12 has a thickness less than 2.5 inches and was not originally evaluated for fracture toughness per ASME Code Appendix G, Section G2223. Nozzle N12 is not limiting for P-T curves as discussed in Section A.2.2.1.4; however, as nozzle N12 was evaluated for impact on the P-T curves it meets the definition of a beltline component per 10 CFR 50, Appendix G. The associated nozzle-to-vessel weld is an austenitic weld and, therefore, is not subject to the fracture toughness requirements of 10 CFR 50, Appendix G.

Nozzle N6 is included in the evaluation for USE in Section A.2.2.1.2. Nozzle N6 is evaluated for ART in Section A.2.2.1.3 below. Nozzle N6 is not the limiting material for the vessel. However, as nozzle N6 was evaluated for ART it meets the definition of a beltline component per 10 CFR 50, Appendix G. The associated nozzle-to-vessel weld is a ferritic weld and, therefore, is subject to the fracture toughness requirements of 10 CFR 50, Appendix G. The nozzle-to-vessel weld for nozzle N6 is also included in the evaluation for USE in Section A.2.2.1.2 and is evaluated for ART in Section A.2.2.1.3.

The beltline definition for the period of extended operation includes the lower shell (Course #1 / Ring #21), lower-intermediate shell (Course #2 / Ring #22), associated vertical (longitudinal) welds, the girth (circumferential) weld that connects the lower and lower-intermediate shells, and nozzles N6 (and its associated nozzle-to-vessel weld) and nozzle N12.

Disposition

Neutron fluence has been projected to the end of the period of extended operation.

A.2.2.1.2 Upper Shelf Energy Evaluation

Appendix G of 10 CFR 50 requires the upper shelf energy (USE) of the vessel beltline materials to remain above 50 ft-lb at all times during plant operation, including the effects of neutron radiation. If USE cannot be shown to remain above this limit, then an equivalent margin analysis (EMA) must be performed to show that the margins of safety against fracture are equivalent to those required by Appendix G of Section XI of the ASME Code.

The initial (unirradiated) USE is not known for all the Columbia vessel plates and welds. For those plates and welds for which the initial USE is known, USE was projected using Regulatory Guide 1.99, Revision 2 methods. For the vessel plates and welds for which the initial USE is not known, USE equivalent margin analyses were performed using the Boiling Water Reactor Owners Group (BWROG) equivalent margin analysis (EMA) methodology. Results from the testing and analysis of surveillance materials were used in the EMA analyses.

All of the projected USE values for the vessel beltline plates, nozzle forgings, and welds for which the initial USE is known remain above 50 ft-lbs through the end of the period of extended operation (54 EFPY). For the vessel beltline plates and welds, for which the initial USE is not known, the maximum decrease in USE was found to be less than the assumed decrease in the associated generic equivalent margin analyses. The maximum predicted decreases in USE for 54 EFPY for these beltline plates and welds are bounded by the generic equivalent margin analyses. Therefore, the projected USE for the vessel beltline plates and welds is acceptable for the period of extended operation.

Energy Northwest agrees that all beltline materials, including the N12 instrumentation nozzles, must be considered when the licensee develops pressure-temperature limits for Columbia in accordance with 10 CFR Part 50, Appendix G and ASME Code, Section XI, Appendix G.

Energy Northwest will continue to develop future pressure-temperature limit curves considering all beltline plates, welds, and nozzles.

Disposition

Upper shelf energy TLAAs have been projected to the end of the period of extended operation for all reactor vessel beltline materials. Additionally, a specific 54 EFPY equivalent margins analysis will be performed for the N12 nozzle forgings prior to the period of extended operation.

A.2.2.1.3 Adjusted Reference Temperature Analysis

In addition to USE, the other key parameter that characterizes the fracture toughness of a material is the RT_{NDT}. This reference temperature changes as a function of exposure to neutron radiation resulting in an adjusted reference temperature, ART.

The initial RT_{NDT} is the reference temperature for the unirradiated material. The change due to neutron radiation is referred to as ΔRT_{NDT}. The ART is calculated by adding the initial RT_{NDT}, the ΔRT_{NDT}, and a margin to account for uncertainties as prescribed in Regulatory Guide 1.99, Revision 2.

The ART evaluations of record for the vessel beltline plates, nozzle forgings, and welds for the currently licensed period (33.1 EFPY) include power uprate conditions. Based on projected fluence values, the methodology in Regulatory Guide 1.99 was used to project the ART for 54 EFPY. The ART values projected to 54 EFPY are used to develop P-T limit curves. Projected ART values are well below the 200°F end of life ART suggested in Section 3 of Regulatory Guide 1.99 and are, thus, acceptable for the period of extended operation.

Disposition

Reactor vessel adjusted reference temperature TLAAs have been projected to the end of the period of extended operation.

A.2.2.1.4 Pressure-Temperature Limits

To ensure that adequate margins of safety are maintained for various modes of reactor operation, 10 CFR 50, Appendix G specifies pressure and temperature requirements for affected materials for the service life of the reactor vessel. The basis for these fracture toughness requirements is ASME Section XI, Appendix G. The ASME Code requires P-T limits be established for hydrostatic pressure tests and leak tests; for operation with the core not critical during heatup and cooldown; and for core critical operation.

The Columbia P-T limit curves were revised in 2005 to include the effects of power uprate to 3486 MWt and dispositioned as bounding for uprate to 3544 MWt. The P-T limits are valid for 33.1 EFPY through the end of the currently licensed period. The curves were reviewed in 2009 to assure that the N12 instrumentation nozzle did not affect the existing curves. P-T limits for the period of extended operation will be calculated using the most accurate fluence projections available at the time of the recalculation. The projections may be adjusted if there are changes in core design or if additional surveillance capsule results show the need for an adjustment. The projected ART for the period of extended operation above gives confidence that future P-T curves will provide adequate operating margin.

Energy Northwest will continue to develop pressure-temperature limits in accordance with the Title 10 of the Code of Federal Regulations Part 50, Appendix G (10 CFR Part 50, Appendix G) and ASME Code, Section XI, Appendix G, considering all beltline plates, welds, and nozzles.

License amendment requests to revise the P-T limits will be submitted to the NRC for approval, when necessary to comply with 10 CFR 50 Appendix G, as part of the Reactor Vessel Surveillance Program.

Disposition

The TLAA for P-T limits will be adequately managed for the period of extended operation as part of the Reactor Vessel Surveillance Program.

A.2.2.1.5 Reactor Vessel Circumferential Weld Inspection Relief

BWRVIP-74-A, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," reiterated the recommendation of BWRVIP-05, "BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," that vessel circumferential welds could be exempted from examination. The NRC safety evaluation report (SER) for BWRVIP-74 agreed, but required that plants apply for this relief request individually. The relief request is required to demonstrate that at the expiration of the current license, the circumferential welds will satisfy the limiting conditional failure probability in the (BWRVIP-05) evaluation. Energy Northwest requested and received permanent relief from vessel shell circumferential (girth) weld volumetric examinations through 33.1 EFPY.

The reactor pressure vessel circumferential weld parameters at 51.6 EFPY have been projected to remain within the bounding (64 EFPY) vessel parameters from the BWRVIP-05 SER. As such, the conditional probability of failure for circumferential welds remains below the limits contained in the SER for BWRVIP-05.

Disposition

The TLAA for reactor vessel circumferential weld examination relief has been projected to the end of the period of extended operation.

A.2.2.1.6 Reactor Vessel Axial Weld Failure Probability

The NRC SER for BWRVIP-74-A evaluated the failure frequency of axially oriented welds in BWR reactor vessels, and determined failure frequency acceptance criteria for 40 years of reactor operation. Applicants for license renewal are required to evaluate axially oriented vessel welds to show that their failure frequency remains below the acceptance criteria in the SER for BWRVIP-74. An acceptable way to do this is to show that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in the SER.

The Columbia limiting axial weld mean RT_{NDT} at 54 EFPY is projected to remain well below the RT_{NDT} from the SER for BWRVIP-74, thus the Columbia axial weld failure frequency meets the acceptable criteria.

Disposition

The TLAA for the reactor vessel axial weld failure probability has been projected to the end of the period of extended operation.

A.2.2.2 METAL FATIGUE

Fatigue evaluations for mechanical components are identified as TLAAs; therefore, the effects of fatigue must be addressed for license renewal. Fatigue is an age-related degradation mechanism caused by cyclic duty on a component by either mechanical or thermal loads.

The ASME Boiler and Pressure Vessel Code requires evaluation of transient thermal and mechanical load cycles for Class 1 components. Cumulative usage factors for Class 1 components are calculated based on normal and upset design transient definitions. The design transients used to generate cumulative usage factors for Class 1 components are contained in FSAR Section 3.9.1.1. Energy Northwest is required to monitor design transients listed in FSAR Table 3.9-1 to ensure that plant components are maintained within the design limits.

Calculation of fatigue usage values is not required for non-Class 1 SSCs. Instead, stress intensification factors and lower stress allowables are used to ensure components are adequately designed for fatigue.

The reactor coolant environmental effects of fatigue on plant components were also evaluated.

The design cycles for Columbia are summarized in FSAR Section 3.9 and FSAR Table 3.9-1. Energy Northwest counts all fatigue significant cycles, not only for the design transients listed in FSAR Table 3.9-1 but also for the analysis of other plant components. The events listed in FSAR Table 3.9-1 have been evaluated and in some cases regrouped for easier counting. Faulted conditions listed in the FSAR are not used in the fatigue analyses and are not counted. Additional transients determined to be fatigue significant after the original design have been added to the counting procedure, while FSAR Table 3.9-1 lists the original design cycles. The projected number of occurrences of design transients to 60 years determined that some analyzed numbers of transients may be exceeded. These projections were done using linear extrapolation from the beginning of plant life. Recent operating experience suggests lower projections and as additional operating data is accumulated, subsequent projections will refine the number of cycles expected in 60 years. Energy Northwest manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached.

A.2.2.2.1 Reactor Pressure Vessel Fatigue Analyses

The reactor vessel assembly consists of the reactor pressure vessel (RPV), the vessel support skirt, the shroud support, nozzles, penetrations, stub tubes, head closure flanges, head closure studs, refueling bellows support, and stabilizer brackets.

Design cumulative usage factors (CUFs) for the limiting RPV assembly locations are contained in design reports and were calculated based on the design transients. Energy Northwest manages fatigue for the RPV assembly components using the Fatigue Monitoring Program to track transient cycles and requires corrective action before any analyzed number of cycles is reached.

Disposition

The effects of aging on the intended functions of the RPV will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

A.2.2.2.2 Reactor Pressure Vessel Internals

Fatigue analyses of the overall RPV internals (including the jet pump assemblies) were performed pre-startup as part of the plant design. Component specific fatigue analyses of the jet pumps were performed more recently to bound actual plant operation. Each of these analyses is discussed below.

Reactor Vessel Internals Fatigue Analyses

The RPV internals are described in terms of two assemblies: core support structures and reactor internals. Core support structures include the shroud, shroud support (included as part of the reactor vessel for fatigue), core plate with core plate hold-down bolts, top guide, fuel supports, and control rod guide tubes. Reactor internals include the jet pump assemblies, jet pump instrumentation, feedwater spargers, vessel head spray nozzle, differential pressure line, incore flux monitor guide tubes, surveillance sample holders, core spray line (in-vessel) and spargers, incore instrument housings, low pressure coolant injection coupling, steam dryer, shroud head and steam separator assembly, guide rods, and control rod drive thermal sleeves.

The normal, test, and upset service load cycles used for the design and fatigue analysis for the core support structures and reactor internals are shown in FSAR Table 3.9-1. Calculation of CUFs for the reactor internals was performed as part of a NSSS design evaluation.

Review of the RPV internals in association with power uprate determined that stresses on the vessel internals remained well below all limits. No recalculation of cumulative usage factors was determined to be required. Energy Northwest manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached.

Disposition

The effects of aging on the intended functions of the RPV internals will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

Jet Pump Fatigue Analyses

In August 2000, Columbia operated for a period of time with the recirculation pumps in an unbalanced mode (pump speeds different by more than 50 percent). The effect of that flow imbalance on the jet pumps was an additional accumulation of fatigue usage.

As a result of inspections during the Spring 2001 outage (R-15), a fatigue analysis of the jet pumps was performed and cumulative usage factors were determined.

Jet pump clamps were installed during the 2005 outage (R-17) to minimize flow induced vibration. These clamps greatly reduced the future potential for riser brace fatigue.

As a result of evaluations after the 2007 outage the usage factors were extended to 60 years. The maximum CUF of the jet pump risers for 60 years of operation is projected to remain below the fatigue limit. Energy Northwest manages fatigue using the Fatigue Monitoring Program to track transient cycles and require corrective action before any analyzed number of cycles is reached. The Fatigue Monitoring Program credits the BWR Vessel Internals Program to monitor the jet pump gaps. Together, these actions effectively manage the fatigue of the jet pumps through the period of extended operation.

Disposition

The effects of aging on the intended functions of the jet pumps will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

A.2.2.2.3 Reactor Coolant Pressure Boundary Piping and Piping Component Fatigue Analyses

The Class 1 boundary encompasses all reactor coolant pressure boundary piping (pipe and fittings) and in-line components subject to ASME Section XI, Subsection IWB, inspection requirements. Fatigue analyses of Class 1 piping are based on the transients found in the Columbia piping specifications that are in turn based on the design transients listed in FSAR Section 3.9.

Potential high energy line break (HELB) intermediate locations can be eliminated based on CUFs of less than 0.1 if other stress criteria are also met. The usage factors, as calculated in the design fatigue analyses, account for the design transients assumed for the original 40-year life of the plant. Therefore, the determination of CUFs used in the selection of postulated high energy line intermediate break locations are TLAAs. The Fatigue Monitoring Program will identify when the transients for piping systems are approaching their analyzed number of cycles. Prior to any transient exceeding its analyzed number of cycles for a piping system, the associated analyses will be reviewed to determine whether any additional locations need to be designated as postulated HELB locations.

All Class 1 piping was reviewed for the power uprate. The evaluation determined that there was adequate margin in each system to accommodate the power uprate. Design fatigue usage for 40 years of operation and projected fatigue usage for the period of extended operation are established for the limiting reactor coolant pressure boundary components.

A review of documentation found several fatigue analyses for Class 1 valve stress reports found fatigue analyses that were TLAAs. The fatigue usage for those valves is based on transients that are tracked by the Fatigue Monitoring Program.

Metal fatigue for all Class 1 reactor coolant pressure boundary piping and in-line components is managed by the Fatigue Monitoring Program. The Fatigue Monitoring Program will identify when the transients for piping systems are approaching their analyzed numbers of cycles. Prior to any transient exceeding its analyzed number of cycles for a piping system, the design calculations for that system will be reviewed and appropriate actions will be taken.

Disposition

The effects of aging on the intended functions of the reactor coolant pressure boundary piping and components will be adequately managed for the period of extended operation by the Fatigue Monitoring Program.

A.2.2.3 NON-CLASS 1 COMPONENT FATIGUE ANALYSES

The non-Class 1 mechanical components susceptible to fatigue fit into one of two major categories: (1) piping and in-line components (piping, valves, tubing, traps, thermowells, etc.) or (2) non-piping components (vessels, heat exchangers, tanks, pumps, etc.).

Non-Class 1 components that are Quality Group B or C are designed and constructed as ASME Section III Code Class 2 and 3, respectively. The design of ASME Class 2 and 3 piping systems incorporates a stress range reduction factor for determining acceptability of piping design with respect to thermal stresses. Non-Class 1 components designated as Quality Class D are designed to ANSI B31.1, which also incorporates stress range reduction factors based upon the number of thermal cycles. In general, a stress range reduction factor of 1.0 in the stress analyses applies for up to 7,000 thermal cycles. The allowable stress range is reduced by the stress range reduction factor if the number of thermal cycles exceeds 7,000. If fewer than 7,000 cycles are expected through the period of extended operation, then the fatigue analysis (stress range reduction factor) of record will remain valid through the period of extended operation.

Because none of the non-Class 1 vessels, heat exchangers, storage tanks, or pumps were designed to ASME Section VIII, Division 2 or ASME Section III, Subsection NC-3200, no fatigue evaluation is required. Therefore, there are no fatigue TLAAs for these components.

The fatigue evaluation of non-Class 1 piping and in-line components evaluated the associated operating temperature against the threshold temperature value for fatigue of the material. If the threshold temperature value was exceeded, then the number of transient cycles for the piping or in-line component was projected. In each case, the number of projected cycles for 60 years was found to be less than 7,000 for piping and in-line components whose temperatures exceed threshold values. Therefore, fatigue for non-Class 1 piping and in-line components remains valid for the period of extended operation.

Disposition

The TLAA for non-Class 1 component fatigue analyses remains valid for the period of extended operation.

A.2.2.4 EFFECTS OF REACTOR COOLANT ENVIRONMENT ON FATIGUE LIFE OF COMPONENTS AND PIPING

Applicants for license renewal are required to address the reactor coolant environmental effects on fatigue of plant components. The minimum set of components for a BWR of Columbia's vintage is derived from NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," as follows:

1. Reactor vessel shell and lower head
2. Reactor vessel feedwater nozzle
3. Reactor recirculation piping (including inlet and outlet nozzles)
4. Core spray line reactor vessel nozzle and associated Class 1 piping
5. Residual heat removal return line Class 1 piping
6. Feedwater line Class 1 piping

Energy Northwest has analyzed these locations for the effects of the reactor coolant environment on fatigue in support of license renewal. Energy Northwest has also analyzed other limiting components beyond those locations indentified in NUREG/CR-6260 for the effects of the reactor coolant environment. Original fatigue usage calculations were reviewed, and the transient groupings and load pairs used in those analyses were carried over to the environmentally-assisted fatigue analyses, with revised non-environmentally assisted usage factors determined.

An effective fatigue life adjustment factor, F_{en}, that considers a time weighted average of operation with normal water chemistry and hydrogen water chemistry over 60 years of operation, was determined for each load pair analyzed for the components. The fatigue life adjustment factors were applied to the revised component load pair usage factors, and the environmentally-adjusted usage factors were summed to obtain environmentally-adjusted CUFs to verify acceptability of the components for the period of extended operation.

Using fatigue data projected by the Fatigue Monitoring Program and the methodology summarized above, the limiting locations were evaluated. None of the locations evaluated have an environmentally adjusted CUF of greater than 1.0 during the period of extended operation.

For the period of extended operation, on an ongoing basis, ensure that all the limiting locations in Class 1 components and Class 1 systems have been evaluated for the effect of reactor water environment.

The aging effect of fatigue, including consideration of the environmental effects, will be adequately managed for the period of extended operation using the Fatigue Monitoring Program.

Disposition

The effects of environmentally-assisted fatigue on the intended functions of the NUREG/CR-6260 and other limiting locations will be adequately managed for the period of extended operation using the Fatigue Monitoring Program.

A.2.2.5 ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

Environmental qualification analyses for electrical equipment are identified as TLAAs. NRC regulation 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," requires licensees to identify electrical equipment covered under this regulation and to maintain a qualification file demonstrating that the equipment is qualified for its application and will perform its safety function up to the end of its qualified life. The EQ Program implements the requirements of 10 CFR 50.49 and will be used to manage the effects of aging on the intended functions of the components associated with environmental qualification TLAAs for the period of extended operation.

Disposition

The effects of aging on the intended functions of the environmentally qualified components will be adequately managed for the period of extended operation by the EQ Program.

A.2.2.6 FATIGUE OF PRIMARY CONTAINMENT, ATTACHED PIPING, AND COMPONENTS

The Primary Containment and attached piping and components susceptible to fatigue resulting from the effects of plant transients are evaluated below.

A.2.2.6.1 Primary Containment

The cycles used in the fatigue evaluation of the containment components are provided in FSAR Table 3A.4.1-3. No operating basis earthquakes have been experienced by Columbia through 2007, and the containment analysis for five operating basis earthquakes remains valid for 60 years of plant operation. The safe shutdown earthquake and post-loss of coolant accident (LOCA) chugging are once in a lifetime events and are not projected to occur during the extended period of operation. Safety relief valve actuations have been projected through 60 years of operation based on the number of actual events through 2007. The fatigue analyses performed using these events will remain valid for the period of extended operation.

As the cycles on which the containment fatigue analysis is based will not be exceeded for 60 years of operation, these analyses will remain valid for the period of extended operation.

Disposition

The TLAA associated with fatigue of the containment remains valid for the period of extended operation.

A.2.2.6.2 ASME Class MC Components

Class MC components include the primary containment vessel shell, large openings (equipment hatch, personnel hatches, and access hatch), penetrations (all except the large openings), and attachments (pipe supports in the wetwell, welding pads in the drywell, supports for the stabilizer truss, seal and shear lugs at the drywell floor, supports for the downcomer bracing system, pipe whip supports, radial beam supports, cap truss supports, catwalks, monorail, and platforms). The Class MC components were analyzed for fatigue using the transients listed in FSAR Table 3A.4.1-3. As these cycles will not be exceeded for 60 years of operation, the Class MC component fatigue analysis will remain valid for the period of extended operation.

A specific fatigue analysis was performed for the main steam penetrations using the transients listed in FSAR Table 3A.4.1-3. This analysis will remain valid for the period of extended operation as these cycles will not be exceeded for 60 years of operation.

The effects of power uprate on the containment system response were reviewed and determined to be negligible. The containment peak pressure values remain virtually unaffected by the power uprate and extended load line limit. The LOCA containment dynamic loads are not affected by power uprate, and safety relief valve containment loads will remain below their design allowables. (See FSAR Section 3A.)

All events, including safety relief valve actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the Class MC containment components remains valid for the period of extended operation.

Disposition

The TLAAs for fatigue of the ASME Class MC components remain valid through the end of the period of extended operation.

A.2.2.6.3 Downcomers

Although not an ASME Code requirement, a fatigue evaluation of the downcomers was performed. The fatigue evaluation of the downcomer lines in the wetwell air volume was based on the number of cycles presented in FSAR Table 3A.4.1-3. The maximum fatigue usage factor for the downcomers is provided in FSAR Table 3A.4.2-4 and FSAR Table 3A.4.2-5.

All events, including safety relief valve actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the downcomers remains valid for the period of extended operation.

Disposition

The TLAA for fatigue of the downcomers remains valid through the end of the period of extended operation.

A.2.2.6.4 Safety Relief Valve Discharge Piping

Although not an ASME Code requirement, a fatigue evaluation of the safety relief valve (SRV) discharge piping was performed. The fatigue evaluation used the number of cycles as presented in FSAR Table 3A.4.1-3. The maximum fatigue usage factor for all 18 SRV discharge lines in the wetwell air volume is below the ASME allowable limits per FSAR Section 3A.4.2.4.6.

The SRV actuations for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the SRV discharge piping remains valid for the period of extended operation.

Disposition

The TLAA for fatigue of the SRV discharge piping remains valid through the end of the period of extended operation.

A.2.2.6.5 Diaphragm Floor Seal

The diaphragm floor seal is located at the inside surface of the primary containment vessel periphery. It provides a flexible, pressure tight seal between the primary containment vessel and the diaphragm floor and is capable of accommodating differential thermal expansion between them.

The fatigue evaluation was performed using the cycles in FSAR Table 3A.4.1-3. The maximum cumulative usage factor is less than the fatigue limit per FSAR Table 3A.4.1-5. All events, including SRV actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the diaphragm floor seal remains valid for the period of extended operation.

Disposition

The TLAA for fatigue of the containment diaphragm floor seal remains valid through the end of the period of extended operation.

A.2.2.6.6 ECCS Suction Strainers

The original Columbia ECCS suction strainers were replaced with a new strainer design constructed from cold-worked austenitic stainless steel. A linear elastic fracture mechanics analysis was performed to bound all the martensitic material in the suction strainer screens. A crack depth was assumed based on the depth of the Alpha Prime martensite in the strainer screen material.

Cyclic stresses were considered in the crack growth analysis of the suction strainers. The fatigue crack evaluation determined that the assumed cracks will not propagate to a critical size for the remaining life of the plant. The maximum computed stress intensity value (K) was less than that required to cause cracking in Alpha martensite formed in austenitic stainless steel.

The stress value conservatively included direct pressure and inertial components from SRV actuation, operating basis earthquake (OBE) loads, and SRV steam chugging. (See FSAR Table 3A.4.1-3.)

All events, including safety relief valve actuations, for 60 years of operation are projected to remain below the containment cyclic basis from FSAR Table 3A.4.1-3. Consequently, the analysis of the ECCS suction strainers remains valid for the period of extended operation.

Disposition

The TLAA for crack growth of the ECCS suction strainers remains valid through the end of the period of extended operation.

A.2.2.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

The TLAAs that do not fit into any of the previous major categories are evaluated below.

A.2.2.7.1 Reactor Vessel Shell Indications

Two indications in the reactor vessel shell were identified using ultrasonic inspection methods during the 2005 inservice inspections. The indications were present in past inservice inspection examinations, but became rejectable under current ASME Section XI, IWB-3610 requirements. The rejected indications were evaluated and determined to be acceptable for continued service without repair, as reported to the NRC. The indications were evaluated per the guidelines of ASME Section XI, IWB-3610, which include acceptance criteria based on the applied stress intensity factors, using conservative assumptions in the applied stresses to determine the stress intensity factors for comparison to Code allowables.

This conservative evaluation calculated a fatigue crack growth at the end of 33.1 EFPY vessel service life that is insignificant in comparison to the bounding initial crack size. It also determined that the applied stress intensity factor is well below the allowable stress intensity factor.

The calculation is based on time-limited assumptions of neutron fluence and SRV blowdown cycles for 40 years. While it is not expected that the applied stress intensity factor will exceed the allowable fracture toughness during the period of extended operation, cracking near the subject reactor vessel welds is managed by the Inservice Inspection (ISI) Program.

Energy Northwest will re-evaluate the indication based on the results of the 2015 inspection and either project this analysis through the period of extended operation or continue augmented inspections as required by the ASME code.

Disposition

Cracking of the reactor vessel shell near welds BG and BM will be adequately managed through the period of extended operation by the Inservice Inspection (ISI) Program.

A.2.2.7.2 Sacrificial Shield Wall

FSAR Section 3.8.3.6 provides a value of neutron fluence for the outside face of the sacrificial shield wall that is based on 40 years of plant operation. Projections done for 60 years of operation, including increase in fluence due to power uprate, determined that the estimated neutron fluence on the sacrificial shield wall will remain below the threshold for neutron damage of concrete and reinforcing steel. Therefore, the sacrificial shield wall can be expected to perform its radiation shielding function through the period of extended operation.

Disposition

The TLAA associated with the sacrificial shield wall fluence has been projected to the end of the period of extended operation.

A.2.2.7.3 Main Steam Flow Restrictor Erosion Analyses

The main steam line flow restrictors are designed to limit coolant flow rate from the reactor vessel (before the MSIVs are closed) to less than 200 percent of normal flow in the event of a main steam line break outside the containment. Erosion of a flow restrictor is a safety concern since it could impair the ability of the flow restrictor to limit vessel blowdown following a main steam line break. Since erosion is a time-related phenomenon, the analysis for the effect it has on the flow restrictors over the life of the plant is a TLAA. Cast stainless steel (SA351, Type CF8) was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion from high velocity steam.

The erosion of the main steam flow restrictors has been projected for the period of extended operation. The projection concludes that after 60 years of erosion on the main steam flow restrictors, the choked flow will still be less than 200 percent of normal flow. Therefore, the main steam flow restrictors will continue to perform their intended function and the existing accident radiological release analysis will remain valid for the period of extended operation.

Disposition

The TLAA for erosion of the main steam line flow restrictors has been projected to the end of the period of extended operation.

A.2.2.7.4 Core Plate Rim Hold-Down Bolts

The NRC safety evaluation report that references BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines," for license renewal identifies loss of preload on the core plate rim hold-down bolts as one of the TLAA that must be addressed by applicants seeking license renewal.

Disposition

At least two years prior to the period of extended operation, Energy Northwest will install core plate wedges unless:

- a site-specific analysis is approved by the NRC that resolves core plate bolt loss of preload due to both stress relaxation and cracking, or
- an NRC approved method is developed to inspect the core plate bolts for cracking and a site-specific analysis for loss of preload due to stress relaxation of the core plate bolts is approved by the NRC.

A.2.2.7.5 Crane Load Cycle Limit

All in-scope cranes at Columbia were designed to Crane Manufacturers Association of America (CMAA) Specification 70, "*Specification for Electric Overhead Traveling Cranes*" which provides a design load cycle limit based on service class for the associated cranes. This load cycle limit for each crane was identified as a potential TLAA.

Disposition

To address this potential TLAA a 60-year projection of load cycles was developed for all cranes in the scope of license renewal and compared to the design load cycle limits of CMAA 70. For all cranes the 60-year projection of load cycles is within the applicable design load cycle limit of CMAA 70. Therefore, this TLAA remains valid for the period of extended operation.

A.3 REFERENCES

A.3-1 BWROG Report GE-NE-523-A71-0594-A, Rev 1, "Alternate BWR Feedwater Nozzle Inspection Requirements," May 2000

A.3-2 EPRI Report No. 1011838, "Recommendations for An Effective Flow Accelerated Corrosion Program (NSAC-202L-R3)," May 2006

A.3-3 EPRI TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables," August 1994

Appendix B

RESPONSE TO REGULATORY ISSUES
RESULTING FROM TMI-2

TABLE OF CONTENTS

Appendix B

RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

LIST OF TABLES

Appendix B

RESPONSE TO REGULATORY ISSUES RESULTING FROM TMI-2

LIST OF FIGURES

I.A.1.2 Shift Supervisor Responsibilities

Position (NUREG-0578, 2.2.1.A)

a. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

b. Plant procedures shall be reviewed to ensure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

 1. The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The idea shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.

 2. The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

 3. If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

c. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function of the shift supervisor is to provide for ensuring safety.

d. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for ensuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

Clarification

The table attached provides clarification to the above position.

Columbia Generating Station Position

The administrative duties of the shift manager have been reviewed; inappropriate functions were delegated to other personnel including the shift support supervisor. The shift support supervisor will assist the shift manager by directing personnel assigned to perform balance-of-plant operating functions and by performing shift administrative duties.

Procedures have been reviewed to ensure that the shift manager, control room supervisor, shift support supervisor, and operator functions are defined adequately to establish the shift manager as the commanding authority for plant operations relative to other plant management. The shift manager is to ensure the safe operation of the plant under all conditions. During an emergency, the responsibility for directing and controlling the actions of the operating crew to place and maintain the plant in a safe condition rests with the shift manager. During accident conditions, the shift manager will normally be in the control room at all times until properly relieved. He may elect to direct recovery activities at the scene of the accident.

This principle has been reinforced by management directive that emphasizes that the shift manager’s primary responsibility is the safe operation of the plant under all conditions.

The shift manager’s administrative duties will be reviewed annually by the crew operations manager to ensure that administrative responsibilities do not interfere with the primary responsibility.

Appropriate documentation will be available onsite for review by the Nuclear Regulatory Commission (NRC) I&E Branch.

This position has been accepted in the NRC Staff Safety Evaluation Report NUREG-0892 dated March 1982, section 13.5.1.8.

Table I.A.1.2-1

Shift Supervisor Responsibilities (2.2.1.A)

NUREG-0578 Position (Position Number)	Clarification
Highest Level of Corporate Management (1.)	Chief Nuclear Officer
Periodically Reissue (1.)	Annual Reinforcement of Company Policy
Management Direction (1.)	Formal Documentation of Shift Personnel, All Plant Management, Copy to IE Region
Properly Defined (2.0)	Defined in Writing in a Plant Procedure
Until Properly Relieved (2.B)	Formal Transfer of Authority, Valid SRO License, Recorded in Plant Log
Temporarily Absent (2.C)	Any Absence
Control Room Defined (2.C)	Includes Shift Manager Office Adjacent to the Control Room
Designated (2.C)	In Administrative Procedures
Clearly Specified	Defined in Administrative Procedures
SRO Training	Specified in ANS 3.1 (Draft) Section 5.2.1.8
Administrative Duties (4.)	Not Affecting Plant Safety
Administrative Duties Reviewed (4.)	On Same Interval as Reinforcement: i.e., Annual by Chief Nuclear Officer

This requirement was met before fuel loading. See NUREG-0578, Section 22.1a, Item 4 and NRC letters of September 27 and November 9, 1979

The italicized information is historical and was provided to support the application for an operating license.

I.C.1 GUIDANCE FOR THE EVALUATION AND DEVELOPMENT OF PROCEDURES FOR TRANSIENTS AND ACCIDENTS

Position *(NUREG-0737)*

In the letters of September 13 and 27, October 10 and 30, and November 9, 1979, the Office of Nuclear Reactor Regulation required licensees of operating plants, applicants for operating licenses and licensees of plants under construction to perform analyses of transients and accidents, prepare emergency procedure guidelines, upgrade emergency procedures, including procedures for operating with natural circulation conditions, and to conduct operator retraining (see also Item I.A.2.1). Emergency procedures are required to be consistent with the actions necessary to cope with the transients and accidents analyzed. Analyses of transients and accidents were to be completed in early 1980 and implementation of procedures and retraining were to be completed 3 months after emergency procedure guidelines were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions are being developed. In the course of review of these matters on Babcock and Wilcox (B&W) designed plants, the staff will follow up on the bulletin and orders matters relating to analysis methods and results, as listed in NUREG-0660, Appendix C (see Table C.1, Items 3, 4, 16, 18, 24, 25, 26, 27; Table C.2, Items 4, 12, 17, 18, 19, 20; and Table C.3, Items 6, 35, 37, 38, 39, 41, 47, 55, 57).

Changes to Previous Requirements and Guidance:

a. Modification to Clarification

1. Addresses owners' group and vendor submittals.

2. References to task action plan Items I.C.8 and I.C.9.

3. Scope of procedures review is explained.

4. Establishes configuration control of guidelines for emergency procedures.

b. Modification to Implementation

1. Deleted reference to NUREG-0578, Recommendation 2.1.9 for Item I.C.1(a)2, inadequate core cooling.

The complete NRC position description and clarification is contained in NUREG-0737 - Task I.C.1.

This requirement is to be completed by fuel load.

Clarification

None.

Columbia Generating Station Position

Columbia Generating Station (CGS) has participated, and continues to participate, in the BWR Owner's Group program to develop Emergency Procedure Guidelines for General Electric Boiling Water Reactor. Following are a brief description of the submittals to date, and a justification of their adequacy to support guidelines development.

a. *Description of Submittals*

1. *NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," August 1979; including additional sections submitted in prepublication form since August 1979.*

(a) *Section 3.1.1 (Small Break LOCA).*

Description and analysis of small break loss-of-coolant events, considering a range of break sizes, location, and conditions, including equipment failures and operator errors; description and justification of analysis methods.

(b) *Section 3.2.1 (Loss of Feedwater) - revised and resubmitted in prepublication from March 31, 1980.*

Description and analysis of loss of feedwater events, including cases involving stuck-open relief valves, and including equipment failures and operator errors; description and justification of analysis methods.

(c) *Section 3.2.2 (Other Operational Transients) - submitted in prepublication form March 31, 1980; revised and resubmitted in prepublication form August 22, 1980.*

Description and analysis of each FSAR Chapter 15 event resulting in a reactor system transient; demonstration of applicability of *analyses of 3.1.1, 3.2.1, and 3.5.2.1 to each event; demonstration of applicability of Emergency Procedure Guidelines to each event.*

(d) *Section 3.3 (BWR Natural and Forced Circulation).*

Description of natural and forced circulation cooling; factors influencing natural circulation, including noncondensables; re-establishment of forced circulation under transient and accident conditions.

(e) *Section 3.5.2.1 (Analyses to Demonstrate Adequate Core Cooling) - submitted in prepublication form November 30, 1979; revised and resubmitted in prepublication form September 16, 1980.*

Description and analysis of loss-of-coolant events, loss of feedwater events, and stuck-open relief valves events, including severe multiple equipment failures and operator errors which, if not mitigated, could result in conditions of inadequate core cooling.

(f) *Section 3.5.2.3 (Diverse Methods of Detecting Adequate Core Cooling) - submitted in prepublication form December 28, 1979.*

Description of indications available to the BWR operator for the detection of adequate core cooling (detailed instrument responses are described in 3.1.1, 3.2.1, and 3.5.2.1).

(g) *Section 3.5.2.4 (Justification of Analysis Methods) - submitted in pre-publication form September 16, 1980.*

Description and justification of analysis methods for extremely degraded cases treated in 3.5.2.1.

2. *BWR Emergency Procedure Guidelines (Revision 3).*

Guidelines for BWR Emergency Procedures based on identification and response to plant symptoms; including a range of equipment failures and operator errors; including severe multiple equipment failures and operator errors which, if not mitigated, would result in conditions of inadequate core cooling; including conditions when core cooling status is uncertain or unknown.

3. NEDO-24708A, Revision 1, December 1980.

b. Adequacy of Submittals:

The submittals described in (a) above have been discussed and reviewed extensively among the BWR Owner's Group, the General Electric Company, and the NRC staff. The NRC staff has found (NUREG-0737 p. I.C.1-3) that "the analysis and guidelines submitted by General Electric Company (GE) Owners' Group…comply with the requirements (of the NUREG-0737 clarification)." In Reference 1, the Director of the Division of Licensing states, "we find the Emergency Procedure Guidelines acceptable for trial implementation (on six LRG-1 plants with applications for operating licenses pending)."

CGS believes that in view of these findings, no further detailed justification of the analysis or guidelines is necessary at this time.

Reference 1 further states, "(during the course of implementation we may identify areas that require modification or further analysis and justification." The enclosure of Reference 1 identifies several such areas. CGS will work with the BWR Owners' Group in responding to such requests.

By our commitment to work with the Owners' Group on such requests, on schedules mutually agreed to by the NRC and the Owners' Group, and by reference to the BWR Owners' Group analyses and guidelines already submitted, our response to the NUREG-0737 requirement "for reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures" is complete.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, Supplement 5 dated April 1984, section 13.5.2.2.

<u>References</u>

1. Letter, D. G. Eisenhut (NRC) to S. T. Rogers (BWR Owners' Group), regarding Emergency Procedure Guidelines, October 21, 1980.

I.C.2 SHIFT AND RELIEF TURNOVER PROCEDURES

<u>Position</u>

The licensees shall review and revise as necessary the plant procedure for shift and relief turnover to ensure the following:

a. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisors to complete and sign. The following items, as a minimum, shall be included in the checklist.

1. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

2. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console (what to check and criteria for acceptable status shall be included in the checklist).

3. Identification of systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement (this shall be recorded as a separate entry on the checklist).

b. Checklists or logs shall be provided for completion by the offgoing and ongoing auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by themselves could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist).

c. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure (for example, periodic independent verification of system alignments).

Clarification

None.

Columbia Generating Station Position

The control room operator's checklist is designed to do the following:

a. Ensure that critical plant parameters are monitored and are within allowable limits,

b. Ensure the availability and correct alignment of essential systems, and

c. Identify all systems or components which are in a degraded mode of operation and compare each length of time in the degraded mode to Technical Specifications action requirements.

The off-going and on-coming shift manager, control room supervisor, and on-coming control room operator positions will signify checklist status and content.

A checklist designed for balance-of-plant shift turnover will identify any equipment under maintenance or test which could either (a) by itself degrade a system which is critical to the prevention and mitigation of operational transients and accidents or (b) initiate an operational transient.

The off-going or on-coming shift support supervisors and the on-coming equipment operators with rounds will signify checklist status and content for the balance-of-plant checklists.

CGS established a system to evaluate the effectiveness of the shift and relief turnover procedure.

This italicized text is historical and was provided to support the application for an operating license.

With CGS receiving an operating license December 19, 1983, and going through test and startup phases prior to that date the shift and relief turnover procedures have been under continuous scrutiny for over 2 years. This has resulted in changes reviewed and accepted by the Plant Operations Committee to increase the efficiency and effectiveness of the procedures.

I.C.4 CONTROL ROOM ACCESS

<u>Position</u> (NUREG-0578 2.2.2.A)

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and to predesignated NRC personnel. Provisions shall include the following:

a. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access, and

b. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room.

Clarification

None.

Columbia Generating Station Position

A Columbia Generating Station procedure has been implemented to establish the shift manager (SRO) and, in his absence, the control room supervisor (SRO) as the authority and responsibility for limiting access to the control room. Nonessential personnel are excluded from the control room when their presence is hampering operations. Nonessential personnel are defined as those not required by the shift manager to assist in safe plant operation and may include anyone not normally assigned a shift control room position. If required, plant security can be used to enforce the policy.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.1.8.

Additionally, procedures establish the same line of succession for control room authority and responsibility in the event of an emergency. The procedures specifically address lines of communication and authority for management personnel not in direct command of operations and assigned responsibilities outside the control room. Instructions or orders impacting operations are reviewed by the operations manager and transmitted to the shift manager.

I.C.6 GUIDANCE ON PROCEDURES FOR VERIFYING CORRECT PERFORMANCE OF OPERATING ACTIVITIES

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to ensure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Implementation of automatic status monitoring if required will reduce the extent of human verification of operations and maintenance activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases - one before and one after installation of automatic status monitoring equipment, if required, in accordance with Item I.D.3.

Clarification

Item I.C.6 of the NRC Task Action Plan (NUREG-0660) and Recommendation 5 of NUREG-0585 propose requiring that licensees' procedures be reviewed and revised, as necessary, to ensure that an effective system of verifying the correct performance of operating activities is provided. An acceptable program for verification of operating activities is described below.

The American Nuclear Society has prepared a draft revision to ANSI Standard N18.7-1972 (ANS 3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." A second proposed revision to Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," which is to be issued for public comment in the near future, will endorse the latest draft revision to ANS 3.2 subject to the following supplemental provisions:

a. Applicability of the guidance of Section 5.2.6 should be extended to cover surveillance testing in addition to maintenance.

b. In lieu of any designated senior reactor operator (SRO), the authority to release systems and equipment for maintenance or surveillance testing or return-to-service may be delegated to an onshift SRO, provided provisions are made to ensure that the shift supervisor is kept fully informed of system status.

c. Work permits involving tagging for maintenance or surveillance testing are verified by the shift manager (or his designee) for correct implementation of control measures. Independent verification by qualified individuals is made for installation or removal of temporary modifications such as jumpers, lifted leads or bypass lines. Routine independent verification of equipment status at the location of the equipment will be performed for return-to-service activities of all important safety-related equipment having no control room status indications. These verifications will be by qualified equipment operators.

d. Equipment control procedures should include assurance that control room operators are informed of changes in equipment status and the effects of such changes.

e. For the return-to-service of equipment important to safety, a second qualified operator should verify proper systems alignment unless functional testing can be performed without compromising plant safety, and all equipment, valves, and switches involved in the activity are correctly aligned.

NOTE: A licensed operator possessing knowledge of the systems involved and the relationship of the systems to plant safety would be a "qualified" person. The staff is investigating the level of qualification necessary for other operators to perform these functions.

For plants that have or will have automatic system status monitoring as discussed in Task Action Plan Item I.D.3, NUREG-0660, the extent of human verification of operations and maintenance activities will be reduced. However, the need for such verification will not be eliminated in all instances.

Columbia Generating Station Position

Procedures implement an effective system for verification of operating activities important to safety. These procedures were implemented prior to fuel load. The preparation of these procedures was guided by ANS 3.2 Section 5.2.6 and the following supplemental provisions.

a. ANS 3.2 Section 5.2.6 will be applied to both maintenance and technical specification surveillances as described below.

b. The shift manager has the designated responsibility for implementing procedures for release of systems and equipment for maintenance or surveillance testing and for return-to-service. This responsibility may be delegated to a licensed SRO. The shift manager will remain informed by reviewing records and receiving turnover.

c. Clearance tagging for maintenance or surveillance testing are independently verified by the shift manager (or his designee) for correct implementation of control measures. Independent verification is also made for installation or removal of temporary modifications such as jumpers, lifted leads, or bypass lines on safety-related or fire protection systems not controlled by approved procedures. Routine independent verification of equipment status at the location of the equipment will be performed for return-to-service activities of all safety-related and fire protection equipment having no control room status indications.

d. Equipment control procedures are implemented through the control room such that control room personnel are aware of changes being made in equipment status and the effects of such changes.

e. Routine independent verification of status at the location of safety-related or fire protection equipment is limited to return-to-service activities performed prior to startups following refueling or long-term outages in accordance with the ALARA concept to limit accumulation of personnel radiation exposures. In addition to the above, independent verification of the return-to-service position of safety-related locked valves will be made whenever their status is changed.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated March 1982, section 13.5.1.8.

I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

Position

Obtain nuclear steam supply system (NSSS) vendor review of low power testing procedures to further verify their adequacy.

This requirement must be met before fuel loading (NUREG-0694).

Clarification

None.

Columbia Generating Station Position

The NSSS vendor (General Electric Company) has reviewed and documented the low power testing procedures, power ascension test procedures, and emergency procedures. This review considered the BWR Emergency Procedure guidelines submitted to the NRC on behalf of BWR Owners' Group on June 30, 1980, by letter from R. H. Buchholz to D. G. Eisenhut.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated March 1982, section 13.5.2.3 and confirmed in I&E Inspection 84-04.

I.C.8 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NEAR-TERM OPERATING LICENSE APPLICANTS

Position

Correct emergency procedures, as necessary, based on NRC audit of selected plant emergency operating procedures (e.g., small-break LOCA, loss of feedwater, restart of engineered safety features following a loss of ac power, stream line break, or steam-generated tube rupture).

This action will be completed prior to issuance of a full-power license (NUREG-0694).

Clarification

None.

Columbia Generating Station Position

CGS has developed procedures based on the BWR Owners' Group Emergency Procedure Guidelines. These procedures are further addressed in response to I.C.1, Short-Term Accident Analysis and Procedure Revision.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 13.5.2.3.

I.D.1 CONTROL ROOM DESIGN REVIEWS

Position

In accordance with Task Action Plan I.D.1, Control Room Design Reviews (NUREG-0660), all licensees and applicants for operating licenses will be required to conduct a detailed control room design review to identify and correct design deficiencies. This detailed control room design review is expected to take about a year. Therefore, the Office of Nuclear Reactor Regulation (NRR) requires that those applicants for operating licenses who are unable to complete this review prior to issuance of a license make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule approved by NRC for correcting deficiencies. These applicants will be required to complete the more detailed control room reviews on the same schedule as licensees with operating plants (NUREG-0737).

Clarification

NRR is presently developing human engineering guidelines to assist each licensee and applicant in performing detailed control room review. A draft of the guidelines has been published for public comment as NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation." The due date for comments on this draft document was September 29, 1980. NRR will issue the final version of the guidelines as NUREG-0700, by February 1981, after receiving, reviewing, and incorporating substantive public comments from operating reactor licensees, applicants for operating licenses, human factors engineering experts, and other interested parties. NRR will issue evaluation criteria, by July 1981, which will be used to judge the acceptability of the detailed reviews performed and the design modification implemented.

Applicants for operating licenses who will be unable to complete the detailed control room design review prior to issuance of a license are required to perform a preliminary control room design assessment to identify significant human factors problems. Applicants will find it of value to refer to the draft document NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation," in performing the preliminary assessment. NRR will evaluate the applicants' preliminary assessments including the performance by NRR of onsite review/audit. The NRR onsite review/audit will be on a schedule consistent with licensing needs and will emphasize the following aspects of the control room:

a. The adequacy of information presented to the operator to reflect plant status for normal operation, anticipated operational occurrences, and accident conditions,

b. The groupings of displays and the layout of panels,

c. Improvements in the safety monitoring and human factors enhancement of controls and control displays,

d. The communications from the control room to points outside the control room, such as the onsite technical support center, remote shutdown panel, offsite telephone lines, and to other areas within the plant for normal and emergency operation,

e. The use of direct rather than derived signals for the presentation of process and safety information to the operator,

f. The operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems,

g. The adequacy of operating procedures and operator training with respect to limitations of instrumentation displays in the control room,

h. The categorization of alarms, with unique definition of safety alarms, and

i. The physical location of the shift supervisor's office either adjacent to or within the control room complex.

Prior to the onsite review/audit, NRR will require a copy of the applicant's preliminary assessment and additional information which will be used in formulating the details of the onsite review/audit.

<u>*Columbia Generating Station Position*</u>

CGS has undertaken an aggressive program to complete a control room review program in accordance with this task.

The schedule and activities for the review of the CGS Control Room and submittal of an assessment report to the NRR are as follows:

a. *A preliminary assessment of CGS's Control Room based on the BWR Owners' Subgroup review program draft criteria and NRC draft document NUREG/CR-158 was submitted to NRR in January 1982.*

b. *A Detailed Control Room Design Review (DCRDR) Preliminary Report based on a review of the CGS Control Room by the BWR Owners' Group and CGS in-house Human Factors Task Force against the BWR Owners' Group Control Room Design Review Program Plan and NUREG-0700 was submitted to NRR in April 1983.*

c. *Based on NRR reviews of the preliminary DCRDR report and onsite audit, a Response to NRC Human Factors Engineering Preliminary Design Assessment Audit Report was submitted to NRR in October 1983.*

d. *A CGS Control Room Design Review Program Plan documenting the CGS methodology and resources used, in accordance with NUREG-0700, was submitted in February 1984.*

e. *A DCRDR Final Report, per the CGS operating license was submitted to NRR on November 1, 1985, Letter GO2-85-758.*

The schedule and activities for the implementation of corrections for the CGS Control Room are as follows:

a. *All major hardware and procedural findings noted during the preliminary DCRDR report were completed prior to fuel load.*

b. *All residual findings and findings noted in the DCRDR final report are scheduled to be completed during the first refueling outage.*

The NRC Safety Evaluation Report (SER) for the CGS DCRDR was issued as Reference 1. Energy Northwest responded to the SER in Reference 2. By Reference 3 Energy Northwest stated that all DCRDR items had been implemented. In Reference 4 the NRC stated that based upon the Reference 3 submittal, they found that CGS satisfies all of the DCRDR requirements of Supplement 1 to NUREG-0737 and that TMI Item I.D.1.2 was considered *closed (note that NUREG O737 and its Supplement 1 do not have an Item 1.D.1.2; only I.D.1).*

References:

1. *Letter, G. W. Knighton (NRC) to G. C. Sorensen (SS), "Detailed Control Room Design Review (TAC No. 56181)," dated October 13, 1987.*

2. *Letter, G. C. Sorensen (SS) to NRC, "Nuclear Plant No. 2, Detailed Control Room Design Review (TAC No. 56181)," GO2-88-074, dated March 29, 1988.*

3. *Letter, G. C. Sorensen (SS) to NRC, "Nuclear Plant No. 2, Operating License NPF-21 Detailed Control Room Design Review (TAC No. 56181)," GO2-91-198, dated October 29, 1991.*

4. *Letter, P. L. Eng (NRC) to G. C. Sorensen (SS), "Status of TMI Item I.D.1.1, 'Detailed Control Room Design Review' (DCRDR) at Washington Public Power Supply System Nuclear Project No. 2 (WNP-2) (TAC NO. 56181)," dated November 13, 1991.*

I.G.1 PREOPERATIONAL AND LOW-POWER TESTING

Position (NUREG-0660)

The objective is to increase the capability of the shift crews to operate facilities in a safe and competent manner by assuring that training for plant changes and off-normal events is conducted. Near-term operating license facilities will be required to develop and implement intensified training exercises during the low-power testing programs. This may involve the repetition of startup tests on different shifts for training purposes. Based on experience from the near-term operating license facilities, requirements may be applied to other new facilities or incorporated into the plant drill requirement (Item I.A.2.5). Review comprehensiveness of test programs.

NRR will require new operating licensees to conduct a set of low-power tests to accomplish the requirements. The set of tests will be determined on a case-by-case basis for the first few plants. Then NRR will develop acceptance criteria for low-power test programs to provide "hands on" training for plant evaluation and off-normal events for each operating shift. It is not expected that all tests will be required to be conducted by each operating shift. Observation by one shift of training of another shift may be acceptable.

NRR will develop criteria in conjunction with initial near-term operating license reviews.

Licensees will (1) define training plan prior to loading fuel, and (2) conduct training prior to full-power operation.

Clarification

None.

Columbia Generating Station Position

Energy Northwest committed to meet the intent of NUREG-0660 by performance of a special low power test subprogram which provided supplemental operator training in the areas of response to abnormal plant conditions and familiarity with critical systems. The special subprogram amplified the well-established training value of the Startup Test Program (STP) through (1) instruction on the content, goals, and requirements of the program, (2) addition of selected special tests to the STP to demonstrate abnormal scenarios and uses of critical systems and/or emergency operating procedures to control them, and (3) utilization of the knowledge and experience gained during the STP in the training programs for future operators.

The overall Startup Test Program is outlined in Chapter 14 while the conduct of operations is discussed in Chapter 13. During the preoperational and power ascension test phases, the operations personnel were intimately involved in the performance of the various test procedures. With the impetus provided by the responsible test phase organization, the operations staff was charged with establishing the required plant/system conditions, initiating and controlling the desired test transient and returning the plant/system to its normal condition. The operations staff provided the physical ability to accomplish the Startup Test Program. In this fashion, the completion of the Startup Test Program provided an unparalleled training opportunity for the operators.

The following outlines those additional actions Energy Northwest implemented to augment the extensive training benefits inherent in the existing STP program:

I. *Development and Implementation of a Training Course on the STP*

    A. *General Classroom Instruction (prior to testing)*

        1. *STP Overview*

            a. *Organization, Delineation of Responsibilities, Goals*

            b. *Administrative and Emergency Procedures*

            c. *Preop and Power Ascension Test Schedule*

2. *Review Selected STP Specifics, for example;*

   a. *Pertinent Preop Test Purposes, Procedures, Anticipated Results*

   b. *Integrated System Cold Functional Tests*

   c. *Fuel Loading, Heatup, Power Ascension Test Purposes, Procedures, Anticipated Results*

   d. *Special Test Subprogram Test Purposes, Procedures, Anticipated Results*

3. *Review Expected Utilization of STP Data*

   a. *Documentation of Plant Safety*

   b. *Feedback/Confirmation of Anticipated Results*

B. *Test Phase Instruction Performed by Test Director on a Shift Basis (during testing)*

1. *Review of the Immediate Test Schedule*

2. *Discussion of the Impending Tests: Procedures, Anticipated Results, Precautions*

3. *Review/Disseminate Plant Response Data from Previous Shift(s)*

C. *Post-STP Completion Instruction Performed by Test director (following testing)*

1. *Review Plant Design Changes/System Modifications Required*

II. *Development and Performance of a Special Test Subprogram*

A. *Additional RCIC System Tests*

1. *RCIC Operation Following Loss of AC Power to the System*

2. *RCIC Operation to Prove DC Separation*

B. *Integrated Reactor Vessel Level Instrumentation Functional Test*

C. Integrated Containment Pressure Instrumentation Functional Test

D. Simulated Loss of Control and Instrument Air Test

E. Repetition of Some Normal STP Tests, for example:

1. Feedwater Pump Trip/Recirc Runback Demonstration

2. Turbine Trip/Generator Load Rejection Within Bypass Valve Capacity

3. Pressure Regulator Setpoint Changes

4. Recirculation Pump Trips

5. Feedwater Level Setpoint Changes

III. Utilization of the STP Data

A. Refine the CGS Simulator Response Models, as appropriate

B. Incorporate a Major Plant Transient Response Section in Operator Training Program, as appropriate

C. Update License Program Training and Requalification Material, as appropriate.

It was anticipated that every participating member of the operations staff would obtain valuable knowledge and experience through participation in the CGS Startup Test Program. Each received appropriate classroom instruction and through judicious scheduling of tests, most were exposed to a variety of plant/system transient responses (or review of results thereof). The training received is continually reinforced through normal requalification program refinements. Future license candidates also benefit from the training material upgrades resulting from the STP experience.

With this program outline, Energy Northwest met the intent of NUREG-0660, Item I.G.1. Specific details of the training program, additional test procedures, and documentation methods have been developed and are available for onsite NRC I&E review.

This position has been accepted in the NRC Safety Evaluation Report (NUREG-0892, dated December 1982, section 14.)

II.B.1 REACTOR COOLANT SYSTEM VENTS

Position

Each applicant and licensee shall install reactor coolant system (RCS) and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the events shall conform to the requirements of Appendix A to 10 CFR 50, "General Design Criteria." The vent system shall be designed with sufficient redundancy that ensures a low probability of inadvertent or irreversible actuation.

Each licensee shall provide the following information concerning the design and operation of the high point vent system:

a. Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for LOCAs initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10 CFR 50.46.

b. Submit procedures and supporting analysis for operator use of the vents that also include the information available to the operator for initiating or terminating vent usage.

Clarification

a. General

1. The important safety function enhanced by this venting capability is core cooling. For events beyond the present design basis, this venting capability will substantially increase the plant's ability to deal with large quantities of noncondensable gas which could interfere with core cooling.

2. Procedures addressing the use of the RCS vents should define the conditions under which the vents should be used as well as the conditions under which the vents should not be used. The procedures should be directed toward achieving a substantial increase in the plant being able to maintain core cooling without loss of containment integrity for events beyond the design basis. The use of vents for accidents within the

normal design basis must not result in a violation of the requirements of 10 CFR 50.44 or 10 CFR 50.46.

3. The size of the reactor coolant vents is not a critical issue. The desired venting capability can be achieved with vents in a fairly broad spectrum of sizes. The criteria for sizing a vent can be developed in several ways. One approach which may be considered is to specify a volume of noncondensable gas to be vented and in a specific venting time. For containments particularly vulnerable to failure from large hydrogen releases over a short period of time, the necessity and desirability for contained venting outside the containment must be considered (e.g., into a decay gas collection and storage system).

4. Where practical, the RCS vents should be kept smaller than the size corresponding to the definition of LOCA (10 CFR 50, Appendix A). This will minimize the challenges to the emergency core cooling system (ECCS) since the inadvertent opening of a vent smaller than the LOCA definition would not require ECCS actuation, although it may result in leakage beyond technical specification limits. On PWRs, the use of new or existing lines whose smallest orifice is larger than the LOCA definition will require a valve in series valve that can be closed from the control room to terminate the LOCA that would result if an open vent valve could not be reclosed.

5. A positive indication of valve position should be provided in the control room.

6. The reactor coolant vent system shall be operable from the control room.

7. Since the RCS vent will be part of the RCS pressure boundary, all requirements for the reactor pressure boundary must be met, and, in addition, sufficient redundancy should be incorporated into the design to minimize the probability of an inadvertent actuation of the system. Administrative procedures, may be a viable option to meet the single-failure criterion. For vents larger than the LOCA definition, an analysis is required to demonstrate compliance with 10 CFR 50.46.

8. The probability of a vent path failing to close, once opened, should be minimized; this is a new requirement. Each vent must have its power supplied from an emergency bus. A single failure within the power and control aspects of the reactor coolant vent system should not prevent

isolation of the entire vent system when required. On BWRs, block valves are not required in lines with safety valves that are used for venting.

9. Vent paths from the primary system to within containment should go to those areas that provide good mixing with containment air.

10. The reactor coolant vent system (i.e., vent valves, block valves, position indication devices, cable terminations, and piping) shall be seismically and environmentally qualified in accordance with IEEE 344-1975 as supplemented by Regulatory Guide 1.100, 1.92 and SEP 3.92, 3.43, and 3.10. Environmental qualifications are in accordance with the May 23, 1980 Commission Order and memorandum (CLI-80-21).

11. Provisions to test for operability of the reactor coolant vent system should be part of the design. Testing should be performed in accordance with subsection IWV of Section XI of the ASME Code for Category B valves.

12. It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human-factor analysis should be performed taking into consideration:

    (a) The use of this information by an operator during both normal and abnormal plant conditions,

    (b) Integration into emergency procedures,

    (c) Integration into operator training, and

    (d) Other alarms during emergency and need for prioritization of alarms.

b. BWR Design Considerations

1. Since the BWR Owners' Group has suggested that the present BWR designs have an inherent capability to vent, a question relating to the capability of existing systems arises. The ability of these systems to vent the RCS of noncondensable gas generated during an accident must be demonstrated. Because of differences among the head vent systems for BWRs, each licensee or applicant should address the specific design features of this plant and compare them with the generic venting capability proposed by the BWR Owners' Group. In addition, the ability

of these systems to meet the same requirements as the PWR vent system must be documented.

2. In addition to RCS venting, each BWR licensee should address the ability to vent other systems, such as the isolation condenser which may be required to maintain adequate core cooling. If the production of a large amount of noncondensable gas would cause the loss of function of such a system, remote venting of that system is required. The qualifications of such a venting system should be the same as that required for PWR venting systems.

c. PWR Vent Design Considerations

1. Each PWR licensee should provide a capability to vent the reactor vessel head. The reactor vessel head vent should be capable of venting noncondensable gas from the reactor vessel hot legs (to the elevation of the top of the outlet nozzle) and cold legs (through head jets and other leakage paths).

2. Additional venting capability is required for those portions of each hot leg that cannot be vented through the reactor vessel head vent or pressurizer. It is impractical to vent each of the many thousands of tubes in a U-tube steam generator; however, the staff believes that a procedure can be developed that ensures sufficient liquid or steam can enter the U-tube region so that decay heat can be effectively removed from the RCS. Such operating procedures should incorporate this consideration.

3. Venting of the pressurizer is required to ensure its availability for system pressure and volume control. These are important considerations, especially during natural circulation.

Columbia Generating Station Position

The reactor coolant vent line is located at the very top of the reactor vessel as shown in Figure 3.6-51. This 2-in. line contains two safety-related Class 1E motor-operated valves (MS-V-1 and MS-V-2) that are operated from the control room. The location of this line permits it to vent the entire RCS normally connected to the reactor pressure vessel (RPV), with the exception of the reactor coolant isolation cooling (RCIC) head spray piping which comprises approximately 0.6 ft^3 of volume above the elevation of the RPV. This small volume was considered in the original design of the RCIC system and is of no consequence to its operation. In addition, since this vent line is part of the original design for the unit, it has already been considered in all the design basis accident analyses contained elsewhere in the FSAR.

The Columbia Generating Station (CGS) BWR/5 is provided with 18 power-operated safety grade relief valves which can be manually operated from the control room to vent the RPV. The point of connection to the vent lines (main steam lines) from near the top of the vessel to these valves is such that accumulation of gases above that point in the vessel will not affect natural circulation of the reactor core.

These power-operated relief valves satisfy the intent of the NRC position. Information regarding the design, qualification, power source, etc., of these valves is provided in Section 5.2.2.

The BWR Owners' Group position is that the requirement of single failure criteria for prevention of inadvertent actuation of these valves, and the requirement that power be removed during normal operation, are not applicable to BWRs. These valves serve an important function in mitigating the effects of transients and at CGS provide ASME code overpressure protection. Therefore, the addition of a second "block" valve to the vent lines would result in a less safe design and a violation of the code. Moreover, the inadvertent opening of a relief valve in a BWR is a design basis event and is a controllable transient.

In addition to these power-operated relief valves, the CGS BWR/5 includes various other means of high-point venting. Among these are

a. Normally closed reactor vessel head vent valves, operable from the control room, which discharge to the drywell;

b. Normally open reactor head vent line, which discharges to a main steam line;

c. Main steam-driven RCIC system turbines, operable from the control room, which exhaust to the suppression pool; and

d. Main steam-driven reactor feedwater pumps operable from the control room, which exhaust to the plant condenser when not isolated. Condenser gases are continuously processed through the offgas system.

Although the power-operated relief valves fully satisfy the intent of the venting requirement, these other means also provide protection against the accumulation of noncondensables in the RPV.

Under most circumstances, no selection of vent path is necessary because the relief valves [as part of the automatic depressurization system (ADS)], high-pressure core spray (HPCS), and RCIC will function automatically in their designed modes to ensure adequate core cooling and provide continuous venting to the suppression pool.

Analyses of inventory-threatening events with very severe degradations of system performance have been conducted. These were submitted by GE for the BWR Owners' Group to the NRC Bulletins and Orders Task Force on November 30, 1979. The fundamental conclusion of these studies was that if only one ECCS is injecting into the reactor, adequate core cooling would be provided and the production of large quantities of hydrogen would be avoided. Therefore, it is not desirable to interfere with ECCS functions to prevent venting.

The small-break accident (SBA) guidelines emphasize the use of HPCS/RCIC as a first line of defense for inventory-threatening events which do not quickly depressurize the reactor. If these systems succeed in maintaining inventory, it is desirable to leave them in operation until the decision to proceed to cold shutdown is made. Thus the reactor will be vented via RCIC turbine steam being discharged to the suppression pool. Termination of this mode of venting could also terminate inventory makeup if the HPCS had failed also. This would necessitate reactor depressurization via the safety/relief valve (SRV), which of course is another means of venting.

If the HPCS/RCIC are unable to maintain inventory, the SBA guidelines call for use of ADS or manual SRV actuation to depressurize the reactor so that the low-pressure coolant injection (LPCI) and/or low-pressure core spray (LPCS) systems can inject water. Thus, the reactor would be vented via the SRV to the suppression pool. Termination of this mode of venting is not recommended. It is preferable to remain unpressurized; however, if inventory makeup requires HPCS or RCIC restart, that can be accomplished manually by the operator. It is more desirable to establish and maintain core cooling than to avoid venting. If the HPCS/RCIC and SRVs are not operable (a very degraded and extremely unlikely case), another emergency means of venting the reactor must be used. It is emphasized, however, that such emergency venting would be in the interest of core cooling and, therefore, could be employed under Emergency Procedure Guidelines.

It is thus concluded that there is no reason to interfere with ECCS operation to avoid venting. It is further concluded that the Emergency Procedure Guidelines, by correctly specifying operator actions for HPCS, RCIC, and SRV operation, also correctly specify operator actions to vent the reactor.

In the event of HPCS failure and continued vessel pressurization, the effect of noncondensables in the RCIC turbine steam was evaluated for three cases:

1. Continuous evolution of noncondensables due to radiolysis,
2. Quasi-continuous evolution of noncondensables due to core heatup, and
3. The presence of a quantity of noncondensables in the reactor at the time of HPCS/RCIC startup.

Case 1 is a normal operating mode for RCIC and is of no concern.

For Case 2 to exist, the core must be uncovered. Such a condition requires multiple failures as shown in the degraded cooling analyses. Core uncovery is prevented (or cladding heatup into the rapid oxidation range is prevented) when only one ECCS is operating. For small pipe break or a loss of feedwater, which would allow the reactor to remain at pressure, the HPCS and/or RCIC pumps would maintain inventory and there would be no substantial hydrogen production. If neither HPCS nor RCIC could maintain inventory, the reactor would be automatically or manually depressurized via SRVs (or via the break, for larger breaks). Low-pressure water injection systems (LPCI or LPCS) would then make up inventory. With the core covered neither the rapid generation of noncondensables nor their accumulation would be possible.

The performance of RCIC under Case 3 is of concern only if there has been a very substantial production of hydrogen due to core uncovery and there is a need to start the RCIC. This is extremely unlikely and an intolerable circumstance, because it could arise only if the core were allowed to remain uncovered for a long period with the reactor at high pressure. Automatic depressurization system operation and explicit operating instructions and the Emergency Operator Guidelines are intended to preclude this. If the level has fallen with the reactor at high pressure, the vessel would be depressurized either automatically or manually to permit low pressure injection independent of RCIC performance.

In the post-LOCA condition, it is possible to have noncondensable gases come out of solution while operating the residual heat removal (RHR) system. These gases would accumulate at the top of the RHR heat exchanger since this is a system high point and an area of relatively low flow. Gases trapped here will be vented through a 2-in. vent line with two safety-related Class 1E motor-operated valves (MO-F073A and MO-F074A or MO-F073B and MO-F074B) operated from the control room (as shown in Figure 5.4-15). As this vent line and associated valves are part of the original design, they have also been considered in the design basis accident analysis contained elsewhere in the FSAR.

The result of a break in the SRV discharge piping, or any of the other pipe lines for the systems enumerated above, would be the same as a small steam line break. A complete steam line break is part of the design basis, and smaller size breaks have been shown to be of lesser severity. A number of reactor system blowdowns due to stuck-open relief valves (also equivalent to a small steam line break) have confirmed this in practice. Thus no new analyses are required to show conformance with 10 CFR 50.46.

Because the relief valves and RCIC will vent the reactor continuously, and because containment hydrogen calculations in normal safety analysis calculations assume continuous venting, no special analyses are required to demonstrate "that the direct venting of noncondensable gases with perhaps high hydrogen concentrations does not result in violation of combustible gas concentration limits in containment."

Conclusion and Comparison with Requirements

The conclusion from this vent evaluation for CGS is as follows:

a. Reactor vessel head vent valves exist to relieve head pressure (at shutdown) to the drywell via remote operator action;

b. The reactor vessel head can be vented during operating conditions via the SRVs to the suppression pool;

c. The RCIC system provides an additional vent pathway to the suppression pool;

d. The size of the vents is not a critical issue because BWR SRVs have substantial capacity, exceeding the full power steaming rate of the nuclear boiler;

e. The SRVs vent to the containment suppression pool, where discharged steam is condensed without causing a rapid containment pressure/temperature transient;

f. The SRVs are not smaller than the NRC defined small LOCA. Inadvertent actuation is a design basis event and a demonstrated controllable transient;

g. Inadvertent actuation is of course undesirable, but since the SRVs serve an important protective function, no steps such as removal of power during normal operation should be taken to prevent inadvertent actuation;

h. A direct indication of SRV position is provided in the control room per Table 7.5-1, item 21. Temperature sensors in the discharge lines confirm possible valve leakage;

i. Each SRV is remotely operable from the control room;

j. Each SRV is seismically and Class 1E qualified;

k. Block valves are not required, so block valve qualifications are not applicable;

l. No new 10 CFR 50.46 conformance calculations are required because the vent provisions are part of the systems in the plant's original design and are covered by the original design bases; and

m. Plant procedures govern the operator's use of the relief mode for venting reactor pressure. These procedures are available for NRC inspection at the plant.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 5.4.3.1.

II.B.3 POSTACCIDENT SAMPLING CAPABILITY

Position

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hr) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18.75 rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3 or 1.4 release of fission products. If the review indicates that personnel could not promptly and safely obtain the samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hr) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases (which indicate cladding failure), iodines and cesiums (which indicate high fuel temperatures), and nonvolatile isotopes (which indicate fuel melting). The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications or equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).

Clarification

The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13 and October 30, 1979, clarification letters.

a. The licensee shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hr or less from the time a decision is made to take a sample.

b. *The licensee shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hr time frame established above, quantification of the following:*

1. *Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and nonvolatile isotopes),*

2. *Hydrogen levels in the containment atmosphere,*

3. *Dissolved gases (e.g., H_2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids, and*

4. *Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.*

c. *Reactor coolant and containment atmosphere sampling during postaccident conditions shall not require an isolated auxiliary system [e.g., the letdown system, reactor water cleanup (RWCU) system] to be placed in operation to use the sampling system.*

d. *Pressurized reactor coolant samples are not required if the licensee can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or H_2 gas in reactor coolant samples is considered adequate. Measuring the O_2 concentration is recommended but is not mandatory.*

e. *The time for a chloride analysis to be performed is dependent on two factors: (1) if the plant's coolant water is seawater or brackish water, and (2) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the licensee shall provide for a chloride analysis within 24 hr of the sample being taken. For all other cases, the licensee shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.*

f. *The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of General Design Criterion (GDC) 19 (Appendix A, 10 CFR 50) (i.e., 5 rem whole body, 75 rem extremities). (Note that the design and operational review criterion was changed from the operational limits of 10 CFR 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979, letter from H. R. Denton to all licensees.)*

g. *The analysis of primary coolant samples for boron is required for PWRs. (Note that Revision 2 of Regulatory Guide 1.97, when issued, will likely specify the need for primary coolant boron analysis capability at BWR plants.)*

h. *If inline monitoring is used for any sampling and analytical capability specified herein, the licensee shall provide backup sampling through grab samples and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.*

i. *The licensee's radiological and chemical sample analysis capability shall include provisions to:*

   1. *Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guides 1.3 or 1.4 and 1.7. Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 μCi/g to 10 Ci/g.*

   2. *Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.*

j. *Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.*

k. *In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:*

   1. *Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for flow restrictions to limit*

reactor coolant loss from a rupture of the sample line. The postaccident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.

2. *The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high-efficiency particulate air (HEPA) filters.*

3. *Guidelines for analytical or instrumentation range are given in Table II.B.3-1.*

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains a description of the postaccident sampling system in Section 11.6.

Columbia Generating Station is using a General Electric postaccident sampling system capable of sampling the primary containment and reactor building atmosphere and of obtaining liquid samples from the reactor, RHR loops, and various reactor building sumps. This system is designed to obtain grab samples which may be analyzed onsite or transported to offsite facilities for more detailed analysis if necessary. The sample station is located in the radwaste building and is shielded to reduce radiation exposure rates to the operator. All remote-operated valves are controlled from this area. Lead pigs are provided for radiation protection when transporting samples either to onsite facilities or offsite. A more detailed description follows.

Gas samples will be obtained from locations in the drywell, the suppression pool atmosphere, and from the secondary containment atmosphere. The sample system is designed to operate at pressures ranging from subatmospheric to maximum design pressures of the primary and secondary containment. Heat-traced sample lines are used outside the primary containment to prevent precipitation of moisture and resultant loss of particulates and iodines in the sample lines. The gas samples may be passed through a particulate filter and silver zeolite cartridge for determination of particulate activity and iodine activity by subsequent analysis of the samples on a gamma spectrometer system. Alternatively, the sample flow bypasses the particulate/iodine sampler, is chilled to remove moisture, and a 15-ml grab sample can be taken for determination of gaseous radioactivity and for gas composition by gas chromatography. This size sample vial has been adopted for all gas samples to be consistent with present offgas sample vial counting factors.

Reactor coolant samples will be obtained from two points in the jet pump pressure instrument system when the reactor is at pressure. The jet pump pressure system has been determined to be an optimum sample point for accident conditions. The pressure taps are well protected from damage and debris. If the recirculation pumps are secured, the water level will be raised about 18 in. above normal. This provides natural circulation of the bulk coolant past the taps. Also, the pressure taps are located sufficiently low to permit sampling at a reactor water level even below the lower core support plate.

A single sample line is also connected to both loops in the RHR system. This provides a means of obtaining a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool liquid sample can be obtained from the RHR loop lined up in the suppression pool cooling mode. Samples from the five drain sumps in the reactor building are also available.

The sample system isolation valves are controlled from the local control panel. The sample system is designed for a purge flow of 1 gpm, which is sufficient to maintain turbulent flow in the sample line. Purge flow is returned to the suppression pool. The high flush flow also serves to alleviate cross-contamination of the samples when switching from one sample point to another.

All liquid samples are taken into septum bottles mounted on sampling needles. The sample station is basically a bypass loop on the sample purge line. In the normal lineup, the sample flows through a conductivity cell (readable range 0.1 to 1000 μS/cm) and then through a ball valve bored out to 0.10-ml volume. Flow through the sample panel is established, the valve is rotated 90°, and a syringe is used to flush the sample plus a measured volume of diluent (generally 10 ml) through the valve and into the sample bottle. This provides a dilution of 100:1 to the sample. Alternatively, the valve sampling sequence can be repeated 10 times to provide a 1-ml sample diluted 10:1. The sample is transported to the laboratory for further dilution and subsequent analysis. Alternatively, the sample flow can be diverted through a 70-ml bomb to obtain a large pressurized volume. This 70-ml volume can be circulated and depressurized into a known volume gas expansion chamber. The pressure change in this chamber will be used to calculate the total dissolved gases in the reactor coolant. A grab sample of these gases may be taken through a septum port for subsequent analysis. Ten milliliter aliquots of this degassed liquid can also be taken for on or offsite chemical analyses requiring a relatively large sample. A radiation monitor in the liquid sample enclosure monitors liquid flow from the sample station to provide immediate assessment of the sample activity level. This monitor also provides information as to the effectiveness of the demineralized water flushing of the sample system following sample operation. The control instrumentation is installed in two 2 ft x 2 ft x 6 ft high standard cabinet control panels. One panel contains the conductivity and radiation level readouts. Another control panel contains the flow, pressure and temperature indicators, and the various control valves and switches.

A graphic display panel, installed directly below the main control panel, shows the status of the pumps and valves at all times. The panel also indicates the relative position of the pressure gauges and other items of concern to the operator. The use of this panel will improve operator comprehension and assist in trouble-shooting operation.

Appropriate sample handling tools, a gas sampler vial positioner and gas vial cask are available to the operator at the sampling station. The gas vial is installed and removed by use of the vial positioner through the front of the gas sampler. The vial is then manually placed down in the cask with the positioner which allows the vial to be maintained about 3 ft from the individual performing the operation.

The small-volume (10 ml) liquid sample is remotely obtained through the bottom of the sample station by use of the small-volume cask and cask positioner. The cask positioner holds the cask and positions the cask directly under the liquid sampler. The sample vial is manually raised within the cask to engage the hypodermic needles. When the sample vial has been filled, the bottle is manually withdrawn into the cask. The sample vial is always contained within lead shielding during this operation. The cask is then lowered and sealed prior to transport to the laboratory.

A large-volume cask and cask positioner is available for transporting large liquid samples. A 21-ml bottle is contained within a lead shielded cask. This sample bottle is raised from its location in the cask to the sample station needles for bottle filling. The sample station will only deliver 10 ml to this sample bottle. When filled, the bottle is withdrawn into the cask. The sample bottle is always shielded by 5 to 6 in. of lead when in position under the sample station and during the fill and withdraw cycles, thus reducing operator exposure.

The cask is transported to the required position under the sample station by a dolly cask positioner. When in position this cask is hydraulically elevated approximately 1.5 in. by a small hand pump for contact with the sample station shielding under the liquid sample enclosure floor. The sample bottle is raised, held, and lowered by a simple push/pull cable. The cask is sealed by a threaded top plug that inserts above the sample bottle. The weight of this large-volume cask is approximately 700 lb.

The particulate filters and iodine cartridges are removed via a drawer arrangement. The quantity of activity which is accumulated on the cartridges is controlled by a combination of flow orificing and time sequence control of the flow valve opening. In addition, the deposition of iodine is monitored during sampling using a radiation detector installed adjacent to the cartridge. These samples will hence be limited to activity levels which will normally not require shielded sample carriers to transport the samples to the laboratory.

The power supply to the sample station and all associated equipment will not be shed during accident conditions. The system design is such that a sample can be drawn and analyzed within the required 3 hr, after a 1 hr preparation time.

The postaccident sampling station will provide conductivity measurements in line as an indicator of liquid chemical concentrations and changing chemical conditions. The system allows collection of grab samples for gas analysis of O_2, N_2, H_2, and direct gamma spectrometric determination of aliquots of gas samples. The system also allows collection of iodine samples on a silver zeolite cartridge to minimize noble gas interference in the determination of iodine isotopic content. Liquid samples will be analyzed for pH using a semimicro pH electrode and additionally analyzed for boron and chloride using ion chromatography. An aliquot of the sample may also be analyzed for gross activity or isotopic content by gamma ray spectrometry. All laboratory analysis meet Regulatory Guide 1.97 requirements for sensitivity and range, with the exception of the range for dissolved gases. However, the analytical capability for dissolved gases is consistent with the maximum dissolved gas concentrations expected for BWRs.

The postaccident sample system will be used quarterly for operability testing. During this testing a reactor coolant sample will be taken and analyzed for gamma isotopic content. In addition, a containment atmosphere sample will be taken and analyzed for gas composition and gamma isotopic content. The results of these analyses will be compared, where possible, to results obtained through normal plant sampling systems to verify the representatives of postaccident system samples. Classroom and practical factors training will be provided on system operation, as well as proper handling and analysis of highly radioactive samples. Refresher training will be provided annually.

A yearly drill will be performed in which the postaccident sample system will be used to obtain samples. These samples will be drawn, transported, and analyzed for accident parameters as if they were postaccident highly radioactive samples.

Based on information developed by General Electric, Energy Northwest has developed plant-specific procedures for the determination of the extent of core damage under accident conditions. The procedures provide for distinguishing between fuel cladding failure and fuel melt based on isotopes present and concentration. The extent of damage is based on concentrations present of isotopic mixture of xenon, krypton, iodine, and cesium.

The estimated maximum potential whole body dose to retrieve a reactor coolant sample under worst-case accident conditions is 0.36 rem; the source being airborne noble gas activity in the radwaste building from effluent releases. Lapsed time is about 1 hr.

The maximum dose rate from a 0.1 ml reactor coolant sample (1 hr decay) in a 4-in.-thick lead transport cask is less than 5 mR/hr at 1 ft. Exposure to analyze a sample is expected to be less than 100 mR.

All valves used are fully qualified for the environment in which they are located inside and outside reactor containment.

Power for the postaccident sampling equipment is supplied from either Division 1 or Division 2 critical power sources and will be available during accident conditions.

The staff review of this position in NUREG-0892, dated December 1982, recognized several issues requiring resolution and consolidated them in Licensing Condition 9. Subsequent Energy Northwest submittals, primarily Amendment 23 to the FSAR, resulted in the staff finding the postaccident sampling system acceptable in Supplement 4 NUREG-0892, section 9.3.2.4. A requirement to have the system completed and operable prior to exceeding 5% power was made a condition to the license (NPF-21 issued December 20, 1983). Energy Northwest letter GO2-84-272 dated April 27, 1984, reported the system completed and operable thus satisfying the licensing condition.

II.F.1.3 Containment High-Range Radiation Monitor

Position

Radiation level monitors with a maximum range of 10^8 R/hr shall be installed in containment. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

Clarification

a. Provide two radiation monitor systems in containment which are documented to meet the requirements of Table II.F.1-3.

b. The specification of 10^8 R/hr in the above position was based on a calculation of postaccident containment radiation levels that included both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA containment environments but gamma-sensitive instruments can be so qualified. To follow the course of an accident, a containment monitor that measures only gamma radiation is adequate. The requirement was revised in the October 30, 1979, letter to provide for a photon-only measurement with an upper range of 10^7 R/hr.

c. The monitors shall be located in containment(s) in a manner as to provide a reasonable assessment of area radiation conditions inside containment. The monitors shall be widely separated so as to provide independent measurements and shall "view" a large fraction of the containment volume. Monitors should not be placed in areas which are protected by massive shielding and should be reasonably accessible for replacement, maintenance, or calibration. Placement high in a reactor building dome is not recommended because of potential maintenance difficulties.

d. For BWR Mark III containments, two such monitoring systems should be inside both the primary containment (drywell) and the secondary containment.

e. The monitors are required to respond to gamma photons with energies as low as 60 keV and to provide an essentially flat response for gamma energies between 100 keV and 3 MeV, as specified in Table II.F.1-3. Monitors that use thick shielding to increase the upper range will underestimate postaccident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gammas and are not acceptable.

Columbia Generating Station Position

This italicized text is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in Sections 7.5.1.5.3, 7.5.2.2.3, 11.5.2.2.3.2, and Table 7.5-1, item 8.

Columbia Generating Station concurs with the intent of this position and has installed high range gamma detection monitors in the following primary containment locations:

a. 515 ft level Azimuth 290°and
b. 516 ft level Azimuth 51.5°.

The detectors are unshielded and mounted on the wall in areas least influenced by shielding due to surrounding piping, etc. They are accessible for calibration and will be calibrated according to the Technical Specifications. Plant drawings will be revised to reflect their addition and location.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated December 1982, section 12.3.4.1.

Table II.F.1-3

Containment High-Range Radiation Monitor

Requirement	-	The capability to detect and measure the radiation level within the reactor containment during and following an accident.
Range	-	1 rad/hr to 10^8 rads/hr (beta and gamma) or alternatively 1 R/hr to 10^7 R/hr (gamma only).
Response	-	60 keV to 3 MeV photons, with linear energy response $\pm 20\%$) for photons of 0.1 MeV to 3 MeV. Instruments must be accurate enough to provide usable information.
Redundant	-	A minimum of two physically separated monitors (i.e., monitoring widely separated spaces within containment).
Design and qualification	-	Category 1 instruments as described in Appendix A, except as listed below.
Special calibration	-	In situ calibration by electronic signal substitution is acceptable for all range decades above 10 R/hr. In situ calibration for at least one decade below 10 R/hr shall be by means of calibrated radiation source. The original laboratory calibration is not an acceptable position due to the possible differences after in situ installation. For high-range calibration, no adequate sources exist, so an alternate was provided.
Special environmental qualifications	-	Calibrate and type-test representative specimens of detectors at sufficient points to demonstrate linearity through all scales up to 10^6 R/hr. Prior to initial use, certify calibration of each detector for at least one point per decade of range between 1 R/hr and 10^3 R/hr.

II.F.1.4 Containment Pressure Monitor

Position

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

Clarification

a. Design and qualification criteria are outlined in Appendix A;

b. Measurement and indication capability shall extend to 5 psia for subatmospheric containments;

c. Two or more instruments may be used to meet requirements. However, instruments that need to be switched from one scale to another scale to meet the range requirements are not acceptable;

d. Continuous display and recording of the containment pressure over the specified range in the control room is required; and

e. The accuracy and response time specifications of the pressure monitor shall be provided and justified to be adequate for their intended function.

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in the following sections: 7.5.1.5.1, 7.5.2.2.3, and Table 7.5-1, item 37.

Columbia Generating Station has designed a system to meet this criteria. A description of the system is provided in Section 7.5.

The range, accuracy, and response time of these instruments are

Range	*= -5 to +3 psig*
	0 to 25 psig
	0 to 180 psig
Instrument accuracy (loop)	*= ±2% of full scale*

Response time = 0 to 100% full scale in less that 1 sec

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, sections 6.2.1.1.1 and 7.5.2.6.

II.F.1.5 Containment Water Level Monitor Position

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow range instrument shall be provided for PWRs and cover the range from the bottom to the top of the containment sump. A wide range instrument shall also be provided for PWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000-gal capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 ft above the normal water level of the suppression pool.

Clarification

a. *The containment wide-range water level indication channels shall meet the design and qualification criteria as outlined in Appendix A. The narrow-range channel shall meet the requirements of Regulatory Guide 1.89;*

b. *The measurement capability of 600,000 gal is based on recent plant designs. For older plants with smaller water capacities, licensees may propose deviations from this requirement based on the available water supply capability at their plant;*

c. *Narrow-range water level monitors are required for all sizes of sumps but are not required in those plants that do not contain sumps inside the containment;*

d. *For BWR pressure-suppression containments, the ECCS suction line inlets may be used as a starting reference point for the narrow-range and wide-range water level monitors, instead of the bottom of the suppression pool; and*

e. *The accuracy requirements of the water level monitors shall be provided and justified to be adequate for their intended function.*

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in the following sections: 7.5.1.5.7, 7.5.2.2.3, and Table 7.5-1, item 14.

In Columbia Generating Station, the variable to be measured is the suppression chamber water level. Columbia Generating Station has expanded its suppression chamber water level instruments to cover this requirement. A description is provided in Section 7.5.

The accuracy and response time of this instrument are

Instrument accuracy	*= ± of full scale*
Instrument response time	*= 0 to 100% of full scale in less than 1 sec*

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, sections 6.2.1.1.2 and 7.5.2.6.

II.F.1.6 *Containment Hydrogen Monitor*

Position

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10% hydrogen concentration under both positive and negative ambient pressure.

Clarification

a. *Design and qualification criteria are outlined in Appendix A,*

b. *The continuous indication of hydrogen concentration is not required during normal operation,*

   If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection, and

c. *The accuracy and placement of the hydrogen monitors shall be provided and justified to be adequate for their intended function.*

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for these monitors in the following sections: 6.2.5.2.2, 7.5.1.5.4, 7.5.2.2.3, and Table 7.5-1, item 10.

Columbia Generating Station concurs with the intent of this position. The existing monitors are redundant and provide continuous display and redundant recording in the control room. The instruments are seismically and environmentally qualified to Class 1 requirements with a range *of 0-30% hydrogen concentration. A complete design description is provided in Section 6.2.5.2.*

The accuracy of this instrument is

Instrument accuracy (loop) = $\pm$*0.2%* H_2 *in the range 2-6* H_2 *and*
$\pm$*2.0% for remainder of full scale*

II.F.2 INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING

Position

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided (NUREG-0737).

Clarification

None.

Columbia Generating Station Position

CGS actively participated in the efforts of the BWR Owner's Group (BWROG) and the Licensing Review Group (LRG) to develop an industry understanding of NRC's concerns and an approach to detect inadequate core cooling.

An analysis of in-core thermocouples, as proposed in recently published Safety Evaluation Reports applicable to BWRs, led the BWROG, LRG, and CGS to conclude that in-core thermocouples did not serve as effective instruments for detection of inadequate core cooling and did not substantially improve the safety of the plant. The two major deficiencies of incore thermocouples are inadequate (i.e., long) response time and potentially erroneous indications. In addition, a risk assessment of the effect on the addition of in-core thermocouples has concluded that even if in-core thermocouples were arbitrarily assumed to provide an effective backup to the plant water level detectors, overall plant risk would not be significantly reduced. Based on this risk analysis, in-core thermocouples were not considered to be a cost effective modification for CGS. The results of the above studies were presented to the NRC by the BWROG and LRG executives in a meeting in Bethesda on December 17, 1981.

In Operating License NF-21 issued December 19, 1983 the staff conditioned the license to "implement the staff's requirements regarding additional instrumentation for detection of inadequate core cooling which may result from the staff's review of the BWR Owner's Group reports (SLI 8211 and SLI 8218)…." Generic Letter 84-23 comprised the staff's review and requested additional information. The Energy Northwest response to Generic Letter 84-23, Letter GO2-84-617 dated November 27, 1984, satisfied the licensing condition and closed this issue.

II.K.1.5 Assurance of Proper Engineered Safety Feature Functioning

Position

Review all valve positions, positioning requirements, positive controls, and related test and maintenance procedures to ensure proper engineered safety feature (ESF) functioning. See NRC Bulletins 79-06A Item 8, 79-06B Item 7, and 79-08 Item 6.

This requirement shall be met before fuel loading.

Clarification

None.

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR discusses this topic in Sections 7.1.2.4, 7.3.1.1, 7.3.2.1.2, 7.3.2.1.3, and Appendix B, Section I.C.6.

Directives on valve positioning requirements, positive controls, and test and maintenance procedures associated with ESF systems have been prepared. Motor-operated valves in safety systems are normally maintained in a configuration such as to require the least number of valve automatic movements on system actuation. System initiation logic is such that valves automatically move to the required position when required. The position of vital manual ECCS valves is controlled by the use of and documentation of locks on valve handwheels. In addition, numerous vital manual valves have position status indicating lights in the control room.

Columbia Generating Station is equipped with ESF system status displays, which continuously monitor the ESF systems and provide indication to the operator of a system bypass or inoperability introduced during testing or maintenance which renders the system(s) unable to respond to an initiation signal. Typical parameters monitored include the following:

a. Valve position,

b. Power available to motor-operated valves,
c. Initiation logic power available,
d. Power sources (including emergency diesels) available, and
e. Breaker status.

Alarms are provided on a system level basis. Indication is provided on a component level basis.

Surveillance and testing procedures for ESF systems will include checks to ensure the system is returned to standby status on completion of testing.

When ESF equipment is removed from service for maintenance, procedures require documentation of removal and return to service. Functional tests of equipment returned to service following maintenance are required by these procedures to ensure operability. NUREG-0892, the WNP-2 Safety Evaluation Report, discussed this issue and listed confirmation of procedures as confirmatory issue No. 22. Energy Northwest letter GO2-83-247 dated March 23, 1983, "Confirmatory Issue No. 22, Assurance of ESF Functioning (II.K.1.5) and Safety-Related System Operability Status (II.K.1.10)," satisfied the confirmatory issue, subsequently listed as resolved in Supplement 4 to NUREG-0892.

II.K.1.22 Proper Functioning of Heat Removal Systems

Position

Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense. (IE Bulletin 79-08).

Clarification

None.

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains information regarding RCIC operation in Sections 5.4.6 and 7.4.1.1; information regarding HPCS is contained in 6.3.2.2.1 and 7.3.1.1.1.1. RHR information is contained in Sections 5.4.7.1.1, 6.2.2 and 7.3.1.1.5 (suppression pool cooling mode) and 5.4.7.1.5 and 5.4.7.2.6 (shutdown cooling mode).

Energy Northwest letter GO2-80-107, dated May 23, 1980, responded to IE Bulletin 79-08. Additional information pertaining to the above requirement is provided below.

Initial Core Cooling:

Following a loss of feedwater and reactor scram, a low reactor water level signal (level 2) will automatically initiate main steam line isolation valve closure. At the same time this signal will put the HPCS and RCIC systems into the reactor coolant makeup injection mode. These systems will continue to inject water into the vessel until a high water level signal (level 8) automatically trips RCIC and closes the HPCS injection valve. The HPCS pump remains running on minimum flow bypass.

Following a high reactor water level 8 trip, the HPCS injection valve will automatically reopen when reactor water level decreases to low water level 2. The RCIC system will automatically reinitiate after a high water level 8 trip when reactor water level decreases to low water level trip 2.

The HPCS and RCIC systems have redundant supplies of water. Normally they take suction from the condensate storage tank (CST). The HPCS and RCIC systems suctions will automatically transfer from the CST to the suppression pool if the CST water is depleted or, for the HPCS system, the suppression pool water level increases to a high level.

The RCIC system will start automatically on receipt of a low water level (level 2) initiation signal. On receipt of this initiation signal, the following events occur simultaneously unless otherwise noted:

a. *Test bypass valves to condensate storage tank closes (if open);*

b. *Steam supply valve to turbine opens;*

c. *Pump discharge injection valve opens when the turbine steam supply valve is open;*

d. *Gland seal system starts;*

e. *Cooling water supply valve to lube oil cooler opens;*

f. *Pump suction valve from condensate storage tank opens (if closed);*

g. *The turbine control system brings the turbine up to speed as soon as the steam supply valve leaves its full closed position. Pump discharge flow develops as soon as the pump discharge pressure is sufficient to open the check valve between the pump and the reactor vessel. As pump discharge and steam inlet pressure change with a variable reactor pressure range, the control signal will be sent to the turbine to maintain constant steady state pump flow; and* *h. When pump discharge pressure reaches a predetermined pressure, the minimum flow valve opens until system flow reaches a predetermined flow, then it will close.*

RCIC flow may be directed away from the vessel by diverting the pump discharge to the CST. This is accomplished by closing injection valve RCIC-V-13 and opening the test return valves (RCIC-V-22 and 59). The system is returned to injection mode by closing RCIC-V-59 and then opening RCIC-V-13. This mode of operation will not be used during events where an unacceptable source term is identified in primary containment. Diverting RCIC flow to the CST is not a safety-related function nor does this mode affect the ability of RCIC to initiate during plant transients. The system automatically switches to injection mode if the water level decreases to the low level initiation point (Level 2).

The HPCS system will start automatically upon receipt of a low water level (level 2) initiation signal. Upon receipt of this initiation signal, the following events occur simultaneously unless otherwise noted:

a. High-pressure core spray diesel generator starts;

b. High-pressure core spray pump starts;

c. High-pressure core spray suction valve and HPCS injection valve open;

d. Suppression pool test return and bypass valves close (if open);

e. Minimum flow bypass valve automatically opens if HPCS pump is delivering pressure and system flow is low. Minimum flow bypass valve automatically closes when the flow rate from the pump reaches a predetermined flow;

f. High-pressure core spray service water pumps starts; and

g. High-pressure core spray room cooler fan starts.

The operator can manually initiate the HPCS and RCIC systems from the control room before the level 2 automatic initiation level is reached. The operator has the option of manual control after automatic initiation. The operator can verify that these systems are delivering water to the reactor vessel by

a. Verifying reactor water level increases when systems initiate,

b. Verifying systems flow using flow indicators in the control room, and *c.* *Verifying system flow is to the reactor by checking control room position indication of motor-operated valves. This ensures no diversion of system flow to other than the reactor.*

Therefore, the HPCS and RCIC can maintain reactor water level at full reactor pressure and until pressure decreases to where low pressure systems such as the LPCS of LPCI can maintain water level.

Containment Cooling:

After reactor scram and isolation and establishment of satisfactory core cooling, the operator would start containment cooling. This mode of operation removes heat resulting from SRV discharge to the suppression pool. This would be accomplished by placing the RHR system in the containment/suppression pool cooling mode, or the suppression pool spray mode, i.e., RHR suction from and discharge to the suppression pool. A summary of the operator actions is given in the following:

a. *Start the associated RHR standby service water (SW) pump, if not already running,*

b. *Open the SW pump discharge valve, if not already open,*

c. *Open the SW loop return valve, if not already open,*

d. *Start the associated RHR pump,*

e. *Close the associated RHR heat exchanger bypass valve,*

f. *Adjust system flow by adjusting the RHR test return valve if in the suppression pool cooling mode, and*

g. *Open the suppression pool spray valve if in the spray mode.*

The Operator could verify proper operation of the RHR system containment cooling function from the control room by the following:

a. *Verifying RHR and SW system flow using system control room flow indicators,*

b. *Verifying correct RHR and SW system flow paths using control room position indication of motor-operated valves, and*

c. *On branch lines that could divert flow from the required flow paths, closing the motor-operated valves and noting the effect on RHR and SW flow rate.*

Extended Core Cooling:

When the reactor has been depressurized, the RHR system can be placed in the long-term shutdown cooling mode. The operator manually terminates the containment cooling mode of one of the RHR loops and places the loop in the shutdown cooling mode as follows:

a. *Trip the RHR pump to be used for shutdown cooling,*

b. *Close associated motor-operated valve in the suppression pool suction and LPCI discharge line to the vessel,*

c. *Open shutdown cooling suction valves from and discharge valves to the reactor vessel, and*

d. *Restart the RHR pump.*

In this operating mode, the RHR system can cool the reactor to cold shutdown. Proper operation and flow paths in this mode can be verified by methods similar to those described for the containment cooling mode.

In conclusion, the plant design is fully adequate to meet the intent of the requirements of auxiliary heat removal when the main system is inoperable.

II.K.1.23 *Reactor Vessel Level Instrumentation*

Position

Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status. Instruct operators to utilize other available information to initiate safety systems (IE Bulletin 79-08).

Clarification

None.

Columbia Generating Station Position

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for the Reactor Vessel Level

Instrumentation and the design basis of the Safety Related Display Instrumentation in the following sections: 7.5.1.1.1, 7.7.1.1.2.2, 7.7.1.4.2.1, 7.5.2, and Table 7.5-1.

NEDO-24708 describes the multiple water level instrumentation provided in the BWR control room for the operator. An outline of the specific indication for Columbia Generating Station is provided in the following paragraphs, which fully meets the intent of the plant requirements and the NRC requirements.

Reactor vessel water level is continuously monitored by four recorders for normal, transient, and accident conditions. These four instruments are divided into two divisions of two instruments each to provide an overlapping range from above the maximum operating level to below the active core. Thus, adequate information is provided to the operator for manual initiation of safety actions and for assurance of the vessel water level at all times.

Those sensors used to provide automatic safety equipment initiation are arranged in a four-quadrant vessel tap configuration with the four sensors divided electrically between two divisions.

In addition, the operating procedures will reflect the requirements for the operators to also rely on the information provided by other plant parameter indications relating to vessel level.

A separate set (to that described above) of range level instrumentation provides reactor level control via the reactor feedwater system. This set also indicates or records in the control room. Additionally, an upset range (0-180 in.) and a shutdown range (0-400 in.) are provided for operator information.

The safety-related systems or functions served by safety-related reactor water level instrumentation are the following:

RCIC
HPCS
LPCS
RHR/LPCI
ADS
Nuclear steam supply shutoff system (NSSSS)
Reactor protection system (RPS)
Standby gas treatment system (SGTS)
Emergency power system
Secondary containment isolation
Main control room and critical switchgear HVAC
Standby service water system
Containment instrument air system
Trip of nonessential loads

Low reactor vessel water level is used in the initiation logic of all systems listed above. In addition, the RCIC and HPCS systems shut down on high reactor vessel water level. HPCS and RCIC will automatically restart if low reactor level is again reached (see response to TMI Items II.K.1.22 and II.K.3.13, respectively, for further discussion). Additional information about reactor vessel level instrumentation is also provided in Section 5.2 and in Figure 3.6-1.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated March 1982, section 7.5.2.1.

II.K.3.21 *Restart of Core Spray and Low Pressure Coolant Injection Systems*

Position

The core spray and low pressure coolant injection (LPCI) system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The core spray and LPCI system logic should be modified so that these systems will restart, if required, to assure adequate core cooling. Because this design modification affects several core cooling modes under accident conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

Clarification

Modification of system design should be made in accordance with those requirements set forth in Sections 4.12, 4.13, and 4.16 of IEEE Standard 279-1971 with regard to protective function bypasses and completion of protective action once initiated.

Columbia Generating Station Position

CGS as a participant in the BWR Owner's Group endorses the position presented in the letter dated December 29, 1980, from D. B. Waters to the NRC (attention D. G. Eisenhut), Subject: "BWR Owner's Group Evaluation of NUREG-0737 Requirements." The position presented in enclosure 2 to this letter concludes that the current system design is adequate and no design changes are required. CGS concurs in this position.

It should be noted that this design allows the operator to evaluate the plant and avoid an automatic restart that may have an adverse impact on the situation.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 7.3.2.1.

II.K.3.25 Effect of Loss of Alternating-Current Power on Pump Seals

Position

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating-current (ac) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

Clarification

The intent of this position is to prevent excessive loss of reactor coolant system (RCS) inventory following an anticipated operational occurrence. Loss of ac power for this case is construed to be loss of offsite power. If seal failure is the consequence of loss of cooling water to the reactor coolant pump (RCP) seal coolers for 2 hr, due to loss of offsite power, one acceptable solution would be to supply emergency power to the component cooling water pump. This topic is addressed for Babcock and Wilcox (B&W) reactors in Item II.K.2.16.

Columbia Generating Station Position

Columbia Generating Station, as a participant in the BWR Owners' Group, endorses the position developed by General Electric for the Owners' Group. This position has been transmitted in a letter from the BWR Owners' Group to the NRC, T. J. Dente to Darrell G. Eisenhut, dated September 21, 1981. In this supplement to the BWR Owners' Group evaluation of NUREG-0737, Item II.K.3.25, General Electric presented test data from a test performed at the Bingham Pump Company's test facility in 1973 on the CGS recirculation pump. During the operability testing of the pump at rated temperature and pressure the seal cavity was deprived of seal purge and the external heat exchanger was deprived of coolant. As a result, the seal cavity temperature exceeded 270°F. Test personnel visually monitored pump leakage for more than five hours and observed no leakage beyond the capability of the 1-in. seal drain lines, less than 5 gpm. These test results provide confirmation that loss of cooling to the Bingham pump seal for 5 hr does not lead to unacceptable seal leakage. This loss is easily compensated for by normal water level controls and presents no hazard to the health and safety of the public.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 15.1.2.

II.K.3.44 Adequate Core Cooling for Transients with a Single Failure

Position

For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which result in a stuck-open relief valve should be included in this category (NUREG-0737).

Clarification

None.

Columbia Generating Station Position

CGS as a member of the BWR Owners' Group endorses the following position statement and analysis prepared by GE on behalf of the Owners' Group:

Introduction:

This report has been prepared as the BWR Owners' Group generic response to NUREG-0737 Task Item II.K.3.44 which addresses the issue of adequate core cooling for transients with a single failure for those plants identified in Table II.K.3.44-4.

At the outset it should be noted that the conditions described in II.K.3.44 (i.e., transients plus single failures) go beyond the current BWR design basis and that the item's reference to transients with multiple failures goes beyond the regulatory requirements as specified in Regulatory Guide 1.70, Revision 3. The multiple failures specified involve consideration of a stuck-open relief valve (SORV) combined with the worst single failure. GE and the Owners' Group continues to support the current BWR design basis approach. This report is intended to provide information to address Item II.K.3.44, but does not reflect our intention to change the current BWR design basis approach.

It is shown that, for the GE BWR/2 through BWR/6 plants, the core remains covered for any transient with the worst single failure. This is achieved without any operator action to manually initiate ECCS or other inventory makeup systems. The worst transient with the worst single failure is shown to be the loss of feedwater (LOF) event with a failure of the high pressure ECCS or one isolation condenser (IC) loop, whichever is applicable.

For the bounding LOF event, studies which included even more degraded conditions have been documented in Reference 1. The degraded conditions cover the failure of HPCS (or HPCI or FWCI or IC) and one SORV. Reference 1 shows that the core will remain covered and therefore that no fuel failure would occur.

Criteria, Scope and Assumptions:

NUREG-0737 Item II.K.3.44 requires that the licensees demonstrate adequate core cooling to prevent the fuel from incurring significant damage for the anticipated transients combined with the worst single failure. To meet this requirement, either one of the following two criteria should be satisfied:

a. The reactor core remains covered with water until stable conditions are achieved, or

b. No significant fuel damage results from core uncovery.

For BWR plants, this report will show that Criterion 1 is met. The report makes the following assumptions:

a. A representative plant of each BWR product line, BWR/2 through BWR/6, is used to represent all of the plants of that product line,

b. The anticipated transients as identified in NRC Regulatory Guide 1.70, Revision 3 were considered,

c. The single failure is interpreted as an active failure, and

d. All plant systems and components are assumed to function normally, unless identified as being failed.

Discussion:

Table II.K.3.44-1 lists all of the transients which were considered in this study. The event sequence of each transient was examined for each product line to determine the impact on core cooling. The following three factors were used to determine the worst transient and the worst single failure:

a. Reduction or loss of main feedwater or coolant makeup or heat removal systems, especially high pressure systems, e.g., HPCI, feedwater coolant injection (FWCI), HPCS, RCIC or isolation condenser (IC),

b. Steam release paths causing rapid reactor coolant inventory loss, e.g., SRVs, turbine, or turbine bypass valves, and

c. Power level, especially the timing of scram.

Based on these considerations, a comparison was made among the transients in Table II.K.3.44-1.

In Reference 2, the events of Table II.K.3.44-1 are compared in detail for a typical BWR/4 plant. In particular the impact on core cooling for each transient is evaluated by comparison to the analysis results for the LOF event in the section titled "Applicability of Analyses." It is found that the LOF event is the most severe transient from the core cooling viewpoint due to its rapid depletion of reactor coolant inventory. This conclusion has generic applicability to all BWR product lines covered by this study.

The same approach was also used to select the single failures which would pose the greatest challenge to core cooling. Among all of the possible failures considered (Table II.K.3.44-2 the following failures are identified as the most important ones:

- *a. Failure of HPCI or HPCS or FWCI or one IC loop, whichever is applicable,*
- *b. Failure of RCIC, and*
- *c. One of the SRVs, which has opened as a result of the transient, fails to close.*

Items a and b are the possible limiting failures because they represent loss of high pressure inventory makeup or heat removal systems which would be relied on following a loss of feedwater event. Item c is a possible limiting failure, because it results in the largest steam release rate from the vessel compared to other possible release paths (e.g., a stuck-open turbine bypass valve). No other failures identified in Table II.K.3.44-2 result in a direct challenge to core cooling capability.

Because of the relatively low steam loss capacity through one SORV (Item c) compared to the makeup water capacity of the highest capacity makeup water system, the failure of the highest capacity high pressure makeup system (Item a) would be worse than a stuck-open relief valve (Item c). For example, for a typical BWR/4, representative values of HPCI makeup and SRV flow are 18% and 6% of rated feedwater flow, respectively. Because of the higher makeup rate of HPCI/HPCS relative to RCIC (3% of rated feedwater flow), Item a would be worse than Item b. Table II.K.3.44-3 lists the worst combination of transient and single failure for the GE BWR product lines covered by this study.

Even with the worst single failure in combination with the LOF event, the RCIC or at least one IC loop will function to provide makeup and/or to remove decay heat while the vessel pressure remains high. The design basis for the RCIC or the IC is such that they are capable of removing decay heat with the vessel being isolated. Analyses of the LOF event with the worst single failure have been performed to support this conclusion. For example, for BWR/2 plants, such analyses are documented in Reference 1, Table 3.2.1.1.5-5. These analyses show that the isolation condenser heat removal capacity is greater than the decay heat generation rate and will lead to a safe and stable condition. Similar analysis have been performed for representative plants with the RCIC system. These analyses show that for the worst transient *with the worst single failure, the minimum water level for different BWR product lines ranges from 6 ft to 11 ft above the top of the active fuel.*

With even more degraded conditions, i.e., one SORV in addition to the worst case transient with the worst single failure, reference plant analyses in Reference 1, Tables 3.2.1.1.5-9 and 3.2.1.1.5-10 show that for the plants analyzed the RCIC system can automatically provide sufficient inventory to keep the core covered even with a single failure plus a SORV. This capability is not a design basis for the RCIC system, and not all plants have been analyzed to demonstrate this capability. If a plant should not have this capability, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV. It should be noted that manual depressurization is the proper operator action for all plants during loss of inventory conditions when the high pressure cooling system(s), are unable to restore and maintain RPV level. These proper operator actions are allowed for in the NUREG-0737 requirement.

For plants without RCIC, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV.

Conclusion:

The anticipated transients in NRC Regulatory Guide 1.70, Revision 3, were reviewed for all BWR product lines BWR/2 through BWR/6 from a core cooling viewpoint. The LOF event was identified to be the most limiting transient which would challenge core cooling. The BWR is designed so that the high pressure makeup or inventory maintenance systems or heat removal systems (HPCI, HPCS, FWCI, RCIC or IC) are independently capable of maintaining the water level above the top of the active fuel given a loss of feedwater. The detailed analyses show that even with the worst single failure in combination with the LOP event, the core remains covered.

Furthermore, even with more degraded conditions involving one SORV in addition to the worst transient with the worst single failure, studies show that the core remains covered during the whole course of the transient either due to RCIC operation or due to manual depressurization.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, section 15.1.2.

References:

1. *Section 3.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, March 31, 1980.*

2. *Section 3.2.2 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, June 30, 1980.*

3. *Section 3.5.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, August 31, 1979.*

Table II.K.3.44-1

Summary of Initiating Transients
(Reference: NRC Regulatory Guide 1.70, Revision 3)

---

1. *Loss of feedwater heating*
2. *Feedwater controller failure - maximum demand*
3. *Pressure regulator failure - open*
4. *Inadvertent safety/relief valve opening*
5. *Inadvertent residual heat removal (RHR) shutdown cooling operation*
6. *Pressure regulator failure - closed*
7. *Generator load rejection*
8. *Turbine trip*
9. *Main steam isolation valve (MSIV) closure*
10. *Loss of condenser vacuum*
11. *Loss of normal ac power*
12. *Loss of feedwater flow*
13. *Failure of RHR shutdown cooling*
14. *Recirculation pump trip*
15. *Recirculation flow control failure - decreasing flow*
16. *Rod withdrawal error*
17. *Abnormal startup of idle recirculation pump*
18. *Recirculation flow control failure - increasing flow*
19. *Fuel loading error*
20. *Inadvertent startup of high pressure core spray (HPCS) or high pressure coolant injection (HPCI) or feedwater coolant injection (FWCI) or isolation condenser (IC), whichever is applicable.*

Table II.K.3.44-2

List of Single Failures Which Can Potentially Degrade the Course of a BWR Transient

1. *One or all of the bypass valves fail to modulate open when required.*
2. *One of the bypass valves, which has opened as a result of the transient, fails to close.*
3. *Failure to trip the turbine or feedwater pumps on high water level.*
4. *One main steam isolation valve (MSIV) fails to close when required.*
5. *One of the safety/relief valves fails to open when required.*
6. *One of the safety/relief valves, which has opened as a result of the transient, fails to close.*
7. *Failure to trip one recirculation pump.*
8. *Failure to run back the recirculation pumps.*
9. *Failure of high pressure coolant injection (HPCI) or high pressure core spray (HPCS) or feedwater coolant injection (FWCI) or one isolation condenser (IC) loop, whichever is applicable.*
10. *Failure of reactor core isolation cooling (RCIC) or one IC loop, whichever is applicable.*
11. *Failure of one low pressure coolant injection (LPCI) loop or the low pressure core spray (LPCS) system.*
12. *Loss of one residual heat removal (RHR) system heat exchanger.*
13. *A single control rod stuck while the remainder of the control rods are moving.*
14. *Failure to achieve the rod block function (i.e., a single control rod will withdraw upon erroneous withdrawal demand).*
15. *Loss of one diesel generator if loss of ac power was the initiating event.*

Table II.K.3.44-3

Worst Case of Transient with a Single Failure for Different BWR Product Lines

Product Line	*Transient with a Single Failure (Worst Case)*
BWR/2	*LOF + Failure of one IC loop (Oyster Creek only)* *LOF + Failure of FWCI (Nine Mile Point only)*
BWR/3	*LOF + Failure of FWCI (Millstone only)* *LOF + Failure of HPCI (others)*
BWR/4	*LOF + Failure of HPCI*
BWR/5	*LOF + Failure of HPCS*
BWR/6	*LOF + Failure of HPCS*

Table II.K.3.44-4

Participating Utilities[a]
NUREG-0737

Boston Edison	*Pilgrim 1*
Caroline Power & Light	*Brunswick 1 and 2*
Commonwealth Edison	*LaSalle 1 and 2, Dresden 1-3, Quad Cities 1 and 2*
Georgia Power	*Hatch 1 and 2*
Iowa Electric Light & Power	*Duane Arnold*
Jersey Central Power & Light	*Oyster Creek 1*
Niagara Mohawk Power	*Nine Mile Point 1 and 2*
Nebraska Public Power District	*Cooper*
Northeast Utilities	*Millstone 1*
Philadelphia Electric	*Peach Bottom 2 and 3; Limerick 1 and 2*
Power Authority of the State of New York	*FitzPatrick*
Tennessee Valley Authority	*Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 and 2*
Vermont Yankee Nuclear Power	*Vermont Yankee*
Detroit Edison	*Enrico Fermi 2*
Mississippi Power & Light	*Grand Gulf 1 and 2*
Pennsylvania Power & Light	*Susquehanna 1 and 2*
Energy Northwest	*Columbia Generating Station*
Cleveland Electric Illuminating	*Perry 1 and 2*
Houston Lighting & Power	*Allens Creek*
Illinois Power	*Clinton Station 1 and 2*
Public Service of Oklahoma	*Black Fox 1 and 2*
Long Island Lighting	*Shoreham*

[a] *Report applies to plants included herein whose owners participated in the report development.*

II.K.3.45 *Evaluation of Depressurization with Other than Automatic Depressurization System*

Position

Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRVs) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown (NUREG-0737).

Clarification

None.

Columbia Generating Station Position

CGS as a member of the BWR Owners' Group endorses the following position statement and analysis prepared by GE on behalf of the Owners' Group.

The evaluation of alternate modes of depressurization other than full actuation of the Automatic Depressurization System (ADS) is made for those plants listed in Table II.K.3.45-5 with regard to the effect of such reduced depressurization rates on core cooling and vessel integrity.

Depressurization by full ADS actuation constitutes a depressurization from about 1050 psig to 180 psig in approximately 3.3 minutes. Such an event, which is not expected to occur more than once in the lifetime of the plant, is well within the design basis of the reactor pressure vessel. This conclusion is based on the analysis of several transients requiring depressurization via the ADS valves. Results of these analyses indicate that the total vessel fatigue usage is less than 1.0. Therefore, no change in the depressurization rate is necessary. However, to comply with the above request reduced depressurization rates were analyzed and compared with the full ADS actuation. The alternate modes considered cause vessel pressure to traverse the same pressure range in (1) depressurization case 1 (ranges from 6-10 minutes depending on plant size and ADS capacity), and (2) depressurization case 2 (ranges from 15-20 minutes). The case 2 depressurization bounds the possible increase in depressurization time by producing an undesirably long core uncovered time. The case 1 depressurization gives the results of an intermediate depressurization. These modes are achieved by opening a reduced number of relief valves. These blowdown rates are illustrated by Figure II.K.3.45-1.

Assumptions:

The major assumptions used for the core cooling analysis are as follows:

a. *No high pressure cooling systems are available,*

b. *All low pressure ECCS is available, and*

c. *Assumptions as stated in NEDO-24708, Section 3.1.1.3, "Justification of Analysis Methods," which includes the use of 1978 ANS Decay Heat (mean value).*

Results:

a. *Vessel Integrity*

The depressurization events considered are full ADS blowdown and blowdown over 10 and 20 minute intervals. The reactor vessel stresses for these events are within the acceptance stress limits defined by ASME Code Section III for emergency conditions (Level C). The core support structures and other safety-related internal components are also within applicable emergency condition stress limits.

The ADS operating conditions which affect fatigue usage of vessel or core support structures are not significantly different for fast and slow blowdown events. Specific calculations of fatigue usage are not required for emergency conditions (Level C). However, available pressure vessel fatigue analyses show the usage per event to be < 0.1 per full ADS event.

In summary, reactor vessel and core support structure integrity is assured for the blowdown rates considered if an ADS event should occur, and reduced rates of depressurization do not significantly decrease fatigue usage.

b. *Core Cooling Capability*

Examination of the reduced depressurization rates under consideration with respect to core cooling concerns shows that:

1. *Vessel depressurization for a case 2 blowdown (15-20 minutes) causes the core to be uncovered for a lengthy period of time even assuming system initiation at the earliest reasonable time.*

2. *Vessel depressurization for a case 1 blowdown (6-10 minutes), when actuated at the same level as the full ADS case, will result in less vessel inventory* at *the time of ECCS injection and can result in longer periods of core uncovery.*

3. *Vessel depressurization for a case 1 blowdown (6-10 minutes) when actuated considerably earlier than at the ADS initiation setpoint can result in some improvement in core cooling. However, the operator is required to act more quickly in these cases (i.e., within 1-6 minutes after the accident). This earlier depressurization also reduces the time available to start high pressure system injection and hence to avoid the need for manual depressurization. It also increases the frequency of depressurization.*

The results of the calculations are presented in Tables II.K.3.45-1 through II.K.3.45-4. They show the total core uncovered time and remaining vessel inventory at the time of low pressure ECCS injection. A discussion of these results follows below.

Discussion:

The results are based upon calculations performed with the assumptions stated earlier using a representative BWR/3 and a BWR/6 to show consistency of results across the product lines. The transients considered are an outside steam line break and a stuck-open relief valve. The ADS will depressurize the vessel to the low pressure ECCS injection setpoint when no high pressure cooling systems are available. The depressurizations used are initiated at different times based on the downcomer water level. The first initiation time considered is when the water level is at the top of the active fuel which is consistent with the original design for most plants and thus is the basis for comparison. The second initiation time considered is the downcomer water level of 34 feet from the bottom of the vessel which still provides the operator with a reasonable time to attempt to start the high pressure systems. The last initiation time considered is the high pressure makeup system setpoint (Level 2 for BWR/6 and Level 1 for BWR/3) plus 60 seconds which is the earliest time in which depressurizaton could be expected to occur.

The core cooling criteria used in assessing the impact of a reduced depressurization rate are:

a. *Inventory in the core and lower plenum at the time of low pressure ECCS injection as predicted by the SAFE model (Reference 1), and*

b. *The total time which the top of the active fuel (TAF) remains uncovered as predicted by the SAFE model (Reference 1).*

The first criterion demonstrates the increased mass loss due to boiloff for the longer blowdown, since mass loss due to flashing will be independent of the depressurization rate providing the boundary pressure values are the same for all the rates. The second criterion is a measure of the resultant core temperature.

Table II.K.3.45-1 gives the results for a BWR/6 assuming an outside steam line break. As the length of depressurization is increased the vessel inventory at the time the ECCS injection decreases and the total core uncovered time increases. Table II.K.3.45-1 further shows that the actuation times based on higher water levels (i.e., 34 ft and Level 2 +60 sec) longer depressurizations exhibit the same trends. Furthermore, for any particular depressurization rate, raising the actuation level increases the vessel inventory at ECCS injection and decreases the total core uncovered time. However, this also decreases the time the operator has available to try to get high pressure level control systems working in order to avoid the need to depressurize.

Table II.K.3.45-2 shows that these same results are exhibited for the case of a stuck-open relief valve. Table II.K.3.45-3 shows the results for a BWR/3 assuming an outside steam line break. Examination of the table shows the same trends as Table II.K.3.45-1, and therefore the results are applicable to all product lines. Table II.K.3.45-4 shows that these general trends are independent of the models used by exhibiting the same trends for a BWR/3 using standard Appendix K licensing assumptions.

Conclusion:

The cases considered show that no appreciable improvement can be gained by a slower depressurization based on core cooling considerations. A significantly slower depressurization rate will result in increased core uncovered time. A moderate decrease in the depressurizaton rate necessitates an earlier actuation time resulting in less time available for operator action to start high pressure ECCS without significant benefit to vessel fatigue usage. This will also result in an increased frequency of ADS actuation.

Finally, it is of paramount importance to note that the ADS is not a normal core cooling system; it is a backup for high pressure cooling systems (feedwater, RCIC, HPCI/HPCS). If ADS operation is ever required in a BWR, it will be because core cooling is threatened. Since a full ADS blowdown is well within the design basis of the reactor pressure vessel and ADS is properly designed to minimize the threat to core cooling, no change in the depressurization rate is necessary.

Reference:

1. NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," August 1979.

Table II.K.3.45-1

Results for BWR/6 Outside Steam Line Break
No High Pressure Systems Available

Depressurization Case	Depressurization Initiation: Level	Depressurization Initiation: Time (sec)	Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
Full ADS	TAF[a]	1086.0	26	1.603×10^5
Case 1	TAF	1086.0	117	1.528×10^5
Case 1	34'	610.6	10	1.779×10^5
Full ADS	Level 2[b] +60 sec	78.3	No uncovery	1.993×10^5
Case 1	Level 2 +60 sec	78.3	No uncovery	1.937×10^5
Case 2	Level 2	78.3	390	1.755×10^5

[a] Top of active fuel.
[b] High pressure initiation setpoint plus 60 sec.

Table II.K.3.45-2

Results for BWR/6 Stuck-Open Relief Valve
No High Pressure Systems Available

Depressurization Case	*Depressurization Initiation*		*Core Uncovered Time (sec)*	*Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)*
	Level	*Time (sec)*		
Full ADS	*TAF*[a]	*642.6*	*No uncovery*	1.836×10^5
Case 1	*TAF*	*642.6*	*15*	1.787×10^5
Case 1	*34'*	*391.8*	*No uncovery*	1.889×10^5
Case 1	*Level 2*[b] *+60 sec*	*77.7*	*No uncovery*	1.961×10^5

[a] *Top of active fuel.*
[b] *High pressure initiation setpoint plus 60 sec.*

Table II.K.3.45-3

Results for BWR/3 Outside Steam Line Break
No High Pressure Systems Available

Depressurization Case	Depressurization Initiation: Level	Depressurization Initiation: Time (sec)	Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
Full ADS	TAF[a]	1527.8	155	2.027×10^5
Case 1	TAF	1527.8	170	1.975×10^5
Case 1	34'	701.6	51	2.291×10^5
Full ADS	Level 1[b] +60 sec	364.4	No uncovery	2.446×10^5
Case 1	Level 1 +60 sec	364.4	10	2.394×10^5

[a] Top of active fuel.
[b] High pressure initiation setpoint plus 60 sec.

Table II.K.3.45-4

Results for BWR/3 Outside Steam Line Break on Appendix K Assumptions with No High Pressure Systems

Depressurization Case	Depressurization Initiation: Level	Depressurization Initiation: Time (sec)	Core Uncovered Time (sec)	Liquid Inventory in Core and Lower Plenum at Low Pressure ECCS Injection (lb)
Full ADS	TAF[a]	759.4	264	1.960×10^5
Case 1	TAF	759.4	277	1.913×10^5
Full ADS	Level l[b] +60 sec	145.6	175	2.210×10^5
Case 1	Level 1 +60 sec	145.6	191	2.165×10^5

[a] Top of active fuel.
[b] High pressure initiation setpoint plus 60 sec.

Table II.K.3.45-5

Participating Utilities[a]
NUREG-0737

Boston Edison	*Pilgrim 1*
Caroline Power & Light	*Brunswick 1 and*
Commonwealth Edison	*LaSalle 1 and Dresden 2 and Quad Cities 1and 2*
Georgia Power	*Hatch 1 and 2*
Iowa Electric Light & Power	*Duane Arnold*
Jersey Central Power & Light	*Oyster Creek 1*
Niagara Mohawk Power	*Nine Mile Point 1 and 2*
Nebraska Public Power District	*Cooper*
Northeast Utilities	*Millstone 1*
Northern States Power	*Monticello*
Philadelphia Electric	*Peach Bottom 2 and 3; Limerick 1 and 2*
Power Authority of the State of New York	*FitzPatrick*
Tennessee Valley Authority	*Browns Ferry 1-3; Hartsville1-4, Phipps Bend 1 and 2*
Vermont Yankee Nuclear Power	*Vermont Yankee*
Detroit Edison	*Enrico Fermi 2*
Long Island Lighting	*Shoreham*
Mississippi Power & Light	*Grand Gulf 1 and 2*
Pennsylvania Power & Light	*Susquehanna 1 and 2*
Energy Northwest	*Columbia Generating Station*
Cleveland Electric Illuminating	*Perry 1 and 2*
Houston Lighting & Power	*Allens Creek*
Illinois Power	*Clinton Station 1and 2*
Public Service of Oklahoma	*Black Fox 1 and 2*

[a] *Report applies to plants included herein whose owners participated in the report development.*

II.K.3.46 *Response to List of Concerns from ACRS Consultant (Michelson Concerns)*

Position

General Electric should provide a response to the Michelson concerns as they relate to BWRs. See NUREG-0660, Appendix C, Table c.3, Item 46 (Reference 1) and NUREG-0626, Section 4, Item A.17 (Reference 6c).

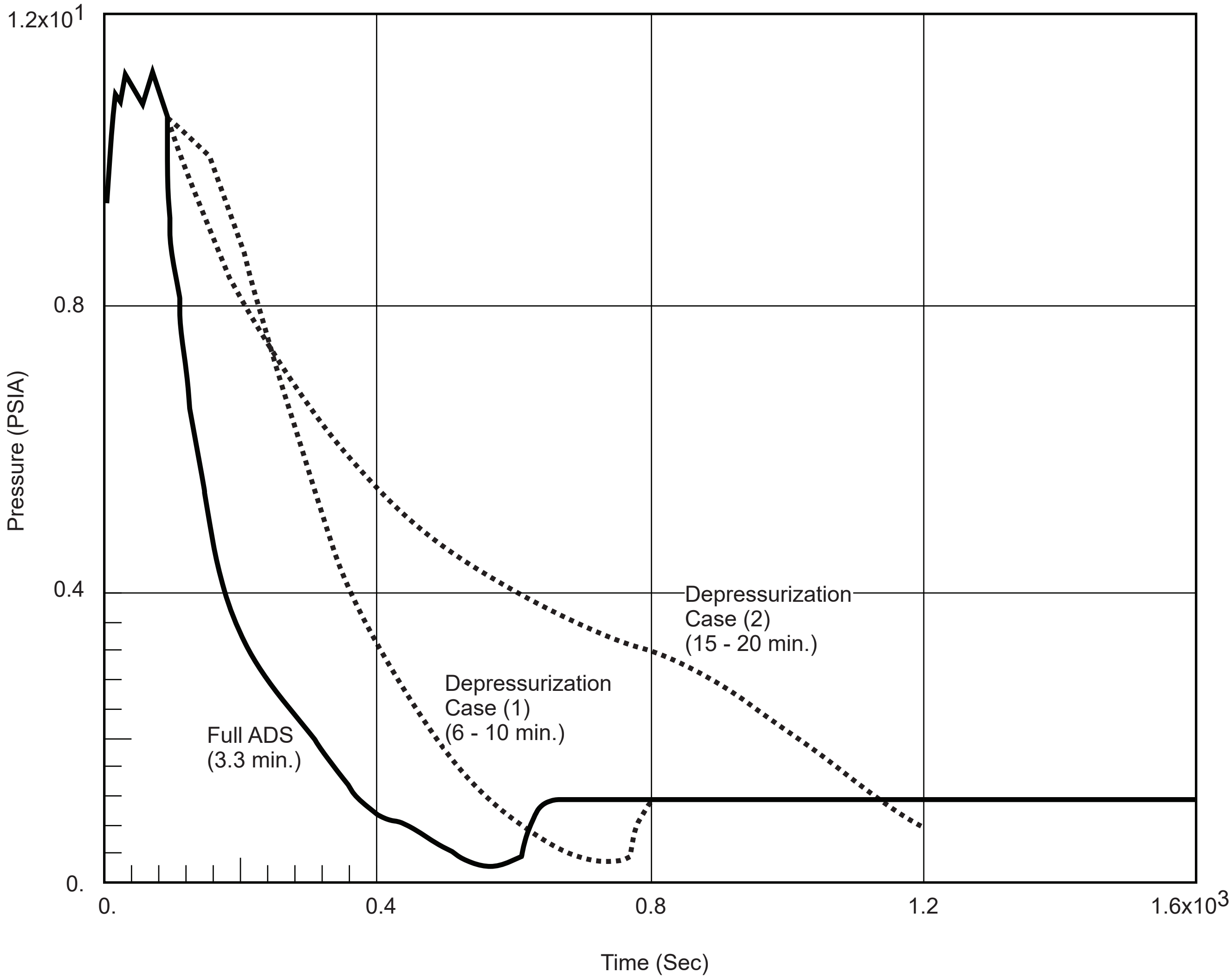
Clarification

None.

Columbia Generating Station Position

GE, acting for the BWR Owners' Group, responding to these concerns in a letter, "Response to Questions Posed by Mr. C. Michelson," R. H. Buchholz (GE) to D. F. Ross, dated February 21, 1980. Submittal of this letter completes the action required by this task.

This position has been accepted in the NRC Safety Evaluation Report NUREG-0892, dated December 1982, Section 6.3.6.



Columbia Generating Station
Final Safety Analysis Report

Vessel Blowdown Rates Used in Analysis

Draw. No. 990578.72 | Rev. | Figure II.K.3.45-1

III.D.1.1 Primary Coolant Sources Outside Containment

Position (Full Power License Requirement)

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

a. Immediate Leak Reduction

   1. Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

   2. Measure actual leakage rates with system in operation and report them to the NRC.

b. Continuing Leak Reduction

   1. Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

Dated Requirement

Applicants shall submit the information requested in the "Clarification" section of this position at least 4 months prior to issuance of a fuel-loading license.

This requirement shall be implemented by applicants for operating license prior to issuance of a full-power license. See NUREG-0737, Section III.D.1.1.

Clarification

Applicants shall provide a summary description, together with initial leak-test results, of their program to reduce leakage from systems outside containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a serious transient or accident.

a. Systems that should be leak tested are as follows (any other plant system which has similar functions or postaccident characteristics even though not specified herein, should be included):

   - Residual heat removal (RHR),

- Containment spray recirculation,
- High pressure injection recirculation,
- Containment and primary coolant sampling,
- Reactor core isolation cooling,
- Makeup and letdown (PWRs only),
- Waste gas (includes headers and cover gas system outside of containment in addition to decay or storage system).

Include a list of systems containing radioactive materials which are excluded from program and provide justification for exclusion.

b. Testing of gaseous systems should include helium leak detection or equivalent testing methods.

c. Should consider program to reduce leakage potential release paths due to design and operator deficiencies as discussed in our letter to all operating nuclear power plants regarding North Anna and related incidents, dated October 17, 1979.

This requirement applies to all operating license applicants.

Columbia Generating Station Position

Columbia Generating Station has performed a systems design review and established criteria for a surveillance/preventive maintenance program to limit to as-low-as-practical, leakage from systems outside containment which could transport highly radioactive fluids during a serious transient or accident.

a. Systems Review

The systems for leak paths for primary coolant outside containment showed three potentially unisolated leak paths which could contain highly radioactive fluids during a serious accident or transient. These three leak paths originate at the reactor building sumps with a transport pathway to the waste collection tanks in the radwaste building. The three leak path lines have been addressed in a licensing technical change. Dual auto-isolation valves have been added to each of the three lines along with accompanying isolation logic.

b. Leakage Monitoring

A leakage surveillance and preventive maintenance program* for those systems within secondary containment which could transport highly radioactive fluids in the case of a serious reactor transient or accident has the following features.

1. Designation of systems included within the leakage surveillance and preventive maintenance program:

   (a) Residual Heat Removal,
   (b) Reactor Core Isolation Cooling,
   (c) High Pressure Core Spray,
   (d) Low Pressure Core Spray,
   (e) Primary Containment Atmospheric Control,
   (f) Primary Containment Atmospheric Monitoring,
   (g) Post Accident Sampling.

2. A system list which identifies the components to be inspected, the method of inspection or measurement, and the surveillance frequency.

3. Routine inspections by operators of visually accessible portions of designated systems during normal operating conditions or test mode.

4. Detailed leakage inspection and measurement defined for designated systems during initial test program and thereafter.

5. An aggressive preventive maintenance program with high priority assigned to leakage-related work or designated systems.

6. A review cycle for leakage-related work requests to evaluate possible modifications to keep leakage as low as is reasonably achievable.

III.D.3.3 *Improved Inplant Iodine Instrumentation Under Accident Conditions*

Position *(NUREG-0737)*

a. Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

* This program takes exception for those systems which cannot be tested until startup due to required plant conditions. Program documentation will be available onsite for NRC I&E review.

b. *Each applicant for a fuel-loading license to be issued prior to January 1, 1981 shall provide the equipment, training, and procedures necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.*

Clarification

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments using sample media that will collect iodine selectively over xenon (e.g., silver ziolite) for the following reasons:

a. *The physical size of the auxiliary and/or fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.*

b. *Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.*

c. *Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.*

d. *The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high-dose-rate areas.*

After January 1, 1981, each applicant and licensee shall have the capability to remove the sampling cartridge to a low background, low contamination area for further analysis. Normally, counting rooms in auxiliary buildings will not have sufficiently low backgrounds for such analyses following an accident. In the low background area, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble gases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples under accident conditions. There should be sufficient samplers to sample all vital areas.

For applicants with fuel loading dates prior to January 1, 1981, provide by fuel loading (until January 1, 1981) the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached single-channel analyzer (SCA). The SCA window should be calibrated to the 365 KeV of Iodine-131 using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

<u>*Columbia Generating Station Position*</u>

This italicized information is historical and was provided to support the application for an operating license. The FSAR contains descriptions for this instrumentation in the following sections: 7.5.2.2.3, 12.3.4.2, 12.3.4.4, 12.5.2.1, 12.5.3.5, and Emergency Plan Section 8.7.5.

Columbia Generating Station is responding to this position as follows: Four fixed, one mobile continuous air monitoring system, and one movable local alarming continuous air monitor are provided for air sampling in plant areas where personnel may be present during accident conditions. In addition, 10 low volume air sampling systems will be strategically located throughout the plant in frequently occupied areas to continuously draw air samples for subsequent analysis.

Grab samples will be obtained using varying volume air samplers that are both ac and dc powered.

Movable local alarming continuous air monitors are placed at predetermined plant locations for personnel protection and to substantiate the quality of the plant breathing atmosphere. These monitors have local readouts (charts) and radioiodine sampling capabilities.

Energy Northwest is currently using activated charcoal cartridges for radioiodine analysis and is evaluating the attributes of silver zeolite. On completion of a satisfactory evaluation Energy Northwest will, where applicable, incorporate silver zeolite into its air sampling program. The charcoal cartridges are used in conjunction with a Ge (Li) gamma spectroscopy system located in a low background, low contamination area such as the radiochemistry lab in the near site facility. Prior to analysis, cartridges are purged in a fume hood using plant air, instrument air, bottled air, or bottled nitrogen which is stored onsite.

Station procedures are provided for obtaining and evaluating both routine and non-routine air samples. In addition to initial training provided for Health Physics/Chemistry personnel, periodic drills are conducted in accordance with the Emergency Plan.

This position has been accepted in the NRC Safety Evaluation Report, NUREG-0892, dated December 1982, Section 12.5.2.

Appendix F

FIRE PROTECTION EVALUATION

TABLE OF CONTENTS

Section | Page

Appendix F

FIRE PROTECTION EVALUATION

TABLE OF CONTENTS (Continued)

Appendix F

FIRE PROTECTION EVALUATION

TABLE OF CONTENTS (Continued)

Section Page

Appendix F

FIRE PROTECTION EVALUATION

TABLE OF CONTENTS (Continued)

Appendix F

FIRE PROTECTION EVALUATION

LIST OF TABLES

Appendix F

FIRE PROTECTION EVALUATION

LIST OF FIGURES

Appendix F

FIRE PROTECTION EVALUATION

LIST OF FIGURES (Continued)

Appendix F

FIRE PROTECTION EVALUATION

F.1 INTRODUCTION

The Fire Protection Evaluation summarizes the overall fire protection program (FPP) at Columbia Generating Station (CGS). The Fire Protection Evaluation describes those fire protection related organizational responsibilities, administrative and technical controls, fire suppression and detection systems, fire hazards analyses, and the post-fire safe shutdown methods, which comprise the FPP. Columbia Generating Station FPP performance goals include:

Defense-in-Depth

The CGS FPP uses the concept of defense-in-depth to achieve the required degree of reactor safety. This concept entails the use of echelons of administrative controls, fire protection systems and features, and post-fire safe-shutdown capability to achieve the following objectives:

a. Prevent fires from starting.
b. Detect rapidly, control, and extinguish promptly those fires that do occur.
c. Provide protection for structures, systems, and components (SSC) important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant.

Safety-Related Structures, Systems, and Components

NRC General Design Criteria (GDC) 3 of Appendix A to 10 CFR Part 50 requires that the FPP protect SSCs important to safety from the effects of fire. However, the post-fire loss of function of systems used to mitigate the consequences of design-basis accidents does not per se impact public safety. The FPP must protect all equipment important to safety; however, the need to limit fire damage to systems required to achieve and maintain post-fire safe-shutdown conditions is greater than the need to limit fire damage to those systems required to mitigate the consequences of design-basis accidents.

Post-Fire Safe-Shutdown

The CGS FPP ensures that one success path of SSCs necessary for hot shutdown is free of fire damage. The reactor safety and performance goals for safe shutdown after a fire should ensure that the specified acceptable fuel design limits are not exceeded. Section III.L of Appendix R to 10 CFR Part 50 is followed for post-fire reactor safety and performance goals for alternate remote shutdown.

Prevention of Radiological Release

The CGS FPP demonstrates that the plant will maintain the ability to minimize the potential for radioactive releases to the environment in the event of a fire. Fires are treated as anticipated operational occurrences as defined in Appendix A to 10 CFR Part 50.

The CGS structures that must satisfy the FPP are those buildings designated as "Plant Areas" in references F.7.8.a through F.7.8.f procedures.

F.1.1 FIRE PROTECTION PROGRAM

The approved fire protection program and the changes thereto are contained in this Appendix of the FSAR except for certain other sections of the FSAR included in the Fire Protection Program by Reference F.7.1.

Appendix F is divided into seven sections. This first section contains background information on the development of the fire protection program.

Section F.2 contains a description of the plant fire protection systems. The codes and standards considered and used in the design of the systems are listed. Deviations from code design commitments are identified.

Section F.3 presents point-by-point comparisons of the plant fire protection program to the guidelines of Branch Technical Position (BTP) APCSB 9.5-1 Appendix A, and with the specific commitments to 10 CFR 50, Appendix R, Section III.

Section F.4 describes the methods used to implement the post-fire safe shutdown protection commitments to 10 CFR 50, Appendix R. The selection of the post-fire shutdown equipment and the circuit analysis methods are also described in Section F.4. The fire hazards analysis for each fire area describes the respective area, combustible loading, fire protection features which may be used to mitigate the consequences of a potential fire, and the methods used to ensure post-fire safe shutdown capability.

Section F.5 references Licensee Controlled Specifications (LCS) 1.10 that contain the fire protection system operational conditions, compensatory measures, and testing requirements for the essential portions of the fire protection systems.

Section F.6 contains the fire protection arrangement drawings and Section F.7 lists the references.

F.1.2 BACKGROUND

NRC General Design Criteria for Nuclear Power Plants, Appendix A of 10 CFR 50 establish the minimum requirements for the design of nuclear power plants. See FSAR Section 3.1.2.1.3 for the CGS comparison to GDC Criterion 3 for fire protection.

The construction permit for CGS was granted March 1973 and the design of the plant fire systems began in the following years. Section F.2.1 describes the code-of record edition of the committed fire codes followed for plant design. Section 1.2.2.12.11 provides a summary of the CGS fire protection systems.

Following the March 22, 1975 Browns Ferry Fire, BTP APCSB 9.5-1, Appendix A was issued. On September 30, 1976, Energy Northwest was requested to conduct an evaluation of the FPP at CGS using the guidelines in BTP APCSB 9.5-1 Appendix A. Since then, the comparison to BTP APCSB 9.5-1, Appendix A has been maintained current in FSAR Appendix F, Table F.3-1.

10 CFR 50, Appendix R and 10 CFR 50.48 became effective on February 17, 1981. 10 CFR 50, Appendix R added new expectations for the fire protection of safe shutdown capability, emergency lighting, and lubricating oil collection systems for non-inerted containment reactor coolant pumps. Appendix R, Sections III.G/L, III.J, and III.O are 10 CFR 50.48 requirements for plants licensed to operate prior to January 1, 1979. Columbia Generating Station received its operating license on December 20, 1983 and Appendix R is not an applicable regulation to CGS. In letter dated October 15, 1981, the NRC requested CGS submit a comparison to Appendix R that would be used as a guideline for review of fire protection requirements. In NRC Safety Evaluation Report (SER) dated March 1982 Section 9.5.1 indicated Energy Northwest agreed to conform to 10 CFR 50, Appendix R. The above paragraph discussion indicates Appendix R to 10 CFR 50 is a commitment for CGS and not an applicable regulatory requirement. Therefore, CGS is not an “Appendix R plant,” but does maintain a comparison to all the sections of Appendix R as “commitments” in FSAR Table F.3-2. Deviations to 10 CFR 50, Appendix R are documented in Table F.3-2. A deviation to Appendix R, Sections III.G/L and III.J has a higher potential to impact the ability to achieve post-fire safe shutdown. Since CGS has an inerted primary containment, Appendix R, Section III.O is not applicable.

From 1982 to 1989, various NUREG-0892 NRC SERs for the CGS FPP were issued. Section F.7.4 lists the SERs for the CGS FPP. These SERs compared CGS to the Standard Review Plan BTP CMEB 9.5.1 (which includes the combined guidelines of BTP 9.5-1, Appendix A and 10 CFR 50, Appendix R).

Generic Letters 86-10 and 88-12 provided guidance on moving the fire protection Technical Specifications into the FSAR and adopting the standard fire protection license condition. Each of these changes was approved in SER dated May 25, 1989 and incorporated into Facility

Operating License (FOL) Amendment 67 (see Reference F.7.4.m). The fire protection system Technical Specifications was moved to FSAR F.5 but later moved to LCS 1.10.

Facility Operating License Amendment 67 modified FOL Condition 2.C.(14) such that the approved FPP (FSAR Amendment 39 and SERs) may be altered without prior NRC approval provided the change does not adversely impact the ability to achieve and maintain safe shut down in the event of fire. Based on the FOL Condition 2.C.(14) criteria and initial date of issuance, numerous FSAR changes have been made to Appendix F since FSAR Amendment 39. The FOL Condition 2.C.(14) “approved CGS FPP” is the current amendment of FSAR Appendix F and its referenced documents.

Based on the above, section F.7.1 lists the applicable FPP regulatory requirements and commitments.

F.2 FIRE PROTECTION SYSTEMS

Fire protection is provided through a combination of active and passive features which function to detect, contain, and suppress potential fires. These features include:

a. Fire resistive construction

b. Fire detection and alarm systems

c. Fire suppression systems

    1. Fire water supply system

    2. Deluge water spray systems

    3. Wet pipe sprinkler systems

    4. Preaction sprinkler systems

    5. Carbon dioxide systems

    6. Halon 1301 systems

    7. Dry chemical suppression systems

d. Manual fire fighting equipment

    1. Protective clothing and self-contained breathing apparatus (SCBA)

    2. Yard fire hydrants

    3. Standpipes, hose, and foam carts

    4. Portable extinguishers

    5. Smoke removal

e. Operator action equipment

   1. Emergency lighting

   2. Emergency communications

The design of the plant fire protection features is described below.

F.2.1 APPLICABLE INDUSTRY STANDARDS

The following industry standards are used, where applicable, in the design of the fire protection systems serving the reactor building, radwaste/control building, diesel generator building, turbine generator building, circulating water pump house, water filtration building 33, and transformer yard. Design-related differences between the installed plant configuration and industry standards are listed in Table F.2-1. See Section F.2.7 for inspection and testing.

a. NFPA 10 - 1975, Standard for Portable Fire Extinguishers;

b. NFPA 12 - 1973, Standard on Carbon Dioxide Extinguishing Systems;

c. NFPA 12A - 1973, Standard on Halogenated Fire Extinguishing Agent-Halon 1301;

d. NFPA 13 - 1975, Standard for the Installation of Sprinkler Systems;

e. NFPA 14 - 1974, Standard for the Installation of Standpipe and Hose Systems;

f. NFPA 15 - 1973, Standard for Water Spray Fixed Systems for Fire Protection;

g. NFPA 20 - 1974, Standard for the Installation of Centrifugal Fire Pumps;

h. NFPA 24 - 1973, Standard for Outside Protection;

i. NFPA 30 - 1973, Standard for Flammable and Combustible Liquids Code. See Table F.3-1 paragraph D.2.d for applicability;

j. NFPA 50A - 1973, Standard for Gaseous Hydrogen Systems at Consumer Sites. See Table F.3-1 paragraph D.2.b for applicability;

k. NFPA 70 - 1975, National Electric Code. Used for the design of electrical equipment and wiring for the main control room cabinet Halon 1301 systems and for wiring of the fire detection and alarm initiating devices;

l. NFPA 72A - 1975, Standard for the Installation, Maintenance and Use of Local Protective Signaling Systems for Watchman, Fire Alarm and Supervisory Service;

m. NFPA 72D - 1975, Standard for the Installation, Maintenance and Use of Proprietary Protective Signaling Systems for Guard, Fire Alarm, and Supervisory Service;

n. NFPA 72E - 1974, Standard for Automatic Fire Detectors;

o. NFPA 78 - 1975, Lightning Protection Code. See Table F.3-1 paragraph A.4 for applicability;

p. NFPA 80 - 1974, Standard for Fire Doors and Windows;

q. NEDO-10466-A, Power Generation Control Complex Design Criteria and Safety Evaluation. See Table F.3-1 paragraph E.4.a for applicability;

r. IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations. Where cable does not meet IEEE 383, NFPA 262-1990 or UL 910-1985 may be used. See Table F.3-1 paragraph D.3.f for further clarification;

s. Regulatory Guide 1.52, Revision 1, Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants. See Table F.3-1 paragraph D.4.d for applicability;

t. ANSI A21.4,-1974. See Table F.3-1 paragraph E.2.a for applicability;

u. NFPA 72-2013, National Fire Alarm and Signaling Code. See F.2.3 for applicability;

v. AMSE A.17.1 – 2010, Safety Code for Elevators. For Elevator Fire Protection Panel FP-CP-MT4; and

w. NFPA 72 – 2010, National Fire Alarm and Signaling Code. For Elevator Fire Protection Panel FP-CP-MT4.

Current editions of the above codes are used for modifications and additions to the plant fire protection systems when new facilities or systems are constructed or enhanced and defense-in-depth is warranted. In some cases, the guidance of more recent code editions may be followed which deviates from designs of the above code of record, without a corresponding Table F.2-1 discussion (when managed through administrative controls and maintained as a plant record).

F.2.2 FIRE RESISTIVE CONSTRUCTION

Fire barriers and fire resistive construction prevent the spread of fire from one location to another. Fire resistance is provided in building construction through the use of noncombustible structural materials. Rated fire barriers further isolate certain high hazard areas and provide additional separation for those systems needed for post-fire safe shutdown.

Essential fire rated assemblies are those fire area boundary features which separate fire areas with redundant post-fire safe shutdown equipment/cables or those fire areas containing redundant post-fire safe shutdown cables where one division is protected by raceway fire barriers. The overall category of fire rated assemblies (see LCS 1.10.5) can be broken into subcategories of fire area boundary features, raceway fire barriers, and fireproof coatings.

Figures F.6-1 through F.6-5 show the fire area boundaries, barrier hourly fire ratings, and barrier classifications. Reference F.7.7.o is the raceway fire barrier drawings.

F.2.2.1 Fire Area Boundary Features

Structural fire barriers may be provided by wall, floor, or ceiling assemblies. The fire rating of structural fire barriers is described in Section F.4 fire hazards analysis. A concrete wall with a thickness of 6 in. or greater provides a 3-hr rating. Based on the construction of masonry fire barriers, the fire rating may vary from 2 to 3 hr. The fire resistance rating for structures is determined using information from the NFPA Fire Protection Handbook, vendor data, industry fire resistance directories, and/or engineering evaluation. The containment fire barrier is not a standard 3-hr rated assembly but is adequate to prevent fire propagation.

Fire doors, fire dampers, and fire rated penetration seals are typically designed with a fire rating equivalent to that of the structural barrier in which they are installed. The 2-hr barriers may have 1.5-hr rated doors and dampers.

Fire doors are installed to the guidelines of NFPA 80 - 1974, with exceptions contained in Table F.2-1. Non-fire rated specialty doors (air lock, flood, radiation shield, and blast doors) located in fire barriers are installed based on equivalent door construction, as approved in Reference F.7.4.c.

Penetrations for ventilation systems through fire rated barriers are protected by fire dampers. Some plant areas have 1.5-hr rated fire dampers in 3-hr barriers, as approved by Reference F.7.4.a. Certain fire damper assemblies consist of a 3-hr listed fire door as the guillotine or trap door, installed in unlisted frames or supports. The construction and installation of the frames and supports is similar to listed assemblies. Although the design has not been fire tested and listed as a fire damper assembly, it was approved by Reference F.7.4.f. As approved in Reference F.7.4.l, fire dampers are not drop tested under air flow conditions since administrative controls are present to shut down ventilation on confirmation of a fire. All fire dampers in rooms containing safety-related equipment are qualified to Seismic Category I.

Conduit, piping, and cable penetrations are sealed where they pass through the barrier, except for some internal conduit seals where evaluation has shown no seal is required. Penetration seals provide a fire resistance equal to that of the barrier unless a fire protection evaluation has justified a lesser fire rating. Grouted penetrations are sealed with grout to the same thickness of the wall and are assumed not to degrade the rating of the penetrated fire barrier. The fire rating of nongrouted penetration seal designs is established by tests performed in accordance with Reference F.7.6.b. Qualification of fire-rated and pressure-rated penetration seals is contained in Reference F.7.6.a. Configuration control of penetration seals is maintained by Reference F.7.5.q.

The containment barrier and penetrations are nonstandard fire barriers not qualified by representative fire testing. See Section F.2.2.5 for more details.

F.2.2.2 Raceway Fire Barriers

Raceway fire barriers are used to prevent damage to designated circuits within a fire area in the event the redundant post-fire safe shutdown circuits are damaged by fire. Raceway fire barriers wraps are constructed of Darmatt KM-1, or 3M Interam E-50D/E54A.
Darmatt KM-1 raceway fire barriers are installed to 1 or 3-hr rated designs qualified by fire testing meeting Generic Letter 86-10 Supplement 1 acceptance criteria (Reference F.7.6.m).
3M Interam raceway fire barriers are installed to 3-hr rated designs qualified by fire testing meeting Generic Letter 86-10 acceptance criteria (Reference F.7.6.k). Structural steel supports and intervening steel members for raceway fire barriers are wrapped to the distance qualified by fire testing. Load bearing supports in 1-hr fire areas need not be protected to the structural barrier (Reference F.7.3.g). Reference F.7.4.f approved that unprotected commodities can be located above raceway fire barriers wraps.

A second category of raceway fire barriers is Whittaker mineral insulated (MI) fire rated cable. MI fire rated cable is 3-hr rated in Fire Areas R-1 and TG-1, and credited as 1-hr rated in Fire Area RC-3 (Reference F.7.6.j). In 3-hr areas, the MI fire rated cable is routed to ensure the fire induced collapse of unprotected items does not adversely affect cable operability (Reference F.7.7.o). The support designs limit the amount of zinc exposure and the potential for liquid metal embrittlement (Reference F.7.5.u and F.7.7.o).

F.2.2.3 Fireproof Coatings

Thermo-Lag 330-1 is used as a fire resistive coating on certain reactor building structural steel members supporting post-fire safe shutdown credited instrument tubing and tray support TS-5269 to protect Whittaker MI fire rated cable routed below (Reference F.7.6.l).

F.2.2.4 Electrical Separation Barriers

Electrical separation barriers are present throughout the plant to limit internally generated fire damage to nearby redundant safety-related systems. See Section 8.3.1.4 for more detail.

Plant building construction is further described below. The Section F.4.4.4 fire hazards analysis for each fire area has additional building construction and fire rating details.

F.2.2.5 Reactor Building

Exterior walls, floors, and ceilings are reinforced concrete from the top of the foundation mat to the refueling floor level. The minimum thickness of reinforced-concrete walls is 1 ft. From the refueling level to the top of the roof, the exterior walls are framed with structural steel and are enclosed with insulated metal wall panels. The reactor building is separated from other plant buildings by 3-hr fire rated reinforced-concrete walls and nonrated steel airtight doors. The building roof is a Factory Mutual Class I insulated steel roof deck.

Within the reactor building, Class 1E motor control centers are enclosed to provide separation from the general area hazards. Partial height concrete walls on the 471 ft, 501 ft, and 522 ft el. protect four Division 2 instrument racks. Fire barriers with nonrated steel flood doors separate the safety-related pump rooms below grade.

Primary containment is inerted during operation. There is no permanently installed fire protection equipment inside containment. Portable extinguishers and manual hoses are available for fire suppression when containment is deinerted for maintenance during plant outages.

The annular gap constructed between the metal shell and the primary containment vessel and the concrete biological shield wall, above 446 ft, is filled with a compressible insulating spacer system consisting of polyurethane flexible foam sheets butted at the joints and cemented directly to the primary containment shell, a jacket of premolded fiberglass reinforced polyester jacket panels, and epoxy flashing. The foam spacer is in a confined space, exposed to a minimal quantity of air through clearance around pipe penetrations. There is adequate spatial separation from the foam to the nearest combustible (electrical cable insulation) to reduce the possibility of a fire spreading into the foam liner. Mechanical penetrations within a 20-ft surface radius of Appendix R protected containment penetrations in Division 1 fire areas are 3-hr fire rated to ensure the combustible spacer/liner material does not ignite. Other containment mechanical penetrations have nonrated radiant energy refractory ceramic fiber seals. Fire spread in the annular gap would be very slow due to the limited space and oxygen deficient atmosphere. The metal vessel liner and the concrete bioshield wall would act as large heat sinks and further slow fire propagation. The use of refractory ceramic fiber seals was approved by Reference F.7.4.1.

Stair and elevator shafts in the reactor building are constructed of noncombustible reinforced concrete. Air locks are constructed of reinforced concrete with steel airtight doors.

F.2.2.6 Radwaste/Control Building

The vital island section of the building consists of reinforced-concrete walls, floors, and ceilings from the top of the foundation mat up to and including the roof slab. The radwaste sections of the building are constructed of reinforced-concrete walls, floors, and ceilings at the lower levels and structural steel framing with reinforced-concrete floors and enclosure walls on insulated metal wall panels at the upper levels. The building roof is Factory Mutual Class I insulated steel roof deck.

The main control room walls are 3-hr rated reinforced concrete.

The main control room contains steel enclosed power generation control complex (PGCC) units which are divisionally separated. Each unit consists of a false floor assembly, a vertical panel and/or benchboard panel, and a termination cabinet. All cables entering through the floor cable penetrations are sealed. The cables enter either directly into the false floor assembly to the control panels and terminate there or into an enclosed steel trough which extends to the termination cabinets. The remaining cables penetrating the control room floor behind the termination cabinets are compatible divisional cables routed in flexible metal conduit. Penetrations into the back of the panel assembly are fire stopped or sealed.

The remote shutdown room, the vital switchgear rooms and battery rooms, the reactor protection system rooms, and their respective mechanical equipment rooms are divisionally separated by 3-hr rated enclosures.

Stairs constructed of noncombustible material are enclosed in 2-hr minimum fire rated walls. The elevator is enclosed in a reinforced-concrete shaft.

From grade level 441 ft to 460 ft, the west wall facing the alternate health physics building is 3-hr rated.

F.2.2.7 Turbine Generator Building

The turbine building is separated from all other areas of the plant by noncombustible reinforced masonry block and/or concrete construction with hollow metal or steel doors. The building roof is a Factory Mutual Class I insulated steel roof deck.

The exterior walls of the turbine building are reinforced concrete or structural steel covered by insulated metal panels. Within the area, reinforced-concrete walls contain the turbine, feedwater heaters, and condenser. At the operating floor level, the reinforced-concrete walls isolating the turbine continue for a height of 23 ft 6 in. From the top of this wall, the structure changes to structural steel covered with insulated metal panels up to the roof level. A section of the exterior north wall is also structural steel covered with insulated metal panels. Equipment access areas at the grade, mezzanine, and operating levels are contained with reinforced-concrete masonry units and insulated metal panels.

Rated fire barriers are provided to isolate high hazard areas:

a. The turbine generator lube oil conditioning system room (containing reservoir, separator, transfer pump, etc.) is located within 3-hr fire rated reinforced-concrete and masonry block walls. The oil cooler heads are open to the 501 ft floor level but is protected by deluge system 55;

b. The turbine generator lube oil storage tanks are located within 3-hr fire rated reinforced-concrete and masonry block walls and fire doors;

c. The auxiliary boiler room is separated from adjacent areas by 3-hr fire rated reinforced-concrete and masonry block walls;

d. The hydrogen seal oil room is separated from adjacent areas by 3-hr fire rated reinforced-concrete and masonry block walls;

e. The makeup water pump house transformer vaults are separated from adjacent areas by 3-hr fire rated reinforced-concrete and masonry block walls;

f. See Figures F.6-1 and F.6-2 for turbine building north wall facing transformer yard fire rating; and

g. From grade level 441 ft to 501 ft, the west wall facing the adjustable speed drive (ASD) building (Column D.3-H) is 3-hr fire rated.

Stairs of noncombustible material are enclosed in walls of 2-hr minimum rated construction. The elevator is enclosed in a reinforced-concrete shaft.

F.2.2.8 Diesel Generator Building

Exterior walls, floors, and ceilings are reinforced concrete of varying thicknesses from the top of the foundation mat to the roof. The building is divided into separate compartments by reinforced-concrete walls. The walls separating the diesel compartments and the walls separating the diesel generator building from adjacent plant buildings are 3-hr fire rated. The exterior walls of the building are nonrated.

F.2.2.9 Standby Service Water Pump Houses No. 1A and 1B

Exterior walls and roof are of nonrated reinforced-concrete construction. Floors are metal grating or reinforced concrete.

F.2.2.10 Service Building

The service building is separated from the turbine building and the reactor building by 3-hr rated reinforced-concrete walls.

F.2.2.11 Circulating Water Pump House and Chlorination Building

The building has a reinforced-concrete floor, insulated metal wall panels, and a metal roof deck over structural steel framing. The circulating water pump house and the chlorination sections of the building are separated by a reinforced-concrete masonry wall. The diesel fire pump fuel storage tank room is isolated by 2-hr rated walls.

F.2.2.12 Cooling Towers

The cooling towers are of noncombustible construction (except for fan shrouds, fan blades, fill material, and drift eliminators).

F.2.2.13 Water Filtration Building 33

The building has a reinforced-concrete floor, insulated metal wall panels, and metal roof deck over structural steel framing. All barriers are nonrated.

F.2.2.14 North Yard Transformers

The yard transformers are separated from the turbine building by 2-hr rated barriers and spatial separation. Fire barrier walls are installed between the main transformers E-TR-M1, E-TR-M2, E-TR-M3 and E-TR-M4. Other transformers are not separated by fire barriers.

F.2.2.15 Technical Support Center

The technical support center is separated from the radwaste building by 3-hr rated barriers.

F.2.2.16 Alternate Health Physics Building

The alternate health physics building is separated from the radwaste building and turbine building by 3-hr rated barriers.

F.2.2.17 Reactor Recirculation Pump Adjustable Speed Drive Building

The reactor recirculation (RRC) pump ASD building has a reinforced-concrete floor, insulated wall panels, and a metal roof deck over structural steel framing. The building walls on the west and north side are 2-hr rated. The adjacent turbine building wall is 3-hr rated. The concrete barriers separating and to the north of the ASD transformers are 2-hr fire rated.

F.2.3 FIRE DETECTION AND ALARM SYSTEMS

The fire detection and alarm systems are designed to rapidly identify developing fire conditions. Signals from plant fire detection instruments and fire suppression system alarms are transmitted via a proprietary fire alarm system to a fire alarm panel in the main control room.

Standard and functional zone annunciation indicator lights are located on the fire control panel in the main control room. Standard zone annunciation results from the installed fire detection instruments. Functional zone annunciation derives from the activation of individual devices such as deluge system flow devices, wet pipe sprinkler system flow devices, preaction system flow devices and low pressure sensors, carbon dioxide flow devices, and fire pump status. Some remote fire control panels and all main control room fire control panels have individual bells that sound automatically whenever their associated alarm devices are activated. There are no devices to automatically record incoming signals to the main control room. See Table F.2-1 for alternate recording methods.

Ionization, photoelectric, air duct ionization, thermal, ultraviolet fire detectors or incipient smoke detection are installed in hazard areas of the plant. Smoke detectors (ionization and photoelectric) are generally installed in areas containing moderate amounts of combustibles with no large combustible oil or gas hazards. Ionization detectors are not located in areas where the background radiation exceeds the manufacturer's rating. The sensitivity of thermal detectors is based on the normal average air temperature in the area where they are located. The incipient smoke detection system is located in the RW 467´ vital island where early warning is beneficial to fire safety. The incipient detectors draw a continuous flow of air through sampling ports into tubing spaced near the ceiling.

Manual fire alarm pull stations are generally located near exterior doorways and at each elevation of the main plant buildings in close proximity to the stairwells. Manual fire alarms are wired with other detection and alarm devices in appropriate fire detection zones.

Standard and functional alarms in the main control room do not initiate a plant-wide alarm signal. Depending on the fire condition, voice announcements over the public address system or emergency evacuation alarms may be used to warn plant personnel. A manual push button in the control room initiates a coded fire alarm radio signal to the DOE fire department dispatch center.

The fire protection system wiring for alarm initiation, alarm signaling, and control room annunciation at the fire control panel is electrically supervised to prevent false fire alarms due to open or grounded wiring. The supervisory circuitry sounds a trouble alarm using a single buzzer on the fire control panel on detection of open circuits, short circuits, low water pressure, low air pressure, or other trouble condition.

Fire detection systems which actuate suppression systems in safety-related areas have Class A circuitry (as defined in NFPA 72D - 1975). Other fire detection system wiring is Class B.

The plant fire detection system is powered from a local power panel which is normally supplied from uninterruptible power. Backup power is supplied from onsite emergency diesel generators.

The fire control panel mounted in the main control room is designated Seismic Category IM; all panel mounted equipment in this room is designated Seismic Category II. Other fire detection equipment, components, and accessories are designated Seismic Category II.

Portable detection systems may be used as a backup to fixed plant fire detection systems or as additional compensatory measures.

The fire detection system is designed in accordance with the guidelines of NFPA 72D - 1975 and NFPA 72E – 1974, except the incipient smoke detection system is designed in accordance with the guidelines of NFPA 72-2013. Differences between the installed plant configuration and the NFPA code sections are documented in Table F.2-1. Reference F.7.4.f approved deletion of fire detection in various plant areas.

The Radwaste elevator (MT-ELEV-4) fire detection zone is designed in accordance with the guidelines of ASME A.17.1 – 2010 and NFPA 72-2010. Detection is provided for every elevator car landing, the top of the elevator hoist way, and the equipment room. The system provides primary elevator recall, alternative elevator recall, and fire fighter emergency operation.

F.2.4 FIRE SUPPRESSION SYSTEMS

Automatic and manual suppression systems and manual fire fighting equipment are located within the plant as described below. The type of fire suppression provided for a particular plant area is based on consideration of the nature of the fire hazard in the area, the type of equipment protected, and the physical arrangement of the area. Fixed automatic suppression systems are installed to protect areas or equipment containing large quantities of combustibles, oils, or gases. Reference F.7.4.c approved the lack of fire suppression in various plant areas. Plant areas with fire suppression coverage and type of suppressant are shown in Figures F.6-7 through F.6-11.

The fire protection system is designed such that inadvertent operation or failure of any component of the system will not impair the ability of engineered safety features to safely shut down or isolate the reactor, or to limit the release of radioactivity to the environment in the event of an accident.

Fire protection system piping in Seismic Category I areas of the reactor building, the diesel generator building, the radwaste control building, and the reactor/radwaste corridors, required to be seismically supported/mounted, are designed to Seismic Category IM and Quality

Assurance Class II+. Fire protection system piping not required to be seismically supported/mounted are designed to Seismic Category II and Quality Assurance Class II.

F.2.4.1 Fire Protection Water Supplies

The fire protection water supply system consists of a primary fire water supply, a secondary fire water supply, and yard mains to distribute water to the yard hydrant isolation valves and building standpipes. The fire protection water supply system is shown schematically in Reference F.7.7.1 and Figure F.6-21.

The primary water supply is drawn from the circulating water pump house basin. See Table F.3-1 section E.2.d for additional details.

The primary fire protection water supply consists of three fire pumps: two electric (FP-P-2A and FP-P-2B) and one diesel driven (FP-P-1), each of which have a design capacity of 2000 gpm at a total dynamic head of 289 ft. The primary fire pump discharge lines are piped so that each electric motor-driven pump discharges to the underground fire main loop (also referred to as fire main ring header).

Each of the three primary fire pumps is furnished with an automatic air release valve. In addition, the primary diesel-driven pump is furnished with a pressure relief valve and an open discharge cone back to the circulating water basin. Each electric motor-driven pump is furnished with a circulation relief valve. Three 10-in. fire protection branch lines have been provided (one for each fire pump) to a flow element, six-headed test header for fire pump testing. Fire protection water to the plant underground fire protection loop is supplied by two 12-in. fire protection main feed lines from the fire pump discharge.

The secondary water supply is drawn from a 400,000-gal embankment supported bladder tank (FP-TK-110) with a dedicated water supply of 284,640 gal. The water supply is delivered to the fire main loop by diesel-driven fire pump (FP-P-110) located in the water filtration building. The diesel fire pump is rated at 2500 gpm at a total dynamic head of 323 ft. The secondary water supply connects to the fire loop through a 10-in. branch line.

A pressure maintenance jockey pump (primary water supply jockey pump (FP-P-3) or secondary water supply jockey pump (FP-P-111)) is normally running to maintain system pressure. Pressure control valves installed on the jockey pumps discharge limit system pressure to below 175 psig.

One or multiple fire pumps will start if the other running fire pumps cannot maintain system pressure. A drop in system pressure below 120 psig will cause motor-driven fire pump (FP-P-2A) to automatically start. A second motor-driven pump (FP-P-2B) will start after a 10 second delay, if pressure drops to 110 psig. The primary diesel-driven pump (FP-P-1) will start after a 15 second delay (20 second delay for loss of controller power), if pressure drops to 110 psig. The secondary diesel-driven fire pump (FP-P-110) will start after a 30 second delay (35 second delay for loss of controller power), if pressure drops to 100 psig. The above fire pump sequencing, along with reduced voltage soft start controllers and standpipe vacuum breakers, limit system pressure transients (Reference F.7.3.x).

The capacity of the fire water pumps is based on a maximum probable water system demand (1872 gpm in the cable spreading room), 500 gpm for a hose stream, and standby pump capacity available. Each motor-driven fire pump controller and each diesel-driven fire pump controller contains automatic start controls and manual start/stop controls. Any fire pump can be started either locally or from the main control room. After a start, a fire pump can be stopped only locally at the pump controller. Fire pump start, failure to start, and loss of current to the motor-driven pumps is indicated in the control room. Diesel-driven fire pump alarms include fire pump start, fire pump failure to start, high jacket water temperature, low oil pressure, and engine overspeed.

In the event of electrical power failure to a diesel-driven fire pump controller, the associated diesel-driven fire pump will start automatically. Both motor-driven fire pumps are inoperative during loss of offsite power.

Since either water supply can provide the necessary water demand and the circulating water basin is not considered a tank, the primary and secondary water supplies need not be interconnected.

Mitigation of system water hammer, from actuation of suppression systems causing standpipe voiding, is accomplished by diesel fire pump sequencing, redundant vacuum breakers at various standpipes (see Section F.2.5.3), and check valve FP-V-26 on the RWB-1 standpipe.

Fire protection water is distributed through a 12-in. underground fire main to supply station hydrants, fire hose stations, and suppression systems. The looped arrangement of the fire protection system ensures continued flow to the remainder of the system when sections of the system are isolated for tests or repairs. Post indicator valves sectionalize the yard loop to increase the reliability of fire protection water supply in case of a fire main break.

A series of 12-in. and one 8-in. branch lines lead from the underground fire main loop to various building standpipes. Each line contains an outside post indicator isolation valve. See Reference F.7.7.1 for more detail.

A fire main is routed under the diesel generator building. This was approved according to Reference F.7.4.k.

Leakage in the fire protection underground is monitored by a flow totalizer on the bypass line of the detector check valve on the discharge line of the jockey pump in the circulating water pump house. Serious leaks or a rupture of the fire protection system piping could also be indicated by fire pump running alarms in the main control room with no concurrent fixed automatic or preaction fire protection system operating alarms, no detector fire alarms, and no report of any fire or use of fire hose.

The location of a fire main leak may be determined by visual observation. If no visual indications are present, the location of the leak could be determined by using the sectionalizing valves to isolate a section of the system and observing the flow meter gauge on the detector check valve. The leak would be indicated by a decrease in flow as the section is isolated.

The fire protection water supply system interfaces with other plant systems include: 1) the 480 V AC distribution system supplies power to fire pump motors FP-M-P/2A (E-SL-51) and FP-M-P/2B (E-SL-61), 2) the tower makeup (TMU) system provides water from the Columbia River to the circulating water (CW) system basin which is the primary fire protection water supply, 3) the potable water cold (PWC) system provides water from PWC-TK-100 to the FP-TK-110 bladder tank which is the secondary fire protection water supply, 4) the fire protection water supply system provides water for motor cooling for both plant service water (TSW) pumps 1A and 1B (TSW-P-1A and TSW-P-1B) during initial TSW system startup and for bearing lubrication to TSW pump 1B (TSW-P-1B) during initial TSW system startup and 5) the fire water supply system provides a water sample to the dehalogenation system (CL-SKID-2) when TSW is not in-service. The fire protection water supply system can provide water via fire hose connections to: 1) the control air system (CAS), service air (SA) system via the cooling jacket water (CJW) system as an emergency source of cooling in the event that TSW is lost; 2) the condensate (COND) system as an alternate injection system to the reactor pressure vessel, 3) the fuel pool cooling (FPC) system spent fuel pool as an emergency makeup source in the event that demineralized water(DW) and standby service water (SW) are lost.

The fire pump installation is designed in accordance with the guidelines of NFPA 20 - 1974. Differences between the fire pump installation and the NFPA code sections are listed in Table F.2-1. The installation of the underground fire main is designed in accordance with the guidelines of NFPA 24 - 1973. Differences between the underground fire main installation and the NFPA code sections are listed in Table F.2-1.

F.2.4.2 Wet Pipe Sprinkler Systems

Wet pipe sprinkler systems are installed to provide automatic fire suppression of general area hazards. Wet pipe sprinklers consist of closed sprinklers attached to piping which contains water under pressure at all times. System operation is initiated when the local temperature rise from a fire reaches the operating temperature of fusible link sprinkler heads. Water discharge allows the hinged clapper in the alarm check valve to open. Valve operation provides remote alarm/indication in the main control room.

Temperature ratings for automatic sprinkler heads are selected based on normal area temperatures and proximity to heat generating components.
Sprinkler system piping may be designed using pipe schedules or hydraulically calculated to provide a minimum design density according to the nature of the hazard protected. See Figures F.6-7 through F.6-11 for locations of wet pipe sprinkler systems.

The wet pipe sprinkler system installation in the main control room is designed in accordance with the guidelines of NFPA 13 - 1975. This is the only wet pipe sprinkler system which protects a safety-related area. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.4.3 Preaction Sprinkler Systems

Preaction systems are used in areas where inadvertent operation of the sprinklers could damage or cause outages of vital electrical equipment. Preaction systems are installed in the cable spreading room and cable chase in the radwaste building, the reactor/radwaste corridor, the diesel generator building, and the RRC pump ASD building.

The preaction systems have closed fusible link sprinkler heads. Downstream of the control valve, the preaction sprinkler piping is normally dry and pressurized with air to supervise piping system integrity. Low air system pressure, which could indicate damaged piping or sprinkler heads, is alarmed in the control room. The CAS system provides supervisory air for preaction systems, except P85 which has its own compressor. Fire detectors located in the protected area activate a solenoid valve to open the deluge valve, supplying water to fill and pressurize the sprinkler system piping. Pull stations are also provided to allow manual operation of the preaction system. Sprinkler flow is not initiated until the local temperature increases to the operating temperature of the closed fusible link sprinkler heads.

In the cable spreading room, cable chase, ASD building, and reactor/radwaste corridor smoke detectors are used to trip the preaction system. The diesel generator preaction systems are actuated by thermal detectors. Detector operation and preaction system flow devices alarm in the main control room.

The preaction sprinkler systems installed in safety-related areas are designed in accordance with the guidelines of NFPA 15 - 1973. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.4.4 Deluge Water Spray Systems

Deluge water spray systems are used where fast response may be required to control or extingui sh a fire. A deluge system employs open nozzles attached to a normally dry piping system. Fire detectors located in the hazard area activate a solenoid valve to open the deluge valve and initiate water flow. Electric heat actuating devices (HAD) indicate fire conditions by sensing an abnormally high temperature or an unusually rapid rise in temperature. Detector operation and deluge system waterflow devices alarm in the main control room.

Deluge water spray systems provide automatic fire protection for various locations in the turbine generator building where oil is stored or piped, for yard transformers, and for the reactor feed pump rooms in the turbine generator building. Spray nozzles near the transformer bushings are carefully placed to avoid flashovers at the bushings or to the piping.

Manually actuated deluge water spray systems are installed to protect charcoal filters in certain HVAC filter units. High temperature signals are used to alarm control room operators to potential fire conditions. The CAS system supplies air to the air operators of the SGT deluge valves.

Deluge water spray systems installed in safety-related plant areas are designed in accordance with the guidelines of NFPA 13 - 1975 and NFPA 15 - 1973. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.4.5 Carbon Dioxide Fire Suppression Systems

The low pressure carbon dioxide system automatically provides fire protection for the turbine generator exciter housing. A 1-in. manual carbon dioxide hose station, with reel and 100 ft of hose, is also provided for exciter housing protection on the turbine operating floor (501 ft). The carbon dioxide storage tank also provides carbon dioxide for generator purging during startup and shutdown conditions. The capacity of the carbon dioxide unit is 6 tons. Interlocks are provided such that the generator purge system cannot draw down tank level below that needed for automatic fire protection of the exciter housing.

The carbon dioxide unit is located in the northwest corner of the 441 ft level of the turbine generator building. The low pressure carbon dioxide storage tank maintains liquid carbon dioxide at approximately 300 psig and 0°F by refrigeration. The refrigeration is accomplished by a compressor and refrigeration coil within the vessel. The carbon dioxide storage unit is electrically powered and automatically controlled and monitored by means of pressure switches. High or low carbon dioxide pressure causes a remote alarm and indication in the main control room.

Thermal detectors located in the generator exciter housing provide early warning alarm in the main control room allowing the operator to review and evaluate the problem prior to manual or automatic actuation of the system. Automatic operation of the carbon dioxide system is initiated when the temperature increases to the setpoint of the high temperature detector. However, if a fire is noticed before the temperature detector actuates the system, the system can be manually actuated by a break glass station located near the carbon dioxide protected area. An automatic timer regulates the carbon dioxide discharge for both automatic and manual electric operation to provide even distribution of the discharge.

Actuation of the system alarms locally and remotely in the main control room. The local alarms consist of two separate alarm devices located near the protected area. One device sounds 20 sec before its associated carbon dioxide system is released and the other device sounds continuously during the duration of such release.

The carbon dioxide system is designed in accordance with the guidelines of NFPA 12 - 1973. The carbon dioxide distribution system is shown schematically in Reference F.7.7.n.

F.2.4.6 Halon 1301 Fire Suppression Systems

Halon 1301 suppression systems are installed in normally occupied areas where the application of water would be inappropriate. Halon 1301 provides automatic fire protection for the main control room PGCC under floor areas.

Eighteen Halon 1301 systems are installed in the various main control room PGCC subfloor duct sections to discharge on activation of their associated thermal detector units. Each system is sized to provide a 20% Halon concentration for a minimum duration of 20 minutes. Cable penetrations into the PGCC are sealed to contain Halon discharge. Thermal detector operation also causes a local alarm and indication on the main control room fire control panel. Smoke detectors are located in each PGCC section to provide early warning alarm. Each system includes supervision features which actuate a trouble alarm and indication on the main control room fire control panel in case of a wiring or component failure.

The PGCC Halon suppression system is designed in accordance with the guidelines of NFPA 12A - 1973 and Reference F.7.5.j. See Section 8.3.1.4.3.6.2 and Figure 8.3-36 for more detail. The Halon system was approved according to Reference F.7.4.a.

F.2.4.7 Dry Chemical Fire Suppression Systems

Dry chemical suppression systems may be found installed in approved portable hazardous material storage buildings within the plant. These systems automatically actuate by melting of the fusible link(s) or manually by a local pull station. Columbia Generating Station is not committed to NFPA 17 compliance.

F.2.5 MANUAL FIRE FIGHTING EQUIPMENT

Manual fire fighting equipment includes protective clothing, SCBA, fire hydrants and hydrant hose equipment, standpipe and fire hose stations, AFFF foam carts, portable fire extinguishers, and smoke removal equipment.

F.2.5.1 Protective Clothing and Self-Contained Breathing Apparatus

Protective clothing and SCBAs are provided in designated locations for use by the plant fire brigade. The SCBA positive pressure masks are National Institute for Occupational Safety and Health (NIOSH) approved. At least a 1-hr supply of breathing air in extra bottles is located onsite for each required SCBA. See Table F.3-2 III.H for more details.

F.2.5.2 Yard Fire Hydrants and Hydrant Hose Equipment

Fire hydrants are provided at approximately 300 ft intervals along the fire main loop around the main plant buildings and at each standby service water pump house. A mobile fire response vehicle is equipped with the equivalent of three hose houses (see Table F.2-1). Fire hydrants adjacent to the transformers and the diesel generator building are strategically located as backup protection in the event of a large scale fire in these areas. Fire mains and hydrants are designed in accordance with NFPA 24 - 1973. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.5.3 Standpipes, Hose, and Foam Carts

Standpipe and hose connections provide a second line of defense for fires which may get beyond the extinguishing capabilities of hand fire extinguishers. Standpipes and hose racks are installed so that all safety-related areas are within 30 ft of the nozzle when 100 ft of 1.5-in. hose is attached to the connection. The reactor building has 150 ft of 1.5-in. hose to reach all areas as approved in Reference F.7.4.d. Most standpipes are located in protected stairways. Each standpipe contains an isolation valve, hose racks on each landing, takeoffs to sprinkler or other water fire protection systems where applicable, and a pressure gauge at the top of each standpipe. Two vacuum breakers are installed at the top of standpipes RB-1, RB-2, RWB-1, RWB-2, TGB-1, TGB-2, and TGB-3, but only a single vacuum breaker per standpipe is required to be functional. During a fire water system actuation, the vacuum breakers introduce an air bubble that mitigates potential pressure transients. Venting the small volume of trapped air would not hamper fire fighting activities. To ensure the availability of primary and secondary fire protection, the following standpipes have been interconnected: TGB-1 and TGB-2; TGB-3, TGB-5, and RWB-1; and DG-1 and the 12-in. branch line to RWB-1. Hose station locations are shown on Figures F.6-7 through F.6-11. Where large combustible liquid fire hazards exist, AFFF foam eductors/carts are present. Standpipes and hose are designed in accordance with NFPA 14 - 1974. Differences between the installed plant configuration and the NFPA code sections are listed in Table F.2-1.

F.2.5.4 Portable Extinguishers

Portable extinguishers are strategically located within the plant to provide plant personnel with a readily available means to extinguish a fire in its early stages. Halon 1211, dry chemical, foam/water AB and wheeled dry chemical extinguishers are used. Portable fire extinguishers are installed in accordance with NFPA 10 - 1975 based on the class and quantity of combustibles in that location.

F.2.5.5 Smoke Removal

Portable fans are available for smoke removal. Fixed smoke removal fans consist of WEA-FN-52 which purges the cable spreading room, cable chase, and remote shutdown room. WEA-FN-7 is located on the radwaste building 507-ft roof and is used primarily for purging the main control room. Large portable fan REA-FN-16 can be connected to the reactor building HVAC exhaust at 471 ft and 572 ft. See Section 6.4 for control room actions and habitability during onsite and offsite fires. Smoke purging activities include monitoring to prevent an uncontrolled release.

F.2.6 OPERATOR ACTION EQUIPMENT

Equipment for credited operator actions consists of emergency lighting and communication equipment.

F.2.6.1 Emergency Lighting

Fire protection credited emergency lighting falls into two categories: (a) 1.5-hr battery-backed life safety lighting systems and diesel backed emergency AC lighting and (b) 8-hr Appendix R credited lighting consists of fixed 8-hr battery units, diesel backed normal-emergency AC lighting and portable 8-hr lanterns. See Section 9.5.3 and Figures F.6-18 through F.6-20 for more detail.

F.2.6.2 Emergency Communications

Private branch exchange (PBX) is used for some post-fire safe shutdown operator manual actions that require communication with the control room or the remote shutdown room, See Figures F.6-18 through F.6-20. The specific manual operator actions that require PBX communications are listed in Reference F.7.3.d. LCS 1.10.8 ensures the specific credited PBX phones remain functional. Fire brigade activities utilize either radio or PBX phones for communication with the control room or remote shutdown room. No single fire will disable fire brigade communications (Reference F.7.3.ff). See Section 9.5.2 for more detail on communications.

F.2.7 INSPECTION AND TESTING

Periodic inspection and testing of fire suppression water supply systems, essential spray and sprinkler systems, fire hose stations, yard fire hydrant and hydrant hose equipment, essential fire rated assemblies, fire detection instrumentation, PFSS lighting, and PFSS communications is in accordance with LCS 1.10. Periodic inspection and testing of carbon dioxide suppression system, Halon systems, dry-chemical suppression system, manual fire extinguishers, non-essential spray and sprinkler systems, and non-essential fire-rated assemblies is in accordance with either Section F.2.1 NFPA codes, insurer criteria, manufacturer recommendations, or applicable industry guidance as documented in the engineering evaluations per Section F.4.2.3.

Periodic testing is performed within the specified intervals with a maximum allowable extension not to exceed 25% of the interval. Periodic tests need not be performed on inoperable equipment. Testing which would require entry into high radiation areas is performed when radiation levels allow. However, there are some areas of CGS that remain high radiation areas at all times which will require an ALARA evaluation to determine the respective testing interval.

Inspections of the fire pump diesel engines will be conducted periodically in accordance with plant procedures prepared in conjunction with the manufacturer's recommendations.

Table F.2-1

Code Deviations

CODE SECTION		POSITION	
	NFPA 13-1975		
3-9.3	Protection of Piping Against Damage Where Subject to Earthquakes	3-9.3	Protection of Piping Against Damage Where Subject to Earthquakes
3-9.3.3	Sleeves shall be provided around all piping extending through the walls, floors, platforms, and foundations. (a) Minimum clearance between the pipe and sleeve shall not be less than 1 in. for pipes 1 in. through 3.5 in. and 2 in. for pipe sizes 4 in. and larger. (b) The clearance between pipe and sleeve shall be filled with noncombustible flexible material such as mineral wool, fiberglass, or equivalent.	3-9.3.3	No design limitations exist to ensure annular gap is greater than 1 or 2 in. Where piping penetrates a fire-rated barrier, penetration seals are installed in which the seal design accounts for pipe movement. Piping in safety-related areas is seismically qualified.
3-11	Joining of Pipes and Fittings	3-11	Joining of Pipes and Fittings
3-11.2.2	Sections of welded piping shall be joined by means of screwed flanged or flexible gasketed joints or other approved fittings.	3-11.2.2	The control room sprinkler system as installed used other design criteria (seismic and flooding concerns) which required welding as the method of installation.
3-13	Valves	3-13	Valves
3-13.2.3	Valves controlling sprinkler systems, except underground gate valves with roadway boxes, shall be supervised open by one of the following methods: (a) Central station, proprietary or remote station alarm service, (b) Local alarm service which will cause the sounding of an audible alarm at a constantly attended point, (c) Locking valves open, (d) Sealing of valves and approved weekly recorded inspection when valves are located within fenced enclosures under the control of the owner.	3-13.2.3	Control valves are locked or sealed open and inspected quarterly.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
3-14	Hangers	3-14	Hangers
3-14.1.5	The components of hanger assemblies which attach directly to building structure, except for mild steel hangers formed from rod, shall be listed.	3-14.1.5	Not all hangers are listed. For hangers with special seismic requirements the hanger design is certified by a registered professional engineer in accordance with Section 3-14.1.2.
3-16	Sprinkler Alarms	3-16	Sprinkler Alarms
3-16.2	Local waterflow alarms shall be provided on all sprinkler systems having more than 20 sprinklers.	3-16.2	Columbia Generating Station (CGS) sprinkler systems do not have local waterflow alarms. Each CGS suppression system has a proprietary protective alarm system that annunciates in the continuously manned control room. This will rapidly prompt manual suppression activities. On average, the plant has a low human occupancy. Thus, actuation of local alarms will have little effect since there is typically no one present to benefit from them.
3-16.3.1	The alarm apparatus for a wet-pipe system shall consist of an approved alarm check valve or other approved waterflow detecting alarm device with the necessary attachments required to give an alarm.	3-16.3.1	The UL Listing and FM Approval of the alarm check valve have been voided by drilling a small hole through the alarm bypass check valve to prevent trapping excess system pressure. In addition, a second torsion spring has been installed on the alarm check valve clapper of some systems to help reseat the clapper and prevent false alarms. These changes have no adverse impact on the alarm check valve's reliability or the system's capability to suppress fires.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
4-4	Locations or Conditions Involving Special Consideration	4-4	Locations or Conditions Involving Special Consideration
4-4.20	Small Rooms. In small rooms such as rest rooms, toilets, closets, and offices with smooth ceilings, sprinklers may be located a maximum distance of 7 ft 6 in. from any two walls of this room providing the total area of the room divided by the number of sprinklers does not exceed the limitation of 4-2.2.1 and 4-2.2.2. The maximum area of such a room is defined as 800 ft^2 for Light Hazard and 520 ft^2 for Ordinary Hazard occupancies.	4-4.20	Small Rooms. Sprinkler heads are located a maximum distance of 7 ft 6 in. from two walls as required by code. In the control room shift manager's office, there are two sprinklers in an area of approximately 250 ft^2. Later revisions of this code (1985) allow sprinkler heads in small rooms to be located up to 9 ft from one wall. The exception has been used in this room. The sprinklers are below the maximum spacing of 130 ft^2 for ordinary hazard occupancy.

Table F.2-1

Code Deviations (Continued)

CODE SECTION	POSITION
NFPA 14-1974	
CHAPTER 1 – GENERAL INFORMATION	CHAPTER 1 - GENERAL INFORMATION
14 Combined Systems	14 Combined Systems
145 Each outlet from a combined riser to the sprinkler system shall have an individual control valve of the same size as the outlet.	145 The TGB-1 standpipe connection for deluge system #D55 is reduced from 10 in. to 4 in. before the control valve. The connection size is sufficient to provide the water supply required by the deluge system.
15 Approved Devices	15 Approved Devices
151 All devices and materials used in standpipe systems shall be of approved type. Note: NFPA 14-1996 section 2-6 requires the valves to be listed.	151 Vacuum breakers installed at the top of standpipes RB-1, RB-2, RWB-1, RWB-2, TGB-1, TGB-2, and TGB-3 are not UL or FM approved, since none are available. The vacuum breakers are constructed of approved materials. Each of the above standpipes has redundant vacuum breakers that will ensure reliability. The vacuum breakers mitigate fire water system pressure transients and help to ensure fire water system availability. Leakage failure of a vacuum breaker would not reduce the water supply below minimum flow rates and potential flooding is bounded by existing analysis. The UL listed, cast iron isolation valves FP-V-29D (for standpipe riser RB-1) and FP-V-394 (for riser RB-2) were replaced by cast steel valves in 1998. The cast steel valves are not listed, but are approved. The cast steel valves are stronger, more ductile and resistant to yield fractures. The corrosion properties of the cast steel valves are acceptable. The presence of these stronger valves makes the two tallest CGS standpipe risers more resistant to water hammer induced valve ruptures.

Table F.2-1

Code Deviations (Continued)

CODE SECTION	POSITION
21 Design Basis	21 Design Basis
218 An approved means of maintaining a positive pressure on all zones of standpipe systems shall be provided.	218 During system transients, pressure at the top of some standpipes may not maintain a positive pressure. However, water hammer analysis shows the system pressure to remain within design limits (Reference F.7.3.x).
CHAPTER 3 - NUMBER AND LOCATION OF STANDPIPES	CHAPTER 3 - NUMBER AND LOCATION OF STANDPIPES
32 Number of Standpipes	32 Number of Standpipes
321 The number of hose stations for Class I and Class III services in each building and in each section of a building divided by fire walls shall be such that all portions of each story of the building are within 30 ft of a nozzle attached to not more than 100 ft of hose.	321 The reactor building requires 150 ft long hoses to reach all areas. This was approved per Reference F.7.4.d. The radwaste building room C405 requires 250 ft of hose. This is not a safety-related area of the plant.
CHAPTER 4 - HOSE OUTLETS	CHAPTER 4 - HOSE OUTLETS
41 Location of Hose	41 Location of Hose
412 Hose outlets for Class I service should be located in a stairway enclosure, and for Class II service in the corridor or space adjacent to the stairway enclosure and connected through the wall to the standpipe. For Class III service, the outlets for large hose should be located in a stairway enclosure, and for small hose located in the corridor or space adjacent to the stairway enclosure.	412 Hose stations are installed for Class III service. Building standpipes were originally provided with large hose outlets located in the stairways. Fire tactics have changed to prefer smaller hose lines for plant fire suppression activities. Smaller hose lines are currently provided.
413 Valves of approved indicating type shall be provided at the main riser for controlling branch lines to hose outlets so that in the event that the branch is broken during the fire, the fire department may shut off this branch, conserving the water for their use.	413 Valves are not provided at the branch lines to hose outlets at the main risers. The standpipe system is welded to increase its reliability under normal and fire conditions.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
44	Hose Valves	44	Hose Valves
442	Where the static pressure at any standpipe outlet exceeds 100 lb/in.^{2}, an approved device shall be installed at the outlet to reduce the pressure with required flow at the outlet to 100 lb/in.^{2}	442	At certain hose stations, the static pressure at the hose outlet could exceed 100 psi. Hose stations are provided for use only by the plant fire brigade. The fire brigade is hands-on trained and drilled on the use of high pressure hose lines. Pressure reducing valves are not required.
451	Nozzles shall be of an approved type and have a discharge coefficient not exceeding 7.5.	451	The Protek Model #379 fog nozzle is not UL Listed or FM Approved. Its construction is similar to the Protek Model #366 which is FM Approved. The Protek Model #379 was field tested during fire brigade training and was found to be an effective hose nozzle.
CHAPTER 5 - WATER SUPPLIES		CHAPTER 5 - WATER SUPPLIES	
56	Fire Department Connections	56	Fire Department Connections
561	A connection through which the public fire department can pump water into the standpipe system makes a desirable auxiliary supply. One or more fire department connections shall be provided for each Class I or Class III standpipe system.	561	Fire department connections are not provided. The capability exists for the Fire Department to draft from on-site water storage and pump into the underground fire protection water supply distribution system utilizing a fire hydrant.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
	NFPA 15-1973		
CHAPTER 2 - SYSTEM COMPONENTS		CHAPTER 2 - SYSTEM COMPONENTS	
2030	Spray Nozzles	2030	Spray Nozzles
2031	Care shall be taken in the application of nozzle types. Distance of "throw" or location of nozzle from surface shall be limited by the nozzle's discharge characteristics (see 4070). Care shall also be taken in the selection of nozzles to obtain waterways which are not easily obstructed by debris, sediment, sand, etc., in the water. Requirements for strainers and their placement are described in 2110 and 4110.	2031	Nozzles were selected based on protection requirements. Strainers are not provided for all small orifice nozzle systems.
2040	Piping	2040	Piping
2042	Galvanized pipe shall be used except that; where corrosion of galvanized pipe may be caused by corrosive atmospheres or the water, or by additives to the water, other suitable coatings shall be provided.	2042	Exterior surface of piping is galvanized.
2050	Fittings	2050	Fittings
2052	Rubber gasketed fittings subject to direct fire exposure are generally not suitable. Where necessary for piping flexibility, or for locations subject to earthquake, explosion, or similar hazards, such installations are acceptable. In such cases, special hanging or bracing may be necessary.	2052	Rubber gaskets are used for flange connections at preaction system valves in the area protected by the preaction system. The remainder of the piping joints are threaded connections. Pipe supports for these preaction systems are designed and installed to Seismic Category I requirements.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
CHAPTER 4 - SYSTEM DESIGN AND INSTALLATION		CHAPTER 4 - SYSTEM DESIGN AND INSTALLATION	
4020	Design Guides	4020	Design Guides
4021	Water spray systems shall conform to the applicable requirements of the following Standards of the National Fire Protection Association, except where otherwise specified herein: - Installation of Sprinkler Systems (NFPA No 13 - 1973) - Installation of Standpipe and Hose Systems (NFPA 14 - 1973) - Wetting Agents (NFPA 18 - 1973) - Installation of Centrifugal Fire Pump (NFPA 20 - 1972) - Water Tanks for Private Fire Protection (NFPA 22 - 1971) - Outside Protection (NFPA 24 - 1973) - Supervision of Valves (NFPA 26 - 1958) - National Electric Code (NFPA 70 - 1971) - Central Station Protective Signaling Systems (NFPA 71 - 1972) - Local Protective Signaling Systems (NFPA 72A - 1972) - Auxiliary Protective Signaling Systems (NFPA 72B - 1972) - Remote Station Protective Signaling Systems (NFPA 72C - 1972) - Proprietary Protective Signaling Systems (NFPA 72D - 1973) - Protection from Exposure Fires (NFPA 80A - 1970) - Indoor General Storage (NFPA 231C - 1972) - Rack Storage of Materials (NFPA 231C - 1973) Note: Components of the electrical portions of these protective systems, where installed in locations subject to hazardous vapors or dusts, shall be of types approved for use therein.	4021	The design of the systems has been reviewed by the authority having jurisdiction and approved for insurance purposes. CGS is not committed to meet all of the specified NFPA codes.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
4030	Density and Application	4030	Density and Application
4032	(b) Nozzles shall be installed to impinge on the areas of the source of the fire, and where spills may travel or accumulate. The water application rate on the provable surface of the spill shall be at the rate of not less than 0.50 gpm/ft^2.	4032	(b) A water spray density of 0.30 gpm/ft^2 is provided in areas of potential spill in the diesel generator rooms. The diesel fuel piping and storage tanks are welded, Seismic Category I systems; thus a line break and resulting fuel spill are unlikely. The day tanks are in separate rooms which have an average density of approximately 0.90 gpm/ft^2.
4052	Area Drainage	4052	Area Drainage
	(a) Adequate provisions shall be made to promptly and effectively dispose of all liquids from the fire area during operation of all systems in the fire area. Such provisions shall be adequate for: (1) Water discharged from fixed fire protection systems at maximum flow (2) Water likely to be discharged by hose streams (3) Surface water (4) Cooling water normally discharged to the system		(a) The RRC ASD transformer sumps are not sized to contain the total contents of 10 minutes of deluge actuation, manual hose stream, and the contents of the transformer oil. The ASD transformers are not safety-related. Fire-rated barriers separate the two transformers, the transformers from the ASD building, and the transformers from the turbine building. The grade slopes away from the transformers to a yard french drain.
4063	Drain Valves. Readily accessible drains shall be provided for low points in underground and aboveground piping.	4063	Drains are provided; however, not all drains are readily accessible.
4100	Hangers	4100	Hangers
4101	System piping shall be adequately supported. All supports in the fire area should be protected by the system. In any area where possibility of explosion may be recognized, special care shall be taken to support the piping from portions of the structure least liable to disruption.	4101	Not all supports are protected by the spray patterns. Failure of unprotected supports is unlikely as the systems are supported to Seismic Category IM requirements.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
4110	Strainers	4110	Strainers
4111	Main pipeline cleaners shall be provided for all systems using nozzles with waterways less than 3/8 in. and for any system where the water is likely to contain obstructive material.	4111	The manually actuated deluge systems which protect the SGTs and control room HVAC charcoal filter units have nozzles less than 3/8 in. but are not provided with strainers. These interior systems are periodically tested with air to verify the nozzles are not obstructed.
CHAPTER 8 - AUTOMATIC DETECTION EQUIPMENT		CHAPTER 8 - AUTOMATIC FIRE DETECTORS	
8050	RESPONSE TIME	8050	RESPONSE TIME
8051	The heat detection system shall be designed to cause actuation of the special system water control valve within 20 sec under expected fire conditions. Under test conditions when exposed to a standard heart source, the system shall operate within 40 sec. These are to be considered as maximum response times subject to the considerations described in 8011 and 8031.	8051	Response time of detectors is not checked by plant procedures. Detectors are checked for operation only. The heat detection system does not have any artificial delays that would prevent the immediate activation of the system. Later editions of this code have removed the time limit and replaced it with this intent only.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
	NFPA 20-1974		
CHAPTER 2 - GENERAL		CHAPTER 2 – GENERAL	
2-8	Equipment Protection	2-8	Equipment Protection
2-8.6	Floors shall be pitched for adequate draining of escaping water or fuel away from critical equipment such as the pump, driver, controller, fuel tank, etc.	2-8.6	The equipment is installed on concrete pedestals.
2-9	Discharge Pipe and Fittings	2.9	Discharge Pipe and Fittings
2-9.7	Protection of Piping Against Damage Due to Movement	2-9.7	Protection of Piping Against Damage Due to Movement
2-9.7.1	A clearance of not less than 1 in. (25.4 mm) shall be provided around pipes which pass through walls or floors.	2-9.7.1	Not all penetrations are provided with a 1-in. annular clearance. Fire pump discharge piping is designed to Seismic Category II requirements.
CHAPTER 6 - ELECTRIC DRIVE FOR PUMPS		CHAPTER 6 - ELECTRIC DRIVE FOR PUMPS	
6-3.3.2	The voltage at the motor shall not drop more than five percent below the voltage rating of the motors when the pumps are being driven at rated output, pressure, and speed, and when the lines between the power stations(s) and the motors are carrying their peak loads.	6-3.3.2	The running voltage for FP-M-P/2A and FP-M-P/2B is acceptable when the system is fed from TR-S. However, when fed from TR-N, the normal running voltage drop is slightly more than 5% below rated voltage. Since the two NEMA Standard fire pump motors are rated to operate satisfactorily at 10% below rated voltage, this condition will not affect motor operability.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
CHAPTER 7 - ELECTRIC DRIVE CONTROLLERS		CHAPTER 7 - ELECTRIC DRIVE CONTROLLERS	
7-1.1	General	7-1.1	General
7-1.1.1	All controllers shall be specifically listed for fire pump service.	7-1.1.1	Fire pump controllers FP-CP-2A and FP-CP-2B are UL listed for fire pump service. The controllers are reduced voltage type to provide a soft start to reduce pressure transients. Circuit failure of the new controllers would cause a hard start which could cause pressure transients in excess of that allowed. Therefore, the new controllers were modified to cause the pump to fail “off” in the remote occurrence of a circuit failure. This voids the UL listing. Upon failure of a single electric fire pump, the other electric pump would be available. If both electric fire pumps were inoperable, there are two diesel fire pumps available. LCS 1.10.1 limits fire pump inoperability periods.
CHAPTER 8 - DIESEL ENGINE DRIVE		CHAPTER 8 - DIESEL ENGINE DRIVE	
8-2	Engines	8-2	Engines
8-2.2.1	Engines, after the corrections for altitude and ambient temperature specified in 8-2.2.2 and 8-2.2.3 below, shall have a bare engine brake horsepower rating not less than 20 percent greater than the maximum brake horsepower required to drive the pump at its rated revolutions per minute.	8-2.2.1	After making the corrections, neither FP-ENG-1 or FP-ENG-110 provide 20% greater horsepower. However, operating experience shows the engines do have sufficient horsepower to meet the required water flow rates under any conditions of pump load.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
CHAPTER 9 - ENGINE DRIVE CONTROLLERS		CHAPTER 9 - ENGINE DRIVE CONTROLLERS	
9-1.3	Construction	9-1.3	Construction
9-1.3.4	Locked Cabinet. All switches required to keep the controller in the "automatic" position shall be within locked cabinets having break glass panels.	9-1.3.4	Locked Cabinet. Pump controller cabinets are not locked. Controllers are supervised; "non-auto" alarms are monitored in the main control room.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
	NFPA 24-1973		
CHAPTER 3 - VALVES		CHAPTER 3 - VALVES	
36	Identifying and Securing	36	Identifying and Securing
3601	All control valves shall be plainly marked indicating the section or portion controlled. To ensure that valves are kept open, it is essential to provide central station proprietary valve supervisory service and/or to secure the valves in the open position using an acceptable type of seal which must be destroyed before the valve can be closed. Weekly recorded inspections shall be made.	3601	Yard control valves are labeled in accordance with the plant tagging procedures. Valves are locked in position and inspected quarterly.
CHAPTER 5 - HOSE HOUSES AND EQUIPMENT		CHAPTER 5 - HOSE HOUSES AND EQUIPMENT	
56	Equipment - General	56	Equipment - General
5601	Depending on local conditions and subject to approval of the authority having jurisdiction, each hose house should be equipped with: 2 - Underwriters' play pipes 1 - pair play pipe brackets 1 - fire axe 1 - fire axe brackets 1 - crowbar 1 - extra hydrant wrench (in addition to wrench on hydrant) 4 - coupling spanners 2 - hose and ladder straps 1 - Underwriter's play pipe holder 2 - 2.5-in. hose washers (spares)	5601	A mobile fire response vehicle is equipped with the equivalent equipment of three hose houses. This includes: 600 ft. - 2.5-in. hose 600 ft. - 1.5-in. hose 3 - 2.5-in. adjustable fog nozzles 6 - 1.5-in. adjustable fog nozzles 6 - hydrant wrenches 12 - coupling spanners 3 - 2.5-in. shut off valves 3 - 2.5-in. x 1.5-in. x 1.5-in. wye valves 6 - 2.5-in. hose washers (spares) 6 - 1.5-in. hose washers (spares) 3 - crowbars Play pipes, play pipe brackets, play pipe holders, fire axes, fire axe brackets, and hose/ladder straps are not necessary for fire fighting and are not required by NFPA 24-2002.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
58	Nozzles	58	Nozzles
5801	Nozzles shall be approved type.	5801	The Protek Model #379 fog nozzle is not UL Listed or FM Approved. Its construction is similar to the Protek Model #366 which is FM Approved. The Protek Model #379 was field tested during fire brigade training and was found to be an effective hose nozzle.
59	Domestic Service Use Prohibited	59	Domestic Service Use Prohibited
5901	The use of hydrants and hose for purposes other than fire or fire drills shall be prohibited.	5901	The use of hydrants for nonfire-related activities is controlled by plant procedures under controlled conditions only.
CHAPTER 8 - UNDERGROUND PIPE AND FITTINGS		CHAPTER 8 - UNDERGROUND PIPE AND FITTINGS	
81	Selection of Pipe	81	Selection of Pipe
8101	Piping shall be approved asbestos cement, cast iron, ductile iron, reinforced concrete, steel, or other approved pipe. Steel pipe shall have minimum thickness of 0.250 in., and be coated and lined. See paragraph 8301 for required coating and lining.	8101	CGS has ductile iron, cast iron, and steel pipe installed in the fire protection underground loop. The ductile and cast iron piping is cement lined per ANSI A21.4. The steel pipe installed in the fire protection underground loop system is not cement lined. Later editions of this code required only that steel pipe be coated (not lined).
83	Coating and Lining	83	Coating and Lining
8301	Where coating or lining or both are required for pipe or fitting, the coating or lining or both shall be approved. Coating and Lining Standards. The following apply to the application of coating and linings: - American Standard for Cement Mortar Lining for Cast-Iron Pipe and Fittings for Water, ANSI A21.4-1974, AWWA C104-71.	8301	The exterior of underground fire protection piping is coated with bitumastic enamel and coal tar. See paragraph 8101 above for discussion of interior coating.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
	- AWWA Standard for Coal-Tar Enamel.Protective Coatings for Steel Water Pipe, AWWA C203-66. - AWWA Standard for Cement-Mortar Protective Lining and Coating for Steel Water Pipe, AWWA C205-71. - AWWA Standard for Cement-Mortar Lining of Water Pipe Lines in Place, Sizes 16 in. and Over, AWWA C602-67.		
CHAPTER 9 - RULES FOR LAYING PIPE		CHAPTER 9 - RULES FOR LAYING PIPE	
91	Depth of Cover	91	Depth of Cover
9101	The depth of cover over water pipes should be determined by the maximum depth of frost penetration in the locality where the pipe is laid, and in those locations where frost is not a factor, the depth of cover shall be not less than 2.5 ft to prevent mechanical injury. Pipe under driveways shall be buried a minimum of 3 ft and under railroad tracks a minimum 4 ft. Recommended depth of cover above the top of underground yard mains is indicated in Figure 91.	9101	Certain piping in the warehouse area does not have the required depth of cover. However, it was verified that the depth of bury is adequate for this locality (Reference F.7.3.v).
93	Protection Against Damage	93	Protection Against Damage
9301	Pipe should not be run under buildings or under heavy piles or iron, coal, etc. Where piping necessarily passes under a building, the foundation walls shall be arched over the pipe. See paragraph 3502. [Paragraph 3502 … It is also recommended that valves be installed to shut off sections of pipe under buildings.]	9301	The routing of a fire main under the diesel generator building was approved by the NRC in Reference F.7.4.k.
9302	Where riser is close to building foundations, underground fittings of proper design and type shall be used to avoid pipe joints being located in or under the foundations.	9302	See paragraph 9301 above.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
9303	Special care is necessary in running pipes under railroad tracks, under roads carrying heavy trucking, under large piles of iron, under building having heavy machinery liable to fall and under buildings containing hammers or other machinery or having heavy trucking which will subject the buried piping to shock or vibration. Where subject to such breakage, pipes should be run in a covered pipe trench or otherwise be properly guarded.	9303	See paragraph 9301 above.
96	Anchoring Fire Mains	96	Anchoring Fire Mains
9605	Thrust blocks are satisfactory where soil is suitable. Table 9605 gives bearing areas against undisturbed vertical well of a trench in soil equivalent to sand and gravel cemented with clay. For other soils, the values in the table should be multiplied by an appropriate factor.	9605	Thrust blocks were not installed against undisturbed soil. Design drawings specified a minimum area requirement in square feet of thrust block to be in contact with the trench wall. Compression of soil behind the thrust blocks was used to obtain a high density equivalent to undisturbed soil.

TABLE 9605
AREA OF BEARING FACE OF
CONCRETE THRUST BLOCKS

Pipe Size (in.)	1/4 bend (ft^2)	1/8 bend (ft^2)	Tees, Plugs, Caps, Hydrants (ft^2)
4	2	2	2
6	5	3	4
8	8	5	6
10	13	7	9
12	18	10	13
14	25	14	18
16	32	18	23

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
	NFPA 30-1973		
2343	Flammable or combustible liquid storage tanks located inside of buildings shall be provided with an automatic-closing heat actuated valve.	2343	Diesel generator and HPCS day tanks are not equipped with an automatic-closing heat actuated shutoff valve. The day tank rooms are equipped with preaction sprinkler systems and are 3-hr rated. Piping from day tanks to diesels are routed primarily in floor trenches and have substantial construction (Reference F.7.6.h).

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
NFPA 72D-1975			
CHAPTER 1 - GENERAL		CHAPTER 1 - GENERAL	
ARTICLE 120 - SYSTEM FACILITIES		ARTICLE 120 - SYSTEM FACILITIES	
1210	System Operation	1210	System Operation
1211	The proprietary system shall be arranged to receive and record all signals received at its central supervising station and to transmit to the fire department, or other location acceptable to the authority having jurisdiction, indication of the building or group of buildings from which an alarm has been received. The transmitting means shall be reliable and use supervised circuits. Where permissible and deemed necessary, the means shall consist of a direct supervised circuit to the fire department or a municipal fire, alarm box, either ordinary or auxiliary type, within 50 ft of the central supervising station.	1211	The system receives but does not automatically record all signals at the fire control panel in the main control room. The circuits are supervised. Fire alarms are manually logged. Logs are retained as plant records. A manual push button on the fire control panel is used to transmit a radio fire alarm for outside fire department assistance.
1212	Recording devices shall be designed and arranged to automatically provide a permanent record of the incoming signal and date and time of receipt.	1212	See paragraph 1211 above.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
ARTICLE 200 - GENERAL		ARTICLE 200 - GENERAL	
2022	Equipment: All devices, combination of devices, and equipment constructed and installed in conformity with this standard shall be approved for the purposes for which they are intended.	2022	The use of refurbished fire alarm system components is acceptable where the component has not been modified from its original design as certified by the refurbishing company and post-maintenance testing shows the device is fully functional. Under these limitations, the fire alarm system will still perform its design function. Certain smoke detector and control panel module combinations are "approved" equipment. See Reference F.7.6.bb.
ARTICLE 210 - WIRING		ARTICLE 210 - WIRING	
2110	The installation of wiring and equipment shall be in accordance with Article 760, Fire Protective Signaling Systems of the National Electrical Code, NFPA No. 70 - 1975.	2110	Article 760 of the 1978 edition of the National Electric Code was used for the installation of wiring and equipment for the protective signaling system.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
ARTICLE 220 - POWER SUPPLY SOURCES		ARTICLE 220 - POWER SUPPLY SOURCES	
2224	A separate power supply, independent of the main power supply, shall be provided for the operation of trouble signals. The secondary power supply may be used for this purpose.	2224	The plant fire alarm panels do not annunciate loss of ac power. Loss of ac power to the fire alarm equipment is annunciated on other panels located in the main control room.
2230	Power Supply for Remotely Located Control Equipment	2230	Power Supply for Remotely Located Control Equipment
2231	Additional power supplies when provided for control units, transmitters, or other equipment, essential to system operation, located remote from the central supervising station, shall comprise a primary (main), secondary (standby), and a trouble power supply which shall meet the same requirements as for the central supervising station power supplies. See Paragraphs 2220 through 2224.	2231	Each local fire control panel is provided with a single power supply.
2240	Light and Power Services	2240	Light and Power Services
2243	An overcurrent protective device of suitable current-carrying capacity and capable of interrupting the maximum short-circuit current to which it may be subjected shall be provided in each ungrounded conductor. The overcurrent protective device shall be enclosed in a locked or sealed cabinet located immediately adjacent to the point of connection to the light and power conductors.	2243	Cabinets are not locked or sealed but are located in access controlled areas.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
CHAPTER 3 - TYPES OF SIGNALING SERVICES		CHAPTER 3 - TYPES OF SIGNALING SERVICES	
ARTICLE 340 - SPRINKLER SYSTEM WATERFLOW ALARM AND SUPERVISORY SIGNAL SERVICE		ARTICLE 340 - SPRINKLER SYSTEM WATERFLOW ALARM AND SUPERVISORY SIGNAL SERVICE	
3444	Water storage containers shall be supervised to obtain two separate and distinctive signals, one indicating that the required water level has been lowered or increased and the other indicating restoration to the normal level. a. A pressure tank supervisory attachment shall indicate both high and low level conditions. A signal shall be obtained when the water level is lowered or raised 3 in. from the required level. b. A supervisory attachment for other than pressure tanks shall indicate a low level condition. A signal shall be obtained when the water level is lowered 12 in. from the required level.	3444	Fire water is supplied from the circulating water basin or the 400,000 gal bladder tank. The levels are checked manually by equipment operators once per shift.
3445	Water storage containers shall be supervised to obtain two separate and distinctive signals, one indicating that the temperature of the water has been lowered to 40°F, and the other indicating restoration to proper temperature.	3445	Fire water is supplied from the circulating water basin or the 400,000 gal bladder tank. The water temperature is not supervised or alarmed. The circulating water system is continuously recirculated. The bladder tank is provided with a manually initiated recirculation pump to prevent freezing.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
ARTICLE 350 - AUTOMATIC SMOKE ALARM SERVICE		ARTICLE 350 - AUTOMATIC SMOKE ALARM SERVICE	
3540	Circuit Arrangement	3540	Circuit Arrangement
3541	A smoke detecting combination of a Class A Proprietary System shall be capable of operating for a smoke alarm signal during a single break or a single ground fault condition of the circuit wiring conductors (a) between the central supervising station and the smoke alarm signal transmitter and (b) between the smoke alarm signal transmitter and the smoke detector control unit, except as indicated in Paragraph 3542.	3541	Class A wiring is used only on detection wiring activating suppression systems in safety-related areas. All other circuits are Class B wiring including connections from local suppression panels to the fire control panel in the main control room. The Class A wiring, where provided, meets the requirements of this code section.
3542	The requirement of Paragraph 3541 does not apply to the circuits between the smoke alarm signal transmitter and the smoke detector control unit if both of these units are located in a common enclosure, or in adjacent enclosures not more than 3 ft apart and having the circuits between the enclosures run in conduit.	3542	Class A wiring is used only on detection wiring activating suppression systems in safety-related areas. All other circuits are Class B wiring including connections from local suppression panels to the fire control panel in the main control room. The Class A wiring, where provided, meets the requirements of this code section.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
	NFPA 72E-1974		
CHAPTER 4 - SMOKE DETECTORS		CHAPTER 4 - SMOKE DETECTORS	
4-4	Spacing	4-4	Spacing
4-4.5	High Ceilings	4-4.5	High Ceilings
4-4.5.2	For proper protection for buildings with high ceilings, detectors shall be installed alternately at two levels; one half at ceiling level, and the other held at least 3 ft below the ceiling. See Figure A-4.5.4 of Appendix.	4-4.5.2	Smoke detectors are not installed at alternating levels on the ceilings. Intermediate level detectors are installed in the cable chase (radwaste control building).
4-4.6	Beam Construction. Beams 8 in. or less in depth can be considered equivalent to a smooth ceiling in view of the "spill over" effect of smoke. In beam construction over 8 in. in depth, movement of heated air and smoke may be slowed by the pocket or bay formed by the beams. In this case, spacing shall be reduced. If the beams exceed 18 in. in depth and are more than 8 ft on centers, each bay shall be treated as a separate area requiring at least one detector.	4-4.6	Beam Construction. Various plant locations have smoke detectors that are close to beams and other large obstructions and have bays deeper than 18 inches without a smoke detector. These deviations have been evaluated and are acceptable (Reference F.7.6.o).

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
	NFPA 80-1974		
1-5	Classifications and Types of Doors	1-5	Classification and Types of Doors
1-5.1.1	Only labeled doors shall be used.	1-5.1.1	CGS has various specialty doors in fire barriers which are not labeled for fire. These doors are required to meet other design considerations associated with a nuclear facility. Specialty doors include flood, airtight, radiation shielding, low- and high-range blast and bullet resistance. These nonlabeled door types have been previously approved by the NRC (Reference F.7.4.c).
2-1	Swinging Doors with Builders Hardware	2-1	Swinging Doors with Builders Hardware
2-1.5.1	Only labeled steel door frames shall be used. The requirements to be a labeled door implies that there are no untested frame modifications, such as frame holes, which void the label.	2-1.5.1	Only labeled hollow metal steel door frames are used; however, where nonfactory frame holes are present, grout may be installed inside the frame at the area of the frame defect. Grouted frames do not void the frame laboratory label.
2-1.5.4	The clearance between the door and the frame and between meeting edges of doors swinging in pairs shall not exceed 1/8 in. The clearance between the bottom of the door and the floor surface shall not exceed 0.75 in. regardless of the existence of a raised sill or threshold.	2-1.5.4	The clearance between the door and frame and between double doors may exceed NFPA 80 dimensions by 0.125 in. Door bottom clearance can exceed NFPA 80 dimensions by 0.25 in. Industry fire testing has shown that similar construction fire doors meet a 3-hr fire rating with the above clearances. See Reference F.7.5.r.
2-1.7.4.5	A closing device shall be installed on every fire door except elevator and power-operated dumbwaiter doors.	2-1.7.4.5	Various specialty fire doors are not equipped with automatic closing devices. The presence and design of specialty doors has been previously approved by the NRC and ANI. See above. Note: the complete list of NFPA 80-1974 deviations for specialty doors in fire barriers is not further listed here.

Table F.2-1

Code Deviations (Continued)

CODE SECTION		POSITION	
2-9	Access Doors	2-9	Access Doors
2-9.2.2	When installed in a vertical surface, access doors shall be self-closing. This shall be accomplished by use of a closer or by top hinging to provide gravity closing.	2-9.2.2	Fire doors R413 and R610 are elevated equipment access doors that are only used for large equipment removal and are normally locked. Thus, periodic verification of self-closing is not performed.
4-1	General Care and Maintenance	4-1	General Care and Maintenance
4-1-3	Doors, shutters, and windows shall be operable at all times. They shall be kept closed and latched or arranged for automatic closing.	4-1.3	Fire doors D104, D105, and D107 may not always self-close due to differential pressure. These doors are equipped with strobe lights and are monitored by security.

F.3 COMPLIANCE WITH FIRE PROTECTION REGULATORY DOCUMENTS

Branch Technical Position (BTP) APCSB 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976, provides guidance on the preferred alternatives for fire protection design for nuclear power plants for which applications for construction permits were docketed prior to July 1, 1976. Table F.3-1 provides a comparison of the Columbia Generating Station (CGS) fire protection program to BTP APCSB 9.5-1 Appendix A. The comparison describes how the CGS fire protection program implements the BTP recommendations.

10 CFR 50 Appendix R, “Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979” provides guidance on various topics not addressed BTP APCSB 9.5-1 Appendix A including ensuring the ability to achieve and maintain post-fire safe shutdown. Table F.3-2 provides a comparison of the CGS fire protection program to 10 CFR 50 Appendix R and describes how the CGS fire protection program implements alternatives to the Appendix R guidelines.

See Section F.1.2 for the regulatory significance of BTP APCSB 9.5-1 Appendix A and 10 CFR 50 Appendix R.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
A. OVERALL REQUIREMENTS FOR NUCLEAR PLANT FIRE PROTECTION PROGRAM	A. OVERALL REQUIREMENTS FOR NUCLEAR PLANT FIRE PROTECTION PROGRAM
A.1 Personnel	A.1 Personnel
Responsibility for the overall fire protection program should be assigned to a designated person in the upper level of management. This person should retain ultimate responsibility even though formulation and assurance of program implementation is delegated. Such delegation of authority should be to staff personnel prepared by training and experience in fire protection and nuclear plant safety to provide a balanced approach in directing the fire protection programs for nuclear power plants. The qualification requirements for the fire protection engineer or consultant who will assist in the design and selection of equipment, inspect and test the completed physical aspects of the system, develop the fire protection program, and assist in the fire-fighting training for the operating plant should be stated. Subsequently, the FSAR should discuss the training and the updating provisions such as fire drills provided for maintaining the competence of the station fire-fighting and operating crew, including personnel responsible for maintaining and inspecting the fire protection equipment. The fire protection staff should be responsible for a. coordination of building layout and systems design with fire area requirements, including consideration of potential hazards associated with postulated design basis fires. b. design and maintenance of fire detection, suppression, and extinguishing systems. c. fire prevention activities. d. training and manual fire-fighting activities of plant personnel and the fire brigade. Note: NFPA 6 - Recommendations for Organization of Industrial Fire Loss Prevention, contains useful guidance for organization and operation of the entire fire loss prevention program.	The Chief Nuclear Officer is the management official responsible for the adequacy of implementation and effectiveness of the fire protection program at the facility. The Plant Fire Marshal serves as the principal point of contact for the plant fire protection program. The position responsibilities include ensuring that the fire protection administrative controls for fire protection system/component testing, maintenance, and remedial actions are adequately implemented, monitoring plant activities and plant condition for fire prevention and combustible controls, and ensuring the plant fire brigade is adequately trained, staffed, and equipped. Energy Northwest staff includes an engineer meeting the qualifications listed in Section 13.1.3.3.3. The qualified Fire Protection Engineer is delegated the responsibility for ensuring the technical adequacy of elements of the fire protection program. This responsibility is implemented through the review of proposed fire protection program changes, design changes, and procedure changes. The qualified fire protection engineer is also responsible for the assessment of the effectiveness of the fire protection programs in support of the Plant General Manager.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
A.2 Design Basis	A.2 Design Basis
The overall fire protection program should be based upon evaluation of potential fire hazards throughout the plant and the effect of postulated design basis fires related to maintaining ability to perform safety shutdown functions and minimize radioactive releases to the environment.	The overall fire protection program is based on evaluation of potential fire hazards throughout the plant relative to maintaining the ability to safely shut down the plant and minimize the releases of radioactivity to the environment. See Section F.4 for the Columbia Generating Station (CGS) fire hazards analysis.
A.3 Backup	A.3 Backup
Total reliance should not be placed on a single automatic fire suppression system. Appropriate backup fire suppression capability should be provided.	Automatic fire suppression systems have been installed in areas where there are significant fire hazards. Automatic suppression systems are backed up by hose stations and portable fire extinguishers distributed throughout the plant.
A.4 Single Failure Criterion	A.4 Single Failure Criterion
A single failure in the fire suppression system shall not impair both the primary and backup fire suppression capability. For example, redundant fire water pumps with independent power supplies and controls should be provided. Postulated fires or fire protection system failures need not be considered concurrent with other plant accidents or the most severe natural phenomena. The effects of lightning strikes should be included in the overall plant fire protection program.	A combination of design features provides fire protection in the event of fire protection system component failures. Malfunction — Consequences Electric fire pump motor failure — Second electric fire pump on separate power supply Electric fire pumps fail due to loss of offsite power. — Two diesel fire pumps available - one 2000 gpm and one 2500 gpm Water source low water level (no makeup) — Primary fire pumps are supplied from the circ water pump house, second diesel fire pump is supplied from separate water supply. Yard pipe rupture — Isolate portion of main loop header using sectionalizing valves. System pipe rupture — Isolate using system isolation valve. Use backup hose from standpipe and/or hydrants.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM

System alarm check valve fails to open	Use manual fire fighting equipment (hoses and portable extinguishers)
Detection system wire short	Trouble alarm in control room
Loss of offsite power to detection system	Detection system is provided with backup power from an uninterruptible power supply.
Fire dampers	All fire dampers serving rooms containing safety-related equipment are qualified to Seismic Category I.

The plant is provided with redundant fire pumps which supply water to the fire water supply loop from two separate water supplies (see paragraph E.2.c.).

The fixed water suppression system and the backup fire hose station are connected to the same riser in the following safety-related areas:

a. Main control room emergency filter units (with standpipe cross-connection),

b. Standby gas treatment filter units, and

c. Reactor building sump vent filter units

These combination systems are permitted under NFPA 14-1974. A pipe rupture coincident with a fire is not, however, considered credible as the pipe is a passive component.

Lightning rods and steel towers are used to minimize the potential for lightning-caused fires. The reactor building and stacks are equipped with a lightning protection system. Air terminals are installed and spaced along the roof in accordance with NFPA 78-1975. The vent stack lightning protection

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
	mast, the communications and fire protection masts, and the air terminals are bonded to structural steel and/or heavy copper conductors which connect directly to the plant ground grid. The height of the reactor building and its installed air terminals provide zones of protection for the diesel generator building and the safety-related portions of the radwaste/control building. The metal wall panels of the turbine building are grounded directly to the structural steel, which in turn is bonded to the plant ground grid.
A.5 Fire Suppression Systems	A.5 Fire Suppression Systems
Failure or inadvertent operation of the fire suppression system should not incapacitate safety-related systems or components. Fire suppression systems that are pressurized during normal plant operation should meet the guidelines specified in APCSB Branch Technical Position 3-1, "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment."	The safety-related areas which have fixed fire suppression systems include the following: a. The standby gas treatment (SGT) filter units in the reactor building are provided with manually activated water spray that is operated from the main control room. b. The cable spreading room in the radwaste control building has an automatic preaction system. c. The diesel generator building has an automatic preaction system installed to protect each diesel generator, day tank, and oil transfer pump room. d. The main control room emergency filter units in the radwaste control building have manually actuated water spray systems within the units. e. The radwaste control building cable chase and portions of the diesel generator corridor and the radwaste-reactor building corridor have an automatic preaction system. f. The control room power generation control complex (PGCC) subfloor sections longitudinal cable ducts have automatic Halon 1301 systems.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
	g. The control room office areas have automatic sprinkler protection.
	The deluge spray systems for the SGT filter units and the control room emergency filter units are actuated by remote manual action to prevent inadvertent wetting. The redundant units are physically separated and would remain operable.
	A failure or inadvertent operation of a preaction sprinkler system in the cable spreading room, cable chase, or in the diesel generator building would not incapacitate the safety-related systems as two actions would be required for water to be released: the feed mains and lines must be flooded and the sprinkler heads must be fused.
	Failure or inadvertent operation of the PGCC Halon 1301 system does not incapacitate safety-related systems.
	Fire suppression systems that are pressurized during normal plant operation meet the guidelines specified in BTP ASB 3-1. Potential flooding due to failure of the fire protection system piping has been included in plant flooding analyses.
A.6 Fuel Storage Areas	A.6 Fuel Storage Areas
The fire protection program (plans, personnel, and equipment) for buildings storing new reactor fuel and for adjacent fire zones which could affect the fuel storage zone should be fully operational before fuel is received on the site.	The fire protection program for all fuel storage areas was fully operational when fuel was received at the site.
Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	
A.7 Fuel Loading	A.7 Fuel Loading
The fire protection program for an entire reactor unit should be fully operational prior to initial fuel loading in that reactor unit.	The fire protection programs for the entire power unit were fully operational prior to initial fuel loading.
Schedule for implementation of modifications, if any, will be established on a case-by-case basis.	

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
A.8 Multiple-Reactor Sites	A.8 Multiple-Reactor Sites
On multiple-reactor sites where there are operating reactors and construction of remaining units is being completed, the fire protection program should provide continuing evaluation and include additional fire barriers, fire protection capability, and administrative controls necessary to protect the operating units from construction fire hazard. The superintendent of the operating plant should have the lead responsibility for site fire protection.	CGS is not a multiple-reactor site.
A.9 Simultaneous Fires	A.9 Simultaneous Fires
Simultaneous fires in more than one reactor need not be postulated, where separation requirements are met. A fire involving more than one reactor unit need not be postulated except for facilities shared between units.	CGS is not a multiple reactor site.
B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE	B. ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE
B.1 Administrative procedures consistent with the need for maintaining the performance of the fire protection system and personnel in nuclear power plants should be provided.	B.1 Administrative procedures for maintaining performance of fire protection systems and personnel are provided.
Guidance is contained in the following publications: NFPA 4 - Organization for Fire Services NFPA 4A - Organization for Fire Department NFPA 6 - Industrial Fire Loss Prevention NFPA 7 - Management of Fire Emergencies NFPA 8 - Management Responsibility for Effects of Fire on Operations NFPA 27 - Private Fire Brigades	The listed NFPA codes have been superseded. The current equivalent NFPA codes may be used as guidance.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
B.2	Effective administrative measures should be implemented to prohibit bulk storage of combustible materials inside or adjacent to safety-related buildings or systems during operation or maintenance periods. Regulatory Guide 1.39, "Housekeeping Requirements for Water-Cooled Nuclear Power Plants," provides guidance of housekeeping, including the disposal of combustible materials.	B.2	Administrative procedures for housekeeping and fire protection control the introduction of combustible materials into the plant.
B.3	Normal and abnormal conditions or other anticipated operations such as modifications (e.g., breaking fire stops, impairment of fire detection and suppression systems) and refueling activities should be reviewed by appropriate levels of management for appropriate special actions and procedures such as fire watches or temporary fire barriers implemented to assure adequate fire protection and reactor safety. In particular: a. Work involving ignition sources such as welding and flame cutting should be done under closely controlled conditions. Procedures governing such work should be reviewed and approved by persons trained and experienced in fire protection. Persons performing and directly assisting in such work should be trained and equipped to prevent and combat fires. If this is not possible, a person qualified in fire protection should directly monitor the work and function as a fire watch. b. Leak testing and similar procedures such as air flow determinations should use one of the commercially available aerosol techniques. Open flames or combustion generated smoke should not be permitted.	B.3	Normal and abnormal conditions and other anticipated operations and refueling activities are reviewed by management for appropriate special actions. Primary implementing procedures are listed in Section F.7.8. In particular: a. Work involving ignition sources is done under controlled conditions and procedures governing such work will be reviewed and approved by persons trained and experienced in fire protection. Persons performing and assisting in such work are trained and equipped to prevent and control fires. Qualified personnel monitor the work and act as fire watch. b. Leak testing uses instrumentation or soapy water. Smoke detector testing may use aerosol cans. Open flames or combustion generated smoke are not permitted.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
c. Use of combustible material, e.g., HEPA and charcoal filters, dry ion exchange resins or other combustible supplies, in safety-related areas should be controlled. Use of wood inside buildings containing safety-related systems or equipment should be permitted only when suitable non-combustible substitutes are not available. If wood must be used, only fire retardant treated wood (scaffolding, lay down blocks) should be permitted. Such materials should be allowed into safety-related areas only when they are to be used immediately. Their possible and probable use should be considered in the fire hazard analysis to determine the adequacy of the installed fire protection systems.	c. Provisions have been made for controlling the use of combustible materials in safety-related areas. Use of wood in the permanent structure of buildings containing safety-related systems or equipment is not permitted except when suitable non-combustible substitutes are not available. If wood is used only pressure impregnated fire retardant or fire retardant coated wood is permitted. The use of minor amounts of transient untreated wood is not considered a significant hazard. For more than minor amounts in safety-related areas, additional compensating measures are implemented as necessary. d. Equipment or supplies shipped in untreated combustible packaging containers may be unpacked in safety-related areas if required for operating reasons. All combustible packing materials are removed from the area as soon as practicable after the unpacking.
B.4 Nuclear power plants are frequently located in remote areas, at some distance from public fire departments. Also, first response fire departments are often volunteer. Public fire department response should be considered in the overall fire protection program. However, the plant should be designed to be self-sufficient with respect to fire fighting activities and rely on the public response only for supplemental or backup capability.	B.4 The plant is designed to be self-sufficient with respect to fire-fighting activities. The plant fire brigade is trained in fire-fighting procedures. Supplemental fire-fighting capability is available from the local fire department. Interagency agreements delineate the responsibilities and duties of the local fire department during a coordinated response.
B.5 The need for good organization, training and equipping of fire brigades at nuclear power plant sites requires effective measures be implemented to assure proper discharge of these functions. The guidance in Regulatory Guide 1.101, "Emergency Planning of Nuclear Power Plants," should be followed as applicable.	B.5 See the CGS Emergency Plan.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
a. Successful fire-fighting requires testing and maintenance of the fire protection equipment, emergency lighting, and communication, as well as practice as brigades for the people who must utilize the equipment. A test plan that lists the individuals and their responsibilities in connection with routine tests and inspections of the fire detection and protection systems should be developed. The test plan should contain the types, frequency and detailed procedures for testing. Procedures should also contain instructions on maintaining fire protection during those periods when the fire protection system is impaired or during periods of plant maintenance, e.g., fire watches or temporary hose connections to water systems.	Procedures have been prepared for the testing and maintenance of the fire protection equipment, emergency lighting, and communication equipment. Procedures list responsibilities in connection with routine tests and inspections of the fire detection and protection systems. Procedures for compensatory measures are implemented when fire systems are impaired. The plant fire brigade composition is described in Section 13.1.2.3.4. The fire brigade training requirements are described in Section 13.2.2.5.
b. Basic training is a necessary element in effective fire fighting operation. In order for a fire brigade to operate effectively, it must operate as a team. All members must know what their individual duties are. They must be familiar with the layout of the plant and equipment location and operation in order to permit effective firefighting operations during times when a particular area is filled with smoke or is insufficiently lighted. Such training can only be accomplished by conducting drills several times a year (at least quarterly) so that all members of the fire brigade have had the opportunity to train as a team, testing itself in the major areas of the plant. The drills should include the simulated use of equipment in each area and should be preplanned and post-critiqued to establish the training objective of the drills and determine how well these objectives have been met. These drills should periodically (at least annually) include local fire department	

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
participation where possible. Such drills also permit supervising personnel to evaluate the effectiveness of communications within the fire brigade and with the on-scene fire team leader, the reactor operator in the control room, and the offsite command post.	
c. To have proper coverage during all phases of operation, members of each shift crew should be trained in fire protection. Training of the plant fire brigade should be coordinated with the local fire department so that responsibilities and duties are delineated in advance. This coordination should be part of the training course and implemented into the training of the local fire department staff. Local fire departments should be educated in the operational precautions when fighting fires on nuclear power plant sites. Local fire departments should be made aware of the need for radioactive protection of personnel and the special hazards associated with a nuclear power plant site.	
d. NFPA 27, "Private Fire Brigade," should be followed in organization, training, and fire drills. This standard also is applicable for the inspection and maintenance of fire fighting equipment. Among the standards referenced in this document, the following should be utilized: NFPA 194, "Standard for Screw Threads and Gaskets for Fire Hose Couplings," NFPA 196, "Standards for Fire Hose," NFPA 197, "Training Standard on Initial Fire Attacks," NFPA 601, "Recommended Manual of Instructions and Duties for the Plant Watchman on Guard." NFPA booklets and pamphlets listed on page 27-11 of Volume 8, 1971-72, are also applicable for good training references. In addition, courses in fire	

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
prevention and fire suppression which are recognized and/or sponsored by the fire protection industry should be utilized.	
C. QUALITY ASSURANCE PROGRAM	C. QUALITY ASSURANCE PROGRAM
C.1 Design Control and Procurement Document Control	C.1 Design Control and Procurement Document Control
Measures should be established to assure that all design-related guidelines of the Branch Technical Position are included in design and procurement documents and that deviations therefrom are controlled.	At the time BTP APCSB 9.5-1 was issued, the basic design of all fire protection equipment and systems had been completed. The established engineering procedures require the design and design changes to be reviewed by cognizant personnel to ensure material, parts, and equipment specified will meet or exceed the design criteria. Design and design changes are incorporated into design and/or procurement documents which contain requirements that deviations be documented and controlled. Design and procurement activities are audited and reviewed on a scheduled and surveilled basis.
C.2 Instructions, Procedures, and Drawings	C.2 Instructions, Procedures, and Drawings
Inspections, tests, administrative controls, fire drills, and training that govern the fire protection program should be prescribed by documented instructions, procedures, or drawings and should be accomplished in accordance with these documents.	Specifications are prepared, when required, to define design requirements. Instructions, procedures, and drawings additionally define and implement fire protection requirements. Contractors/suppliers are requested to provide instructions, procedures, or drawings as stipulated by contract/procurement documents. During plant operation, the fire protection program and those portions of the fire protection systems which are designated as essential fire protection systems (see LCS 1.10) are subject to the applicable portions of the CGS Operational Quality Assurance Program Description (OQAPD).
C.3 Control of Purchased Material, Equipment, and Services	C.3 Control of Purchased Material, Equipment, and Services
Measures should be established to assure that purchased material, equipment, and services conform to the procurement documents.	Contractors/suppliers are required to provide inspection and/or test documentation as stipulated by contract/procurement documents. Identification and traceability requirements are included in procurement documents as required. Source surveillance and/or receiving inspection will depend on the degree of design control applied.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
C.4 Inspection	C.4 Inspection
A program for independent inspection of activities affecting fire protection should be established and executed by, or for, the organization performing the activity to verify conformance with documented installation drawings and test procedures for accomplishing the activities.	Purchase orders/contracts are reviewed to provide applicable quality assurance requirements. Source surveillance and/or receiving inspections are performed depending on the degree of design control applied. Plant quality control or cognizant field engineering performs inspection/surveillance, as required, to ensure compliance with fire protection requirements.
C.5 Test and Test Control	C.5 Test and Test Control
A test program should be established and implemented to assure that testing is performed and verified by inspection and audit to demonstrate conformance with design and system readiness requirements. The tests should be performed in accordance with written test procedures; test results should be properly evaluated and acted on.	During construction, contractors performing installation and tests were required to perform inspections which ensured system readiness were performed in accordance with approved procedures. Additionally, these contractors were subject to surveillance and/or audit for compliance to fire protection requirements. Modifications to installations are required to be tested to ensure system readiness using approved procedures.
C.6 Inspection, Test, and Operating Status	C.6 Inspection, Test, and Operating Status
Measures should be established to provide for the identification of items that have satisfactorily passed required tests and inspections.	All items received are identified to ensure proper traceability and status. This traceability is sufficiently ensured during installation and test. A system of tagging is used during operations to establish operating status or to prevent inadvertent operation.
C.7 Non-Conforming Items	C.7 Non-Conforming Items
Measures should be established to control items that do not conform to specified requirements to prevent inadvertent use or installation.	Inspection procedures require that items that do not conform to specified requirements be tagged and segregated to prevent inadvertent installation.
C.8 Corrective Action	C.8 Corrective Action
Measures should be established to assure that conditions adverse to fire protection, such as failures, malfunctions, deficiencies, deviations, defective components, uncontrolled combustible material and non-conformances are promptly identified, reported, and corrected.	Those portions of the fire protection system which are designated as essential fire protection systems (see LCS 1.10) are subject to the applicable portions of the CGS OQAPD. Plant procedures require that conditions adverse to fire protection, such as failures, malfunctions, deficiencies, deviations, defective components, uncontrolled combustible material, and nonconformances are promptly identified, reported, and corrected.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
C.9 Records	C.9 Records
Records should be prepared and maintained to furnish evidence that the criteria enumerated above are being met for activities affecting the fire protection program.	During design and construction, the quality assurance program required vendors and contractors to prepare and maintain documents indicating compliance with quality assurance requirements. During operations, documents indicating compliance with quality assurance requirements are prepared in accordance with the applicable portions of the CGS OQAPD.
C.10 Audits	C.10 Audits
Audits should be conducted and documented to verify compliance with the fire protection program including design and procurement documents; instructions; procedures and drawings; and inspection and test activities.	During design and construction, a surveillance/audit program was implemented to include design and procurement documents, instructions, procedures, and drawings; inspection, and test activities. Procurement documents were reviewed for application of source surveillance requirements. Site contractors were subject to surveillance/audit to ensure compliance to fire protection requirements. Audits are performed in accordance with the OQAPD.
D. GENERAL GUIDELINES FOR PLANT PROTECTION	D. GENERAL GUIDELINES FOR PLANT PROTECTION
D.1 Building Design	D.1 Building Design
D.1.a Plant layouts should be arranged to: a. Isolate safety-related systems from unacceptable fire hazards, and b. Alternatives: 1. redundant safety-related systems that are subject to damage from a single fire hazard should be protected by a combination of fire retardant coatings and fire detection and suppression systems, or 2. a separate system to perform the safety function should be provided.	D.1.a Those portions of redundant systems which are required for post-fire safe shutdown are protected in accordance with 10 CFR 50 Appendix R, Section III.G, as detailed in Section F.4. Safety-related equipment which is not required for post-fire safe shutdown is generally separated to minimize potential risk from a single fire hazard. Cabling for the safety-related equipment which is not required for post-fire safe shutdown is routed in accordance with divisional electrical separation requirements (Section 8.3), not in accordance with Appendix R commitments, and could be subject to damage from a single exposure fire. Fire area boundaries serve to separate fire hazards from safety-related systems.
D.1.b In order to accomplish 1.(a) above, safety-related systems and fire hazards	D.1.b In designing the plant, careful consideration has been given to equipment location, fire walls,

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

	BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM
	should be identified throughout the plant. Therefore, a detailed fire hazard analysis should be made. The fire hazards analysis should be reviewed and updated as necessary.		barriers, material selection, and fire protection system design. A fire hazards analysis is included in Section F.4. Proposed plant modifications are evaluated for impact on the validity of the fire hazards analysis.
	Additional fire hazards analysis should be done after any plant modification.		Revisions to the fire hazards analyses are performed as required.
D.1.c	For multiple reactor sites, cable spreading rooms should not be shared between reactors. Each cable spreading room should be separated from other areas of the plant by barriers (walls and floors) having a minimum fire resistance of three hr. Cabling for redundant safety divisions should be separated by walls having three hour fire barriers.	D.1.c	CGS is not a multiple reactor site. The cable spreading room is separated from other fire areas by 3-hr barriers.
D.1.d	Interior wall and structural components, thermal insulation materials and radiation shielding materials and sound-proofing should be non-combustible. Interior finishes should be non-combustible or listed by a nationally recognized testing laboratory, such as Factory Mutual or Underwriters' Laboratory, Inc. for flame spread, smoke and fuel contribution of 25 of less in its use configuration (ASTM E-84 Test, "Surface Burning Characteristics of Building Materials"). Alternative guidance for constructed plants is shown in Section E.3 "Cable Spreading Room".	D.1.d	Interior wall and structural components, thermal insulation materials on piping and HVAC duct, and some radiation shielding materials are noncombustible. Silicone impregnated tungsten and blanket radiation shielding are combustible, but are administratively controlled in Reference F.7.8.e. Decontaminable coatings have flame spreads less than 25. Paint on concrete or masonry block is not considered a fire hazard. Auxiliary rooms within the main control room and the north wall of the radwaste control room have plastic laminate faced wall panels. The plastic laminate faced wall panels are UL listed for a flame spread of 25 and a smoke developed rating of 40. The materials in these rooms are not, however, considered to present a significant fire hazard. The combustibility of Thermo-Lag 330-1 has been considered in the fire hazards analysis.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
			The combustible containment barrier spacer material is shielded from fire exposure by ceramic fiber in the annular gap of mechanical containment penetrations. See Section F.2.2.5 for more details. Shielding material installed within access doors at certain penetrations in the primary containment sacrificial shield wall is under the trade name of "Permali." Flame spread and smoke contribution are both under 25.
D.1.e	Metal deck roof construction should be noncombustible (see the building materials directory of the Underwriters' Laboratory, Inc.) or listed as Class I by Factory Manual System Approval Guide. Where combustible material is used in metal deck roofing design, acceptable alternatives are (i) replace combustibles with non-combustible materials, (ii) provide an automatic sprinkler system, or (iii) provide ability to cover roof exterior and interior with adequate water volume and pressure.	D.1.e	All metal deck roof systems meet the requirements of Factory Mutual Class I insulated steel roof decks.
D.1.f	Suspended ceilings and their supports should be of non-combustible construction. Concealed spaces should be devoid of combustibles. Adequate fire detection and suppression systems should be provided where full implementation is not practicable.	D.1.f	Suspended ceilings and their supports are of noncombustible construction. Within the control room, there are no exposed combustibles in concealed spaces above the suspended ceilings. All electrical cable above the suspended ceiling is routed in conduit. Cable trays are routed above the suspended ceilings of the 487-ft radwaste chemistry laboratory.
D.1.g	High voltage - high amperage transformers installed inside buildings containing safety related systems should be of the dry type or insulated and cooled with non-combustible liquid. Safety related systems that are exposed to flammable oil filled transformers should be protected from the effects of a fire by: (i) replacing with dry transformers or transformers that are insulated and	D.1.g	All high voltage transformers installed inside safety-related building areas are cooled with high flash point insulating fluid. The indoor river makeup transformers are enclosed in 3-hr barriers without automatic suppression. Fire Areas RC-8 and RC-14, containing the radwaste building 467-ft switchgear room transformers, are enclosed in 3-hr barriers without automatic suppression.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
cooled with non-combustible liquid; or (ii) enclosing the transformer with a three-hour fire barrier and installing automatic water spray protection.	
D.1.h Buildings containing safety related systems, having openings in exterior walls closer than 50 ft to flammable oil filled transformers should be protected from the effects of a fire by: (i) closing of the opening to have fire resistance equal to three hr (ii) constructing a three-hour barrier between the transformers and the wall openings; or (iii) closing the openings and providing the capability to maintain a water curtain in case of fire.	D.1.h There are no oil-filled transformers located within 50 ft of the exterior wall of a safety-related building. The main step-up transformers, the normal auxiliary transformers, the startup auxiliary power transformers, and the backup auxiliary power transformers are oil filled and located within 50 ft north of the turbine generator building. They are protected by deluge sprinklers. The turbine generator building wall is 2-hr rated reinforced concrete and insulated metal panel with 1.5-hr fire-rated doors. Fire barrier walls are installed between the main transformers E-TR-M1, E-TR-M2, E-TR-M3 and E-TR-M4. There are no barriers between other north yard transformers. Four additional oil-filled transformers are located in the cooling tower area. The RRC pump ASD transformers are protected by deluge systems. The adjacent RRC pump ASD building wall is 2-hr rated and turbine building wall is 3-hr rated. A 2-hr barrier separates the divisional transformers.
D.1.i Floor drains, sized to remove expected fire fighting water flow, should be provided in those areas where fixed water fire suppression systems are installed. Drains should also be provided in other areas where hand hose lines may be used if such fire fighting water could cause unacceptable damage to equipment in the area. Equipment should be installed on pedestals, or curbs should be provided as required to contain water and direct it to floor drains. See NFPA 92M, "Waterproofing and Draining of Floors." Drains in areas	D.1.i Floor drains for the turbine oil reservoir, turbine lube oil storage, and hydrogen seal oil rooms discharge into sumps. There are no floor drains in the diesel generator day tank rooms. The floor drain systems in areas where fixed fire protection systems are located are not sized adequately to accept the large quantity of water which could be discharged over a long period of time. Flooding may be relieved through open doorways.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
containing combustible liquids should have provisions for preventing the spread of the fire throughout the drain system. Water drainage from areas which may contain radioactivity should be sampled and analyzed before discharge to the environment. In operating plants or plants under construction, if accumulation of water from the operation of new fire suppression systems does not create unacceptable consequences, drains need not be installed.	Potential actuation of fire protection systems has been evaluated to ensure that it would not adversely affect any safety-related equipment by flooding. Most equipment has been installed on raised concrete pads or pedestals. The NFPA 92M expectation for periodic inspection of barriers for possible leak paths is implemented for the fire/flood barriers addressed in Information Notice 88-60 (see Reference F.7.6.q). Water flowing down stairwells or into elevator shafts will not degrade safety-related equipment. All drains empty into sumps which are divided into radioactive and nonradioactive sumps according to the areas served. See FSAR 9.3.3.2.2 and FSAR 11.2.2.2.2 radioactive floor drain systems and FSAR 9.3.3.2.3 for nonradioactive floor drain system. In all buildings where fixed fire suppression systems or hand hose stations are actuated and flooding does occur, water could ultimately flow into the basement area and cover the sumps and floor. a. Areas where no or little radiation is present, the excessive quantity of water will dilute any possible contamination. This water could be pumped into the yard by portable equipment after the fire is suppressed. b. Areas where contaminated particles are prevalent, which have had flooding, must have the floor area monitored. 1. Non-contaminated water could be pumped into the yard.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
			2. Contaminated water would be left in the basement until the sump can be reactivated to discharge the water to the radwaste floor drain collection tank.
			As indicated above, temporary flooding beyond the drainage system provided is possible if water is discharged for extended periods.
D.1.j	Doors, walls, and ceilings enclosing separate fire areas should have minimum fire rating of 3 hr. Penetrations in these fire barriers, including conduits and piping, should be sealed or closed to provide a fire resistance rating at least equal to that of the fire barrier itself. Door openings should be protected with equivalent rated doors, frames and hardware that have been tested and approved by a nationally recognized laboratory. Such doors should be normally closed and locked or alarmed with alarm and annunciation in the control room. Penetrations for ventilation system should be protected by a standard "fire door damper" where required. Refer to NFPA 80, "Fire Doors and Windows." The fire hazard in each area should be evaluated to determine barrier requirements. If barrier fire resistance cannot be made adequate, fire detection and suppression should be provided, such as: (i) water curtain in case of fire (ii) flame retardant coatings (iii) additional fire barriers	D.1.j	See Section F.2.2 and LCS 1.10.5 for a description of building construction and fire rated assemblies.
D.2	Control of Combustibles	D.2	Control of Combustibles
D.2.a	Safety-related systems should be isolated or separated from combustible materials. When this is not possible because of the nature of the safety system or the combustible material, special protection	D.2.a	Safety-related systems have been isolated or separated from combustible materials to the extent possible. The emergency diesel generator fuel oil day tanks are located in separate rooms with 3-hr fire-rated walls and

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

	BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM
	should be provided to prevent a fire from defeating the safety system function. Such protection may involve a combination of automatic fire suppression, and construction capable of withstanding and containing a fire that consumes all combustibles present. Examples of such combustible materials that may not be separable from the remainder of its system are: (1) Emergency diesel generator fuel oil day tanks, (2) Turbine-generator oil and hydraulic control fluid systems, (3) Reactor coolant pump lube oil system.		3-hr fire-rated door assemblies. The turbine generator oil reservoir and coolers and hydraulic control reservoir and coolers are separated from each other by fire-rated walls and are protected by deluge sprinkler system. The turbine-generator oil reservoir coolers are open to the turbine-generator operating floor but the opening is protected by a deluge sprinkler system. The feedwater pump rooms are not separated by fire barriers but are protected by deluge systems. The reactor recirculation pumps are not protected by an automatic fire suppression system since the containment is inerted. Reactor recirculation, pump bearing temperature and oil level and containment temperature and pressure are monitored.
D.2.b	Bulk gas storage (either compressed or cryogenic), should not be permitted inside structures housing safety-related equipment. Storage of flammable gas such as hydrogen, should be located outdoors or in separate detached buildings so that a fire or explosion will not adversely affect any safety related systems or equipment. Refer to NFPA 50A, "Gaseous Hydrogen Systems." Care should be taken to locate high pressure gas storage containers with the long axis parallel to building walls. This will minimize the possibility of wall penetration in the event of a container failure. Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled. Refer to NFPA 5, "Industrial Fire Loss Prevention."	D.2.b	A separate building, remote from the main buildings of the plant, is provided for bulk storage of hydrogen bottles. The location is north of the turbine generator building such that a fire or explosion would not affect safety-related buildings or equipment. The building is of noncombustible construction and complies with NFPA Standard 50A (1973). The storage facility consists of a three-sided elevated building with louvers to ensure proper ventilation. All bottles are stored in a vertical position. The hydrogen supply piping is installed inside a culvert to ensure proper protection of the hydrogen line. All electrical equipment within the hydrogen storage facility is rated for installation in a hazardous area Class I, Division II, Group B. The hydrogen storage facility has an elaborate grounding system. These precautions minimize the occurrence of fires and explosions. The hydrogen gas supply system is shown in Figures 1.2-2 and 10.2-4. The Hydrogen Water Chemistry (HWC) Hydrogen Storage and Supply Facility (HSSF), a separate and remote facility, provides bulk storage of both liquid and gaseous hydrogen for hydrogen injection into the

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
	condensate/feedwater system to mitigate Intergranular Stress Corrosion Cracking (IGSCC) in the internals of the reactor vessel. The HSSF is located approximately 430 yards southeast of the Sewage Treatment Plant Blower and Laboratory Building (Building #24 on Figure 1.2-1). This outdoor non-safety-related facility meets the siting considerations of EPRI NP-5283-SR-A and is far removed from the main plant buildings, such that a fire or explosion at the HSSF would not affect plant safety-related buildings or equipment. The HSSF is designed to comply with NFPA 30-2000, NFPA 50A-1999, NFPA 50B-1999, and NFPA 70-2002. The storage facility consists of a 14,000-gallon liquid hydrogen storage tank, two redundant liquid hydrogen pumps and ambient air vaporizers, six high-pressure gas hydrogen storage tubes, a back-up hydrogen gas tube trailer assembly, a 1,500-gallon liquid nitrogen storage tank, and two redundant ambient air nitrogen vaporizers for system purging. The HSSF is supplied from plant power, is designed for lightning protection, and the grounding grid is connected to the site grid. All electrical equipment installed in high hazardous areas meet the requirements of NFPA 70-2002. In the yard area of the plant, the buried hydrogen supply line is encased in a guard pipe that provides mechanical protection and a means to monitor the pipe for leakage. The vent of the guard pipe is directed to a hydrogen detector outside the TG building. The hydrogen supply pipe is routed through the Turbine Generator Building 441' west end, which is not a safety-related plant area. The HSSF isolation and monitoring devices alarm at the Remote Annunciator Panel, located in the plant chemistry lab (RW 487'). HSSF is equipped with UV/IR flame sensors that isolate the hydrogen supply and alarm at both the Remote Annunciator Panel and

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
	Control Room. The hydrogen supply lines are equipped with excess flow check valves to shut off the gas flow in the event of a pipe break. The hydrogen supply system incorporates hydrogen leak detectors at non-welded pipe connections within Fire Area TG-1. The HWC system is automatically shut down upon receipt of a high-high hydrogen signal from these hydrogen leak detectors. These design features minimize the occurrence of fires and explosions. Minimum amounts of compressed gases are permanently stored in safety-related buildings where the gases are required for system functioning. These are limited to the following: - Nitrogen - 2% hydrogen in argon - 2% hydrogen in nitrogen - 6% hydrogen in argon - 2% oxygen in argon - 6% oxygen in argon - Freon - 10% methane in argon - Propane - Helium - Scott air pack bottles With the exception of the air pack bottles, the compressed gases are stored in a vertical position and are seismically restrained. The air pack bottles are stored horizontally, but do not present a hazard to any safety-related equipment. The propane is used in a laboratory and does not present a hazard to any safety-related equipment. The other types of compressed gas bottles do not present explosive hazards. Temporary use of flammable and fuel compressed gases is controlled by plant procedures.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
D.2.c	The use of plastic materials should be minimized. In particular, halogenated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute non-combustible materials are not available. All plastic materials, including flame and fire retardant materials, will burn with an intensity and BTU production in a range similar to that of ordinary hydrocarbons. When burning, they produce heavy smoke that obscures visibility and can plug air filters, especially charcoal and HEPA. The halogenated plastics also release free chlorine and hydrogen chloride when burning, which are toxic to humans and corrosive to equipment.	D.2.c	The use of plastic materials, in particular halogenated plastics, are minimized to the extent practical. See response to paragraph D.3.f.
D.2.d	Storage of flammable liquids should, as a minimum, comply with the requirements of NFPA 30, "Flammable and Combustible Liquids Code."	D.2.d	Flammable liquids, as defined in NFPA 30-1973, are not used in plant systems. The storage of combustible liquids in plant systems conforms to the requirements of NFPA 30-1973. See Table F.2-1 and item F.9 for approved NFPA 30 deviations. Flammable/combustible liquids for incidental used in maintenance and operations are normally stored in accordance with NFPA 30. Exceptions may be authorized by special handling permits in accordance with plant procedures. Note that the storage restrictions within a fire area are implemented using the NFPA 30 definition of fire area(s) - not the fire area boundaries as defined for the purpose of post-fire safe shutdown analysis.
D.3	Electric Cable Construction, Cable Trays, and Cable Penetrations	D.3	Electric Cable Construction, Cable Trays, and Cable Penetrations
D.3.a	Only non-combustible material should be used for cable tray construction.	D.3.a	All cable trays, covers, their supports, and hardware are constructed of non-combustible material.
D.3.b	See section E3 for fire protection guidelines for cable spreading rooms.	D.3.b	See paragraph E.3 below.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
D.3.c	Automatic water sprinkler systems should be provided for cable trays outside the cable spreading room. Cables should be designed to allow wetting down with deluge water without electrical faulting. Manual hose stations and portable hand extinguishers should be provided as backup. Safety-related equipment in the vicinity of such cable trays, that does not itself require water fire protection, but is subject to unacceptable damage from sprinkler water discharge, should be protected from sprinkler system operation or malfunction. When safety-related cables do not satisfy the provisions of Regulatory Guide 1.75, all exposed cables should be covered with an approved fire retardant coating and a fixed automatic water fire suppression system should be provided.	D.3.c	Spacial separation or electrical separation barriers have been provided between redundant safety-related cable trays as described in Section 8.3. Fixed water suppression systems for all such cable trays outside the cable spreading room are, therefore, considered unnecessary. The cable spreading room and the cable chase in the radwaste/control building and the radwaste-reactor building corridor, however, contain redundant safety-related cables in trays and are located such that the heat resulting from a fire could not be dissipated. Therefore, these areas are provided with automatic water sprinkler systems even where the plant divisional separation guidelines are met. Manual hose stations and portable extinguishers are available for backup. All hose stations are equipped with fog nozzles. Use of these fog nozzles is not likely to cause unacceptable damage to any safety-related equipment when used by trained personnel in the prescribed manner. 2-½ in. hose monitors do have the capability to go solid stream and would not be used on interior energized electrical equipment fires.
D.3.d	Cable and cable tray penetration of fire barriers (vertical and horizontal) should be sealed to give protection at least equivalent to that fire barrier. The design of fire barriers for horizontal and vertical cable trays should, as a minimum, meet the requirements of ASTM E-119, "Fire Test of Building Construction and Materials," including the hose stream test.	D.3.d	Cable and cable tray penetrations in fire barriers are sealed with a fire rating equivalent to that of the penetrated area unless fire protection evaluation has justified a lesser fire rating. Nongrouted electrical penetration seals designs through fire rated barriers are fire rated based on the criteria established in Reference F.7.6.b (which uses the ASTM E-119 time temperature curve).

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
	Where installed penetration seals are deficient with respect to fire resistance, these seals may be protected by covering both sides with an approved fire retardant material. The adequacy of using such material should be demonstrated by suitable testing.		
D.3.e	Fire breaks should be provided as deemed necessary by the fire hazards analysis. Flame or flame retardant coatings may be used as a fire break for grouped electrical cables to limit spread of fire in cable ventings. Possible cable derating owing to use of such coating materials must be considered during design.	D.3.e	Thermo-Lag and Flamemastic coated cable tray fire breaks have been abandoned in place (Reference F.7.6.e). Where long vertical run trays breach nonrated barriers, silicone foam seals which fill the entire blockout are maintained as fire breaks. Where coating materials are used on cables, derating of cables is considered in the design.
D.3.f	Electric cable constructions should as a minimum pass the current IEEE No. 383 flame test. This does not imply that cables passing this test will not require additional fire protection. For cable installation in operating plants and plants under construction that do not meet the IEEE No. 383 flame test requirements, all cables must be covered with an approved flame retardant coating and properly derated.	D.3.f	All safety-related cabling meets the IEEE 383-1974 flame test requirements. Generally, cabling within plant cable trays, cable penetrations, and enclosures meets IEEE 383-1974 flame test requirements. Certain lighting circuits and low energy wiring within plant control panels, racks, and other electrical enclosures do not meet the IEEE 383-1974 requirements. The use of polyvinyl chloride (PVC) cabling is minimized. Where IEEE 383 rated cable is not available for a particular application, cable procured to meet National Electric Code guidelines for fire resistance for plenum rated cabling using NFPA 262-1990, UL 910-985, or equivalent may be used.
D.3.g	To the extent practical, cable construction that does not give off corrosive gases while burning should be used. Applicable to new cable installations.	D.3.g	Cables are generally jacketed with a cross-linked polyolephin (XLPE) material which gives off as little corrosive gas as practical. The use of polyvinyl chloride (PVC) cabling is minimized.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
D.3.h	Cable trays, raceways, conduit, trenches, or culverts should be used only for cables. Miscellaneous storage should not be permitted, nor should piping for flammable or combustible liquids or gases be installed in these areas. Installed equipment in cable tunnels or culverts need not be removed if they present no hazard to the cable runs as determined by the fire hazards analysis.	D.3.h	Cable trays, raceways, and conduits are used only for cables. There are no cable tunnels or culverts in the plant. There are no provisions for miscellaneous storage in cable areas, nor are flammable or combustible liquids or gases installed in these areas.
D.3.i	The design of cable tunnels, culverts and spreading rooms should provide for automatic or manual smoke venting as required to facilitate manual fire fighting capability.	D.3.i	There are no cable tunnels or culverts in the plant. Air from the cable spreading room normally passes into the cable chase through openings protected by 3-hr fire-rated dampers and then back to a ventilation unit. Smoke detectors spaced through both areas and a smoke detector, mounted in the ductwork, monitor the return air. On actuation of the detector, an alarm sounds in the control room. The control room operator can then shut down the ventilation unit. As the cable spreading room and cable chase are each protected by an automatic preaction sprinkler system designed for cable tray fire extinguishment, a fire would be of limited duration. Smoke from a fire would be purged through the actuation of a fixed exhaust fan and ductwork and discharged directly to the atmosphere. The use of fans and ducting to discharge smoke to the atmosphere would help maintain visibility in both the cable chase and the cable spreading room.
D.3.j	Cables in the control room should be kept to the minimum necessary for operation of the control room. All cables entering the control room should terminate there. Cables should not be installed in floor trenches or culverts in the control room.	D.3.j	The main control room is composed mainly of a “panel assembly” system. Each “panel assembly” consists of a termination cabinet, a subfloor section (with enclosed, segregated ducts for cable routing), and a vertical panel and/or benchboard assembly.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
Existing cabling installed in concealed floor and ceiling spaces should be protected with an automatic total flooding Halon system.	A raised floor is provided for the entire room. The "panel assembly" subfloor sections comprise a major portion of this false floor. Panel assembly ducts, termination cabinet cable entrance/exit areas, and vertical panel and benchboard assembly cable entrance/exit areas are located beneath the false floor. Most cables entering the room enter the termination cabinets directly. They are either terminated there or route directly to vertical panels or benchboards for termination. Some cables enter the false floor outside the "panel assemblies." They then route either into the panel assemblies, or to other control room equipment not a part of the "panel assembly" system (lighting panels, relay panels, etc.). A Halon extinguishing system is provided for the subfloor sections longitudinal cable ducts. Seals for Halon containment are provided at the entrance and exit points to the ducts. All penetrations into the main control room are provided with fire-rated seals. Cables entering the false floor outside the "panel assemblies" are enclosed in rigid steel conduit, metallic flexible conduit (with the outer jacket removed), covered metal troughs, Haveg Siltemp tape, or suitable fire resistive cable as identified in NFPA 70 for under raised floors. All cables in the suspended ceiling area are enclosed in conduit. For this reason, an automatic flooding system is not deemed necessary.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
D.4 Ventilation	D.4 Ventilation
D.4.a The products of combustion that need to be removed from a specific fire area should be evaluated to determine how they will be controlled. Smoke and corrosive gases should generally be automatically discharged directly outside to a safe location. Smoke and gases containing radioactive materials should be monitored in the fire area to determine if release to the environment is within the permissible limits of the plant Technical Specifications. The products of combustion which need to be removed from a specific fire area should be evaluated to determine how they will be controlled.	D.4.a Products of combustion are removed from specific areas by two methods, as follows: a. Areas with direct duct connections to the exhaust system discharge directly to the atmosphere. These areas are: 1. Turbine generator building a) Reactor feed pump rooms b) Mechanical vacuum pump rooms c) Auxiliary boiler room 2. Reactor building a) LPCS pump room b) RHR pump rooms c) RCIC pump room d) HPCS pump room e) CRD pump room 3. Diesel generator building a) Diesel oil day tank rooms b) Diesel generator rooms c) Diesel oil transfer pump rooms d) Air compressors and electrical equipment rooms 4. Circulation water pump house b. Areas of the plant to which air is supplied and return air is routed to other areas of higher potential radioactivity prior to final exhaust are: 1. Turbine generator building (a) Turbine oil reservoir and conditioner room (b) H_2 seal oil unit room (c) Turbine lube oil storage room (d) General area containing (1) Service and instrument air compressors (2) Condensate pumps (3) Condensate booster pumps (4) Turbine oil transfer lines (5) Cables

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
	2. Reactor building general area containing (a) SLC pumps (b) Cables (c) Standby gas treatment units (d) Sump vent filter units 3. Radwaste building general area containing (a) Exhaust air filter units (b) Cables Exhaust air from the reactor, radwaste, and turbine generator buildings is monitored to determine the quantity of radioactive material being released to the environment. Smoke removal equipment, such as a fixed and a portable fan and flexible ducting are available in the radwaste/control and reactor buildings to aid in smoke removal. The basic air flow patterns were established by exhausting directly from potentially contaminated areas, as well as indirectly by inducing air from nonpotentially contaminated areas into shielded areas before discharging to the atmosphere. See Section F.2.5.5 for more details on smoke removal. Fire dampers were provided in ducting and wall penetrations to protect areas containing large quantities of combustibles or redundant post-fire safe shutdown systems against the postulated fires according to the severity of the fire as determined by the fire loading in the hazards analysis. The portable fan and ducting provide the latitude of allowing the existing fire barrier dampers to remain in a closed position while exhausting the impeding smoke from the fire area.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

	BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM
D.4.b	Any ventilation system designed to exhaust smoke or corrosive gases should be evaluated to ensure that inadvertent operation or single failures will not violate the controlled areas of the plant design. This requirement includes containment functions for protection of the public and maintaining habitability for operations personnel.	D.4.b	All ventilation systems designed to exhaust smoke and corrosive gases are functioning during normal plant operation with the exception of the SGT units and the portable smoke removal units. Standby fans are available for backup operation of the ventilation systems in the reactor, radwaste, and turbine generator buildings. Inadvertent operation or single failures of these units will not violate safety requirements for the plant personnel or the public.
D.4.c	The power supply and controls for mechanical ventilation systems should be run outside the fire area served by the system.	D.4.c	The power supply and controls for mechanical ventilation systems have not always been run outside the fire areas served by the system. The fire hazards analysis demonstrates that post-fire safe shutdown capability is not jeopardized by this cable routing.
D.4.d	Fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52, "Design Testing and Maintenance Criteria for Atmospheric Cleanup Air Filtration."	D.4.d	Fire suppression systems have been installed in the safety-related standby gas treatment filter unit, control room emergency filter unit, and the reactor sump vent filter unit in accordance with Regulatory Guide 1.52. The offgas system charcoal units are contained in eight ASME, Section III, Class 3 coded vessels in the radwaste building. They are not protected by a fire suppression system. Valving, however, breaks the tanks down into groups that can be closed off to eliminate oxygen thereby extinguishing a fire. The probability of flame spread from the units is considered small and they are well separated from safety-related circuits and components.
D.4.e	The fresh air supply intakes to areas containing safety related equipment or systems should be located remote from the exhaust air outlets and smoke vents of other fire areas to minimize the possibility of contaminating the intake air with the products of combustion.	D.4.e	The fresh air supply intakes to areas containing safety-related equipment or systems are located with sufficient separation from exhaust air outlets and smoke vents to minimize the possibility of contaminating the intake air with products of combustion.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
D.4.f Stairwells should be designed to minimize smoke infiltration during a fire. Staircases should serve as escape routes and access routes for fire fighting. Fire exit routes should be clearly marked. Stairwells, elevators and chutes should be enclosed in masonry towers with minimum fire rating of three hr and automatic fire doors at least equal to the enclosure construction, at each opening into the building. Elevators should not be used during fire emergencies.	D.4.f Enclosed fire rated stairwells and elevators provide either a 2-hr or 3-hr fire rating, with 1.5 hr minimum fire doors. See Figures F.6-1 through F.6-5. Door T207 to the service building roof is nonrated. Enclosed fire rated stairwells are not equipped with ventilation and would effectively limit smoke infiltration. Elevators are not typically used for egress during fire emergencies.
D.4.g Smoke and heat vents may be useful in specific areas such as cable spreading rooms and diesel fuel oil storage areas and switchgear rooms. When natural-convection ventilation is used, a minimum ratio of 1 sq. ft of venting area per 200 sq. ft of floor area should be provided. If forced-convection ventilation is used, 300 CFM should be provided for every 200 sq. ft of floor area. See NFPA No. 204 for additional guidance on smoke control.	D.4.g Provisions for smoke and heat relief are discussed in paragraphs D.3.i and D.4.a above. In areas where smoke and heat are removed by the normal ventilation systems, a minimum of 300 cfm is provided for every 200 ft^2 of floor area except in the following areas:

Area	Ventilation per 200 ft^2	Supplementary Ventilation Equipment
Safety-Related Areas		
HPCS pump room	251 cfm	Portable fan flex duct
RHR-2A pump room	148 cfm	Portable fan-flex-duct
RHR-2B pump room	127 cfm	Portable fan-flex-duct
SGT-general area	207 cfm	Portable fan-flex-duct
D.O. transfer pump room	278 cfm	Portable fan-flex-duct
Cable spreading rooms	24 cfm[a]	Fixed fan-flex-duct
Control room	0 cfm	Fixed fan-flex duct
Control bldg. mech. duct equipment room	0 cfm	Fixed fan-flex duct
Cable chase	205 cfm	Fixed fan-flex duct

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
			Non-Safety-Related Areas Turbine L.O. storage room — 277 cfm — Portable fan-flex duct TG operating floor[b] — 274 cfm — Portable fan-flex duct [a] 1000 cfm purge air. [b] Roof vents are not provided. Portable and fixed fans with flexible ducting are provided to allow smoke removal from rooms in which additional ventilation is required.
D.4.h	Self-contained breathing apparatus, using full face positive pressure masks, approved by NIOSH (National Institute of Occupational Safety and Health - approval formerly given by the US Bureau of Mines) should be provided for fire brigade, damage control, and control room personnel. Control room personnel may be furnished breathing air by a manifold.	D.4.h	Provisions have been made to ensure that adequate self-contained breathing apparatus (SCBA) are available for fire fighting, damage control personnel, and control room operating personnel. These units are independent of respiratory protective equipment provided for general plant activities. See Table F.3-2 of Section III.H for more SCBA requirements.
D.4.i	Where total flooding gas extinguishing systems are used, area intake and exhaust ventilation dampers should close upon initiation of gas flow to maintain necessary gas concentration. See NFPA 12, “Carbon Dioxide Systems,” and 12A, “Halon 1301 Systems.”	D.4.i	The total flooding Halon 1301 system for the main control room PGCC ducts does not require closure of any ventilation dampers to maintain necessary gas concentration.
D.5	Lighting and Communication	D.5	Lighting and Communication
D.5.a	Fixed emergency lighting should consist of sealed beam units with individual 8-hour minimum battery power supplies.	D.5.a	Fixed emergency lighting for egress consists of 1.5-hr Life Safety and Appendix R 8-hr emergency lights consisting of fixed emergency battery units, portable lanterns and diesel backed normal-emergency AC lights. Eight-hour portable lanterns are staged to perform post-fire safe shutdown manual actions outside the control room. See Section 9.5.3.2.4 for emergency lighting systems.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
			In critical areas, such as the Main Control Room, emergency lighting is installed and powered from the emergency buses which are supplied by the diesel generators. All plant areas, which must be manned for post-fire safe shutdown and all associated access/egress routes, have been provided with adequate lighting such that any required operator actions can be accomplished. The plant emergency lighting systems are further described in Section 9.5.3.
D.5.b	Suitable sealed-beam battery powered portable hand lights should be provided for emergency use.	D.5.b	Suitable sealed-beam, battery-powered portable hand lights have been provided.
D.5.c	Fixed emergency communication should use voice powered head sets at preselected locations.	D.5.c	Voice powered head sets are provided throughout the plant at preset locations.
D.5.d	Fixed repeaters installed to permit use of portable radio communication units should be protected from exposure fire damage.	D.5.d	The in-plant radio repeater is located in Fire Area DG-10 which has fire detection and is isolated from major fire hazards by 3-hr fire barriers. The fire brigade leader communicates with the fire brigade members using radios. The fire brigade leader communicates with the control room or the remote shutdown room using either radios or PBX phones. Certain PBX phones are credited for post-fire safe shutdown activities. The specific actions that require PBX communications are listed in Reference F.7.3.d. See Sections F.2.6.2, 9.5.2 and LCS 1.10.8 for more detail. The PBX communication system for post-fire safe shutdown credits the PBX battery (E-B0-PBX) for 8 hours of operation following a loss of off-site power even though the system has a diesel generator backup.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
E. FIRE DETECTION AND SUPPRESSION	E. FIRE DETECTION AND SUPPRESSION
E.1 Fire Detection	E.1 Fire Detection
E.1.a Fire detection systems should as a minimum comply with NFPA 72D, "Standard for Installation, Maintenance and Use of Proprietary Protective Signaling Systems." Deviations from the requirements of NFPA 72D should be identified and justified.	E.1.a The fire detection system conforms to NFPA 72D for a Class B designation with the following exceptions: detection circuits that actuate fire suppression systems in safety-related areas are Class A. Incoming signals to the control room fire panel are manually recorded. CGS employs a pre-alarm detection system which sounds an alarm signal in the control room only. The control room operator manually sounds a building wide alarm over the public address system. All signals to the control room are identified by zones which designate the building, floor, and cause of alarm. A manual push button radio fire alarm reporter is used to transmit an alarm to the offsite fire department. Pre-alarm detectors are installed according to UL recommendations and spacing, except as justified in Table F.2-1. Certain testing which would require entry into high radiation areas may not be performed during power operation. See Section F.2 for further discussion of the fire detection system.
E.1.b Fire detection system should give audible and visual alarm and annunciation in the control room. Local audible alarms should also sound at the location of the fire.	E.1.b Fire detection systems provide audible and visual alarms in the control room. Plant-wide alarms and public address announcements are initiated by the main control room operator in accordance with emergency procedures.
E.1.c Fire alarms should be distinctive and unique. They should not be capable of being confused with any other plant system alarms.	E.1.c Fire alarms are distinctive and unique from all other plant system alarms.
E.1.d Fire detection and actuation systems should be connected to the plant emergency power supply.	E.1.d Fire detection and actuation systems are connected to power panels which are supplied by uninterruptible power supplies.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
E.2	Fire Protection Water Supply System	E.2	Fire Protection Water Supply System
E.2.a	An underground yard fire main loop should be installed to furnish anticipated fire water requirements, NFPA 24 - Standard for Outside Protection - gives necessary guidance for such installation. It references other design codes and standards developed by such organizations as the American National Standards Institute (ANSI) and the American Water Works Association (AWWA). Lined steel or cast iron pipe should be used to reduce internal tuberculation. Such tuberculation deposits in an unlined pipe over a period of years can significantly reduce water flow through the combination of increased friction and reduced pipe diameter. Means for treating and flushing the systems should be provided. Approved visually indicating sectional control valves, such as post indicator valves, should be provided to isolate portions of the main for maintenance or repair without shutting off the entire system. The fire main system piping should be separate from service or sanitary water system piping. Visible location marking signs for underground valves is acceptable. Alternative valve position indicators should also be provided. For operating plants, fire main system piping that can be isolated from service or sanitary water system piping is acceptable.	E.2.a	The underground yard fire main circles the plant. NFPA 24-1973 was used as the design code. The fire main is constructed of 12-in. ductile iron, cast iron, and steel pipe. The underground pipe, valves, and fittings have an applied coating of bituminous material with a minimum thickness of 1 mil. The interior coating on ductile iron and cast iron piping conforms to the requirements of ANSI A21.4. All underground valves in the fire main loop have post indicators for visual indication and to isolate portions of the fire main. The underground fire main is periodically flushed. The fire protection water system is independent of the domestic system. See F.2.4.1 for other plant system interfaces.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
E.2.b	A common yard fire main loop may serve multi-unit nuclear power plant sites if cross-connected between units. Sectional control valves should permit maintaining independence of the individual loop around each unit. For such installations, common water supplies may also be utilized. The water supply should be sized for the largest single expected flow. For multiple reactor sites with widely separated plants (approaching 1 mile or more), separate yard fire main loops should be used. Sectionalized systems are acceptable.	E.2.b	CGS is not a multiple reactor site.
E.2.c	If pumps are required to meet system pressure or flow requirements, a sufficient number of pumps should be provided so that 100% capacity will be available with one pump inactive (e.g., three 50% pumps or two 100% pumps). The connection to the yard fire main loop from each fire pump should be widely separated, preferably located on opposite sides of the plant. Each pump should have its own driver with independent power supplies and control. At least one pump (if not powered from the emergency diesels) should be driven by nonelectrical means, preferably diesel engine. Pumps and drivers should be located in rooms separated from the remaining pumps and equipment by a minimum 3-hr fire wall. Alarms indicating pump running, driver availability, or failure to start should be provided in the control room. Details of the fire pump installation should as a minimum conform to NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps."	E.2.c	Fire pumps are required to meet the fire protection system pressure and flow requirements. This system design has been accepted by the insuring authority. Three fire pumps, each with a flow rate of 2000 gpm, are located in the circulating water pump house and draw water from the circulating water pump house basin. This is the primary source of water for fire protection. Two of the pumps are electrically driven and powered from separate electrical buses. The third pump is powered by its own diesel engine. The three pumps are spatially separated with approximately 23 ft between electric pumps and 30 ft between the nearest electric driven pump and the diesel driven pump. The pump house hall is protected by a fixed sprinkler system. The pumps and drivers are elevated above the floor by concrete pedestals thus floor drainage is not a concern. Each pump is capable of supplying 100% of the fire water flow rate except under the following conditions: a. Due to the complexity of cable tray routing in the cable chase and cable spreading rooms, two pumps are required to meet the fire water system design requirements, and

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM
		b. The 100% pump flow rate capacity would be limited to the fixed system and two interior hoses. If exterior hoses are used, there would be a slight reduction in system and hose densities. Two supply lines run parallel to each other from the circulating water pump house fire pumps to the south side of the plant fire water supply loop where they connect to the loop with a 10-ft separation. A back up diesel-driven fire pump rated at 2500 gpm is provided and located in the filtration building. The pump draws water from a 400,000 gal bladder tank. It discharges into the north side of the plant fire water supply loop. NFPA 20-1974 was used for design guidance in the fire pump installation. The fire pumps are UL listed and Factory Mutual approved. Alarms indicating pump running and power failure malfunction are provided for each pump in the main control room.
E.2.d Two separate reliable water supplies should be provided. If tanks are used, two 100% (minimum of 300,000 gal each) system capacity tanks should be installed. They should be so interconnected that pumps can take suction from either or both. However, a leak in one tank or its piping should not cause both tanks to drain. The main plant fire water supply capacity should be capable of refilling either tank in a minimum of 8 hr. Common tanks are permitted for fire and sanitary or service water storage. When this is done, however, minimum fire water storage requirements should be dedicated by means of a vertical standpipe for other water services.	E.2.d	Two separate reliable water supplies are provided (see Figure F.6-21). The primary water supply is the circulating water pump house basin. The circulating water basin is not dedicated to fire protection, but is a reliable water volume (Reference F.7.3.dd). The water level in the basin is monitored and it provides 100% of the fire water supply as defined in paragraph E.2.e. Should the quantity of water drop to a low level an alarm signals the Control Room operator to initiate the makeup water pumps. Excluding a loss-of-offsite power, an inexhaustible quantity of makeup water can be supplied to the basin at the rate of 12,500 to 25,000 gpm from the cooling tower makeup water system from the Columbia River. Water is returned to the basin from the cooling towers by gravity feed. At the low level, the total

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
			water available to the fire pumps in the basin and its gravity fed tributary piping is greater than 300,000 gal. A backup water supply is provided by a 400,000 gal bladder tank which provides 100% of the fire water supply as defined in paragraph E.2.e. It has a dedicated water supply of 284,640 gal. The bladder tank can be refilled in approximately 8 hr. The primary water supply volume is at the circulating water pump house basin and the secondary water supply tank is FP-TK-110. Figure F.6-21 shows the two fire water supplies are at opposite sides of the site. Based on this large separation, interconnection of the two fire water supplies is not practical.
E.2.e	The fire water supply (total capacity and flow rate) should be calculated on the basis of the largest expected flow rate for a period of two hr, but not less than 300,000 gallons. This flow rate should be based (conservatively) on 1000 gpm for manual hose stream plus the greater of: a. all sprinkler heads opened and flowing in the largest designed fire area; or b. the largest open head deluge system(s) operating.	E.2.e	The requirement of 1000 gpm for manual hose streams has been reduced to 500 gpm by BTP CMEB 9.5.1 (NUREG-0800). The fire protection system water supply is designed to meet the water flow demand assuming the shortest leg of the fire main loop is inoperable. The required water supply of 284,640 gal is based on a 2-hr flow period for the largest demand of a sprinkler system in a safety-related area of 2372 gpm (sprinkler demand for the cable spread room which includes 500 gpm for hose streams). See also paragraph E.2.d.
E.2.f	Lakes or fresh water ponds of sufficient size may qualify as sole source of water for fire protection, but require at least two intakes to the pump supply. When a common water supply is permitted for fire protection and the ultimate heat sink, the following should also be satisfied:	E.2.f	Two sources of water are provided for fire protection. See paragraph E.2.d above. The fire water supply is independent of the ultimate heat sink.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
	a. The additional fire protection water requirements are designed into the total storage capacity; and b. Failure of the fire protection system should not degrade the function of the ultimate heat sink.		
E.2.g	Outside manual hose installation should be sufficient to reach any location with an effective hose stream. To accomplish this, hydrants should be installed approximately every 250 feet on the yard main system. The lateral to each hydrant from the yard main should be controlled by a visually indicating or key operated (curb) valve. A hose house, equipped with hose and combination nozzle, and other auxiliary equipment recommended in NFPA 24, "Outside Protection," should be provided as needed but at least every 1000 ft. Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings and standpipe risers.	E.2.g	The yard fire main loop includes hydrants installed approximately every 300 ft. Each hydrant has a post indicating control valve (see Figure F.6-21). A mobile fire response vehicle is equipped with the equivalent of three hose houses (see Table F.2-1). This provides sufficient hose so that a single fire at any plant location can be reached by an effective hose stream. A combination fog shut-off type hose nozzle is provided. Threads are compatible with those used by the local fire department.
E.3.a	Each automatic sprinkler system and manual hose station standpipe should have an independent connection to the plant underground water main. Headers fed from each end are permitted inside buildings to supply multiple sprinkler and standpipe systems. When provided, such headers are considered an extension of the yard main system. The header arrangement should be such that no single failure can impair both the primary and backup fire protection systems. Each sprinkler and standpipe system should be equipped with OS&Y (outside screw and yoke) gate valve, or other approved shut off valve, and water flow alarm. Safety related equipment that does not itself require sprinkler water fire protection, but is subject	E.3.a	Each automatic sprinkler system does not have an independent connection to the fire main loop. Sectionalizing valves have been installed in the yard loop to isolate impairments. Standpipes in the radwaste/control and diesel generator buildings have been interconnected with other standpipes so that a single failure would not impair systems protecting safety-related equipment. See paragraph A.4 above for further discussion of the single failure criterion. Each sprinkler and standpipe system within the permanent plant island is controlled by an OS&Y gate valve or other approved shut-off valve. Alarm type check or deluge valves are installed as required in each sprinkler system and cause an alarm in the control

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

	BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM
	to unacceptable damage if wetted by sprinkler water discharge, should be protected by water shields or baffles.		room on water flow. There are no flow alarms on hose station standpipes but the control room operator would be aware of a flow by the main fire pumps operating annunciators. There is no safety-related equipment that is subject to unacceptable damage if wetted by sprinkler water discharge. Buildings in the plant industrial area with installed sprinkler systems are isolated from the yard main by post indicating valves. These systems are alarmed to the Protected Area Access Security Control Center (SCC).
E.3.b	All valves in the fire water systems should be electrically supervised. The electrical supervision signal should indicate in the control room and other appropriate command locations in the plant (see NFPA 26, "Supervision at Valves"). When electrical supervision of fire protection valves is not practicable, an adequate management supervision program should be provided. Such a program should include locking valves open with strict key control; tamper proof seals; and periodic visual check of all valves.	E.3.b	Water supply control valves in the fire water system are locked open. Outside valves are provided with post indicators. Valves that control water to the fire protection system are controlled as follows: a. Valves larger than 2-in. are locked in the wide open position with non-breakable shackle locks, b. Valves 2-in. and smaller controlling water supplies are sealed in the full open position, c. Valves to sprinkler or deluge alarm lines are sealed in the open position, and d. Valves that control water flow are checked quarterly.
E.3.c	Automatic sprinkler systems should as a minimum conform to requirements of appropriate standards such as NFPA 13, "Standard for the Installation of Sprinkler Systems", and NFPA 15, "Standard for Water Spray Fixed Systems."	E.3.c	Installed sprinkler systems were designed using NFPA 13-1975 and NFPA 15-1973. Fire protection systems installed in safety-related areas have been specifically reviewed to identify deviations from the code requirements. See Section F.2.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A		CGS FIRE PROTECTION PROGRAM	
E.3.d	Interior manual hose installation should be able to reach any location with at least one effective hose stream. To accomplish this, standpipes with hose connections equipped with a maximum of 75 ft of 1.5 in. woven jacket lined fire hose and suitable nozzles should be provided in all buildings, including containment, on all floors and should be spaced at not more than 100-ft intervals. Individual standpipes should be of at least 4-in. diameter for multiple hose connections and 2.5-in. diameter for single hose connections. These systems should follow the requirements of NFPA No. 14 for sizing, spacing and pipe support requirements of NFPA No. 14 for sizing, spacing and pipe support requirements (NELPIA).	E.3.d	Standpipes and manual hose stations were designed using NFPA 14-1974. Hose stations are presently provided with 150 ft of 1.5-in. rubber lined fire hose with shutoff type fog nozzle and are capable of reaching any location with at least one effective hose stream in all building fire areas. The interior manual hose installations provide hose connections equipped with a maximum of 100 ft of 1.5-in. fire hose in most safety-related areas. The reactor building requires 150-ft hose lengths. The modified arrangement allows any location that contains, or could present a fire exposure hazard, to safety-related equipment to be reached with at least one effective hose stream as defined in NFPA 14.
	Hose stations should be located outside entrances to normally unoccupied areas and inside normally occupied areas. Standpipes serving hose stations in areas housing safety-related equipment should have shut off valves and pressure reducing devices (if applicable) outside the area.		Hose stations are presently located inside enclosed stairways to the various fire areas of all buildings. All hose stations and their shutoff valves serving areas housing safety-related equipment are located outside of the area.
E.3.e	The proper type of hose nozzles to be supplied to each area should be based on the fire hazard analysis. The usual combination spray/straight stream nozzle may cause unacceptable mechanical damage (for example, the delicate electronic equipment in the control room) and be unsuitable. Electrically safe nozzles should be provided at locations where electrical equipment or cabling is located.	E.3.e	Manual hose stations are equipped with all fog nozzles for use with Class A, B, and C fires. Hose station fog nozzles (1.5-in. diameter) do not have straight stream capability and are electrically safe. Hose monitors (2.5-in. diameter) are available for use on large oil fires and have the capability to go straight stream, but would not be used on energized electrical equipment or in control rooms.
E.3.f	Certain fires such as those involving flammable liquids respond well to foam suppression. Consideration should be given to use of any of the available foams for such specialized protection application. These include the more common chemical and mechanical low expansion foams, high expansion foam and the relatively new aqueous film forming foam (AFFF).	E.3.f	Portable AFFF foam units are staged in designated areas for fighting combustible liquid fires. There is no bulk storage of flammable liquids included in the plant design.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
E.4 Halon Suppression Systems	E.4 Halon Suppression Systems
The use of Halon fire extinguishing agents should as a minimum comply with the requirements of NFPA 12A and 12B, "Halogenated Fire Extinguishing Agent Systems - Halon 1301 and Halon 1211." Only UL of FM approved agents should be used. In addition to the guidelines of NFPA 12A and 12B, preventative maintenance and testing of the systems, including check weighing of the Halon cylinders should be done at least quarterly. Particular consideration should also be given to: a. minimum required Halon concentration and soak time b. toxicity of Halon c. toxicity and corrosive characteristics of thermal decomposition products of Halon	Halon 1301 extinguishing systems are installed in the control room PGCC subfloor sections longitudinal cable ducts. The systems comply with the requirements of NFPA Standard 12A and GE Topical Report NEDO 10466-A. The Halon system for the control room PGCC subfloor sections longitudinal cable ducts in Area 1 consist of high pressure cylinders and necessary piping, nozzles, valves and detectors for suppressing fires in each of the sections. The Halon system will provide 20% concentration by volume for a 20-minute duration in the subfloor section ducts. The Halon 1301 agent is considered noninjurious to room occupants when the design concentration of the gas for total flooding does not exceed 7% of room volume. Halon discharges in the PGCC subfloor only, not in the occupied areas of the control room. A local alarm is installed to alert personnel prior to any discharge. It is considered that there will be no immediate adverse effects to sensitive electronic equipment due to thermal decomposition products of Halon 1301 under fire and nonfire conditions.
E.5 Carbon Dioxide Suppression Systems	E.5 Carbon Dioxide Suppression Systems
The use of carbon dioxide extinguishing systems should as a minimum comply with the requirements of NFPA 12, "Carbon Dioxide Extinguishing Systems." Particular consideration should be given to a. Minimum required CO_2 concentration and soak time: b. Toxicity of CO_2; c. Possibility of secondary thermal shock (cooling damage);	A low-pressure carbon dioxide extinguishing system is installed in the exciter housing of the turbine generator. During outages when the exciter housing is accessible, the CO_2 system is disarmed. The system was designed using NFPA 12-1973 where applicable.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
d. Offsetting requirements for venting during CO_2 injection to prevent overpressurization versus sealing to prevent loss of agent;	
e. Design requirements from overpressurization; and	
f. Possibility and probability of CO_2 systems being out-of-service because of personnel safety consideration. CO_2 systems are disarmed whenever people are present in an area so protected. Areas entered frequently (even though duration time for any visit is short) have often been found with CO_2 systems shut off.	
E.6 Portable Extinguishers	E.6 Portable Extinguishers
Fire extinguishers should be provided in accordance with guidelines of NFPA 10 and 10A, "Portable Fire Extinguishers, Installation, Maintenance and Use." Dry chemical extinguishers should be installed with due consideration given to cleanup problems after use and possible adverse effects on equipment installed in the area.	Dry chemical portable fire extinguishers are located throughout CGS. Halon 1211 portable extinguishers are also present in electronic equipment areas. Portable extinguishers were selected using NFPA 10-1975.
F. GUIDELINES FOR SPECIFIC PLANT AREAS	F. GUIDELINES FOR SPECIFIC PLANT AREAS
F.1 Primary and Secondary Containment	F.1 Primary and Secondary Containment
F.1.a Normal Operation	F.1.a Normal Operation
Fire protection requirements for the primary and secondary containment areas should be provided on the basis of specific identified hazards. For example: a. Lubricating oil or hydraulic fluid system for the primary coolant pumps b. Cable tray arrangements and cable penetrations	The primary containment is inerted with nitrogen. In the secondary containment, manually actuated fire suppression systems have been provided for each charcoal filter bed and roughing filter in the standby gas treatment unit and each charcoal filter bed in the sump vent filter unit. Operation of these systems will not compromise the operation of safety-related systems. Automatic fire

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
c. Charcoal filters Fire suppression systems should be provided based on the fire hazards analysis. Fixed fire suppression capability should be provided for hazards that could jeopardize safe plant shutdown. Automatic sprinklers are preferred. An acceptable alternate is automatic gas (Halon or CO_2) for hazards identified as requiring fixed suppression protection. An enclosure may be required to confine the agent if a gas system is used. Such enclosures should not adversely affect safe shutdown, or other operating equipment in containment. Automatic fire suppression capability need not be provided in the primary containment atmospheres that are inerted during normal operation. However, special fire protection requirements during refueling and maintenance operations should be satisfied as provided below.	detection is provided throughout the secondary containment with annunciation in the control room. Detectors were selected and located after evaluating the hazards involved.
F.1.b Refueling and Maintenance Refueling and maintenance operations in containment may introduce additional hazards such as contamination control materials, decontamination supplies, wood planking, temporary wiring, welding and flame cutting (with portable compressed fuel gas supply). Possible fires would not necessarily be in the vicinity of fixed detection and suppression systems. Management procedures and controls necessary to assure adequate fire protection are discussed in Section B.3.a of this table.	F.1.b Refueling and Maintenance Plant procedures establish fire protection controls during refueling and maintenance operations. Manual fire fighting capability is provided in secondary containment by standpipes with hose stations and portable fire extinguishers Adequate self-contained breathing apparatus is available for fire fighting. See Table F.3-2, paragraph III-H.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
In addition, manual fire fighting capability should be permanently installed in containment. Standpipes with hose stations, and portable fire extinguishers, should be installed at strategic locations throughout containment for any required manual fire fighting operations. Equivalent protection from portable systems should be provided if it is impractical to install standpipes with hose stations. Adequate self-contained breathing apparatus should be provided near the containment entrances for fire fighting and damage control personnel. These units should he independent of any breathing apparatus or air supply systems provided for general plant activities.	
F.2 Control Room	F.2 Control Room
The control room is essential to safe reactor operation. It must be protected against disabling fire damage and should be separated from other areas of the plant by floors, walls and roofs having minimum fire resistance ratings of 3 hr. Control room cabinets and consoles are subject to damage from two distinct fire hazards: a. Fire originating within a cabinet or console, and b. Exposure fire involving combustibles in the general room area. Manual fire fighting capability should be provided for both hazards. Hose stations and portable water and Halon extinguishers should be located in the control room to eliminate the need for operators to leave the control room. An additional hose piping shut off valve and pressure reducing device should be installed outside the control room. Hose stations adjacent to the control room with portable extinguishers in the control room are acceptable.	The control room is separated from other areas of the plant by floor, walls, and ceiling having a minimum fire resistance rating of 3 hr. Access to the control room is gained by passing through low range blast doors with construction equivalent to that of a 3-hr fire-rated door. The exit from the control room consists of a door from the air lock to the stairwell which has a construction equivalent to that of a 1.5-hr fire-rated door, and a 1.5 hr rated doors from the stairwell to adjacent areas. The control room PGCC subfloor sections longitudinal cable ducts are protected from fire by a total flooding Halon 1301 system. Portable Halon and dry chemical extinguishers are located inside the control room and a standby hose station is provided adjacent to the control room for manual fighting of fires in cabinets, consoles, and involving combustibles in the general room area. Fire detection in the PGCC cabinets and consoles is provided by smoke detectors. Fire detection in the PGCC subfloor sections longitudinal cable ducts is provided by smoke and thermal detectors. Alarm and

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
Nozzles that are compatible with the hazards and equipment in the control room should be provided for the manual hose station. The nozzles chosen should satisfy actual fire fighting needs, satisfy electrical safety and minimize physical damage to electrical equipment from hose stream impingement.	annunciation are provided in the control room. Fire alarms in other parts of the plant are alarmed and annunciated in the control room.
Fire detection in the control room cabinets, and consoles should be provided by smoke and heat detectors in each fire area. Alarm and annunciation should be provided in the control room. Fire alarms in other parts of the plant should also be alarmed and annunciated in the control room.	
Breathing apparatus for control room operators should be readily available. Control room floors, ceiling, supporting structures, and walls, including penetrations and doors, should be designed to a minimum fire rating of three hr. All penetration seals should be air tight.	Adequate numbers of SCBA are provided for fire fighting and damage control personnel. All penetration seals to the control room are pressure resistant. All ventilation penetrations into the control room are protected by 3-hr fire-rated dampers.
The control room ventilation intake should be provided with smoke detection capability to automatically alarm locally and isolate the control room ventilation system to protect operators by preventing smoke from entering the control room.	The control room ventilation intake is provided with smoke detection that alarms in the control room. The control room is also monitored by area smoke detectors. Smoke is prevented from entering the control room from other areas due to the pressurization of the room by the ventilation system. Makeup air for the control room ventilation system is drawn through the outside air intake which is located approximately 87 ft above the ground. If smoke is observed entering the intake, the control room operator has the option of drawing the makeup air through alternate intakes remote from the main plant buildings.
Manually operated venting of the control room should be available so that operators have the option of venting for visibility. Manually operated ventilation systems are acceptable.	A fire in Fire Area RC-13 could close fire dampers which prevents control room pressurization and could allow some smoke infiltration into the control room. A nearby range fire could result in diluted smoke at each remote air intake. Significant smoke intake would actuate duct smoke detectors. If desired, operators can close control room air intake valves, which would also prevent control room pressurization. In either case, the control room operators can don staged SCBA or open control room doors and purge with smoke removal fan WEA-FN-7. See section F.2.5.5.
Cables should not be located in concealed floor and ceiling spaces. All cables that enter the control room should terminate in the control room. That is, no cabling should be simply routed through the control room from one area to another.	All cables in the suspended ceiling of the control room are in electric metallic tubing (EMT) type conduit. All cables in the raised floor extending beyond the PGCC cabinets are either enclosed in rigid steel conduit covered metal troughs, flexible metal conduit (with the outer jacket removed), Haveg Siltemp tape, or suitable fire resistive cable as identified in NFPA 70 for under raised floors. There are no automatic fixed Halon systems other than those protecting the PGCC subfloor sections longitudinal cable ducts.
If such concealed spaces are used, however, they should have fixed automatic total flooding Halon protection.	

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
F.3.a Cable Spreading Room The preferred acceptable methods (for fire suppression) are: a. Automatic water system such as closed head sprinklers, open head deluge, or open directional spray nozzles. Deluge and open spray systems should have provisions for manual operation at a remote station; however, there should also be provisions to preclude inadvertent operation. Location of sprinkler heads of spray nozzles should consider cable tray sizing and arrangements to assure adequate water coverage. Cables should be designed to allow wetting down with deluge water without electrical faulting. Open head deluge and open directional spray systems should be zoned so that a single failure will not deprive the entire area of automatic fire suppression capability. The use of foam is acceptable, provided it is of a type capable of being delivered by a sprinkler or deluge system, such as an aqueous film forming foam (AFFF). b. Manual hoses and portable extinguishers should be provided as backup. c. Each cable spreading room of each unit should have divisional cable separation, and be separated from the other and the rest of the plant by a minimum 3-hr rated fire wall (see NFPA 251 or ASTM E-119 for fire test resistance rating). d. At least two remote and separate entrances are provided to the room for access by fire brigade personnel; and e. Aisle separation provided between tray stacks should be at least 3 ft wide and 8 ft high.	F.3.a Cable Spreading Room The cable spreading room is protected by a closed head preaction sprinkler system designed to protect the overhead and to protect alternate open cable trays horizontally every 10 ft of the cable tray. A large number of smoke detectors are installed to reduce detection time. Cables have been designed to allow wetting without electrical fault. Inadvertent operation is prevented by the preaction system because either a manual trip from a local manual pull station or an automatic trip from the ceiling mounted smoke detectors is required to actuate the deluge valve and flood the system with water. In addition sprinkler heads must be heat actuated before water will flow from the system. The system has been designed taking into consideration cable tray sizing and arrangements such that there is adequate water coverage. Dry chemical portable extinguishers are available inside and outside the cable spreading room. A manual hose station is located immediately outside one of the entrances. An additional hose can be extended from the next lower floor at the other entrance. The cable spreading room is separated from other areas of the plant by walls having a minimum fire resistance of 3 hr. There are two remote and separate entrances to the room having doors with a 3-hr rating. Generally, tray stacks are separated by 3-ft aisles and aisle headroom is typically 8 ft; however, there are some tray crossover and support obstructions which hamper but do not preclude access. Cables have been arranged to provide divisional separation in accordance with CGS electrical separation guidelines as described in Section 8.3.1.4.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
F.3.b Cable Spreading Room	F.3.b Cable Spreading Room
For cable spreading rooms that do not provide divisional cable separation of c, in addition to meeting a, b, d, and e (of paragraph F.3.a) above, the following should also be provided: a. Divisional cable separation should meet the guidelines of Regulatory Guide 1.75, "Physical Independence of Electric Systems." b. All cabling should be covered with a suitable fire retardant coating. c. As an alternate to a above, automatically initiated gas systems (Halon or CO_2) may be used for primary fire suppression, provided a fixed water system is used as a backup. d. Plants that cannot meet the guidelines of Regulatory Guide 1.75, in addition to meeting a, b, d and e above, an auxiliary shutdown system with all cabling independent of the cable spreading room should be provided.	The cable spreading room is designed to provide divisional separation as stated in paragraph F.3.a.
F.4 Plant Computer Room	F.4 Plant Computer Room
Safety-related computers should be separated from other areas of the plant by barriers having a minimum three-hour fire resistant rating. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Manual hose stations and portable water and Halon fire extinguishers should be provided.	The plant computers are not safety related.
F.5 Switchgear Rooms	F.5 Switchgear Rooms
Switchgear rooms should be separated from the remainder of the plant by minimum three-hour rated fire barriers to the extent practicable. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Fire hose stations and portable extinguishers should be readily available.	Safety-related switchgear rooms C206 and C208 have been separated from the remainder of the plant by 3 hr rated barriers. Duct penetrations serving the switchgear rooms are provided with 3 hr rated fire dampers. Cable penetrations are sealed. Automatic smoke detectors are provided to alarm in the control room. Manual hose stations and Halon 1211 portable extinguishers are available.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
	Non-safety related switchgear in the SW portion of the turbine building 471' is not enclosed by rated fire barriers, but has automatic smoke detection, manual hose stations, and dry chemical portable extinguishers
Acceptable protection for cables that pass through the switchgear room is automatic water or gas agent suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.	Cable routing has been designed such that cables either originate or terminate at the switchgear cabinets and do not just "pass through" the room.
F.6 Remote Safety-Related Panels	F.6 Remote Safety-Related Panels
The general area housing remote safety-related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be provided.	All areas housing remote safety-related panels are provided with smoke detectors which alarm and annunciate in the control room. Local alarms can be initiated from the control room. Halon 1211 portable extinguishers and hose stations are available. Combustible materials are controlled and limited to those required for operation.
F.7 Station Battery Rooms	F.7 Station Battery Rooms
Battery rooms should be protected against fire explosions. Battery rooms should be separated from each other and other areas of the plant by barriers having a minimum fire rating of 3-hr inclusive of all penetrations and openings. See NFPA 69, "Standard on Explosion Prevention Systems." Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration well below 2 vol. % hydrogen concentration. Standpipe and hose and portable extinguishers should be provided.	Battery rooms are separated from each other and other areas of the plant by walls with a minimum fire rating of 3 hr. Door assemblies are also 3-hr rated. Ventilation penetrations serving the battery rooms are protected by 1.5-hr fire rated dampers. This is in excess of that required by the fire loading. Other penetrations serving the battery rooms are sealed. The ventilation systems serving the battery room will maintain the hydrogen concentration below 2%.
Alternatives:	Halon 1211 portable extinguishers and hose stations are available to the battery rooms.
a. Provide a total fire rated barrier enclosure of the battery room complex that exceeds the fire load contained in the room.	
b. Reduce the fire load to be within the fire barrier capability of 1.5 hr. or	
c. Provide a remote manual actuated sprinkler system in each room and provide the 1.5-hr fire	

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
barrier separation.	
F.8 Turbine Lubrication and Control Oil Storage and Use Areas	F.8 Turbine Lubrication and Control Oil Storage and Use Areas
A blank fire wall having a minimum resistance rating of 3 hr should separate all areas containing safety-related systems and equipment from the turbine oil system. When a blank wall is not present, open head deluge protection should be provided for the turbine oil hazards and automatic open head water curtain protection should be provided for wall openings.	The turbine oil system is located in the turbine generator building, separate from all safety-related equipment by a minimum 3-hr fire-rated barrier and/or by spatial separation of at least 50 ft. Components of the turbine oil system are protected by deluge spray or wet sprinkler systems. The ceiling opening in the turbine oil reservoir room is protected by a deluge system.
F.9 Diesel Generator Areas	F.9 Diesel Generator Areas
Diesel generators should be separated from each other and other areas of the plant by fire barriers having a minimum fire resistance rating of three hr. Automatic fire suppression such as AFFF foam, or sprinklers should be installed to combat any diesel generator or lubricating oil fires. Automatic fire detection should be provided to alarm and annunciate in the control room and alarm locally. Drainage for fire fighting water and means for local manual venting of smoke should be provided. Day tanks with total capacity up to 1100 gal are permitted in the diesel generator area under the following conditions: a. The day tank is located in a separate enclosure, with a minimum fire resistance rating of three hr, including doors or penetrations. These enclosures should be capable of containing the entire contents of the day tanks. The enclosure should be ventilated to avoid accumulation of oil fumes. b. The enclosure should be protected by automatic fire suppression systems such as AFFF or sprinklers.	The diesel generators are separated from each other and other areas of the plant by walls and doors having a minimum fire resistance rating of 3 hr, except at 472 ft 9 in. (see FHA for Fire Areas DG-2 or DG-3). Each diesel generator and day tank is protected by a preaction sprinkler system. Fire detectors are provided for the diesel generator and day tanks which alarm and annunciate in the control room. Rooms with major radio equipment have smoke detection. Means for automatic smoke venting in the diesel generator rooms is accomplished through actuation of the mechanical exhaust air system. Water which would be emitted from the preaction or manual hose systems would be carried away by the floor drain system and through the exterior hinged door flap to the yard. Day tanks, each having a 3000-gal capacity, are provided in separate enclosed areas. One tank is provided for each diesel generator. The day tank enclosures have a minimum fire resistance, including doors, of 3 hr. Enclosure penetrations are sealed. The day tank areas are vented to avoid the accumulation of oil fumes. The enclosures are capable of containing the entire contents of the day tanks. No floor drains are provided in the day tank rooms.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
When day tanks cannot be separated from the diesel generator one of the following should be provided for the diesel generator area: a. Automatic open head deluge or open head spray nozzle system(s), b. Automatic closed head sprinklers, c. Automatic AFFF that is delivered by a sprinkler deluge or spray system, d. Automatic gas system (Halon or CO_2) may be used in lieu of foam or sprinklers to combat diesel generator and/or lubricating oil fires.	Although the total gallon capacity of the day tank exceeds 1100 gal (based on the hourly consumption of the tandem diesels), adequate structural, ventilation, and fire extinguishment features are provided.
F.10 Diesel Fuel Oil Storage Areas Diesel fuel oil tanks with a capacity greater than 1100 gal should not be located inside the buildings containing safety-related equipment. They should be located at least 50 ft from any building containing safety-related equipment, or if located within 50 ft, they should be housed in a separate building with construction having a minimum fire resistance rating of 3 hr. Buried tanks are considered as meeting the 3-hr fire resistance requirements. See NFPA 30, "Flammable and Combustible Liquids Code," for additional guidance. When located in a separate building, the tank should be protected by an automatic fire suppression system such as AFFF or sprinklers. Tanks, unless buried, should not be located directly above or below safety-related systems or equipment regardless of the fire rating of separating floors or ceilings.	F.10 Diesel Fuel Oil Storage Areas The diesel oil storage tanks are buried in the yard except for the end portion of each tank containing the transfer pump which extends under the diesel generator building. Each transfer pump is housed in its own room and is separated from other parts of the plant by a fire barrier with a minimum rating of 3 hr. Each pump room is vented mechanically to avoid accumulation of oil fumes. Automatic fire detection is provided in each room to alarm and annunciate in the control room. Each room is protected by a preaction sprinkler system.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
In operating plants where tanks are located directly above or below the diesel generators and cannot reasonably be moved, separating floor, and main structural members should, as a minimum, have fire resistance rating of three hr. Floors should be liquid tight to prevent leaking of possible oil spills from one level to another. Drains should be provided to remove possible oil spills and fire fighting water to a safe location. One of the following acceptable methods of fire protection should also be provided: a. Automatic open head deluge or open head spray nozzle system(s); b. Automatic closed head sprinklers; or c. Automatic AFFF that is delivered by a sprinkler system or spray system.	
F.11 Safety-Related Pumps Pump houses and rooms housing safety-related pumps should be protected by automatic sprinkler protection unless a fire hazards analysis can demonstrate that a fire will not endanger other safety-related equipment required for safe plant shutdown. Early warning fire detection should be installed with alarm and annunciation locally and in the Control Room. Local hose stations and portable extinguishers should also be provided.	F.11 Safety-Related Pumps Safety-related pumps in the reactor building and in the standby service water pump houses are not protected by sprinklers. Early warning fire detection which alarms and annunciates in the main control room is installed in these areas. Portable fire extinguishers and local hose stations are available. The fire hazards analysis for these areas indicates that a fire will not endanger post-fire safe shutdown capability. The non-safety-related circulating water pumps and fire pumps in the circulating water pump house and the secondary diesel fire pump in the water filtration building are protected by automatic sprinkler systems.
F.12 New Fuel Area Hand portable extinguishers should be located within this area. Also, local hose stations should be located outside but within hose reach of this area. Automatic fire detection should alarm and annunciate in the control room and alarm locally. Combustibles should be limited to a minimum in the new fuel area. The storage area should be provided with a drainage system to preclude accumulation of water.	F.12 New Fuel Area New fuel is temporarily stored in a storage rack on the 606-ft elevation of the reactor building. Manual hose stations and dry chemical fire extinguishers are provided in the vicinity. Control room alarms are initiated by the automatic fire detection system. Local audible alarms can be manually sounded from the control room.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
The storage configuration of new fuel should always be so maintained as to preclude criticality for any water density that might occur during fire water application.	
F.13 Spent Fuel Pool Area	F.13 Spent Fuel Pool Area
Protection for the spent fuel pool area should be provided by local hose stations and portable extinguishers. Automatic fire detection should be provided to alarm and annunciate in the Control Room and to alarm locally.	Manual hose stations and dry chemical fire extinguishers are provided in the vicinity of the spent fuel pool. Automatic fire detectors are provided which alarm and annunciate in the control room. Local audible alarms can be manually sounded from the control room.
F.14 Radwaste Building	F.14 Radwaste Building
The radwaste building should be separated from other areas of the plant by fire barriers having at least three-hour ratings. Automatic sprinklers should be used in all areas where combustible materials are located. Automatic fire detection should be provided to annunciate the alarm in the control room and alarm locally. During a fire, the ventilation systems in these areas should be capable of being isolated. Water should drain to liquid radwaste building sumps. Acceptable alternative fire protection is automatic fire detection to alarm and annunciate in the control room, in addition to manual hose stations and portable extinguishers consisting of hand held and large wheeled units.	The radwaste building is separated from other areas of the plant by fire barrier walls and door assemblies which have fire ratings adequate for the fire loadings. All penetrations in the fire barrier walls are sealed. Automatic sprinkler systems have been provided to protect the prefiltration in the radwaste building exhaust filter systems. In addition, automatic sprinkler protection has been provided over the combustible storage on the 467-ft and 487-ft elevations of the building, and in the solid waste processing area on the 437-ft elevation. Fire detectors are installed in hazard areas to alarm and annunciate in the main control room. Manual hose stations and portable extinguishers are also provided. Water from the fire suppression systems would be drained into the floor drain system which is then pumped into the floor drain collection tank.
F.15 Decontamination Areas	F.15 Decontamination Areas
The decontamination areas should be protected by automatic sprinklers if flammable liquids are stored. Automatic fire detection should be provided to annunciate and alarm in the control room and alarm locally. The ventilation system should be capable of being isolated. Local hose stations and hand portable extinguishers should be provided as backup to the sprinkler system.	The principal decontamination area is located on the 467-ft level of the radwaste building. A personnel decontamination area is located on the 487-ft level of the radwaste building. The decontamination areas are monitored by automatic fire detectors. The decontamination area on the 467-ft elevation is protected by an automatic sprinkler system. Each area has dry chemical portable extinguishers and manual hose stations

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
	provided. Flammable liquids are not stored in decontamination areas. Capability for isolation of the ventilation system is not considered necessary for fire control due to the nature of the combustible loading in the area.
F.16 Safety-Related Water Tanks	F.16 Safety-Related Water Tanks
Storage tanks that supply water for safe shutdown should be protected from the effects of fire. Local hose stations and portable extinguishers should be provided. Portable extinguishers should be located in nearby hose houses. Combustible materials should not be stored next to outdoor tanks. A minimum of 50 ft of separation should be provided between outdoor tanks and combustible materials where feasible.	Water for shutdown is supplied from the condensate storage tanks which are located in the transformer yard on the north side of the turbine generator building. The tanks are separated from the yard area by a wall approximately 18 ft high. Portable extinguishers are provided in the turbine generator building. Manual hose stations are available from the yard hydrants or the turbine generator building. The suppression pool in the reactor building supplies water for post-fire safe shutdown. Manual hose stations and portable extinguishers are provided in the building.
F.17 Cooling Towers	F.17 Cooling Towers
Cooling towers should be of non-combustible construction or so located that a fire will not adversely affect any safety-related systems or equipment. Cooling towers should be of non-combustible construction when the basins are used for the ultimate heat sink or for the fire. Cooling towers of combustible construction, so located that a fire in them could adversely affect safety-related systems or equipment should be protected with an open head deluge system installation with hydrants and hose houses strategically located.	The cooling towers are constructed of non-combustible materials (except for fan shrouds, fan blades, fill material, and drift eliminators). The cooling towers are located remote from any safety-related buildings or equipment. The cooling tower basins are not used for the ultimate heat sink. There is a separate reliable fire protection water supply provided by a bladder tank remotely located away from the cooling towers.
F.18 Miscellaneous Areas	F.18 Miscellaneous Areas
Miscellaneous areas such as records storage areas, shops, warehouses, and auxiliary boiler rooms should be so located that a fire or effects of a fire, including smoke, will not adversely affect any safety-related systems or equipment. Fuel oil tanks for auxiliary boilers should be buried or provided with dikes to contain the entire tank contents.	Miscellaneous areas such as records storage areas, shops, warehouses, and auxiliary boiler rooms are located such that a fire or the effects of a fire, including smoke, will not adversely affect any safety-related systems or equipment. The auxiliary boiler fuel oil tank is buried in the yard.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
G. SPECIAL PROTECTION GUIDELINES	G. SPECIAL PROTECTION GUIDELINES
G.1 Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems	G.1 Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems
This equipment is used in various areas throughout the plant. Storage locations should be chosen to permit fire protection by automatic sprinkler systems. Local hose stations and portable equipment should be provided as backup. The requirements of NFPA 51 and 51B are applicable to these hazards. A permit system should be required to utilize this equipment. Also refer to 2f herein.	Bulk storage of flammable gases is in a special structure well separated from plant structures. When not in use (to support of ongoing maintenance activities), flammable gas welding equipment is stored in designated areas which do not contain safe post-fire shutdown systems. A permit system is used for welding control and/or temporary storage of welding gases in all areas except for those specifically designated. Plant procedures call for protection or removal of combustibles, protection of equipment/cabling, and fire watch during and after the welding operation. During normal plant operation, ordinary welding and cutting is done in designated welding areas, which may not have automatic suppression. However, manual suppression equipment is available.
G.2 Storage Areas for Dry Ion Exchange Resins	G.2 Storage Areas for Dry Ion Exchange Resins
Dry ion exchange resins should not be stored near essential safety-related systems. Dry unused resins should be protected by automatic wet pipe sprinkler installations. Detection by smoke and heat detectors should alarm and annunciate in the control room and alarm locally. Local hose stations and portable extinguishers should provide backup for these areas. Storage areas of dry resin should have curbs and drains. Refer to NFPA 92M, "Waterproofing and Draining of Floors."	Bulk storage of dry ion exchange resins is located on 467 ft elevation of the radwaste building. There are no safety-related systems or equipment located in this area. Automatic sprinkler protection is provided. Portable extinguishers and hose stations are available. Floor drains are provided for removal of fire fighting water.
G.3 Hazardous Chemicals	G.3 Hazardous Chemicals
Hazardous chemicals should be stored and protected in accordance with the recommendations of NFPA 49, "Hazardous Chemicals Data." Chemicals storage areas should be well ventilated and protected against flooding conditions since some chemicals may react with water to produce ignition.	Hazardous chemicals are controlled in accordance with plant procedures.

Table F.3-1

Comparison with BTP 9.5-1 Appendix A (Continued)

BTP 9.5-1 APPENDIX A	CGS FIRE PROTECTION PROGRAM
G.4 Materials Containing Radioactivity	G.4 Materials Containing Radioactivity
Materials that collect and contain radioactivity such as spent ion exchange resins, charcoal filters, and HEPA filters should be stored in closed metal tanks or containers that are located in areas free from ignition sources of combustibles. These materials should be protected from exposure to fires in adjacent areas as well. Consideration should be given to requirements for removal of isotopic decay heat from entrained radioactive materials.	Spent resins are contained in metal vessels or containers. HEPA and charcoal filters are disposed of on a routine basis such that no large accumulation exists. After removal, the interior storage is in a controlled area where hose stations and fire extinguishers are readily available.

Table F.3-2

Comparison with the Specific Commitments to 10 CFR 50 Appendix R

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
I. INTRODUCTION AND SCOPE	I. INTRODUCTION AND SCOPE
This appendix applies to licensed nuclear power electric generating stations that were operating prior to January 1, 1979, except to the extent set forth in § 50.48(b) of this part. With respect to certain generic issues for such facilities it sets forth fire protection features required to satisfy Criterion 3 of Appendix A to this part.[1] A Fire Protection Safety Evaluation Report that has been issued for each operating plant states how these guidelines were applied to each facility and identifies open fire protection issues that will be resolved when the facility satisfies the appropriate requirements of Appendix R to Part 50. Criterion 3 of Appendix A to this part specifies that "Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions." When considering the effects of fire, those systems associated with achieving and maintaining safe shutdown conditions assume major importance to safety because damage to them can lead to core damage resulting from loss of coolant through boiloff. The phrases "important to safety" or "safety-related" will be used throughout this Appendix R as applying to all safety functions. The phrase "safe shutdown" will be used throughout this appendix as applying to both hot and cold shutdown functions.	Appendix R, Section I, is provided here for information only.

[1] Clarification and guidance with respect to permissible alternatives to satisfy Appendix A to BTP 9.5-1 has been provided in four other NRC documents:

"Supplementary Guidance on Information Needed for Fire Protection Evaluation," dated October 21, 1976;
"Sample Technical Specifications," dated May 12, 1977;
"Nuclear Plant Fire Protection Functional Responsibilities, Administrative Control and Quality Assurance," dated June 14, 1977;
"Manpower Requirements for Operating Reactors," dated May 11, 1978.

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
Because fire may affect safe shutdown systems and because the loss of function of systems used to mitigate the consequences of design basis accidents under post-fire conditions dose not per se impact public safety, the need to limit fire damage to systems desired to achieve and maintain safe shutdown conditions is greater than the need to limit fire damage to those systems required to mitigate the consequences of design basis accidents. Three levels of fire damage limits are established according to the safety functions of the structure, system, or component.	

Safety Function	Fire damage limits
Hot shutdown	One train of equipment necessary to achieve hot shutdown from either the control room or emergency control station(s) must be maintained free of fire damage by a single fire, including an exposure fire.[2]
Cold shutdown	Both trains of equipment necessary to achieve cold shutdown may be damaged by a single fire, but damage must be limited so that at least one train can be repaired or made operable within 72 hr using onsite capability.
Design basis accidents	Both trains of equipment necessary for mitigation of consequences following design basis accidents may be damaged by a single exposure fire.

[2]Exposure fire - An exposure fire is a fire in a given area that involves either in situ or transient combustibles and is external to any structures, systems, or components located in or adjacent to that same area. The effects of such fire (e.g. smoke, heat, or ignition) can adversely affect those structures, systems, or components important to safety. Thus, a fire involving one train of safe shutdown equipment may constitute an exposure fire for the redundant train located in the same area and a fire involving combustibles other than either redundant train may constitute an exposure fire to both redundant trains located in the same area.

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
The most stringent fire damage limit shall apply for those systems that fall into more than one category. Redundant systems used to mitigate the consequences of other design basis accidents but not necessary for safe shutdown may be lost to a single exposure fire. However, protection shall be provided so that a fire within only one such system will not damage the redundant system.	
II. GENERAL REQUIREMENTS	II. GENERAL REQUIREMENTS
A. Fire Protection Program	A. Fire Protection Program
A fire protection program shall be established at each nuclear power plant. The program shall establish the fire protection of structures, systems, and components important to safety at each plant and the procedures, equipment, and personnel required to implement the program at the plant site.	The Columbia Generating Station (CGS) fire protection program establishes the fire protection policy for the protection of structures, systems, and components important to safety and describes the plant procedures, equipment, and personnel required to implement the program at the plant site.
The fire protection program shall be under the direction of an individual who has been delegated authority commensurate with the responsibilities of the position and who has available staff personnel knowledgeable in both fire protection and nuclear safety.	The personnel assigned responsibilities for the fire protection program are described in Table F.3-1, Section A.1.
The fire protection program shall extend the concept of defense-in-depth to fire protection in fire areas important to safety, with the following objectives:	The fire protection program shall extend the concept of defense-in-depth to fire protection in fire areas important to safety, with the following objectives:
- to prevent fires from starting;	- to prevent fires from starting;
- to detect rapidly, control, and extinguish promptly those fires that do occur; and	- to detect rapidly, control, and extinguish promptly those fires that do occur; and
- to provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant.	- to provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant in the event of fire.

Table F.3-2

Comparison with the Specific Commitments to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
B. Fire Hazards Analysis	B. Fire Hazards Analysis
A fire hazards analysis shall be performed by qualified fire protection and reactor systems engineers to (1) consider potential in situ and transient fire hazards; (2) determine the consequences of fire in any location in the plant on the ability to safely shutdown the reactor or on the ability to minimize and control the release of radioactivity to the environment; and (3) specify measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability as required for each fire area containing structures, systems, and components important to safety in accordance with NRC guidelines and regulations.	The CGS fire hazards analysis is provided in Section F.4.
C. Fire Prevention Features	C. Fire Prevention Features
Fire protection features shall meet the following general requirements for all areas that contain or present a fire hazard to structures, systems, or components important to safety.	Fire prevention features have been established at CGS as listed below:
1. In situ fire hazards shall be identified and suitable protection provided.	1. The combustible loading calculation (Reference F.7.3.b) identifies the in-situ and the maximum expected transient fire loading in each plant fire area. The combustible loading calculation results are an input to the fire hazards analysis.
2. Transient fire hazards associated with normal operation, maintenance, repair, or modification activities shall be identified and eliminated where possible. Those transient fire hazards that can not be eliminated shall be controlled and suitable protection provided.	2. Plant procedures control the introduction of combustible materials into the safety-related areas of the plant.
3. Fire detection systems, portable extinguishers, and standpipe and hose stations shall be installed.	3. Fire detection systems, portable fire extinguishers, and standpipe and hose connections are installed.
4. Fire barriers or automatic suppression systems or both shall be installed as necessary to protect redundant systems or components necessary for safe shutdown.	4. Fire barriers or automatic suppression systems or both are installed for the protection of redundant post-fire safe shutdown equipment as detailed in the fire hazards analysis.
5. A site fire brigade shall be established, trained, and equipped and shall be on site at all times.	5. The plant fire brigade has been established, trained, and equipped. The fire brigade is maintained onsite at all times. The fire brigade composition may be less than the minimum requirements for a period of time
6. Fire detection and suppression systems shall be designed, installed, maintained, and tested by	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
personnel properly qualified by experience and training in fire protection systems.	not to exceed 2 hr in order to accommodate unexpected absence provided immediate action is taken to fill the required position.
7. Surveillance procedures shall be established to ensure that fire barriers are in place and that fire suppression systems and components are operable.	6. Fire detection and suppression systems are designed by qualified engineering personnel. Maintenance and testing is performed by qualified plant maintenance and operations personnel in accordance with plant procedures.
	7. Periodic testing procedures have been established to ensure that essential fire barriers are in place and that fire detection and suppression systems are operable.
D. Alternative or Dedicated Shutdown Capability	D. Alternative or Dedicated Shutdown Capability
In areas where the fire protection features cannot ensure safe shutdown capability in the event of a fire in that area, alternative or dedicated shutdown capability shall be provided.	Alternative shutdown capability is provided for use in the event of a fire in the main control room.
III. SPECIFIC REQUIREMENTS	III. SPECIFIC REQUIREMENTS
A. Water Supplies for Fire Suppression Systems	A. Water Supplies for Fire Suppression Systems
Two separate water supplies shall be provided to furnish necessary water volume and pressure to the fire main loop.	See Section F.2.4.1 and Table F.3-1 (paragraphs E.2.a through E.2.g) for a description of the fire protection system water supplies.
Each supply shall consist of a storage tank, pump, piping, and appropriate isolation and control valves. Two separate redundant suctions in one or more intake structures from a large body or water (river, lake, etc.) will satisfy the requirement for two separated water storage tanks. These supplies shall be separated so that a failure of one supply will not result in a failure of the other supply.	
Each supply of the fire water distribution system shall be capable of providing for a period of 2 hr the maximum expected water demands as determined by the fire hazards analysis for safety-related fire areas or other areas that present a fire exposure hazard to safety-related areas.	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
When storage tanks are used for combined service water/fire water use the minimum volume for fire uses shall be ensured by means of dedicated tanks or by some physical means such as a vertical standpipe for other water service. Administrative controls including locks for tank outlet valves, are unacceptable as the only means to ensure minimum water volume.	
Other water systems used as one of the two fire water supplies shall be permanently connected to the fire main system and shall be capable of automatic alignment to the fire main system. Pumps, controls, and power supplies in these systems shall satisfy the requirements for the main fire pumps. The use of other water systems for fire protection shall not be incompatible with their functions required for safe plant shutdown. Failure of the other system shall not degrade the fire main system.	
B. Sectional Isolation Valves	B. Sectional Isolation Valves
Sectional valves or key operated valves shall be installed in the fire main loop to permit isolation of portions of the fire main loop for maintenance or repair without interrupting the entire water supply.	See Section F.2.4.1 and Table F.3-1, paragraph E.2.a. for a description of the fire protection system sectional isolation valves.
C. Hydrant Isolation Valves	C. Hydrant Isolation Valves
Valves shall be installed to permit isolation of outside hydrants from the fire main for maintenance or repair without interrupting the water supply to automatic or manual fire suppression systems in any area containing or presenting a fire hazard to safety-related or safe shutdown equipment.	See Section F.2.4.1 and Table F.3-1, paragraph E.2.a. for a description of the fire protection system hydrant isolation valves.
D. Manual Fire Suppression	D. Manual Fire Suppression
Standpipe and hose systems shall be installed so that at least one effective hose stream will be able to reach any location that contains or presents an exposure fire hazard to structures, systems, or components important to safety.	See Section F.2.5.3 and Table F.3-1, paragraph E.2.g and E.3.d for a description of the hose standpipe system. Fire hose stations in the reactor building are adequate to reach drywell fire hazards.

Table F.3-2

Comparison with the Specific Commitments to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
Access to permit effective functioning of the fire brigade shall be provided to all areas that contain or present an exposure fire hazard to structures, systems, or components important to safety.	
Standpipe and hose stations shall be inside PWR containments and BWR containments that are not inerted. Standpipe and hose stations inside containment may be connected to a high quality water supply of sufficient quantity and pressure other than the fire main loop if plant specific features prevent extending the fire main supply inside containment. For BWR drywells, standpipe and hose stations shall be placed outside the dry well with adequate lengths of hose to reach any location inside the dry well with an effective hose stream.	
E. Hydrostatic Hose Tests	E. Hydrostatic Hose Tests
Fire hose shall be hydrostatically tested at a pressure of 150 psi or 50 psi above maximum fire main pressure, whichever is greater. Hose stored in outside hose houses shall be tested annually. Interior standpipe hose shall be tested every 3 years.	See LCS 1.10.3 for a description of fire system hose hydrostatic testing.
F. Automatic Fire Detection	F. Automatic Fire Detection
Automatic fire detection systems shall be installed in all areas of the plant that contain or present a hazard to safe shutdown or safety-related systems or components. These fire detection systems shall be capable of operating with or without offsite power.	See Section F.2.3 and Table F.3-1, paragraphs E.1.a through E.1.d for a description of the fire detection system.
G. Fire Protection of Safe Shutdown Capability	G. Fire Protection of Safe Shutdown Capability
1. Fire protection features shall be provided for structures, systems, and components important to safe shutdown. These features shall be capable of limiting fire damage so that:	Fire protection of post-fire safe shutdown capability is provided as detailed in the fire hazards analysis, Section F.4.
a. One train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) is free of fire damage; and	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
b. Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72 hr.	
2. Except as provided for in paragraph G.3 of this section, where cables or equipment, including associated non-safety circuits that could prevent operation or cause maloperation due to hot shorts, open circuits, or shorts to ground of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area outside of primary containment, one of the following means of ensuring that one of the redundant trains is free of fire damage shall be provided.	Deviations to section III.G.2 include the use of MI fire-related cable (see Section F.2.2.2 and Reference F.7.6.j), use of operator manual actions (see Section F.4.3.1 and Reference F.7.6.u) , and unprotected Division 2 instrument sensing lines associated with MS-LT-26D (see Reference F.7.6.x).
a. Separation of cables and equipment and associated non-safety circuits of redundant trains by a fire barrier having a 3-hr rating. Structural steel forming a part of or supporting such fire barriers shall be protected to provide fire resistance equivalent to that required of the barrier.	
b. Separation of cables and equipment and associated non-safety circuits of redundant trains by a horizontal distance of more than 20 ft with no intervening fire hazards. In addition, fire detectors and an automatic fire suppression system shall be installed in the fire area.	
c. Enclosure of cable and equipment and associated non-safety circuits of one redundant train in a fire barrier having a 1-hr fire rating. In addition, fire detectors and an automatic fire suppression system shall be installed in the fire area.	
Inside noninerted containments one of the following fire protection means shall be provided:	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
d. Separation of cables and equipment and associated non-safety circuits of redundant trains by a horizontal distance of more than 20 ft with no intervening combustibles or fire hazards;	
e. Installation of fire detectors and an automatic fire suppression system in the fire area; or	
f. Separation of cables and equipment and associated non-safety circuits of redundant trains by a noncombustible radiant energy shield.	
3. Alternative or dedicated shutdown capability and its associated circuits[3] independent of cables, systems, or components in the area, room, or zone under consideration shall be provided:	
a. Where the protection of system whose function is required for hot shutdown does not satisfy the requirement of paragraph G.2 of this section; or	
b. Where redundant trains of system required for hot shutdown located in the same fire area may be subject to damage from fire suppression activities or from the rupture or inadvertent operation of the fire suppression systems.	
In addition, fire detection and a fixed fire suppression system shall be installed in the area, room, or zone under consideration.	

[3] Alternative shutdown capability is provided by rerouting, relocating, or modification of existing systems; dedicated shutdown capability is provided by installed new structures and systems for the function of post-fire shutdown.

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
H. Fire Brigade	H. Fire Brigade
A site fire brigade trained and equipped for fire fighting shall be established to ensure adequate manual fire fighting capability for all areas of the plant containing structures, systems, or components important to safety. The fire brigade shall be at least five members on each shift. The brigade leader and at least two brigade members shall have sufficient training in or knowledge of plant safety-related systems to understand the effects of fire and fire suppressants on safe shutdown capability. The qualification of fire brigade members shall determine their ability to perform strenuous fire fighting activities. The shift supervisor shall not be a member of the fire brigade. The brigade leader shall be competent to assess the potential safety consequences of a fire and advise control room personnel. Such competence by the brigade leader may be evidenced by possession of an operator's license or equivalent knowledge of plant safety-related systems.	The CGS plant complies with commitments related to post-fire safe shutdown plant equipment. The fire brigade composition is specified in Section 13.1.2.3.4. See paragraph II.C.5 above and Table F.3-1, paragraphs B.2 through B.5.
The minimum equipment provided for the brigade shall consist of personal protective equipment such as turnout coats, boots, gloves, hard hats, emergency communication equipment, portable lights, portable ventilation equipment, and portable extinguishers. Self-contained breathing apparatus using full-face positive pressure masks approved by National Institute for Occupational Safety and Health (NIOSH) - approval formerly given by the U.S. Bureau of Mines) shall be provided for fire brigade damage control and control room personnel. At least 10 masks shall be available for fire brigade personnel. Control room personnel may be furnished breathing air by a manifold system piped from a storage reservoir if practical. Service or rated operating life shall be a minimum of 0.5 hr for the self-contained units.	
At least a 1-hr supply of breathing air in extra bottles shall be located on the plant site for each unit of self-contained breathing apparatus. In addition, an onsite 6-hr supply of reserve air shall be provided and arranged to permit quick and complete replenishment	CGS has a minimum of 10 SCBA units available for fire brigade use. The 1-hr plus 6-hr reserve air supply is provided by charged SCBA bottles staged onsite (see Reference F.7.6.r). The control room SCBA air supply (for non-Appendix R fires) is

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
of exhausted air supply bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air shall be used and the compressors shall be operable assuming a loss of offsite power. Special care must be taken to locate the compressor in areas free of dust and contaminants.	provided by bottles charged from the onsite SCBA compressor (see Reference F.7.6.s) that is not provided with offsite power.
I. Fire Brigade Training	I. Fire Brigade Training
The fire brigade training program shall ensure that the capability to fight potential fires is established and maintained. The program shall consist of an initial classroom instruction program followed by periodic classroom instruction, fire fighting practice, and fire drills.	The CGS plant fire brigade training program is described in Section 13.2.2.5. The requirements of this section were used as guidance in the development of this program. See Table F.3-1, paragraph B.5.
1. Instruction a. The initial classroom instruction shall include: (1) Indoctrination of the plant fire fighting plan with specific identification of each individual's responsibilities. (2) Identification of the type and location of fire hazards and associated types of fires that could occur in the plant. (3) The toxic and corrosive characteristics of expected products of combustion. (4) Identification of the location of fire fighting equipment for each fire area and familiarization with the layout of the plant including access and egress routes to each area. (5) The proper use of available fire fighting equipment and the correct method of fighting each type of fire. The types of fires covered should include fires in energized electrical equipment, fires in cables and cable trays, hydrogen fires, fires involving flammable and	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
combustible liquids or hazardous process chemicals, fires resulting from construction or modifications (welding), and record file fires.	
(6) The proper use of communication, lighting, ventilation, and emergency breathing equipment.	
(7) The proper method for fighting fires inside buildings and confined spaces.	
(8) The direction and coordination of the fire fighting activities (fire brigade leaders only).	
(9) Detailed review of fire fighting strategies and procedures.	
(10) Review of latest plant modifications and corresponding changes in fire fighting plans.	
NOTE: Items (9) and (10) may be deleted from the training of no more than two of the non-operations personnel who may be assigned to the fire brigade.	
b. The instruction shall be provided by qualified individuals who are knowledgeable, experienced, and suitably trained in fighting the types of fires that could occur in the plant and in using the types of equipment available in the nuclear power plant.	See F.7.6.z for required instructor qualifications.
c. Instruction shall be provided to all fire brigade members and fire brigade leaders.	
d. Regular planned meetings shall be held at least every 3 months for all brigade members to review changes in the fire protection program and other subjects as necessary.	
e. Periodic refresher training sessions shall be held to repeat the classroom instruction program for all brigade members over a	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
2-year period. These sessions may be concurrent with the regular planned meetings.	
2. Practice	
Practice sessions shall be held for each shift fire brigade on the proper method of fighting the various types of fires that could occur in a nuclear power plant. These sessions shall provide brigade members with experience in actual fire extinguishment and the use of emergency breathing apparatus under strenuous conditions encountered in fire fighting. These practice sessions shall be provided at least once per year for each fire brigade member.	
3. Drills	
a. Fire brigade drills shall be performed in the plant so that the fire brigade can practice as a team.	
b. Drills shall be performed at regular intervals not to exceed 3 months for each shift fire brigade. Each fire brigade member should participate in each drill, but must participate in at least two drills per year.	
A sufficient number of these drills, but not less that one for each shift fire brigade per year, shall be unannounced to determine the fire fighting readiness of the plant fire brigade, brigade leader, and fire protection systems and equipment. Persons planning and authorizing an unannounced drill shall ensure that the responding shift fire brigade members are not aware that a drill is being planned until it is begun. Unannounced drills shall not be scheduled closer than 4 weeks.	
At least one drill per year shall be performed on a "back shift" for each shift fire brigade.	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
c. The drills shall be preplanned to establish the training objectives of the drill and shall be critiqued to determine how well the training objectives have been met. Unannounced drills shall be planned and critiqued by members of the management staff responsible for plant safety and fire protection. Performance deficiencies of a fire brigade or of individual fire brigade members shall be remedied by scheduling additional training for the brigade members. Unsatisfactory drill performance shall be followed by a repeat drill within 30 days.	
d. At 3-year intervals, a randomly selected unannounced drill shall be critiqued by qualified individuals independent of the licensee's staff. A copy of the written report from such individuals shall be available for NRC review.	
e. Drills shall as a minimum include the following:	
(1) Assessment of fire alarm effectiveness.	
(2) Assessment of each brigade member's knowledge of his or her role in the fire fighting strategy for the area assumed to contain the fire. Assessment of the brigade member's conformance with established plant fire fighting procedures and use of fire fighting equipment, including self-contained breathing apparatus, communication equipment, and ventilation equipment to the extent practicable.	
(3) The simulated use of fire fighting equipment required to cope with the situation and type of fire selected for	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
the drill. The area and type of fire chosen for the drill should differ from those used in the previous drill so that brigade members are trained in fighting fires in various plant areas. The situation selected should simulate the size and arrangement of a fire that could reasonably occur in the area selected, allowing for fire development due to the time required to respond, to obtain equipment, and organize for the fire, assuming loss of automatic suppression capability.	
(4) Assessment of brigade leader's direction of the fire fighting effort as to thoroughness, accuracy, and effectiveness.	
4. Records	
Individual records of training provided to each fire brigade member, including drill critiques, shall be maintained for at least 3 years to ensure that each member receives training in all parts of the training program. These records of training shall be available for NRC review. Retraining or broadened training for fire fighting within buildings shall be scheduled for all those brigade members whose performance records show deficiencies.	
J. Emergency Lighting	J. Emergency Lighting
Emergency lighting units with at least an 8-hr battery power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.	Emergency lighting is provided as detailed in Section 9.5.3.
K. Administrative Controls	K. Administrative Controls
Administrative controls shall be established to minimize fire hazards in areas containing structures, systems, and components important to safety. These controls shall establish procedures to:	The CGS plant complies with these commitments through implementation of the procedures of Reference F.7.8 which contain the program administrative controls. See Table F.3-1, paragraphs B.1 through B.5.

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
1. Govern the handling and limitation of the use of ordinary combustible materials, combustible and flammable gases and liquids, high efficiency particulate air and charcoal filters, dry ion exchange resins, or other combustible supplies in safety-related areas.	
2. Prohibit the storage of combustibles in safety-related areas or establish designated storage areas with appropriate fire protection.	
3. Govern the handling of and limit transient fire loads such as combustible and flammable liquids, wood and plastic products, or other combustible materials in buildings containing safety-related systems or equipment during all phases of operating, and especially during maintenance, modification, or refueling operations.	
4. Designate the onsite staff member responsible for the in plant fire protection review of proposed work activities to identify potential transient fire hazards and specify required additional fire protection in the work activity procedure.	
5. Govern the use of ignition sources by use of a flame permit system to control operations. A separate permit shall be issued for each area where work is to be done. If work continues over more than one shift, the permit shall be valid for not more than 24 hr when the plant is operating or for the duration of a particular job when the plant is shutdown.	Ignition source permit extensions are strictly controlled during plant operating conditions.
6. Control the removal from the area of all waste, debris, scrap, oil spills, or other combustibles resulting from the work activity immediately following completion of the activity, or at the end of each work shift, whichever comes first.	
Maintain the periodic housekeeping inspections to ensure continued compliance with these administrative controls.	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
8. Control the use of specific combustibles in safety-related areas. All wood used in safety-related areas during maintenance, modification, or refueling operations (such as laydown blocks or scaffolding) shall be treated with a flame retardant. Equipment or supplies (such as new fuel) shipped in untreated combustible packing containers may be unpacked in safety-related areas if required for valid operating reasons. However, all combustible materials shall be removed from the area immediately following the unpacking. Such transient combustible material, unless stored in approved containers, shall not be left unattended during lunch breaks, shift changes, or other similar periods. Loose combustible packing material such as wood or paper excelsior, or polyethylene sheeting shall be placed in metal containers with tight-fitting self-closing metal covers.	Minor amounts of untreated wood are allowed to account for necessary tools and equipment used within plant areas.
9. Control actions to be taken by an individual discovering a fire, for example, notification of control room, attempt to extinguish fire, and actuation of local fire suppression systems.	
10. Control actions to be taken by the control room operator to determine the need for brigade assistance on report of a fire or receipt of alarm on control room annunciator panel, for example, announcing location of fire over PA system, sounding fire alarms, and notifying the shift supervisor and the fire brigade leader of the type, size, and location of the fire.	
11. Control the actions to be taken by the fire brigade after notification by the control room operator of a fire, for example, assembling in a determined location, receiving directions from the fire brigade leader, and discharging specific fire fighting responsibilities including selection and transportation of fire fighting equipment to fire location, selection of protective equipment, operating instructions for use of fire suppression systems, and use of preplanned strategies for fighting fires in specific areas.	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
12. Define the strategies for fighting fires in all safety-related areas presenting a hazard to safety-related equipment. These strategies shall designate:	
a. Fire hazards in each area covered by the specific prefire plans.	
b. Fire extinguishants best suited for controlling the fires associated with the fire hazards in that area and the nearest location of these extinguishants.	
c. Most favorable direction from which to attack a fire in each area in view of the ventilation direction, access hallways, stairs, and doors that are most likely to be free of fire, and the best station or elevation for fighting the fire. All access and egress routes that involve locked doors should be specifically identified in the procedure with the appropriate precautions and methods for access specified.	
d. Plant systems that should be managed to reduce the damage potential during a local fire and the location of local and remote controls for such management (e.g. any hydraulic or electrical systems in the zone covered by the specific fire fighting procedure that could increase the hazards in the area because of overpressurization or electrical hazards).	
e. Vital heat-sensitive system components that need to be kept cool while fighting a local fire. Particularly hazardous combustibles that need cooling should be designated.	
f. Organization of fire fighting brigades and the assignment of special duties according to job title so that all fire fighting functions are covered by any complete shift personnel complement. These duties include command control of the brigade,	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
transporting fire suppression and support equipment to the fire scenes, applying the extinguishant to the fire, communication with the control room, and coordination with outside fire departments.	
g. Potential radiological and toxic hazards in fire zones.	
h. Ventilation system operation that ensures desired plant air distribution when ventilation flow is modified for fire containment or smoke clearing operations.	
i. Operations requiring control room and shift engineer coordination or authorization.	
j. Instructions for plant operators and general plant personnel during fire.	
L. Alternative and Dedicated Shutdown Capability	L. Alternative and Dedicated Shutdown Capability
1. Alternative or dedicated shutdown capability provided for a specific fire area shall be able to (a) achieve and maintain subcritical reactivity conditions in the reactor, (b) maintain reactor coolant inventory, (c) achieve and maintain hot standby[4] conditions for a PWR (hot shutdown for a BWR); (d) achieve cold shutdown conditions thereafter. During the post-fire shutdown, the reactor coolant system process variables shall be maintained within those predicted for a loss of normal ac power, and the fission product boundary integrity shall not be affected; i.e. there shall be no fuel clad damage, rupture of any primary coolant boundary, or rupture of the containment boundary.	Alternative shutdown capability is provided for use in the event of a main control room fire. CGS does not utilize dedicated shutdown capability. Sections F.4.3 and F.4.4 address post-fire safe shutdown assumptions and methodology. See Section F.4.3.2 for the remote post-fire safe shutdown system and Table F.4-1 for equipment credited for remote post-fire safe shutdown.
2. The performance goals for the shutdown functions shall be:	

[4] As defined in the Standard Technical Specifications.

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
a. The reactivity control function shall be capable of achieving and maintaining cold shutdown reactivity conditions.	
b. The reactor coolant makeup function shall be capable of maintaining the reactor coolant level above the top of the core for BWRs and within the level indication in the pressurizer for PWRs.	
c. The reactor heat removal function shall be capable or achieving and maintaining decay heat removal.	
d. The process monitoring function shall be capable of providing direct readings of the process variables necessary to perform and control the above functions.	
e. The supporting functions shall be capable of providing the process cooling, lubrication, etc., necessary to permit the operation of the equipment used for safe shutdown functions.	
3. The shutdown capability for specific fire areas may be unique for each such area, or it may be one unique combination of systems for all such areas. In either case, the alternative shutdown capability shall be independent of the specific fire area(s) and shall accommodated post-fire conditions where offsite power is available and where offsite power is not available for 72 hr. Procedures shall be in effect to implement this capability.	
4. If the capability to achieve and maintain cold shutdown will not be available because of fire damage, the equipment and systems comprising the means to achieve and maintain the hot standby or hot shutdown condition shall be capable of maintaining such conditions until cold shutdown can be achieved. If such equipment and systems will not be capable of being powered by both onsite and offsite electric	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
power systems because of fire damage, an independent onsite power system shall be provided. The number of operating shift personnel, exclusive of fire brigade members, required to operate such equipment and systems shall be onsite at all times.	
5. Equipment and systems comprising the means to achieve and maintain cold shutdown shall not be damaged by fire, or the fire damage to such equipment and systems shall be limited so that the systems can be made operable and cold shutdown can be achieved within 72 hr. Materials for such repairs shall be readily available onsite and procedures shall be in effect to implement such repairs. If such equipment and systems used prior to 72 hr after the fire will not be capable of being powered by both onsite and offsite electric power systems because of fire damage, an independent onsite power system shall be provided. Equipment and systems used after 72 hr may be powered by offsite power only.	
6. Shutdown system installed to ensure post-fire shutdown capability need not be designed to meet Seismic Category I criteria, single failure criteria, or other design basis accident criteria, except where required for other reasons, e.g. because of interface with or impact on existing safety system, or because of adverse valve actions due to fire damage.	
7. The safe shutdown equipment and systems for each fire area shall be known to be isolated from associated non-safety circuits in the fire area so that hot shorts, open circuits or shorts to ground in the associated circuits will not prevent operation of the safe shutdown equipment. The separation and barriers between trays and conduits containing associated circuits of one safe shutdown division and trays and conduits containing associated circuits or safe shutdown	

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
cables from the redundant division, or the isolation of the associated circuits such that a postulated fire involving associated circuits will not prevent safe shutdown.[5]	
M. Fire Barrier Cable Penetration Seal Qualification	M. Fire Barrier Cable Penetration Seal Qualification
Penetration seal designs shall use only noncombustible materials and shall be qualified by tests that are comparable to tests used to rate fire barriers. The acceptance criteria for the test shall include:	CGS complies with this commitment except that silicone foam is combustible. See Section F.2.2 for a discussion of penetration seal qualification.
N. Fire Doors	N. Fire Doors
Fire doors shall be self-closing or provided with closing mechanisms and shall be inspected semiannually to verify that automatic hold-open, release, and closing mechanisms and latches are operable. One of the following measures shall be provided to ensure they will protect the opening as required in case of fire: 1. Fire doors shall be kept closed and electrically supervised at a continuously manned location; 2. Fire doors shall be locked closed and inspected weekly to verify that the doors are in the closed position; 3. Fire doors shall be provided with automatic hold-open and release mechanisms and inspected daily to verify that doorways are free of obstructions; or 4. Fire doors shall be kept closed and inspected daily to verify that they are in the closed position.	See Section F.2.2.1 and LCS 1.10.5 for a discussion of fire doors.

[5] An acceptable method of complying with this alternative would be to meet Regulatory Guide 1.75 position 4 related to associated circuits and IEEE Standard 384-1974 (Section 4.5) where trays from redundant safety divisions are so protected that postulated fires affect trays from only one safety division.

Table F.3-2

Comparison with the Specific Commitments
to 10 CFR 50 Appendix R (Continued)

10 CFR 50 APPENDIX R SECTION	CGS FIRE PROTECTION PROGRAM
The fire brigade leader shall have ready access to keys for any locked fire doors.	
Areas protected by automatic total flooding has suppression systems shall have electrically supervised self-closing fire doors or shall satisfy option 1 above.	
O. Oil Collection System for Reactor Coolant Pump	O. Oil Collection System for Reactor Coolant Pump
The reactor coolant pump shall be equipped with an oil collection system if the containment is not inerted during normal operation. The oil collection system shall be so designed, engineered, and installed that failure will not lead to fire during normal or design basis accident conditions and that there is reasonable assurance that the system will withstand the safe shutdown earthquake.[6]	The CGS plant has a nitrogen inerted containment and therefore this does not apply to CGS.

[6] See Regulatory Guide 1.29 - "Seismic Design Classification," Paragraph C.2.

F.4 FIRE HAZARDS ANALYSIS

The fire hazards analysis determines the adequacy of the fire protection features to prevent and mitigate the consequences of a postulated fire. A fire hazards analysis is performed for each fire area within the reactor building, the radwaste control building, the diesel generator building, the standby service water pump houses, reactor recirculation system (RRC) pump adjustable speed drive (ASD) building, and the turbine generator building.

The fire hazards analysis identifies the potential fire consequences based on consideration of the design basis fire, the location of post-fire safe shutdown equipment and cabling located within the area, the construction of the fire area, and the available fire protection systems. Potential fire consequences are evaluated to:

- Ensure the capability to achieve and maintain safe shutdown,
- Prevent radioactive release to ensure the health and safety of the public,
- Ensure safe egress for employees, and
- Provide for plant property protection.

The ability of the plant to attain and maintain post-fire safe shutdown is evaluated against the following:

- 10 CFR 50 Appendix A, General Design Criterion 3, Fire Protection,
- 10 CFR 50 Appendix R, Section III.G, Fire Protection of Safe Shutdown Capability,
- 10 CFR 50 Appendix R, Section III.J, Emergency Lighting, and
- 10 CFR 50 Appendix R, Section III.L, Alternative and Dedicated Shutdown Capability.

Clarification on the above was obtained from various generic letters (Reference F.7.2.f).

The methodology used to perform the fire hazards analyses is detailed below.

F.4.1 PLANT FIRE AREA ARRANGEMENT

The plant buildings are divided into fire areas generally based on the location of equipment needed for safe post-fire shutdown and on the construction of the building walls, floor, and ceiling assemblies. A fire area is that portion of a building or plant site which is separated from other areas by barriers which are sufficient to withstand the fire hazards associated with the area and which will protect important equipment outside the area from a fire within the area. Section F.4.4.3 provides a listing and description of the plant fire areas. Drawings which show the arrangement of the plant fire areas are contained in Section F.6.

F.4.2 DESIGN BASIS FIRE

The fire hazards analysis uses the concept of a "design basis fire" to estimate the magnitude and severity of a potential fire. Design basis fires are those postulated to result from the combustion of the exposed combustibles within the fire area, assuming that no manual or automatic fire fighting has been initiated. The effects of the design basis fire are evaluated to ensure the adequacy of the fire area boundaries and to evaluate the potential effects of the fire on plant equipment located within the area. The combustible loading for each fire area is contained in calculation FP-02-85-03.

The combustible loading value is intended to provide an approximate estimate of the probable maximum fire severity. The combustible load concept does not account for factors such as ceiling height, ventilation, combustible concentrations, or storage methods which may significantly affect actual fire growth. The combustible load is usually conservative as it assumes total combustion whereas more accurate methods account for residue and incomplete combustion. The combustible load provides a conservative, relative measure of expected fire severity in each plant fire area. This conservatism in the combustible loading calculation generally accounts for combustibles which are not specifically included in the area fire loading.

F.4.2.1 Combustible Loading Assumptions

To calculate the area combustible loading, the major sources of combustibles within each plant fire area are identified. The entire weight of cable insulation in cable trays (covered or open) is included in the combustible loading. Cables inside conduits and within fire rated raceway barriers are not considered in the overall area combustible loading calculation. Enclosures or electrical panels are expected to prevent the electrical cabling from significantly contributing to the general area fire hazard. The only exception is cabling inside main control room electrical panels which is included in the combustible loading calculation. Cabling within the main control room power generation control complex (PGCC) underfloor raceways is excluded due to the protective steel enclosures and Halon protection.

Similarly, oil or grease in totally enclosed bearing housings in which the oil or grease is not pressurized or recirculated (such as the grease inside a motor operator) is not included in the combustible load calculations. Flammable/combustible liquids stored inside listed storage cabinets are also not considered to contribute to the general area fire hazard.

The transient combustible loading is generally included in the area combustible loading calculation by adding a value of 7,496,500 Btu (corresponding to a 55-gal drum of oil) to the heat release for the fire area. Certain fire areas may have larger or smaller transient fire loadings due to fire area location and use. The transient combustible value for the fire area is assumed to represent a bounding value of the potential transient fire loading and is not expected to exactly correlate with plant walkdown data.

Floor covering materials are considered combustible if they represent an unusual hazard (wood, plastic or rubberized floor coverings and carpeting).

F.4.2.2 Combustible Loading Calculations Methodology

The combustible loading values were developed as follows:

a. First, the major sources of combustibles (oil, electrical cable, charcoal, and storage) are identified. Data from plant equipment manuals is used when available to verify the oil and charcoal quantities. The amount of electrical cable within each area is obtained from electrical raceway information. Quantities of other materials were estimated during plant walkdowns.

b. Second, the heat release from each combustible is multiplied by its heat of combustion yielding the heat released. The lower heat of combustion value is used as the combustion products remain gaseous under fire conditions. This value represents a ‘maximum’ heat release as incomplete oxidation or partial burning in an actual fire would reduce the heat release. See Reference F.7.3.b for a list of material heat of combustion values (Btu/lb).

c. Next, the gross floor area (the floor area within the inside perimeter of the outside walls of the building with no deduction for interior walls, columns, or other features) of the fire area is calculated using dimensions taken from (or scaled from) plant drawings.

d. The total heat released (Btu) from the in-situ combustible materials in the fire area is totaled with the assumed heat release due to transient fire loading. This value is divided by the gross floor area (ft^2) yielding the fire loading for the fire area in Btu/ft^2.

e. The expected duration of the fire may be estimated from the combustible loading calculation by dividing the fire loading in the fire area by 80,000 Btu/ft^2. This value corresponds to a 1-hr fire loading (Reference F.7.2.j).

f. The Section F.4.4.4 detailed Fire Hazards Analysis (FHA) does not list the specific combustible loading in Btu/ft^2 or expected fire duration. The detailed combustible loading analysis is in calculation FP-02-85-03 (Reference F.7.3.b). The detailed FHA, Section F.4.4.4, lists the relative fire area hazard severity as follows:

Low = 0 to 80,000 Btu/ft^2
Medium = between 80,000 and 160,000 Btu/ft^2
High = above 160,000 Btu/ft^2

The above is based on NFPA (Reference F.7.2.j) with additional conservative margin.

F.4.2.3 Fire Protection Engineering Evaluations

In accordance with the guidance of Generic Letter 86-10, fire protection engineering evaluations may be performed to assess the adequacy of alternatives to prescriptive fire protection guidance documents. Examples include deviations to NFPA codes, partial area suppression or detection, less than 3-hr barriers, etc., and typically involve a comparison of the hazards to the fire protection features. Fire protection engineering evaluations deviating from NRC committed guidance documents should be prepared/approved by a qualified fire protection engineer, meet Standard License Condition 2.c(14) and be maintained on file for NRC review.

F.4.3 POST-FIRE SAFE SHUTDOWN

The systems and equipment which are designated as post-fire safe shutdown equipment represent the minimum equipment which is necessary to bring the plant to a safe cold shutdown condition in the event of a fire in any area of the plant. Only that portion of post-fire safe shutdown equipment which is expected to be free of fire damage is credited for post-fire safe shutdown, although other plant systems and equipment could also be available for use after a fire.

The development of the post-fire safe shutdown equipment list is based on the following:

- The post-fire safe shutdown systems must be capable of accommodating conditions where offsite power is available or where offsite power is not available for 72 hr.

- Fires are not postulated to occur simultaneously with other plant accidents or design basis events such as a loss-of-coolant accident (LOCA), an operating basis earthquake, or a safe shutdown earthquake.

- Single failure (including operator error) is not considered (i.e., only a single shutdown train is required to mitigate a design basis fire). For example, a single failure of a remote shutdown transfer switch is not considered in the analysis of the remote shutdown system.

- All plant equipment is functional (not in test, maintenance, or out of service) at the time of fire.

- The post-fire safe shutdown systems need not be designed to cope with other plant accidents such as pipe breaks or stuck valves, except those portions of the systems which interface with or impact existing safety systems.

- The safe shutdown capability should not be adversely affected by a fire which results in the loss of all automatic function from unprotected circuits located in the area in conjunction with worst case spurious actuations or signals resulting from a fire.

- Fail safe circuits (electrical divisions 4, 5, 6, and 7) are designed to fail in a safe manner if subjected to fire damage. For example, reactor scram, once initiated, cannot be overridden as a consequence of fire.

- Alternative shutdown systems used in the event of a main control room fire must meet the commitments to 10 CFR 50, Appendix R Section III.L, with the exception of the following:

  Section III.L.1 requires that "during post-fire shutdown, the reactor coolant system process variables be maintained within those predicted for a loss of normal ac power." The Columbia Generating Station (CGS) analysis is based on maintaining reactor parameters within those values predicted for the existing Chapter 15 transient analyses. Spurious signals are considered one at a time, and are evaluated to determine whether the signal could indirectly or directly affect safe shutdown capability (Reference F.7.5.c).

- Three phase power feeders are assumed not to fail in such a manner as to reconnect to an adjacent three phase power feeder and cause an electrically isolated motor to operate except for those supplying power to high-to-low pressure interface valves.

- Due to low fire loading and the large size of Fire Area R-1 or available fire suppression and detection systems in Fire Areas TG-1, Zone TG-12, and RC-3, the failure of Seismic Category I supports and steel raceways in such a manner that cross circuiting of cables between raceways or loss of safe shutdown equipment from falling debris is not considered to be credible.

- Failure of nonseismically supported electrical components of lighting, communication, fire protection, and security systems have been evaluated to ensure post-fire safe shutdown components in Seismic Category I areas are not affected.

- Stainless steel instrument sensing lines and their supports have been analyzed to ensure that the lines will not fail as a result of the temperature increases resulting from potential fire conditions in the vicinity of the lines. See section F.4.4.4 Fire area R-1 section 8.a. for more details.

- A properly coordinated circuit protective device (fuse, breaker, etc.) will isolate any downstream fault that results from a design basis fire even if the protective device is in the fire area.

- The emergency or abnormal response procedures allow the operator sufficient information to determine which equipment is available for post-fire shutdown in the event of a fire outside the main control room.

- There are no actions (repairs) taken by plant staff to bring back into service a piece of equipment which has failed due to fire conditions and is necessary for safe post-fire shutdown.

To provide the capability to safely shut down with or without offsite power available, post-fire shutdown is accomplished using the suppression pool for reactor inventory and depressurization (Reference F.7.3.c).

Post-fire safe shutdown may be initiated by a manual reactor scram or by an automatic scram resulting from a loss of offsite power with the accompanying loss of normal feedwater. The negative reactivity available due to control rod insertion upon scram will maintain subcriticality from event initiation to cold shutdown. The high pressure systems (e.g., HPCS or RCIC) are assumed to be unavailable for post-fire shutdown.

The main steam isolation valves (MSIVs) are closed manually or automatically by a loss of the grid. Vessel isolation occurs as the water level decreases and no high pressure makeup systems are available. Upon isolation, the vessel pressure increases resulting in the safety/relief valve (SRV) opening and discharging steam to the suppression pool. Manual operation of the automatic depressurization system (ADS) SRVs is initiated to rapidly depressurize the vessel and allow initiation of residual heat removal system in its alternative cooling mode. The automatic features of the systems such as the RHR logic circuitry or auto synchronizing of the diesel generator are not credited for post-fire safe shutdown.

At least five SRVs and one residual heat removal loop are available for post-fire shutdown for a fire in any area. In the event of a main control room fire, at least five SRVs are available (three SRV controls are provided on each remote shutdown panel). Depressurization is accomplished using five SRVs as a minimum, as prescribed in the Emergency Operating Procedures (EOPs). GE analysis shows that peak clad temperature and reactor pressure vessel (RPV) water level remain acceptable for a blowdown initiated when wide range water level instrument indicates TAF (-150 in. including loop inaccuracies) (Reference F.7.3.c). TAF is shown to be reached at approximately 22 minutes after main steam line isolation, if no low pressure system injection occurs. (Reference F.7.3.gg).

The RHR system is used in its alternate shutdown cooling mode to remove decay heat and maintain the suppression pool temperature below limits. Cooling water to the RHR system is supplied by the service water system.

Instrumentation for reactor vessel water level, reactor vessel pressure, suppression pool temperature, and suppression pool water level are used for process monitoring during post-fire shutdown.

Ventilation systems for the main control room, remote shutdown room, vital switchgear rooms, cable spreading room/cable chase, safe shutdown pump rooms, and MCC rooms in the reactor building are evaluated to ensure they remain available to support post-fire shutdown where required.

See Figures F.6-12 through F.6-17 and Reference F.7.7.q for post-fire safe shutdown one-line and P&ID drawings. See Figures F.6-18 through F.6-20 for post-fire safe shutdown credited lighting and communication components.

High to low pressure interfaces are defined as any low pressure piping that connects directly to the reactor coolant system boundary. To prevent a LOCA outside the primary containment from occurring due to a DBF, protection of at least one of two series high-to-low pressure interface valves is required. Energy Northwest does not consider paths with three or more normally closed valves to be a concern during fire-generated spurious equipment operation. High to low pressure interface flow paths requiring two or less spurious actuations are evaluated relative to their safety significance. The following is a listing of high to low pressure interface valves evaluated for the effects of fire.

a. RHR-V-123A and RHR-V-123B, RHR-V-53A and RHR-V-53B, RHR-V-8 and RHR-V-9 - during normal plant operation, power is removed from RHR-V-9, RHR-V-123A and RHR-V-123B. This precludes operation via spurious control circuit energization. The power cable is routed in a grounded steel conduit containing no energized circuits in fire areas R-1 and RC-3 (RHR-V-9) to prevent valve opening.

b. MS-V-1 and MS-V-2 - the spurious opening of these valves result in an equivalent small break LOCA inside containment with a potential for radiological release to the environment. Multiple system actuations will also occur as a result of the expected high drywell pressure. The results of the analysis are listed below:

1. RPV inventory loss is minimal with direct RPV inventory return to the suppression pool,

2. Resulting containment parameters are bounded by the small break LOCA analysis,

3. Multiple system actuations have no effect on safe shutdown, and

4. Radioactivity release will be minimal since containment will isolate on a FA signal limiting dose to less than 10 CFR 100 limits.

c. RCIC-V-45 and RCIC-RD-1 and RCIC-RD-2:

1. RPV inventory losses are well within the makeup capability of the protected RHR system,

2. Flooding in secondary containment does not affect safe shutdown, and

3. The potential radioactivity releases offsite are well below 10 CFR 100 limits.

d. RWCU-FCV-33 and RWCU-V-34 or RWCU-V-35 - plant procedures direct the closure of a manual isolation valve RWCU-V-32 as part of the fire safe shutdown process.

e. RCIC-V-65 to RCIC-V-66, HPCS-V-5, LPCS-V-6, RHR-V-41A to -41B to -41C, RHR-V-50A to RHR-V-53A, RHR-V-50B to RHR-V-53B – flow paths are multiple testable check valves and the check valve operators can neither unseat nor prevent from seating the valve flapper when a differential pressure exists across the valve (valves are for testing purposes only). A fire induced failure of the solenoid actuators for the pneumatic operators cannot cause the valves to simultaneously open.

f. PSR-V-X77A/1 to PSR-V-X77A/2 and PSR V-X77A/3 to PSR-V-X77A/4 – flow paths are via sample valves which are keylocked shut. Since the outboard Containment Isolation Valves PSR-V-X77A/2 and PSR-V-X77A/4 are also keylocked shut, fire cannot cause the valves to simultaneously open.

F.4.3.1 Normal Post-Fire Safe Shutdown Equipment

One train of the normal post-fire safe shutdown equipment is used to bring the plant to a safe cold shutdown condition from the main control room. The normal post-fire safe shutdown systems consist of two redundant trains (Division 1 and Division 2) as follows:

The Division 2 post-fire safe shutdown system consists of equipment and cabling of the following systems:

RHR B (alternate shutdown cooling mode Division 2),
SW B (Division 2),
ADS/MSRV (Division 2),
Supporting heating, ventilating, and air-conditioning (HVAC) systems (Division 2),
System status monitoring instrumentation (Division 2),
MSIVs (Division 2), and
Supporting electrical power, DG and battery (Division 2).

The Division 1 post-fire safe shutdown system consists of equipment and cabling of the following systems:

RHR A (alternate shutdown cooling mode, Division 1),
SW A (Division 1),
ADS/MSRV (Division 1),
Supporting HVAC systems (Division 1),
System status monitoring instrumentation (Division 1),
MSIVs (Division 1), and
Supporting electrical power including DG and battery (Division 1).

The automatic features of these systems, such as the RHR logic circuitry or auto-synchronizing of the diesel generator are not credited. Only those instruments which are designated as post-fire safe shutdown equipment have been evaluated to ensure their availability in the event of fire.

Normal shutdown operator manual actions are identified and evaluated in the Reference F.7.3.d. Reference F.7.6.u identifies which normal shutdown manual operator actions are a 10 CFR 50 Appendix R III.G.2 deviation and documents their feasibility and reliability.

The normal post-fire safe shutdown equipment is listed in Table F.4-1.

F.4.3.2 Remote Post-Fire Safe Shutdown Equipment

In the event of a main control room fire, selected portions of the Division 1 and Division 2 post-fire safe shutdown systems are used to shut down the reactor from outside the control room. Necessary instrumentation and controls for three Division 1 and three Division 2 SRVs, Division 2 RHR, Division 2 service water, and supporting power and ventilation systems are located on the remote shutdown and other local panels. Manual transfer switches isolate the controls for certain components from the main control room.

The only operator actions which are credited prior to evacuation are manual reactor scram and MSIV closure. Prior to control room evacuation, the operators will request Security to unlock security doors required for remote shutdown and announce the reactor scram and control room evacuation. If time is available, prior to control room evacuation, the operators will also perform the following actions:

- Manually initiate reactor core isolation cooling (RCIC),
- Start SW loop A and B,
- Trip the main generator, and
- Transfer SM-7 and SM-8 to the backup transformer.

The MSIVs and the reactor protection system (RPS) are fail safe systems which are routed in grounded raceways to ensure that loss of power resulting from a fire will fail these circuits to a safe condition.

Following evacuation of the control room, the operators

- Transfer control away from the control room to the remote shutdown and other local panels,

- Start standby service water pump to provide cooling water to the diesel generator,

- Start diesel generator 2,

- Initiate RHR in the alternate shutdown cooling mode (injection of suppression pool water directly into the reactor) when the reactor pressure is reduced below the RHR pump design operating pressure,

- Operate a minimum of five SRVs using the controls at the remote and alternate remote shutdown panels when RPV level reaches 150 in. indicated, and

Reference F.7.3.d lists all remote shutdown operator manual actions.

Indication for the following parameters is located on the remote shutdown panels:

Reactor water level,
Reactor pressure,
Suppression pool water level,
Suppression pool water temperature,
Residual heat removal pump flow, and
Standby service water pump discharge pressure.

The Division 2 diesel generator supplied emergency lighting in the remote shutdown areas at el. 467 ft of the radwaste building has been evaluated to ensure the lighting will remain available in the event of a control room fire.

The remote post-fire shutdown system thus consists of the following:

RHR B (Division 2),
SW B (Division 2),
ADS/MSRV (Division 1 and Division 2),
Supporting HVAC systems (Division 2),
System status monitoring instrumentation, and
Supporting power train including DG-2 and Division 1 and Division 2 battery.

The automatic features of these systems, such as the RHR logic circuitry or auto-synchronizing of the diesel generator are not credited. Only those instruments which are designated as post-fire safe shutdown equipment been evaluated to ensure their availability in the event of fire.

Controls and instrumentation for the RCIC system are located on the remote shutdown panel. However, the RCIC system and the high-pressure core spray (HPCS) system have not been protected from the effects of a control room fire.

The major components for remote post-fire safe shutdown are listed in Table F.4-1.

F.4.4 FIRE AREA ANALYSES

F.4.4.1 Post-Fire Safe Shutdown

The potential consequences of fire damage are analyzed by evaluating the post-fire safe shutdown equipment by fire area. Post-fire safe shutdown equipment in the fire area is assumed damaged by the postulated fire, unless the equivalent level of fire protection specified by Appendix R, Section III.G is provided or the configuration is within the basis of an approved deviation.

For fire areas outside the main control room, the equipment/cabling within the area is reviewed to ensure that redundant post-fire shutdown systems remain available. First, the area is assigned as Division 1 or Division 2 based on the train of post-fire safe shutdown equipment which would be lost due to a fire in the area. Any cabling or equipment of the redundant division (which is credited for operation of post-fire safe shutdown) which is located within the area is then identified. Equipment and cabling within the main control room is evaluated to ensure that a fire will not prevent remote shutdown.

Potential multiple high impedance faults are evaluated in Reference F.7.3.ee per the Reference F.7.2.w base case. Safe shutdown power supplies that do not meet the base case are credible and are addressed in Reference F.7.3.d.

Any spurious signal cables (those cables which could cause a malfunction if compromised by a hot short, open circuit, or short to ground) which could affect the post-fire safe shutdown are analyzed to identify the potential effects of fire on post-fire safe shutdown capability. Only one spurious actuation alone, with the effects of that actuation, are assumed to occur at a time for remote shutdown (Reference F.7.4.j). For normal shutdown, multiple spurious operations (MSO) is assumed per Reference F.7.2.x.

The adequacy of the construction of the fire area boundaries is evaluated as part of the fire hazards analysis by a comparison of the area fire hazards to the active and passive fire protection features and specific post-fire safe shutdown requirements.

The fire hazards analysis for certain areas is unique:

U-1. A fire hazards analysis is performed for primary containment (Fire Area R-2); however, the post-fire safe shutdown capability is not specifically evaluated as primary containment is inerted during power operation;

U-2. The main control room (Fire Area RC-10) is analyzed to ensure the remote shutdown system will remain available;

F.4.4.2 Control of Radioactive Release

A fire induced radioactive release to the environment can occur via one of the following mechanisms:

a. Inadvertent primary coolant release to the environment,

b. Inadvertent radwaste system release to the environment,

c. Contaminated smoke due to the combustion of radioactive material, and

d. Contaminated water produced as a product of fire suppression in areas containing radioactive material.

Normal plant operating procedures provide guidance for ensuring that appropriate design features are used to monitor and control the release of radioactivity to the environment which may occur as the result of a fire or fire fighting activities. Specific design features to be used will be determined at the time of the fire by health physics personnel and the Environmental Field Team, as necessary. The design features provided along with fire brigade training will ensure that any release of radiation due to fire will be controlled and monitored.

Reactor coolant system integrity is among several functional requirements necessary to achieve safe shutdown. Equipment necessary to meet these functional requirements has been identified and analyzed.

The liquid waste management system is discussed in Section 11.2. The system is designed to process potentially radioactive liquids from fire suppression activities in a manner which limits radiation exposure and controls the release of potentially radioactive material.

In the reactor building, turbine building, and radwaste building, contaminated liquid resulting from fire suppression activities in contaminated areas is routed through floor drains to the liquid waste management system. The HVAC exhaust vents in these buildings are provided with radiation monitors and can be isolated to limit the spread of smoke. In addition, procedural controls and fire brigade training stress the need to control and minimize the potential release of fire suppression water and smoke. Environmental field teams would be used as needed to monitor releases from the turbine generator, reactor, or radwaste buildings due to a significant fire.

Table F.4-1

Required Post-Fire Safe Shutdown (PFSS) Equipment
List of Primary Components

ADS/SRV SYSTEM

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
MS-SPV-3DA	R-2	MS-SPV-3DB	R-2	MS-SPV-3DA	R-2
MS-SPV-4AA	R-2	MS-SPV-4AB	R-2	MS-SPV-4AB	R-2
MS-SPV-4BA	R-2	MS-SPV-4BB	R-2	MS-SPV-4BB	R-2
MS-SPV-4CA	R-2	MS-SPV-4CB	R-2	MS-SPV-4CB	R-2
MS-SPV-5BA	R-2	MS-SPV-5BB	R-2	MS-SPV-5BA	R-2
MS-SPV-5CA	R-2	MS-SPV-5CB	R-2	MS-SPV-5CA	R-2

HI-LO PRESSURE INTERFACE

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
MS-V-2	R-2	MS-V-1	R-2	N/A	N/A
RCIC-V-45	R-6	N/A	N/A	N/A	N/A
RHR-V-8	R-1	RHR-V-9	R-2	RHR-V-9	R-2
RHR-V-53A	R-1	RHR-V-53B	R-1	RHR-V-53B	R-1
RHR-V-123A	R-2	RHR-V-123B	R-2	RHR-V-123B	R-2
RWCU-FCV-33	R-1	N/A	N/A	N/A	N/A
RWCU-V-34	R-1	N/A	N/A	N/A	N/A
RWCU-V-35	R-1	N/A	N/A	N/A	N/A

HVAC SYSTEM

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
DEA-FN-11	DG-2	DEA-FN-21	DG-3	DEA-FN-21	DG-3
DEA-FN-12	DG-2	DEA-FN-22	DG-3	DEA-FN-22	DG-3
DMA-FN-11	DG-2	DMA-FN-21	DG-3	DMA-FN-21	DG-3
DMA-FN-12	DG-2	DMA-FN-22	DG-3	DMA-FN-22	DG-3
PRA-FN-1A	SW-1	PRA-FN-1B	SW-2	PRA-FN-1B	SW-2
RRA-FN-2	R-5	RRA-FN-3	R-4	RRA-FN-3	R-4
RRA-FN-11	R-1	N/A	N/A	N/A	N/A
RRA-FN-13	R-1	N/A	N/A	N/A	N/A
WMA-AD-51A1	RC-11	WMA-AD-51B1	RC-12	N/A	N/A
N/A	N/A	WMA-AD-52/1	RC-12	N/A	N/A
N/A	N/A	WMA-AD-52/2	RC-12	N/A	N/A
WMA-EHC-7A	RC-5	WMA-EHC-8	RC-6	WMA-EHC-8	RC-6
WMA-EHC-7B	RC-5				
WMA-FN-51A	RC-11	WMA-FN-51B	RC-12	N/A	N/A

Table F.4-1

Required Post-Fire Safe Shutdown (PFSS) Equipment
List of Primary Components

HVAC SYSTEM

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
WMA-FN-52A	RC-11	WMA-FN-52B	RC-12	WMA-FN-52B	RC-12
WMA-FN-53A	RC-11	WMA-FN-53B	RC-12	WMA-FN-53B	RC-12
N/A	N/A	CCH-CR-1B	RC-13	N/A	N/A
N/A	N/A	CCH-P-1B	RC-13	N/A	N/A

MECHANICAL EQUIPMENT

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
RHR-RO-5A	R-5	RHR-RO-5B	R-4	RHR-RO-5B	R-4
N/A	N/A	RHR-V-19	R-4	RHR-V-19	R-4
RHR-V-31A	R-5	RHR-V-31B	R-4	RHR-V-31B	R-4
RHR-V-41A	R-2	RHR-V-41B	R-2	RHR-V-41B	R-2
RHR-V-50A	R-2	RHR-V-50B	R-2	RHR-V-50B	R-2
RHR-V-84A	R-5	RHR-V-84B	R-4	RHR-V-84B	R-4
N/A	N/A	RHR-V-89	R-4	RHR-V-89	R-4
RHR-V-731	R-5	RHR-V-732	R-4	N/A	N/A
SW-V-1A	SW-1	SW-V-1B	SW-2	SW-V-1B	SW-2
SW-V-224A	RC-11	SW-V-224B	RC-12	N/A	N/A
SW-V-225A	RC-11	SW-V-225B	RC-12	N/A	N/A
SW-V-227A	RC-11	SW-V-227B	RC-12	N/A	N/A
SW-V-822A	RC-11	SW-V-822B	RC-12	N/A	N/A
SW-V-823A	RC-11	SW-V-823B	RC-12	N/A	N/A

MSIV SYSTEM

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
MS-V-28A	TG-1	MS-V-22A	R-2	MS-V-22A	R-2
MS-V-28B	TG-1	MS-V-22B	R-2	MS-V-22B	R-2
MS-V-28C	TG-1	MS-V-22C	R-2	MS-V-22C	R-2
MS-V-28D	TG-1	MS-V-22D	R-2	MS-V-22D	R-2

PFSS INSTRUMENTATION

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
CMS-LR-3	RC-10	CMS-LR-4	RC-10	CMS-LI-2R	RC-9
CMS-TR-5	RC-10	CMS-TR-6	RC-10	CMS-TI-43R	RC-9
MS-LR/PR-623A	RC-10	MS-LR/PR-623B	RC-10	MS-LI-10	RC-9
				MS-PI-2	RC-9

Table F.4-1

Required Post-Fire Safe Shutdown (PFSS) Equipment
List of Primary Components

PFSS INSTRUMENTATION

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
N/A	N/A	N/A	N/A	RHR-FT-1	M-21
RHR-FI-603A	RC-10	RHR-FI-603B	RC-10	RHR-FI-5	RC-9
SW-FI-9A	RC-10	SW-FI-9B	RC-10	SW-PI-32BR	RC-9
N/A	N/A	MS-SPV-126D	M-27	N/A	N/A

POWER DISTRIBUTION

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
DG-GEN-DG1	DG-2	DG-GEN-DG2	DG-3	DG-GEN-DG2	DG-3
DO-P-1A	DG-4	DO-P-1B	DG-5	DO-P-1B	DG-5
DO-P-4A1	DG-2	DO-P-4B1	DG-3	DO-P-4B1	DG-3
DO-P-4A2	DG-2	DO-P-4B2	DG-3	DO-P-4B2	DG-3
DO-TK-1A	DG-4	DO-TK-1B	DG-5	DO-TK-1B	DG-5
DO-TK-3A	DG-8	DO-TK-3B	DG-9	DO-TK-3B	DG-9
DSA-AR-1A	DG-2	DSA-AR-1B	DG-3	DSA-AR-1B	DG-3
E-SM-DG1/7	DG-2	E-SM-DG2/8	DG-3	E-SM-DG2/8	DG-3
E-SM-7	RC-14	E-SM-8	RC-8	E-SM-8	RC-8
E-SL-71	RC-14	N/A	N/A	N/A	N/A
E-SL-73	RC-14	E-SL-83	RC-8	E-SL-83	RC-8

RHR SYSTEM

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
RHR-FCV-64A	R-5	RHR-FCV-64B	R-4	RHR-FCV-64B	R-4
RHR-P-2A	R-5	RHR-P-2B	R-4	RHR-P-2B	R-4
RHR-V-3A	R-5	RHR-V-3B	R-4	RHR-V-3B	R-4
RHR-V-4A	R-5	RHR-V-4B	R-4	RHR-V-4B	R-4
RHR-V-6A	R-5	RHR-V-6B	R-4	RHR-V-6B	R-4
RHR-V-16A	R-1	RHR-V-16B	R-1	RHR-V-16B	R-1
RHR-V-17A	R-1	RHR-V-17B	R-1	N/A	N/A
N/A	N/A	RHR-V-23	R-4	N/A	N/A

Table F.4-1

Required Post-Fire Safe Shutdown (PFSS) Equipment
List of Primary Components

RHR SYSTEM

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
RHR-V-24A	R-1	RHR-V-24B	R-4	RHR-V-24B	R-4
RHR-V-27A	R-1	RHR-V-27B	R-4	RHR-V-27B	R-4
N/A	N/A	RHR-V-40	R-4	N/A	N/A
RHR-V-42A	R-1	RHR-V-42B	R-21	RHR-V-42B	R-21
RHR-V-48A	R-5	RHR-V-48B	R-4	RHR-V-48B	R-4
N/A	N/A	RHR-V-49	R-4	RHR-V-49	R-4
RHR-V-68A	R-5	RHR-V-68B	R-4	RHR-V-68B	R-4
RHR-V-73A	R-5	RHR-V-73B	R-4	N/A	N/A
RHR-V-74A	R-5	RHR-V-74B	R-4	N/A	N/A
N/A	N/A	RHR-V-115	R-4	RHR-V-115	R-4
N/A	N/A	RHR-V-116	R-4	RHR-V-116	R-4
N/A	N/A	RHR-V-182	R-4	RHR-V-182	R-4

SW SYSTEM

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
SW-P-1A	SW-1	SW-P-1B	SW-2	SW-P-1B	SW-2
SW-TCV-11A	RC-11	SW-TCV-11B	RC-12	N/A	N/A
SW-V-2A	SW-1	SW-V-2B	SW-2	SW-V-2B	SW-2
SW-V-12A	SW-1	SW-V-12B	SW-2	SW-V-12B	SW-2
SW-V-75A	R-5	SW-V-75B	R-1	N/A	N/A
N/A	N/A	SW-V-187A	R-1	SW-V-187A	R-1
N/A	N/A	SW-V-188A	R-1	SW-V-188A	R-1
SW-V-187B	R-1	SW-V-187B	R-1	SW-V-187B	R-1
SW-V-188B	R-1	SW-V-188B	R-1	SW-V-188B	R-1

AUXILIARY POWER DISTRIBUTION EQUIPMENT

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
E-B1-1	RC-5	E-B1-2	RC-6	E-B1-2	RC-6
E-C1-1A	RC-4	E-C1-2A	RC-7	E-C1-2A	RC-7
E-C1-1B	RC-4	E-C1-2B	RC-7	E-C1-2B	RC-7
E-PNL-C1/1	RC-4	E-PNL-C1/2	RC-7	E-PNL-C1/2	RC-7
E-IN-3A	RC-4	E-IN-2A	RC-7	N/A	N/A
E-IN-3B	RC-4	E-IN-2B	RC-7	N/A	N/A

Table F.4-1

Required Post-Fire Safe Shutdown (PFSS) Equipment (Continued)
List of Primary Components

AUXILIARY POWER DISTRIBUTION EQUIPMENT

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
E-DISC-MC7F/3A1	RC-11	E-DISC-8F4B1	RC-12	N/A	N/A
E-DP-S1/1	RC-4	E-DP-S1/2	RC-7	E-DP-S1/2	RC-7
E-DP-S1/1A	RC-10	E-DP-S1/2A	RC-10	N/A	N/A
E-DP-S1/1F	RC-14	E-DP-S1/2D	RC-9	E-DP-S1/2D	RC-9
E-DP-S1/1E	DG-2	E-DP-S1/2E	DG-3	E-DP-S1/2E	DG-3
E-ELP-7FD	RC-10	E-ELP-8FD	RC-10	N/A	N/A
E-ELP-7FDA	RC-10	E-ELP-8FDA	RC-10	N/A	N/A
E-MC-S1/1D	RC-4	E-MC-S1/2D	RC-7	E-MC-S1/2D	RC-7
E-MC-7A	RC-4	E-MC-8A	RC-7	E-MC-8A	RC-7
E-MC-7AA	DG-2	E-MC-8AA	DG-3	E-MC-8AA	DG-3
E-MC-7B	R-1	E-MC-8B	R-18	E-MC-8B	R-18
E-MC-7BA	R-1	E-MC-8BA	R-18	E-MC-8BA	R-18
E-MC-7BB	R-1	E-MC-8BB	R-4	E-MC-8BB	R-4
E-MC-7F	RC-11	E-MC-8F	RC-12	E-MC-8F	RC-12
E-PP-7A	RC-4	E-PP-8A	RC-7	E-PP-8A	RC-7
E-PP-7AA	RC-10	E-PP-8AA	RC-10	N/A	N/A
E-PP-7AAA	DG-2	E-PP-8AAA	DG-3	E-PP-8AAA	DG-3
E-PP-7AB	SW-1	E-PP-8AB	SW-2	E-PP-8AB	SW-2
E-PP-7AE	R-1	E-PP-8AF	RC-9	E-PP-8AF	RC-9
E-PP-7AG	SW-1	E-PP-8AG	SW-2	E-PP-8AG	SW-2
E-PP-7FA	RC-11	E-PP-8FA	RC-12	N/A	N/A
E-PNL-IN/3	RC-4	E-PNL-IN/2	RC-7	N/A	N/A
E-TR-7A	RC-4	E-TR-8A	RC-7	E-TR-8A	RC-7
E-TR-7AAA	DG-2	E-TR-8AAA	DG-3	E-TR-8AAA	DG-3
E-TR-7AF	SW-1	E-TR-8AF	SW-2	E-TR-8AF	SW-2
E-TR-7/71	RC-14	N/A	N/A	E-TR-8/83	RC-8
E-TR-7/73	RC-14	E-TR-8/83	RC-8	E-TR-8/83	RC-8
E-TR-7AF/1	SW-1	E-TR-8AF/1	SW-2	E-TR-8AF/1	SW-2
E-TR-7AAA/1	DG-2	E-TR-8AAA/1	DG-3	E-TR-8AAA/1	DG-3
E-SM-7/75/2	RC-14	E-TR-8A/2	RC-9	E-TR-8A/2	RC-9
E-TR-7FD	RC-10	E-TR-8FD	RC-10	E-B1-1	RC-5
E-TR-7A/1	RC-4	RHR-DISC-V/9	RC-7	E-DP-S1/1	RC-4
N/A	N/A	N/A	N/A	E-DP-S1/1F	RC-14

Table F.4-1

Required Post-Fire Safe Shutdown (PFSS) Equipment
List of Primary Components

AUXILIARY EQUIPMENT

DIVISION 1 PFSS		DIVISION 2 PFSS		REMOTE SHUTDOWN	
EPN	FIRE AREA	EPN	FIRE AREA	EPN	FIRE AREA
DELETED	DELETED	DELETED	DELETED	N/A	N/A
E-IR-21	SW-1	N/A	N/A	E-CP-ARS	RC-14
E-IR-P004	R-1	E-IR-22	SW-2	E-IR-22	SW-2
E-IR-P018	R-1	E-IR-P021	M-21	N/A	N/A
RCC-V-130	R-1	E-IR-P027	M-27	N/A	N/A
E-IR-66	R-1	N/A	N/A	N/A	N/A
E-CNTR-WMA/EHC/7A	RC-5	E-CNTR-WMA/EHC/8	RC-6	E-CNTR-WMA/EHC/8	RC-6
E-CNTR-WMA/EHC/7B	RC-5	RWCU-V-32	R-1	RWCU-V-32	R-1
WMA-FD-57	RC-11	SW-42-7BB6A	R-1	SW-42-7BB6A	R-1
WMA-RMS-FN/53B	RC-10	SW-42-7BA7A	R-1	SW-42-7BA7A	R-1
SW-42-8BB6A	R-4	SW-42-8BB6A	R-4	SW-42-8BB6A	R-4
SW-42-8BA10C	R-18	SW-42-8BA10C	R-18	SW-42-8BA10C	R-18

F.4.4.3 Scope of Areas Evaluated in Fire Hazards Analysis

Fire areas included in the fire hazards analysis are those plant areas within the primary plant structure and those remote buildings with credited post-fire safe shutdown equipment. See the following table for the listing of evaluated fire areas. The fire area boundaries are shown as fire rated barriers on Figures F.6-1 through F.6-5.

The outdoor yard area is not analyzed as a fire area in the F.4 fire hazards analysis for the following reasons:

- The yard has underground duct banks with post-fire safe shutdown cables that route from the Diesel and Radwaste buildings to the Service Water Pump houses. Each duct bank is a separate electrical division. Each divisional duct bank has at least one manhole. The manholes have spatial separation. Therefore, post-fire safe shutdown can be achieved in the event of a fire in a single duct bank,

- Remote buildings credited in the fire protection program (service water pump house 1 and 2, circulating water pump house, water filtration building 33) with nonrated barriers are sufficiently separated from each other and from the plant that a single exposure fire would not spread to more than one building,

- The Hydrogen Storage and Supply Facility (HSSF) is located approximately 0.6 miles southeast of the plant and stores approximately 9800 pounds of liquid and gaseous hydrogen. This separation ensures a fire or explosion at the HSSF has no impact on the operability of systems credited for post-fire safe shutdown (References F.7.3.bb, F.7.3.cc, and F.7.5.t). The Hydrogen Water Chemistry (HWC) system is not safety-related,

- Where nearby exposure hazards exist, plant buildings have rated fire barriers. See Sections F.2.2.14 through F.2.2.17, and

- Yard fire hazards are not postulated to impair the yard fire protection water supply system.

- The DG building south exterior wall is not fire rated and the HVAC air intake is not equipped with fire dampers. To ensure a yard fire does not spread to multiple DG fire areas, the exterior concrete pad is sloped to drain combustible liquids away from the building. Administrative control of transient combustibles ensures excessive amounts of combustibles are not stored within 10 feet of the DG building exterior. Yard structures and DG-4 are not placed within 50 feet of the non-rated south DG barrier.

The fire protection water supply buildings (circulating water pump house and water filtration building 33) are not analyzed as fire areas in the F.4 fire hazards analysis for the following reasons:

- They do not contain any post-fire safe shutdown equipment, other than the fire pumps,
- The water supply system has a sufficient capacity to provide the maximum water demand from either the primary or secondary supply,
- The redundant water supply buildings are sufficiently separated that a single exposure fire would not spread between the subject buildings, and
- The redundant water supply buildings are remote and would not be an exposure hazard to the plant.

The general service building (GSB) was originally considered in the fire hazards analysis. However, the GSB is not analyzed in the fire hazards analysis for the following reasons:

- The building does not contain any credited post-fire safe shutdown,
- The only safety-related equipment in the building are two motor-operated auxiliary steam isolation valves (AS-V-68A/68B) at 458 ft Column K.4-3.2. The isolation of the auxiliary steam system is a safety-related function since it is a potential high energy line break (HELB) source to the reactor building which could affect the qualified life of safety-related equipment. Since a GSB fire would not cause a HELB and a reactor building HELB need not be considered concurrent with a fire, the GSB area of the safety-related valves does not warrant a fire hazards analysis,
- The building is entirely isolated from the turbine and reactor building by 3-hr barriers, and
- Although GSB sprinkler and detection system alarms annunciate in the control room and use plant power, their inoperability has no impact on post-fire safe shutdown.

Building 25 (PAAP) is not analyzed in the fire hazards analysis for the following reasons:

- The building does not contain any components necessary for post-fire safe shutdown except for communication equipment. For a design basis fire in building 25, the communication system is not required.

- There are no safety related components is this building. The only connections to the plant distribution power system are made through manual disconnect switches that are normally open.

- The building is separated from the plant buildings by the yard and fire rated barriers.

The following is a listing of the fire areas and their post-fire safe shutdown code.

Diesel generator building - HPCS diesel generator room	1	DG-1
Diesel generator building - Diesel generator 1A room	1	DG-2
Diesel generator building - Diesel generator 1B room	2	DG-3
Diesel generator building - DG 1A diesel oil tank pump room	1	DG-4
Diesel generator building - DG 1B diesel oil tank pump room	2	DG-5
Diesel generator building - HPCS diesel oil tank pump room	#	DG-6
Diesel generator building - HPCS diesel day tank room	#	DG-7
Diesel generator building - DG 1A diesel day tank room	1	DG-8
Diesel generator building - DG 1B diesel day tank room	2	DG-9
Diesel generator building - Deluge valve equipment room	#	DG-10
Reactor building - General equipment area	1	R-1
Reactor building - Primary containment	U	R-2
Reactor building - HPCS pump room	#	R-3
Reactor building - RHR B pump room, pipe chase, pipe tunnels, H2 recombiner MCC room, heat exchanger rooms, and south valve rooms	2	R-4
Reactor building - RHR A pump room, pipe chase, pipe tunnels, heat exchanger rooms	1	R-5
Reactor building - RCIC pump room	2	R-6
Reactor building - RHR pump room	1	R-7
Reactor building - LPCS pump room	1	R-8
Reactor building - Stair A6	#	R-9
Reactor building - Elevator No. 2	#	R-10
Reactor building - Stair A5	#	R-11
Reactor building - Elevator No. 1	#	R-12
Reactor building - 422 ft lobby outside of stair A5	#	R-15
Reactor building - MCC room Division 2	2	R-18
Reactor building - South valve room	2	R-21
Reactor building - Instrument rack E-IR-P009 enclosure	2	M-9
Reactor building - Instrument rack E-IR-P021 enclosure	2	M-21
Reactor building - Instrument rack E-IR-P027 enclosure	2	M-27
Radwaste control building - Radwaste general nonvital equipment area	2	RC-1
Radwaste control building - Cable spreading room	1	RC-2

Radwaste control building - Cable chase		1	RC-3
Radwaste control building - Electrical equipment room No. 1		1	RC-4
Radwaste control building - Battery room No. 1		1	RC-5
Radwaste control building - Battery room No. 2		2	RC-6
Radwaste control building - Electrical equipment room No. 2		2	RC-7
Radwaste control building - Switchgear room No. 2		2	RC-8
Radwaste control building - Remote shutdown room		2	RC-9
Radwaste control building - Main control room		U	RC-10
Radwaste control building - Unit A - air-conditioning room		1	RC-11
Radwaste control building - Unit B - air-conditioning room		2	RC-12
Radwaste control building - Communications room, instrument shop, chiller area, and HVAC chase		2	RC-13
Radwaste control building - Switchgear room No. 1		1	RC-14
Radwaste control building - Stair A8 and room C100		#	RC-15
Radwaste control building - Stair A7		#	RC-16
Radwaste control building - Elevator No. 4 and room C504		#	RC-17
Radwaste control building - Stair A13		#	RC-18
Radwaste control building - Corridor C205		2	RC-19
Radwaste control building - PASS area/pipe chase		1	RC-20
Reactor recirculation pump ASD building		#	ASD
Standby service water pump house 1A		1	SW-1
Standby service water pump house 1B		2	SW-2
Turbine generator building - General equipment area		2	TG-1
Turbine oil storage room	Fire zone TG-2	#	
Auxiliary boiler room	Fire zone TG-5	#	
Hydrogen seal oil room	Fire zone TG-7	#	
Turbine oil reservoir room	Fire zone TG-9	#	
West transformer vault	Fire zone TG-10	#	
East transformer vault	Fire zone TG-11	#	
441 ft southern corridors	Fire zone TG-12	2	
Turbine generator building – Stair A1		#	TG-3
Turbine generator building – Elevator No. 3		#	TG-4
Turbine generator building – Stair A3		#	TG-6
Turbine generator building – Stair A4		#	TG-8

LEGEND

Plant Fire Area Identification

The prefix of the fire area number corresponds to the building in which the fire area is located as follows:

ASD	Reactor recirculation pump ASD building
DG	Diesel generator building
M	Instrument Rack room
R	Reactor building
RC	Radwaste/control building
S	Service building
SW	Standby service water pump house(s)
TG	Turbine generator building

See Figures F.6-1 through F.6-5 for fire area locations.

Explanation of Codes

This code indicates that this fire area does not contain equipment or cables for either division of post-fire safe shutdown equipment.

1 This code indicates that this fire area contains Division 1 post-fire safe shutdown equipment or cables that are exposed to the fire and not protected. Division 1 fire areas that contain Division 2 post-fire safe shutdown equipment or cables are required to be protected or justified.

2 This code indicates that this fire area contains Division 2 post-fire safe shutdown equipment or cables that are exposed to the fire and not protected. Division 2 fire areas that contain Division 1 post-fire safe shutdown equipment or cables are required to be protected or justified.

U This code indicates that this fire area has been uniquely analyzed for post-fire safe shutdown. Refer to the fire hazards analysis methodology in Section F.4.4.

F.5 ESSENTIAL FIRE PROTECTION SYSTEM OPERABILITY/TESTING PROGRAM

The operability requirements, compensatory actions, and testing requirements for the essential fire protection systems are located in Licensee Controlled Specification (LCS) 1.10, Fire Protection.

F.6 FIRE PROTECTION ARRANGEMENT DRAWINGS

F.7 FIRE PROTECTION PROGRAM REFERENCES

F.7.1 REGULATORY DOCUMENTS/OTHER FSAR FIRE PROTECTION COMMITMENTS

F.7.1.1 Columbia Generating Station Regulatory Requirements

a. 10 CFR 50.48, Fire Protection

b. 10 CFR 50, Appendix A, General Design Criterion 3, Fire Protection

c. Facility Operating License (FOL) Condition 2.C.(14), Fire Protection Program

F.7.1.2 Columbia Generating Station Commitments

a. Branch Technical Position (BTP) Auxiliary Power Conversion Systems Branch (APCSB) 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976 (see Table F.3-1)

b. 10 CFR 50 Appendix R, Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979 (see Table F.3-2)

c. FSAR Appendix F Fire Protection Evaluation

d. Section 1.2.2.12.11, Fire Protection System

e. Section 3.1.2.1.3, Criterion 3 - Fire Protection

f. Section 8.3.1.4, Independence of Redundant Systems

g. Section 9.5.2, Communication Systems

h. Section 9.5.3, Plant Lighting Systems

i. Sections 13.1.2.3.4 and 13.2.2.5, Fire Brigade

j. Section 13.1.3.3.3, Fire Protection Engineer

k. Licensee Controlled Specification 1.10, Fire Protection

l. Emergency Plan

m. Operational Quality Assurance Program Description (OQAPD) which commits to Regulatory Guide 1.189 (April 2001), Section 1.7.10, “Audits”

F.7.2 INDUSTRY GUIDANCE

a. Regulatory Guide 1.189, Fire Protection for Nuclear Power Plants

b. BTP Chemical Engineering Branch (CMEB) 9.5-1 Guidelines for Fire Protection for Nuclear Power Plants, Revision 2, July 1, 1981

c. NUREG 0800 Standard Review Plan, Section 9.5.1, Fire Protection Program, Revision 3, July 1981

d. BTP ASB 3-1, Rev. 1, 1981, Protection Against Postulated Piping Failures in Fluid Systems Outside Containment (attached to SRP 3.6.1)

e. NRC Inspection and Enforcement Manual, Inspection Procedure 64100, Post-Fire Safe Shutdown, Emergency Lighting and Oil Collection, Inspection Procedure 64704, Fire Protection/Prevention Program

f. NRC Generic Letters (GL), applicable sections of: GL 77-02, GL dated 9/7/79, GL 81-04, GL 81-12, GL dated 4/7/82, GL 82-21, GL 83-33, GL 85-01, GL 86-10, GL 86-10 Supplement 1, GL 88-12, GL 88-20 Supplement 4, GL 92-08, GL 92-08 Supplement 1, GL 93-06

g. NRC Information Notices (IN), applicable sections of: IN 80-05, IN 80-11, IN 82-28, IN 83-41, IN 83-69, IN 84-09, IN 84-16, IN 84-34, IN 84-57, IN 84-92, IN 85-09, IN 85-85, IN 86-17, IN 86-35, IN 87-14, IN 87-50, IN 88-04, IN 88-04 Supplement 1, IN 88-05, IN 88-05, IN 88-56, IN 88-60, IN 88-64, IN 89-52, IN 89-63, IN 90-23, IN 91-17, IN 91-47, IN 91-77, IN 91-79, IN 92-18, IN 92-28, IN 92-46, IN 92-52, IN 92-55, IN 92-82, IN 93-40, IN 93-41, IN 94-12, IN 94-22, IN 94-26, IN 94-28, IN 94-31, IN 94-35, IN 94-58, IN 94-86, IN 94-86 Supplement 1, IN 95-27, IN 95-33, IN 95-36, IN 95-36 Supplement 1, IN 95-48, IN 95-49, IN 95-49 Supplement 1, IN 95-52, IN 95-52 Supplement 1, IN 97-01, IN 97-37, IN 97-59, IN 97-70, IN 97-72, IN 97-73, IN 97-82, IN 98-31, IN 99-05, IN 99-07, IN 99-17

h. NRC Policy Paper, Secretary of Commission (SECY), applicable sections of: SECY-81-114, SECY-82-268, SECY-83-269, SECY-85-306 and 306B, SECY-93-143, SECY-93-232, SECY-94-090, SECY-94-127, SECY-95-034, SECY-96-134, SECY-96-146, SECY-97-127, SECY-98-058, SECY-98-230, SECY-99-140, SECY-99-152, SECY-99-182, SECY-99-204

i. National Fire Protection Association (NFPA) Codes. See Section F.2.1 for major committed codes.

j. Fire Protection Handbook, National Fire Protection Association, Boston, Massachusetts

k. Underwriters Laboratories (UL) listings from UL Building Materials Directory and UL Fire Resistance Directory (current editions)

l. ASTM E 84-1981, Standard Test Method for Surface Burning Characteristics of Building Materials

m. ASTM E 119-1988, Fire Test of Building Construction and Materials

n. ASTM E 136-1982, Standard Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C

o. UL 910-1985, Test Method for Fire and Smoke Characteristics of Electrical and Fiber Optic Cables Used in Air Handling Spaces

p. Factory Mutual Approval Guide (current editions)

q. IEEE 383-1974, Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations

r. Regulatory Guide 1.52, Revision 1, Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Plants

s. ANSI A21.4, Cement-Mortar Lining for Cast-Iron and Ductile-Iron Pipe Fittings for Water

t. ASME Boiler and Pressure Vessel Code, Section III, Rules for the Construction of Nuclear Power Plant Components

u. Nuclear Electric Insurance Limited, Members Manual, Chapter 7, Primary Property Loss Control Programs

v. Washington Administrative Code (WAC)

w. NEI 00-01, Revision 1, Guidance for Post-Fire Safe Shutdown Circuit Analysis, Appendix B.2, Justification for the Elimination of Multiple High Impedance

x. NEI 00-01, Revision 2, Guidance for Post-Fire Safe Shutdown Circuit Analysis, Section 4 and Appendix G; as endorsed by Regulatory Guide 1.189 Revision 2

F.7.3 CALCULATIONS/TECHNICAL MEMOS

a. CE-02-90-39, Fire Resistance Rating of Hollow Concrete Block

b. FP-02-85-03, Combustible Loading Calculation

c. GEH-0000-0075-4920, “GE14 Fuel Design Cycle-Independent Analyses for Energy Northwest Columbia Generating Station” (most recent version referenced in the COLR)

d. NE-02-85-19, Revised Appendix R Safe Shutdown Analysis

e. NE-02-84-17, Bio-Shield Penetration Analysis for Fire Protection

f. NE-02-86-23, Temperature Response of Structural Components to Appendix R Fire

g. NE-02-86-39, Evaluation of Structural Supports for One Hour Fire Barriers

h. DELETED

i. DELETED

j. DELETED

k. NE-02-94-35, Post-fire Safe Shutdown System Impacts

l. FP Flooding calculations: ME-02-02-23, ME-02-02-32, ME-02-02-40, ME-02-02-41, ME-02-02-43

m. HVAC/Room Heatup PFSS Calculations ME-02-99-06, ME-02-99-18, and ME-02-99-22, and CVI 1097-01,1.

n. B&R 2.05.01, Calculation for Battery and Battery Charger 250 V DC and 24 V DC

o. B&R 2.06.20, Calc for Cable Ampacity Verification for Conduit and Tray

p. B&R 7.10.12, Calculation For FP of Instrument Tubing

q. TM-1308, Evaluation of Potential Plant Transients Due to Postulated 10 CFR 50 Appendix R Fire

r. TM-2007, Reactor Building Instrument Rack Fire Hazards Analysis

s. TM-2043, Augmented Quality Requirements

t. TM-2075, Mitigation of Radiological Releases from a Fire

u. TM-2103, Leakage Requirements of Penetration Seals

v. ME-02-89-11, Calculation of Frost Protection of Warehouse Complex Fire Mains

w. ME-02-98-15, Evaluation of Fire Protection System for Water Hammer Effects

x. ME-02-99-05, Fire Protection System Water Hammer Analysis with Vacuum Breakers and Soft Start Electric Pumps

y. E/I-02-01-01, Sizing Calculation for the Plant PBX Telephone System Replacement Battery (VRLA type cells).

z. ENW-CGS-FHA-02, SL-5573, Columbia Generating Station Independent Spent Fuel Storage Installation Fire Hazards Analysis

aa. ENW-CGS-FHA-01, ISFSI Fire Hazards Calculation

bb. CE-02-03-19, ABS Consulting Report 1192510-R-002, "Frequency Estimation of Hydrogen Line and Hydrogen Storage Tank Explosions."

cc. CE-02-03-20, ABS Consulting Report 1192510-C-001, "HSSF Energetic Events Analysis."

dd. TM-1235, Appendix R Dedicated Volume of Water for Fire Protection

ee. TM-2161, Technical Evaluation of High Impedance Faults in Accordance with NEI 00-01 Revision 1

ff. NE-02-13-02, Hazards Analysis – Radio Obsolescence Project

gg. CVI 981-01, 134 "GNF2 Fuel Design Cycle-Independent Analyses for Energy Northwest Columbia Generating Station"

F.7.4 APPLICABLE NRC SAFETY EVALUATION REPORTS

a. NUREG-0892, Safety Evaluation Report Related to the Operation of WPPSS Nuclear Project No. 2, March 1982

b. NUREG-0892, Safety Evaluation Report Related to the Operation of WPPSS Nuclear Project No. 2, Supplement 1, August 1982

c. Fire Protection Supplemental Safety Evaluation Report - WPPSS Nuclear Project No. 2, dated December 27, 1982

d. Fire Protection Supplemental Safety Evaluation Report - WPPSS Nuclear Project No. 2, dated March 17, 1983

e. NUREG 0892, Safety Evaluation Report Related to the Operation of WPPSS Nuclear Project No. 2, Supplement No. 3, May 1983

f. NUREG 0892, Safety Evaluation Report Related to the Operation of WPPSS Nuclear Project No. 2, Supplement No. 4, December 1983

g. Letter GI2-84-100, dated August 24, 1986, Supplemental Safety Evaluation

h. Letter GI2-86-020, dated March 14, 1986, Safety Evaluation Report Washington Nuclear Project No. 2 Appendix R Requirements - Noncompliance

i. Letter GI2-86-0089, R. M. Bernero to D. F. Kirsh, dated December 4, 1986, Evaluation of WNP-2 Fire Protection Analysis, with attached Safety Evaluation Report

j. Letter LI2-87-025, dated November 11, 1987, Fire Protection Safety Evaluation Report - FSAR Amendment No. 37, Washington Nuclear Project Number 2 (WNP-2)

k. Letter GI2-89-042, dated May 12, 1989, Safety Evaluation-Report Input WNP-2: Underground Fire Main Analysis

l. Letter GI2-89-048, dated May 22, 1989, Safety Evaluation by the Office of Nuclear Reactor Regulation, Evaluating Implementing Details of the Approved Fire Protection Program, Washington Public Power Supply System Nuclear Project No. 2

m. Letter GI2-89-051, dated May 25, 1989, Issuance of Amendment No. 67 to Facility Operating License No. NPF-21 - WPPSS Nuclear Project No. 2. [includes new Fire Protection License Condition 2.c.(14)]

F.7.5 OTHER MISCELLANEOUS

a. Letter GO2-82-396, dated April 22, 1982, Subject: Nuclear Plant No. 2 Response to SER on FSAR Section 9.5.1 Fire Protection Program

b. Letter GO2-83-243, dated March 21, 1983, Subject: Fire Protection Safe Shutdown Analysis

c. Letter GO2-86-613, dated June 30, 1986, Subject: Nuclear Plant No. 2, Operating License NPF-21, WNP-2 Fire Protection Program, Request for Additional Information

d. Letter GO2-88-006, dated January 6, 1988, Subject: WNP-2 Fire Protection Reevaluation Status Report

e. Letter GO2-88-008, dated January 11, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report

f. Letter GO2-88-090, dated April 15, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report, Supplemental Information

g. Letter GO2-88-155, dated July 15, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report, Supplemental Information

h. Letter GO2-88-222, dated October 28, 1988, Subject: Nuclear Plant No. 2 Fire Protection and Safety Shutdown Capability, Response to Safety Evaluation Report (Revised Response)

i. Letter GO2-88-256, dated November 30, 1988, Subject: Nuclear Plant No. 2, Operating License NPF-21, Fire Protection Reevaluation Report - Status Report

j. GE Topical Report NEDO-10466-A, Power Generation Control Complex Design Criteria and Safety Evaluation (same as March 1978 NEDO-10466 referenced in SER)

k. DELETED

l. DELETED

m. Design Specification Division 200, Section 209, Post Fire Safe Shutdown (PFSS) Analysis Requirements

n. Engineering Standards Manual EES-1, Cable and Raceway Penetration Schedule (CARPS) Users Manual

o. Engineering Standards Manual EES-5, General Fuse Selection Criteria

p. Design Specification Division 300, Section 306, Fire Protection Detection and Suppression System

q. Penetration Seal Tracking System (PSTS) Database

r. Warnock Hersey International Fire Test File WHI-0495-0799 and 0800, Report of the Fire Endurance and Hose Stream Testing of Fire Rated Door Assembly Installed with Excessive Clearances, WNP-2 QA Vault Reel 502, Location 1-69

s. GE Topical Report, NEDE-24988-P, Analysis of Generic BWR Safety/Relief Valve Operability Test Results, October 1981

t. Electric Power Research Institute (EPRI), Guidelines for Permanent BWR Hydrogen Water Chemistry Installations – 1987 Revision, NP-5283-SR-A, September 1987.

u. INPO OE18226, Test Failure of Meggitt Safety System Inc. Cable, dated March 16, 2006.

F.7.6 FIRE PROTECTION ENGINEERING EVALUATIONS

a. Fire Protection File (FPF) 1.1 Items 13 through 61, Overall Qualification of Penetration Seals

b. FPF 1.1 Item 12, Penetration Seal Fire Test Review Acceptance Criteria

c. FPF 1.1 Item 16, Internal Conduit Sealing Criteria

d. FPF 1.5 Item 2, Consolidation of Fire Areas R-17 and R-19 with Fire Area R-4

e. FPF 1.7 Item 19, Evaluation of WNP-2 Vertical Cable Tray Fire Breaks

f. FPF 1.5 Item 3, Evaluation of Fire Area Boundary Between Fire Area DG-2 and DG-3

g. FPF 1.5 Item 4, Thermo-Lag Coated Wall and Blind Corridor

h. FPF 3.2 Item 3, Emergency Diesel Fuel Flash Point

i. FPF 1.1 Item 56, GL 86-10 Evaluation - Seal R206-5052

j. FPF 1.11 Item 2, Qualification of Whittaker MI Cable as a 3-hr Raceway Fire Barrier

k. FPF 1.2.2 Item 1, Analysis of 3M Fire Barrier Wrap – Conduit 2ADS-32-2

l. FPF 1.12 Item 2, Qualification of Thermo-Lag 330-1 as a Steel Fireproof Coating

m. FPF 1.2.3 Item 2, Qualification of Darmatt KM-1 Raceway Fire Barriers

n. FPF 3.22 Item 2, Thermo-Lag Resolution - Impact of Changes to Fire Area PFSS Divisions

o. FPF 2.1 Item 34, Compliance With NFPA 72E-1974 Smoke Detector Placement

p. FPF 2.6 Item 30, Adequacy of DG Building Heat Collectors and Water Spray Nozzles Remote From Ceiling

q. FPF 1.1 Item 40, Re-Analysis of NRC Information Notice 88-60

r. FPF 2.13 Item 13, Fire Brigade Equipment

s. FPF 2.10 Item 30, Control Room Habitability Smoke Intrusion Analysis

t. FPF 3.2 Item 2, Main Control Room Carpet Addition

u. FPF 4.1 Item 2, Normal Shutdown Manual Action Feasibility Review

v. FPF 3.7 Item 44, Scope of Augmented, OQAPD, and Essential Fire Protection Systems

w. FPF 2.15 Item 1, Reanalysis of Columbia Fire System Surveillance

x. FPF 1.12 Item 24, Fire-Induced Boiling of Fluid in Instrument Tube Sensing Lines

y. FPF 1.13 Item 2, Flexible Steel Conduit/Siltemp Fire Resistance Evaulation

z. FPF 3.6 Item 3, Fire Brigade Trainer Qualifications

aa. FPF 1.12 Item 25, Qualification of Instrument Tube supports

bb. FPF 2.1 Item 50, Fire Alarm Component Test Evaluation

F.7.7 FIRE PROTECTION REFERENCE DRAWINGS

a. FM892-1, Fire Area Boundary Plan - Ground Floor

b. FM892-2, Fire Area Boundary Plan - Mezzanine Floors

c. FM892-3, Fire Area Boundary Plan - Operating Floor

d. FM892-4, Fire Area Boundary Plan - Reactor Building Miscellaneous Elevations

e. FM892-5, Fire Area Boundary Plan - Miscellaneous Floors and Buildings

f. FM892-6, Zones of Limited Combustibles, Reactor Building

g. FM892-7, Fire Suppression System Plan 437', 441'

h. FM892-8, Fire Suppression System Plan 467', 471'

i. FM892-9, Fire Suppression System Plan 501', 525'

j. FM892-10, Fire Suppression System Plan, Reactor Building, Miscellaneous Elevations

k. FM892-11, Fire Suppression System Plan, Miscellaneous, Floors and Buildings

l. M515-1, M515-4, and M515-5, Flow Diagram - Fire Protection System

m. M515-2, Flow Diagram - Fire Protection System - Details

n. M515-3, Flow Diagram - Fire Protection System - CO_2 Distribution

o. E948, Raceway Fire Barrier Location Drawings

p. D-DM-100, Darmatt KM-1 Installation Details

q. PFSS One-Lines and PFSS System P&IDs

r. M932-1 and M932-2, Fire Main Ring Header

F.7.8 FIRE PROTECTION PROGRAM IMPLEMENTING PROCEDURES

a. Site-Wide Procedure (SWP), SWP-FPP-01, Nuclear Fire Protection Program

b. PPM 1.3.10, Plant Fire Protection Program Implementation, includes

1. Emergency response capability (Fire Brigade)
2. Fire response and reporting
3. Surveillance, inspection, and testing
4. Safe shutdown capability
5. Miscellaneous use of fire system water
6. Miscellaneous Fire Protection Requirements
7. B5b Program Responsibilities
8. Fire Loss Prevention
9. Use of Fire PSA

c. PPM 1.3.10A, Control of Ignition Sources

d. PPM 1.3.10B, Active Fire System Operability and Impairment Control

e. PPM 1.3.10C, Control of Transient Combustibles

f. PPM 1.3.57, Barrier Impairment

g. ABN-FIRE, Fire

h. ABN-CR-EVAC, Control Room Evacuation and Remote Cooldown

i. PPM 15 Volume Series Inspection, Test, and Surveillance Procedures

j. Industrial Safety Program Manual, Chapter 10, “Fire Protection and Life Safety”

k. Fire Protection Program Manual

Appendix I

LICENSING REVIEW GROUP ISSUES

TABLE OF CONTENTS

Appendix I

LICENSING REVIEW GROUP ISSUES

TABLE OF CONTENTS (Continued)

Appendix I

LICENSING REVIEW GROUP ISSUES

TABLE OF CONTENTS (Continued)

Appendix I

LICENSING REVIEW GROUP ISSUES

TABLE OF CONTENTS (Continued)

Appendix I

LICENSING REVIEW GROUP ISSUES

LIST OF TABLES

Appendix I

LICENSING REVIEW GROUP ISSUES

LIST OF FIGURES

I.1 INTRODUCTION

The italicized information is historical and was provided to support the application for an operating license.

The Licensing Review Group (LRG) was formed in April 1980 to provide a vehicle for expediting the licensing process for General Electric (GE) boiling water reactors (BWR). The group was made up of six utilities, GE, and the consulting firm of KMC. Membership was at both the executive and technical level.

All applicants were in the near-term operating license (NTOL) stage of the licensing process. The basis of establishing the LRG consisted of the fact that most issues for NTOL BWR plants are identical or very similar. It was felt that this common ground could be used advantageously in the NRC review process. The NRC assigned a Project Licensing Manager to interface with the LRG.

All utilities represented in the LRG are identified below. The plants indicated are ordered chronologically in the licensing process, with LaSalle County-1 being the first for which NRC issued a Safety Evaluation Report (SER).

Plant	*Utility*
LaSalle County-1	*Commonwealth Edison Company*
Zimmer	*Cincinnati Gas and Electric Company*
Shoreham	*Long Island Lighting Company*
Susquehanna-1	*Pennsylvania Power and Light Company*
Fermi-2	*Detroit Edison Company*
Columbia Generating Station	*Energy Northwest*

The LRG worked on a lead plant concept with LaSalle County-1 acting as the lead plant. Subsequent to the issuance of the SER for LaSalle, NRC issued SERs for Zimmer, Shoreham, Susquehanna, and Fermi (refer to References 1 through 5).

Interface with staff from various branches of NRC identified issues for the specific branches. Often, the issues consisted of a question or questions previously developed by NRC. Whenever possible, a common position on the issue was developed which was applicable to all plants. In some cases, however, uniqueness of design or other variables precluded a common position.

Plant unique positions were then developed. This appendix is for Columbia Generating Station, but uses common positions when applicable.

The order of presentation for an issue is as follows: The issue is presented, then the details of the issue follow under the "Question" heading. The response is then given. The numbers in parentheses (e.g., 5.4.4, 6.2) reference the applicable sections in the FSAR. Applicable questions are referenced as appropriate since in many instances the issue was previously addressed in a Columbia Generating Station question response.

References:

1. *U.S. Nuclear Regulatory Commission (NRC), NUREG-0519, "Safety Evaluation Report by the Office of Nuclear Reactor Regulation in the Matter of Commonwealth Edison Company, LaSalle County Station, Units No. 1 and 2," Dockets No. 50-373/374.*

2. *NRC, NUREG-0528, Supplement No. 1, "SER by the Office of Nuclear Reactor Regulation, NRC, in the Matter of Cincinnati Gas and Electric Company, William H. Zimmer Nuclear Power Station, Unit 1," Docket No. 50-358.*

3. *NRC, Office of Nuclear Reactor Regulation, NUREG-0420, "SER Related to the Operations of Shoreham Nuclear Power Station, Unit No. 1, Docket No. 50-322, Long Island Lighting Company," April 1981.*

4. *NRC, Office of Nuclear Reactor Regulation, NUREG-0776, "SER Related Operation of Susquehanna Steam Electric Station, Units 1 and 2, Dockets No. 50-387 and 50-388, Pennsylvania Power and Light Company, Allegheny Electric Cooperative, Inc.," April 1981.*

5. *NRC, Office of Nuclear Reactor Regulation, NUREG-0798, "SER Related to the Operation of Enrico Fermi Atomic Power Plant, Unit No. 2, Docket No. 50-341, Detroit Edison Company et al.," July 1981.*

I.2 CONTAINMENT SYSTEMS BRANCH

ISSUE: CSB-1 STEAM BYPASS OF THE SUPPRESSION POOL (6.2.1.1)

Question:

The applicant approach to suppression pool bypass is not consistent with Branch Technical Position CSB 6-5. The applicant must commit to perform a low power surveillance leakage test of the containment at each refueling outage.

Response:

The response to above stated concern is provided in response to Question 031.070.

ISSUE: CSB-2 POOL DYNAMIC LOCA AND SRV LOADS

Question:

The staff has completed its review of the short-term program and developed acceptance criteria. We require that the applicant commit to our acceptance criteria or justify any exceptions taken.

Response:

NRC acceptance criteria as well as the supplements thereto are being reviewed and adhered to where possible. Where exceptions are taken, such as in the case of SRV load definition (see Reference 1), or chugging load definition (see Reference 2), these exceptions are being discussed and reviewed with the staff.

References:

1. *"SRV Loads - Improved Definition and Application Methodology for Mark II Containments" (submitted in August 1980).*

2. *"Chugging Loads - Revised Definition and Application Methodology for -Mark II Containments" (based on 4TCO Test Results) (submitted in July 1981).*

ISSUE: CSB-3 CONTAINMENT PURGE SYSTEM

Question:

A 2-inch vent line exists in the purge system to bleed off excess primary containment pressure during operation. We require the applicant to evaluate this 2-inch bypass purge system in light of the criteria of Branch Technical Position CSB 6-4.

Response:

The 2-inch bypass valves, used for pressure control during operation, are located in parallel with each purge system exhaust valve. These 2 inch-150# globe valves meet all the design requirements of the containment isolation system. They are designed to the same pressure/temperature ratings of the containment and purge valves and are designed to close within 4 sec against the 45 psig containment design pressure. All four bypass valves can be remotely operated from the control room, are designed to close an F, A, and Z isolation signals and are being operationally qualified against applicable seismic and hydrodynamic loads.

ISSUE: CSB-4 COMBUSTIBLE GAS CONTROL (6.2.5)

DELETED

ISSUE: CSB-5 CONTAINMENT LEAKAGE TESTING

DELETED

I.3 CORE PERFORMANCE BRANCH

ISSUE: CPB-1 LOAD ASSESSMENT OF FUEL ASSEMBLY COMPONENTS

Question:

The proposed addition of Appendix A to SRP 4.2 provides guidance for the analysis of fuel assembly components and acceptance criteria for fuel assembly response to externally applied forces. The applicant's fuel assembly capability should be assessed accordingly.

Response:

General Electric has completed development of fuel assembly loads modeling and results acceptance criteria both deemed to be in accordance with the requirements of Appendix A to SRP 4.2. The LRG lead plant (LaSalle) has been evaluated accordingly with acceptable results, which were forwarded to the NRC June 8, 1981. A similar analysis will be performed for Columbia Generating Station (CGS).

ISSUE: CPB-2 WATERSIDE CORROSION

Question:

The applicant has not addressed the potential for fuel corrosion failure similar to that which occurred at the Vermont Yankee plant.

Response:

As indicated in the General Electric presentation given to the NRC in December 1979, the failures appeared to be associated with a metallic incursion in the feedwater. This event has occurred only once in the BWR operating history and is unlikely to reoccur.

Subsequent to this event, General Electric provided an operation recommendation for corrosion product control which should preclude this type of event at CGS. Energy Northwest plans to employ those General Electric operating recommendations which have been proven to be effective at several operating BWR plants for maintaining water quality parameters at or below GE's water quality specification limits.

References:

1. Letter from R. E. Engel (GE) to M. Tokar (NRC), MFN-172-80, "Corrosion Product Control", dated October 3, 1980.

ISSUE: CPB-3 CHANNEL BOX WEAR

Question:

Provide more detailed and specific information on the Channel Box Wear concern as applicable to the CGS design.

Response:

General Electric observed wear on the water rods in 8 x 8R fuel assemblies in the fall of 1979. In the referenced letter it was concluded that the observed wear does not affect the functionality of the water rods in the bundle or plant safety.

Since the observed wear General Electric has modified the 8 x 8R water rod design. To improve the margin of reliability of the 8 x 8R fuel design, a modification to the water rod and spacer positioning/water rod has been developed. This modified design has shorter water rod and spacer positioning/water rod lower end plugs, and modified expansion springs on the upper end plugs. These changes have been shown to be effective by successful operation of the short shank 8 x 8 fuel design and from extensive flow-induced vibration testing. This modified water rod concept is being installed on new fuel, such as for CGS, as a prudent means of assuring increased margin of fuel reliability. Thus, the modification does not constitute an unreviewed safety question to CGS based on the criteria given in 10 CFR 50.59.

Reference:

1. *Letter, J. S. Charnley (GE) to T. A. Ippolito (NRC), "Water Rod Lower End Plug Inspection Results," dated July 28, 1980.*

ISSUE: CPB-4 FUEL CLADDING, SWELLING, AND RUPTURE MODELS

Question:

The applicant has not provided information to assure that for the fuel cladding in a LOCA "the degree of swelling and incidence of rupture are not underestimated" as required by Appendix K of 10 CFR 50.46. The procedures proposed in NUREG-0630 introduce additional conservatism and should be utilized to perform supplemental calculations to the current ECCS analyses.

Response:

General Electric recently transmitted supplemental calculations to the NRC, "Fuel Swell and Rupture Model - Experimental Data Review and Sensitivity Studies," May 15, 1981. This *document contains a discussion of the first stress and circumferential strain data applicable to the BWR, and presents results from the sensitivity studies performed comparing the NUREG-0630 models with the current GE models.*

Hoop stress versus rupture temperature sensitivity studies were performed using a combination of the two curves (adjusted GE stress curve and NUREG-0630). These studies resulted in a change in PCT of ±10°F. Even though this PCT impact is small, GE proposes to review the current stress model to incorporate the adjusted curve. Implementation of the adjusted curve will be coincidental with implementation of the complete LOCA model improvement package. Also, the document shows that NUREG-0630 perforation strain versus temperature curve is not applicable to BWR fuel and that substitution of a bounding NUREG-0630 curve into the current GE ECCS analysis has negligible effect on the peak clad temperature (PCT). Based on this, it is maintained that the current GE strain model is valid for the BWR and should continue to be used for ECCS calculations at CGS.

Reference:

1. *Letter, R. H. Buchholz (GE) to L. S. Rubenstein (NRC), "General Electric Fuel Clad Swelling and Rupture Model," dated May 15, 1981.*

ISSUE: CPB-5 FISSION GAS RELEASE

Question:

Provide more detailed and specific information on the Fission Gas Release concern as applicable to the CGS design.

Response:

The effects of high burnups and subsequent fission gas release on fuel thermal-mechanical design analyses was addressed in the proprietary General Electric presentation to the NRC on Extended Burnups, March 24, 1981. Burnups to 50 GWd/MT are considered in the stress analyses documented in NEDE-24011-PA. This analysis is applicable to CGS fuel.

ISSUE: CPB-6 STABILITY ANALYSIS

Question:

Please refer to NRC Question 221.009 for this question.

Response:

Please refer to the response to NRC Question 221.009.

ISSUE: CPB-7 CHANNEL BOX DEFLECTION

Question:

The applicant has not referenced General Electric Licensing Topical Report NEDE-21354-P which describes the fuel channel design. Of specific concern is the commitment to control rod driveline friction testing recommended in Section 4.4.2 of NEDE-21354-P.

Response:

To resolve the channel box deflection issue, Energy Northwest has initiated a channel management program for CGS. The elements of this program include:

a. *Compiling complete operating history records for each channel. Data to be collected include channel location, orientation of welded sides, exposure, and control history.*

b. *Compiling complete analytical history records for each channel including fast fluence (>1 MeV) , and flux gradient history.*

c. *Measurement of post-operation channel box deflection.*

Energy Northwest is planning to measure channel box deflection after each refueling outage for selected channels which are discharged to the spent fuel pool. The reuse of discharged channels will be determined based upon these measurements as compared to predetermined criteria. Other items which will be addressed in this program include development of channel manufacturing history data and analytical, predictive capability.

The Channel Management Program has already resulted in some potential improvement in channel operation. Data from Commonwealth Edison measurements which recently became available indicate that major channel bow may be a strong function of channel manufacturing history rather than location of the channel within the core. Their data indicate that prime candidates for channel bow are manufactured from two pieces of stock material not from the same original material batch. Also, Commonwealth Edison channels which experienced major bow, in many cases, were never on the core periphery.

Based on this information, Energy Northwest has identified which of the CGS channels are manufactured from mismatched halves (75 out of 764) and we have set up special plans to *manage the use of these channels to minimize potential channel bow. These measures include taking advantage of core locations which are not adjacent to control blades and, in addition, identification of locations of minimal exposure and fast flux tilt.*

In addition to the above channel management program, Energy Northwest is proposing to take a number of operational actions to monitor channel distortion in the core. Prior to startup after each reload, scram time testing and rod notch testing will be performed. For rods which fail the above test, the pressure test described in NEDE-21534-P (4.4.2) will then be performed.

I.4 INSTRUMENTATION AND CONTROL SYSTEMS BRANCH

ISSUE: ICSB-1 PHYSICAL SEPARATION AND ELECTRICAL ISOLATION (7.1.4, 7.2.3, and 7.6.3)

Question:

In the applicant's design, Class 1E instrumentation do not adhere to adequate separation criteria, have not been qualified, and do not adhere to separation of Class 1E to non-Class 1E instrumentation.

Response:

Columbia Generating Station (CGS) Class 1E instrumentation has been reevaluation to the requirements NUREG-0588, Category II, as described in the Equipment Qualification Report referenced in 3.11. Class 1E instrumentation is adequately separated as described in the response to Question 031.100 and as additionally agreed to in CGS docket letter GO2-81-146, dated June 18, 1981.

ISSUE: ICSB-2 ANTICIPATED TRANSIENT WITHOUT SCRAM (ATWS)

Question:

We require that the applicant agrees to implement plant modifications on a scheduled basis in conformance with the Commission's final resolution of ATWS. In the event that LaSalle starts operation before necessary plant modifications are implemented, we require some interim actions be taken by LaSalle in order to reduce, further, the risk from ATWS events.

The applicant will be required to:

a. Develop emergency procedures to train operators to recognize an ATWS event, including consideration of scram indicators, rod position indicators, flux monitors, vessel level and pressure indicators, relief valve and isolation valve indicators, and containment temperature, pressure, and radiation indicators.

b. Train operators to take action in the event of an ATWS including consideration of immediately manual scramming the reactor by using the manual scram buttons followed by changing rod scram switches to the scram position, stripping the feeder breakers on the reactor protection system power distribution buses, opening the scram discharge volume drain valve, prompt actuation of the *standby liquid control system, and prompt placement of the RHR in the pool cooling mode to reduce the severity of the containment conditions.*

Response:

See the response to RSB-22.

ISSUE: ICSB-3 TEST TECHNIQUES (7.1.4)

Question:

In order to perform routine surveillance testing, it is necessary for the applicant to pull fuses. We consider that this design does not satisfy the requirements of IEEE Standard 279-1971, Paragraphs 4.11 and 4.20.

Response:

The responses to Questions 031.039 and 031.061 address this issue. Part (b) of the response to Question 031.039 is repeated below:

> *"In no instance will it be necessary during testing… to either lift leads or remove fuses."*

ISSUE: ICSB-4 SAFETY SYSTEM SETPOINTS (7.1.4)

Question:

The range of Class 1E system sensors may be exceeded in the worst case combination of setpoint and accuracy.

Response:

a. *All calculated setpoints (taking into account drift) will be within sensor range and will be in accord with Technical Specification Limits.*

b. *Certain setpoints are dependent upon actual plant location or operation (i.e., background radiation) and can only be determined at a later date. If an incompatibility exists with regard to sensor range the instrument will be replaced. This position applies for all instruments where conflicts are detected.*

ISSUE: ICSB-5 DRAWINGS

Question:

The one line drawings and schematics contradict the functional control drawings and system description which are provided in the FSAR. Furthermore, contact utilization charts contradict the actual schematics.

Response:

The contradiction between the drawings and the system descriptions has been eliminated as the result of a major effort spent in rewriting Chapter 7 with this concern in mind. With regard to inconsistencies between the functional control diagrams and schematics, all FSAR drawings and those listed in Chapter 1.7 are updated and distributed every 6 months.

ISSUE: ICSB-6 RCIC CLASSIFICATION

Question:

Refer to Question 031.015 and LRG Issue RSB-6.

Response:

Refer to responses to Question 031.015 and LRG Issue RSB-6.

ISSUE: ICSB-7 SAFETY-RELATED DISPLAY (7.5)

Question:

The design of the safe shutdown indication does not satisfy the requirements of IEEE Standard 279-1971, Paragraph 4.10.

Response:

CGS safety-related display instrumentation will be designed to comply with the requirements of Regulatory Guide 1.97, Revision 2. Section 7.5 has been amended to discuss the degree of conformance for CGS for each indication applicable as described in Regulatory Guide 1.97 and IEEE Standard 279-1971.

ISSUE: ICSB-8 ROD BLOCK MONITOR
(7.6)

Question:

The applicant does not agree that the rod block monitor is a protection system.

Response:

The NRC has conducted an extensive review of the RMCS including refueling interlocks RBM, RWM, RSCS on various dockets. Plants with open items having similar designs will be conformed to the Zimmer design (i.e., the resolution will be reviewed and resolution bases if applicable will be incorporated).

The Zimmer design review has been completed and the issue resolved. This closure basis will be relied upon. CGS system is similar to the design proposed for the Zimmer plant as delineated below:

a. The four flow monitors are interconnected by armored cable and shield cables and there are open spaces around the cables which penetrate fire barriers between redundant channels.

b. Both rod block monitor channels are connected by data buses which are enclosed in a metal shield and run along the top of the cabinet.

c. The wiring of the rod block monitor bypass switch satisfies the CGS separation criteria.

d. The rod block monitor is a modified design and contains multiplexing circuitry which interfaces with the new reactor manual control system.

Items a, b, and c have been verified at CGS site as to their existence. The NRC met with General Electric on Item d. and the staff has approved the current design and transient analysis with the addition of periodic technical specification testing to assure system operability. CGS will include a surveillance requirement in the Technical Specification for the rod block monitor.*

** A GE/NRC generic meeting was held in Bethesda on January 22, 1981 to discuss the new reactor manual control system utilized on most NTOL plants. The NRC has been concerned for many years about the appropriateness of utilizing the RBM (not fully safety grade) in transient mitigation.*

ISSUE: ICSB-9 MSIV LEAKAGE CONTROL SYSTEM

Question:

We identified a single failure to the MSIV leakage control system which could lead to possible failure of the system during testing or operation.

Response:

Please see the revised response to Question 031.076.

I.5 MATERIALS ENGINEERING BRANCH

ISSUE: MTEB-1 PRESERVICE AND INSERVICE INSPECTION OF CLASS 1, 2, AND 3 COMPONENTS PER 10 CFR 50.55a(g)

Question:

Preservice and inservice inspection of Class 1, 2, and 3 components have not been submitted.

Response:

The response to the above stated concern is provided in the response to Question 121.010.

ISSUE: MTEB-2 EXEMPTIONS FROM APPENDIX G AND H TO 10 CFR 50
MTEB-3 (5.1.4) (5.3.2) (5.3.3)

Question:

The Columbia Generating Station (CGS) reactor vessel does not meet the specific requirements of Appendix G and H to 10 CFR 50. Identify and justify your exemptions.

Response:

CGS, as a member of the Licensing Review Group (LRG), has submitted information of fracture toughness and surveillance program requirements to show compliance with Appendix G and H to 10 CFR 50. This submittal (Reference 1) was similar to that which has been approved by the NRC for the preceding LRG members (LaSalle County, Susquehanna, Shoreham, Zimmer, and Fermi-2).

Reference:

1. Letter GO2-81-532, G. D. Bouchey to A. Schwencer, "Appendix G and H Information, Responses to Materials Engineering Branch - Component Integrity Section," dated December 18, 1981.

ISSUE: MTEB-4 REACTOR TESTING AND COOLDOWN LIMITS (5.3)

Question:

Insufficient information has been submitted for us to assess that the methods used to provide stress intensity values, are equivalent to those obtained from Appendix G of ASME Code; clarification and justification of the methods used to construct the operating pressure temperature limits should be provided.

Response:

CGS has provided information to show compliance with the methods of Appendix G of Section III of the ASME Boiler and Pressure Code (Summer 1972 Addenda). Compliance with Appendix G for this vessel is to provide operating limitations on pressure and temperature based on fracture toughness. These operating limits assure that a margin of safety against a nonductile failure of this vessel is the same as that for a vessel built to the Summer 1972 Addenda.

The specific temperature limits for operation when the core is critical are based on an approved modification to 10 CFR 50, Appendix G, Paragraph IV.A.2.c. The approved modification and justification for it is given in GE Licensing Topical Report NEDO-21778-A (Reference 1).

See Reference 1 to MEB-2 and MEB-3.

Reference:

1. Letter to Dr. G. G. Sherwood (GE) from Olan V. Parr (NRC), "Review of General Electric Topical Report, Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors," November 13, 1978 (see GE Transmittal T-1727).

ISSUE: MTEB-5 GENERAL DESIGN CRITERION 51

Question:

The applicant must demonstrate that the primary containment pressure boundary at CGS meets the requirements of General Design Criterion 51 of 10 CFR 50.

<u>Response</u>:

GDC-51 requires that under operating, maintenance, testing, and postulated accident conditions (1) the ferritic materials of the containment pressure boundary behave in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized.

The CGS containment system includes a ferritic steel primary containment vessel and head enclosed by a reinforced concrete shield structure. The ferritic materials of the containment pressure boundary that were considered in the evaluation for compliance to GDC-51 are those that have been applied in the fabrication of the containment vessel and head, equipment hatch, personnel lock, and penetrations and components of the fluid system including valves required to isolate the system. These components are the parts of the containment system that are not backed by concrete and must sustain loads during the performance of the containment function under the conditions cited by GDC-51.

CGS containment pressure boundary is comprised of ASME Code Class I, Class 2, and MC components. Based upon the review performed by the NRC, it was determined that the fracture toughness requirements in ASME Code Editions and Addenda typical of those used in the design of the CGS containment may not ensure compliance with GDC-51 for all areas of the containment pressure boundary. The basis for this decision was that the fracture toughness criteria that had been applied in construction differ in Code classifications and Code Edition and Addenda. Therefore, the Class I, Class 2, and Class MC components of the CGS containment pressure boundary were reviewed according to the fracture toughness requirements of the Summer 1977 Addenda of Section III for Class 2 components and fracture toughness data presented in NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing of PWR Steam Generator and Reactor Coolant Pump Supports."

Based on review of the available fracture toughness data and material fabrication histories, and the use of correlations between metallurgical characteristics and material fracture toughness, it was concluded that the ferritic materials in the CGS containment pressure boundary meet the fracture toughness requirements that are specified for Class 2 components by the 1977 Addenda of Section III of the ASME Code. Compliance with these Code requirements provide reasonable assurance that the CGS reactor containment pressure boundary materials will behave in a non-brittle manner, that the probability of rapidly propagating fracture will be minimized, and that the requirements of GDC-51 are satisfied.

I.6 MECHANICAL ENGINEERING BRANCH

ISSUE: MEB-1 ASYMMETRICAL LOCA AND SSE AND ANNULUS PRESSURIZATION LOADS ON REACTOR VESSEL INTERNALS AND SUPPORTS (3.9.2)

Question:

Document your reevaluation of the safety-related systems and components based upon the load combinations, response combination methodology, and acceptance criteria required by us as presented at our meeting of December 12, 1978. (Reference letter dated September 18, 1978.)

Response:

This issue was discussed at the Mechanical Engineering Branch (MEB) Safety Evaluation Report (SER) meeting held September 29 through October 1, 1981, for Columbia Generating Station (CGS). Load combinations and acceptance criteria are provided in the responses to the MEB SER questions 23 and 25, presented at that meeting (see Table MEB-1-1). Results of the reevaluation will be provided in the New Loads update of 3.9, to be provided in a future amendment.

Table MEB-1-1

Load Combination and Acceptance Criteria for ASME Code Class 1, 2, and 3 NSSS Piping and Equipment

Load Combination	*Design Basis*	*Evaluation Basis*	*(Service Level)*
$N + SRV_{(ALL)}$	Upset	Upset	(B)
$N + OBE$	Upset	Upset	(B)
$N + OBE + SRV_{(ALL)}$	Emergency	Upset	(B)
$N + SSE + SRV_{(ALL)}$	Faulted	Faulted*	(D)
$N + SBA + SRV$	Emergency	Emergency*	(C)
$N + IBA + SRV$	Faulted	Faulted*	(D)
$N + SBA + SRV_{(ADS)}$	Emergency	Emergency*	(C)
$N + SBA + OBE + SRV_{(ADS)}$	Faulted	Faulted*	(D)
$N + IBA + OBE + SRV_{(ADS)}$	Faulted	Faulted*	(D)
$N + SBA/IBA + SSE + SRV_{(ADS)}$	Faulted	Faulted*	(D)
**N + LOCA + SSE	Faulted	Faulted*	(D)

LOAD DEFINITION LEGEND

Normal (N) - *Normal and/or abnormal loads depending on acceptance criteria.*

OBE - *Operational basis earthquake loads.*

SSE - *Safe shutdown earthquake loads.*

SRV - *Safety/relief valve discharge induced loads from two adjacent valves (one valve actuated when adjacent valve is cycling).*

SRV_{ALL} - *The loads induced by actuation of all safety/relief valves which activate within milliseconds of each other (e.g., turbine trip operational transient).*

Table MEB-1-1 (Continued)

SRV_{ADS}	-	*The loads induced by the actuation of safety/relief valves associated with automatic depressurization system which activate within milliseconds of each other during the postulated small or intermediate size pipe rupture.*
LOCA	-	*The loss-of-coolant accident associated with the postulated pipe rupture of large pipes (e.g., main steam, feedwater, recirculation piping).*
$LOCA_1$	-	*Pool swell drag/fallout loads on piping and components located between the main vent discharge outlet and the suppression pool water upper surface.*
$LOCA_2$	-	*Pool swell impact loads on piping and components located above the suppression pool water upper surface.*
$LOCA_3$	-	*Oscillating pressure induced loads on submerged piping and components during condensation oscillations.*
$LOCA_4$	-	*Building motion induced loads from chugging.*
$LOCA_5$	-	*Building motion induced loads from main vent air clearing.*
$LOCA_6$	-	*Vertical and horizontal loads on main vent piping.*
$LOCA_7$	-	*Annulus pressurization loads.*
SBA	-	*The abnormal transients associated with a small break accident.*
IBA	-	*The abnormal transients associated with an intermediate break accident.*

* *All ASME Code Class 1, 2, and 3 piping systems which are required to function for safe shutdown under the postulated events shall meet the requirements of NRC's "Interim Technical Position Function Capability of Passive Components" - by MEB.*

** *The most limiting case combination among $LOCA_1$ through $LOCA_7$.*

ISSUE: MEB-2 PREOPERATIONAL VIBRATION ASSURANCE PROGRAM (3.9.2, 3.9.5)

Question:

Additional information is required concerning the basis for the allowable vibration amplitude derived and clarification of the use of twice this allowable is acceptable.

Response:

This item has been closed by MEB prior to LRG review. It is not documented in lead plant or subsequent plant SERs. For additional information see responses to Questions 110.022, 110.023, and 110.024.

ISSUE: MEB-3 DYNAMIC RESPONSE COMBINATION USING THE SRSS TECHNIQUE

Question:

We are studying the problem of utilizing the square-root-of-the-sum-of-the-squares (SRSS) for determining responses other than LOCA and SSE as you have used. By not utilizing the absolute sum method, the review may be extended if we do not agree that the SRSS methodology is applicable.

Response:

The response to this issue was provided during the Mechanical Engineering Branch meeting for CGS, September 29 through October 1, 1981. (See Attachment 1.)

ATTACHMENT 1

Question No. 26
(3.9.3.1)

The methods of combining responses to all of the loads requested in (a) above is required. Our position in this issue for Mark II plants is outlined in NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses". However, since the primary containment for the CGS plant is a free-standing steel pressure vessel and the plant is in a higher seismic zone, the staff will require that the criteria in Section 4 of NUREG-0484, Revision 1, "Criteria for Combination of Dynamic Responses Other Than Those of SSE and LOCA," be satisfied if the square-root-of-the-sum-of-the-squares method of combining these responses is used. (Reference Regulatory Position E (2) in the enclosure to a letter from J. R. Miller, NRC, to Dr. G. G. Sherwood, GE, "Review of General Electric Topical Report NEDE-24010-P," dated June 19, 1980.) The conclusions of NUREG-0484, Revision 1, are based on the studies performed by GE in NEDE-24010-P and BNL in NUREG/CR-1330. The applicant must demonstrate that an SRSS combination of dynamic responses achieves the 84% nonexceedance probability level because of the difference in containment and seismic level which were not included in the earlier studies.

Response:

When a seismic response from a high seismic input, like that from Hanford, is combined with another dynamic response (e.g., SRV discharge loads), depending on the relative magnitudes of the two responses being combined, the shape of the cumulative distribution function (CDF) of the combined response will change. If the maximum magnitude of one of the responses is very large compared to the other response being combined, the CDF curve will almost be vertical and it is immaterial if these two responses are combined using the SRSS or the Absolute Sum (ABS) rule. However, if the maximum magnitudes of the two responses are about equal, use of SRSS vs. ABS rule to combine the responses will cause significant difference in the combined response. In addition, in this case, the CDF curve will be more like S-shaped with the non-exceedance probability (NEP) of SRSS being close to 84%. In the generic Mark II study, examples from both such cases were considered with more examples from the case with responses of comparable magnitudes. This study showed that all these Mark II cases meet the requirements of NUREG-0484. Hence the GE Topical Report NEDE-24010-P, "Technical Bases for the Use of SRSS Method for Combining Dynamic Loads for Mark II Plants," is also applicable to CGS with high seismic input.

The impact of the free-standing steel primary containment is discussed in the areas as follows:

a. *Vessel and Internals*

   Vessel and internals are not attached to and not affected by the steel containment.

b. *Piping Systems and Floor Mounted Equipment*

   The dynamic input to these components at their containment support locations may be affected by the steel containment response to the dynamic loads under consideration and hence, may be different from that obtained from concrete containment. However, the frequencies contributing to the responses of major structures and components in both types of plants will not be significantly different but will fall into the same general range.

The structural frequencies will only determine the magnitude of amplification or attenuation of the response. For multi-frequency random-type dynamic loads, the components of input loads whose frequencies coincide with the structural natural frequencies will be amplified and these components will dominate the response. Although the predominant response of a particular structural component may vary somewhat in frequency between the concrete and steel containment configuration, the variances are expected to be small for the range of frequencies of interest for major structures because of the similarities in systems, types of structural configurations, construction materials, and massiveness of buildings. Therefore, key characteristics of the responses (duration of strong response motion and number of peaks) are primarily determined by the input component loads to the structure, and because of the similarity of the dynamic nature of the input loads due to earthquake, SRV, and LOCA for both types of containment, their structural responses will have similar dynamic characteristics. Hence, the response of the mechanical components and piping systems supported from the two types of containments will also be similar. Hence, the use of SRSS combinations for combining the dynamic responses for the CGS application will be demonstrated to meet the 84% non-exceedance probability level.

ISSUE: MEB-4 OBE PLUS SRV FATIGUE ANALYSIS

Question:

Clarify your consideration of the cyclic loadings due to the operating basis earthquake (OBE) and safety/relief valve actuation in your NSSS fatigue analysis.

Response:

For the NSSS piping, 50 peak OBE cycles are used. For other NSSS equipment and components, a generic study serves as the basis for 10 peak OBE cycles. As shown in Reference 1, 10 peak OBE cycles can envelope the cumulative fatigue damage of hundreds of less severe earthquake cycles. Section 3.9 of the FSAR was revised to reflect this position.

The methodologies used to evaluate the fatigue effects due to combined SRV and OBE loads are documented in Reference 2. In the fatigue analysis of NSSS equipment, piping, reactor pressure vessel, and RPV internal components, the actual calculated loads due to OBE and SRV are combined to show compliance with upset limits of fatigue.

References:

1. *Letter from R. Artigas to R. Bosnak, "Number of OBE Fatigue Cycles in the BWR NSSS Design," September 17, 1981.*

2. *Letter from R. B. Johnson to R. Bosnak, "GE Position on Fatigue Analysis," June 29, 1981.*

ISSUE: MEB-5 STRESS CORROSION CRACKING OF STAINLESS STEEL COMPONENTS - DESIGN MODIFICATION

Question:

You are requested to review all ASME Code Class 1, 2, and 3 pressure boundary piping, safe ends and fitting material, including weld metal at your facility to determine if the material selection, processing guidelines, or inspection requirements set forth in NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," are satisfied.

Response:

The response to the above stated concern is provided in the response to NUREG-0313, Revision 1, which was submitted to the NRC September 2, 1981, via GO2-81-268, *G. D. Bouchey to A. Schwencer, "Hardship Exemption Request for Implementation of NUREG-0313, Revision 1."*

ISSUE: MEB-6 PUMP AND VALVE OPERABILITY ASSURANCE PROGRAM (3.9.3.2)

Question:

Additional information has been requested regarding your analytical and testing methods for your pump and valve operability assurance program.

Response:

a. *Pumps*

In addition to the tests called for in the FSAR, active safety-related pumps have been analyzed to find the natural frequencies of the pump. When these frequencies were above the ZPA of the seismic floor response spectra, static analyses were performed on the pumps. When the analyses established that the resultant stresses in the pumps were below allowables and the deflections under these loads were less than clearances between moving parts, operability was established. No pumps have been identified which need to have additional testing or analysis to establish operability.

b. *Valves*

In addition to the tests mentioned in the response to Question 110.032, seismic analyses have been and are being performed on the active safety-related valves which were not prototypically tested. The tests, along with the analysis showing clearance at critical points, demonstrate operability under normal plus SSE loading.

Where the analyses do not show clearances, the valves are being retested as part of the requalification program. If the test and/or analyses did not include hydrodynamic loads where applicable, the valves are being retested or reanalyzed using the proper loading as part of the requalification program.

Where valve accelerations resulting from piping analyses are not yet known, the peak acceleration for frequencies over 8 hz on the 0.005 damping floor response spectra is used as input acceleration for valve analysis and testing. The acceptability of this criteria are being established by comparing piping analysis accelerations to these peaks. The test reports, analyses, and requalification *plans were made available and audited by the NRC-SQRT (Seismic Qualification Review Team) and NRC-PVORT (Pump and Valve Operability Review Team) during November 1982.*

ISSUE: MEB-7 BOLTED CONNECTIONS FOR SUPPORTS (3.9.3)

Question:

You have not provided the allowable limits for buckling for the reactor vessel support skirt subjected to faulted conditions. In addition, we requested information concerning the design of support bolts and bolted connections.

Response:

The responses to Questions 24 (Attachment 1) and 42 (Attachment 2) from the CGS draft SER respond to this issue.

ATTACHMENT 1

Question No. 24
(3.9.3.1)

Several references are made in Table 3.9.2(a) through 3.9.2(ac) to allowable stresses for bolting. Specifically, what loading combinations and allowable stress limits are used for bolting for (a) equipment anchorage, (b) component supports, and (c) flange connections. Where are these limits defined?

Response:

a. Floor Mounted Equipment

1. Equipment Anchorage Bolting

The floor anchored mechanical equipment (pumps, heat exchangers, and RCIC turbine) in GE's scope of supply are mounted on a concrete floor or a steel structure. The design of concrete anchor bolts for the equipment mounted on concrete floor, and the responsibility to prescribe and meet the necessary codes and stress limits are in the AE's scope of supply. The design of attachment bolts for the equipment mounted on steel structure, and the responsibility to prescribe and meet the necessary codes and stress limits are also in the AE's scope of supply. GE works with the interface limit of 10,000 psi in tension or shear for the only purpose of sizing bolt holes in the equipment base, based on the required nominal size and number of bolts for maximum loads.

2. Component Support Bolting

(a) RWCU Pump

The support bolting of this non-safety essential pump is designed for the effects of pipe load and SSE load to the requirements of the ASME code, Section III, Appendix XVII. The stress limits of 0.41Sy for tension and 0.15Sy for shear are used.

(b) RCIC Turbine

The pump-to-base plate bolting is designed as follows:

(1) Normal Plus Upset

a) Primary membrane:

1.0S

b) Primary membrane plus bending:

1.5S, where S is the allowable stress limit per the ASME Code Section III, Appendix I, Table 1-7.3.

(2) Emergency or Faulted

Stresses shall be less than 1.2 times the allowable limits for "Normal plus Upset" given above.

(c) Flanged Connection Bolting

There are no flange type connections in component supports.

b. Piping Supports and Pipe Mounted Equipment (Valves and Pump) Supports

The supports are hanger and snubber type (including clamps) linear standard components as defined by the ASME Code Section III, Subsection NF. The bolts used in these supports meet criteria of NF-3280 for Service Levels A and B and NF-3230 for Service Levels C and D. (Note: NF-3280 is applicable to bolting for Service Levels A and B. NF-3230 is applicable to linear supports; it refers to Appendix VII which is applicable to bolting for Service Levels C and D.)

ATTACHMENT 2

Question No. 42
(3.9.3.4)

The applicant's response to NRC Question 110.029 is not completely acceptable. Paragraph 3.9.3.4 implies that the reactor vessel support skirt was designed to an allowable compressive load of 0.8 material yield stress. It is not clear how the applicant's design would meet the staff's acceptable allowable load of two-thirds of critical buckling load. In addition, the applicant has assumed the critical buckling stress as the material yield stress at temperature. Provide basis for this assumption.

Response:

This issue was addressed and approved by the NRC on the Susquehanna DSER docket.

Refer to the response to Susquehanna DSER 3.9.3-6. A similar response is provided as follows:

Per GE design specification, the permissible compressive load on the reactor vessel support skirt cylinder (plate and shell type component support) was limited to 90% of the load which produces yield stress, divided by the safety factor for the condition being evaluated. The effects of fabrication and operational eccentricity was included. The safety factor for faulted conditions was 1.125.

An analysis of reactor pressure vessel support skirt buckling for faulted conditions shows that the support skirt has the capability to meet ASME Code Section III, Paragraph F-1370(c) faulted condition limits of 0.67 times the critical buckling strength of the support at temperature assuming that the critical buckling stress limit corresponds to the material yield stress at temperature. The faulted condition analyzed included the compressive loads due to the design basis maximum earthquake, the overturning moments and shears due to the jet reaction load resulting from a severed pipe, and the compressive effects on the support skirt due to the thermal and pressure expansion of the reactor vessel. The expected maximum earthquake loads for the Hanford 2 reactor vessel support skirt are less than 50% of the maximum design basis loads used in the buckling analysis described; therefore, the expected faulted loads are well below the critical buckling limits of Paragraph F-1370(c) for this reactor vessel support skirt. The expected earthquake loads for this reactor were determined using the seismic dynamic analysis methods described in Section 3.7.

Based on currently defined faulted condition loads including annulus pressurization and SSE loads, the maximum compressive stress in the support skirt for axial and bending loads is less than the upset condition allowables determined by the methods of NB-3133.6 of the ASME Code. This assures satisfactory margin against buckling for the faulted condition loads.

ISSUE: MEB-8 PUMP AND VALVE INSERVICE TEST PER 10 CFR 50.55a(g)

Question:

You have not submitted your proposed program for the inservice testing of pumps and valves as required by 10 CFR 50.55a(g).

Response:

The CGS pump and valve inservice test program plant was submitted to the NRC via letter GO2-81-322, G. D. Bouchey to A. Schwencer, "Pump and Valve Test Program Plan," dated October 1, 1981.

ISSUE: MEB-9 REVIEW OF IN SITU TEST PROGRAM OF THE SAFETY/RELIEF VALVE

Question:

No specific question identified for this issue.

Response:

Extensive in-plant SRV actuation test programs have been implemented at Caorso (Italy) and Tokai-2 (Japan), two BWR plants with Mark II containment configuration and equipped with x-quenchers of a design essentially identical to those used in CGS. Test results from the above programs, which are available to the NRC, have been used to develop an improved SRV discharge load definition for specific application to CGS (see Report, "SRV Loads, Improved Definition for Mark II Containments, Proprietary Section") and to confirm that the difference between bulk pool temperature and local pool temperature at the quencher discharge is within the value assumed in the suppression pool temperature transient analysis for CGS. As stated in Reference 3, implementation of additional SRV tests to measure or confirm the adequacy of the SRV load definition is unnecessary, but an in-plant test to measure local to bulk pool temperature difference will be performed.

References:

1. *Letter GO2-80-172, D. L. Renberger to B. J. Youngblood, "Submittal of SRV Report," dated August 8, 1980.*

2. *Letter, J. J. Verderber to B. J. Youngblood, "Submittal of Proprietary SRV Report," dated August 27, 1980.*

3. Letter GO2-81-524, G. D. Bouchey to A. Schwencer, "Suppression Pool Temperature Transient Analysis and In-Plant SRV Test," dated December 15, 1981.

ISSUE: MEB-10 CRACKING OF JET PUMP HOLD-DOWN BEAMS

Question:

Additional information is required concerning the actions being taken by the licensee to preclude cracking of the jet pump hold-down beams.

Response:

As discussed in response to IE Bulletin 80-07, CGS will comply with the GE generic resolution. Since the jet pump hold-down beams have already been installed, CGS will reduce the beam preload from 30 kips to 25 kips which is expected to increase beam operating time to crack initiation at the 2.5% probability level to a range of 19 to 40 years. Also, during operation, periodic inspections will be conducted as part of our overall in-service inspection program. Inspection frequencies will be developed in the future based on lead plant inspection results and the results of future testing at General Electric. (See Reference 1.)

References:

1. Letter, G. D. Bouchey to R. L. Tedesco, GO2-80-279, "Cracking of BWR Jet Pump Hold Down Beams," dated December 4, 1980.

ISSUE: MEB-11 CONTROL ROD DRIVE RETURN LINE

Question:

We have not completed our review of GE Topical Report NEDE-21821-2A addressing reactor feedwater nozzle/sparger design modification for cracks nor have we completed GE's generic modification to the control rod drive return nozzle. This may require additional request for information.

Response:

Energy Northwest's response to NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Line Nozzle Cracking," has been completed. The current status of our position on the CRD cracking problem is as follows:

a. CRD return line has been cut and capped as allowed by NUREG-0619, page 31.

b. CRD return line has been rerouted through redundant equalizing valves to the exhaust water header.

c. The control rod drive preoperational test will demonstrate that the system is fully operational and that all components including the hydraulic drive mechanisms, pumps, and flow control valves function properly. The CRD system will be configured with the modifications noted in the NRC concern.

d. In order to assure satisfactory system operation with the single failure of an equalizing valve, the proposed design modification will include the addition of two equalizing valves installed in a parallel configuration. The failure of either valve will not impair CRD operation for any foreseen operating or accident condition.

e. There will be no increased potential for carbon steel corrosion products to be deposited in the drives. All lines in the CGS hydraulic system after the drive water filters are made of stainless steel.

f. The NRC requested GE by letter of January 28, 1980, to recalculate the makeup flow capacity for the 251-inch BWR-5 without the CRD return line. This generic information has been provided by letter of May 2, 1980, from R. L. Gridley, GE, to D. G. Eisenhut, NRC, concurrently with this docketed response for LaSalle. The results indicate that the 251-inch BWR-5 CRD system without a return line (capped Nozzle 10) can achieve a vessel makeup flow in excess of its calculated boiloff rate of 180 gpm. This confirms the same boiloff rate as previously documented in a March 14, 1979, submittal from GE. Furthermore, since the CRD system is not designed to perform an ECCS function, the additional testing to demonstrate the required return flow capacity to the vessel is not warranted.

ISSUE: MEB-12 CONFIRMATORY PIPING ANALYSIS

Question:

This item is comprised of two issues:

a. The NRC requires piping system data for the purpose of running confirmatory stress calculations to assure compliance with IE Bulletin 79-14.b.

b. *Documentation of the preoperational vibration test program for all ASME, Section III, Class 1, 2, and 3 high energy piping systems and all Seismic Category I portions of moderate and high energy piping systems.*

<u>Response</u>:

a. *A summary of CGS inspection program and the design control measures utilized to assure an adequate design for the Seismic Category I piping systems are contained in a letter from D. L. Renberger to R. H. Engelken," WPPSS Nuclear Project No. 2, IE Bulletin 79-14," dated September 7, 1979 (Reference 1). Presently, CGS has an established program to develop as-built drawings documenting the final configuration of the piping systems together with their supports. The preparation of the as-built drawings is currently underway and these as-built drawings will provide the basis for the final design assessment of the piping systems. However, in order for NRC to proceed with the confirmatory piping analysis and to verify the compliance of the design data with the as-built configuration, Reference 3 provided the necessary piping design data as requested in Reference 2.*

b. *The preoperational/startup piping vibration program includes all Class 1, 2, and 3 high energy piping systems inside Seismic Category I structures or those portions of high energy systems whose failures could adversely affect the functioning of safety-related structures, systems, or components. The program also includes all Seismic Category I portions of moderate energy piping systems outside containment.*

All systems contained in the preoperational/startup vibration program, as documented in Section 14.2, are operated at rated flow and the piping system is either visually inspected or monitored for steady state vibration by remote readout transducers. If during this initial system operation visual observation indicated that piping vibration is significant, measurements are made with a hand-held vibrograph. The results will then be reviewed by the appropriate engineering group to determine the acceptability of the measured vibration values. For the main steam, recirculation, feedwater, RCIC,and SRV discharging piping, the measured vibration is compared against test acceptance criteria. The results are also reviewed by the responsible piping design organization to confirm proper system performance. Documentation of the test results and engineering evaluation performed on them becomes a part of the Startup Test Program files. A summary report is generated and would be available for NRC review following commercial operation.

<u>References:</u>

1. *Letter from D. L. Renberger to R. H. Engelken, "WPPSS Nuclear Project No. 2, IE Bulletin 79-14," dated September 7, 1979, GO2-79-156.*

2. *Letter from R. L. Tedesco to R. L. Ferguson, "Confirmatory Piping Analysis for WNP-2," dated June 22, 1981.*

3. *Letter G. D. Bouchey to L. J. Auge (Manager, Energy Technology Center), dated September 9, 1981, GO2-81-279.*

I.7 POWER SYSTEMS BRANCH

ISSUE: PSB-1 LOW OR DEGRADED GRID VOLTAGE

Question:

The electrical system does not meet our requirements for protection under low or degraded voltage conditions.

Response:

NRC requirements for protection under low or degraded voltage conditions are detailed in Question 040.036 which references revised 8.3.1.1.1 and 8.3.1.2.4.3.

ISSUE: PSB-2 TEST RESULTS FOR THE DIESEL GENERATORS (8.3.2)

Question:

Test results for the diesel generators to indicate margin have not been submitted.

Response:

PSB-2 identifies two margin tests to be accomplished during the preoperational testing of the diesels. The first, a "steady-state margin test," involves loading the unit in excess of the total design accident loads to demonstrate some margin over the total design requirements. The other test, a "start-load margin test," involves applying a step function load in excess of the largest motor to demonstrate the start-load capability of the set with some margin.

Preoperational testing of Columbia Generating Station (CGS) emergency diesels will include subjecting the diesels to 100% rated load as well as loading the units to their two-hour rating, both of which are larger than the combined design accident loads.

During the loss of power tests, occurring during the preoperational testing phase, a test will be made to demonstrate the start-load capability of the units over that which is required. This test involves loading the diesel generator to 100% design load and dropping the largest motor on the associated bus. This motor will then be restarted. This test demonstrates the diesel generator unit has the capability to start the largest motor on its respective bus while concurrently feeding the rest of the bus loads and still remain within the voltage and frequency requirements of Regulatory Guide 1.9.

The HPCS diesel generator will not be required to fulfill the requirements of Regulatory Guide 1.9, with respect to the voltage and frequency drop, during this particular test as clarified in 8.3.1.2.1.4. Preoperational test results will be available for NRC review during the normal inspection enforcement period.

ISSUE: PSB-3 CONTAINMENT ELECTRICAL PENETRATIONS

Question:

The reactor electrical penetrations do not conform to Regulatory Guide 1.63 and test results do not demonstrate that the electrical penetrations can maintain their integrity for maximum fault current.

Response:

NRC concerns regarding electrical penetration capability under maximum fault (short circuit) conditions are expressed in LaSalle FSAR Question 040.106. That question addresses the effect upon containment integrity of fault current i^2t, assuming failure of the circuit primary protective overcurrent device.

LaSalle's response took credit for the fusing properties of cable external to the penetration conductors to provide overcurrent protection backup to the primary overcurrent device. The response reflected a common Licensing Review Group (LRG) position.

The LaSalle SER rejects the LRG position, advising that credit cannot be given for assumed equipment failure (cable fusing). It mandates that fault current protection devices (circuit breakers and/or fuses) to backup the primary over-current protective devices be provided as required to limit fault current surges to levels less than those for which the penetrations are qualified.

NRC concerns in this area are addressed to CGS in Questions 040.031 and 040.035. These questions were not as explicit regarding the NRC concern as was the question addressed to LaSalle. The CGS response to Question 040.035 predated much of the NRC/LaSalle dialogue and requires revision.

The original response to Question 040.034 provided data indicating the capability of penetration primary overcurrent protective devices to clear faults before penetration i^2t capability is exceeded.

Additional analysis has been performed to determine the maximum i^2t available at electrical penetrations for the case of failure of the circuit primary protective devices to function, which requires the backup overcurrent protective device to clear the fault. Where the analysis *demonstrates that penetration i^2t capability is exceeded, a second overcurrent protective device has been added in series with the circuit primary overcurrent protective device.*

The responses to Question 040.034 and 040.035 have been revised to reflect the results of this analysis.

ISSUE: PSB-4 ADEQUACY OF THE 120 V AC RPS POWER SUPPLY (8.3.1.1.6)

Question:

The applicant committed to the generic resolution, or to expedite their license, will commit to the surveillance requirements which were applied to Hatch-2.

Response:

Energy Northwest is committed to implement, prior to fuel loading, the RPS MG set design modification developed by General Electric for generic application. The FSAR has been revised to reflect the design modification.

ISSUE: PSB-5 THERMAL OVERLOAD MARGIN

Question:

We require the applicant to provide the detailed analysis and/or criteria which was used to select setpoints for the thermal overload protection devices for valve motors in safety systems and the details as to how these devices will be tested.

Response:

Motor thermal overloads for Class 1E motor-operated valves (MOVs) are chosen two sizes larger than those which would be required based upon normal full load running current. The resultant overload protection (approximately 140% of motor full load current) permits MOVs to operate for extended periods of time at moderate overloads; tripping occurs just prior to motor damage.

Class 1E motor control centers are located in environmentally controlled rooms such that overload ambient temperature variation is not a significant factor.

Initial testing of overload heaters serving safety-related MOVs is performed by Energy Northwest during the Test and Startup Program. This testing is accomplished by injecting a *test current through the overload device, thus, simulating an overcurrent of the motor operator and verifying that the device stops valve travel by deenergizing the motor starter and/or alarms at the appropriate alarm panel, as applicable. Acceptance criteria for these tests are derived by manufacturers' curves for the devices or applicable codes and standards where available.*

Periodic surveillance testing of thermal overloads serving safety-related MOVs will be in accordance with the CGS technical specifications. A representative sample of at least 25% will be tested at least once per 18 months, such that all will be tested once per six years. The test itself will be essentially the same as that described above.

ISSUE: PSB-6 RELIABILITY OF DIESEL GENERATOR

Question:

No specific question identified for this issue.

Response:

The reliability of starting and accepting design load in the required time was fully demonstrated for the Div. 1 and Div. 2 D-Gs by the successful completion of the 300 Start Qualification Test performed on D-G Unit 1 in accordance with NRC BTP-EICSB-2 prior to shipment. The reliability of the HPCS D-G has been verified by a prototype test on an eventually identical unit. See Reference 4.

In response to other concerns on the reliability of all the D-G units, see the responses to, Questions 040.080 through 040.089.

The HPCS D-G (Div. 3) has been given preoperational tests to demonstrate the reliability of starting and accepting design load in the required time, and that the system has adequate margin in all respects, such as starting time, accelerating time, engine torque, and long-term carrying capability.

The 300 Start Qualification Test Report for D-G Unit 1 is available for the NRC's review at the plant site. See Reference 2.

The HPCS D-G (Div. 3) Site Preoperational Test Report is available to the NRC for review at the plant site. See Reference 3.

References:

1. NRC Branch Technical Position EICSB-2

2. *Prototype 300 Start Qualification Test Report, B&R File No. 53-00-7014 and 53-00-7015.*

3. *HPCS D-G Acceptance Test, PT-7.2-A*

4. *GE Document No. NEDO-10905-3, Licensing Topical Report-High-Pressure Core Spray System Power Supply Unit.*

ISSUE: PSB-7 PERIODIC DIESEL GENERATOR TESTING

Question:

Diesel generator testing once every 18 months is required by Regulatory Guide 1.108.

Response:

The Technical Specifications for CGS comply with Regulatory Guide 1.108 requirements for testing the diesel generators on 18-month intervals. In addition, a test has been included to verify that after an interruption of onsite power the loads are shed from the emergency buses and that subsequent loading of the onsite sources is through the load sequencer. See the response to Question 040.037.

I.8 REACTOR SYSTEMS BRANCH

ISSUE: RSB-1 INTERNALLY GENERATED MISSILES
(3.5.1)

Question:

The applicant has not supplied the information to show that all safety-related systems and components within the containment, including the containment, are protected from missiles.

With regard to missiles sizes of concern, what is the valve size below which, if failure should occur in a high pressure system, damage to other components within the primary containment would not be significant? State criteria used to determine this size. Identify all valves in the primary containment larger than this size and identify the missile protection provided for each valve (either physical location or barrier).

Response

All safety-related systems and components at Columbia Generating Station (CGS) are protected from credible plant. A response identifying criteria and methodology and the final results for inside and outside containment in the third quarter of 1982 (letter no. GO2-82-672).

Valve parts are not postulated as credible missile sources if double retention features exist or bonnet bolting is shown to have high margins of safety. All valves in our plant were evaluated on this basis and it was concluded that valves are not credible missile sources.

ISSUE: RSB-2 CONTROL ROD SYSTEM
(4.6.2)

Question:

As a result of eliminating the control rod drive system return line, we are reviewing generically with regard to the impact on control rod drive system performance. Consequently, we require the applicant to submit system performance data directly applicable to CGS and will require the applicant to conform to the conclusion of the generic study as applicable to CGS.

Response:

See the response to MEB-11.

See also the revised response to Question 211.019.

References:

1. *Letter, G. G. Sherwood (GE) to E. G. Case (NRC), "Control Rod Drive (CRD) Return Line Removal," dated January 27, 1978.*

2. *Letters, G. G. Sherwood (GE) to V. Stello (NRC) and R. J. Mattson (NRC), "Control Rod Drive (CRD) Return Line Removal," dated July 14, 1978.*

3. *Letters, G. G. Sherwood (GE) to V. Stello (NRC) and R. J. Mattson (NRC), "Control Rod Drive (CRD) Return Line Removal," dated February 22, 1979.*

ISSUE: RSB-3 SAFETY/RELIEF VALVES
(5.2.2 and 6.3.2)

Question:

Additional information is required both for qualification test and operating experience with the applicant's safety/relief valves.

Response:

The response to the above stated concern is provided in the revised response to Question 211.051. Also refer to response to Question 211.209.

ISSUE: RSB-4 TRIP OF RECIRCULATION PUMPS TO MITIGATE ATWS
(5.2.2)

Question:

We require reperformance of the overpressure analysis to consider the effect of the ATWS RPT.

Response:

Section 5.2.2 was revised as part of the ODYN analysis which has been submitted to the NRC.

This section incorporates the confirmatory analysis of the overpressure protection report including the ATWS recirculation pump trip. Also see revised response 15.8 and response to Question 211.049.

ISSUE: RSB-5 DETECTION OF INTERSYSTEM LEAKAGE (5.2.5)

Question:

We requested that the applicant show how it intends to detect leakage from the reactor coolant systems into both the low pressure coolant injection (3 trains) and low pressure core spray systems as required by Regulatory Guide 1.45.

Response:

Intersystem leakage will be detected by pressure instrumentation with control room readout in accordance with Regulatory Guide 1.45. The response to CGS FSAR Question 211.009 provides information on this issue.

ISSUE: RSB-6 REACTOR CORE ISOLATION COOLING PUMP SUCTION

Question:

The applicant must supply further information to determine whether the RCIC pump suction has to be automatically switched from the condensate storage tank to the suppression pool in the event of a safe shutdown earthquake and concomitant failure of the condensate storage tank.

Response:

As stated in the response to Question 211.046, an automatic safety-grade switchover to a Seismic Category I supply (suppression pool) has been provided. A description of the automatic switchover has been provided in the response to Question 211.146.

ISSUE: RSB-7 SHUTDOWN UNINTENTIONALLY OF THE REACTOR CORE ISOLATION COOLING SYSTEM

Question:

Show how the design of the RCIC protection system prevents unintentional shutdown of the system, when the system is required, because of spurious ambient temperature signals from areas in and around the system (especially in the RCIC pump room)

Response:

See the revised response to Question 211.010.

ISSUE: RSB-8 RHR ALTERNATE SHUTDOWN DEMONSTRATION

Question:

The applicant must perform tests to show that flow through the safety/relief valves is adequate to provide the necessary fluid relief required consistent with the analyses reported in Section 15.2.9 of the FSAR.

Response:

Refer to the revised response to Question 211.025. Also, NUREG-O737, Item II D.1 is related to Issue RSB-8. A discussion on NUREG-O737 items is contained in Appendix B.

ISSUE: RSB-9 CATEGORIZATION OF VALVES WHICH ISOLATE RHR FROM REACTOR COOLANT SYSTEM (5.4.2)

Question:

We require that the valves which serve to isolate the residual heat removal system from the reactor coolant system be classified Category A/C in accordance with the provisions of Section XI of the ASME code.

Response:

Please refer to RSB-13.

ISSUE: RSB-10 AVAILABLE NET POSITIVE SUCTION HEAD

Question:

The applicant must verify that the suction lines in the suppression pool leading to the ECCS pumps are designed to preclude adverse vortex formation and air injection which could effect pumps performance.

Response:

All ECCS suction lines in the suppression pool have been designed with large diameter piping (24 inches) to reduce inlet velocity. In the worst conceivable case, where there is a leak from an ECCS pump suction line into the largest of the ECCS pump rooms, the water level in the suppression pool is calculated to equalize at elevation 455'-9". In the calculation, no credit is taken for makeup to the suppression pool nor for pumping water leaking into the affected room/ suppression pool. The RCIC pump suction is an 8-inch pipe. The submergence of the top edge of the suction piping with suppression pool water level at 455 ft-9 in. is as follows:

		Penetrations	Depth (C.L.)	Submergence
RHR Loop	"A"	(X-35)	447'-0"	7.8'
	"B"	(X-32)	447'-0"	7.8'
	"C"	(X-36)	447'-7"	7.2'
LPCS		(X-34)	447'-7"	7.2'
HPCS		(X-31)	438'-9"	16.0'
RCIC		(X-33)	452'-0"	3.4'

The minimum depth at which vortex formation at the suction inlets will be prevented is:

	Flow Rate (max)	Velocity	Submergence
RHR	8000 gpm	5.674 fps	2.41'
LPCS	7800 gpm	5.533 fps	2.35'
HPCS	7175 gpm	5.089 fps	2.16'
RCIC	600 gpm	3.295 fps	0.84'

The RCIC pump suction will have 2.5 ft of submergence. The inlet to each of the ECCS lines is at least 5 ft deeper than required to preclude vortexing, and therefore, vortex formation is not considered a problem.

See also the response to Question 211.062 for further information.

ISSUE: RSB-11 ASSURANCE OF FILLED ECCS LINE (6.3.2)

Question:

Instrumentation is not sufficiently sensitive to detect voids at the top of ECCS pipe lines. The applicant must provide adequate instrumentation to assure filled ECCS lines.

Response:

Filled ECCS lines are assured by:

a. *Jockey pump system on same division as system being filled,*
b. *Pressure switch on pump discharge with control room annunciation,*
c. *Technical Specification surveillance - upon high point vents to check for air.*

See also the response to Question 211.079 for additional information.

ISSUE: RSB-12 OPERABILITY OF ADS

Question:

Show that the air supply to the ADS is sufficient for the extended operating time required and is assured by reliability data that the ADS will function as required.

Response:

Safety-related backup to the CIA system is provided by redundant, independent nitrogen gas bottle banks. Upon loss of CIA, the system will be automatically isolated as the backup nitrogen supply is automatically fed into the system. The nitrogen bottle supply is sized for a 30-day supply to the seven ADS valves. The nitrogen supply can farther be backed up by a portable auxiliary nitrogen supply (if necessary) which can be connected outside the reactor building. Please refer to Section 9.3.1.2.2 and the responses to Questions 031.121 and 211.048.

ISSUE: RSB-13 LEAKAGE RATE TESTING OF VALVES USED TO ISOLATE REACTOR COOLANT SYSTEM (5.3.2)

DELETED

ISSUE: RSB-14 OPERABILITY OF ECCS PUMPS (6.3.2)

Question:

The applicant must provide assurance that the ECCS pumps can function for an extended time (maintenance free) under the most limiting post-LOCA conditions.

Response:

This issue has been closed on Zimmer, Shoreham, and LaSalle dockets on the basis of information presented in response to NRC questions. Similar information has been provided on the rest of the dockets. The response to CGS Question 211.072 has been revised to include the latest information available.

NUREG-0737 Task II.B.2 is related to the issue discussed above and is addressed in Appendix B of the FSAR. The shielding evaluation referred to in Appendix B will show that the ECCS pumps will operate for the accident duration (assumed to be six months), using the source terms from II.B.2.

ISSUE: RSB-15 ADDITIONAL LOCA BREAK SPECTRUM (6.3)

Question:

The staff does not concur that the Zimmer LOCA analysis is an appropriate break spectrum for CGS because of: 1) higher power level in CGS, 2) different fuel assembly design in CGS, and 3) higher PCTs predicted for CGS.

The staff requires that the applicant provide the following LOCA analyses to complete the break spectrum:

- *a. One additional recirculation line break with a C_D coefficient 0.6 times the DBA, using the large break model analysis.*
- *b. One additional recirculation line break (0.02 ft^2) using the small break model analysis.*

Response:

This issue has been closed on the LaSalle docket on the basis of information presented in response to NRC questions. Similar information has been provided in the revised response to CGS FSAR Question 211.068.

ISSUE: RSB-16 LOCA ANALYSIS
(6.3.4)

Question:

You have analyzed the effect on the DBA-LOCA of instantaneous closure of the flow control valve (FCV) in the unbroken loops. This overly conservative result indicated an increase in peak clad temperature (PCT) of 300°F which, if added to the DBA-L0CA PCT, would be in excess of the maximum PCT criterion of 10 CFR 50.46.

Response:

The response to this issue was provided in Amendment No. 11 as a response to Question 211.083. The response to this question is summarized and expanded upon below.

FCV closure in the unbroken loop is not expected to occur during the LOCA event. However, even if the FCV were signaled to close for some unlikely reason (LOCA plus two failures: failure of drywell high pressure signal such that FCV lockup does not occur, and failure of FCV controls), backup electronic velocity-limiters are included in the recirculation control system to limit FCV velocity to 10 ± 1% actuator stroke rate. Additional multiple specific component failures in these limiters must occur to cause full closure of the FCV at velocities in excess of this value. The combined probability of occurrence of these specific failure modes during LOCA is less than 10^{-6} per year. Accordingly, the electronically limited rate of 10 ± 1% of FCV actuator stroke/rate is considered a realistic yet conservative closure rate.

Using approved standard licensing models, ECCS analyses were performed to determine the effect (sensitivity) on peak cladding temperature from FCV closure at the 11% per second rate. The calculated maximum peak temperature increase was ≤45°F for CGS. This contrasts markedly with the approximate 300°F rise in cladding temperature associated with an arbitrary assumption of instant closure of the FCV, as was cited on another BWR/5 docket.

Thus, the peak cladding temperature effect is concluded to be very small. The probability of FCV fast closure simultaneously with a LOCA is extremely remote. Accordingly, fast FCV closure in conjunction with the DBA-LOCA is not expected to occur and need not be compared to the maximum PCT criterion of 10 CFR 50.46.

ISSUE: RSB-17 OPERATOR ACTION, ANALYSIS OF CRACK IN THE RHR LINE (6.3.4)

Question:

Provide the following information related to pipe breaks or leaks in high or moderate energy lines outside containment associated with the RHR system when the plant is in a shutdown cooling mode.

a. Provide the discharge rate from pipe breaks for the systems outside containment used to maintain core cooling. This valve should be consistent with the requirements of SRP 3.6.1 and BTP APCSB 3-1.

b. Determine the time frame available for recovery based on these discharge rates and their effect on core cooling.

c. Describe the alarms available to alert the operator to the event, the recovery procedures to be utilized by the operator, and the time available for operator action.

A single failure criterion consistent with SRP 3.6.1 and BTP ABCSB 3-1 should be applied in the evaluation of the recovery procedures utilized.

Response:

a. The RHR system is a low pressure system, and all of the piping outside of the primary coolant pressure boundary is classified as "moderate energy" piping and, according to the NRC standards cited, only cracks (i.e., not breaks) are considered in moderate energy piping. Reactor vessel pressure must be decreased to below 135 psig before the RHR system can be connected to the reactor vessel. The largest suction pipe is 24 in. Schedule 40 pipe. A crack in this pipe corresponding to the maximum crack size would produce a flow rate of 1443 gpm, with no allowance for flow reduction due to two-phase flow. This is the maximum possible in any RHR system pipe. A crack of this magnitude would be detected by the leak detection system or area radiation detectors and sump alarms. Isolation of the reactor would occur by operator action, or automatically from the leak detection system or from the reactor protection system on Level 3 reactor water level.

b. If a break should occur in one RHR shutdown cooling loop outside the containment during shutdown, the following action is taken upon detection and isolation. The main steam isolation valves will be reopened and reactor excess *steam will blow down to the main condenser until the shutdown cooling process via the other RHR loop is established. Time: less than 1 hour.*

The redundant shutdown cooling loop components are also not assumed to fail under the cited NRC requirements of BTP APCSB 3-1.

If the pipe crack should occur in the common manifold supplying both redundant loops, the isolation mechanism is the same as before, but recovery would require reversion to the alternate shutdown configuration discussed in Section 15.2.9. In this configuration, vessel water is circulated from the suppression pool to the RHR heat exchanger to the vessel with return to the suppression pool via the ADS discharge lines. Time: less than 1 hour.

If the pipe crack should occur in the RHR service water piping, sump alarms would result in operator isolation of that loop and establishment of cooling in the redundant shutdown loop. Time: less than 1 hour.

In evaluating the above analysis, the following is also offered. If the main condenser vacuum has been lost and the MSIVs are already closed prior to the crack occurrence, reestablishment of condenser vacuum, MSIV reopening, vessel inventory control, and restart of steam dump to the main condenser is possible in about 2 hours. Vessel inventory can be controlled by overflow through the reactor water cleanup system if too high, and by use of feedwater pumps or HPCS/LPCS/LPCI if too low. Vessel pressure is controlled by manual operation of safety/relief valves on MSIV closure as required.

c. *The alarms available have been described in the response to part (a) and part (b) of this question. The recovery procedures to be utilized by the operator, and the time available for operator action are provided below.*

A special analysis was made by a hypothesized crack in the BWR suction line outside of primary containment during operation in the shutdown cooling mode. This analysis was performed with the standard GE LOCA models. For this event, the realistic or actual system conditions are as follows:

> *No high pressure systems are available for water inventory restoration, i.e., no feedwater, no HPCS, and no RCIC, but the reactor water level is at normal elevation at the start of this event. Vessel pressure is less than 150 psia and the MSIVs are closed at the start of this event. The decay heat is approximately 1% of rated power, i.e., approximately 4 hours have elapsed subsequent to reactor scram or shutdown.*

For a conservative solution to this hypothetical event, the following sequence of events and conditions were assumed to exist or ensue from the hypothesized crack in the suction line:

a. *Crack occurs in the RHR lines water; level decreases to reactor vessel Level 3; then RHR isolation commences and is completed 40 seconds later.*

b. *System pressure rises as a result of the isolation to where the vessel pressure reaches the SRV setpoint, thus causing them to open, blow down, and reclose.*

c. *Inventory depletion results from blowdown and from leakage out of these cracked lines.*

d. *The operator manually actuates ADS to reduce vessel pressure to where the low pressure ECCS can replenish the water inventory.*

e. *Water level is restored to within normal limits to protect the core from over temperature.*

Results are presented in Figures I.8-1 through I.8-4 for a bounding calculation of this event. The standard Appendix K assumptions were used along with these conservative initial conditions.

a. *The timing index was started at the RHR isolation (when Level 3 was attained) to neglect the time for the level to fall from normal water level to Level 3 (about 2 minutes).*

b. *An initial pressure of 1055 psia was assumed to neglect the pressure rise time from the 150 psia (pressure permissive for shutdown cooling) upon completion of the RHR isolation to the 1055 pressure attainment. This results in increased mass loss during the 40-second isolation period due to greater driving pressure. It also decreases the time increment needed for pressure to attain the relief valve setpoint.*

c. *The analysis assumes that scram occurs coincident with the start of the timing instead of 4 hours earlier. This assumption maximizes the peak clad temperature and steam production during the transient thus driving more fluid from the vessel and prolonging the blowdown phase.*

d. *Only one LPCS and one LPCI loop were assumed to be available throughout the event. Operator action does not include possible diversion of the other two LPCI loops from the RHR mode.*

e. The crack area used in the analysis is defined consistently with the MEB 3-1 guidance for crack size. This crack area is consistent with FSAR postulates.

Results from this conservative analysis show that more than 20 minutes are available for the operator to depressurize the vessel. Once the system pressure is below the LPCI or LPCS shutoff head, the reactor water level is restored to normal limits very rapidly. The maximum clad temperature is much less than the arbitrary 2200°F limitation.

ISSUE: RSB-18 LOCA ANALYSIS - DIVERSION OF LOW PRESSURE COOLANT INJECTION SYSTEM (6.3.4)

Question:

The issue is… "If low pressure coolant injection diversion prior to ten minutes is allowed by design, then procedural restrictions alone are not sufficient unless analyses are submitted which show compliance with 10 CFR 5O.46 for diversion earlier than ten minutes."

Response:

Analyses of BWR performance following a small break LOCA and LOCA mitigation under degraded conditions have been performed by General Electric as a part of the BWR Owners' Group program. Analyses bases, assumptions, and conclusions are discussed in GE report NEDO-24708A, Revision 1, December 1980, entitled, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors." Reference is made to 3.1.1 (Small Break LOCA) and 3.5.2 (Inadequate Core Cooling). It should be noted that these analyses were performed utilizing "realistic" assumptions as defined in 3.1.1.2 and 3.5.2.4. The conclusion, 3.5.2.1.8, summarizes the capability of the BWR to maintain adequate core cooling, even under severely degraded conditions resulting from multiple failures and operator errors, following a loss of inventory either through a pipe break or through the safety relief/valve.

Based on the first group of analyses presented, it was concluded that for any plant and any loss of inventory event, the ability of ADS and one low pressure ECC system provides adequate core cooling if no high pressure injection is available. These analyses covered the case of multiple mechanical or electrical failures and operator errors that might have caused the failure of the system, assumed to be unavailable.

The second set of analyses addressed the condition of the vessel being at high pressure with a low water level. It was shown that operator actions either to initiate high pressure systems or to depressurize the vessel and initiate at least one low pressure system, terminate this condition *and assure adequate core cooling. The analyses showed that even for such severely degraded transients, there is sufficient time for operator action to mitigate the consequences.*

The third set of analyses addressed the condition of the vessel being at low pressure with a low water level but with the low pressure systems not injecting. It was shown that operator actions either to start the low pressure systems injecting into the vessel or to initiate the high pressure systems, terminate this condition and assure adequate core cooling.

For all analyses, it was shown that the process variable information available to the operator in the control room is sufficient to adequately warn of an inventory threatening event and to present the information the operator needs to assure that appropriate actions are taken to maintain adequate core cooling. The control room indications will not mislead the operator when taking corrective actions. Even under the extremely degraded conditions considered in these analyses, the BWR requires only the most basic operator actions to mitigate the consequences of an inventory threatening event.

If the operator were to divert LPCI prior to ten minutes post-LOCA, such an action would be considered an operator error. Since the current ECCS performance evaluation already assumes the accident, a loss of offsite power and a worst active single failure, an additional operator error is considered to be an additional Appendix K assumption. It is therefore appropriate that the "realistic" assumption analyses be considered for this situation as stated in the conclusion in NEDO-24708A "for any plant and any loss of inventory event, the adequate availability of ADS and one low pressure ECC system provides adequate core cooling…"

This analysis is deemed acceptable to provide satisfactory assurance of acceptable event consequences, in consideration of the equipment failures and operator errors assumed.

To resolve the concern of the NRC staff that premature diversion of low pressure coolant injection (LPCI) flow to containment sprays could adversely effect core cooling, the CGS symptom based emergency procedures will be carefully constructed to caution the operator against such diversion unless "adequate core cooling is assured." These procedures, which were developed with the assistance of the BWR Owners' Group and reviewed and accepted by the NRC staff, clearly identify LPCI diversion as secondary to the core cooling requirements except in those instances, outside the plant design envelope, which involve multiple failures and for which maintenance of containment integrity is required to minimize risk to the environment.

ISSUE: RSB-19 FAILURE OF FEEDWATER HEATER
(15.1)

Question:

The applicant's analysis for the failure of the feedwater heater indicates that the temperature drop is no greater than 100°F. At a domestic boiling water reactor an actual feedwater temperature occurred which demonstrated a temperature difference of 150°F. The applicant must justify the decrease in temperature drop used for this event or recalculate the transient by using a justified temperature decrease to assure conformance with applicable criteria.

Response:

Refer to revised response to Question 211.087.

ISSUE: RSB-20 USE OF NONRELIABLE EQUIPMENT IN ANTICIPATED OPERATIONAL TRANSIENTS
(15.1)

Question:

In analyzing anticipated operational transients, the applicant took credit for equipment which has not been shown to be reliable. Our position is that this equipment be identified in the technical specifications with regard to availability, setpoints, and surveillance testing. The applicant must submit its plan for implementing this requirement along with any system modification that may be required to fulfill the requirement.

Response:

The response to the above stated concern is provided in response to Questions 211.085, 211.086, and 211.155.

ISSUE: RSB-21 USE OF NON-SAFETY GRADE EQUIPMENT IN SHAFT SEIZURE ACCIDENT
(15.3)

Question:

The applicant included the use of non-safety grade equipment in his analysis for shaft seizure and shaft break accidents. We require that these accidents be reanalyzed without allowance for the use of non-safety grade equipment.

Response:

The response to the above stated concern is provided in the revised response to Question 211.092. Questions 211.185 and 211.211 also reference this concern.

ISSUE: RSB-22 ATWS
(15.2.1)

Question:

We require that the applicant agrees to implement plant modifications on a scheduled basis in conformance with the Commission's final resolution of ATWS. In the event that LaSalle starts operation before necessary plant modifications are implemented, we require some interim actions be taken by LaSalle in order to further reduce the risk from ATWS events. The applicant will be required to:

a. *Develop emergency procedures to train operators to recognize an ATWS event, including consideration of scram indicators, rod position indicators, flux monitors, vessel level and pressure indicators, relief valve and isolation valve indicators, and containment temperature, pressure, and radiation indicators.*

b. *Train operators to take action in the event of an ATWS including consideration of immediately manual scramming the reactor by using the manual scram buttons followed by changing rod scram switches to the scram position, stripping the feeder breakers on the reactor protection system power distribution buses, opening the scram discharge volume drain valve, prompt actuation of the standby liquid control system, and prompt placement of the RHR in the pool cooling mode to reduce the severity of the containment conditions.*

Response:

See 1.5.1.1.2 for a discussion of CGS modifications which addresses compliance to the final ATWS rule. The required procedure development and operator training were accomplished prior to fuel load.

ISSUE: RSB-23 PEACH BOTTOM TURBINE TRIP TESTS
(4.4.1, 4.4.2)

Question:

These tests have been evaluated and assessed using the ODYN computer code.

Response:

The NRC has completed their review of the ODYN Code. See the Safety Evaluation Report letter of November 4, 1980.

Also, see Chapters 4 and 15. The appropriate sections of these chapters have been revised utilizing results of re-analysis of required transients using the ODYN Code. See the revised response to Question 211.049.

Refer also to RSB-4.

ISSUE: RSB-24 MCPR
(4.4.1, 4.4.2, 15.1)

Question:

After completion of over-pressure analysis, the minimum critical power ratio must be recalculated taking into consideration the turbine trip without bypass event.

The transient of generator load rejection without bypass results in an MCPR equal to 1.02 which is below the safety limit of 1.06. The applicant classified this event an infrequent occurrence which would allow some fuel damage. We do not concur with this classification for this event, and we require that the operating limit be modified to satisfy the MCPR limit of 1.06.

Response:

The response to the above stated concern is provided in revised response to Question 211.084.

ISSUE: RSB-25 GEXL CORRELATION

Question:

Although we conclude that the GEXL correlation is acceptable for initial core load, we are concerned that GEXL correlation may not be conservative for reload operation.

Response:

Columbia Generating Station will use the applicable correlation to predict the onset of transition boiling for all reloads.

ISSUE: RSB-26 STABILITY EVALUATION

Question:

Please refer to NRC Question 221.009 for this question.

Response:

Please refer to the response to NRC Question 221.009.

ISSUE: RSB-27 SCRAM DISCHARGE VOLUME

Question:

The applicant should assess, reevaluate, and possibly modify the present scram system in light of the incident at Browns Ferry 3, where a manual scram failed to insert all control rods.

Response:

The CGS scram discharge volume (SDV) design has been evaluated against the NRC generic study "BWR Scram Discharge System Safety Evaluation" of December 1, 1980. The results of this evaluation indicated that the current CGS scram discharge system design was acceptable with implementation of some minor modifications. A summary of the evaluation results and the required modifications are provided below.

a. *Hydraulic Coupling - The current SDV design provides two separate scram discharge volume headers, with an integral instrumented volume (IV) at the end of each header. This design configuration ensures a direct hydraulic couple between the SDVs and IVs.*

b. *Instrumentation - The existing level sensors (six total) are all of one design, i.e., float type (magnetrol) level switches. To meet the specified requirements, six additional diverse level sensors will be added to provide full redundancy for level monitoring and scram initiation. In addition, all level instrumentation will be relocated and repiped directly to the IVs rather than being connected to the vent and drain lines.*

c. *Vent and Drain Lines - The CGS design incorporates an independent vent and drain system for the SDV. The scram discharge headers are presently vented directly to the reactor building atmosphere and the system drain is piped directly from the bottom of the IVs to the building's radioactive drain system. A second vent valve and drain valve will be added to provide redundant SDV isolation during a reactor scram.*

d. *Surveillance Testing - Additional surveillance test procedures will be implemented to ensure operability of the level instruments, vent and drain isolation valves, as well as the overall system.*

Please refer to response to Question 010.041.

ISSUE: RSB-28 SRV SURVEILLANCE

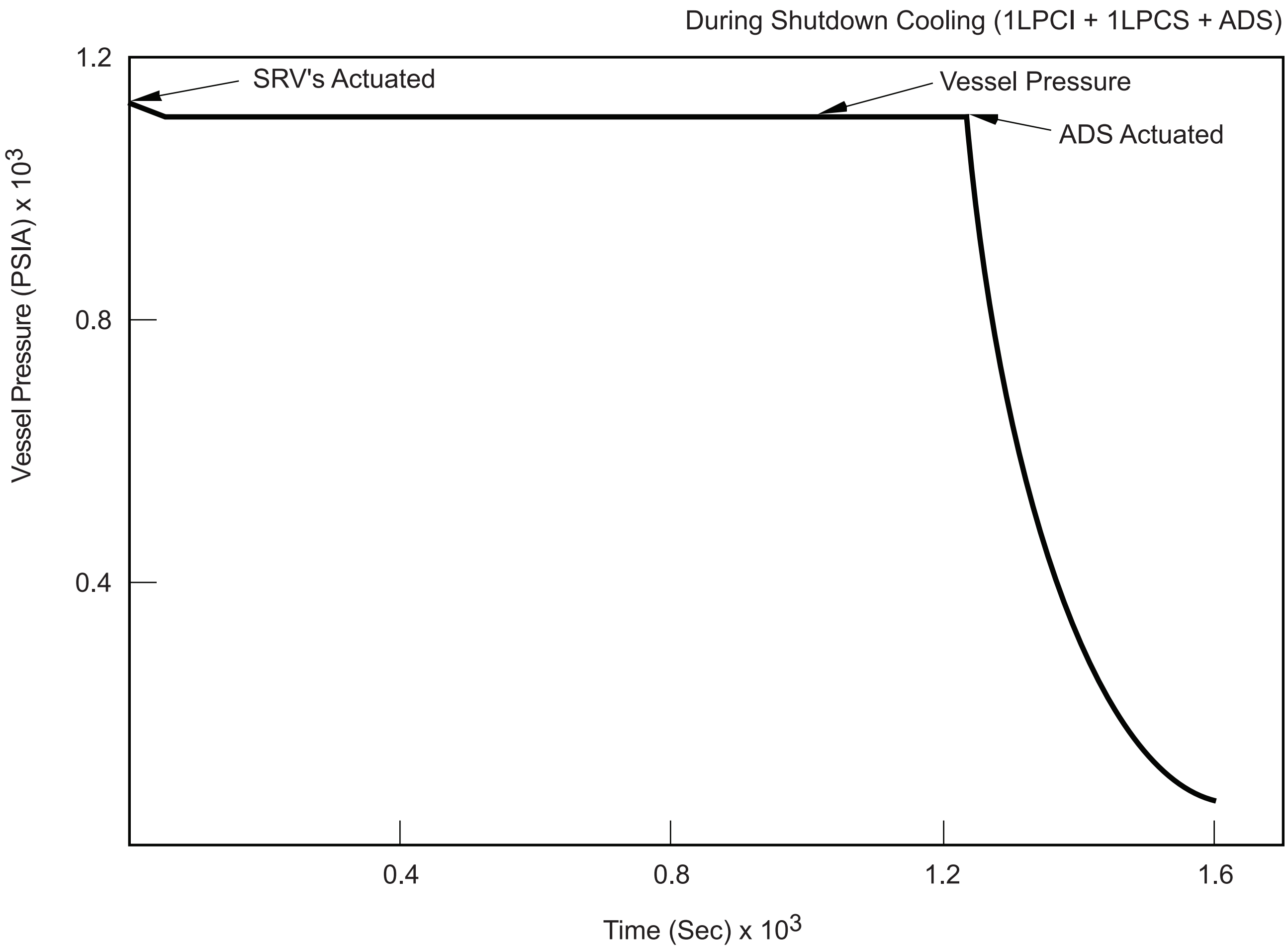
Question:

A safety/relief valve surveillance program should be developed to record operating and maintenance experience to facilitate identification of generic safety/relief valve problems.

Response:

CGS will develop a surveillance program for safety/relief valves similar to that being developed by the BWR Owners' Group submitted to the NRC by letter GO2-81-563, G. D. Bouchey to A. Schwencer, "LRG Appendix I," dated December 30, 1981.

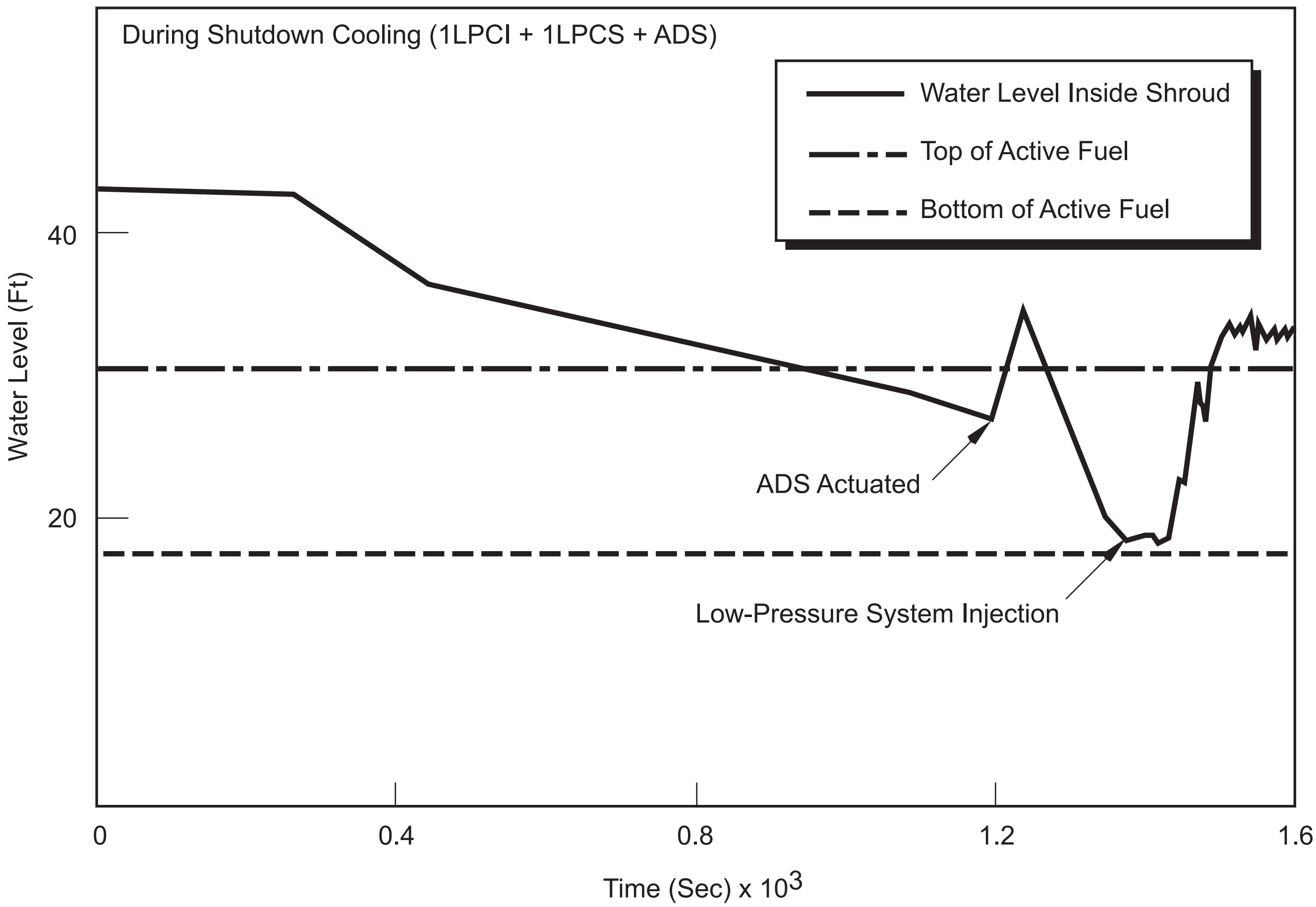
The CGS safety/relief valve surveillance program will be available for onsite review.



Columbia Generating Station
Final Safety Analysis Report

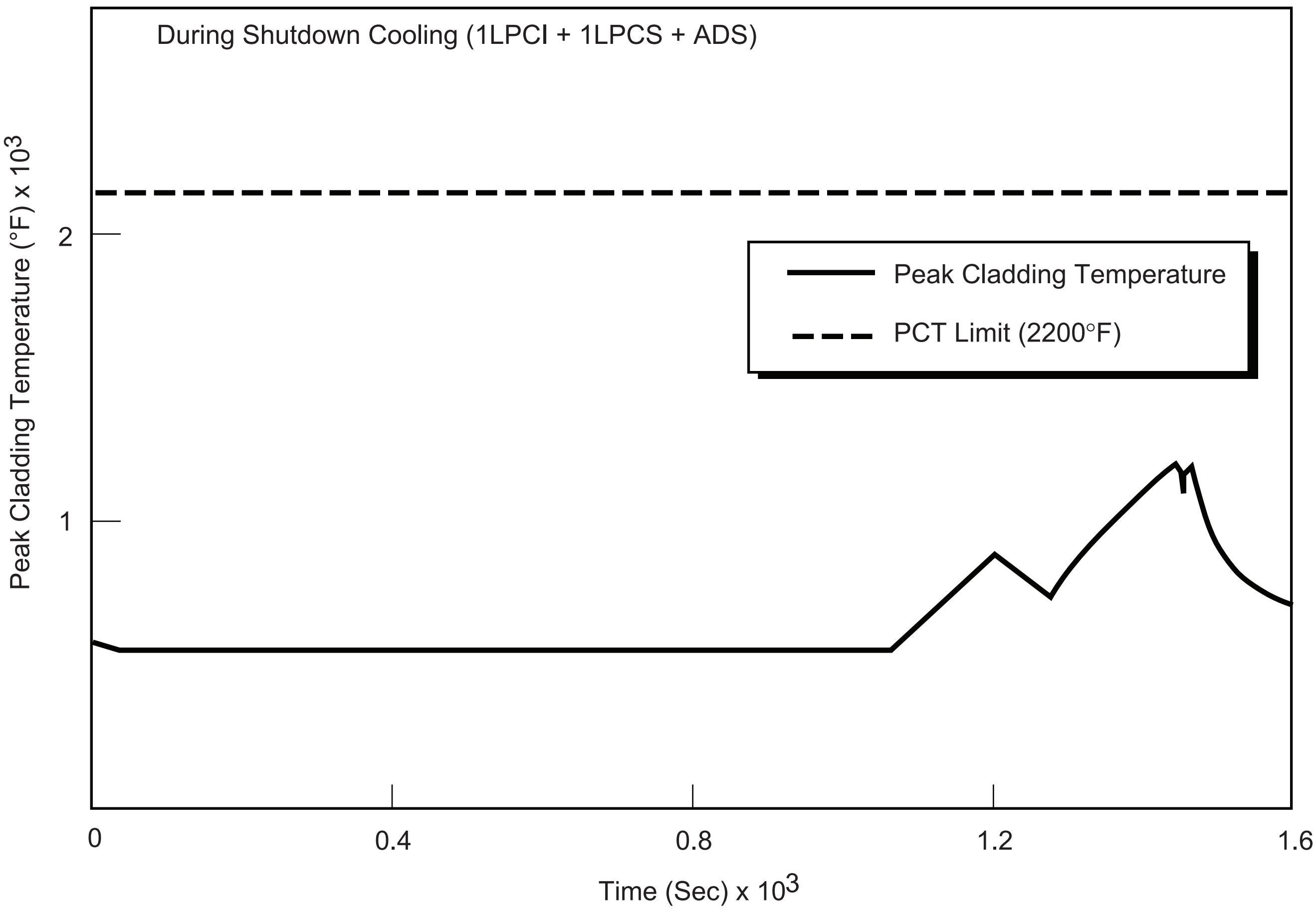
Vessel Pressure Versus Time for a Crack in the RHR Line

Draw. No. **970187.15**	Rev.	Figure **I.8-1**

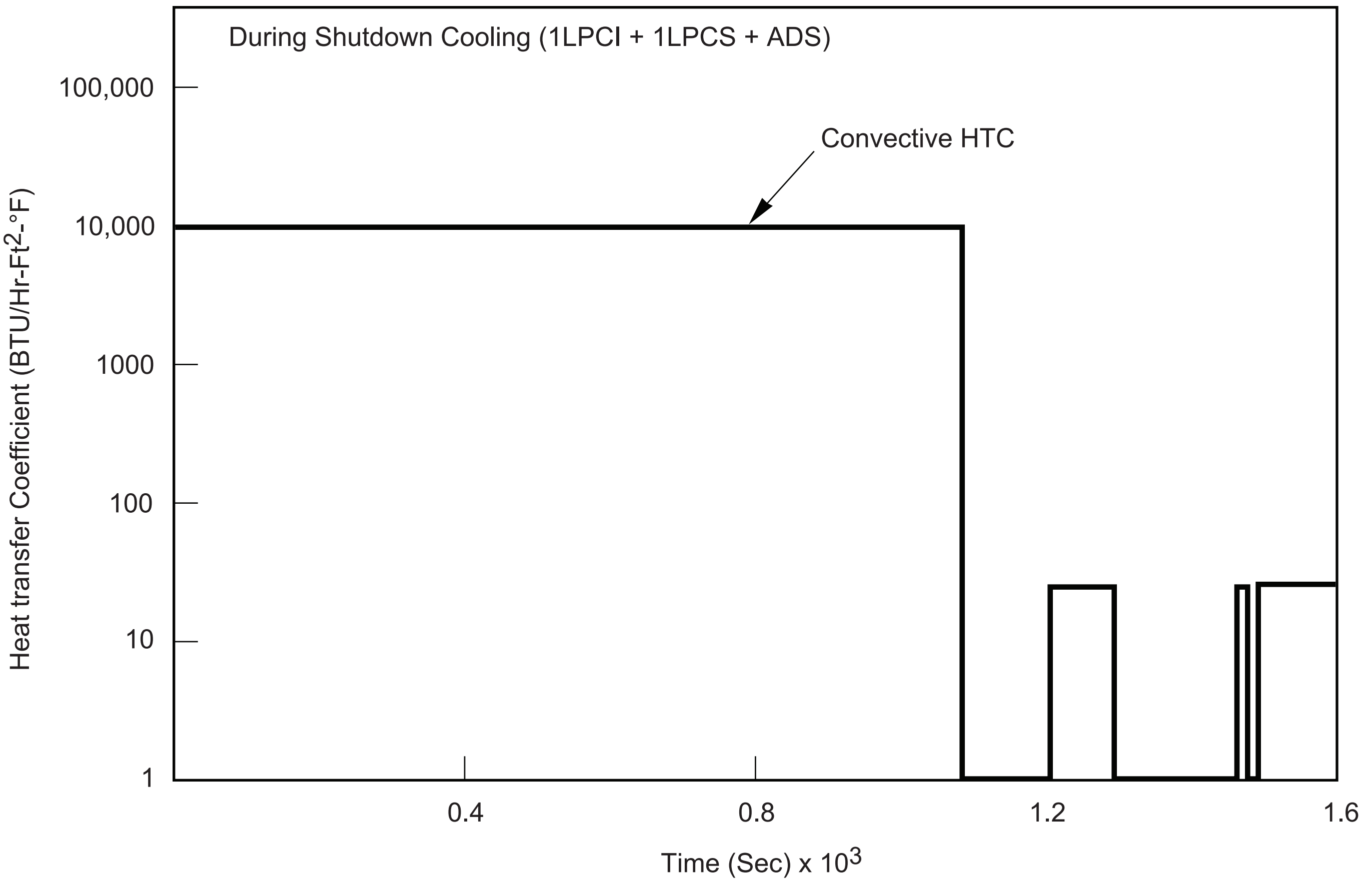


Water Level Versus Time for a Crack in the RHR Line

Draw. No. 970187.16 | Rev. | Figure I.8-2



Peak Cladding Temperature Versus Time for a Crack in the RHR Line



Columbia Generating Station
Final Safety Analysis Report

HTC at PCT Node Versus Time for a Crack in the RHR Line

Draw. No. 970187.18 | Rev. | Figure I.8-4

Appendix J

SHIELDING EVALUATION REPORT

Burns and Roe, Inc., performed the analysis of radiation levels occurring inside primary containment, assembled, edited, reviewed, and approved this technical report for Energy Northwest.

EDS Nuclear Incorporated performed the analysis of radiation levels occurring in the reactor building secondary containment under subcontract to Burns and Roe, Inc. Later revisions have been issued by Energy Northwest to incorporate plant changes.

Energy Northwest performed the analysis of radiation levels occurring in areas outside the reactor building secondary containment.

Appendix J

SHIELDING EVALUATION REPORT

TABLE OF CONTENTS

Appendix J

SHIELDING EVALUATION REPORT

TABLE OF CONTENTS (Continued)

Section Page

Appendix J

SHIELDING EVALUATION REPORT

TABLE OF CONTENTS (Continued)

Appendix J

SHIELDING EVALUATION REPORT

TABLE OF CONTENTS (Continued)

Appendix J

SHIELDING EVALUATION REPORT

TABLE OF CONTENTS (Continued)

Appendix J

SHIELDING EVALUATION REPORT

LIST OF TABLES

Appendix J

SHIELDING EVALUATION REPORT

LIST OF TABLES (Continued)

Appendix J

SHIELDING EVALUATION REPORT

LIST OF FIGURES

Appendix J

SHIELDING EVALUATION REPORT

LIST OF FIGURES (Continued)

Appendix J

SHIELDING EVALUATION REPORT

LIST OF FIGURES (Continued)

Appendix J

SHIELDING EVALUATION REPORT

LIST OF FIGURES (Continued)

Appendix J

SHIELDING EVALUATION REPORT

LIST OF FIGURES (Continued)

SUMMARY

The Three Mile Island (TMI-2) accident has generated a concern that during an accident in which significant core damage occurs, the postaccident operations requiring the use of systems containing contaminated fluid may induce abnormally high radiation doses to safety-related equipment and components which make it difficult to operate the systems. The NRC initially addressed this concern with NUREG-0578 and NUREG-0737 and recommended a design review to evaluate the functional capability of safety-related equipment and radiation exposure to personnel during the postulated post-LOCA operations.

Radiation levels have been determined for all areas containing safety-related equipment, vital areas, and access routes which are required for the postulated post-LOCA operation.

Radiation levels determined for safety-related equipment inside primary containment. The analysis included the shadow shielding effect of installed equipment and the effect of iodine plateout were used to more accurately calculate the radiation levels inside containment.

Radiation levels were determined for safety-related equipment. The radiation source term leaking into secondary containment was reduced by the loss of halogens to plateout inside primary containment.

Radiation levels calculated for safety-related equipment outside secondary containment are reported in Table J.6-1.

Figures J.6-8 through J.6-18 identify the vital areas which require personnel access on either a continuous or infrequent basis during post-LOCA operations.

Safety-related equipment will either be qualified for the radiation level it functions in, or it will be relocated to a radiation zone it is qualified for, or it will be replaced with comparable equipment which is qualified for the particular radiation level that has been determined.

Vital areas and access routes were evaluated for post-LOCA operations and are reported in Table J.6-2 and Figures J.6-8 through J.6-18. All areas and access routes are in compliance with NUREG-0737.

ABSTRACT

This report presents a radiation shielding design review of the equipment and systems of the Energy Northwest Columbia Generating Station. The original report was prepared in September 1982. The equipment and systems are evaluated on the basis of a postulated accident which in addition to normal plant radiation levels during its 40-year life may contain highly radioactive fluids. This design review recommended by the NRC (NUREG-0578 and NUREG-0737) evaluates the functional capability of safety-related equipment and personnel radiation exposure during the postaccident operations.

This design review evaluates the postaccident radiation conditions for personnel located in vital areas (areas which require access or occupancy during the post-LOCA scenario) on either a continuous or infrequent basis.

The postulated loss-of-coolant accident (LOCA) scenarios and the operations of the safety-related systems were reviewed. Radioactive sources contained within each system were developed. Radiation levels were calculated at safety-related equipment locations, as well as at selected locations outside the reactor building to which access may be required for postaccident operations.

J.1 INTRODUCTION

This report presents a detailed description of the results and the review of plant shielding and radiation environmental conditions for equipment and systems which may be used in postaccident operations for Columbia Generating Station (CGS). The review was initiated in response to Section 2.1.6.b of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendation," and to Part II.B.2 of NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident."

The design review determined the postaccident radiation environmental conditions for equipment required for postaccident operations inside the primary containment, inside the secondary containment, and outside the secondary containment.

The 6-month total postaccident radiation dose rate as a function of time and the integrated dose were calculated at safety-related equipment locations inside the CGS reactor building, inside primary containment, and at selected locations (vital areas) outside the reactor building.

Section J.2 discusses the regulatory requirements on which this report is based and provides a description of the tasks performed for this shielding evaluation.

Section J.3 provides the systems review and source term assumptions used as input for the definition of the postaccident radiological environment.

Section J.4 discusses the work performed during this project relating to safety-related equipment located outside of the reactor building and the access and occupancy of vital areas. This consists of the calculation of dose rates outside the reactor building.

Section J.5 discusses the methods of calculation including the use of computer codes, identifying the parameters that have a significant effect on the radiation dose rates, and the dose rate and cumulative dose calculation procedure.

Section J.6 presents a summary of the results.

J.2 REQUIREMENTS

General Design Criterion 4 (10 CFR 50 Appendix A) requires that systems and components important to safety be designed to accommodate the environmental conditions associated with accidents. The Three Mile Island (TMI-2) accident has generated a concern that during an accident in which significant core damage occurs, the postaccident operations requiring the use of systems containing contaminated fluid may induce abnormally high radiation doses to safety-related equipment and components which may make it difficult to operate the systems. The NRC Lessons Learned Task Force initially addressed this concern in Section 2.1.6.b of NUREG-0578 (Reference J.7-1) and recommended a design review be performed on such systems so that the functional capability of safety-related equipment located in close proximity to the resulting high radiation field will not be unduly degraded.

Described in this section is a discussion of the current regulatory requirements and guidelines used.

J.2.1 SHIELDING EVALUATION REGULATORY REQUIREMENTS

NUREG-0578 Section 2.1.6.b requires that each licensee perform a radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The scope of the review includes the following:

a. Identification of the locations of vital areas and safety-related equipment,

b. Evaluation of the radiation level at each location, and

c. Provision for adequate access to vital areas and assurances of postaccident equipment operation through design changes, increased permanent or temporary shielding, or postaccident procedural controls.

To perform this review, the NRC has provided guidance in the following documents ("documents of record"):

a. NUREG-0578, Section 2.1.6.b, Reference J.7-1,

b. NUREG-0588, Revision 1, Section 1.4, Reference J.7-2,

c. NUREG-0660, Section II.B.2, Reference J.7-3,

d. Clarification Letter to NUREG-0578, dated September 5, 1980, Section II.B.2, Reference J.7-4,

e. NUREG-0737, Section II.B.2, Reference J.7-5,

f. IE Bulletin No. 79-01B, Reference J.7-6, and

g.. IE Bulletin 79-01B, Supplement 2, dated September 30, 1980, Reference J.7-7.

The regulatory requirements in the above mentioned documents are summarized in the following sections.

J.2.1.1 Accident Analysis Requirements

The postaccident radiation environment should be based on the most severe design basis accidents (DBA) during or following which equipment must remain functional. This includes the consideration of the entire spectrum of loss-of-coolant accident (LOCA) events which can lead to a degraded core condition. These accident conditions include the following:

a. Loss-of-coolant accident events which completely depressurize the primary system, and

b. Loss-of-coolant accident events in which the primary system may not be depressurized.

J.2.1.2 Source Term Assumptions

The radioactive source terms for the postulated accident conditions as described in Section J.2.1.1 should be equivalent to the source terms recommended in Regulatory Guides 1.3 and 1.7 and Standard Review Plan Section 15.6.5. The source term assumptions consistent with current licensing requirements used for equipment qualification and access evaluations are summarized as follows:

a. The fission product fractions assumed to be released from the fuel rods during a LOCA are the following:

Noble gases	100%
Halogens	50%
Remaining fission products	1%

For the analyses, 50% of the halogens and 1% of the solids were assumed to be diluted into the suppression pool and liquid carrying systems. The halogens were also assumed to be in the airborne source while iodines were assumed in the plateout source. Thus, some care is necessary in summing calculated doses to prevent double counting of the sources. The post-LOCA source contribution from liquid and plateout sources are analyzed separately and the worst dose is tabulated for that evaluation rather than the sum of both doses. Thus, double counting of the fission product fractions is eliminated where possible;

b. The above release is assumed to occur and be distributed instantaneously at the start of the accident. The plateout is assumed to occur over an effective time of 5 hr after the accident;

c. Until depressurized, liquid in the reactor coolant system (RCS) and other systems which are not isolated from the core and which contain the reactor coolant at the start of the LOCA contain 100% noble gases, 50% halogens, and 1% of the remaining fission products. These radioactive materials are mixed homogeneously in a volume no greater than the RCS liquid space;

d. Liquid in the suppression pool and any system not isolated from the core at the start of the LOCA, and containing only liquid from a depressurized source, is assumed to contain 50% halogens and 1% of the remaining fission products. These radioactive materials are diluted homogeneously in a volume no greater than the combined volumes of the suppression pool and the RCS liquid space;

e. The primary containment atmosphere and systems which are not isolated from the primary containment atmosphere at the start of the LOCA are assumed to contain at least 100% noble gases and 50% halogens initially. These radioactive materials are diluted homogeneously in a volume no greater than the combined volumes of the drywell and suppression pool air spaces; and

f. Primary containment plateout source term is obtained by allowing the airborne halogens released (50%) to plateout on primary containment surfaces in accordance with the guidelines presented in NUREG/CR-0009 until the airborne elemental iodine concentration is decreased by a factor of 200.

g. Until the reactor vessel is depressurized, gases in the steam lines and any other vapor-containing lines not isolated from the core at the start of the LOCA are assumed to contain at least 100% noble gases and 25% halogens. These are diluted uniformly in a volume no greater than the RCS steam space and adjoining unisolated steam lines.

J.2.1.3 <u>Vital Area Access Requirements</u>

As defined in NUREG-0737 (Reference J.7-5), a vital area is an area which will or may require occupancy to permit an operator to help in the mitigation of an accident or perform postaccident operations. The accident scenarios discussed in Section J.2.1.1 and the source term assumptions in Section J.2.1.2 are used for the evaluation of vital area access and occupancy. The total radiation exposure to personnel in vital areas should not be in excess of

5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident. For areas requiring continuous occupancy (e.g., the control room, onsite technical support center, etc.), the dose rate criteria limits the total radiation exposure to less than 15 mrem/hr (averaged over 30 days).

J.2.1.4 Systems Containing the Sources

Systems considered in the shielding review are those systems that could have the potential of containing a high level of radioactivity postaccident. For those systems connected directly to the RCS or to the primary containment atmosphere and not isolated at the start of the accident, the radioactivity is assumed to be instantaneously mixed within the unisolated parts of the system.

J.2.1.5 Safety-Related Equipment (C1E/SRM)

The safety-related (C1E/SRM) equipment list contains all equipment necessary to mitigate the consequences of an accident, bring the plant to a safe shutdown condition, and provide long-term cooling capability. This list includes equipment located inside as well as outside the primary containment.

J.2.2 SHIELDING EVALUATION TASK DESCRIPTION

The shielding evaluation tasks which have been completed to date are as follows:

a. Review all accident scenarios and accident conditions that could result in a limiting radiation environment for all the pieces of safety-related equipment on the C1E/SRM (safety-related) list that are located in the reactor building;

b. Identify systems and components that could potentially contain radioactive materials postaccident;

c. Generate source term assumptions based on regulatory requirements discussed in Section J.2.1;

d. Calculate accident radiation service conditions for the safety-related equipment located inside the reactor building;

e. Calculate gamma dose rates at selected locations outside the reactor building due to radioactive sources inside the reactor building;

f. Identify vital areas and equipment to evaluate the access to and occupancy of the vital areas in accordance with the requirements listed in Section J.2.1;

g. Conduct a primary containment analysis of LOCA events in which the RCS may not depressurize (or may repressurize) with a degraded core condition. The primary containment radiation environment was determined with the use of 100% noble gases, 50% halogens, and 1% of the remaining fission products for the period of time during which the activity is isolated to the RCS;

h. Calculate the radiation dose to safety-related equipment in the reactor building from post-LOCA airborne radiation and from normal piping sources inside primary containment streaming through the bioshield wall penetrations; and

i. The safety-related equipment list contains all equipment required to "mitigate" the consequences of an accident, bring the plant to a safe shutdown condition, and provide long-term cooling capability. The completeness of the safety-related equipment list has been verified.

J.2.3 SHIELDING EVALUATION ITEM DELETED FROM SHIELDING ANALYSIS CONSIDERATION

Columbia Generating Station has addressed all the issues needed to comply with the NUREG-660 II.B.2 position except as follows: Columbia Generating Station takes exception to the portion of the task that specifies that a review of "safety-related" equipment which may be degraded by radiation during postaccident operation be provided for a non-LOCA, high-energy line break source term. The pipe break/missile analysis described in Sections 3.5 and 3.6 addresses nonmechanistic pipe breaks inside and outside containment. These pipe breaks do not lead mechanistically to a radiation release due to fuel failures beyond those allowed in normal operation. Hence, the source term identified and applied outside containment is entirely hypothetical and would be a new design basis beyond the scope of current regulations.

J.3 ANALYTICAL METHODOLOGY

To develop the method used in the calculation of radiation doses, a review of all the postulated accident scenarios and system operations were performed. Source term assumptions were developed based on the results of accident analysis and system review, as well as the regulatory guidelines described in Section J.2.1. The systems and components inside the reactor building that have the potential of becoming contaminated during or following the accident were identified.

The following subsections describe these activities in greater detail. Section J.3.1 describes the accident scenario chosen for this analysis. Section J.3.2 identifies all the contaminated systems. Section J.3.3 describes the source term assumptions generated for each contaminated system. Section J.3.4 identifies the time period considered for this study.

J.3.1 ACCIDENT SCENARIO

The accident analyses consistent with FSAR Chapter 15 for small- and large-break loss-of-coolant accidents (LOCAs) were considered. The entire spectrum of LOCA conditions that could result in a degraded core configuration was reviewed and it was concluded that there is no single accident scenario that could result in a limiting radiation environment for all the safety-related equipment located in the reactor building. Therefore, the accident scenario chosen here is based on a nonmechanistic LOCA in which core damage is experienced at the beginning of the accident. Primary containment isolation is assumed to be achieved prior to radioactivity transport.

A review of the postaccident operation of the C1E/SRM (safety-related) systems was conducted. The result of this review indicated that the worst-case accident for the steam supply system (highest source term) was the pressurized reactor coolant system (RCS). For the liquid systems [the emergency core cooling system (ECCS), the residual heat removal (RHR), and the reactor core isolation cooling (RCIC) systems], as well as the primary containment atmosphere and primary containment atmosphere control (CAC) system, the worst-case accident is the depressurized reactor coolant system with the post-LOCA core release functions dispersed within the primary containment.

J.3.2 CONTAMINATED SYSTEMS

To perform the radiation dose calculations, it was necessary to identify the systems which would or could contain highly radioactive materials during the postaccident period. Systems required to operate during the postaccident period are as follows:

a. Systems necessary to mitigate the consequences of a large- or small-break LOCA,

b. Portions of systems that are in communication with systems containing radioactive liquids or gases, and

c. Defined by the NRC as being required, such as the gaseous radwaste system (see Section J.3.2.3).

J.3.2.1 Systems Included for Primary Containment Analysis

The following systems were considered:

a. High-pressure core spray (HPCS),

b. Low-pressure core spray (LPCS),

c. RHR,

d. RCIC,

e. Floor drains and equipment drains (FDR-EDR),

f. Reactor water cleanup (RWCU),

g. Main steam (MS),

h. Reactor recirculation (RRC),

i. Sample lines (PSR),

j. Automatic depressurization system (ADS), and

k. Low-pressure coolant injection (LPCI) function of the RHR system after depressurization.

J.3.2.2 Systems Included for Secondary Containment Analysis

The following systems were considered:

a. RCIC,
b. RHR,
c. LPCI,
d. LPCS,
e. HPCS,
f. MS, up to second isolation valve,

g. MS line isolation valve-leakage control system (MSIV-LCS),
h. Primary containment,
i. Secondary containment atmosphere, and
j. Standby gas treatment (SGT).

The following systems were also considered due to their potential to affect isolation valves or extend the primary containment source terms into secondary containment.

a. Containment atmosphere monitoring (CMS),

b. Containment supply purge (CSP),

c. Containment exhaust purge (CEP),

d. Blank penetrations,

e. Personnel access doors into the wetwell and drywell,

f. Instrumentation penetrations, and

g. All post-LOCA inboard and outboard isolation valves and their connected piping sources.

J.3.2.3 Systems Excluded

All systems required to mitigate the consequences of an accident have been included. Of those systems recommended for consideration in regulatory documents, one system (gaseous radwaste) has been excluded.

The gaseous radwaste is isolated by the primary containment and reactor vessel isolation control system and will not receive contaminated gas unless operation is manually initiated. The Columbia Generating Station (CGS) operating and accident procedures do not take credit for nor anticipate using this system. Since CGS philosophy is based on containment of the core releases within the primary containment, this system will not be required and was, therefore, excluded from consideration.

J.3.3 SOURCE TERM ASSUMPTIONS

Regulatory requirements specify that source terms equivalent to those recommended in Regulatory Guides 1.3 and 1.7 and Standard Review Plan Section 15.6.5 be used in the LOCA accident analysis. Additional guidance is given in NUREG-0588 (Reference J.7-2) and NUREG-0737 (Reference J.7-5) and is documented in Section J.2.1. Source term assumptions were generated based on the review of the operation of the safety systems. Because a nonmechanistic LOCA scenario was chosen for this analysis, the worst contaminated situation for the fluid contained within each system was conservatively assumed. Tables J.3-1, J.3-2, and J.3-3 list the assumptions involved in the distribution of fission products used in this analysis. These assumptions are consistent with the regulatory requirements discussed in Section J.2.1.

A review of the operation of each of the systems discussed in Section J.3.2 was also conducted. This review identified the source of contaminated fluid contained within each system postaccident. Using the source term assumptions discussed in Tables J.3-1, J.3-2, and J.3-3, together with the results of this system review, the limiting source term (activity divided by dilution factor) was determined for each system. Table J.3-4 is a summary of the system operations and source term assumptions developed for each contaminated system identified in Section J.3.2.

J.3.4 TIME PERIOD CONSIDERED FOR STUDY

All systems were conservatively assumed to become contaminated at the start of the accident and remain contaminated until the integrated radiation dose reached it asymptotic value. It was noted that the integrated dose becomes nearly asymptotic to a constant value beyond about 6 months. Therefore, 6 months is the time period chosen for accident dose qualification in this report.

Table J.3-1

Distribution of Fission Products in the Worst Post-Loss-of-Coolant Accident Situation for Areas Inside Containment Depressurized Reactor Coolant System

	Primary Containment [a] Air and Steam Space		Suppression Pool and Reactor Coolant System Water Volume	
Fission Products	Fraction [b]	Dilution Volume [c]	Fraction[b]	Dilution Volume [c]
Noble gases	100%	Drywell air plus	0%	Suppression pool water and RCS water volume
Halogens	50% [d,e]	Suppression pool	50%	
Particulates	0%	Air	1%	

[a] A uniform distribution between drywell and suppression pool atmosphere has been assumed.

[b] Expressed in percentage (%) of total core inventory at end-of-life conditions (1000 days at 3556 MWt).

[c] Represents the total volume in which the fraction of core fission products is assumed to be homogeneously mixed.

[d] In calculating the radiation dose at a particular location, it is not necessary to assume that all source distribution assumptions are conservative simultaneously. Instead, a set of mutually compatible assumptions will be used which gives the maximum dose for the location being considered. The post-LOCA source contributors are used to calculate independent doses for each contributor. The worst dose is tabulated for that system rather than the sum of all contributors (i.e., 50% halogens airborne and 50% halogens in the water). Thus double counting of the fission product fractions is eliminated.

[e] First order iodine plateout occurs during the first 5-6 hr of the post-LOCA time frame when the elemental halogen concentration is reduced by a factor of 200. This methodology is in accordance with NUREG/CR-0009. Of the halogens released, 95.5% is available for plateout. Virtually all of the available halogens plateout within the initial 5 hr after the accident (0.5% remain airborne).

Table J.3-2

Distribution of Fission Products in the Worst Post-Loss-of-Coolant Accident Situation for Areas Inside Containment Pressurized Reactor Coolant System[a]

	Drywell Air Space[a]	Suppression Pool Water Volume and Air Space[a]	Reactor Coolant System Water Volume[a]		Reactor Coolant System Steam Space[a]	
Fission products	Fraction[b]	Fraction[b]	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]
Noble gases	0%	0%	100%[d]	RCS water volume[e]	100%[e]	Normal RCS steam space[f]
Halogens	0%	0%	50%[g]		25%	
Particulates	0%	0%	1%		0%	

[a] The reactor coolant system will remain pressurized for a short period of time (17 hr) and then will be depressurized.

[b] Expressed in percentage (%) of total core inventory at end-of-life conditions (1000 days at 3556 MWt).

[c] Represents the total volume in which the fraction of core fission products is assumed to be homogeneously mixed.

[d] The 100% of noble gases, present during the 17 hr of the pressurized RCS during a LOCA, are homogeneously mixed in the water and steam dilution volumes identified.

[e] The dilution volume is the RCS water volume plus the RWCU lines up to the isolation valves, RHR lines to the isolation valves, and the RRC lines during the 17 hr of the pressurized RCS scenario.

[f] The dilution volume is the normal RCS steam space plus the MS lines up to the isolation valves during the 17 hr of the pressurized RCS scenario.

[g] In calculating the radiation dose at a particular location, it is not necessary to assume that all source distribution assumptions are conservative simultaneously. Instead, a set of mutually compatible assumptions will be used which gives the maximum dose for the location being considered. The post-LOCA source contributors are used to calculate independent doses for each contributor. The worst dose is tabulated for that system rather than the sum of all contributors (i.e., 50% halogens airborne and 50% halogens in the water). Thus double counting of the fission product fractions is eliminated.

Table J.3-3

Distribution of Fission Products in the Worst
Post-Loss-of-Coolant Accident Situation
for Areas Outside Containment

	Primary Containment Air Space		Suppression Pool Water Volume		Reactor Coolant System Steam Space[a]		Reactor Coolant System Water Volume[a]	
Fission Products	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]	Fraction[b]	Dilution Volume[c]
Noble gases	100%	Drywell	0%	Suppression pool water plus RCS water	100%	Normal	100%	RCS
Halogens	50%[d]	Air plus	50%[e]		25%	RCS	50%	Water
Particulates	0%	Suppression pool air	1%		0%	Steam space	1%	Volume

[a] Based on pressurized reactor coolant system.

[b] Expressed in percentage (%) of total core at end-of-life conditions (1000 days at 3556 MWt).

[c] Represents the total volume in which the fraction of core fission products is assumed to be homogeneously mixed.

[d] 95% of the halogens released from the core are assumed to plateout within approximately 5 hr as allowed by NUREG/CR-0009. The plateout dose was considered in the total calculation of radiation dose to equipment inside primary containment.

[e] In calculating the radiation dose at a particular location, it is not necessary to assume that all source distribution assumptions are simultaneously conservative. Instead, a set of mutually compatible assumptions will be used which gives the maximum dose for the location being considered. The post-LOCA source contributions are used to calculate independent doses for each contributor. The worst dose is tabulated for that system rather than the sum of total contributors (i.e., 50% halogens airborne and 50% halogens in the water). Thus double counting of the fission of product fractions is eliminated.

Table J.3-4

System Operation and Source Term Assumptions

System	Operation Postaccident	Contaminated Space	Source Term Assumptions
HPCS	Suction from condensate storage tank and/or suppression pool and discharge to the reactor vessel.	Suppression pool	(1)
LPCS	Suction from suppression pool and discharge to the reactor vessel.	Suppression pool	(1)
LPCI	Suction from suppression pool and discharge to the core.	Suppression pool	(1)
(6) RCIC steam system	Steam bleed-off from reactor steam space is used to drive the RCIC turbine, and exhausts into the suppression pool.	RCS steam space	(2)
RCIC liquid system	Suction from condensate storage tank or suppression pool and discharge to the reactor vessel.	Suppression pool	(1)
RHR system	(1) Shutdown cooling mode - suction from reactor recirculation system suction line and discharge into the reactor recirculation discharge line.	RCS liquid space	Note a
	(2) Alternate shutdown cooling mode - suction from suppression pool and discharge to core recirculates and cools the water in the suppression pool.	Suppression pool	(1) Note b
	(3) Containment spray cooling mode - suction from suppression pool and discharge into the drywell and suppression pool.	Suppression pool	(1)
	(4) Reactor steam condensing mode.	System mode deleted from plant	

Table J.3-4

System Operation and Source Term Assumptions (Continued)

System	Operation Postaccident	Contaminated Space	Source Term Assumptions
Main steam supply (MS)	Stagnant steam from the reactor vessel terminates at the second MSIV.	RCS steam space	(2)
MSIV-LCS (MSLC)	Steam bleed-off from main steam line, diluted, and discharged into the SGTS.	RCS steam space	(2) Note c
SGT filters (SGTS)	Process the halogens from primary containment leakage and MSIV-LCS.	Primary containment and secondary containment atmosphere	(3)
Primary containment (PCN)	Primary containment is isolated postaccident.	Primary containment atmosphere	(4)
Suppression pool	The primary function of the suppression pool is to contain and condense the blowdown from the RCS postaccident.	Suppression pool liquid	(1)
Secondary containment (SCN)	The primary function of the secondary containment is to contain all the leakage from the primary containment postaccident.	Primary containment atmosphere	(5)
Sample lines	Actuated to obtain primary containment atmosphere samples per NUREG-0737 (Reference J.7-5).	Primary containment atmosphere	(2)
Sample lines	Actuated to obtain liquid samples per NUREG-0737.	RCS liquid space	(1)
Reactor water cleanup (RWCU)	Reactor water cleanup system isolated during post-LOCA. Liquid up to the second isolation valve is considered contaminated.	RCS liquid	(1)
Reactor recirculation (RRC)	Suction from RRC system suction line and discharge into the reactor recirculation discharge line.	RRC liquid; RCS liquid	(1)
Floor drains and equipment drains (FDR/EDR)	Liquid from ruptured pipes or leaky seals discharged into the suppression pool.	RCS liquid	(1)

Table J.3-4

System Operation and Source Term Assumptions (Continued)

System	Operation Postaccident	Contaminated Space	Source Term Assumptions
Automatic depressurization system (ADS)	Automatic or manual depressurization of the reactor vessel by blowdown of the RCS into the suppression pool.	RCS steam	(2)
Automatic depressurization system (ADS)	Alternate shutdown cooling mode with reflood of reactor vessel and discharge into suppression pool.	Suppression pool	(1)
Containment monitoring system (CMS)	Continues to monitor primary containment atmosphere conditions.	Isolation of primary containment into secondary containment	(4)
Containment supply purge (CSP)	Isolated - no action required.	Isolation of primary containment into secondary containment	(4)
Containment exhaust purge (CEP)	Isolated - no action required.	Isolation of primary containment into secondary containment	(4)
Blank penetrations	None	Isolation of primary containment into secondary containment	(4)
Personnel access doors to primary containment	None	Isolation of primary containment into secondary containment	(4)
Instrumentation penetrations	None	Isolation of primary containment into secondary containment	(4)
All post-LOCA inboard and outboard isolation valves	As defined per Columbia Generating Station system requirements post-LOCA	Isolation valves and their connected piping which extends into secondary containment	Note d

Source Term Assumptions

(1) 50% halogens and 1% solid fission products diluted with suppression pool water plus RCS water.

(2) 100% noble gases and 25% halogens diluted with the RCS steam space.

Table J.3-4

System Operation and Source Term Assumptions (Continued)

(3) 50% halogens leaked from the primary containment is assumed to be deposited in the SGT filters at the rate of 0.67% per day. See Section J.5.3.3.1 for justification. 100% noble gases pass through also but are not absorbed.

(4) 100% noble gases and 50% halogens diluted with the primary containment air space. First order iodine plateout (0-95% elemental iodine) inside primary containment was considered.

(5) Assumptions involved in the calculation of source terms for secondary containment atmosphere are discussed in Section J.5.3.2.1.

(6) Based on a pressurized reactor coolant system.

[a] According to accident mitigation procedures, this mode of operation is not used after a degraded core condition is identified.

[b] Full discussion of source term assumptions for alternate shutdown cooling are presented in Section J.5.3.3.1.

[c] For the portion of system after the distribution header, credit is taken for dilution by clean air. See Section J.5.3.3.1 for justification.

[d] For all isolated systems the source term for the isolation valves will be primary containment atmosphere unless the penetration is filled with water that remains during the post-LOCA scenario. All penetrations and their associated isolation valves which contain a flowing fluid during post-LOCA operations are analyzed with the post-LOCA source term of that flowing fluid.

J.4 ACCESS AND OCCUPANCY OF VITAL AREAS

NUREG-0578 initiated the requirement for a design review to identify the location of vital areas in which personnel occupancy may be unduly limited by the radiation fields during postaccident operations. It required that each licensee provide adequate access to vital areas through design changes, increased permanent or temporary shielding, or postaccident procedural controls. NUREG-0737 further makes the point that the purpose of this design review is to determine what actions can be taken over the short-term to reduce radiation levels and increase the capability of operators to control and mitigate the consequences of an accident.

This shielding evaluation includes the calculation of gamma dose rates at selected locations outside the reactor building due to radioactive sources inside. The radioactive source terms obtained from ORIGEN computer calculations coupled with recommendations from Regulatory Guide 1.109 were the basis for the assumptions used in evaluating vital areas and access routes outside the reactor building.

J.4.1 DOSE RATES OUTSIDE THE REACTOR BUILDING

An analysis was conducted to determine the dose rates at selected locations outside the reactor building for personnel access purposes. The radiation level in the various areas outside the reactor building is defined by the following three radioactive sources:

a. Direct gamma ray dose from radioactive piping located inside the reactor building and attenuated through the walls of the reactor building,

b. Gamma shine dose from airborne activity inside the reactor building, and

c. Gamma dose from airborne activity outside the reactor building.

Radiation levels outside the reactor building were determined by the zone dose method as discussed in Section J.5.4. Representative zones were chosen at selected locations outside the reactor building such as ground level outside the railroad bay, sampling room, etc. The worst point in a zone was chosen to be the point directly outside the reactor building wall, at a height of 6 ft above floor elevation, at a lateral point determined by inspection to receive the highest dose along that wall.

The zones outside the reactor building are indicated by the letters Y and Z in the various elevations. The shine dose contribution to areas outside the reactor building (Zones Y and Z) were included in the dose calculations shown in Figures J.6-11 through J.6-18.

Attachment J.H presents the methodology used to calculate the radiation doses for the various vital areas.

J.4.2 VITAL AREAS AND ACCESS ROUTES OUTSIDE THE REACTOR BUILDING

Radiation calculated for the access routes were based on the assumption that no individual would be in an access route longer than 30 minutes for the first 8 hr after the postulated LOCA before reaching the vital area of interest.

The assumption was also made that no individual would occupy an infrequent occupied vital area longer than 30 minutes for the first 8 hr after the postulated LOCA.

All integrated radiation doses calculated for time spent in the access routes and vital areas were less than the guidelines presented in NUREG-0737.

J.4.3 VITAL AREAS AND ACCESS ROUTES INSIDE THE REACTOR BUILDING

Analysis has been completed to take credit for a vital area in the reactor building railroad bay and on the west side of the 522-ft el. The analysis of reactor building zones is discussed in Section J.5.3. The access route to the reactor building is discussed in Sections J.4.1 and J.4.2. See Section J.6.3 for a description of the access to the 522-ft el. of the reactor building.

J.5 METHODS

Due to the large number of C1E/SRM components in primary containment, it was decided to calculate the worst point dose from each of the major sources in the drywell and wetwell, and then sum the doses for a conservative estimate of the total integrated dose.

The secondary containment radiation dose assessment portion of the shielding evaluation was initiated by dividing the reactor building into radiation zones. Because of the large number of radioactive piping and safety-related equipment in the building, the division of the various regions of the secondary containment into radiation zones permits a precise, detailed calculation of the total integrated dose at the “worst target” location. The methods for performing the calculations are discussed in detail in the following sections.

The radiation dose assessment of safety-related equipment outside of the reactor building was done by calculating the radiation dose of each vital area where safety-related equipment was located. The assumptions and methodology used to perform these calculations are discussed in detail in the following sections and in Attachment J.H.

J.5.1 THE USE OF COMPUTER CODES

The two computer codes used in the primary containment shielding evaluation were ORIGEN2 and QAD-CG. Descriptions of the two codes are found in References J.7-8, J.7-9, J.7-10, and J.7-17. ORIGEN2 was used to compute the radioactive source terms (inside containment) used by QAD-CG to calculate the radiation doses from piping and various pieces of equipment.

The three computer codes used in the original secondary containment radiation shielding review were ORIGEN, SCAP-BR, and QAD-P5A. Descriptions of the codes are found in References J.7-10, J.7-11, and J.7-18. ORIGEN computes the radioactive source terms used by QAD-P5A to compute the radiation from piping and other source configurations to pieces of equipment. SCAP-BR computes the radiation dose contribution to safety-related equipment in the reactor building from primary containment airborne radiation streaming through the bioshield wall penetrations.

ORIGEN and ORIGEN2 are fission product source term codes which solve the equations of radioactive growth and decay for large numbers of isotopes. The codes have been used to calculate the radioactivity of fission products and fuel materials that were assumed to be released from the reactor core during the postulated loss-of-coolant accident (LOCA) to become the primary containment source terms for the dose rate calculations. SCAP-BR is similar to QAD-CG with the added capability to determine the radiation dose contribution due to scattering.

J.5.2 SOURCE TERM DEVELOPMENT FOR PRIMARY CONTAINMENT

The radiation level at any given location inside the primary containment of Columbia Generating Station (CGS) following the postulated LOCA such as that described in Section J.3.1 is determined from the following major source contributors:

a. Gamma ray dose from airborne radioactive sources suspended in the drywell and wetwell inside primary containment (airborne gamma dose),

b. Gamma ray dose from piping and/or equipment containing contaminated fluids which are recirculated inside primary containment (direct gamma dose),

c. Gamma and beta ray dose from iodines plated out inside primary containment (iodine plateout), and

d. Beta ray dose emitted by airborne radioactive sources suspended in the drywell and wetwell inside primary containment (airborne beta dose).

The initial phase of this analysis was concerned with the determination of radioactive source terms for the liquids and gases inside primary containment. The ORIGEN2 computer code was used for this calculation. The fission product inventory at the end of fuel life (1000 days irradiation at a power level of 3556 MWt) was assumed to be available for release immediately following the accident. The release fractions and resulting concentrations of noble gases, halogens, and other fission products in the gaseous and liquid fluids were computed. A detailed description of the analysis including the assumptions used is provided in Attachment J.F.

J.5.3 SOURCE TERM DEVELOPMENT FOR SECONDARY CONTAINMENT

The radiation level at a given location inside the secondary containment of CGS following an accident such as that described in Section J.3.1 is defined by the following major source contributors:

a. Gamma ray dose from airborne radioactive sources inside secondary containment (airborne gamma dose),

b. Gamma ray dose from radioactive sources suspended in the drywell and the wetwell inside primary containment (containment shine dose),

c. Gamma ray dose from piping and/or equipment containing contaminated fluids which are recirculated inside the reactor building (direct gamma dose),

d. Beta ray dose emitted by airborne radioactive sources inside secondary containment (airborne beta dose), and

e. Gamma ray dose from liquid piping and airborne radioactive sources inside primary containment which stream through bioshield wall penetrations into secondary containment (bioshield penetration streaming dose).

The initial phase of this analysis was concerned with the definition of radioactive source terms for the liquid and gas containing systems. The ORIGEN computer code was used for this calculation. The fission products at the end of fuel life (1000 days irradiation at a power level of 3556 MWt) were assumed to be available for release immediately following the accident. The released fractions of noble gases, halogens, and other fission products to the gaseous and liquid sources were computed. Subsequent fission product depletion and daughter product generation were then calculated for 20 time periods, covering a total period of 1 year. A detailed description of the analysis, including the assumptions used, as well as results of the source terms, is found in Attachment J.B and Reference J.7-12.

J.5.3.1 Parametric Studies for Direct Piping Dose in Secondary Containment

The purpose of the parametric study was to identify the parameters which have a significant effect on the radiation dose rates inside secondary containment. The computer code QAD-P5A was used to develop a correlation scheme for the significant parameters such that a simplified procedure for calculating radiation dose rates for complex source and receptor geometries can be developed. The dose rate at a target distance of 8 ft radially outwards from the centerline of an 8-in. schedule 40 pipe, infinitely long (standard pipe), was first calculated and defined as the standard dose rate. The results of this parametric study were then correlated as a set of correction factors to the standard dose rate. A simplified procedure was developed to calculate the dose rates and cumulate doses for complicated source-target configurations by using these correction factors. The development of these correction factors and the result of the parametric study inside secondary containment is discussed in Attachment J.B.

J.5.3.2 Dose Rate and Cumulative Dose Calculation Procedure

The results of the source term calculations and those of the parametric study were used to generate and cumulate doses for complicated source target configurations inside secondary containment. The following steps were taken to define the radiation service conditions for the pieces of safety-related equipment:

a. Based on the accident scenarios, contaminated systems, and assumptions defined in Section J.3, the radioactive source terms for liquid-containing and gas-containing systems were developed;

b. Radiation zones were selected and the radiation zone boundaries were carefully defined based on shield wall locations, contaminated piping locations, and locations of safety-related C1E/SRM equipment;

c. The radiation environment in each secondary containment zone (zone dose) was calculated (see Attachment J.B for the procedure). A zone dose is the radiation dose (gamma) that bounds the magnitude of dose received by all the pieces of safety-related C1E/SRM equipment located within that zone;

d. The zone dose as calculated in step c was used, as a first cut, to qualify all the pieces of safety-related C1E/SRM equipment located within that zone; and

e. For the pieces of safety-related C1E/SRM equipment that could not be qualified for the conservative radiation environment calculated in step c, the integrated dose for that piece of equipment was redefined based on a more realistic and refined approach.

J.5.3.2.1 Calculation of Airborne Gamma Doses Inside Secondary Containment

The time-dependent post-LOCA activity levels as calculated by the ORIGEN computer code were used as input for the calculation of the airborne gamma dose rates and integrated doses inside the cubicles in the secondary containment. The assumptions used in this analysis are as follows:

a. Activity that leaks into the secondary containment is homogeneously mixed with the secondary containment atmosphere prior to its removal from the atmosphere through the standby gas treatment system (SGTS);

b. The SGTS flow rate of 2430 scfm was assumed to be the flow rate of the effluent air. This is equivalent to one reactor building air change per day;

c. Air that leaks out of the primary containment flows directly and totally into the secondary containment. Bypass leakage was not considered;

d. Geometric factors were used to convert the semi-infinite cloud gamma dose to a finite gamma dose; and

e. Primary containment leakage rate of 0.5 wt %/day was considered.

Justifications of the above assumptions are stated in Attachment J.B. The equations that were used for the gamma dose calculations are described in Attachment J.B. Primary containment airborne beta dose results are discussed in Attachment J.G.

J.5.3.2.2 Procedure for the Calculation of Radiation Zone Dose in Secondary Containment

As discussed previously, the gamma radiation level at a given location inside the secondary containment of CGS following a LOCA is determined for four types of radioactive source distributions:

a. Fission products suspended in the atmosphere of the secondary containment (airborne gamma dose),

b. Gamma irradiation from the primary containment (shine dose),

c. Direct gamma irradiation from the radioactive fluid contained inside recirculating pipes (direct dose), and

d. Gamma ray dose from liquid piping and airborne radioactive sources inside primary containment which stream through bioshield wall penetrations into secondary containment (bioshield penetration streaming dose).

The dose contributed by each of these sources is determined by the location of the equipment, the time-dependent distribution of the source, and the effects of shielding.

A step-by-step procedure for calculating radioactive zone doses is shown in Attachment J.C. The methods presented in that procedure make it possible to calculate the worst case gamma dose from the above-mentioned source contributors inside radiation zones of the secondary containment. In general, this procedure for determining zone doses consists of a correction factor method for calculating direct dose rates.

As discussed in Attachment J.B, the correction factor method for calculating dose rates provides a convenient and fairly precise way of determining direct dose rates due to generic pipe segments. For radioactive fluid contained within components of geometry other than generic pipe segments, such as residual heat removal (RHR) heat exchangers, SGTS filters, hydrogen recombiners, etc., special QAD-P5A computer modeling was performed to calculate the gamma dose contribution due to those systems. A brief description of the guidelines used in modeling special components is found in Attachment J.B.

An evaluation of beta dose is necessary for qualification of safety-related equipment that is beta sensitive and not adequately protected against beta radiation. The beta dose analysis for secondary containment is presented in Section J.5.5. Beta dose is discussed in more detail in Attachment J.D as related to secondary containment radiation contributors.

J.5.3.3 Calculation of Radiation Doses Due to Special Systems and Components Inside Secondary Containment

As discussed in Attachments J.B and J.C, the correction factor method for calculating gamma dose rates and integrated doses is involved with the application of the dose correction factors (pipe diameter, pipe length, and radial distance correction factors) to a standard dose rate curve. A standard dose is defined as the gamma radiation measured at a target distance of 8 ft and emitted by radioactive sources contained within the suppression pool liquid and recirculated within infinitely long 8-in. schedule 40 piping. The systems that contain such radioactive fluids are the reactor coolant system, high-pressure core spray, low-pressure core spray, and residual heat removal systems. Other systems which contain fluids of different source terms and dilutions are considered special sources. The systems that need to be considered for special sources are the following:

a. Standby gas treatment system filters,
b. Main steam system, and
c. Main steam isolation valve leakage control system (MSIV-LCS).

J.5.3.3.1 Source Term Assumptions in Secondary Containment

The assumptions for the calculations of source terms inside secondary containment for special source systems are listed as follows:

Standby Gas Treatment System Filters

a. The SGTS filters will be loaded by halogens at the rate of 0.67% primary containment free volume per day. This consists of 0.5% per day of primary containment leakage and 0.17% per day of leakage due to the MSIV-LCS system. No holdup of this activity in the secondary containment is assumed;

b. The released halogen fraction is 50% of the core halogen inventory. This halogen fraction is assumed to be composed of 95.5% elemental, 2% organic, and 2.5% particulate halogens; and

c. The particulate halogens are assumed to be homogeneously distributed within the prefilters and the particulate filters, while the elemental and organic halogens are assumed to be homogeneously distributed within the charcoal filters.

Assumption a is consistent with the assumptions used in the accident analysis (Reference J.7-13 and Section J.3.1).

Assumption b is the NRC recommended assumption for the distribution of halogen inventory (Reference J.7-14).

Assumption c is necessary because the time-dependent distribution of activity within a filter is unknown. The homogeneous assumption, therefore, is considered appropriate and conservative for zone dose assessment.

Containment Atmosphere Control System

The function of the CAC system was to process the primary containment atmosphere to remove oxygen after a LOCA accident. Therefore, this system was assumed to be filled with gaseous source containing 2.5% halogens and 100% noble gases diluted with the primary containment free volume, although it is now deactivated.

Main Steam System

The main steam lines are located inside and outside the primary containment; they include the main steam lines in the steam tunnel and the RCIC turbine supply and exhaust lines. The radioactive source term for this system is assumed to be composed of 100% noble gases and 25% halogens, distributed throughout the reactor coolant system (RCS) steam space.

Alternate (Suppression Pool) Shutdown Cooling

To prevent failure of the RHR pumps due to excessive radiation exposure, the alternate shutdown cooling mode is the only allowable mode for shutdown cooling once a degraded core condition has been identified.

A small pipe-break accident will take approximately 6 hr to depressurize from 1000 psi to 150 psi through automatic depressurization system (ADS) valve actuations. Once a degraded core is identified and the reactor is sufficiently depressurized, within 17 hr after the accident, the ADS valves actuation will be maintained to dilute the primary coolant source concentration with the suppression pool since the alternate shutdown cooling mode will be used for decay heat removal.

For the large pipe-break accident the primary coolant source concentration will be diluted by the water in the suppression pool due to blowdown of the vessel through the large break or automatic actuation of the ADS valves. Once the vessel has been depressurized the water level in the vessel will be maintained with the emergency core cooling system while decay heat is removed by suppression pool cooling.

Thus, in all degraded core scenarios the primary coolant is diluted with the suppression pool prior to initiating the suppression pool shutdown cooling mode.

Main Steam Isolation Valve Leakage Control System

The MSIV-LCS system is a vacuum-type system which collects leakage between and downstream of the closed isolation valves and then releases it to the atmosphere through the SGTS. Leakage through the valve stems (maximum leakage of 11.5 scfh as described in Reference J.7-15) is directed to a distribution header or low-pressure manifold where clean air is brought in to dilute the contaminated steam before exhausting to the SGTS filter unit at a rated flow rate of 50 scfm. Thus the source term in the portion of piping system before the distribution header is conservatively assumed to be the same as that of the main steam system. For the portion of the piping after the header, credit is taken for the dilution by the clean air. This assumption is consistent with that recommended in Reference J.7-16.

J.5.3.3.2 Secondary Containment Analysis Method

The correction factor method is used for the calculation of the direct dose contribution due to the piping systems described in Section J.5.3.3, with the exception of the SGTS filter system. A description of the analysis of the SGTS filter is documented in Attachment J.D. Generic piping dose rate and integrated dose (dose at a target distance of 8 ft away from the centerline of an infinitely long 8-in. schedule 40 pipe) for each system were developed using the source term assumptions discussed in Section J.5.3.1 and are shown in Attachment J.B. Parametric studies were also performed to investigate the variation of dose rates due to pipe diameter, pipe length, and target distance for pipe segments containing source terms. The gaseous source term correction factors derived as a result of this parametric study (described in Attachment J.B), together with the generic dose rate curves generated for each system, were used to calculate the direct gamma dose contribution on a target.

J.5.3.3.3 Calculation of Radiation Doses Inside Secondary Containment on Generic Mechanical Equipment

Table J.5-1 is a sample list of generic mechanical equipment that are on the safety-related equipment list. For conservatism, the direct dose on the containment pieces of generic mechanical equipment is assumed to be the fluid contact dose. Figure J.5-1 is an illustration of the point where the direct dose is calculated on a piping segment.

The secondary containment source term assumptions developed in Section J.5.3 are used for the calculation of radioactive source terms for different systems, and the fluid contact dose was calculated using QAD-P5A by following the guidelines set forth in Attachment J.C. Figures J.5-2 through J.5-3 are 6-month integrated fluid contact doses versus pipe diameter.

These curves are intended to give conservative, upper-bound direct gamma dose estimates for the qualification of the pieces of generic mechanical equipment and components in the various systems. To use these curves to calculate the direct doses on generic mechanical equipment, the following steps should be taken.

a. Identify the system on which the equipment or component is located,

b. Identify the diameter of the contaminated pipe on which the equipment is located, and

c. The 6-month integrated dose for that piece of equipment or component can be determined by reading the appropriate curve.

J.5.4 SOURCE TERM DEVELOPMENT FOR C1E/SRM EQUIPMENT OUTSIDE THE REACTOR BUILDING

The radiation level at any given location outside the reactor building following the postulated LOCA as described in Section J.3.1 is determined from the following major source contributors:

a. Direct gamma dose from radioactive piping located inside the reactor building and attenuated through the walls of the reactor building,

b. Gamma shine dose from airborne activity inside the reactor building, and

c. Gamma ray dose from airborne activity outside the reactor building.

A detailed description of the method of analysis, including the assumptions used, as well as results of the source terms is found in Attachment J.H.

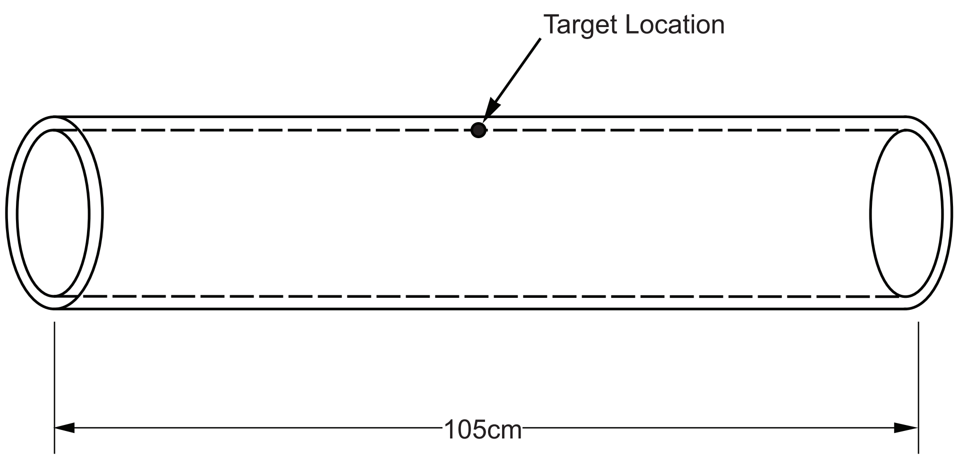
J.5.5 METHODOLOGY OF BETA DOSE ANALYSIS

The finite source volume used for the beta dose analysis in secondary containment is a sphere surrounded by a shell of sufficient thickness to stop all outside beta particles from entering the source volume. This finite spherical source volume is conservative for any generalized source shape (the dose at the center of the sphere is higher than the dose at any point of any generalized source shape of equal total volume). A discussion of this beta analysis methodology is presented in Attachment J.D.

Table J.5-1

Generic Mechanical Equipment

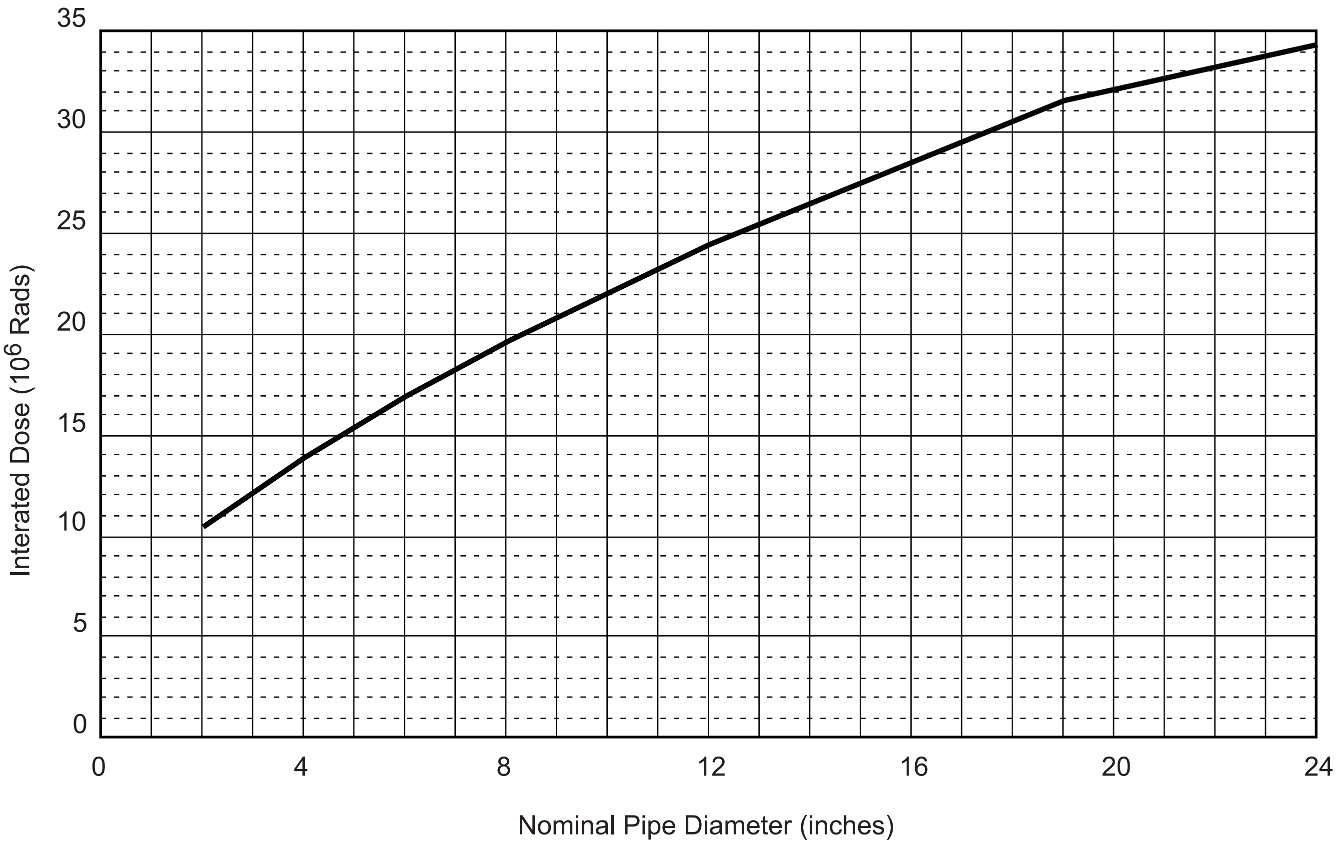
Valve packing
Lubricants
Seals
Expansion joints
Pressure relief valve
Flow element
Rupture disk
Gasket material
Conductivity element
Valve
Strainers
Steam traps
Filters (piping)
Temperature elements
Tanks
Moisture separators
Evaporator
Heat exchanger
Air washer (scrubber)
Pumps



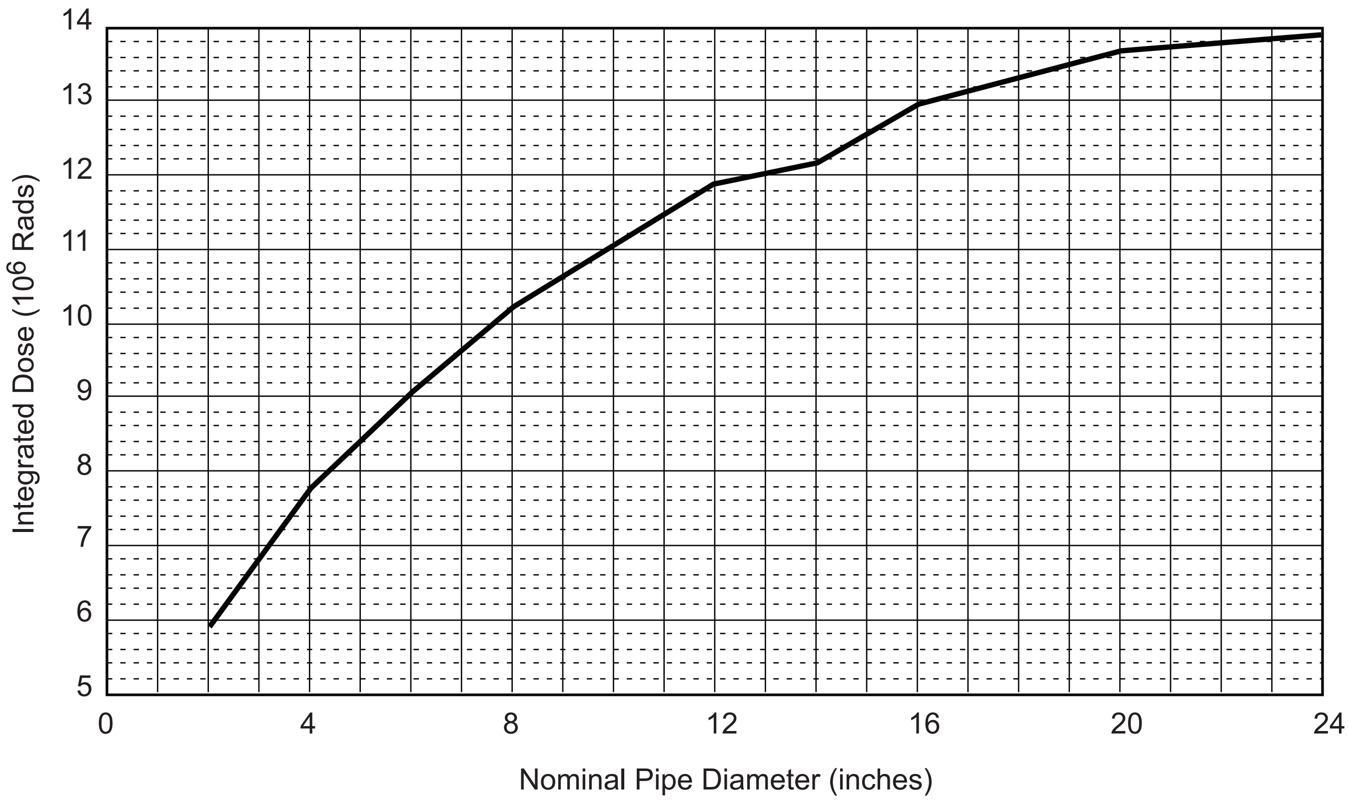
Columbia Generating Station
Final Safety Analysis Report

Dose Model Liquid Source

Draw. No. 970187.23 | Rev. | Figure J.5-1



Sixth Month Integrated Fluid Contact Dose for MS, RCIC (Steam) System, and MSLC System Upstream of the Header



Sixth Month Integrated Fluid Contact Dose for Pipes Containing Liquid Source Term (RHR, HPCS, LPCS, RCIC Liquid Systems)

J.6 RESULTS

All loss-of-coolant accident (LOCA) scenarios and accident conditions that could result in a limiting radiation environment for all the Columbia Generating Station (CGS) safety-related equipment on the C1E* list were reviewed and analyzed accordingly. Shielding (shield doors) was constructed for zones 522D, 572N, 572D, and 572H due to the radiation exposure of safety-related equipment in these zones.

In addition a shield wall was designed and installed on the southeast portion of the 501 ft el. against the bioshield wall to protect C1E* equipment from RRC piping radiation sources (normal operation) which stream through penetrations X-100A, X-105A, and X-100B.

The completeness of the safety-related equipment list has been verified. The safety-related equipment list contains all equipment required to "mitigate the consequences of an accident, bring the plant to safe shutdown conditions and provide long-term cooling capability."

Systems that could potentially contain radioactive material during and following the accident have been identified as listed in Sections J.3.2.1 and J.3.2.2.

The accident radiation doses indicated in Section J.6.1 and Table J.6-1 generated as a result of this analysis, are intended solely for the purpose of the qualification of safety-related equipment.

J.6.1 PRIMARY CONTAINMENT RADIATION RESULTS

Due to the large number of safety-related components it was deemed impractical to calculate the integrated dose to each piece of equipment. Therefore, the worst point dose from each of the major sources in the drywell and wetwell was calculated, and then summed for a conservative estimate of the total integrated dose. The dose sum of the worst-case source contributors in the drywell is 7.6×10^7 rads, but 7.4×10^7 rads is used as the worst-case dose for the equipment qualification program. All of the worst-case contributors cannot be present for a particular accident. Thus, the largest worst-case dose is calculated for the depressurized reactor coolant system. The worst-case dose is applied to safety-related equipment with an elevation within 5 ft of core midplane. Safety-related equipment in the drywell outside this elevation span is assigned a dose of 7.0×10^7 rads. In the wetwell, the maximum gamma dose above the suppression pool is 9.5×10^7 rads (see Section J.F.3 for discussion on photon energy and anticipated dose reduction of the above results). These results include the contributions from all major gamma sources within primary containment during normal operation as well as the 6-month period contribution following a postulated LOCA. Tables J.F-1 and J.F-2 give a breakdown of the integrated dose contribution from each of the

---

* Environmental qualification (EQ) of safety-related mechanical (SRM) equipment has been eliminated from the overall CGS EQ program.

major gamma sources to the drywell and the wetwell. The 40-year integrated gamma doses due to normal operation are taken from Reference J.7-20.

This methodology for determining a worst-case dose for equipment in the drywell is not valid for the region inside the sacrificial shield wall or under the reactor pressure vessel. A point-specific radiation dose calculation is required for all components present in either of these two regions.

Specific calculations have been performed for equipment that was evaluated individually for total integrated dose. Results of these calculations are summarized in Reference J.7-26.

In accordance with Section 1.4(8) of Reference J.7-2, only the gamma dose need be considered for "shielded components." Since beta radiation is so readily attenuated, virtually any enclosure of sensitive components will be sufficient to classify the component as "shielded." A review of all safety-related equipment located inside primary containment determined that most C1E* equipment is sufficiently shielded against beta radiation. Thus, the beta dose contribution is excluded from the total integrated radiation doses compiled for equipment qualification purposes unless a beta-sensitive component is not adequately protected from the airborne beta environment. When required to include beta dose contributions, a finite source volume is used. The source volume is a sphere surrounded by a shell of sufficient thickness to stop all beta particles from entering the source volume. This finite spherical source volume is conservative for any generalized source volume shape (the dose at the center of the sphere is higher than the dose at any point of any generalized source shape of equal total volume). A discussion of the results is presented in Attachment J.G.

J.6.2 SECONDARY CONTAINMENT RADIATION RESULTS

The integrated direct gamma dose (40 years and 6 months LOCA - direct gamma, gamma shine, and airborne gamma) was evaluated for the worst target of all C1E* equipment in each zone and is used for qualification of all the other C1E* equipment in that zone. The 40-year integrated gamma doses (Figures J.6-1 through J.6-10) are taken from References J.7-20 and J.7-21. The direct gamma dose contribution outside primary containment due to sources inside the primary containment was investigated. Safety-related equipment located in the direct shine path through the penetrations was evaluated in Reference J.7-23. All post-LOCA radiation dose contributions to safety-related equipment from streaming through the bioshield wall penetrations were included in the radiation doses. Evaluation of bioshield wall penetrations identified radiation dose problems associated with some of those penetrations (Reference J.7-24). The post-LOCA evaluation of safety-related equipment assumed the C1E* equipment was shielded for 40-year normal operations. To adequately protect C1E* equipment a concrete wall was designed and installed for penetrations X-100A, X-105A, and X-100B. The

* Environmental qualification (EQ) of safety-related mechanical (SRM) equipment has been eliminated from the overall CGS EQ program.

remaining penetrations evaluated (Reference J.7-25) were surveyed during plant startup to confirm radiation analysis calculations.

Airborne beta doses outside containment were evaluated in accordance with the methodology described in Section J.5.5 and Attachment J.D. The beta dose contribution is excluded from the total integrated radiation doses compiled for equipment qualification purposes unless a beta sensitive component is not adequately protected from the airborne beta environment.

J.6.3 RADIATION RESULTS IN THE VITAL AREAS AND ACCESS ROUTES

Figures J.6-8 through J.6-16 present the vital areas and access routes located outside the reactor building. Figures J.6-17 and J.6-18 present the vital areas and access routes located inside the reactor building. The doses indicated on each figure are also the 6-month LOCA integrated gamma doses to be used for C1E* (safety-related) equipment qualification purposes. Table J.6-1 also presents a summary of the 6-month LOCA integrated gamma doses on all C1E* equipment located in vital areas.

Figures J.6-17 and J.6-18 show the access route in the reactor building for operation of SW-V-75AA and SW-V-75BB, the manual isolation valves for the service water to fuel pool cooling makeup water supply.

Radiation levels of vital areas and access routes were determined at selected locations outside the reactor building due to radioactive sources inside the reactor building and release of radiation activity from the reactor building elevated vent. The vital areas and access routes analyzed are consistent with those discussed in NUREG-0737, Item II.B.2 (Reference J.7-5). The radiation levels determined for the vital areas and access routes identified in Figures J.6-8 through J.6-18 are summarized in Table J.6-1. All of the vital areas and access routes have radiation levels less than the guidelines presented in NUREG-0737.

The total dose received at a vital area during a post-LOCA scenario is obtained by summing the exposure dose enroute to the vital area and the radiation dose at the vital area. These doses are listed in Table J.6-2.

The analysis completed for vital areas and access routes assumed that except for the reactor building railroad bay and on the west side of the 522-ft el. there would be no access to equipment or areas located within the reactor building during the post-LOCA scenario. The exceptions are shown in Figures J.6-17 and J.6-18 and Table J.6-2. Access to the reactor building railroad bay for 3 hr is allowed to provide the ability to fill or exchange N_2 bottles. The entry to the west side of the 522-ft el. is to allow SW-V-75AA and/or SW-V-75BB to be opened (see Section 9.1.3.2.3). These valves are readily accessible and the entire opening

* Environmental qualification (EQ) of safety-related mechanical (SRM) equipment has been eliminated from the overall EQ program.

evolution for one of these valves would take 2.17 minutes and could be performed at $\boxed{9.7}$ hr with the resulting exposure of $\boxed{3.8}$ rem. Under worst-case conditions, at least one of these valves would need to be opened by 10 hr. Once a manual valve is opened, the spent fuel pool level can be controlled with the motor-operated valve from the main control room.

Table J.6-1

Six-Month Total Integrated Dose (Loss-of-Coolant Accident) to Areas Containing C1E Equipment Outside the Reactor Building

Vital Area Description	Radiation Level[a] Direct Gamma Shine +Airborne Gamma (rads)
Control room (el. 501 ft)	0.21
Technical support center	0.21
Sale area (el. 487 ft)	6.5
Nitrogen supply to ADS accumulators (el. 437 ft)	3.9
Standby service water pump valves	1.7
Remote shutdown room (el. 467 ft)	3.9
Switchgear room 1 (el. 467 ft)	3.9
Switchgear room 2 (el. 467 ft)	3.9
Radwaste control room (el. 467 ft)	3.9
Battery racks, dc battery chargers, two motor control centers (MCCs) (el. 467 ft)	3.9
Three MCCs and three switchgears (el. 437 ft)	3.9
Direct current battery charger and rack (el. 437 ft)	3.9
Diesel oil tanks (el. 437 ft)	3.9
Solid radwaste control panel and decontamination station control panel (el. 437 ft)	3.9

[a] Volume correction factors for a semi-infinite cloud were applied to the control room and technical support center. If the volume correction factors were to be applied to all areas, the integrated dose would be reduced by a minimum of fivefold.

Table J.6-2

Vital Areas and Access Route List of Radiation
Exposure to Personnel During the Required
Post-Loss-of-Coolant Accident Operations

Vital Area Description	Radiation Exposure		
	Gamma Whole Body (rem)	Thyroids (rem)[a)]	Beta Skin (rads)
Control room (el. 501 ft)[b]	0.21	0.21[c]	0.95
Technical support center[b]	0.21	0.21[c]	0.95
Security center[b]	3.1	13.4[d]	4.8
Auxiliary security center[b]	1.7		2.7
Sample analysis area (EOC)[b]	0.0013	-	-
Standby service water pump valves (cooling ponds)[e]	0.3	0.94[d]	0.46
All infrequently occupied vital areas inside the radwaste and diesel generator buildings[b]	0.13[f]	1.6[d]	0.48
Sampler for elevated release duct (roof turbine building)[e]	2.5	8.0[d]	3.8
Reactor building railroad bay (N_2 bottles)[g]	0.4	-	-
Reactor building 522-ft el. (SW-V-75AA and/or SW-V-75BB[h]	$\boxed{3.8}$	-	-
Postaccident sample area (el. 487 ft)[e]	0.36	3.2[d]	0.96
Access Routes			
All access routes inside the radwaste and diesel generator buildings[e]	0.13[f]	1.6[d]	0.48
All access routes[i] outside the radwaste and diesel generator buildings[e]	0.53	1.6[d]	0.8

Table J.6-2

Vital Areas and Access Route List of Radiation
Exposure to Personnel During the Required
Post-Loss-of-Coolant Accident Operations (Continued)

[a] If self-contained respiratory equipment (SCBA) is used, the thyroid dose will essentially equal the whole-body dose.

[b] Area of continuous occupancy.

[c] Assumes self-contained respiratory equipment was used by personnel during 0-3 hr post-LOCA situation.

[d] No respiratory equipment was assumed.

[e] Area occupied 0.5 hr at times after 1 hr into the LOCA.

[f] A volume correction factor for the semi-infinite cloud was included in the calculation.

[g] Assumes entry after 12 days post-LOCA for 3-hr occupancy with respiratory equipment for railroad bay portion of reactor building only.

[h] Assumes entry after 9.0 hr post-LOCA for a 2.17-minute evolution to open SW-V-75AA or SW-V-75BB with respiratory equipment and in full PC gear following access routes shown in Figures J.6-17 and J.6-18. The 2.17 minutes consists of a 1.83-minute transit (1.5 minutes in 522K and 0.33 minutes in 522H) and a 0.33-minute occupancy time in 522H.

[i] Extremely conservative analysis since the plume of airborne radioactivity cannot simultaneously cover all access routes.

J.7 REFERENCES

J.7-1 NUREG-0578, "TMI Lessons Learned Task Force Status Report and Short-Term Recommendations."

J.7-2 NUREG-0588, Rev. 1, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment."

J.7-3 NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident."

J.7-4 Clarification letter to NUREG-0578, September 5, 1980.

J.7-5 NUREG-0737, "Clarification of TMI Action Plant Requirements."

J.7-6 IE Bulletin No. 79-01B, "Environmental Qualification of Class 1E Equipment."

J.7-7 Supplement No. 2 to IE Bulletin 79-01B, September 30, 1980.

J.7-8 Oak Ridge National Laboratory, "ORIGEN2, Isotope Generation and Depletion Code - Matrix Exponential Method," ORNL Report No. CCC-371.

J.7-9 J. F. Perkins, U.S. Army Missile Command, Redstone Arsenal, Alabama, Report No. RR-TR-63-11 (July, 1963).

J.7-10 Oak Ridge National Laboratory, "Modifications of the Point-Kernel QAD-P5A," ORNL-4181, July 1968.

J.7-11 Oak Ridge National Laboratory, "ORIGEN-79, Isotope Generation and Depletion Code - Matrix Exponential Method," ORNL Report No. CCC-217.

J.7-12 EDS Report No. 01-0740-1138, Revision 0, "Source Term Report," December 1980.

J.7-13 Columbia Generating Station FSAR, Section 15.6.5.5.1.1, Amendment 27, November 1982.

J.7-14 Regulatory Guide 1.3 "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," Revision 2, June 1974.

J.7-15 Columbia Generating Station FSAR, Sections 6.7.2 and 6.7.3.

J.7-16 Standard Review Plan, Section 15.6.5, “Loss of Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary.”

J.7-17 Oak Ridge National Laboratory, “QAD-CG, A Combinitorial Geometry Version of QAD-P5A, A Point-Kernal Code,” ORNL Report No. CCC-307.

J.7-18 Byoun, Yoon and Babel, Paul J., “Description of Computer Program (SCAP-BR),” User’s Manual.

J.7-19 Impell Calculation #0740-004-019, “Fluid Contact Dose Calculation.”

J.7-20 Letter BRWP-81-288, dated July 29, 1981, “Forty-Year Integrated Dose for Radiation Zones in the Reactor Building.”

J.7-21 Letter BRWP-RO-81-181, dated September 29, 1981, “Forty-Year Integrated Dose for Radwaste and Turbine Buildings.”

J.7-22 Burns and Roe calculation 5.01.78.

J.7-23 Burns and Roe calculation 5.01.030, “Total Accident Integrated Dose to Equipment in the Reactor Building From Primary Containment Penetration Streaming.”

J.7-24 Letter BWRP-RO-82-186, dated June 18, 1982, “Bioshield Wall Penetrations with Unresolved Shielding Concerns.”

J.7-25 Burns and Roe Technical Memorandum, TM-1295, “Bioshield Wall Penetration Shielding Requirements,” dated April 6, 1983.

J.7-26 Calculation 1140-006-CLIST, “C1E/SRM Containment List.”

J.7-27 Letter EDSWP-81-015, dated February 18, 1981, “SGTS Filter Modeling Assumption.”

J.7-28 Murphy and Campe “Nuclear Power Plants Control Room Ventilation System Design,” 13th AEC Air Cleaning Conference.

J.7-29 Letter EDSWP-80-031, “Shielding Design Input Data.”

J.7-30 Theodore Rockwell III, “Reactor Shielding Design Manual,” U.S. AEC, TID-7004, March 1956.

J.7-31 David A. Slade "Meteorology and Atomic Energy," U.S. AEC, July 1968.

J.7-32 Record of Conversation, D. A. Wert to J. A. Ogawa, dated September 22, 1980, "Shielding Source Term."

J.7-33 Letter BREDS-RO-81-17 dated December 11, 1981, A. N. Kugler to E. A. Daugherty.

J.7-34 NUREG/CR-009, Technical Basis for Models of Spray Washout of Airborne Contaminants in Containment Vessels, October 1978.

J.7-35 Columbia Generating Station FSAR, Amendment 11, Table 6.2-12.

J.7-36 Columbia Generating Station FSAR, Table 6.2-1.

J.7-37 Not used

J.7-38 EDS Nuclear Inc., Calculation 0740-004-004, Rev. 0.

J.7-39 EDS Nuclear Inc., Calculation 0740-004-006, Rev. 0.

J.7-40 Columbia Generating Station FSAR, Section 15.6.5.

J.7-41 Standard Review Plan, Section 6.5.3, "Fission Product Control Systems," Nuclear Regulatory Commission, June 1975.

J.7-42 Columbia Generating Station FSAR, Section 6.2, Table 6.2-2.

J.7-43 Columbia Generating Station FSAR, Section 6.2, Table 6.2-11.

J.7-44 WPBR-R0081-143, Holmberg to Forrest, "Plant Shielding Analysis - WNP-2," August 8, 1981.

J.7-45 Burns and Roe calculation 5.01.59, "Primary Containment 6 Month Accident Source Terms ORIGEN2."

J.7-46 Burns and Roe calculation 5.01.60, "Six Month Accident Integrated Dose in Primary Containment - Depressurized Case - QAD-CG."

J.7-47 Burns and Roe calculation 5.01.62, "Dose Rate for 26" Main Steam Lines Inside Primary Containment."

J.7-48 Burns and Roe calculation 5.01.63, "RWCU Piping Sources in Containment (Normal Operations)."

J.7-49 Burns and Roe calculation 5.01.64, "RWCU, RRC, and RHR Lines in Containment (Shielding - Normal Operation)."

J.7-50 Burns and Roe calculation 5.01.69, "Total Integrated Dose, Accident & Operation, from Systems and Primary Containment Atmosphere to Safety Related Equipment Located EDS - Pressurized Case."

J.7-51 Burns and Roe calculation 5.01.74, "Six Month Accident Integrated Dose in Primary Containment -Depressurized Case - QAD."

J.7-52 Burns and Roe calculation 5.01.75, "Accident Integrated Dose for Systems - Depressurized Case."

J.7-53 Burns and Roe calculation 5.01.76, "Total Integrated Dose, Accident & Operation, to Safety-Related Equipment in Containment Located by EDS Due to Systems."

J.7-54 Burns and Roe calculation 5.01.77, "Total Integrated Dose, Accident & Operation, from Systems and Primary Containment Atmosphere to Safety-Related Equipment in Containment Located by EDS - Depressurized Case."

J.7-55 Burns and Roe calculation 5.01.20, "WPPSS Sacrificial and Bioshield Calculations."

J.7-56 Burns and Roe calculation 5.45.07, "Post-LOCA MSIV Leakage Calculation."

J.7-57 Calculation 0740-004-VLIST, "Reactor Building SRM Active Valve, Pump, Fan, and Turbine List."

J.7-58 0740-073-001 Parameter Penetration Study.

J.7-59 Ianni, P. W., "Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors," APED-5458, March 1968.

J.7-60 "Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves," APED-5750, General Electric Company, Atomic Power Equipment Department, March 1969.

J.7-61 "Power Uprate with Extended Load Line Limit Safety Analysis for WNP-2," NEDC-32141P, General Electric Company.

J.7-62 "General Evaluations of General Electric Boiling Water Reactor Power Uprate - Volume 1," NEDC-31984P, General Electric Company.

Attachment J.A

UNISOLATED LEAKING BUILDING PATH REPORT

A basic assumption to the plant shielding analysis is that the reactor isolates such that there is no radiation leakage path to the outside. A leakage path investigation was done verifying the above assumption. While performing this investigation, the total number of lines (69) penetrating the RB boundary, the associated system components and interface systems were reviewed.

The assumption eliminating the consideration of leakage is consistent with NUREG-0737, Clarification 2. This investigation assumed that containment isolation occurred prior to the egress of highly radioactive fluids. Additionally, it assumed that all safety-related equipment was available, and that all safety systems were pressurized. Therefore, at any interface, such as a heat exchanger, no potential leakage was considered if the nonradioactive system was at a higher pressure than the radioactive system. This investigation has not considered leakage from equipment seals, closed valves, or pipe rupture, except in the evaluation of the equipment and floor drain systems. The systems considered are tabulated by drawing number in Table J.A-1.

Table J.A-1

System Flow Diagrams Employed
to Perform The Review

Drawing Number	Revision	Drawing Number	Revision
M501	10	M536	12
M502	17	M537	25
M503	5	M538	9
M504	25	M539	28
M505	14	M540	15
M506	23	M541	13
M507	27	M542	4
M508	25	M543	17
M509	10	M544	10
M510	30	M545	15
M511	15	M546	10
M512	8	M547	9
M513	33	M548	14
M514	13B	M549	14A
M515	17C	M550	9
M516	20	M551	8
M517	25	M552	12
M518	14	M553	10
M519	18	M554	11
M520	15	M555	7
M521	20	M556	10
M522	6	M557	4
M523	29	M607 Sheet 1	7
M524	19	M607 Sheet 2	5
M525	19	M607 Sheet 3	3
M526	25		
M527	18		
M528	15		
M529	21		
M530	18		
M531	24		
M532	20		
M533 Sheet 1	1		
M533 Sheet 2	1		
M533 Sheet 3	1		
M534	16		
M535 Sheet 1	26		
M535 Sheet 2	21		

Attachment J.B

SOURCE TERM DEVELOPMENT AND PARAMETRIC STUDIES FOR SECONDARY CONTAINMENT

The major tools used in the development of source terms and parametric studies inside secondary containment were the ORIGEN and QAD-P5A computer codes. Descriptions of the codes are in References J.7-11 and J.7-10. ORIGEN was used to compute the activities and energies of fission products released from the reactor core. The output of ORIGEN [the time-dependent energies and activity of radioactive fission products following loss-of-coolant accident (LOCA)] was used as input to QAD-P5A to calculate the airborne, shine, and direct doses for standard geometrics as well as the basis of direct dose parametric studies.

J.B.1 RADIOACTIVE SOURCE TERMS IN SECONDARY CONTAINMENT

The ORIGEN computer code (Reference J.7-11) was used to calculate the radioactive source terms inside secondary containment for liquid-containing and gas-containing systems. The fission products at the end of fuel life were assumed to be available for release immediately following the accident. The concentrations of noble gases, halogens, and other fission products released to the gaseous and liquid sources were computed. Subsequent fission product decay and daughter product generation were then calculated for 20 time periods, covering a total period of 1 year.

The assumptions used in determining the initial distribution and leakage of radioactivity in the primary containment air and liquid space are as follows:

a. 100% of the noble gases and 50% of the halogens are distributed homogeneously within the primary containment free volume immediately following the postulated accident;

b. 50% of the halogens and 1% of the remaining fission products in the core are mixed instantaneously and homogeneously with the primary containment liquid space. The primary containment liquid space is defined as the sum of the suppression pool liquid and the reactor coolant system (RCS) liquid; and

c. The fission products available for release are defined as the total inventory generated in the equilibrium core after 1000 days at reactor power of 3556 MWt.

Assumptions a and b are NRC recommended assumptions for defining radioactivity release fractions for the qualification of safety-related equipment (Reference J.7-2) and are detailed in References J.7-32 and J.7-34.

Assumption c represents the maximum burnup level in the core and the fission products at the end of fuel life prior to radioactivity release and is conservative.

Table J.B-1 shows the gamma activity concentration at selected time periods for the liquid-containing system. The results of Table J.B-1 were used as input in the dose parametric study. Due to rapid decay of the high-energy isotopes, the average gamma energy for the gas-containing system varies from 0.8 MeV at the beginning of the accident to 0.3 MeV at 1 year after the accident.

J.B.2 AIRBORNE DOSE IN SECONDARY CONTAINMENT

The time-dependent post-LOCA activity levels as calculated by the ORIGEN computer code were used as input in the calculation of the airborne beta and gamma dose rates and integrated doses inside the cubicles in the secondary containment. The assumptions used in this analysis are as follows:

a. Activity that leaks into the secondary containment is homogeneously mixed with the secondary containment atmosphere prior to its removal from the atmosphere through the standby gas treatment system (SGTS). This is consistent with the NRC-recommended assumptions used for calculation of doses inside primary containment (Reference J.7-2 and J.7-34);

b. An SGTS flow rate of 2430 scfm was assumed to be the flow rate of the effluent air. This is the designed minimum accident flow rate (Reference J.7-35) based on one reactor building airchange per day;

c. Air that leaks out of the primary containment flows directly and totally into the secondary containment. Bypass leakage is not considered. This is conservative when considering dose in the secondary containment, since it maximizes the buildup of radioactivity in the secondary containment;

d. Geometric factors are used to convert the semi-infinite cloud gamma dose to a finite gamma dose. This assumption is used in Reference J.7-28, and is based on an average gamma ray energy of 0.733 MeV. The effect of time dependence of average gamma ray energies has been proven to be negligible; and

e. Primary containment activity leakage rate is 0.5%/day. This is consistent with the assumptions established in Reference J.7-29.

A model of the primary and secondary containment atmosphere is shown in Figure J.B-1. The activity concentration of a certain isotope inside the containment is changing due to the following three mechanisms:

a. Transport of activity due to air leakage,

b. Depletion of activity due to radioactive decay and plateout of elemental halogens inside primary containment, and

c. Increases in activity levels due to daughter product generation from fission product decay.

According to References J.7-2 and J.7-34, plateout may be modeled by an expotential removal process:

$$A(t) = A(0) \exp(-\lambda_p t)$$

Where λ_p is the removal constant due to plateout.

The first step in this calculation is to model the decay and transport of the airborne radionuclides.

General airborne activity balance in containment:

$$\frac{d}{dt}(C_{li} V_l) = \underbrace{-\,Q_l C_{l_i}}_{\text{leakage}} \quad \underbrace{-\lambda_i C_{li} V_l}_{\text{decay}} \quad \underbrace{-\lambda_{pi} C_{li} V_l}_{\text{plateout}} + \underbrace{\Sigma_j \lambda_j C_{lj} V_l}_{\text{growth}} \qquad \text{(J.B-1)}$$

where

C_{1i}	=	concentration of isotope "i"
Q_1	=	leakage rate from primary containment
V_1	=	volume of primary containment
λ_i	=	radioactive decay constant of isotope "i"
λ_{pi}	=	plateout removal constant of isotope "i"

The term $\sum_j \lambda_j C_{1i} V_1$ reflects the growth of a given nuclide as the result of decay of parent nuclides.

The original release of nuclides consists only of halogens and noble gases. Since fission products are neutron-rich, decay of fission products proceeds toward higher atomic numbers.

In this manner, halogens will decay into noble gases, and then to higher atomic-numbered elements. Since the decay chain reaches a stable isotope after only a few decays, it can be seen that upon release of these airborne nuclides, the halogens have no significant airborne parent nuclides. This term may be neglected in the case of halogens.

Case 1 - Containment Halogens

Elemental iodine undergo plateout (Reference J.7-34) so equation (J.B-1) becomes:

$$\frac{d}{dt}(C_{1i}V_1) = -Q_1 C_{1i} - \lambda_i C_{1i} V_1 - \lambda_{pi} C_{1i} V_1 \qquad \text{(J.B-2)}$$

Solving (J.B-2) with the initial condition;

at t = 0,

$C_{1i} = C_{1i}(0)$,

$$C_{1i}(t) = C_{1i}(0)\ \exp\left(-\left(\frac{Q_1}{V_1} + \lambda_i + \lambda_{pi}\right)t\right) \qquad \text{(J.B-3)}$$

Particulate and organic iodine are assumed unaffected by plateout (Reference J.7-34).

Equations (J.B-3) for particulate and organic iodine may then be shown to be

$$C_{1i}(t) = C_{1i}(0)\ \exp\left(-\left(\frac{Q_1}{V_1} + \lambda_i\right)t\right) \qquad \text{(J.B-4)}$$

One can note, at this point, that all three iodine species have factors of

$$C_{1i}(0)\ \exp(-\lambda_i t)$$

in the equations. This term may be defined as

$$S_i(t) = C_{1i}(0)\ \exp(-\lambda_i t)\ V_1 \qquad \text{(J.B-5)}$$

$S_i(t)$ is seen to be the total activity released into the system as a result of decay. $S_i(t)$ is independent of the transport of the nuclides. The following definitions will be made.

f_e = fraction of total iodine that are elemental
f_p = fraction of total iodine that are particulate
f_o = fraction of total iodine that are organic

Equations (J.B-3) and (J.B-4) can be combined to get

$$C_{1iH}(t) = \left[f_e \exp(-\lambda_p t) + (f_o + f_p)\right] \exp\left[-Q_1 t/V_1 \frac{S_{iH}(t)}{V_1}\right] \qquad \text{(J.B-6)}$$

where

$C_{1iH}(t)$ = total iodine concentration in primary containment
$S_{iH}(t)$ = total iodine activity
λ_p = plateout constant for elemental iodine

At this point, Reference J.7-2 allows only a factor of 200 reduction for elemental iodine plateout effects.

So when

$$\exp(-\lambda_p t) = \frac{1}{200}, \text{ then } \lambda_p \text{ becomes zero.} \qquad \text{(J.B-7)}$$

Defining: $t_p = \dfrac{\mathrm{Ln}\,(200)}{\lambda_p}$

Equation (J.B-6) may be rewritten as

$$C_{1iH}(t) = \frac{S_{iH}(t)}{V_1} \exp\left[-Q_1 t/V_1\right] f_H(t) \qquad \text{(J.B-8)}$$

Where $f_H(t)$ is defined as

$$\text{(a)} \quad f_H(t) = f_e \exp(-\lambda_p t) + f_p + f_o \qquad t \le t_p \qquad \text{(J.B-9)}$$

$$\text{(b)} \quad f_H(t) = (f_e / 200) + f_p + f_o \qquad t \ge t_p$$

<u>Case 2 - Containment Noble Gases</u>

Noble gases do not undergo plateout. Daughter products are also conservatively assumed to act as noble gases. Equation (J.B-1) for noble gases becomes

$$\frac{d}{dt}(C_{1i}V_1) = -Q_1C_{1i} - \lambda_i C_{1i}V_1 + \Sigma_j \lambda_j C_{1j}V_1 \qquad \text{(J.B-10)}$$

Integrating equation (J.B-10) gives

$$C_{1i}(t) = \exp\left[-Q_1 t / V_1\right] \exp\left[-\lambda_i t\right] (B + f_i(t)) \qquad \text{(J.B-11)}$$

where

$$f_i(t) = \int \Sigma_j \lambda_j C_{ij} \exp -\left[Q_1 / V_1 + \lambda i\right] dt \qquad \text{(J.B-12)}$$

and B is a constant to be determined.

All daughter products of plated-out iodine are conservatively assumed to be re-released into the containment atmosphere as if the iodine were airborne. For the first isotope in a series (no parent nuclide), j = 0 and $f_o(t) = 0$.

Since $C_{1j}(t)$ has the same form as $C_{1i}(t)$, equation (J.B-12) becomes

$$f_i(t) = \int \Sigma_j \lambda_j (B + f_j(t)) e^{(\lambda_i - \lambda_j)t} dt \qquad \text{(J.B-13)}$$

Equation (J.B-13) shows that the only dependence on Q_1/V_1 is that carried over from the parent isotope is $f_n(t)$. Since $f_o(t)$ is independent of Q_1/V_1, $f_i(t)$ is independent of Q_1/V_1. Equation (J.B-11) can thus be rewritten as

$$C_{1i}(t) = e^{-(Q_1/V_1)t} S_i(t) / V_1 \qquad \text{(J.B-14)}$$

where

$$S_i(t) = \exp\left[-\lambda_i t\right] (B + f_i(t)) V_1 \qquad \text{(J.B-15)}$$

It can be seen that $S_i(t)$ is the solution to equation (J.B-10) without the leakage term. $S_i(t)$ is the activity for the total inventory of nuclides released from the reactor core. $S_i(t)$ values are determined by the use of ORIGEN. $S_i(t)$ includes radioactive decay and daughter product growth.

For a general airborne activity balance in the reactor building (secondary containment):

$$\frac{d}{dt}(C_{2i}V_2) = + \underbrace{Q_i C_{1i}}_{\text{leakage in}} - \underbrace{Q_2 C_{2i}}_{\text{leakage out}} - \underbrace{\lambda_i C_{2i} V_2}_{\text{decay}} + \underbrace{\sum_j \lambda_j C_{2j} V_2}_{\text{growth}} \qquad \text{(J.B-16)}$$

where

C_{2i} = concentration of isotope "i" in the reactor building
Q_2 = leakage rate from reactor building
V_2 = volume of the reactor building

Plateout inside secondary containment is conservatively neglected.

Case 3 - Iodine Inside the Reactor Building

As in Case 1, the growth term of equation (J.B-16) is negligible. Equation (J.B-16) can be integrated to give

$$C_{2i}(t) = e^{-(Q_2/V_2 + \lambda_i)t}\left[B + \frac{Q_1}{V_2}\int e^{(Q_2/V_2 + \lambda_i)t} C_{1i}(t)\, dt\right] \qquad \text{(J.B-17)}$$

From equation (J.B-8), $C_{1i}(t)$ is substituted into (J.B-17)

$$C_{2i}(t) = Be^{(Q_2/V_2 + \lambda_i)t} + \frac{Q_1}{V_2} e^{-(Q_2/V_2 + \lambda_i)t}\int \exp\ (Q_2/V_2 + \lambda_i)t$$

$$\left(\frac{S_{iH}(t)}{V_1} e^{-Q_1 t/V_1} f_H(t)\right) dt \qquad \text{(J.B-18)}$$

Substituting equation (J.B-5) into (J.B-18) results in

$$C_{2i}(t) = B\exp\left[-(Q_2/V_2 + \lambda_i)t\right] + \frac{Q_1}{V_2} C_{1i}(0) \exp -(Q_2/V_2 + \lambda_i)t \qquad \text{(J.B-19)}$$

$$\int \exp\left[(Q_2/V_2 - Q_1/V_1)t\right] f_H(t)\ dt$$

$f_H(t)$ is a complex function of time (equation J.B-9). $C_{2i}(t)$ must be solved in a series of solutions to equation (J.B-19).

For simplification, the following factors are defined

$$x = \frac{Q_2}{V_2} - \frac{Q_1}{V_1}$$

$$y = x - \lambda_p$$

Equation (J.B-19) becomes

$$C_{2i}(t) = B\exp - (Q_2 / V_2 + \lambda_i)t + \frac{Q_1}{V_2 V_1} S_{iH}(t) \exp -(Q_2 / V_2 + \lambda_i)t \int e^{xt} f_H^{(t)} dt \qquad \text{(J.B-20)}$$

Integrating (J.B-20) for $0 \le t \le t_p$ with the initial condition; $C_{2i}(0) = 0$ gives

(For $S_{iH}(t) = S_{iH}(0)\ e^{-\lambda_i t}$):

$$C_{2i}(t) = \frac{Q_1}{V_1 V_2} S_{iH}(t) \left(e\exp[-Q_1 t / V_1] \left(\frac{f_e}{y} \exp[-\lambda_p t] + \frac{f_p + f_o}{x}\right) - e^{-Q_2 t / V_2} \left(\frac{f_e}{y} + \frac{f_p + f_o}{x}\right)\right) \qquad \text{(J.B-21)}$$

Defining

$K_1 = \left(\frac{-f_e}{y} + \frac{f_p + f_o}{x}\right)$; (J.B-21) becomes (for $0 \le t \le t_p$): (J.B-22)

$$C_{2i}(t) = \frac{Q_1}{V_1 V_2} S_{iH}(t) \left(\left(\frac{f_e}{y} \exp[-\lambda_p t] + \frac{f_p + f_o}{x}\right) \exp[-Q_1 t / V_1] + K_1 \exp[-Q_2 t / V_2]\right)$$

And (for t ³ t_p): (J.B-23)

$$C_{2i}(t) = B\exp[-(Q_2 / V_2 + \lambda_i)t] + \frac{Q_1}{V_1 V_2} S_{iH}(t) \exp[-Q_2 / V_2 t] \int e^{xt} \left(\frac{f_e}{200} + f_p + f_o\right) dt$$

Solving (J.B-23) gives (J.B-24)

$$C_{2i}(t) = B\exp\left[-(Q_2/V_2 + \lambda_i)t\right] + \frac{Q_1}{V_1 V_2} S_{iH}(t)\exp\left[-Q_2/V_2 t\right]$$
$$\left(\frac{f_e/200 + f_o + f_p}{x}\right)e^{xt}$$

At t = tp (from J.B-22)): (J.B-25)

$$C_{2i}(t_p) = \frac{Q_1}{V_1 \ V_2} S_{iH}(t_p) \begin{bmatrix} K_1 e\,xp\left[-(Q_2/V_2)t_p\right] + \left(\frac{f_e}{y}\ e\ -\lambda_p t_p\right. \\ \left. + \left(\frac{f_o + f_p}{x}\right)\right) e\,xp\left[-Q_1 t_p/V_1\right] \end{bmatrix}$$

By definition of t_p [eq. (J.B-7)]: $\exp\left[-\lambda_p t_p\right] = \frac{1}{200}$

Combining (J.B-24) and (J.B-25) at t = t_p gives (J.B-26)

$$B\exp\left[-(Q_2/V_2 + \lambda_i)t_p\right] = \frac{Q_1}{V_1 V_2} S_{iH}(t_p)\ e\,xp\left[-(Q_2/V_2)t_p\right]$$
$$\left(K_1 + \frac{f_e}{200}\left(\frac{1}{y} - \frac{1}{x}\right) e^{xt}\ p\right)$$

and

$$B = \frac{Q_1}{V_1 V_2} S_{iH}(0) K_2 \quad \text{(J.B-27)}$$

where

$$K_2 = K_1 + \frac{f_e}{200}\ \left(\frac{1}{y} - \frac{1}{x}\right) e^{\ xt}\ \ p \quad \text{(J.B-28)}$$

So (J.B-24) becomes (for $t_p \leq t$)

$$C_{2i}(t) = \frac{Q_1}{V_1 V_2} S_{iH}(t)\ \ (K_2 e^{-Q_2 t/V_2} + \left(\frac{f_e/200 + f_o + f_p}{x}\right)e^{-Q_1 t/_1} \quad \text{(J.B-29)}$$

Equations (J.B-22) and (J.B-29) may be combined to form a general solution as follows:

$$C_{2i}(t) = S_{iH}(t) \quad F_{2H}(t)/V_2 \quad \text{(J.B-30)}$$

where (for $0 \le t \le t_p$)

$$F_{2H}(t) = \frac{Q_1}{V_1} \left(K_1 \exp\left[-Q_2 t/V_2\right] + \left(\frac{f_e}{y} \exp\left[-\lambda_p t\right] + \frac{f_p + f_o}{x}\right) \exp\left[-Q_1 t/V_1\right]\right)$$

for ($t \ge t_p$) (J.B-31)

$$F_{2H}(t) = \frac{Q_1}{V_1} \left(K_2 \exp\left[-Q_2 t/V_2\right] + \left(\frac{f_e/200 + f_o + f_p}{x}\right) \exp\left[-Q_1 t/V_1\right]\right)$$

Case 4: Noble Gases Inside the Reactor Building

Equation (J.B-16) for noble gases may be rewritten as

$$\frac{d}{dt}(C_{2i}) - (Q_1/V_2)\ C_{1i} - (Q_2/V_2 + \lambda_i)\ C_{2i} + \sum_j \lambda_j C_{2j} \qquad \text{(J.B-32)}$$

Integrating (J.B-32) gives (J.B-33)

$$C_{2i}(t) \exp\left[(Q_2/V_2 + \lambda_i)t\right] = B + \int \exp\left[(Q_2/V_2 + \lambda_i)t\right] \left(\frac{Q_1}{V_2}\ C_{1i}(t) + \sum_j \lambda_j C_{2j}(t)\right) dt$$

$C_{1i}(t)$ is found from equation (J.B-14) to be

$$C_{1i}(t) = \exp\left[-(Q_1/V_1)t\right]\ S_i(t)/V_1$$

$S_i(t)$ cannot be found analytically; hence equation (J.B-33) cannot be found analytically through this method. However, in deriving equation (J.B-14), it was shown that if all parent nuclides are transported identically, then the solution of equations consisting of transport and radioactive decay can be separated. Since the halogens are not transported in the same manner as noble gases, this is not strictly true. However, the assumption of daughter growth as if the halogens were transported will be conservative, due to the nonconsideration of the physical holdup in primary to secondary leakage of daughters of halogens.

Equation (J.B-14) may be rewritten as

$$V_1 C_{1i}(t) = S_{iN}(t)\ F_{1N}(t) \qquad \text{(J.B-34)}$$

where

$$F_{1N}(t) = \exp[-Q_1 t/V_1] \qquad \text{(J.B-35)}$$

$S_{iN}(t)$ is the noble gas total activity term, as before. $F_{1N}(t)$ is the fraction of that activity remaining in primary containment.

Equation (J.B-16) may be modified to show the fractions of activity, rather than total isotopic activity, in secondary containment to give

$$\frac{d}{dt}(F_{2N}) = \frac{Q_1}{V_1} F_{1N} - \frac{Q_2}{V_2} F_{2N} \qquad \text{(J.B-36)}$$

Integrating equation (J.B-36) with initial conditions:

at t=0, $F_{2N} = 0$; gives

$$F_{2N}(t) = \frac{Q_1}{V_1 x} \left(\exp\left[-Q_1 t/V_1\right] - \exp\left[-Q_2 t/V_2\right]\right) \qquad \text{(J.B-37)}$$

$C_{2i}(t)$ is then found from

$$C_{2i}(t) = S_{iN}(t)\, F_{2N}(t)/V_2 \qquad \text{(J.B-38)}$$

λ_p is found in Reference J.7-2 to be determined

$$\lambda_p = K_g A_1/V_1 \qquad \text{(J.B-39)}$$

K_g is conservatively assumed to be equal to 0.05 cm/sec (Reference J.7-34).

A_1 is the surface area inside the drywell = $3.2 \times 10^7 \text{cm}^2$ (Reference J.7-33).

$V_1 = 5.68 \times 10^9 \text{cm}^3$ (Reference J.7-36)

$\lambda_p = 1.01 \text{ hr}^{-1}$

To calculate the airborne gamma dose rate inside the secondary containment, the method as described in Reference J.7-28 is used:

$$D_{\gamma\infty} = \sum_{i=1}^{n} 0.25 \overline{E}_{\gamma} i \,(C_{2i} \text{ noble gas} + C_{2i} \text{ halogen}) \qquad \text{(J.B-40)}$$

$$D_\gamma = \frac{D\gamma\infty}{GF} \qquad \text{(J.B-41)}$$

$$GF = \frac{1173}{V^{0.338}} \qquad \text{(J.B-42)}$$

where

$D_{\gamma\infty}$ = semi-infinite gamma cloud dose rate (rads/sec)

$\bar{E}\gamma_i$ = average gamma energy of the isotope (MeV)

C_{2i} = activity concentration inside secondary containment (Ci/m^3)

GF = geometric factor used to scale the semi-infinite gamma cloud dose to a finite cloud dose

V = volume of the finite cloud (ft^3)

By taking $S_i(t)$ from ORIGEN output and using equations (J.B-31) and (J.B-37) to calculate $F_2(t)$, the total gamma dose in secondary containment can be computed by using equations (J.B-40) through (J.B-42).

The airborne semi-infinite cloud gamma dose rates are shown in Figure J.B-2. As can be observed from the figures, the gamma doses inside secondary containment reach their peaks at around three days after the accident, and decay slowly thereafter due to the depletion of radioactivity by radioactive decay and removal through the SGTS.

The geometric factor in equation (J.B-42) is developed in Reference J.7-28 for average gamma energies of 0.733 MeV. There has been a concern that this geometric factor may vary appreciably with time due to the faster decay rate of the high energy isotopes. The average gamma energy during various time periods following the accident were computed and the results show that the average gamma energy varies from 0.3 MeV to 0.8 MeV. As discussed in Reference J.7-31, the geometric factor changes by less than 5% within that energy range. It is therefore concluded that the change in the geometric factors with time is negligible, and that equation (J.B-42) can be used to calculate the finite cloud gamma dose inside the secondary containment.

J.B.3 PARAMETRIC STUDIES FOR DIRECT PIPING DOSE

The purpose of the parametric study was to identify the parameters which have a significant affect on the radiation dose rates. The computer code QAD-P5A was used to develop a correlation scheme for the significant parameters such that a simplified procedure for calculating radiation dose rates for complex source and receptor geometries can be developed. The dose rate at a target distance of 8 ft radially outwards from the centerline of an 8-in. schedule 40 pipe, infinitely long (standard pipe) was first calculated and defined as the standard dose rate. A parametric study was then performed to investigate the effects of the variation of parameters such as pipe length, pipe diameter, shield thickness, and target locations on the dose rate. The results of this parametric study were then correlated as a set of correction factors to the standard dose rate. A simplified procedure was developed to calculate the dose rates and cumulate doses for the multitude of source-target configurations by using these correction factors.

J.B.3.1 Functional Dependence of Various Parameters on Secondary Containment Dose Rates

The gamma ray energy flux from a line source "S_L" to a detector point "P" (see Figure J.B-3) is shown in Reference J.7-30 as

$$\phi = \frac{BS_L}{4\pi r} \, {}_0\!\int^{\theta 1} \exp - b_1 \operatorname{Sec} \theta_{d\theta} \; - \int^{\theta 2} \exp - b_1 \operatorname{Sec} \theta_{d\theta} \qquad \text{(J.B-43)}$$

where

ϕ = uncollided gamma ray flux (photons/cm^2 - sec)
b_1 = total attentuation through shield
S_L = source strength of line source (photons/cm sec)
B = buildup factor
θ = angle subtended by the length of the line source (see Figure J.B-3)

The source strength "S_L" is a function of the volume of liquid inside the pipe segments, which is also a function of the diameter and volume of the pipe. The angles "θ1" and "θ2" are also functions of "a/r" and "b/r," respectively (see Figure J.B-18 for definition of "a/r" and "b/r" respectively). Therefore, the functional dependence of gamma ray dose rates on the various parameters can be represented by the following equation:

$$\phi = \phi_o * F_D * F_R * F_L \left[(a/r, b_1) + F_L \, (b/r, b_1)\right] \qquad \text{(JB-44)}$$

where

ϕ_o = base gamma ray flux for standard pipe
F_D = pipe diameter correction factor
F_R = radial distance correction factor
F_L = $(a/r, b_1)$ = pipe length correction factor

J.B.3.2 Parametric Study Procedures

The procedure for performing this parametric study is documented as follows:

a. Calculate the dose rate at a target distance of 8 ft from the centerline of an 8-in. schedule 40 pipe infinitely long (standard pipe);

b. Perform parametric studies on the variation of dose rates with

   1. Radial distance from the pipe centerline,
   2. Length of the pipe,
   3. Nominal pipe diameter,
   4. Time, and
   5. Axial position along the pipe;

c. Correlate the results of the parametric study by a set of geometric correction factors;

d. Develop a procedure for calculating dose rates by using the correction factors; and

e. Verify the correlation scheme by calculating the dose rates at different target locations due to source piping of varied geometries through the use of QAD-P5A computer code, and compare the results to those obtained by using the procedure developed in step d.

J.B.3.3 Direct Dose Parametric Study Results Inside Secondary Containment

The standard pipe gamma dose rate and integrated dose curves for the different systems having different source term assumptions (defined in Section J.5.3.2) are shown in Figures J.B-4 through J.B-11. The various correction factors were calculated by the following correlation.

$$F_R(r) = \frac{\text{Dose rate at a radial distance "r" from an infinitely long 8-in. sch 40 pipe}}{\text{Dose rate at a radial distance of 8 ft from an infinitely long 8-in. sch 40 pipe}}$$

$$F_L(\ell) = \frac{\text{Dose rate at a radial distance of 8 ft from an 8-in. sch 40 pipe of length "}2\ell\text{"}}{\text{Dose rate at a radial distance of 8 ft from an infinitely long 8-in. sch 40 pipe}}$$

$$F_D(d) = \frac{\text{Dose rate at a radial distance of 8 ft from an infinitely long sch 40 pipe of nominal diameter "d"}}{\text{Dose rate at a radial distance of 8 ft from an infinitely long 8-in. sch 40 pipe}}$$

The above mentioned correction factors for liquid system source terms are shown in Figures J.B-12, J.B-13, and J.B-14. The correction factor curves for gaseous source terms are shown in Figures J.B-15, J.B-16, and J.B-17.

J.B.3.4 Correction Factor Method of Determining Direct Doses in Secondary Containment

Using the parametric curves from Section J.B.3.3, one obtains dose rates at varied radial distances (between 2 ft to 40 ft) from varied pipe diameters (between 2 in. to 24 in.) of varied lengths (between 2 ft to infinity) at any given time period within 1 year. The step-by-step procedure for calculating direct dose is as follows:

a. Identify a/r, b/r parameters and obtain pipe length correction factor F_L from Figure J.B-13 or J.B-16, depending on the system being considered. (See Figure J.B-18 for definition of "a/r" and "b/r");

b. Obtain the standard dose rate from the standard dose rate curve for time "t" desired;

c. Obtain the pipe diameter correction factor $F_D(d)$;

d. Obtain radial distance correction factor $F_R(r)$; and

e. The dose rate for the given pipe segment can be computed by

   Dose Rate = (Standard Dose Rate) $(F_R)(F_D)(F_L)$.

Table J.B-2 compares the results for dose rate of 17 different pipe geometry and target locations as calculated using the correction factor method to those calculated by using the computer code QAD-P5A. It was observed that the biggest difference in results between the two methods is less than 10%. It is concluded that the correction factor method is adequate for calculating direct dose.

Table J.B-1

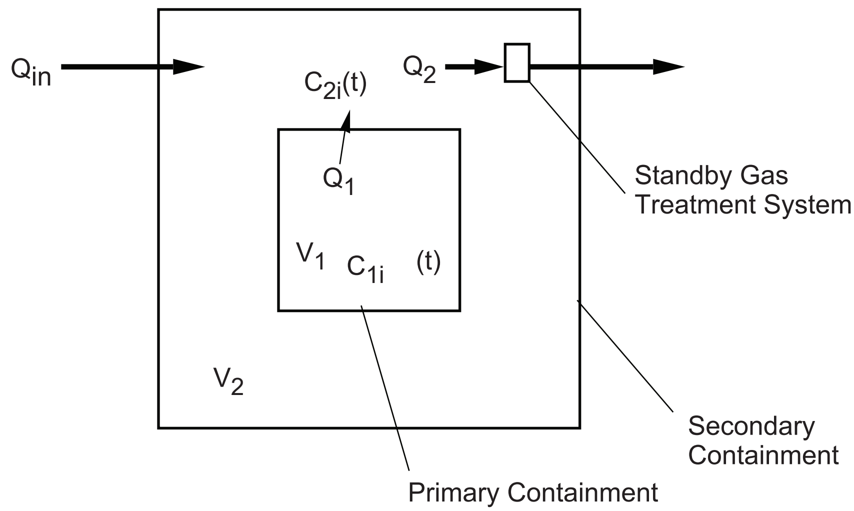
Gamma Energy Concentration (photons/sec-cm^3) in Liquid-Containing Systems

	Gamma Energy (MeV)											
Time	0.30	0.63	1.10	1.55	1.99	2.38	2.75	3.25	3.70	4.22	4.70	5.25
0 min	1.32E+09	7.25E+09	2.33E+09	1.63E+09	1.28E+08	1.00E+08	1.33E+08	3.61E+07	1.90E+07	2.82E+07	4.58E+07	3.39E+05
2 min	1.17E+09	7.17E+09	2.03E+09	6.17E+08	1.25E+08	4.54E+07	4.88E+07	2.42E+07	1.03E+07	7.17E+06	1.02E+07	2.10E+05
6 min	1.06E+09	6.92E+09	1.85E+09	5.63E+08	1.22E+08	1.99E+07	1.55E+07	1.62E+07	7.34E+06	8.50E+05	5.84E+05	8.09E+04
20 min	9.71E+08	6.21E+09	1.69E+09	5.00E+08	1.14E+08	1.30E+07	8.21E+06	9.17E+06	5.25E+06	2.03E+04	3.55E+03	2.86E+03
1 hr	8.84E+08	4.75E+09	1.41E+09	3.84E+08	1.01E+08	7.71E+06	3.36E+06	2.60E+06	2.17E+06	1.43E+00	3.66E-01	2.01E-01
3 hr	8.50E+08	2.65E+09	9.92E+08	2.28E+08	7.75E+07	2.77E+06	3.61E+05	3.74E+05	1.58E+05	3.26E-03	1.55E-03	9.71E-04
9 hr	9.04E+08	1.29E+09	5.00E+08	1.05E+08	3.88E+07	7.71E+05	9.04E+03	2.35E+04	6.17E+01	3.26E-03	1.55E-03	9.71E-04
1 day	8.09E+08	7.17E+08	1.39E+08	3.73E+07	8.84E+06	6.17E+05	1.30E+03	6.29E+01	5.17E-03	3.26E-03	1.54E-03	9.71E-04
3 days	5.54E+08	2.71E+08	1.79E+07	1.91E+07	9.34E+05	5.71E+05	1.10E+03	3.56E+01	5.17E-03	3.26E-03	1.54E-03	9.67E-04
9 days	3.16E+08	1.22E+08	4.58E+06	1.36E+07	5.71E+05	4.29E+05	1.09E+03	3.46E+01	5.13E-03	3.22E-03	1.53E-03	9.59E-04
30 days	5.42E+07	6.46E+07	1.73E+06	4.38E+06	2.67E+05	1.48E+05	1.05E+03	3.31E+01	4.96E-03	3.12E-03	1.48E-03	9.29E-04
60 days	8.17E+06	4.42E+07	9.29E+05	1.03E+06	1.49E+05	3.94E+04	9.92E+02	3.13E+01	4.71E-03	2.98E-03	1.41E-03	8.88E-04
90 days	3.99E+06	3.45E+07	7.13E+05	3.60E+05	1.14E+05	1.75E+04	9.38E+02	2.96E+01	4.54E-03	2.86E-03	1.35E-03	8.50E-04
120 days	3.25E+06	2.77E+07	6.25E+05	2.19E+05	1.00E+05	1.26E+04	8.88E+02	2.80E+01	4.38E-03	2.75E-03	1.30E-03	8.17E-04
150 days	2.90E+06	2.27E+07	5.79E+05	1.83E+05	9.17E+04	1.11E+04	8.38E+02	2.64E+01	4.21E-03	2.66E-03	1.26E-03	7.92E-04
180 days	2.64E+06	1.89E+07	5.42E+05	1.69E+05	8.50E+04	1.04E+04	7.92E+02	2.50E+01	4.08E-03	2.57E-03	1.22E-03	7.67E-04

Table J.B-2

Comparison of Direct Dose Rate Results

Target Location and Pipe Geometry					Dose Rate Results			
Pipe Diameter (cm)	Pipe Length (cm)	Target Location r (cm)	a (cm)	b (cm)	Time After Accident (hr)	Correction Factor Method (rad/hr)	Computer Results (rad/hr)	Difference (%)
6	800	548.6	570	230	24	52.7	53.3	-1.1
6	800	91.4	720	80	24	484	479	+1.0
6	800	1006.8	650	150	24	15.3	16.1	+5.0
8	800	548.6	570	230	24	77.0	80.4	-4.23
8	800	391.4	720	80	24	105.0	110.0	-4.5
8	800	1066.8	650	150	24	22.4	24.4	-8.2
2	700	100.0	600	100	720	5.36	5.32	0.75
2	700	1066.8	600	100	720	0.159	0.146	8.9
2	700	100	-900	1600	720	0.0126	0.0123	2.3
2	700	1066.8	200	900	720	0.128	0.124	3.2
12	400	1066.8	-400	800	720	1.14	1.21	-5.8
12	400	100	350	50	720	72.5	71.4	1.5
12	400	609.6	350	50	720	4.66	4.93	-5.5
12	400	1066.8	350	50	720	1.57	1.73	-9.3
10	600	304.8	-243.8	548.6	0.0333	554	539	2.7
10	600	121.9	450	150	0.0333	7617	7396	-3.0
10	600	1005.8	450	150	0.0333	258	280	-7.9

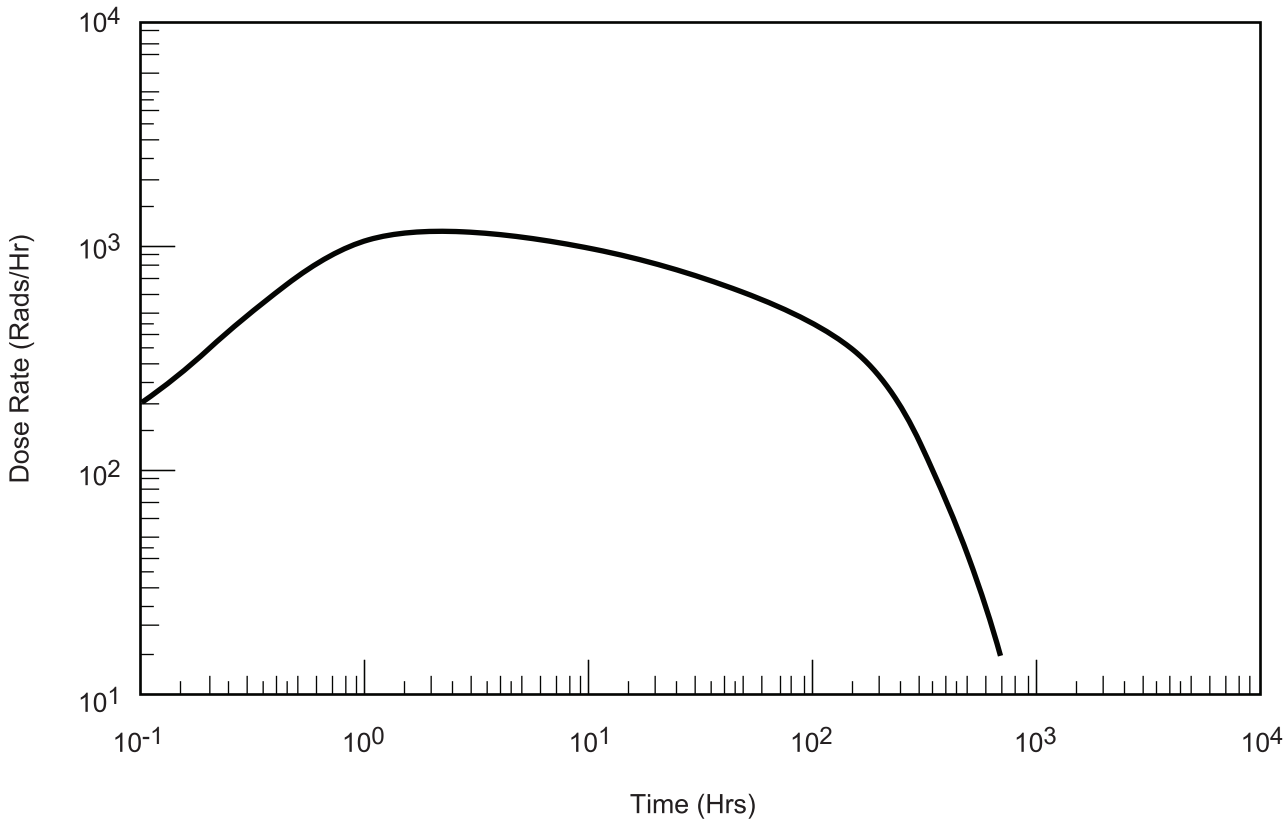


Q_2 = Air Leakage Rate from Secondary Containment (m^3/sec)
Q_1 = Air In-leakage Rate from Primary Containment (m^3/sec)
V_2 = Volume of Secondary Containment (m^3)
V_1 = Volume of Primary Containment (m^3)
i = Nuclide Index
$C_{2i}(t)$ = Activity Concentration in Secondary Containment (Ci/m^3)
$C_{1i}(t)$ = Activity Concentration in Primary Containment (Ci/m^3)
Q_{in} = Clean Air In-leakage Rate (m^3/sec)

Columbia Generating Station
Final Safety Analysis Report

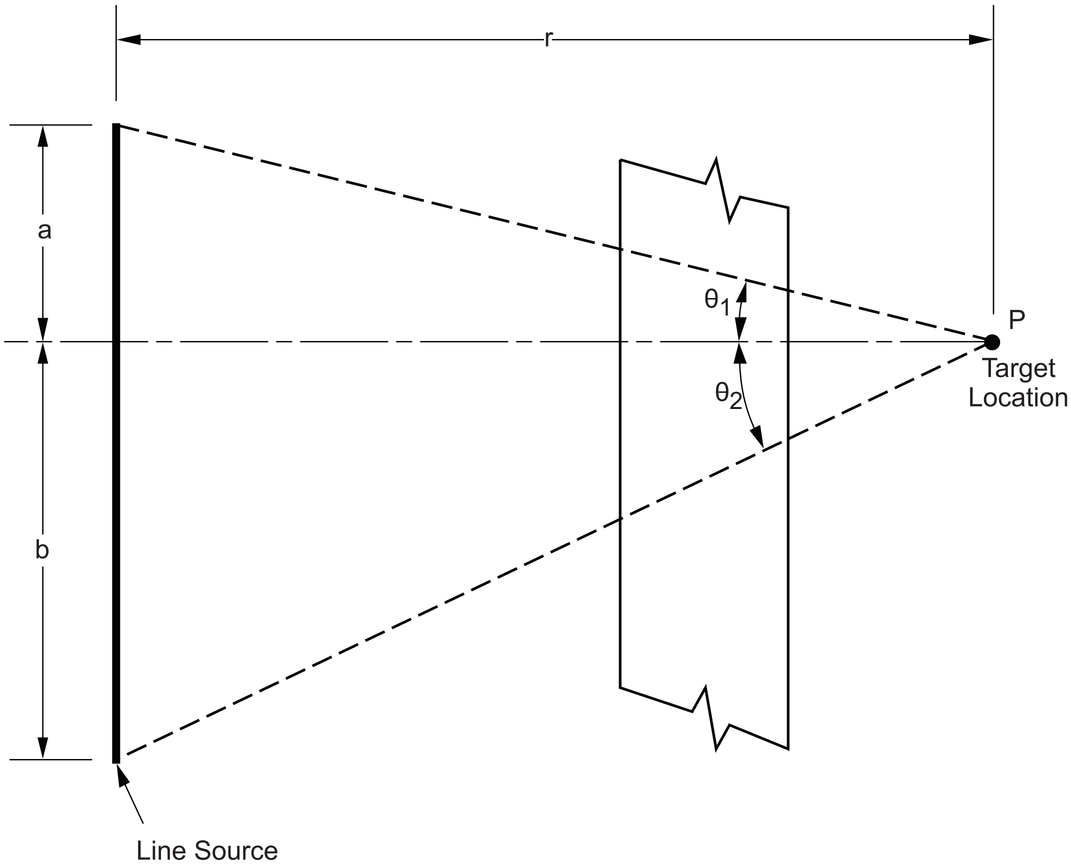
Model of the Primary and Secondary Containment

Draw. No. 970187.24 | Rev. | Figure J.B-1



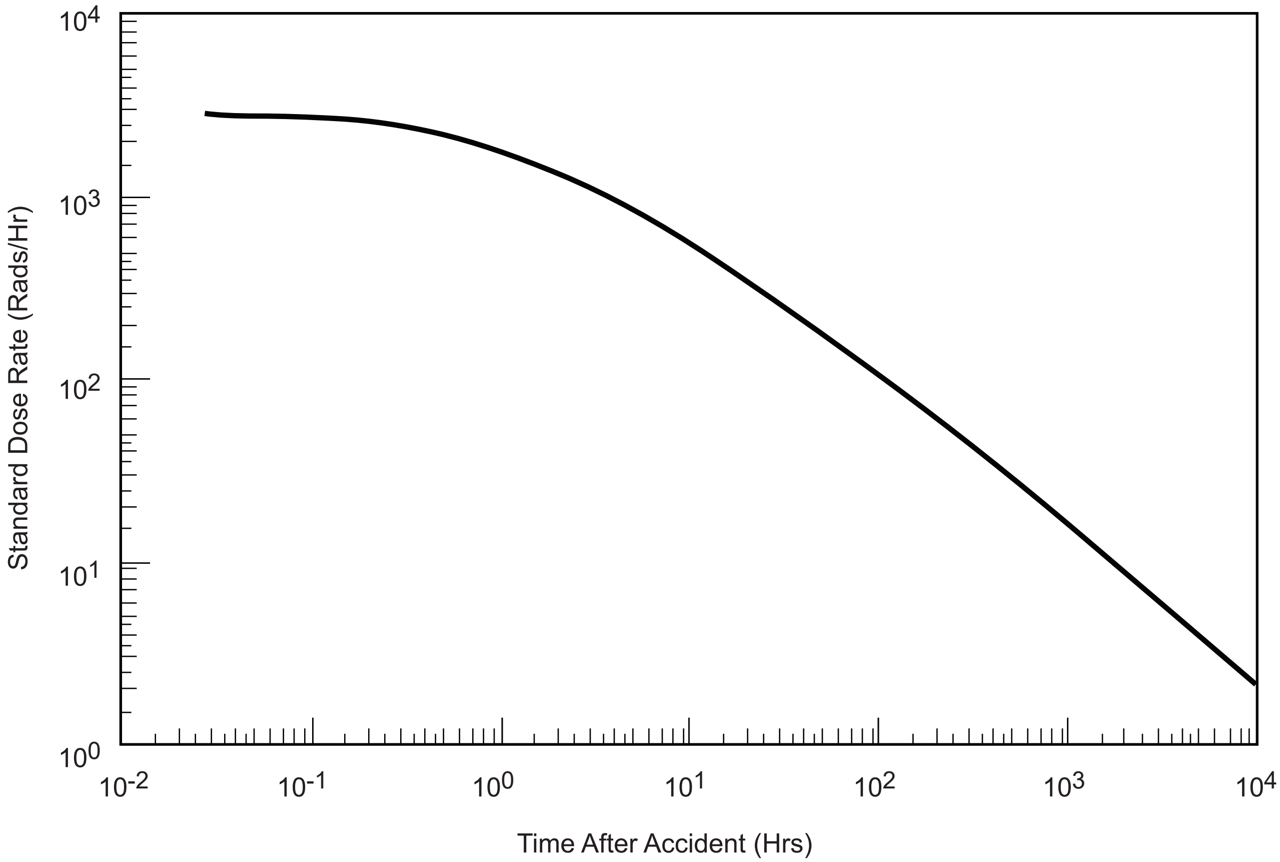
0.5%/Day Primary Containment Leakage Rate

Time-Dependent Gamma Dose Rate for a Semi-Infinite Cloud of Fission Products at Secondary Containment Concentrations



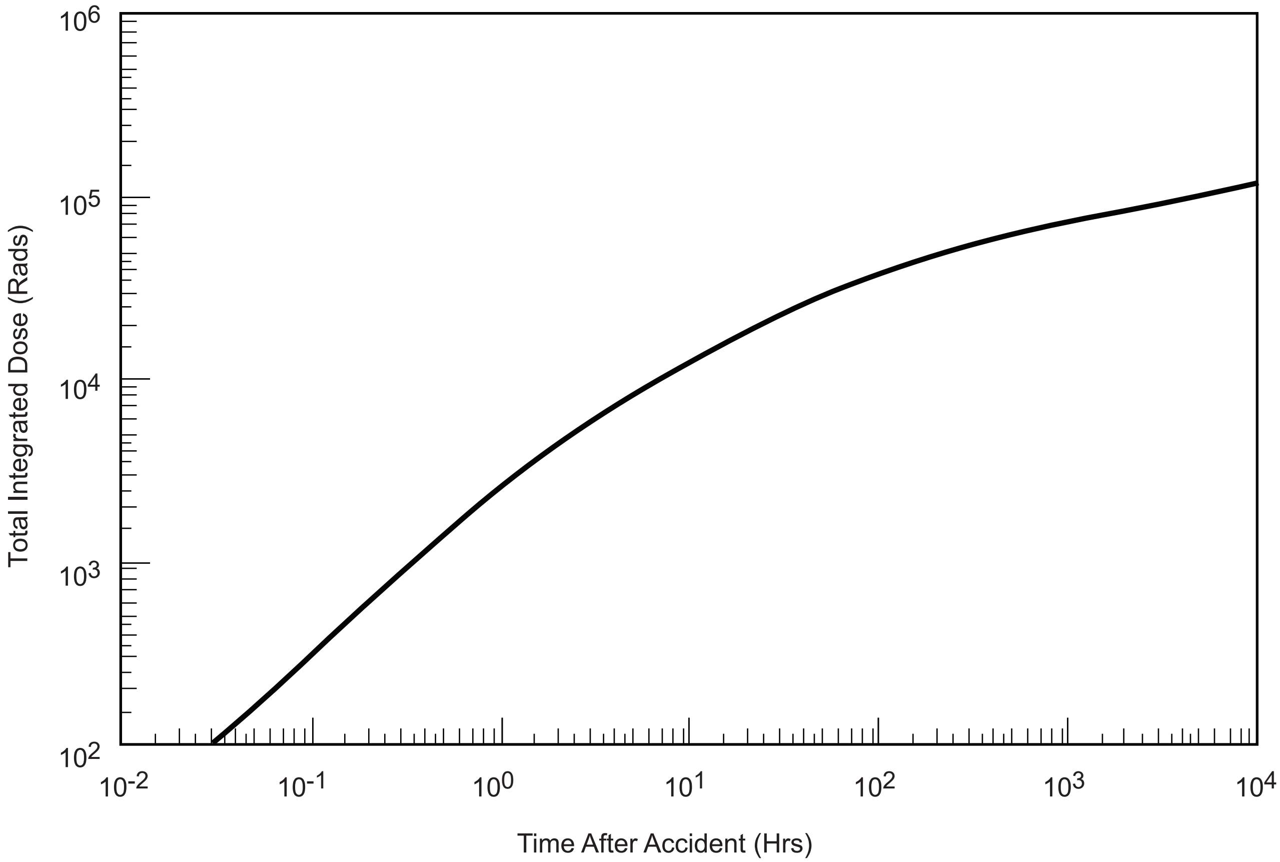
$$b_i = \sum_i \mu_i t_i$$

Illustration of Parameters Used in the Shielding Equation



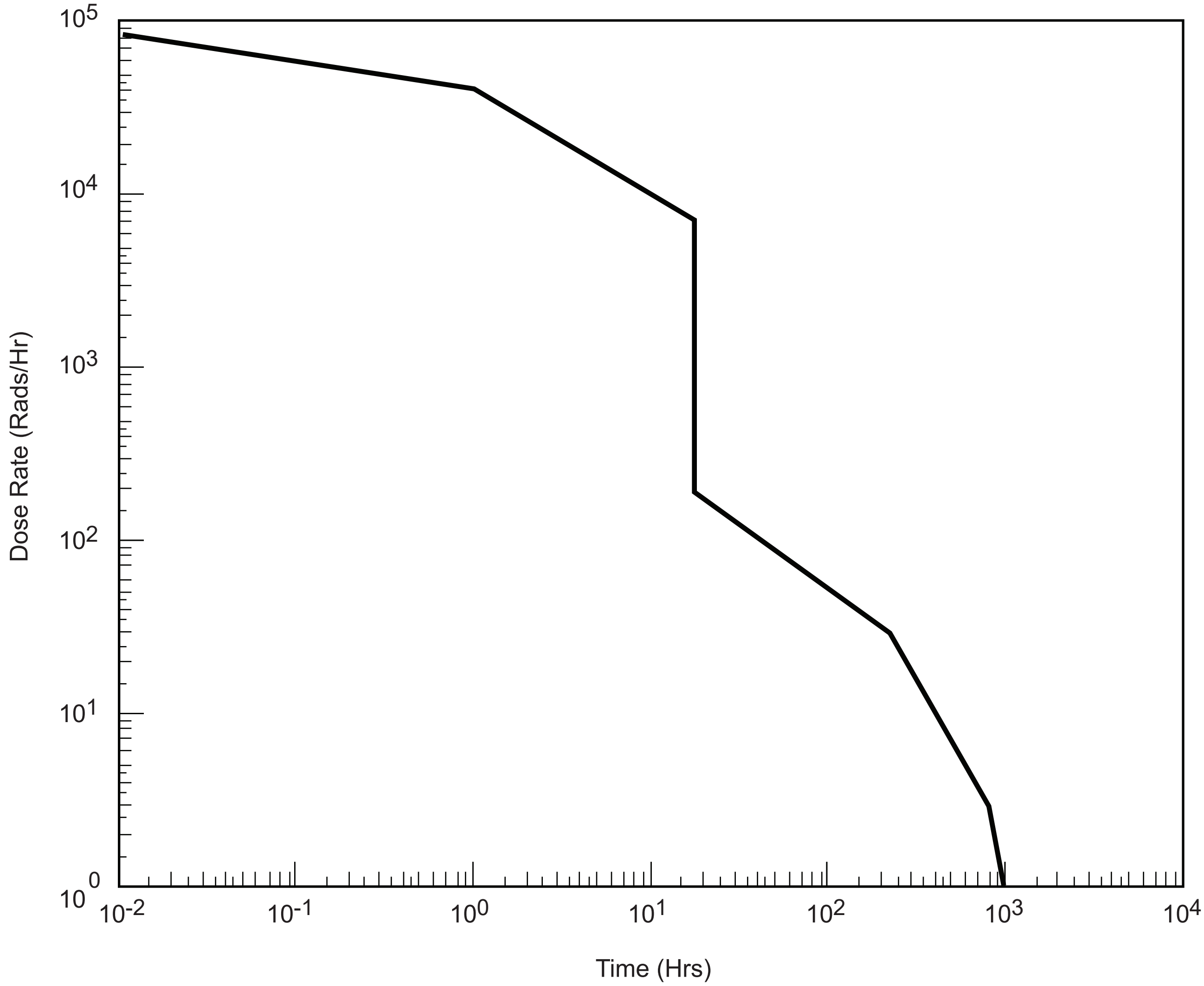
Standard Gamma Dose Rate Curve for Liquid Containing Systems (RCIC Liquid System and RHR System)

Draw. No. 970187.27 | Rev. | Figure J.B-4

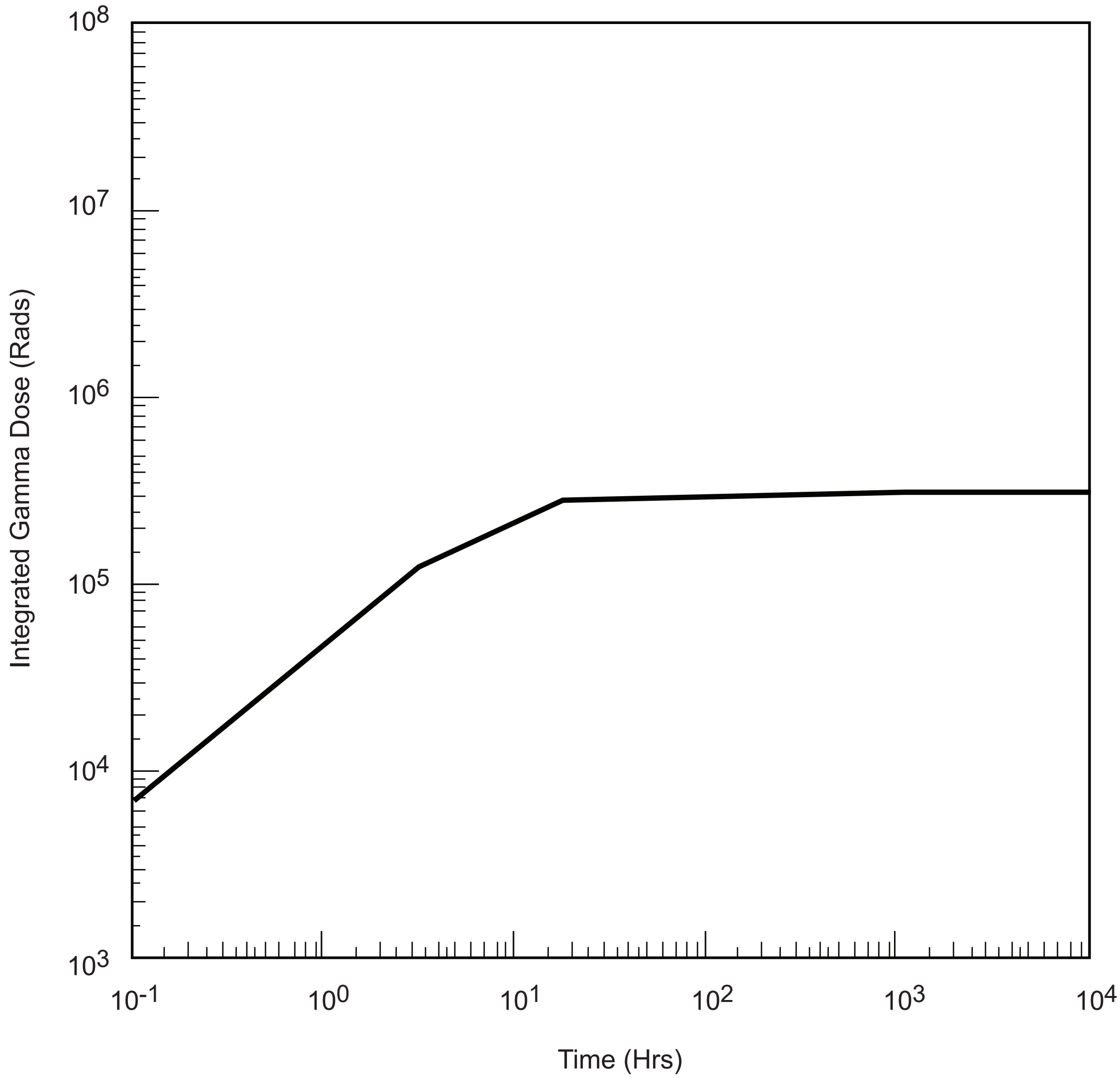


Columbia Generating Station Final Safety Analysis Report	**Standard Integrated Gamma Dose Rate Curve for Pipes in Liquid Containing Systems (RCIC Liquid System and RHR System)**
	Draw. No. 970187.28 | Rev. | Figure J.B-5

Form No. 960690



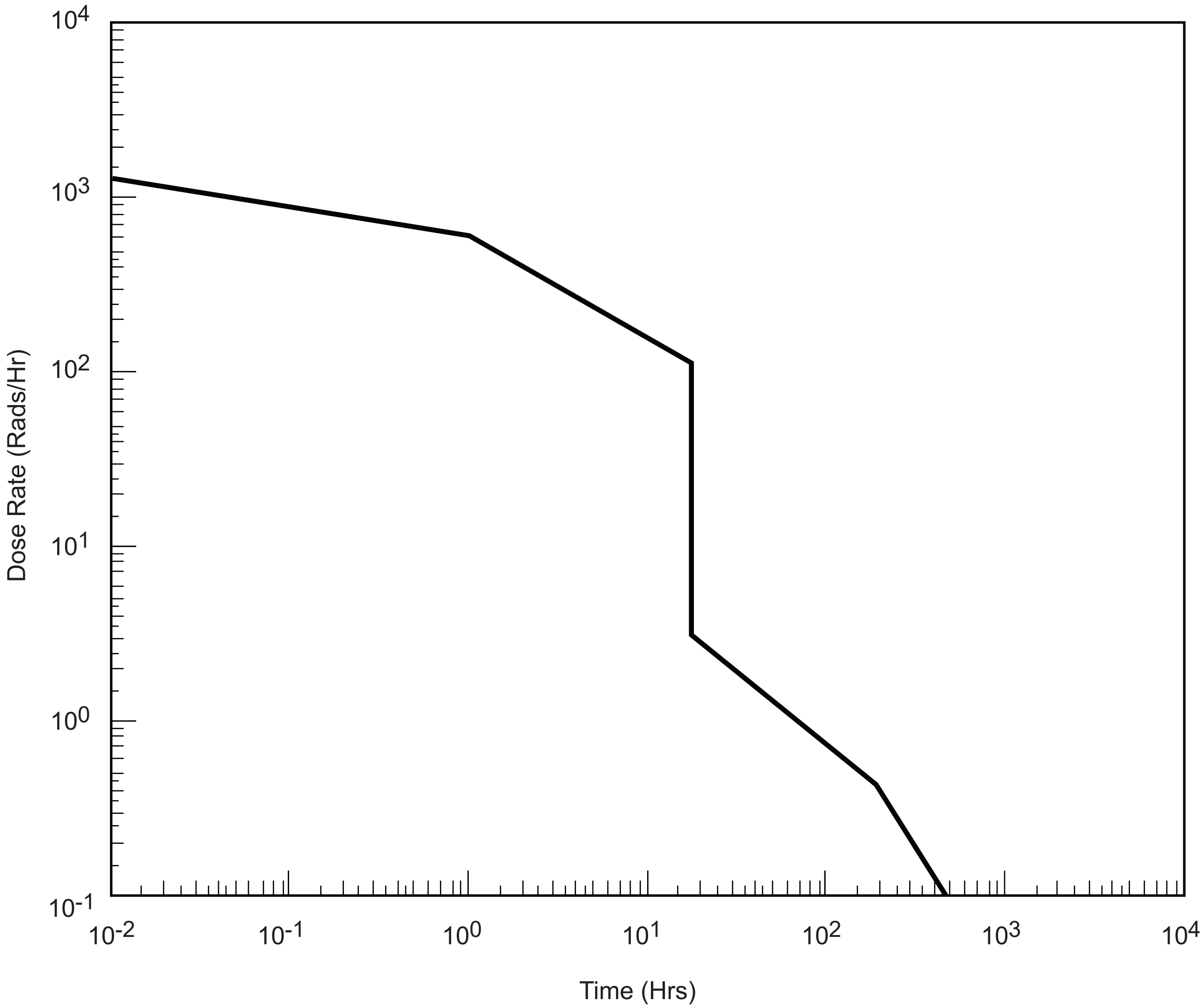
Columbia Generating Station Final Safety Analysis Report	Standard Gamma Dose Rate Curve for Pipes in the RCIC Steam System and MSIV-LCS Steam System Before the Header		
	Draw. No. 970187.29	Rev.	Figure J.B-6



Columbia Generating Station
Final Safety Analysis Report

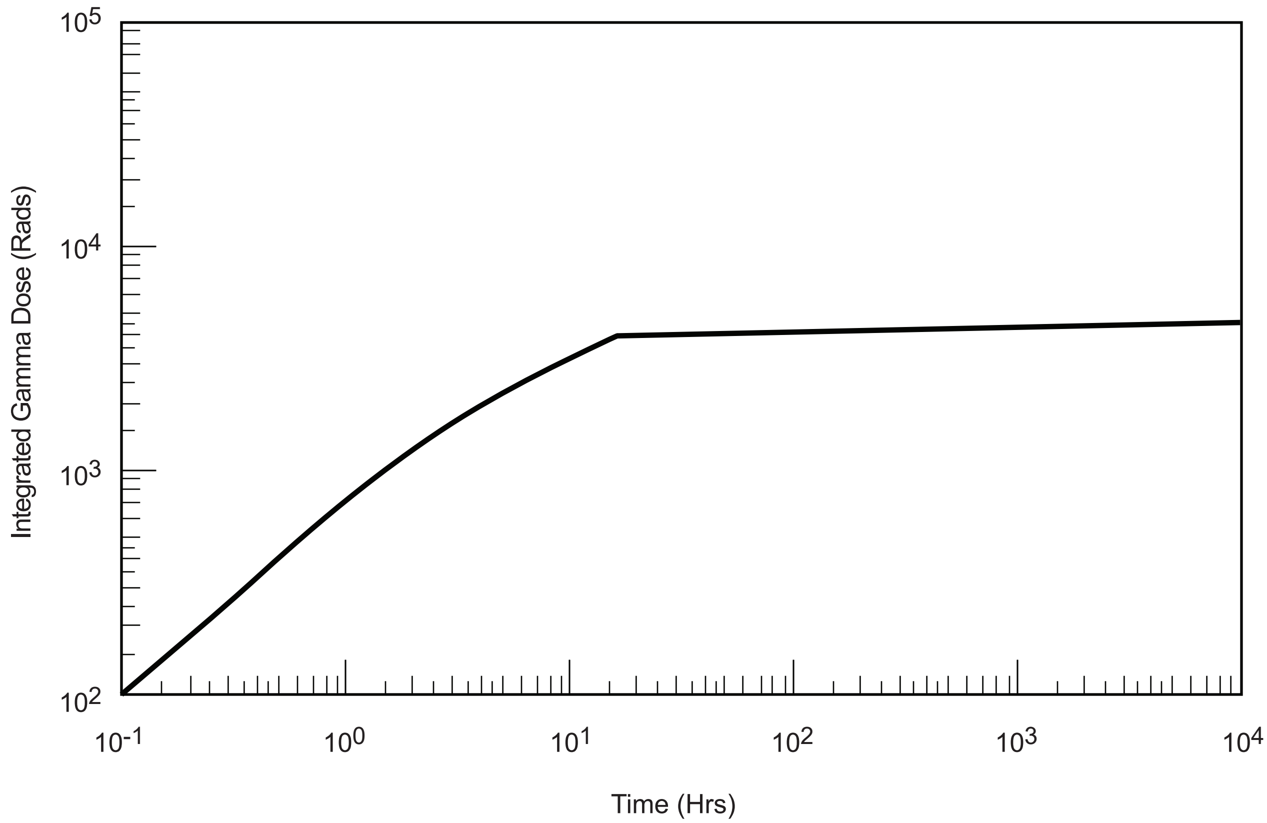
Standard Integrated Gamma Dose Curve for Pipes in the RCIC Steam System and MSIV-LCS Steam System Before the Header

Draw. No. 970187.30	Rev.	Figure J.B-7



Standard Gamma Dose Rate Curve for Pipes in the MSIV-LCS Steam System After the Header

Draw. No. 970187.31 | Rev. | Figure J.B-8

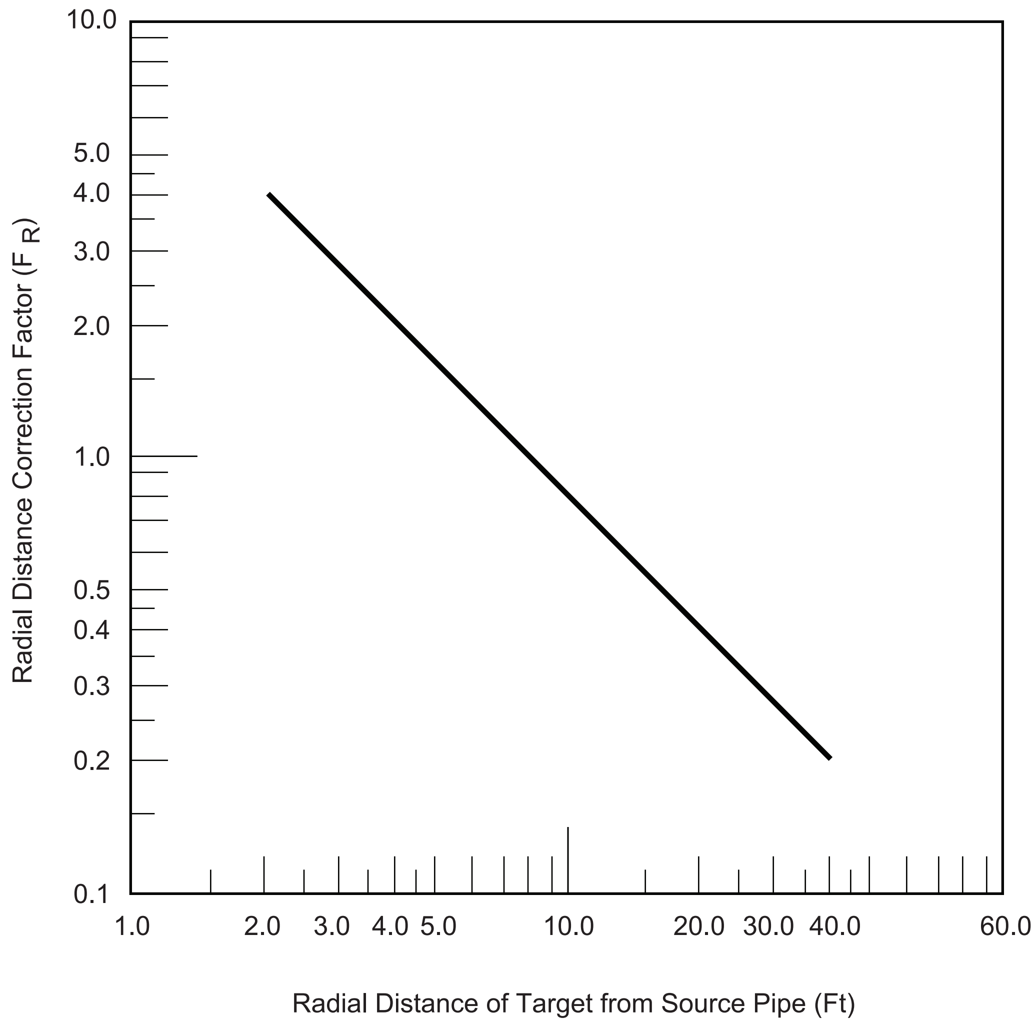


Standard Integrated Gamma Dose Curve for Pipes in the MSIV-LCS Steam System After the Header

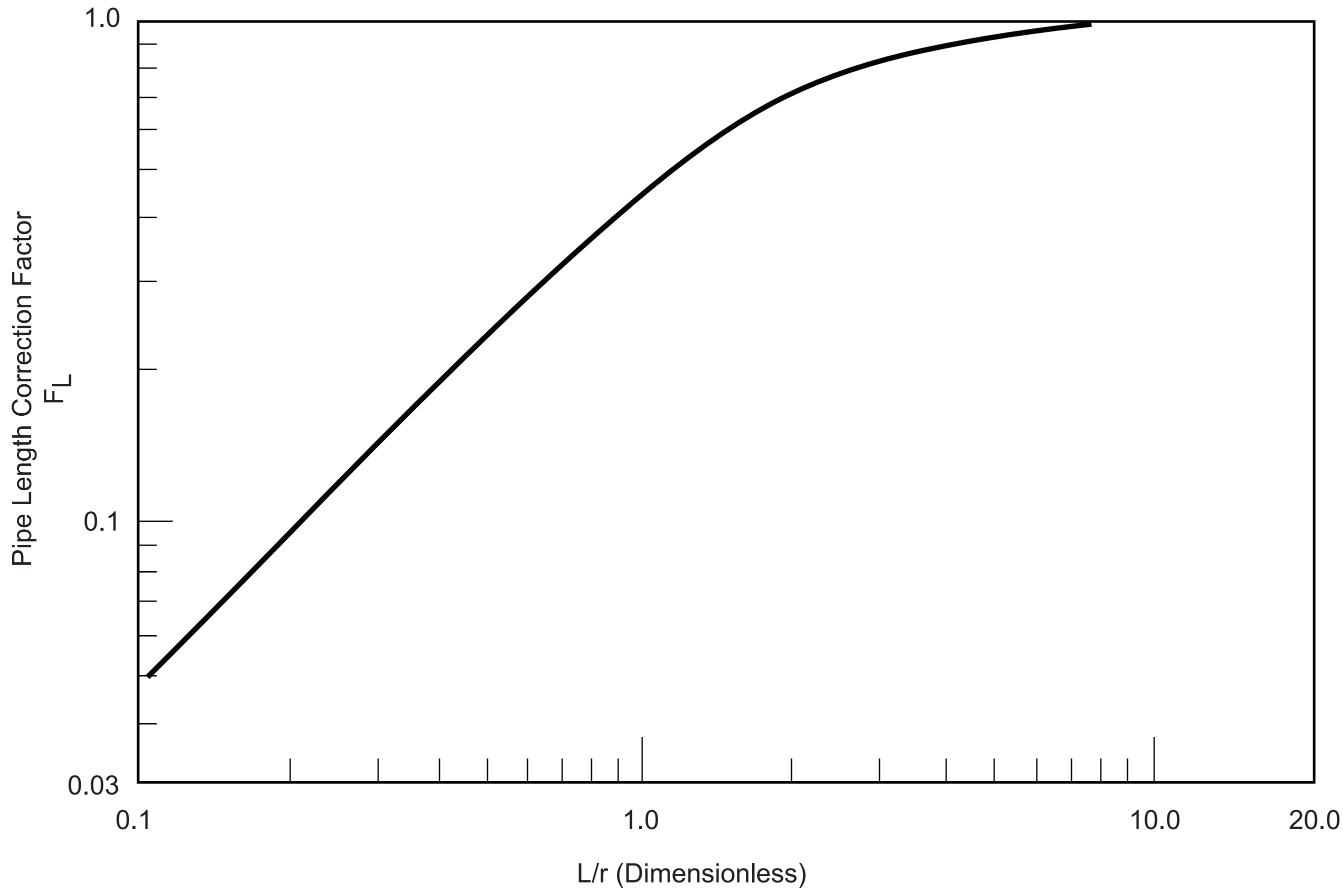
Draw. No. 970187.32 | Rev. | Figure J.B-9

Deleted

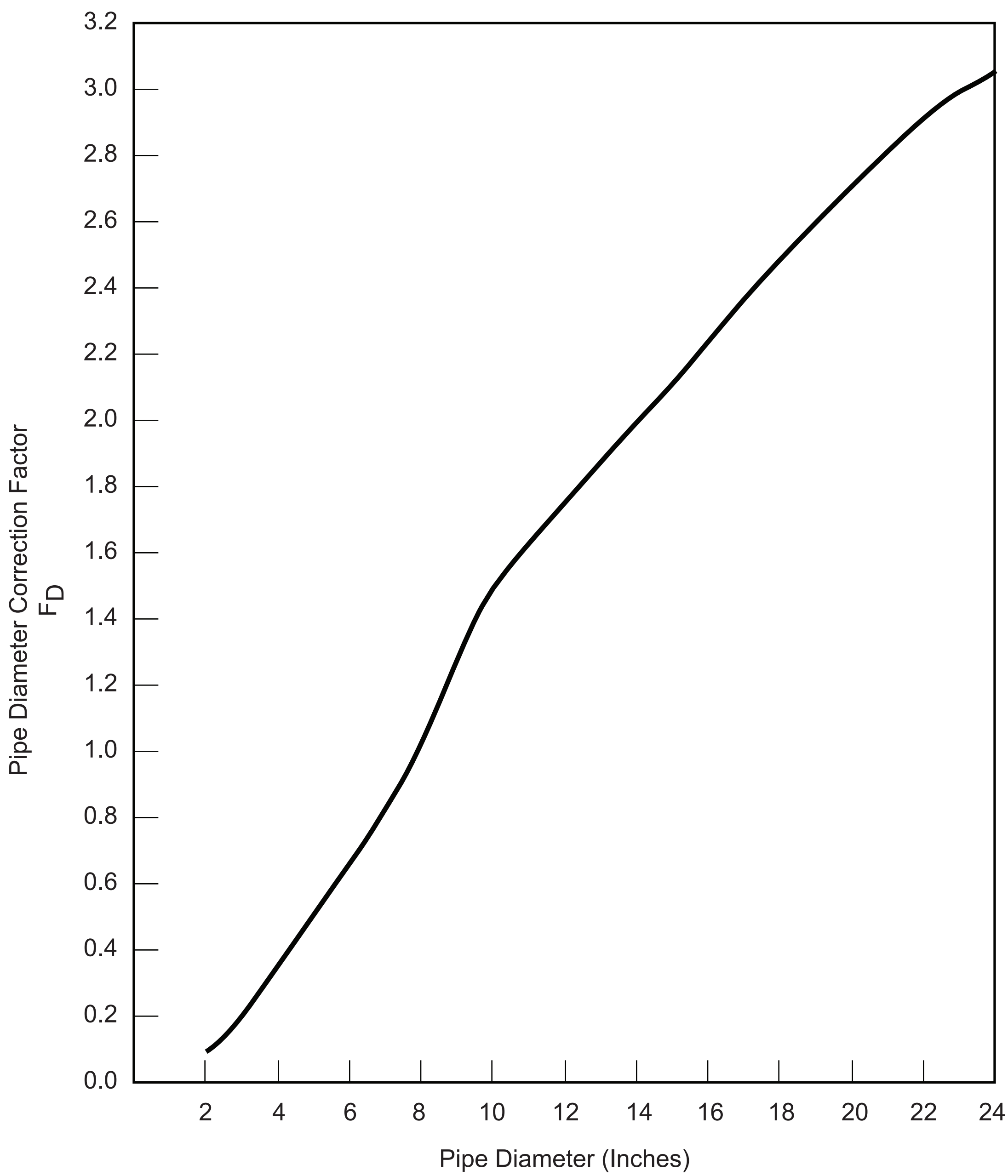
Deleted



Columbia Generating Station Final Safety Analysis Report	Radial Distance Correction Factor for Liquid Sources
	Draw. No. 970187.35 | Rev. | Figure J.B-12



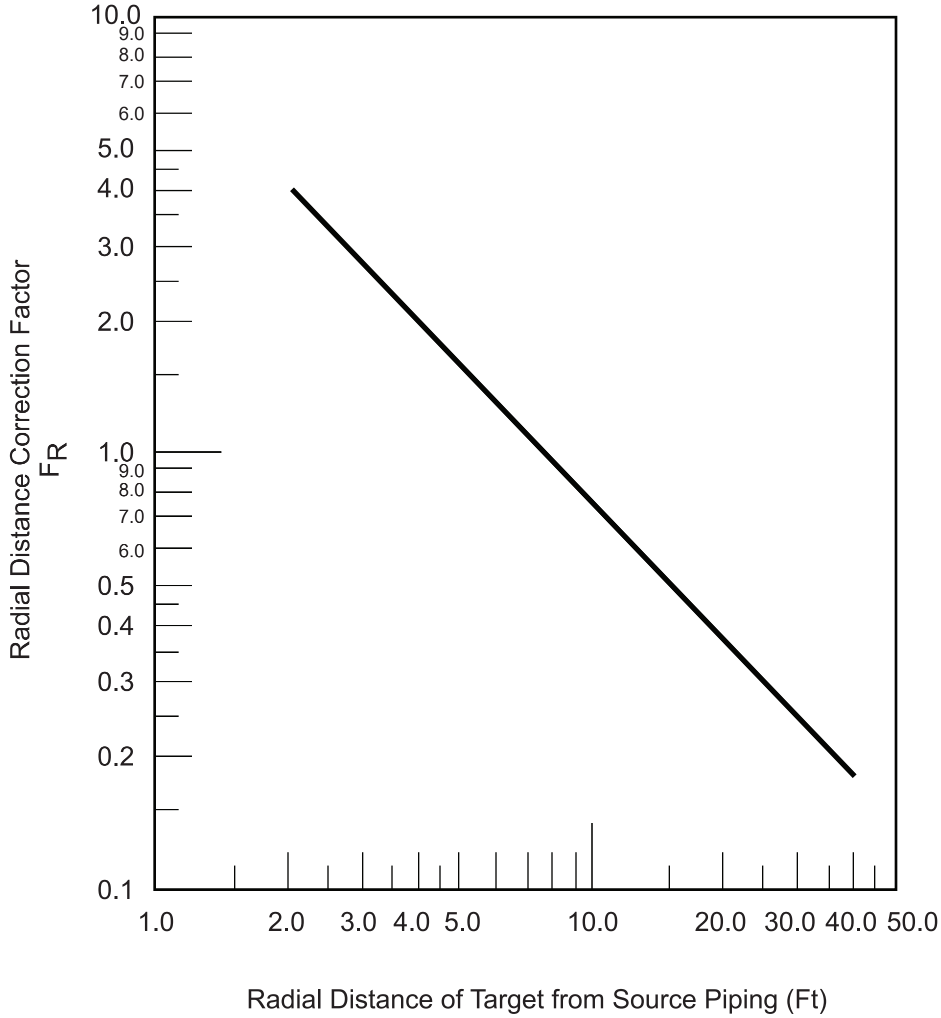
Pipe Length Correction Factor for Liquid Sources



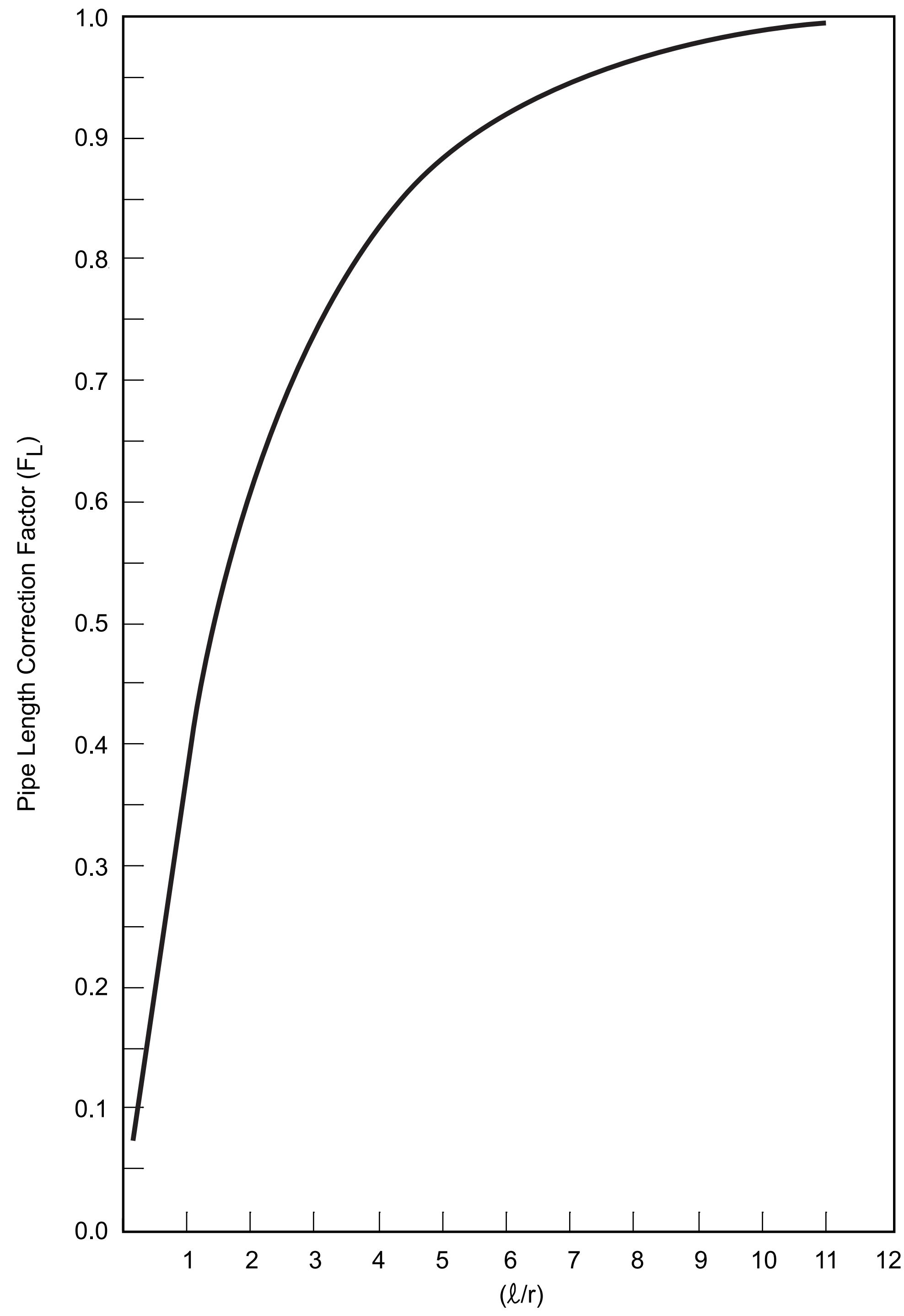
Columbia Generating Station
Final Safety Analysis Report

Pipe Diameter Correction Factor for Liquid Sources

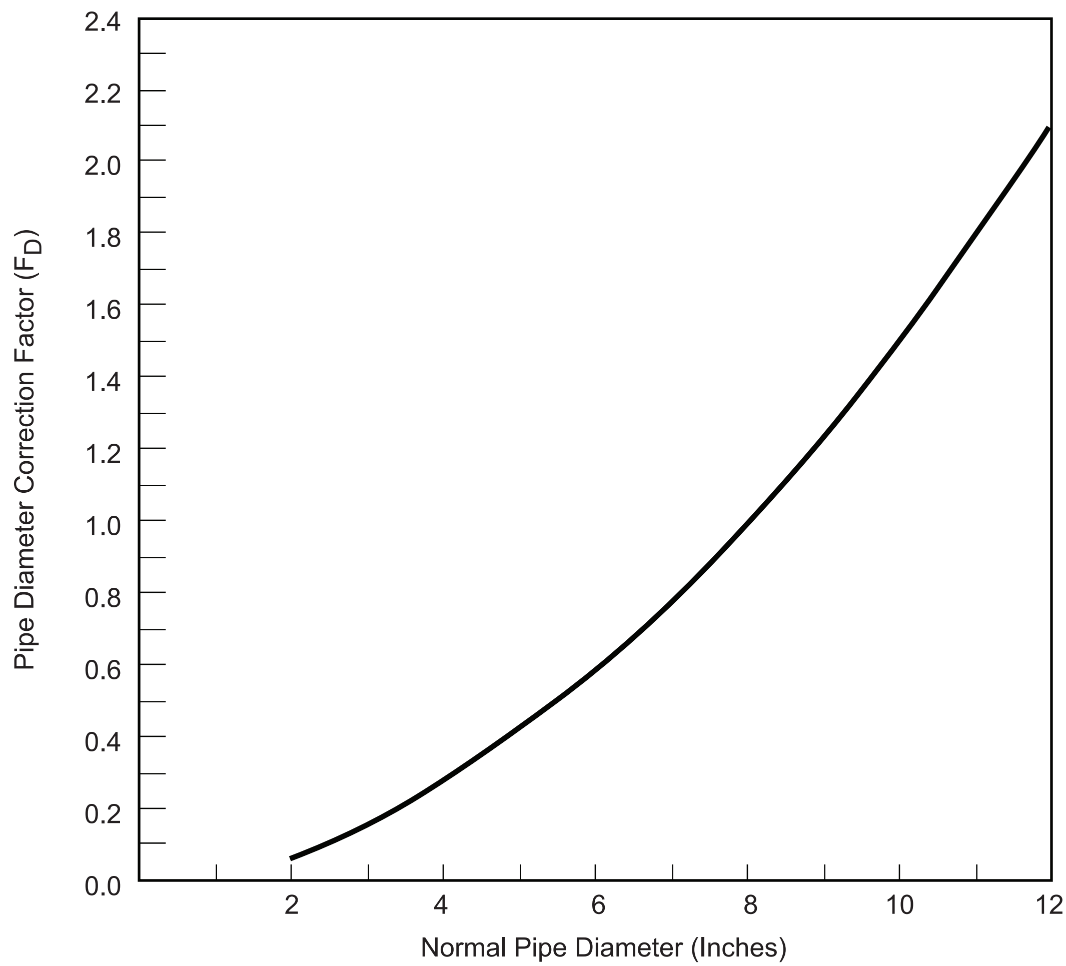
Draw. No. **970187.37** Rev. Figure **J.B-14**



Columbia Generating Station **Final Safety Analysis Report**	**Radial Distance Correction Factor for Gaseous Sources**	
	Draw. No. **970187.38**	Rev.
	Figure **J.B-15**	



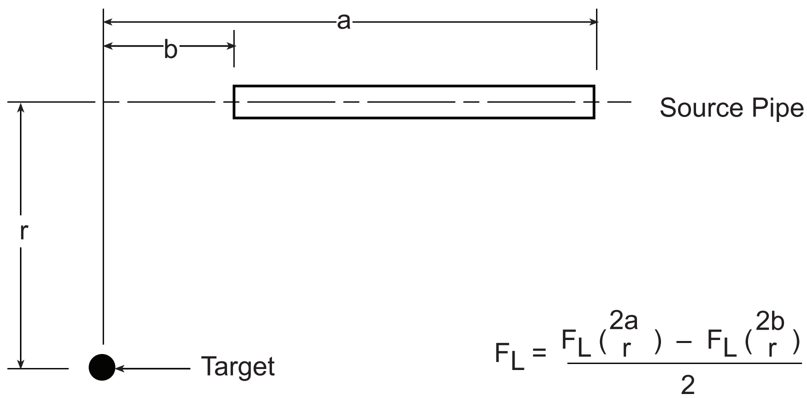
Pipe Length Correction Factor for Gaseous Sources



Pipe Diameter Correction Factor for Gaseous Sources

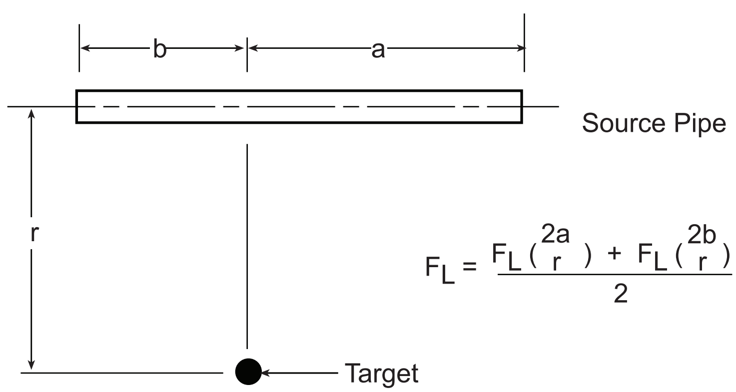
Draw. No. 970187.40 | Rev. | Figure J.B-17

Configuration 1



$$F_L = \frac{F_L\left(\frac{2a}{r}\right) - F_L\left(\frac{2b}{r}\right)}{2}$$

Configuration 2



$$F_L = \frac{F_L\left(\frac{2a}{r}\right) + F_L\left(\frac{2b}{r}\right)}{2}$$

Attachment J.C

PROCEDURE FOR THE CALCULATION OF SECONDARY CONTAINMENT RADIATION ZONE GAMMA DOSES

J.C.1 INTRODUCTION

Three Mile Island Lessons Learned Short Term Recommendations (NUREG-0578) Section 2.1.6.b, requires all nuclear power plant licensees to calculate post-loss-of-coolant accident (LOCA) environmental conditions for all safety-related equipment. This procedure is specifically concerned with the definition of the postaccident radiological environments in the secondary containment of Columbia Generating Station (CGS), a BWR.

The assumptions used in this procedure are based on a nonmechanistic LOCA scenario in which core damage is experienced at the beginning of the accident and primary containment isolation is achieved prior to radiation transport.

The radiation level at a given location inside the secondary containment of CGS during and following such an accident is defined by the following major source contributors.

Airborne gamma dose	Gamma ray dose from airborne radioactive sources inside secondary containment
Containment shine dose	Gamma ray dose from radioactive sources suspended in the drywell and the wetwell inside primary containment
Direct gamma dose	Gamma ray dose from piping containing recirculating radioactive fluids
Bioshield penetration streaming dose	Gamma ray dose from liquid piping and airborne radioactive sources inside primary containment which stream through bioshield wall penetrations into secondary containment

The methods presented in this procedure make it possible to calculate the worst-case gamma ray dose due to the above mentioned source of contributors inside radiation zones (see Section J.C.2 for the definition of radiation zones) of the secondary containment of CGS. The radiation zone dose calculated by using this procedure is applicable solely for the purpose of environmental qualification of safety-related equipment.

The following sections of this procedure describe the nomenclature, assumptions, and methods used in calculating radiation dose rates and cumulative doses. Section J.C.2 defines the terms and nomenclature found in this procedure. The assumptions and approximation used in developing the dose rate calculation method, as well as limitations to this method, are stated in Section J.C.3. Section J.C.4 provides a step-by-step procedure for determining the worst-case gamma dose rate and cumulative dose inside a particular radiation zone. The calculation of airborne beta dose is defined in a separate calculation procedure and is not included in this procedure (see Attachment J.E).

J.C.2 DEFINITION OF TERMS

This section contains the definition of the terms and symbols as used in this procedure:

CIND: (rads) — Cumulative integrated dose
Cumulative dose due to exposure to the decaying radioactive sources.

D_a: (rads/hr) — Airborne gamma dose rate
Gamma dose rate resulting from radioisotopes suspended in the atmosphere of the secondary containment.

D_d: (rads/hr) — Direct dose rate
Gamma dose rate resulting from the radioactive fluid contained inside recirculating pipes.

D_s: (rads/hr) — Shine dose rate
Gamma dose rate in the secondary containment resulting from radioisotopes suspended and deposited inside primary containment.

D_B: (rads/hr) — Bioshield penetration streaming dose
Gamma dose rate contributed by the liquid piping and airborne radioactive sources inside primary containment which stream through the bioshield wall.

D_t: (rads/hr) — Total gamma dose rate
Gamma dose rate contributed by the sum of airborne, direct, and shine from penetrations into secondary containment.

$$D_t = D_a + D_d + D_s + D_B$$

GF: — Geometric factor
Scaling factor used to convert semi-infinite airborne gamma dose to finite dose inside enclosed air spaces.

$$D_a = \frac{D_{a,\infty}}{GF}$$

$$GF = \frac{1173}{V^{0.338}}$$ (Reference J.7-39)

F_L: Length conversion factor
A scaling factor dependent on the source pipe segment length and spatial orientation relative to a target (see Figure J.C-1 for the calculation of this factor). F_L is used to convert the standard dose to the dose emitted by a pipe segment of finite length.

F_D: Diameter conversion factor
A scaling factor dependent on the source pipe diameter. F_D is used to convert the standard dose to the dose emitted by a pipe of specified diameter.

F_R: Radial distance conversion factor
A scaling factor dependent on the radial distance of the target from the source piping. F_R is used to convert the standard dose to the dose at a target of specified radial distance from the source piping.

F_t: Total dose contribution correction factor
A scaling factor used to convert the standard dose to the dose at a target from a pipe segment of specified geometry and orientation.

$$F_t = F_D * F_R * F_L$$

F_s: Sum of dose contribution correction factor
A scaling factor used to convert the standard dose to the radiation zone dose due to all the significant pipe sources in the zone.

$$F_S = \sum_{i=1}^{n} F_{ti}$$

Radiation zone: A region in the secondary containment defined to be such that gamma radiation calculated in the zone bounds the magnitude of dose received by the pieces of safety-related equipment located in that zone.

Source term: The total radiated gamma energy associated with a specified quantity of radioactive material released from the reactor as the result of a postulated accident.

Special sources: Radioactive source of such geometry or concentration that cannot be approximated by pipe segments of diameters 2 in. through 24 in. and containing contaminated liquid of activity concentration established in Section J.C.3.1. This can be a heat exchanger, standby gas treatment filter, pump, etc.

Standard dose: Gamma dose at a target having a radial distance of 8 ft from the centerline of an infinitely long, 8-in.- diameter schedule 40 pipe.

Target: The point in space chosen to represent the location of an object for which a dose rate and/or cumulative dose is being calculated.

Worst case target: Location of the piece of safety-related equipment inside a radiation zone which will experience the highest gamma dose among all the pieces of safety-related equipment in that zone.

J.C.3 ASSUMPTIONS, APPROXIMATIONS, AND LIMITATIONS

J.C.3.1 Basic Assumptions to be Used in the Analysis

Gamma doses and dose rates inside radiation zones will be determined for four types of radioactive source distribution:

Major Source	Contributors
Airborne gamma dose	Isotopes suspended in the atmosphere of the secondary containment
Shine dose	Gamma irradiation from the primary containment
Direct dose	Direct gamma irradiation from the radioactive fluid contained inside recirculating pipes
Streaming dose	Gamma irradiation from liquid piping sources inside primary containment and primary containment atmosphere streaming through bioshield wall penetrations

The dose contributed by each of these sources is determined by the location of the equipment, the time dependent distribution of the source, and the effects of shielding.

The assumptions used in determining the initial distribution and leakage of radioactivity in the primary containment are as follows:

a. 100% of the noble gases and 50% of the halogens initially in the reactor core will be distributed homogeneously within the primary containment free volume immediately following the postulated accident. Plateout of 95% of the elemental iodines is allowed to occur in accordance with Reference J.7-34;

b. 50% of the halogens and 1% of the remaining fission products in the core will be mixed homogeneously with the primary containment liquid space instantaneously. The primary containment liquid space is defined as the sum of the suppression pool liquid and the reactor coolant system (RCS) liquid. Assumptions a and b are NRC-recommended assumptions for defining radioactivity release fractions for the qualification of safety-related equipment (Reference J.7-2) and are consistent with the accident analysis (Reference J.7-13);

c. The core fission product source term is defined as the total product generated in the core after 1000 days at a reactor power of 3556 MWt. This represents the maximum burnup level in the core prior to radioactivity release and is conservative; and

d. Primary containment leakage of 0.50% volume/day was considered and is consistent with the assumptions established in Reference J.7-13.

J.C.3.1.1 Assumptions Used in the Calculation of Airborne Dose Rate Inside Secondary Containment

a. Activity that leaks into the secondary containment is homogeneously mixed with the secondary containment atmosphere prior to its removal from the atmosphere by the standby gas treatment system (SGTS) exhaust fans. This is consistent with the NRC-recommended assumptions used for calculation of doses inside primary containment (Reference J.7-2);

b. The SGTS flow rate of 2430 scfm is assumed to be the flow rate of the effluent air and is based on one reactor building air change per day;

c. Air that leaks out of the primary containment flows directly into the secondary containment. Bypass leakage is not considered. This is conservative when considering dosage in the secondary containment, since it maximizes the buildup of radioactivity in the secondary containment; and

d. Geometric factors provide a good approximation to convert the semi-infinite cloud dose to a finite cloud dose and is based on the results presented in Reference J.7-28 and based on average gamma ray energy of 0.733 MeV. The effect of variation of this parameter due to difference in gamma ray energies have been proven to be negligible (see Attachment J.B for justification).

J.C.3.1.2 Assumptions Used for the Calculation of Shine or Streaming Dose From Primary Containment

a. No depletion of activity due to leakage is assumed to maximize the source activity and is conservative;

b. The airborne source is assumed to be uniformly distributed in the drywell and in the wetwell air space. The effect of the plateout of iodine is not considered in secondary containment;

c. Activity in the wetwell water volume is assumed to be uniformly distributed in the sump water. Assumptions b and c are based on the plateout modeling and source term assumption contained within References J.7-2 and J.7-34;

d. The dosage at a point inside the region closest to the source is considered to be representative of the gamma dose in the region which maximizes the gamma ray dose at the region and is conservative; and

e. The liquid piping sources inside primary containment are assumed to be uniformly distributed in the RCS for the first 17 hr post-LOCA. The liquid piping sources inside primary containment are assumed to be uniformly distributed in the RCS plus the suppression pool after the first 17 hr post-LOCA. This is consistent with the CGS operations procedure to depressurize and utilize the alternate shutdown cooling mode within 17 hr post-LOCA once a degraded core condition is identified.

J.C.3.1.3 Assumptions and Approximations Used in the Calculation of Direct Doses

a. No valve leakage is assumed, which is consistent with Reference J.7-5, Item II.B.2, Clarification (2);

b. Schedule 40 piping is assumed, which is a conservative simplification of the calculation process. Because the majority of the pipe segments considered are schedule 40 piping, and because increases in pipe schedule can only decrease the dose rate at the targets, this approximation is considered to be conservative and appropriate;

c. Heat exchangers and pumps can be approximated as pipe systems. The volume of radioactive liquid in the component and its length are used to determine an equivalent volume of liquid. This is a crude approximation for dose rates contributed by complex geometries. Because the pump and heat exchanger walls are thicker than the pipe walls of schedule 40 piping, this assumption is conservative; and

d. Radioactive piping with diameters 2-1/2 in. or less was not modeled unless it was determined that such a pipe was a major source contributor. A major source contributor is defined as the only radioactive pipe in a target area or the radioactive pipe of closest proximity to the target. This is made because the dose contributions due to pipe segments of diameter less than 2-1/2 in. are generally negligible, unless they are major source contributors.

J.C.3.2 Limitations

The following limitations apply to the use of this procedure for the calculation of radiation zone doses.

a. This procedure is only applicable to the calculation of radiation zone gamma doses in the secondary containment of CGS;

b. The assumptions stated in Section J.C.3.1 are basic to the methodology used in this procedure. Changes in any of the assumptions will affect the accuracy of the results generated using this procedure;

c. The calculation of direct doses using the generic curves in this procedure is limited to liquid sources in schedule 40 pipe segments or equivalent pipe segments with nominal pipe diameters ranging from 2 in. to 24 in. Any deviation from these pipe geometries should be modeled as special cases. Note: Schedule 40 piping is used because the majority of the pipe segments to be considered are standard pipes (schedule 40). Increases in the pipe schedule only introduces conservatism in the results;

d. The results for direct dose calculated using the generic curves were found to be accurate to within 10% (see Reference J.7-39 for error study); and

e. Source piping located 40 ft or further from the target is generally an insignificant dose contributor. If its contribution is not found to be negligible, it should be considered as a special source.

J.C.4 PROCEDURES FOR THE CALCULATION OF SECONDARY CONTAINMENT RADIATION ZONE DOSES

This procedure describes the method used in calculating the gamma radiation doses inside radiation zones. For equipment located inside a zone, the following four sources contribute to the total dose level.

a. Airborne dose (gamma),
b. Direct gamma dose from sources within pipes,
c. Direct gamma shine dose from drywell and wetwell, and
d. Gamma streaming dose from drywell and wetwell.

A step-by-step procedure is discussed in the following sections for the calculation of the maximum total gamma dose and dose rates for each zone.

J.C.4.1 Procedure A: Radiation Zone Dose Calculation

The first step in preparing a zone dose calculation is to identify all the parameters to be used. This includes the identification of all the potential sources and targets, both inside and outside the zone, and the identification of the dimensions of the zone. Figure J.C-2 is a step-by-step flowchart of the calculation procedure. When identifying sources outside the zone, sources at the upper and lower elevations in the review process are included. A conservative dose estimate is used to determine whether a source outside a zone is a significant contributor. For example, if the closest pipe segment in the zone is a few feet away from a target, then the dose estimate will show that a pipe segment outside the room at 30 ft is insignificant by comparison. Conversely, if a target is located near a wall with several pipes on the other side of a wall, then those pipes may become significant source contributors and are included in the final evaluation for the target.

J.C.4.2 Procedure B: Airborne Dose Calculation in Secondary Containment

Because the semi-infinite airborne dose and dose rates are already calculated and shown in Figures J.C-6 and J.C-7, the only calculation involved in determining the airborne dose is the conversion of the semi-infinite cloud dose at reactor building concentrations to a finite cloud dose inside the cubicles in which the radiation zones are defined. The first step in this calculation is to determine the volume which defines the air space (or zone) of interest. An enclosed air space is defined as a cubicle, at least 95% shielded by concrete (or equivalent shielding) at least 1 ft thick.

To convert a semi-infinite cloud dose (calculated in Reference J.7-38) to a finite cloud dose, a geometric factor is used.

$$D_a(t) = \frac{D_{a,\infty}(t)}{GF} \tag{J.4-1}$$

where $GF = \dfrac{1173}{V^{0.338}}$ (Reference J.7-39) (J.4-2)

GF	=	geometric factor (dimensionless)
V	=	volume of the enclosed air space (ft^3)

Similarly,

$$CIND_a(t) = \frac{CIND_{a,\infty}(t)}{GF} \tag{J.4-3}$$

Figure J.C-3 is a step-by-step flowchart of the procedure for calculating airborne gamma doses.

J.C.4.3 Procedure C: Primary Containment Shine Dose Calculation

Containment shine doses are calculated using the QAD-P5A computer code. Guidelines for preparing input parameters are documented in Procedure E and Reference J.7-10. The modeling procedure and the accuracy of the results are highly dependent on the geometry to be modeled, specification of the source volume, and the selection of a buildup factor. Figure J.C-4 is a step-by-step procedure for calculating containment shine doses.

J.C.4.4 Procedure D: Direct Dose Calculation

The first step in the direct dose calculation (from Reference J.7-39) is the identification of the "worst-case" target. Normally, the worst-case target is the piece of equipment that is closest to the major source piping and can be selected by inspection. However, if situations arise such that the worst-case target cannot be chosen by simple inspection, order-of-magnitude calculations are performed for each potential worst-case target in the zone. These calculations are illustrated in Steps 3a through 3c of Figure J.C-5.

The next step is to identify special sources. Special sources are defined as source geometries that cannot be represented by liquid pipe segments between 2 and 24 in. in diameter. Example special sources are SGTS filters, reactor core isolation cooling (RCIC) steam pipe, turbines, and heat exchangers larger than 24-in. diameter. Other components such as pumps and small heat exchangers should be modeled as pipes. The pipe cross-sectional area is calculated by dividing the total fluid volume by the effective length of the component.

The contribution due to sources with shield walls is investigated next. Figure J.C-13 is used for this evaluation. If these sources are determined to be significant contributors, special QAD-P5A modeling procedures as described in Procedure E are followed.

It is unlikely that all sources under consideration will contribute significantly to the dose at a specific target. If all source contributions were to be calculated, the time involved in performing the calculation would be unnecessarily long without making a substantial improvement in the accuracy of the results.

Hence, as the sources are being identified, good judgment is used to distinguish between sources which contribute significantly to the target dose and those sources which do not.

An insignificant source is determined by comparing its dose contribution to the source making the largest dose contribution. The comparison is facilitated by arranging sources in decreasing order of importance and assigning rank numbers to the sources. The largest dose contributor is given a ranking number of 1. The largest dose contributor is determined by inspection of the sketches and drawings being used. The largest dose contributor is generally the longest segment with the largest pipe diameter and the least amount of intervening shielding between the target and source. All sources which are in the radiation zone and have been assumed to be insignificant contributors are listed as such to indicate that those sources have been considered.

Equations Used in the Calculation of Dose Rates

The following procedure is followed for the calculation of correction of dose rates factors of dose rates (Step 9 through Step 12 of Figure J.C-5):

a. Identify the radial distance of the pipe segment from the target; read F_R from Figure J.C-11.

   If the target is in contact with the source piping, read F_D from Table J.C-1 and set F_R and F_L equal to 1.

   (Note: dose rate is not a function of pipe length and radial distance.)

   If the target is geometrically in line with the source pipe segment, as shown in configuration 3 of Figure J.C-1, set $F_L=1$ and read F_D and F_R from Figures J.C-14 and J.C-15, respectively.

   (Note: F_L is defined here because dose rate is not sensitive to pipe length variation.)

b. Identify the pipe diameter; read F_D from Figure J.C-10.

c. Determine F_L from Figure J.C-12; use equations in Figure J.C-1 to calculate this factor.

d. The total dose contribution factor for a given pipe segment (I) is given as

$$F_t(I) = F_D(I) * F_R(I) * F_L(I)$$

e. When all the significant contributions have been calculated, sum the total dose contribution factors.

$$F_s = \sum_{n=1}^{n} F_t\ (I)$$

f. To determine if a source is negligible, the following test should be performed:

When N source segments are being considered and the dose contribution of ranking I is less than 1/10 of the dose rate calculated from the largest source divided by (N-I), the sources remaining should not contribute more than 10% to the total source contribution. This level of accuracy should be adequate for most calculations.

The total integrated direct dose and dose rate can be calculated.

$$D_D(t) = D_{Do}(t) \bullet F_s + D_D(t) \qquad \text{(Special Sources)}$$

$$CIND_D(t) = CIND_{Do}(t) \bullet F_s + D_D(t) \qquad \text{(Special Sources)}$$

where $D_{Do}(t)$ and $CIND_{Do}(t)$ are dose rates and cumulative doses for standard pipe segments and are found on Figures J.C-8 and J.C-9.

J.C.4.5 Procedure E: QAD-P5A Modeling Procedure

Direct dose contribution due to special sources and/or sources with shield walls should be calculated using the QAD-P5A computer code. This computer code is three-dimensional and calculates dose rates at specified target locations from radioactive volume, line, and point sources. Attenuation due to shield materials, if applicable, is also applied.

The accuracy of the results is highly affected by the manner by which the source volume is divided, and the position of the target relative to the source point. Therefore, a sensitivity study on the specification of the source volume should be performed. This can be achieved by increasing the number of source volume divisions until the dose rate results converge to within 5%.

Another factor to be considered is the specification of the buildup factor. As a general rule, aluminum buildup factor should be used when concrete shield is encountered, and iron energy buildup factor should be used when considering attenuation through steel shield.

J.C.4.6 Procedure F: Streaming Dose Calculation

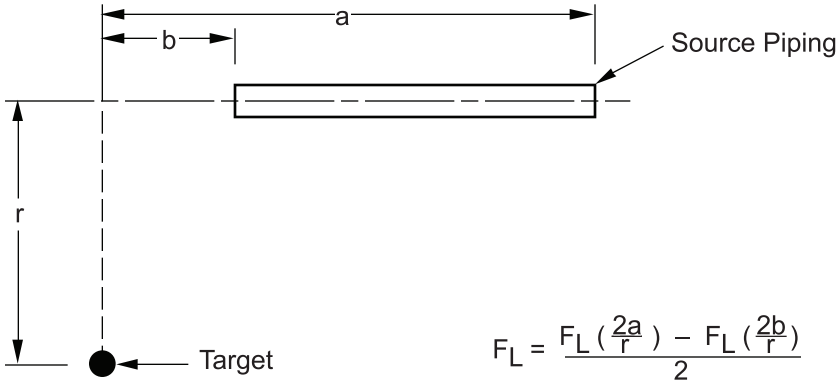
Containment streaming doses through the bioshield wall penetrations are calculated using the SCAP-BR and QAD-CG computer codes. The modeling procedure and the accuracy of the results are highly dependent on the geometry to be modeled, specification of the source volume, and the selection of a buildup factor.

Table J.C-1

Diameter Correction Factor (F_D) for Targets in
Contact With the Source Piping

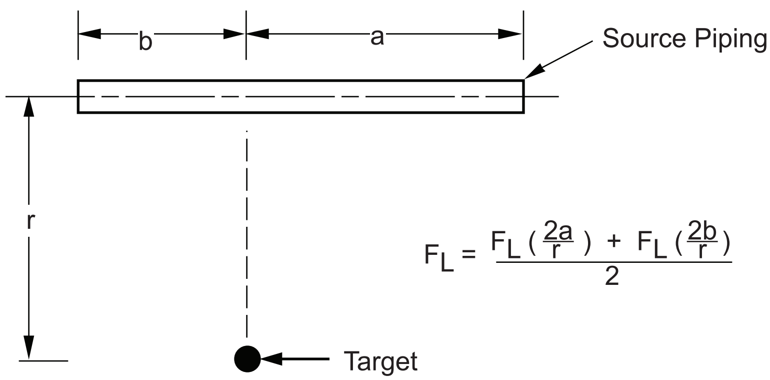
Nominal Pipe Diameter (in.)	Pipe Diameter Correction Factor (F_D)
2	18.4
4	24.4
6	54.6
8	33.3
10	35.3
12	35.3
14	35.5
16	33.7
20	32.0
24	29.6

Configuration 1



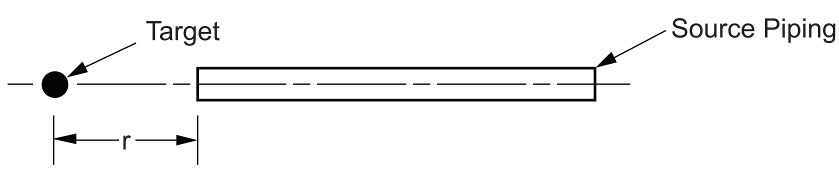
$$F_L = \frac{F_L\left(\frac{2a}{r}\right) - F_L\left(\frac{2b}{r}\right)}{2}$$

Configuration 2



$$F_L = \frac{F_L\left(\frac{2a}{r}\right) + F_L\left(\frac{2b}{r}\right)}{2}$$

Configuration 3



$$F_L = 1$$

Start

Step 1 — Identify Dimensions of Zone

Step 2 — Locate Targets Inside Zone on the Zone Sketch

Step 3 — Identify All Dose Contributing Sources Inside Zone and Locate on Zone Sketch

Step 4 — Identify All Possible Dose Contributing Sources Outside Zone

Step 5 — Calculate Airborne Gamma Dose Rate and Integrated Dose (Refer to Procedure B)

Step 6 — Calculated Shine and Streaming Gamma Dose Rate and Integrated Dose (Refer to Procedure C)

Step 7 — Calculate Direct Dose Gamma Dose Rate and Integrated Dose (Procedure D)

Step 8 — Calculate Total Gamma Dose and Dose Rate

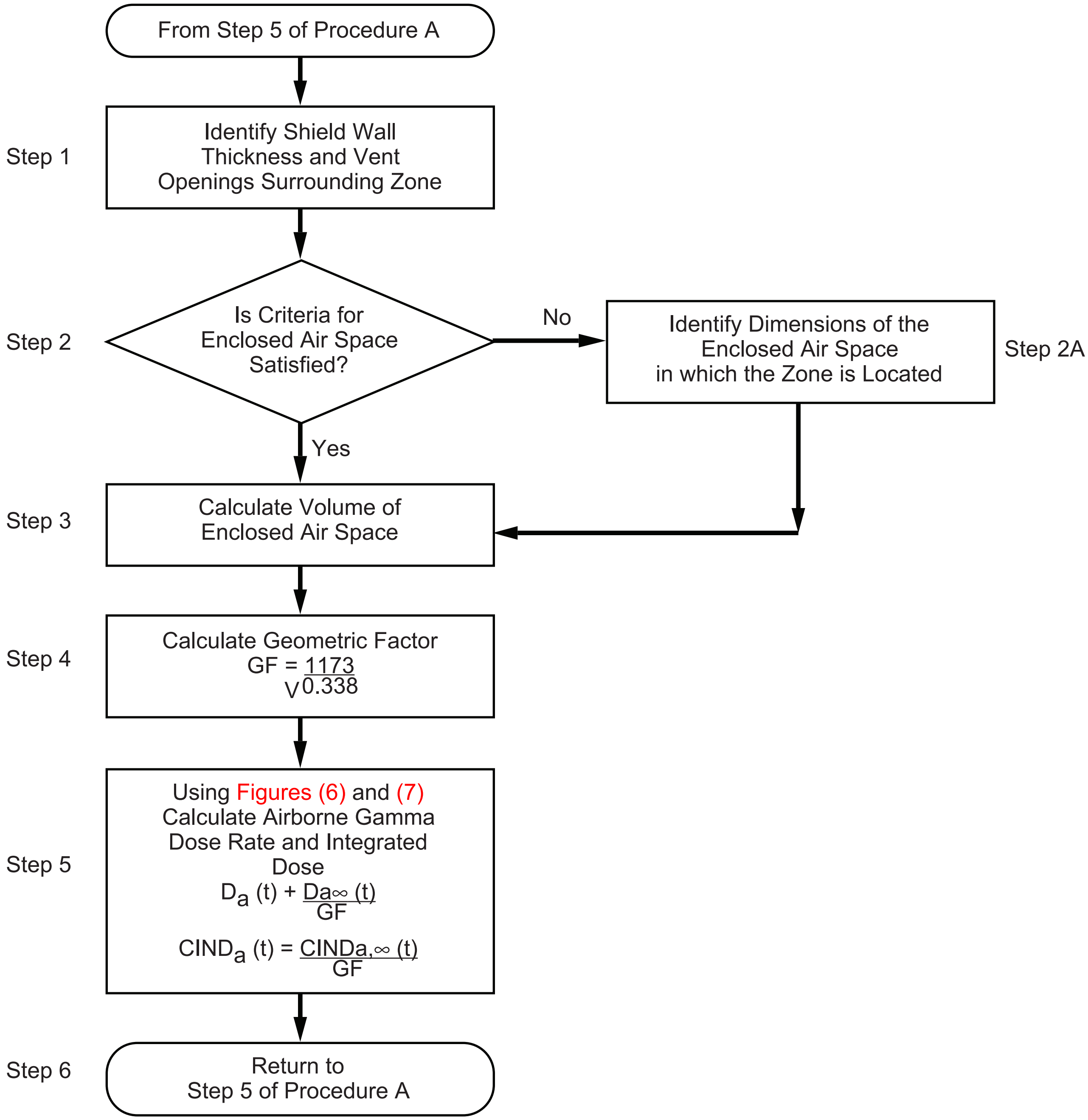
$$D_t = D_a + D_d + D_s + D_B$$

$$CIND_t = CIND_a + CIND_d + CIND_s + CIND_B$$

Step 9 — Complete Table 1

Step 10 — PLCT Total Dose Rate and Integrated Dose

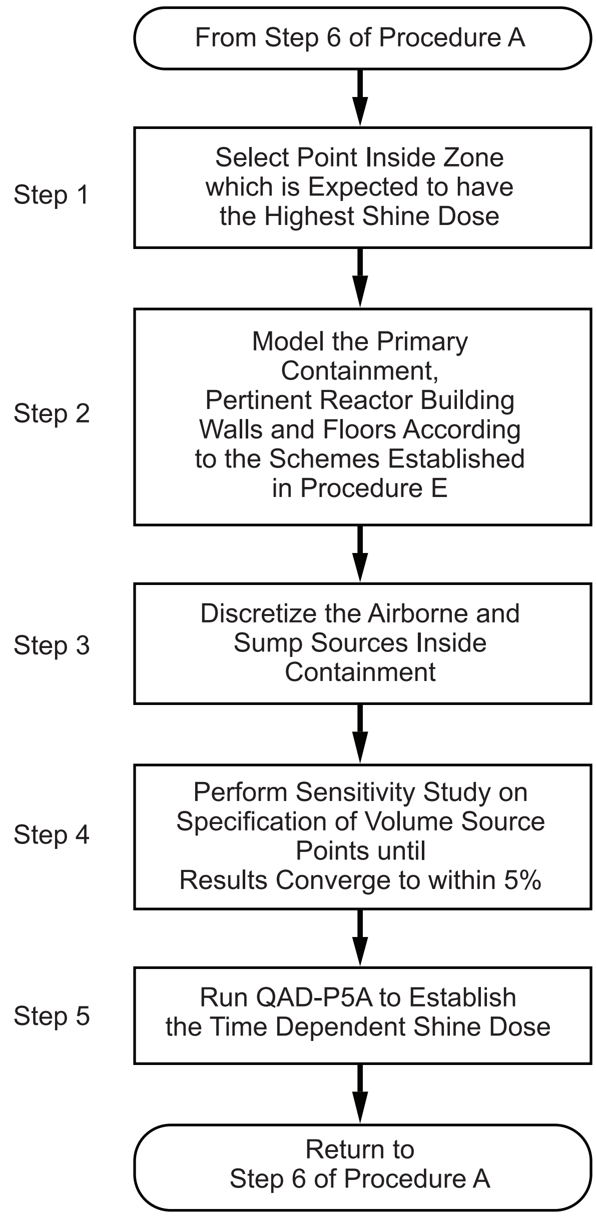
Problem Completed



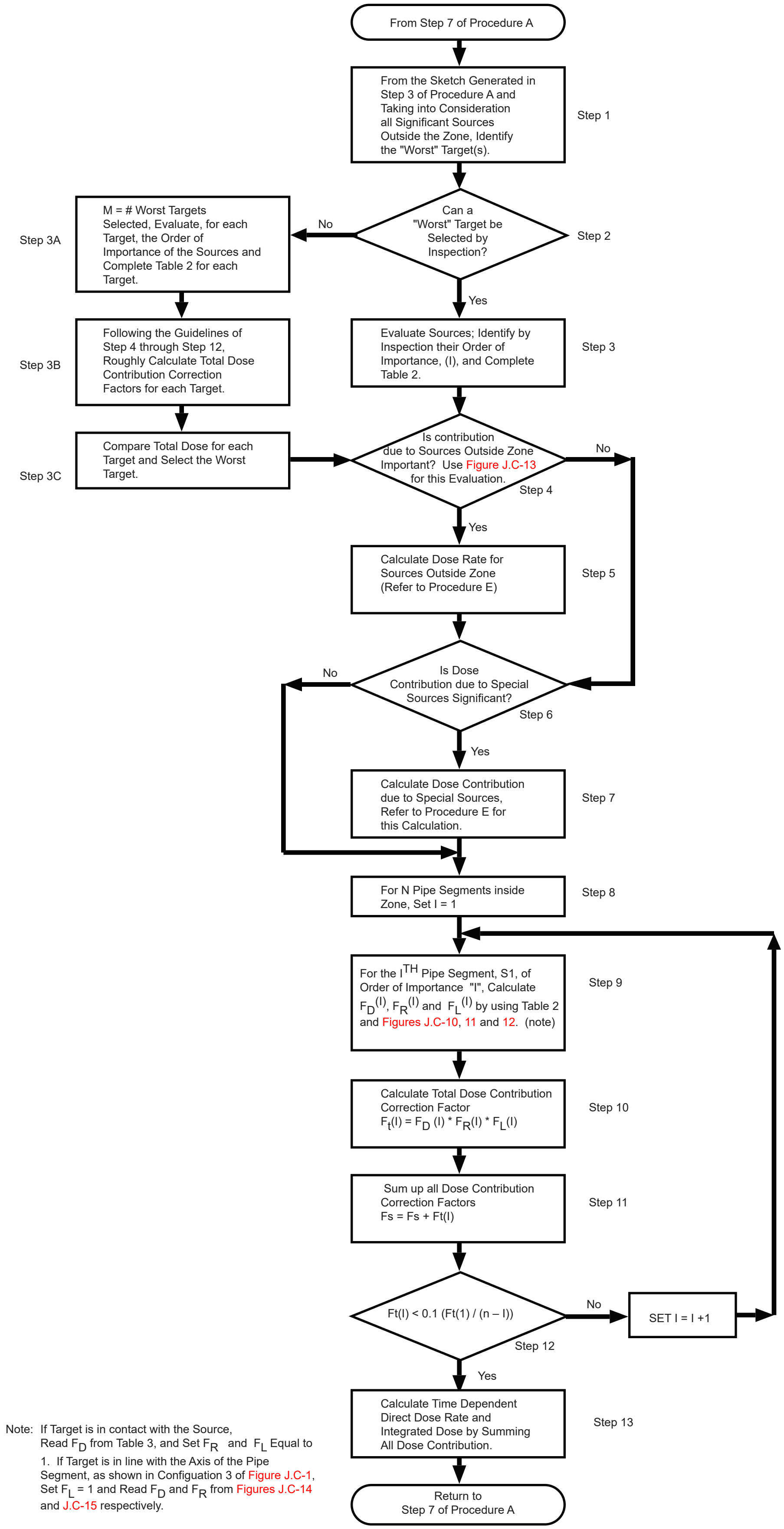
Columbia Generating Station
Final Safety Analysis Report

Procedure B: Procedure for Calculating Airborne Gamma Dose Rate and Integrated Doses

Draw. No. 970187.53 | Rev. | Figure J.C-3



Procedure C: Procedure for Calculation of Containment Shine Dose

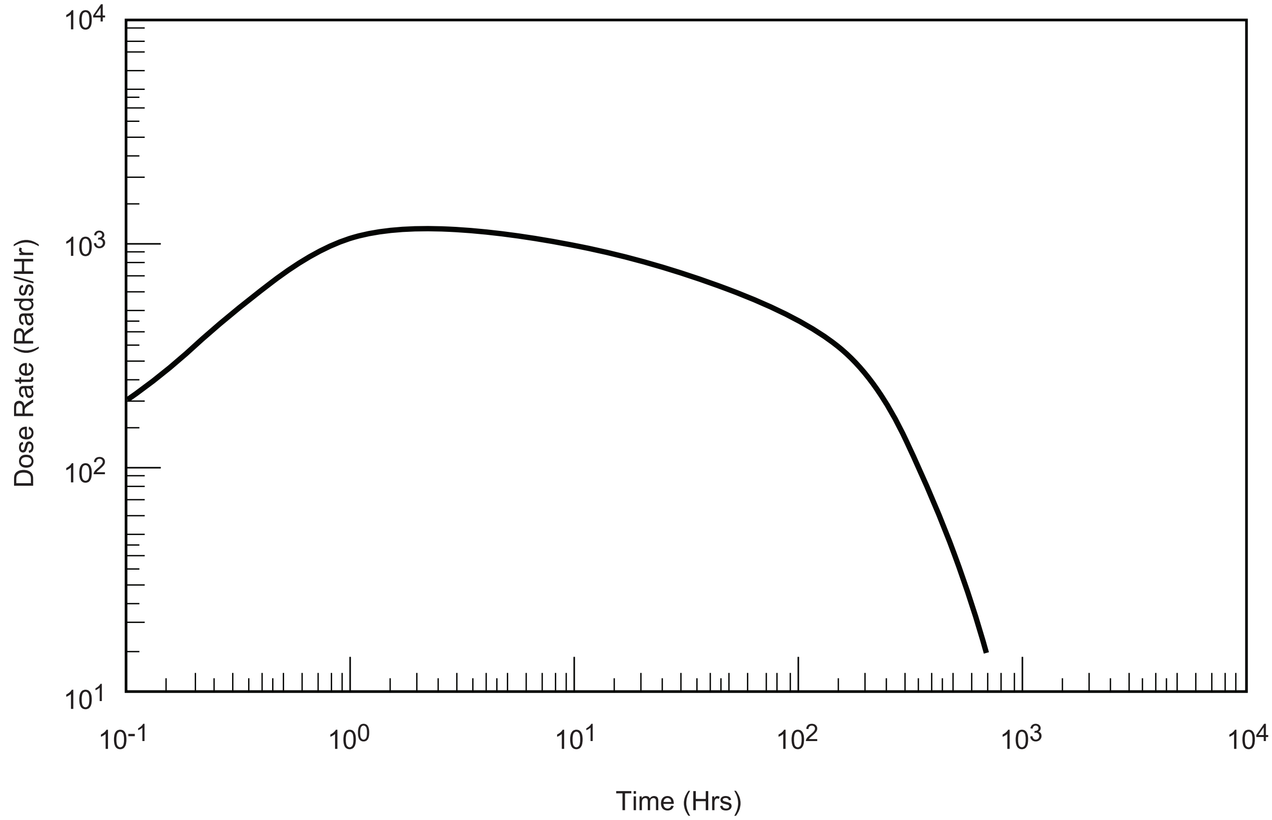


Columbia Generating Station
Final Safety Analysis Report

Procedure D: Procedure for Calculation of Direct Dose Rate and Integrated Dose

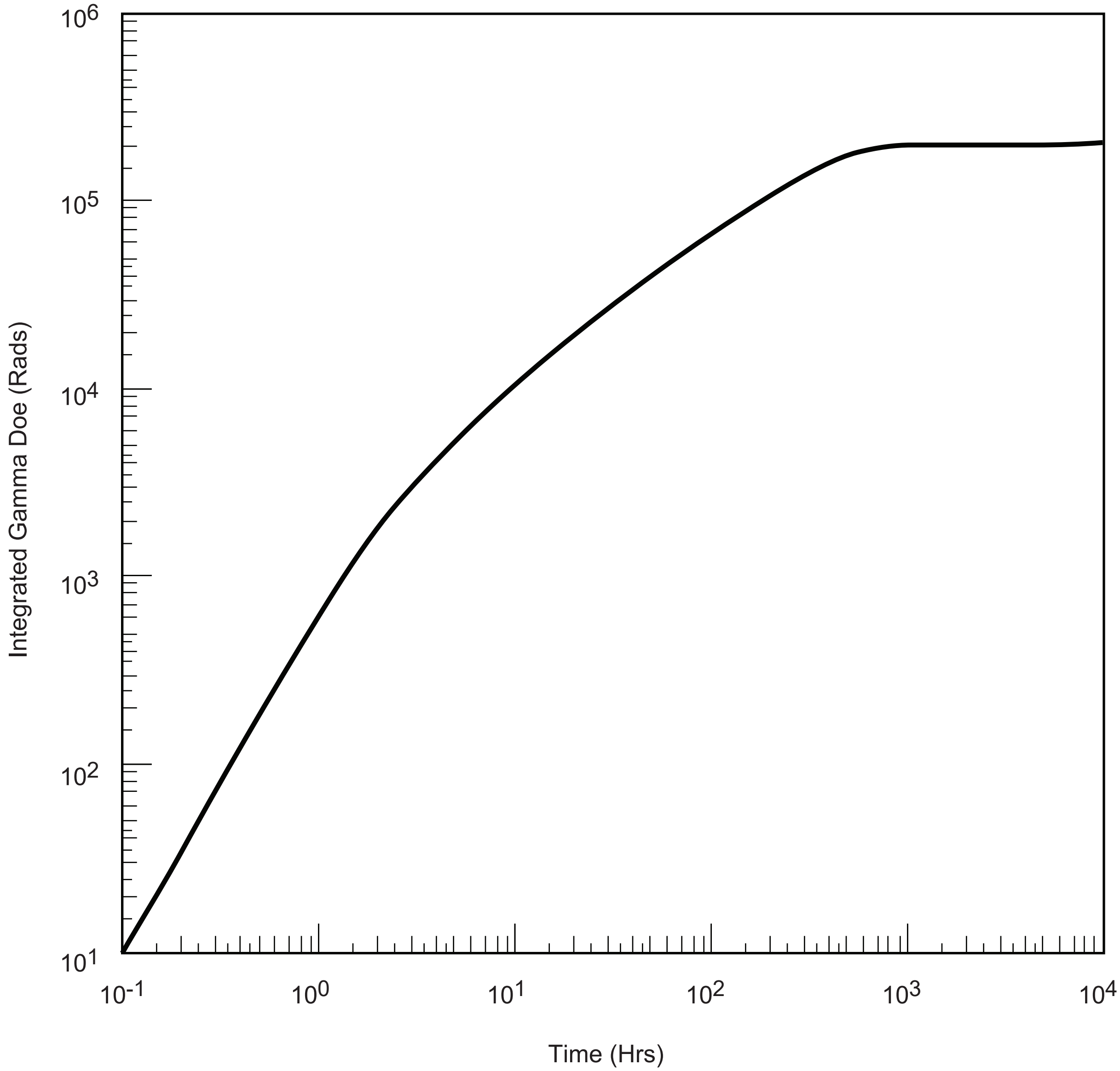
Draw. No. 970187.55	Rev.	Figure J.C-5

Form No. 960690



0.5%/Day Primary Containment Leakage Rate

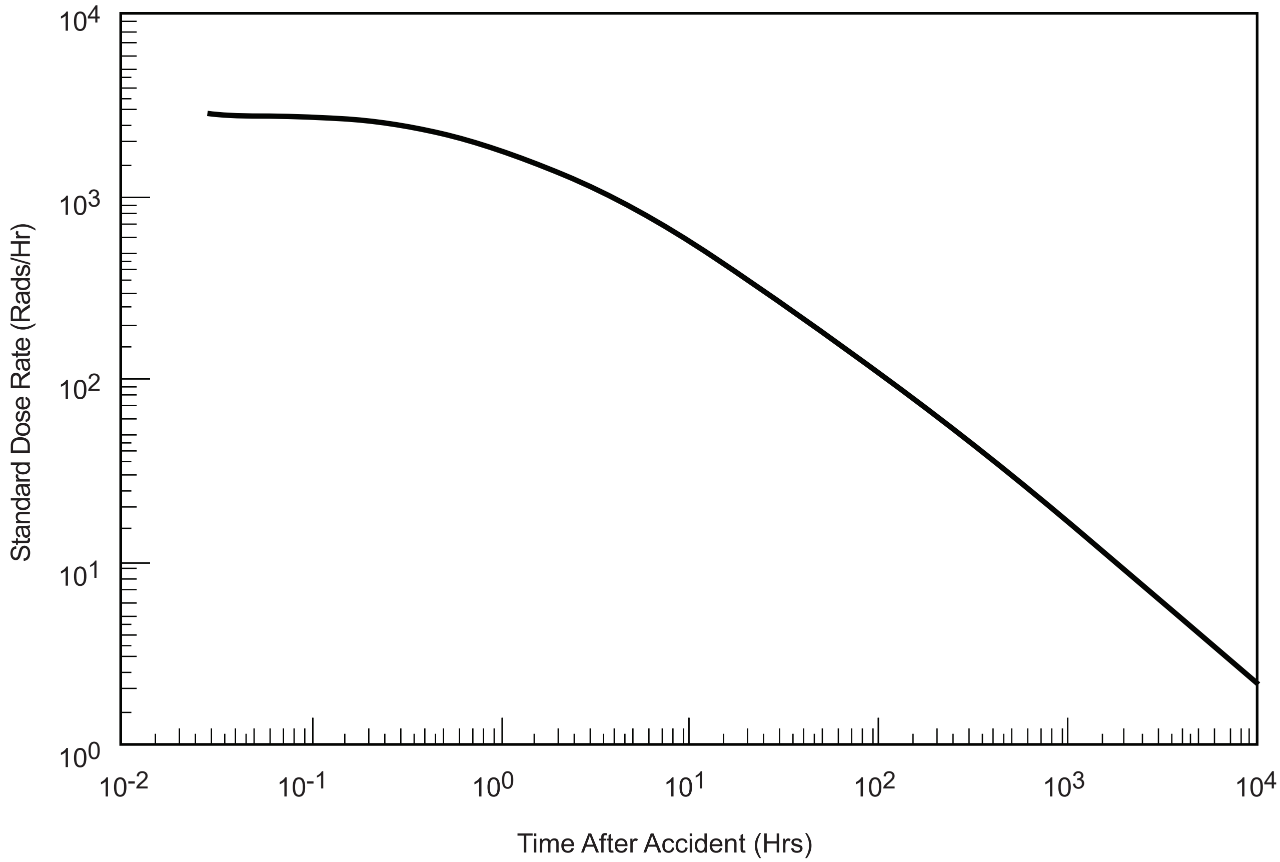
Columbia Generating Station **Final Safety Analysis Report**	**Time-Dependent Gamma Dose Rate for a Semi-Infinite Cloud of Fission Products at Secondary Containment Concentrations**
	Draw. No. **970187.56** Rev. Figure **J.C-6**



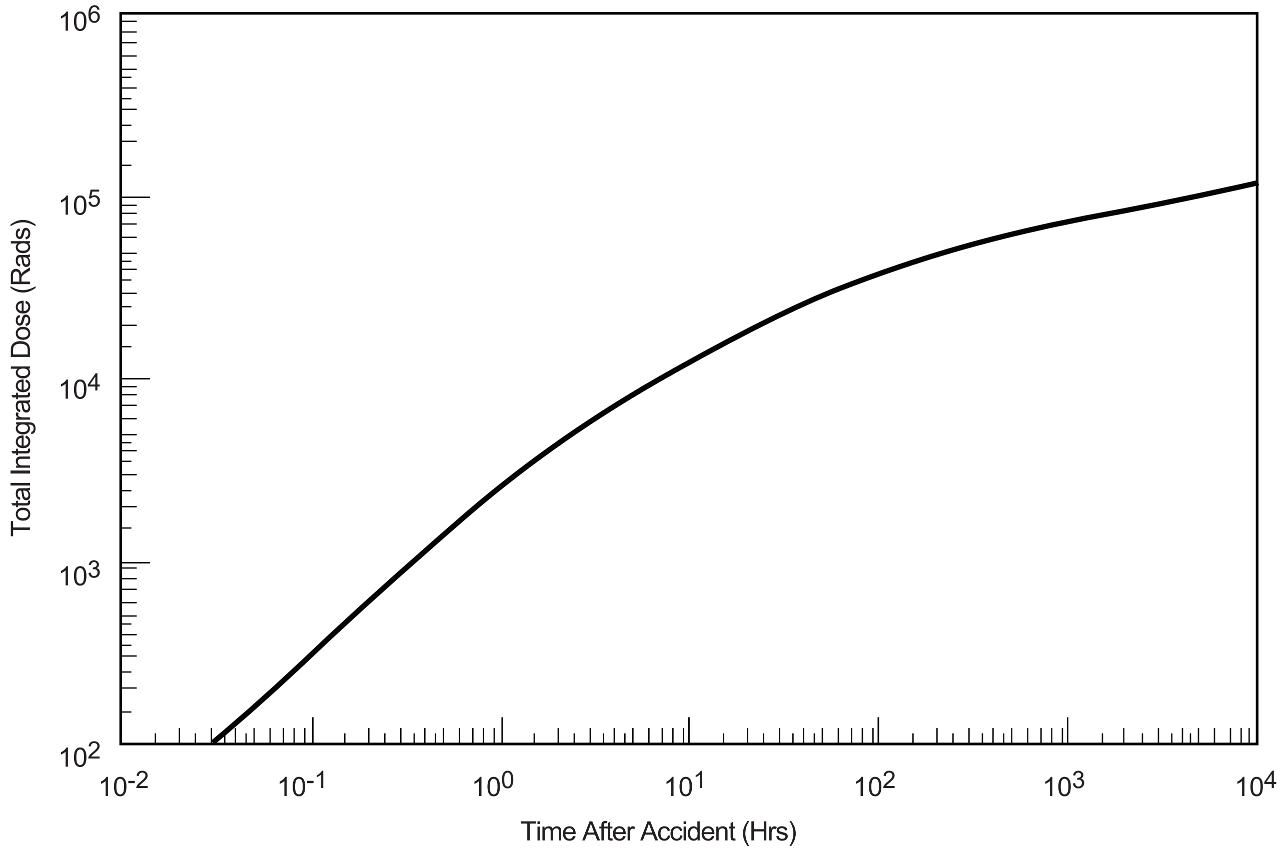
0.5%/Day Primary Containment Leakage Rate

Time-Dependent, Integrated Gamma Dose Rate for a Semi-Infinite Cloud of Fission Products at Secondary Containment Concentrations

Draw. No. 970187.57	Rev.	Figure J.C-7

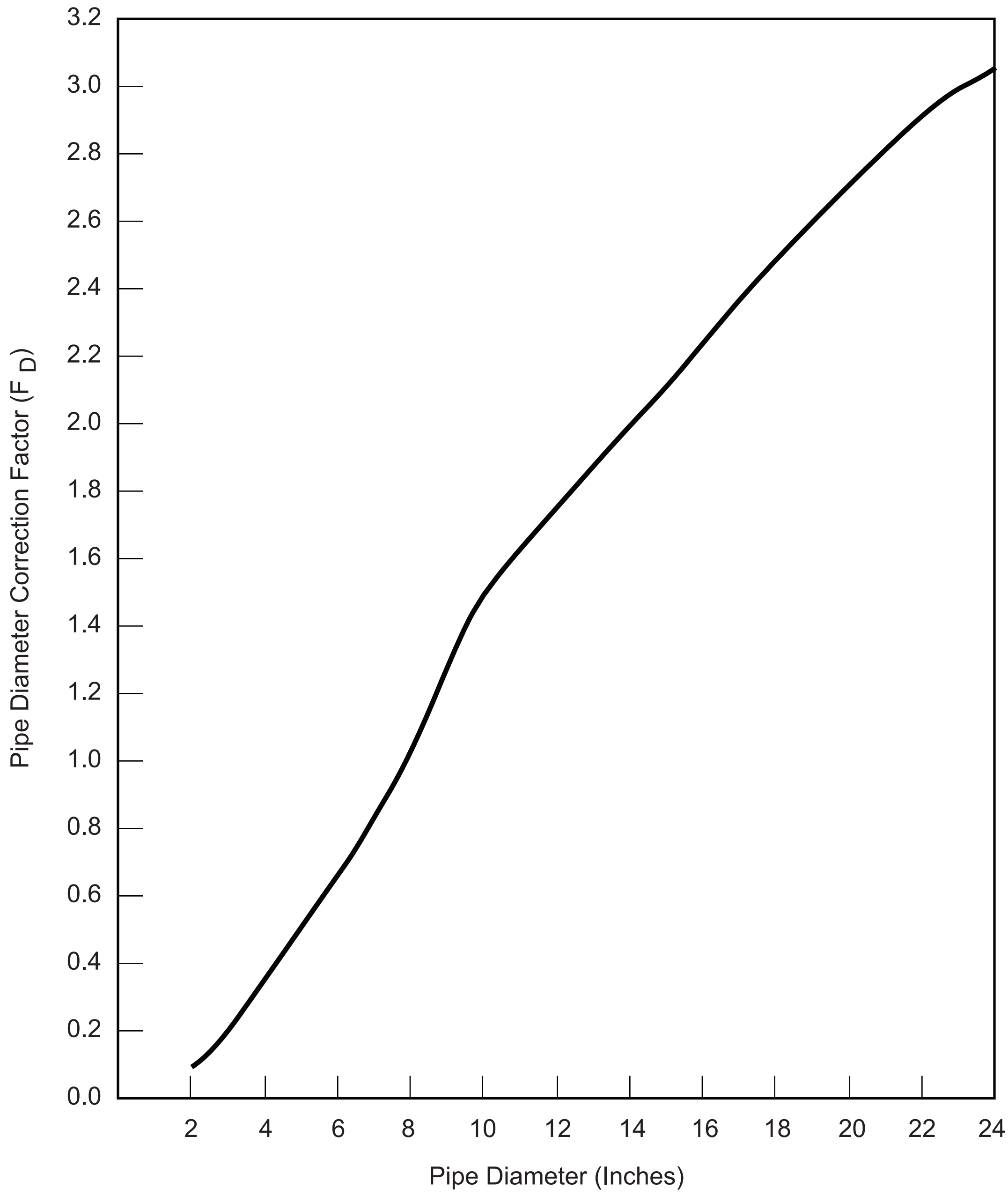


Gamma Dose Rate at Target 8 ft Away from Standard Pipe



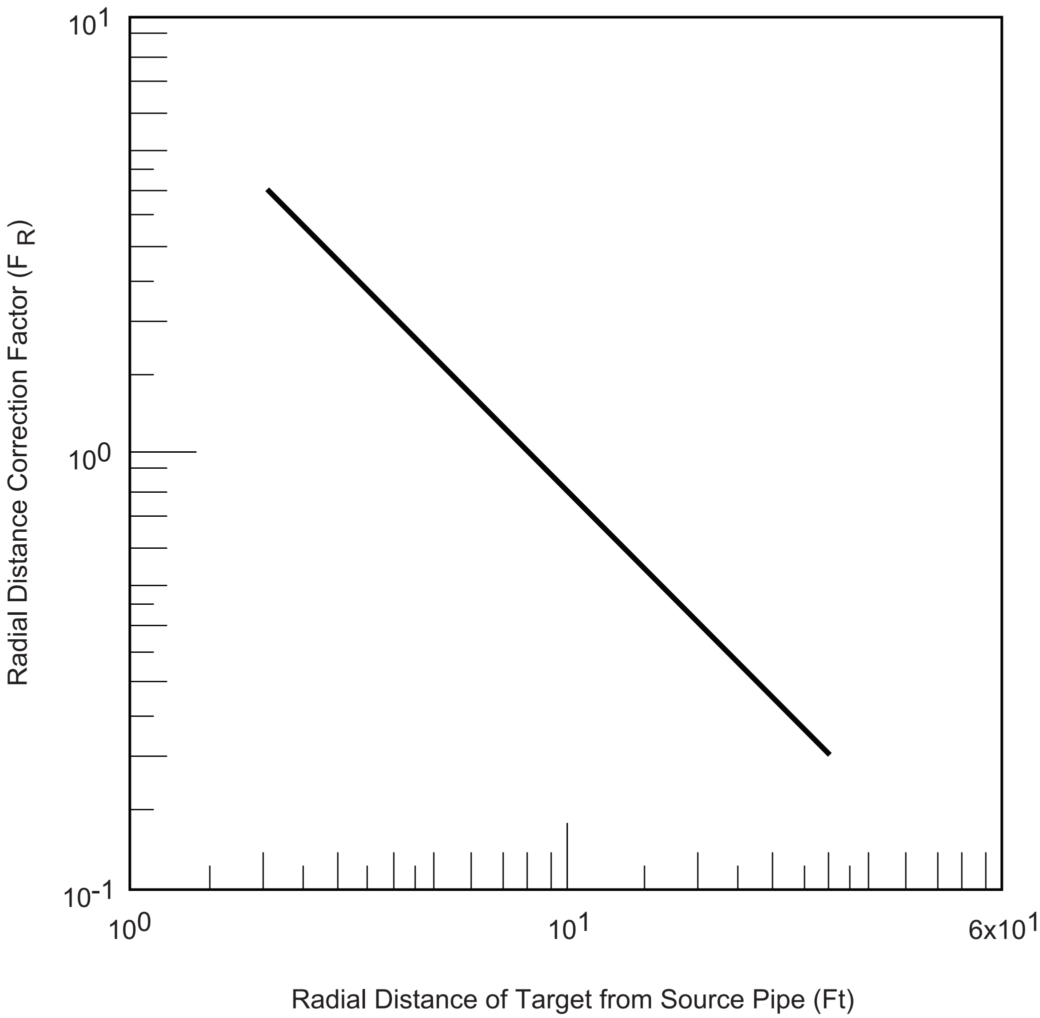
Gamma Integrated Dose at a Target 8 ft Away from Standard Pipe

Draw. No. 970187.59 | Rev. | Figure J.C-9

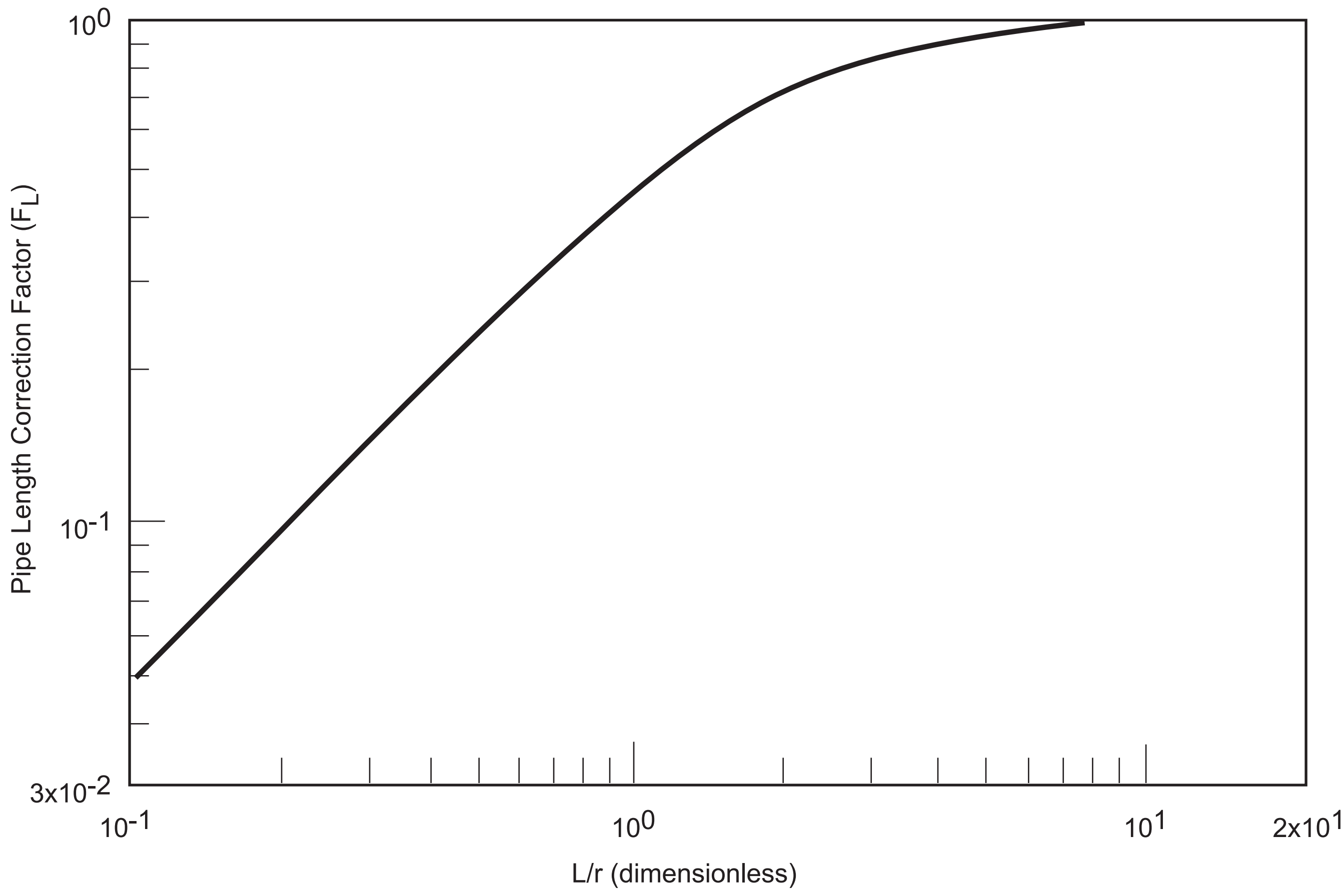


Pipe Diameter Correction Factor

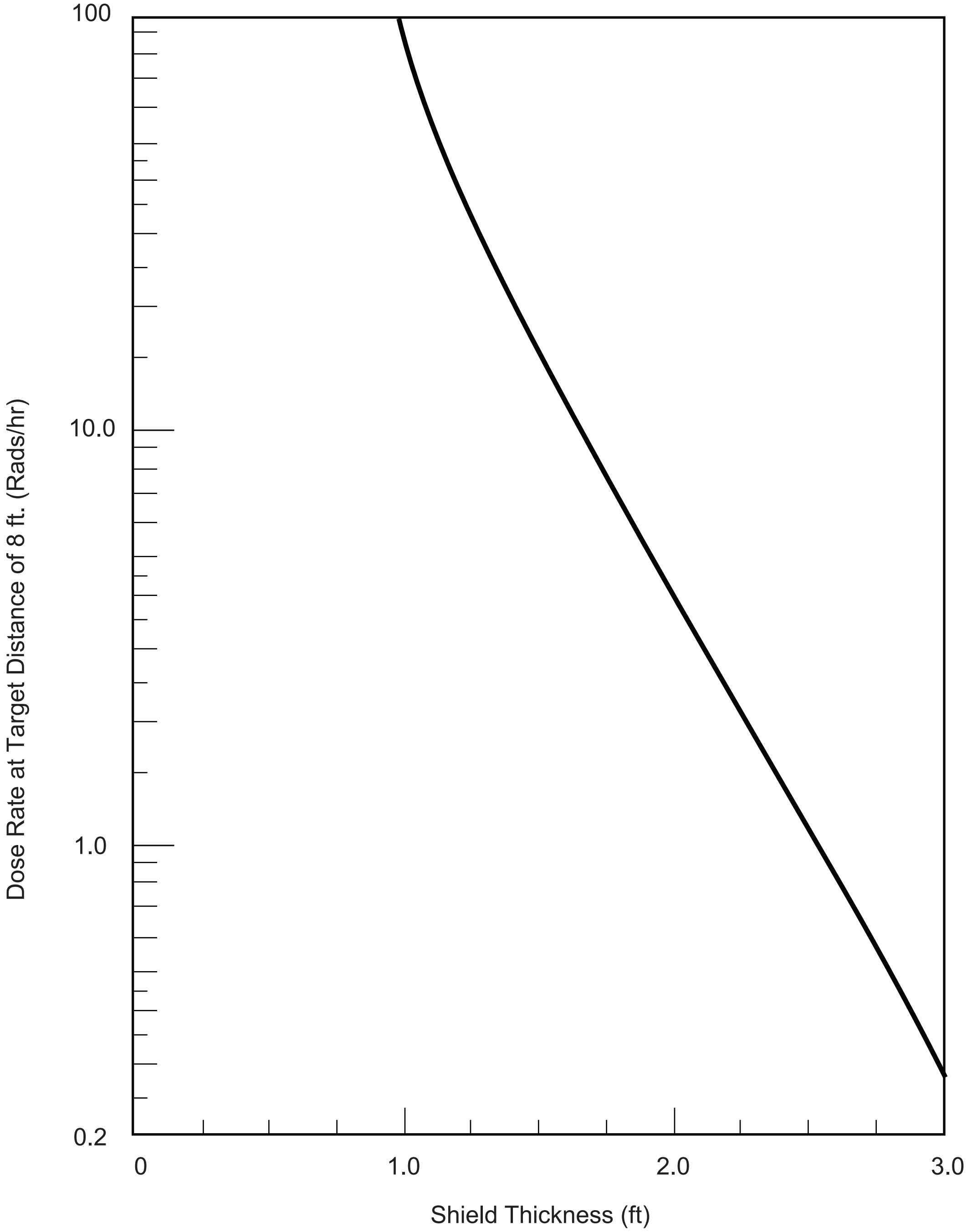
Draw. No. 970187.60 | Rev. | Figure J.C-10



Radial Distance Correction Factor

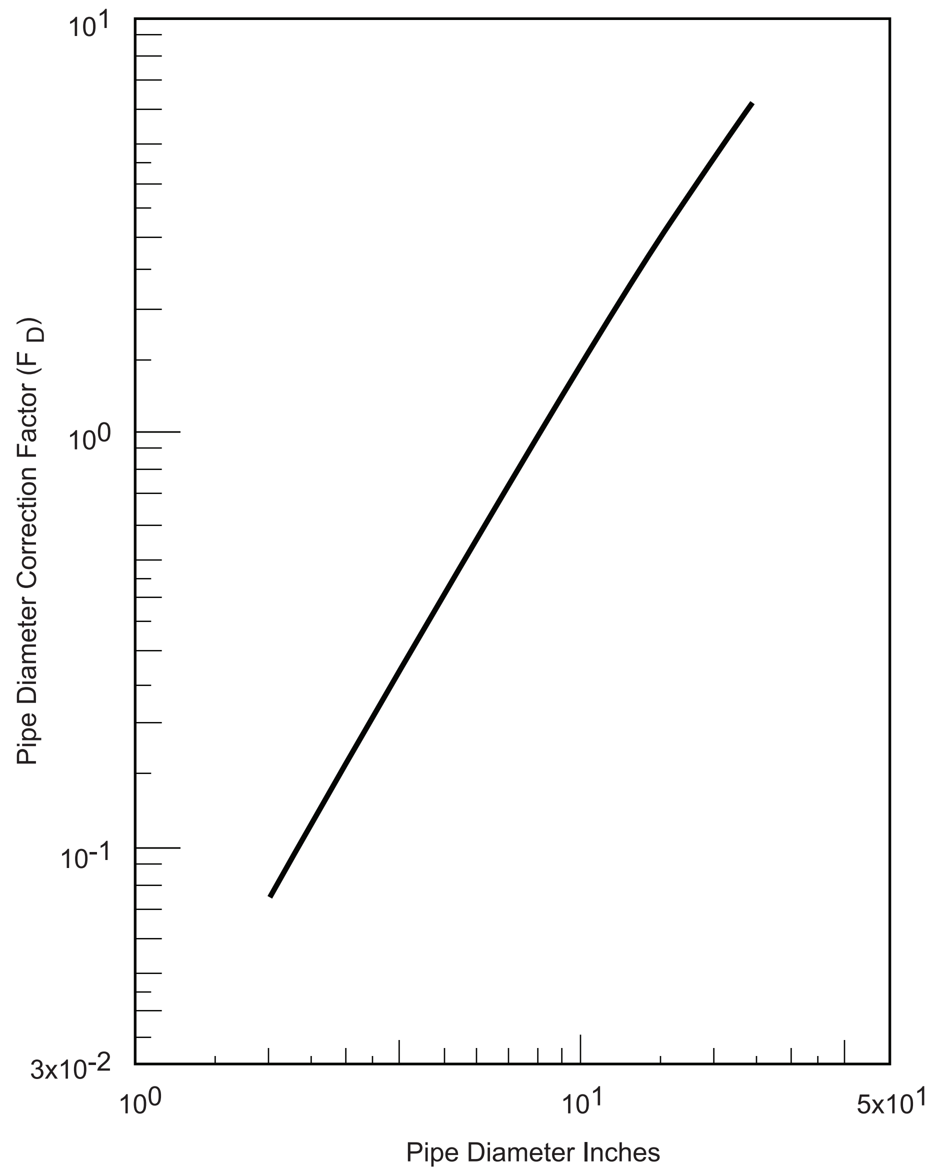


Pipe Length Correction Factor



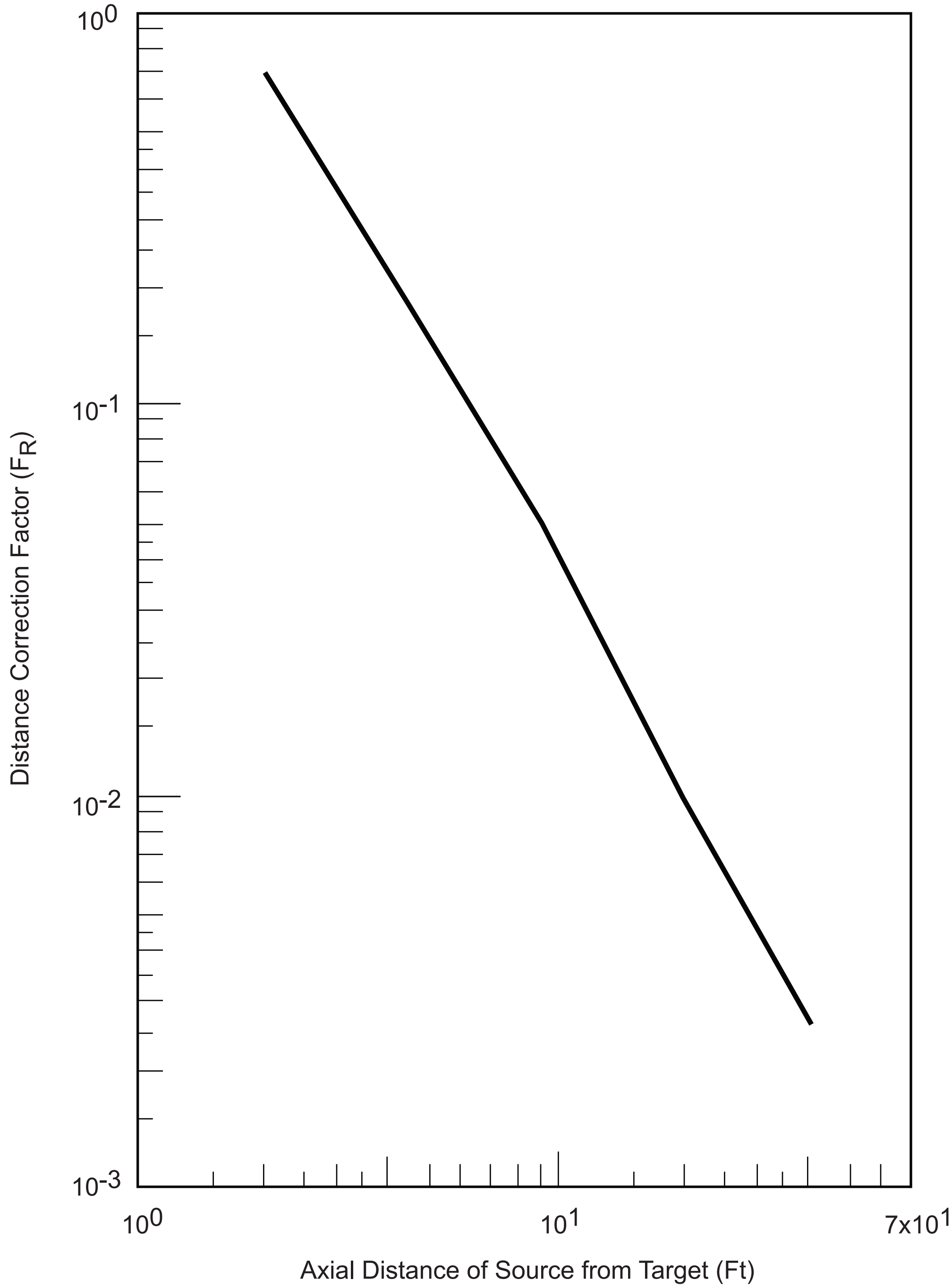
Note: This Figure is to be used for estimation purposes only.
Refer to Procedure E for calculating Dose rates outside shield walls

Columbia Generating Station Final Safety Analysis Report	Dose Rate Versus Concrete Shield-Thickness for Standard Pipe (8 in. Sch 40)
	Draw. No. 970187.63 | Rev. | Figure J.C-13



Configuration 3 of Figure J.C-1

Pipe Diameter Correction Factor for Targets Located Axially in Line with Source Piping



Configuration 3 of Figure J.C-1

Distance Correction Factor for Targets Located Axially in Line with Source Piping

Attachment J.D

CALCULATION OF THE RADIATION

The standby gas treatment system (SGTS) filters are located in the reactor building (el. 572 ft) and function to process the radioactive contaminated gaseous effluent from the primary and secondary containment. In the event of a loss-of-coolant accident (LOCA) in the primary containment the SGTS will be actuated. The gaseous contaminants that leak out of the primary containment will be filtered by the SGTS. It will adsorb the iodines in the charcoal filters and the particulates in the prefilters and high-efficiency particulate air (HEPA) filters. Plateout in the primary containment of the iodines released from the core was considered in the radiation assessment of the SGTS. Depending on the radioactive source distribution and the primary containment leakage rate, the radioactive iodine concentration in the filters will be increasing with time as more and more is deposited on the filters. Main steam isolation valve (MSIV) leakage is also considered in the radiation dose calculations.

The purpose of this study was to evaluate the time dependent gamma radiation level for safety-related equipment located near the SGTS filters and in adjacent rooms post-LOCA.

The time-dependent activity concentration in each of the filters is first calculated. The time and energy-dependent gamma activity levels on the SGTS filters is developed by a combination of computer runs and hand calculations and is used as input to the QAD-P5A computer code to calculate the gamma radiation levels for the pieces of safety-related equipment located in the room. A discussion of the analysis follows.

J.D.1 DESCRIPTION OF THE STANDBY GAS TREATMENT SYSTEM FILTERS

Figure J.D-1 is a drawing of the SGTS filter train. The SGTS consists of two fully redundant filter trains, each of which consists of the following components in series:

a. A demister to remove entrained water particles in the incoming air stream;

b. Two banks of electrical coil heaters designed to limit the humidity of the incoming air to 70% at design flow during post-LOCA conditions;

c. A bank of prefilters to remove large particles from the airstream (Figure J.D-2);

d. A bank of HEPA filters to remove the remaining particulates from the airstream (Figure J.D-2);

e. Two 4-in. deep beds of charcoal adsorber filters, arranged as shown in Figure J.D-1, are designed to capture the elemental and organic halogens from the airstream. The dimensions of the charcoal filters are shown in Figure J.D-3; and

f. A second bank of HEPA filters, identical to that described in item d above. The function of this second HEPA filter bank is to capture contaminated charcoal dust which may escape from the charcoal filters.

Both SGTS filter units are located in reactor building el. 572 and are automatically actuated and become fully operational within 34 sec of the event of any of the following three isolation signals:

a. High radiation in the reactor building ventilation exhaust duct,
b. High drywell pressure, and
c. Low water level in the reactor vessel.

J.D.2 CALCULATION OF TIME-DEPENDENT FILTER ACTIVITY CONCENTRATION

The analysis of the time-dependent transport of the radioactivity from the primary containment to the SGTS filters and the activity concentration on each filter is based on the following assumptions:

a. The SGTS filters are assumed to be loaded by iodine at a rate based on atmospheric leakage from primary containment of 0.67 wt %/day. This is composed of 0.5% direct from primary containment leakage and 0.17% via the MSIV. This is based on the primary containment rated leakage flow rate and the calculated MSIV leakage (Reference J.7-40). The containment rated leakage flow rate is 0.5%/day. The MSIV leakage was originally determined to be 0.23%/day, but a reevaluation has resulted in a revision of the MSIV leakage to 0.17%/day as referenced in J.7-40. Since the revision resulted in a lower value the original analysis with MSIV leakage of 0.23%/day is conservative. Thus, the radiation zone calculations were not revised to reflect the MSIV leakage of 0.17%/day since the original analysis was conservative;

b. Straight exhaust through the filters, with no mixing or holdup in the secondary containment atmosphere, is assumed based on an NRC recommended assumption for the analysis for fission product control systems (Reference J.7-41);

c. The elemental iodine in primary containment plateout on primary containment surfaces until one part in 200 of the elemental iodine remain airborne (0.5% of the total iodine). This is consistent with Reference J.7-14;

d. The released halogen fraction is 50% of the core inventory. This halogen fraction is assumed to be composed of 95.5% elemental, 2% organic, and 2.5% particulate iodines. This is consistent with Reference J.7-14;

e. The particulate halogens will be homogeneously distributed within the prefilters and the HEPA filters, while the elemental and organic iodines will be homogeneously distributed within the two charcoal filters of the filter train. This is conservative and necessary because the time-dependent collection of iodines in the filters has not been defined. The homogenous assumption is reasonable; and

f. Leakage past the MSIVs discharges directly to the inlet of the operating SGTS filter unit. Therefore, it bypasses the secondary containment volume. This is conservative and necessary because the time dependent collection of iodines in the filters has not been defined. The homogenous assumption is reasonable.

The time- and energy-dependent gamma activity concentration in the SGTS filters was first investigated as discussed in Section J.5.3.3. This analysis was performed by a combination of computer analysis and hand calculations. The activity concentration of a halogen isotope inside a SGTS filter is changing with time due to the following three mechanisms:

a. Transport of activity from the primary containment and deposition of the filters due to air leakage,

b. Depletion of activity due to radioactive decay and plateout of elemental halogens inside primary containment, and

c. Increases in activity levels due to daughter fission product generation from radioactive decay of other isotopes.

The activity balance on the SGTS filters can be described by (from equation J.B-16, Attachment J.B)

$$\frac{d}{dt}(A_i) = Q_1 C_{1i}(t) - {}_i A_i + {}_j {}_j A_j \qquad \text{(J.D-1)}$$

leakage in - decay + growth

where

A_i	=	activity (iodine) deposited on the SGT filters
$C_{1i}(t)$	=	airborne concentration of iodine isotope "i"
Q_1	=	flow rate (volume) from the primary containment

As in Attachment J.B (equation J.B-1, J.B-2) the growth term is negligible.

$C_{1i}(t)$ is given by equation J.B-8 of Attachment J.B as

$$C_{1i}(t) = (S_{iH}(t)/V_1)\ f_H(t)\ \exp\ (-Q_1 t/V_1) \qquad \text{(J.D-2)}$$

V_1 is the volume of primary containment

$f_H(t)$ is defined by

$$f_H(t) = f_e\ e^{-\lambda}{}_p{}^t + f_p + f_o \quad \text{where } t \leq t_p \qquad \text{(J.D-3)}$$

$$f_H(t) = (\frac{f_e}{200}) + f_p + f_o \quad \text{where } t \geq t_p$$

Integrating (J.D-2) gives the following, where B is a constant to be determined:

$$A_i(t) = Be^{-\lambda}{}_i{}^t + e^{-\lambda}{}_i{}^t \int e^{\lambda}{}_i{}^t\ Q_1 C_{li}(t)\ dt \qquad \text{(J.D-4)}$$

$C_{1i}(t)$ is substituted into (J.D-4) from (J.D-2) to give

$$A_i(t) = Be^{-\lambda}{}_i{}^t + \frac{e^{-\lambda}{}_i{}^t}{V_1} \int Q_1\ S_{iH}(t)\ f_H(t)\ e(\lambda_i - Q_1/V_1)^t dt \qquad \text{(J.D-5)}$$

Substituting the definition of $S_{iH}(t)$ from equation J.B-5 of Attachment J.B, where $A_{1i}(0)$ is the original activity in primary containment

$$(S_{iH}(t)) = C_{li}\ (0)\ e^{-\lambda}{}_i{}^t\ V_1 = A_{li}\ (0)\ e^{-\lambda}{}_i{}^t$$

$$A_i(t) = Be^{-\lambda}{}_i{}^t + A_{li}\ (0)\ e^{-\lambda}{}_i{}^t \int \frac{Q_1}{V_1}\ f_H(t)\ \exp\left[-(Q_1 / V_1)^t\right] dt \qquad \text{(J.D-6)}$$

$f_H(t)$ consists of three chemical species: organic, particulate, and elemental iodine. Equation (J.D-6) must be solved for each species, so the species will be separated at this point:

$$\theta_o(t) = f_o$$

$$\theta_p(t) = f_p \tag{J.D-7}$$

$$\theta_e(t) = f_e \; e^{-\lambda_p t} \quad 0 \leq t \leq tp$$

$$\theta_e(t) = \frac{f_e}{200} \quad \text{where } t_p \leq t$$

$$f_H(t) = \theta_o(t) + \theta_p(t) + \theta_e(t)$$

To clarify the solution of (J.D-6), the following definitions are made:

$$X = {}^{-\lambda}p^{-q}$$

$$q = \frac{Q_1}{V_1}$$

Since $\theta_e(t)$ has step-function changes, solutions to (J.D-6) require a series solution - one for both of the time bands:

$$0 \leq t_p \leq \infty$$

<u>Organic Iodines</u>

Equation (J.D-6) for all times t becomes

$$A_i(t) = Be^{-\lambda_i t} + A_{li}(0) \; q \; f_o e^{-\lambda_i t} \frac{e^{-qt}}{-q} \tag{J.D-8}$$

At t=0, A_i=0, so

$$A_i(t) = + \; f_o \; A_{1i}(0) \; e^{-\lambda_i t} \left[1 - e^{-qt} \right] \tag{J.D-9}$$

Since

$$A_{1i}(0)e^{-\lambda_i t} = S_{iH}(t)$$

from equation J.B-5 (from Attachment J.B), we define

$$A_i(t) = S_{iH}(t) \quad \phi_o(t) \tag{J.D-10}$$

where

$$\phi_o(t) = + f_o\ (1 - e^{-q\,t})$$

$\phi_o(t)$ = fraction of organic halogens on the SGTS filters

Particulate Iodines

Particulate halogens are obtained in the same manner as organic halogens. The only difference is that f_o is replaced by f_p.

Elemental Iodines

For $0 \leq t \leq t_p$, equation (J.D-6) becomes

$$A_i(t) = Be^{-\lambda}{}_i{}^t + A_{li}\ (0)\ e^{-\lambda}{}_i{}^t\ q\ (e^{-\lambda}{}_p{}^t\ f_e)\ e^{-qt}\ dt \qquad \text{(J.D-11)}$$

since at $t = 0$, $A_i = 0$

$$A_i(t) = q\ \frac{f_e}{x}\ A_{li}(0)\ e^{-\lambda}{}_i{}^t\ (e^{xt} - 1) \qquad \text{(J.D-12)}$$

For $t_p \leq t$, equation (J.D-6) becomes

$$A_i(t) = Be^{-\lambda}{}_i{}^t + A_{li}\ (0)\ e^{-\lambda}{}_i{}^t \int q\ (\frac{f_e}{200})\ e^{-qt}\ dt \qquad \text{(J.D-13)}$$

Integrating, with initial condition of $t = t_p$

$$A_i = \frac{qf_e}{x}\ A_{li}\ (0)e^{-\lambda}{}_i{}^t\ p\ (e^{xt_p} - 1)$$

$$A_i(t) = f_e\ A_{li}\ (0)\ \exp - \lambda_i t\ \frac{q}{x} \left[(e^{xt}[t\,p] - 1) + \frac{x}{200\,q}\ (e^{-qt}[t\,p] - e^{-qt}) \right] \qquad \text{(J.D-14)}$$

The activity on the SGTS filter may then be generally described by

$$A_i(t) = S_{iH}(t)\ \phi(t) \qquad \text{(J.D-15)}$$

where $\phi(t)$ is the fraction of released iodines located on the filters and is defined by

$$\phi(t) = \phi_o(t) + \phi_p(t) + \phi_e(t) \qquad \text{(J.D-16)}$$

where

$$\phi_o(t) = f_o\,(1 - e^{-qt})$$
$$\phi_p(t) = f_p\,(1 - e^{-qt})$$

$$e(t) = \begin{cases} F_e \dfrac{q}{x}\,(e^{xt} - 1) & (\text{For } 0 \le t \le t_p) \\ F_e \dfrac{q}{x}\left[(e^{xt}\,p_{-1}) + \dfrac{x}{200\,q}\,(e^{-qt}\,p_{-e}^{-qt})\right] & (\text{For } t_p \le t) \end{cases}$$

J.D.3 CALCULATION OF RADIATION DOSE FROM THE STANDBY GAS TREATMENT SYSTEM FILTER

After the activity concentration in each filter segment is determined, the gamma radiation dose for safety-related equipment located in the SGTS filter room is determined by the use of computer code QAD-P5A (Reference J.7-10). The QAD-P5A modeling procedure as described in Attachment J.C is followed for this analysis. The following modeling assumptions were used:

a. Self-shielding of the filters is conservatively neglected because the density of the charcoal dust or the wire mesh (prefilter and HEPA filters) in the filters is low. Neglecting the self-shielding effect of the filters will not add too much conservatism to the results; and

b. Shielding due to the sheet metal filter housing is conservatively neglected due to computer code stability considerations. The shielding effect of the thin sheet metal filter housing is negligible.

One zone and four subzones were evaluated for the SGTS system and the five C1E/SRM components evaluated are

a. SGT-DV-1A3,
b. FPC-LIS-1A,
c. SGT-EHO-1B1,
d. SGT-MO-5B1, and
e. SGT-TE-6A1/7A1.

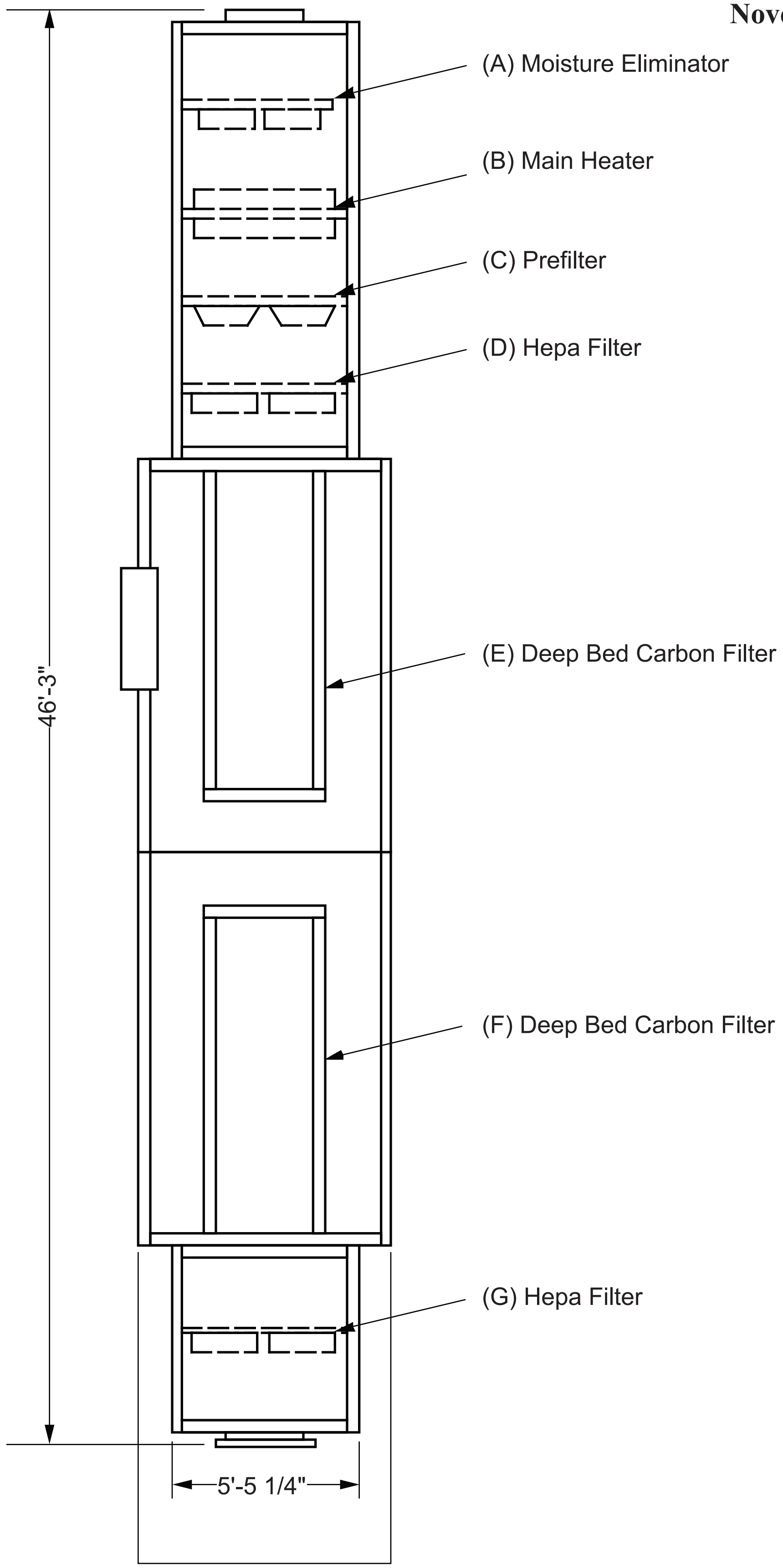
These targets are evaluated according to their proximity to the SGTS filters.

The time-dependent, gamma ray activity concentration as calculated using the method described in Section J.D.2 was used as input to the QAD-P5A model described in Attachment J.C. The dose rate results of this analysis were integrated numerically to give time-dependent, integrated doses. Table J.D-1 shows the direct gamma dose rate and integrated results for each of the five targets.

Table J.D-1

Direct Gamma Dose Rate and Integrated Dose Results
for Targets in the Standby Gas Treatment System Room

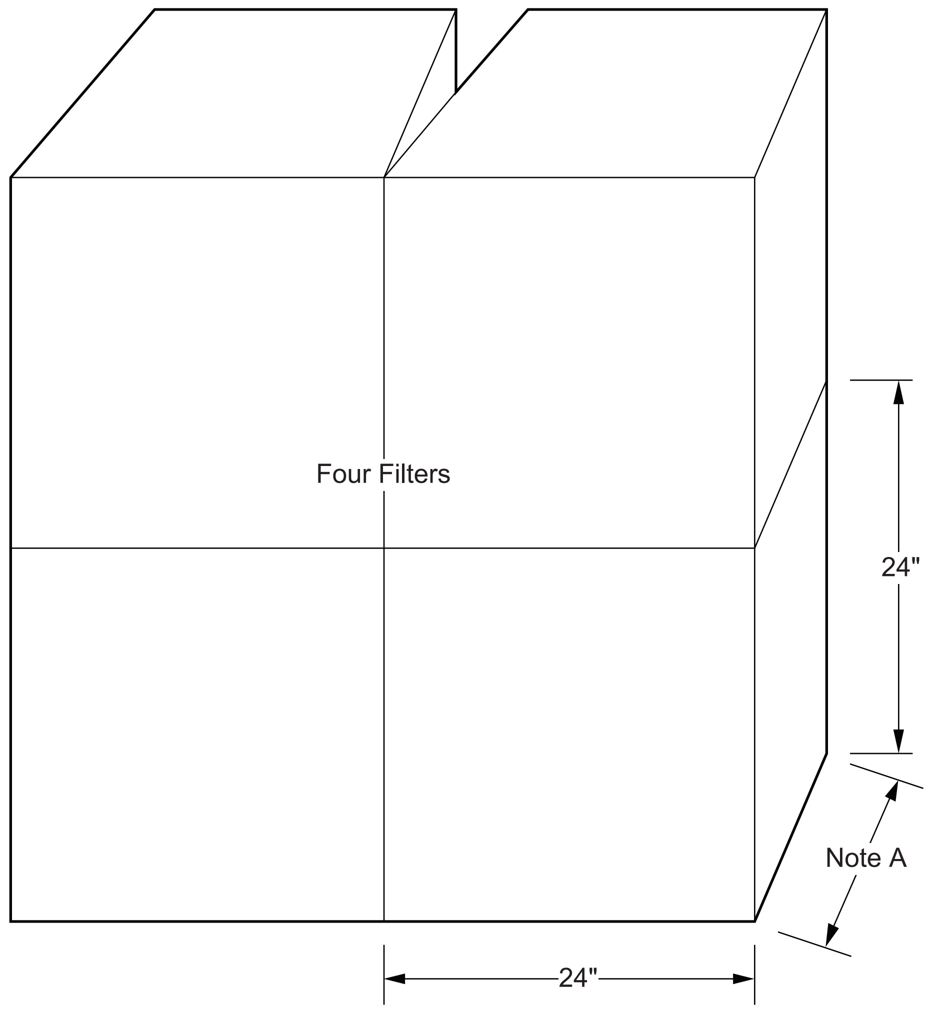
	FPC-LIS-1A		SGT-EHO-1B1		SGT-MO-5B1		SGT-TE-6Al/7A1	
Time (hr)	Dose Rate (rad/hr)	Integrated Dose (rad)	Dose Rate (rad/hr)	Integrated Dose (rad)	Dose Rate (rad/hr)	Integrated Dose (rad)	Dose Rate (rad/hr)	Integrated Dose (rad)
0	8.6E+02	4.3E+01	2.7E+02	1.4E+01	9.9E+02	5.0E+01	4.8E+04	2.5E+03
1	4.1E+03	2.3E+03	1.3E+03	7.3E+02	4.7E+03	2.6E+03	2.3E+05	1.4E+05
3	3.8E+03	1.0E+04	1.2E+03	3.3E+03	4.4E+03	1.2E+04	2.1E+05	5.8E+05
9	2.3E+03	2.9E+04	7.6E+02	9.3E+03	2.6E+03	3.3E+04	1.2E+05	1.6E+06
24	1.6E+03	5.8E+04	5.1E+02	1.9E+04	1.7E+03	6.6E+04	7.7E+04	3.1E+06
72	1.2E+03	1.2E+05	3.8E+02	4.0E+04	1.3E+03	1.4E+05	5.4E+04	6.3E+06
216	1.2E+03	3.0E+05	3.9E+02	9.5E+04	1.3E+03	3.3E+05	5.5E+04	1.4E+07
720	5.7E+02	7.5E+05	1.7E+02	2.4E+05	6.1E+02	8.1E+05	2.5E+04	3.4E+07
1440	7.6E+01	9.8E+05	2.3E+01	3.1E+05	8.1E+01	1.1E+06	3.3E+03	4.4E+07
2160	7.7E+00	1.0E+06	2.5E+00	3.2E+05	8.2E+00	1.1E+06	3.3E+02	4.6E+07
4320	1.0E-02	1.0E+06	6.4E-03	3.2E+05	1.0E-02	1.1E+06	2.3E-01	4.6E+07



Columbia Generating Station
Final Safety Analysis Report

Standby Gas Treatment Filter

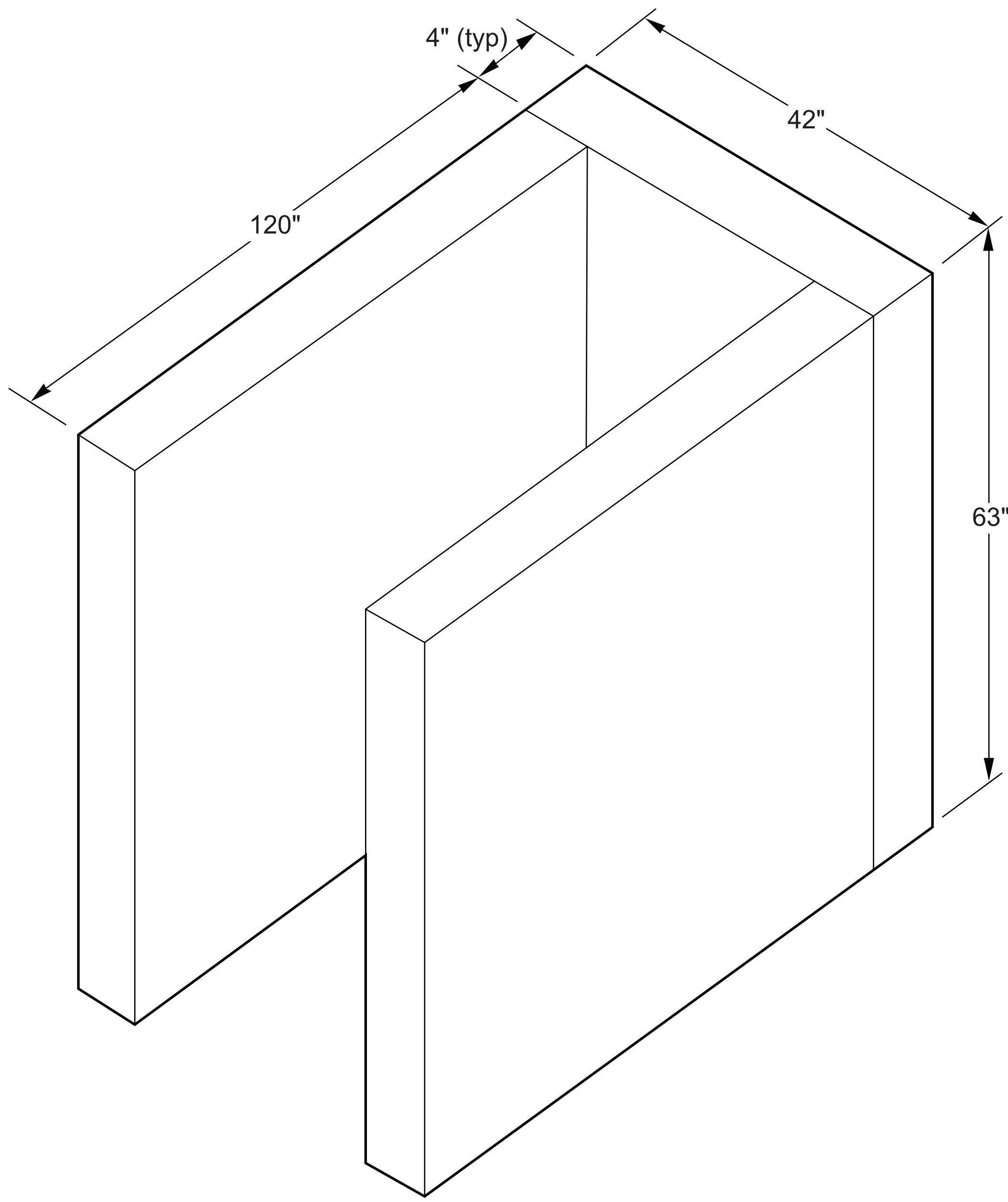
Draw. No. 970187.66 | Rev. | Figure J.D-1



Note A: Prefilter 8"
HEPA Filter 11 1/2 "

Geometry of Prefilters and HEPA Filters

Draw. No. 970187.67 | Rev. | Figure J.D-2



Not to Scale

Columbia Generating Station
Final Safety Analysis Report

Geometry of Charcoal Filters

Draw. No. 970187.68 | Rev. | Figure J.D-3

Attachment J.E

BETA DOSE CALCULATION METHOD

The source volume used for the beta dose analysis in secondary containment is a sphere surrounded by a shell of sufficient thickness to stop all outside beta particles from entering the source volume. This spherical source volume is conservative for any generalized source volume shape. The dose at the center of the sphere is higher than the dose at any point of any generalized source of equal total volume.

The assumptions used in this analysis are as follows:

a. Atmosphere inside the equipment casing is identical to the atmosphere in the reactor building which is conservative because there will be some actual delay in transport of the gaseous fission products into the equipment;

b. The initial beta source term used was 100% of core noble gases and 50% of core halogens based on NUREG-0588, Revision 1 and NUREG-CR/0009 (References J.7-29 and J.7-34);

c. Daughter products of the airborne noble gases and halogens are included in the calculation of the airborne dose. This is conservative and was required by the use of ORIGEN2 as a source code (Reference J.7-8);

d. Plateout of halogens inside primary containment was utilized as allowed in accordance with Reference J.7-34. The dose contribution of fission products plated out on equipment casings was neglected. This is based on the NRC recommended assumptions (Reference J.7-34). The deletion of dose contributions from fission products plated out on equipment casings is acceptable, since equipment surface areas are small relative to the available containment surface area. In addition, the beta radiation emitted from plated out fission products would be absorbed in the equipment casing and, hence, would not affect internal components;

e. The primary to secondary leak rate is 0.5% of primary containment, wt %/day is consistent with the assumptions established in Reference J.7-2;

f. The standby gas treatment system (SGTS) operates at the minimum flow of 2430 scfm based on the SGTS flow rate assumption of one reactor building air change per day;

g. Primary to secondary leakage is homogeneously mixed in the secondary containment atmosphere consistent with the NRC-recommended assumptions used for the calculation of doses inside primary containment (Reference J.7-2);

h. No halogen plateout in the secondary containment was assumed; and

i. A spherical volume and equipment casing will be used which is conservative.

The beta dose to equipment is dependent on the internal volume size of the piece of equipment. The beta dose is determined through the use of any energy dependent geometry factor and a ratio of the internal equipment volume to an infinite cloud. The beta dose contribution is excluded from the total integrated radiation doses shown on the radiation zone maps and tables for the C1E* equipment in the reactor building. If determination of a beta dose contribution to a C1E* component is required then a calculation to determine the internal volume size and perhaps the angle of incidence of the beta cloud to the sensitive component is performed. The results of the beta calculation are then included in the equipment qualification files for that beta sensitive equipment.

The beta calculation is determined by the airborne dose at the center of the spherical source as a function of the volume of the sphere.

The variation of beta dose rate from a typical beta energy distribution in a one-dimensional absorbing medium can be approximated by the formula:

$$D(X) = A \exp(-\mu_E X) \qquad \text{(J.E-1)}$$

where

D(X)	=	dose at a point X
A	=	constant
X	=	position in the material
μ_E	=	a parameter that depends on beta energy

This relationship holds approximately up to the point where all beta particles are absorbed. This point is called the range of the beta particles. The range of a beta particle is dependent upon the energy of the beta particle and is denoted r_E.

Both of the parameters μ_E and r_E may be determined by empirical formulas given below, based on the maximum energy of the beta particles, and approximately independent of the absorbing medium.

* Environmental qualification (EQ) of safety-related mechanical equipment has been eliminated from the overall Columbia Generating Station EQ program (SRM).

$$\mu_E = 17\rho\ (E_{max})^{-1.14} \qquad \text{(J.E-2)}$$

$$r_E = (0.412/\rho)\ E^n \text{ for } 0.01 \le E \le 3 \qquad \text{(J.E-3)}$$

$$= (0.530E - 0.106)/\rho \text{ for } 2.3 \le E \le 20 \qquad \text{(J.E-4)}$$

ρ is material density (in g/cm^3)
E is energy of beta particle (in MeV)
μE is in cm^{-1}
r_E is in cm
n is 1.265 - .0954 LnE

The dose at a given point from a single beta source is now transformed into a dose from a uniform concentration of airborne sources which extend from radius zero to radius r. K is a constant.

$$D(r) = K(1 - \exp(\mu_E r)) \qquad \text{(J.E-5)}$$

This relationship is valid for $r \le r_E$. At $r \le r_E$, none of the beta particles originating beyond r_E reach the target point. Hence, at this radius, an effective infinite medium for airborne beta radiation has been reached. The dose from a volume such that $r \ge r_E$ is equal to the dose from an infinite volume, which is denoted $D\infty$.

The dose as a function of volume radius is thus found to be given by the dual relation:

$$D(r) = D\infty \frac{(1 - \exp(-\mu_E r))}{(1 - \exp(-\mu_E r_E))} \qquad 0 \le r \le r_E \qquad \text{(J.E-6)}$$

This relation may be transformed to a function of volume by noting that $V = 4\pi r^3/3$.

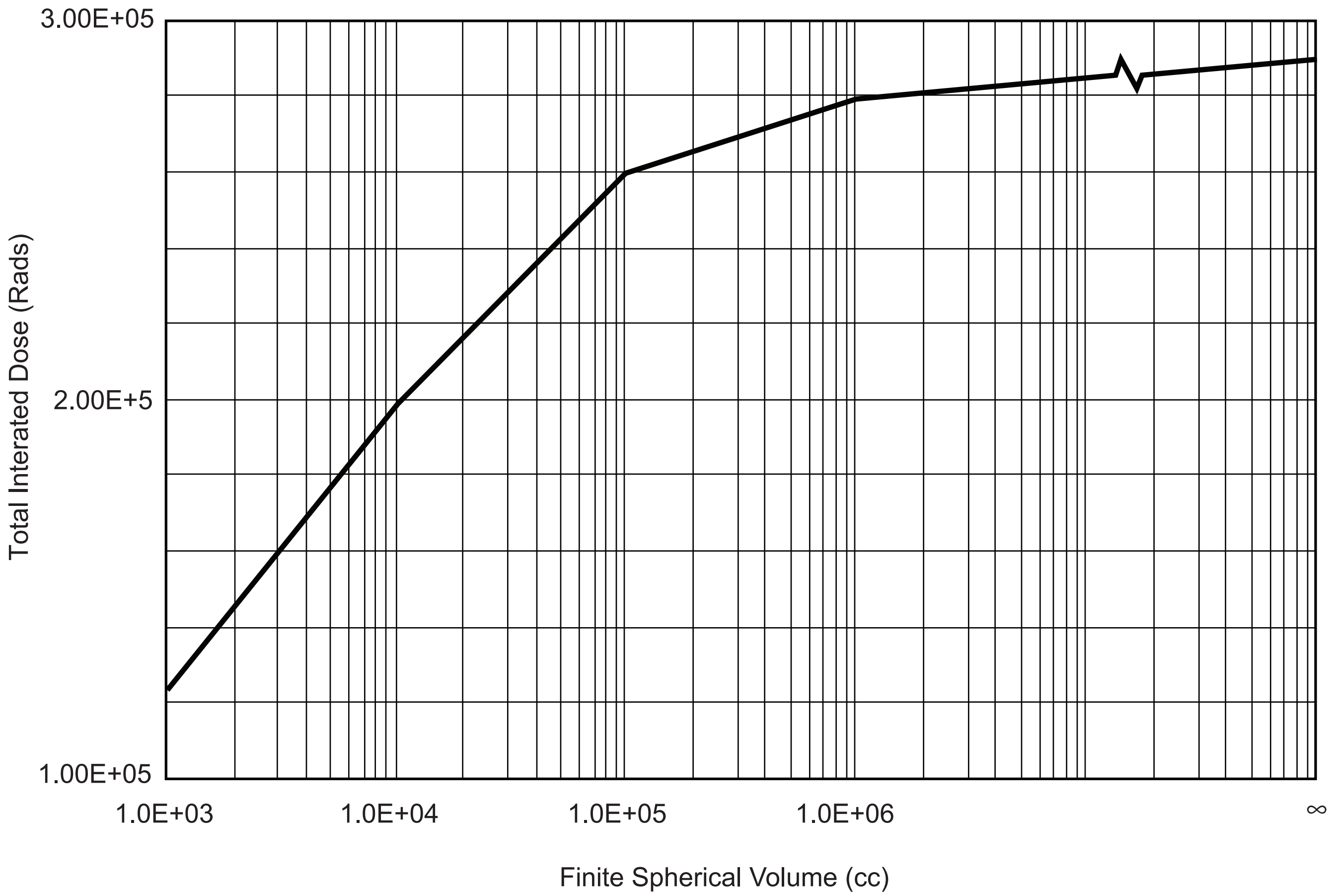
Since μ_E and r_E vary for each beta energy, this equation cannot be solved analytically for the case of a mixture of many beta energies - which is the case at hand. However, since $D\infty$ for each beta energy is known (from the calculation of the semi-infinite source), $D_{E(v)}$ for each beta energy at a given volume may be determined. All contributions to the total dose at a given volume are then added together.

The volumes evaluated in this analysis were 10^3, 10^4, 10^5, and 10^6 cm^3. Table J.E-1 summarizes the semi-infinite volume for each beta energy group. Table J.E-1 also indicates the beta dose reduction factor for each of the beta energy groups at the finite beta volumes of interest. A plot of the integrated 6-month doses for these finite beta volumes is shown in Figure J.E-1. These results reflect the reduction in beta air dose from the semi-infinite medium air dose to a finite volume medium air dose. The integrated beta infinite airborne dose for the reactor building as a function of time post-loss-of-coolant accident (LOCA) is shown in Figure J.E-2.

Table J.E-1

Dose Rate Reduction Factors for the Post-Loss-of-Coolant Accident
Beta Energy Groups at Finite Volumes

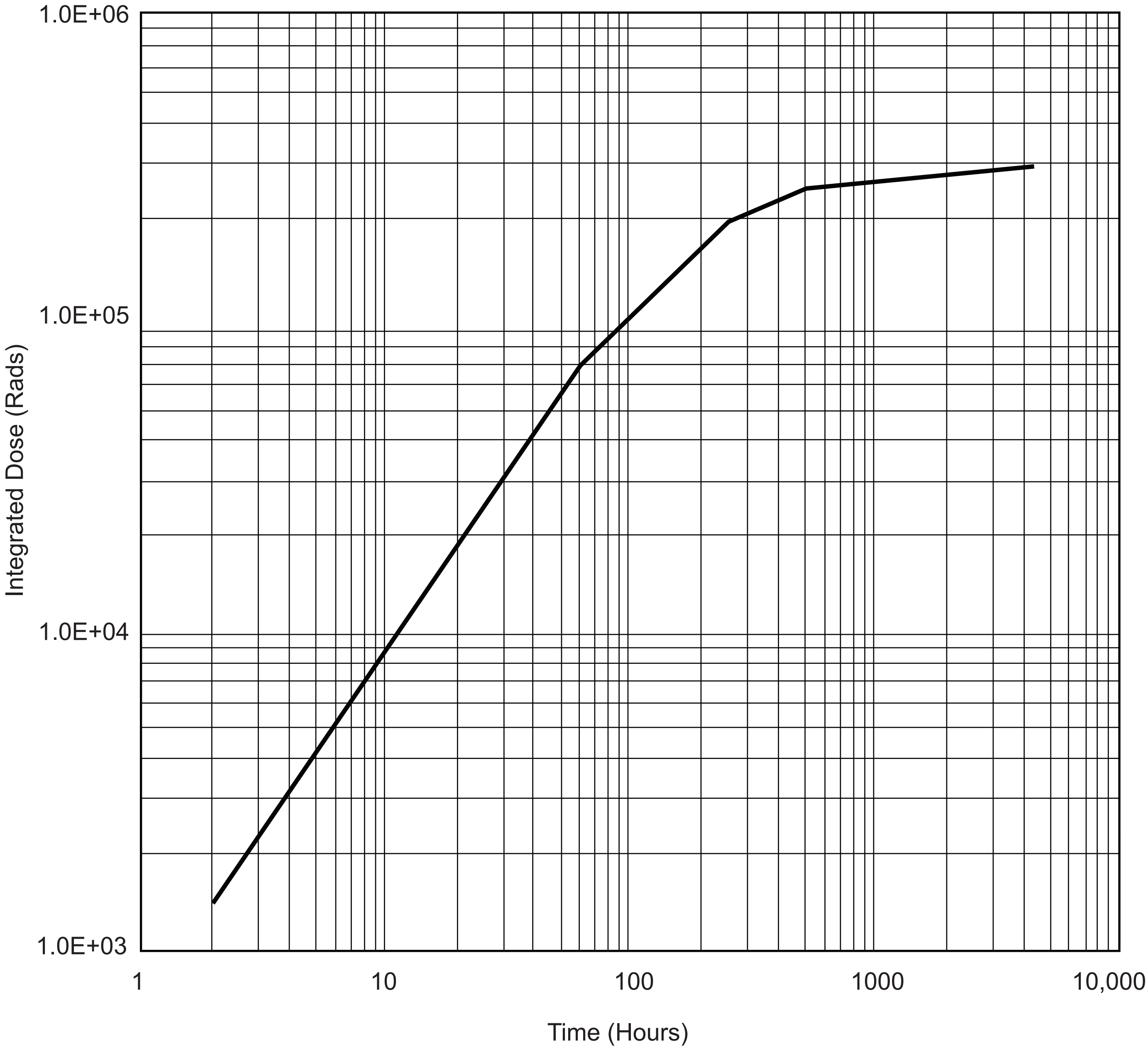
Energy Group (MeV)	V_E (cm^3)	$\frac{D(V)}{D_{\infty}}$ for Volumes			
		10^3 cm^3	10^4 cm^3	10^5 cm^3	10^6 cm^3
0.02 - 0.10	120.0	1.0	1.0	1.0	1.0
0.10 - 0.20	4.08×10^5	0.486	0.763	0.960	1.0
0.20 - 0.40	8.58×10^6	0.260	0.478	0.755	0.955
0.40 - 0.70	1.36×10^8	0.127	0.254	0.468	0.744
0.70 - 1.0	1.04×10^9	0.0695	0.144	0.284	0.513
1.0 - 1.3	3.46×10^9	0.0467	0.0979	0.199	0.380
1.3 - 1.6	8.18×10^9	0.0348	0.0735	0.152	0.299
1.6 - 2.0	1.59×10^{10}	0.0276	0.0585	0.122	0.244
2.0 - 2.5	3.20×10^{10}	0.0215	0.0457	0.0960	0.195
2.5 - 3.0	6.47×10^{10}	0.0167	0.0356	0.0752	0.155



Columbia Generating Station
Final Safety Analysis Report

Total Integrated Beta Cloud Airborne Dose as a Function of Size

Draw. No. 960222.64	Rev.	Figure J.E-1



Integrated Beta Infinite Airborne Dose for the Reactor Building

Draw. No. 960222.65 | Rev. | Figure J.E-2

Attachment J.F

PRIMARY CONTAINMENT ANALYSES

J.F.1 STATEMENT OF PROBLEM

It is required by NRC regulations (NUREG-0737 and NUREG-0588, References J.7-5 and J.7-2) that safety-related equipment be qualified to withstand the radiation environment in which they are located for the 40 years of normal plant operation plus for the 6 months following a postulated design basis loss-of-coolant accident (LOCA). This attachment presents a summary of the evaluation of the radiation environment inside the primary containment of Columbia Generating Station (CGS) during normal plant operation and for the 6 months following the postulated LOCA. This attachment also calculates the maximum integrated dose due to those radiation sources.

J.F.2 BASIC APPROACH

NUREG-0737 offers two approaches for evaluating the qualification of equipment within primary containment; pressurized versus depressurized reactor coolant system, with the more conservative to be considered the base case. Both cases assume the same source (100% noble gas, 50% halogens, and 1% particulates of the core inventory). The difference between the two is that in the pressurized case, the source is assumed to remain in the reactor coolant system for the first 17 hr (Reference J.7-44) after the accident and then is assumed to be released into the primary containment. In the depressurized case, there is assumed to be an instantaneous release of 100% of the core noble gases and 50% of the core halogens to the free volume of the primary containment (Reference J.7-45). It is also assumed that 50% of the core halogens and 1% of the core solids are released to the reactor coolant and the suppression pool. This causes some double counting of halogens and hence some conservatism, since only 50% of the core halogens need ever be considered for release after a LOCA.

Both scenarios, the pressurized and depressurized were evaluated and it was determined that for CGS the depressurized case results in higher integrated doses (References J.7-46, J.7-50, and J.7-54). Therefore, it was considered to be the base case.

Due to the large number of C1E* components inside primary containment, it was deemed impractical (from both scheduling and cost considerations) to calculate the integrated dose to each piece of equipment. Therefore, it was decided to calculate the worst point dose from each of the major sources in the drywell and wetwell, and then to sum these for a conservative estimate of the total integrated dose. This methodology for determining a worst-case dose for equipment in the drywell is not valid for the region inside the sacrificial shield wall or under

* Environmental qualification (EQ) of safety-related mechanical equipment has been eliminated from the overall CGS EQ program (SRM).

the reactor pressure vessel. A point-specific radiation dose calculation is required for all components present in either of these two regions.

J.F.3 DRYWELL

The integrated dose from each of the major sources to the drywell is tabulated in Table J.F-1. All values are the maximum dose for each source considered. Since the maximum dose does not occur at the same location or the same time from all sources, it is not appropriate to sum them to obtain the total integrated dose. All of the maximum doses calculated cannot be present for a particular accident. The highest dose (7.4×10^7) is calculated for a depressurized reactor coolant system.

This dose is conservative since all of the source contributors summed do not have the maximum dose at the same location. If it were determined that certain pieces of equipment could not withstand the maximum dose, a more detailed calculation would unquestionably result in an integrated dose of lower than 7.4×10^7 rads. A lower bound for the more detailed calculation would be about 10^7 rads.

One major factor regarding the airborne contribution needs to be addressed here to understand the results in Tables J.F-1 and J.F-2. Of the total airborne contribution (3.5×10^7 rads) slightly over 50% of it is due to photons which have an energy of less than 0.045 MeV. These photons are readily attenuated. As such, virtually any amount of shielding will result in a reduction by a factor of approximately two in the total airborne dose. Such an example is the smallest size conduit used in containment which has a wall thickness of 0.179 in.

This is not the only conservatism in the calculation; however, it is the most noteworthy. The following section addresses the individual contributors, assumptions, sources, models, etc., used to calculate the integrated dose.

J.F.3.1 Sources

There are six major radiation sources to the equipment in the drywell. Two of these sources are present during normal operation and four sources are present after a LOCA. They are

	Normal Ops	Sources
Rx Core	Normal Ops	Neutrons emanating directly from the reactor core and the resultant capture gammas.

Systems	Normal Ops	The following systems are the main sources of radiation during normal plant operation: a. Residual heat removal (RHR) system, b. Reactor water cleanup (RWCU) system, c. Main steam (MS) system, and d. Reactor recirculation (RRC) system.
Systems	Post-LOCA	In addition to the systems considered under normal operation, (except for the MS) the following systems were also considered post-LOCA: a. High-pressure core spray (HPCS), b. Low-pressure core spray (LPCS), and c. Reactor core isolation cooling (RCIC).
Airborne	Post-LOCA	Airborne radiation from radionuclides (noble gases and halogens) which are postulated to be released into the primary containment atmosphere following a LOCA.
Plateout	Post-LOCA	Plateout on surfaces within containment. This consists of radioactive iodines which are initially airborne and subsequently plateout (Reference J.7-34).
Wetwell	Post-LOCA	The radionuclides contained within the wetwell as a result of the blowdown after the accident.

J.F.3.1.1 Reactor (Normal Operation - Drywell)

There exists a general radiation field inside primary containment due to normal plant operation. Part of this field is due to neutron leakage from the reactor core. A fraction of those neutrons penetrate the reactor vessel into the reactor cavity. Some will traverse vertically while others will penetrate the sacrificial shield wall. In addition, secondary gammas will be generated from neutron interaction with materials along their path.

ANISN, a one-dimensional discrete ordinates computer code was used to calculate the transport of these neutrons, and the generation of secondary gamma rays (Reference J.7-55).

The total neutron and gamma dose rates outside the sacrificial shield wall at core mid-plane are calculated to be

a. 5.7 rad/hr neutron, and
b. 50 rad/hr gamma

An estimate was made to determine the axial variation of the dose rate based on geometric and material attenuation factors. The approximate dose rate reduction factors are shown in Table J.F-3 as a function of distance from the core mid-plane.

J.F.3.1.2 Systems (Normal Operation - Drywell)

During normal operation, a radiation field exists within containment due in part to radioactivity contained within the piping inside primary containment.

The single major source within the piping is ^{16}N [produced by the (n,p) ^{16}O ^{16}N reaction within the core]. The dose from other sources such as fission products, corrosion products, etc., are too small compared to ^{16}N to be considered.

Calculations were done to determine the dose rate to which equipment was exposed. The results indicated that the dose rate ranged from a high of 35 rad/hr to a low of 0.36 rad/hr. These calculations were performed with KAP-V and QAD-BR. They took into account the following systems: RHR, RWCU, MS, and RRC (References J.7-47, J.7-48, and J.7-49). The ^{16}N source used was 40 μCi/g (FSAR Table 11.1-4) maximum. This is the source strength of the ^{16}N in the coolant exiting the reactor. Based on this initial source, the source strength for the pipes of the systems considered was evaluated, and the dose calculations were then performed.

J.F.3.1.3 System (Post-Loss-of-Coolant Accident) - Drywell

The dose rate calculations for systems post-LOCA were performed using a method similar to that used for the systems under normal operation with two exceptions. The first was that in addition to the RHR, RWCU, and RRC systems, the HPCS, LPCS, and RCIC systems were also included. The second exception was that a different source was used (References J.7-48 and J.7-49). After a LOCA, the predominant source past the first minute or so is the assumed fission product release from the core. The ^{16}N inventory, with a 7.1-sec half-life decays away in less than a minute once the (n,p) ^{16}O ^{16}N reaction stops occurring (after the reactor shuts down).

For the base case, i.e., the depressurized case, it was assumed that 50% of the core halogens and 1% of the core solids were released and distributed within the suppression pool and the reactor coolant systems (References J.7-51, J.7-52, and J.7-53). As noble gases were produced by the radioactive decay of the halogens, they were discounted on the premise that they would be released from the liquid to the gas rapidly. The released inventory is then decayed for 37 discrete time intervals out to 6 months (these are given in Table J.F-7). An average source strength is then calculated for the 6-month period. The source strength is given in Table J.F-4.

J.F.3.1.4 Airborne - Drywell

A nonmechanistic accident scenario was postulated in calculating the airborne source. It was assumed that after 1000 days of operation at 3556 MWt (105% of core power), 100% of the noble gases and 50% of the halogens contained within the reactor core are instantaneously released. After the release, no additional contribution of either noble gases or halogens is considered. Also, plateout of halogens is considered (see Section J.F.3.1.5). The average airborne source strength is given in Table J.F-5.

The above source is calculated via the ORIGEN2 computer code. After the source strength was determined, the dose rate was calculated using the QAD-CG computer code. Details of the model and the calculation are discussed in Section J.F.5. The value for the airborne contribution presented in Table J.F-1 represents the dose rate at a point within the drywell which is predominantly surrounded by air. This point was chosen because of the absence of structural steel, piping, etc., surrounding the dose point. This would result in an upper limit dose rate which could be expected to occur in the drywell.

The effect of the shielding afforded by the structural steel, piping, etc. (i.e., "shadow shielding"), within containment was considered. Advantage was taken of "shadow shielding" when considering the contribution of the more distant airborne sources (References J.7-48 and J.7-49). This significantly reduces the dose rate compared to the case where "shadow shielding" is not employed. See Section J.F.5 for modeling of "shadow shielding."

J.F.3.1.5 Plateout - Drywell

The basis for determining the plateout source is 50% iodine inventory released after 1000 days irradiation at a power level of 3556 MWt. However, the plateout source is only those iodines which are removed from the airborne source and assumed to plateout on the surfaces within containment. As such, plateout removes sources from the airborne source, and this was accounted for in the calculations. It was assumed, however, that the noble gases generated by the decay of the plated out halogens (I $\rightarrow$ Xe and BR $\rightarrow$ KR) are instantaneously released and are mixed within the free volume of the drywell. In this manner, both the airborne and plateout sources are determined with no "double counting" of nuclides. The plateout source is given in Table J.F-6.

When the halogens are initially released, not all of them are considered available to plateout. Of the halogens released, 2.0% are in the form of organic compounds, and 2.5% are in the form of particulates (Reference J.7-2); and both of these forms are assumed not to plateout.

The remaining 95.5% are considered to be in an elemental state of which one-two hundredth remain airborne and the rest plateout. Therefore, no more than 95% of the released halogens can ever plateout. The plateout was assumed to occur with an effective deposition velocity of 0.05 cm/sec. This translated into an effective half-life of 1.01 hr^{-1} (References J.7-34 and J.7-45). Given this half-life, the limit of a reduction of a factor of 200 is attained in slightly over 5 hr. After that time, the percentage of plated out halogens remains constant at 95%.

The dose calculations were performed with the computer code QAD-CG, incorporating a model similar to that used for the airborne dose. See Section J.F.5 for discussion of model and calculations.

Initial calculations were performed with the total plateout being distributed over: (1) the drywell lateral surface, top, and bottom; (2) inner, outer and top surfaces of the sacrificial shield wall; and (3) heat reflector of pressure vessel surface. Given this distribution area, the maximum dose rate calculated was 7.04×10^3 rad/hr. However, when the remaining surface areas within containment (i.e., equipment, piping, structural steel, etc.) were considered, the area over which the source would be plated out increased sevenfold. A counter-balancing effect to this reduction in plated out concentration was that the source would be more universally distributed around any given receiver. It was estimated that the net effect would reduce the calculated maximum dose rate by a factor of approximately three.

It is noted that the energy spectrum for the plateout source is significantly harder than that of the airborne. As such, the comments in Section J.F.3 regarding low energy photons are not completely applicable.

J.F.3.1.6 Wetwell - Drywell

The wetwell was also considered as a source to the drywell. However, due to distance, self-attenuation, and the available shielding from the 2-ft-thick diaphragm floor, its contribution to the drywell was negligible.

It was assumed that 50% of the halogens and 1% of the particulates from the core were entrained in the water in the suppression pool. This is the same source used for the systems post-LOCA. The air space volume above the suppression pool was assumed to have the same volumetric source strength as the drywell air space. These are conservative premises since only a total of 50% of the core halogens are assumed to be released after the accident.

J.F.4 WETWELL

The results for the wetwell are given in Table J.F-2. Doses were calculated for detector points both within the suppression pool as well as in the free volume above it using QAD-CG, applying the same modeling techniques as was used in the drywell.

With regard to the airborne contribution, the volumetric source strength is the same as the drywell airborne source and the comments in Section J.F.3.1 regarding the low-energy photons applicability to the wetwell.

There does exist some double counting of nuclides in the wetwell analysis. The airborne source is 100% noble gases and 50% halogens, released into the containment (wetwell and drywell) free volume. For the suppression pools the source is 50% halogens and 1% particulates. Since only 50% of the total core halogens are assumed to be released after an accident, they are double counted (the effect is small, however, because of the shielding offered by the suppression pool water.) Another conservatism in the airborne source in the wetwell is that, since the path for the wetwell airborne sources is via the downcomers and then up through the suppression pool, some halogens are expected to be entrained in the water during this transfer (this was not considered in the calculation.) The result would have been a smaller airborne source and in turn a smaller dose.

J.F.4.1 Sources

There are three sources of radiation to the equipment in the wetwell, all of which are present only after an accident.

a. Airborne

   The airborne source is present as a result of the initial blowdown into the suppression pool via the downcomers,

b. Plateout

   Plateout of halogens onto the surfaces in the wetwell (i.e., containment, downcomers, etc.), and

c. Suppression Pool

   The radionuclides contained within the suppression pool as a result of the blowdown after the accident.

J.F.4.1.1 Airborne - Wetwell

The airborne source, on a specific volume basis, is equal to the airborne source in the drywell (i.e., 100% noble gas and 50% halogen released into the total primary containment immediately following a LOCA). However, the amount of "shadow shielding" within the wetwell is much less than in the drywell. Hence, the contribution from sources further away is greater. This factor accounts for the increased dose rate in the wetwell with respect to the drywell (due to airborne sources). Dose calculations in the wetwell were done in similar manner as for the drywell (i.e., using QAD-CG).

J.F.4.1.2 Plateout - Wetwell

As in the drywell, the source of the plateout in the wetwell is the halogens. However, the area available for plateout is smaller in the wetwell than the drywell. This results in a dose rate in the wetwell slightly more than double that in the drywell.

J.F.4.1.3 Suppression Pool - Wetwell

The source in the suppression pool was assumed to be 50% of the halogens and 1% of the particulates instantaneously released from the core into the pool and the reactor coolant system. It is further assumed that as noble gases are produced by the decay of the halogens (I→Xe and Bγ→Kγ), they "bubble out" of the pool, hence they are not considered a source term. Dose rates both in the suppression pool as well as in the wetwell free volume were calculated using QAD-CG.

J.F.5 QAD-CG MODEL

The QAD-CG computer program was used to calculate dose rates for both the airborne source as well as the plateout. In both cases, i.e., airborne and plateout, similar modeling techniques were used. This section defines the modeling used in both calculations (with only the drywell used for illustrative purposes).

The QAD-CG computer code makes use of a geometry package, which allows the user to model a calculation with the use of predetermined geometric bodies. The user defines a set of geometric "bodies" (boxes, truncated cones, spheres, cylinders, etc.) and using these "bodies," the user defines "zones" by intersection or forming unions of them to build the shapes desired in a manner analogous to "intersections" and "unions" when one deals with sets. The model is done three-dimensionally thereby allowing the user considerable flexibility. These "zones" are then what constitute the computer model. The parts of "bodies" that are not used have no effect on the model.

As an example, a dumbbell could be defined as the union of three "bodies": two spheres and a long, thin cylinder between them (see Figure J.F-1). Likewise, a hemisphere could be formed by intersection of a sphere with a box (see Figure J.F-1). In this manner, a complex model can be defined.

In our case, the basic model was defined as a truncated cone (approximating the containment shell) and two cylinders (approximating the sacrificial shield wall and the reactor vessel). Figure J.F-2 illustrates this in a sectional view. The free volume of the drywell was compartmentalized into cubes, 7 ft on a side. These cubes were formed by intersection of a series of tall rectangles, which are 7 ft on a side in cross-section, with cylinders at 7-ft high intervals. Each 7-ft high cylinder constitutes the elevational boundaries of what is referred to as a "layer" below. Combining these "bodies" appropriately one winds up with a truncated cone (containment) with two cylinders (i.e., sacrificial wall and reactor vessel) and the remainder of the volume forced with cubes (except on the boundary of the cone or cylinders). Figure J.F-3 illustrates this model, while Figure J.F-4 illustrates how the layer from el. 513 ft 6 in. to el. 520 ft 6 in. is modeled.

All major structures, pipes (6 in. and above), hangers, etc., within the drywell were then located, and the mass of steel in each cubicle determined. These were translated into average densities such that each cube had an average density assigned to it. These are illustrated on Figures J.F-5 to J.F-9 for the lower five layers; for the purpose of clarity, the densities shown are much cruder than the 41 used in the code. In those cubicles which are noted to have zero density, the density of air was assumed.

In Figures J.F-7 to J.F-9 a large void (air only) exists in the southwest (fourth) quadrant in layers 3 and 4. It was in this region that the airborne dose rate was calculated. This region provides us with a volume which is large enough so that the "shadow shielding" (smearing discrete shielding within a cubicle into an average density in the cubicle) beyond its boundary is justified.

Several runs were made using this model with various source volumes. Three runs were made placing the source terms within the elevational boundaries of layers 3, 4, and 5, respectively, and another run was made by placing the source from the lower elevational boundary of layer 1 up to the upper elevational boundary of layer 2. It was noted that >95% of the total dose contribution from these five layers came equally from layers 3 and 4. In other words, the further away the source layer, the smaller the contribution. Also, shadowing shielding in layers 1 and 2 provided sufficient attenuation as to make the contribution to the total dose negligible. The same is true also for all layers above layer 5.

Plateout was calculated in a similar manner, increasing the source until successive contributions became negligible. For the plateout, the dose point was taken near the sacrificial shield wall. Other points were also considered, but the dose rate near the sacrificial shield wall was found to be the maximum. Again, the dose point was taken between layers 3 and 4 to maximize the dose rate.

J.F.6 CODES

J.F.6.1 <u>FSPROD</u>

FSPROD is a computer program which calculates the inventory and activity of radioactive fission products, produced from the thermal fission of ^{235}U, as a function of fission rate and decay time after fission. The program is used in establishing the gross and specific gamma and beta activity of those fission products. The calculation incorporates 123 fission product nuclides and is based on Perkins and King data.

J.F.6.2 ORIGEN2

ORIGEN2 is a point depletion and decay computer code for use in simulating nuclear fuel cycles and calculating the nuclide composition of materials contained therein. The code represents a revision and update of the original ORIGEN computer code. The general function of the ORIGEN2 computer code is to calculate the nuclides present in various nuclear materials by determining the buildup and depletion of nuclides during irradiation and decay. The code can also account for reprocessing (i.e., chemical separation) and continuous feed, removal, and accumulation of nuclear materials.

J.F.6.3 QAD-BR

QAD-BR is a point kernal computer code designed to evaluate gamma penetration of various shield configurations. It is a modification of QAD-P5A; i.e., it has no capability for neutron calculations. The program provides an estimate of the uncollided and collided gamma flux, dose rate, energy deposition, and other quantities which result from a point-by-point representation of volume-distribution source of radiation.

J.F.6.4 QAD-CG

QAD-CG is also a modification of the QAD-P5A computer program. It is similar to QAD-BR in application with the major difference being in the geometry description. QAD-CG makes use of a combinatorial geometry package originally developed for MORSE. It is one of the more versatile geometry packages to be available in the QAD family of computer codes.

J.F.6.5 KAP-V

KAP-V is a hybrid of the QAD computer code. Analytically, it is identical to QAD as it is a point kernal code. The major differences are changes in input allowing more flexibility in running successive cases. It also has internal libraries for attenuation and buildup data which can be used by default for convenience.

J.F.6.6 ANISN

ANISN is a one-dimensional Sn transport code with anisotropic scattering. It allows for the solution of the transport equation for neutrons and photons using the discrete ordinate method.

Table J.F-1[a]

Integrated Dose in Drywell

Source	Maximum Average Dose Rate[b] (rad/hr)	Exposure Time	Dose[b] (rad)
Reactor	5.6×10^{1}	32 years[c]	1.6×10^{7}
Systems - normal	3.5×10^{1}	32 years[c]	9.9×10^{6}
Systems - LOCA	---	6 months	3.2×10^{6}
Airborne	---	6 months	3.7×10^{7}
Plateout	---	6 months	1.0×10^{7}
Suppression pool	---	6 months	$<4.5 \times 10^{4}$

[a] Not valid for regions inside the sacrificial shield wall or under the reactor pressure vessel (a point specific radiation calculation is required for components in these two regions).

[b] Maximum dose rate from individual contributors does not necessarily occur at the same location or for the same accident.

[c] (40-year plant life) x (0.8) availability to account for down time.

Table J.F-2

Integrated Dose in Wetwell

Source	Maximum Average Dose Rate[a] (rad/hr)	Exposure Time	Dose[a] (rad)
Dose above suppression pool			
Airborne	1.8×10^4	6 months	8.2×10^7
Suppression pool	2.0×10^2	6 months	9.1×10^5
Plateout	2.7×10^3	6 months	1.2×10^7
Dose within suppression pool			
Airborne	2.9×10^2	6 months	1.4×10^6
Suppression pool	5.5×10^2	6 months	2.5×10^6

[a] Maximum dose rate from individual contributors does not necessarily occur at the same location.

Table J.F-3

Approximate Dose Rate Reduction Factor
Versus Distance from Core Mid-Plane
for Reactor Integrated Dose

Distance (ft)	Reduction Factor
0	1.0
5	0.5
10	0.02
15	1×10^{-5}

Table J.F-4

Suppression Pool and System
(Loss-of-Coolant Accident) Liquid Source Terms
0-6 Month Average After Loss-of-Coolant Accident

MeV	MeV/sec	MeV/cm^3-sec[a]
0.015	1.8E+14	4.4E+4
0.025	3.5E+14	8.5E+4
0.0375	4.8E+14	1.2E+5
0.0575	1.4E+14	3.5E+4
0.085	5.8E+14	1.4E+5
0.125	2.2E+15	5.3E+5
0.225	4.0E+15	9.6E+5
0.375	4.8E+16	1.2E+7
0.575	5.5E+16	1.3E+7
0.85	7.2E+16	1.7E+7
1.25	1.5E+16	3.7E+6
1.75	1.8E+16	4.3E+6
2.25	2.1E+15	5.1E+5
2.75	9.1E+14	2.2E+5
3.5	1.1E+14	2.6E+4
5.0	7.4E+13	1.8E+4

[a] Volume considered was that of the suppression pool plus that of the reactor coolant system.

Table J.F-5

Airborne Source Terms
0-6 Month Average After Loss-Of-Coolant Accident

MeV	MeV/sec	MeV/cm^3-sec[a]
0.015	2.5E+14	2.5E+4
0.025	2.1E+14	2.1E+4
0.0375	6.9E+15	7.1E+5
0.0575	3.0E+13	3.0E+3
0.085	1.4E+16	1.4E+6
0.125	3.7E+13	3.8E+3
0.225	4.4E+15	4.5E+5
0.375	3.0E+15	3.1E+5
0.575	4.0E+15	4.1E+5
0.85	3.2E+15	3.2E+5
1.25	3.4E+15	3.5E+5
1.75	2.6E+15	2.7E+5
2.25	3.9E+15	4.0E+5
2.75	6.7E+14	6.9E+4
3.5	2.1E+14	2.2E+4
5.0	9.5E+13	9.7E+3

[a] Volume considered was total; i.e., drywell plus wetwell free volume.

Table J.F-6

Drywell Plateout Source Terms
0-6 Month Average After Loss-Of-Coolant Accident

MeV	MeV/sec	MeV/cm^3-sec[a]
0.015	3.6E+13	6.3E+5
0.025	1.8E+14	3.2E+6
0.0375	5.4E+13	9.5E+5
0.0575	2.0E+13	3.6E+5
0.085	3.2E+14	5.7E+6
0.125	1.9E+13	3.4E+5
0.225	2.8E+15	4.9E+7
0.375	4.4E+16	7.7E+8
0.575	2.4E+16	4.2E+8
0.85	7.6E+15	1.3E+8
1.25	9.6E+15	1.7E+8
1.75	3.4E+15	5.9E+7
2.25	5.2E+14	9.2E+6
2.75	7.3E+12	1.3E+5
3.5	1.3E+13	2.3E+5
5.0	2.9E+11	5.1E+3

[a] These values should be reduced by a factor of seven when all structural, component and equipment surfaces in containment are considered.

Table J.F-7

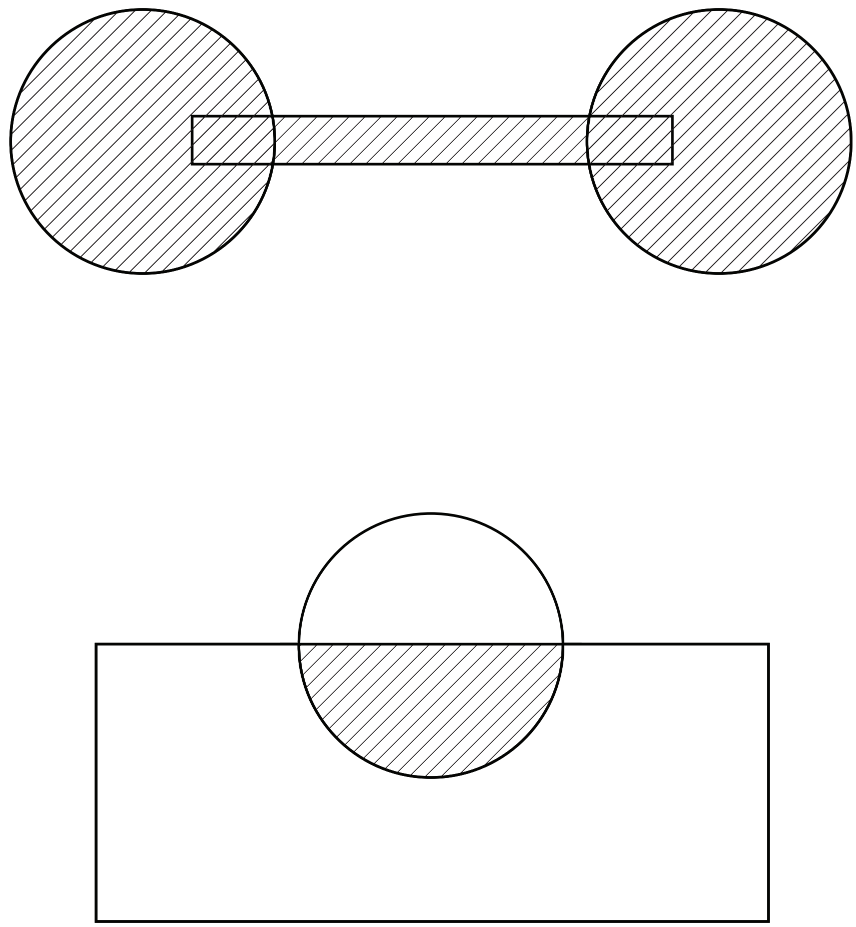
Time Mesh Spacing Used in Source Calculations
(Minutes)

0	640	28800
20	800	36000
40	960	43200
60	1120	57600
80	1280	72000
100	1440	86400
120	2160	108000
180	2880	129600
240	3600	151200
300	4320	172800
360	5040	216000
420	5740	259200
480	14400	

Table J.F-8

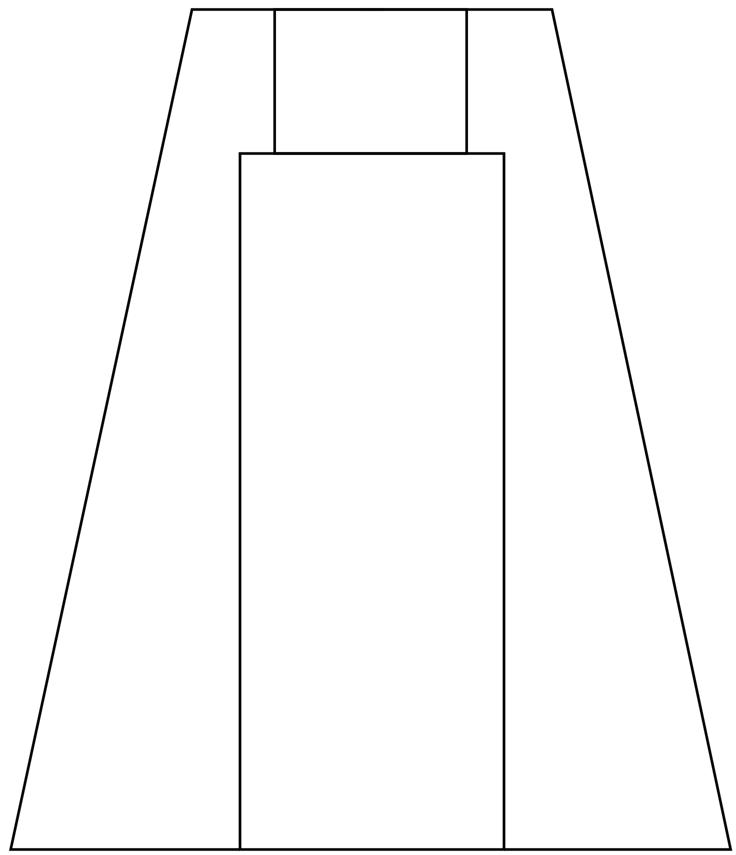
Source Energy Group Structure

Lower Boundary (MeV)	Upper Boundary (MeV)	Average Energy (MeV)
0.00	0.02	0.015
0.02	0.03	0.025
0.03	0.045	0.0375
0.045	0.07	0.0575
0.07	0.10	0.085
0.10	0.15	0.125
0.15	0.30	0.225
0.30	0.45	0.375
0.45	0.70	0.575
0.70	1.0	0.85
1.0	1.5	1.25
1.5	2.0	1.75
2.0	2.5	2.25
2.5	3.0	2.75
3.0	4.0	3.5
4.0	6.0	5.0



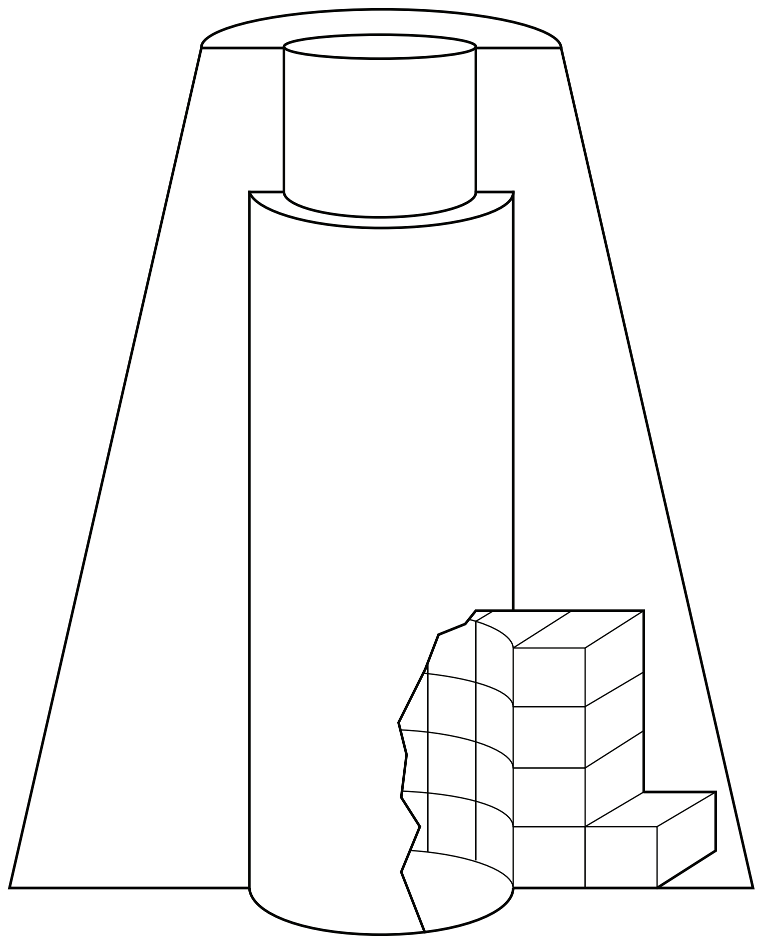
Geometry Examples

Draw. No. 970187.69 | Rev. | Figure J.F-1

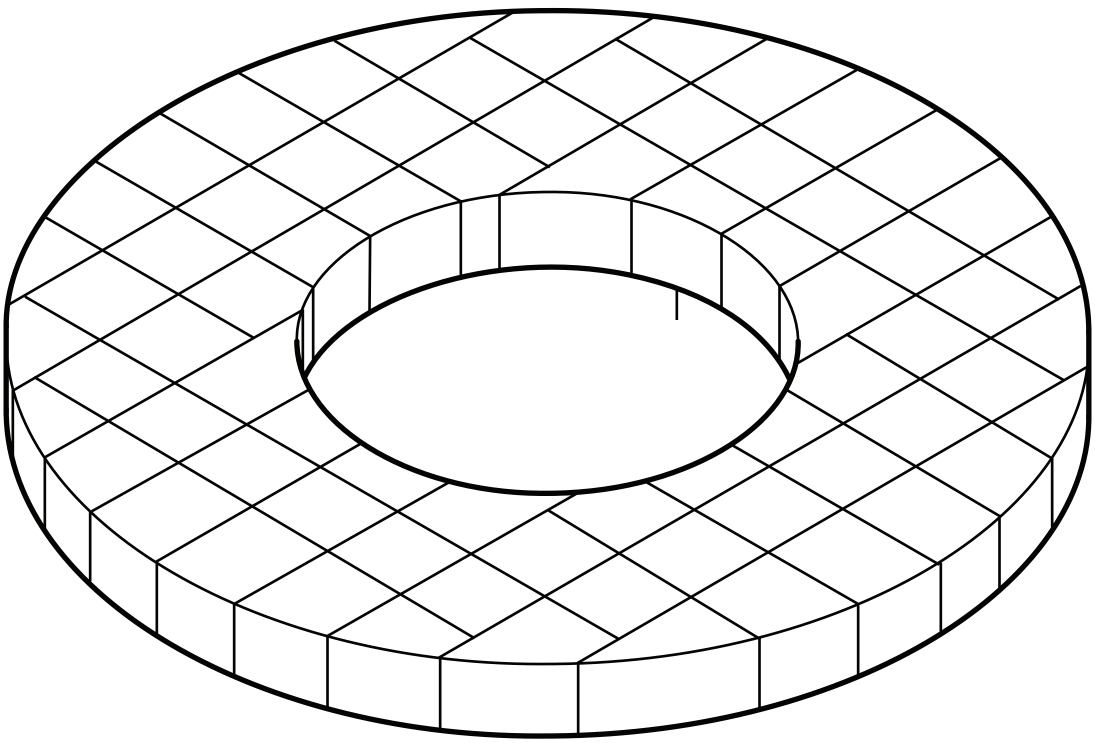


Basic QAD-CG Drywell Model

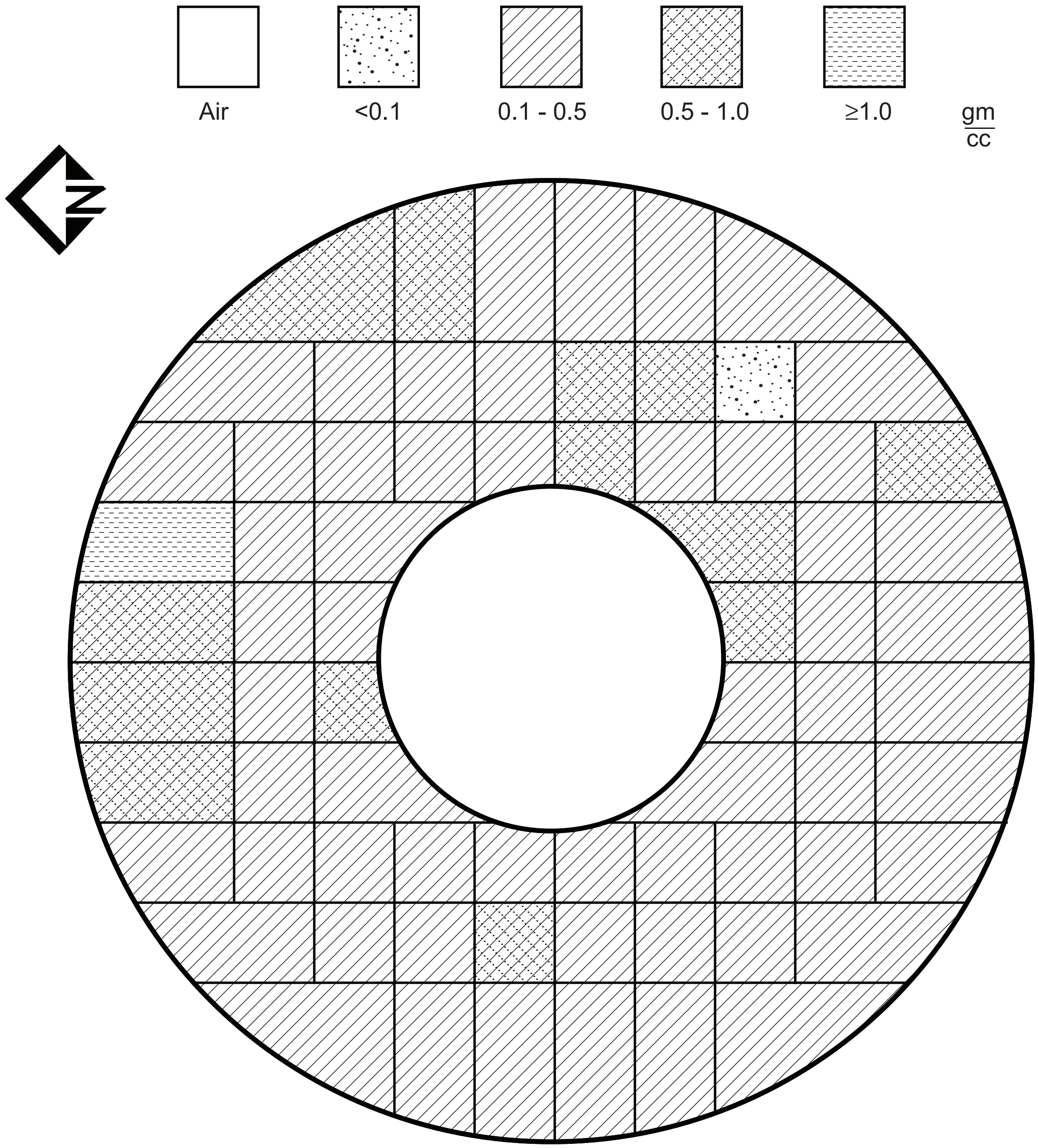
Draw. No. 970187.70 | Rev. | Figure J.F-2



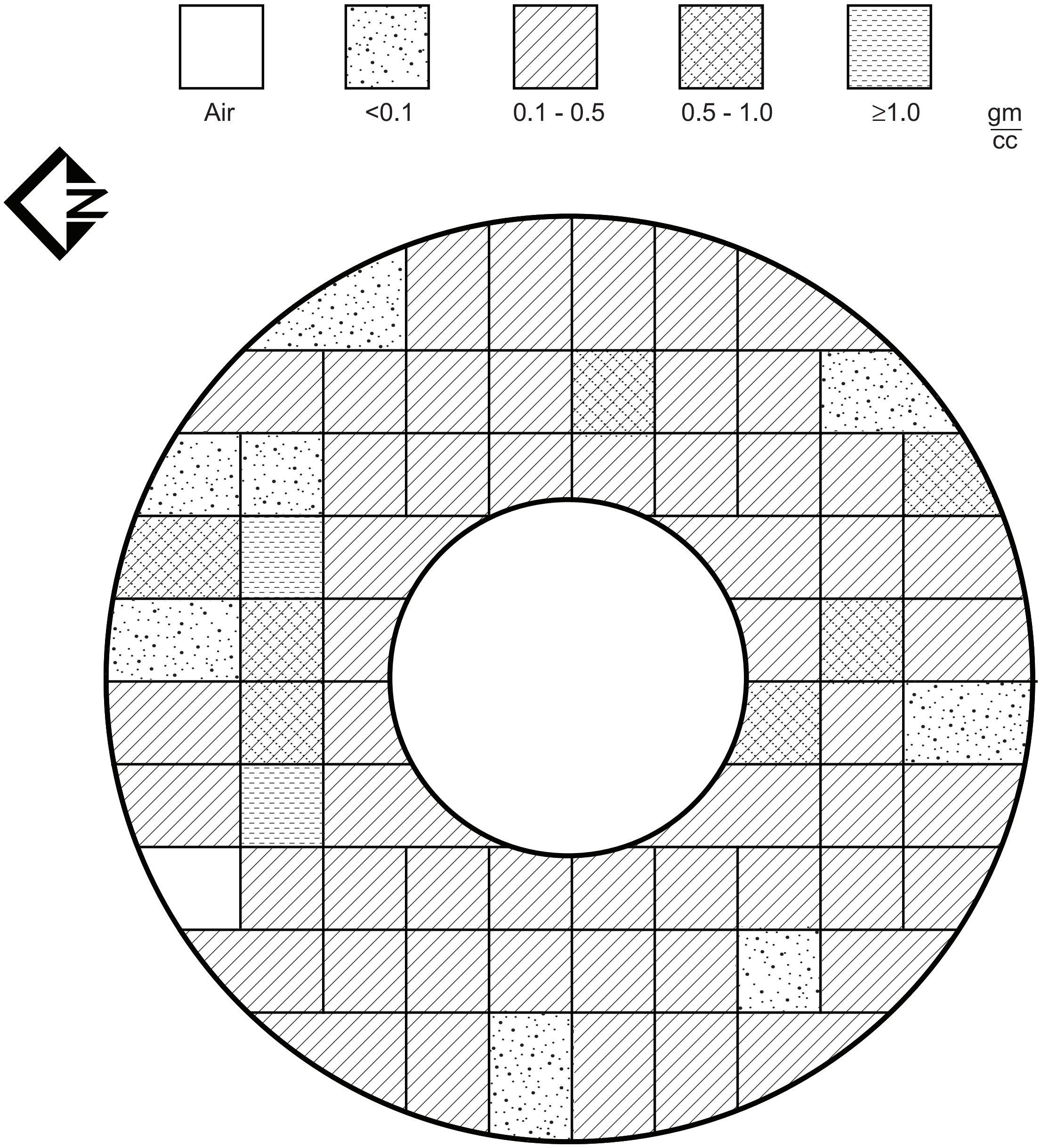
Isometric of Drywell Model



Isometric of El. 513 ft 6 in. to 520 ft 6 in.



Illustrative Only - Code Used 41 Density Groups

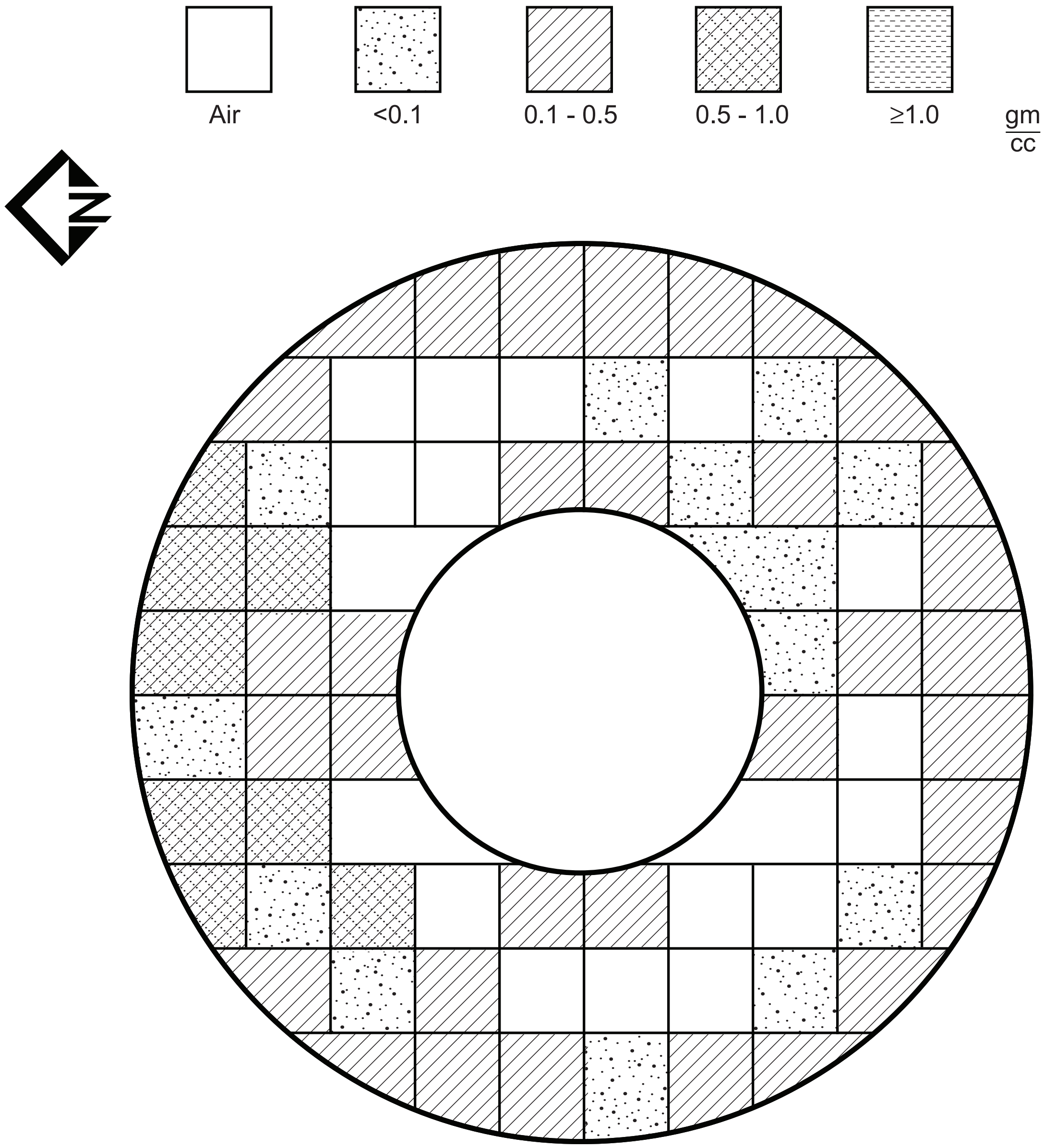


Illustrative Only - Code Used 41 Density Groups

Plan at El. 506 ft 6 in.

Columbia Generating Station
Final Safety Analysis Report

Draw. No. 970187.74 | Rev. | Figure J.F-6

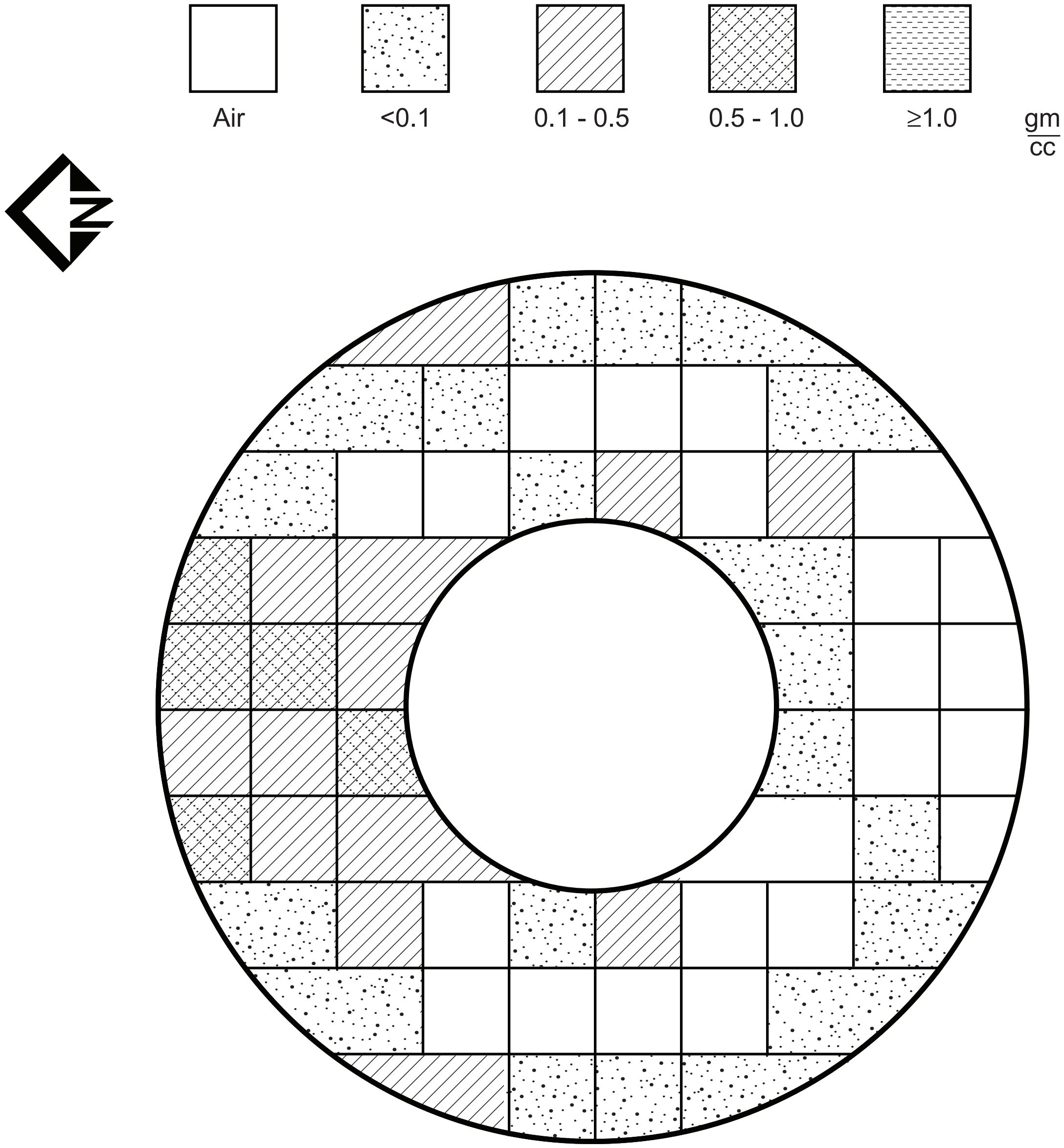


Illustrative Only - Code Used 41 Density Groups

Columbia Generating Station
Final Safety Analysis Report

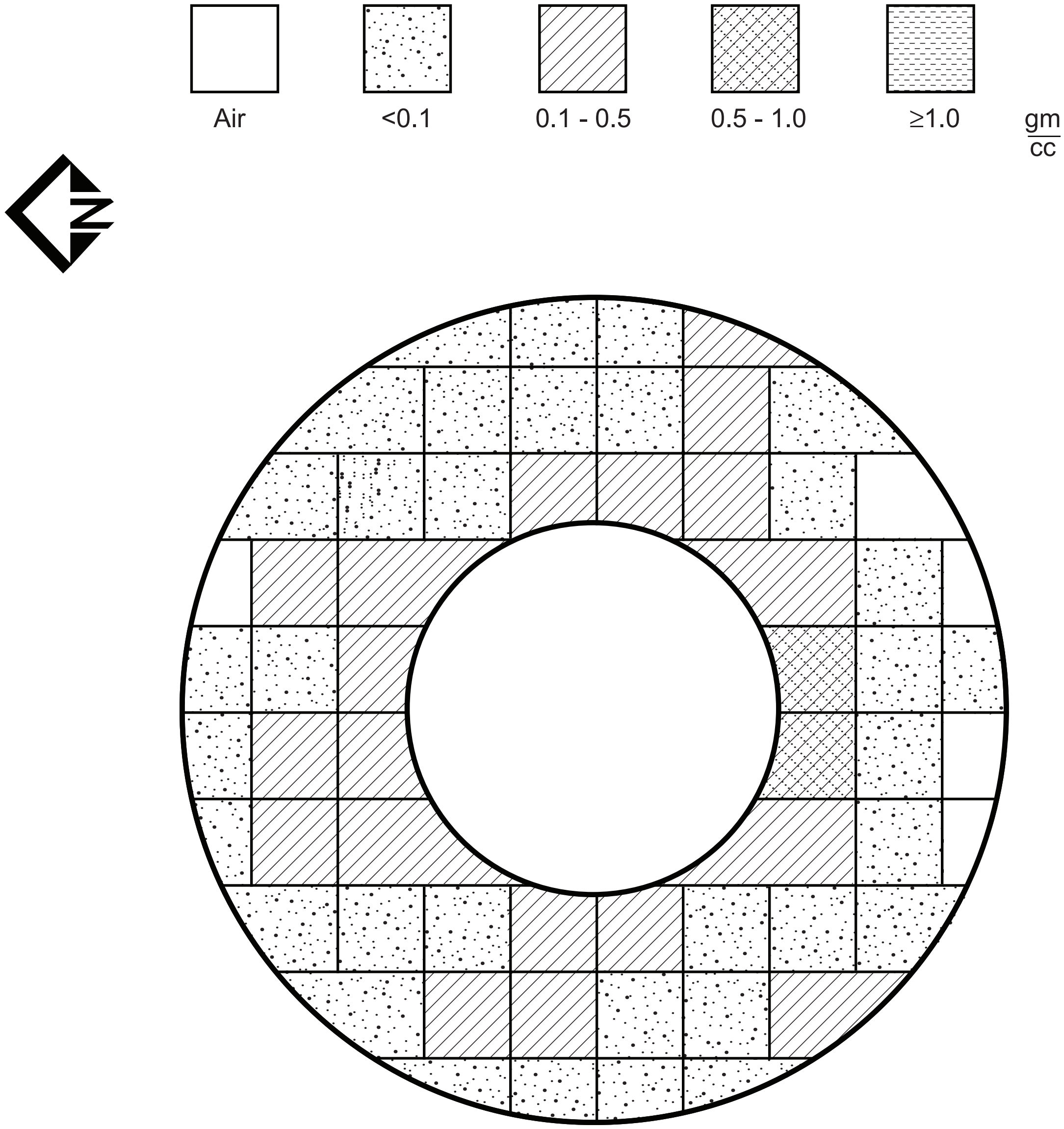
Plan at El. 513 ft 6 in.

Draw. No. 970187.75	Rev.	Figure J.F-7



Illustrative Only - Code Used 41 Density Groups

Plan at El. 520 ft 6 in.



Illustrative Only - Code Used 41 Density Groups

Attachment J.G

BETA DOSE CONTRIBUTION IN PRIMARY CONTAINMENT

The source volume used for the beta dose analysis in primary containment is a sphere surrounded by a shell of sufficient thickness to stop all outside beta particles from entering the source volume. This spherical source volume is conservative for any generalized source volume shape (the dose at the center of the sphere is higher than the dose at any point of any generalized source of equal total volume).

The assumptions used in the analysis are as follows:

a. Atmosphere inside the equipment casing is identical to the atmosphere in primary containment. This is conservative because there will actually be some delay in transport of the gaseous fission products into the equipment;

b. The initial beta source term used was 100% of core noble gases and 50% of core halogens (References J.7-2 and J.7-34);

c. Daughter products of the airborne noble gases and halogens are included in the calculation of the airborne dose which is conservative and was required by the use of ORIGEN2 as a source code (Reference J.7-8);

d. Plateout of halogens inside primary containment was utilized as allowed per Reference J.7-34. The dose contribution of fission products plated out on equipment casings was neglected. The deletion of dose contributions from fission products plated out on equipment casings is acceptable, since equipment surface areas are small relative to the available containment surface area. In addition, the betas emitted from plated out fission products would be absorbed in the equipment casing and, hence, would not affect internal components;

e. No primary to secondary containment leakage is assumed since it maximizes the beta source concentration in primary containment;

f. Activity is assumed to be uniformly distributed throughout the containment free volume which is reasonable, considering the mixing effects of the loss-of-coolant accident (LOCA) blowdown and the operation of the drywell fan coolers; and

g. A spherical volume representing the equipment casing will be used.

The beta dose to equipment is dependent on the internal volume size of the piece of equipment. The beta dose is determined through the use of an energy dependent geometry factor and a ratio of the internal equipment volume to an infinite cloud. The beta dose contribution is excluded from the worst case total integrated gamma doses of primary containment shown in Section J.6.1 and Tables J.F-1 and J.F-2. The beta dose contribution is also excluded from the value, pump, and fan tables for C1E/SRM equipment in a primary containment environment.

The discussion and development of beta dose rate variation due to beta energy distribution in a one-dimensional absorbing medium is also valid for primary containment analysis.

Thus, the dose as a function of volume radius is given by the dual relation:

$$D(r) = D\infty \frac{[1-\exp(-\mu_E r)]}{[1-\exp(-\mu_E r_E)]} \qquad 0 \le r \le r_E$$

This relation may be transformed to a function of volume by noting that $V = 4\pi r^3/3$.

Since μ_E and r_E vary for each beta energy, this equation cannot be solved analytically from the case of a mixture of many beta energies, which is the case at hand. However, since $D\infty$ for each beta energy is known (from the calculation of the semi-infinite source), $D_{E(v)}$ for each beta energy at a given volume may be determined. All contributions to the total dose at a given volume are then added together.

The volumes evaluated in this analysis were 10^3, 10^4, 10^5, and 10^6 cm^3. Table J.G-1 summarizes the semi-infinite volume for each beta energy group. Table J.G-1 also indicates the beta dose reduction factor for each of the beta energy groups at the finite beta volumes of interest. A plot of the integrated post-LOCA doses for these finite beta volumes is shown in Figure J.G-1. These results reflect the reduction in beta air dose from the semi-infinite medium air dose to a finite volume air dose.

The integrated beta infinite airborne dose for the primary containment as a function of time post-LOCA is shown in Figure J.G-2.

The absorbed beta dose within a physical target is not always equal to the beta dose at a mathematical point in air at the surface of that piece of equipment. The beta ionization energy (dose) deposited on the surface of a solid object is distributed in a thin surface layer to a depth equal to the beta range in the material. The relative material penetration of the different beta energy groups is used to provide a total integrated LOCA dose as a function of material depth.

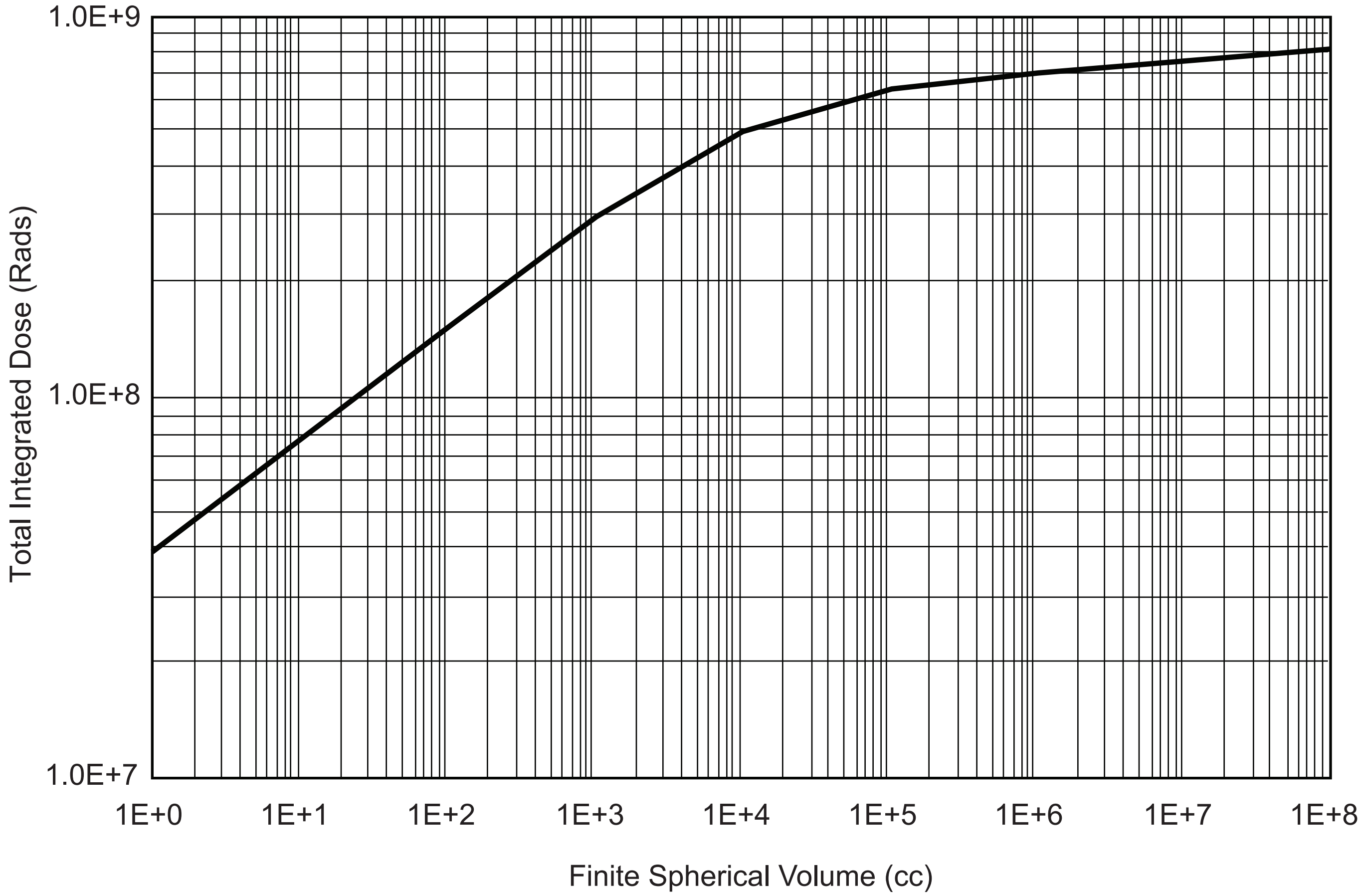
Finite volume beta dose reduction factors were determined for each of the 10 beta energy groups. These factors are used to provide total integrated LOCA dose as a function of material penetration to reduce volume exposure.

Thus, the integrated dose values (Figure J.G-1) can be used as the absorbed material dose with a standard order of magnitude for reduction for material beyond 0.030-in. thickness or a dose reduction versus thickness based on the range of beta penetration within the material can be calculated.

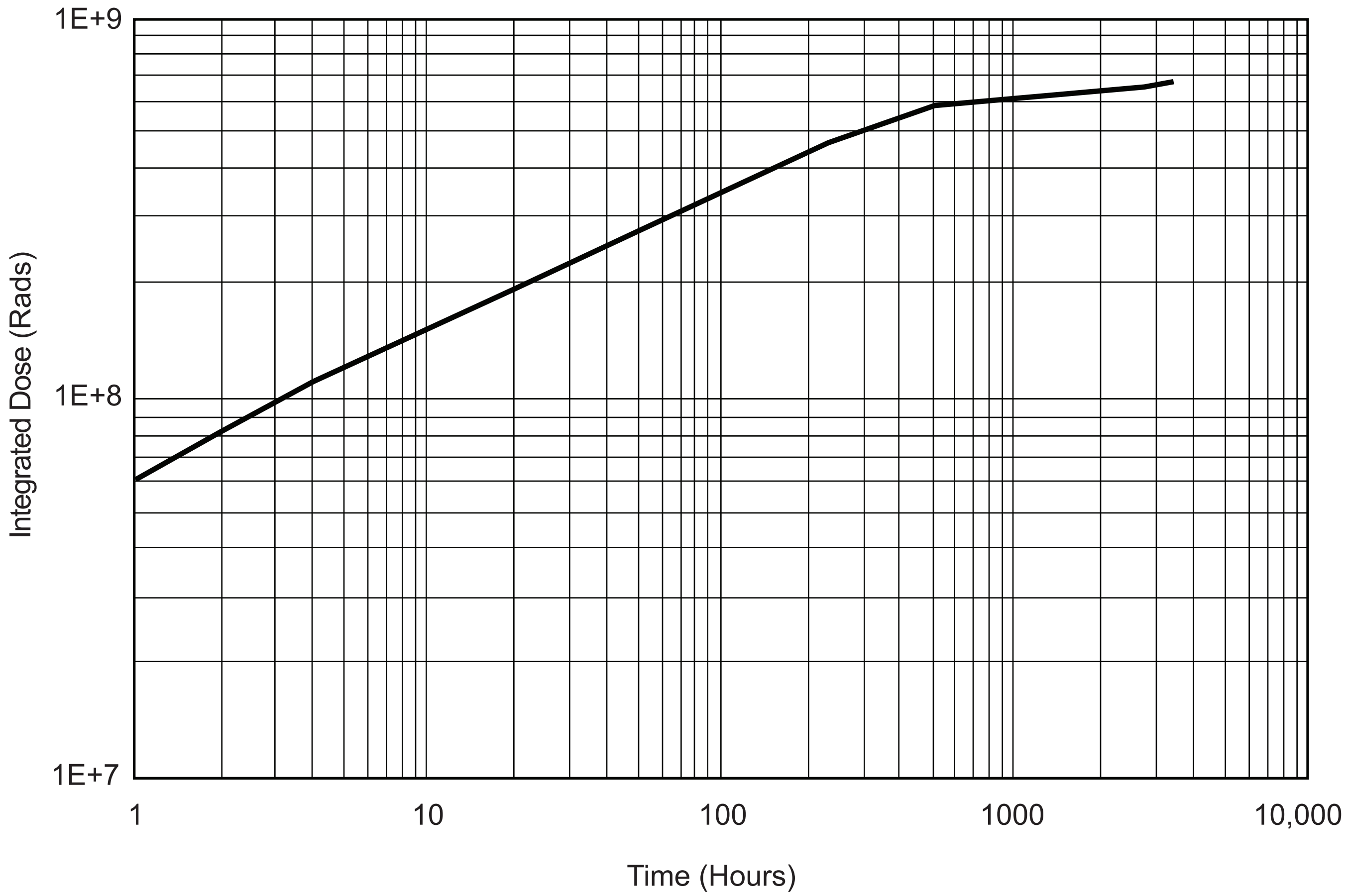
Table J.G-1

Dose Rate Reduction Factors for the
Post-Loss-of-Coolant Accident
Beta Energy Groups at Finite Volumes

Energy Group (MeV)	V_E (cm^3)	$\frac{D(V)}{D_\infty}$ for Volumes			
		10^3 cm^3	10^4 cm^3	10^5 cm^3	10^6 cm^3
0.02 - 0.10	120.0	1.0	1.0	1.0	1.0
0.10 - 0.20	4.08×10^5	0.486	0.763	0.960	1.0
0.20 - 0.40	8.58×10^6	0.260	0.478	0.755	0.955
0.40 - 0.70	1.36×10^8	0.127	0.254	0.468	0.744
0.70 - 1.0	1.04×10^9	0.0695	0.144	0.284	0.513
1.0 - 1.3	3.46×10^9	0.0467	0.0979	0.199	0.380
1.3 - 1.6	8.18×10^9	0.0348	0.0735	0.152	0.299
1.6 - 2.0	1.59×10^{10}	0.0276	0.0585	0.122	0.244
2.0 - 2.5	3.20×10^{10}	0.0215	0.0457	0.0960	0.195
2.5 - 3.0	6.47×10^{10}	0.0167	0.0356	0.0752	0.155



Total Integrated Beta Cloud Airborne Dose in Primary Containment as a Function of Size



Integrated Beta Infinite Airborne Dose for Primary Containment

Attachment J.H

VITAL AREAS AND ACCESS ROUTES ANALYZED FOR POST-LOSS-OF-COOLANT-ACCIDENT OPERATIONS

This attachment represents the methodology and assumptions used to determine the integrated dose to equipment and personnel for vital areas and access routes outside the reactor building during post-loss-of-coolant accident (LOCA) operations. The source term is the reactor building elevated vent with gaseous effluents being filtered by the standby gas treatment system (SGTS) prior to discharge to the atmosphere.

J.H.1 SOURCE OF RADIOACTIVITY TO THE REACTOR BUILDING ELEVATED VENT

Two contributions were considered as the source of the radioactivity to the reactor building elevated vent:

a. Leakage from the drywell to the reactor building and discharged via the SGTS to the reactor building elevated vent was assumed at a rate of

   0.5%/day = 2.1E-4/hr, and

b. Leakage from the assumed leaks on the main steam isolation valves (MSIVs) in the main steam tunnel was assumed at a rate of

   0.17%/day = 7.1E-5/hr (Reference J.7-56)

   Thus, the total leakage rate of activity from the primary system is assumed to be

   0.67%/day = 2.8E-4/hr.

J.H.1.1 Reactor Building Air Discharge Rate

All radioactivity considered outside the reactor building is assumed to discharge via the reactor building elevated vent.

The removal rate of the reactor building ventilation can be determined as follows:

$$\text{Removal rate} = \frac{\text{SGTS discharge rate}}{\text{Reactor building volume}}$$

SGTS discharge flow = 2430 ft^3/minute

Reactor building volume = 3.5E+6 ft^3

Thus, the removal rate is as follows representing one volume change per day:

$$\text{Removal rate} = \frac{(2430\ \text{ft}^3/\text{min})(60\ \text{min/hr})}{3.5\text{E}+6\ \text{ft}^3}$$

Removal rate = 4.2E-2/hr

This removal rate was used in the determination of radiation levels outside the reactor building.

J.H.2 POSTACCIDENT DESIGN DOSE (PADD)

A small computer program (PADD) was written to complete the calculations for the 18 nuclides over various time periods and sum the results. The equation used to determine the dose is as follows:

$$\text{Dose(rad)} = \text{DF(j)} \left(\frac{\chi}{Q_1} * \text{TF} * \frac{Q1_j + Q2_j}{3600}\right) \qquad \text{(J.H-1)}$$

where

Dose_{ji} = Rads from jth nuclide for the ith time period.

DF_j = Gamma dose factors for semi-infinite cloud $\frac{\text{Rad} * \text{m}^3}{\text{Ci} * \text{hr}}$ for jth nuclide.

χ/Q_1 = sec/m^3 for gaseous releases from the reactor building vent to the atmosphere for the ith time period.

RF = Removal fraction of activity via the standby gas treatment.

TF = 0.01 for particulates and iodines (99% efficiency or RF).

TF = 1.0 for noble gases (FSAR Section 6.5).

$Q1_j$ = Integrated activity of jth nuclide over ith time period that was released via leaks in the MSIVs (curies/hour).

$Q2_j$ = Integrated activity of jth nuclide over the ith time period that was released via leakage from the primary to secondary containment (curies/hour).

3600 = Conversion from hours to seconds.

J.H.2.1 Assumptions Used in χ/Q Calculation Methodology

The following equation from "Meteorology and Atomic Energy" (Reference J.7-31) was used to determine the χ/Q values shown in Table J.H-1.

$$\text{Dilution} = 2.22(M)\left(3.16 + 0.1\frac{S}{(Aex)^{1/2}}\right)^2 \frac{V_{mean}}{V_{ex}} \qquad \text{(J.H-2)}$$

= F_B (building wake factor)

M = 1 if intake and exhaust same elevation

M = 2 if intake and exhaust separated by one floor

M = 4 if intake is in building wake cavity

S = shortest intake exhaust arc length

Aex = exhaust area

V_{mean} = mean approach flow

V_{ex} = mean exhaust flow

The intake was assumed to be for category F weather conditions with a V_{mean} = 1 meter/sec.

Then $\chi/Q = \dfrac{1}{F_B \; R_R}$

F_B = building wake factor

R_R = release rate from reactor building vent (m^3/sec)

Concentration in reactor vent

$C_V = Q/R_R$

where

Q = curies/sec released

Concentration at intake C_I = C_V/F_B

C_I also = $Q(\chi/Q)$

Therefore:

$$C_i = \frac{C_V}{F_B} = Q(\chi / Q) = (\frac{Q}{F_B \quad R_R})$$

$$(\chi / Q) = \frac{1}{(F_B)(R_R)} = \text{total dilution factor } (D_F).$$

An F class stability was assumed for atmosphere conditions and 5% meteorology was then applied for time periods from 0 to 180 days. The dilution factors decrease by the following ratios for the time periods indicated.

Time (hr)	0-2	2-8	8-24	24-96	96-4320
Ratio	1.0	0.35	0.04	0.02	0.01

The dilution factors were multiplied by the 5% meteorology ratios to determine the actual χ/Q values used in these computations as presented in Table J.H-1.

J.H.2.2 Integrated Activity Equations Used in this Analysis

The time dependent activity of each nuclide being released from the MSIV was analyzed as follows:

$$\frac{dA1}{dt} = PA_o e\,(-\lambda + \frac{0.0067}{24})\,t \qquad \text{(J.H-3)}$$

where

P = Fractional leak from MSIV per hour (7.1 E-5/hr)

A_o = Initial activity of jth nuclide in primary containment at t = 0 hr

Thus, the activity concentration over a time period of t_1 to t_2 is

$$Q_1 = \int_{t_1}^{t_2} PA_o \; e \left[-(\lambda + 2.8E - 4)t \right]$$

or

$$Q_1 = \frac{PA_o}{(\lambda + 2.8E\text{-}4)} \left[e^{-(\lambda + 2.8E\text{-}4)\ t1} - e^{-(\lambda + 2.8E\text{-}4)\ t2} \right] \qquad \text{(J.H-4)}$$

The integrated activity concentration from the primary to secondary containment leakage, Q2, was calculated as follows:

$$\frac{dA_2}{dt} = KA_1 - L_2C_2 - \lambda A_2 \qquad \text{(J.H-5)}$$

where

K = Fractional leak rate from primary containment

$= \frac{0.005}{24hr} = 2.1E-4\ hr-1$

A_0 = Activity in primary containment

$= A_o \exp\left[-(\lambda + \frac{0.0067}{24})t\right]$

A_1 = Initial activity (Ci) at t = 0

$\frac{0.0067}{24}$ = Leakage removal rate from primary containment per hour

= 2.8E-4 hr^{-1}

L2 = Discharge rate from reactor building vent via standby gas treatment
= 2430 ft^3/min (60 min/hr)

= 1.46E+5 ft^3/hr

C2 = Activity concentration in secondary containment

A2 = Curies in secondary containment

V2 = Volume in secondary containment

Rearranging

$$\frac{dA2}{dt} = kA_o \exp\left[-(\lambda + 2.8E\text{-}4)t\right] - \frac{L2}{V2} A2 - \lambda A2$$

or (J.H-5A)

$$dA2 = kA_o e^{-F_1 t} - (\frac{L2}{V2} + \lambda)\ A2$$

$$dA2 = \left[kA_o e^{-F_1 t} - F_2\ A2 \right] dt$$

where

$$F_2 = \lambda + \frac{L2}{V2}$$

$$F_1 = (\lambda + 2.8E\text{-}4)$$

$$A2' = kA_1 - F_2 A2$$

$$A2' + F_2 A_2 = r(t)$$

$$r(t) = kA_o e^{-F_1 t} \qquad \text{(J.H-6)}$$

solving

$$A2 = e^{-F_2 t} \left[(\frac{kA_o}{F_2 - F_1}) \right] e^{(F_2 - F_1)t} + C$$

$$\text{at } t=o,\ A2 = o \qquad \text{(J.H-7)}$$

$$c = -0.005 A_o$$

Thus,

$$A_2(t) = 0.005 A_o e^{-\lambda t} (1 - e^{-(.0042)t})$$

$$Q2 = \frac{L2\ A_2(t)}{V2} \text{ or} \qquad \text{(J.H-8)}$$

$$Q2 = \frac{1.45E+5\ ft^3 / hr}{3.5E+6\ ft^3} \left[0.005 A_o e^{-\lambda j t} (1 - e^{-C2t}) \right]$$

where C2 = 0.042 (J.H-9)

thus,

$$Q2 = 2.11E\text{-}4 \ A_o e^{-\lambda_j t} \ (1 - e^{-C2t})$$

To determine the integrated concentration:

$$Q2(t) = 2.1E\text{-}4 A_o \int_{t_1}^{t_2} \left[e^{-\lambda t} - e^{-(\lambda + C2)t}\right] dt \qquad \text{(J.H-10)}$$

Solving,

$$Q2 = 2.1E\text{-}4 A_o \left[e^{-\lambda t_1} - e^{-\lambda t_2}\right] \frac{(e^{-C2t_1} - e^{-C_2 t_2})}{\lambda + C2} \qquad \text{(J.H-11)}$$

The values of Q1 and Q2 are substituted in for each nuclide and each time period. Then using equation (J.H-1), the dose commitment for each nuclide and each time period may be calculated. These results are presented in Section J.6.3.

Table J.H-1

Post-Loss-of-Coolant Accident χ/Q Values[a] Used for Calculations of Integrated Doses Outside the Reactor Building

Area	Time (hr) 0-2	2-8	8-24	24-96	96-4320 (180 days)
Security center	2.1E-4[b]	7.35E-5	8.4E-6	4.2E-6	2.1E-6
Auxiliary security center	1.2E-4	4.2E-5	4.8E-6	2.4E-6	1.2E-6
Sample analysis area (end of cycle)	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Nitrogen supply to accumulators	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Standby service water pump valves	1.2E-4	4.2E-5	4.8E-6	2.4E-6	1.2E-6
Remote shutdown room	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Switchgear room 1	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Switchgear room 2	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Radwaste control room	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Battery racks Direct current battery charger Motor control center	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Three motor control centers/ Three switchgears Direct current battery charger and rack	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Diesel oil tanks	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Solid radwaste control panel	2.6E-4	9.1E-5	1.0E-5	5.0E-6	2.5E-6
Sample of elevated release duct	8.0E-4	2.8E-4	3.2E-5	1.6E-5	8.0E-6

The standby service water pump valves are approximately 700 ft from the release point. This distance is too great to calculate a dilution based solely on a building wake factor. However, the conservative assumption will be made that the dilution at the valves is the same as at the auxiliary guard house which is only 420 ft.

[a] These values are based on an MSIV leak rate of 0.22%/day not the 0.17%/day previously listed. The results are acceptable and conservative for a leak rate of 0.17%/day.

[b] Read as 2.1 x 10^{-4} etc.